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NATIONAL ENERGY TECHNOLOGY LABORATORY

COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 1: BITUMINOUS COAL AND NATURAL GAS TO ELECTRICITY



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ACRONYMS AND ABBREVIATIONS

AACE	Association for the Advancement of Cost Engineering
AC	Alternating current
acfm	Actual cubic feet per minute
ACI	Activated carbon injection
AF	Availability factor
AGR	Acid gas removal
Ar	Argon
Aspen	Aspen Plus®
atm	Atmosphere (14.696 psi)
BACT	Best Available Control Technology
BDL	Blowdown losses
BEC	Bare erected cost
BFD	Block flow diagram
BFW	Boiler feedwater
BOP	Balance of plant
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
$CaCO_3$	Calcium carbonate
$CaSO_4$	Calcium sulfate
CCS	Carbon capture and storage
CF	Capacity factor
CFR	Code of Federal Regulations
CGE	Cold gas efficiency
CH_4	Methane
CH_4S	Methanethiol
Cl^-	Chloride ion
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
CWR	Cooling water return
CWS	Circulating water system
CWT	Cold water temperature
db, DB	Dry basis
DC	Direct current
DCS	Distributed control system
DI	De-ionized
DLN	Dry low NOx
DOE	Department of Energy
DSI	Dry sorbent injection
EAF	Equivalent availability factor
EGU	Electric utility steam generating unit
ELG	Effluent Limitation Guidelines
EMF	Emission modification factors
Eng'g CM H.O.& Fee	Engineering, construction management, home office and fees
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
EPC	Engineering, procurement and construction
EPCC	Engineering, procurement and construction cost
EPRI	Electric Power Research Institute
ESP	Electrostatic precipitator
FD	Forced draft
FE	Fossil Energy
FEB	Fossil Energy Baseline
FG	Flue gas
FGD	Flue gas desulfurization
FRP	Fiberglass-reinforced plastic
ft	Foot, feet
ft^3	Cubic feet
FW	Feedwater
GADS	Generating Availability Data System
gal	Gallon
GDP	Gross domestic product
GEP	General Electric Power
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
Gt	Gigatonne
h, hr	Hour
H_2	Hydrogen
H_2O	Water
HCl	Hydrochloric acid
HCO_3	Bicarbonate
Hg	Mercury
HHV	Higher heating value
hp	Horsepower
HP	High pressure
HRSG	Heat recovery steam generator
HSS	Heat stable salt
HVAC	Heating, ventilating, and air conditioning
HWT	Hot water temperature
HX	Heat exchanger
Hz	Hertz
I&C	Instrumentation and control
ICR	Information Collection Request
ID	Induced draft
IGCC	Integrated gasification combined cycle
IGV	Inlet guide vane
in.	Inch
in. Hg	Inch mercury
IOU	Investor-owned utility
IP	Intermediate pressure
IPM	Integrated Planning Model
IRROE	Internal rate of return on equity
ISO	International Organization for Standardization
kg/GJ	Kilograms per gigajoule
kg/hr	Kilograms per hour
kg/s	Kilograms per second
kgmol	Kilogram mole
kgmol/hr	Kilogram moles per hour
kJ	Kilojoule
kJ/hr	Kilojoules per hour
kJ/kg	Kilojoules per kilogram
kJ/m^3	Kilojoules per cubic meter
kJ/Nm^3	Kilojoules per normal cubic meter
km	Kilometer
KO	Knockout
kV	Kilovolt
kW, kWe	Kilowatt electric
kWh	Kilowatt-hour
kWt	Kilowatt thermal
lb	Pound
lb/gal	Pound per gallon
lb/ft^2	Pounds per square foot
lb/ft^3	Pounds per cubic foot
lb/hr	Pounds per hour
lb/MMBtu	Pounds per million British thermal units
lb/MWh	Pounds per megawatt hour
lb/s	Pounds per second
lb/TBtu	Pounds per trillion British thermal units
lbmol/hr	Pound moles per hour
LCOE	Levelized cost of electricity
LHV	Lower heating value
LIW	Loss-in-weight
LNB	Low NOx burner
LP	Low pressure
lpm	Liters per minute
m	Meter
M	Thousand
m/min	Meters per minute
m^3/min	Cubic meters per minute
MATS	Mercury and Air Toxics Standards
MCR	Maximum continuous rate
MEA	Monoethanolamine
mi	Mile
MJ/Nm^3	Megajoules per normal cubic meter
MJ/scm	Megajoule per standard cubic meter
mm	Millimeter
MM	Million
MMacf	Million actual cubic feet
MMBtu	Million British thermal units
MMBtu/hr	Million British thermal units per hour
MNQC	Multi Nozzle Quiet Combustor

mol%	Percent by mole
MPa	Megapascal
MpaG	Megapascal, gauge
MVA	Mega volt-amps
MW	Megawatt
MWe	Megawatt electric
MWh	Megawatt-hour
N_2	Nitrogen
N/A	Not applicable
NaCl	Sodium chloride
NaOH	Sodium hydroxide
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
NO	Nitric oxide
NOAK	N^{th}-of-a-kind
NOx	Nitrogen oxide
NSPS	New Source Performance Standards
NSR	New Source Review
NTU	Nephelometric turbidity unit
O_2	Oxygen
O&M	Operation and maintenance
OEM	Original equipment manufacturers
OFA	Overfire air
O-H, OH	Overhead
OP/VWO	Over pressure/valve wide open
PA	Primary air
PAC	Powdered activated carbon
PC	Pulverized coal
p.f.	Power factor
ph	Phase
pH	Power of hydrogen
PM	Particulate matter
PostCCC	Post combustion carbon capture system
POTW	Publicly-owned treatment works
ppb	Parts per billion
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
ppt	Parts per trillion
PSD	Prevention of Significant Deterioration
psi	Pounds per square inch
psia	Pound per square inch absolute
psig	Pound per square inch gage
QGESS	Quality Guidelines for Energy System Studies
RH	Reheater
RO	Reverse osmosis
RR	Ramp rate
SC	Supercritical
SC&T	Shell Catalyst & Technologies
scfh	Standard cubic feet per hour
scfm	Standard cubic feet per minute
Sch.	Schedule
SCR	Selective catalytic reduction process or equipment
SDA	Spray dryer absorber
SDE	Spray dryer evaporator
Shell	Shell Global Solutions
SNCR	Selective non-catalytic reduction
SOA	State-of-the-art
SO_2	Sulfur dioxide
SO_3	Sulfur trioxide
SS	Stainless steel
STG	Steam turbine generator
SubC	Subcritical
T&S	Transport and storage
TASC	Total as-spent cost
TDS	Total dissolved solids
TEG	Triethylene glycol
TOC	Total overnight cost
tonne	Metric ton (1,000 kg)
TPC	Total plant cost
tpd	Ton per day
tph	Tons per hour
U.S.	United States

UCC	United Conveyor Corporation	$/GJ	Dollars per gigajoule
V	Volt	$/kW	Dollars per kilowatt
V-L	Vapor liquid portion of stream (excluding solids)	$/MMBtu	Dollars per million British thermal units
vol%	Percent by volume	$M	Millions of dollars
VT	Voltage transformers	µS/cm	Micro Siemens per cm
wt%	Percent by weight	°C	Degrees Celsius
yr	Year	°F	Degrees Fahrenheit
ZLD	Zero liquid discharge	5-10s	50-hour work week

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EXECUTIVE SUMMARY

This report presents an independent assessment of the cost and performance of select fossil energy power systems—pulverized coal (PC) and natural gas combined cycle (NGCC) plants—using a systematic, transparent technical and economic approach. This is Volume 1 of a five-volume series, which comprises the following reports:

- 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
- Volume 5: Natural Gas Electricity Generating Units for Flexible Operation

The cost and performance of fossil fuel-based generation technologies represented in this report (and the series at large) are important inputs to assessments and determinations of technology combinations to be utilized to meet the projected demands of future power markets. From a research and development perspective, this report is used to assess goals and metrics and to provide a consistent basis for comparing developing technologies.

