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OFFICE OF FOSSIL ENERGY

Cost and Performance Baseline for Fossil Energy Plants
Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity
Revision 3

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Disclaimer

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Table of Contents

Exhibits

Acronyms and Abbreviations

acfm	Actual cubic feet per minute
ACI	Activated carbon injection
AGR	Acid gas removal
ANSI	American National Standards Institute
AR	As received
Aspen	Aspen Plus®
atm	Atmosphere (14.696 psi)
BACT	Best available control technology
BAH	Booz Allen Hamilton
BEC	Bare erected cost
BFD	Block flow diagram
BFW	Boiler feedwater
Btu	British thermal unit
Btu/hr	British thermal units per hour
Btu/kWh	British thermal units per kilowatt hour
Btu/lb	British thermal units per pound
Btu/scf	British thermal units per standard cubic foot
CCF	Capital charge factor
CCS	Carbon capture and storage
CDR	Carbon dioxide recovery
cf	Cubic feet
CF	Capacity factor
cfm	Cubic feet per minute
CFR	Code of Federal Regulations
CGE	Cold gas efficiency
CH_4	Methane
CL	Closed-loop
cm	Centimeter
CO	Carbon monoxide
CO_2	Carbon dioxide
COE	Cost of electricity
COS	Carbonyl sulfide
CS	Carbon steel
CT	Combustion turbine
CTG	Combustion turbine-generator
CWP	Circulating water pump
CWS	Circulating water system
CWT	Cold water temperature
DCS	Distributed control system
DI	De-ionized
DLN	Dry low NOx
DOE	Department of Energy
DSI	Dry sorbent injection
EAF	Equivalent availability factor
EIA	Energy Information Administration
EMF	Emission modification factors
EPA	Environmental Protection Agency
EPC	Engineer/Procure/Construct
EPRI	Electric Power Research Institute
EOR	Enhanced oil recovery
ESPA	Energy Sector Planning and Analysis
FD	Forced draft
FE	Fossil energy
FG	Flue gas
FGD	Flue gas desulfurization
FOAK	First-of-a-kind
FRP	Fiberglass-reinforced plastic
ft	Foot, Feet
ft, w.g.	Feet of water gauge
FW	Feedwater
GADS	Generating Availability Data System
gal	Gallon
gal/MWh	Gallons per megawatt hour
GDP	Gross domestic product
GEE	General Electric Energy
GJ	Gigajoule
GJ/hr	Gigajoules per hour
gpd	Gallons per day
gpm	Gallons per minute
gr/100 scf	grains per one hundred standard cubic feet
GRI	Gas Research Institute
GWh	Gigawatt-hour
h, hr	Hour
H_2	Hydrogen
H_2O	Water
H_2S	Hydrogen sulfide
H_2SO_4	Sulfuric acid
HCl	Hydrochloric acid
Hg	Mercury
HHV	Higher heating value
hp	Horsepower
HP	High pressure
HRSG	Heat recovery steam generator
HSS	Heat stable salts
HV	High voltage

HVAC	Heating, ventilating, and air conditioning
HWT	Hot water temperature
Hz	Hertz
ICR	Information Collection Request
ID	Induced draft
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronics Engineers
IGCC	Integrated gasification combined cycle
IGV	Inlet guide vane
in. H_2O	Inch water
in. Hga	Inch mercury (absolute pressure)
in. W.C.	Inch water column
IOU	Investor-owned utility
IP	Intermediate pressure
IPM	Integrated Planning Model
ISO	International Organization for Standardization
kg/GJ	Kilograms per gigajoule
kg/hr	Kilograms per hour
kgmol	Kilogram mole
kgmol/hr	Kilogram moles per hour
kJ	Kilojoule
kJ/hr	Kilojoules per hour
kJ/kg	Kilojoules per kilogram
km	Kilometer
KO	Knockout
kPa	Kilopascal
kV	Kilovolt
kW, kWe	Kilowatt electric
kWh	Kilowatt-hour
kWt	Kilowatt thermal
LAER	Lowest Achievable Emission Rate
lb	Pound
lb/gal	Pound per gallon
lb/hr	Pounds per hour
lb/ft^2	Pounds per square foot
lb/MMBtu	Pounds per million British thermal units
lbmol	Pound mole
lbmol/hr	Pound moles per hour
lb/MWh	Pounds per megawatt hour
lb/TBtu	Pounds per trillion British thermal units
LHV	Lower heating value
LNB	Low NOx burner
LP	Low pressure
lpm	Liters per minute
LV	Low voltage
m	Meter
m/min	Meters per minute
m^3/min	Cubic meters per minute
md	Millidarcy (a measure of permeability)
MeOH	Methanol
mi	Mile
mpg	Miles per gallon
M	Thousand
Mbbl	Thousand barrels
Mcf	Thousand cubic feet
MAC	Main air compressor
MAF	Moisture and ash free
MATS	Mercury and Air Toxics Standards
MCR	Maximum continuous rate
MDEA	Methyldiethanolamine
MEA	Monoethanolamine
MHz	Megahertz
MJ/Nm^3	Megajoules per normal cubic meter
MM	Million
MMBtu	Million British thermal units
MMBtu/hr	Million British thermal units per hour
MMscf	Million standard cubic feet
MMscfd	Million standard cubic feet per day
MMscfy	Million standard cubic feet per year
mole%	Mole percent (percent by mole)
MNQC	Multi Nozzle Quiet Combustor
MPa	Megapascal
MTG	Methanol to gasoline
MVA	Mega volt-amps
MW	Megawatt
MWe	Megawatt electric
MWh	Megawatt-hour
MWt	Megawatt thermal
N_2	Nitrogen
N_2O	Nitrous oxide
N/A	Not applicable
NAAQS	National Ambient Air Quality Standards
NaOH	Sodium hydroxide
Neg.	Negligible
NEMA	National Electrical Manufacturers Association
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Council

NETL	National Energy Technology Laboratory
NG	Natural gas
NGCC	Natural gas combined cycle
NH_3	Ammonia
Nm^3	Normal cubic meter
Nm^3/hr	Normal cubic meter per hour
NOAK	N^{th}-of-a-kind
NOx	Oxides of nitrogen
NSPS	New Source Performance Standards
NSR	New Source Review
O_2	Oxygen
O&M	Operation and maintenance
OD	Outside diameter
OEM	Original equipment manufacturers
OFA	Overfire air
OPPA	Office of Program Planning & Analysis
OP/VWO	Over pressure/valve wide open
OSHA	Occupational Safety and Health Administration
PA	Primary air
PC	Pulverized coal
p.f.	Power factor
PFD	Process flow diagram
PM	Particulate matter
PM_{10}	Particulate matter measuring 10 µm (micrometers) or less
PO	Purchase order
POTW	Publicly owned treatment works
ppm	Parts per million
ppmv	Parts per million volume
ppmvd	Parts per million volume, dry
ppmw	Parts per million weight
ppmwd	Parts per million weight, dry
PAC	Powdered activated carbon
PSD	Prevention of significant deterioration
psi	Pounds per square inch
psia	Pound per square inch absolute
psid	Pound per square inch differential
psig	Pound per square inch gage
PSFM	Power systems financial model
PTFE	Teflon (Polytetrafluoroethylene)
PV	Present value
QGESS	Quality Guidelines for Energy System Studies
Qty	Quantity
R&D	Research and development
RD&D	Research, Development, and Demonstration
RH	Reheater
RSP	Required selling price
RTO	Regional transmission operations/operator
SC	Supercritical
SC PC	Supercritical Pulverized Coal
scf	Standard cubic feet
scfd	Standard cubic feet per day
scfh	Standard cubic feet per hour
scfm	Standard cubic feet per minute
Sch.	Schedule
scmh	Standard cubic meter per hour
SCR	Selective catalytic reduction process or equipment
SG	Specific gravity
SO_2	Sulfur dioxide
SOx	Oxides of sulfur
SNCR	Selective non-catalytic reduction process or equipment
SS	Stainless steel
SS Amine	SS Specialty Amine
st	Short ton
STG	Steam turbine generator
SubC PC	Subcritical pulverized coal
SWS	Sour water scrubber
Syngas	Synthetic gas
T&D	Transmission and distribution
TASC	Total as-spent cost
TCR	Total capital requirement
TEWAC	Totally Enclosed Water-to-Air Cooled
tonne	Metric ton (1,000 kg)
TOC	Total overnight cost
TPC	Total plant cost
tpd	Ton per day
tph	Tons per hour
TPI	Total plant investment
T&S	Transport and storage
U.S.	United States
USC	Ultra-supercritical
V	Volt
VOC	Volatile organic compound
VO&M	Variable operations and maintenance
V-L	Vapor liquid portion of stream (excluding solids)
vol%	Volume percent
WB	Wet bulb

wg	Water gauge
WGCU	Warm gas cleanup
WGS	Water gas shift
wt%	Weight percent
yr	Year
ZnO	Zinc oxide
ZnS	Zinc sulfide
$/GJ	Dollars per gigajoule
$/kW	Dollars per kilowatt
$/MMBtu	Dollars per million British thermal units
$M	Millions of dollars
µS/cm	micro Siemens per cm
°C	Degrees Celsius
°F	Degrees Fahrenheit
5-10s	Fifty hour work weeks

Executive Summary

This report presents the cost and performance results of pulverized coal (PC) and natural gas combined cycle (NGCC) plants, using a consistent technical and economic approach that reflects current market conditions. The primary value of this report lies not in the absolute accuracy of the capital cost estimates for the individual cases (estimated to be -15%/+30%), but in application of a consistent approach to allow meaningful comparisons of relative costs among the cases evaluated.

This report is part of an update to Volume 1 of a four volume series, which consists of:

- Volume 1: Bituminous Coal and Natural Gas to Electricity
- Volume 2: Coal to Synthetic Natural Gas and Ammonia (Various Coal Ranks)
- Volume 3: Low Rank Coal and Natural Gas to Electricity
- Volume 4: Bituminous Coal to Liquid Fuels

The cost and performance data have been updated for all PC and NGCC cases in this report, which constitutes Volume 1a. IGCC cases, previously integrated with the PC and NGCC cases in Revision 2a, will be incorporated separately into a Volume 1b. Section 6 has a revision control table listing the updates applied to this report.

Six power plant configurations were analyzed in this report, including four PC cases – two subcritical and two supercritical (SC) (with and without CO_2 capture); and two state-of-the-art 2013 F-Class combustion turbine-based NGCC plants (with and without CO_2 capture). While labeled as SC conditions, the SC steam cycle conditions utilized in this report are also generally representative of commercial plants characterized as ultra-supercritical (USC), particularly with respect to temperature (1100°F). Because efficiency is more sensitive to steam cycle temperature than pressure, the resulting performance is at or near that of top-performing commercially available USC PC plants. The Shell Cansolv CO_2 capture system utilized in this report is an amine-based solvent system. A summary of the case configurations in the report is shown in Exhibit ES-1.

Exhibit ES-1 Case configuration summary

Case	Unit Cycle	Steam Cycle, psig/°F/°F	Combustion Turbine	Boiler Technology	CO_2 Separation
B11A	PC	2400/1050/1050	N/A	Subcritical PC	N/A
B11B	PC	2400/1050/1050	N/A	Subcritical PC	Cansolv
B12A	PC	3500/1100/1100	N/A	SC PC	N/A
B12B	PC	3500/1100/1100	N/A	SC PC	Cansolv
B31A	NGCC	2400/1050/1050	2 x State-of-the-art 2013 F-Class	HRSG	N/A
B31B	NGCC	2400/1050/1050	2 x State-of-the-art 2013 F-Class	HRSG	Cansolv

All plant configurations were evaluated based on installation at a greenfield site. Capacity factors (CF) are assumed to approximately equal availability at 85% for all configurations. Achieving such capacity factors would require that these plants be near the top of the dispatch list.

The nominal net plant output for this study targets 550 megawatts (MW). The actual net output varies between technologies because the combustion turbines (CT) in the NGCC cases are manufactured in discrete sizes, but the boilers and steam turbines in the PC cases are readily available in a wide range of capacities. The result is that all of the PC cases have a net output of 550 MW, but the NGCC cases have net outputs of 559 MW (with capture) and 630 MW (without capture).

Environmental emission requirements are based on the mercury (Hg) and hydrochloric acid (HCl) limits, set by the March 2013 update to the Utility Mercury and Air Toxics Standards (MATS), and particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxide (NOx) limits, set by the February 2013 update to the New Source Performance Standards (NSPS).

Mercury, SO_2, NOx, and PM are actively controlled in all PC cases with dry sorbent injection (DSI) and activated carbon injection (ACI); wet flue gas desulfurization (FGD); low NOx burners (LNB) with overfire air (OFA) and selective catalytic reduction (SCR); and a baghouse, respectively. NOx is controlled in both NGCC cases with LNBs and an SCR.

All of the power plant configurations with carbon capture in this report are designed to achieve 90 percent capture, resulting in atmospheric CO_2 emissions at levels far below proposed EPA regulation.[1]

The methodology for developing the results presented in this report included performing steady-state simulations of the six power plant configurations using the Aspen Plus® (Aspen) process modeling software. The major plant equipment performance and process limits were based upon published reports, information obtained from vendors and users of the technology, performance data from design/build utility projects, and/or best engineering judgment.

This revision reflects varying degrees of technology vendor input for updates to the pollution control equipment for PC plants, and the CO_2 capture, CO_2 compression, and steam turbine technology for PC and NGCC plants; however, the final assessment of performance and cost was determined independently and is not endorsed by the individual vendors.

The mass and energy balance data from the Aspen models were used to size major pieces of equipment. These equipment sizes formed the basis for the cost estimations. Capital and operating costs for the major equipment and plant sub-systems were estimated by WorleyParsons based on simulation results and through scaled estimates from previous design/build projects. Assumed fuel prices are $2.78/GJ ($2.94/MMBtu) for Illinois No. 6 coal and $5.81/GJ ($6.13/MMBtu) for natural gas, both on a higher heating value (HHV) basis, delivered to the Midwest, and in 2011 United States (U.S.) dollars.[2]

The cost metric used in this study is the cost of electricity (COE), which is the revenue that must be received by the generator per net megawatt-hour produced to meet the desired internal rate of return on equity. The COE is assumed to escalate at a nominal annual rate equal to the general inflation rate, i.e., it remains constant or levelized in real terms over the operational period of the power plant. The cost of CO_2 transport and storage (T&S) of $11 per tonne of CO_2 is added to

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[1] The Environmental Protection Agency (EPA) proposed a new source performance standard on April 13, 2012, for emissions of carbon dioxide for new fossil fuel-fired electric utility generating units. As of the publication of this report, the proposed regulation has been published in the Federal Register. (46) The limit set by the proposed regulation is 1,100 lb-CO_2/MWh-gross.

[2] As specified in the Quality Guidelines for Energy System Studies (QGESS) document on "Fuel Prices for Selected Feedstocks in NETL Studies." (45)

the COE and represents a 62 km (100 mile) CO_2 pipeline and storage in a deep saline formation in the Midwest.[3]

The cost and performance of the various fossil fuel-based technologies will be important in determining which combination of technologies will be utilized to meet the demands of the power market in the future.

Selection of new generation technologies will depend on many factors, including:

- Capital and operating costs
- Overall energy efficiency
- Fuel prices
- COE
- Availability, reliability, and environmental performance
- Current and future regulations governing air, water, and solid waste discharges from fossil-fueled power plants
- Market penetration of clean coal technologies that have matured and improved as a result of recent commercial-scale demonstrations under the Department of Energy's (DOE) Clean Coal and Carbon Management Program

[3] Estimated using the FE/NETL CO_2 Transport Cost Model and the FE/NETL CO_2 Saline Storage Cost Model. Additional detail on development of these costs is available in the May 2014 revision of the QGESS document "Carbon Dioxide Transport and Storage Costs in NETL Studies." (27)

Results Analysis

Exhibit ES-2 shows the performance and environmental profile summary for all cases. A graph of the net plant efficiency (HHV basis) is provided in Exhibit ES-3.

Exhibit ES-2 Performance summary and environmental profiles

	Pulverized Coal Boiler				NGCC	
	PC Subcritical		PC Supercritical		State-of-the-art 2013 F-Class	
Case Name (Old Case Name)[A]	B11A (9)	B11B (10)	B12A (11)	B12B (12)	B31A (13)	B31B (14)
PERFORMANCE						
Gross Power Output (MWe)	581	644	580	642	641	601
Auxiliary Power Requirement (MWe)	31	94	30	91	11	42
Net Power Output (MWe)	550	550	550	550	630	559
Coal Flow rate (lb/hr)	412,005	516,170	395,053	495,578	N/A	N/A
Natural Gas Flow rate (lb/hr)	N/A	N/A	N/A	N/A	185,484	185,484
HHV Thermal Input (kW_t)	1,408,630	1,764,768	1,350,672	1,694,366	1,223,032	1,223,032
Net Plant HHV Efficiency (%)	39.0%	31.2%	40.7%	32.5%	51.5%	45.7%
Net Plant HHV Heat Rate (Btu/kWh)	8,740	10,953	8,379	10,508	6,629	7,466
Raw Water Withdrawal, gpm	5,538	8,441	5,105	7,882	2,646	4,023
Process Water Discharge, gpm	1,137	1,920	1,059	1,813	595	999
Raw Water Consumption, gpm	4,401	6,521	4,045	6,069	2,051	3,024
CO_2 Capture Rate (%)	0%	90%	0%	90%	0%	90%
CO_2 Emissions (lb/MMBtu)	204	20	204	20	119	12
CO_2 Emissions (lb/MWh-gross)	1,683	190	1,618	183	773	82
CO_2 Emissions (lb/MWh-net)	1,779	223	1,705	214	786	89
SO_2 Emissions (lb/MMBtu)	0.085	0.000	0.085	0.000	0.001	0.000
SO_2 Emissions (lb/MWh-gross)	0.700	0.000	0.673	0.000	0.006	0.000
NOx Emissions (lb/MMBtu)	0.085	0.075	0.088	0.078	0.003	0.003
NOx Emissions (lb/MWh-gross)	0.700	0.700	0.700	0.700	0.020	0.022
PM Emissions (lb/MMBtu)	0.011	0.010	0.011	0.010	0.000	0.000
PM Emissions (lb/MWh-gross)	0.090	0.090	0.090	0.090	0.000	0.000
Hg Emissions (lb/TBtu)	0.363	0.321	0.377	0.333	0.000	0.000
Hg Emissions (lb/MWh-gross)	3.00E-06	3.00E-06	3.00E-06	3.00E-06	0.00E+00	0.00E+00

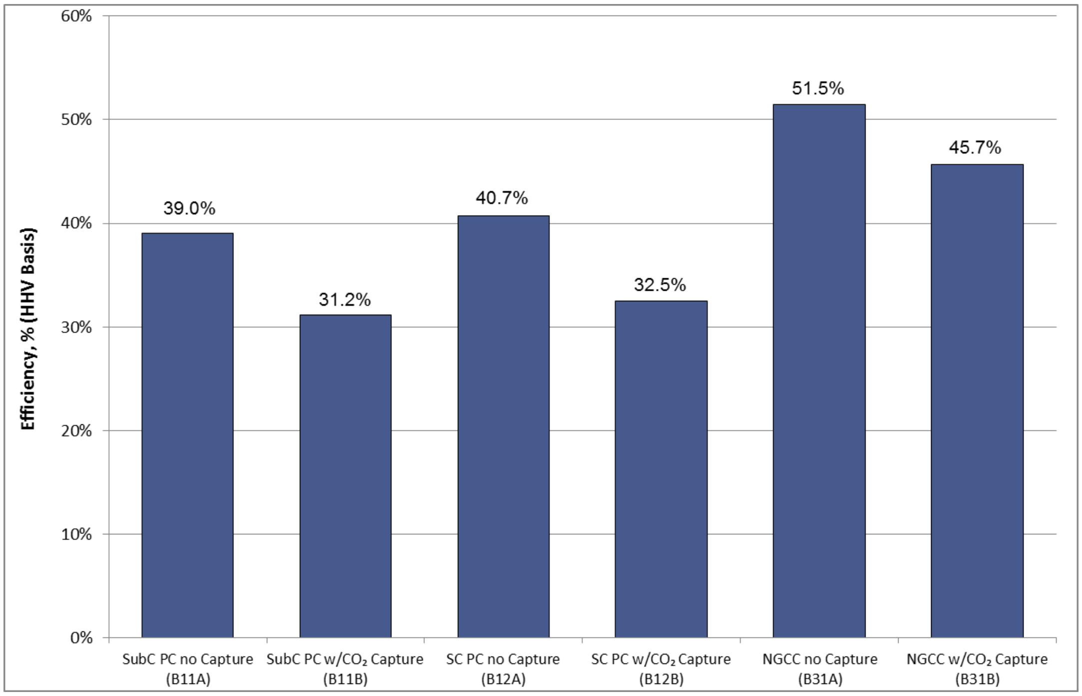
[A] Previous versions of this report used a different naming convention. The old case numbers are provided here, paired with the new case numbers for reference.

The primary conclusions that can be drawn are:

- The NGCC cases have the highest net efficiency of all the technologies, both without CO_2 capture (51.5 percent) and with CO_2 capture (45.7 percent). The next highest efficiency is the non-capture SC PC case, with an efficiency of 40.7 percent.
- For the PC cases, adding CO_2 capture results in a relative efficiency penalty of 20 percent (8 percentage points).
- For the NGCC case, adding CO_2 capture results in a relative efficiency penalty of 11 percent (6 percentage points). The NGCC penalty is less than the PC penalty because:
  - Natural gas is less carbon intensive than coal (based on the fuel compositions used in this study, natural gas contains 32 lb carbon/MMBtu of heat input and coal contains 56 lb/MMBtu).
  - The NGCC non-capture plant is more efficient, thus there is less total CO_2 to capture and compress (NGCC non-capture CO_2 emissions are approximately 54-

56 percent lower than the PC cases) when normalized to equivalent net power outputs.
  - These effects are offset slightly by the lower concentration of CO_2 in the NGCC flue gas (4% vs. 13% for PC). When normalized to CO_2 captured, the energy penalty is 0.16 kWh and 0.13 kWh per lb of CO_2 captured for NGCC and PC, respectively.
- Estimated emissions of Hg, PM, NOx, and SO_2 are all at or below the applicable regulatory limits currently in effect.

Exhibit ES-3 Net plant efficiency (HHV basis)



Source: NETL

The cost results for all cases are provided in Exhibit ES-4. A graph of the COE is provided in Exhibit ES-5.

Exhibit ES-4 Cost summary

	Pulverized Coal Boiler*				NGCC*	
	PC Subcritical		PC Supercritical		State-of-the-art 2013 F-Class	
Case Name	B11A	B11B	B12A	B12B	B31A	B31B
COST						
Total Plant Cost (2011$/kW)	1,960	3,467	2,026	3,524	685	1,481
Bare Erected Cost	1,582	2,665	1,646	2,716	561	1,117
Home Office Expenses	158	257	165	263	51	97
Project Contingency	220	427	216	430	73	193
Process Contingency	0	118	0	115	0	75
Total Overnight Cost (2011$MM)	1,336	2,346	1,379	2,384	528	1,008
Total Overnight Cost (2011$/kW)	2,429	4,267	2,507	4,333	838	1,804
Owner's Costs	469	800	480	809	154	323
Total As-Spent Cost (2011$/kW)	2,755	4,865	2,842	4,940	901	1,945
COE ($/MWh) (excluding T&S)	82.0	133.5	82.3	133.2	57.6	83.3
Capital Costs	37.8	71.0	39.0	72.2	11.8	26.9
Fixed Costs	9.3	15.1	9.6	15.4	3.4	6.6
Variable Costs	9.2	15.1	9.1	14.7	1.7	4.0
Fuel Costs	25.7	32.2	24.6	30.9	40.7	45.9
COE ($/MWh) (including T&S)	82.0	143.5	82.3	142.8	57.6	87.3
CO_2 T&S Costs	0.0	10.0	0.0	9.6	0.0	4.0
CO_2 Captured Cost (excluding T&S), $/tonne	N/A	56.2	N/A	58.2	N/A	71.1
CO_2 Avoided Cost (including T&S), $/tonne	N/A	91.0	N/A	89.4	N/A	93.8

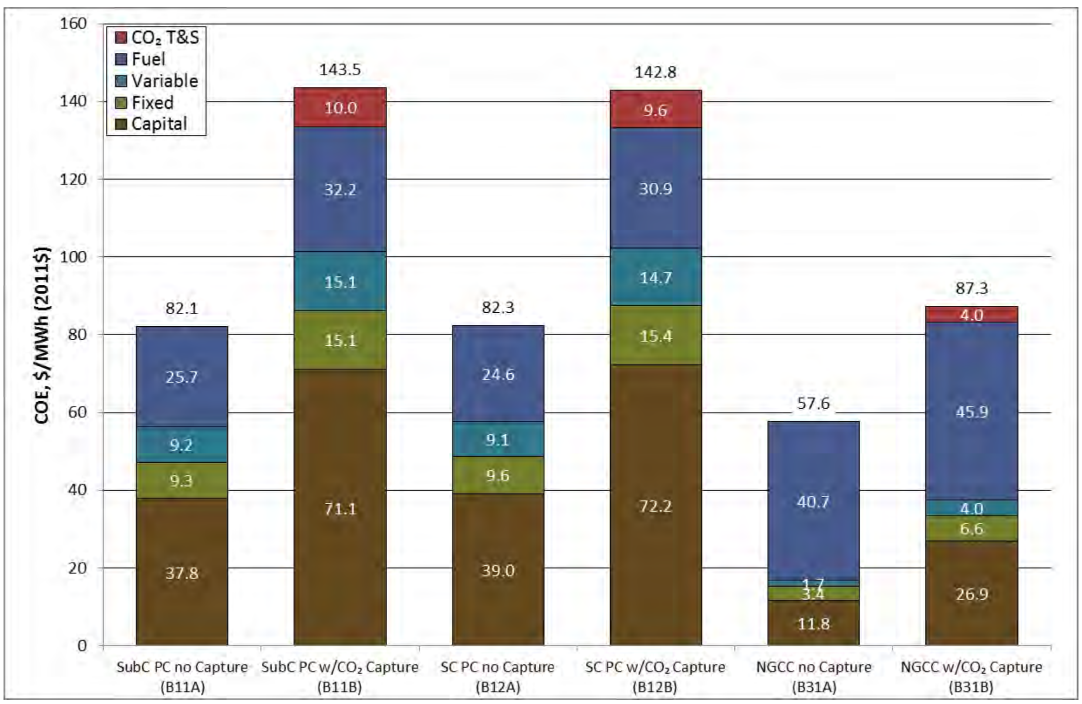
*Cases without capture use conventional financing; all others use high-risk financial asssumptions consistent with NETL's "QGESS: Cost Estimation Methodology for NETL Assessments of Power Plant Performance." (1)

The primary conclusions that can be drawn are:

- Based on total overnight cost (TOC) in $/kW, NGCC capital costs are approximately 34% and 42% of the PC capital costs for non-capture and capture cases, respectively.
- Capital costs for subcritical and SC PC are essentially equivalent within the accuracy of this report for a constant power output.
- The addition of CO_2 capture increases the capital costs – normalized to an equivalent net power output – by 74% and 115% for PC and NGCC, respectively.
- NGCC plant COEs are 70% and 61% of the PC plant COEs, for non-capture and capture cases, respectively.
- The difference between the SC PC and subcritical PC COEs is minor, given the level of accuracy of the study estimate.
- The capital cost component represents the largest portion of the COE in PC cases, ranging from 46-51 percent of the total COE. The capital cost in NGCC cases represents 21-31 percent of the total COE.
- The fuel cost component represents the largest portion of the COE in NGCC cases, ranging from 53-71 percent of the total COE. The fuel cost in PC cases represents 22-31 percent of the total COE.

- CO_2 T&S costs add between $4/MWh (NGCC) and $10/MWh (PC) to the COE, which is less than 7 percent of the total for all capture cases.
- The NGCC case incurs a smaller increase in COE by the addition of CO_2 capture than PC cases (52 percent versus approximately 75 percent).
- Despite the higher net plant efficiency and lower increase in COE, both the costs of CO_2 avoided and captured are higher for NGCC cases than PC cases (costs of CO_2 avoided are essentially equivalent within the accuracy of this report with the NGCC case having a 3-5 percent greater cost than the PC cases) due to the relatively lower concentration and amount of CO_2 available for capture.
- In the event that future legislation assigns a cost to carbon emissions, all of the technologies examined in this report will become more expensive. The technologies without carbon capture will be impacted to a larger extent than those with carbon capture, and coal-based technologies will be impacted more than natural gas-based technologies.

Exhibit ES-5 COE by cost component*



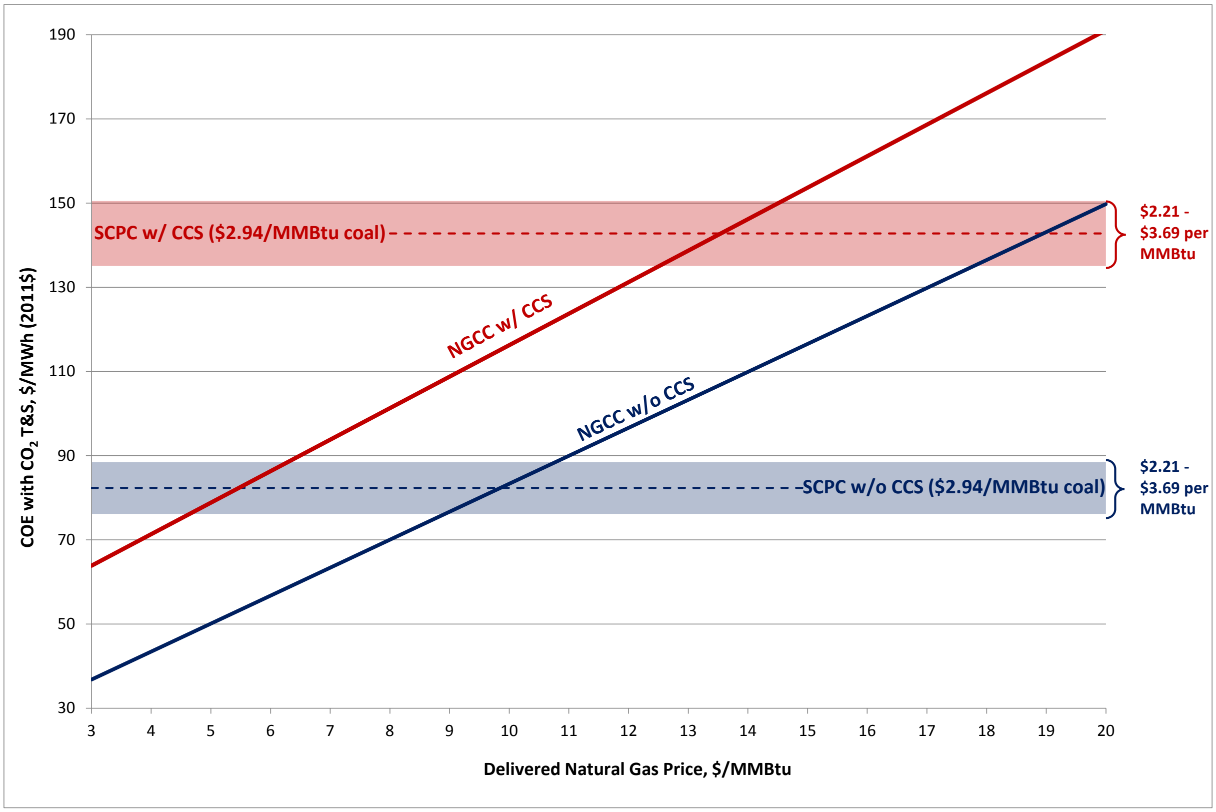
Source: NETL

*Cases without capture use conventional financing; all others use high-risk financial asssumptions consistent with NETL's "QGESS: Cost Estimation Methodology for NETL Assessments of Power Plant Performance." (1)

Sensitivities

Exhibit ES-6 shows the COE sensitivity to fuel costs for the SC PC and NGCC cases. The bands for the SC PC cases represent a variance of the coal price from $2.21 - $3.69/MMBtu (±25% of the study value $2.94/MMBtu). This highlights regions of competitiveness of NGCC with SCPC systems for cases with and without CCS as a function of delivered natural gas price. As an example, at a coal cost of $3/MMBtu, the COE of the non-capture SC PC case equals non-capture NGCC at a natural gas price of approximately $10.0/MMBtu. Similarly, the SC PC and NGCC cases with capture have equivalent COEs at a coal price of $3.0/MMBtu and a natural gas price of approximately $13.5/MMBtu.

Exhibit ES-6 COE sensitivity to fuel costs



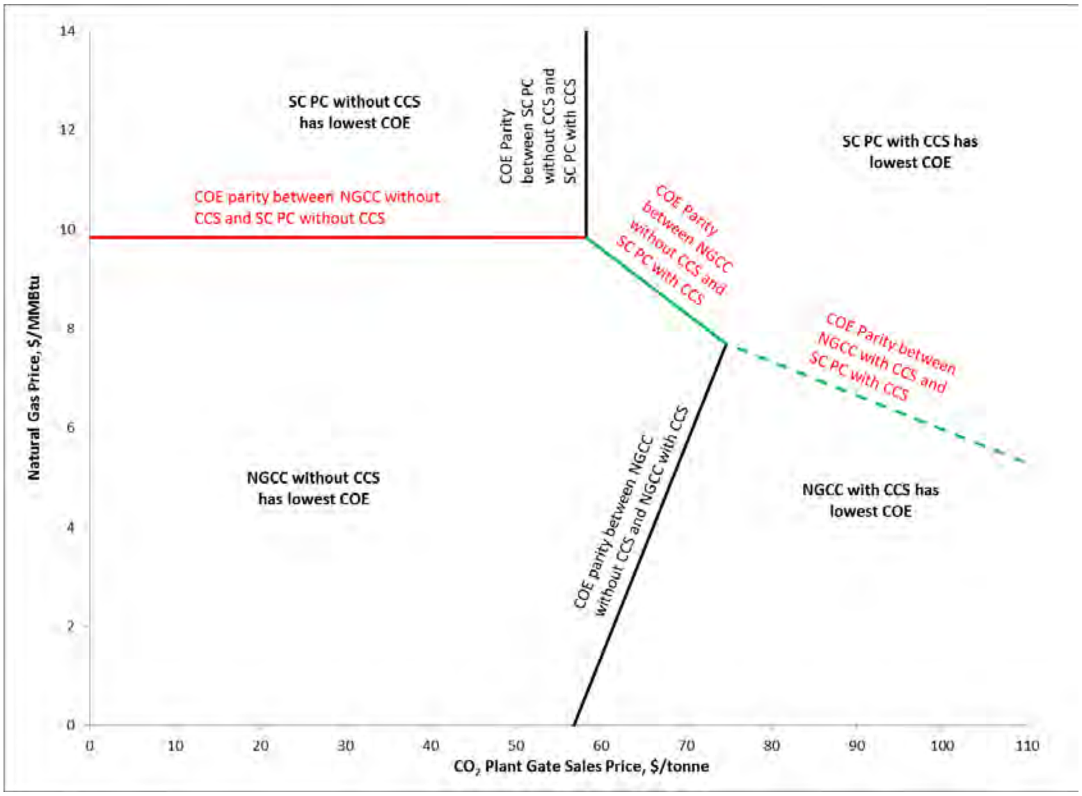
Source: NETL

Sale of the captured CO_2 for utilization and storage in CO_2 enhanced oil recovery (EOR) has the potential to provide a revenue stream to both the SC PC and NGCC capture plant configurations. The plant gate CO_2 sales price will ultimately depend on a number of factors including plant location and crude oil prices. The impact of CO_2 sales price and the implications on the competitiveness of the capture technologies can be considered in a "phase diagram" type plot, as shown in Exhibit ES-7. The lines in the plot represent COE parity between different pairs of technologies.

The plot demonstrates the following points:

- Non-capture plants are the low-cost option below a first-year CO_2 price of $56/tonne ($51/ton).
- NGCC is preferred when natural gas prices are below $10/MMBtu with a CO_2 revenue below $56/tonne (and a capacity factor of 85 percent). The natural gas price that provides parity between the various NGCC and PC cases drops off at higher CO_2 revenues reaching $6/MMBtu at approximately $100/tonne ($91/ton).

Exhibit ES-7 Lowest cost technology options at various natural gas and CO_2 sales prices



Source: NETL

Special Considerations on Reported Costs

Capital Costs:

The capital cost estimates documented in this report reflect an uncertainty range of -15%/+30%, consistent with AACE Class 4 cost estimates (i.e., feasibility study) (2) (3) (4), based on the level of engineering design performed. In all cases, the report intends to represent the next commercial offering and relies on vendor cost estimates for component technologies. It also applies process contingencies at the appropriate subsystem levels in an attempt to account for expected but undefined costs, which can be a challenge for emerging technologies.

Costs of mature technologies and designs:

The cost estimates for plant designs that only contain fully mature technologies, which have been widely deployed at commercial scale (e.g., PC and NGCC power plants without CO_2 capture), reflect nth-of-a-kind (NOAK) on the technology commercialization maturity spectrum. The costs of such plants have dropped over time due to "learning by doing" and risk reduction benefits that result from serial deployments as well as from continuing R&D.

Costs of emerging technologies and designs:

The cost estimates for plant designs that include technologies that are not yet fully mature (e.g., any plant with CO_2 capture) use the same cost estimating methodology as the mature plant designs, which does not fully account for the unique cost premiums associated with the initial, complex integrations of emerging technologies in a commercial application. Thus, it is anticipated that initial deployments of the capture plants may incur costs higher than those reflected within this report.

Other factors:

Actual reported project costs for all of the plant types are also expected to deviate from the cost estimates in this report due to project- and site-specific considerations (e.g. contracting strategy, local labor costs, seismic conditions, water quality, financing parameters, local environmental concerns, weather delays, etc.) that may make construction more costly. Such variations are not captured by the reported cost uncertainty.

Future Cost Trends:

Continuing research, development, and demonstration (RD&D) is expected to result in designs that are more advanced than those assessed by this report, leading to costs that are lower than those estimated herein.

1 Introduction

The objective of this report is to present an accurate, independent assessment of the cost and performance of pulverized coal (PC) and natural gas combined cycle (NGCC) plants, using a consistent technical and economic approach that reflects current market conditions.

This report is part of an update to Volume 1 of the four volume series, which consists of:

- Volume 1: Bituminous Coal and Natural Gas to Electricity
- Volume 2: Coal to Synthetic Natural Gas and Ammonia (Various Coal Ranks)
- Volume 3: Low Rank Coal and Natural Gas to Electricity
- Volume 4: Bituminous Coal to Liquid Fuels

The cost and performance data have been updated for all PC and NGCC cases in this report, which constitutes Volume 1a. IGCC cases, previously integrated with the PC and NGCC cases in Revision 2a, are incorporated separately into a Volume 1b. (5) Section 6 has a revision control table listing the updates applied to this report.

Selection of new generation technologies will depend on many factors, including:

- Capital and operating costs
- Overall energy efficiency
- Fuel prices
- Cost of Electricity (COE)
- Availability, reliability, and environmental performance
- Current and future regulations governing air, water, and solid waste discharges from fossil-fueled power plants
- Market penetration of clean coal technologies that have matured and improved as a result of recent commercial-scale demonstrations under the Department of Energy's (DOE) Clean Coal and Carbon Management Program

Six power plant configurations were analyzed in this report, including four PC cases – two subcritical and two supercritical (SC) (with and without CO_2 capture); and two state-of-the-art 2013 F-Class combustion turbine-based NGCC plants (with and without CO_2 capture). While labeled as SC conditions, the SC steam cycle conditions utilized in this report are also generally representative of commercial plants characterized as ultra-supercritical (USC), particularly with respect to temperature (1,100°F). Because efficiency is more sensitive to steam cycle temperature than pressure, the resulting performance is at or near that of top-performing commercially available USC PC plants. The Shell Cansolv CO_2 capture system utilized in this report is an amine-based solvent system. A summary of the case configurations in the report is shown in Exhibit 1-1.

This revision reflects varying degrees of technology vendor input for updates to the pollution control equipment for PC plants, and the CO_2 capture, CO_2 compression, and steam turbine technology for PC and NGCC plants; however, the final assessment of performance and cost was determined independently and is not endorsed by the individual vendors.

Generating Unit Configurations

A summary of plant configurations considered in this report is presented in Exhibit 1-1. Components for each plant configuration are described in more detail in the corresponding report sections for each case.

The NGCC cases have different gross and net power outputs because of the combustion turbine (CT) size constraint. The state-of-the-art 2013 F-class CT used to model the NGCC cases comes in a standard size of 211 MW when operated at conditions set by the International Standards Organization (ISO). Each case uses two CTs for a combined gross output of 422 MW. In the combined cycle a heat recovery steam generator (HRSG) extracts heat from the CT exhaust to power a steam turbine.

The net output in the NGCC CO_2 capture case is significantly reduced, compared to the non-capture case due to the high auxiliary power load and significant extraction steam requirement of the CO_2 capture system.

While the two CTs provide 422 MW gross output in both NGCC cases, the overall combined cycle gross output ranges from 601 to 641 MW, which results in a range of net output from 559 (Case B31B) to 630 MW (Case B31A). The natural gas feed rate is held constant in both cases at 84,134 kg/hr (185,484 kb/hr).

All four PC cases have a net output of 550 MW. The boiler and steam turbine industry's ability to match unit size to a custom specification has been commercially demonstrated enabling a common net output comparison of the PC cases in this report. The coal feed rate was increased in the CO_2 capture cases to increase the gross steam turbine output and account for the higher auxiliary load, resulting in a constant net output.

The balance of this report is organized as follows:

- Chapter 2 provides the basis for technical, environmental, and cost evaluations.
- Chapter 3 describes the PC technologies modeled and presents the results for the four PC cases.
- Chapter 4 describes the NGCC technologies modeled and presents the results for the two NGCC cases.
- Chapter 5 provides a cross comparison of NGCC and PC cases
- Chapter 6 includes a record of report revisions.

Exhibit 1-1 Case descriptions

Case (Old Case Name[A])	Unit Cycle	Steam Cycle, psig/°F/°F	Combustion Turbine	Boiler Technology	Oxidant	Sulfur Removal/ Recovery	PM Control	NOx Control	CO_2 Separation[B]
B11A (9)	PC	2400/1050/1050	N/A	Subcritical PC	Air	Wet FGD/ Gypsum	Baghouse	LNB w/OFA and SCR	N/A
B11B (10)	PC	2400/1050/1050	N/A	Subcritical PC	Air	Wet FGD/ Gypsum	Baghouse	LNB w/OFA and SCR	Cansolv
B12A (11)	PC	3500/1100/1100	N/A	SC PC	Air	Wet FGD/ Gypsum	Baghouse	LNB w/OFA and SCR	N/A
B12B (12)	PC	3500/1100/1100	N/A	SC PC	Air	Wet FGD/ Gypsum	Baghouse	LNB w/OFA and SCR	Cansolv
B31A (13)	NGCC	2400/1050/1050	2 x State-of-the-art 2013 F-Class	HRSG	Air	N/A	N/A	LNB and SCR	N/A
B31B (14)	NGCC	2400/1050/1050	2 x State-of-the-art 2013 F-Class	HRSG	Air	N/A	N/A	LNB and SCR	Cansolv

[A]Previous versions of this report used a different naming convention. The old case numbers are provided here, paired with the new case numbers for reference.

[B]All cases have a nominal 90 percent removal rate based on the total feedstock minus unburned carbon in ash (PC cases). The rate of CO_2 capture from the flue gas in the Cansolv systems varies. An explanation for the difference is provided in Section 2.4.3. All cases sequester the CO_2 offsite.

2 General Evaluation Basis

For each of the plant configurations analyzed in this report an Aspen Plus® (Aspen) model was developed and used to generate material and energy balances, which were, in turn, used to provide a design basis for items in the major equipment list. The equipment list and material balances were used as the basis for generating the capital and operating cost estimates. Performance and process limits were based upon published reports, information obtained from vendors and users of the technology, performance data from design/build utility projects, and/or best engineering judgment. Capital and operating costs were estimated by WorleyParsons based on simulation results and through scaled estimates from previous design/build projects. Ultimately, a COE was calculated for each of the cases and is reported as the revenue requirement figure-of-merit.

The balance of this section discusses the design basis common to all technologies, as well as environmental targets and cost assumptions used in the study. Technology specific design criteria are covered in subsequent chapters.

2.1 Site Characteristics

All plants in this report are assumed to be located at a generic plant site in Midwestern U.S., with site characteristics and ambient conditions as presented in Exhibit 2-1 and Exhibit 2-2. The ambient conditions are the same as ISO conditions.

Exhibit 2-1 Site characteristics

Parameter	Value
Location	Greenfield, Midwestern U.S.
Topography	Level
Size (Pulverized Coal), acres	300
Size (Natural Gas Combined Cycle), acres	100
Transportation	Rail or Highway
Ash Disposal	Off-Site
Water	50% Municipal and 50% Ground Water

Exhibit 2-2 Site ambient conditions

Parameter	Value
Elevation, (ft)	0
Barometric Pressure, MPa (psia)	0.101 (14.696)
Average Ambient Dry Bulb Temperature, °C (°F)	15 (59)
Average Ambient Wet Bulb Temperature, °C (°F)	10.8 (51.5)
Design Ambient Relative Humidity, %	60
Cooling Water Temperature, °C (°F)[A]	15.6 (60)
Air composition based on published psychrometric data, mass %	
N_2	72.429
O_2	25.352
Ar	1.761
H_2O	0.382
CO_2	0.076
Total	100.00

[A]The cooling water temperature is the cooling tower cooling water exit temperature. This is set to 8.5°F above ambient wet bulb conditions in ISO cases.

The land area for PC cases assumes that 30 acres are required for the plant proper and the balance provides a buffer of approximately 0.25 mi to the fence line. The extra land could also provide for a rail loop if required (rail loop not included in this analysis). In the NGCC cases it was assumed the plant proper occupies about 10 acres leaving a buffer of 0.15 mi to the plant fence line.

In all cases it was assumed that the steam turbine is enclosed in a turbine building; in the PC cases the boiler is also enclosed. The CTs in the NGCC cases are not enclosed.

The following design parameters are considered site-specific, and are not quantified for this report. Allowances for normal conditions and construction are included in the cost estimates.

- Flood plain considerations
- Existing soil/site conditions
- Water discharges and reuse
- Rainfall/snowfall criteria
- Seismic design
- Buildings/enclosures
- Local code height requirements
- Noise regulations – Impact on site and surrounding area
- Other localized environmental concerns
- Weather delays

2.2 Coal Characteristics

The design coal is Illinois No. 6 with characteristics presented in Exhibit 2-3. The coal properties are from the January 2012 revision of the Quality Guidelines for Energy System Studies (QGESS) document “Detailed Coal Specifications.” (6)

The Power Systems Financial Model (PSFM) was used to derive the capital charge factors (CCF) for this report. (7) The PSFM requires that all cost inputs have a consistent cost year basis. Because the capital and operating cost estimates are in June 2011 dollars, the fuel costs must also be in June 2011 dollars.

Assumed fuel price is \$2.78/GJ (\$2.94/MMBtu) for Illinois No. 6 coal, on a higher heating value (HHV) basis, delivered to the Midwest, and in 2011 United States (U.S.) dollars.[4]

[4] As specified in the November 2012 QGESS document on “Fuel Prices for Selected Feedstocks in NETL Studies.” (45)

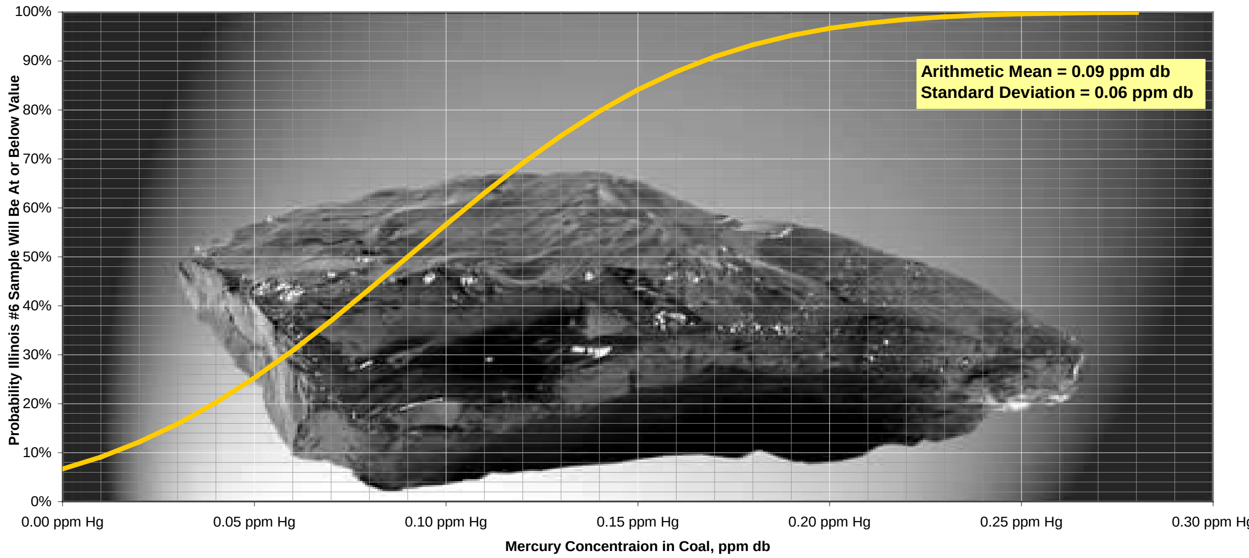
Exhibit 2-3 Design coal

Rank	Bituminous	
Seam	**Illinois No. 6 (Herrin)**	
Source	**Old Ben Mine**	
Proximate Analysis (weight %)[A]		
	As Received	**Dry**
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile Matter	34.99	39.37
Fixed Carbon	44.19	49.72
Total	100.00	100.00
Sulfur	2.51	2.82
HHV, kJ/kg (Btu/lb)	27,113 (11,666)	30,506 (13,126)
LHV, Btu/lb (Btu/lb)	26,151 (11,252)	29,544 (12,712)
Ultimate Analysis (weight %)		
	As Received	**Dry**
Moisture	11.12	0.00
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen[B]	6.88	7.75
Total	100.00	100.00

[A]The proximate analysis assumes sulfur as volatile matter.
[B]By difference.

The mercury content of 34 samples of Illinois No. 6 coal has an arithmetic mean value of 0.09 ppmwd with standard deviation of 0.06 based on coal samples shipped by Illinois mines. (8) Hence, as illustrated in Exhibit 2-4, there is a 50 percent probability that the mercury content in the Illinois No. 6 coal would not exceed 0.09 ppmwd. The coal mercury content for this report was assumed to be 0.15 ppmwd for all PC cases, which corresponds to the mean plus one standard deviation and encompasses about 84 percent of the samples. It was further assumed that all of the coal Hg enters the gas phase and none leaves with the bottom ash (9).

Exhibit 2-4 Probability distribution of mercury concentration in the Illinois No. 6 coal



Source: NETL

2.3 Natural Gas Characteristics

Natural gas is utilized as the fuel in Cases B31A and B31B (NGCC with and without CO_2 capture), and its composition is presented in Exhibit 2-5. The natural gas properties are from the January 2012 revision of the QGESS document "Specification for Selected Feedstocks" (10) with the addition of methanethiol (mercaptan). (11)

Assumed fuel price is $5.81/GJ ($6.13/MMBtu) for natural gas, on a higher heating value (HHV) basis, delivered to the Midwest, and in 2011 United States (U.S.) dollars.[5]

Exhibit 2-5 Natural gas composition

Component		Volume Percentage	
Methane	CH_4	93.1	
Ethane	C_2H_6	3.2	
Propane	C_3H_8	0.7	
n-Butane	C_4H_{10}	0.4	
Carbon Dioxide	CO_2	1.0	
Nitrogen	N_2	1.6	
Methanethiol[A]	CH_4S	$5.75x10^{-6}$	
	Total	100.00	
		LHV	**HHV**
kJ/kg (Btu/lb)		47,454 (20,410)	52,581 (22,600)
MJ/scm (Btu/scf)		34.71 (932)	38.46 (1,032)

[A]The sulfur content of natural gas is primarily composed of added Mercaptan (methanethiol, CH_4S) with trace levels of H_2S (11).
Note: Fuel composition is normalized and heating values are calculated

[5] As specified in the November 2012 QGESS document on "Fuel Prices for Selected Feedstocks in NETL Studies." (45)

2.4 Environmental Targets

Environmental targets were established for each of the technologies as follows:

- Mercury (Hg) and hydrochloric acid limits were set by the March 2013 update to the Utility Mercury and Air Toxics Standards (MATS) for PC technologies. (12), (13), (14)
- Particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxide (NOx) limits were set by the February 2013 update to the New Source Performance Standards (NSPS) for PC and NGCC technologies. (14), (15)

The regulations divide the coal types into low rank and non-low rank based on their heating value. Coals with a higher heating value (HHV) of greater than 8,300 Btu per pound (Btu/lb) on a moist, mineral-matter free basis are considered non-low rank. Therefore, Illinois No. 6 coal, with an HHV (moist, mineral-matter free) of 12,900 Btu/lb, is considered a non-low rank coal.

The emission limits imposed by MATS and NSPS that apply to each technology in this report are provided in Exhibit 2-6.

Exhibit 2-6 MATS and NSPS emission limits for PM, HCl, SO_2, NOx, and Hg

Pollutant[A]	PC (lb/MWh-gross)	NGCC (lb/MWh-gross)
SO_2	1.00	0.90
NOx	0.70	0.43
PM (Filterable)	0.09	N/A
Hg	$3x10^{-6}$	N/A
HCl	0.010	N/A

[A]CO emissions may be considered in later revisions of this report, if necessary.

These new regulations apply to PC and NGCC technologies that begin construction after May 3, 2011. Furthermore, these regulations state that (14)**,** (16):

> *Fossil fuel* is defined as natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.
>
> *Electric utility steam generating units (EGU)* are defined as a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit.
>
> *Fossil fuel-fired* means an EGU that is capable of combusting more than 25 MW of fossil fuels. To be capable of combusting fossil fuels, an EGU would need to have these fuels allowed in its operating permit and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities).
>
> *Coal-fired electric utility steam generating units* are defined as an EGU and meet the definition of "fossil fuel-fired," which is that it burns coal for more than 10 percent of the average annual heat input during any three consecutive calendar years or for more than 15 percent of the annual heat input during any one calendar year.

Unit designed for low-rank virgin coal subcategory is defined as any coal-fired EGU that is designed to burn, and that is burning, non-agglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) that is constructed and operates at or near the mine that produces such coal.

Unit designed for coal ≥8,300 Btu/lb subcategory is defined as any coal-fired EGU that is not a coal-fired EGU in the "unit designed for low rank virgin coal" subcategory.

Other regulations that could affect emissions limits from a new plant include the New Source Review (NSR) permitting process and Prevention of Significant Deterioration (PSD). The NSR process requires installation of emission control technology, meeting either BACT determinations for new sources being located in areas meeting ambient air quality standards (attainment areas), or Lowest Achievable Emission Rate (LAER) technology for sources being located in areas not meeting ambient air quality standards (non-attainment areas). Environmental area designation varies by county and can be established only for a specific site location. Based on the EPA Green Book Non-attainment Area Map relatively few areas in the Midwestern U.S. are classified as "non-attainment," so the plant site for this report was assumed to be in an attainment area. (15)

In addition to federal regulations, state and local jurisdictions can impose even more stringent regulations on a new facility. However, since each new plant has unique environmental requirements, it was necessary to apply some judgment in setting the environmental targets for this report.

2.4.1 PC

Exhibit 2-7 provides the emissions limits for PC plants as well as a brief summary of the control technology utilized to satisfy the limits.

Exhibit 2-7 Environmental targets for PC cases

Pollutant	PC (lb/MWh-gross)	Control Technology
SO_2	1.00	Wet limestone scrubber
NOx	0.70	Low NOx burners, overfire air and SCR
PM (Filterable)	0.09	Fabric filter
Hg	3×10^{-6}	Co-benefit capture, dry sorbent injection[A], activated carbon injection
HCl	0.010	SO_2 surrogate[B]

[A]Limits SO_3 levels and their detrimental effects on activated carbon injection (See Section 3.1.6)
[A]SO_2 may be utilized as a surrogate for HCl measurement if the EGU utilizes wet FGD. (17)

It was assumed that low NOx burners (LNB) and staged overfire air (OFA) would limit NOx emissions to 0.5 lb/MMBtu and that selective catalytic reduction (SCR) technology would be 83-85 percent efficient. By adjusting the ammonia flow rate in the SCR, the NOx emissions limit was able to be met exactly.

The wet limestone scrubber was assumed to be 98 percent efficient, which results in SO_2 emissions below the NSPS SO_2 limit. Current technology allows wet flue gas desulfurization

(FGD) removal efficiencies in excess of 99 percent, but based on NSPS requirements, such high removal efficiency is not necessary.

The fabric filter was assumed to be capable of achieving an efficiency of greater than 99.9 percent. As the required efficiency was approximately 99.9 percent for each case, the efficiency was varied in order to meet the PM emissions limit exactly.

The mercury removal efficiency required to meet the emission limit is approximately 97 percent in each case. It was assumed that the total mercury removal rate resulting from the combination of pollution control technologies used (SCR, dry sorbent injection (DSI), activated carbon injection (ACI), fabric filters, and FGD) would meet the limit exactly. DSI is required to limit the effects of SO_3 on Hg capture due to the high sulfur content of the coal in this study. Section 3.1.6 provides a detailed discussion regarding mercury removal and the various systems involved.

2.4.2 NGCC

Exhibit 2-8 provides the emissions limits for NGCC plants as well as a brief summary of the control technology utilized to satisfy the limits.

Exhibit 2-8 Environmental targets for NGCC cases

Pollutant	NGCC (lb/MWh-gross)	Control Technology
SO_2	0.90	Low sulfur content fuel
NOx	0.43	Dry low NOx burners and SCR
PM (Filterable)	N/A	N/A
Hg	N/A	N/A
HCl	N/A	N/A

The NGCC cases were designed to achieve approximately 1.0 ppmvd NOx emissions (referenced to 15 percent O_2) through the use of a dry low NOx (DLN) burner in the CTG – the DLN burners are a low NOx design and reduce the emissions to about 9 ppmvd (18) (assumed to be approximately 98 percent NO and referenced to 15 percent O_2) – and an SCR (19).

While a state-of-the-art 2013 F-class CT alone produces NOx emissions below the limit shown in Exhibit 2-8, an SCR was included to ensure the plant met the EPAs prevention of significant deterioration (PSD) program by installing the best available control technology (BACT). The SCR system is designed for 90 percent NO reduction while firing natural gas.

The total sulfur content of natural gas is typically limited by contract terms and industry practice to between 0.25 and 1.00 gr/100 scf with the average total sulfur content being 0.34 gr/100 scf. (11) For the purpose of this report, the natural gas was assumed to contain the average value of total sulfur of 0.34 gr/100 scf (4.71×10^{-4} lb-S/MMBtu). It was also assumed that the added mercaptan (CH_4S) was the sole contributor of sulfur to the natural gas. The mercaptan concentration of the natural gas was provided in Exhibit 2-5 as 5.75×10^{-6} mol% (7.06×10^{-4} lb-CH_4S/MMBtu).

If the natural gas contained 1.00 gr-S/100 scf, the SO_2 emissions for the non-capture case would be 0.018 lb/MWh-gross. The CO_2 capture system removes virtually all SO_2 from the flue gas.

The pipeline natural gas was assumed to contain no particulate matter (PM), Hg, or HCl, resulting in zero emissions.

2.4.3 Carbon Dioxide

The EPA proposed a new source performance standard on April 13, 2012 for emissions of carbon dioxide for new fossil fuel-fired electric utility generating units. As of the publication of this report, the EPA is finalizing a rule that may set CO_2 emissions limits below that of fossil fuel-fired electric utlity generation units without CO_2 capture.

The PC and NGCC cases both assume that all of the combusted carbon in the fuel is converted to CO_2 in the flue gas. Carbon dioxide is also generated from limestone in the FGD system and added as activated carbon (for mercury removal). The CO_2 capture plant design is for 90 percent capture of the CO_2 exiting the FGD system, resulting in emissions of 180 - 190 lb/MWh gross and 82 lb/MWh gross for PC and NGCC plants, respectively.

2.5 Capacity Factor

2.5.1 Capacity Factor Assumptions

Availability is the percent of time during a specific period that a generating unit is capable of producing electricity. This report assumes that each new plant would be dispatched any time it is available and would be capable of generating the nameplate capacity when online. Therefore, the capacity factor (CF) and availability are equal. The operating period selected is also important. The calculations assume that the capacity factor and availability are constant over the life of the plant, but in actual operation may require that a plant have a higher peak availability to counter lower availability in the first several years of operation.

2.5.2 Existing Plant Data

The North American Electric Reliability Council (NERC) Generating Availability Data System (20) (GADS) provides information on existing plants (e.g. Generating Analysis Reports, Generating Availability Reports, Generating Unit Statistical Brochure, Historical Availability Statistics). These data for coal plants (e.g. PC technology) include average availability and plant capacity factor data, by fuel type and plant capacity.

The GADS database provides data on many plant operating characteristics. Three metrics are used in this report to evaluate existing plant availability and capacity factors (availability factor (AF), net capacity factor (NCF), and equivalent availability factor (EAF)). The metrics can be defined by the following equations.

$$NCF = \frac{NAG}{PH * \left(\frac{GMC - CU}{Aux}\right)}$$

Where:
NAG – Net actual generation
PH – number of hours a unit was in the active state
GMC – Gross maximum capacity
CU – Capacity utilized for unit station service
Aux – Auxiliaries

$$AF = \frac{PH - (POH + FOH + MOH)}{PH}$$

Where:
POH – Planned outage hours

FOH – Forced outage hours
MOH – Maintenance outage hours

$$EAF = \frac{(PH - (POH + FOH + MOH)) - (EUDH + EPDH + ESEDH)}{PH}$$

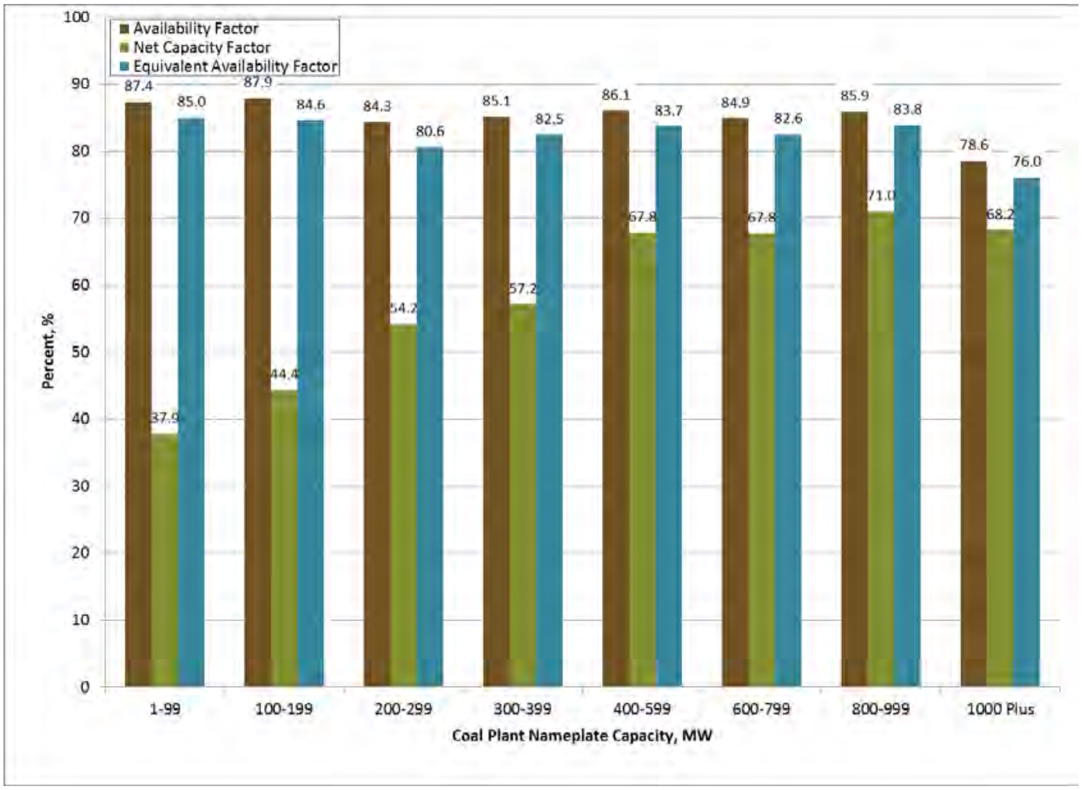
Where:
EUDH – Equivalent un-planned derated hours
EPDH – Equivalent planned derated hours
ESEDH – Equivalent seasonal derated hours

The EAF is essentially a measure of the plant CF, assuming there is always a demand for the output. The EAF accounts for planned and scheduled derated hours as well as seasonal derated hours. As such, the EAF matches this report's definition of CF.

2.5.3 Capacity Factor for Coal Units without Carbon Capture

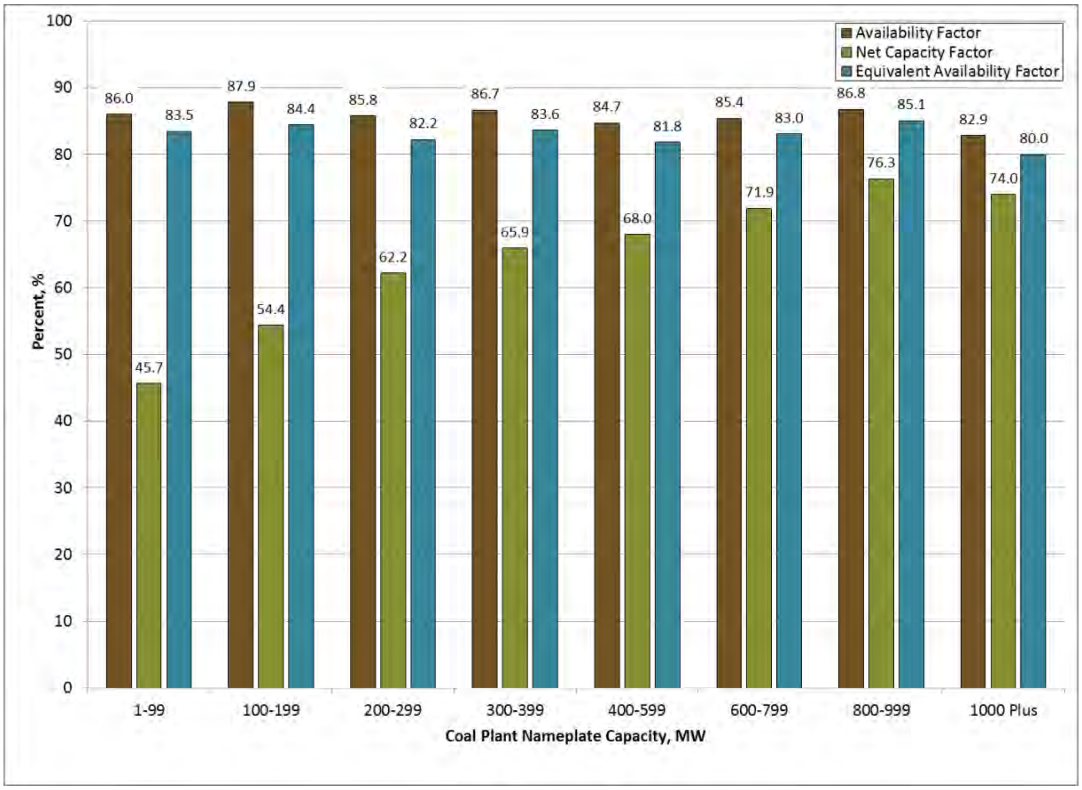
Exhibit 2-9 presents GADS coal unit availability and capacity factor data for generating plants in 2011. In order to provide perspective on these metrics over time, Exhibit 2-10 presents the same metrics averaged over the period 2007-2011. The number of generating units included in the 2011 data is presented in Exhibit 2-11.

Exhibit 2-9 Coal plant availability and capacity factor data for units reporting in 2011



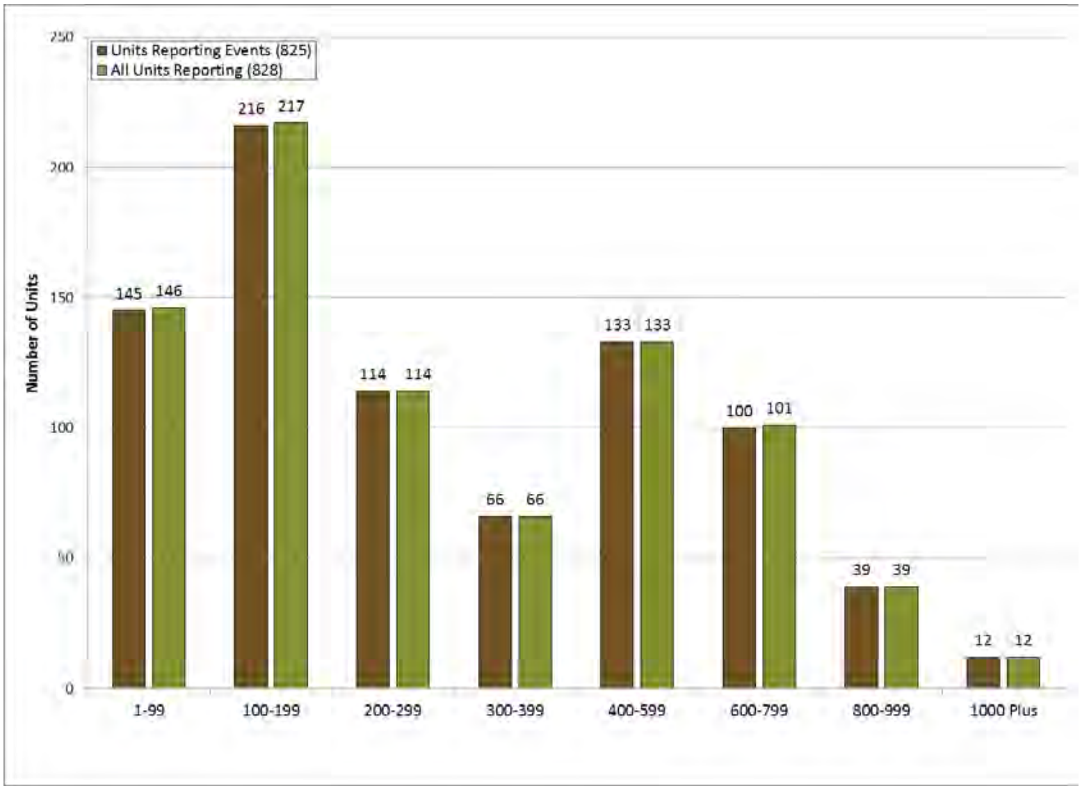
Source: NETL

Exhibit 2-10 Coal plant availability and CF average data over the period 2007-2011



Source: NETL

Exhibit 2-11 Number of coal units included in the 2011 data

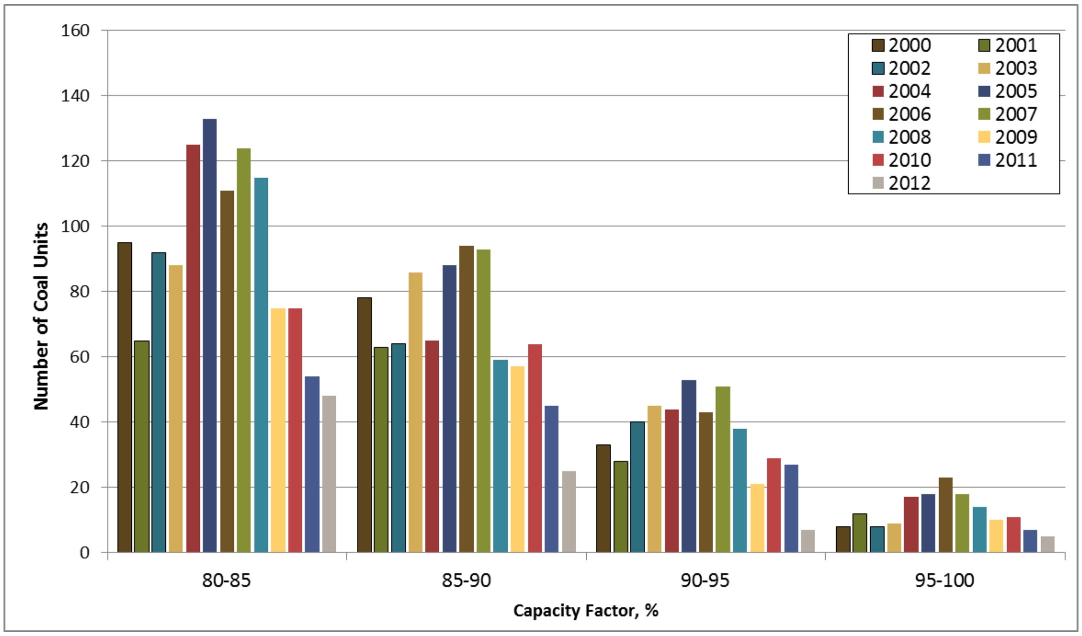


Source: NETL

The baseline study net unit capacity is 550 MW. The average EAF for coal-fired plants in the 400-599 MW size range was 83.7 percent in 2011 and averaged 81.8 percent from 2007-2011. The average net capacity factor for these units is less than 70 percent, which reflects the demand and how the plants were dispatched.

While the assumption for this report is that a unit will be dispatched when it is available, it is useful to have perspective on the ability of coal units to achieve high capacity factors. The Ventyx Velocity Suite (21) database provides data on individual unit performance. Exhibit 2-12 presents data on the number of units that achieved greater than 80 percent capacity factor in a given year for each year from 2000 through 2012.

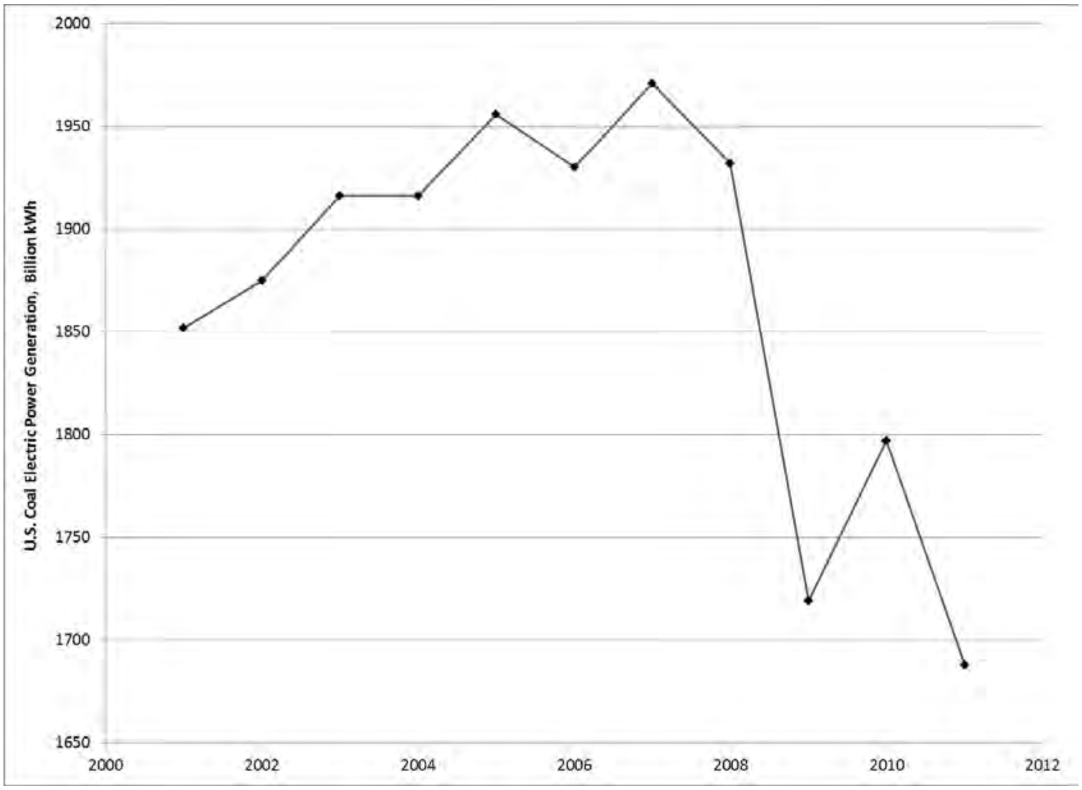
Exhibit 2-12 Number of coal units reporting capacity factors greater than 80%



Source: NETL

The 2006-2007 peak in the number of units operating with a given capacity factor is related to the U.S. coal electricity demand. Exhibit 2-13 presents EIA data (22) on electricity generation that shows a peak in 2007.

Exhibit 2-13 U. S. coal electricity power generation



Source: NETL

The GADS data show an average coal unit availability greater than 80 percent and the individual unit data from Ventyx Velocity show up to 162 coal units have operated in a given year with capacity factors greater than 85 percent. The current study costs are based on mature plant technology. Based on a review of the available data, an 85 percent capacity factor is selected for the PC coal units.

2.5.4 Capacity Factor for Natural Gas Combined Cycle (NGCC) Plants

Similar data as used for PC plants were reviewed for natural gas combined cycle plants. The GADS database shows an average availability of 87.8 percent for 160 combined cycle plants in 2011. The data over the last ten years show an availability of ~ 90 percent for each year. The average availability from 1980 to 1995 ranged from 80-90 percent. An 85 percent capacity factor is selected for NGCC plants.

2.5.5 Capacity Factor for Plants with Carbon Capture

The addition of carbon capture adds extra equipment to the power plant. Preliminary reliability analyses show small reductions in reliability if the reliability of the base plant components is kept constant. A solvent-based carbon capture technology is used in this report for both power plant configurations (PC and NGCC). The capture and CO_2 compression technologies have commercial operating experience with demonstrated ability for high reliability. Given the use of commercial technology, albeit at smaller scale, the assumption is made that the capacity factors for a given plant with and without carbon capture are the same. Thus, the capacity factor for PC and NGCC plants with capture is 85 percent.

The DOE Energy Information Agency (EIA), in their Annual Energy Outlook 2013, projected a capacity factor of 85 percent for new advanced coal with capture and 87 percent for new advanced coal without capture.

2.5.6 Perspective

Reported unit data and reported plant experience support the capability to achieve the selected availability factors for the plants. Important factors required to achieve these availability projections include a quality plant design that utilizes lessons learned from similar plant designs, a focus on life cycle costs, a smart predictive maintenance, a trained plant staff, and an economic demand for unit power. An illustration of lessons learned and the resulting high plant availability that can be obtained is reported by Richwine. (23)

Plant availability is determined by the plant technology, the capital cost invested in the plant (e.g. what is the design approach with respect to minimizing scheduled and unplanned maintenance), the maintenance requirements and the 'customer' requirements for the electricity (e.g. customer costs due to a unit not being available). Since the unavailability cost will decrease with increasing unit availability and the maintenance and capital costs increase with increasing unit availability, there will be an optimum economic unit availability for a given application. The current study assumes that the plant design, plant maintenance, and electricity demand are consistent with the selected availability.

The existing plant data have not been analyzed with regard to the performance of individual plant availability over the life of the plant. As stated, this report assumes a constant availability of 85 percent for each year over the life of the plant. It is recognized that the availability of a given plant will vary over the life of the plant. As demonstrated by existing plant data, coal plants can be designed and operated with yearly availability ranging from 85-100 percent. It is assumed that the plants in this report will have yearly availability factors above and below the selected values with the effective or levelized availability for the life of the plant being the selected value.

2.6 Raw Water Withdrawal and Consumption

A water balance was performed for each case on the major water consumers in the process. The total water demand for each subsystem was determined and internal recycle water available from various sources like boiler feedwater (BFW) blowdown and condensate from flue gas (in CO_2 capture cases) was applied to offset the water demand. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is the water removed from the ground or diverted from a municipal source for use in the plant. Raw water consumption is also accounted for as the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products, or otherwise not returned to the water source from which it was withdrawn.

Raw water makeup was assumed to be provided 50 percent by a publicly owned treatment works (POTW) and 50 percent from groundwater. Raw water withdrawal is defined as the water metered from a raw water source and used in the plant processes for any and all purposes, such as cooling tower makeup, BFW makeup, ash handling makeup, and FGD system makeup. The difference between withdrawal and process water returned to the source is consumption. Consumption represents the net impact of the process on the water source.

BFW blowdown and a portion of the sour water stripper blowdown were assumed to be treated and recycled to the cooling tower. The cooling tower blowdown and the balance of the SWS blowdown streams were assumed to be treated and 90 percent returned to the water source with the balance sent to the ash ponds for evaporation.

The largest consumer of raw water in all cases is cooling tower makeup. It was assumed that all cases utilized a mechanical draft, evaporative cooling tower, and all process blowdown streams were assumed to be treated and recycled to the cooling tower. The design ambient wet bulb temperature of 11°C (51.5°F) (Exhibit 2-1 and Exhibit 2-2) was used to achieve a cooling water temperature of 16°C (60°F) using an approach of 5°C (8.5°F). The cooling water range was assumed to be 11°C (20°F). The cooling tower makeup rate was determined using the following (24):

- Evaporative losses of 0.8 percent of the circulating water flow rate per 10°F of range
- Drift losses of 0.001 percent of the circulating water flow rate
- Blowdown losses (BDL) were calculated as follows:

$$BDL = \frac{EL}{CC - 1}$$

Where:
EL – Evaporative Losses
CC – Cycles of concentration

The cycles of concentration are a measure of water quality and a mid-range value of four (4) was chosen for this report.

The water balances presented in subsequent sections include the water demand of the major water consumers within the process, the amount provided by internal recycle, the amount of raw water withdrawal by difference, the amount of process water returned to the source, and the raw water consumption, again by difference.

2.7 Cost Estimating Methodology

Detailed information pertaining to topics such as contracting strategy, EPC contractor services, estimation of capital cost contingencies, owner's costs, cost estimate scope, economic assumptions, finance structures, cost of electricity, etc. are available in the April 2011 revision of the QGESS document "Cost Estimation Methodology for NETL Assessment of Power Plant Performance." (1) Select portions are repeated in this report for completeness.

<u>Capital Costs:</u>

The capital cost estimates documented in this report reflect an uncertainty range of -15%/+30%, consistent with AACE Class 4 cost estimates (i.e., feasibility study) (2) (3) (4), based on the level of engineering design performed. In all cases, the report intends to represent the next commercial offering, and relies on vendor cost estimates for component technologies. It also applies process contingencies at the appropriate subsystem levels in an attempt to account for expected but undefined costs (a challenge for emerging technologies).

<u>Costs of mature technologies and designs:</u>

The cost estimates for plant designs that only contain fully mature technologies, which have been widely deployed at commercial scale (e.g., PC and NGCC power plants without CO_2 capture), reflect nth-of-a-kind (NOAK) on the technology commercialization maturity spectrum. The costs of such plants have dropped over time due to "learning by doing" and risk reduction benefits that result from serial deployments as well as from continuing R&D.

Costs of emerging technologies and designs:

The cost estimates for plant designs that include technologies that are not yet fully mature (e.g., any plant with CO_2 capture) use the same cost estimating methodology as for the mature plant designs, which does not fully account for the unique cost premiums associated with the initial, complex integrations of emerging technologies in a commercial application. Thus, it is anticipated that initial deployments of the capture plants may incur costs higher than those reflected within this report.

Other factors:

Actual reported project costs for all of the plant types are also expected to deviate from the cost estimates in this report due to project- and site-specific considerations (e.g. contracting strategy, local labor costs, seismic conditions, water quality, financing parameters, local environmental concerns, weather delays, etc.) that may make construction more costly. Such variations are not captured by the reported cost uncertainty.

Future Cost Trends:

Continuing research, development, and demonstration (RD&D) is expected to result in designs that are more advanced than those assessed by this report, leading to costs that are lower than those estimated herein.

2.7.1 Capital Costs

As illustrated in Exhibit 2-14, this report defines capital cost at five levels: BEC, EPCC, TPC, TOC, and TASC. BEC, EPCC, TPC, and TOC are "overnight" costs and are expressed in "base-year" dollars. The base year is the first year of capital expenditure. TASC is expressed in mixed, current-year dollars over the entire capital expenditure period, which is assumed in most NETL studies to last five years for coal plants and three years for natural gas plants.

The Bare Erected Cost (BEC) comprises the cost of process equipment, on-site facilities and infrastructure that support the plant (e.g., shops, offices, labs, road), and the direct and indirect labor required for its construction and/or installation. The cost of EPC services and contingencies are not included in BEC. BEC is an overnight cost expressed in base-year dollars.

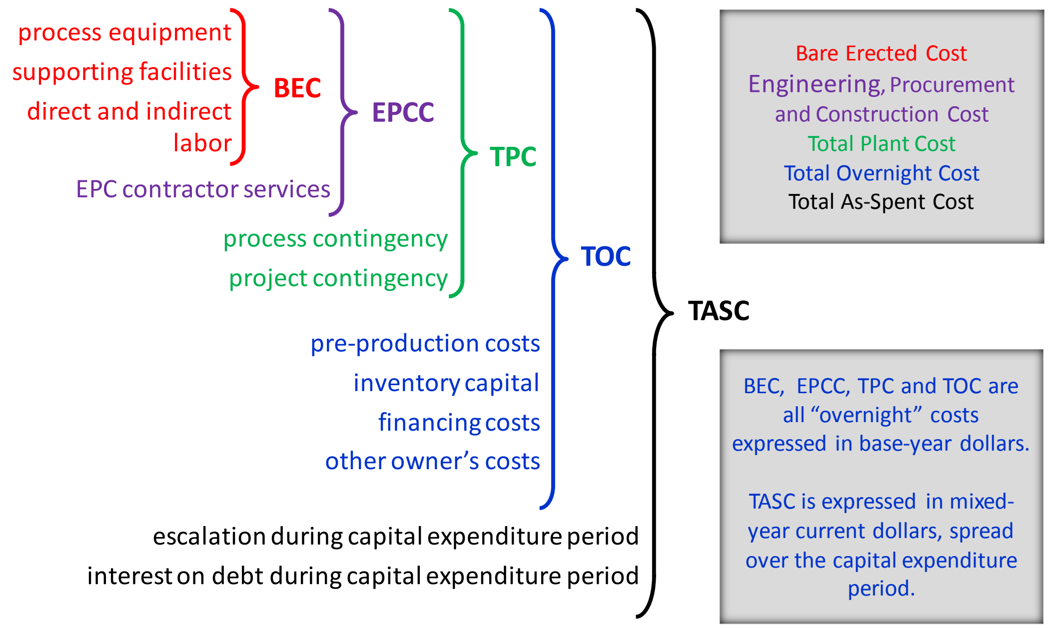
The Engineering, Procurement and Construction Cost (EPCC) comprises the BEC plus the cost of services provided by the engineering, procurement and construction (EPC) contractor. EPC services include: detailed design, contractor permitting (i.e., those permits that individual contractors must obtain to perform their scopes of work, as opposed to project permitting, which is not included here), and project/construction management costs. EPCC is an overnight cost expressed in base-year dollars.

The Total Plant Cost (TPC) comprises the EPCC plus project and process contingencies. TPC is an overnight cost expressed in base-year dollars.

The Total Overnight Cost (TOC) comprises the TPC plus all other overnight costs, including owner's costs. TOC is an "overnight" cost, expressed in base-year dollars and as such does not include escalation during construction or interest during construction.

The Total As-Spent Cost (TASC) is the sum of all capital expenditures as they are incurred during the capital expenditure period including their escalation. TASC also includes interest during construction. Accordingly, TASC is expressed in mixed, current-year dollars over the capital expenditure period.

Exhibit 2-14 Capital cost levels and their elements



Source: NETL

2.7.1.1 Cost Estimate Basis and Classification

The TPC and Operation and Maintenance (O&M) costs for each of the cases in the study were estimated by WorleyParsons using an in-house database and conceptual estimating models. Costs were further calibrated using a combination of adjusted vendor-furnished and actual cost data from recent design projects.

2.7.1.2 System Code-of-Accounts

The costs are grouped according to a process/system oriented code of accounts. This type of code-of-account structure has the advantage of grouping all reasonably allocable components of a system or process so they are included in the specific system account. (This would not be the case had a facility, area, or commodity account structure been chosen instead).

2.7.1.3 Estimate Scope

The estimates represent a complete power plant facility on a generic site. The plant boundary limit is defined as the total plant facility within the "fence line" including coal receiving and water supply system, but terminating at the high voltage side of the main power transformers. T&S cost is not included in the reported capital cost or O&M costs, but is treated separately and added to the COE.

2.7.1.4 Capital Cost Assumptions

WorleyParsons developed the capital cost estimates for each plant using the company's in-house database and conceptual estimating models for each of the specific technologies. This database and the respective models are maintained by WorleyParsons as part of a commercial power plant design base of experience for similar equipment in the company's range of power and process projects. A reference bottom-up estimate for each major component provides the basis for the estimating models.

Other key estimate considerations include the following:

- Labor costs are based on Midwest, Merit Shop. The estimating models are based on U.S. Gulf Coast and the labor has been factored to Midwest. The basis for the factors is the PAS, Inc. (PAS) "Merit Shop Wage & Benefit Survey," which is published annually. Based on the data provided in PAS, WorleyParsons used the weighted average payroll plus fringe rate for a standard craft distribution as developed for the estimating models. PAS presents information for eight separate regions. For this report, Region 5 (IL, IN, MI, MN, OH, and WI) was selected.
- The estimates are based on a competitive bidding environment, with adequate skilled craft labor available locally.
- Labor is based on a 50-hour work-week (5-10s). No additional incentives such as per-diem allowances or bonuses have been included to attract craft labor.
- While not included at this time, labor incentives may ultimately be required to attract and retain skilled labor depending on the amount of competing work in the region, and the availability of skilled craft in the area at the time the projects proceed to construction.
- The estimates are based on a greenfield site.
- The site is considered to be Seismic Zone 1, relatively level, and free from hazardous materials, archeological artifacts, or excessive rock. Soil conditions are considered adequate for spread footing foundations. The soil bearing capability is assumed adequate such that piling is not needed to support the foundation loads.
- Engineering and Construction Management are estimated at 8-10 percent of BEC. These costs consist of all home office engineering and procurement services as well as field construction management costs. Site staffing generally includes a construction manager, resident engineer, scheduler, and personnel for project controls, document control, materials management, site safety, and field inspection.

2.7.1.5 Price Fluctuations

During the course of this report, the prices of equipment and bulk materials fluctuated substantially. Some reference quotes pre-dated the 2011 year cost basis while others were received post-2011. All vendor quotes used to develop these estimates were adjusted to June 2011 dollars accounting for the price fluctuations. Price indices, e.g. The Chemical Engineering Plant Cost Index (25) and the Gross Domestic Product Chain-type Price Index (26), were used as needed for these adjustments. While these overall indices are nearly constant, it should be noted that the cost of individual equipment types may still deviate from the June 2011 reference point.

2.7.1.6 Cross-comparisons

In all technology comparison studies, the relative differences in costs are often more significant than the absolute level of TPC. This requires cross-account comparison between technologies to review the consistency of the direction of the costs.

In performing such a comparison, it is important to reference the technical parameters for each specific item, as these are the basis for establishing the costs. Scope or assumption differences can quickly explain any apparent anomalies.

2.7.1.6.1 Process Contingency

Process contingencies were applied to the estimates in this report as follows:

- Cansolv System – 20 percent on all PC/NGCC capture cases - post-combustion capture process unproven at commercial scale for power plant applications
- Instrumentation and Controls –5 percent on the PC and NGCC capture cases – integration issues

2.7.1.7 Owner's Costs

Two examples of what could be included in the "other" owner's costs are rail spur and switch yard costs. Rail spur costs would only be applied to the PC cases; however, the switch yard costs would be included in all cases.

Switch yard costs are dependent on voltage, configuration, number of breakers, layout, and air-insulated vs. gas-insulated. As a rule of thumb, a 345 kV switchyard (air-insulated, ring bus) would cost roughly $850,000 per breaker.

On-site only rails (excludes long runs) would be expected to cost in the range of $850,000 to $950,000 per mi (relatively flat level terrain) plus the costs of any switches/turnouts (approximately $50,000 each) and road crossings (approximately $300 per lineal foot).

Additional details and explanation of owner's costs are available in the April 2011 revision of the QGESS document "Cost Estimation Methodology for NETL Assessment of Power Plant Performance" (1).

2.7.2 Operation and Maintenance Costs

The production costs or operating costs and related maintenance expenses (O&M) pertain to those charges associated with operating and maintaining the power plants over their expected life. These costs include:

- Operating labor
- Maintenance – material and labor
- Administrative and support labor
- Consumables
- Fuel
- Waste disposal
- Co-product or by-product credit (that is, a negative cost for any by-products sold)

There are two components of O&M costs; fixed O&M, which is independent of power generation, and variable O&M, which is proportional to power generation. Taxes and insurance are included as fixed O&M costs, totaling 2 percent of the TPC.

2.7.2.1 Operating Labor

Operating labor cost was determined based on of the number of operators required for each specific case. The average base labor rate used to determine annual cost is $39.70/hour. The associated labor burden is estimated at 30 percent of the base labor rate.

2.7.2.2 Maintenance Material and Labor

Maintenance cost was evaluated on the basis of relationships of maintenance cost to initial capital cost. This represents a weighted analysis in which the individual cost relationships were considered for each major plant component or section.

2.7.2.3 Administrative and Support Labor

Labor administration and overhead charges are assessed at a rate of 25 percent of the burdened O&M labor.

2.7.2.4 Consumables

The cost of consumables, including fuel, was determined on the basis of individual rates of consumption, the unit cost of each specific consumable commodity, and the plant annual operating hours.

Quantities for major consumables such as fuel and sorbent were taken from technology-specific heat and mass balance diagrams developed for each plant application. Other consumables were evaluated on the basis of the quantity required using reference data.

The quantities for initial fills and daily consumables were calculated on a 100 percent operating capacity basis. The annual cost for the daily consumables was then adjusted to incorporate the annual plant operating basis, or CF.

Initial fills of the consumables, fuels and chemicals, are different from the initial chemical loadings, which are included with the equipment pricing in the capital cost.

2.7.2.5 Waste Disposal

Waste quantities and disposal costs were determined/evaluated similarly to the consumables. In this report fly ash and bottom ash from the PC cases are considered a waste with a disposal cost of $27.80/tonne ($25.11/ton).

2.7.2.6 Co-Products and By-Products

By-product quantities were also determined similarly to the consumables. However, due to the variable marketability of these by-products, specifically gypsum and sulfur, no credit was taken for their potential salable value.

It should be noted that by-product credits and/or disposal costs could potentially be an additional determining factor in the choice of technology for some companies and in selecting some sites. A high local value of the product can establish whether or not added capital should be included in the plant costs to produce a particular co-product. Ash is a potential by-product in certain markets; however, due to the activated carbon injection in the PC cases, the fly ash may not be marketable. As stated above, the ash is considered a waste in this report with a concomitant disposal cost.

2.7.3 CO_2 Transport and Storage

The cost of CO_2 transport and storage (T&S) in a deep saline formation is estimated using the FE/NETL CO_2 Transport Cost Model and the FE/NETL CO_2 Saline Storage Cost Model. Additional detail on development of these costs is available in the May 2014 revision of the QGESS document "Carbon Dioxide Transport and Storage Costs in NETL Studies." (27)

T&S costs are reported as first-year costs in $/tonne of CO_2, increasing at a nominal rate of 3 percent per year, consistent with the general inflation rate assumed in NETL's energy systems studies. From the perspective of the CO_2 source (e.g., a power plant or other energy conversion facility), these costs are treated as a disposal cost for each tonne of CO_2 captured during the assumed 30-year operational period. From the pipeline and storage site's perspective, this cost represents the first year break-even price they must charge across the 30-year operational period to cover all costs and provide the required internal rate of return on equity (IRROE). All costs are reported in 2011 dollars.

The Transport Cost Model provides cost estimates for the construction and operation of a dedicated pipeline for transporting CO_2 from a CO_2 source to a CO_2 storage site. The pipeline is assumed to be buried in the shallow subsurface and the CO_2 along the pipeline is assumed to be at the temperature of the surrounding soil, typically about 50 ºF. The CO_2 entering the pipeline at the plant gate is assumed to be at a pressure of 2,200 psig and exiting the pipeline at the storage site at a pressure of 1,200 psig. At these pressures, CO_2 is a liquid at temperatures from approximately -64°F to 88°F.

It is further assumed that the pipeline is 100 km long (62.1 mi) and transports 3.2 million tonnes of CO_2 each year on average or approximately 8,770 tonnes per day on average. The pipeline is designed to operate at 80 percent of its maximum mass flow capacity, so the design maximum daily mass flow rate of CO_2 is about 10,960 tonnes/day. The model determines the smallest standard diameter pipe that can transport this mass flow of CO_2 the required distance without boosting the pressure. The model also determines the smallest standard diameter pipe that can transport this mass flow of CO_2 the required distance assuming boost pumps are placed at equal intervals along the pipeline to boost the pressure from 1,200 psig to 2,200 psig. The model then determines which of these configurations (e.g., no boost pumps, one boost pump, two boost pumps, three boost pumps, etc.) is least expensive. The capital and operating costs used in the model were taken from the open literature. The capital costs for the pipeline are based on capital costs for natural gas pipelines reported in the Oil and Gas Journal with adjustments for the higher pressures used in CO_2 pipelines.

The financial parameters used in the FE/NETL CO_2 Transport Cost Model are:

- Debt to equity ratio: 50%/50%
- Nominal interest rate on debt: 4.5%/year
- Nominal IRROE: 12%
- Escalation rate: 3%
- Tax rate: 38%
- Project contingency factor of 15%

The FE/NETL CO_2 Transport Cost Model determines the first year break-even price that needs to be charged to transport the CO_2 in order to cover all costs including the minimum return on equity. The model uses a weighted average cost of capital methodology in determining the break-even first year CO_2 price. From the perspective of the CO_2 source, the break-even price is also the minimum cost of transporting CO_2. Transport costs are estimated to be $2.24/tonne in 2011 dollars.

Storage costs are based on the FE/NETL CO_2 Saline Storage Cost Model. This model provides detailed cost estimates for the injection and monitoring of CO_2 under U.S. Environmental Protection Agency regulations for Class VI injection wells as well as monitoring and reporting requirements under Subpart RR of the Greenhouse Gas Reporting Rule.

Inputs to the FE/NETL CO_2 Saline Storage Cost Model that have a significant influence on cost include financial parameters, the timelines for the various stages of storage and important activities occurring in each stage. The financial parameters include:

- Debt to equity ratio: 45%/55%
- Nominal interest rate on debt: 5.5%/year
- Nominal IRROE: 12%
- Escalation rate: 3%
- Financial responsibility requirements for post-injection site care and site closure are met by pre-funding a modified trust fund over the period of injection operations
- Project contingency factor of 15% and process contingency factor of 20%

In the FE/NETL CO_2 Saline Storage Cost Model, the sequestration process is divided into six stages. The timelines and important activities impacting costs for these stages are as follows:

- Regional evaluation and initial site selection: 1 year
- Site characterization: 3 years; four sites undergo site characterization with one successful site selected; pore space rights are leased
- Permitting: 2 years; drill, test and complete injection wells
- Operations: 30 years; installation of buildings, surface equipment, monitoring wells and other monitoring equipment; comply with permit requirements; fund modified trust fund to cover financial responsibility requirements for post-injection site care and site closure
- Post-injection site care and site closure: 50 years; continue monitoring, verification and accounting (MVA) per permit; costs are covered by storage site operator's trust fund
- Long-term stewardship: (This stage is not explicitly included in the model.) The possible financial implication of long-term stewardship is included in the model as a state-sponsored trust fund that the storage operator pays into during operations

Due to the variances in the geologic formations that make up saline formations across the U.S., region-specific storage and monitoring costs are developed to correspond to the plant locations used in NETL techno-economic studies of energy conversion facilities. Results from the FE/NETL CO_2 Saline Storage Cost Model for storage and monitoring costs were aligned with the NETL studies by taking four generic plant locations and overlaying them with possible sequestration basins from the cost model resulting in the following pairings:

- Midwest plant location – Illinois Basin
- Texas plant location – East Texas Basin
- North Dakota plant location – Williston Basin
- Montana plant location – Powder River Basin

CO_2 storage supply-cost curves were developed for each of the four basins of interest with the resulting cost for each basin at 25 gigatonnes (Gt) of potential storage shown in Exhibit 2-15. Choosing this point on the supply-cost curves provides a conservative estimate of the storage cost since many decades, if not more than a century, will pass before 25 Gt of CO_2 is stored in any of the four individual basins. For example, 25 Gt of storage would be sufficient for 125 GW of coal power with 90 percent CO_2 capture operating over 30 years.

The far right column of Exhibit 2-15 shows the total T&S costs used in NETL system studies for each plant location rounded to the nearest whole dollar. Only the $11/tonne value is used in this volume of the baseline study report since all cases are located in the Midwest.

Exhibit 2-15 CO_2 transport and storage costs

Plant Location	Basin	Transport (2011 $/tonne)	Storage Cost at 25 Gt (2011 $/tonne)	T&S Value for System Studies[A] (2011$/tonne)
Midwest	Illinois	2.24	8.69	11
Texas	East Texas		8.83	11
North Dakota	Williston		13.95	16
Montana	Powder River		21.81	24

[A]The sum of transport and storage costs is rounded to the nearest dollar

2.7.4 Cost of CO_2 Captured and Avoided

The cost of captured CO_2 represents the minimum CO_2 plant gate sales price that will incentivize carbon capture in lieu of a defined reference non-capture plant. The cost of captured CO_2 is calculated using the following formula:

$$Cost\ of\ CO_2\ Captured = \frac{(COE_{CCS} - COE_{Non\ CCS})}{CO_2\ Captured}$$

The cost of CO_2 avoided represents the minimum CO_2 emissions price that will, when applied to both the capture and non-capture plant, incentivize carbon capture in lieu of a defined reference non-capture plant. The cost of CO_2 avoided is calculated using the following formula:

$$Cost\ of\ CO_2\ Avoided = \frac{(COE_{CCS\ with\ T\&S} - COE_{Non\ CCS})}{CO_2\ Emissions_{Non\ CCS} - CO_2\ Emissions_{CCS}}$$

where:

- CCS – the capture plant for which the cost of CO_2 captured/avoided is being calculated
- Non-CCS – the reference non-capture plant, as described below
- COE – the cost of electricity, reported in $/MWh
  - The CCS plant includes compression to 2,215 psia
  - For CO_2 Captured, the COE excludes transportation and storage (T&S) costs
  - For CO_2 Avoided, the COE includes T&S costs
- CO_2 Captured – the rate of CO_2 captured, reported in tonne/MWh
- CO_2 Emissions – the rate of CO_2 emitted out the stack, reported in tonne/MWh

For today's greenfield coal with CCS plants, the reference non-capture plant used to calculate the cost of captured and avoided CO_2 is a supercritical pulverized coal (SCPC) plant without capture. For a greenfield natural gas-based power system, the reference plant used to calculate the cost of captured and avoided CO_2 is a non-capture natural gas-based plant.

3 Pulverized Coal Rankine Cycle Plants

Four PC fired Rankine cycle power plant configurations were evaluated and the results are presented in this section. Each design is based on a market-ready technology that is assumed to be commercially available in time for the plant startup date. All designs employ a one-on-one configuration comprised of a state-of-the art PC steam generator firing Illinois No. 6 coal and a steam turbine.

The PC cases are evaluated with and without CO_2 capture on a common 550 MWe net basis. The designs that include CO_2 capture have a larger gross unit size to compensate for the higher auxiliary loads. The constant net output sizing basis is selected because it provides for a meaningful side-by-side comparison of the results. The boiler and steam turbine industry ability to match unit size to a custom specification has been commercially demonstrated enabling common net output comparison of the PC cases in this report.

Steam conditions for the Rankine cycle cases were selected based on a survey of boiler and steam turbine original equipment manufacturers (OEM), who were asked for the most advanced steam conditions that they would guarantee for a commercial project in the US with subcritical and SC PC units rated at nominal 550 MWe net capacities and firing Illinois No. 6 coal. (28) Based on the OEM responses, the following single-reheat steam conditions were selected for the study:

- For subcritical cases (B11A and B11B) – 16.5 MPa/566°C/566°C (2,400 psig/1,050°F/1,050°F)
- For SC cases (B12A and B12B) – 24.1 MPa/593°C/593°C (3,500 psig/1,100°F/1,100°F)

Steam temperature selection for boilers depends upon fuel corrosiveness. Most of the contacted OEMs were of the opinion that the steam conditions in this range would be limited to low sulfur coal applications (such as PRB). Their primary concern is that elevated temperature operation while firing high sulfur coal (such as Illinois No. 6) would result in an exponential increase of the material wastage rates of the highest temperature portions of the superheater and reheater (RH) due to coal ash corrosion, requiring pressure parts replacement outages approximately every 10 or 15 years. This cost would offset the value of fuel savings and emissions reduction due to the higher efficiency. In addition, three of the most recently built SC units in North America have steam cycles similar to this report's design basis, namely James E. Rogers Energy Complex in North Carolina, which started operations in 2012 (27.0 MPa/568°C/579°C [3,922 psia/1,055°F/1,075°F]) and Prairie State Energy Campus units 1 and 2, which also started operation in 2012 (26.2 MPa/568°C/568°C [3,800 psig/1,055°F/1,055°F]).

The evaluation basis details, including site ambient conditions, fuel composition and the emissions control basis, are provided in Section 2 of this report.

3.1 PC Common Process Areas

The PC cases have process areas that are common to each plant configuration, such as coal receiving and storage, emissions control technologies, power generation, etc. As detailed descriptions of these process areas in each case section would be burdensome and repetitious, they are presented in this section for general background information. The performance features of these sections are then presented in the case-specific sections.

3.1.1 Coal, Activated Carbon, and Sorbent Receiving and Storage

The function of the Coal Receiving and Storage system is to unload, convey, prepare, and store the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to and including the slide gate valves at the outlet of the coal storage silos. The system is designed to support short-term operation at the 5 percent over pressure/valves wide open (OP/VWO) condition (16 hours) and long-term operation of 90 days or more at the maximum continuous rating (MCR).

The scope of the sorbent receiving and storage system includes truck roadways, turnarounds, unloading hoppers, conveyors and the day storage bin.

Operation Description - The coal is delivered to the site by 100-car unit trains comprised of 91 tonne (100 ton) rail cars. The unloading is done by a trestle bottom dumper, which unloads the coal into two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 8 cm x 0 (3" x 0) coal from the feeder is discharged onto a belt conveyor. Two conveyors with an intermediate transfer tower are assumed to convey the coal to the coal stacker, which transfer the coal to either the long-term storage pile or to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor, which transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 2.5 cm x 0 (1" x 0) by the coal crushers. The coal is then transferred by conveyor to the transfer tower. In the transfer tower the coal is routed to the tripper that loads the coal into one of the six boiler silos.

Limestone is delivered to the site using 23 tonne (25 ton) trucks. The trucks empty into a below grade hopper where a feeder transfers the limestone to a conveyor for delivery to the storage pile. Limestone from the storage pile is transferred to a reclaim hopper and conveyed to a day bin.

Non-halogenated powdered activated carbon (PAC) is delivered to the site using 18 tonne (20 ton) trucks. The trucks pneumatically unload into a storage silo where a feeder hopper transfers the PAC to a screw feeder that conveys the PAC into the drop tube. PAC is fed through the drop tube directly into the eductor suction port. The carbon is transferred from the eductor suction port through the piping system and injected through a distribution of lances across the flue gas ductwork upstream of the baghouse.

Hydrated lime is delivered and distributed in a manner very similar to that of the PAC: the sorbent is contained in the main storage silo and fed to a weigh hopper for conveying through transport piping to the sorbent distribution manifold upstream of the air preheater.

3.1.2 Steam Generator and Ancillaries

The steam generator for the subcritical PC plants is a drum-type, wall-fired, balanced draft, natural circulation, totally enclosed dry bottom furnace, with superheater, reheater, economizer and air preheater.

The steam generator for the SC plants is a once-through, spiral-wound, Benson-boiler, wall-fired, balanced draft type unit with a water-cooled dry bottom furnace. It includes a superheater, reheater, economizer, and air preheater.

The combustion systems for both subcritical and SC steam conditions are equipped with LNBs and OFA. It is assumed for the purposes of this report that the power plant is designed for operation as a base-load unit but with some consideration for daily or weekly cycling.

3.1.2.1 Scope

The steam generator includes the following for both subcritical and SC PCs, except where otherwise indicated:

- Drum-type evaporator (subcritical only)
- Once-through type steam generator (SC only)
- Startup circuit, including integral separators (SC only)
- Water-cooled furnace, dry bottom
- Two-stage superheater
- Reheater (RH)
- Economizer
- Spray type desuperheater
- Soot blower system
- Air preheaters (Ljungstrom type)
- Coal feeders and pulverizers
- Low NOx Coal burners and light oil igniters/ warm-up system
- OFA system
- Forced draft (FD) fans
- Primary air (PA) fans
- Induced draft (ID) fans

The following subsections describe the operation of the steam generator.

3.1.2.2 Feedwater and Steam

For the subcritical steam system feedwater (FW) enters the economizer, recovers heat from the combustion gases exiting the steam generator, and then passes to the boiler drum, from where it is distributed to the water wall circuits enclosing the furnace. After passing through the lower and upper furnace circuits and steam drum in sequence, the steam passes through the convection enclosure circuits to the primary superheater and then to the secondary superheater.

The steam then exits the steam generator en route to the high pressure (HP) turbine. Steam from the HP turbine returns to the steam generator as cold reheat and returns to the intermediate pressure (IP) turbine as hot reheat.

For the SC steam system FW enters the bottom header of the economizer and passes upward through the economizer tube bank, through stringer tubes, which support the primary superheater, and discharges to the economizer outlet headers. From the outlet headers, water flows to the furnace hopper inlet headers via external downcomers. Water then flows upward through the furnace hopper and furnace wall tubes. From the furnace, water flows to the steam water separator. During low load operation (operation below the Benson point), the water from the separator is returned to the economizer inlet with the boiler recirculating pump. Operation at loads above the Benson point is once through.

Steam flows from the separator through the furnace roof to the convection pass enclosure walls, primary superheater, through the first stage of water attemperation, to the furnace platens. From the platens, the steam flows through the second stage of attemperation and then to the intermediate superheater. The steam then flows to the final superheater and on to the outlet pipe terminal. Two stages of spray attemperation are used to provide tight temperature control in all high temperature sections during rapid load changes.

Steam returning from the turbine passes through the primary reheater surface, then through crossover piping containing inter-stage attemperation. The crossover piping feeds the steam to the final reheater banks and then out to the turbine. Inter-stage attemperation is used to provide outlet temperature control during load changes.

3.1.2.3 Air and Combustion Products

Combustion air from the FD fans is heated in Ljungstrom type air preheaters, recovering heat energy from the exhaust gases exiting the boiler. This air is distributed to the burner windbox as secondary air. Air for conveying PC to the burners is supplied by the PA fans. This air is heated in the Ljungstrom type air preheaters to permit drying of the PC, and a portion of the air from the PA fans bypasses the air preheaters to be used for regulating the outlet coal/air temperature leaving the mills.

The PC and air mixture flows to the coal nozzles at various elevations of the furnace. The hot combustion products rise to the top of the boiler and pass through the superheater and reheater sections. The gases then pass through the economizer and air preheater. The gases exit the steam generator at this point and flow to the SCR reactor, dry sorbent injection (DSI) manifold, activated carbon injection (ACI) manifold, fabric filter, ID fan, FGD system, and stack.

3.1.2.4 Fuel Feed

The crushed Illinois No. 6 bituminous coal is fed through feeders to each of the mills (pulverizers), where its size is reduced to approximately 72 percent passing 200 mesh and less than 0.5 percent remaining on 50 mesh. (29) The PC exits each mill via the coal piping and is distributed to the coal nozzles in the furnace walls using air supplied by the PA fans.

3.1.2.5 Ash Removal

The furnace bottom comprises several hoppers, with a clinker grinder under each hopper. The hoppers are of welded steel construction, lined with refractory. The hopper design incorporates a water-filled seal trough around the upper periphery for cooling and sealing. Water and ash discharged from the hopper pass through the clinker grinder to an ash sluice system for conveyance to hydrobins, where the ash is dewatered before it is transferred to trucks for offsite disposal. The description of the balance of the bottom ash handling system is presented in Section 3.1.11. The steam generator incorporates fly ash hoppers under the economizer outlet and air preheater outlet.

3.1.2.6 Burners

A boiler of this capacity employs approximately 24 to 36 coal nozzles arranged at multiple elevations. Each burner is designed as a low-NOx configuration, with staging of the coal combustion to minimize NOx formation. In addition, OFA nozzles are provided to further stage combustion and thereby minimize NOx formation.

Oil-fired pilot torches are provided for each coal burner for ignition, warm-up and flame stabilization at startup and low loads.

3.1.2.7 Dry sorbent Injection

The hydrated lime injection manifold is located directly before the air preheaters. This SO_3 control system is discussed in detail in Section 3.1.6.

3.1.2.8 Air Preheaters

Each steam generator is furnished with two vertical-shaft Ljungstrom regenerative type air preheaters. These units are driven by electric motors through gear reducers.

3.1.2.9 Soot Blowers

The soot-blowing system utilizes an array of 50 to 150 retractable nozzles and lances that clean the furnace walls and convection surfaces with jets of HP steam. The blowers are sequenced to provide an effective cleaning cycle depending on the coal quality and design of the furnace and convection surfaces. Electric motors drive the soot blowers through their cycles.

3.1.3 NOx Control System

The plants are designed to achieve the environmental target of 0.70 lb/MWh-gross. Two measures are taken to reduce the NOx. The first is a combination of LNBs and the introduction of staged OFA in the boiler. The LNBs and OFA reduce the emissions to about 0.5 lb/MMBtu.

The second measure taken to reduce the NOx emissions is the installation of an SCR system prior to the air heater. SCR uses ammonia and a catalyst to reduce NOx to N_2 and H_2O. The SCR system consists of three subsystems: reactor vessel, ammonia storage and injection, and gas flow control. The SCR system is designed for 83-85 percent reduction with 2 ppmv ammonia slip at the end of the catalyst life.

The SCR capital costs are included with the boiler costs, as is the cost for the initial load of catalyst.

Selective non-catalytic reduction (SNCR) was considered for this application. However, with the installation of the LNBs and OFA system, the boiler exhaust gas contains relatively small amounts of NOx, which makes removal of the quantity of NOx with SNCR to reach the emissions limit difficult. SNCR works better in applications that contain medium to high quantities of NOx and require removal efficiencies in the range of 40 to 60 percent. Because of the catalyst used, SCR can achieve higher efficiencies with lower concentrations of NOx.

3.1.3.1 SCR Operation Description

The reactor vessel is designed to allow proper retention time for the ammonia to contact the NOx in the boiler exhaust gas. Ammonia is injected into the gas immediately prior to entering the reactor vessel. The catalyst contained in the reactor vessel enhances the reaction between the ammonia and the NOx in the gas. Catalysts consist of various active materials such as titanium dioxide, vanadium pentoxide, and tungsten trioxide. The operating range for vanadium/titanium-based catalysts is 260°C (500°F) to 455°C (850°F). The boiler is equipped with an economizer bypass to provide flue gas to the reactors at the desired temperature during periods of low flow rate, such as low load operation. Also included with the reactor vessel is soot-blowing equipment used for cleaning the catalyst.

The ammonia storage and injection system consists of the unloading facilities, bulk storage tank, vaporizers, dilution air skid, and injection grid.

The flue gas flow control consists of ductwork, dampers, and flow straightening devices required to route the boiler exhaust to the SCR reactor and then to the air heater. The economizer bypass and associated dampers for low load temperature control are also included.

3.1.4 Activated Carbon Injection

The PAC injection manifold is located directly before the baghouse. (30) This system will be discussed in detail in Section 3.1.6.

3.1.5 Particulate Control

The fabric filter (or baghouse) consists of two separate single-stage, in-line, multi-compartment units. Each unit is of high (0.9-1.5 m/min [3-5 ft/min]) air-to-cloth ratio design with a pulse-jet on-line cleaning system. The ash is collected on the outside of the bags, which are supported by steel cages. The dust cake is removed by a pulse of compressed air. The bag material is polyphenylensulfide (PPS) with intrinsic Teflon Polytetrafluoroethylene (PTFE) coating. (31) The bags are rated for a continuous temperature of 180°C (356°F) and a peak temperature of 210°C (410°F). Each compartment contains a number of gas passages with filter bags, and heated ash hoppers supported by a rigid steel casing. The fabric filter is provided with necessary control devices, inlet gas distribution devices, insulators, inlet and outlet nozzles, expansion joints, and other items as required.

The use of ACI and DSI increases the calcium content of the fly ash and adds an additional burden to the fabric filter. The addition of calcium is not expected to increase the leaching of trace metals from the fly ash significantly. The ACI and DSI systems increase the total amount of particulate matter by approximately 26 percent.

Fly ash from bituminous-fired plants (Class F fly ash) is sometimes sold for use as filler material in concrete mixtures. The use of Class F fly ash for concrete manufacture is not as common as the use of Class C fly ash (from high-calcium-containing coals); the latter is more valuable as a replacement for Portland cement in concrete mixtures. Class F fly ash must have a low unburned carbon content to be used in cement mixtures. The inclusion of activated carbon and hydrated lime (or, rather, the $CaSO_4$ reaction product) will render the fly ash unsuitable for use in concrete mixtures.

3.1.6 Mercury Removal[6]

Mercury removal is partially achieved through flue gas reactions between mercury and available halogens and carbon.

Halogens in the coal, primarily chlorine, influence the fraction of oxidized mercury that is formed as the flue gas passes through the SCR and air preheater. Therefore, the overall mercury removal in control devices such as fabric filters and wet scrubbers is also influenced by halogens in the coal (concentrations of chlorine greater than 500 ppmv do not appear to have any additional impact on the rate of mercury oxidation (32)).

The presence of an SCR can impact the amount of SO_3 or H_2SO_4 that is present in the flue gas. Sulfuric acid can impact the ability of unburned carbon to adsorb mercury. Based on the

[6] Much of the text, descriptions, and images within this section were sourced, with permission, from a quote provided by ADA-ES to NETL, unless otherwise noted. The information relates to a mercury control system designed by ADA-ES. The quote also provided all images credited to them.

assumptions and design bases of the PC cases in this study, the estimated SO_3 concentration at the inlet of the air preheater, without mitigation, is 59 ppmvd. At these levels, low mercury removal is expected from either unburned carbon or added activated carbon. Therefore, dry sorbent injection is included in the PC plant designs in order to reduce the SO_3 levels to approximately 2 ppmvd, as discussed in Section 3.1.6.1.

The rate of mercury oxidation is also affected by the ammonia concentration. Since the SCR is operated more aggressively for nitrogen oxide (NOx) control, the ammonia levels increase and the fraction of oxidized mercury decreases. (33)

Unburned carbon can act as a catalyst to promote mercury oxidation as well as to adsorb mercury. In general, sufficient unburned carbon is present at plants firing bituminous coals such that one or both of these factors will have a significant influence on the overall mercury removal achieved in the system. (34)

The presence of unburned carbon and/or activated carbon on the fabric filter surface, in combination with relatively high levels of hydrogen halides (e.g. HCl) in the flue gas, is expected to result in high levels of oxidized mercury exiting the fabric filter. Oxidized mercury is water soluble and should be readily removed in the wet scrubber. Depending on the chemistry in the scrubber, some of the captured mercury may be reduced back to the relatively insoluble elemental form, which will then be re-emitted from the scrubber. The control systems employed in this study minimize the amount of mercury entering the scrubber, which reduces the risk of exceeding the emission limit. Even with low levels entering the scrubber, there is a risk of periodic spikes in mercury at the stack if mercury collected and concentrated in a recirculating scrubber is released. However, to a large extent, the periodic surges can be managed through careful operations and, because the regulations specify a 30- or 90-day averaging period, the impact of the surges on compliance can be minimized.

EPA used a statistical method to calculate the Hg co-benefit capture from units using a “best demonstrated technology” approach, which for bituminous coals was considered to be a combination of a fabric filter and an FGD system. The statistical analysis resulted in a co-benefit capture estimate of 86.7 percent with an efficiency range of 83.8 to 98.8 percent. (35) EPA’s documentation for their Integrated Planning Model (IPM) provides mercury emission modification factors (EMF) based on 190 combinations of boiler types and control technologies. The EMF is simply one minus the removal efficiency.

For PC boilers (as opposed to cyclones, stokers, fluidized beds, and ‘others’) with a fabric filter, SCR and wet FGD, the EMF is 0.1, which corresponds to a removal efficiency of 90 percent; (36) the average reduction in total Hg emissions developed from EPA’s Information Collection Request (ICR) data on U.S. coal-fired boilers using bituminous coal, fabric filters, and wet FGD is 98 percent. (37) The referenced sources bound the co-benefit Hg capture for bituminous coal units employing SCR, a fabric filter, and a wet FGD system between 83.8 and 98 percent. It was assumed that the co-benefit potential of the equipment utilized in the PC cases of this report is 90 percent, as it is near the mid-point of the previously mentioned range, and it also matches the value used by EPA in their IPM.

The potential co-benefit capture of the systems utilized in the PC cases does not satisfy the requirements of the mercury emission limit, therefore, a cost and performance estimate was obtained from ADA-ES, which stated that activated carbon injection (ACI) and dry sorbent injection (DSI) would be required.

Location of the DSI relative to the air preheater impacts the mercury removal efficiency of the ACI system. The mercury limit is assumed to be achievable with a DSI location downstream of the air preheater; however, the upstream location of the air preheater allows for a lower flue gas outlet temperature from the air preheater, which improves plant performance as well as increases the carbon efficiency by up to 25 percent.

3.1.6.1 Dry Sorbent Injection

Illinois No. 6 coal contains relatively high levels of sulfur (2.82 wt%). ADA-ES estimated that nominally 36 ppmvd of sulfur trioxide (SO_3) will be present at the outlet of the air preheater resulting from coal combustion and oxidation across the SCR.

SO_3 can be detrimental to the effectiveness of both unburned carbon and activated carbon for mercury control, as evidenced by the results from a testing program conducted at the Mercury Research Center. The test using an ESP-configured system with an activated carbon injection rate of 10 lb/MMacf upstream of the air preheater, which showed that at SO_3 levels above 20 ppm, less than 50 percent mercury removal was achieved. At SO_3 levels above 10 and 3 ppm, less than 70 and 80 percent mercury removal was achieved, respectively. (38)

Hydrated lime injection was selected for SO_3 control and located upstream of the air preheater, which allows the air preheater to operate at a lower downstream flue gas temperature (290°F) and increases the overall plant efficiency compared to a system with no DSI or DSI downstream of the air preheater. Without SO_3 mitigation, the downstream flue gas temperature must be maintained above the acid dew point temperature (approximately 337°F).

Operation Description – The DSI and ACI injection systems are nearly identical, therefore, the description provided below pertains to both systems.

As shown in Exhibit 3-1, the DSI system is based on dilute-phase, pneumatic conveying of hydrated lime at a metered rate from a bulk storage silo to the flue gas ductwork where it mixes with the flue gas and reacts with the SO_3 to form $CaSO_4$, which is captured in the fabric filter.

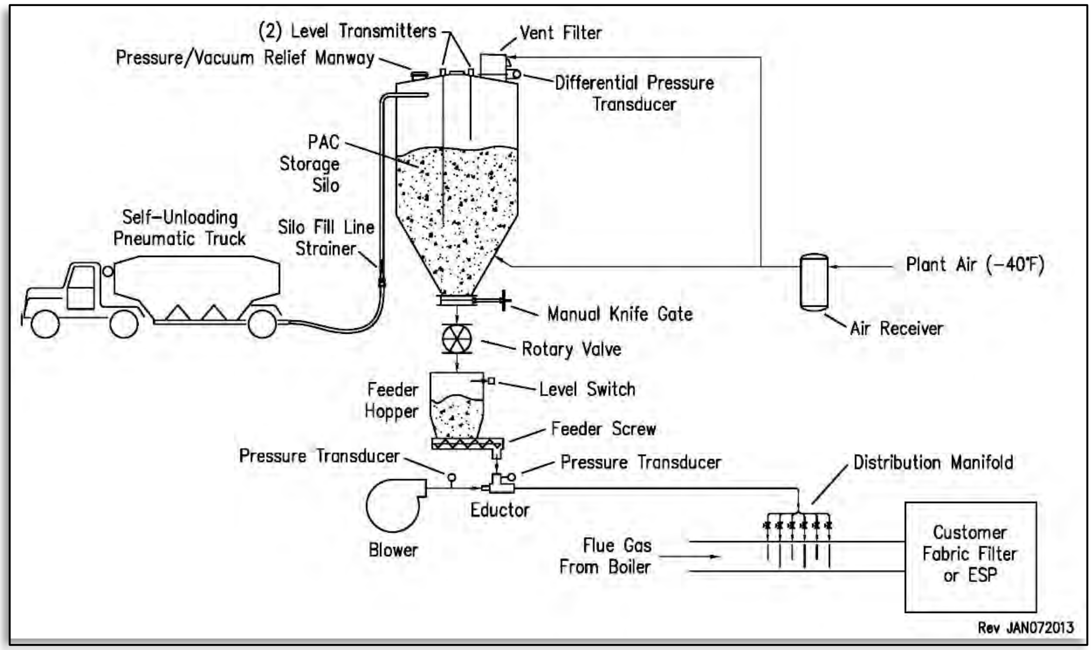
The hydrated lime is delivered in 40,000 lb batches by self-unloading pneumatic trucks. The hydrated lime is unloaded from the truck via an on-board compressor into the dry, welded-steel storage silo where the displaced air is vented through a silo vent filter. The hydrated lime level in the silo is measured by system instrumentation. A combination of compressed air fluidization valves and nozzles is used to pulse compressed air, promoting mass flow of the hydrated lime out of the silo chisel-type cone.

Fluidized hydrated lime is then transferred from the silo by a rotary valve into the feeder hopper where it is temporarily stored until conveyed by the screw feeder into the drop tube. The speed of the screw feeder determines the feed rate into the drop tube. Hydrated lime is fed through the drop tube directly into the eductor suction port.

Motive air, provided by low-pressure blowers and fed into the eductors, produces a vacuum at the suction port. This helps draw the hydrated lime and air into the mixing zone directly downstream of the eductor discharge. The hydrated lime is transported through the piping system and is distributed to an array of injection lances specifically designed to disperse the hydrated lime across the cross section of the flue gas ductwork upstream of the air preheater.

The DSI system is monitored and controlled by the distributed control system (DCS) to adjust to varying demand.

Exhibit 3-1 Typical injection process flow diagram

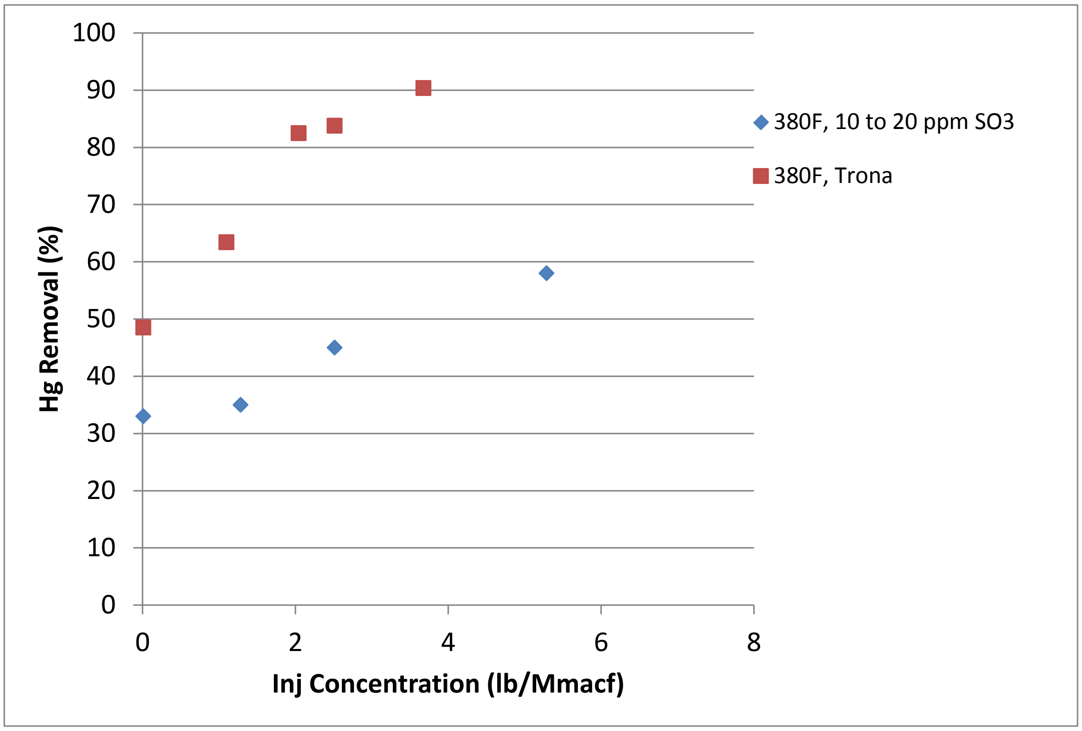


Source: Permission granted from ADA-ES

3.1.6.2 Activated Carbon Injection

ADA-ES conducted a mercury control trial using ACI and trona-based DSI on a unit with an installed fabric filter and high (greater than 20 ppm) levels of SO_3 in the flue gas. For this test, the flue gas temperature was 380°F. Results from this test are presented in Exhibit 3-2 and indicate that high mercury removal can be achieved when alkaline materials are present with activated carbon on a bag surface (improved performance is expected at lower temperatures).

Exhibit 3-2 Mercury removal across a fabric filter during a high-sulfur bituminous test



Source: Permission granted from ADA-ES

In order to meet the mercury emission limit, PAC is injected at a rate of approximately 2.7 lb/MMacf in all PC cases.

Operation Description – The ACI system's injection manifold is located directly upstream of the fabric filter and is otherwise identical to that of the DSI system and is described in Section 3.1.6.1.

3.1.7 Flue Gas Desulfurization

The FGD system is a wet limestone forced oxidation positive pressure absorber non-reheat unit, with wet-stack, and gypsum production. The function of the FGD system is to scrub the boiler exhaust gases to remove the SO_2 prior to release to the environment, or entering into the Carbon Dioxide Removal (CDR) facility. Sulfur removal efficiency is 98 percent in the FGD unit for all cases. For Cases B11B and B12B with CO_2 capture, the SO_2 content of the scrubbed gases must be further reduced to approximately 1 ppmv to minimize formation of amine heat stable salts (HSS) during the CO_2 absorption process. The CDR unit includes a polishing scrubber to reduce the flue gas SO_2 concentration from about 37 ppmv at the FGD exit to the required level prior to the CDR absorber. The scope of the FGD system is from the outlet of the ID fans to the stack inlet (Cases B11A and B12A) or to the CDR process inlet (Cases B11B and B12B). The system description is divided into three sections:

- Limestone Handling and Reagent Preparation
- FGD Scrubber
- Byproduct Dewatering

3.1.7.1 Limestone Handling and Reagent Preparation System

The function of the limestone reagent preparation system is to grind and slurry the limestone delivered to the plant. The scope of the system is from the day bin up to the limestone feed system. The system is designed to support continuous base load operation.

Operation Description - Each day bin supplies a 100 percent capacity ball mill via a weigh feeder. The wet ball mill accepts the limestone and grinds the limestone to 90 to 95 percent passing 325 mesh (44 microns). Water is added at the inlet to the ball mill to create limestone slurry. The reduced limestone slurry is then discharged into a mill slurry tank. Mill recycle pumps, two per tank, pump the limestone water slurry to an assembly of hydrocyclones and distribution boxes. The slurry is classified into several streams, based on suspended solids content and size distribution.

The hydrocyclone underflow with oversized limestone is directed back to the mill for further grinding. The hydrocyclone overflow with correctly sized limestone is routed to a reagent storage tank. Reagent distribution pumps direct slurry from the tank to the absorber module.

3.1.7.2 FGD Scrubber

The flue gas exiting the air preheater section of the boiler passes through one of two parallel fabric filter units, then through the ID fans and into the one 100 percent capacity absorber module. The absorber module is designed to operate with counter-current flow of gas and reagent. Upon entering the bottom of the absorber vessel, the gas stream is subjected to an initial quenching spray of reagent. The gas flows upward through the spray zone, which provides enhanced contact between gas and reagent. Multiple spray elevations with header piping and nozzles maintain a consistent reagent concentration in the spray zone. Continuing upward, the reagent-laden gas passes through several levels of moisture separators. These consist of chevron-shaped vanes that direct the gas flow through several abrupt changes in direction, separating the entrained droplets of liquid by inertial effects. The scrubbed flue gas exits at the top of the absorber vessel and is routed to the plant stack or CDR process.

The scrubbing slurry falls to the lower portion of the absorber vessel, which contains a large inventory of liquid. Oxidation air is added to promote the oxidation of calcium sulfite contained in the slurry to calcium sulfate (gypsum). Multiple agitators operate continuously to prevent settling of solids and enhance mixture of the oxidation air and the slurry. Recirculation pumps recirculate the slurry from the lower portion of the absorber vessel to the spray level. Spare recirculation pumps are provided to ensure availability of the absorber.

The absorber chemical equilibrium is maintained by continuous makeup of fresh reagent, and blowdown of byproduct solids via the bleed pumps. A spare bleed pump is provided to ensure availability of the absorber. The byproduct solids are routed to the byproduct dewatering system. The circulating slurry is monitored for pH and density.

This FGD system is designed for wet stack operation. Scrubber bypass or reheat, which may be utilized at some older facilities to ensure the exhaust gas temperature is above the saturation temperature, is not employed in this reference plant design because new scrubbers have improved mist eliminator efficiency, and detailed flow modeling of the flue interior enables the placement of gutters and drains to intercept moisture that may be present and convey it to a drain. Consequently, raising the exhaust gas temperature above the FGD discharge temperature of 56°C (133°F) is not necessary.

3.1.7.3 Byproduct Dewatering

The function of the byproduct dewatering system is to dewater the bleed slurry from the FGD absorber modules. The dewatering process selected for this plant is gypsum dewatering producing wallboard grade gypsum. The scope of the system is from the bleed pump discharge connections to the gypsum storage pile.

Operation Description - The recirculating reagent in the FGD absorber vessel accumulates dissolved and suspended solids on a continuous basis as byproducts from the SO_2 absorption process. Maintenance of the quality of the recirculating slurry requires that a portion be withdrawn and replaced by fresh reagent. This is accomplished on a continuous basis by the bleed pumps pulling off byproduct solids and the reagent distribution pumps supplying fresh reagent to the absorber.

Gypsum (calcium sulfate) is produced by the injection of oxygen into the calcium sulfite produced in the absorber tower sump. The bleed from the absorber contains approximately 20 wt% gypsum. The absorber slurry is pumped by an absorber bleed pump to a primary dewatering hydrocyclone cluster. The primary hydrocyclone performs two process functions. The first function is to dewater the slurry from 20 wt% to 50 wt% solids. The second function of the primary hydrocyclone is to perform a $CaCO_3$ and $CaSO_4{\bullet}2H_2O$ separation. This process ensures a limestone stoichiometry in the absorber vessel of 1.10 and an overall limestone stoichiometry of 1.05. This system reduces the overall operating cost of the FGD system. The underflow from the hydrocyclone flows into the filter feed tank, from which it is pumped to a horizontal belt vacuum filter. Two 100 percent filter systems are provided for redundant capacity.

3.1.7.4 Hydrocyclones

The hydrocyclone is a simple and reliable device (no moving parts) designed to increase the slurry concentration in one step to approximately 50 wt%. This high slurry concentration is necessary to optimize operation of the vacuum belt filter.

The hydrocyclone feed enters tangentially and experiences centrifugal motion so that the heavy particles move toward the wall and flow out the bottom. Some of the lighter particles collect at the center of the cyclone and flow out the top. The underflow is thus concentrated from 20 wt% at the feed to 50 wt%.

Multiple hydrocyclones are used to process the bleed stream from the absorber. The hydrocyclones are configured in a cluster with a common feed header. The system has two hydrocyclone clusters, each with five 15 cm (6 inch) diameter units. Four cyclones are used to continuously process the bleed stream at design conditions, and one cyclone is spare.

Cyclone overflow and underflow are collected in separate launders. The overflow from the hydrocyclones still contains about 5 wt% solids, consisting of gypsum, fly ash, and limestone residues and is sent back to the absorber. The underflow of the hydrocyclones flows into the filter feed tank from where it is pumped to the horizontal belt vacuum filters.

3.1.7.5 Horizontal Vacuum Belt Filters

The secondary dewatering system consists of horizontal vacuum belt filters. The pre-concentrated gypsum slurry (50 wt%) is pumped to an overflow pan through which the slurry flows onto the vacuum belt. As the vacuum is pulled, a layer of cake is formed. The cake is dewatered to approximately 90 wt% solids as the belt travels to the discharge. At the discharge end of the filter, the filter cloth is turned over a roller where the solids are dislodged from the filter cloth. This cake falls through a chute onto the pile prior to the final byproduct uses. The required vacuum is provided by a vacuum pump. The filtrate is collected in a filtrate tank that provides surge volume for use of the filtrate in grinding the limestone. Filtrate that is not used for limestone slurry preparation is returned to the absorber.

3.1.8 Carbon Dioxide Recovery Facility[7]

A CDR facility is used, along with compressors and a dryer, in Cases B11B and B12B to remove 90 percent of the CO_2 in the flue gas exiting the FGD unit. The facility then purifies it and compresses it to a supercritical condition. The flue gas exiting the FGD unit contains about 1 percent more CO_2 than the raw flue gas because of the CO_2 liberated from the limestone in the FGD absorber vessel. The CDR is comprised of the pre-scrubber, CO_2 absorber, CO_2 stripper, and absorbent purification unit.

The CO_2 recovery process for Cases B11B and B12B is based on data given by Shell Cansolv in 2012. A typical flowsheet is shown in Exhibit 3-3. This process is designed to recover high-purity CO_2 from low pressure (LP) streams that contain oxygen, such as flue gas from coal-fired power plants, CT exhaust gas, and other waste gases.

3.1.8.1 Pre-scrubber Section

The flue gas from the FGD section is sent through a booster fan to drive the gas through downstream equipment starting with the pre-scrubber inlet cooling section. The cooler is operated as a direct contact cooler that saturates and sub-cools the flue gas. Saturation and sub-cooling are beneficial to the system as they improve the amine absorption capacity, thus reducing amine circulation rate. After the cooling section, the flue gas is scrubbed with caustic in the pre-scrubber sulfur polishing section. This step reduces the SO_2 concentration entering the CO_2 absorber column to 1 ppmv, and also reduces the NO_2 concentration by 50 percent.

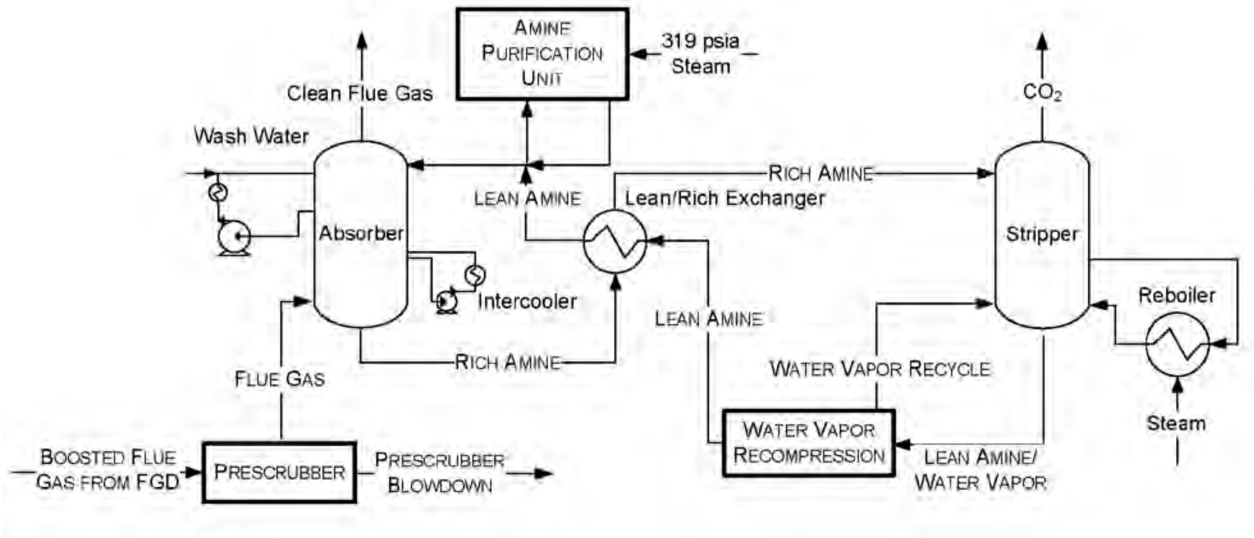
3.1.8.2 CO_2 Absorber Section

The Cansolv absorber is a single, rectangular, acid resistant, brick-lined concrete structure containing stainless-steel packing.

There are four packing sections in the Cansolv absorber. The first three are used for CO_2 absorption, and the final section is a water-wash section. This specific absorber geometry and design provides several cost advantages over more traditional column configurations while maintaining equivalent or elevated performance. The flue gas enters the absorber and flows counter-current to the Cansolv solvent. Approximately 90 percent of the inlet CO_2 is absorbed into the lean solvent, and the remaining CO_2 exits the main absorber section and enters the water-wash section of the absorber. Prior to entering the bottom packing section, hot amine is collected, removed, and pumped through a heat exchanger to provide intercooling and limit water losses. The cooled amine is then sent back to the absorber just above the final packing section.

[7] Much of the text and descriptions within this section were sourced, with permission, from data provided by Shell Cansolv to NETL, unless otherwise noted. The information relates to a CO_2 removal system designed by Shell Cansolv.

Exhibit 3-3 Cansolv CO_2 capture process typical flow diagram



Source: NETL

The water-wash section at the top of the absorber is used to remove volatiles or entrained amine from the flue gas, as well as to condense and retain water in the system. The wash water is removed from the bottom of the wash section, pumped through a heat exchanger, and is then re-introduced at the top of the wash section. This wash water is made up of recirculated wash water as well as water condensed from the flue gas. The flue gas treated in the water-wash section is then released to atmosphere.

3.1.8.3 Amine Regeneration Section

The rich amine is collected at the bottom of the absorber and pumped through a rich/lean heat exchanger where heat from the lean amine is exchanged with the rich amine. The Cansolv rich/lean solvent heat exchanger is a stainless steel plate and frame type with a 5°C (9°F) approach temperature. Additional options for heat integration in the Cansolv system include a second heat exchanger after the rich/lean solvent heat exchanger where low-pressure steam condensate from the regenerator reboiler or intermediate-pressure steam condensate from the amine purification section may be used to further pre-heat the rich solvent. The rich amine continues and enters the stripper near the top of the column. The stripper is a stainless steel vessel using structured stainless steel packing. The regenerator reboiler uses low-pressure steam to produce water vapor that flows upwards, counter-current to the rich amine flowing downwards, and removes CO_2 from the amine. The Cansolv regenerator reboiler is a stainless steel plate and frame type with a 3°C (5°F) approach temperature. Lean amine is collected in the stripper bottoms and flows to a flash vessel where water vapor is released. The water vapor is then recompressed and recycled to the bottom of the stripper to continue stripping CO_2. The lean amine is then pumped through the same rich/lean heat exchanger to exchange heat from the lean amine to the rich amine and continues on to the lean amine tank.