Fifteen[a] power plant configurations are analyzed in this report. A summary of the configurations is shown in Exhibit ES-1:

- Six PC power plant configurations—three subcritical (SubC) and three supercritical (SC) (four with [two 90 percent and two 95 percent] and two without CO_2 capture).
- Nine NGCC power plant configurations—three state-of-the-art 2023 F-Class combustion turbines, three state-of-the-art 2023 1x1 H-Class combustion turbines, and three state-of-the-art 2023 2x1 H-Class combustion turbines (six with [three 90 percent and three 95 percent] and three without CO_2 capture).

[a] Additional PC and NGCC cases that include CO_2 capture rates above 95 percent are reported in a separate section at the end of the Executive Summary, with additional details available in the appendices.

Exhibit ES-1. Case configuration summary

Case[A]	Plant Type	Steam Cycle[B], psig/°F/°F	Combustion Turbine	Boiler/HRSG Technology	Oxidant	Sulfur Removal	PM Control	NOx Control	CO_2 Separation	Capture Rate[C]	Process Water Treatment
B11A	PC	2400/1050/1050	N/A	SubC PC	Air	Wet FGD/ Gypsum	Baghouse	LNB with OFA and SCR	N/A	N/A	Spray dryer evaporator
B11B.90									CANSOLV	90%	
B11B.95										95%	
B12A		3500/1100/1100		SC PC[B]					N/A	N/A	
B12B.90									CANSOLV	90%	
B12B.95										95%	
B31A	NGCC	2494/1085/1085	2 x State-of-the-art 2023 F-Class	HRSG		N/A	N/A	LNB and SCR	N/A	N/A	N/A
B31B.90									CANSOLV	90%	
B31B.95										95%	
B32A.1		2501/1085/1085	1 x State-of-the-art 2023 H-Class						N/A	N/A	
B32B.1.90									CANSOLV	90%	
B32B.1.95										95%	
B32A.2		2494/1085/1085	2 x State-of-the-art 2023 H-Class						N/A	N/A	
B32A.2.90									CANSOLV	90%	
B32A.2.95										95%	

[A]All plants in this report are assumed to be located at a generic plant site in the midwestern United States

[B]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, particularly with respect to temperature (593°C [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 ultra-supercritical PC plants.

[C]The capture rates for all cases is based on the amount of carbon in the stack gas relative to the total carbon in, less unburned carbon present in ash (PC cases). All cases sequester the CO_2 offsite.

All plant configurations were evaluated based on installation at a greenfield site. Capacity factors (CFs) used were 85 percent for all PC and NGCC configurations. Availability is defined as 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, CF and availability are equal. The calculations assume that the CF and availability are constant over the life of the plant. These plants are considered to be built for a thirty-year life, are well-maintained plants with sufficient and adequate maintenance budgets, and are operated in a manner that supports the assumed CF. Achieving such CFs would require that these plants be near the top of the dispatch list. This report includes a sensitivity analysis on the impact of plant capacity factor on levelized cost of electricity (LCOE).

The combustion turbines (CTs) used in each of the NGCC configurations are manufactured in discrete sizes, with each of the configurations assuming the combustion turbines operate at their rated output. While the gross output of the combustion turbines is consistent within each of the NGCC configurations, the net outputs vary.

The variance in NGCC net output, within a configuration, is caused by the significant auxiliary load imposed in the CO_2 capture cases—primarily due to CO_2 compression—and the steam needed for CO_2 capture, which reduces steam turbine output. The nominal net plant output for all PC plants in this study is 650 MW.

Air pollution control devices for all technologies are designed to meet the limits of the February 2013 update to the New Source Performance Standards (NSPS) for sulfur dioxide (SO_2), nitrogen oxide (NOx), and particulate matter (PM), and the April 2023 update to the Utility Mercury and Air Toxics Standards (MATS) for mercury (Hg) and hydrochloric acid (HCl). Water effluent streams are regulated by the May 2024 update to the Effluent Limitation Guidelines (ELG), and all plants in the study are in compliance.

For the PC cases, SO_2, NOx, PM, Hg, and HCl are actively controlled with wet flue gas desulfurization (FGD), low NOx burners (LNBs) with overfire air (OFA) and selective catalytic reduction (SCR), a baghouse, dry sorbent injection (DSI) and activated carbon injection (ACI), and a spray dryer evaporator to treat FGD blowdown, respectively.

For NGCC cases, NOx (assumed to be the only pollutant requiring active controls) is controlled with LNBs and an SCR.

All power plant configurations that include CO_2 capture are designed to achieve 90 percent or greater capture, resulting in steady state full load atmospheric CO_2 emissions at or below allowable levels under currently promulgated Environmental Protection Agency (EPA) regulations.[b]

[b] On April 24, 2024, EPA issued a final rule (EPA, 2024b) regulating greenhouse gas emissions from fossil fuel-fired electric generating units that would be applicable to the coal and natural gas power plant configurations described in this report. The final rule includes different emissions standards based on technology, unit operating profiles (e.g., low, intermediate or base load operations) and compliance dates. The power plant configurations included here are evaluated as base load facilities operated at steady state full load (100% nameplate capacity). The PC plants described in this report could be expected to operate beyond 2039 and are assumed to be in compliance with the 2024 final rule.

Vendor quotes were obtained for the various NGCC plants within this report, reflecting 2023 F-Class, 1x1 H-Class, and 2x1 H-Class configurations. The combustion turbine used in the 1x1 H-Class plant is larger and more advanced than that of the 2x1 H-Class plant. The H-Class combustion turbines were selected to 1) provide an H-Class configuration (1x1) that was comparable in output to the PC plants, produced a volume of flue gas that could be treated with a single train CO_2 capture system, and represented the most advanced commercial offering; and 2) provide an H-Class configuration (2x1) and combustion turbine that was consistent with previous revisions of this study. The final assessment of performance and cost was determined independently by NETL and is not endorsed by the individual vendors.

For PC cases, existing costs were escalated to reflect a 2023-year dollar using the methodology outlined in NETL's "Quality Guidelines for Energy System Studies: Capital Cost Scaling Methodology: Revision 4b Report" (NETL, 2025a).

To ensure methodologically-sound, consistent, and transparent technology assessments and comparisons, NETL relies upon its Quality Guidelines for Energy System Studies (QGESS) reports, which provide guidance on topics such as recommended feedstock specifications and pricing, (NETL, 2019a) (NETL, 2019b) (NETL, 2025c) recommendations for performance modeling assumptions, (NETL, 2025d) and guidance for cost estimation methodology (NETL, 2025b).

The methodology for developing the performance results presented in this report included performing steady-state simulations of the power plant configurations at the nameplate rating using the Aspen Plus® (Aspen) process modeling software. The major plant equipment performance and process limits were based on published reports, information obtained from vendors and users of the technology, performance data from design/build utility projects, and/or best engineering judgment (NETL, 2025d). Mass and energy balance data from the Aspen models were used to size major pieces of equipment, which formed the basis for developing the cost estimates presented.