The water vapor and stripped CO_2 flow up the stripper where they are contacted with recycled reflux to condense a portion of the vapor. The remaining gas continues to the condenser where it is partially condensed. The two-phase mixture then flows to a reflux accumulator where the CO_2 product gas is separated and sent to the CO_2 compressor at approximately 30 psia, and the remaining water is collected and returned to the stripper as reflux.

The flow of steam to the regenerator reboiler is proportional to the rich amine flow to the stripper; however, the flow of low-pressure steam is also dependent on the stripper top temperature. For the steady-state case described here, the low-pressure steam requirement for the reboiler only is calculated as approximately 1,100 Btu/lb CO_2 for the Cansolv process, which is satisfied by extracting steam from the crossover pipe between the IP and LP sections of the steam turbine.

3.1.8.4 Amine Purification Section

The purpose of the amine purification section is to remove a portion of the HSS as well as ionic and non-ionic amine degradation products. The Cansolv amine purification process is performed in batch.

3.1.8.4.1 Ion Exchange

The HSS form due to residual amounts of NO_2 and SO_2 in the flue gas. The acids formed by the oxidative degradation of the amine, as well as through reactions with NO_2 and SO_2, neutralize a portion of the amine making it inactive to further CO_2 absorption. Therefore, excess HSS are removed via an ion exchange (resin bed contained within a column).

3.1.8.4.2 Thermal Reclaimer

The ionic and non-ionic amine degradation products are removed in the thermal reclaimer by distilling a slipstream – taken from the treated amine exiting the ion exchanger – under vacuum conditions to separate the water and amine. This process leaves the non-ionic degradation products in the bottom, which are pumped to a storage tank, diluted and cooled with process water, and then disposed. A portion of the condensed amine and water is returned to the absorber column with the rest being sent to the lean amine tank.

3.1.9 Gas Compression and Drying System

The compression system was modeled based on vendor supplied data, similar in design to that presented in the Carbon Capture Simulation Initiative's (CCSI) paper "Centrifugal Compressor Simulation User Manual." (39) The design was assumed to be an 8-stage front-loaded centrifugal compressor with stage discharge pressures presented in Exhibit 3-4.

Exhibit 3-4 CO_2 compressor interstage pressures

Stage	Outlet Pressure, MPa (psia)	Stage Pressure Ratio
1	0.44 (64)	2.23
2	0.92 (133)	2.14
3	1.72 (250)	1.90
4	3.04 (441)	1.78
5	4.80 (696)	1.59
6	6.97 (1,011)	1.53
7	10.36 (1,502)	1.49
8	15.27 (2,215)	1.48

Power consumption for this large compressor was estimated assuming a polytropic efficiency of 89 percent and a mechanical efficiency of 97 percent for the first 7 stages and a polytropic efficiency of 91 percent for the final stage.

Intercooling is included for each stage with the first three stages including water knockout. There is no aftercooler included in this design.

A triethylene glycol (TEG) dehydration unit is included between stages 4 and 5, operating at 3.03 MPa (439 psia), to reduce the moisture concentration of the CO_2 stream to 300 ppmw. The dryer was designed based on a paper published by the Norwegian University of Science and Technology (NTNU) (40) titled "Conditioning of CO_2 Coming from a CO_2 Capture Process for Transport and Storage Purposes."

In an absorption process, such as in a TEG dehydration unit, the gas containing water flows up through a column while the TEG flows downward. The solvent binds the water by physical absorption; water is more soluble in the solvent than in other components of the gas mixture. The dried gas exits at the top of the column, while the solvent rich in water exits at the bottom. After depressurization to around atmospheric pressure, the solvent is regenerated by heating it and passing it through a regeneration column where the water is boiled off. Depending on configuration a TEG unit can reduce water concentrations to below 10 ppm. (41)

Several alternatives to rejecting the heat of CO_2 compression to cooling water were investigated in a separate study. (42) The first alternative consisted of using a portion of the heat to pre-heat BFW while the remaining heat was still rejected to cooling water. This configuration resulted in an increase in net plant efficiency of 0.3 percentage points (absolute). The second alternative modified the CO_2 compression intercooling configuration to enable integration into a LiBr-H_2O absorption refrigeration system, where water is the refrigerant. In the CO_2 compression section, the single intercooler between each compression stage was replaced with one kettle reboiler and two counter-current shell and tube heat exchangers. The kettle reboiler acts as the generator that rejects heat from CO_2 compression to the LiBr-H_2O solution to enable the separation of the refrigerant from the brine solution. The second heat exchanger rejects heat to the cooling water. The evaporator heat exchanger acts as the refrigerator and cools the CO_2 compression stream by vaporizing the refrigerant. Only five stages of CO_2 compression were necessary for Approach 2. The compression ratios were increased from the reference cases to create a compressor outlet temperature of at least 93°C (200°F) to maintain a temperature gradient of 6°C (10°F) in the kettle reboiler. This configuration resulted in a net plant efficiency increase of 0.1 percentage points (absolute).

It was concluded that the small increase in efficiency did not justify the added cost and operational complexity of the two configurations and hence they were not incorporated into the base design.

3.1.10 Power Generation

The steam turbine is designed for long-term operation (90 days or more) at MCR with throttle control valves 95 percent open. It is also capable of a short-term 5 percent OP/VWO condition (16 hours).

For the subcritical cases, the steam turbine is a tandem compound type, consisting of HP-IP-two LP (double flow) sections enclosed in three casings, designed for condensing single reheat operation, and equipped with non-automatic extractions and four-flow exhaust. The turbine drives a hydrogen-cooled generator. The turbine has DC motor-operated lube oil pumps, and main lube oil pumps, which are driven off the turbine shaft. (43) The exhaust pressure is 50.8

cm (2 in) Hg in the single pressure condenser. There are seven extraction points. The condenser is two-shell, transverse, single pressure with divided waterbox for each shell.

The steam-turbine generator systems for the SC plants are similar in design to the subcritical systems. The differences include steam cycle conditions and steam extractions points. The subcritical design has seven steam extraction points for both capture and non-capture cases, whereas the capture SC plant has only 6 extraction points and the non-capture SC plant has 8 extraction points. The reason for the differences between the two SC plants (B12A and B12B) is discussed in Section 3.1.11.

Turbine bearings are lubricated by a closed-loop, water-cooled pressurized oil system. Turbine shafts are sealed against air in-leakage or steam blowout using a labyrinth gland arrangement connected to a LP steam seal system. The generator stator is cooled with a CL water system consisting of circulating pumps, shell and tube or plate and frame type heat exchangers, filters, and deionizers, all skid-mounted. The generator rotor is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft.

Operation Description - The turbine stop valves, control valves, reheat stop valves, and intercept valves are controlled by an electro-hydraulic control system. Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 16.5 MPa/566°C (2,400 psig/1,050ºF) for the subcritical cases and 24.1MPa /593°C (3,500 psig/1,100°F) for the SC cases. The steam initially enters the turbine near the middle of the HP span, flows through the turbine, and returns to the boiler for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 566°C (1,050ºF) in the subcritical cases and 593°C (1,100°F) in the SC cases. After passing through the IP section, the steam enters a crossover pipe, which transports the steam to the two LP sections. The steam divides into four paths and flows through the LP sections exhausting downward into the condenser. The last stages of the LP sections operate as condensing turbines with an exit liquid fraction ranging from 9.2 percent to 9.5 percent.

The turbine is designed to operate at constant inlet steam pressure over the entire load range.

3.1.11 Balance of Plant

The balance of plant components consist of the condensate, FW, main and reheat steam, extraction steam, ash handling, ducting and stack, waste treatment and miscellaneous systems as described below.

3.1.11.1 Condensate

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator and through the LP FW heaters. Each system consists of one main condenser; two variable speed electric motor-driven vertical condensate pumps each sized for 50 percent capacity; four LP heaters (two in Case B12B); and one deaerator with storage tank.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided downstream of the gland steam condenser to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

LP FW heaters 1 through 4 are 50 percent capacity, parallel flow, and are located in the condenser neck. All remaining FW heaters are 100 percent capacity shell and U-tube heat exchangers. Each LP FW heater is provided with inlet/outlet isolation valves and a full capacity bypass. LP FW heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the condenser. Pneumatic level control valves control normal drain levels in the heaters. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Pneumatic level control valves control dump line flow.

While Case B11B returns all process extraction steam (CO_2 capture and drying requirements) condensate to the deaerator, the SC Case B12B requires this condensate to be returned after the condenser upstream of the condensate polisher. This is required as the SC cases do not have a blowdown stream. If the condensate was returned to the deaerator, there would be a buildup of contaminants. An impact of this design is that two of the LP FW heaters are not required in the SC capture case (B12B), as the condensate return increases the FW temperature above that which would be exiting the second LP FW heater.

3.1.11.2 Feedwater

The function of the FW system is to pump the FW from the deaerator storage tank through the HP FW heaters to the economizer. One turbine-driven BFW pump sized at 100 percent capacity is provided to pump FW through the HP FW heaters. One 25 percent motor-driven BFW pump is provided for startup. The pumps are provided with inlet and outlet isolation valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by automatic recirculation valves, which are a combination check valve in the main line and in the bypass, bypass control valve, and flow sensing element. The suction of the boiler feed pump is equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

Each HP FW heater is provided with inlet/outlet isolation valves and a full capacity bypass. FW heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the deaerator. Pneumatic level control valves control normal drain level in the heaters. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

The deaerator is a horizontal, spray tray type with internal direct contact stainless steel (SS) vent condenser and storage tank.

The boiler feed pump turbine is driven by main steam up to 60 percent plant load. Above 60 percent load, extraction from the IP turbine exhaust provides steam to the boiler feed pump steam turbine.

3.1.11.3 Main and Reheat Steam

The function of the main steam system is to convey main steam from the boiler superheater outlet to the HP turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the boiler reheater and from the boiler reheater outlet to the IP turbine stop valves.

Main steam exits the boiler superheater through a motor-operated stop/check valve and a motor-operated gate valve and is routed in a single line feeding the HP turbine. A branch line off the IP turbine exhaust feeds the boiler feed water pump turbine during unit operation starting at approximately 60 percent load.

Cold reheat steam exits the HP turbine, flows through a motor-operated isolation gate valve and a flow control valve, and enters the boiler reheater. Hot reheat steam exits the boiler reheater through a motor-operated gate valve and is routed to the IP turbine.

3.1.11.4 Extraction Steam

The function of the extraction steam system is to convey steam from turbine extraction points through the following routes:

- From HP turbine extraction to heater 7 (and 8 in SC cases)
- From IP turbine extraction to heater 6 and the deaerator (heater 5)
- From LP turbine extraction to heaters 1, 2, 3, and 4

The turbine is protected from overspeed on turbine trip, from flash steam reverse flow from the heaters through the extraction piping to the turbine. This protection is provided by positive closing, balanced disc non-return valves located in all extraction lines except the lines to the LP FW heaters in the condenser neck. The extraction non-return valves are located only in horizontal runs of piping and as close to the turbine as possible.

The turbine trip signal automatically trips the non-return valves through relay dumps. The remote manual control for each heater level control system is used to release the non-return valves to normal check valve service when required to restart the system.

3.1.11.5 Circulating Water System

It is assumed that the plant is serviced by a public water facility and has access to groundwater for use as makeup cooling water with minimal pretreatment. All filtration and treatment of the circulating water are conducted on site. A mechanical draft, wood frame, counter-flow cooling tower is provided for the circulating water heat sink. Two 50 percent CWPs are provided. The circulating water system (CWS) provides cooling water to the condenser, the auxiliary cooling water system, and the CDR facility and CO_2 compressors in capture cases.

The auxiliary cooling water system is a CL system. Plate and frame heat exchangers with circulating water as the cooling medium are provided. This system provides cooling water to the lube oil coolers, turbine generator, boiler feed pumps, etc. All pumps, vacuum breakers, air release valves, instruments, controls, etc. are included for a complete operable system.

The CDR and CO_2 compression systems in Cases B11B and B12B requires a substantial amount of cooling water that is provided by the PC plant CWS. The additional cooling loads imposed by the CDR and CO_2 compressors are reflected in the significantly larger CWPs and cooling tower in those cases.

3.1.11.6 Ash Handling System

The function of the ash handling system is to provide the equipment required for conveying, preparing, storing, and disposing of the fly ash and bottom ash produced on a daily basis by the boiler, along with the hydrated lime and activated carbon injected for mercury control (discussed in Section 3.1.6). The scope of the system is from the baghouse hoppers, air heater and economizer hopper collectors, and bottom ash hoppers to the hydrobins (for bottom ash) and truck filling stations (for fly ash). The system is designed to support short-term operation at the

5 percent OP/VWO condition (16 hours) and long-term operation at the 100 percent guarantee point (90 days or more).

The fly ash collected in the baghouse and the air heaters is conveyed to the fly ash storage silo. A pneumatic transport system using LP air from a blower provides the transport mechanism for the fly ash. Fly ash is discharged through a wet unloader, which conditions the fly ash and conveys it through a telescopic unloading chute into a truck for disposal.

As mentioned in Section 3.1.5, the use of ACI and DSI increases the calcium content of the fly ash and adds an additional burden to the fabric filter. The addition of calcium is not expected to increase the leaching of trace metals from the fly ash significantly. The ACI and DSI systems increase the total amount of particulate matter by approximately 26 percent.

The bottom ash from the boiler is fed into a clinker grinder. The clinker grinder is provided to break up any clinkers that may form. From the clinker grinders the bottom ash is sluiced to hydrobins for dewatering and offsite removal by truck.

Ash from the economizer hoppers and pyrites (rejected from the coal pulverizers) is conveyed using water to the economizer/pyrites transfer tank. This material is then sluiced on a periodic basis to the hydrobins.

3.1.11.7 Ducting and Stack

One stack is provided with a single fiberglass-reinforced plastic (FRP) liner. The stack is constructed of reinforced concrete. The stack is 152 m (500 ft) high for adequate particulate dispersion.

3.1.11.8 Waste Treatment/Miscellaneous Systems

An onsite water treatment facility treats all runoff, cleaning wastes, blowdown, and backwash. It is anticipated that the treated water will be suitable for discharge into existing systems and be within the EPA standards for suspended solids, oil and grease, pH, and miscellaneous metals.

The waste treatment system is minimal and consists, primarily, of neutralization and oil/water separators (along with the associated pumps, piping, etc.).

Miscellaneous systems consisting of fuel oil, service air, instrument air, and service water are provided. A storage tank provides a supply of No. 2 fuel oil used for startup and for a small auxiliary boiler. Fuel oil is delivered by truck. All truck roadways and unloading stations inside the fence area are provided.

3.1.11.9 Buildings and Structures

Foundations are provided for the support structures, pumps, tanks, and other plant components. The following buildings are included in the design basis:

- Steam turbine building
- Boiler building
- Administration and service building
- Makeup water and pretreatment building
- Fuel oil pump house
- Coal crusher building
- Continuous emissions monitoring building
- Pump house and electrical equipment building
- Guard house
- Runoff water pump house
- Industrial waste treatment building
- FGD system buildings

3.1.12 Accessory Electric Plant

The accessory electric plant consists of switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, and wire and cable. It also includes the main power transformer, required foundations, and standby equipment.

3.1.13 Instrumentation and Control

An integrated plant-wide control and monitoring DCS is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of multiple video monitor and keyboard units. The monitor/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to provide 99.5 percent availability. The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are implemented as supervised manual, with operator selection of modular automation routines available.

3.1.14 Performance Summary Metrics

This section details the methodologies of several metrics reported in the performance summaries of the PC cases.

Steam Generator Efficiency

The steam generator efficiency is equal to the amount of heat transferred in the boiler divided by the thermal input provided by the coal. This calculation is represented by the equation:

$$SGE = \frac{BH}{CH}$$

Where:
SGE – steam generator efficiency
BH – boiler thermal output
CH – coal thermal input

The heat transferred in the boiler is provided by the Aspen models, and the thermal input of the coal is the product of the coal feed rate and the heating value of the coal.

Steam Turbine Efficiency

The steam turbine efficiency is calculated by taking the steam turbine power produced and dividing it by the difference between the thermal input and thermal consumption. This calculation is represented by the equation:

$$STE = \frac{STP}{(TI - TC)}$$

Where:
STE – steam turbine efficiency
STP – steam turbine power
TI – thermal input
TC – thermal consumption

The thermal input is considered to be the main steam.

The thermal consumption is only present in the capture cases. It is the enthalpy difference between the streams extracted for the capture and CO_2 dryer systems and the condensate returned to the condenser (steam extraction – condensate return).

Steam Turbine Heat Rate

The steam turbine heat rate is calculated by taking the inverse of the steam turbine efficiency. This calculation is represented by the equation:

$$STHR = \frac{1}{STE} * 3{,}412$$

Where:
STHR – steam turbine heat rate, Btu/kWh
STE – steam turbine efficiency, fraction

3.2 Subcritical PC Cases

This section contains an evaluation of plant designs for Cases B11A and B11B, which are based on a subcritical PC plant with a nominal net output of 550 MWe. Both plants use a single reheat 16.5 MPa/566°C/566°C (2,400 psig/1,050°F/1,050°F) cycle. The main difference between the two configurations is that Case B11B includes CO_2 capture while Case B11A does not.

The balance of this section is organized as follows:

- Process and System Description provides an overview of the technology operation as applied to Case B11A. The systems that are common to all PC cases were covered in Section 3.1 and only features that are unique to Case B11A are discussed further in this section.
- Key Assumptions is a summary of study and modeling assumptions relevant to Cases B11A and B11B.
- Sparing Philosophy is provided for both Cases B11A and B11B.
- Performance Results provides the main modeling results from Case B11A, including the performance summary, environmental performance, carbon/sulfur balances, water balance, mass and energy balance diagrams and energy balance table.
- Equipment List provides an itemized list of major equipment for Case B11A with account codes that correspond to the cost accounts in the Cost Estimates section.
- Cost Estimates provides a summary of capital and operating costs for Case B11A.
- Process and System Description, Performance Results, Equipment List and Cost Estimates are discussed for Case B11B.

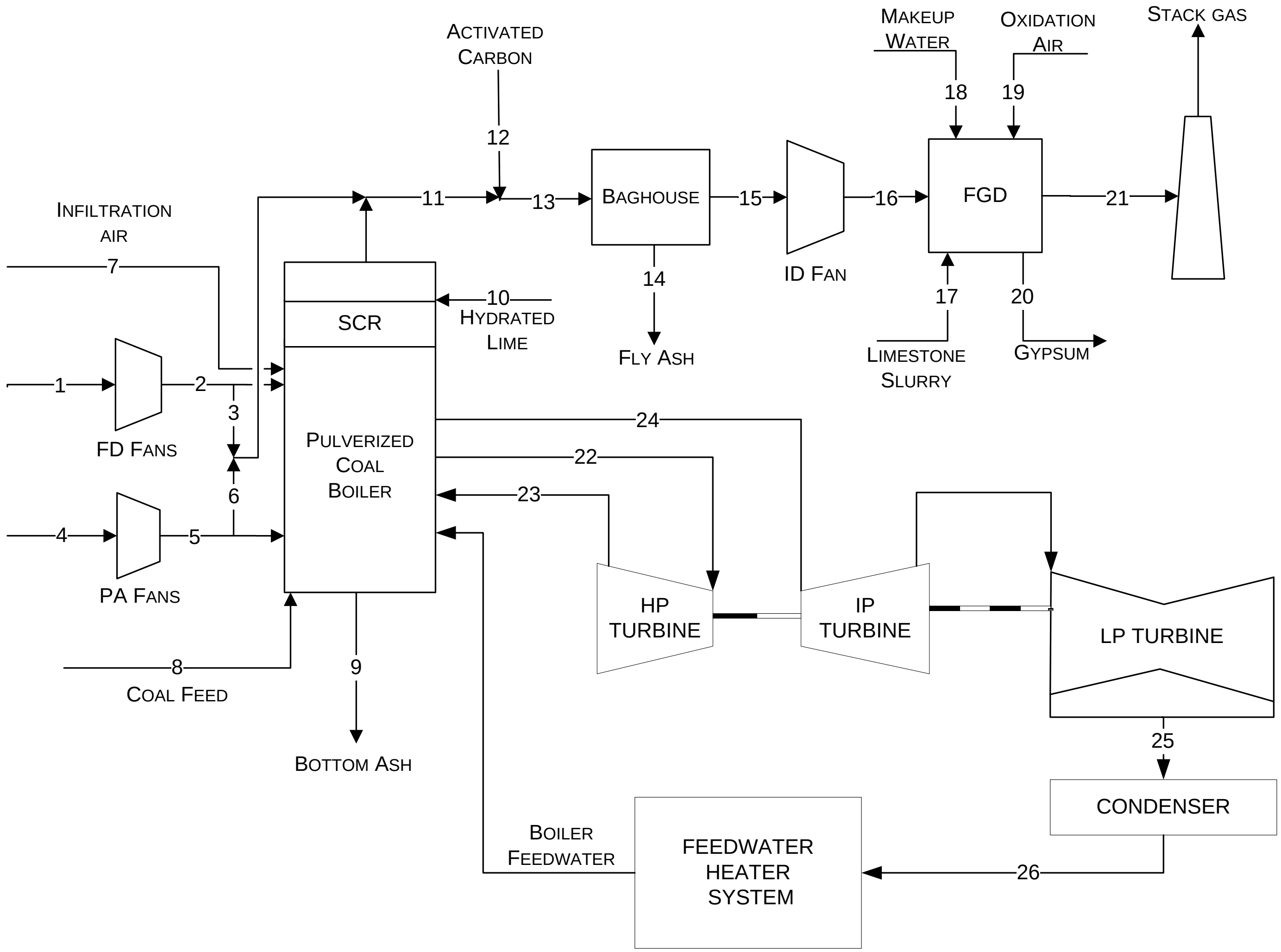
3.2.1 Process Description

In this section the subcritical PC process without CO_2 capture is described. The system description follows the block flow diagram (BFD) in Exhibit 3-5 and stream numbers reference the same Exhibit. The tables in Exhibit 3-6 provide process data for the numbered streams in the BFD.

Coal (stream 8) and PA (stream 4) are introduced into the boiler through the wall-fired burners. Additional combustion air, including the OFA, is provided by the FD fans (stream 1). The boiler operates at a slight negative pressure so air leakage is into the boiler, and the infiltration air is accounted for in stream 7. Streams 3 and 6 show Ljungstrom air preheater leakages from the FD and PA fan outlet streams to the boiler exhaust.

Flue gas exits the boiler through the SCR reactor where ammonia is injected to reduce NOx compounds, followed by hydrated lime injection (stream 10) for the reduction of SO_3. It then passes through the combustion air preheater (where the air preheater leakages are introduced) and is cooled to 143°C (289°F) (stream 11) before PAC is injected (stream 12) for mercury reduction. The flue gas then passes through a fabric filter for particulate removal (stream 15). An ID fan increases the flue gas temperature to 153°C (308°F) and provides the motive force for the flue gas (stream 16) to pass through the FGD unit. FGD inputs and outputs include makeup water (stream 18), oxidation air (stream 19), limestone slurry (stream 17) and product gypsum (stream 20). The clean, saturated flue gas exiting the FGD unit (stream 21) passes to the plant stack and is discharged to the atmosphere.

Exhibit 3-5 Case B11A block flow diagram, subcritical unit without CO_2 capture



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Source: NETL

Exhibit 3-6 Case B11A stream table, subcritical unit without capture

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
V-L Mole Fraction														
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000	0.0088	0.0000	0.0088	0.0000
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1376	0.0000	0.1376	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0000	0.0831	0.0000	0.0831	0.0000
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7345	0.0000	0.7345	0.0000
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0340	0.0000	0.0340	0.3333
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0020	0.0000	0.0020	0.6667
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000
V-L Flowrate (kg_{mole}/hr)	51,529	51,529	1,526	15,829	15,829	2,179	1,126	0	0	0	72,228	0	72,228	3
V-L Flowrate (kg/hr)	1,486,984	1,486,984	44,042	456,786	456,786	62,866	32,480	0	0	0	2,145,010	0	2,145,010	164
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	186,882	3,624	3,766	18,264	109	18,372	18,372
Temperature (°C)	15	19	19	15	25	25	15	15	149	27	143	27	143	143
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) [A]	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	0.00	0.00	0.00	---	---
AspenPlus Enthalpy (kJ/kg) [B]	-97.58	-93.45	-93.45	-97.58	-87.03	-87.03	-97.58	-2,114.05	97.18	-13,306.82	-2,399.51	3.40	-2,399.39	-2,632.02
Density (kg/m^3)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	---	0.9	---	0.9	1.5
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	---	29.698	---	29.698	53.376
V-L Flowrate (lb_{mole}/hr)	113,603	113,603	3,365	34,898	34,898	4,803	2,481	0	0	0	159,235	0	159,235	7
V-L Flowrate (lb/hr)	3,278,239	3,278,239	97,095	1,007,041	1,007,041	138,595	71,605	0	0	0	4,728,938	0	4,728,938	362
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	412,005	7,990	8,303	40,264	240	40,504	40,504
Temperature (°F)	59	66	66	59	78	78	59	59	300	80	289	80	289	289
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.4	14.7	14.4	14.7	14.4	14.4
Steam Table Enthalpy (Btu/lb) [A]	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---				---	---
AspenPlus Enthalpy (Btu/lb) [B]	-42.0	-40.2	-40.2	-42.0	-37.4	-37.4	-42.0	-908.9	41.8	-5,720.9	-1,031.6	1.5	-1,031.6	-1,131.6
Density (lb/ft^3)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	---	0.053	---	0.053	0.096

[A] Steam table reference conditions are 32.02°F & 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit 3-6 Case B11A stream table, subcritical unit without capture (continued)

	15	16	17	18	19	20	21	22	23	24	25	26
V-L Mole Fraction												
Ar	0.0088	0.0088	0.0000	0.0000	0.0092	0.0000	0.0082	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.1376	0.1376	0.0000	0.0000	0.0003	0.0001	0.1288	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0831	0.0831	1.0000	1.0000	0.0099	0.9999	0.1451	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.7345	0.7345	0.0000	0.0000	0.7732	0.0000	0.6854	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0340	0.0340	0.0000	0.0000	0.2074	0.0000	0.0325	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0020	0.0020	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mole}/hr)	72,225	72,225	2,394	9,596	764	177	78,266	87,854	82,001	82,001	72,119	73,186
V-L Flowrate (kg/hr)	2,144,846	2,144,846	43,130	172,870	22,042	3,183	2,258,148	1,582,718	1,477,271	1,477,271	1,299,243	1,318,467
Solids Flowrate (kg/hr)	0	0	18,467	0	0	28,641	0	0	0	0	0	0
Temperature (°C)	143	153	15	27	167	56	56	593	355	566	38	39
Pressure (MPa, abs)	0.10	0.11	0.10	0.11	0.31	0.10	0.10	16.65	4.28	4.19	0.01	2.04
Steam Table Enthalpy (kJ/kg) [A]	274.35	285.60	---	111.65	184.48	---	286.09	3,473.89	3,098.44	3,593.58	1,980.12	163.34
AspenPlus Enthalpy (kJ/kg)[B]	-2,397.38	-2,386.13	-14,995.75	-15,964.53	56.67	-12,481.91	-2,940.30	-12,506.41	-12,881.86	-12,386.71	-14,000.17	-15,816.96
Density (kg/m^3)	0.8	0.9	1,003.6	992.3	2.4	833.1	1.1	47.7	16.0	11.1	0.1	993.6
V-L Molecular Weight	29.697	29.697	18.015	18.015	28.857	18.018	28.852	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mole}/hr)	159,229	159,229	5,278	21,155	1,684	389	172,548	193,685	180,781	180,781	158,995	161,348
V-L Flowrate (lb/hr)	4,728,575	4,728,575	95,086	381,114	48,595	7,018	4,978,363	3,489,296	3,256,825	3,256,825	2,864,341	2,906,721
Solids Flowrate (lb/hr)	0	0	40,712	0	0	63,142	0	0	0	0	0	0
Temperature (°F)	289	308	59	80	332	133	133	1,050	671	1,050	101	101
Pressure (psia)	14.2	15.2	15.0	15.7	45.0	14.7	14.7	2,414.7	620.5	608.1	1.0	295.5
Steam Table Enthalpy (Btu/lb)[A]	117.9	122.8	---	48.0	79.3	---	123.0	1,493.5	1,332.1	1,545.0	851.3	70.2
AspenPlus Enthalpy (Btu/lb)[B]	-1,030.7	-1,025.9	-6,447.0	-6,863.5	24.4	-5,366.3	-1,264.1	-5,376.8	-5,538.2	-5,325.3	-6,019.0	-6,800.1
Density (lb/ft^3)	0.052	0.055	62.650	61.950	0.153	52.011	0.067	2.975	1.000	0.692	0.004	62.028

[A]Steam table reference conditions are 32.02°F & 0.089 psia

[B]Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

3.2.2 Key System Assumptions

System assumptions for Cases B11A and B11B, subcritical PC with and without CO_2 capture, are compiled in Exhibit 3-7.

Exhibit 3-7 Subcritical PC plant study configuration matrix

	Case B11A w/o CO_2 Capture	Case B11B w/CO_2 Capture
Steam Cycle, MPa/°C/°C (psig/°F/°F)	16.5/566/566 (2,400/1,050/1,050)	16.5/566/566 (2,400/1,050/1,050)
Coal	Illinois No. 6	Illinois No. 6
Condenser pressure, mm Hg (in Hg)	50.8 (2)	50.8 (2)
Boiler Efficiency, HHV %	89	89
Cooling water to condenser, °C (ºF)	16 (60)	16 (60)
Cooling water from condenser, °C (ºF)	27 (80)	27 (80)
Stack temperature, °C (°F)	56 (133)	42 (107)
SO_2 Control	Wet Limestone Forced Oxidation	Wet Limestone Forced Oxidation
FGD Efficiency, % (A)	98	98 (B, C)
NOx Control	LNB w/OFA, SCR, and Polishing Scrubber	LNB w/OFA, SCR, and Polishing Scrubber
SCR Efficiency, % (A)	83	85
Ammonia Slip (end of catalyst life), ppmv	2	2
Particulate Control	Fabric Filter	Fabric Filter
Fabric Filter efficiency, % (A)	99.9	99.9
Ash Distribution, Fly/Bottom	80% / 20%	80% / 20%
SO_3 Control	DSI	DSI
Mercury Control	Co-benefit Capture and ACI	Co-benefit Capture and ACI
CO_2 Control	N/A	Cansolv
Overall Carbon Capture (A)	N/A	90%
CO_2 Sequestration	N/A	Off-site Saline Formation

[A]Removal efficiencies are based on the flue gas content
[B]An SO_2 polishing step is included to meet more stringent SOx content limits in the flue gas (~1 ppmv) to reduce formation of amine HSS during the CO_2 absorption process
[C]SO_2 exiting the post-FGD polishing step is absorbed in the CO_2 capture process making stack emissions negligible

3.2.2.1 Balance of Plant – Cases B11A and B11B

The balance of plant assumptions are common to all cases and are presented in Exhibit 3-8.

Exhibit 3-8 Balance of plant assumptions

Parameter	Value
Cooling system	Recirculating Wet Cooling Tower
Fuel and Other storage	
Coal	30 days
Ash	30 days
Gypsum	30 days
Limestone	30 days
Hydrated lime	30 days
Activated carbon	30 days
Plant Distribution Voltage	
Motors below 1 hp	110/220 V
Motors between 1 hp and 250 hp	480 V
Motors between 250 hp and 5,000 hp	4,160 V
Motors above 5,000 hp	13,800 V
Steam and CT generators	24,000 V
Grid Interconnection voltage	345 kV
Water and Waste Water	
Makeup Water	The water supply is 50 percent from a local POTW and 50 percent from groundwater, and is assumed to be in sufficient quantities to meet plant makeup requirements. Makeup for potable, process, and DI water is drawn from municipal sources.
Process Wastewater	Storm water that contacts equipment surfaces is collected and treated for discharge through a permitted discharge.
Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant is sized for 5.68 cubic meters per day (1,500 gallons per day)
Water Discharge	Most of the process wastewater is recycled to the cooling tower basin. Blowdown will be treated for chloride and metals, and discharged.

3.2.3 Sparing Philosophy

Single trains are used throughout the design with exceptions where equipment capacity requires an additional train. There is no redundancy other than normal sparing of rotating equipment. The plant design consists of the following major subsystems:

- One dry-bottom, wall-fired PC subcritical boiler (1 x 100%)
- Two SCR reactors (2 x 50%)
- One DSI system (1 x 100%)
- One ACI system (1 x 100%)
- Two single-stage, in-line, multi-compartment fabric filters (2 x 50%)
- One wet limestone forced oxidation positive pressure absorber (1 x 100%)
- One steam turbine (1 x 100%)
- For Case B11B only, one CO_2 absorption system, consisting of an absorber, stripper, and ancillary equipment (1 x 100%) and two CO_2 compression systems (2 x 50%)

3.2.4 Case B11A Performance Results

The plant produces a net output of 550 MWe at a net plant efficiency of 39.0 percent (HHV basis). Overall performance for the plant is summarized in Exhibit 3-9. Exhibit 3-10 provides a detailed breakdown of the auxiliary power requirements.

Exhibit 3-9 Case B11A plant performance summary

Performance Summary	
Total Gross Power, MWe	**581**
CO_2 Capture/Removal Auxiliaries, kWe	0
CO_2 Compression, kWe	0
Balance of Plant, kWe	31,153
Total Auxiliaries, MWe	**31**
Net Power, MWe	**550**
HHV Net Plant Efficiency (%)	39.0%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,221 (8,740)
LHV Net Plant Efficiency (%)	40.5%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,894 (8,430)
HHV Boiler Efficiency, %	89.1%
LHV Boiler Efficiency, %	92.4%
Steam Turbine Cycle Efficiency, %	46.3%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,774 (7,369)
Condenser Duty, GJ/hr (MMBtu/hr)	2,362 (2,239)
As-Received Coal Feed, kg/hr (lb/hr)	186,882 (412,005)
Limestone Sorbent Feed, kg/hr (lb/hr)	18,467 (40,712)
HHV Thermal Input, kWt	1,408,630
LHV Thermal Input, kWt	1,358,641
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.038 (10.1)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.030 (8.0)
Excess Air, %	20.9%

Exhibit 3-10 Case B11A plant power summary

Power Summary	
Steam Turbine Power, MWe	581
Total Gross Power, MWe	**581**
Auxiliary Load Summary	
Coal Handling and Conveying, kWe	440
Pulverizers, kWe	2,800
Sorbent Handling & Reagent Preparation, kWe	890
Ash Handling, kWe	650
Primary Air Fans, kWe	1,390
Forced Draft Fans, kWe	1,770
Induced Draft Fans, kWe	6,940
SCR, kWe	50
Activated Carbon Injection, kWe	23
Dry sorbent Injection, kWe	90
Baghouse, kWe	90
Wet FGD, kWe	2,950
CO_2 Capture/Removal Auxiliaries, kWe	0
CO_2 Compression, kWe	0
Miscellaneous Balance of Plant[A,B], kWe	2,000
Steam Turbine Auxiliaries, kWe	400
Condensate Pumps, kWe	990
Circulating Water Pumps, kWe	4,850
Ground Water Pumps, kWe	500
Cooling Tower Fans, kWe	2,510
Transformer Losses, kWe	1,820
Total Auxiliaries, MWe	**31**
Net Power, MWe	**550**

[A]Boiler feed pumps are turbine driven
[B]Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

3.2.4.1 Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B11A is presented in Exhibit 3-11. SO_2 emissions are utilized as a surrogate for HCl emissions, therefore HCl is not reported.

Exhibit 3-11 Case B11A air emissions

	kg/GJ (lb/MMBtu)	Tonne/year (ton/year)[A]	kg/MWh (lb/MWh)
SO_2	0.036 (0.085)	1,374 (1,514)	0.318 (0.700)
NOx	0.036 (0.085)	1,374 (1,514)	0.318 (0.700)
Particulate	0.005 (0.011)	177 (195)	0.041 (0.090)
Hg	1.56E-7 (3.63E-7)	0.006 (0.006)	1.36E-6 (3.00E-6)
CO_2[B]	88 (204)	3,303,826 (3,641,844)	764 (1,683)
CO_2[C]	-	-	807 (1,779)
	mg/Nm³		
Particulate Concentration[D,E]	14.66		

[A]Calculations based on an 85 percent capacity factor
[B]CO_2 emissions based upon gross power
[C]CO_2 emissions based on net power instead of gross power
[D]Concentration of particles in the flue gas after the baghouse
[E]Normal conditions given at 32°F and 14.696 psia

SO_2 emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The saturated flue gas exiting the scrubber is vented through the plant stack.

NOx emissions are controlled to about 0.5 lb/MMBtu through the use of LNBs and OFA. An SCR unit then further reduces the NOx concentration by 83 percent to 0.08 lb/MMBtu.

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment (SCR, ACI, fabric filter, DSI, and wet FGD) is 96.8 percent.

CO_2 emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 3-12. The carbon input to the plant consists of carbon in the coal, carbon in the air, PAC, and carbon in the limestone reagent used in the FGD absorber. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant mostly as CO_2 through the stack, however, the PAC is captured in the fabric filter and some leaves as gypsum.

Exhibit 3-12 Case B11A carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		**kg/hr (lb/hr)**
Coal	119,128 (262,631)	Stack Gas	121,094 (266,967)
Air (CO_2)	272 (599)	FGD Product	179 (394)
PAC	109 (240)	Baghouse	109 (240)
FGD Reagent	1,874 (4,131)	CO_2 Product	0
		CO_2 Dryer Vent	0
		CO_2 Knockout	0
Total	**121,382 (267,601)**	**Total**	**121,382 (267,601)**

Exhibit 3-13 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur captured in the fabric filter via hydrated lime, and sulfur emitted in the stack gas.

Exhibit 3-13 Case B11A sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	4,684 (10,327)	FGD Product	4,526 (9,978)
		Stack Gas	92 (204)
		Polishing Scrubber and Solvent Reclaiming	0
		Baghouse	66 (145)
Total	**4,684 (10,327)**	**Total**	**4,684 (10,327)**

Exhibit 3-14 shows the water balance for Case B11A.

Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is re-used as internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a POTW for use in the plant and was assumed to be provided 50 percent by a POTW and 50 percent from groundwater. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for any and all purposes, such as FGD makeup, BFW makeup, and cooling tower makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source.

Exhibit 3-14 Case B11A water balance

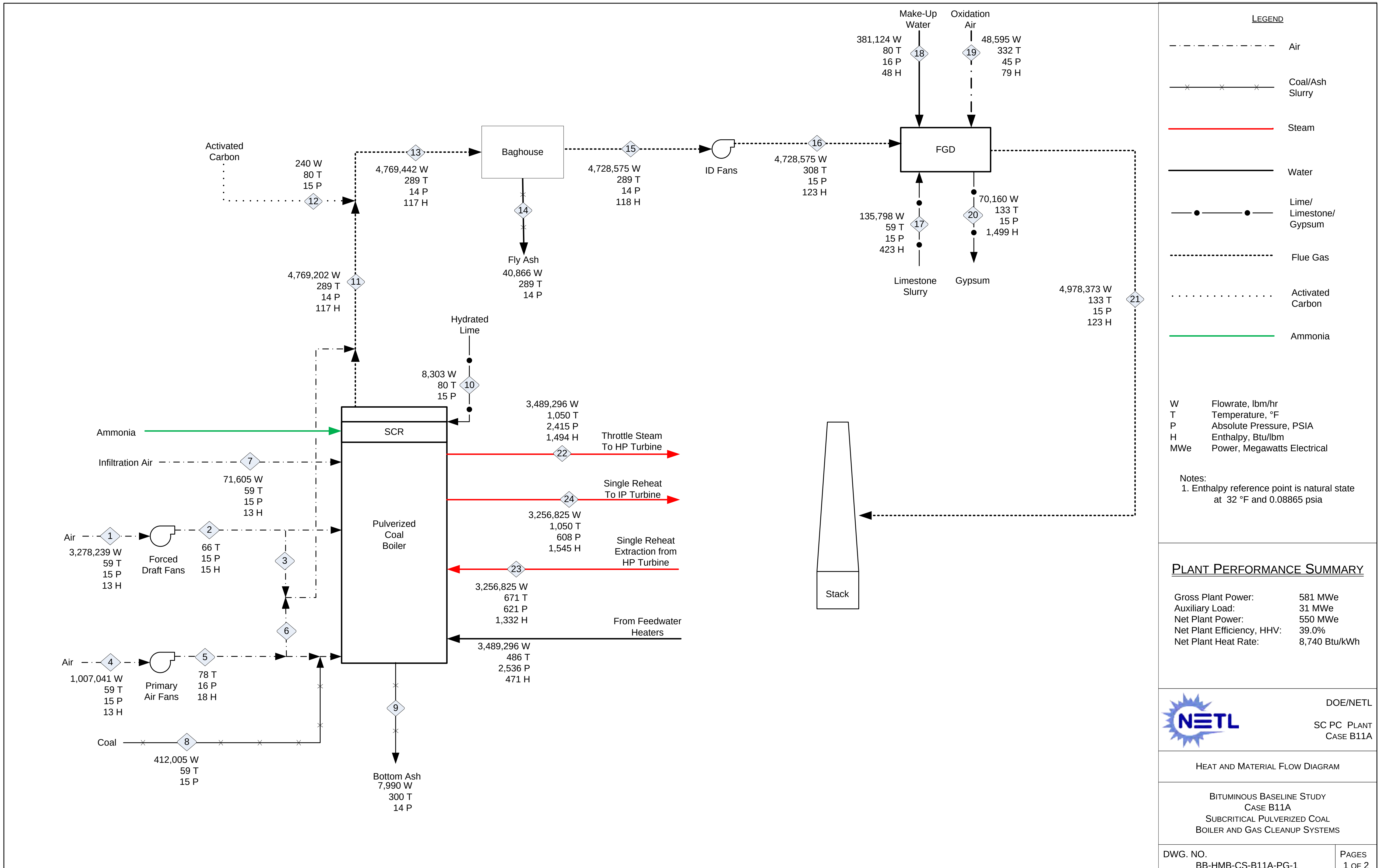
Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)
FGD Makeup	3.61 (952)	–	3.61 (952)	–	3.61 (952)
CO_2 Drying	–	–	–	–	–
Capture System Makeup	–	–	–	–	–
Deaerator Vent	–	–	–	0.05 (14)	-0.05 (-14)
Condenser Makeup	**0.32 (85)**	**–**	**0.32 (85)**	**–**	**0.32 (85)**
BFW Makeup	0.32 (85)	–	0.32 (85)	–	0.32 (85)
Cooling Tower	**18.89 (4,991)**	**1.86 (491)**	**17.04 (4,500)**	**4.25 (1,123)**	**12.79 (3,378)**
FGD Dewatering	–	1.86 (491)	-1.86 (-491)	–	-1.86 (-491)
CO_2 Capture Recovery	–	–	–	–	–
CO_2 Compression KO	–	–	–	–	–
BFW Blowdown	–	0.27 (71)	-0.27 (-71)	–	-0.27 (-71)
Total	**22.82 (6,029)**	**1.86 (491)**	**20.96 (5,538)**	**4.30 (1,137)**	**16.66 (4,401)**

3.2.4.2 Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the Case B11A PC boiler, the FGD unit, and steam cycle as shown in Exhibit 3-15 and Exhibit 3-16.

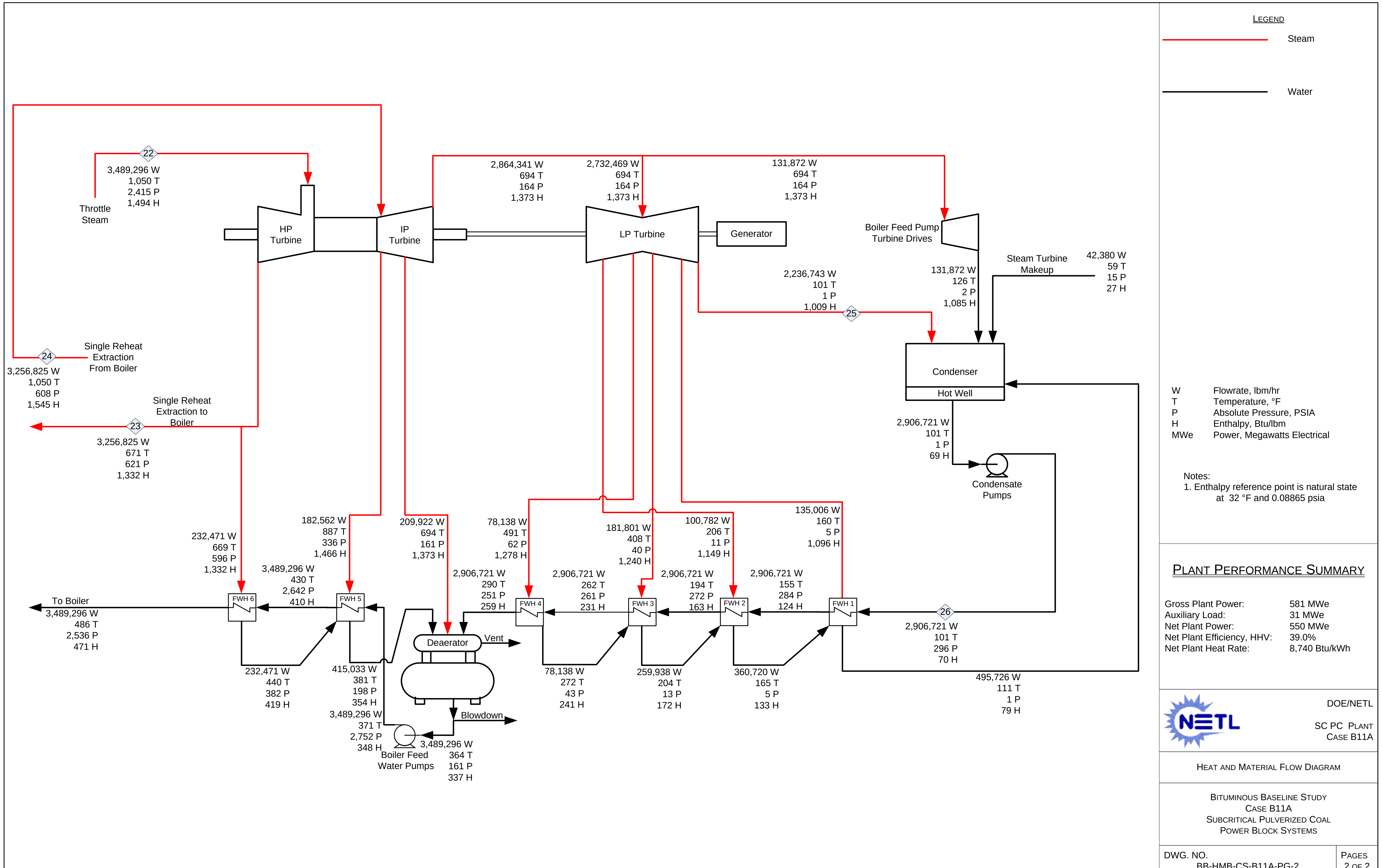
An overall plant energy balance is provided in tabular form in Exhibit 3-17. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-9) is calculated by multiplying the power out by a generator efficiency of 98.5 percent.

Exhibit 3-15 Case B11A heat and mass balance, subcritical PC boiler without CO_2 capture



Source: NETL

Exhibit 3-16 Case B11A heat and mass balance, subcritical steam cycle



Source: NETL

Exhibit 3-17 Case B11A overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	5,071 (4,806)	4.2 (4.0)	–	5,075 (4,810)
Air	–	59.7 (56.6)	–	59.7 (56.6)
Raw Water Makeup	–	78.8 (74.7)	–	78.8 (74.7)
Limestone	–	0.40 (0.38)	–	0.40 (0.38)
Auxiliary Power	–	–	112 (106)	112 (106)
TOTAL	**5,071 (4,806)**	**143.2 (135.7)**	**112 (106)**	**5,326 (5,048)**
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	–	0.4 (0.4)	–	0.4 (0.4)
Fly Ash + FGD Ash	–	2.1 (2.0)	–	2.1 (2.0)
Stack Gas	–	646 (612)	–	646 (612)
Sulfur	–	–	–	–
Motor Losses and Design Allowances	–	–	34 (33)	34 (33)
Condenser	–	2,362 (2,239)	–	2,362 (2,239)
Non-Condenser Cooling Tower Loads	–	106 (100)	–	106 (100)
CO_2	–	0.0 (0.0)	–	0.0 (0.0)
Cooling Tower Blowdown	–	31.6 (29.9)	–	31.6 (29.9)
CO_2 Capture Losses	–	–	–	–
Ambient Losses[A]	–	107.7 (102.0)	–	107.7 (102.0)
Power	–	–	2,092 (1,983)	2,092 (1,983)
TOTAL	**–**	**3,255 (3,085)**	**2,126 (2,015)**	**5,382 (5,101)**
Unaccounted Energy[B]	–	-55 (-52)	–	-55 (-52)

[A]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers.
[B]By difference

3.2.5 Case B11A – Major Equipment List

Major equipment items for the subcritical PC plant with no CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 3.2.6. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

Case B11A – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	40 tonne (40 ton)	2	1
9	Feeder	Vibratory	150 tonne/hr (170 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	310 tonne/hr (340 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	150 tonne (170 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	310 tonne/hr (340 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	310 tonne/hr (340 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	690 tonne (800 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 29 tonne (32 ton) Feeder - 120 kg/hr (260 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 200 tonne (220 ton) Feeder – 4,140 kg/hr (9,130 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	80 tonne/hr (90 tph)	1	0
23	Limestone Conveyor No. L1	Belt	80 tonne/hr (90 tph)	1	0
24	Limestone Reclaim Hopper	N/A	20 tonne (20 ton)	1	0
25	Limestone Reclaim Feeder	Belt	60 tonne/hr (70 tph)	1	0
26	Limestone Conveyor No. L2	Belt	60 tonne/hr (70 tph)	1	0
27	Limestone Day Bin	w/ actuator	240 tonne (270 ton)	2	0

Case B11A – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	30 tonne/hr (40 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	30 tonne/hr (40 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	20 tonne/hr (22 tph)	1	1
4	Limestone Ball Mill	Rotary	20 tonne/hr (22 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	77,200 liters (20,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,300 lpm @ 10m H_2O (340 gpm @ 40 ft H_2O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5 cyclone bank	320 lpm (90 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	439,000 liters (116,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	910 lpm @ 9m H_2O (240 gpm @ 30 ft H_2O)	1	1

Case B11A – Account 3: Feedwater and Miscellaneous Systems and Equipment

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,271,000 liters (336,000 gal)	2	0
2	Condensate Pumps	Vertical canned	24,300 lpm @ 300 m H_2O (6,400 gpm @ 800 ft H_2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	1,762,000 kg/hr (3,885,000 lb/hr), 5 min. tank	1	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	29,200 lpm @ 2,200 m H_2O (7,700 gpm @ 7,200 ft H_2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	8,700 lpm @ 2,200 m H_2O (2,300 gpm @ 7,200 ft H_2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	730,000 kg/hr (1,600,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	730,000 kg/hr (1,600,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	730,000 kg/hr (1,600,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	730,000 kg/hr (1,600,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	1,740,000 kg/hr (3,840,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	1,740,000 kg/hr (3,840,000 lb/hr)	1	0
12	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
13	Fuel Oil System	No. 2 fuel oil for light off	1,135,624 liter (300,000 gal)	1	0
14	Service Air Compressors	Flooded Screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
15	Instrument Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	2	1
16	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
17	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,800 lpm @ 30 m H_2O (5,500 gpm @ 100 ft H_2O)	2	1
18	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H_2O (1,000 gpm @ 290 ft H_2O)	1	1
19	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H_2O (700 gpm @ 210 ft H_2O)	1	1
20	Raw Water Pumps	Stainless steel, single suction	6,070 lpm @ 20 m H_2O (1,600 gpm @ 60 ft H_2O)	2	1
21	Ground Water Pumps	Stainless steel, single suction	2,430 lpm @ 270 m H_2O (640 gpm @ 880 ft H_2O)	5	1
22	Filtered Water Pumps	Stainless steel, single suction	1,920 lpm @ 50 m H_2O (510 gpm @ 160 ft H_2O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	1,839,000 liter (486,000 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	650 lpm (170 gpm)	1	1
25	Liquid Waste Treatment System	--	10 years, 24-hour storm	1	0

Case B11A – Account 4: Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Subcritical, drum wall-fired, low NOx burners, overfire air	1,740,000 kg/hr steam @ 17.9 MPa/574°C/574°C (3,840,000 lb/hr steam @ 2,600 psig/1,065°F/1,065°F)	1	0
2	Primary Air Fan	Centrifugal	251,000 kg/hr, 3,400 m^3/min @ 123 cm WG (554,000 lb/hr, 121,100 acfm @ 48 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	818,000 kg/hr, 11,200 m^3/min @ 47 cm WG (1,803,000 lb/hr, 394,100 acfm @ 19 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,180,000 kg/hr, 23,400 m^3/min @ 89 cm WG (2,601,000 lb/hr, 826,500 acfm @ 35 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	2,360,000 kg/hr (5,200,000 lb/hr)	2	0
6	SCR Catalyst	--	--	3	0
7	Dilution Air Blower	Centrifugal	130 m^3/min @ 108 cm WG (4,600 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	142,000 liter (38,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	27 lpm @ 90 m H_2O (7 gpm @ 300 ft H_2O)	2	1

Case B11A – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,180,000 kg/hr (2,601,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	47,000 m^3/min (1,661,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	164,000 lpm @ 65 m H_2O (43,000 gpm @ 210 ft H_2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	3,980 lpm (1,050 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	80 m^3/min @ 0.3 MPa (2,920 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	990 lpm (260 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	32 tonne/hr (35 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	610 lpm @ 13 m H_2O (160 gpm @ 40 ft H_2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	400,000 lpm (100,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	3,170 lpm @ 21 m H_2O (840 gpm @ 70 ft H_2O)	1	1
12	Activated Carbon Injectors	---	120 kg/hr (260 lb/hr)	1	0
13	Hydrated Lime Injectors	---	4,140 kg/hr (9,130 lb/hr)	1	0

Case B11A – Account 7: Ducting and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 5.8 m (19 ft) diameter	1	0

Case B11A – Account 8: Steam Turbine Generator and Auxiliaries

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	612 MW 16.5 MPa/566°C/566°C (2400 psig/ 1050°F/1050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	680 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,600 GJ/hr (2,460 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

Case B11A – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	487,000 lpm @ 30 m (129,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 2710 GJ/hr (2570 MMBtu/hr) heat duty	1	0

Case B11A – Account 10: Ash and Spent Sorbent Recovery and Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	--	--	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	--	--	2	0
3	Clinker Grinder	--	4.0 tonne/hr (4.4 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	--	--	6	0
5	Hydroejectors	--	--	12	
6	Economizer /Pyrites Transfer Tank	--	--	1	0
7	Ash Sluice Pumps	Vertical, wet pit	160 lpm @ 17 m H_2O (40 gpm @ 56 ft H_2O)	1	1
8	Ash Seal Water Pumps	Vertical, wet pit	7,570 lpm @ 9 m H_2O (2000 gpm @ 28 ft H_2O)	1	1
9	Hydrobins	--	150 lpm (40 gpm)	1	1
10	Baghouse Hopper (part of baghouse scope of supply)	--	--	24	0
11	Air Heater Hopper (part of boiler scope of supply)	--	--	10	0
12	Air Blower	--	20 m^3/min @ 0.2 MPa (650 scfm @ 24 psi)	1	1
13	Fly Ash Silo	Reinforced concrete	1,200 tonne (1,300 ton)	2	0
14	Slide Gate Valves	--	--	2	0
15	Unloader	--	--	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
16	Telescoping Unloading Chute	--	110 tonne/hr (130 tph)	1	0

Case B11A – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 650 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 0 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 33 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 5 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B11A – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.2.6 Case B11A – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 3-18 shows a detailed breakdown of the capital costs; Exhibit 3-19 shows the owner's costs, along with the, TOC, and TASC; Exhibit 3-20 shows the initial and annual O&M costs; and Exhibit 3-21 shows the COE breakdown.

The estimated TPC of the subcritical PC boiler with no CO_2 capture is $1,960/kW. No process contingency is included in this case because all elements of the technology are commercially proven. The project contingency is 11.2 percent of the TPC. The COE is $82.1/MWh.

Exhibit 3-18 Case B11A total plant cost details

	Case:	B11A – Subcritical PC w/o CO_2							Estimate Type:	Conceptual	
	Plant Size (MW,net):	550							Cost Base:	Jun 2011	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
	1	Coal & Sorbent Handling									
1.1	Coal Receive & Unload	$4,103	$0	$1,849	$0	$5,952	$595	$0	$982	$7,529	$14
1.2	Coal Stackout & Reclaim	$5,303	$0	$1,185	$0	$6,488	$649	$0	$1,071	$8,207	$15
1.3	Coal Conveyors	$4,930	$0	$1,173	$0	$6,103	$610	$0	$1,007	$7,720	$14
1.4	Other Coal Handling	$1,290	$0	$271	$0	$1,561	$156	$0	$258	$1,975	$4
1.5	Sorbent Receive & Unload	$164	$0	$49	$0	$212	$21	$0	$35	$269	$0
1.6	Sorbent Stackout & Reclaim	$2,644	$0	$478	$0	$3,122	$312	$0	$515	$3,949	$7
1.7	Sorbent Conveyors	$943	$205	$228	$0	$1,376	$138	$0	$227	$1,741	$3
1.8	Other Sorbent Handling	$570	$134	$295	$0	$999	$100	$0	$165	$1,263	$2
1.9	Coal & Sorbent Hnd. Foundations	$0	$4,756	$6,270	$0	$11,026	$1,103	$0	$1,819	$13,948	$25
	Subtotal	**$19,948**	**$5,095**	**$11,797**	**$0**	**$36,840**	**$3,684**	**$0**	**$6,079**	**$46,602**	**$85**
	2	Coal & Sorbent Prep & Feed									
2.1	Coal Crushing & Drying	$2,351	$0	$452	$0	$2,803	$280	$0	$462	$3,545	$6
2.2	Coal Conveyor to Storage	$6,019	$0	$1,296	$0	$7,315	$731	$0	$1,207	$9,253	$17
2.5	Sorbent Prep Equipment	$4,491	$194	$920	$0	$5,605	$560	$0	$925	$7,090	$13
2.6	Sorbent Storage & Feed	$541	$0	$204	$0	$745	$75	$0	$123	$943	$2
2.9	Coal & Sorbent Feed Foundation	$0	$548	$481	$0	$1,029	$103	$0	$170	$1,301	$2
	Subtotal	**$13,401**	**$742**	**$3,353**	**$0**	**$17,496**	**$1,750**	**$0**	**$2,887**	**$22,133**	**$40**
	3	Feedwater & Miscellaneous BOP Systems									
3.1	Feedwater System	$18,097	$0	$6,235	$0	$24,332	$2,433	$0	$4,015	$30,780	$56
3.2	Water Makeup & Pretreating	$5,536	$0	$1,751	$0	$7,288	$729	$0	$1,603	$9,620	$17
3.3	Other Feedwater Subsystems	$6,083	$0	$2,497	$0	$8,581	$858	$0	$1,416	$10,855	$20
3.4	Service Water Systems	$1,109	$0	$580	$0	$1,689	$169	$0	$372	$2,229	$4
3.5	Other Boiler Plant Systems	$7,482	$0	$7,074	$0	$14,556	$1,456	$0	$2,402	$18,413	$33
3.6	FO Supply Sys & Nat Gas	$327	$0	$382	$0	$709	$71	$0	$117	$897	$2
3.7	Waste Treatment Equipment	$3,632	$0	$2,103	$0	$5,735	$573	$0	$1,262	$7,570	$14
3.8	Misc. Equip. (Cranes, Air Comp., Comm.)	$3,205	$0	$991	$0	$4,197	$420	$0	$923	$5,540	$10
	Subtotal	**$45,472**	**$0**	**$21,614**	**$0**	**$67,086**	**$6,709**	**$0**	**$12,109**	**$85,903**	**$156**
	4	Boiler & Accessories									
4.1	PC Boiler & Accessories	$152,353	$0	$99,495	$0	$251,848	$25,185	$0	$27,703	$304,736	$554
4.2	SCR	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0
4.5	Primary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0
4.6	Secondary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0
4.9	Boiler Foundations	$0	w/14.1	w/14.1	$0	$0	$0	$0	$0	$0	$0
	Subtotal	**$152,353**	**$0**	**$99,495**	**$0**	**$251,848**	**$25,185**	**$0**	**$27,703**	**$304,736**	**$554**
	5A	Gas Cleanup & Piping									
5A.1	Absorber Vessels & Accessories	$69,501	$0	$14,860	$0	$84,361	$8,436	$0	$9,280	$102,077	$186
5A.2	Other FGD	$3,627	$0	$4,082	$0	$7,709	$771	$0	$848	$9,328	$17

Case:		B11A – Subcritical PC w/o CO_2							Estimate Type:	Conceptual	
Plant Size (MW,net):		550							Cost Base:	Jun 2011	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
5A.3	Bag House & Accessories	$19,695	$0	$12,414	$0	$32,109	$3,211	$0	$3,532	$38,852	$71
5A.4	Other Particulate Removal Materials	$1,333	$0	$1,417	$0	$2,749	$275	$0	$302	$3,327	$6
5A.5	Gypsum Dewatering System	$5,536	$0	$934	$0	$6,470	$647	$0	$712	$7,829	$14
5A.6	Mercury Removal System	$4,205	$925	$4,135	$0	$9,265	$927	$0	$1,019	$11,211	$20
	Subtotal	**$103,898**	**$925**	**$37,841**	**$0**	**$142,664**	**$14,266**	**$0**	**$15,693**	**$172,623**	**$314**
	7	**HRSG, Ducting, & Stack**									
7.3	Ductwork	$10,981	$0	$6,932	$0	$17,913	$1,791	$0	$2,956	$22,660	$41
7.4	Stack	$10,920	$0	$6,346	$0	$17,267	$1,727	$0	$1,899	$20,893	$38
7.9	Duct & Stack Foundations	$0	$1,190	$1,413	$0	$2,604	$260	$0	$573	$3,437	$6
	Subtotal	**$21,902**	**$1,190**	**$14,692**	**$0**	**$37,784**	**$3,778**	**$0**	**$5,428**	**$46,990**	**$85**
	8	**Steam Turbine Generator**									
8.1	Steam TG & Accessories	$66,400	$0	$7,465	$0	$73,865	$7,387	$0	$8,125	$89,377	$163
8.2	Turbine Plant Auxiliaries	$419	$0	$891	$0	$1,310	$131	$0	$144	$1,585	$3
8.3	Condenser & Auxiliaries	$8,232	$0	$2,742	$0	$10,974	$1,097	$0	$1,207	$13,279	$24
8.4	Steam Piping	$26,402	$0	$10,700	$0	$37,102	$3,710	$0	$6,122	$46,934	$85
8.9	TG Foundations	$0	$1,249	$2,062	$0	$3,311	$331	$0	$728	$4,371	$8
	Subtotal	**$101,453**	**$1,249**	**$23,861**	**$0**	**$126,563**	**$12,656**	**$0**	**$16,327**	**$155,546**	**$283**
	9	**Cooling Water System**									
9.1	Cooling Towers	$11,134	$0	$3,443	$0	$14,577	$1,458	$0	$1,604	$17,639	$32
9.2	Circulating Water Pumps	$2,236	$0	$143	$0	$2,378	$238	$0	$262	$2,878	$5
9.3	Circ. Water System Auxiliaries	$612	$0	$81	$0	$693	$69	$0	$76	$839	$2
9.4	Circ. Water Piping	$0	$5,158	$4,671	$0	$9,829	$983	$0	$1,622	$12,434	$23
9.5	Make-up Water System	$554	$0	$712	$0	$1,266	$127	$0	$209	$1,602	$3
9.6	Component Cooling Water Sys.	$499	$0	$383	$0	$882	$88	$0	$146	$1,116	$2
9.9	Circ. Water Foundations & Structures	$0	$2,726	$4,526	$0	$7,252	$725	$0	$1,595	$9,573	$17
	Subtotal	**$15,035**	**$7,884**	**$13,960**	**$0**	**$36,879**	**$3,688**	**$0**	**$5,513**	**$46,080**	**$84**
	10	**Ash & Spent Sorbent Handling Systems**									
10.6	Ash Storage Silos	$796	$0	$2,435	$0	$3,231	$323	$0	$355	$3,909	$7
10.7	Ash Transport & Feed Equipment	$5,286	$0	$5,240	$0	$10,526	$1,053	$0	$1,158	$12,736	$23
10.9	Ash/Spent Sorbent Foundation	$0	$180	$221	$0	$401	$40	$0	$88	$529	$1
	Subtotal	**$6,081**	**$180**	**$7,896**	**$0**	**$14,157**	**$1,416**	**$0**	**$1,601**	**$17,174**	**$31**
	11	**Accessory Electric Plant**									
11.1	Generator Equipment	$1,945	$0	$311	$0	$2,256	$226	$0	$186	$2,667	$5
11.2	Station Service Equipment	$3,348	$0	$1,122	$0	$4,470	$447	$0	$369	$5,286	$10
11.3	Switchgear & Motor Control	$3,843	$0	$668	$0	$4,510	$451	$0	$496	$5,457	$10
11.4	Conduit & Cable Tray	$0	$2,635	$8,513	$0	$11,148	$1,115	$0	$1,839	$14,103	$26
11.5	Wire & Cable	$0	$5,017	$8,969	$0	$13,986	$1,399	$0	$2,308	$17,692	$32
11.6	Protective Equipment	$317	$0	$1,099	$0	$1,416	$142	$0	$156	$1,713	$3
11.7	Standby Equipment	$1,499	$0	$35	$0	$1,534	$153	$0	$169	$1,856	$3
11.8	Main Power Transformers	$9,846	$0	$206	$0	$10,052	$1,005	$0	$1,106	$12,163	$22
11.9	Electrical Foundations	$0	$359	$914	$0	$1,274	$127	$0	$280	$1,681	$3
	Subtotal	**$20,797**	**$8,012**	**$21,837**	**$0**	**$50,647**	**$5,065**	**$0**	**$6,909**	**$62,620**	**$114**

Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
	Case:	B11A – Subcritical PC w/o CO_2					Estimate Type:	Conceptual			
	Plant Size (MW,net):	550					Cost Base:	Jun 2011			
	12	Instrumentation & Control									
12.1	PC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0
12.5	Signal Processing Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards, Panels & Racks	$528	$0	$323	$0	$850	$85	$0	$140	$1,076	$2
12.7	Distributed Control Sys. Equipment	$5,328	$0	$950	$0	$6,278	$628	$0	$691	$7,596	$14
12.8	Instrument Wiring & Tubing	$3,213	$0	$5,846	$0	$9,059	$906	$0	$1,495	$11,459	$21
12.9	Other I & C Equipment	$1,506	$0	$3,486	$0	$4,992	$499	$0	$549	$6,040	$11
	Subtotal	**$10,574**	**$0**	**$10,605**	**$0**	**$21,179**	**$2,118**	**$0**	**$2,875**	**$26,171**	**$48**
	13	Improvements to Site									
13.1	Site Preparation	$0	$56	$1,196	$0	$1,252	$125	$0	$275	$1,653	$3
13.2	Site Improvements	$0	$1,866	$2,465	$0	$4,331	$433	$0	$953	$5,717	$10
13.3	Site Facilities	$3,344	$0	$3,508	$0	$6,851	$685	$0	$1,507	$9,044	$16
	Subtotal	**$3,344**	**$1,922**	**$7,168**	**$0**	**$12,434**	**$1,243**	**$0**	**$2,736**	**$16,413**	**$30**
	14	Buildings & Structures									
14.1	Boiler Building	$0	$10,193	$8,958	$0	$19,151	$1,915	$0	$5,266	$26,332	$48
14.2	Turbine Building	$0	$14,726	$13,715	$0	$28,442	$2,844	$0	$7,821	$39,107	$71
14.3	Administration Building	$0	$703	$743	$0	$1,446	$145	$0	$398	$1,988	$4
14.4	Circulation Water Pumphouse	$0	$201	$160	$0	$361	$36	$0	$99	$497	$1
14.5	Water Treatment Buildings	$0	$691	$629	$0	$1,320	$132	$0	$363	$1,815	$3
14.6	Machine Shop	$0	$470	$316	$0	$786	$79	$0	$216	$1,080	$2
14.7	Warehouse	$0	$319	$319	$0	$638	$64	$0	$175	$877	$2
14.8	Other Buildings & Structures	$0	$260	$221	$0	$482	$48	$0	$132	$662	$1
14.9	Waste Treating Building & Str.	$0	$498	$1,511	$0	$2,010	$201	$0	$553	$2,763	$5
	Subtotal	**$0**	**$28,061**	**$26,573**	**$0**	**$54,634**	**$5,463**	**$0**	**$15,024**	**$75,122**	**$137**
	Total	**$514,258**	**$55,260**	**$300,691**	**$0**	**$870,209**	**$87,021**	**$0**	**$120,883**	**$1,078,113**	**$1,960**

Exhibit 3-19 Case B11A owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$8,261	$15
1 Month Maintenance Materials	$1,013	$2
1 Month Non-fuel Consumables	$2,245	$4
1 Month Waste Disposal	$448	$1
25% of 1 Months Fuel Cost at 100% CF	$2,577	$5
2% of TPC	$21,562	$39
Total	**$36,106**	**$66**
Inventory Capital		
60 day supply of fuel and consumables at 100% CF	$24,698	$45
0.5% of TPC (spare parts)	$5,391	$10
Total	**$30,088**	**$55**
Other Costs		
Initial Cost for Catalyst and Chemicals	$0	$0
Land	$900	$2
Other Owner's Costs	$161,717	$294
Financing Costs	$29,109	$53
Total Overnight Costs (TOC)	**$1,336,034**	**$2,429**
TASC Multiplier (IOU, low-risk, 35 year)	1.134	
Total As-Spent Cost (TASC)	**$1,515,063**	**$2,755**

Exhibit 3-20 Case B11A initial and annual operating and maintenance costs

Case:	**B11A – Subcritical PC w/o CO_2**				**Cost Base:**	**Jun 2011**
Plant Size (MW,net):	**550**	**Heat Rate-net (Btu/kWh):**		**8,740**	**Capacity Factor (%):**	**85**
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):	39.70		**$/hour**	Skilled Operator:	2.0	
Operating Labor Burden:	30.00		**% of base**	Operator:	9.0	
Labor O-H Charge Rate:	25.00		**% of labor**	Foreman:	1.0	
				Lab Tech's, etc.:	2.0	
				Total:	**14.0**	
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$6,329,450	$11.509
Maintenance Labor:					$6,888,918	$12.527
Administrative & Support Labor:					$3,304,592	$6.009
Property Taxes and Insurance:					$21,562,266	$39.209
Total:					**$38,085,227**	**$69.254**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$10,333,377	$2.52347
Consumables						
	Consumption				**Cost ($)**	
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	3,987	$1.67	$0	$2,070,683	$0.50567
Makeup and Waste Water Treatment Chemicals (lbs):	0	19,300	$0.27	$0	$1,603,749	$0.39164
Limestone (ton)	0	489	$33.48	$0	$5,074,576	$1.23924
Hydrated Lime (ton)	0	100	$155.00	$0	$4,791,509	$1.17011
Activated Carbon (ton)	0	3	$1,255.00	$0	$1,120,453	$0.27362
Ammonia (19% NH_3, ton)	0	72	$330.00	$0	$7,327,095	$1.78932
SCR Catalyst (m^3)	0	0.33	$8,938.80	$0	$908,626	$0.22189
Subtotal:				**$0**	**$22,896,691**	**$5.59150**
Waste Disposal						
Fly Ash (ton)	0	490	$25.11	$0	$3,816,576	$0.93203
Bottom Ash (ton)	0	96	$25.11	$0	$750,758	$0.18334
Subtotal:				**$0**	**$4,567,334**	**$1.11537**
By-Products						
Gypsum (ton)	0	84	$0.00	$0	$0	$0.00000
Subtotal:				**$0**	**$0**	**$0.00000**
Variable Operating Costs Total:				**$0**	**$37,797,401**	**$9.23034**
Fuel Cost						
Illinois Number 6 (ton):	0	4,944	$68.54	$0	$105,133,037	$25.67409
Total:				**$0**	**$105,133,037**	**$25.67409**

Exhibit 3-21 Case B11A COE breakdown

Component	Value, $/MWh	Percentage
Capital	37.8	46%
Fixed	9.3	11%
Variable	9.2	11%
Fuel	25.7	31%
Total (Excluding T&S)	**82.1**	**N/A**
CO_2 T&S	0.0	0%
Total (Including T&S)	**82.1**	**N/A**

3.2.7 Case B11B – PC Subcritical Unit with CO_2 Capture

The plant configuration for Case B11B, subcritical PC, is the same as Case B11A with the exception that the Cansolv system was used for the CDR facility. The nominal net output was maintained at 550 MW by increasing the boiler size and turbine/generator size to account for the greater auxiliary load imposed by the CDR facility and CO_2 compressors. Unlike the NGCC cases where gross output was fixed by the available size of the CTs, the PC cases utilize boilers and steam turbines that can be procured at nearly any desired output making it possible to maintain a constant net output.

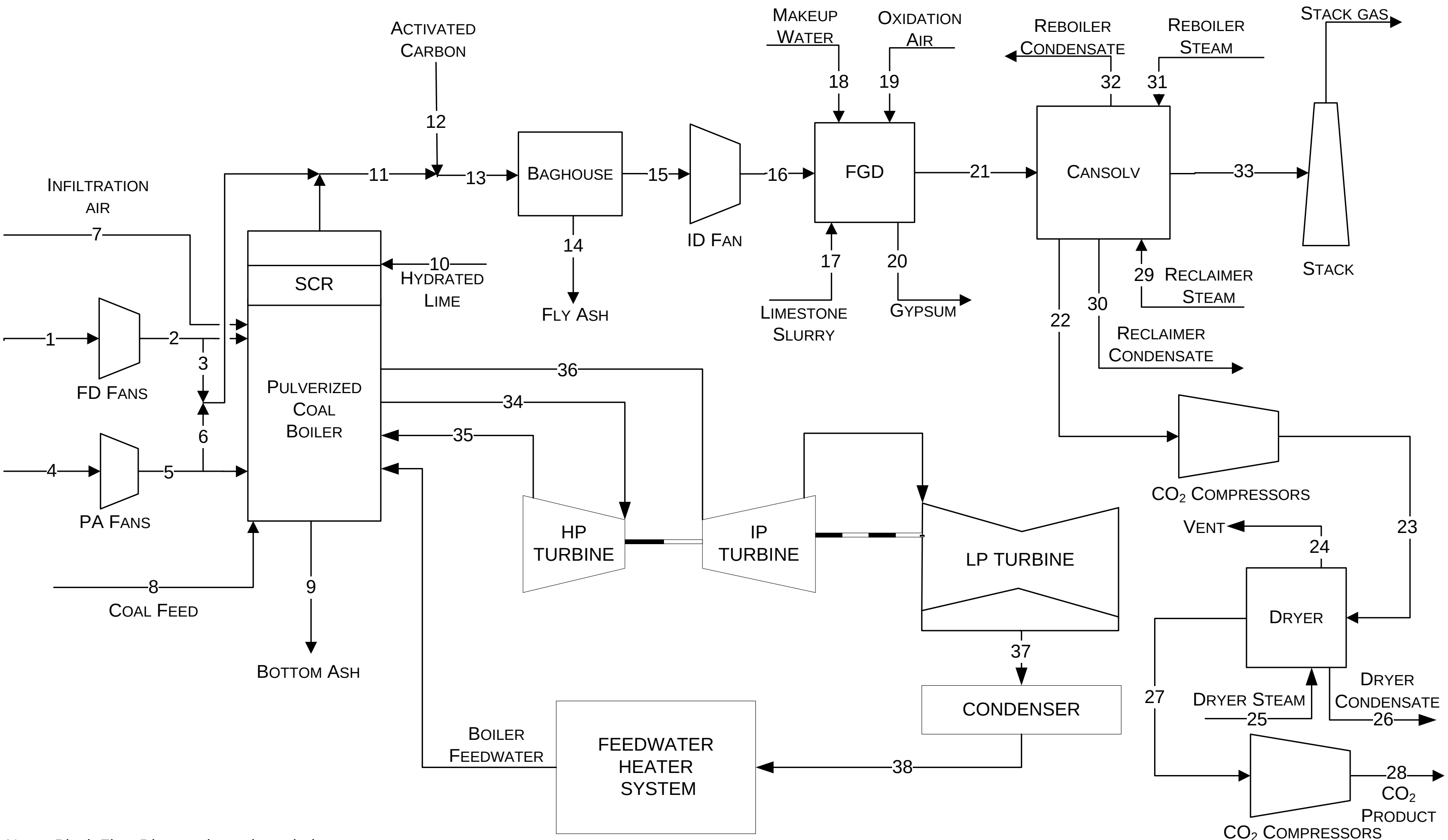
The process description for Case B11B is essentially the same as Case B11A with one notable exception, the addition of CO_2 capture and compression. A BFD and stream tables for Case B11B are shown in Exhibit 3-22 and Exhibit 3-23, respectively. Since the CDR facility process description was provided in Section 3.1.8, it is not repeated here.

3.2.8 Case B11B Performance Results

The Case B11B modeling assumptions were presented previously in Section 3.2.2.

The plant produces a net output of 550 MW at a net plant efficiency of 31.2 percent (HHV basis). Overall plant performance is summarized in Exhibit 3-24; Exhibit 3-25 provides a detailed breakdown of the auxiliary power requirements. The CDR facility, including CO_2 compression, accounts for over half of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for over 13 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility and CO_2 compressors.

Exhibit 3-22 Case B11B block flow diagram, subcritical unit with CO_2 capture



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Source: NETL

Exhibit 3-23 Case B11B stream table, subcritical unit with capture

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
V-L Mole Fraction														
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000	0.0088	0.0000	0.0088	0.0000
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1376	0.0000	0.1376	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0000	0.0831	0.0000	0.0831	0.0000
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7345	0.0000	0.7345	0.0000
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0340	0.0000	0.0340	0.3333
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0020	0.0000	0.0020	0.6667
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000
V-L Flowrate (kg_{mole}/hr)	64,558	64,558	1,912	19,831	19,831	2,729	1,410	0	0	0	90,489	0	90,489	4
V-L Flowrate (kg/hr)	1,862,938	1,862,938	55,177	572,275	572,275	78,760	40,691	0	0	0	2,687,332	0	2,687,332	206
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	234,131	4,541	4,719	22,881	136	23,017	23,017
Temperature (°C)	15	19	19	15	25	25	15	15	149	27	143	27	143	143
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) [A]	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	0.00	0.00	0.00	---	---
AspenPlus Enthalpy (kJ/kg) [B]	-97.58	-93.45	-93.45	-97.58	-87.03	-87.03	-97.58	-2,114.05	97.18	-13,306.82	-2,399.50	3.40	-2,399.38	-2,632.03
Density (kg/m^3)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	---	0.9	---	0.9	1.5
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	---	29.698	---	29.698	53.376
V-L Flowrate (lb_{mole}/hr)	142,325	142,325	4,215	43,721	43,721	6,017	3,109	0	0	0	199,495	0	199,495	9
V-L Flowrate (lb/hr)	4,107,075	4,107,075	121,644	1,261,650	1,261,650	173,636	89,709	0	0	0	5,924,552	0	5,924,552	454
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	516,170	10,010	10,403	50,444	300	50,745	50,745
Temperature (°F)	59	66	66	59	78	78	59	59	300	80	289	80	289	289
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.4	14.7	14.4	14.7	14.4	14.4
Steam Table Enthalpy (Btu/lb) [A]	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---				---	---
AspenPlus Enthalpy (Btu/lb) [B]	-42.0	-40.2	-40.2	-42.0	-37.4	-37.4	-42.0	-908.9	41.8	-5,720.9	-1,031.6	1.5	-1,031.5	-1,131.6
Density (lb/ft^3)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	---	0.053	---	0.053	0.096

[A] Steam table reference conditions are 32.02°F & 0.089 psia

[B] Aspen thermodynamic reference state is the component’s constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit 3-23 Case B11B stream table, subcritical unit with capture (continued)

	15	16	17	18	19	20	21	22	23	24	25	26	27	28
V-L Mole Fraction														
Ar	0.0088	0.0088	0.0000	0.0000	0.0092	0.0000	0.0082	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.1376	0.1376	0.0000	0.0000	0.0003	0.0001	0.1288	0.9824	0.9977	0.0497	0.0000	0.0000	0.9993	0.9993
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0831	0.0831	1.0000	1.0000	0.0099	0.9999	0.1451	0.0176	0.0023	0.9503	1.0000	1.0000	0.0007	0.0007
N_2	0.7345	0.7345	0.0000	0.0000	0.7732	0.0000	0.6854	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0340	0.0340	0.0000	0.0000	0.2074	0.0000	0.0325	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0020	0.0020	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mole}/hr)	90,485	90,485	2,999	12,020	957	221	98,055	11,571	11,394	19	15	15	11,375	11,375
V-L Flowrate (kg/hr)	2,687,126	2,687,126	54,035	216,549	27,615	3,988	2,829,081	503,956	500,768	364	264	264	500,404	500,404
Solids Flowrate (kg/hr)	0	0	23,136	0	0	35,882	0	0	0	0	0	0	0	0
Temperature (°C)	143	153	15	27	167	56	56	29	29	29	476	203	29	40
Pressure (MPa, abs)	0.10	0.11	0.10	0.11	0.31	0.10	0.10	0.20	3.03	3.03	2.42	1.70	2.89	15.27
Steam Table Enthalpy (kJ/kg) [A]	274.36	285.60	---	111.65	184.48	---	286.10	42.52	-6.01	137.83	3,408.95	863.91	-5.92	-205.59
AspenPlus Enthalpy (kJ/kg) [B]	-2,397.37	-2,386.12	-14,995.75	-15,964.53	56.67	-12,481.91	-2,940.32	-8,972.02	-8,974.91	-15,229.20	-12,571.34	-15,116.38	-8,970.17	-9,169.84
Density (kg/m^3)	0.8	0.9	1,003.6	992.3	2.4	833.2	1.1	3.5	63.3	374.4	7.1	861.8	59.9	789.2
V-L Molecular Weight	29.697	29.697	18.015	18.015	28.857	18.018	28.852	43.553	43.950	19.308	18.015	18.015	43.991	43.991
V-L Flowrate (lb_{mole}/hr)	199,486	199,486	6,613	26,500	2,110	488	216,174	25,510	25,120	42	32	32	25,078	25,078
V-L Flowrate (lb/hr)	5,924,098	5,924,098	119,126	477,408	60,881	8,792	6,237,055	1,111,033	1,104,005	803	581	581	1,103,202	1,103,202
Solids Flowrate (lb/hr)	0	0	51,005	0	0	79,106	0	0	0	0	0	0	0	0
Temperature (°F)	289	308	59	80	332	133	133	85	85	85	888	397	85	104
Pressure (psia)	14.2	15.2	15.0	15.7	45.0	14.7	14.7	28.7	439.4	439.4	350.5	247.3	419.4	2,214.7
Steam Table Enthalpy (Btu/lb) [A]	118.0	122.8	---	48.0	79.3	---	123.0	18.3	-2.6	59.3	1,465.6	371.4	-2.5	-88.4
AspenPlus Enthalpy (Btu/lb) [B]	-1,030.7	-1,025.8	-6,447.0	-6,863.5	24.4	-5,366.3	-1,264.1	-3,857.3	-3,858.5	-6,547.4	-5,404.7	-6,498.9	-3,856.5	-3,942.3
Density (lb/ft^3)	0.052	0.055	62.650	61.950	0.153	52.013	0.067	0.216	3.953	23.375	0.446	53.800	3.737	49.267

[A] Steam table reference conditions are 32.02°F & 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit 3-23 Case B11B stream table, subcritical unit with capture (continued)

	29	30	31	32	33	34	35	36	37	38
V-L Mole Fraction										
Ar	0.0000	0.0000	0.0000	0.0000	0.0103	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0000	0.0000	0.0000	0.0163	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	1.0000	1.0000	0.0671	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.0000	0.0000	0.0000	0.0000	0.8652	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0410	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mole}/hr)	87	87	29,214	29,214	77,673	110,081	102,661	102,661	61,864	63,201
V-L Flowrate (kg/hr)	1,561	1,561	526,301	526,300	2,166,238	1,983,144	1,849,458	1,849,458	1,114,489	1,138,575
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	355	215	266	151	41	566	355	566	38	39
Pressure (MPa, abs)	4.28	2.20	0.51	0.51	0.10	16.65	4.28	4.19	0.01	1.32
Steam Table Enthalpy (kJ/kg) [A]	3,098.44	921.65	2,994.07	635.95	151.94	3,473.89	3,098.44	3,593.58	1,976.98	162.43
AspenPlus Enthalpy (kJ/kg)[B]	-12,881.86	-15,058.64	-12,986.23	-15,344.34	-794.66	-12,506.41	-12,881.86	-12,386.71	-14,003.31	-15,817.87
Density (kg/m^3)	16.0	846.4	2.1	916.3	1.1	47.7	16.0	11.1	0.1	993.3
V-L Molecular Weight	18.015	18.015	18.015	18.015	27.889	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mole}/hr)	191	191	64,406	64,406	171,241	242,688	226,328	226,328	136,386	139,333
V-L Flowrate (lb/hr)	3,441	3,441	1,160,294	1,160,293	4,775,737	4,372,084	4,077,357	4,077,357	2,457,027	2,510,129
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	671	419	512	304	107	1,050	671	1,050	101	101
Pressure (psia)	620.5	319.0	73.5	73.5	14.7	2,414.7	620.5	608.1	1.0	190.7
Steam Table Enthalpy (Btu/lb)[A]	1,332.1	396.2	1,287.2	273.4	65.3	1,493.5	1,332.1	1,545.0	850.0	69.8
AspenPlus Enthalpy (Btu/lb)[B]	-5,538.2	-6,474.0	-5,583.1	-6,596.9	-341.6	-5,376.8	-5,538.2	-5,325.3	-6,020.3	-6,800.5
Density (lb/ft^3)	1.000	52.840	0.129	57.202	0.068	2.975	1.000	0.692	0.004	62.010

[A]Steam table reference conditions are 32.02°F & 0.089 psia

[B]Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit 3-24 Case B11B plant performance summary

Performance Summary	
Total Gross Power, MWe	**644**
CO_2 Capture/Removal Auxiliaries, kWe	16,600
CO_2 Compression, kWe	36,560
Balance of Plant, kWe	41,161
Total Auxiliaries, MWe	**94**
Net Power, MWe	**550**
HHV Net Plant Efficiency (%)	31.2%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,556 (10,953)
LHV Net Plant Efficiency (%)	32.3%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,146 (10,565)
HHV Boiler Efficiency, %	89.1%
LHV Boiler Efficiency, %	92.4%
Steam Turbine Cycle Efficiency, %	52.5%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	6,854 (6,497)
Condenser Duty, GJ/hr (MMBtu/hr)	2,022 (1,916)
As-Received Coal Feed, kg/hr (lb/hr)	234,131 (516,170)
Limestone Sorbent Feed, kg/hr (lb/hr)	23,136 (51,005)
HHV Thermal Input, kWt	1,764,768
LHV Thermal Input, kWt	1,702,141
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.058 (15.4)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.045 (11.9)
Excess Air, %	20.9%

Exhibit 3-25 Case B11B plant power summary

Power Summary	
Steam Turbine Power, MWe	644
Total Gross Power, MWe	**644**
Auxiliary Load Summary	
Coal Handling and Conveying, kWe	490
Pulverizers, kWe	3,510
Sorbent Handling & Reagent Preparation, kWe	1,110
Ash Handling, kWe	820
Primary Air Fans, kWe	1,740
Forced Draft Fans, kWe	2,220
Induced Draft Fans, kWe	8,700
SCR, kWe	60
Activated Carbon Injection, kWe	28
Dry sorbent Injection, kWe	113
Baghouse, kWe	110
Wet FGD, kWe	3,700
CO_2 Capture/Removal Auxiliaries, kWe	16,600
CO_2 Compression, kWe	36,560
Miscellaneous Balance of Plant[A,B], kWe	2,000
Steam Turbine Auxiliaries, kWe	400
Condensate Pumps, kWe	550
Circulating Water Pumps, kWe	8,210
Ground Water Pumps, kWe	760
Cooling Tower Fans, kWe	4,250
Transformer Losses, kWe	2,400
Total Auxiliaries, MWe	**94**
Net Power, MWe	**550**

[A]Boiler feed pumps are turbine driven
[B]Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

3.2.8.1 Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B11B is presented in Exhibit 3-26. SO_2 emissions are utilized as a surrogate for HCl emissions, therefore HCl is not reported.

Exhibit 3-26 Case B11B air emissions

	kg/GJ (lb/MMBtu)	Tonne/year (ton/year)[A]	kg/MWh (lb/MWh)
SO_2	0.000 (0.000)	0 (0)	0.000 (0.000)
NOx	0.032 (0.075)	1,523 (1,679)	0.318 (0.700)
Particulate	0.004 (0.010)	196 (216)	0.041 (0.090)
Hg	1.38E-7 (3.21E-7)	0.007 (0.007)	1.36E-6 (3.00E-6)
CO_2[B]	9 (20)	413,912 (456,260)	86 (190)
CO_2[C]	-	-	101 (223)
	mg/Nm^3		
Particulate Concentration[D,E]	12.97		

[A]Calculations based on an 85 percent capacity factor
[B]CO_2 emissions based on gross power
[C]CO_2 emissions based on net power instead of gross power
[D]Concentration of particles in the flue gas after the baghouse
[E]Normal conditions given at 32°F and 14.696 psia

SO_2 emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The SO_2 emissions are further reduced to 1 ppmv using a NaOH based polishing scrubber in the CDR facility. The remaining low concentration of SO_2 is essentially completely removed in the CDR absorber vessel resulting in very low SO_2 emissions.

NOx emissions are controlled to about 0.5 lb/MMBtu through the use of LNBs and OFA. An SCR unit then further reduces the NOx concentration by 85 percent to 0.07 lb/MMBtu.

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment (SCR, ACI, fabric filter, DSI, and wet FGD) is 97.2 percent.

Ninety percent of the CO_2 in the flue gas is removed in CDR facility.

The carbon balance for the plant is shown in Exhibit 3-27. The carbon input to the plant consists of carbon in the coal, carbon in the air, PAC, and carbon in the limestone reagent used in the FGD absorber. Carbon leaves the plant mostly as CO_2 through the stack, however, the PAC is captured in the fabric filter and some leaves as gypsum. The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in, represented by the following fraction:

$$\frac{Carbon\ in\ Stack}{(Total\ Carbon\ In)} = \left(1 - \left(\frac{33{,}446}{335{,}258}\right) * \right) 100 = 90.0\%$$

Exhibit 3-27 Case B11B carbon balance

Carbon In		**Carbon Out**	
	kg/hr (lb/hr)		**kg/hr (lb/hr)**
Coal	149,246 (329,031)	Stack Gas	15,171 (33,446)
Air (CO_2)	340 (751)	FGD Product	224 (494)
PAC	136 (300)	Baghouse	136 (300)
FGD Reagent	2,348 (5,175)	CO_2 Product	136,528 (300,992)
		CO_2 Dryer Vent	11 (25)
		CO_2 Knockout	0 (1)
Total	**152,070 (335,258)**	**Total**	**152,070 (335,258)**

Exhibit 3-28 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur emitted in the stack gas, and sulfur removed in the polishing scrubber.

Exhibit 3-28 Case B11B sulfur balance

Sulfur In		**Sulfur Out**	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	5,868 (12,937)	FGD Product	5,670 (12,500)
		Stack Gas	0 (0)
		Polishing Scrubber and Solvent Reclaiming	116 (255)
		Baghouse	82 (182)
Total	**5,868 (12,937)**	**Total**	**5,868 (12,937)**

Exhibit 3-29 shows the overall water balance for the plant. The exhibit is presented in an identical manner as was for Case B11A.

Exhibit 3-29 Case B11B water balance

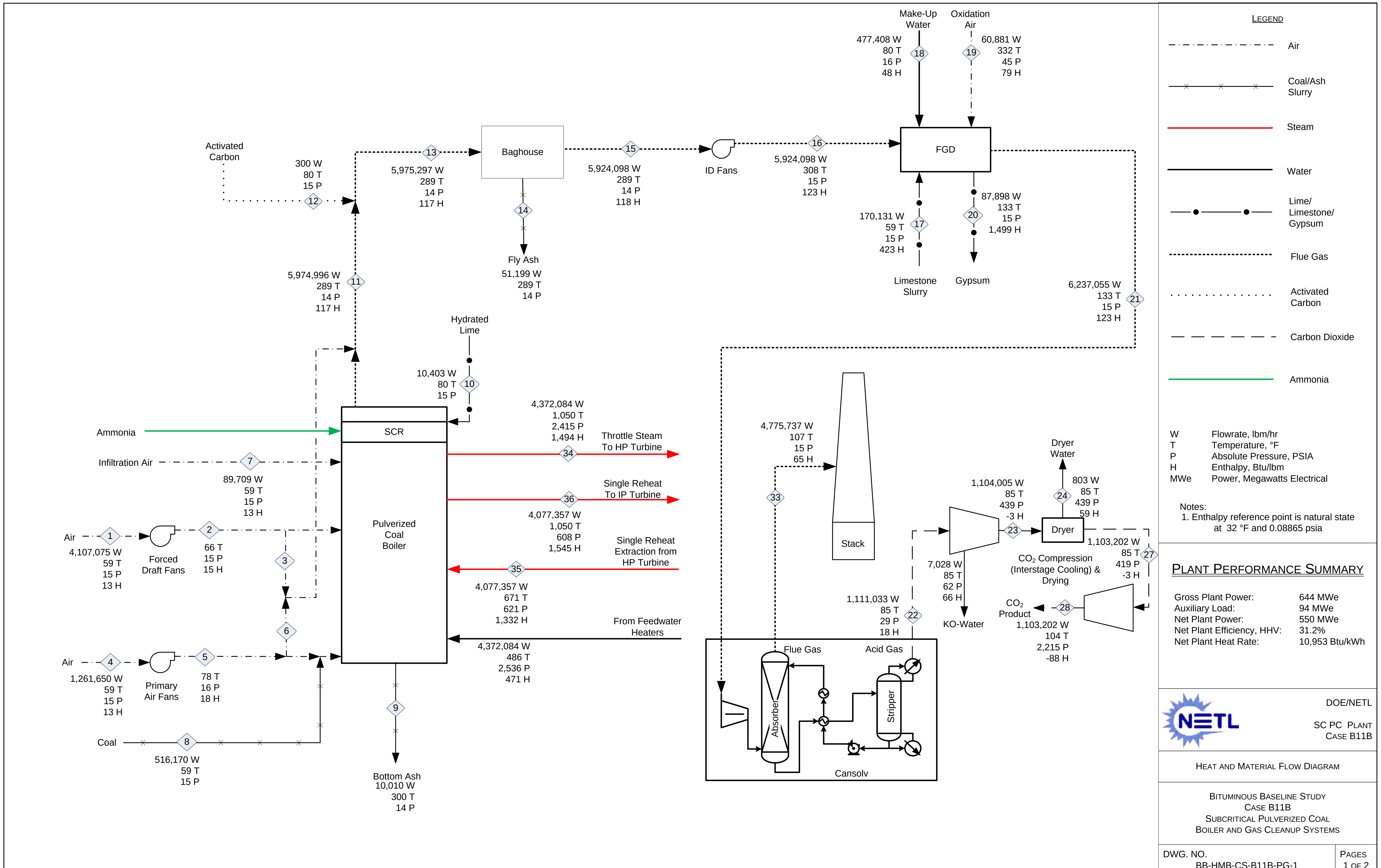
Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)
FGD Makeup	4.52 (1,193)	–	4.52 (1,193)	–	4.52 (1,193)
CO_2 Drying	–	–	–	0.01 (2)	-0.01 (-2)
Capture System Makeup	0.02 (6)	–	0.02 (6)	–	0.02 (6)
Deaerator Vent	–	–	–	0.07 (18)	-0.07 (-18)
Condenser Makeup	**0.40 (106)**	**–**	**0.40 (106)**	**–**	**0.40 (106)**
BFW Makeup	0.40 (106)	–	0.40 (106)	–	0.40 (106)
Cooling Tower	**31.99 (8,451)**	**4.98 (1,315)**	**27.01 (7,136)**	**7.19 (1,900)**	**19.82 (5,235)**
FGD Dewatering	–	2.33 (615)	-2.33 (-615)	–	-2.33 (-615)
CO_2 Capture Recovery	–	2.65 (700)	-2.65 (-700)	–	-2.65 (-700)
CO_2 Compression KO	–	0.05 (14)	-0.05 (-14)	–	-0.05 (-14)
BFW Blowdown	–	0.34 (89)	-0.34 (-89)	–	-0.34 (-89)
Total	**36.93 (9,755)**	**4.98 (1,315)**	**31.95 (8,441)**	**7.27 (1,920)**	**24.68 (6,521)**

3.2.8.2 Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the Case B11B PC boiler, the FGD unit, CDR system and steam cycle in Exhibit 3-30 and Exhibit 3-31. An overall plant energy balance is provided in tabular form in Exhibit 3-32.

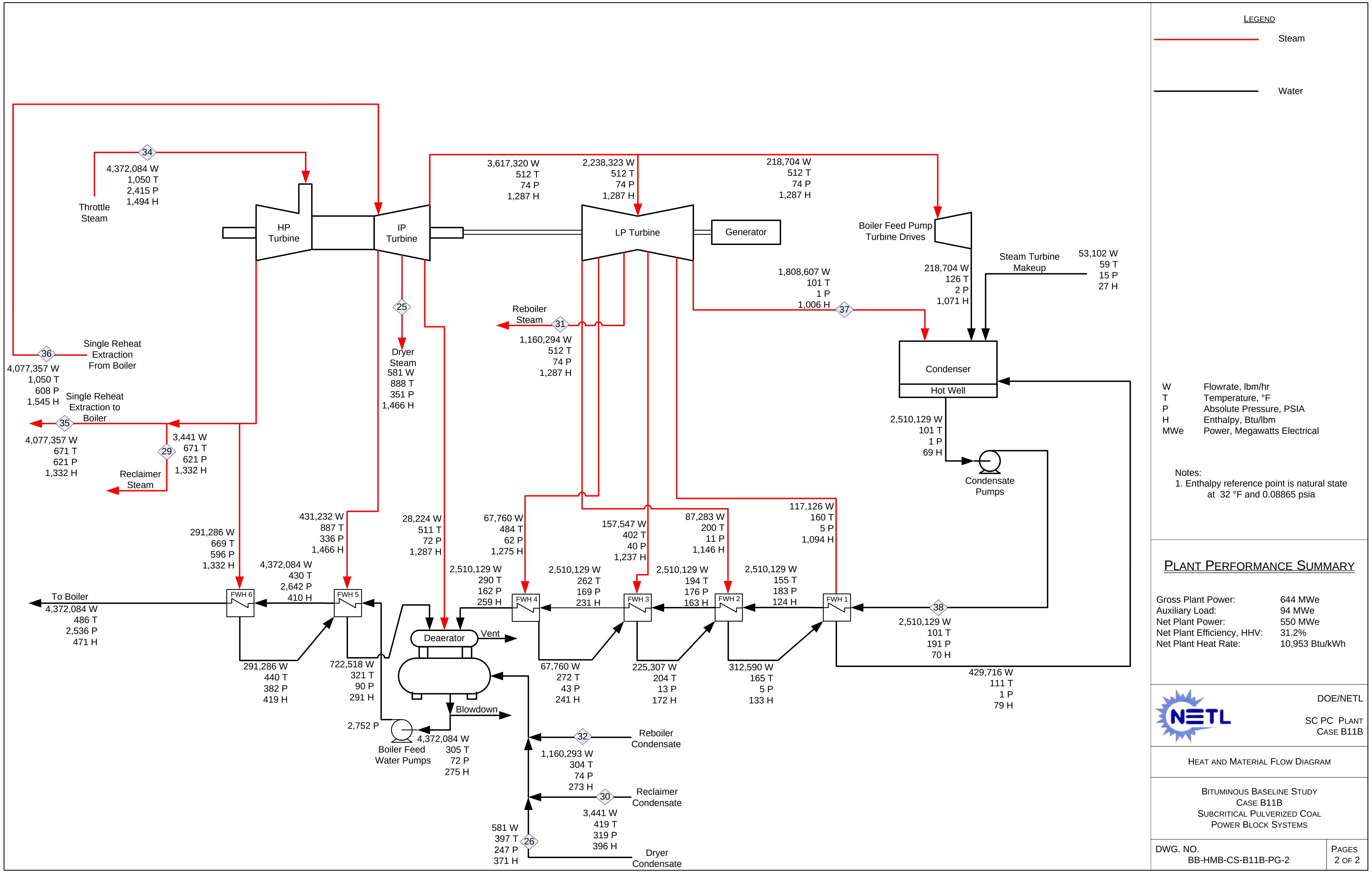
The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-24) is calculated by multiplying the power out by a generator efficiency of 98.5 percent. The capture process heat out stream represents heat rejected to cooling water and ultimately to ambient via the cooling tower. The same is true of the condenser heat out stream. The CO_2 compressor intercooler load is included in the capture process heat out stream.

Exhibit 3-30 Case B11B heat and mass balance, subcritical PC boiler with CO_2 capture



Source: NETL

Exhibit 3-31 Case B11B heat and mass balance, subcritical steam cycle



Source: NETL

Exhibit 3-32 Case B11B overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	6,353 (6,022)	5.3 (5.0)	–	6,358 (6,027)
Air	–	74.8 (70.9)	–	74.8 (70.9)
Raw Water Makeup	–	120.1 (113.9)	–	120.1 (113.9)
Limestone	–	0.50 (0.48)	–	0.50 (0.48)
Auxiliary Power	–	–	340 (322)	340 (322)
TOTAL	**6,353 (6,022)**	**200.8 (190.3)**	**340 (322)**	**6,894 (6,534)**
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	–	0.5 (0.5)	–	0.5 (0.5)
Fly Ash + FGD Ash	–	2.6 (2.5)	–	2.6 (2.5)
Stack Gas	–	329 (312)	–	329 (312)
Sulfur	2.1 (2.0)	0.0 (0.0)	–	2.2 (2.0)
Motor Losses and Design Allowances	–	–	44 (42)	44 (42)
Condenser	–	2,022 (1,916)	–	2,022 (1,916)
Non-Condenser Cooling Tower Loads	–	106 (100)	–	106 (100)
CO_2	–	-102.9 (-97.5)	–	-102.9 (-97.5)
Cooling Tower Blowdown	–	53.4 (50.7)	–	53.4 (50.7)
CO_2 Capture Losses	–	2,050 (1,943)	–	2,050 (1,943)
Ambient Losses[A]	–	137.2 (130.0)	–	137.2 (130.0)
Power	–	–	2,319 (2,198)	2,319 (2,198)
TOTAL	**2.1 (2.0)**	**4,492 (4,358)**	**2,363 (2,240)**	**6,857 (6,599)**
Unaccounted Energy[B]	–	36 (-66)	–	36 (-66)

[A]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers.
[B]By difference

3.2.9 Case B11B – Major Equipment List

Major equipment items for the subcritical PC plant with CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 3.2.10. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

Case B11B – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
8	Reclaim Hopper	N/A	50 tonne (50 ton)	2	1
9	Feeder	Vibratory	190 tonne/hr (210 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	390 tonne/hr (430 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	190 tonne (210 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	390 tonne/hr (430 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	390 tonne/hr (430 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	860 tonne (900 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 36 tonne (40 ton) Feeder - 150 kg/hr (330 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 250 tonne (270 ton) Feeder - 5,190 kg/hr (11,440 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	100 tonne/hr (110 tph)	1	0
23	Limestone Conveyor No. L1	Belt	100 tonne/hr (110 tph)	1	0
24	Limestone Reclaim Hopper	N/A	20 tonne (20 ton)	1	0
25	Limestone Reclaim Feeder	Belt	80 tonne/hr (80 tph)	1	0
26	Limestone Conveyor No. L2	Belt	80 tonne/hr (80 tph)	1	0
27	Limestone Day Bin	w/ actuator	310 tonne (340 ton)	2	0

Case B11B – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	40 tonne/hr (50 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	40 tonne/hr (50 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	25 tonne/hr (28 tph)	1	1
4	Limestone Ball Mill	Rotary	25 tonne/hr (28 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	97,700 liters (26,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,620 lpm @ 10m H_2O (430 gpm @ 40 ft H_2O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5 cyclone bank	410 lpm (110 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	550,000 liters (145,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,150 lpm @ 9m H_2O (300 gpm @ 30 ft H_2O)	1	1

Case B11B – Account 3: Feedwater and Miscellaneous Systems and Equipment

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,592,000 liters (421,000 gal)	2	0
2	Condensate Pumps	Vertical canned	21,000 lpm @ 200 m H_2O (5,600 gpm @ 500 ft H_2O)	1	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
3	Deaerator and Storage Tank	Horizontal spray type	2,208,000 kg/hr (4,868,000 lb/hr), 5 min. tank	1	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	36,600 lpm @ 2,300 m H_2O (9,700 gpm @ 7,500 ft H_2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	10,900 lpm @ 2,300 m H_2O (2,900 gpm @ 7,500 ft H_2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	630,000 kg/hr (1,380,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	630,000 kg/hr (1,380,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	630,000 kg/hr (1,380,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	630,000 kg/hr (1,380,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	2,180,000 kg/hr (4,810,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	2,180,000 kg/hr (4,810,000 lb/hr)	1	0
12	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
13	Fuel Oil System	No. 2 fuel oil for light off	1,135,624 liter (300,000 gal)	1	0
14	Service Air Compressors	Flooded Screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
15	Instrument Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	2	1
16	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
17	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,800 lpm @ 30 m H_2O (5,500 gpm @ 100 ft H_2O)	2	1
18	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H_2O (1,000 gpm @ 290 ft H_2O)	1	1
19	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H_2O (700 gpm @ 210 ft H_2O)	1	1
20	Raw Water Pumps	Stainless steel, single suction	9,170 lpm @ 20 m H_2O (2,420 gpm @ 60 ft H_2O)	2	1
21	Ground Water Pumps	Stainless steel, single suction	3,670 lpm @ 270 m H_2O (970 gpm @ 880 ft H_2O)	5	1
22	Filtered Water Pumps	Stainless steel, single suction	2,420 lpm @ 50 m H_2O (640 gpm @ 160 ft H_2O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	2,318,000 liter (612,000 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	830 lpm (220 gpm)	1	1
25	Liquid Waste Treatment System	--	10 years, 24-hour storm	1	0

Case B11B – Account 4: Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Subcritical, drum wall-fired, low NOx burners, overfire air	2,180,000 kg/hr steam @ 17.9 MPa/574°C/574°C (4,810,000 lb/hr steam @ 2,600 psig/1,065°F/1,065°F)	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
2	Primary Air Fan	Centrifugal	315,000 kg/hr, 4,300 m^3/min @ 123 cm WG (694,000 lb/hr, 151,700 acfm @ 48 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	1,025,000 kg/hr, 14,000 m^3/min @ 47 cm WG (2,259,000 lb/hr, 493,800 acfm @ 19 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,478,000 kg/hr, 29,300 m^3/min @ 89 cm WG (3,258,000 lb/hr, 1,035,400 acfm @ 35 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	2,960,000 kg/hr (6,520,000 lb/hr)	2	0
6	SCR Catalyst	--	--	3	0
7	Dilution Air Blower	Centrifugal	170 m^3/min @ 108 cm WG (5,800 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	182,000 liter (48,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	35 lpm @ 90 m H_2O (9 gpm @ 300 ft H_2O)	2	1

Case B11B – Account 5A: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,478,000 kg/hr (3,259,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	59,000 m^3/min (2,082,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	205,000 lpm @ 65 m H_2O (54,000 gpm @ 210 ft H_2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	4,990 lpm (1,320 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	100 m^3/min @ 0.3 MPa (3,660 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,250 lpm (330 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	39 tonne/hr (44 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	760 lpm @ 13 m H_2O (200 gpm @ 40 ft H_2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	500,000 lpm (130,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	3,980 lpm @ 21 m H_2O (1,050 gpm @ 70 ft H_2O)	1	1
12	Activated Carbon Injectors	---	150 kg/hr (330 lb/hr)	1	0
13	Hydrated Lime Injectors	---	5,190 kg/hr (11,440 lb/hr)	1	0

Case B11B – Account 5B: Carbon Dioxide Recovery

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Cansolv	Amine-based CO_2 capture technology	1,556,000 kg/hr (3,430,000 lb/hr) 19.6 wt % CO_2 concentration	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
2	Cansolv LP Condensate Pump	Centrifugal	10,788 lpm @ 1 m H_2O (2,850 gpm @ 4 ft H_2O)	1	1
3	Cansolv HP Condensate Pump	Centrifugal	10,782 lpm @ 1.1 m H_2O (2,848 gpm @ 4 ft H_2O)	1	1
4	CO_2 Dryer	Triethylene glycol	Inlet: 132.0 m^3/min (4,655 acfm) @ 3.0 MPa (439 psia) Outlet: 2.9 MPa (419 psia) Water Recovered: 364 kg/hr (803 lb/hr)	1	0
5	CO_2 Compressor	Integrally geared, multi-stage centrifugal	275,140 kg/hr @ 15.3 MPa (606,579 lb/hr @ 2,215 psia)	2	0

Case B11B – Account 7: Ducting and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 5.6 m (19 ft) diameter	1	0

Case B11B – Account 8: Steam Turbine Generator and Auxiliaries

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	678 MW 16.5 MPa/566°C/566°C (2400 psig/ 1050°F/1050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	750 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,220 GJ/hr (2,110 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

Case B11B – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	824,000 lpm @ 30 m (218,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 4600 GJ/hr (4360 MMBtu/hr) heat duty	1	0

Case B11B – Account 10: Ash and Spent Sorbent Recovery and Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	--	--	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	--	--	2	0
3	Clinker Grinder	--	5.0 tonne/hr (5.5 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	--	--	6	0
5	Hydroejectors	--	--	12	
6	Economizer /Pyrites Transfer Tank	--	--	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
7	Ash Sluice Pumps	Vertical, wet pit	200 lpm @ 17 m H_2O (50 gpm @ 56 ft H_2O)	1	1
8	Ash Seal Water Pumps	Vertical, wet pit	7,570 lpm @ 9 m H_2O (2000 gpm @ 28 ft H_2O)	1	1
9	Hydrobins	--	190 lpm (50 gpm)	1	1
10	Baghouse Hopper (part of baghouse scope of supply)	--	--	24	0
11	Air Heater Hopper (part of boiler scope of supply)	--	--	10	0
12	Air Blower	--	20 m^3/min @ 0.2 MPa (820 scfm @ 24 psi)	1	1
13	Fly Ash Silo	Reinforced concrete	1,500 tonne (1,700 ton)	2	0
14	Slide Gate Valves	--	--	2	0
15	Unloader	--	--	1	0
16	Telescoping Unloading Chute	--	140 tonne/hr (160 tph)	1	0

Case B11B – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 650 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 20 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 102 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 15 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B11B – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.2.10 Case B11B – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 3-33 shows a detailed breakdown of the capital costs; Exhibit 3-34 shows the owner's costs, TOC, and TASC; Exhibit 3-35 shows the initial and annual O&M costs; and Exhibit 3-36 shows the COE breakdown.

The estimated TPC of the subcritical PC boiler with CO_2 capture is $3,467/kW. Process contingency represents 3.4 percent of the TPC and project contingency represents 12.3 percent. The COE, including CO_2 T&S costs of $10.0/MWh, is $143.5/MWh.

Exhibit 3-33 Case B11B total plant cost details

	Case:	B11B – Subcritical PC w/ CO_2							Estimate Type:	Conceptual	
	Plant Size (MW,net):	550							Cost Base:	Jun 2011	
Item	Description	Equipment	Material	Labor		Bare Erected	Eng'g CM	Contingencies		Total Plant Cost	
No.		Cost	Cost	Direct	Indirect	Cost	H.O.& Fee	Process	Project	$/1,000	$/kW
	1	Coal & Sorbent Handling									
1.1	Coal Receive & Unload	$4,719	$0	$2,126	$0	$6,845	$684	$0	$1,129	$8,658	$16
1.2	Coal Stackout & Reclaim	$6,098	$0	$1,363	$0	$7,461	$746	$0	$1,231	$9,438	$17
1.3	Coal Conveyors	$5,670	$0	$1,348	$0	$7,018	$702	$0	$1,158	$8,878	$16
1.4	Other Coal Handling	$1,483	$0	$312	$0	$1,795	$180	$0	$296	$2,271	$4
1.5	Sorbent Receive & Unload	$189	$0	$56	$0	$245	$25	$0	$40	$310	$1
1.6	Sorbent Stackout & Reclaim	$3,054	$0	$552	$0	$3,606	$361	$0	$595	$4,562	$8
1.7	Sorbent Conveyors	$1,090	$237	$264	$0	$1,590	$159	$0	$262	$2,011	$4
1.8	Other Sorbent Handling	$658	$155	$340	$0	$1,154	$115	$0	$190	$1,459	$3
1.9	Coal & Sorbent Hnd. Foundations	$0	$5,469	$7,211	$0	$12,680	$1,268	$0	$2,092	$16,040	$29
	Subtotal	**$22,962**	**$5,861**	**$13,572**	**$0**	**$42,395**	**$4,239**	**$0**	**$6,995**	**$53,629**	**$98**
	2	Coal & Sorbent Prep & Feed									
2.1	Coal Crushing & Drying	$2,728	$0	$524	$0	$3,252	$325	$0	$537	$4,114	$7
2.2	Coal Conveyor to Storage	$6,984	$0	$1,504	$0	$8,488	$849	$0	$1,401	$10,737	$20
2.5	Sorbent Prep Equipment	$5,199	$225	$1,065	$0	$6,489	$649	$0	$1,071	$8,209	$15
2.6	Sorbent Storage & Feed	$626	$0	$237	$0	$863	$86	$0	$142	$1,092	$2
2.9	Coal & Sorbent Feed Foundation	$0	$635	$557	$0	$1,191	$119	$0	$197	$1,507	$3
	Subtotal	**$15,538**	**$860**	**$3,886**	**$0**	**$20,284**	**$2,028**	**$0**	**$3,347**	**$25,659**	**$47**
	3	Feedwater & Miscellaneous BOP Systems									
3.1	Feedwater System	$21,284	$0	$7,333	$0	$28,618	$2,862	$0	$4,722	$36,201	$66
3.2	Water Makeup & Pretreating	$7,468	$0	$2,362	$0	$9,830	$983	$0	$2,163	$12,975	$24
3.3	Other Feedwater Subsystems	$7,155	$0	$2,937	$0	$10,092	$1,009	$0	$1,665	$12,766	$23
3.4	Service Water Systems	$1,496	$0	$783	$0	$2,278	$228	$0	$501	$3,007	$5
3.5	Other Boiler Plant Systems	$8,860	$0	$8,377	$0	$17,236	$1,724	$0	$2,844	$21,804	$40
3.6	FO Supply Sys & Nat Gas	$348	$0	$406	$0	$754	$75	$0	$124	$953	$2
3.7	Waste Treatment Equipment	$4,899	$0	$2,836	$0	$7,735	$774	$0	$1,702	$10,210	$19
3.8	Misc. Equip. (Cranes, Air Comp., Comm.)	$3,406	$0	$1,054	$0	$4,460	$446	$0	$981	$5,887	$11
	Subtotal	**$54,915**	**$0**	**$26,088**	**$0**	**$81,002**	**$8,100**	**$0**	**$14,702**	**$103,805**	**$189**
	4	Boiler & Accessories									
4.1	PC Boiler & Accessories	$178,369	$0	$116,485	$0	$294,854	$29,485	$0	$32,434	$356,773	$649
4.2	SCR	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0
4.5	Primary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0
4.6	Secondary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0
4.9	Boiler Foundations	$0	w/14.1	w/14.1	$0	$0	$0	$0	$0	$0	$0
	Subtotal	**$178,369**	**$0**	**$116,485**	**$0**	**$294,854**	**$29,485**	**$0**	**$32,434**	**$356,773**	**$649**
	5A	Gas Cleanup & Piping									
5A.1	Absorber Vessels & Accessories	$81,951	$0	$17,522	$0	$99,473	$9,947	$0	$10,942	$120,362	$219
5A.2	Other FGD	$4,277	$0	$4,813	$0	$9,090	$909	$0	$1,000	$10,999	$20

	Case:	B11B – Subcritical PC w/ CO_2							Estimate Type:	Conceptual	
	Plant Size (MW,net):	550							Cost Base:	Jun 2011	
Item	Description	Equipment	Material	Labor		Bare Erected	Eng'g CM	Contingencies		Total Plant Cost	
No.		Cost	Cost	Direct	Indirect	Cost	H.O.& Fee	Process	Project	$/1,000	$/kW
5A.3	Bag House & Accessories	$23,533	$0	$14,833	$0	$38,366	$3,837	$0	$4,220	$46,423	$84
5A.4	Other Particulate Removal Materials	$1,593	$0	$1,693	$0	$3,285	$329	$0	$361	$3,975	$7
5A.5	Gypsum Dewatering System	$6,338	$0	$1,069	$0	$7,407	$741	$0	$815	$8,963	$16
5A.6	Mercury Removal System	$4,817	$1,060	$4,736	$0	$10,613	$1,061	$0	$1,167	$12,842	$23
	Subtotal	**$122,509**	**$1,060**	**$44,666**	**$0**	**$168,234**	**$16,823**	**$0**	**$18,506**	**$203,564**	**$370**
	5B	**CO_2 Removal & Compression**									
5B.1	CO_2 Removal System	$172,746	$63,159	$134,933	$0	$370,838	$31,957	$63,914	$83,088	$549,796	$1,000
5B.2	CO_2 Compression & Drying	$51,118	$7,668	$16,831	$0	$75,616	$7,562	$0	$16,636	$99,813	$182
	Subtotal	**$223,863**	**$70,827**	**$151,763**	**$0**	**$446,454**	**$39,518**	**$63,914**	**$99,723**	**$649,609**	**$1,182**
	7	**HRSG, Ducting, & Stack**									
7.3	Ductwork	$11,362	$0	$7,172	$0	$18,533	$1,853	$0	$3,058	$23,445	$43
7.4	Stack	$10,271	$0	$5,969	$0	$16,240	$1,624	$0	$1,786	$19,651	$36
7.9	Duct & Stack Foundations	$0	$1,120	$1,329	$0	$2,449	$245	$0	$539	$3,233	$6
	Subtotal	**$21,633**	**$1,120**	**$14,470**	**$0**	**$37,223**	**$3,722**	**$0**	**$5,383**	**$46,329**	**$84**
	8	**Steam Turbine Generator**									
8.1	Steam TG & Accessories	$70,000	$0	$8,020	$0	$78,020	$7,802	$0	$8,582	$94,404	$172
8.2	Turbine Plant Auxiliaries	$452	$0	$961	$0	$1,412	$141	$0	$155	$1,709	$3
8.3	Condenser & Auxiliaries	$7,394	$0	$2,956	$0	$10,350	$1,035	$0	$1,138	$12,523	$23
8.4	Steam Piping	$30,222	$0	$12,249	$0	$42,471	$4,247	$0	$7,008	$53,725	$98
8.9	TG Foundations	$0	$1,346	$2,223	$0	$3,569	$357	$0	$785	$4,712	$9
	Subtotal	**$108,067**	**$1,346**	**$26,408**	**$0**	**$135,822**	**$13,582**	**$0**	**$17,669**	**$167,073**	**$304**
	9	**Cooling Water System**									
9.1	Cooling Towers	$16,119	$0	$4,985	$0	$21,104	$2,110	$0	$2,321	$25,536	$46
9.2	Circulating Water Pumps	$3,228	$0	$228	$0	$3,456	$346	$0	$380	$4,181	$8
9.3	Circ. Water System Auxiliaries	$839	$0	$111	$0	$950	$95	$0	$104	$1,149	$2
9.4	Circ. Water Piping	$0	$7,067	$6,400	$0	$13,466	$1,347	$0	$2,222	$17,035	$31
9.5	Make-up Water System	$714	$0	$917	$0	$1,631	$163	$0	$269	$2,063	$4
9.6	Component Cooling Water Sys.	$684	$0	$525	$0	$1,209	$121	$0	$199	$1,529	$3
9.9	Circ. Water Foundations & Structures	$0	$3,743	$6,215	$0	$9,958	$996	$0	$2,191	$13,145	$24
	Subtotal	**$21,583**	**$10,810**	**$19,381**	**$0**	**$51,774**	**$5,177**	**$0**	**$7,687**	**$64,638**	**$118**
	10	**Ash & Spent Sorbent Handling Systems**									
10.6	Ash Storage Silos	$902	$0	$2,759	$0	$3,661	$366	$0	$403	$4,430	$8
10.7	Ash Transport & Feed Equipment	$5,990	$0	$5,938	$0	$11,928	$1,193	$0	$1,312	$14,433	$26
10.9	Ash/Spent Sorbent Foundation	$0	$204	$251	$0	$454	$45	$0	$100	$600	$1
	Subtotal	**$6,892**	**$204**	**$8,948**	**$0**	**$16,044**	**$1,604**	**$0**	**$1,815**	**$19,463**	**$35**
	11	**Accessory Electric Plant**									
11.1	Generator Equipment	$2,066	$0	$330	$0	$2,396	$240	$0	$198	$2,833	$5
11.2	Station Service Equipment	$5,368	$0	$1,800	$0	$7,168	$717	$0	$591	$8,476	$15
11.3	Switchgear & Motor Control	$6,161	$0	$1,070	$0	$7,232	$723	$0	$795	$8,750	$16
11.4	Conduit & Cable Tray	$0	$4,225	$13,651	$0	$17,876	$1,788	$0	$2,950	$22,613	$41
11.5	Wire & Cable	$0	$8,045	$14,381	$0	$22,426	$2,243	$0	$3,700	$28,369	$52
11.6	Protective Equipment	$317	$0	$1,099	$0	$1,416	$142	$0	$156	$1,713	$3

	Case:	B11B – Subcritical PC w/ CO_2							Estimate Type:	Conceptual	
	Plant Size (MW,net):	550							Cost Base:	Jun 2011	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
11.7	Standby Equipment	$1,574	$0	$37	$0	$1,611	$161	$0	$177	$1,949	$4
11.8	Main Power Transformers	$12,712	$0	$221	$0	$12,933	$1,293	$0	$1,423	$15,649	$28
11.9	Electrical Foundations	$0	$386	$983	$0	$1,369	$137	$0	$301	$1,807	$3
	Subtotal	**$28,198**	**$12,656**	**$33,572**	**$0**	**$74,426**	**$7,443**	**$0**	**$10,291**	**$92,160**	**$168**
	12	**Instrumentation & Control**									
12.1	PC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0
12.5	Signal Processing Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards, Panels & Racks	$608	$0	$371	$0	$979	$98	$49	$169	$1,295	$2
12.7	Distributed Control Sys. Equipment	$6,134	$0	$1,094	$0	$7,228	$723	$361	$831	$9,143	$17
12.8	Instrument Wiring & Tubing	$3,699	$0	$6,731	$0	$10,429	$1,043	$521	$1,799	$13,793	$25
12.9	Other I & C Equipment	$1,733	$0	$4,013	$0	$5,747	$575	$287	$661	$7,270	$13
	Subtotal	**$12,174**	**$0**	**$12,209**	**$0**	**$24,383**	**$2,438**	**$1,219**	**$3,460**	**$31,501**	**$57**
	13	**Improvements to Site**									
13.1	Site Preparation	$0	$62	$1,318	$0	$1,380	$138	$0	$304	$1,822	$3
13.2	Site Improvements	$0	$2,057	$2,718	$0	$4,775	$478	$0	$1,051	$6,303	$11
13.3	Site Facilities	$3,687	$0	$3,868	$0	$7,554	$755	$0	$1,662	$9,972	$18
	Subtotal	**$3,687**	**$2,119**	**$7,904**	**$0**	**$13,710**	**$1,371**	**$0**	**$3,016**	**$18,097**	**$33**
	14	**Buildings & Structures**									
14.1	Boiler Building	$0	$10,735	$9,434	$0	$20,169	$2,017	$0	$3,328	$25,513	$46
14.2	Turbine Building	$0	$15,664	$14,589	$0	$30,254	$3,025	$0	$4,992	$38,271	$70
14.3	Administration Building	$0	$763	$807	$0	$1,570	$157	$0	$259	$1,986	$4
14.4	Circulation Water Pumphouse	$0	$208	$165	$0	$374	$37	$0	$62	$473	$1
14.5	Water Treatment Buildings	$0	$931	$849	$0	$1,780	$178	$0	$294	$2,252	$4
14.6	Machine Shop	$0	$511	$343	$0	$853	$85	$0	$141	$1,080	$2
14.7	Warehouse	$0	$346	$347	$0	$693	$69	$0	$114	$877	$2
14.8	Other Buildings & Structures	$0	$283	$241	$0	$523	$52	$0	$86	$662	$1
14.9	Waste Treating Building & Str.	$0	$541	$1,642	$0	$2,183	$218	$0	$360	$2,762	$5
	Subtotal	**$0**	**$29,983**	**$28,416**	**$0**	**$58,399**	**$5,840**	**$0**	**$9,636**	**$73,875**	**$134**
	Total	**$820,390**	**$136,845**	**$507,769**	**$0**	**$1,465,004**	**$141,373**	**$65,133**	**$234,664**	**$1,906,174**	**$3,467**

Exhibit 3-34 Case B11B owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$11,919	$22
1 Month Maintenance Materials	$1,719	$3
1 Month Non-fuel Consumables	$3,776	$7
1 Month Waste Disposal	$561	$1
25% of 1 Months Fuel Cost at 100% CF	$3,228	$6
2% of TPC	$38,123	$69
Total	**$59,326**	**$108**
Inventory Capital		
60 day supply of fuel and consumables at 100% CF	$32,759	$60
0.5% of TPC (spare parts)	$9,531	$17
Total	**$42,289**	**$77**
Other Costs		
Initial Cost for Catalyst and Chemicals	$0	$0
Land	$900	$2
Other Owner's Costs	$285,926	$520
Financing Costs	$51,467	$94
Total Overnight Costs (TOC)	**$2,346,083**	**$4,267**
TASC Multiplier (IOU, high-risk, 35 year)	1.140	
Total As-Spent Cost (TASC)	**$2,674,534**	**$4,865**

Exhibit 3-35 Case B11B initial and annual operating and maintenance costs

Case:	**B11B – Subcritical PC w/o CO_2**				**Cost Base:**	**Jun 2011**
Plant Size (MW,net):	**550**	**Heat Rate-net (Btu/kWh):**		**10,953**	**Capacity Factor (%):**	**85**
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		39.70	**$/hour**	Skilled Operator:		2.0
Operating Labor Burden:		30.00	**% of base**	Operator:		11.3
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Tech's, etc.:		2.0
				Total:		**16.3**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$7,384,208	$13.431
Maintenance Labor:					$11,686,525	$21.257
Administrative & Support Labor:					$4,767,683	$8.672
Property Taxes and Insurance:					$38,123,487	$69.343
Total:					**$61,961,903**	**$112.703**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$17,529,787	$4.28219
Consumables						
	Consumption				**Cost ($)**	
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	6,077	$1.67	$0	$3,156,296	$0.77102
Makeup and Waste Water Treatment Chemicals (lbs):	0	29,418	$0.27	$0	$2,444,559	$0.59716
Limestone (ton)	0	612	$33.48	$0	$6,357,560	$1.55303
Hydrated Lime (ton)	0	125	$155.00	$0	$6,002,945	$1.46640
Activated Carbon (ton)	0	4	$1,255.00	$0	$1,403,736	$0.34291
CO_2 Capture System Chemicals[A]	Proprietary					
Triethylene Glycol (gal)	0	407	$6.57	$0	$829,372	$0.20260
Ammonia (19% NH_3, ton)	0	92	$330.00	$0	$9,376,827	$2.29058
SCR Catalyst (m^3)	0	0.41	$8,938.80	$0	$1,138,354	$0.27808
Subtotal:				**$0**	**$38,511,747**	**$9.40767**
Waste Disposal						
Fly Ash (ton)	0	614	$25.11	$0	$4,781,508	$1.16803
Bottom Ash (ton)	0	121	$25.11	$0	$940,569	$0.22976
Amine Purification Unit Waste (ton)	0	21	$0.00	$0	$0	$0.00000
Thermal Reclaimer Unit Waste (ton)	0	2	$0.00	$0	$0	$0.00000
Prescrubber Blowdown Waste (ton)	0	46	$0.00	$0	$0	$0.00000
Subtotal:				**$0**	**$5,722,077**	**$1.39779**
By-Products						
Gypsum (ton)	0	106	$0.00	$0	$0	$0.00000
Subtotal:				**$0**	**$0**	**$0.00000**
Variable Operating Costs Total:				**$0**	**$61,763,611**	**$15.08765**
Fuel Cost						
Illinois Number 6 (ton):	0	6,194	$68.54	$0	$131,713,383	$32.17501
Total:				**$0**	**$131,713,383**	**$32.17501**

[A]CO_2 Capture System Chemicals includes Ion Exchange Resin, NaOH, and Cansolv Solvent.

Exhibit 3-36 Case B11B COE breakdown

Component	Value, $/MWh	Percentage
Capital	71.1	50%
Fixed	15.1	11%
Variable	15.1	11%
Fuel	32.2	22%
Total (Excluding T&S)	**133.5**	**N/A**
CO_2 T&S	10.0	7%
Total (Including T&S)	**143.5**	**N/A**

3.3 Supercritical PC cases

This section contains an evaluation of plant designs for Cases B12A and B12B, which are based on a SC PC plant with a nominal net output of 550 MWe. Both plants use a single reheat 24.1 MPa/593°C/593°C (3,500 psig/1,100°F/1,100°F) cycle. The only difference between the two plants is that Case B12B includes CO_2 capture while Case B12A does not.

The balance of this section is organized in an analogous manner to the subcritical PC section:

- Process and System Description for Case B12A
- Key Assumptions for Cases B12A and B12B
- Sparing Philosophy for Cases B12A and B12B
- Performance Results for Case B12A
- Equipment List for Case B12A
- Cost Estimates for Case B12A
- Process and System Description, Performance Results, Equipment List and Cost Estimates for Case B12B

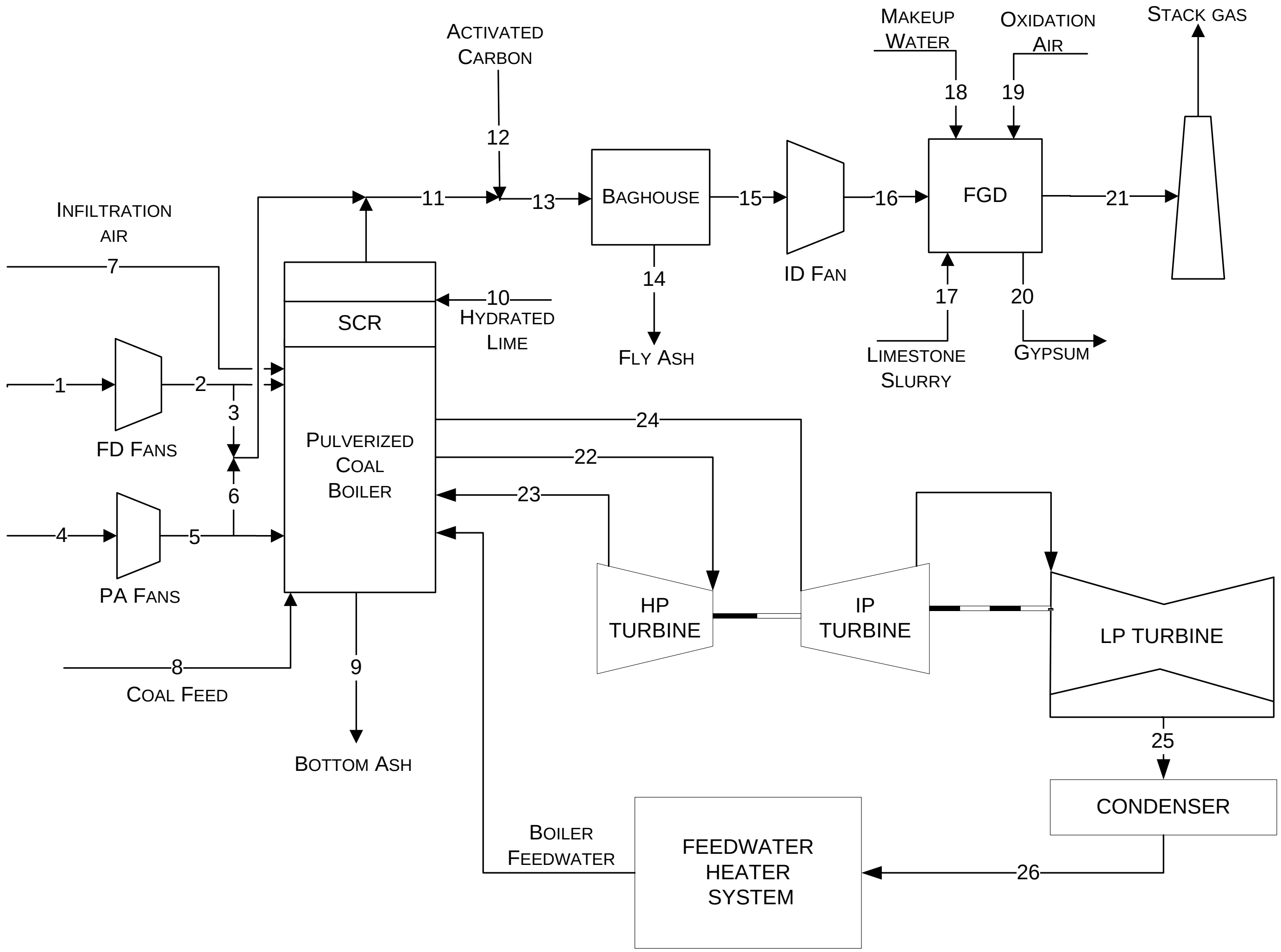
3.3.1 Process Description

In this section the SC PC process without CO_2 capture is described. The system description is nearly identical to the subcritical PC case without CO_2 capture but is repeated here for completeness. The description follows the BFD in Exhibit 3-37 and stream numbers reference the same Exhibit. The tables in Exhibit 3-38 provide process data for the numbered streams in the BFD.

Coal (stream 8) and PA (stream 4) are introduced into the boiler through the wall-fired burners. Additional combustion air, including the OFA, is provided by the FD fans (stream 1). The boiler operates at a slight negative pressure so air leakage is into the boiler, and the infiltration air is accounted for in stream 7. Streams 3 and 6 show Ljungstrom air preheater leakages from the FD and PA fan outlet streams to the boiler exhaust.

Flue gas exits the boiler through the SCR reactor where hydrated lime is injected (stream 10) for the reduction of SO_3. It then passes through the combustion air preheater (where the air preheater leakages are introduced) and is cooled to 143°C (289°F) (stream 11) before PAC is injected (stream 12) for mercury reduction. The flue gas then passes through a fabric filter for particulate removal (stream 15). An ID fan increases the flue gas temperature to 153°C (308°F) and provides the motive force for the flue gas (stream 16) to pass through the FGD unit. FGD inputs and outputs include makeup water (stream 18), oxidation air (stream 19), limestone slurry (stream 17) and product gypsum (stream 20). The clean, saturated flue gas exiting the FGD unit (stream 21) passes to the plant stack and is discharged to the atmosphere.

Exhibit 3-37 Case B12A block flow diagram, supercritical unit without CO_2 capture



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Source: NETL

Exhibit 3-38 Case B12A stream table, supercritical unit without capture

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
V-L Mole Fraction														
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000	0.0088	0.0000	0.0088	0.0000
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1376	0.0000	0.1376	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0000	0.0831	0.0000	0.0831	0.0000
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7345	0.0000	0.7345	0.0000
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0340	0.0000	0.0340	0.3333
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0020	0.0000	0.0020	0.6667
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000
V-L Flowrate (kg_{mole}/hr)	49,410	49,410	1,463	15,178	15,178	2,089	1,079	0	0	0	69,258	0	69,258	3
V-L Flowrate (kg/hr)	1,425,833	1,425,833	42,230	438,001	438,001	60,280	31,143	0	0	0	2,056,795	0	2,056,795	158
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	179,193	3,475	3,611	17,512	104	17,616	17,616
Temperature (°C)	15	19	19	15	25	25	15	15	149	27	143	27	143	143
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) [A]	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	0.00	0.00	0.00	---	---
AspenPlus Enthalpy (kJ/kg) [B]	-97.58	-93.45	-93.45	-97.58	-87.03	-87.03	-97.58	-2,114.05	97.18	-13,306.82	-2,399.46	3.40	-2,399.34	-2,632.07
Density (kg/m^3)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	---	0.9	---	0.9	1.5
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	---	29.698	---	29.698	53.376
V-L Flowrate (lb_{mole}/hr)	108,931	108,931	3,226	33,463	33,463	4,605	2,379	0	0	0	152,687	0	152,687	7
V-L Flowrate (lb/hr)	3,143,424	3,143,424	93,102	965,627	965,627	132,896	68,659	0	0	0	4,534,456	0	4,534,456	347
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	395,053	7,661	7,962	38,608	230	38,838	38,838
Temperature (°F)	59	66	66	59	78	78	59	59	300	80	289	80	289	289
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.4	14.7	14.4	14.7	14.4	14.4
Steam Table Enthalpy (Btu/lb) [A]	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---				---	---
AspenPlus Enthalpy (Btu/lb) [B]	-42.0	-40.2	-40.2	-42.0	-37.4	-37.4	-42.0	-908.9	41.8	-5,720.9	-1,031.6	1.5	-1,031.5	-1,131.6
Density (lb/ft^3)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	---	0.053	---	0.053	0.096

[A] Steam table reference conditions are 32.02°F & 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit 3-38 Case B12A stream table, supercritical unit without capture (continued)

	15	16	17	18	19	20	21	22	23	24	25	26
V-L Mole Fraction												
Ar	0.0088	0.0088	0.0000	0.0000	0.0092	0.0000	0.0082	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.1376	0.1376	0.0000	0.0000	0.0003	0.0001	0.1288	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0831	0.0831	1.0000	1.0000	0.0099	0.9999	0.1451	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.7345	0.7345	0.0000	0.0000	0.7732	0.0000	0.6854	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0340	0.0340	0.0000	0.0000	0.2074	0.0000	0.0325	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0020	0.0020	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mole}/hr)	69,255	69,255	2,296	9,201	732	169	75,048	88,629	74,095	74,095	66,938	67,115
V-L Flowrate (kg/hr)	2,056,637	2,056,637	41,356	165,764	21,135	3,052	2,165,283	1,596,685	1,334,839	1,334,839	1,205,905	1,209,098
Solids Flowrate (kg/hr)	0	0	17,707	0	0	27,462	0	0	0	0	0	0
Temperature (°C)	143	153	15	27	167	56	56	593	342	593	38	39
Pressure (MPa, abs)	0.10	0.11	0.10	0.11	0.31	0.10	0.10	24.23	4.90	4.80	0.01	1.80
Steam Table Enthalpy (kJ/kg) [A]	274.35	285.60	---	111.65	184.48	---	286.10	3,477.96	3,049.83	3,652.36	1,978.90	163.04
AspenPlus Enthalpy (kJ/kg) [B]	-2,397.32	-2,386.08	-14,995.75	-15,964.53	56.67	-12,481.91	-2,940.27	-12,502.33	-12,930.47	-12,327.94	-14,001.40	-15,817.25
Density (kg/m^3)	0.8	0.9	1,003.6	992.3	2.4	833.1	1.1	69.2	19.2	12.3	0.1	993.5
V-L Molecular Weight	29.697	29.697	18.015	18.015	28.857	18.018	28.852	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mole}/hr)	152,680	152,680	5,061	20,285	1,615	373	165,452	195,395	163,351	163,351	147,573	147,964
V-L Flowrate (lb/hr)	4,534,108	4,534,108	91,174	365,446	46,596	6,729	4,773,632	3,520,088	2,942,815	2,942,815	2,658,565	2,665,605
Solids Flowrate (lb/hr)	0	0	39,037	0	0	60,544	0	0	0	0	0	0
Temperature (°F)	289	308	59	80	332	133	133	1,100	648	1,100	101	101
Pressure (psia)	14.2	15.2	15.0	15.7	45.0	14.7	14.7	3,514.7	710.8	696.6	1.0	261.6
Steam Table Enthalpy (Btu/lb) [A]	118.0	122.8	---	48.0	79.3	---	123.0	1,495.3	1,311.2	1,570.2	850.8	70.1
AspenPlus Enthalpy (Btu/lb) [B]	-1,030.7	-1,025.8	-6,447.0	-6,863.5	24.4	-5,366.3	-1,264.1	-5,375.0	-5,559.1	-5,300.1	-6,019.5	-6,800.2
Density (lb/ft^3)	0.052	0.055	62.650	61.950	0.153	52.011	0.067	4.319	1.197	0.768	0.004	62.022

[A] Steam table reference conditions are 32.02°F & 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

3.3.2 Key System Assumptions

System assumptions for Cases B12A and B12B, SC PC with and without CO_2 capture, are compiled in Exhibit 3-39.

Exhibit 3-39 Supercritical PC plant study configuration matrix

	Case B12A w/o CO_2 Capture	Case B12B w/CO_2 Capture
Steam Cycle, MPa/°C/°C (psig/°F/°F)	24.1/593/593 (3,500/1,100/1,100)	24.1/593/593 (3,500/1,100/1,100)
Coal	Illinois No. 6	Illinois No. 6
Condenser pressure, mm Hg (in Hg)	50.8 (2)	50.8 (2)
Boiler Efficiency, HHV %	89	89
Cooling water to condenser, °C (ºF)	16 (60)	16 (60)
Cooling water from condenser, °C (ºF)	27 (80)	27 (80)
Stack temperature, °C (°F)	56 (133)	42 (107)
SO_2 Control	Wet Limestone Forced Oxidation	Wet Limestone Forced Oxidation
FGD Efficiency, % (A)	98	98 (B, C)
NOx Control	LNB w/OFA, SCR, and Polishing Scrubber	LNB w/OFA, SCR, and Polishing Scrubber
SCR Efficiency, % (A)	83	85
Ammonia Slip (end of catalyst life), ppmv	2	2
Particulate Control	Fabric Filter	Fabric Filter
Fabric Filter efficiency, % (A)	99.9	99.9
Ash Distribution, Fly/Bottom	80% / 20%	80% / 20%
SO_3 Control	DSI	DSI
Mercury Control	Co-benefit Capture and ACI	Co-benefit Capture and ACI
CO_2 Control	N/A	Cansolv
Overall Carbon Capture (A)	N/A	90%
CO_2 Sequestration	N/A	Off-site Saline Formation

[A]Removal efficiencies are based on the flue gas content
[B]An SO_2 polishing step is included to meet more stringent SOx content limits in the flue gas (~1 ppmv) to reduce formation of amine HSS during the CO_2 absorption process
[C]SO_2 exiting the post-FGD polishing step is absorbed in the CO_2 capture process making stack emissions negligible

3.3.2.1 Balance of Plant – Cases B12A and B12B

The balance of plant assumptions are common to all cases and were presented previously in Exhibit 3-8.