The capital and operating costs for the major equipment and plant sub-systems were estimated by Black & Veatch based on the simulation results using an in-house database, legacy plant estimates, and conceptual estimating models. The cost results were further calibrated using a combination of adjusted vendor-furnished data and scaled estimates from previous design/build projects. The cost results are reported in 2023 dollars.[c]

The baseline fuel costs for this analysis are specified in the 2025 revision of the QGESS report, "Fuel Prices for Selected Feedstocks in National Energy Technology Laboratory [NETL] Studies" (NETL, 2025c). The levelized price for Illinois No. 6 coal delivered to the Midwest is $2.46/GJ ($2.60/MMBtu), on a higher heating value (HHV) basis and in 2023 United States (U.S.) dollars (first-year coal price of $2.86/GJ [$3.01/MMBtu]). The levelized price for natural gas delivered to

[c] The Chemical Engineering Plant Cost Index (Chemical Engineering, 2024) indicates relatively high inflation for capital and labor costs between December 2018 and January 2023, with the cost index rising by 30 percent. Considering the number of available indices for cost escalation and the variability in results depending on the selected index, which is not captured by the reported cost uncertainty, the reader should further adjust the reported costs if required by the end use of the data.

the Midwest is $3.25/GJ ($3.42/MMBtu), on an HHV basis and in 2023 U.S. dollars (first-year natural gas price of $5.30/GJ [$5.59/MMBtu]).[d]

The cost metrics used in this report are the first-year cost of electricity (FY COE) and levelized cost of electricity (LCOE), reported in nominal 2023 dollars, which is the revenue that must be received by the generator per net MWh produced to meet the desired return on equity after meeting all debt and tax obligations and operating expenses. Detailed information pertaining to LCOE calculations is available in the 2025 revision of the QGESS report, "Cost Estimation Methodology for NETL Techno-economic Assessments" (NETL, 2025b). The cost of CO_2 transport and storage (T&S), on an equivalent dollar per MWh basis, is added to the COE and represents a 100 km (62 mile) CO_2 pipeline and storage in a deep saline formation in the Midwest.[e] On a unit basis, the cost of T&S applied is based on the capacity factor and annual CO_2 production rate for each case, ranging $9.7–14.2/tonne ($8.8–12.9/ton). The LCOE results shown for the cases considered in this study are not intended to reflect all the potential market pressures experienced by plants operating today, or the price consumers can expect to pay. Rather, the primary focus is on a sound, transparent, consistent methodology to develop those results, built with industry and vendor input, which ultimately leads to an independent benchmark for the cases considered. This outcome is of significant value to internal and external stakeholders.

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

- Capital and operating costs
- Overall energy efficiency
- Operational flexibility (e.g., ramp rate, turndown, start-up time)
- Fuel prices
- Project financial requirements
- Availability, reliability, and environmental performance
- Current and potential regulations governing air, water, and solid waste discharges from fossil-fueled power plants
- Specific site and application constraints and requirements

While critical to the power generation market, operational flexibility is not explicitly considered in the cases in this report. Rather, Volume 5 of the baseline series examines the flexible gas-fired power plant technologies, configurations, and operation (NETL, 2023).

[d] The Energy Information Administration (EIA, n.d.) indicates relatively high volatility for natural gas, with the Henry hub spot price increasing to $7.83/GJ ($8.26/MMBtu) in May 2022. As these fluctuations are not captured by the reported cost uncertainty, the reader should adjust the reported costs if required by the end use of the data.

[e] Estimated using the Office of Fossil Energy and Carbon Management (FECM)/NETL CO_2 Transport Cost Model and the FECM/NETL CO_2 Saline Storage Cost Model. Additional detail on development of these costs is available in the 2024 revision of the QGESS report, "Carbon Dioxide Transport and Storage Costs in NETL Studies" (NETL, 2024).

RESULTS ANALYSIS

The performance and environmental profile summary for PC cases is reported in Exhibit ES-2 and for NGCC cases in Exhibit ES-3. A graph of the net plant efficiency (HHV basis) is provided in Exhibit ES-4.

Exhibit ES-2. Performance summary and environmental profile for PC cases

Case Name	PC					
	SubC PC			SC PC		
	B11A	B11B.90	B11B.95	B12A	B12B.90	B12B.95
CO_2 Capture Rate (%)	0	90	95	0	90	95
Capacity Factor (%)	85	85	85	85	85	85
Gross Power Output (MWe)	688	769	774	686	763	768
Auxiliary Power Requirement (MWe)	38	118	124	36	113	118
Net Power Output (MWe)	650	650	650	650	650	650
Coal Flow Rate (lb/hr)	493,115	630,940	640,819	473,055	600,801	609,741
Natural Gas Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A
HHV Thermal Input (kWt)	1,685,945	2,157,162	2,190,938	1,617,359	2,054,118	2,084,684
Net Plant HHV Efficiency (%)	38.6	30.2	29.7	40.2	31.7	31.2
Net Plant HHV Heat Rate (Btu/kWh)	8,849	11,317	11,495	8,490	10,778	10,938
Raw Water Withdrawal (gpm/MWnet)	10.0	15.3	15.7	9.3	14.3	14.6
Process Water Discharge (gpm/MWnet)	2.1	3.9	4.0	1.9	3.7	3.8
Raw Water Consumption (gpm/MWnet)	8.0	11.4	11.7	7.4	10.6	10.9
CO_2 Emissions (lb/MMBtu)	202	20	10	202	20	10
CO_2 Emissions (lb/MWh-gross)	1,693	195	98	1,628	187	94
CO_2 Emissions (lb/MWh-net)	1,790	230	117	1,718	219	111
SO_2 Emissions (lb/MMBtu)[A]	0.081	0.000	0.000	0.081	0.000	0.000
SO_2 Emissions (lb/MWh-gross)	0.675	0.000	0.000	0.649	0.000	0.000
NOx Emissions (lb/MMBtu)	0.084	0.073	0.072	0.087	0.076	0.076
NOx Emissions (lb/MWh-gross)	0.700	0.700	0.700	0.700	0.700	0.700
PM Emissions (lb/MMBtu)	0.011	0.009	0.009	0.011	0.010	0.010
PM Emissions (lb/MWh-gross)	0.090	0.090	0.090	0.090	0.090	0.090
Hg Emissions (lb/TBtu)	0.359	0.313	0.311	0.373	0.326	0.324
Hg Emissions (lb/MWh-gross)[B]	$3.00x10^{-6}$	$3.00x10^{-6}$	$3.00x10^{-6}$	$3.00x10^{-6}$	$3.00x10^{-6}$	$3.00x10^{-6}$

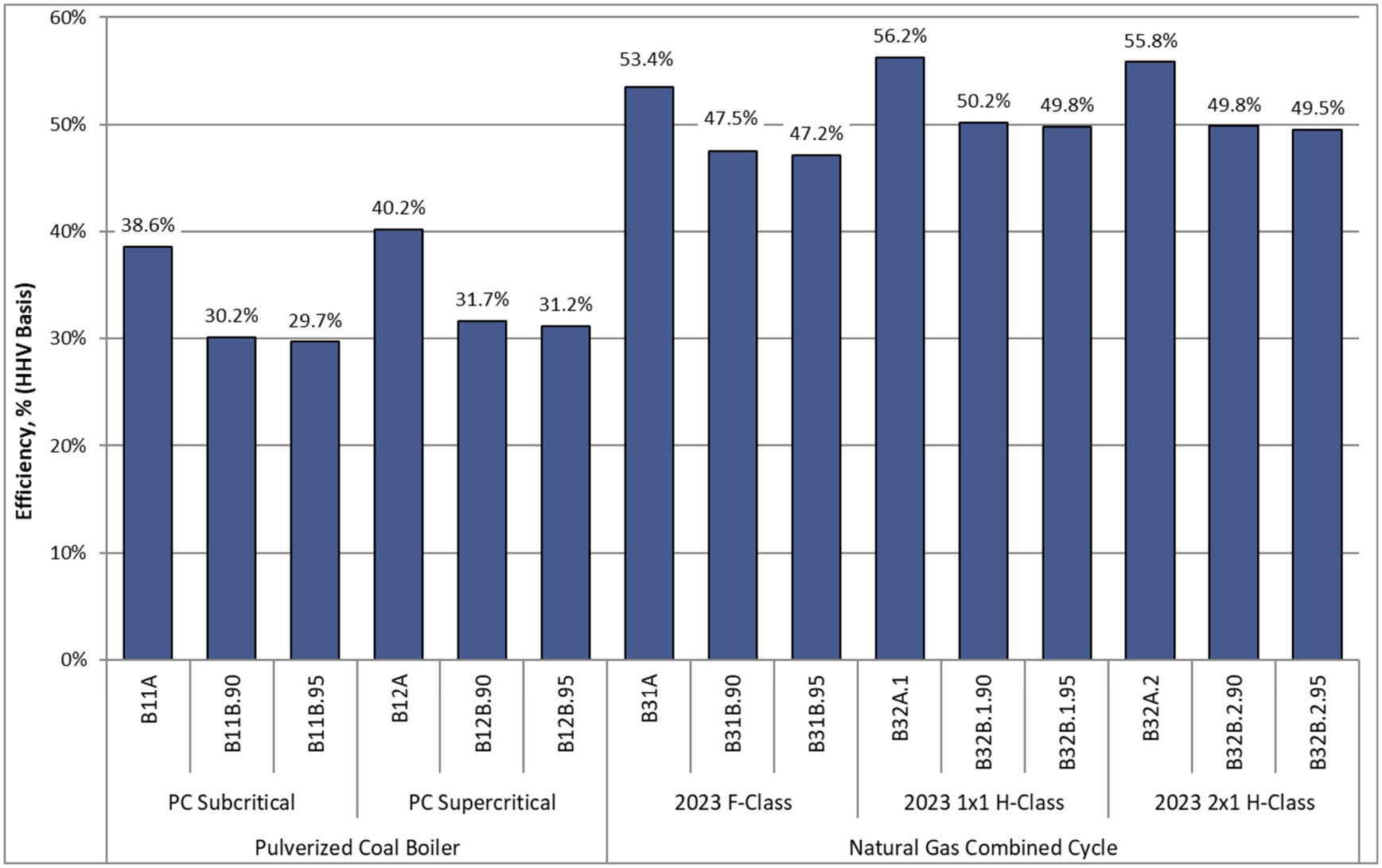
[A] Trace amounts of sulfur emissions may exist in the flue gas stream to the stack in capture cases
[B] The mercury capture units used in PC cases were designed to attain the emissions target of $3.00x10^{-6}$ lb/MWh-gross