3.3.3 Sparing Philosophy

Single trains are used throughout the design with exceptions where equipment capacity requires an additional train. There is no redundancy other than normal sparing of rotating equipment. The plant design consists of the following major subsystems:

- One dry-bottom, wall-fired PC SC boiler (1 x 100%)
- Two SCR reactors (2 x 50%)
- One DSI system (1 x 100%)
- One ACI system (1 x 100%)
- Two single-stage, in-line, multi-compartment fabric filters (2 x 50%)
- One wet limestone forced oxidation positive pressure absorber (1 x 100%)
- One steam turbine (1 x 100%)
- For Case B12B only, one CO_2 absorption system, consisting of an absorber, stripper, and ancillary equipment (1 x 100%) and two CO_2 compression systems (2 x 50%)

3.3.4 Case B12A Performance Results

The plant produces a net output of 550 MWe at a net plant efficiency of 40.7 percent (HHV basis). Overall performance for the plant is summarized in Exhibit 3-40; Exhibit 3-41 provides a detailed breakdown of the auxiliary power requirements.

Exhibit 3-40 Case B12A plant performance summary

Performance Summary	
Total Gross Power, MWe	**580**
CO_2 Capture/Removal Auxiliaries, kWe	0
CO_2 Compression, kWe	0
Balance of Plant, kWe	29,688
Total Auxiliaries, MWe	**30**
Net Power, MWe	**550**
HHV Net Plant Efficiency (%)	40.7%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,841 (8,379)
LHV Net Plant Efficiency (%)	42.2%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,527 (8,082)
HHV Boiler Efficiency, %	89.1%
LHV Boiler Efficiency, %	92.4%
Steam Turbine Cycle Efficiency, %	48.2%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,473 (7,083)
Condenser Duty, GJ/hr (MMBtu/hr)	2,192 (2,078)
As-Received Coal Feed, kg/hr (lb/hr)	179,193 (395,053)
Limestone Sorbent Feed, kg/hr (lb/hr)	17,707 (39,037)
HHV Thermal Input, kWt	1,350,672
LHV Thermal Input, kWt	1,302,740
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.035 (9.3)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.028 (7.4)
Excess Air, %	20.9%

Exhibit 3-41 Case B12A plant power summary

Power Summary	
Steam Turbine Power, MWe	580
Total Gross Power, MWe	**580**
Auxiliary Load Summary	
Coal Handling and Conveying, kWe	430
Pulverizers, kWe	2,690
Sorbent Handling & Reagent Preparation, kWe	850
Ash Handling, kWe	620
Primary Air Fans, kWe	1,330
Forced Draft Fans, kWe	1,700
Induced Draft Fans, kWe	6,660
SCR, kWe	40
Activated Carbon Injection, kWe	22
Dry sorbent Injection, kWe	86
Baghouse, kWe	90
Wet FGD, kWe	2,830
CO_2 Capture/Removal Auxiliaries, kWe	0
CO_2 Compression, kWe	0
Miscellaneous Balance of Plant[A,B], kWe	2,000
Steam Turbine Auxiliaries, kWe	400
Condensate Pumps, kWe	800
Circulating Water Pumps, kWe	4,520
Ground Water Pumps, kWe	460
Cooling Tower Fans, kWe	2,340
Transformer Losses, kWe	1,820
Total Auxiliaries, MWe	**30**
Net Power, MWe	**550**

[A]Boiler feed pumps are turbine driven
[B]Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

3.3.4.1 Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B12A is presented in Exhibit 3-42.

Exhibit 3-42 Case B12A air emissions

	kg/GJ (lb/MMBtu)	Tonne/year (ton/year)[A]	kg/MWh (lb/MWh)
SO_2	0.036 (0.085)	1,317 (1,452)	0.305 (0.673)
NOx	0.038 (0.088)	1,371 (1,511)	0.318 (0.700)
Particulate	0.005 (0.011)	176 (194)	0.041 (0.090)
Hg	1.62E-7 (3.77E-7)	0.006 (0.006)	1.36E-6 (3.00E-6)
CO_2[B]	87 (204)	3,167,890 (3,492,001)	734 (1,618)
CO_2[C]	-	-	774 (1,705)
	mg/Nm^3		
Particulate Concentration[D,E]	15.25		

[A]Calculations based on an 85 percent capacity factor
[B]CO_2 emissions based on gross power
[C]CO_2 emissions based on net power instead of gross power
[D]Concentration of particles in the flue gas after the baghouse
[E]Normal conditions given at 32°F and 14.696 psia

SO_2 emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The saturated flue gas exiting the scrubber is vented through the plant stack.

NOx emissions are controlled to about 0.5 lb/MMBtu through the use of LNBs and OFA. An SCR unit then further reduces the NOx concentration by 83 percent to 0.09 lb/MMBtu.

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment (SCR, ACI, fabric filter, DSI, and wet FGD) is 96.7 percent.

CO_2 emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 3-43. The carbon input to the plant consists of carbon in the coal, carbon in the air, PAC, and carbon in the limestone reagent used in the FGD. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant mostly as CO_2 through the stack, however, the PAC is captured in the fabric filter and some leaves as gypsum.

Exhibit 3-43 Case B12A carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	114,226 (251,825)	Stack Gas	116,112 (255,983)
Air (CO_2)	261 (574)	FGD Product	171 (378)
PAC	104 (230)	Baghouse	104 (230)
FGD Reagent	1,797 (3,961)	CO_2 Product	0
		CO_2 Dryer Vent	0
		CO_2 Knockout	0
Total	**116,388 (256,591)**	**Total**	**116,388 (256,591)**

Exhibit 3-44 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur captured in the fabric filter via hydrated lime, and sulfur emitted in the stack gas.

Exhibit 3-44 Case B12A sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	4,491 (9,902)	FGD Product	4,340 (9,567)
		Stack Gas	89 (195)
		Polishing Scrubber and Solvent Reclaiming	0
		Baghouse	63 (139)
Total	**4,491 (9,902)**	**Total**	**4,491 (9,902)**

Exhibit 3-45 shows the overall water balance for the plant.

Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is re-used as internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a POTW for use in the plant and was assumed to be provided 50 percent by a POTW and 50 percent from groundwater. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for any and all purposes, such as FGD makeup, BFW makeup, and cooling tower makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source balance.

Exhibit 3-45 Case B12A water balance

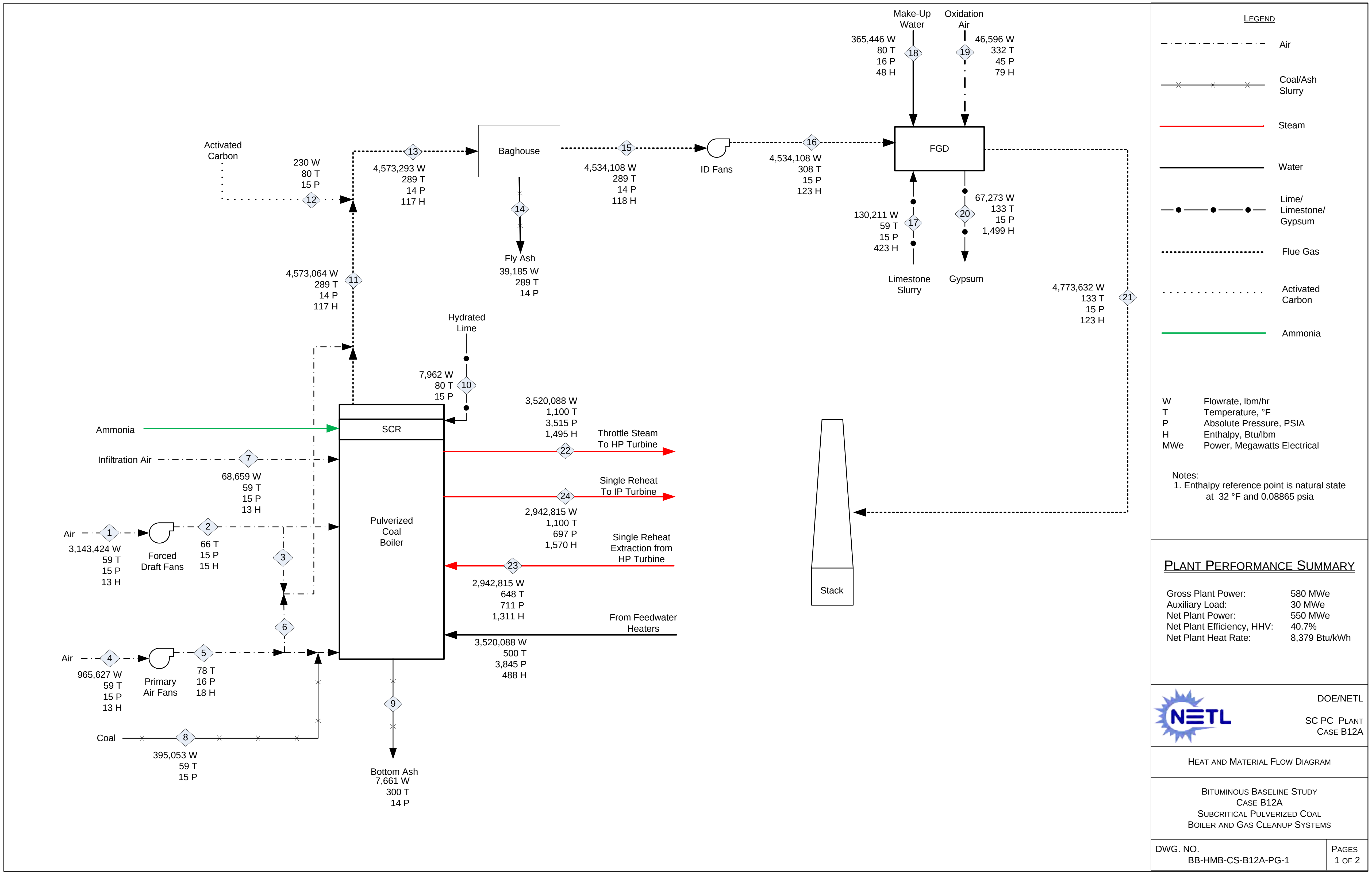
Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)
FGD Makeup	3.46 (913)	–	3.46 (913)	–	3.46 (913)
CO_2 Drying	–	–	–	–	–
Capture System Makeup	–	–	–	–	–
Deaerator Vent	–	–	–	0.05 (14)	-0.05 (-14)
Condenser Makeup	**0.05 (14)**	**–**	**0.05 (14)**	**–**	**0.05 (14)**
BFW Makeup	0.05 (14)	–	0.05 (14)	–	0.05 (14)
Cooling Tower	**17.59 (4,648)**	**1.78 (471)**	**15.81 (4,177)**	**3.96 (1,045)**	**11.86 (3,132)**
FGD Dewatering	–	1.78 (471)	-1.78 (-471)	–	-1.78 (-471)
CO_2 Capture Recovery	–	–	–	–	–
CO_2 Compression KO	–	–	–	–	–
BFW Blowdown	–	–	–	–	–
Total	**21.11 (5,575)**	**1.78 (471)**	**19.32 (5,105)**	**4.01 (1,059)**	**15.31 (4,045)**

3.3.4.2 Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the Case B12A PC boiler, the FGD unit and steam cycle in Exhibit 3-46 and Exhibit 3-47.

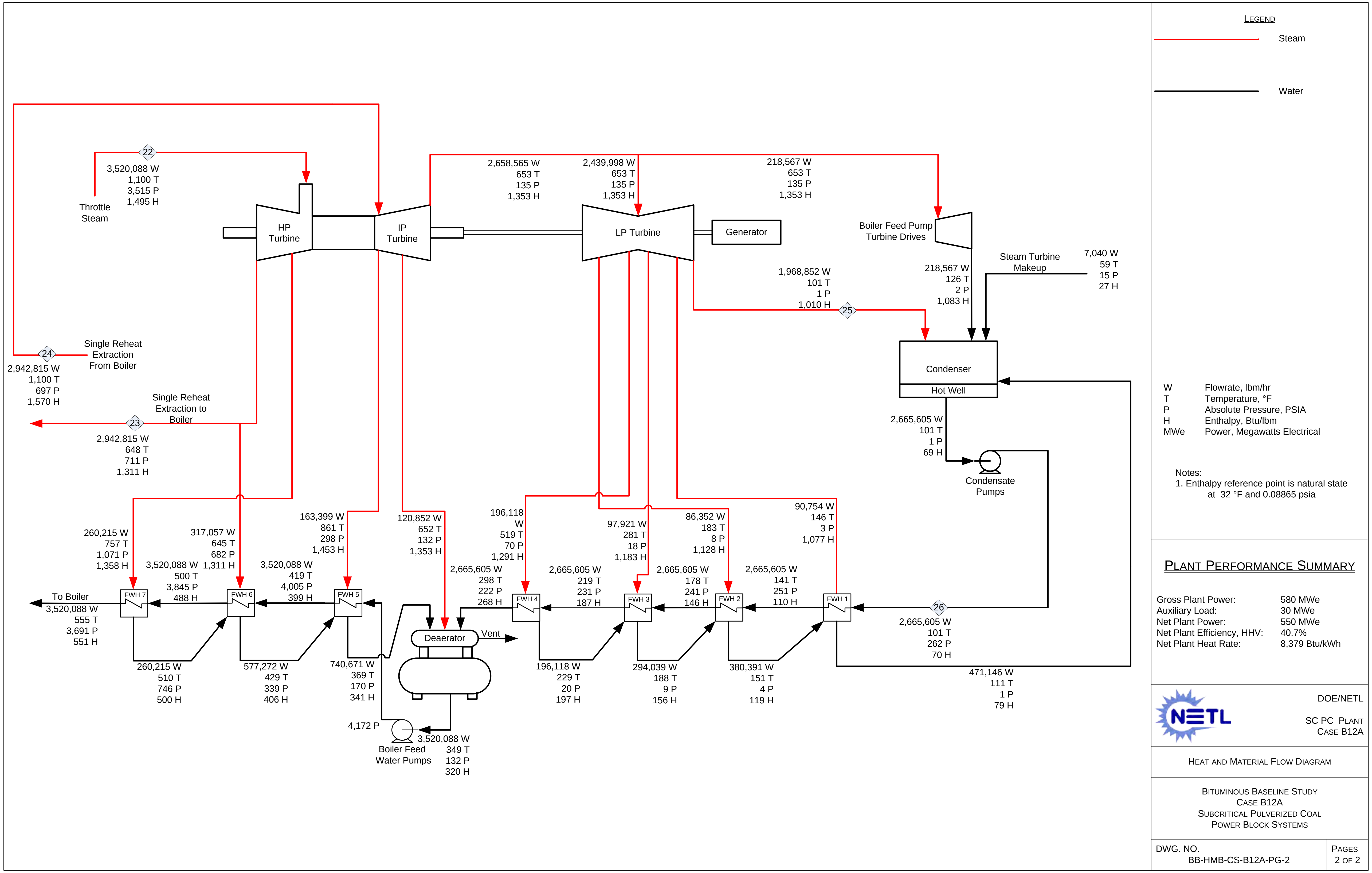
An overall plant energy balance is provided in tabular form in Exhibit 3-48. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-40) is calculated by multiplying the power out by a generator efficiency of 98.5 percent.

Exhibit 3-46 Case B12A heat and mass balance, supercritical PC boiler without CO_2 capture



Source: NETL

Exhibit 3-47 Case B12A heat and mass balance, supercritical steam cycle



Source: NETL

Exhibit 3-48 Case B12A overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	4,862 (4,609)	4.1 (3.9)	–	4,866 (4,613)
Air	–	57.3 (54.3)	–	57.3 (54.3)
Raw Water Makeup	–	72.7 (68.9)	–	72.7 (68.9)
Limestone	–	0.38 (0.36)	–	0.38 (0.36)
Auxiliary Power	–	–	107 (101)	107 (101)
TOTAL	**4,862 (4,609)**	**134.4 (127.4)**	**107 (101)**	**5,104 (4,837)**
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	–	0.4 (0.3)	–	0.4 (0.3)
Fly Ash + FGD Ash	–	2.0 (1.9)	–	2.0 (1.9)
Stack Gas	–	619 (587)	–	619 (587)
Sulfur	–	–	–	–
Motor Losses and Design Allowances	–	–	34 (32)	34 (32)
Condenser	–	2,192 (2,078)	–	2,192 (2,078)
Non-Condenser Cooling Tower Loads	–	106 (100)	–	106 (100)
CO_2	–	0.0 (0.0)	–	0.0 (0.0)
Cooling Tower Blowdown	–	29.4 (27.9)	–	29.4 (27.9)
CO_2 Capture Losses	–	–	–	–
Ambient Losses[A]	–	104.7 (99.2)	–	104.7 (99.2)
Power	–	–	2,087 (1,978)	2,087 (1,978)
TOTAL	**–**	**3,054 (2,894)**	**2,121 (2,010)**	**5,175 (4,905)**
Unaccounted Energy[B]	–	-71 (-67)	–	-71 (-67)

[A]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers.
[B]By difference

3.3.5 Case B12A – Major Equipment List

Major equipment items for the SC PC plant with no CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 3.3.6. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

Case B12A – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	40 tonne (40 ton)	2	1
9	Feeder	Vibratory	150 tonne/hr (160 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	300 tonne/hr (330 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	150 tonne (160 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	300 tonne/hr (330 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	300 tonne/hr (330 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	660 tonne (700 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 28 tonne (30 ton) Feeder - 110 kg/hr (250 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 190 tonne (210 ton) Feeder - 3,970 kg/hr (8,760 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	70 tonne/hr (80 tph)	1	0
23	Limestone Conveyor No. L1	Belt	70 tonne/hr (80 tph)	1	0
24	Limestone Reclaim Hopper	N/A	10 tonne (20 ton)	1	0
25	Limestone Reclaim Feeder	Belt	60 tonne/hr (60 tph)	1	0
26	Limestone Conveyor No. L2	Belt	60 tonne/hr (60 tph)	1	0
27	Limestone Day Bin	w/ actuator	230 tonne (260 ton)	2	0

Case B12A – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	30 tonne/hr (40 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	30 tonne/hr (40 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	19 tonne/hr (21 tph)	1	1
4	Limestone Ball Mill	Rotary	19 tonne/hr (21 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	75,000 liters (20,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,240 lpm @ 10m H_2O (330 gpm @ 40 ft H_2O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5 cyclone bank	310 lpm (80 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	421,000 liters (111,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	880 lpm @ 9m H_2O (230 gpm @ 30 ft H_2O)	1	1

Case B12A – Account 3: Feedwater and Miscellaneous Systems and Equipment

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	211,000 liters (56,000 gal)	2	0
2	Condensate Pumps	Vertical canned	22,300 lpm @ 200 m H_2O (5,900 gpm @ 700 ft H_2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	1,760,000 kg/hr (3,880,000 lb/hr), 5 min. tank	1	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	29,500 lpm @ 3,400 m H_2O (7,800 gpm @ 11,300 ft H_2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	8,800 lpm @ 3,400 m H_2O (2,300 gpm @ 11,300 ft H_2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	670,000 kg/hr (1,470,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	670,000 kg/hr (1,470,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	670,000 kg/hr (1,470,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	670,000 kg/hr (1,470,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	1,760,000 kg/hr (3,870,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	1,760,000 kg/hr (3,870,000 lb/hr)	1	0
12	HP Feedwater heater 8	Horizontal U-tube	1,760,000 kg/hr (3,870,000 lb/hr)	1	0
13	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
14	Fuel Oil System	No. 2 fuel oil for light off	1,135,624 liter (300,000 gal)	1	0
15	Service Air Compressors	Flooded Screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
16	Instrument Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	2	1
17	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,800 lpm @ 30 m H_2O (5,500 gpm @ 100 ft H_2O)	2	1
19	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H_2O (1,000 gpm @ 290 ft H_2O)	1	1
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H_2O (700 gpm @ 210 ft H_2O)	1	1
21	Raw Water Pumps	Stainless steel, single suction	5,670 lpm @ 20 m H_2O (1,500 gpm @ 60 ft H_2O)	2	1
22	Ground Water Pumps	Stainless steel, single suction	2,270 lpm @ 270 m H_2O (600 gpm @ 880 ft H_2O)	5	1
23	Filtered Water Pumps	Stainless steel, single suction	1,690 lpm @ 50 m H_2O (450 gpm @ 160 ft H_2O)	2	1
24	Filtered Water Tank	Vertical, cylindrical	1,619,000 liter (428,000 gal)	1	0
25	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	330 lpm (90 gpm)	1	1
26	Liquid Waste Treatment System	--	10 years, 24-hour storm	1	0

Case B12A – Account 4: Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, drum, wall-fired, low NOx burners, overfire air	1,760,000 kg/hr steam @ 25.5 MPa/602°C/602°C (3,870,000 lb/hr steam @ 3,700 psig/1,115°F/1,115°F)	1	0
2	Primary Air Fan	Centrifugal	241,000 kg/hr, 3,300 m^3/min @ 123 cm WG (531,000 lb/hr, 116,100 acfm @ 48 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	784,000 kg/hr, 10,700 m^3/min @ 47 cm WG (1,729,000 lb/hr, 377,900 acfm @ 19 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,131,000 kg/hr, 22,400 m^3/min @ 89 cm WG (2,494,000 lb/hr, 792,500 acfm @ 35 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	2,260,000 kg/hr (4,990,000 lb/hr)	2	0
6	SCR Catalyst	--	--	3	0
7	Dilution Air Blower	Centrifugal	120 m^3/min @ 108 cm WG (4,300 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	135,000 liter (36,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	26 lpm @ 90 m H_2O (7 gpm @ 300 ft H_2O)	2	1

Case B12A – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,131,000 kg/hr (2,494,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	45,000 m^3/min (1,593,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	157,000 lpm @ 65 m H_2O (41,000 gpm @ 210 ft H_2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	3,820 lpm (1,010 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	80 m^3/min @ 0.3 MPa (2,800 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	960 lpm (250 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	30 tonne/hr (33 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	580 lpm @ 13 m H_2O (150 gpm @ 40 ft H_2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	380,000 lpm (100,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	3,040 lpm @ 21 m H_2O (800 gpm @ 70 ft H_2O)	1	1
12	Activated Carbon Injectors	---	110 kg/hr (250 lb/hr)	1	0
13	Hydrated Lime Injectors	---	3,970 kg/hr (8,760 lb/hr)	1	0

Case B12A – Account 7: Ducting and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 5.7 m (19 ft) diameter	1	0

Case B12A – Account 8: Steam Turbine Generator and Auxiliaries

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	610 MW 24.1 MPa/593°C/593°C (3500 psig/ 1100°F/1100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	680 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,410 GJ/hr (2,290 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

Case B12A – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	453,000 lpm @ 30 m (120,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 2530 GJ/hr (2400 MMBtu/hr) heat duty	1	0

Case B12A – Account 10: Ash and Spent Sorbent Recovery and Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	--	--	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	--	--	2	0
3	Clinker Grinder	--	3.8 tonne/hr (4.2 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	--	--	6	0
5	Hydroejectors	--	--	12	
6	Economizer /Pyrites Transfer Tank	--	--	1	0
7	Ash Sluice Pumps	Vertical, wet pit	150 lpm @ 17 m H_2O (40 gpm @ 56 ft H_2O)	1	1
8	Ash Seal Water Pumps	Vertical, wet pit	7,570 lpm @ 9 m H_2O (2000 gpm @ 28 ft H_2O)	1	1
9	Hydrobins	--	150 lpm (40 gpm)	1	1
10	Baghouse Hopper (part of baghouse scope of supply)	--	--	24	0
11	Air Heater Hopper (part of boiler scope of supply)	--	--	10	0
12	Air Blower	--	20 m^3/min @ 0.2 MPa (630 scfm @ 24 psi)	1	1
13	Fly Ash Silo	Reinforced concrete	1,200 tonne (1,300 ton)	2	0
14	Slide Gate Valves	--	--	2	0
15	Unloader	--	--	1	0

16	Telescoping Unloading Chute	--	110 tonne/hr (120 tph)	1	0

Case B12A – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 650 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 0 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 31 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 5 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B12A – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.3.6 Case B12A – Costs Estimating Results

The cost estimating methodology was described previously in Section 2.7. Exhibit 3-49 shows a detailed breakdown of the capital costs; Exhibit 3-50 shows the owner's costs, TOC, and TASC; Exhibit 3-51 shows the initial and annual O&M costs; and Exhibit 3-52 shows the COE breakdown.

The estimated TPC of the SC PC boiler with no CO_2 capture is $2,026/kW. No process contingency was included in this case because all elements of the technology are commercially proven. The project contingency is 10.7 percent of the TPC. The COE is $82.3/MWh.

Exhibit 3-49 Case B12A total plant cost details

	Case:	B11A – Supercritical PC w/o CO_2							Estimate Type:	Conceptual	
	Plant Size (MW,net):	550							Cost Base:	Jun 2011	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
	1	Coal & Sorbent Handling									
1.1	Coal Receive & Unload	$3,998	$0	$1,801	$0	$5,799	$580	$0	$957	$7,336	$13
1.2	Coal Stackout & Reclaim	$5,167	$0	$1,155	$0	$6,321	$632	$0	$1,043	$7,996	$15
1.3	Coal Conveyors	$4,804	$0	$1,142	$0	$5,946	$595	$0	$981	$7,522	$14
1.4	Other Coal Handling	$1,257	$0	$264	$0	$1,521	$152	$0	$251	$1,924	$3
1.5	Sorbent Receive & Unload	$159	$0	$47	$0	$207	$21	$0	$34	$262	$0
1.6	Sorbent Stackout & Reclaim	$2,574	$0	$465	$0	$3,039	$304	$0	$501	$3,844	$7
1.7	Sorbent Conveyors	$918	$199	$222	$0	$1,340	$134	$0	$221	$1,695	$3
1.8	Other Sorbent Handling	$555	$131	$287	$0	$972	$97	$0	$160	$1,230	$2
1.9	Coal & Sorbent Hnd. Foundations	$0	$4,633	$6,109	$0	$10,743	$1,074	$0	$1,773	$13,590	$25
	Subtotal	**$19,431**	**$4,963**	**$11,493**	**$0**	**$35,888**	**$3,589**	**$0**	**$5,921**	**$45,398**	**$83**
	2	Coal & Sorbent Prep & Feed									
2.1	Coal Crushing & Drying	$2,287	$0	$439	$0	$2,726	$273	$0	$450	$3,448	$6
2.2	Coal Conveyor to Storage	$5,854	$0	$1,260	$0	$7,115	$711	$0	$1,174	$9,000	$16
2.5	Sorbent Prep Equipment	$4,370	$189	$895	$0	$5,454	$545	$0	$900	$6,899	$13
2.6	Sorbent Storage & Feed	$526	$0	$199	$0	$725	$73	$0	$120	$918	$2
2.9	Coal & Sorbent Feed Foundation	$0	$533	$468	$0	$1,001	$100	$0	$165	$1,266	$2
	Subtotal	**$13,037**	**$722**	**$3,262**	**$0**	**$17,021**	**$1,702**	**$0**	**$2,808**	**$21,531**	**$39**
	3	Feedwater & Miscellaneous BOP Systems									
3.1	Feedwater System	$21,709	$0	$6,999	$0	$28,708	$2,871	$0	$4,737	$36,316	$66
3.2	Water Makeup & Pretreating	$5,225	$0	$1,653	$0	$6,878	$688	$0	$1,513	$9,079	$17
3.3	Other Feedwater Subsystems	$6,829	$0	$2,803	$0	$9,632	$963	$0	$1,589	$12,185	$22
3.4	Service Water Systems	$1,046	$0	$548	$0	$1,594	$159	$0	$351	$2,104	$4
3.5	Other Boiler Plant Systems	$8,284	$0	$7,832	$0	$16,116	$1,612	$0	$2,659	$20,387	$37
3.6	FO Supply Sys & Nat Gas	$327	$0	$382	$0	$708	$71	$0	$117	$896	$2
3.7	Waste Treatment Equipment	$3,428	$0	$1,985	$0	$5,413	$541	$0	$1,191	$7,145	$13
3.8	Misc. Equip. (Cranes, Air Comp., Comm.)	$3,201	$0	$990	$0	$4,191	$419	$0	$922	$5,532	$10
	Subtotal	**$50,049**	**$0**	**$23,192**	**$0**	**$73,241**	**$7,324**	**$0**	**$13,079**	**$93,644**	**$170**
	4	Boiler & Accessories									
4.1	PC Boiler & Accessories	$179,905	$0	$102,509	$0	$282,414	$28,241	$0	$31,066	$341,722	$621
4.2	SCR	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0
4.5	Primary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0
4.6	Secondary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0
4.9	Boiler Foundations	$0	w/14.1	w/14.1	$0	$0	$0	$0	$0	$0	$0
	Subtotal	**$179,905**	**$0**	**$102,509**	**$0**	**$282,414**	**$28,241**	**$0**	**$31,066**	**$341,722**	**$621**
	5A	Gas Cleanup & Piping									
5A.1	Absorber Vessels & Accessories	$67,346	$0	$14,399	$0	$81,745	$8,175	$0	$8,992	$98,912	$180
5A.2	Other FGD	$3,514	$0	$3,955	$0	$7,470	$747	$0	$822	$9,038	$16

	Case:	B11A – Supercritical PC w/o CO_2							Estimate Type:	Conceptual	
	Plant Size (MW,net):	550							Cost Base:	Jun 2011	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
5A.3	Bag House & Accessories	$19,040	$0	$12,001	$0	$31,041	$3,104	$0	$3,415	$37,560	$68
5A.4	Other Particulate Removal Materials	$1,289	$0	$1,369	$0	$2,658	$266	$0	$292	$3,216	$6
5A.5	Gypsum Dewatering System	$5,399	$0	$911	$0	$6,309	$631	$0	$694	$7,634	$14
5A.6	Mercury Removal System	$4,093	$900	$4,024	$0	$9,018	$902	$0	$992	$10,911	$20
	Subtotal	**$100,681**	**$900**	**$36,660**	**$0**	**$138,241**	**$13,824**	**$0**	**$15,207**	**$167,272**	**$304**
	7	**HRSG, Ducting, & Stack**									
7.3	Ductwork	$10,663	$0	$6,731	$0	$17,394	$1,739	$0	$2,870	$22,004	$40
7.4	Stack	$10,604	$0	$6,162	$0	$16,766	$1,677	$0	$1,844	$20,287	$37
7.9	Duct & Stack Foundations	$0	$1,156	$1,373	$0	$2,528	$253	$0	$556	$3,337	$6
	Subtotal	**$21,267**	**$1,156**	**$14,266**	**$0**	**$36,689**	**$3,669**	**$0**	**$5,271**	**$45,629**	**$83**
	8	**Steam Turbine Generator**									
8.1	Steam TG & Accessories	$75,300	$0	$8,211	$0	$83,511	$8,351	$0	$9,186	$101,049	$184
8.2	Turbine Plant Auxiliaries	$418	$0	$890	$0	$1,308	$131	$0	$144	$1,582	$3
8.3	Condenser & Auxiliaries	$7,830	$0	$2,737	$0	$10,567	$1,057	$0	$1,162	$12,786	$23
8.4	Steam Piping	$26,525	$0	$10,751	$0	$37,276	$3,728	$0	$6,151	$47,154	$86
8.9	TG Foundations	$0	$1,247	$2,059	$0	$3,305	$331	$0	$727	$4,363	$8
	Subtotal	**$110,073**	**$1,247**	**$24,647**	**$0**	**$135,967**	**$13,597**	**$0**	**$17,370**	**$166,934**	**$304**
	9	**Cooling Water System**									
9.1	Cooling Towers	$10,613	$0	$3,282	$0	$13,895	$1,390	$0	$1,529	$16,814	$31
9.2	Circulating Water Pumps	$2,125	$0	$133	$0	$2,258	$226	$0	$248	$2,732	$5
9.3	Circ. Water System Auxiliaries	$586	$0	$78	$0	$664	$66	$0	$73	$803	$1
9.4	Circ. Water Piping	$0	$4,939	$4,473	$0	$9,412	$941	$0	$1,553	$11,906	$22
9.5	Make-up Water System	$528	$0	$678	$0	$1,206	$121	$0	$199	$1,525	$3
9.6	Component Cooling Water Sys.	$478	$0	$367	$0	$845	$84	$0	$139	$1,069	$2
9.9	Circ. Water Foundations & Structures	$0	$2,616	$4,344	$0	$6,960	$696	$0	$1,531	$9,188	$17
	Subtotal	**$14,330**	**$7,555**	**$13,355**	**$0**	**$35,240**	**$3,524**	**$0**	**$5,273**	**$44,037**	**$80**
	10	**Ash & Spent Sorbent Handling Systems**									
10.6	Ash Storage Silos	$777	$0	$2,379	$0	$3,156	$316	$0	$347	$3,819	$7
10.7	Ash Transport & Feed Equipment	$5,164	$0	$5,119	$0	$10,283	$1,028	$0	$1,131	$12,443	$23
10.9	Ash/Spent Sorbent Foundation	$0	$176	$216	$0	$392	$39	$0	$86	$517	$1
	Subtotal	**$5,941**	**$176**	**$7,714**	**$0**	**$13,831**	**$1,383**	**$0**	**$1,564**	**$16,778**	**$31**
	11	**Accessory Electric Plant**									
11.1	Generator Equipment	$1,942	$0	$310	$0	$2,253	$225	$0	$186	$2,664	$5
11.2	Station Service Equipment	$3,283	$0	$1,101	$0	$4,384	$438	$0	$362	$5,184	$9
11.3	Switchgear & Motor Control	$3,769	$0	$655	$0	$4,423	$442	$0	$487	$5,352	$10
11.4	Conduit & Cable Tray	$0	$2,584	$8,349	$0	$10,934	$1,093	$0	$1,804	$13,831	$25
11.5	Wire & Cable	$0	$4,921	$8,796	$0	$13,717	$1,372	$0	$2,263	$17,352	$32
11.6	Protective Equipment	$306	$0	$1,063	$0	$1,370	$137	$0	$151	$1,658	$3
11.7	Standby Equipment	$1,497	$0	$35	$0	$1,532	$153	$0	$169	$1,854	$3
11.8	Main Power Transformers	$9,846	$0	$206	$0	$10,052	$1,005	$0	$1,106	$12,163	$22
11.9	Electrical Foundations	$0	$359	$913	$0	$1,271	$127	$0	$280	$1,678	$3
	Subtotal	**$20,644**	**$7,864**	**$21,428**	**$0**	**$49,936**	**$4,994**	**$0**	**$6,806**	**$61,735**	**$112**

	Case:	B11A – Supercritical PC w/o CO_2							Estimate Type:	Conceptual	
	Plant Size (MW,net):	550							Cost Base:	Jun 2011	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
	12	Instrumentation & Control									
12.1	PC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0
12.5	Signal Processing Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards, Panels & Racks	$531	$0	$324	$0	$855	$86	$0	$141	$1,082	$2
12.7	Distributed Control Sys. Equipment	$5,357	$0	$955	$0	$6,313	$631	$0	$694	$7,638	$14
12.8	Instrument Wiring & Tubing	$3,230	$0	$5,878	$0	$9,109	$911	$0	$1,503	$11,522	$21
12.9	Other I & C Equipment	$1,514	$0	$3,505	$0	$5,019	$502	$0	$552	$6,073	$11
	Subtotal	**$10,632**	**$0**	**$10,663**	**$0**	**$21,296**	**$2,130**	**$0**	**$2,891**	**$26,316**	**$48**
	13	Improvements to Site									
13.1	Site Preparation	$0	$56	$1,194	$0	$1,250	$125	$0	$275	$1,651	$3
13.2	Site Improvements	$0	$1,864	$2,462	$0	$4,326	$433	$0	$952	$5,710	$10
13.3	Site Facilities	$3,340	$0	$3,504	$0	$6,843	$684	$0	$1,506	$9,033	$16
	Subtotal	**$3,340**	**$1,920**	**$7,160**	**$0**	**$12,420**	**$1,242**	**$0**	**$2,732**	**$16,394**	**$30**
	14	Buildings & Structures									
14.1	Boiler Building	$0	$9,916	$8,714	$0	$18,629	$1,863	$0	$3,074	$23,566	$43
14.2	Turbine Building	$0	$14,161	$13,189	$0	$27,349	$2,735	$0	$4,513	$34,597	$63
14.3	Administration Building	$0	$702	$742	$0	$1,444	$144	$0	$238	$1,827	$3
14.4	Circulation Water Pumphouse	$0	$201	$160	$0	$361	$36	$0	$60	$457	$1
14.5	Water Treatment Buildings	$0	$652	$594	$0	$1,246	$125	$0	$206	$1,576	$3
14.6	Machine Shop	$0	$470	$315	$0	$785	$79	$0	$130	$993	$2
14.7	Warehouse	$0	$318	$319	$0	$637	$64	$0	$105	$806	$1
14.8	Other Buildings & Structures	$0	$260	$221	$0	$481	$48	$0	$79	$609	$1
14.9	Waste Treating Building & Str.	$0	$498	$1,510	$0	$2,008	$201	$0	$331	$2,540	$5
	Subtotal	**$0**	**$27,177**	**$25,764**	**$0**	**$52,941**	**$5,294**	**$0**	**$8,735**	**$66,971**	**$122**
	Total	**$549,332**	**$53,681**	**$302,113**	**$0**	**$905,125**	**$90,513**	**$0**	**$118,723**	**$1,114,361**	**$2,026**

Exhibit 3-50 Case B12A owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$8,509	$15
1 Month Maintenance Materials	$1,071	$2
1 Month Non-fuel Consumables	$2,133	$4
1 Month Waste Disposal	$429	$1
25% of 1 Months Fuel Cost at 100% CF	$2,471	$4
2% of TPC	$22,287	$41
Total	**$36,901**	**$67**
Inventory Capital		
60 day supply of fuel and consumables at 100% CF	$23,659	$43
0.5% of TPC (spare parts)	$5,572	$10
Total	**$29,231**	**$53**
Other Costs		
Initial Cost for Catalyst and Chemicals	$0	$0
Land	$900	$2
Other Owner's Costs	$167,154	$304
Financing Costs	$30,088	$55
Total Overnight Costs (TOC)	**$1,378,634**	**$2,507**
TASC Multiplier (IOU, low-risk, 35 year)	1.134	
Total As-Spent Cost (TASC)	**$1,563,371**	**$2,842**

Exhibit 3-51 Case B12A initial and annual operating and maintenance costs

Case:	**B12A – Supercritical PC w/o CO_2**				**Cost Base:**	**Jun 2011**
Plant Size (MW,net):	**550**	**Heat Rate-net (Btu/kWh):**		**8,379**	**Capacity Factor (%):**	**85**
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):	39.70		**$/hour**	Skilled Operator:		2.0
Operating Labor Burden:	30.00		**% of base**	Operator:		9.0
Labor O-H Charge Rate:	25.00		**% of labor**	Foreman:		1.0
				Lab Tech's, etc.:		2.0
				Total:		**14.0**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$6,329,450	$11.508
Maintenance Labor:					$7,284,427	$13.244
Administrative & Support Labor:					$3,403,469	$6.188
Property Taxes and Insurance:					$22,287,220	$40.521
Total:					**$39,304,567**	**$71.461**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$10,926,640	$2.66803
Consumables						
	Consumption				**Cost ($)**	
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	3,675	$1.67	$0	$1,908,776	$0.46608
Makeup and Waste Water Treatment Chemicals (lbs):	0	17,791	$0.27	$0	$1,478,352	$0.36098
Limestone (ton)	0	468	$33.48	$0	$4,865,781	$1.18811
Hydrated Lime (ton)	0	96	$155.00	$0	$4,594,464	$1.12186
Activated Carbon (ton)	0	3	$1,255.00	$0	$1,074,374	$0.26234
Ammonia (19% NH_3, ton)	0	68	$330.00	$0	$6,967,794	$1.70137
SCR Catalyst (m^3)	0	0.31	$8,938.80	$0	$871,258	$0.21274
Subtotal:				**$0**	**$21,760,800**	**$5.31349**
Waste Disposal						
Fly Ash (ton)	0	470	$25.11	$0	$3,659,558	$0.89358
Bottom Ash (ton)	0	92	$25.11	$0	$719,871	$0.17578
Subtotal:				**$0**	**$4,379,428**	**$1.06936**
By-Products						
Gypsum (ton)	0	81	$0.00	$0	$0	$0.00000
Subtotal:				**$0**	**$0**	**$0.00000**
Variable Operating Costs Total:				**$0**	**$37,066,868**	**$9.05088**
Fuel Cost						
Illinois Number 6 (ton):	0	4,741	$68.54	$0	$100,807,335	$24.61483
Total:				**$0**	**$100,807,335**	**$24.61483**

Exhibit 3-52 Case B12A COE breakdown

Component	Value, $/MWh	Percentage
Capital	39.0	47%
Fixed	9.6	12%
Variable	9.1	11%
Fuel	24.6	30%
Total (Excluding T&S)	**82.3**	**N/A**
CO_2 T&S	0.0	0%
Total (Including T&S)	**82.3**	**N/A**

3.3.7 Case B12B – Supercritical PC with CO_2 Capture

The plant configuration for Case B12B, SC PC, is the same as Case B12A with the exception that the Cansolv system was used for the CDR facility. The nominal net output is maintained at 550 MW by increasing the boiler size and turbine/generator size to account for the greater auxiliary load imposed by the CDR facility and CO_2 compressors. Unlike the NGCC cases where gross output was fixed by the available size of the CTs, the PC cases utilize boilers and steam turbines that can be procured at nearly any desired output making it possible to maintain a constant net output.

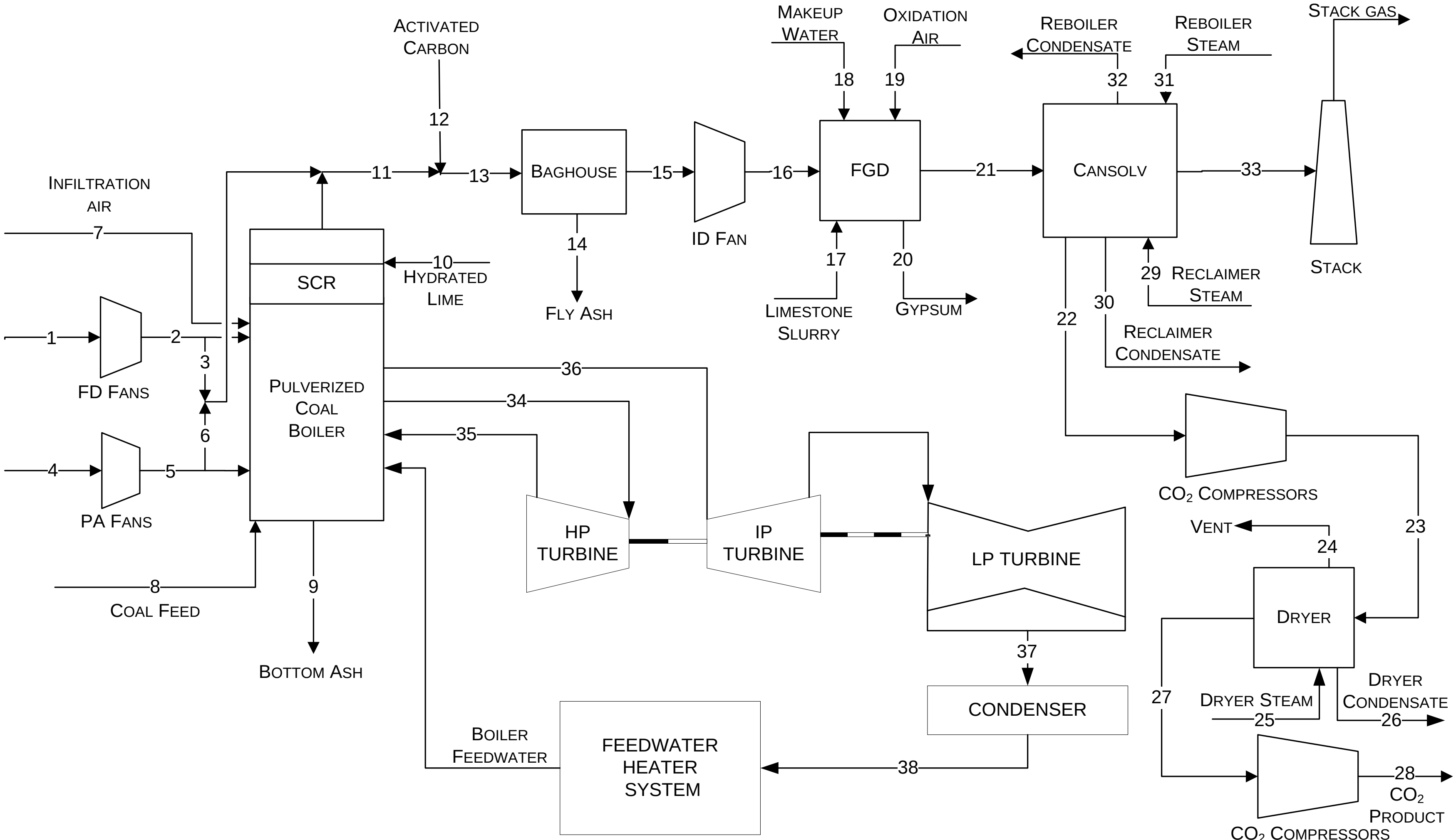
The process description for Case B12B is essentially the same as Case B12A with one notable exception, the addition of CO_2 capture. A BFD and stream tables for Case B12B are shown in Exhibit 3-53 and Exhibit 3-54, respectively. Since the CDR facility process description was provided in Section 3.1.8, it is not repeated here.

3.3.8 Case B12B Performance Results

The Case B12B modeling assumptions were presented previously in Section 3.3.2.

The plant produces a net output of 550 MW at a net plant efficiency of 32.5 percent (HHV basis). Overall plant performance is summarized in Exhibit 3-55; Exhibit 3-56 provides a detailed breakdown of the auxiliary power requirements. The CDR facility, including CO_2 compression, accounts for over half of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for nearly 13 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility and CO_2 compressors.

Exhibit 3-53 Case B12B block flow diagram, supercritical unit with CO_2 capture



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Source: NETL

Exhibit 3-54 Case B12B stream table, supercritical unit with capture

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
V-L Mole Fraction														
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000	0.0088	0.0000	0.0088	0.0000
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1376	0.0000	0.1376	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0000	0.0831	0.0000	0.0831	0.0000
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7345	0.0000	0.7345	0.0000
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0340	0.0000	0.0340	0.3333
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0020	0.0000	0.0020	0.6667
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000
V-L Flowrate (kg_{mole}/hr)	61,983	61,983	1,836	19,040	19,040	2,620	1,354	0	0	0	86,880	0	86,880	4
V-L Flowrate (kg/hr)	1,788,627	1,788,627	52,976	549,448	549,448	75,618	39,068	0	0	0	2,580,136	0	2,580,136	198
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	224,791	4,360	4,530	21,968	131	22,099	22,099
Temperature (°C)	15	19	19	15	25	25	15	15	149	27	143	27	143	143
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) [A]	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-93.45	-93.45	-97.58	-87.03	-87.03	-97.58	-2,114.05	97.18	-13,306.82	-2,399.49	3.40	-2,399.37	-2,632.04
Density (kg/m^3)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	---	0.9	---	0.9	1.5
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	---	29.698	---	29.698	53.376
V-L Flowrate (lb_{mole}/hr)	136,648	136,648	4,047	41,977	41,977	5,777	2,985	0	0	0	191,537	0	191,537	8
V-L Flowrate (lb/hr)	3,943,248	3,943,248	116,791	1,211,325	1,211,325	166,710	86,130	0	0	0	5,688,226	0	5,688,226	436
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	495,578	9,611	9,988	48,432	288	48,720	48,720
Temperature (°F)	59	66	66	59	78	78	59	59	300	80	289	80	289	289
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.4	14.7	14.4	14.7	14.4	14.4
Steam Table Enthalpy (Btu/lb)[A]	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-40.2	-40.2	-42.0	-37.4	-37.4	-42.0	-908.9	41.8	-5,720.9	-1,031.6	1.5	-1,031.5	-1,131.6
Density (lb/ft^3)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	---	0.053	---	0.053	0.096

[A]Steam table reference conditions are 32.02°F & 0.089 psia

[B]Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit 3-54 Case B12B stream table, supercritical unit with capture (continued)

	15	16	17	18	19	20	21	22	23	24	25	26	27	28
V-L Mole Fraction														
Ar	0.0088	0.0088	0.0000	0.0000	0.0092	0.0000	0.0082	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.1376	0.1376	0.0000	0.0000	0.0003	0.0001	0.1288	0.9824	0.9977	0.0492	0.0000	0.0000	0.9993	0.9993
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0831	0.0831	1.0000	1.0000	0.0099	0.9999	0.1451	0.0176	0.0023	0.9508	1.0000	1.0000	0.0007	0.0007
N_2	0.7345	0.7345	0.0000	0.0000	0.7732	0.0000	0.6854	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0340	0.0340	0.0000	0.0000	0.2074	0.0000	0.0325	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0020	0.0020	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mole}/hr)	86,876	86,876	2,880	11,542	919	213	94,143	11,109	10,940	18	14	14	10,921	10,921
V-L Flowrate (kg/hr)	2,579,938	2,579,938	51,879	207,939	26,514	3,829	2,716,229	483,852	480,793	352	255	255	480,441	480,441
Solids Flowrate (kg/hr)	0	0	22,213	0	0	34,451	0	0	0	0	0	0	0	0
Temperature (°C)	143	153	15	27	167	56	56	29	29	29	461	203	29	40
Pressure (MPa, abs)	0.10	0.11	0.10	0.11	0.31	0.10	0.10	0.20	3.03	3.03	2.14	1.64	2.89	15.27
Steam Table Enthalpy (kJ/kg) [A]	274.36	285.60	---	111.65	184.48	---	286.10	42.52	-6.00	138.07	3,379.59	863.65	-5.93	-205.61
AspenPlus Enthalpy (kJ/kg) [B]	-2,397.36	-2,386.11	-14,995.75	-15,964.53	56.67	-12,481.91	-2,940.30	-8,972.02	-8,974.94	-15,237.30	-12,600.71	-15,116.65	-8,970.17	-9,169.86
Density (kg/m^3)	0.8	0.9	1,003.6	992.3	2.4	833.1	1.1	3.5	63.3	377.5	6.4	861.8	59.9	789.2
V-L Molecular Weight	29.697	29.697	18.015	18.015	28.857	18.018	28.852	43.553	43.950	19.294	18.015	18.015	43.991	43.991
V-L Flowrate (lb_{mole}/hr)	191,529	191,529	6,349	25,447	2,026	468	207,551	24,492	24,118	40	31	31	24,078	24,078
V-L Flowrate (lb/hr)	5,687,790	5,687,790	114,374	458,428	58,452	8,441	5,988,260	1,066,711	1,059,968	776	563	563	1,059,192	1,059,192
Solids Flowrate (lb/hr)	0	0	48,970	0	0	75,950	0	0	0	0	0	0	0	0
Temperature (°F)	289	308	59	80	332	133	133	85	85	85	861	397	85	104
Pressure (psia)	14.2	15.2	15.0	15.7	45.0	14.7	14.7	28.7	439.4	439.4	310.1	237.4	419.4	2,214.7
Steam Table Enthalpy (Btu/lb) [A]	118.0	122.8	---	48.0	79.3	---	123.0	18.3	-2.6	59.4	1,453.0	371.3	-2.5	-88.4
AspenPlus Enthalpy (Btu/lb) [B]	-1,030.7	-1,025.8	-6,447.0	-6,863.5	24.4	-5,366.3	-1,264.1	-3,857.3	-3,858.5	-6,550.9	-5,417.3	-6,499.0	-3,856.5	-3,942.3
Density (lb/ft^3)	0.052	0.055	62.650	61.950	0.153	52.011	0.067	0.216	3.953	23.565	0.402	53.801	3.737	49.270

[A] Steam table reference conditions are 32.02°F & 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit 3-54 Case B12B stream table, supercritical unit with capture (continued)

	29	30	31	32	33	34	35	36	37	38
V-L Mole Fraction										
Ar	0.0000	0.0000	0.0000	0.0000	0.0103	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0000	0.0000	0.0000	0.0163	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	1.0000	1.0000	0.0671	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.0000	0.0000	0.0000	0.0000	0.8652	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0410	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mole}/hr)	85	85	27,975	27,977	74,575	111,201	92,880	92,880	51,680	51,902
V-L Flowrate (kg/hr)	1,533	1,533	503,979	504,008	2,079,831	2,003,325	1,673,260	1,673,260	931,021	935,036
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	342	215	269	151	41	593	342	593	38	39
Pressure (MPa, abs)	4.90	2.11	0.51	0.49	0.10	24.23	4.90	4.80	0.01	1.37
Steam Table Enthalpy (kJ/kg) [A]	3,049.83	921.30	3,000.13	635.93	151.94	3,477.96	3,049.83	3,652.36	2,166.50	162.50
AspenPlus Enthalpy (kJ/kg) [B]	-12,930.47	-15,058.99	-12,980.16	-15,344.37	-794.66	-12,502.33	-12,930.47	-12,327.94	-13,813.79	-15,817.80
Density (kg/m^3)	19.2	846.4	2.1	916.3	1.1	69.2	19.2	12.3	0.1	993.3
V-L Molecular Weight	18.015	18.015	18.015	18.015	27.889	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mole}/hr)	188	188	61,675	61,678	164,410	245,157	204,765	204,765	113,934	114,425
V-L Flowrate (lb/hr)	3,379	3,379	1,111,084	1,111,147	4,585,242	4,416,576	3,688,906	3,688,906	2,052,550	2,061,401
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	648	419	517	304	107	1,100	648	1,100	101	101
Pressure (psia)	710.8	306.2	73.5	70.6	14.7	3,514.7	710.8	696.6	1.0	198.7
Steam Table Enthalpy (Btu/lb) [A]	1,311.2	396.1	1,289.8	273.4	65.3	1,495.3	1,311.2	1,570.2	931.4	69.9
AspenPlus Enthalpy (Btu/lb) [B]	-5,559.1	-6,474.2	-5,580.5	-6,596.9	-341.6	-5,375.0	-5,559.1	-5,300.1	-5,938.9	-6,800.4
Density (lb/ft^3)	1.197	52.841	0.128	57.201	0.068	4.319	1.197	0.768	0.004	62.011

[A] Steam table reference conditions are 32.02°F & 0.089 psia

[B] Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit 3-55 Case B12B plant performance summary

Performance Summary	
Total Gross Power, MWe	**642**
CO_2 Capture/Removal Auxiliaries, kWe	16,000
CO_2 Compression, kWe	35,690
Balance of Plant, kWe	39,595
Total Auxiliaries, MWe	**91**
Net Power, MWe	**550**
HHV Net Plant Efficiency (%)	32.5%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,086 (10,508)
LHV Net Plant Efficiency (%)	33.7%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	10,693 (10,135)
HHV Boiler Efficiency, %	89.1%
LHV Boiler Efficiency, %	92.4%
Steam Turbine Cycle Efficiency, %	54.5%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	6,608 (6,263)
Condenser Duty, GJ/hr (MMBtu/hr)	1,867 (1,770)
As-Received Coal Feed, kg/hr (lb/hr)	224,791 (495,578)
Limestone Sorbent Feed, kg/hr (lb/hr)	22,213 (48,970)
HHV Thermal Input, kWt	1,694,366
LHV Thermal Input, kWt	1,634,237
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.054 (14.3)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.042 (11.0)
Excess Air, %	20.9%

Exhibit 3-56 Case B12B plant power summary

Power Summary	
Steam Turbine Power, MWe	642
Total Gross Power, MWe	**642**
Auxiliary Load Summary	
Coal Handling and Conveying, kWe	480
Pulverizers, kWe	3,370
Sorbent Handling & Reagent Preparation, kWe	1,070
Ash Handling, kWe	780
Primary Air Fans, kWe	1,670
Forced Draft Fans, kWe	2,130
Induced Draft Fans, kWe	8,350
SCR, kWe	60
Activated Carbon Injection, kW	27
Dry sorbent Injection, kW	108
Baghouse, kWe	110
Wet FGD, kWe	3,550
CO_2 Capture/Removal Auxiliaries, kWe	16,000
CO_2 Compression, kWe	35,690
Miscellaneous Balance of Plant[A,B], kWe	2,000
Steam Turbine Auxiliaries, kWe	400
Condensate Pumps, kWe	640
Circulating Water Pumps, kWe	7,750
Ground Water Pumps, kWe	710
Cooling Tower Fans, kWe	4,010
Transformer Losses, kWe	2,380
Total Auxiliaries, MWe	**91**
Net Power, MWe	**550**

[A]Boiler feed pumps are turbine driven
[B]Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

3.3.8.1 Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B12B is presented in Exhibit 3-57. SO_2 emissions are utilized as a surrogate for HCl emissions, therefore HCl is not reported.

Exhibit 3-57 Case B12B air emissions

	kg/GJ (lb/MMBtu)	Tonne/year (ton/year)[A]	kg/MWh (lb/MWh)
SO_2	0.000 (0.000)	0 (0)	0.000 (0.000)
NOx	0.033 (0.078)	1,517 (1,672)	0.318 (0.700)
Particulate	0.004 (0.010)	195 (215)	0.041 (0.090)
Hg	1.43E-7 (3.33E-7)	0.006 (0.007)	1.36E-6 (3.00E-6)
CO_2[B]	9 (20)	397,399 (438,058)	83 (183)
CO_2[C]	-	-	97 (214)
	mg/Nm^3		
Particulate Concentration[D,E]	13.45		

[A]Calculations based on an 85 percent capacity factor
[B]CO_2 emissions based on gross power
[C]CO_2 emissions based on net power instead of gross power
[D]Concentration of particles in the flue gas after the baghouse
[E]Normal conditions given at 32°F and 14.696 psia

SO_2 emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The SO_2 emissions are further reduced to 1 ppmv using a NaOH based polishing scrubber in the CDR facility. The remaining low concentration of SO_2 is essentially completely removed in the CDR absorber vessel resulting in very low SO_2 emissions.

NOx emissions are controlled to about 0.5 lb/MMBtu through the use of LNBs and OFA. An SCR unit then further reduces the NOx concentration by 85 percent to 0.08 lb/MMBtu.

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment (SCR, ACI, fabric filter, DSI, and wet FGD) is 97.1 percent.

Ninety (90) percent of the CO_2 in the flue gas is removed in CDR facility.

The carbon input to the plant consists of carbon in the coal, carbon in the air, PAC, and carbon in the limestone reagent used in the FGD. Carbon leaves the plant mostly as CO_2 through the stack, however, the PAC is captured in the fabric filter and some leaves as gypsum. The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in, represented by the following fraction:

$$\frac{Carbon\ in\ Stack}{(Total\ Carbon\ In)} = \left(1 - \left(\frac{32{,}112}{321{,}883}\right)\right) * 100 = 90.0\%$$

Exhibit 3-58 Case B12B carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		**kg/hr (lb/hr)**
Coal	143,292 (315,905)	Stack Gas	14,566 (32,112)
Air (CO_2)	327 (721)	FGD Product	215 (474)
PAC	131 (288)	Baghouse	131 (288)
FGD Reagent	2,254 (4,969)	CO_2 Product	131,081 (288,984)
		CO_2 Dryer Vent	11 (24)
		CO_2 Knockout	0 (1)
Total	**146,004 (321,883)**	**Total**	**146,004 (321,883)**

Exhibit 3-59 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur emitted in the stack gas, and sulfur removed in the polishing scrubber.

Exhibit 3-59 Case B12B sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	5,634 (12,421)	FGD Product	5,444 (12,002)
		Stack Gas	0 (0)
		Polishing Scrubber and Solvent Reclaiming	111 (245)
		Baghouse	79 (175)
Total	**5,634 (12,421)**	**Total**	**5,634 (12,421)**

Exhibit 3-60 shows the overall water balance for the plant. The exhibit is presented in an identical manner as for Case B12A.

Exhibit 3-60 Case B12B water balance

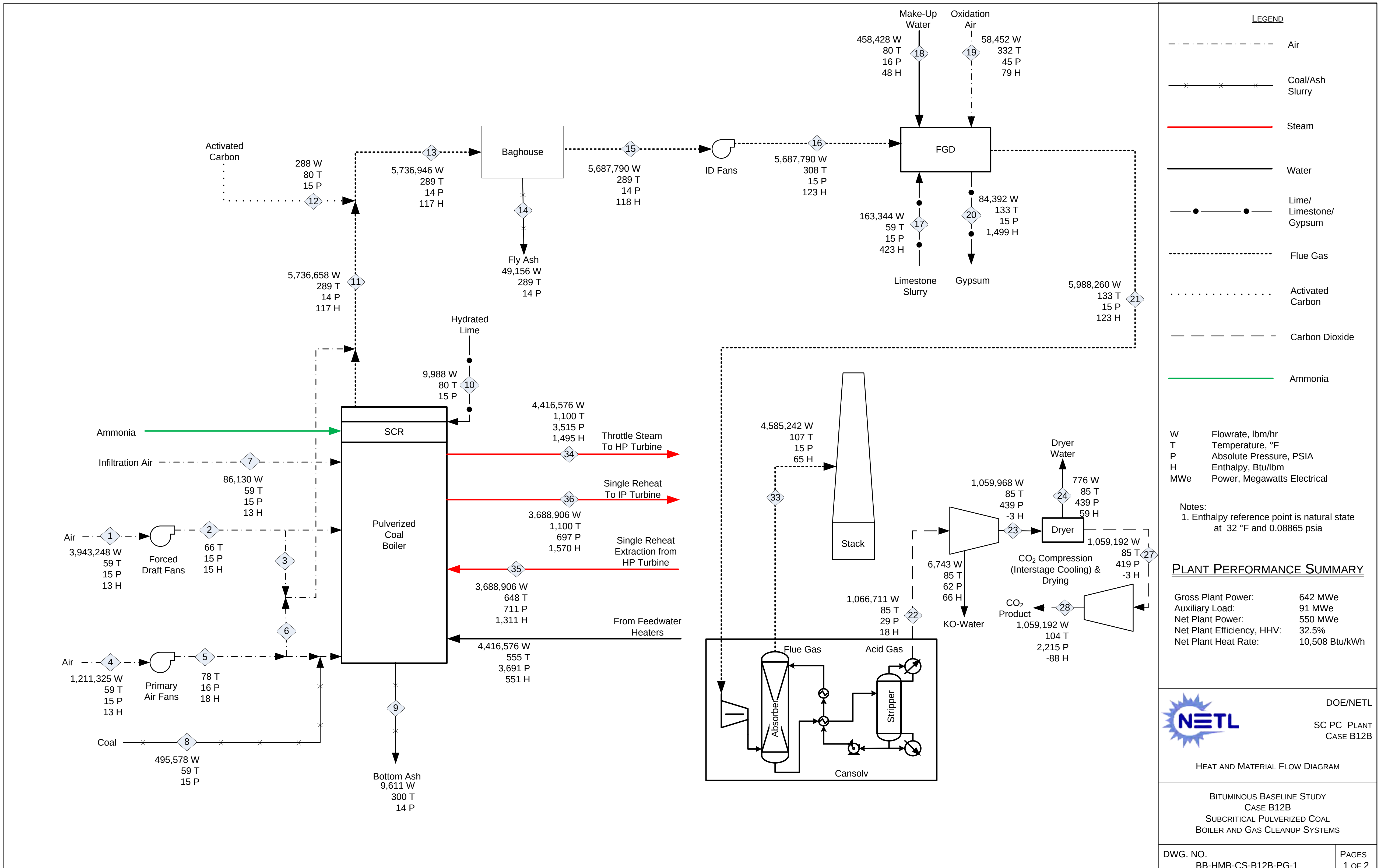
Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)
FGD Makeup	4.34 (1,146)	–	4.34 (1,146)	–	4.34 (1,146)
CO_2 Drying	–	–	–	0.01 (2)	-0.01 (-2)
Capture System Makeup	0.02 (5)	–	0.02 (5)	–	0.02 (5)
Deaerator Vent	–	–	–	0.07 (18)	-0.07 (-18)
Condenser Makeup	**0.07 (18)**	**–**	**0.07 (18)**	**–**	**0.07 (18)**
BFW Makeup	0.07 (18)	–	0.07 (18)	–	0.07 (18)
Cooling Tower	**30.19 (7,976)**	**4.78 (1,262)**	**25.41 (6,714)**	**6.79 (1,794)**	**18.62 (4,920)**
FGD Dewatering	–	2.24 (591)	-2.24 (-591)	–	-2.24 (-591)
CO_2 Capture Recovery	–	2.54 (672)	-2.54 (-672)	–	-2.54 (-672)
CO_2 Compression KO	–	0.05 (13)	-0.05 (-13)	–	-0.05 (-13)
BFW Blowdown	–	–	–	–	–
Total	**34.62 (9,145)**	**4.78 (1,262)**	**29.84 (7,882)**	**6.86 (1,813)**	**22.97 (6,069)**

3.3.8.2 Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the Case B12B PC boiler, the FGD unit, CDR system, and steam cycle in Exhibit 3-61 and Exhibit 3-62. An overall plant energy balance is provided in tabular form in Exhibit 3-63.

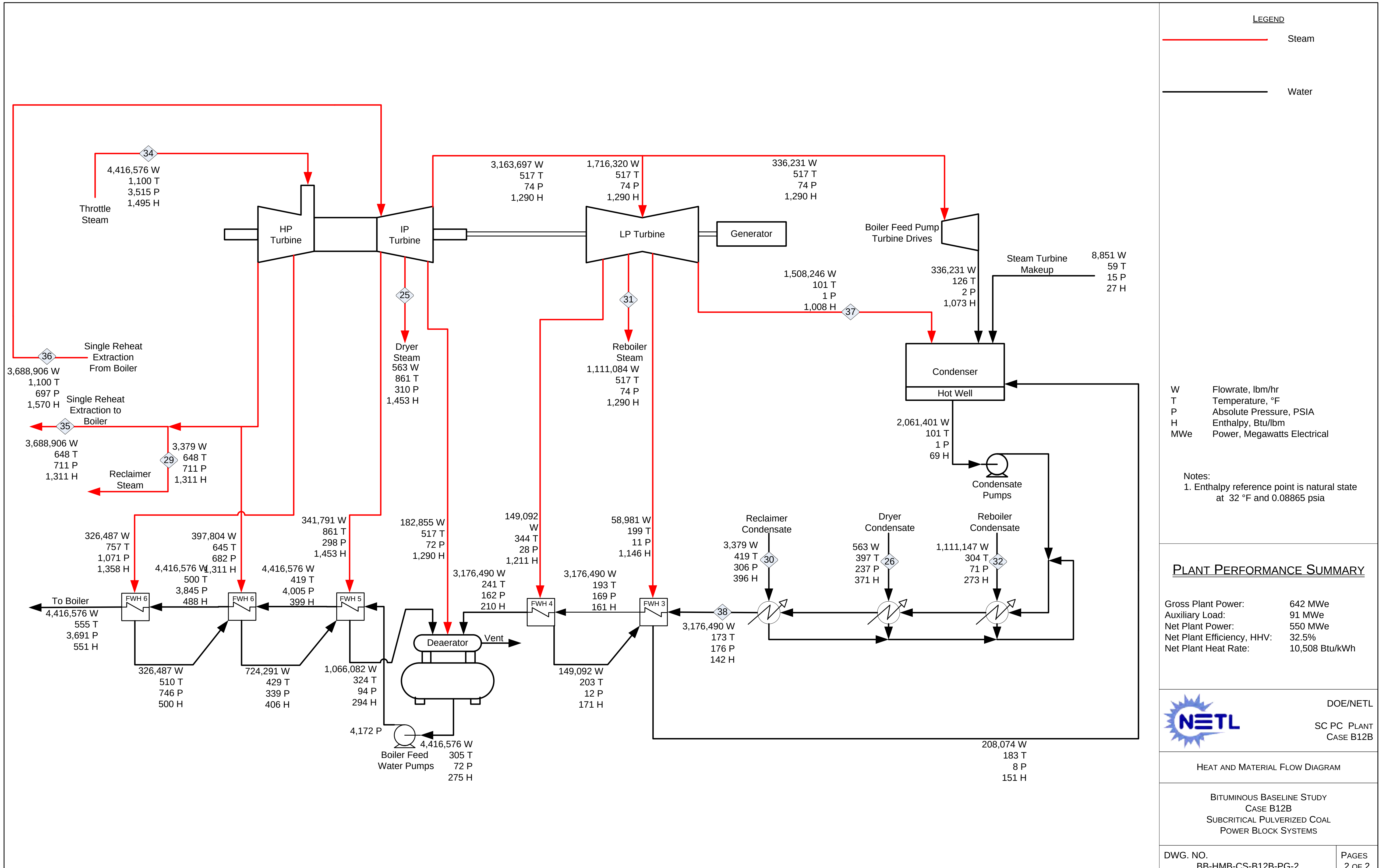
The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-55) is calculated by multiplying the power out by a generator efficiency of 98.5 percent. The capture process heat out stream represents heat rejected to cooling water and ultimately to ambient via the cooling tower. The same is true of the condenser heat out stream. The CO_2 compressor intercooler load is included in the capture process heat out stream.