Exhibit ES-3. Performance summary and environmental profile for NGCC cases

Case Name	NGCC								
	SOA 2023 F-Class			SOA 2023 1x1 H-Class[A]			SOA 2023 2x1 H-Class[A]		
	B31A	B31B.90	B31B.95	B32A.1	B32B.1.90	B32B.1.95	B32A.2	B32B.2.90	B32B.2.95
CO_2 Capture Rate (%)	0	90	95	0	90	95	0	90	95
Capacity Factor (%)	85	85	85	85	85	85	85	85	85
Gross Power Output (MWe)	755	707	705	660	619	617	1,137	1,067	1,064
Auxiliary Power Requirement (MWe)	14	49	51	11	40	42	19	69	72
Net Power Output (MWe)	741	658	654	649	579	575	1,118	998	992
Coal Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Natural Gas Flow Rate (lb/hr)	210,413	210,413	210,413	175,100	175,100	175,100	303,962	303,962	303,962
HHV Thermal Input (kWt)	1,386,417	1,386,417	1,386,417	1,153,739	1,153,739	1,153,739	2,002,815	2,002,815	2,002,815
Net Plant HHV Efficiency (%)	53.4	47.5	47.2	56.2	50.2	49.8	55.8	49.8	49.5
Net Plant HHV Heat Rate (Btu/kWh)	6,385	7,187	7,236	6,068	6,801	6,848	6,113	6,846	6,892
Raw Water Withdrawal (gpm/MWnet)	4.1	7.1	7.2	3.6	6.5	6.6	3.7	6.6	6.7
Process Water Discharge (gpm/MWnet)	1.0	2.5	2.6	0.9	2.4	2.4	0.9	2.4	2.4
Raw Water Consumption (gpm/MWnet)	3.0	4.6	4.6	2.7	4.1	4.1	2.8	4.2	4.2
CO_2 Emissions (lb/MMBtu)	119	12	6	119	12	6	119	12	6
CO_2 Emissions (lb/MWh-gross)	743	79	40	707	76	38	713	76	38
CO_2 Emissions (lb/MWh-net)	757	85	43	719	81	41	725	81	41
SO_2 Emissions (lb/MMBtu)[B]	0.001	0.000	0.000	0.001	0.000	0.000	0.001	0.000	0.000
SO_2 Emissions (lb/MWh-gross)	0.006	0.000	0.000	0.006	0.000	0.000	0.006	0.000	0.000
NOx Emissions (lb/MMBtu)	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
NOx Emissions (lb/MWh-gross)	0.021	0.021	0.021	0.019	0.018	0.018	0.020	0.019	0.019
PM Emissions (lb/MMBtu)	0.003	0.000	0.000	0.002	0.000	0.000	0.003	0.000	0.000
PM Emissions (lb/MWh-gross)	0.017	0.000	0.000	0.014	0.000	0.000	0.016	0.000	0.000
Hg Emissions (lb/TBtu)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Hg Emissions (lb/MWh-gross)	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$

[A]The combustion turbine used in the 1x1 H-Class plant is larger and more advanced than that of the 2x1 H-Class plant
[B]Trace amounts of sulfur emissions may exist in the flue gas stream to the stack in capture cases

Exhibit ES-4. Net plant efficiency (HHV basis)



The primary performance and environmental profile conclusions that can be drawn from the PC cases are as follows:

- Adding 90 percent CO_2 capture results in an HHV efficiency penalty of 8.4 percentage points (21.8 percent), relative to the non-capture case (B11A) for the SubC PC case (B11B.90) and 8.5 percentage points (21.2 percent), relative to the non-capture case (B12A) for the SC PC case (B12B.90).
- The addition of 95 percent CO_2 capture (B11B.95 and B12B.95) results in an HHV efficiency penalty of 0.5 percentage points (1.5–1.6 percent), relative to the 90 percent capture cases (B11B.90 and B12B.90).
- The FGD wastewater blowdown flow rate range to be treated by the spray dryer evaporator spans 209–283 lpm (55–75 gpm). The approximate performance impact of implementing the spray dryer evaporator across the six PC cases is a 0.25–0.27 percentage point decrease in the HHV net plant efficiency. This is due primarily to the diversion of warm flue gas away from the air preheater and to the evaporator, with an additional minor impact resulting from the small auxiliary load required by the spray dryer evaporator.
- Emissions of Hg, HCl, PM, NOx, and SO_2 are all at or below the applicable federal regulatory limits currently in effect for PC technology.

The primary performance and environmental profile conclusions that can be drawn from the NGCC cases are as follows:

- The 1x1 H-Class NGCC cases have the highest HHV net plant efficiency of all the technologies, both without CO_2 capture (56.2 percent in B32A.1) and with CO_2 capture (50.2 and 49.8 percent at 90 percent [B32B.1.90] and 95 percent [B32B.1.95] CO_2 capture rates, respectively). The next highest non-NGCC case efficiency is the non-capture SC PC case (B12A), with an efficiency of 40.2 percent.
- Adding 90 percent CO_2 capture results in an HHV efficiency penalty of 6 percentage points (11 percent), relative to the non-capture cases (B31A, B32A.1, and B32A.2), for the F-Class case (B31B.90) and H-Class cases (B32B.1.90 and B32B.2.90).
- The addition of 95 percent CO_2 capture (B31B.95, B32B.1.95, and B32B.2.95) results in an HHV efficiency penalty of 0.3 percentage points (0.7 percent) for F- and H-Class cases, relative to the 90 percent capture cases (B31B.90, B32B.1.90, and B32B.2.90).
- Natural gas contains no Hg or chloride, and PM, NOx, and SO_2 emissions are all at or below the applicable federal regulatory limits currently in effect for NGCC technology.

The energy penalty for adding CO_2 capture is less in NGCC cases than in PC cases 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 (13.7 kg/GJ) [HHV] of heat input and coal contains 55 lb/MMBtu (23.6 kg/GJ) [HHV]).

- 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 56–60 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 (4–5 vol% versus 12 vol% for PC)—concentration of CO_2 is the driving force for capture from the flue gas in the amine system, and the lower concentration requires more energy (steam and auxiliary load) from the base plant to reach the capture target.

The cost results for PC cases are presented in Exhibit ES-5 and for NGCC cases in Exhibit ES-6. A graph of the LCOE is provided in Exhibit ES-7.

As discussed in the Special Considerations on Reported Costs section below, the capital cost estimates in this report reflect varying uncertainty ranges by technology type. The error bars shown in Exhibit ES-7 represent the potential LCOE range relative to the maximum and minimum capital cost uncertainty ranges. The LCOE ranges presented are not reflective of other changes, such as variation in fuel price, labor price, CF, or other factors.