Exhibit 3-61 Case B12B heat and mass balance, supercritical PC boiler with CO_2 capture



Source: NETL

Exhibit 3-62 Case B12B heat and mass balance, supercritical steam cycle



Source: NETL

Exhibit 3-63 Case B12B overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	6,100 (5,781)	5.1 (4.8)	–	6,105 (5,786)
Air	–	71.9 (68.1)	–	71.9 (68.1)
Raw Water Makeup	–	112.2 (106.3)	–	112.2 (106.3)
Limestone	–	0.48 (0.46)	–	0.48 (0.46)
Auxiliary Power	–	–	329 (311)	329 (311)
TOTAL	**6,100 (5,781)**	**189.6 (179.7)**	**329 (311)**	**6,618 (6,273)**
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	–	0.5 (0.4)	–	0.5 (0.4)
Fly Ash + FGD Ash	–	2.5 (2.4)	–	2.5 (2.4)
Stack Gas	–	316 (300)	–	316 (300)
Sulfur	2.1 (1.9)	0.0 (0.0)	–	2.1 (2.0)
Motor Losses and Design Allowances	–	–	44 (42)	44 (42)
Condenser	–	1,867 (1,770)	–	1,867 (1,770)
Non-Condenser Cooling Tower Loads	–	106 (100)	–	106 (100)
CO_2	–	-98.8 (-93.6)	–	-98.8 (-93.6)
Cooling Tower Blowdown	–	50.4 (47.8)	–	50.4 (47.8)
CO_2 Capture Losses	–	1,970 (1,868)	–	1,970 (1,868)
Ambient Losses[A]	–	133.5 (126.5)	–	133.5 (126.5)
Power	–	–	2,309 (2,189)	2,309 (2,189)
TOTAL	**2.1 (1.9)**	**4,347 (4,120)**	**2,353 (2,231)**	**6,703 (6,353)**
Unaccounted Energy[B]	–	-85 (-80)	–	-85 (-80)

[A]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers.
[B]By difference

3.3.9 Case B12B – Major Equipment List

Major equipment items for the SC PC plant with CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 3.3.10. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

Case B12B – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	50 tonne (50 ton)	2	1
9	Feeder	Vibratory	190 tonne/hr (200 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	370 tonne/hr (410 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	190 tonne (200 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	370 tonne/hr (410 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	370 tonne/hr (410 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	820 tonne (900 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 35 tonne (38 ton) Feeder - 140 kg/hr (320 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 240 tonne (260 ton) Feeder - 4,980 kg/hr (10,990 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	90 tonne/hr (100 tph)	1	0
23	Limestone Conveyor No. L1	Belt	90 tonne/hr (100 tph)	1	0
24	Limestone Reclaim Hopper	N/A	20 tonne (20 ton)	1	0
25	Limestone Reclaim Feeder	Belt	70 tonne/hr (80 tph)	1	0
26	Limestone Conveyor No. L2	Belt	70 tonne/hr (80 tph)	1	0
27	Limestone Day Bin	w/ actuator	290 tonne (320 ton)	2	0

Case B12B – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	40 tonne/hr (50 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	40 tonne/hr (50 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	24 tonne/hr (27 tph)	1	1
4	Limestone Ball Mill	Rotary	24 tonne/hr (27 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	93,100 liters (25,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,570 lpm @ 10m H_2O (410 gpm @ 40 ft H_2O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5 cyclone bank	390 lpm (100 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	528,000 liters (140,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,100 lpm @ 9m H_2O (290 gpm @ 30 ft H_2O)	1	1

Case B12B – Account 3: Feedwater and Miscellaneous Systems and Equipment

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	265,000 liters (70,000 gal)	2	0
2	Condensate Pumps	Vertical canned	17,300 lpm @ 200 m H_2O (4,600 gpm @ 600 ft H_2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	2,208,000 kg/hr (4,868,000 lb/hr), 5 min. tank	1	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	37,000 lpm @ 3,500 m H_2O (9,800 gpm @ 11,400 ft H_2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	11,000 lpm @ 3,500 m H_2O (2,900 gpm @ 11,400 ft H_2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	510,000 kg/hr (1,130,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	510,000 kg/hr (1,130,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	510,000 kg/hr (1,130,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	510,000 kg/hr (1,130,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	2,200,000 kg/hr (4,860,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	2,200,000 kg/hr (4,860,000 lb/hr)	1	0
12	HP Feedwater heater 8	Horizontal U-tube	2,200,000 kg/hr (4,860,000 lb/hr)	1	0
13	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
14	Fuel Oil System	No. 2 fuel oil for light off	1,135,624 liter (300,000 gal)	1	0
15	Service Air Compressors	Flooded Screw	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
16	Instrument Air Dryers	Duplex, regenerative	28 m^3/min (1,000 scfm)	2	1
17	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,800 lpm @ 30 m H_2O (5,500 gpm @ 100 ft H_2O)	2	1
19	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H_2O (1,000 gpm @ 290 ft H_2O)	1	1
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H_2O (700 gpm @ 210 ft H_2O)	1	1
21	Raw Water Pumps	Stainless steel, single suction	8,630 lpm @ 20 m H_2O (2,280 gpm @ 60 ft H_2O)	2	1
22	Ground Water Pumps	Stainless steel, single suction	3,450 lpm @ 270 m H_2O (910 gpm @ 880 ft H_2O)	5	1
23	Filtered Water Pumps	Stainless steel, single suction	2,080 lpm @ 50 m H_2O (550 gpm @ 160 ft H_2O)	2	1
24	Filtered Water Tank	Vertical, cylindrical	1,999,000 liter (528,000 gal)	1	0
25	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	360 lpm (90 gpm)	1	1
26	Liquid Waste Treatment System	--	10 years, 24-hour storm	1	0

Case B12B – Account 4: Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, drum, wall-fired, low NOx burners, overfire air	2,200,000 kg/hr steam @ 25.5 MPa/602°C/602°C (4,860,000 lb/hr steam @ 3,700 psig/1,115°F/1,115°F)	1	0
2	Primary Air Fan	Centrifugal	302,000 kg/hr, 4,100 m^3/min @ 123 cm WG (666,000 lb/hr, 145,600 acfm @ 48 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	984,000 kg/hr, 13,400 m^3/min @ 47 cm WG (2,169,000 lb/hr, 474,100 acfm @ 19 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,419,000 kg/hr, 28,200 m^3/min @ 89 cm WG (3,128,000 lb/hr, 994,100 acfm @ 35 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	2,840,000 kg/hr (6,260,000 lb/hr)	2	0
6	SCR Catalyst	--	--	3	0
7	Dilution Air Blower	Centrifugal	160 m^3/min @ 108 cm WG (5,600 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	174,000 liter (46,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	33 lpm @ 90 m H_2O (9 gpm @ 300 ft H_2O)	2	1

Case B12B – Account 5A: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,419,000 kg/hr (3,129,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	57,000 m^3/min (1,999,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	197,000 lpm @ 65 m H_2O (52,000 gpm @ 210 ft H_2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	4,790 lpm (1,260 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	100 m^3/min @ 0.3 MPa (3,510 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,190 lpm (320 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	38 tonne/hr (42 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	730 lpm @ 13 m H_2O (190 gpm @ 40 ft H_2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	480,000 lpm (130,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	3,820 lpm @ 21 m H_2O (1,010 gpm @ 70 ft H_2O)	1	1
12	Activated Carbon Injectors	---	140 kg/hr (320 lb/hr)	1	0
13	Hydrated Lime Injectors	---	4,980 kg/hr (10,990 lb/hr)	1	0

Case B12B – Account 5B: Carbon Dioxide Recovery

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Cansolv	Amine-based CO_2 capture technology	1,494,000 kg/hr (3,294,000 lb/hr) 19.6 wt % CO_2 concentration	1	0
2	Cansolv LP Condensate Pump	Centrifugal	1,098 lpm @ 1 m H_2O (290 gpm @ 4 ft H_2O)	1	1
3	Cansolv HP Condensate Pump	Centrifugal	1,099 lpm @ 1.1 m H_2O (290 gpm @ 4 ft H_2O)	1	1
4	CO_2 Dryer	Triethylene glycol	Inlet: 127.0 m^3/min (4,469 acfm) @ 3.0 MPa (439 psia) Outlet: 2.9 MPa (419 psia) Water Recovered: 352 kg/hr (776 lb/hr)	1	0
5	CO_2 Compressor	Integrally geared, multi-stage centrifugal	264,163 kg/hr @ 15.3 MPa (582,381 lb/hr @ 2,215 psia)	2	0

Case B12B – Account 7: Ducting and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 5.5 m (18 ft) diameter	1	0

Case B12B – Account 8: Steam Turbine Generator and Auxiliaries

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	675 MW 24.1 MPa/593°C/593°C (3500 psig/ 1100°F/1100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	750 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,050 GJ/hr (1,950 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

Case B12B – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	778,000 lpm @ 30 m (206,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 4340 GJ/hr (4110 MMBtu/hr) heat duty	1	0

Case B12B – Account 10: Ash and Spent Sorbent Recovery and Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	--	--	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	--	--	2	0
3	Clinker Grinder	--	4.8 tonne/hr (5.3 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	--	--	6	0
5	Hydroejectors	--	--	12	
6	Economizer /Pyrites Transfer Tank	--	--	1	0
7	Ash Sluice Pumps	Vertical, wet pit	190 lpm @ 17 m H_2O (50 gpm @ 56 ft H_2O)	1	1
8	Ash Seal Water Pumps	Vertical, wet pit	7,570 lpm @ 9 m H_2O (2000 gpm @ 28 ft H_2O)	1	1
9	Hydrobins	--	190 lpm (50 gpm)	1	1
10	Baghouse Hopper (part of baghouse scope of supply)	--	--	24	0
11	Air Heater Hopper (part of boiler scope of supply)	--	--	10	0
12	Air Blower	--	20 m^3/min @ 0.2 MPa (790 scfm @ 24 psi)	1	1
13	Fly Ash Silo	Reinforced concrete	1,500 tonne (1,600 ton)	2	0
14	Slide Gate Valves	--	--	2	0
15	Unloader	--	--	1	0
16	Telescoping Unloading Chute	--	140 tonne/hr (150 tph)	1	0

Case B12B – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 650 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 20 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 99 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 15 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B12B – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

3.3.10 Case B12B – Cost Estimating Basis

The cost estimating methodology was described previously in Section 2.7. Exhibit 3-64 shows a detailed breakdown of the capital costs; Exhibit 3-65 shows the owner's costs, TOC, and TASC; Exhibit 3-66 shows the initial and annual O&M costs; and Exhibit 3-67 shows the COE breakdown.

The estimated TPC of the SC PC boiler with CO_2 capture is \$3,524/kW. Process contingency represents 3.3 percent of the TPC and project contingency represents 12.2 percent. The COE, including CO_2 T&S costs of \$9.6/MWh, is \$142.8/MWh.

Exhibit 3-64 Case B12B total plant cost details

	Case:	B12B – Supercritical PC w/ CO_2							Estimate Type:	Conceptual	
	Plant Size (MW,net):	550							Cost Base:	Jun 2011	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
	1	Coal & Sorbent Handling									
1.1	Coal Receive & Unload	$4,601	$0	$2,073	$0	$6,674	$667	$0	$1,101	$8,443	$15
1.2	Coal Stackout & Reclaim	$5,946	$0	$1,329	$0	$7,275	$728	$0	$1,200	$9,203	$17
1.3	Coal Conveyors	$5,529	$0	$1,315	$0	$6,843	$684	$0	$1,129	$8,657	$16
1.4	Other Coal Handling	$1,446	$0	$304	$0	$1,751	$175	$0	$289	$2,215	$4
1.5	Sorbent Receive & Unload	$184	$0	$55	$0	$239	$24	$0	$39	$302	$1
1.6	Sorbent Stackout & Reclaim	$2,976	$0	$538	$0	$3,513	$351	$0	$580	$4,444	$8
1.7	Sorbent Conveyors	$1,062	$231	$257	$0	$1,549	$155	$0	$256	$1,960	$4
1.8	Other Sorbent Handling	$641	$151	$332	$0	$1,124	$112	$0	$185	$1,422	$3
1.9	Coal & Sorbent Hnd. Foundations	$0	$5,333	$7,031	$0	$12,364	$1,236	$0	$2,040	$15,640	$28
	Subtotal	**$22,386**	**$5,714**	**$13,233**	**$0**	**$41,333**	**$4,133**	**$0**	**$6,820**	**$52,286**	**$95**
	2	Coal & Sorbent Prep & Feed									
2.1	Coal Crushing & Drying	$2,656	$0	$510	$0	$3,166	$317	$0	$522	$4,005	$7
2.2	Coal Conveyor to Storage	$6,799	$0	$1,464	$0	$8,263	$826	$0	$1,363	$10,453	$19
2.5	Sorbent Prep Equipment	$5,063	$219	$1,037	$0	$6,320	$632	$0	$1,043	$7,994	$15
2.6	Sorbent Storage & Feed	$610	$0	$230	$0	$840	$84	$0	$139	$1,063	$2
2.9	Coal & Sorbent Feed Foundation	$0	$618	$542	$0	$1,160	$116	$0	$191	$1,468	$3
	Subtotal	**$15,128**	**$837**	**$3,784**	**$0**	**$19,749**	**$1,975**	**$0**	**$3,259**	**$24,983**	**$45**
	3	Feedwater & Miscellaneous BOP Systems									
3.1	Feedwater System	$25,158	$0	$8,112	$0	$33,270	$3,327	$0	$5,489	$42,086	$76
3.2	Water Makeup & Pretreating	$7,114	$0	$2,250	$0	$9,365	$936	$0	$2,060	$12,361	$22
3.3	Other Feedwater Subsystems	$7,914	$0	$3,249	$0	$11,163	$1,116	$0	$1,842	$14,121	$26
3.4	Service Water Systems	$1,425	$0	$746	$0	$2,170	$217	$0	$477	$2,865	$5
3.5	Other Boiler Plant Systems	$9,820	$0	$9,284	$0	$19,103	$1,910	$0	$3,152	$24,166	$44
3.6	FO Supply Sys & Nat Gas	$347	$0	$405	$0	$752	$75	$0	$124	$951	$2
3.7	Waste Treatment Equipment	$4,667	$0	$2,702	$0	$7,369	$737	$0	$1,621	$9,727	$18
3.8	Misc. Equip. (Cranes, Air Comp., Comm.)	$3,398	$0	$1,051	$0	$4,449	$445	$0	$979	$5,873	$11
	Subtotal	**$59,843**	**$0**	**$27,798**	**$0**	**$87,641**	**$8,764**	**$0**	**$15,745**	**$112,150**	**$204**
	4	Boiler & Accessories									
4.1	PC Boiler & Accessories	$211,004	$0	$120,229	$0	$331,234	$33,123	$0	$36,436	$400,793	$728
4.2	SCR	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Primary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0
4.6	Secondary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0
4.9	Boiler Foundations	$0	w/14.1	w/14.1	$0	$0	$0	$0	$0	$0	$0
	Subtotal	**$211,004**	**$0**	**$120,229**	**$0**	**$331,234**	**$33,123**	**$0**	**$36,436**	**$400,793**	**$728**
	5A	Gas Cleanup & Piping									
5A.1	Absorber Vessels & Accessories	$79,487	$0	$16,995	$0	$96,482	$9,648	$0	$10,613	$116,743	$212
5A.2	Other FGD	$4,148	$0	$4,668	$0	$8,816	$882	$0	$970	$10,668	$19

	Case:	B12B – Supercritical PC w/ CO_2							Estimate Type:	Conceptual	
	Plant Size (MW,net):	550							Cost Base:	Jun 2011	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
5A.3	Bag House & Accessories	$22,779	$0	$14,358	$0	$37,137	$3,714	$0	$4,085	$44,936	$82
5A.4	Other Particulate Removal Materials	$1,542	$0	$1,638	$0	$3,180	$318	$0	$350	$3,848	$7
5A.5	Gypsum Dewatering System	$6,185	$0	$1,043	$0	$7,229	$723	$0	$795	$8,747	$16
5A.6	Mercury Removal System	$4,702	$1,034	$4,623	$0	$10,359	$1,036	$0	$1,139	$12,534	$23
	Subtotal	**$118,843**	**$1,034**	**$43,325**	**$0**	**$163,202**	**$16,320**	**$0**	**$17,952**	**$197,475**	**$359**
	5B	**CO_2 Removal & Compression**									
5B.1	CO_2 Removal System	$167,289	$61,389	$131,144	$0	$359,822	$31,060	$62,120	$80,756	$533,757	$970
5B.2	CO_2 Compression & Drying	$50,211	$7,532	$16,788	$0	$74,531	$7,453	$0	$16,397	$98,381	$179
	Subtotal	**$217,500**	**$68,921**	**$147,932**	**$0**	**$434,354**	**$38,513**	**$62,120**	**$97,152**	**$632,139**	**$1,149**
	7	**HRSG, Ducting, & Stack**									
7.3	Ductwork	$11,042	$0	$6,970	$0	$18,013	$1,801	$0	$2,972	$22,786	$41
7.4	Stack	$9,983	$0	$5,801	$0	$15,784	$1,578	$0	$1,736	$19,099	$35
7.9	Duct & Stack Foundations	$0	$1,088	$1,292	$0	$2,380	$238	$0	$524	$3,142	$6
	Subtotal	**$21,025**	**$1,088**	**$14,064**	**$0**	**$36,177**	**$3,618**	**$0**	**$5,232**	**$45,027**	**$82**
	8	**Steam Turbine Generator**									
8.1	Steam TG & Accessories	$79,100	$0	$8,815	$0	$87,915	$8,791	$0	$9,671	$106,377	$193
8.2	Turbine Plant Auxiliaries	$450	$0	$958	$0	$1,408	$141	$0	$155	$1,704	$3
8.3	Condenser & Auxiliaries	$6,997	$0	$2,374	$0	$9,370	$937	$0	$1,031	$11,338	$21
8.4	Steam Piping	$30,410	$0	$12,325	$0	$42,735	$4,273	$0	$7,051	$54,060	$98
8.9	TG Foundations	$0	$1,342	$2,217	$0	$3,559	$356	$0	$783	$4,698	$9
	Subtotal	**$116,957**	**$1,342**	**$26,688**	**$0**	**$144,987**	**$14,499**	**$0**	**$18,690**	**$178,176**	**$324**
	9	**Cooling Water System**									
9.1	Cooling Towers	$15,466	$0	$4,783	$0	$20,250	$2,025	$0	$2,227	$24,502	$45
9.2	Circulating Water Pumps	$3,102	$0	$228	$0	$3,330	$333	$0	$366	$4,030	$7
9.3	Circ. Water System Auxiliaries	$811	$0	$107	$0	$918	$92	$0	$101	$1,111	$2
9.4	Circ. Water Piping	$0	$6,831	$6,186	$0	$13,016	$1,302	$0	$2,148	$16,466	$30
9.5	Make-up Water System	$685	$0	$880	$0	$1,565	$157	$0	$258	$1,980	$4
9.6	Component Cooling Water Sys.	$661	$0	$507	$0	$1,168	$117	$0	$193	$1,478	$3
9.9	Circ. Water Foundations & Structures	$0	$3,613	$5,999	$0	$9,612	$961	$0	$2,115	$12,688	$23
	Subtotal	**$20,725**	**$10,443**	**$18,691**	**$0**	**$49,860**	**$4,986**	**$0**	**$7,408**	**$62,254**	**$113**
	10	**Ash & Spent Sorbent Handling Systems**									
10.6	Ash Storage Silos	$882	$0	$2,698	$0	$3,579	$358	$0	$394	$4,331	$8
10.7	Ash Transport & Feed Equipment	$5,856	$0	$5,806	$0	$11,662	$1,166	$0	$1,283	$14,111	$26
10.9	Ash/Spent Sorbent Foundation	$0	$199	$245	$0	$444	$44	$0	$98	$586	$1
	Subtotal	**$6,738**	**$199**	**$8,748**	**$0**	**$15,685**	**$1,569**	**$0**	**$1,774**	**$19,028**	**$35**
	11	**Accessory Electric Plant**									
11.1	Generator Equipment	$2,061	$0	$329	$0	$2,390	$239	$0	$197	$2,826	$5
11.2	Station Service Equipment	$5,290	$0	$1,773	$0	$7,063	$706	$0	$583	$8,352	$15
11.3	Switchgear & Motor Control	$6,072	$0	$1,055	$0	$7,126	$713	$0	$784	$8,623	$16
11.4	Conduit & Cable Tray	$0	$4,164	$13,452	$0	$17,616	$1,762	$0	$2,907	$22,284	$41
11.5	Wire & Cable	$0	$7,928	$14,171	$0	$22,100	$2,210	$0	$3,646	$27,956	$51
11.6	Protective Equipment	$306	$0	$1,063	$0	$1,370	$137	$0	$151	$1,658	$3

Case:		B12B – Supercritical PC w/ CO_2							Estimate Type:	Conceptual	
Plant Size (MW,net):		550							Cost Base:	Jun 2011	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
11.7	Standby Equipment	$1,571	$0	$37	$0	$1,608	$161	$0	$177	$1,945	$4
11.8	Main Power Transformers	$14,769	$0	$221	$0	$14,990	$1,499	$0	$1,649	$18,138	$33
11.9	Electrical Foundations	$0	$385	$980	$0	$1,365	$136	$0	$300	$1,802	$3
	Subtotal	**$30,069**	**$12,477**	**$33,082**	**$0**	**$75,628**	**$7,563**	**$0**	**$10,394**	**$93,584**	**$170**
	12	**Instrumentation & Control**									
12.1	PC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0
12.5	Signal Processing Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards, Panels & Racks	$611	$0	$373	$0	$984	$98	$49	$170	$1,301	$2
12.7	Distributed Control Sys. Equipment	$6,164	$0	$1,099	$0	$7,263	$726	$363	$835	$9,188	$17
12.8	Instrument Wiring & Tubing	$3,717	$0	$6,763	$0	$10,480	$1,048	$524	$1,808	$13,860	$25
12.9	Other I & C Equipment	$1,742	$0	$4,033	$0	$5,775	$577	$289	$664	$7,305	$13
	Subtotal	**$12,233**	**$0**	**$12,269**	**$0**	**$24,502**	**$2,450**	**$1,225**	**$3,477**	**$31,654**	**$58**
	13	**Improvements to Site**									
13.1	Site Preparation	$0	$62	$1,316	$0	$1,378	$138	$0	$303	$1,819	$3
13.2	Site Improvements	$0	$2,053	$2,713	$0	$4,766	$477	$0	$1,049	$6,291	$11
13.3	Site Facilities	$3,680	$0	$3,860	$0	$7,540	$754	$0	$1,659	$9,953	$18
	Subtotal	**$3,680**	**$2,115**	**$7,889**	**$0**	**$13,684**	**$1,368**	**$0**	**$3,010**	**$18,063**	**$33**
	14	**Buildings & Structures**									
14.1	Boiler Building	$0	$10,432	$9,168	$0	$19,599	$1,960	$0	$3,234	$24,793	$45
14.2	Turbine Building	$0	$15,048	$14,015	$0	$29,063	$2,906	$0	$4,795	$36,765	$67
14.3	Administration Building	$0	$762	$806	$0	$1,568	$157	$0	$259	$1,984	$4
14.4	Circulation Water Pumphouse	$0	$208	$165	$0	$373	$37	$0	$62	$472	$1
14.5	Water Treatment Buildings	$0	$887	$808	$0	$1,696	$170	$0	$280	$2,145	$4
14.6	Machine Shop	$0	$510	$342	$0	$852	$85	$0	$141	$1,078	$2
14.7	Warehouse	$0	$346	$346	$0	$692	$69	$0	$114	$875	$2
14.8	Other Buildings & Structures	$0	$282	$240	$0	$523	$52	$0	$86	$661	$1
14.9	Waste Treating Building & Str.	$0	$541	$1,639	$0	$2,180	$218	$0	$360	$2,758	$5
	Subtotal	**$0**	**$29,016**	**$27,530**	**$0**	**$56,547**	**$5,655**	**$0**	**$9,330**	**$71,531**	**$130**
	Total	**$856,131**	**$133,187**	**$505,263**	**$0**	**$1,494,582**	**$144,536**	**$63,345**	**$236,680**	**$1,939,143**	**$3,524**

Exhibit 3-65 Case B12B owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$12,156	$22
1 Month Maintenance Materials	$1,774	$3
1 Month Non-fuel Consumables	$3,605	$7
1 Month Waste Disposal	$539	$1
25% of 1 Months Fuel Cost at 100% CF	$3,099	$6
2% of TPC	$38,783	$70
Total	**$59,957**	**$109**
Inventory Capital		
60 day supply of fuel and consumables at 100% CF	$31,429	$57
0.5% of TPC (spare parts)	$9,696	$18
Total	**$41,125**	**$75**
Other Costs		
Initial Cost for Catalyst and Chemicals	$0	$0
Land	$900	$2
Other Owner's Costs	$290,871	$529
Financing Costs	$52,357	$95
Total Overnight Costs (TOC)	**$2,384,352**	**$4,333**
TASC Multiplier (IOU, high-risk, 35 year)	1.140	
Total As-Spent Cost (TASC)	**$2,718,161**	**$4,940**

Exhibit 3-66 Case B12B initial and annual operating and maintenance costs

Case:	**B12B – Supercritical PC w/o CO_2**				**Cost Base:**	**Jun 2011**
Plant Size (MW,net):	**550**	**Heat Rate-net (Btu/kWh):**		**10,508**	**Capacity Factor (%):**	**85**
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):	39.70	**$/hour**		Skilled Operator:		2.0
Operating Labor Burden:	30.00	**% of base**		Operator:		11.3
Labor O-H Charge Rate:	25.00	**% of labor**		Foreman:		1.0
				Lab Tech's, etc.:		2.0
				Total:		**16.3**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$7,384,208	$13.421
Maintenance Labor:					$12,065,150	$21.928
Administrative & Support Labor:					$4,862,340	$8.837
Property Taxes and Insurance:					$38,782,850	$70.487
Total:					**$63,094,548**	**$114.673**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$18,097,725	$4.41742
Consumables						
	Consumption				**Cost ($)**	
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	5,675	$1.67	$0	$2,947,503	$0.71945
Makeup and Waste Water Treatment Chemicals (lbs):	0	27,472	$0.27	$0	$2,282,848	$0.55721
Limestone (ton)	0	588	$33.48	$0	$6,103,937	$1.48989
Hydrated Lime (ton)	0	120	$155.00	$0	$5,763,495	$1.40679
Activated Carbon (ton)	0	3	$1,255.00	$0	$1,347,742	$0.32897
CO_2 Capture System Chemicals[A]			Proprietary			
Triethylene Glycol (gal)	0	394	$6.57	$0	$802,687	$0.19593
Ammonia (19% NH_3, ton)	0	87	$330.00	$0	$8,943,423	$2.18297
SCR Catalyst (m^3)	0	0.39	$8,938.80	$0	$1,092,946	$0.26677
Subtotal:				**$0**	**$36,775,427**	**$8.97641**
Waste Disposal						
Fly Ash (ton)	0	589	$25.11	$0	$4,590,762	$1.12055
Bottom Ash (ton)	0	116	$25.11	$0	$903,048	$0.22042
Amine Purification Unit Waste (ton)	0	20	$0.00	$0	$0	$0.00000
Thermal Reclaimer Unit Waste (ton)	0	2	$0.00	$0	$0	$0.00000
Prescrubber Blowdown Waste (ton)	0	45	$0.00	$0	$0	$0.00000
Subtotal:				**$0**	**$5,493,809**	**$1.34097**
By-Products						
Gypsum (ton)	0	101	$0.00	$0	$0	$0.00000
Subtotal:				**$0**	**$0**	**$0.00000**
Variable Operating Costs Total:				**$0**	**$60,366,961**	**$14.73480**
Fuel Cost						
Illinois Number 6 (ton):	0	5,947	$68.54	$0	$126,458,921	$30.86699
Total:				**$0**	**$126,458,921**	**$30.86699**

[A] CO_2 Capture System Chemicals includes Ion Exchange Resin, NaOH, and Cansolv Solvent.

Exhibit 3-67 Case B12B COE breakdown

Component	Value, $/MWh	Percentage
Capital	72.2	51%
Fixed	15.4	11%
Variable	14.7	10%
Fuel	30.9	22%
Total (Excluding T&S)	**133.2**	**N/A**
CO_2 T&S	9.6	7%
Total (Including T&S)	**142.8**	**N/A**

3.4 PC Case Summary

The performance results of the four PC plant configurations are summarized in Exhibit 3-68.

Exhibit 3-68 Estimated performance and cost results for PC cases

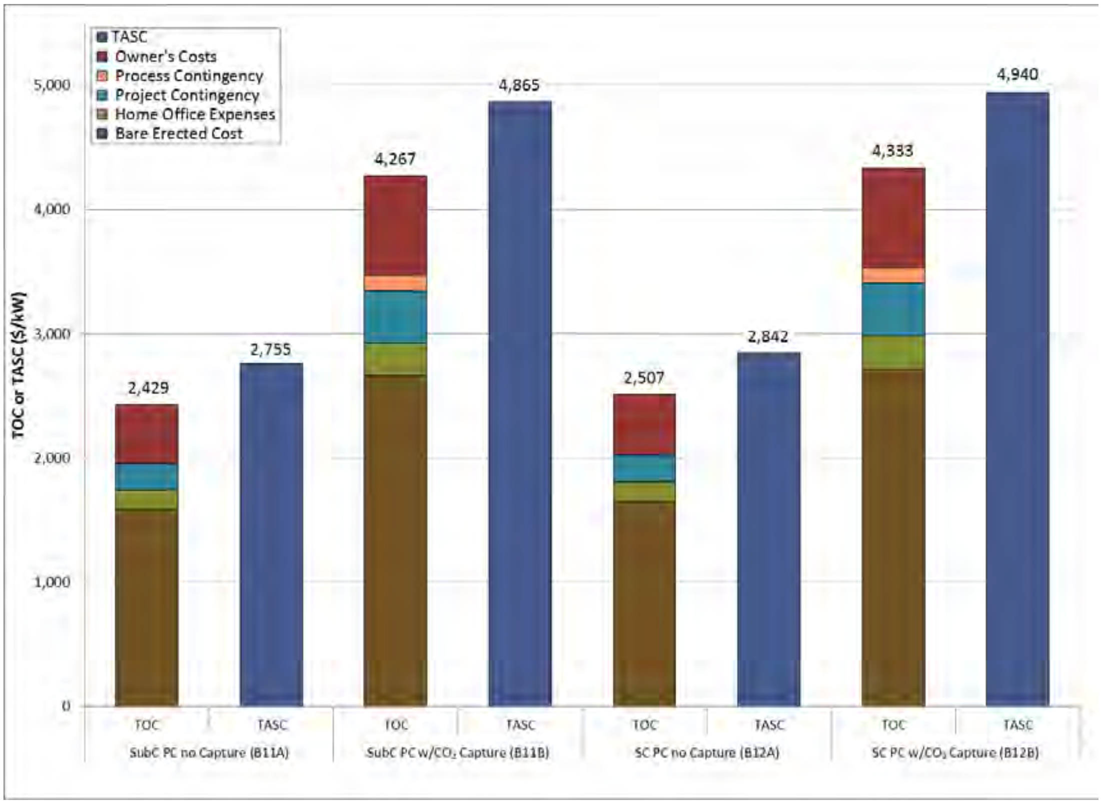
	Pulverized Coal Boiler			
	PC Subcritical		PC Supercritical	
	Case B11A	Case B11B	Case B12A	Case B12B
PERFORMANCE				
Nominal CO_2 Capture	**0%**	**90%**	**0%**	**90%**
Capacity Factor	**85%**	**85%**	**85%**	**85%**
Gross Power Output (MWe)	581	644	580	642
Auxiliary Power Requirement (MWe)	31	94	30	91
Net Power Output (MWe)	550	550	550	550
Coal Flow rate (lb/hr)	412,005	516,170	395,053	495,578
Natural Gas Flow rate (lb/hr)	N/A	N/A	N/A	N/A
HHV Thermal Input (kW_t)	1,408,630	1,764,768	1,350,672	1,694,366
Net Plant HHV Efficiency (%)	39.0%	31.2%	40.7%	32.5%
Net Plant HHV Heat Rate (Btu/kWh)	8,740	10,953	8,379	10,508
Raw Water Withdrawal, gpm	5,538	8,441	5,105	7,882
Process Water Discharge, gpm	1,137	1,920	1,059	1,813
Raw Water Consumption, gpm	4,401	6,521	4,045	6,069
CO_2 Emissions (lb/MMBtu)	204	20	204	20
CO_2 Emissions (lb/MWh-gross)	1,683	190	1,618	183
CO_2 Emissions (lb/MWh-net)	1,779	223	1,705	214
SO_2 Emissions (lb/MMBtu)	0.085	0.000	0.085	0.000
SO_2 Emissions (lb/MWh-gross)	0.700	0.000	0.673	0.000
NOx Emissions (lb/MMBtu)	0.085	0.075	0.088	0.078
NOx Emissions (lb/MWh-gross)	0.700	0.700	0.700	0.700
PM Emissions (lb/MMBtu)	0.011	0.010	0.011	0.010
PM Emissions (lb/MWh-gross)	0.090	0.090	0.090	0.090
Hg Emissions (lb/TBtu)	0.363	0.321	0.377	0.333
Hg Emissions (lb/MWh-gross)	3.00E-06	3.00E-06	3.00E-06	3.00E-06
COST				
Total Plant Cost (2011$/kW)	1,960	3,467	2,026	3,524
Bare Erected Cost	1,582	2,665	1,646	2,716
Home Office Expenses	158	257	165	263
Project Contingency	220	427	216	430
Process Contingency	0	118	0	115
Total Overnight Cost (2011$/MM)	1,336	2,346	1,379	2,384
Total Overnight Cost (2011$/kW)	2,429	4,267	2,507	4,333
Owner's Costs	469	800	480	809
Total As-Spent Cost (2011$/kW)	2,755	4,865	2,842	4,940
COE ($/MWh) (excluding T&S)	82.1	133.5	82.3	133.2
Capital Costs	37.8	71.1	39.0	72.2
Fixed Costs	9.3	15.1	9.6	15.4
Variable Costs	9.2	15.1	9.1	14.7
Fuel Costs	25.7	32.2	24.6	30.9
COE ($/MWh) (including T&S)	82.1	143.5	82.3	142.8
CO_2 T&S Costs	0.0	10.0	0.0	9.6

The following observations can be made regarding plant performance:

- The addition of CO_2 capture and compression to the two PC cases results in an efficiency penalty of 7.8 absolute percent in the subcritical PC case and 8.2 absolute percent in the SC PC case. The efficiency is negatively impacted by the large auxiliary loads of the capture process and CO_2 compression, as well as the large increase in cooling water requirement, which increases the CWP and cooling tower fan auxiliary loads. The auxiliary load increases by 63 MW in the subcritical PC case and by 62 MW in the SC PC case.
- Since the PC cases utilized a wet FGD system, SO_2 emissions could be used as a surrogate for HCl (17). Provided the SO_2 emissions limit is not exceeded, it can be assumed per the MATS regulation that the HCl emissions limit is also satisfied.
- The SO_2 emissions for non-capture cases are nearly identical, with the subcritical PC emissions being higher than SC when normalized by gross output because of the lower efficiency. The CO_2 capture process polishing scrubber and absorber vessel result in negligible SO_2 emissions in CO_2 capture cases.
- Uncontrolled CO_2 emissions on a mass basis are greater for subcritical PC compared to SC because of the lower efficiency. The capture cases result in a 90 percent reduction of carbon for both subcritical and SC PC.

The components of TOC and overall TASC are shown for each PC case in Exhibit 3-69.

Exhibit 3-69 Plant capital cost for PC cases



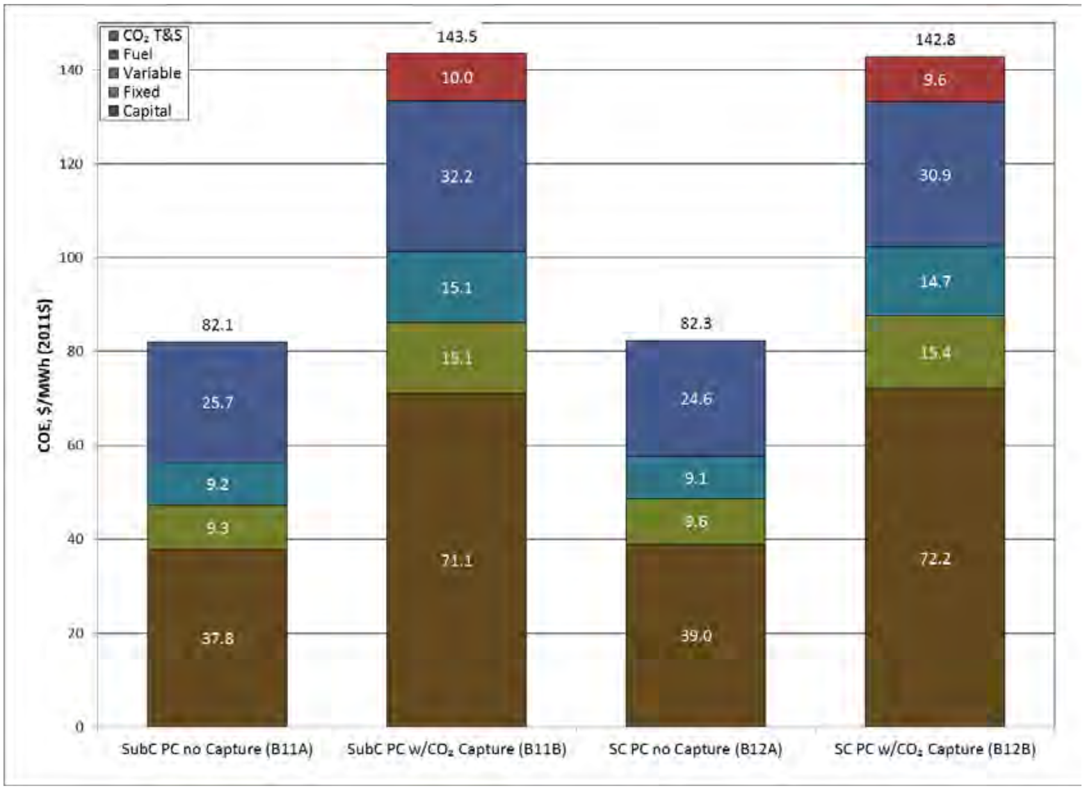
Source: NETL

The following observations about TOC can be made:

- The TOC of the non-capture SC PC case is approximately 3.2 percent greater than non-capture subcritical PC. The TOC of SC PC with CO_2 capture is approximately 1.6 percent greater than subcritical PC with CO_2 capture.
- The TOC penalty for adding CO_2 capture in the subcritical case is 76 percent and is 73 percent in the SC case. In addition to the high cost of the capture process, there is a significant increase in the cost of the cooling towers and CWPs in the CO_2 capture cases because of the larger cooling water demand discussed previously. Also, the gross output of the two PC plants increases by 63 MW (subcritical) and 62 MW (SC) to maintain the net output at 550 MW. The increased gross output results in higher coal flow rate and consequently higher costs for all cost accounts in the estimate.

The COE is shown for the four PC cases in Exhibit 3-70 (including T&S in the capture cases).

Exhibit 3-70 COE for PC cases



Source: NETL

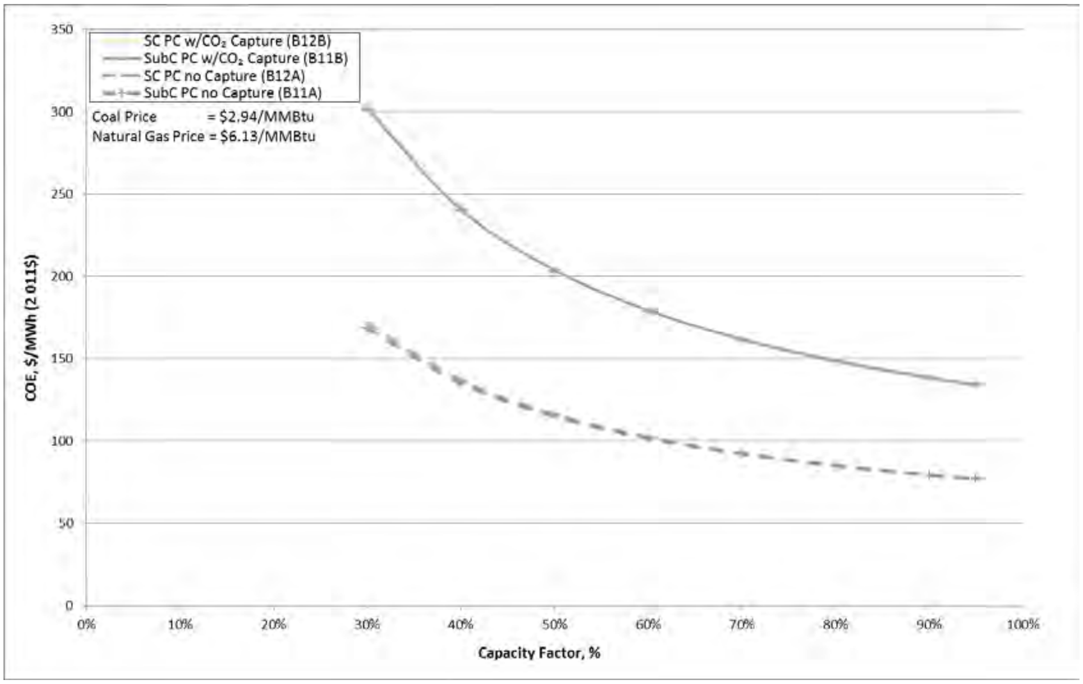
*Cases without capture use conventional financing; all others use high-risk financial asssumptions consistent with NETL's "QGESS: Cost Estimation Methodology for NETL Assessments of Power Plant Performance." (1)

The following observations can be made:

- Capital costs represent the largest fraction of COE in all cases, but particularly so in the CO_2 capture cases. Fuel cost is the second largest component of COE, and capital charges and fuel costs combined represent 72 to 77 percent of the total in all cases.
- In the non-capture cases, the slight increase in capital cost in the SC case is almost offset by the efficiency gain so that the COE for SC PC is only approximately 0.3 percent more than subcritical despite having more than a 3 percent greater TOC.
- In the CO_2 capture cases, the increase in capital is even lower than in the non-capture case and is more than offset by the efficiency gain so that the COE for SC PC is approximately 0.2 percent lower than the subcritical case, despite having a TOC that is nearly 2 percent greater. The COE of the non-capture subcritical PC case and the non-capture SC PC case is well within the limits of the study accuracy. The same is true of the two CO_2 capture cases.

The sensitivity of COE to capacity factor is shown in Exhibit 3-71. Implicit in the curves is the assumption that a capacity factor of greater than 85 percent can be achieved without the expenditure of additional capital. The subcritical and SC cases are nearly identical making it difficult to distinguish between the two lines. The COE increases slightly more rapidly at low CF because the relatively high capital component is spread over fewer kilowatt-hours of generation.

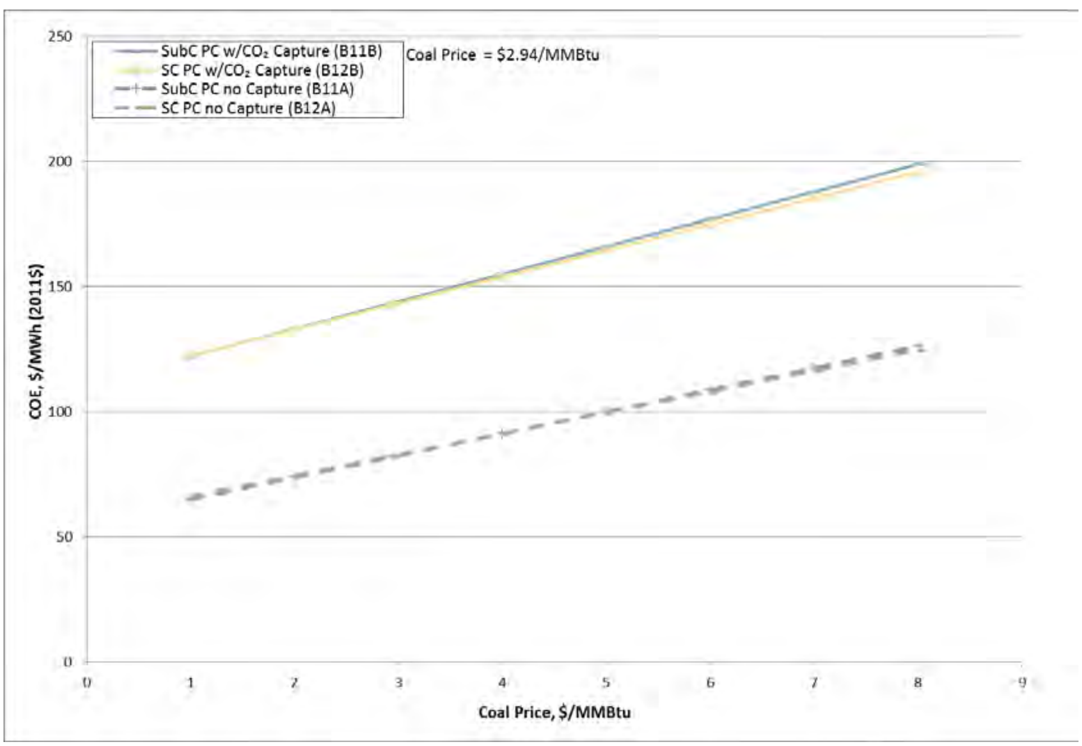
Exhibit 3-71 Sensitivity of COE to capacity factor for PC cases



Source: NETL

COE is relatively insensitive to fuel costs for the PC cases, as shown in Exhibit 3-72. A tripling of coal price from $1-$3/MMBtu results in an approximate COE increase of about 26 percent in the non-capture cases and 18 percent in the CO_2 capture cases.

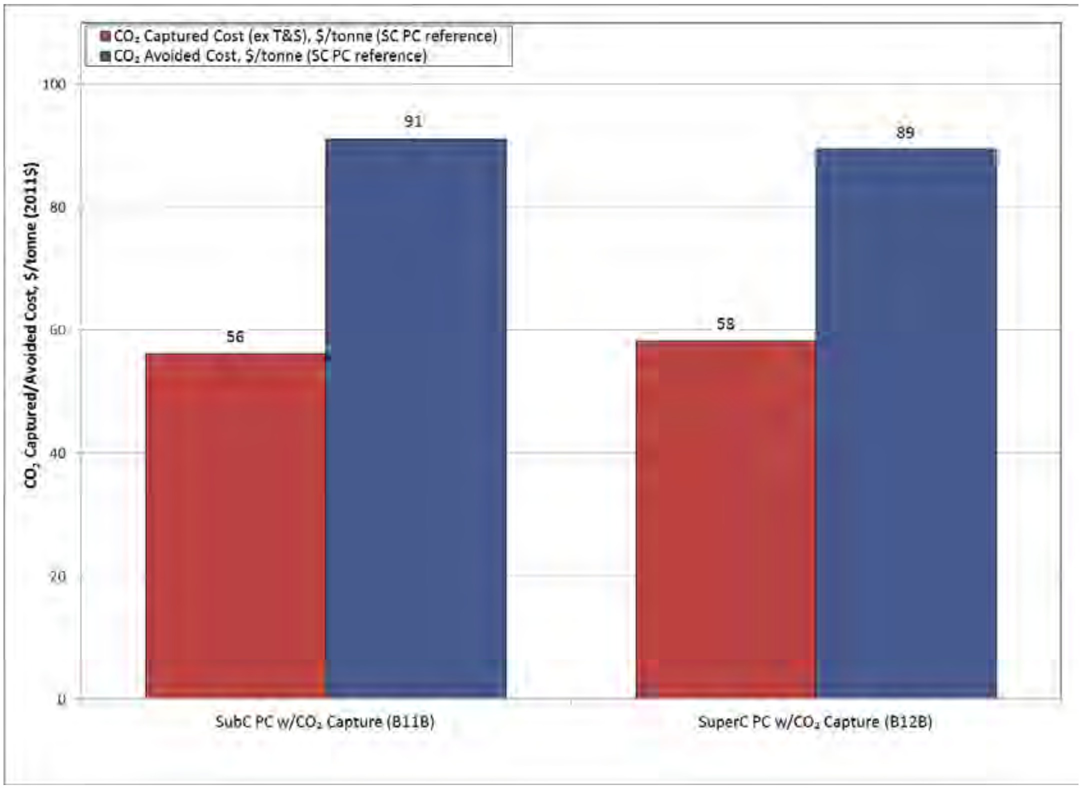
Exhibit 3-72 Sensitivity of COE to coal price for PC cases



Source: NETL

As presented in Section 2.7.4 the CO_2 captured and avoided costs were calculated and the results for the PC CO_2 capture cases – using SC PC as the non-capture reference case – are shown in Exhibit 3-73. The costs are nearly identical for the subcritical and SC PC cases.

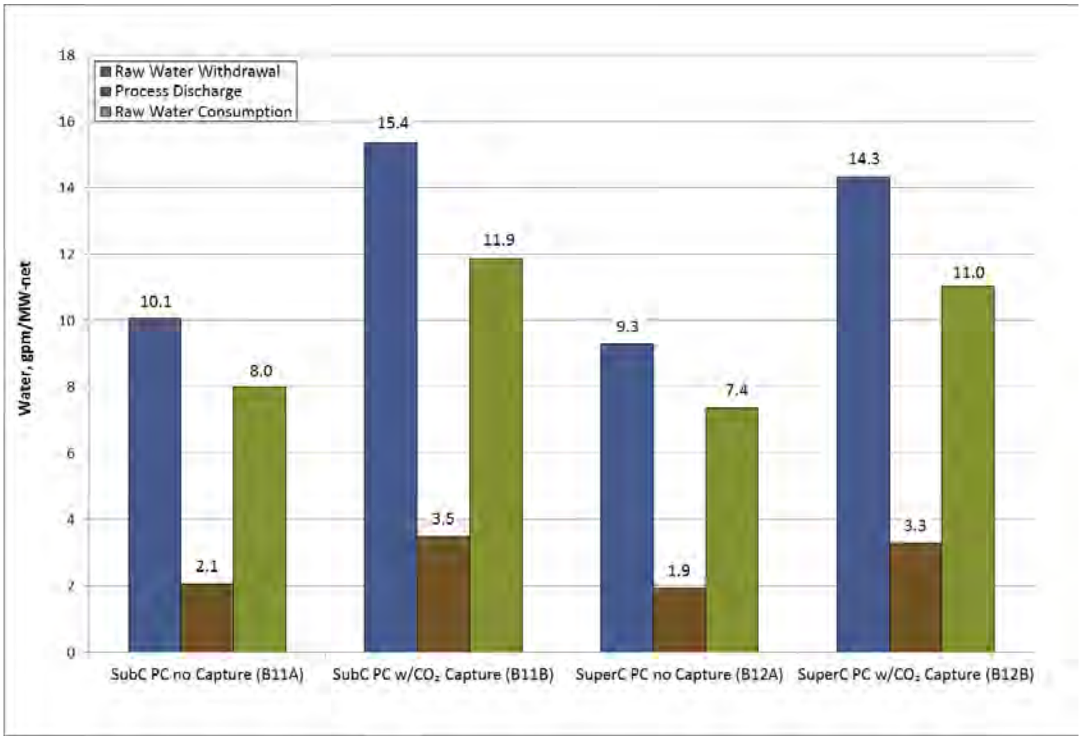
Exhibit 3-73 Cost of CO_2 captured and avoided in PC cases



Source: NETL

The normalized water withdrawal, process discharge and raw water consumption are shown in Exhibit 3-74 for each of the PC cases.

Exhibit 3-74 Raw water withdrawal and consumption in PC cases



Source: NETL

Raw water consumption for all cases is dominated by cooling tower makeup requirements, which accounts for about 81 percent of raw water in non-capture cases and 85 percent of raw water in CO_2 capture cases. The amount of raw water consumption in the CO_2 capture cases is greatly increased by the cooling water requirements of the capture process. Cooling water is required to:

- Reduce the flue gas temperature from 56°C (133°F) (FGD exit temperature) to 30°C (86°F) (CO_2 absorber operating temperature), which also requires condensing water from the flue gas that comes saturated from the FGD unit
- Remove the heat input by the stripping steam to cool the solvent
- Remove the heat input from the auxiliary electric loads
- Remove heat in the CO_2 compressor intercoolers

In the CO_2 capture cases, additional water is recovered from the flue gas as it is cooled to the absorber temperature. The condensate is treated and used as cooling tower makeup.

4 Natural Gas Combined Cycle Plants

Two NGCC power plant configurations were evaluated and are presented in this section. Each design is based on a market-ready technology that is assumed to be commercially available in time to support start-up. Each design consists of two state-of-the-art 2013 F-class CTGs, two HRSGs, and one STG in a multi-shaft 2x2x1 configuration.

The NGCC cases are evaluated with and without CO_2 capture on a common thermal input basis. The NGCC designs that include CDR have a smaller plant net output resulting from the additional CDR facility and CO_2 compressors auxiliary loads. The gross output of the NGCC cases was largely determined by the output of the commercially available CT. Hence, evaluation of the two NGCC designs on a common net output basis was not possible.

The Rankine cycle portion of both designs uses a single reheat 16.5 MPa/566°C/566°C (2,400 psig/1,050°F/1,050°F) steam cycle. A more aggressive steam cycle was considered but not chosen because there are very few HRSGs in operation that would support such conditions. (28)

4.1 NGCC Process Areas

The two NGCC cases are nearly identical in configuration with the exception that Case B31B includes CO_2 capture while Case B31A does not. The process areas that are common to the two plant configurations are presented in this section.

4.1.1 Natural Gas Supply System

It was assumed that a natural gas main with adequate capacity is in close proximity (within 16 km [10 mi]) to the site fence line and that a suitable right-of-way is available to install a branch line to the site. For the purposes of this report it was also assumed that the gas will be delivered to the plant custody transfer point at 3.0 MPa (435 psig) and 38°C (100ºF), which matches the state-of-the-art 2013 F-class fuel system requirements. Hence, neither a pressure reducing station with gas preheating (to prevent moisture and hydrocarbon condensation), nor a fuel booster compressor is required.

As discussed in Section 2.4.2, it was assumed that the natural gas had an added mercaptan composition of $5.75x10^{-6}$ mol%. (11)

A new gas metering station is assumed to be added on the site, adjacent to the new CT. The meter may be of the rate-of-flow type, with input to the plant computer for summing and recording, or may be of the positive displacement type. In either case, a complete timeline record of gas consumption rates and cumulative consumption is provided.

4.1.2 Combustion Turbine

The combined cycle plant is based on two CTGs. The CTG is representative of the state-of-the-art 2013 F-class turbines with an ISO base rating of 211 MW when firing natural gas (18). This machine is an axial flow, single spool, constant speed unit, with variable IGVs, and dry LNB combustion system.

Each CTG is provided with inlet air filtration systems, inlet silencers, lube and control oil systems including cooling, electric motor starting systems, acoustical enclosures including heating and ventilation, control systems including supervisory, fire protection, and fuel systems. No back up fuel was envisioned for these cases.

The CTG is typically supplied in several fully shop-fabricated modules, complete with all mechanical, electrical, and control systems required for CTG operation. Site CTG installation involves module interconnection and linking CTG modules to the plant systems. The CTG package scope of supply for combined cycle application, while project specific, does not vary much from project-to-project. A typical scope of supply is presented in Exhibit 4-1.

Exhibit 4-1 Combustion turbine typical scope of supply

System	System Scope
ENGINE ASSEMBLY	Coupling to Generator, Dry Chemical Exhaust Bearing Fire Protection System, Insulation Blankets, Platforms, Stairs and Ladders
Engine Assembly with Bedplate	Variable Inlet Guide Vane System, Compressor, Bleed System, Purge Air System, Bearing Seal Air System, Combustors, Dual Fuel Nozzles, Turbine Rotor Cooler
Walk-in acoustical enclosure	HVAC, Lighting, and LP CO_2 Fire Protection System
MECHANICAL PACKAGE	HVAC, Lighting, Air Compressor for Pneumatic System, LP CO_2 Fire Protection System
Lubricating Oil System and Control Oil System	Lube Oil Reservoir, Accumulators, 2x100% AC Driven Oil Pumps, DC Emergency Oil Pump with Starter, 2x100% Oil Coolers, Duplex Oil Filter, Oil Temperature and Pressure Control Valves, Oil Vapor Exhaust Fans and Demister, Oil Heaters, Oil Interconnect Piping (SS and CS), Oil System Instrumentation, Oil for Flushing and First Filling
ELECTRICAL PACKAGE	HVAC, Lighting, AC and DC Motor Control Centers, Generator Voltage Regulating Cabinet, Generator Protective Relay Cabinet, DC Distribution Panel, Battery Charger, Digital Control System with Local Control Panel (all control and monitoring functions as well as data logger and sequence of events recorder), Control System Valves and Instrumentation Communication link for interface with plant DCS Supervisory System, Bentley Nevada Vibration Monitoring System, LP CO_2 Fire Protection System, Cable Tray and Conduit Provisions for Performance Testing including Test Ports, Thermowells, Instrumentation and DCS interface cards
INLET AND EXHAUST SYSTEMS	Inlet Duct Trash Screens, Inlet Duct and Silencers, Self-Cleaning Filters, Hoist System For Filter Maintenance, Evaporative Cooler System, Exhaust Duct Expansion Joint, Exhaust Silencers Inlet and Exhaust Flow, Pressure and Temperature Ports and Instrumentation
FUEL SYSTEMS	
NG System	Gas Valves Including Vent, Throttle and Trip Valves, Gas Filter/Separator, Gas Supply Instruments and Instrument Panel
STARTING SYSTEM	Enclosure, Starting Motor or Static Start System, Turning Gear and Clutch Assembly, Starting Clutch, Torque Converter
GENERATOR	Static or Rotating Exciter (Excitation transformer to be included for a static system), Line Termination Enclosure with CTs, VTs, Surge Arrestors, and Surge Capacitors, Neutral Cubicle with CT, Neutral Tie Bus, Grounding Transformer, and Secondary Resistor, Generator Gas Dryer, Seal Oil System (including Defoaming Tank, Reservoir, Seal Oil Pump, Emergency Seal Oil Pump, Vapor Extractor, and Oil Mist Eliminator), Generator Auxiliaries Control Enclosure, Generator Breaker, Iso-Phase bus connecting generator and breaker, Grounding System Connectors
Generator Cooling	Totally Enclosed Water-to-Air-Cooled (TEWAC) System (including circulation system, interconnecting piping and controls), or Hydrogen Cooling System (including H_2 to Glycol and Glycol to Air heat exchangers, liquid level detector circulation system, interconnecting piping and controls)
MISCELLANEOUS	Interconnecting Pipe, Wire, Tubing and Cable Instrument Air System Including Air Dryer On Line and Off Line Water Wash System LP CO_2 Storage Tank Drain System Drain Tanks Coupling, Coupling Cover and Associated Hardware

Electrical generators are provided with the CT package. The generators are assumed to be 24 kV, 3-phase, 60 Hz, constructed to meet American National Standards Institute (ANSI) and National Electrical Manufacturers Association (NEMA) standards for turbine-driven synchronous generators. The generator is TEWAC, complete with excitation system, cooling, and protective relaying.

4.1.3 Heat Recovery Steam Generator

The HRSG is configured with HP, IP, and LP steam drums, and superheater, reheater, and economizer sections. The HP drum is supplied with FW by the HP boiler feed pump to generate HP steam, which passes to the superheater section for heating to 566°C (1,050°F). The IP drum is supplied with FW by the IP boiler feed pump. The IP steam from the drum is superheated to 482°C (900°F) and mixed the HP turbine exhaust before being reheated to 566°C (1,050ºF). The combined flows are admitted into the IP section of the steam turbine. The LP drum provides steam to the LP turbine.

The economizer sections heat condensate and FW (in separate tube bundles). The HRSG tubes are typically comprised of bare surface and/or finned tubing or pipe material. The high-temperature portions are type P91 or P22 ferritic alloy material; the low-temperature portions (less than 399°C [750°F]) are carbon steel (CS). Each HRSG exhausts directly to the stack, which is fabricated from CS plate materials and lined with Type 409 SS. The stack for the NGCC cases is assumed to be 46 m (150 ft) high, and the cost is included in the HRSG account.

4.1.4 NOx Control System

Two measures are taken to reduce the NOx. The first is a DLN burner in the CTG. The DLN burners are a low NOx design and reduce the emissions to about 9 ppmvd (18) (assumed to be approximately 98 percent NO and referenced to 15 percent O_2).

While a state-of-the-art 2013 F-class CT alone produces NOx emissions below the limits described in Section 2.4.2, an SCR was included as a second measure to ensure the plant met the EPA’s PSD program by installing the BACT.

A SCR uses ammonia and a catalyst to reduce NO to N_2 and H_2O. The SCR system consists of a reactor, and ammonia supply and storage system. The SCR system is designed for 90 percent reduction while firing natural gas (19).

Operation Description - The SCR reactor is located in the flue gas path inside the HRSG between the HP and IP sections. The SCR reactor is equipped with one catalyst layer consisting of catalyst modules stacked in line on a supporting structural frame. The SCR reactor has space for installation of an additional layer. Ammonia is injected into the gas immediately prior to entering the SCR reactor. The ammonia injection grid is arranged into several sections, and consists of multiple pipes with nozzles. The ammonia flow rate into each injection grid section is controlled taking into account imbalances in the flue gas flow distribution across the HRSG. The catalyst contained in the reactor enhances the reaction between the ammonia and the NOx in the gas. The catalyst consists of various active materials such as titanium dioxide, vanadium pentoxide, and tungsten trioxide. The optimum inlet flue gas temperature range for the catalyst is 260°C (500°F) to 343°C (650°F).

The ammonia storage and injection system consists of the unloading facilities, bulk storage tank, vaporizers, and dilution air skid.

4.1.5 Carbon Dioxide Recovery Facility

A CDR facility is used in Case B31B to remove 90 percent of the CO_2 in the flue gas exiting the HRSG, purify it, and compress it to a SC condition. It is assumed that all of the carbon in the natural gas is converted to CO_2. The CDR is comprised of flue gas supply, CO_2 absorption, solvent stripping and reclaiming, and CO_2 compression and drying.

The CO_2 absorption/stripping/solvent reclamation process for Case B31B is based on the Cansolv system, previously described in Section 3.1.8, with the exception that no SO_2 polishing step is required in the NGCC case, as the pipeline natural gas sulfur content produces a flue gas with an SO_2 content below the concentration in the outlet of the polishing scrubber used in the PC cases.

Any potential advantage that the natural gas case with CO_2 capture would have over the coal cases with CO_2 capture due to the significantly lower rate of chloride present in the feedstock (which forms HSS in the CO_2 absorber) and SO_2 and NOx gases in the flue gas (which contribute to amine degradation) is minimal as the prescrubber included in the coal cases removes the majority of these contaminants.

Due to the larger volumetric flow rate in the NGCC case compared to the PC cases (147 million ft^3/hr in Case B31B and 90 million ft^3/hr in Case B12B) and the low CO_2 concentration (4.9 mol% in Case B31B and 12.9 mol% in Case B12B), the natural gas case requires a CO_2 absorber over 1.5 times as large as the coal cases. However, as a result of the lower CO_2 content, the CO_2 stripper used in Case B31B is only 40 percent of the volume as the one used in Case B12B.

4.1.6 Steam Turbine

The steam turbine consists of an HP section, an IP section, and a double-flow LP section, all connected to the generator by a common shaft. The HP and IP sections are contained in a single span, opposed-flow casing, with the double-flow LP section in a separate casing.

Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 16.5 MPa/566°C (2,400 psig/1,050°F). The steam initially enters the turbine near the middle of the HP span, flows through the turbine, and is combined with steam from the IP superheater before being returned to the HRSG for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 4.2 MPa/566°C (608 psia/1,050°F). After passing through the IP section, the steam enters a cross-over pipe, which transports the steam to the LP section. A branch line equipped with combined stop/intercept valves conveys LP steam from the HRSG LP drum to a tie-in at the cross-over line. The steam divides into two paths and flows through the LP sections exhausting downward into the condenser.

Turbine bearings are lubricated by a CL, water-cooled pressurized oil system. Turbine shafts are sealed against air in-leakage or steam blowout using a modern positive pressure variable clearance shaft sealing design arrangement connected to a LP steam seal system. The open-air-cooled generator produces power at 24 kV. A static, transformer type exciter is provided. The STG is controlled by a triple-redundant microprocessor-based electro-hydraulic control system. The system provides digital control of the unit in accordance with programmed control algorithms, color monitor/operator interfacing, and datalink interfaces to the balance-of-plant DCS, and incorporates on-line repair capability.

4.1.7 Water and Steam Systems

4.1.7.1 Condensate

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser; and the low-temperature economizer section in the HRSG.

The system consists of one main condenser; two 50 percent capacity, motor-driven vertical multistage condensate pumps (total of two pumps for the plant); one gland steam condenser; condenser air removal vacuum pumps, condensate polisher, and a low-temperature tube bundle in the HRSG.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

4.1.7.2 Feedwater

The function of the feedwater (FW) system is to pump the various FW streams from the deaerator storage tank in the HRSG to the respective steam drums. One 100 percent capacity motor-driven feed pump is provided per each HRSG (total of two pumps for the plant). The FW pumps are equipped with an interstage takeoff to provide IP and LP FW. Each pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

4.1.7.3 Steam System

Main, intermediate, and low pressure steam exits the HRSG superheater section through motor-operated stop/check valves and motor-operated gate valves. The main steam is routed to the HP turbine stop valve. The intermediate steam is combined with the HP turbine exhaust and is conveyed through a motor-operated isolation gate valve to the HRSG reheater and from the HRSG reheater outlet through a motor-operated gate valve to the IP turbines. The low pressure steam is combined with the IP turbine exhaust and is conveyed through a motor-operated isolation gate valve to the LP turbines.

4.1.7.4 Circulating Water System

The function of the CWS is to supply cooling water to condense the main turbine exhaust steam, for the auxiliary cooling system, and for the CDR facility in Case B31B. The system consists of two 50 percent capacity vertical CWPs (total of two pumps for the plant), a mechanical draft evaporative cooling tower, and interconnecting piping. The condenser is a single pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One-half of the condenser can be removed from service for cleaning or plugging tubes. This can be done during normal operation at reduced load.

The auxiliary cooling system is a CL system. Plate and frame heat exchangers with circulating water as the cooling medium are provided. The system provides cooling water to the following systems:

1. CTG lube oil coolers
2. CTG air coolers
3. STG lube oil coolers
4. STG hydrogen coolers
5. Boiler feed water pumps
6. Air compressors
7. Generator seal oil coolers (as applicable)
8. Sample room chillers
9. Blowdown coolers
10. Condensate extraction pump-motor coolers

The CDR system in Case B31B requires a substantial amount of cooling water that is provided by the NGCC plant CWS. The additional cooling load imposed by the CDR is reflected in the significantly larger CWPs and cooling tower in that case.

4.1.7.5 Buildings and Structures

Structures assumed for NGCC cases can be summarized as follows:

1. Generation Building housing the STG
2. CWP House
3. Administration / Office / Control Room / Maintenance Building
4. Water Treatment Building
5. Fire Water Pump House

4.1.8 Accessory Electric Plant

The accessory electric plant consists of all switchgear and control equipment, generator equipment, station service equipment, conduit and cable trays, wire, and cable. It also includes the main transformer, required foundations, and standby equipment.

4.1.9 Waste Treatment/Miscellaneous Systems

An onsite water treatment facility treats all runoff, cleaning wastes, blowdown, and backwash. It is anticipated that the treated water will be suitable for discharge into existing systems and be within the EPA standards for suspended solids, oil and grease, pH, and miscellaneous metals.

The waste treatment system is minimal and consists, primarily, of neutralization and oil/water separators (along with the associated pumps, piping, etc.).

Miscellaneous systems consisting of service air, instrument air, and service water are provided. All truck roadways and unloading stations inside the fence area are provided.

4.1.10 Instrumentation and Control

An integrated plant-wide DCS is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of video monitors and keyboard units. The monitor/keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to provide 99.5 percent availability.

The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are implemented as supervised manual procedures with operator selection of modular automation routines available.

4.1.11 Performance Summary Metrics

This section details the methods used to calculate several metrics reported in the performance summaries of the NGCC cases.

Combustion Turbine Efficiency

The combustion turbine efficiency is calculated by taking the CT power produced and dividing it by the thermal input to the turbines. This calculation is represented by the equation:

$$CTE = \frac{CTP}{TI}$$

Where:
CTE – combustion turbine efficiency
CTP – combustion turbine power
TI – thermal input to turbines

The thermal input is calculated by taking the natural gas feed rate and multiplying it by the heating value of the natural gas and converting it to kWs.

Steam Turbine Efficiency

The steam turbine efficiency is calculated by taking the steam turbine power produced and dividing it by the difference between the thermal input and thermal consumption. This calculation is represented by the equation:

$$STE = \frac{STP}{(TI - TC)}$$

Where:
STE – steam turbine efficiency
STP – steam turbine power
TI – thermal input
TC – thermal consumption

The thermal input is calculated by taking the enthalpy of the flue gas to the HRSG and subtracting the enthalpy of the flue gas exiting the HRSG.

The thermal consumption is only present in the capture cases. It is the enthalpy difference between the streams extracted for the capture and CO_2 dryer systems and the condensate returned to the condenser (steam extraction – condensate return).

Steam Turbine Heat Rate

The steam turbine heat rate is calculated by taking the inverse of the steam turbine efficiency. This calculation is represented by the equation:

$$STHR = \frac{1}{STE} * 3{,}412$$

Where:
STHR – steam turbine heat rate, Btu/kWh
STE – steam turbine efficiency, fraction

4.2 NGCC Cases

This section contains an evaluation of plant designs for Cases B31A and B31B. The balance of this section is organized as follows:

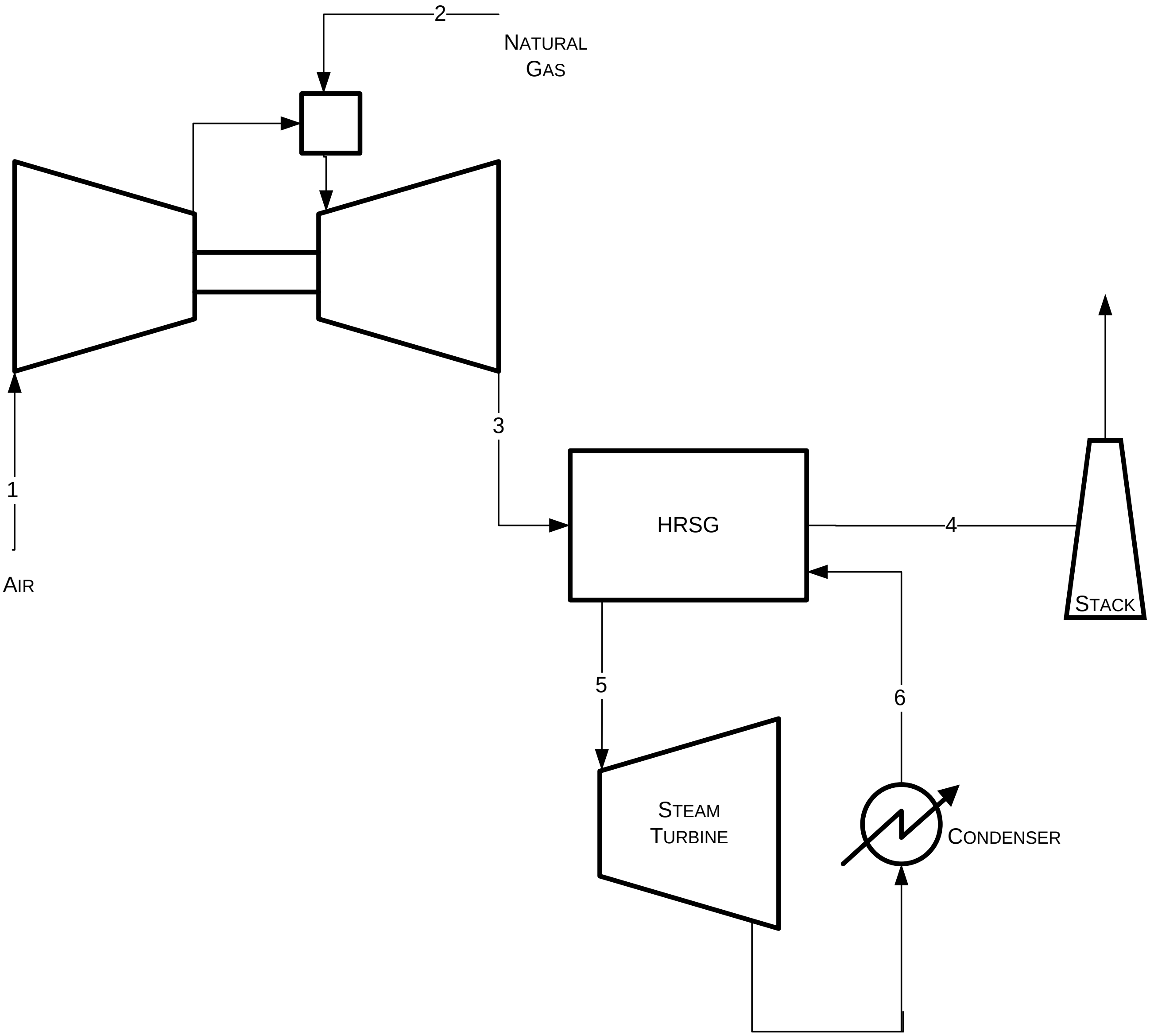
- Process and System Description provides an overview of the technology operation as applied to Case B31A. The systems that are common to all NGCC cases were covered in Section 4.1 and only features that are unique to Case B31A are discussed further in this section.
- Key Assumptions is a summary of study and modeling assumptions relevant to Cases B31A and B31B.
- Sparing Philosophy is provided for both Cases B31A and B31B.
- Performance Results provides the main modeling results from Case B31A, including the performance summary, environmental performance, carbon balance, water balance, mass and energy balance diagrams, and energy balance table.
- Equipment List provides an itemized list of major equipment for Case B31A with account codes that correspond to the cost accounts in the Cost Estimates section.
- Cost Estimates provides a summary of capital and operating costs for Case B31A.
- Process and System Description, Performance Results, Equipment List and Cost Estimates are reported for Case B31B.

4.2.1 Process Description

In this section the NGCC process without CO_2 capture is described. The system description follows the BFD in Exhibit 4-2 and stream numbers reference the same exhibit. The tables in Exhibit 4-3 provide process data for the numbered streams in the BFD. The BFD shows only one of the two CT/HRSG trains, but the flow rates in the stream table are the total for two systems.