Exhibit ES-5. Cost summary for all PC cases

Case Name[A]	PC					
	SubC PC			SC PC		
	B11A	B11B.90	B11B.95	B12A	B12B.90	B12B.95
Total Plant Cost (2023$/kW)	2,471	4,177	4,258	2,584	4,254	4,331
Bare Erected Cost	1,822	2,964	3,019	1,906	3,025	3,078
Home Office Expenses	319	519	528	334	529	539
Project Contingency	331	581	593	345	590	601
Process Contingency	0	113	117	0	109	113
Total Overnight Cost (2023$/MM)	1,985	3,341	3,405	2,072	3,399	3,460
Total Overnight Cost (2023$/kW)	3,054	5,137	5,236	3,188	5,226	5,321
Owner's Costs	583	960	979	604	972	990
Total As-Spent Cost (2023$/kW)	3,704	6,230	6,350	3,866	6,338	6,453
FY COE ($/MWh) (excluding T&S)[B]	86.0	133.6	136.0	86.9	132.8	135.1
Capital Costs	38.3	64.5	65.7	40.0	65.6	66.8
Fixed Costs	11.1	17.9	18.2	11.6	18.2	18.5
Variable Costs	9.8	17.1	17.5	9.7	16.6	16.9
Fuel Costs	26.7	34.1	34.6	25.6	32.5	33.0
FY COE ($/MWh) (including T&S)[B]	86.0	142.7	146.3	86.9	141.7	145.0
CO_2 T&S Costs	N/A	9.1	10.3	N/A	8.9	9.8
LCOE ($/MWh) (excluding T&S)[B]	89.4	140.6	143.2	90.5	140.0	142.5
Capital Costs	38.3	64.5	65.7	40.0	65.6	66.8
Fixed Costs	14.9	23.9	24.3	15.5	24.2	24.6
Variable Costs	13.1	22.8	23.3	12.9	22.2	22.6
Fuel Costs	23.0	29.4	29.9	22.1	28.0	28.4
LCOE ($/MWh) (including T&S)[B]	89.4	152.7	156.9	90.5	151.9	155.6
CO_2 T&S Costs	N/A	12.1	13.7	N/A	11.9	13.1
Cost of CO_2 Captured (ex. T&S), $/tonne[C]	N/A	53.6	52.6	N/A	55.7	54.5
Cost of CO_2 Avoided (incl. T&S), $/tonne[C]	N/A	92.3	91.5	N/A	90.4	89.3

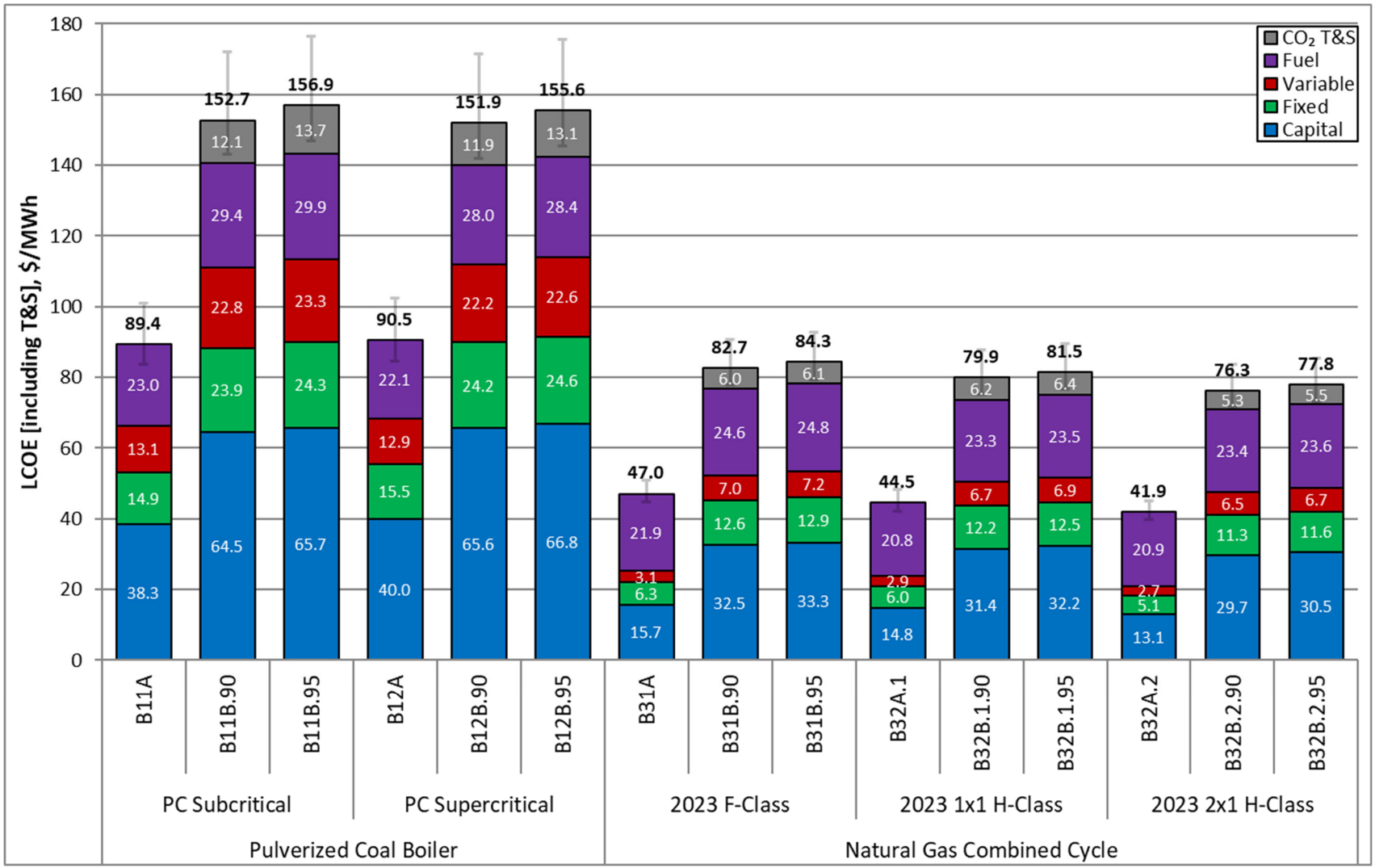
[A]Financing structures are presented in the QGESS report, "Cost Estimation Methodology for NETL Techno-economic Assessments" (NETL, 2025b)
[B]Varying incentives, such as tax credits, could impact the economics of the system
[C]Both the cost of CO_2 captured and cost of CO_2 avoided were calculated based on the non-capture SC PC Case B12A for all coal cases