Ambient air (stream 1) is supplied to an inlet filter and compressed before being combined with natural gas (stream 2) in the dry LNB, which is operated to control the rotor inlet temperature at 1,359°C (2,479°F). The flue gas exits the turbine at 603°C (1,118°F) (stream 3) and passes into the HRSG. The HRSG generates both the main steam and reheat steam for the steam turbine. Flue gas exits the HRSG at 117°C (243°F) and passes to the plant stack.

Exhibit 4-2 Case B31A block flow diagram, NGCC without CO_2 capture



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Source: NETL

Exhibit 4-3 Case B31A stream table, NGCC without capture

	1	2	3	4	5	6
Ar	0.0092	0.0000	0.0089	0.0089	0.0000	0.0000
CH_4	0.0000	0.9310	0.0000	0.0000	0.0000	0.0000
CH_4S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_2H_6	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000
C_3H_8	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000
C_4H_{10}	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0003	0.0100	0.0391	0.0391	0.0000	0.0000
H_2O	0.0099	0.0000	0.0841	0.0841	1.0000	1.0000
N_2	0.7732	0.0160	0.7442	0.7442	0.0000	0.0000
O_2	0.2074	0.0000	0.1238	0.1238	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mole}/hr)	125,541	4,855	130,538	130,538	24,398	32,637
V-L Flowrate (kg/hr)	3,622,750	84,134	3,706,884	3,706,884	439,533	587,969
Solids Flowrate (kg/hr)	0	0	0	0	0	0
Temperature (°C)	15	38	603	117	566	38
Pressure (MPa, abs)	0.10	3.10	0.10	0.10	16.65	0.01
Steam Table Enthalpy (kJ/kg) [A]	30.22	46.29	800.33	256.77	3,473.89	160.78
AspenPlus Enthalpy (kJ/kg)[B]	-97.57	-4,462.93	-616.98	-1,160.55	-12,506.41	-15,819.51
Density (kg/m^3)	1.2	22.2	0.4	0.9	47.7	992.8
V-L Molecular Weight	28.857	17.328	28.397	28.397	18.015	18.015
V-L Flowrate (lb_{mole}/hr)	276,771	10,704	287,786	287,786	53,788	71,953
V-L Flowrate (lb/hr)	7,986,797	185,484	8,172,281	8,172,281	969,004	1,296,250
Solids Flowrate (lb/hr)	0	0	0	0	0	0
Temperature (°F)	59	100	1,118	243	1,050	101
Pressure (psia)	14.7	450.0	15.1	14.8	2,414.7	1.0
Steam Table Enthalpy (Btu/lb)[A]	13.0	19.9	344.1	110.4	1,493.5	69.1
AspenPlus Enthalpy (Btu/lb)[B]	-41.9	-1,918.7	-265.3	-498.9	-5,376.8	-6,801.2
Density (lb/ft^3)	0.076	1.384	0.025	0.056	2.975	61.977

[A]Steam table reference conditions are 32.02°F & 0.089 psia

[B]Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm.

4.2.2 Key System Assumptions

System assumptions for Cases B31A and B31B, NGCC with and without CO_2 capture, are compiled in Exhibit 4-4.

Exhibit 4-4 NGCC plant study configuration matrix

	Case B31A w/o CO_2 Capture	Case B31B w/CO_2 Capture
Steam Cycle, MPa/°C/°C (psig/°F/°F)	16.5/566/566 (2,400/1,050/1,050)	16.5/566/566 (2,400/1,050/1,050)
Fuel	Natural Gas	Natural Gas
Fuel Pressure at Plant Battery Limit MPa (psia)	3.1 (450)	3.1 (450)
Condenser Pressure, mm Hg (in Hg)	50.8 (2)	50.8 (2)
Cooling Water to Condenser, °C (ºF)	16 (60)	16 (60)
Cooling Water from Condenser, °C (ºF)	27 (80)	27 (80)
Stack Temperature, °C (°F)	117 (243)	35 (95)
SO_2 Control	Low Sulfur Fuel	Low Sulfur Fuel
NOx Control	LNB and SCR	LNB and SCR
SCR Efficiency, %[A]	90	90
Ammonia Slip (End of Catalyst Life), ppmv	10	10
Particulate Control	N/A	N/A
Mercury Control	N/A	N/A
CO_2 Control	N/A	Cansolv
Overall Carbon Capture[A]	N/A	90%
CO_2 Sequestration	N/A	Off-site Saline Formation

[A]Removal efficiencies are based on the flue gas content

4.2.2.1 Balance of Plant – Cases B31A and B31B

The balance of plant assumptions are common to both NGCC cases and are presented in Exhibit 4-5.

Exhibit 4-5 NGCC balance of plant assumptions

Parameter	Value
Cooling System	Recirculating Wet Cooling Tower
Fuel and Other Storage	
Natural Gas	Pipeline supply at 3.1 MPa (450 psia) and 38°C (100°F)
Plant Distribution Voltage	
Motors below 1 hp	110/220 V
Motors between 1 hp and 250 hp	480 V
Motors between 250 hp and 5,000 hp	4,160 V
Motors above 5,000 hp	13,800 V
Steam and CT generators	24,000 V
Grid Interconnection voltage	345 kV
Water and Waste Water	
Makeup Water	The water supply is 50 percent from a local POTW and 50 percent from groundwater, and is assumed to be in sufficient quantities to meet plant makeup requirements. Makeup for potable, process, and DI water is drawn from municipal sources.
Process Wastewater	Storm water that contacts equipment surfaces is collected and treated for discharge through a permitted discharge.
Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant is sized for 5.68 m^3/d (1,500 gpd)
Water Discharge	Most of the process wastewater is recycled to the cooling tower basin. Blowdown is treated for chloride and metals, and discharged.

4.2.3 Sparing Philosophy

Dual trains are used to accommodate the size of commercial CTs. There is no redundancy other than normal sparing of rotating equipment. The plant design consists of the following major subsystems:

- Two state-of-the-art 2013 F-Class CTGs (2 x 50%)
- Two 3-pressure reheat HRSGs with self-supporting stacks and SCR systems (2 x 50%)
- One 3-pressure reheat, triple-admission STG (1 x 100%)
- For Case B31B only, one CO_2 absorption systems, consisting of an absorber, stripper, and ancillary equipment (1 x 100%) and two CO_2 compression systems (2 x 50%)

4.2.4 Case B31A Performance Results

The plant produces a net output of 630 MW at a net plant efficiency of 51.5 percent (HHV basis).

Overall plant performance is summarized in Exhibit 4-6; Exhibit 4-7 provides a detailed breakdown of the auxiliary power requirements.

Exhibit 4-6 Case B31A plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	422
Steam Turbine Power, MWe	219
Total Gross Power, MWe	**641**
CO_2 Capture/Removal Auxiliaries, kWe	0
CO_2 Compression, kWe	0
Balance of Plant, kWe	11
Total Auxiliaries, MWe	**11**
Net Power, MWe	**630**
HHV Net Plant Efficiency (%)	51.5%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,994 (6,629)
HHV Combustion Turbine Efficiency, %	34.5%
LHV Net Plant Efficiency (%)	57.0%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,320 (5,990)
LHV Combustion Turbine Efficiency, %	38.1%
Steam Turbine Cycle Efficiency, %	39.1%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	9,201 (8,721)
Condenser Duty, GJ/hr (MMBtu/hr)	1,281 (1,215)
Natural Gas Feed Flow, kg/hr (lb/hr)	84,134 (185,483)
HHV Thermal Input, kWt	1,223,032
LHV Thermal Input, kWt	1,105,162
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.016 (4.2)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.012 (3.3)

Exhibit 4-7 Case B31A plant power summary

Power Summary	
Combustion Turbine Power, MWe	422
Steam Turbine Power, MWe	219
Total Gross Power, MWe	**641**
Auxiliary Load Summary	
Feedwater Pumps, kWe	3,550
SCR, kWe	2
CO_2 Capture/Removal Auxiliaries, kWe	0
CO_2 Compression, kWe	0
Miscellaneous Balance of Plant[A], kWe	500
Combustion Turbine Auxiliaries, kWe	700
Steam Turbine Auxiliaries, kWe	100
Condensate Pumps, kWe	130
Circulating Water Pumps, kWe	2,570
Ground Water Pumps, kWe	240
Cooling Tower Fans, kWe	1,330
Transformer Losses, kWe	1,950
Total Auxiliaries, MWe	**11**
Net Power, MWe	**630**

[A]Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

4.2.4.1 Environmental Performance

The environmental targets for emissions of NOx, SO_2, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B31A is presented in Exhibit 4-8.

Exhibit 4-8 Case B31A air emissions

	kg/GJ (lb/MMBtu)	Tonne/year (ton/year)[A]	kg/MWh (lb/MWh)
SO_2	0.000 (0.001)	13 (15)	0.003 (0.006)
NOx	0.001 (0.003)	44 (49)	0.009 (0.020)
Particulate	0.000 (0.000)	0 (0)	0.000 (0.000)
Hg	0.00E+0 (0.00E+0)	0.000 (0.000)	0.00E+0 (0.00E+0)
CO_2[B]	51 (119)	1,671,433 (1,842,440)	350 (773)
CO_2[C]	-	-	357 (786)

[A]Calculations based on an 85 percent capacity factor
[B]CO_2 emissions based on gross power
[C]CO_2 emissions based on net power instead of gross power

For the purpose of this report, the natural gas was assumed to contain the average value of total sulfur of 0.34 gr/100 scf (4.71×10^{-4} lb-S/MMBtu). (11) It was also assumed that the added mercaptan (CH_4S) was the sole contributor of sulfur to the natural gas. No sulfur capture systems were required.

The NGCC cases were designed to achieve approximately 1.0 ppmvd NOx emissions (at 15 percent O_2) through the use of a DLN burner in the CTG – the DLN burners reduce the emissions to about 9 ppmvd (at 15 percent O_2) (18) – and an SCR – the SCR system is designed for 90 percent NO reduction (19).

The pipeline natural gas was assumed to contain no particulate matter (PM), Hg, or HCl, resulting in zero emissions.

CO_2 emissions are reduced relative to those produced by burning coal given the same power output because of the higher heat content of natural gas, the lower carbon intensity of gas relative to coal, and the higher overall efficiency of the NGCC plant relative to a coal-fired plant.

The carbon balance for the plant is shown in Exhibit 4-9. The carbon input to the plant consists of carbon in the natural gas and carbon as CO_2 in the CT air. Carbon leaves the plant as CO_2 through the stack.

Exhibit 4-9 Case B31A carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	60,768 (133,971)	Stack Gas	61,263 (135,061)
Air (CO_2)	494 (1,090)	CO_2 Product	0 (0)
		CO_2 KO	0 (0)
		CO_2 Dryer Vent	0 (0)
Total	**61,262 (135,061)**	**Total**	**61,263 (135,061)**

As shown in Exhibit 4-10, the sulfur content of the natural gas is insignificant. All sulfur in the natural gas is emitted in the stack gas.

Exhibit 4-10 Case B31A sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	1 (2)	Stack Gas	1 (2)
		Polishing Scrubber/HSS	0 (0)
Total	**1 (2)**	**Total**	**1 (2)**

Exhibit 4-11 shows the water balance for Case B31A. Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is re-used as internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a surface-water source for use in the plant and was assumed to be provided 50 percent by a POTW and 50 percent from groundwater. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for any and all purposes, such as condenser and cooling tower makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source balance.

Exhibit 4-11 Case B31A water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)
CO_2 Drying	–	–	–	–	–
Capture System Makeup	–	–	–	–	–
Condenser Makeup	**0.10 (26)**	**–**	**0.10 (26)**	**–**	**0.10 (26)**
BFW Makeup	0.10 (26)	–	0.10 (26)	–	0.10 (26)
Cooling Tower	**10.01 (2,646)**	**0.10 (26)**	**9.92 (2,620)**	**2.25 (595)**	**7.66 (2,025)**
CO_2 Capture Recovery	–	–	–	–	–
CO_2 Compression Recovery	–	–	–	–	–
BFW Blowdown	–	0.10 (26)	-0.10 (-26)	–	–
Total	**10.11 (2,672)**	**0.10 (26)**	**10.01 (2,646)**	**2.25 (595)**	**7.76 (2,051)**

4.2.4.2 Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the NGCC in Exhibit 4-12. An overall plant energy balance is provided in tabular form in Exhibit 4-13. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-6) is calculated by multiplying the power out by a combined generator efficiency of 98.5 percent.

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Exhibit 4-12 Case B31A heat and mass balance, NGCC without CO_2 capture

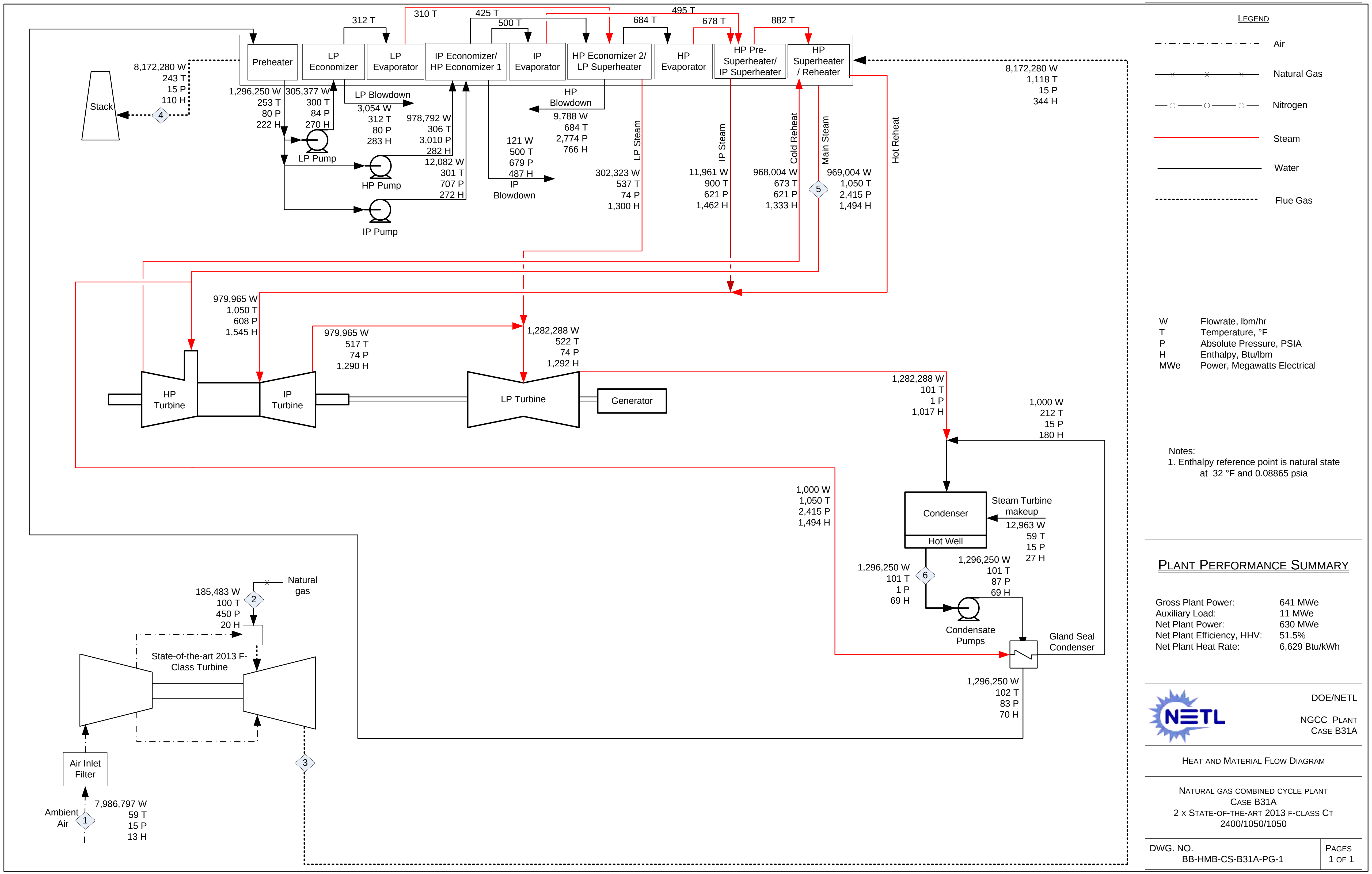

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Exhibit 4-13 Case B31A overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Natural Gas	4,403 (4,173)	2.9 (2.8)	–	4,406 (4,176)
Air	–	109.5 (103.8)	–	109.5 (103.8)
Raw Water Makeup	–	37.7 (35.7)	–	37.7 (35.7)
Auxiliary Power	–	–	40 (38)	40 (38)
TOTAL	**4,403 (4,173)**	**150.1 (142.3)**	**40 (38)**	**4,593 (4,353)**
Heat Out GJ/hr (MMBtu/hr)				
Stack Gas	–	952 (902)	–	952 (902)
Sulfur	–	–	–	–
Motor Losses and Design Allowances	–	–	41 (39)	41 (39)
Condenser	–	1,281 (1,215)	–	1,281 (1,215)
Non-Condenser Cooling Tower Loads	–	26 (25)	–	26 (25)
CO_2	–	–	–	–
Cooling Tower Blowdown	–	16.7 (15.9)	–	16.7 (15.9)
CO_2 Capture Losses	–	–	–	–
Ambient Losses[A]	–	*34.6 (32.8)*	–	*34.6 (32.8)*
Power	–	–	2,306 (2,186)	2,306 (2,186)
TOTAL	**–**	**2,311 (2,190)**	**2,347 (2,225)**	**4,658 (4,415)**
Unaccounted Energy[B]	–	-65 (-62)	–	-65 (-62)

[A]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers.
[B]By difference

4.2.5 Case B31A – Major Equipment List

Major equipment items for the NGCC plant with no CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.2.6. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

Case B31A – Account 2: Fuel and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	70 m^3/min @ 3.1 MPa (2,456 acfm @ 450 psia) 39 cm (16 in) standard wall pipe	16 km (10 mi)	0
2	Gas Metering Station	--	70 m^3/min (2,456 acfm)	1	0

Case B31A – Account 3: Feedwater and Miscellaneous Systems and Equipment

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	776,000 liters (205,000 gal)	2	0
2	Condensate Pumps	Vertical canned	5,430 lpm @ 70 m H_2O (1,430 gpm @ 240 ft H_2O)	2	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP water: 4,100 lpm @ 2,500 m H_2O (1,080 gpm @ 8,210 ft H_2O) IP water: 050 lpm @ 540 m H_2O (10 gpm @ 1,790 ft H_2O) LP water: 1,280 lpm @ 14.0 m H_2O (340 gpm @ 50 ft H_2O)	2	1
4	Auxiliary Boiler	Shop fabricated, water tube	18,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
5	Service Air Compressors	Flooded Screw	13 m^3/min @ 0.7 MPa (450 scfm @ 100 psig)	2	1
6	Instrument Air Dryers	Duplex, regenerative	13 m^3/min (450 scfm)	2	1
7	Closed Cycle Cooling Heat Exchangers	Plate and frame	13 MMkJ/hr (13 MMBtu/hr)	2	0
8	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	5,200 lpm @ 20 m H_2O (1,400 gpm @ 70 ft H_2O)	2	1
9	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 110 m H_2O (1,000 gpm @ 350 ft H_2O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 80 m H_2O (700 gpm @ 250 ft H_2O)	1	1
11	Raw Water Pumps	Stainless steel, single suction	5,600 lpm @ 20 m H_2O (1,500 gpm @ 60 ft H_2O)	2	1
12	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H_2O (40 gpm @ 160 ft H_2O)	2	1
13	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
14	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0
15	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

Case B31A – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	State-of-the-art 2013 F-class w/ dry low-NOx burner	210 MW	2	0
2	Combustion Turbine Generator	TEWAC	230 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

Case B31A – Account 7: HRSG, Ducting, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	46 m (150 ft) high x 8.1 m (27 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 241,743 kg/hr, 16.5 MPa/566°C (532,952 lb/hr, 2,400 psig/1,050°F) Reheat steam - 244,478 kg/hr, 4.1 MPa/566°C (538,981 lb/hr, 593 psig/1,050°F)	2	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
3	SCR Reactor	Space for spare layer	2,040,000 kg/hr (4,490,000 lb/hr)	2	0
4	SCR Catalyst	--	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	10 m^3/min @ 108 cm WG (190 scfm @ 42 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	1.2 lpm @ 90 m H_2O (0.3 gpm @ 300 ft H_2O)	2	1
7	Ammonia Storage Tank	Horizontal tank	33,000 liter (9,000 gal)	1	0

Case B31A – Account 8: Steam Turbine Generator and Auxiliaries

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	231 MW 16.5 MPa/566°C/566°C (2400 psig/ 1050°F/1050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,410 GJ/hr (1,340 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0
4	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0

Case B31A – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	258,000 lpm @ 30 m (68,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 1440 GJ/hr (1360 MMBtu/hr) heat duty	1	0

Case B31A – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 230 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 250 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 0 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 10 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 2 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B31A – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

4.2.6 Case B31A – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 4-14 shows a detailed breakdown of the capital costs; Exhibit 4-15 shows the owner's costs, TOC, and TASC; Exhibit 4-16 shows the initial and annual O&M costs; and Exhibit 4-17 shows the COE breakdown.

The estimated TPC of the NGCC with no CO_2 capture is \$685/kW. No process contingency was included in this case because all elements of the technology are commercially proven. The project contingency is 10.7 percent of TPC. The COE is \$57.6/MWh.

Exhibit 4-14 Case B31A total plant cost details

	Case:	B31A – 2x1 CT NGCC w/o CO_2							Estimate Type:	Conceptual	
	Plant Size (MW,net):	630							Cost Base:	Jun 2011	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
	3	Feedwater & Miscellaneous BOP Systems									
3.1	Feedwater System	$3,215	$3,329	$2,719	$0	$9,263	$834	$0	$1,515	$11,611	$18
3.2	Water Makeup & Pretreating	$1,974	$204	$1,013	$0	$3,191	$287	$0	$696	$4,174	$7
3.3	Other Feedwater Subsystems	$1,506	$498	$416	$0	$2,420	$218	$0	$396	$3,033	$5
3.4	Service Water Systems	$238	$475	$1,531	$0	$2,245	$202	$0	$489	$2,937	$5
3.5	Other Boiler Plant Systems	$1,606	$600	$1,380	$0	$3,586	$323	$0	$586	$4,496	$7
3.6	Natural Gas, incl. pipeline	$17,706	$656	$567	$0	$18,929	$1,704	$0	$3,095	$23,728	$38
3.7	Waste Treatment Equipment	$689	$0	$399	$0	$1,089	$98	$0	$237	$1,424	$2
3.8	Misc. Equip. (Cranes, Air Comp., Comm.)	$1,165	$156	$566	$0	$1,887	$170	$0	$411	$2,469	$4
	Subtotal	**$28,101**	**$5,918**	**$8,592**	**$0**	**$42,611**	**$3,835**	**$0**	**$7,425**	**$53,871**	**$86**
	6	Combustion Turbine & Accessories									
6.1	Combustion Turbine Generator	$104,200	$0	$6,341	$0	$110,541	$9,949	$0	$12,049	$132,539	$211
6.9	Combustion Turbine Foundations	$0	$879	$950	$0	$1,829	$165	$0	$399	$2,392	$4
	Subtotal	**$104,200**	**$879**	**$7,291**	**$0**	**$112,370**	**$10,113**	**$0**	**$12,448**	**$134,931**	**$214**
	7	HRSG, Ducting, & Stack									
7.1	Heat Recovery Steam Generator	$33,050	$0	$6,116	$0	$39,166	$3,525	$0	$4,269	$46,960	$75
7.2	SCR System	$1,973	$829	$1,156	$0	$3,957	$356	$0	$647	$4,960	$8
7.9	HRSG, Duct & Stack Foundations	$0	$551	$517	$0	$1,068	$96	$0	$233	$1,397	$2
	Subtotal	**$35,023**	**$1,379**	**$7,788**	**$0**	**$44,190**	**$3,977**	**$0**	**$5,149**	**$53,316**	**$85**
	8	Steam Turbine Generator									
8.1	Steam TG & Accessories	$36,973	$0	$4,914	$0	$41,887	$3,770	$0	$4,566	$50,223	$80
8.2	Turbine Plant Auxiliaries	$205	$0	$468	$0	$673	$61	$0	$73	$807	$1
8.3	Condenser & Auxiliaries	$2,920	$0	$1,401	$0	$4,321	$389	$0	$471	$5,181	$8
8.4	Steam Piping	$12,237	$0	$4,959	$0	$17,196	$1,548	$0	$2,812	$21,555	$34
8.9	TG Foundations	$0	$968	$1,599	$0	$2,567	$231	$0	$560	$3,357	$5
	Subtotal	**$52,335**	**$968**	**$13,341**	**$0**	**$66,644**	**$5,998**	**$0**	**$8,481**	**$81,123**	**$129**
	9	Cooling Water System									
9.1	Cooling Towers	$2,950	$0	$900	$0	$3,850	$347	$0	$420	$4,616	$7
9.2	Circulating Water Pumps	$1,428	$0	$84	$0	$1,512	$136	$0	$165	$1,813	$3
9.3	Circ. Water System Auxiliaries	$120	$0	$16	$0	$135	$12	$0	$15	$162	$0
9.4	Circ. Water Piping	$0	$3,710	$840	$0	$4,550	$409	$0	$744	$5,703	$9
9.5	Make-up Water System	$310	$0	$398	$0	$708	$64	$0	$116	$887	$1
9.6	Component Cooling Water Sys	$239	$285	$183	$0	$707	$64	$0	$116	$886	$1
9.9	Circ. Water System Foundations	$0	$1,678	$2,786	$0	$4,464	$402	$0	$973	$5,839	$9
	Subtotal	**$5,046**	**$5,673**	**$5,207**	**$0**	**$15,926**	**$1,433**	**$0**	**$2,548**	**$19,907**	**$32**
	11	Accessory Electric Plant									
11.1	Generator Equipment	$5,327	$0	$3,151	$0	$8,477	$763	$0	$693	$9,933	$16
11.2	Station Service Equipment	$1,527	$0	$131	$0	$1,659	$149	$0	$136	$1,944	$3
11.3	Switchgear & Motor Control	$1,879	$0	$326	$0	$2,206	$199	$0	$240	$2,645	$4

	Case:	B31A – 2x1 CT NGCC w/o CO_2							Estimate Type:	Conceptual	
	Plant Size (MW,net):	630							Cost Base:	Jun 2011	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
11.4	Conduit & Cable Tray	$0	$982	$2,830	$0	$3,812	$343	$0	$623	$4,778	$8
11.5	Wire & Cable	$0	$3,156	$1,795	$0	$4,951	$446	$0	$809	$6,206	$10
11.6	Protective Equipment	$0	$722	$2,506	$0	$3,228	$291	$0	$352	$3,871	$6
11.7	Standby Equipment	$128	$0	$120	$0	$248	$22	$0	$27	$297	$0
11.8	Main Power Transformers	$12,475	$0	$190	$0	$12,666	$1,140	$0	$1,381	$15,186	$24
11.9	Electrical Foundations	$0	$164	$417	$0	$581	$52	$0	$127	$760	$1
	Subtotal	**$21,337**	**$5,025**	**$11,466**	**$0**	**$37,828**	**$3,405**	**$0**	**$4,388**	**$45,621**	**$72**
	12	**Instrumentation & Control**									
12.4	Other Major Component Control	$900	$0	$573	$0	$1,473	$133	$0	$241	$1,846	$3
12.6	Control Boards, Panels & Racks	$269	$0	$164	$0	$433	$39	$0	$71	$543	$1
12.7	Computer & Accessories	$4,304	$0	$131	$0	$4,435	$399	$0	$483	$5,318	$8
12.8	Instrument Wiring & Tubing	$0	$801	$1,417	$0	$2,217	$200	$0	$363	$2,779	$4
12.9	Other I & C Equipment	$1,604	$0	$3,715	$0	$5,319	$479	$0	$580	$6,378	$10
	Subtotal	**$7,077**	**$801**	**$6,000**	**$0**	**$13,878**	**$1,249**	**$0**	**$1,737**	**$16,864**	**$27**
	13	**Improvements to Site**									
13.1	Site Preparation	$0	$110	$2,335	$0	$2,445	$220	$0	$533	$3,198	$5
13.2	Site Improvements	$0	$1,008	$1,331	$0	$2,339	$210	$0	$510	$3,059	$5
13.3	Site Facilities	$2,057	$0	$2,158	$0	$4,215	$379	$0	$919	$5,514	$9
	Subtotal	**$2,057**	**$1,117**	**$5,824**	**$0**	**$8,999**	**$810**	**$0**	**$1,962**	**$11,770**	**$19**
	14	**Buildings & Structures**									
14.1	Combustion Turbine Area	$0	$303	$160	$0	$463	$42	$0	$76	$581	$1
14.2	Steam Turbine Building	$0	$2,477	$3,295	$0	$5,772	$519	$0	$944	$7,235	$11
14.3	Administration Building	$0	$568	$385	$0	$952	$86	$0	$156	$1,194	$2
14.4	Circulation Water Pumphouse	$0	$190	$94	$0	$283	$26	$0	$46	$355	$1
14.5	Water Treatment Buildings	$0	$419	$382	$0	$801	$72	$0	$131	$1,004	$2
14.6	Machine Shop	$0	$493	$315	$0	$807	$73	$0	$132	$1,012	$2
14.7	Warehouse	$0	$318	$192	$0	$510	$46	$0	$83	$639	$1
14.8	Other Buildings & Structures	$0	$95	$69	$0	$165	$15	$0	$27	$206	$0
14.9	Waste Treating Building & Str.	$0	$373	$665	$0	$1,038	$93	$0	$170	$1,301	$2
	Subtotal	**$0**	**$5,235**	**$5,557**	**$0**	**$10,791**	**$971**	**$0**	**$1,764**	**$13,527**	**$21**
	Total	**$255,176**	**$26,995**	**$71,067**	**$0**	**$353,237**	**$31,791**	**$0**	**$45,902**	**$430,931**	**$685**

Exhibit 4-15 Case B31A owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$3,632	$6
1 Month Maintenance Materials	$522	$1
1 Month Non-fuel Consumables	$242	$0
1 Month Waste Disposal	$0	$0
25% of 1 Months Fuel Cost at 100% CF	$4,679	$7
2% of TPC	$8,619	$14
Total	**$17,695**	**$28**
Inventory Capital		
60 day supply of fuel and consumables at 100% CF	$291	$0
0.5% of TPC (spare parts)	$2,155	$3
Total	**$2,446**	**$4**
Other Costs		
Initial Cost for Catalyst and Chemicals	$0	$0
Land	$300	$0
Other Owner's Costs	$64,640	$103
Financing Costs	$11,635	$18
Total Overnight Costs (TOC)	**$527,646**	**$838**
TASC Multiplier (IOU, low-risk, 33 year)	1.075	
Total As-Spent Cost (TASC)	**$567,219**	**$901**

Exhibit 4-16 Case B31A initial and annual operating and maintenance costs

Case:	B31A – 2x1 CT NGCC w/o CO_2				Cost Base:	Jun 2011
Plant Size (MW,net):	630	Heat Rate-net (Btu/kWh):		6,629	Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):	39.70	**$/hour**		Skilled Operator:		1.0
Operating Labor Burden:	30.00	**% of base**		Operator:		2.0
Labor O-H Charge Rate:	25.00	**% of labor**		Foreman:		1.0
				Lab Tech's, etc.:		1.0
				Total:		**5.0**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$2,260,518	$3.591
Maintenance Labor:					$3,551,114	$5.641
Administrative & Support Labor:					$1,452,908	$2.308
Property Taxes and Insurance:					$8,618,615	$13.691
Total:					**$15,883,155**	**$25.230**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$5,326,671	$1.13636
Consumables						
	Consumption				**Cost ($)**	
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	1,905	$1.67	$0	$989,284	$0.21105
Makeup and Waste Water Treatment Chemicals (lbs):	0	11,348	$0.27	$0	$943,019	$0.20118
SCR Catalyst (m^3):	w/equip.	0.08	$8,938.80	$0	$229,246	$0.04891
Ammonia (19% NH_3, ton):	0	3.05	$330.00	$0	$311,902	$0.06654
Subtotal:				**$0**	**$2,473,451**	**$0.52767**
Variable Operating Costs Total:				**$0**	**$7,800,123**	**$1.66404**
Fuel Cost						
Natural Gas (MMBtu):	0	100,384	$6.13	$0	$190,912,983	$40.72840
Total:				**$0**	**$190,912,983**	**$40.72840**

Exhibit 4-17 Case B31A COE breakdown

Component	Value, $/MWh	Percentage
Capital	11.8	21%
Fixed	3.4	6%
Variable	1.7	3%
Fuel	40.7	71%
Total (Excluding T&S)	**57.6**	**N/A**
CO_2 T&S	0.0	0%
Total (Including T&S)	**57.6**	**N/A**

4.2.7 Case B31B – NGCC with CO_2 Capture

The plant configuration for Case B31B is the same as Case B31A with the exception that the CDR technology was added for CO_2 capture. The nominal net output decreases to 559 MW because the CT designed output is fixed and the CDR facility significantly increases the auxiliary power load. Additionally, the CDR facility's steam requirements reduces the power output of the steam turbine.

The process description for Case B31B is essentially the same as Case B31A with one notable exception, the addition of CO_2 capture. A BFD and stream tables for Case B31B are shown in

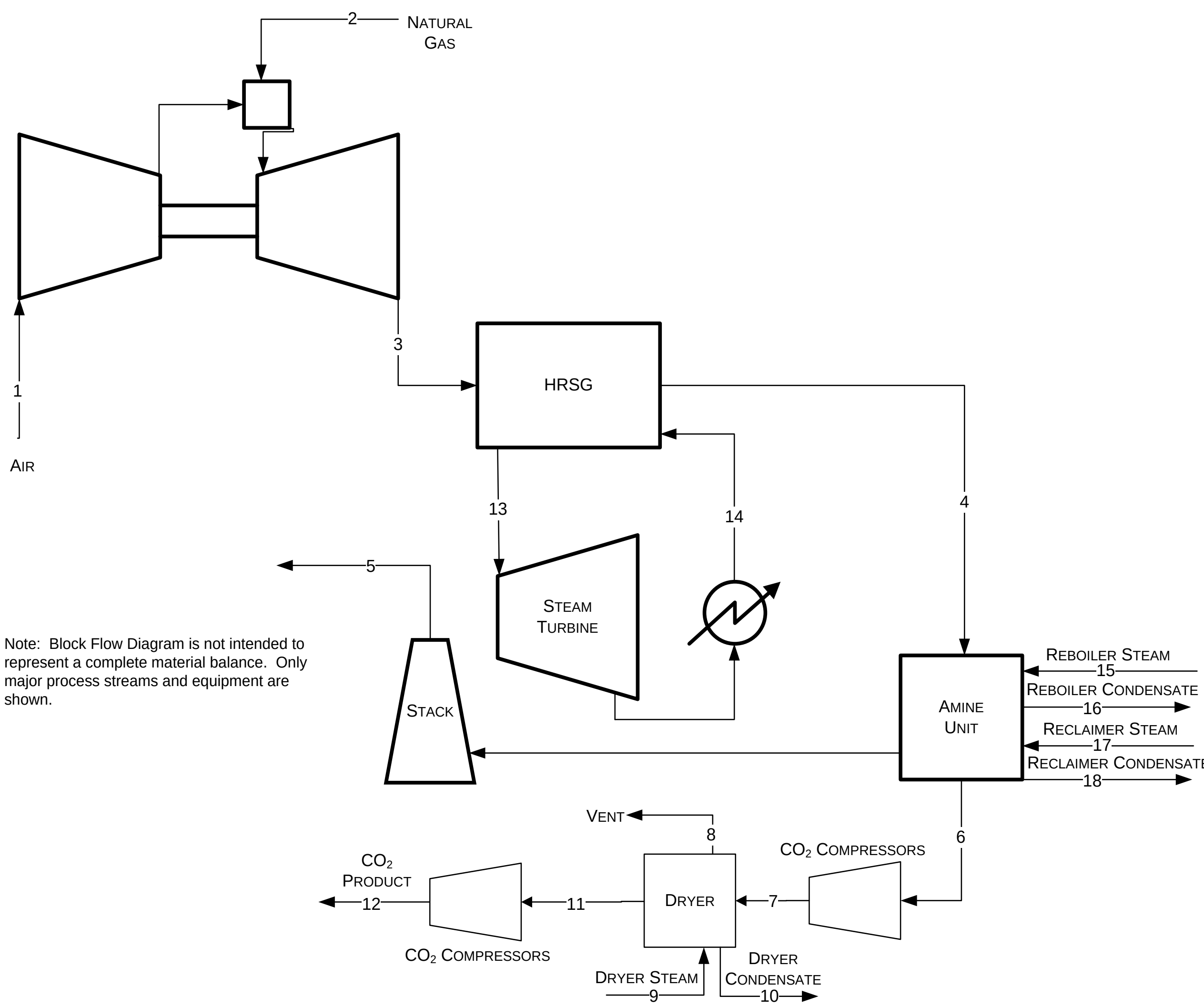
Exhibit 4-18 and Exhibit 4-19, respectively. Since the CDR facility process description was provided in Section 4.1.5, it is not repeated here.

4.2.8 Case B31B Performance Results

The Case B31B modeling assumptions were presented previously in Section 4.2.2.

The plant produces a net output of 559 MW at a net plant efficiency of 45.7 percent (HHV basis). Overall plant performance is summarized in Exhibit 4-20; Exhibit 4-21 provides a detailed breakdown of the auxiliary power requirements. The CDR facility, including CO_2 compression, accounts for over 67 percent of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for nearly 16 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility.

Exhibit 4-18 Case B31B block flow diagram, NGCC with CO_2 capture



Source: NETL

Exhibit 4-19 Case B31B stream table, NGCC with capture

	1	2	3	4	5	6	7	8	9
V-L Mole Fraction									
Ar	0.0092	0.0000	0.0089	0.0089	0.0096	0.0000	0.0000	0.0000	0.0000
CH_4	0.0000	0.9310	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH_4S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_2H_6	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_3H_8	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_4H_{10}	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0003	0.0100	0.0391	0.0391	0.0042	0.9824	0.9977	0.0503	0.0000
H_2O	0.0099	0.0000	0.0841	0.0841	0.0468	0.0176	0.0023	0.9497	1.0000
N_2	0.7732	0.0160	0.7442	0.7442	0.8054	0.0000	0.0000	0.0000	0.0000
O_2	0.2074	0.0000	0.1238	0.1238	0.1340	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mole}/hr)	125,541	4,855	130,538	130,538	120,611	4,673	4,601	8	7
V-L Flowrate (kg/hr)	3,622,750	84,134	3,706,884	3,706,884	3,408,725	203,504	202,217	148	121
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	38	603	117	35	29	29	29	356
Pressure (MPa, abs)	0.10	3.10	0.10	0.10	0.10	0.20	3.03	3.03	4.28
Steam Table Enthalpy (kJ/kg) A	30.22	46.29	800.33	255.91	110.58	42.52	-6.00	137.73	3,100.49
AspenPlus Enthalpy (kJ/kg)B	-97.57	-4,462.93	-616.98	-1,161.40	-449.13	-8,972.02	-8,974.93	-15,221.43	-12,879.81
Density (kg/m^3)	1.2	22.2	0.4	0.9	1.1	3.5	63.3	372.7	16.0
V-L Molecular Weight	28.857	17.328	28.397	28.397	28.262	43.553	43.950	19.322	18.015
V-L Flowrate (lb_{mole}/hr)	276,771	10,704	287,786	287,786	265,902	10,301	10,144	17	15
V-L Flowrate (lb/hr)	7,986,797	185,484	8,172,281	8,172,281	7,514,952	448,649	445,812	327	267
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	100	1,118	242	95	85	85	85	673
Pressure (psia)	14.7	450.0	15.1	14.8	14.7	28.7	439.4	439.4	620.5
Steam Table Enthalpy (Btu/lb)A	13.0	19.9	344.1	110.0	47.5	18.3	-2.6	59.2	1,333.0
AspenPlus Enthalpy (Btu/lb)B	-41.9	-1,918.7	-265.3	-499.3	-193.1	-3,857.3	-3,858.5	-6,544.0	-5,537.3
Density (lb/ft^3)	0.076	1.384	0.025	0.056	0.070	0.216	3.953	23.269	0.998

[A]Steam table reference conditions are 32.02°F & 0.089 psia

[B]Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit 4-19 Case B31B stream table, NGCC with capture (continued)

	10	11	12	13	14	15	16	17	18
V-L Mole Fraction									
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH_4S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_2H_6	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_3H_8	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_4H_{10}	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.9993	0.9993	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	0.0007	0.0007	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mole}/hr)	7	4,593	4,593	24,409	32,641	12,609	12,609	42	42
V-L Flowrate (kg/hr)	121	202,069	202,069	439,734	588,035	227,150	227,150	751	751
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0
Temperature (°C)	203	29	40	566	38	270	151	356	215
Pressure (MPa, abs)	1.64	2.89	15.27	16.65	0.01	0.51	0.49	4.28	2.11
Steam Table Enthalpy (kJ/kg)[A]	863.65	-5.93	-205.61	3,473.89	160.78	3,000.52	635.93	3,100.49	921.30
AspenPlus Enthalpy (kJ/kg)[B]	-15,116.65	-8,970.17	-9,169.86	-12,506.41	-15,819.51	-12,979.77	-15,344.37	-12,879.81	-15,058.99
Density (kg/m³)	861.8	59.9	513.0	47.7	992.8	2.1	916.3	16.0	846.4
V-L Molecular Weight	18.015	43.991	43.991	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mole}/hr)	15	10,127	10,127	53,813	71,961	27,797	27,797	92	92
V-L Flowrate (lb/hr)	267	445,486	445,486	969,448	1,296,395	500,779	500,779	1,656	1,656
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0
Temperature (°F)	397	85	104	1,050	101	517	304	673	419
Pressure (psia)	237.4	419.4	2,214.7	2,414.7	1.0	73.5	70.6	620.5	306.2
Steam Table Enthalpy (Btu/lb)[A]	371.3	-2.5	-88.4	1,493.5	69.1	1,290.0	273.4	1,333.0	396.1
AspenPlus Enthalpy (Btu/lb)[B]	-6,499.0	-3,856.5	-3,942.3	-5,376.8	-6,801.2	-5,580.3	-6,596.9	-5,537.3	-6,474.2
Density (lb/ft³)	53.801	3.737	32.024	2.975	61.977	0.128	57.201	0.998	52.841

[A]Steam table reference conditions are 32.02°F & 0.089 psia

[B]Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

Exhibit 4-20 Case B31B plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	422
Steam Turbine Power, MWe	179
Total Gross Power, MWe	**601**
CO_2 Capture/Removal Auxiliaries, kWe	13,000
CO_2 Compression, kWe	15,010
Balance of Plant, kWe	13,722
Total Auxiliaries, MWe	**42**
Net Power, MWe	**559**
HHV Net Plant Efficiency (%)	45.7%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	7,877 (7,466)
HHV Combustion Turbine Efficiency, %	34.5%
LHV Net Plant Efficiency (%)	50.6%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	7,118 (6,746)
LHV Combustion Turbine Efficiency, %	38.1%
Steam Turbine Cycle Efficiency, %	43.5%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	8,269 (7,838)
Condenser Duty, GJ/hr (MMBtu/hr)	888 (842)
Natural Gas Feed Flow, kg/hr (lb/hr)	84,134 (185,483)
HHV Thermal Input, kWt	1,223,032
LHV Thermal Input, kWt	1,105,162
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.027 (7.2)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.020 (5.4)

Exhibit 4-21 Case B31B plant power summary

Power Summary	
Combustion Turbine Power, MWe	422
Steam Turbine Power, MWe	179
Total Gross Power, MWe	**601**
Auxiliary Load Summary	
Feedwater Pumps, kWe	3,550
SCR, kWe	2
CO_2 Capture/Removal Auxiliaries, kWe	13,000
CO_2 Compression, kWe	15,010
Miscellaneous Balance of Plant[A], kWe	500
Combustion Turbine Auxiliaries, kWe	700
Steam Turbine Auxiliaries, kWe	100
Condensate Pumps, kWe	130
Circulating Water Pumps, kWe	4,310
Ground Water Pumps, kWe	360
Cooling Tower Fans, kWe	2,230
Transformer Losses, kWe	1,840
Total Auxiliaries, MWe	**42**
Net Power, MWe	**559**

[A]Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

4.2.8.1 Environmental Performance

The environmental targets for emissions of NOx, SO_2, and PM were presented in Section 2.4. A summary of the plant air emissions for Case B31B is presented in Exhibit 4-22.

Exhibit 4-22 Case B31B air emissions

	kg/GJ (lb/MMBtu)	Tonne/year (ton/year)[A]	kg/MWh (lb/MWh)
SO_2	0.000 (0.000)	0 (0)	0.000 (0.000)
NOx	0.001 (0.003)	44 (49)	0.010 (0.022)
Particulate	0.000 (0.000)	0 (0)	0.000 (0.000)
Hg	0.00E+0 (0.00E+0)	0.000 (0.000)	0.00E+0 (0.00E+0)
CO_2[B]	5 (12)	167,143 (184,244)	37 (82)
CO_2[C]	-	-	40 (89)

[A]Calculations based on an 85 percent capacity factor
[B]CO_2 emissions based on gross power
[C]CO_2 emissions based on net power instead of gross power

For the purpose of this report, the natural gas was assumed to contain the average value of total sulfur of 0.34 gr/100 scf (4.71×10^{-4} lb-S/MMBtu). (11) It was also assumed that the added mercaptan (CH_4S) was the sole contributor of sulfur to the natural gas. No sulfur capture systems were required.

The NGCC cases were designed to achieve approximately 1.0 ppmvd NOx emissions (at 15 percent O_2) through the use of a DLN burner in the CTG – the DLN burners reduce the emissions to about 9 ppmvd (at 15 percent O_2) (18) – and an SCR – the SCR system is designed for 90 percent NO reduction (19).

The pipeline natural gas was assumed to contain no particulate matter (PM), Hg, or HCl, resulting in zero emissions.

CO_2 emissions are reduced relative to those produced by burning coal given the same power output because of the higher heat content of natural gas, the lower carbon intensity of gas relative to coal, and the higher overall efficiency of the NGCC plant relative to a coal-fired plant.

Ninety percent of the CO_2 in the flue gas is removed in CDR facility.

The carbon balance for the plant is shown in Exhibit 4-23. The carbon input to the plant consists of carbon in the natural gas in addition to carbon in the CT air. Carbon leaves the plant as CO_2 in the stack gas, the CO_2 dryer's vent, and the captured CO_2 product. The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in, represented by the following fraction:

$$\frac{Carbon\ in\ Stack}{(Total\ Carbon\ In)} = \left(1 - \left(\frac{13{,}506}{135{,}061}\right)\right) * 100 = 90.0\%$$

Exhibit 4-23 Case B31B carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	60,768 (133,971)	Stack Gas	6,126 (13,506)
Air (CO_2)	494 (1,090)	CO_2 Product	55,131 (121,544)
		CO_2 KO	0 (0)
		CO_2 Dryer Vent	5 (10)
Total	**61,262 (135,061)**	**Total**	**61,262 (135,061)**

As shown in Exhibit 4-24, the sulfur content of the natural gas is insignificant, comprised entirely of mercaptan (CH_4S) (used as an odorant). (11) All sulfur in the natural gas is removed in the polishing scrubber of the CDR system.

Exhibit 4-24 Case B31B sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	1 (2)	Stack Gas	0 (0)
		Polishing Scrubber/HSS	1 (2)
Total	**1 (2)**	**Total**	**1 (2)**

Exhibit 4-25 shows the overall water balance for the plant.

Exhibit 4-25 Case B31B water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)
CO_2 Drying	–	–	–	0.00 (1)	0.00 (-1)
Capture System Makeup	0.02 (6)	–	0.02 (6)	–	0.02 (6)
Condenser Makeup	**0.10 (26)**	**–**	**0.10 (26)**	**–**	**0.10 (26)**
BFW Makeup	0.10 (26)	–	0.10 (26)	–	0.10 (26)
Cooling Tower	**16.81 (4,440)**	**1.70 (449)**	**15.11 (3,991)**	**3.78 (998)**	**11.33 (2,992)**
CO_2 Capture Recovery	–	1.58 (417)	-1.58 (-417)	–	–
CO_2 Compression Recovery	–	0.02 (6)	-0.02 (-6)	–	-0.02 (-6)
BFW Blowdown	–	0.10 (26)	-0.10 (-26)	–	–
Total	**16.93 (4,472)**	**1.70 (449)**	**15.23 (4,023)**	**3.78 (999)**	**11.45 (3,024)**

4.2.8.2 Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the NGCC in Exhibit 4-26. An overall plant energy balance is provided in tabular form in Exhibit 4-27.

The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-20) is calculated by multiplying the power out by a combined generator efficiency of 98.5 percent. The capture process heat out stream represents heat rejected to cooling water and ultimately to ambient via the cooling tower. The same is true of the condenser heat out stream. The CO_2 compressor intercooler load is included in the capture process heat out stream.

Exhibit 4-26 Case B31B heat and mass balance, NGCC with CO_2 capture

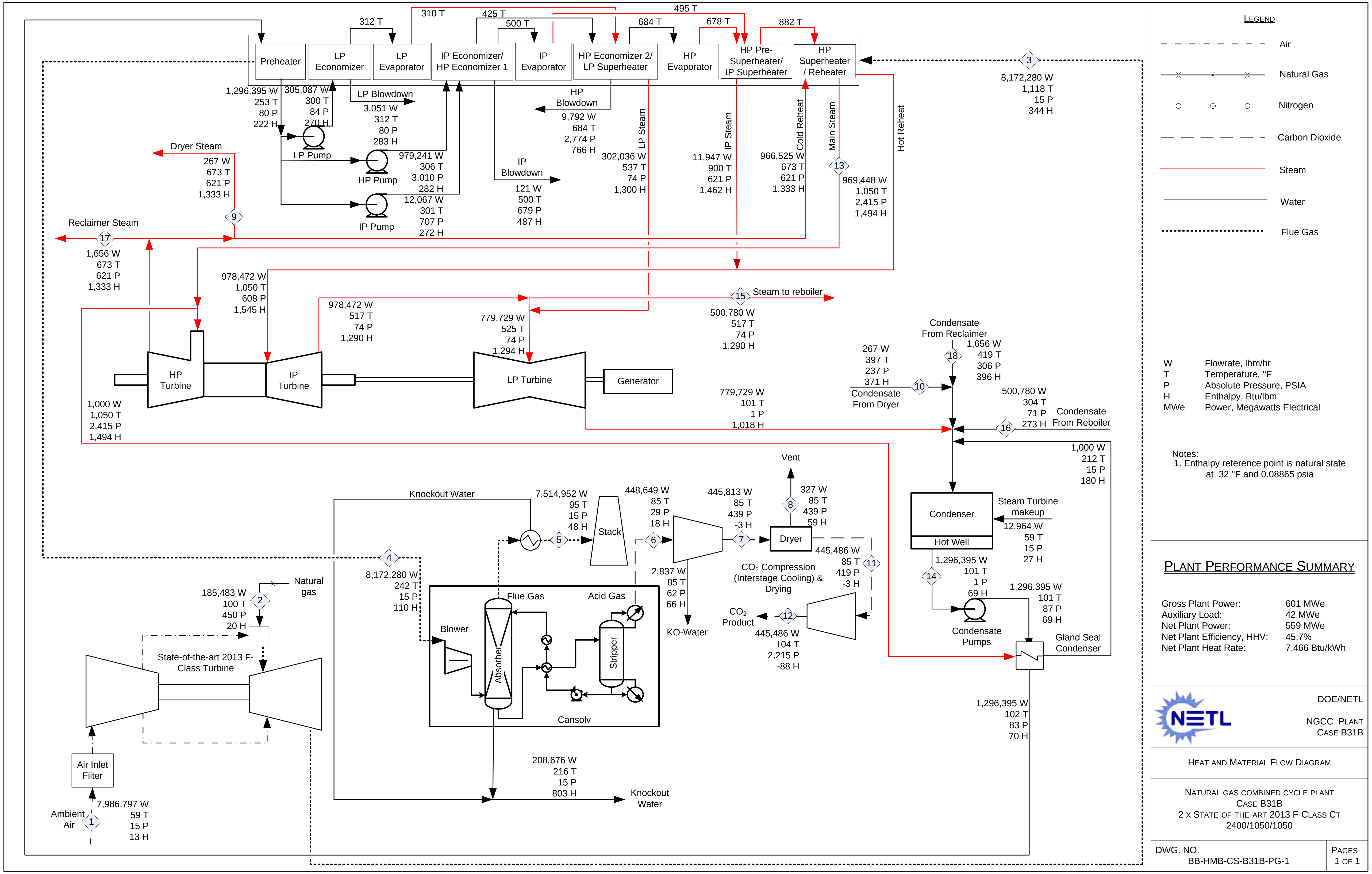


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Exhibit 4-27 Case B31B overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Natural Gas	4,403 (4,173)	2.9 (2.8)	–	4,406 (4,176)
Air	–	109.5 (103.8)	–	109.5 (103.8)
Raw Water Makeup	–	57.3 (54.3)	–	57.3 (54.3)
Auxiliary Power	–	–	150 (142)	150 (142)
TOTAL	**4,403 (4,173)**	**169.7 (160.8)**	**150 (142)**	**4,723 (4,476)**
Heat Out GJ/hr (MMBtu/hr)				
Stack Gas	–	377 (357)	–	377 (357)
Sulfur	0 (0)	0.0 (0.0)	–	0.0 (0.0)
Motor Losses and Design Allowances	–	–	42 (40)	42 (40)
Condenser	–	888 (842)	–	888 (842)
Non-Condenser Cooling Tower Loads	–	26 (25)	–	26 (25)
CO_2	–	-41.5 (-39.4)	–	-41.5 (-39.4)
Cooling Tower Blowdown	–	28.1 (26.6)	–	28.1 (26.6)
CO_2 Capture Losses	–	1,280 (1,213)	–	1,280 (1,213)
Ambient Losses[A]	–	*37.4 (35.5)*	–	*37.4 (35.5)*
Power	–	–	2,163 (2,050)	2,163 (2,050)
TOTAL	**0 (0)**	**2,595 (2,460)**	**2,205 (2,090)**	**4,800 (4,550)**
Unaccounted Energy[B]	–	-77 (-73)	–	-77 (-73)

[A]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers.
[B]By difference

4.2.9 Case B31B Major Equipment List

Major equipment items for the NGCC plant with CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.2.10. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

Case B31B – Account 2: Fuel and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	70 m^3/min @ 3.1 MPa (2,456 acfm @ 450 psia) 39 cm (16 in) standard wall pipe	16 km (10 mi)	0
2	Gas Metering Station	--	70 m^3/min (2,456 acfm)	1	0

Case B31B – Account 3: Feedwater and Miscellaneous Systems and Equipment

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	776,000 liters (205,000 gal)	2	0
2	Condensate Pumps	Vertical canned	5,430 lpm @ 70 m H_2O (1,430 gpm @ 240 ft H_2O)	2	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP water: 4,100 lpm @ 2,500 m H_2O (1,080 gpm @ 8,210 ft H_2O) IP water: 050 lpm @ 540 m H_2O (10 gpm @ 1,790 ft H_2O) LP water: 1,280 lpm @ 14.0 m H_2O (340 gpm @ 50 ft H_2O)	2	1
4	Auxiliary Boiler	Shop fabricated, water tube	18,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
5	Service Air Compressors	Flooded Screw	13 m^3/min @ 0.7 MPa (450 scfm @ 100 psig)	2	1
6	Instrument Air Dryers	Duplex, regenerative	13 m^3/min (450 scfm)	2	1
7	Closed Cycle Cooling Heat Exchangers	Plate and frame	13 MMkJ/hr (13 MMBtu/hr)	2	0
8	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	5,200 lpm @ 20 m H_2O (1,400 gpm @ 70 ft H_2O)	2	1
9	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 110 m H_2O (1,000 gpm @ 350 ft H_2O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 80 m H_2O (700 gpm @ 250 ft H_2O)	1	1
11	Raw Water Pumps	Stainless steel, single suction	8,500 lpm @ 20 m H_2O (2,200 gpm @ 60 ft H_2O)	2	1
12	Filtered Water Pumps	Stainless steel, single suction	170 lpm @ 50 m H_2O (50 gpm @ 160 ft H_2O)	2	1
13	Filtered Water Tank	Vertical, cylindrical	164,000 liter (43,000 gal)	1	0
14	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	360 lpm (100 gpm)	1	0
15	Liquid Waste Treatment System	N/A	10 years, 24-hour storm	1	0

Case B31B – Account 5B: Carbon Dioxide Recovery

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Cansolv	Amine-based CO_2 capture technology	4,078,000 kg/hr (8,990,000 lb/hr) 6.1 wt % CO_2 concentration	1	0
2	Cansolv LP Condensate Pump	Centrifugal	492 lpm @ 1 m H_2O (130 gpm @ 4 ft H_2O)	1	1
3	Cansolv HP Condensate Pump	Centrifugal	2 lpm @ 5 m H_2O (1 gpm @ 15 ft H_2O)	1	1
4	CO_2 Dryer	Triethylene glycol	Inlet: 53.0 m^3/min (1,880 acfm) @ 3.0 MPa (439 psia) Outlet: 2.9 MPa (419 psia) Water Recovered: 148 kg/hr (327 lb/hr)	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
5	CO_2 Compressor	Integrally geared, multi-stage centrifugal	111,105 kg/hr @ 15.3 MPa (244,944 lb/hr @ 2,215 psia)	2	0

Case B31B – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	State-of-the-art 2013 F-class w/ dry low-NOx burner	210 MW	2	0
2	Combustion Turbine Generator	TEWAC	230 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

Case B31B – Account 7: HRSG, Ducting, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	46 m (150 ft) high x 7.0 m (23 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 241,854 kg/hr, 16.5 MPa/566°C (533,197 lb/hr, 2,400 psig/1,050°F) Reheat steam - 244,105 kg/hr, 4.1 MPa/566°C (538,160 lb/hr, 593 psig/1,050°F)	2	0
3	SCR Reactor	Space for spare layer	1,870,000 kg/hr (4,130,000 lb/hr)	2	0
4	SCR Catalyst	--	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	10 m^3/min @ 108 cm WG (190 scfm @ 42 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	1.2 lpm @ 90 m H_2O (0.3 gpm @ 300 ft H_2O)	2	1
7	Ammonia Storage Tank	Horizontal tank	33,000 liter (9,000 gal)	1	0

Case B31B – Account 8: Steam Turbine Generator and Auxiliaries

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	189 MW 16.5 MPa/566°C/566°C (2400 psig/ 1050°F/1050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	210 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	980 GJ/hr (930 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0
4	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0

Case B31B – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	433,000 lpm @ 30 m (114,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 2410 GJ/hr (2290 MMBtu/hr) heat duty	1	0

Case B31B – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 230 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 180 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 8 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 28 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 4 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B31B – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1	0

4.2.10 Case B31B – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 4-28 shows a detailed breakdown of the capital costs; Exhibit 4-29 shows the owner's costs, TOC, and TASC; Exhibit 4-30 shows the initial and annual O&M costs; and Exhibit 4-31 shows the COE breakdown.

The estimated TPC of the NGCC with CO_2 capture is $1,481/kW. Process contingency represents 5.0 percent of the TPC and project contingency represents 13.0 percent. The COE, including CO_2 T&S costs of $4.0/MWh, is $87.3/MWh.

Exhibit 4-28 Case B31B total plant cost details

	Case:	B31B – 2x1 CT NGCC w/ CO_2							Estimate Type:	Conceptual	
	Plant Size (MW,net):	559							Cost Base:	Jun 2011	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost	
				Direct	Indirect			Process	Project	$/1,000	$/kW
	3	Feedwater & Miscellaneous BOP Systems									
3.1	Feedwater System	$3,216	$3,330	$2,720	$0	$9,266	$834	$0	$1,515	$11,615	$21
3.2	Water Makeup & Pretreating	$2,587	$267	$1,328	$0	$4,182	$376	$0	$912	$5,470	$10
3.3	Other Feedwater Subsystems	$1,507	$498	$416	$0	$2,421	$218	$0	$396	$3,034	$5
3.4	Service Water Systems	$312	$623	$2,007	$0	$2,942	$265	$0	$641	$3,849	$7
3.5	Other Boiler Plant Systems	$2,105	$786	$1,809	$0	$4,700	$423	$0	$768	$5,892	$11
3.6	Natural Gas, incl. pipeline	$17,693	$631	$546	$0	$18,871	$1,698	$0	$3,085	$23,655	$42
3.7	Waste Treatment Equipment	$904	$0	$523	$0	$1,427	$128	$0	$311	$1,866	$3
3.8	Misc. Equip. (Cranes, Air Comp., Comm.)	$1,206	$161	$586	$0	$1,953	$176	$0	$426	$2,555	$5
	Subtotal	**$29,530**	**$6,297**	**$9,935**	**$0**	**$45,762**	**$4,119**	**$0**	**$8,055**	**$57,936**	**$104**
	5B	CO_2 Removal & Compression									
5B.1	CO_2 Removal System	$99,453	$41,537	$86,184	$0	$227,175	$18,462	$41,028	$52,926	$339,591	$608
5B.2	CO_2 Compression & Drying	$18,852	$2,828	$7,821	$0	$29,501	$2,655	$0	$6,431	$38,587	$69
	Subtotal	**$118,305**	**$44,365**	**$94,006**	**$0**	**$256,676**	**$21,118**	**$41,028**	**$59,357**	**$378,178**	**$677**
	6	Combustion Turbine & Accessories									
6.1	Combustion Turbine Generator	$104,200	$0	$6,341	$0	$110,541	$9,949	$0	$12,049	$132,539	$237
6.9	Combustion Turbine Foundations	$0	$879	$950	$0	$1,829	$165	$0	$399	$2,392	$4
	Subtotal	**$104,200**	**$879**	**$7,291**	**$0**	**$112,370**	**$10,113**	**$0**	**$12,448**	**$134,931**	**$241**
	7	HRSG, Ducting, & Stack									
7.1	Heat Recovery Steam Generator	$31,120	$0	$5,773	$0	$36,893	$3,320	$0	$4,021	$44,235	$79
7.2	SCR System	$1,973	$829	$1,156	$0	$3,957	$356	$0	$647	$4,960	$9
7.9	HRSG, Duct & Stack Foundations	$0	$442	$415	$0	$857	$77	$0	$187	$1,121	$2
	Subtotal	**$33,093**	**$1,271**	**$7,344**	**$0**	**$41,707**	**$3,754**	**$0**	**$4,855**	**$50,316**	**$90**
	8	Steam Turbine Generator									
8.1	Steam TG & Accessories	$32,860	$0	$4,812	$0	$37,672	$3,390	$0	$4,106	$45,168	$81
8.2	Turbine Plant Auxiliaries	$195	$0	$434	$0	$629	$57	$0	$69	$754	$1
8.3	Condenser & Auxiliaries	$2,260	$0	$1,210	$0	$3,470	$312	$0	$378	$4,160	$7
8.4	Steam Piping	$12,240	$0	$4,961	$0	$17,201	$1,548	$0	$2,812	$21,561	$39
8.9	TG Foundations	$0	$836	$1,380	$0	$2,216	$199	$0	$483	$2,899	$5
	Subtotal	**$47,555**	**$836**	**$12,796**	**$0**	**$61,188**	**$5,507**	**$0**	**$7,848**	**$74,543**	**$133**
	9	Cooling Water System									
9.1	Cooling Towers	$4,260	$0	$1,290	$0	$5,550	$500	$0	$605	$6,654	$12
9.2	Circulating Water Pumps	$2,038	$0	$125	$0	$2,163	$195	$0	$236	$2,593	$5
9.3	Circ. Water System Auxiliaries	$162	$0	$21	$0	$184	$17	$0	$20	$220	$0
9.4	Circ. Water Piping	$0	$5,032	$1,139	$0	$6,171	$555	$0	$1,009	$7,735	$14
9.5	Make-up Water System	$389	$0	$500	$0	$889	$80	$0	$145	$1,115	$2
9.6	Component Cooling Water Sys	$324	$387	$248	$0	$959	$86	$0	$157	$1,202	$2
9.9	Circ. Water System Foundations	$0	$2,294	$3,809	$0	$6,103	$549	$0	$1,330	$7,982	$14
	Subtotal	**$7,173**	**$7,712**	**$7,133**	**$0**	**$22,018**	**$1,982**	**$0**	**$3,502**	**$27,502**	**$49**

Case:		B31B – 2x1 CT NGCC w/ CO_2					Estimate Type:			Conceptual	
Plant Size (MW,net):		559					Cost Base:			Jun 2011	
Item No.	Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Total Plant Cost $/1,000	Total Plant Cost $/kW
	11	Accessory Electric Plant									
11.1	Generator Equipment	$7,182	$0	$4,248	$0	$11,430	$1,029	$0	$934	$13,393	$24
11.2	Station Service Equipment	$2,478	$0	$213	$0	$2,690	$242	$0	$220	$3,153	$6
11.3	Switchgear & Motor Control	$3,049	$0	$530	$0	$3,578	$322	$0	$390	$4,290	$8
11.4	Conduit & Cable Tray	$0	$1,593	$4,590	$0	$6,183	$556	$0	$1,011	$7,750	$14
11.5	Wire & Cable	$0	$5,120	$2,911	$0	$8,031	$723	$0	$1,313	$10,067	$18
11.6	Protective Equipment	$0	$713	$2,474	$0	$3,187	$287	$0	$347	$3,821	$7
11.7	Standby Equipment	$125	$0	$116	$0	$241	$22	$0	$26	$288	$1
11.8	Main Power Transformers	$13,433	$0	$182	$0	$13,615	$1,225	$0	$1,484	$16,324	$29
11.9	Electrical Foundations	$0	$157	$399	$0	$556	$50	$0	$121	$727	$1
	Subtotal	**$26,265**	**$7,583**	**$15,662**	**$0**	**$49,510**	**$4,456**	**$0**	**$5,847**	**$59,813**	**$107**
	12	Instrumentation & Control									
12.4	Other Major Component Control	$998	$0	$636	$0	$1,634	$147	$82	$279	$2,142	$4
12.6	Control Boards, Panels & Racks	$298	$0	$182	$0	$481	$43	$24	$82	$630	$1
12.7	Computer & Accessories	$4,775	$0	$146	$0	$4,921	$443	$246	$561	$6,170	$11
12.8	Instrument Wiring & Tubing	$0	$888	$1,572	$0	$2,460	$221	$123	$421	$3,225	$6
12.9	Other I & C Equipment	$1,780	$0	$4,121	$0	$5,901	$531	$295	$673	$7,400	$13
	Subtotal	**$7,851**	**$888**	**$6,657**	**$0**	**$15,396**	**$1,386**	**$770**	**$2,016**	**$19,568**	**$35**
	13	Improvements to Site									
13.1	Site Preparation	$0	$112	$2,378	$0	$2,490	$224	$0	$543	$3,257	$6
13.2	Site Improvements	$0	$1,026	$1,356	$0	$2,382	$214	$0	$519	$3,115	$6
13.3	Site Facilities	$2,095	$0	$2,198	$0	$4,293	$386	$0	$936	$5,615	$10
	Subtotal	**$2,095**	**$1,138**	**$5,931**	**$0**	**$9,164**	**$825**	**$0**	**$1,998**	**$11,987**	**$21**
	14	Buildings & Structures									
14.1	Combustion Turbine Area	$0	$303	$160	$0	$463	$42	$0	$76	$581	$1
14.2	Steam Turbine Building	$0	$2,195	$2,921	$0	$5,116	$460	$0	$836	$6,412	$11
14.3	Administration Building	$0	$584	$395	$0	$979	$88	$0	$160	$1,227	$2
14.4	Circulation Water Pumphouse	$0	$186	$92	$0	$277	$25	$0	$45	$348	$1
14.5	Water Treatment Buildings	$0	$549	$500	$0	$1,049	$94	$0	$172	$1,315	$2
14.6	Machine Shop	$0	$506	$324	$0	$830	$75	$0	$136	$1,040	$2
14.7	Warehouse	$0	$327	$197	$0	$524	$47	$0	$86	$657	$1
14.8	Other Buildings & Structures	$0	$98	$71	$0	$169	$15	$0	$28	$212	$0
14.9	Waste Treating Building & Str.	$0	$383	$684	$0	$1,067	$96	$0	$174	$1,337	$2
	Subtotal	**$0**	**$5,131**	**$5,344**	**$0**	**$10,475**	**$943**	**$0**	**$1,713**	**$13,130**	**$23**
	Total	**$376,068**	**$76,100**	**$172,100**	**$0**	**$624,267**	**$54,201**	**$41,798**	**$107,639**	**$827,904**	**$1,481**

Exhibit 4-29 Case B31B owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$5,405	$10
1 Month Maintenance Materials	$851	$2
1 Month Non-fuel Consumables	$767	$1
1 Month Waste Disposal	$0	$0
25% of 1 Months Fuel Cost at 100% CF	$4,679	$8
2% of TPC	$16,558	$30
Total	**$28,260**	**$51**
Inventory Capital		
60 day supply of fuel and consumables at 100% CF	$1,239	$2
0.5% of TPC (spare parts)	$4,140	$7
Total	**$5,378**	**$10**
Other Costs		
Initial Cost for Catalyst and Chemicals	$0	$0
Land	$300	$1
Other Owner's Costs	$124,186	$222
Financing Costs	$22,353	$40
Total Overnight Costs (TOC)	**$1,008,381**	**$1,804**
TASC Multiplier (IOU, high-risk, 33 year)	1.078	
Total As-Spent Cost (TASC)	**$1,087,034**	**$1,945**

Exhibit 4-30 Case B31B initial and annual operating and maintenance costs

Case:	**B31B – 2x1 CT NGCC w/ CO_2**				**Cost Base:**	**Jun 2011**
Plant Size (MW,net):	**559**	**Heat Rate-net (Btu/kWh):**		**7,466**	**Capacity Factor (%):**	**85**
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):	39.70		**$/hour**	Skilled Operator:		1.0
Operating Labor Burden:	30.00		**% of base**	Operator:		3.3
Labor O-H Charge Rate:	25.00		**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		1.0
				Total:		**6.3**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$2,861,816	$5.120
Maintenance Labor:					$5,785,827	$10.351
Administrative & Support Labor:					$2,161,911	$3.868
Property Taxes and Insurance:					$16,558,081	$29.623
Total:					**$27,367,635**	**$48.961**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$8,678,741	$2.08520
Consumables						
	Consumption				**Cost ($)**	
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	2,897	$1.67	$0	$1,504,337	$0.36144
Makeup and Waste Water Treatment Chemicals (lbs):	0	17,257	$0.27	$0	$1,433,984	$0.34454
CO_2 Capture System Chemicals[A]		Proprietary				
SCR Catalyst (m^3):	w/equip.	0.08	$8,938.80	$0	$229,246	$0.05508
Triethylene Glycol (gal)	0	165	$6.57	$0	$337,099	$0.08099
Ammonia (19% NH_3, ton):	0	3.05	$330.00	$0	$311,902	$0.07494
Subtotal:				**$0**	**$7,820,762**	**$1.87905**
Waste Disposal						
Amine Purification Unit Waste (ton)	0	4.01	$0.00	$0	$0	$0.00000
Thermal Reclaimer Unit Waste (ton)	0	0.37	$0.00	$0	$0	$0.00000
Prescrubber Blowdown Waste (ton)	0	0.00	$0.00	$0	$0	$0.00000
Subtotal:				**$0**	**$0**	**$0.00000**
Variable Operating Costs Total:				**$0**	**$16,499,502**	**$3.96425**
Fuel Cost						
Natural Gas (MMBtu):	0	100,384	$6.13	$0	$190,912,983	$45.86966
Total:				**$0**	**$190,912,983**	**$45.86966**

[A] CO_2 Capture System Chemicals includes Ion Exchange Resin, NaOH, and Cansolv Solvent.