Exhibit ES-6. Cost summary for all NGCC cases

Case Name[A]	NGCC								
	SOA 2023 F-Class			SOA 2023 1x1 H-Class[B]			SOA 2023 2x1 H-Class[B]		
	B31A	B31B.90	B31B.95	B32A.1	B32B.1.90	B32B.1.95	B32A.2	B32B.2.90	B32B.2.95
Total Plant Cost (2023$/kW)	1,051	2,180	2,235	993	2,111	2,165	876	1,998	2,051
Bare Erected Cost	756	1,473	1,508	714	1,424	1,458	630	1,337	1,371
Home Office Expenses	151	295	302	143	285	292	126	267	274
Project Contingency	144	326	335	136	317	325	119	302	310
Process Contingency	0	86	90	0	86	90	0	91	96
Total Overnight Cost (2023$/MM)	950	1,745	1,776	786	1,486	1,513	1,196	2,424	2,472
Total Overnight Cost (2023$/kW)	1,283	2,651	2,717	1,212	2,566	2,632	1,069	2,428	2,493
Owner's Costs	232	471	482	219	455	467	194	430	442
Total As-Spent Cost (2023$/kW)	1,517	3,136	3,214	1,433	3,036	3,113	1,265	2,872	2,949
FY COE ($/MWh) (excluding T&S)[C]	58.5	87.3	88.8	55.4	83.6	85.0	53.1	81.3	82.7
Capital Costs	15.7	32.5	33.3	14.8	31.4	32.2	13.1	29.7	30.5
Fixed Costs	4.7	9.5	9.7	4.5	9.2	9.4	3.9	8.5	8.7
Variable Costs	2.3	5.3	5.4	2.2	5.0	5.2	2.0	4.9	5.0
Fuel Costs	35.7	40.2	40.4	33.9	38.0	38.3	34.2	38.2	38.5
FY COE ($/MWh) (including T&S)[C]	58.5	91.8	93.4	55.4	88.3	89.8	53.1	85.3	86.8
CO_2 T&S Costs	N/A	4.5	4.6	N/A	4.7	4.8	N/A	4.0	4.1
LCOE ($/MWh) (excluding T&S)[C]	47.0	76.7	78.2	44.5	73.6	75.1	41.9	71.0	72.4
Capital Costs	15.7	32.5	33.3	14.8	31.4	32.2	13.1	29.7	30.5
Fixed Costs	6.3	12.6	12.9	6.0	12.2	12.5	5.1	11.3	11.6
Variable Costs	3.1	7.0	7.2	2.9	6.7	6.9	2.7	6.5	6.7
Fuel Costs	21.9	24.6	24.8	20.8	23.3	23.5	20.9	23.4	23.6
LCOE ($/MWh) (including T&S)[C]	47.0	82.7	84.3	44.5	79.9	81.5	41.9	76.3	77.8
CO_2 T&S Costs	N/A	6.0	6.1	N/A	6.2	6.4	N/A	5.3	5.5
Cost of CO_2 Captured (ex. T&S), $/tonne[D]	N/A	85.4	84.3	N/A	88.6	87.5	N/A	87.9	86.7
Cost of CO_2 Avoided (incl. T&S), $/tonne[D]	N/A	117.1	115.2	N/A	122.3	120.3	N/A	117.9	116.0

[A]Financing structures are presented in the QGESS report, "Cost Estimation Methodology for NETL Techno-economic Assessments" (NETL, 2025b)
[B]The combustion turbine used in the 1x1 H-Class plant is larger and more advanced than that of the 2x1 H-Class plant
[C]Varying incentives, such as tax credits, could impact the economics of the system
[D]Both the cost of CO_2 captured and cost of CO_2 avoided were calculated based on the analogous non-capture NGCC Cases (i.e., B31B cases use B31A as a reference, B32B.1 cases use B32A.1, and B32B.2 cases use B32A.2)

Exhibit ES-7. LCOE by cost component



Note: Financing structures are presented in the QGESS report, "Cost Estimation Methodology for NETL Techno-economic Assessments" (NETL, 2025b)

The primary cost conclusions that can be drawn from the PC cases are as follows:

- When comparing SubC and SC PC cases with equivalent rates of CO_2 capture, the difference in TOCs and LCOEs is within the accuracy of this report.
- The normalized TOC premium for adding CO_2 capture is 64–71 percent, spanning a TOC increase range of $2,038–2,182/kW.
- In all cases, the LCOE (including T&S) is dominated by the capital cost component (42–44 percent) followed by the fuel cost component (18–26 percent).
- The PC cases incur a 68–71 percent increase in LCOE (including T&S costs) due to the addition of 90 percent CO_2 capture.
- The addition of 95 percent CO_2 capture to the SubC PC cases results in an additional LCOE penalty of $4.1/MWh (2.7 percent) in Case B11B.95, compared to Case B11B.90 (including T&S costs). For the SCPC cases, the addition of 95 percent CO_2 capture results in an additional LCOE penalty of $3.7/MWh (2.4 percent) in Case B12B.95, compared to Case B12B.90 (including T&S costs).
- CO_2 T&S costs add $12–14/MWh to the LCOE, which accounts for 8–9 percent of the total LCOE.

The primary cost conclusions that can be drawn from the NGCC cases are as follows:

- The H-Class 2x1 configuration has the lowest normalized TOC for capture and non-capture cases, with the 1x1 H-Class and F-Class being 6–13 percent and 9–20 percent greater, respectively.
- The normalized TOC premium for adding CO_2 capture is 107–133 percent, spanning a TOC increase range of $1,355–1,434/kW.
- Fuel costs represent the largest fraction of LCOE (including T&S costs) in non-capture cases, representing 46–50 percent of the total. In cases with CO_2 capture, capital costs represent the largest fraction of LCOE (including T&S costs), representing 39–40 percent of the total.
- The NGCC cases incur a 76–82 percent increase in LCOE (including T&S costs) due to the addition of 90 percent CO_2 capture.
- The addition of 95 percent CO_2 capture results in an additional LCOE (including T&S costs) penalty of $1.6/MWh (2 percent), compared to cases with 90 percent CO_2 capture.
- CO_2 T&S costs add $5–6/MWh to the LCOE, which accounts for 7–8 percent of the total LCOE.

General cost conclusions that can be drawn between the two technology types are as follows:

- The capital cost component of LCOE is greatest in PC (capture and non-capture) cases (43–44 percent in non-capture cases; 42–43 percent in capture cases) and lowest in NGCC cases (31–33 percent in non-capture cases; 39–40 percent in capture cases).

- The fuel cost component of LCOE is greatest in non-capture NGCC cases (46–50 percent) and lowest in PC cases with CO_2 capture (18–19 percent).
- Based on TOC in $/kW, NGCC 2x1 H-Class capital costs are 34 percent of the SC PC capital costs for non-capture cases (B32A.2 vs B12A), 46 percent of the SC PC capital costs for the 90 percent capture cases (B32B.2.90 vs B12B.90), and 47 percent of the SC PC capital costs for the 95 percent capture cases (B32B.2.95 vs B12B.95).
- NGCC plant LCOEs are 46–54 percent of the SC PC plant LCOEs, when comparing cases with the same rate of CO_2 capture.
- Despite having higher net plant efficiencies and lower LCOEs, both the cost of CO_2 captured and cost of CO_2 avoided are higher for NGCC cases than PC cases due to the lower concentration and amount of CO_2 available for capture.
- If future legislation assigns a cost to carbon emissions, all 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.

SENSITIVITIES

Exhibit ES-8 shows the LCOE sensitivity to natural gas costs for NGCC 1x1 H-Class cases, compared to SC PC cases, with 95 percent capture and without carbon capture and storage (CCS). The bands for the coal cases represent a variance in coal price from $1.85–3.08/GJ ($1.95–3.25/MMBtu) (±25 percent of the base study value of $2.46/GJ [$2.60/MMBtu]). This sensitivity highlights regions of competitiveness for NGCC with SC PC, with and without CCS, as a function of the delivered natural gas price. The base case assumed natural gas price is $3.25/GJ [$3.42/MMBtu].

Exhibit ES-9 shows the LCOE sensitivity to coal costs for SC PC cases, compared to NGCC 1x1 H-Class cases, with 95 percent capture and without CCS. The bands for the natural gas cases represent a variance in natural gas price of $2.43–4.06/GJ ($2.57–4.28/MMBtu) (±25 percent of the base study value of $3.25/GJ [$3.42/MMBtu]). Similar to Exhibit ES-8, this sensitivity highlights regions of competitiveness for NGCC with SC PC, with and without CCS, as a function of the delivered coal price. The base case assumed coal price is $2.46/GJ [$2.60/MMBtu]).

Exhibit ES-8. LCOE sensitivity to natural gas costs

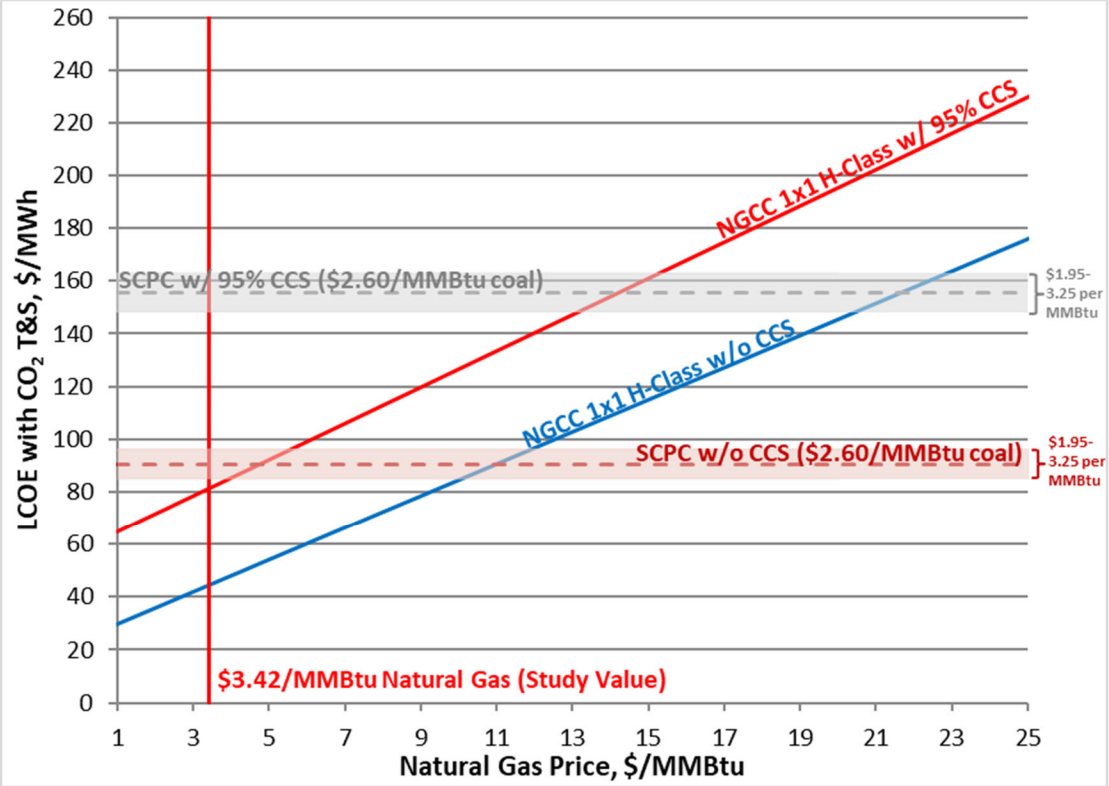
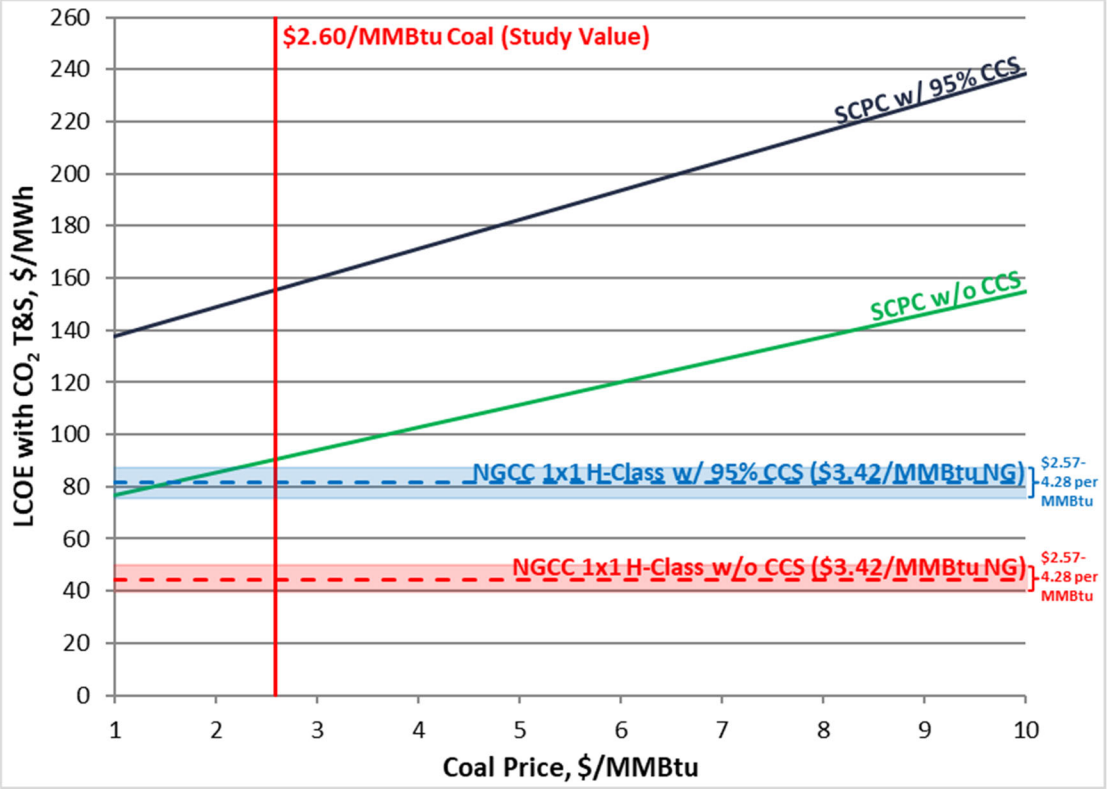