Exhibit 4-31 Case B31B COE breakdown

Component	Value, $/MWh	Percentage
Capital	26.9	31%
Fixed	6.6	8%
Variable	4.0	5%
Fuel	45.9	53%
Total (Excluding T&S)	**83.3**	**N/A**
CO_2 T&S	4.0	5%
Total (Including T&S)	**87.3**	**N/A**

4.3 NGCC Case Summary

The performance results of the two NGCC plant configurations modeled in this report are summarized in Exhibit 4-32.

Exhibit 4-32 Estimated performance and cost results for NGCC cases

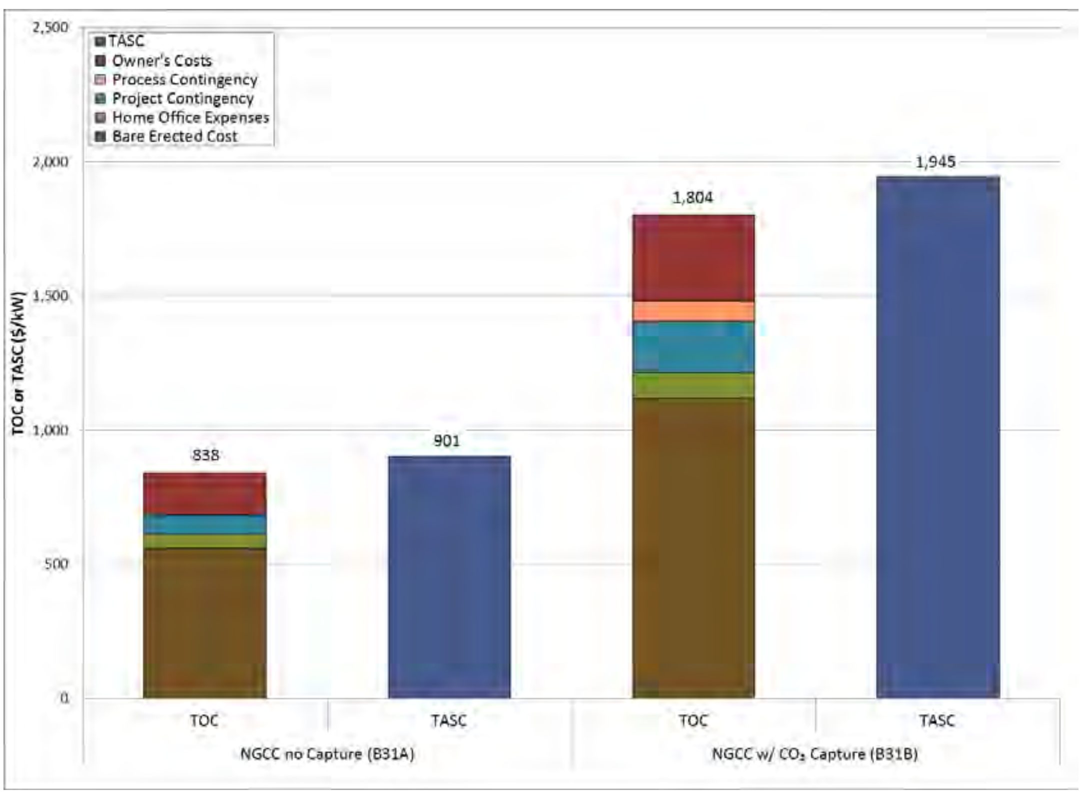
	NGCC	
	State-of-the-art 2013 F-Class	
	Case B31A	Case B31B
PERFORMANCE		
Nominal CO_2 Capture	0%	90%
Capacity Factor	85%	85%
Gross Power Output (MWe)	641	601
Auxiliary Power Requirement (MWe)	11	42
Net Power Output (MWe)	630	559
Coal Flow rate (lb/hr)	N/A	N/A
Natural Gas Flow rate (lb/hr)	185,484	185,484
HHV Thermal Input (kW_t)	1,223,032	1,223,032
Net Plant HHV Efficiency (%)	51.5%	45.7%
Net Plant HHV Heat Rate (Btu/kWh)	6,629	7,466
Raw Water Withdrawal, gpm	2,646	4,023
Process Water Discharge, gpm	595	999
Raw Water Consumption, gpm	2,051	3,024
CO_2 Emissions (lb/MMBtu)	119	12
CO_2 Emissions (lb/MWh-gross)	773	82
CO_2 Emissions (lb/MWh-net)	786	89
SO_2 Emissions (lb/MMBtu)	0.001	0.000
SO_2 Emissions (lb/MWh-gross)	0.006	0.000
NOx Emissions (lb/MMBtu)	0.003	0.003
NOx Emissions (lb/MWh-gross)	0.020	0.022
PM Emissions (lb/MMBtu)	0.000	0.000
PM Emissions (lb/MWh-gross)	0.000	0.000
Hg Emissions (lb/TBtu)	0.000	0.000
Hg Emissions (lb/MWh-gross)	0.00E-06	0.00E-06
COST		
Total Plant Cost (2011$/kW)	685	1,481
Bare Erected Cost	561	1,117
Home Office Expenses	51	97
Project Contingency	73	193
Process Contingency	0	75
Total Overnight Cost (2011$/MM)	528	1,008
Total Overnight Cost (2011$/kW)	838	1,804
Owner's Costs	154	323
Total As-Spent Cost (2011$/kW)	901	1,945
COE ($/MWh) (excluding T&S)	57.6	83.3
Capital Costs	11.8	26.9
Fixed Costs	3.4	6.6
Variable Costs	1.7	4.0
Fuel Costs	40.7	45.9
COE ($/MWh) (including T&S)	57.6	87.3
CO_2 T&S Costs	0.0	4.0

The following observations can be made regarding plant performance with reference to Exhibit 4-32:

- The efficiency of the NGCC case with no CO_2 capture is 51.5 percent (HHV basis). Gas Turbine World provides estimated performance for a state-of-the-art 2013 F-class turbine operated on natural gas in a combined cycle mode, and the reported efficiency is 58.0 percent (LHV basis). (44) Adjusting the result from this report to an LHV basis results in an efficiency of 57.0 percent.
- The efficiency penalty to add CO_2 capture in the NGCC case is 5.8 absolute percent. The efficiency reduction is caused primarily by the auxiliary loads of the capture system and CO_2 compression as well as the significantly increased cooling water requirement, which increases the auxiliary load of the CWPs and the cooling tower fan. CO_2 capture results in a 31 MW increase in auxiliary load compared to the non-capture case.

The components of TOC and overall TASC are shown for the two NGCC cases in Exhibit 4-33. The addition of CO_2 capture more than doubles the TOC cost of the NGCC plant. The process contingency included for the capture process totals $75/kW, which represents approximately 4 percent of the TOC.

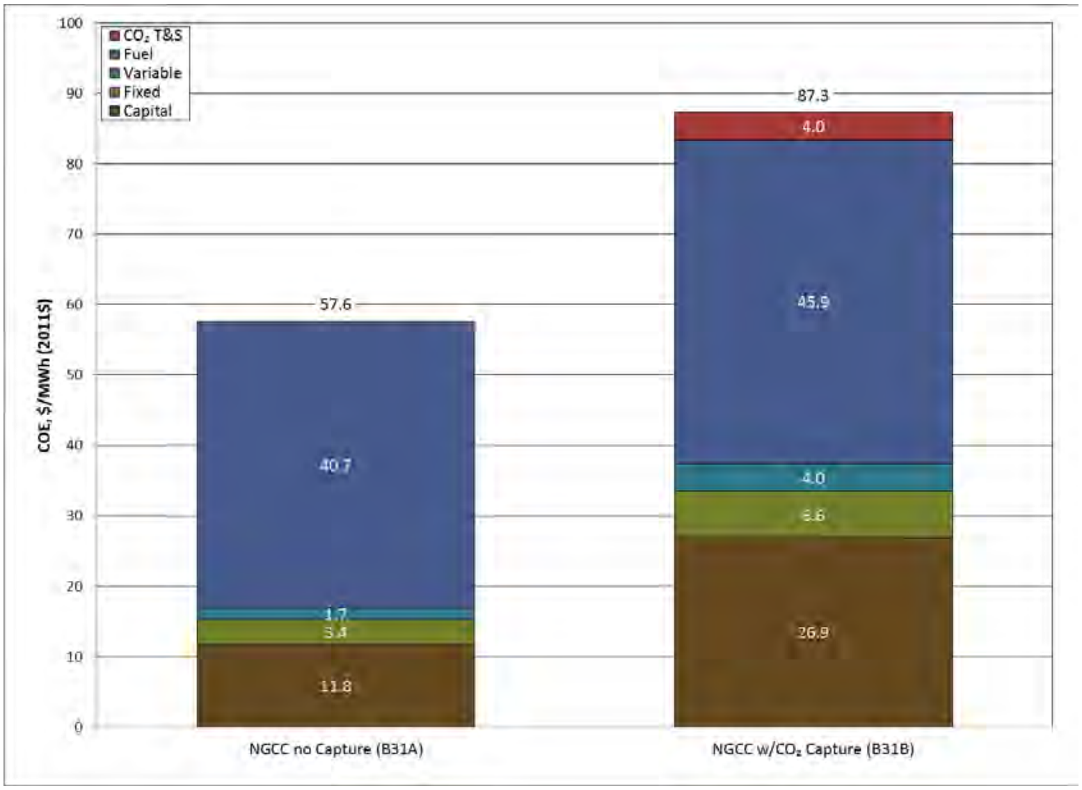
Exhibit 4-33 Plant capital cost for NGCC cases



Source: NETL

Exhibit 4-34 shows that at the study natural gas price, the fuel represents a significant fraction of the total. The fuel component of COE represents 71 percent of the total in the non-capture case and 53 percent of the total in the CO_2 capture case. The CO_2 T&S component of COE is only 5 percent of the total in the CO_2 capture case.

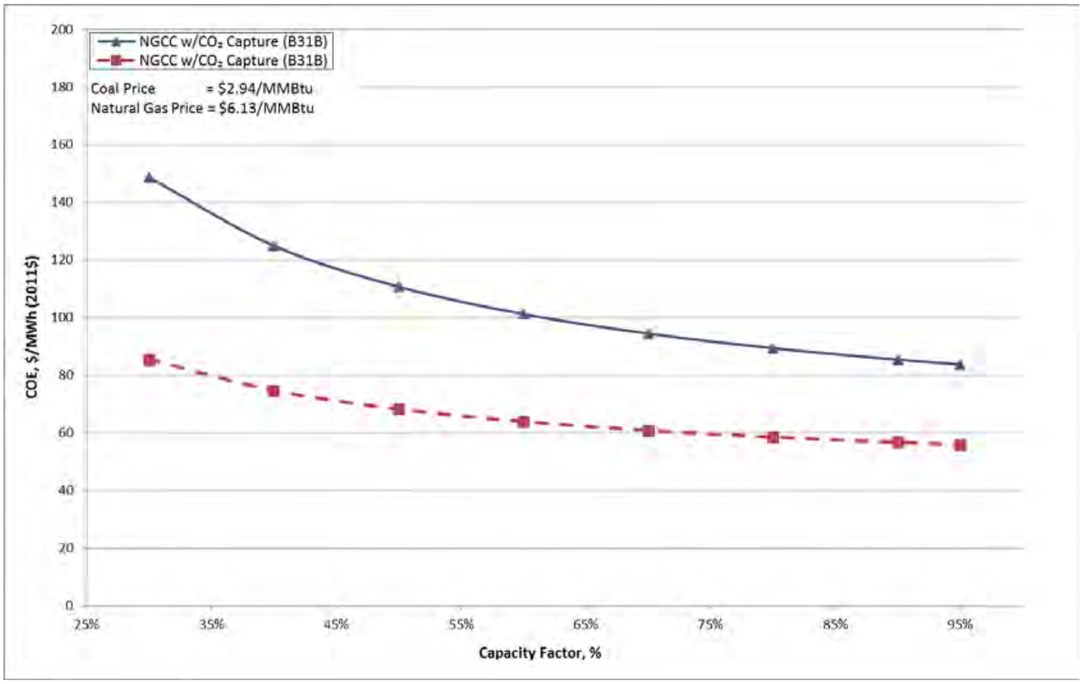
Exhibit 4-34 COE of NGCC cases



Source: NETL

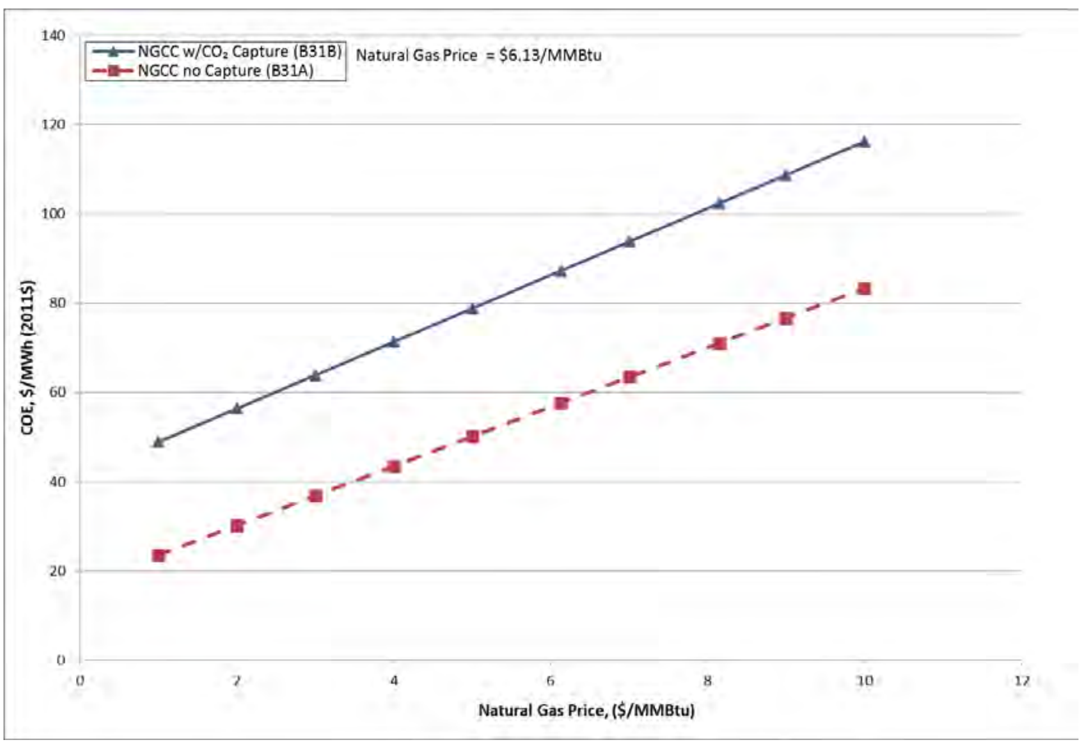
The sensitivity of NGCC COE to CF is shown in Exhibit 4-35. NGCC is relatively insensitive to CF but highly sensitive to fuel cost (as shown in Exhibit 4-36) because of the relatively small capital component. As the capacity factor drops, the decrease in net production is nearly offset by a corresponding decrease in fuel cost. A 33 percent increase in natural gas price (from $6.13 to $8.15/MMBtu) results in a COE increase of 23 percent in the non-capture case and 17 percent in the CO_2 capture case. Because of the higher capital cost in the CO_2 capture case, the impact of fuel price changes is slightly diminished.

Exhibit 4-35 Sensitivity of COE to capacity factor in NGCC cases



Source: NETL

Exhibit 4-36 Sensitivity of COE to fuel price in NGCC cases

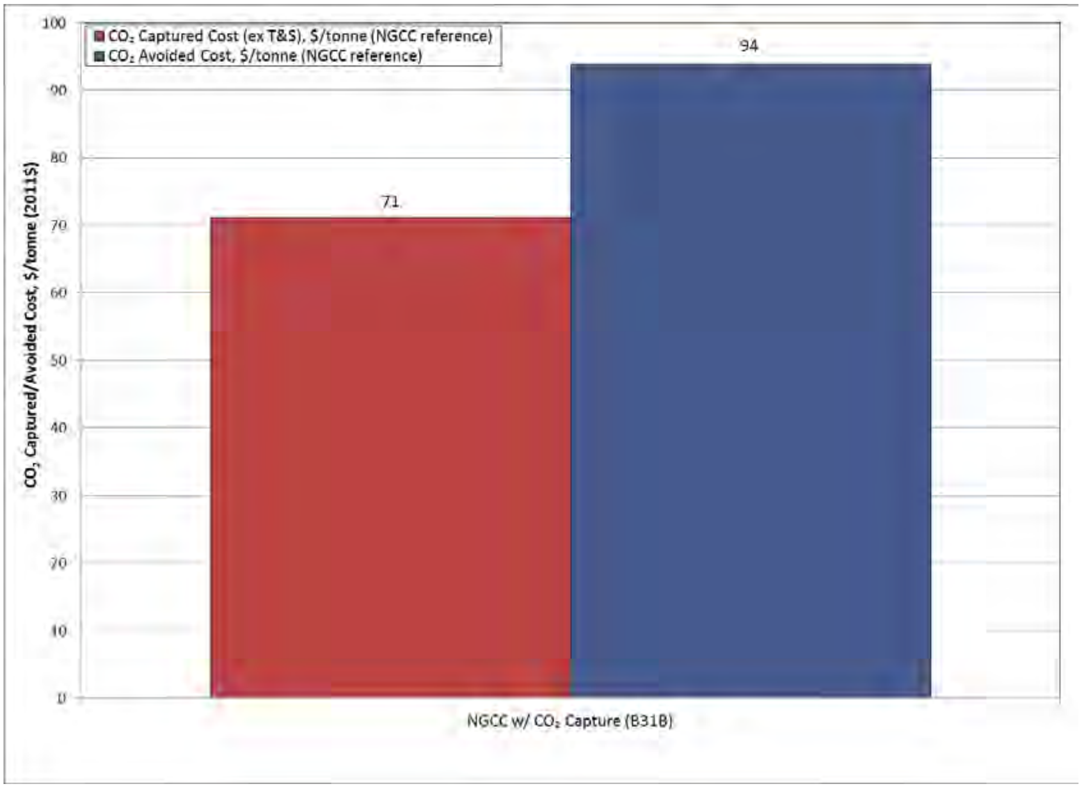


Source: NETL

The first year CO_2 avoided and captured costs were calculated (the methodology and equations were provided in Section 2.7.4), and the results for the NGCC cases are presented in Exhibit

4-37. The cost of CO_2 captured is \$71/tonne (\$65/ton) and the cost of CO_2 avoided is \$94/tonne (\$85/ton) using NGCC without CO_2 capture as the reference.

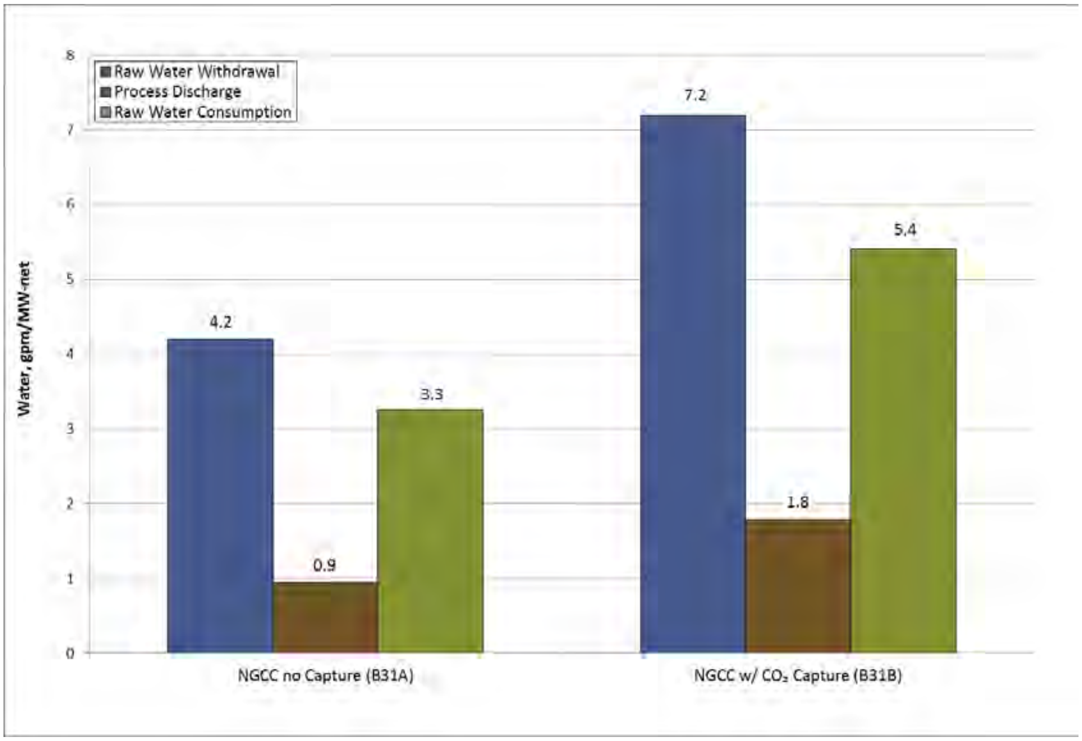
Exhibit 4-37 First year cost of CO_2 captured and avoided in NGCC cases



Source: NETL

The normalized water withdrawal, process discharge and raw water consumption are shown in Exhibit 4-38.

Exhibit 4-38 Raw water withdrawal and consumption in NGCC cases



Source: NETL

The following observations can be made:

- Normalized water withdrawal increases 71 percent and normalized raw water consumption 66 percent in the CO_2 capture case. The high cooling water demand of the capture process results in a large increase in cooling tower makeup requirements.
- Cooling tower makeup comprises approximately 99 percent of the raw water consumption in both NGCC cases. The only internal recycle stream in the non-capture case is the BFW blowdown, which is recycled to the cooling tower. In the CO_2 capture cases, condensate is recovered from the flue gas as it is cooled to the absorber temperature of 30°C (86°F) and is also recycled to the cooling tower.

5 Results Analysis

Summaries of the individual technologies were provided in Sections 3 and 4. This section provides the results of all technologies for cross-comparison.

5.1 Performance

Exhibit 5-1 provides a summary of the performance and environmental profile for all cases.

Exhibit 5-1 Performance summary and environmental profile for all cases

	Pulverized Coal Boiler				NGCC	
	PC Subcritical		PC Supercritical		State-of-the-art 2013 F-Class	
Case Name	B11A	B11B	B12A	B12B	B31A	B31B
PERFORMANCE						
Gross Power Output (MWe)	581	644	580	642	641	601
Auxiliary Power Requirement (MWe)	31	94	30	91	11	42
Net Power Output (MWe)	550	550	550	550	630	559
Coal Flow rate (lb/hr)	412,005	516,170	395,053	495,578	N/A	N/A
Natural Gas Flow rate (lb/hr)	N/A	N/A	N/A	N/A	185,484	185,484
HHV Thermal Input (kW_t)	1,408,630	1,764,768	1,350,672	1,694,366	1,223,032	1,223,032
Net Plant HHV Efficiency (%)	39.0%	31.2%	40.7%	32.5%	51.5%	45.7%
Net Plant HHV Heat Rate (Btu/kWh)	8,740	10,953	8,379	10,508	6,629	7,466
Raw Water Withdrawal, gpm	5,538	8,441	5,105	7,882	2,646	4,023
Process Water Discharge, gpm	1,137	1,920	1,059	1,813	595	999
Raw Water Consumption, gpm	4,401	6,521	4,045	6,069	2,051	3,024
CO_2 Capture Rate, %	0	90	0	90	0	90
CO_2 Emissions (lb/MMBtu)	204	20	204	20	119	12
CO_2 Emissions (lb/MWh-gross)	1,683	190	1,618	183	773	82
CO_2 Emissions (lb/MWh-net)	1,779	223	1,705	214	786	89
SO_2 Emissions (lb/MMBtu)	0.085	0.000	0.085	0.000	0.001	0.000
SO_2 Emissions (lb/MWh-gross)	0.700	0.000	0.673	0.000	0.006	0.000
NOx Emissions (lb/MMBtu)	0.085	0.075	0.088	0.078	0.003	0.003
NOx Emissions (lb/MWh-gross)	0.700	0.700	0.700	0.700	0.020	0.022
PM Emissions (lb/MMBtu)	0.011	0.010	0.011	0.010	0.000	0.000
PM Emissions (lb/MWh-gross)	0.090	0.090	0.090	0.090	0.000	0.000
Hg Emissions (lb/TBtu)	0.363	0.321	0.377	0.333	0.000	0.000
Hg Emissions (lb/MWh-gross)	3.00E-06	3.00E-06	3.00E-06	3.00E-06	0.00E+00	0.00E+00

5.1.1 Energy Efficiency

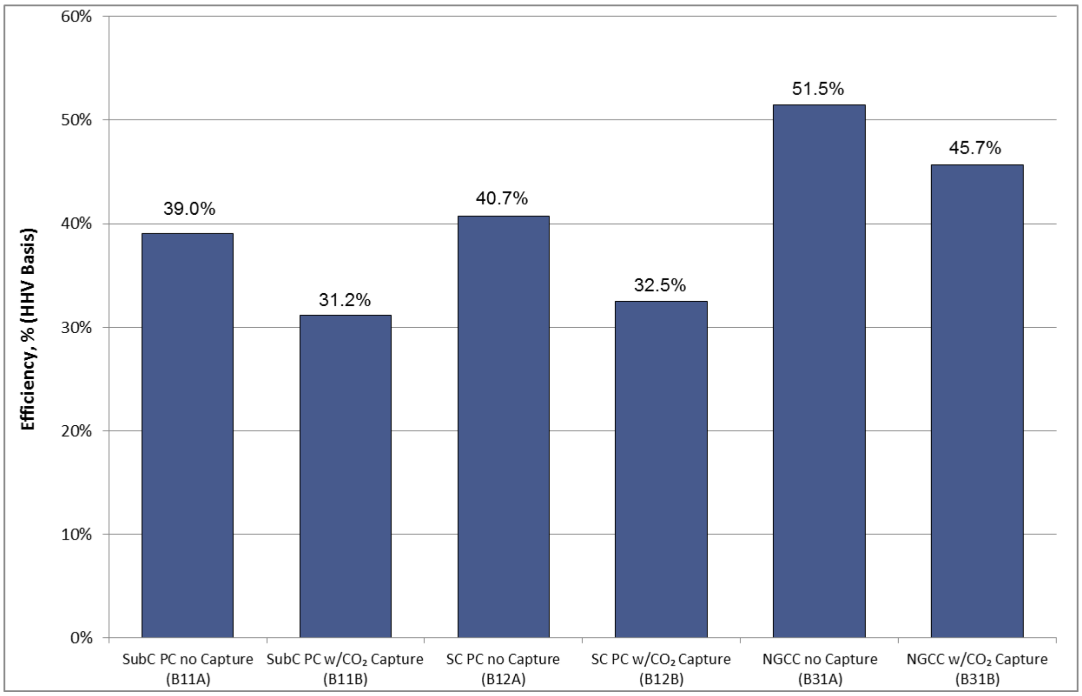
A graph of the net plant efficiency (HHV basis) is provided in Exhibit 5-2.

The primary conclusions that can be drawn are:

- The NGCC cases have the highest net efficiency of all the technologies, both without CO_2 capture (51.5 percent) and with CO_2 capture (45.7 percent). The next highest efficiency is the non-capture SC PC case, with an efficiency of 40.7 percent.
- For the PC cases, adding CO_2 capture results in a relative efficiency penalty of 20 percent (8 percentage points).
- For the NGCC case, adding CO_2 capture results in a relative efficiency penalty of 11 percent (6 percentage points). The NGCC penalty is less than the PC penalty because:

- Natural gas is less carbon intensive than coal (based on the fuel compositions used in this study, natural gas contains 32 lb carbon/MMBtu of heat input and coal contains 56 lb/MMBtu).
- The NGCC non-capture plant is more efficient, thus there is less total CO_2 to capture and compress (NGCC non-capture CO_2 emissions are approximately 54-56 percent lower than the PC cases) when normalized to equivalent net power outputs.
- These effects are offset slightly by the lower concentration of CO_2 in the NGCC flue gas (4% vs. 13% for PC). When normalized to CO_2 captured, the energy penalty is 0.16 kWh and 0.13 kWh per lb of CO_2 captured for NGCC and PC, respectively.

Exhibit 5-2 Net plant efficiency (HHV basis)



Source: NETL

5.1.2 Environmental Emissions

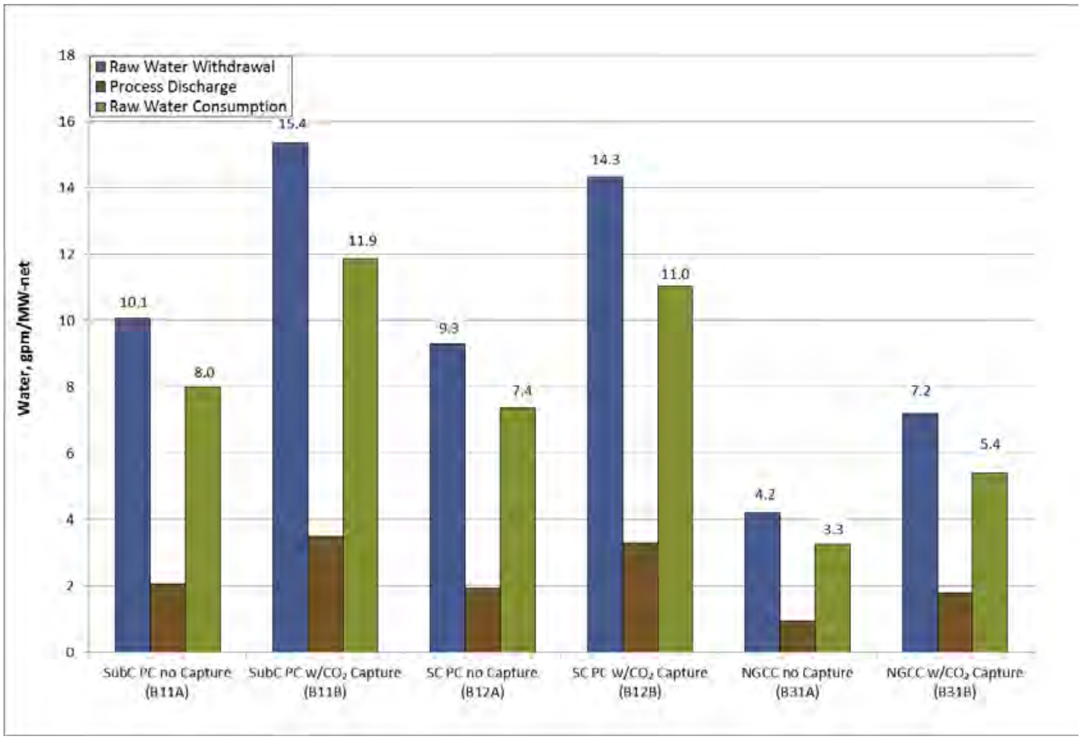
Natural gas does not contain Hg, PM, or HCl, which makes its environmental profile more attractive compared to PC cases. In this report it was assumed that the only sulfur present in natural gas is from the addition of the odorant, mercaptan. This results in an SO_2 emission rate below the regulatory limits without any further control.

Estimated emissions of Hg, PM, NOx, and SO_2 are all at or below the applicable regulatory limits currently in effect for all cases (PC and NGCC)

5.1.3 Water Use

Three water values are presented for each technology in Exhibit 5-3: raw water withdrawal, process discharge, and raw water consumption. Each value is normalized by net output.

Exhibit 5-3 Raw water withdrawal and consumption



Source: NETL

The primary conclusions that can be drawn are:

- NGCC has the lowest raw water consumption of all cases for both non-capture and CO_2 capture cases with the relative normalized raw water consumption for the technologies being 2.2:1.0 (SCPC:NGCC). The relative results are expected given the higher steam turbine output in the PC cases, which results in higher condenser duties, higher cooling water flows, and, ultimately, higher cooling water makeup.
- CO_2 capture imposes a significant water demand on all technologies. The post-combustion capture technology has a significant cooling water demand that results in increased raw water consumption because of increased cooling tower blowdown and cooling tower evaporative losses. The normalized raw water consumption increases by 62 percent for the NGCC case, 50 percent for the SC PC case, and 48 percent for the subcritical PC case. The relative increases reflect the smaller non-capture water requirements that result from less power output generated by the steam turbine. Despite the lower relative water consumption increase for the PC cases, they still have the largest normalized raw water consumption of the capture technologies: 2.0:1.0 (PC: NGCC).

5.2 Cost Results

Exhibit 5-4 provides a summary of the costs for all cases.

Exhibit 5-4 Cost summary for all cases

	Pulverized Coal Boiler				NGCC	
	PC Subcritical		PC Supercritical		State-of-the-art 2013 F-Class	
Case Name	B11A	B11B	B12A	B12B	B31A	B31B
COST						
Total Plant Cost (2011$/kW)	1,960	3,467	2,026	3,524	685	1,481
Bare Erected Cost	1,582	2,665	1,646	2,716	561	1,117
Home Office Expenses	158	257	165	263	51	97
Project Contingency	220	427	216	430	73	193
Process Contingency	0	118	0	115	0	75
Total Overnight Cost (2011$/MM)	1,336	2,346	1,379	2,384	528	1,008
Total Overnight Cost (2011$/kW)	2,429	4,267	2,507	4,333	838	1,804
Owner's Costs	469	800	480	809	154	323
Total As-Spent Cost (2011$/kW)	2,755	4,865	2,842	4,940	901	1,945
COE ($/MWh) (excluding T&S)	82.1	133.5	82.3	133.2	57.6	83.3
Capital Costs	37.8	71.1	39.0	72.2	11.8	26.9
Fixed Costs	9.3	15.1	9.6	15.4	3.4	6.6
Variable Costs	9.2	15.1	9.1	14.7	1.7	4.0
Fuel Costs	25.7	32.2	24.6	30.9	40.7	45.9
COE ($/MWh) (including T&S)	82.1	143.5	82.3	142.8	57.6	87.3
CO_2 T&S Costs	0.0	10.0	0.0	9.6	0.0	4.0
CO_2 Captured Cost (excluding T&S), $/tonne	N/A	56.2	N/A	58.2	N/A	71.1
CO_2 Avoided Cost (including T&S), $/tonne	N/A	91.0	N/A	89.4	N/A	93.8

*Cases without capture use conventional financing; all others use high-risk financial asssumptions consistent with NETL's "QGESS: Cost Estimation Methodology for NETL Assessments of Power Plant Performance." (1)

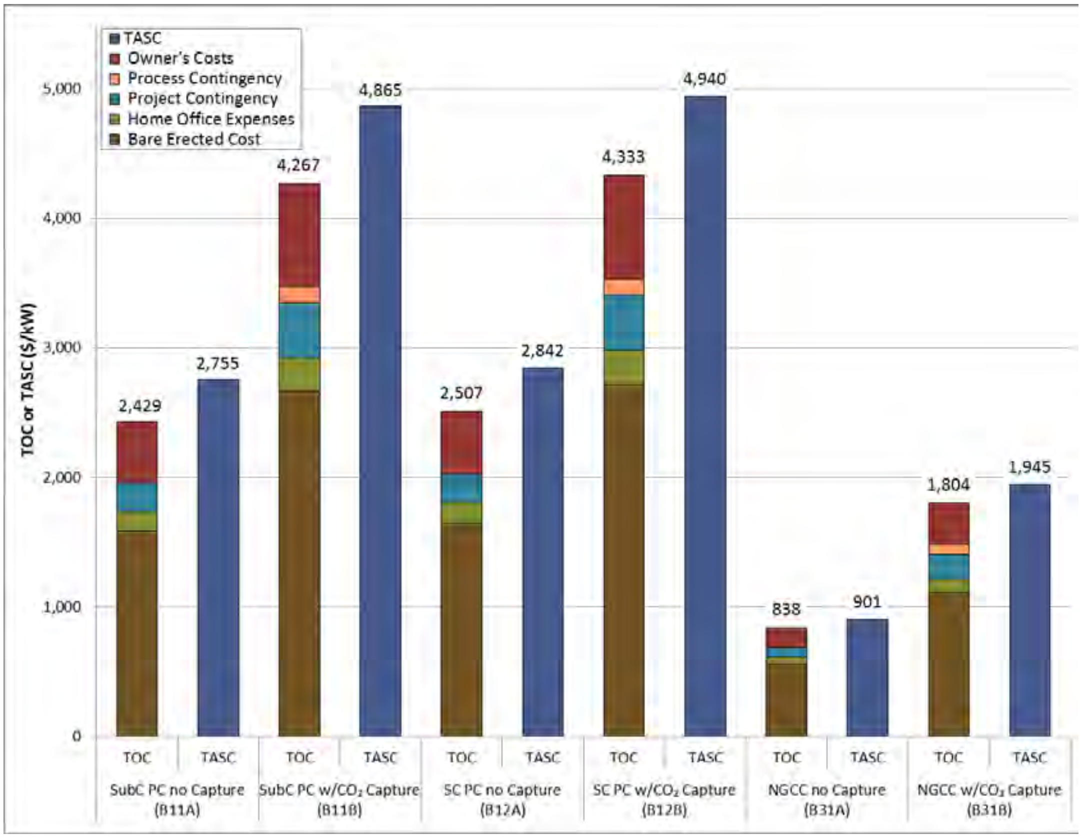
5.2.1 TOC and TASC

In Exhibit 5-5, the normalized components of TOC and overall TASC are shown for each technology.

The following conclusions can be drawn:

- Based on total overnight cost (TOC) in $/kW, NGCC capital costs are approximately 34% and 42% of the PC capital costs for non-capture and capture cases, respectively.
- The NGCC cost advantage over PC is partially enabled by the lack of emission control equipment necessitated for the adherence to current regulations.
- The addition of CO_2 capture technology significantly impacts all technologies. The TOC increases by 76 percent for subcritical PC, 73 percent for SC PC, and 115 percent for NGCC.

Exhibit 5-5 Plant capital costs



Source: NETL

Note: TOC expressed in 2011 dollars. TASC expressed in 2011 to 2015 mixed-year dollars for PC and 2011 to 2013 mixed-year dollars for NGCC

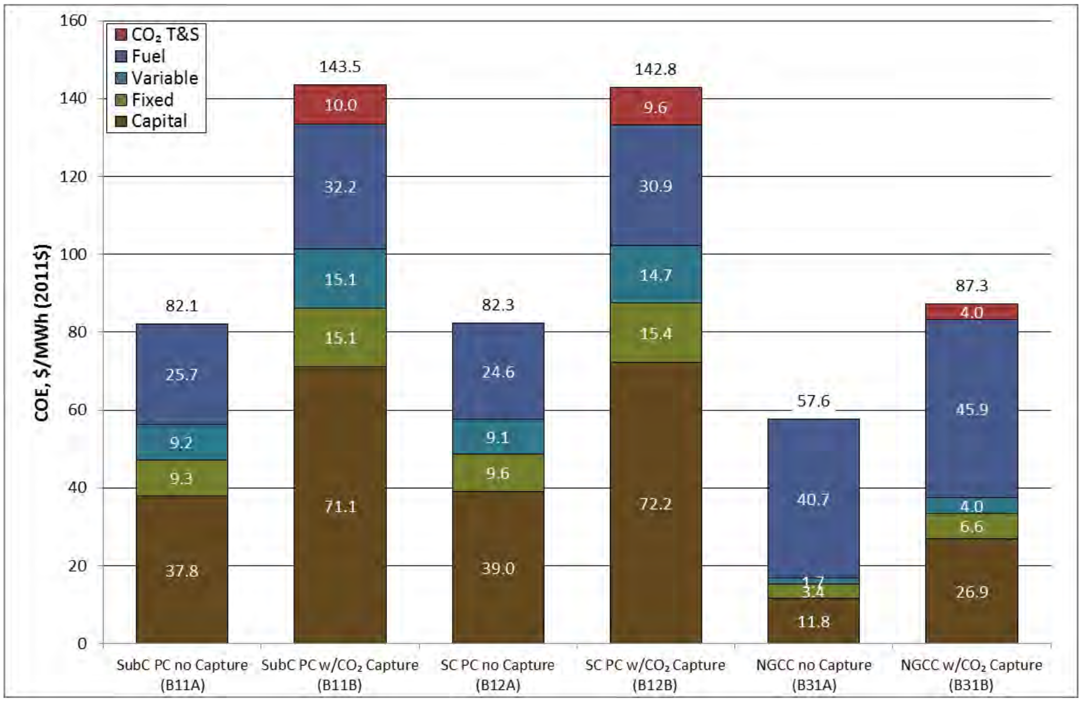
5.2.2 COE

A graph of the net plant efficiency (HHV basis) is provided in Exhibit 5-6.

The primary conclusions that can be drawn are:

- NGCC plant COEs are 70% and 61% of the PC plant COEs, for non-capture and capture cases, respectively.
- The capital cost component represents the largest portion of the COE in PC cases, ranging from 46-51 percent of the total COE. The capital cost in NGCC cases represents 21-31 percent of the total COE.
- The fuel cost component represents the largest portion of the COE in NGCC cases, ranging from 53-71 percent of the total COE. The fuel cost in PC cases represents 22-31 percent of the total COE.
- CO_2 T&S costs add between $4/MWh (NGCC) and $10/MWh (PC) to the COE, which is less than 7 percent of the total for all capture cases.
- While NGCC plants were impacted the most significantly by the addition of CO_2 capture in terms of TOC, due to the small capital component of NGCC plants without CO_2 capture (the cost of fuel is the most significant aspect of the COE for NGCC cases), the NGCC based plants incurred a smaller increase in COE than PC based plants (52 percent versus 74-75 percent).

Exhibit 5-6 COE by cost component



Source: NETL

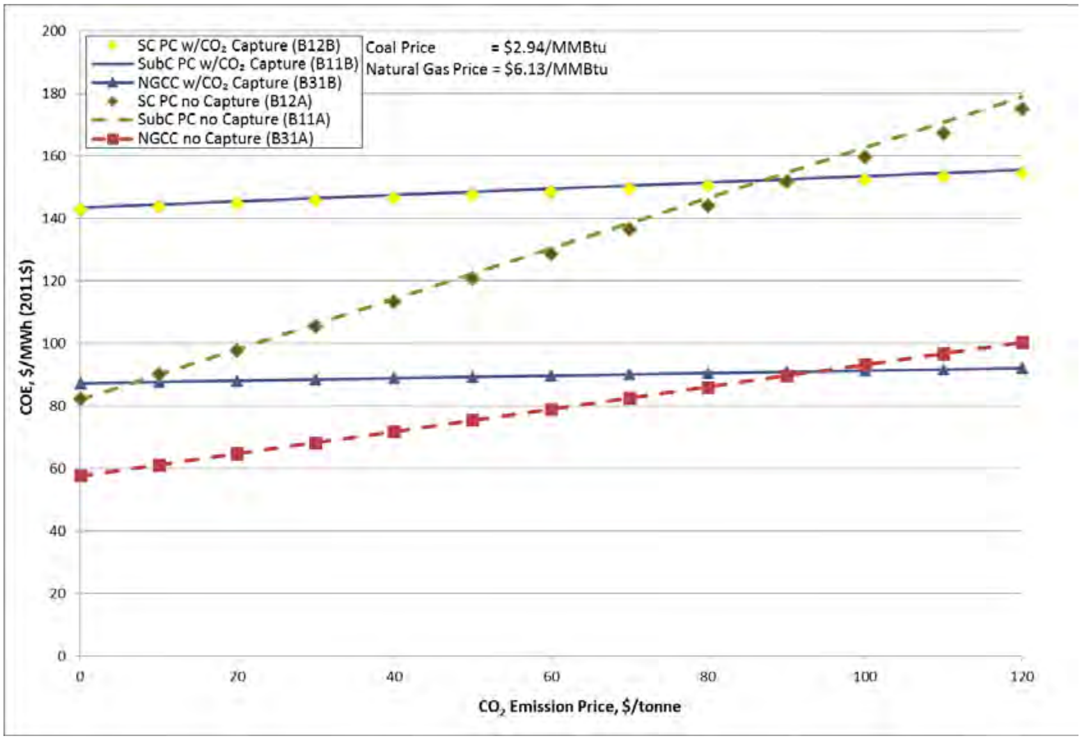
5.2.3 CO_2 Emission Price Impact

In the event that future legislation assigns a cost to carbon emissions, all of the technologies examined in this report will become more expensive. The technologies without carbon capture will be impacted to a larger extent than those with carbon capture, and coal-based technologies will be impacted more than natural gas-based technologies.

The cost of CO_2 avoided is shown in Exhibit 5-7 as the intersection of the CO_2 capture PC case lines with the line for the SC PC non-capture case and the intersection of the NGCC CO_2 capture case line with the line for the NGCC non-capture case. For example, the cost of CO_2 avoided is $89.4/tonne ($81.1/ton) for SC PC and $93.8/tonne ($85.1/ton) for NGCC.

The curves in Exhibit 5-7 represent the study design conditions (capacity factor) and fuel prices used for each technology; namely an 85 percent capacity factor and $2.78/GJ ($2.94/MMBtu) for coal and $5.81/GJ ($6.13 /MMBtu) for natural gas.

Exhibit 5-7 Impact of carbon emissions price on study technologies



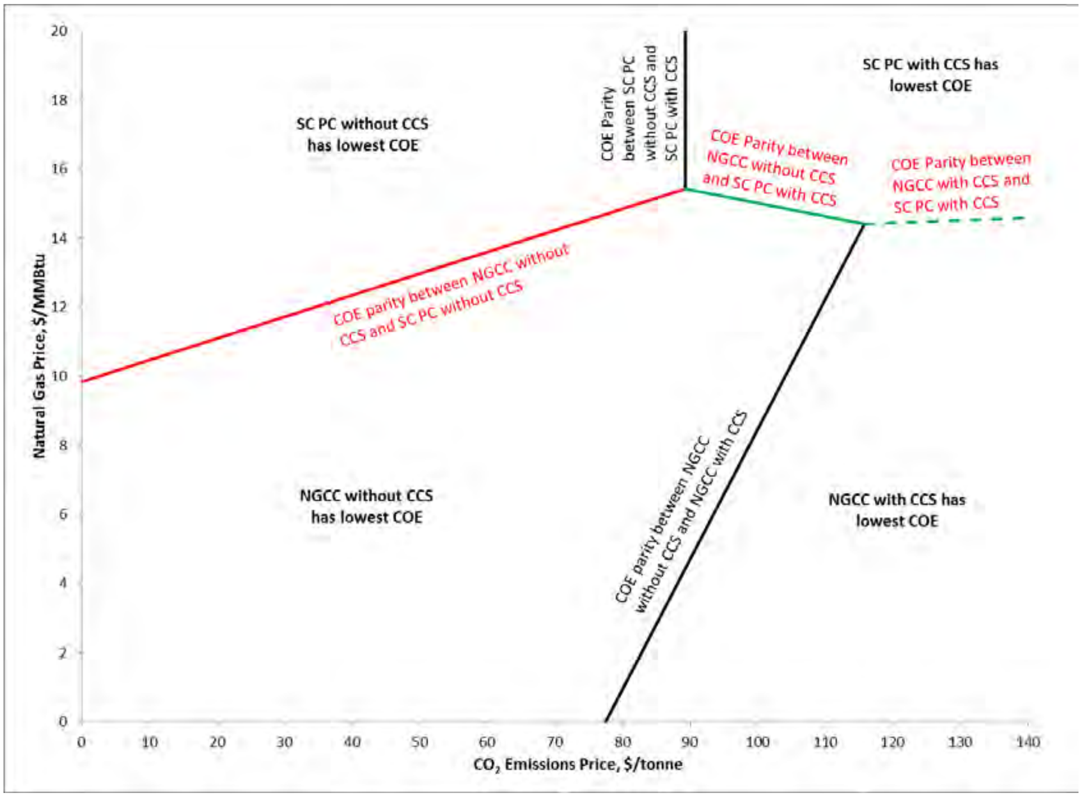
Source: NETL

The following conclusions can be drawn from the carbon emissions price graph:

- The CO_2 emission price impact on COE for the subcritical PC and SC PC cases is indistinguishable for both the CO_2 capture cases and the non-capture cases.
- At the baseline study conditions, non-capture SC PC diverges rapidly from non-capture NGCC as the CO_2 emission cost increases. The lower carbon intensity of natural gas relative to coal and the greater efficiency of the NGCC technology account for this effect.

The impact of CO_2 emissions price and natural gas price and the implications on the competitiveness of the capture technologies can also be considered in a "phase diagram" type plot, as shown in Exhibit 5-8. The lines in the plot represent cost parity between different pairs of technologies.

Exhibit 5-8 Lowest cost power generation options comparing NGCC and PC



Source: NETL

The plot demonstrates the following points:

- Non-capture plants are the low-cost option below a CO_2 price of \$78/tonne (\$71/ton).
- NGCC is always preferred when natural gas prices are below \$10/MMBtu (and a capacity factor of 85 percent).
- Coal plants are always preferred when natural gas prices are above \$15/MMBtu.

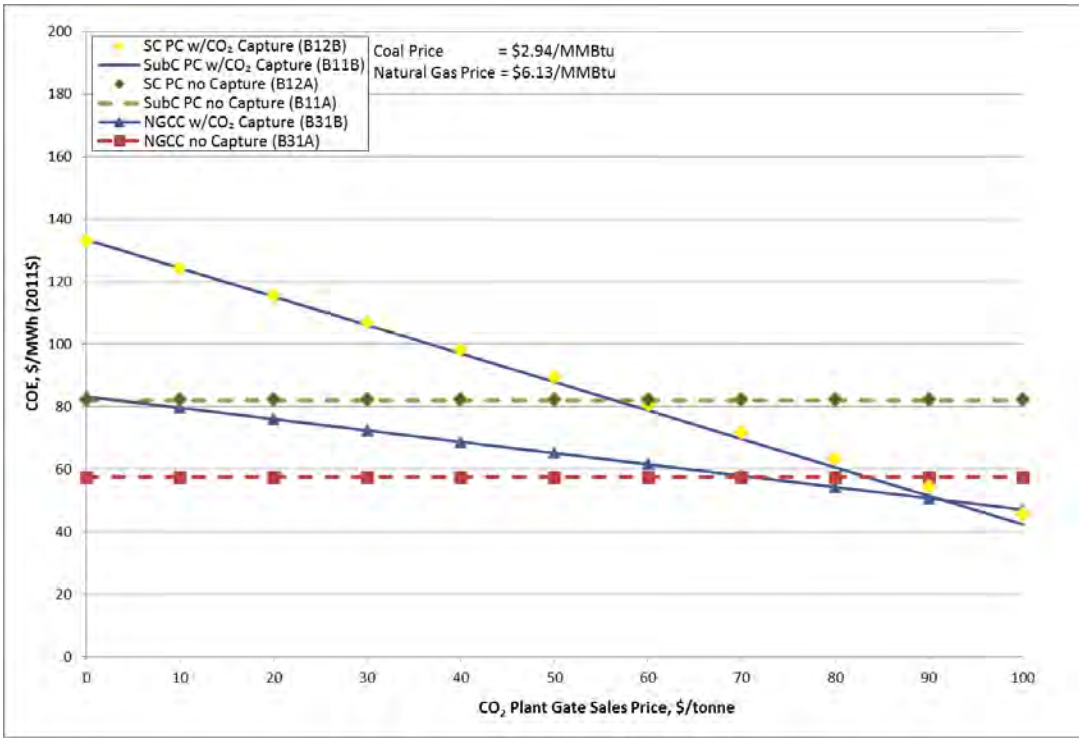
5.2.4 CO_2 Sales Price Impact

Sale of the captured CO_2 for utilization and storage in CO_2 enhanced oil recovery (EOR) has the potential to provide a revenue stream to both the SC PC and NGCC capture plant configurations. The plant gate CO_2 sales price will ultimately depend on a number of factors including plant location and crude oil prices. The cost of CO_2 captured represents the minimum CO_2 plant gate sales price that will incentivize carbon capture in lieu of a defined reference non-capture plant.

The cost of CO_2 captured is shown in Exhibit 5-9 as the intersection of the CO_2 capture PC case lines with the line for the SC PC non-capture case, and the intersection of the NGCC CO_2 capture case line with the line for the NGCC non-capture case. For example, when looking at the exhibit, the cost of CO_2 captured is \$58/tonne (\$53/ton) for SC PC and \$71/tonne (\$64/ton) for NGCC.

The curves in Exhibit 5-9 represent the study design conditions (capacity factor) and fuel prices used for each technology; namely 85 percent for PC and NGCC plants, and \$2.78/GJ (\$2.94/MMBtu) for coal and \$5.81/GJ (\$6.13 /MMBtu) for natural gas.

Exhibit 5-9 Impact of carbon sales price on study technologies



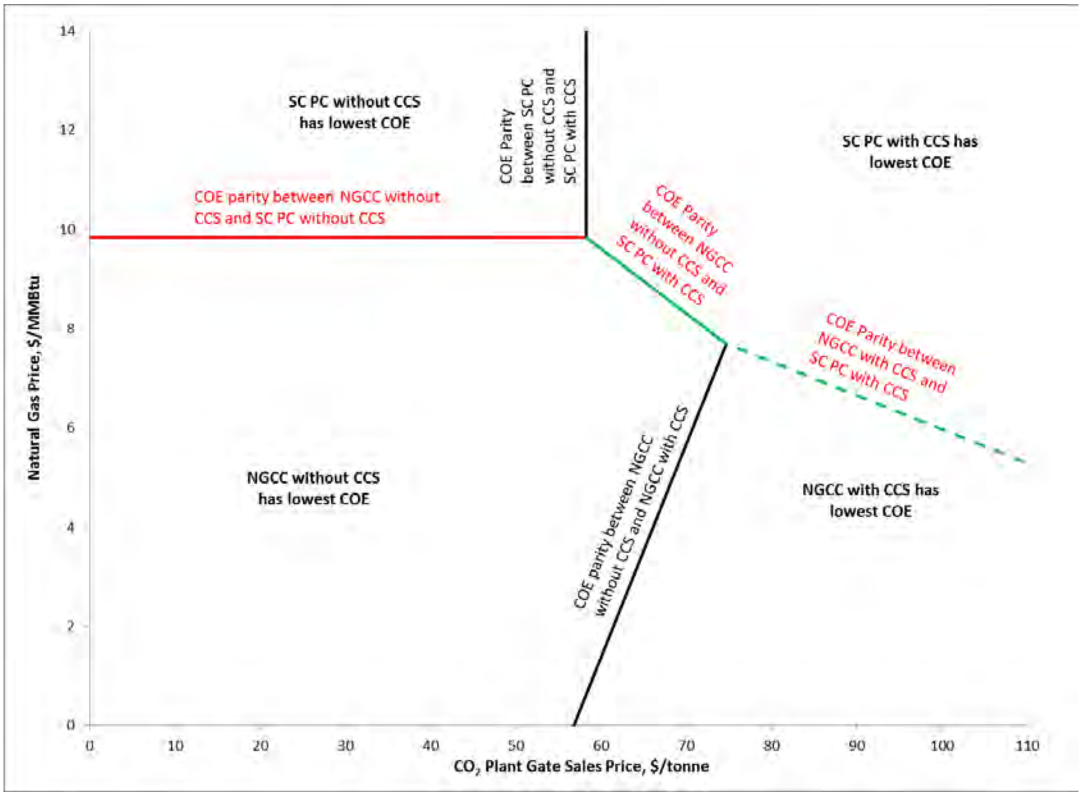
Source: NETL

The following conclusions can be drawn from the carbon sales price graph:

- The CO_2 sales price impact on COE for the subcritical PC and SC PC cases is indistinguishable for both the CO_2 capture cases and the non-capture cases.
- At the baseline study conditions, increasing the price of CO_2 for EOR sales has a greater effect on PC than on NGCC.
- At a CO_2 sales price of $90/tonne, the cost of NGCC with CO_2 capture is nearly equal to that of the subcritical PC and SC PC CO_2 capture cases.

Like technologies and CO_2 emission pricing, the impact of CO_2 sales price and natural gas price and the implications on the competitiveness of the capture technologies can also be considered in a "phase diagram" type plot, as shown in Exhibit 5-10. The lines in the plot represent COE parity between different pairs of technologies.

Exhibit 5-10 Lowest cost power generation options comparing NGCC and coal



Source: NETL

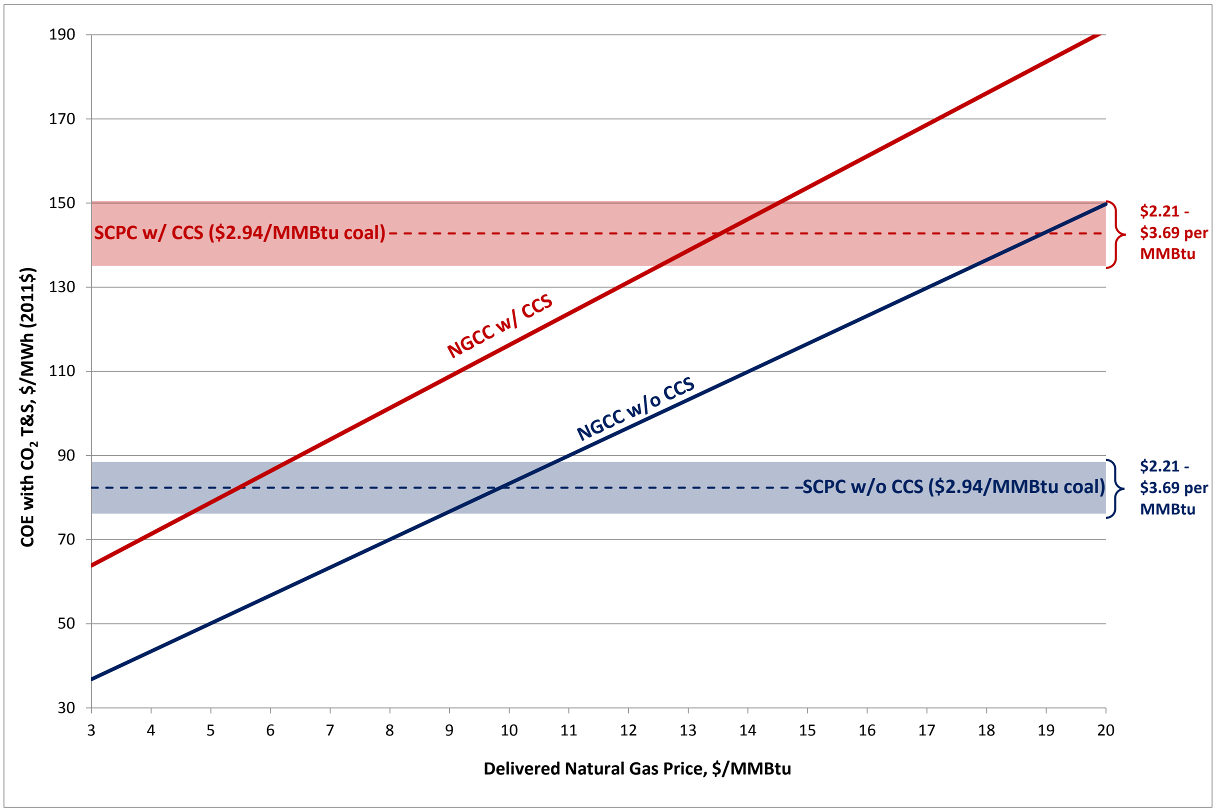
The plot demonstrates the following points:

- Non-capture plants are the low-cost option below a first-year CO_2 price of $56/tonne ($51/ton).
- NGCC is preferred when natural gas prices are below $10/MMBtu with a CO_2 revenue below $56/tonne (and a capacity factor of 85 percent). The natural gas price that provides parity between the various NGCC and PC cases drops off at higher CO_2 revenues reaching $6/MMBtu at approximately $100/tonne ($91/ton).

5.3 Sensitivities

Exhibit 5-11 shows the COE sensitivity to fuel costs for the SC PC and NGCC cases. The bands for the SC PC cases represent a variance of the coal price from $2.21 - $3.69/MMBtu (±25% of the study value $2.94/MMBtu). This highlights regions of competitiveness of NGCC with SCPC systems for cases with and without CCS as a function of delivered natural gas price. As an example, at a coal cost of $3/MMBtu, the COE of the non-capture SC PC case equals non-capture NGCC at a natural gas price of approximately $10/MMBtu. Similarly, the SC PC and NGCC cases with capture have equivalent COEs at a coal price of $3/MMBtu and a natural gas price of approximately $13.5/MMBtu.

Exhibit 5-11 COE sensitivity to fuel costs



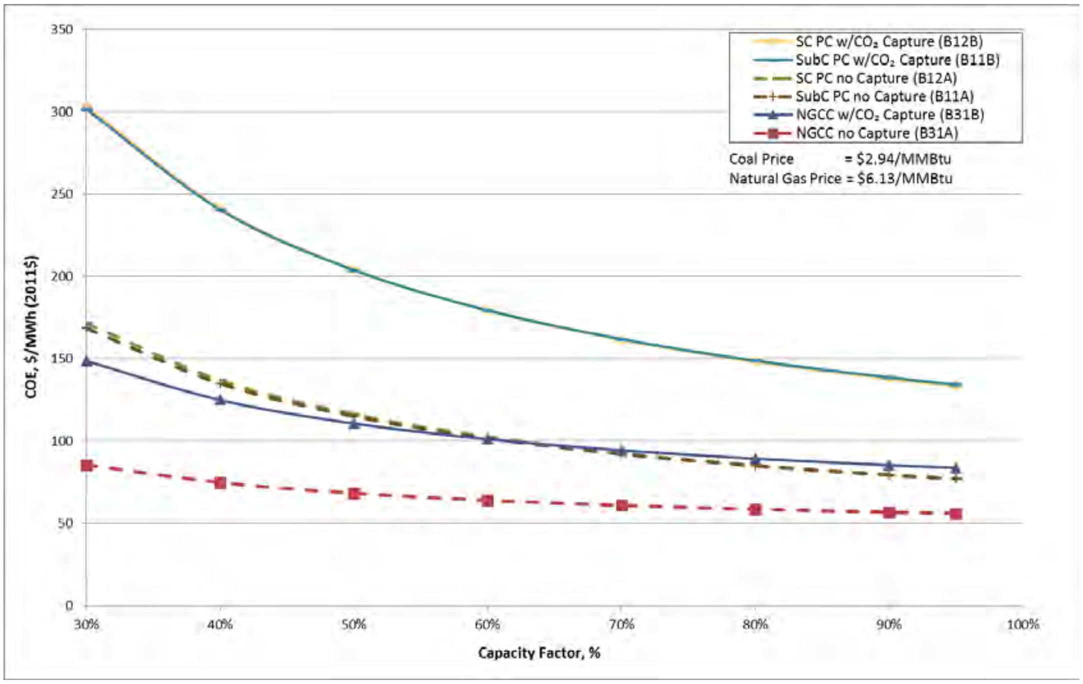
Source: NETL

In Exhibit 5-12, the sensitivity of COE to CF is shown for all technologies. The subcritical and SC PC cases are nearly identical so that the curves are indistinguishable on the graph. The CF is plotted from 30 to 95 percent. The baseline CF is 85 percent for both PC and NGCC technologies. The curves plotted in Exhibit 5-12 for the PC and NGCC cases assume that the CF could be extended to 95 percent with no additional capital equipment.

Technologies with high capital cost (PC with CO_2 capture) show a greater increase in COE with decreased CF. Conversely, NGCC with no CO_2 capture is relatively flat because the COE is dominated by fuel charges, which decrease as the CF decreases. Conclusions that can be drawn from Exhibit 5-12 include:

- At any CF shown, NGCC has the lowest COE out of the non-capture cases.
- The COE of NGCC with CO_2 capture is the lowest of the capture technologies, and the advantage increases as the CF decreases. The relatively low capital cost component of NGCC accounts for the increased cost differential with decreased CF.
- At around a 60 percent CF, the COE of NGCC with CO_2 capture crosses over with the COEs of both PC non-capture cases, with the NGCC case having a higher COE at increasing CFs.

Exhibit 5-12 COE sensitivity to capacity factor



Source: NETL

6 Revision Control

The initial issue of this report was published in May of 2007 and an updated revision was published in November of 2010. Subsequent to the re-issue date, updates have been made to various report sections. These modifications were made for clarification and aesthetic purposes as well as to update the report with more current performance and cost estimates and to bring all costs to a 2011 year dollar basis.

Exhibit 6-1 contains information added, changed, or deleted in successive revisions.

Exhibit 6-1 Record of revisions

Revision Number	Revision Date	Description of Change	Comments
1	8/23/07	Added disclaimer to Executive Summary and Introduction	Disclaimer involves clarification on extent of participation of technology vendors.
		Removed reference to Cases 7 and 8 in Exhibits ES-1 and 1-1 since they no longer exist.	SNG cases moved to Volume 2 of this report as explained in the Executive Summary and Section 1.
		Added Section 2.8	Explains differences in IGCC TPC estimates in this report versus costs reported by other sources.
		Added Exhibit ES-14	Mercury emissions are now shown in a separate exhibit from SO_2, NOx and PM because of the different y-axis scale.
		Corrected PC and NGCC CO_2 capture case water balances	The capture process cooling water requirement for the PC and NGCC CO_2 capture cases was overstated and has been revised.
		Replaced Exhibits ES-4, 3-121, 4-52 and 5-30	The old water usage figures were in gpm (absolute) and in the new figures the water numbers are normalized by net plant output.
		Updated Selexol process description	Text was added to Section 3.1.5 to describe how H_2 slip was handled in the models.
		Revised PC and NGCC CO_2 capture case energy balances (Exhibits 4-21, 4-42 and 5-21)	The earlier version of the energy balances improperly accounted for the capture process heat losses. The heat removed from the capture process is rejected to the cooling tower.
		Corrected Exhibit 4-13 and Exhibit 4-27.	Sensible heat for combustion air in the two NGCC cases was for only one of the two combustion turbines – corrected to account for both turbines
2	10/27/10	Updated circulating water flow rate values in Section 3.1.8.	Revision 1 changes to capture system cooling water flow rate were not made in the text in Section 3.1.8 (Circulating Water System).
		Added Supplemental Chapter 6 "Effect of Higher Natural Gas Prices and Dispatch-Based Capacity Factors"	
		Added Supplemental Chapter 7 "Dry and Parallel Cooling"	

Revision Number	Revision Date	Description of Change	Comments
		Added Supplemental Chapter 8 "GEE IGCC in Quench-Only Configuration with CO_2 Capture"	
		Added Supplemental Chapter 9 "Sensitivity to MEA System Performance and Cost Bituminous Baseline Case B12BA"	
		Updated Aspen models	Major Aspen model updates included: • Converting FORTRAN code based steam cycles to Aspen blocks • Using the Peng-Robinson property method in the Aspen gasifier section • Modifying the AGR used in the IGCC cases to more closely represent commercially available technology • Increasing the capture efficiency of the E-Gas™ plant with capture to achieve 90 percent • Correcting a steam condition error in the supercritical PC cases with capture
		Updated case performance results	Major updates included: • Revising the water balances to include withdrawal and consumption • CAD-based HMB diagrams were replaced with Visio versions
		Completed updating case economic results	Major updates included: • Adding owner's costs to the total plant costs to generate total overnight cost • Updating fuel costs • Revising the T&S methodology to include the July, 2007 Handy-Whitman Index, pore space acquisition costs, and liability costs • Re-costing of cases based on the updated performance results • Switching to COE as the primary cost metric (as opposed to levelized COE)
		Updated report tables, figures and text to reflect the revision 2 changes	
2a	9/19/2013	Section 2.7.1 was revised to clarify the text that explains the level of technology maturity reflected in the plant level cost estimates.	

Revision Number	Revision Date	Description of Change	Comments
3	7/6/2015	Volume 1 has been split into two sub volumes.	Major updates included: • IGCC cases are reported in Volume 1b with a cost-only update (issued as an update to revision 2a) • PC and NGCC cases are reported in Volume 1a with a cost and performance update (issued as revision 3) • Executive summary significantly revised and shortened Results analysis section added
		Separated Supplemental Chapter 6 “Effect of Higher Natural Gas Prices and Dispatch-Based Capacity Factors” into a stand alone report.	
		Separated Supplemental Chapter 7 “Impact of Dry and Parallel Cooling Systems on Cost and Performance of Fossil Fuel Power Plants” into a stand alone report.”	
		Removed Supplemental Chapter 9 “Sensitivity to MEA System Performance and Cost Bituminous Baseline Case 12A”	
		Updated the environmental targets to current limits published by the EPA and presented in Section 2.4	MATS and NSPS regulate SO_2, NOx, Filterable PM, Hg, and HCl on a lb/MWh-gross basis.
		Updated Section 2.5 covering Capacity Factors	Additional information has been included that supports the assumptions made regarding the capacity factors used for each technology type.
		Removed portions of Section 2.7 concerning cost estimating methodology	Many QGESS documents have been published that detail information generic to a number of studies published by NETL. In an effort to reduce the size of this report, text provided in these QGESS documents has been removed and references have been inserted that provide the QGESS document title and revision notation.
		Cost of CO_2 Captured methodology and results have been added.	The Cost of CO_2 avoided methodology has been moved from the executive summary and combined with the Cost of CO_2 Captured methodology in Section 2.7.4.
		Section 2.8 has been updated to reflect current information	

Revision Number	Revision Date	Description of Change	Comments
		The Combustion turbine performance characteristics have been updated	The performance provided in this report reflects a state-of-the-art 2013 F-class combustion turbine for NGCC cases
		Updated Natural Gas Composition	Methanethiol was added to the composition
		Improved the BFD depiction of the HRSGs in NGCC Case	
		All cases have been updated to a new case naming convention.	Ex. Revision 2's Case 9 is now Case B11A

		Performance tables have been updated	Major updates include:
			• Table is split into two sections
			  o Performance summary
			  o Plant power and auxiliary load breakdown
			• PC
			  o Steam generator efficiency
			  o Excess air
			  o Steam turbine cycle efficiency and heat rate
			  o LHV basis efficiency and heat rate
			• NGCC
			  o Combustion turbine efficiency
			  o Steam turbine efficiency and heat rate
			  o LHV basis efficiency and heat rate

		Updated case performance results	Major updates included: • Added particle concentration to emissions results • Updated Energy Balance tables by adding Motor Losses and Design Allowances, Non-Condenser cooling tower loads, and ambient losses

Revision Number	Revision Date	Description of Change	Comments
		Updated Aspen models	Major Aspen model updates included: • Updated steam turbine efficiency • Incorporated exhaust losses into LP turbine efficiency • Changed Capture system in NGCC and PC cases to Cansolv system • Updated many pressure drops to percent of inlet • Corrected temperature approaches • Corrected pressure drops across various systems • Converted to Aspen 8.2 • Converted to Hierarchy models • Converted steam property method to SteamNBS • Updated CO_2 compression system to front loaded 8 stage design in NGCC and PC cases • ACI and DSI systems were added to PC cases • Boiler air preheater exit temperature was reduced to 300°F • Excess O_2 is controlled at the flue gas exiting the boiler at 2.7% dry • Combustion turbine for NGCC cases was updated • Added steam extraction for CO_2 dryer
		Completed updating case economic results	Major updates included: • Updating to 2011 year dollars • Updating the T&S costing methodology • Updating the capital charge factors • Updating fuel prices • Re-costing of cases based on the updated performance results • Updating cost estimates based on recently obtained vendor quotes
		Updated report tables, figures and text to reflect the revision 3 changes	

7 References

1. **National Energy Technology Laboratory.** *Quality Guidelines for Energy System Studies: Cost Estimation Methodology for NETL Assessments of Power Plant Performance.* Pittsburgh : Department of Energy, 2011.

2. **AACE International.** *Conducting Technical and Economic Evaluations – As Applied for the Process and Utility Industries; TCM Framework: 3.2 – Asset Planning, 3.3 Investment Decision Making.* s.l. : AACE International, 2003. Recommended Practice 16R-90.

3. —. *Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries; TCM Framework 7.3 – Cost Estimating and Budgeting.* s.l. : AACE International, 2005. Recommended Practice No. 18R-97.

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