Exhibit ES-9. LCOE sensitivity to coal costs

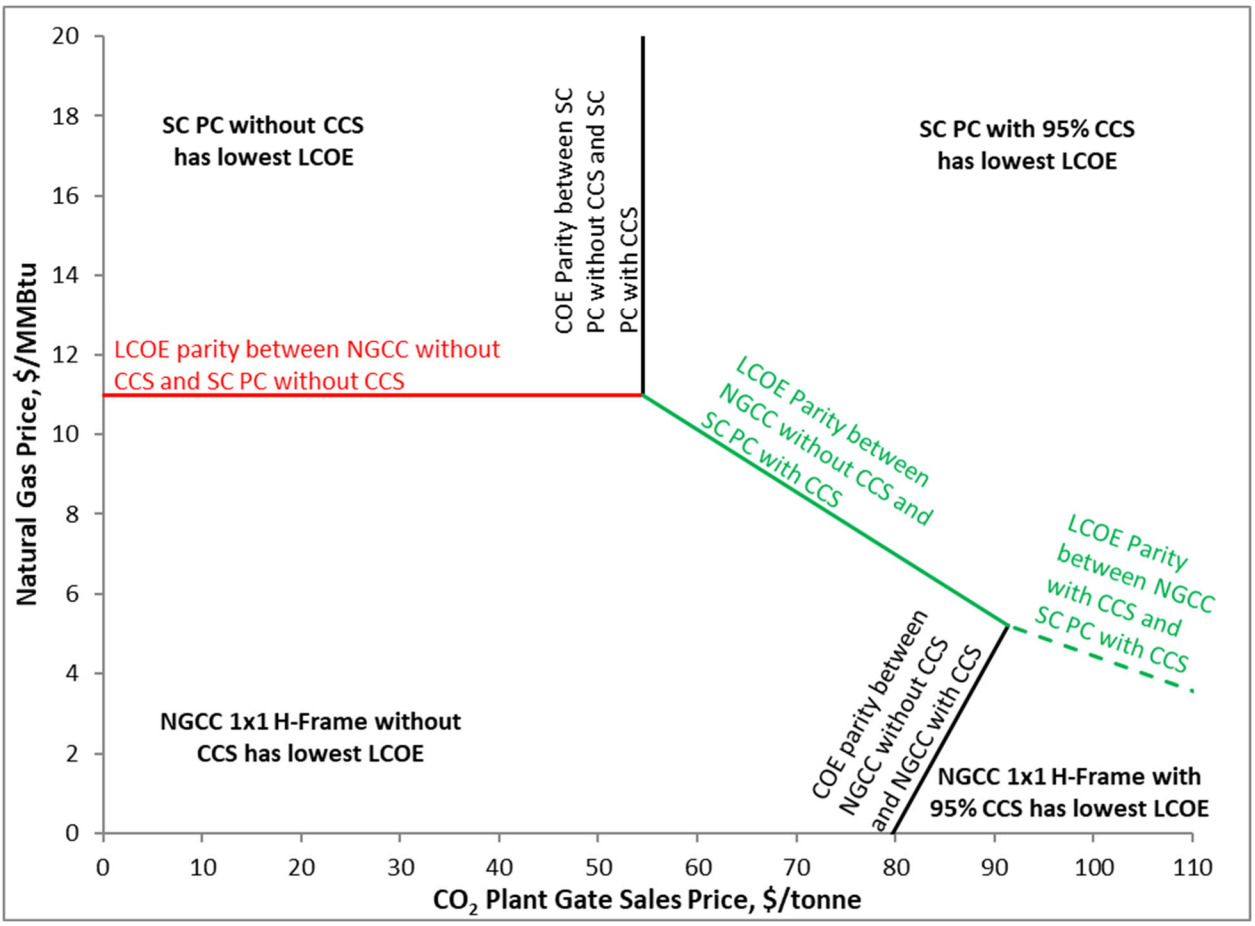


Sale of the captured CO_2 for utilization and storage in enhanced oil recovery (EOR) has the potential to provide a revenue stream for cases with CO_2 capture. The plant gate CO_2 sales price, or the cost of CO_2 captured, will ultimately depend on a number of factors including plant location and crude 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-10. The lines in the plot represent LCOE parity between different pairs of technologies.

The plot demonstrates the following points:

- Non-capture plants are the low-cost option below a CO_2 price of $54.5/tonne ($49.5/ton).
- NGCC is preferred when natural gas prices are below $11.0/MMBtu with a CO_2 sale price below $54.5/tonne ($49.5/ton) (and a CF 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 $5.2/MMBtu at $91.4/tonne (83.0/ton).

Exhibit ES-10. Lowest cost power generation options at various natural gas and CO_2 sales prices for NGCC and PC



SPECIAL CONSIDERATIONS ON REPORTED COSTS

Capital Costs

The capital cost estimates documented in this report reflect varying uncertainty ranges by technology type, as shown in Exhibit ES-11.

Exhibit ES-11. Capital cost uncertainty ranges

Technology	Uncertainty Range	AACE Classification
PC	-15/+30	Class 4
NGCC	-15/+25	Class 4

PC and NGCC cases carry uncertainty ranges that fall within Association for the Advancement of Cost Engineering (AACE) Class 4 cost estimates (i.e., concept screening) (NETL, 2025b) (AACE International, 2003) (AACE International, 2005) based on the level of engineering design performed. Given the recent experience with NGCC plants, the NGCC uncertainty range is slightly smaller than PC. In all cases, this 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," supply chain improvements, vendor competition, and risk reduction benefits that result from serial deployments as well as from continuing research and development.

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 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 early deployments of PC and NGCC plants with CO_2 capture may incur costs higher than those reflected within this report.

Other Factors

Actual reported project costs for all 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 and availability, seismic conditions, water quality, financing

parameters, local environmental concerns, weather delays) that may make construction more costly. Such variations are not captured by the reported cost uncertainty.

Future Cost Trends

Continuing research, development, and demonstration 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 here.

CO_2 Capture Rates Above 95 Percent

Commercial-scale demonstration of solvent-based post-combustion CO_2 capture systems at power generation facilities (specifically PC plants) has shown the ability to capture 90 percent of the CO_2 in the flue gas stream (Greg Kennedy, n.d.) (Giannaris, et al., 2021). Moreover, field-testing of post-combustion CO_2 capture technology as well as vendor and industry feedback on projects currently in the planning stages (including front-end engineering and design projects sponsored by DOE) indicates that capture rates as high as 95 percent are feasible for both coal- and natural gas-fueled electricity generating units (NCCC, 2020b) (NCCC, 2020a) (OBrien, et al., 2022) (International CCS Knowledge Center, November). Given the breadth of publicly available information supporting the capability for post-combustion capture systems to remove greater than 90 percent of the CO_2 in the treated stream, cases for 90 percent and 95 percent capture on NGCC and PC are presented in the main body of this report.

It should be emphasized that technology suppliers (as reflected in vendor-supplied information provided to DOE for this study that included cost and performance estimates for >95 percent CCS [97 percent for NGCC and 99 percent for PC] study cases) as well as subject matter experts acknowledge and support that solvent-based post-combustion CO_2 capture technologies are capable of achieving CO_2 removal rates beyond 95 percent on low-purity streams representative of fossil-fueled combustion. Although technoeconomic analyses of deep decarbonization (≥ 99 percent) of combustion flue gas have been published by others, (Du, Gao, Rochelle, & Bhown, 2021) (IEAGHG, 2019) the relatively limited experience with design and operation of capture systems that can routinely, reliably, and economically achieve very high removal rates requires further study. Technoeconomic analyses of the higher capture rates (97 percent NGCC and 99 percent PC) are included in the appendices to this report. The performance and environmental profile summaries for PC and NGCC cases with CO_2 capture rates greater than 95 percent are shown in Exhibit ES-12; the primary conclusions that can be drawn are as follows:

- The emissions of Hg, HCl, PM, NOx, and SO_2 are all at or below the applicable federal regulatory limits currently in effect for PC and NGCC technologies (natural gas contains no Hg or chloride).
- For the PC cases, adding a CO_2 capture system results in a 9 percentage point (24 percent) reduction in efficiency, compared to the non-capture PC cases. For the NGCC cases, the addition of a CO_2 capture system results in a 7 percentage point (12 percent) reduction in efficiency, compared to non-capture NGCC cases.

The cost results for PC and NGCC cases with CO_2 capture rates greater than 95 percent are shown in Exhibit ES-13; the primary cost conclusions that can be drawn are as follows:

- The addition of CO_2 capture increases the TOC by 71–76 percent for PC cases and 115–137 for NGCC cases.
- The addition of CO_2 capture increases the LCOE, including T&S, by 76–80 percent for PC cases and 82–88 percent for NGCC cases.
    - As discussed in Section 4.1.4, the 2x1 H-Class case B32B.2.97 uses two parallel CO_2 capture trains due to the high volumetric flow rate of flue gas produced. A high-level estimate of a dual-absorber, single-train CO_2 capture system suggests that the TPC of the CO_2 capture system may be reduced by 17 percent, relative to the two-train configuration, which would reduce the LCOE by 4 percent.[f]
- For PC cases, CO_2 T&S costs add $14/MWh to the LCOE, which accounts for 9 percent of the total LCOE. For NGCC cases, CO_2 T&S costs add $6/MWh to the LCOE, which accounts for 7–8 percent of the total LCOE.

[f] As of the publication of this report, no commercial builds have been demonstrated with this design. The estimated cost impact does not reflect any vendor input.

Exhibit ES-12. Performance summary and environmental profile for PC and NGCC cases with CO_2 capture rates greater than 95 percent

Case Name	PC				NGCC					
	SubC PC		SC PC		SOA 2023 F-Class		SOA 2023 1x1 H-Class[A]		SOA 2023 2x1 H-Class[A]	
	B11A	B11B.99	B12A	B12B.99	B31A	B31B.97	B32A.1	B32B.1.97	B32A.2	B32B.2.97
CO_2 Capture Rate (%)	0	99	0	99	0	97	0	97	0	97
Capacity Factor (%)	85	85	85	85	85	85	85	85	85	85
Gross Power Output (MWe)	688	780	686	774	755	702	660	615	1,137	1,060
Auxiliary Power Requirement (MWe)	38	130	36	123	14	52	11	43	19	74
Net Power Output (MWe)	650	650	650	650	741	650	649	572	1,118	986
Coal Flow Rate (lb/hr)	493,115	651,832	473,055	619,732	N/A	N/A	N/A	N/A	N/A	N/A
Natural Gas Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	210,413	210,413	175,100	175,100	303,962	303,962
HHV Thermal Input (kWt)	1,685,945	2,228,591	1,617,359	2,118,843	1,386,417	1,386,417	1,153,739	1,153,739	2,002,815	2,002,815
Net Plant HHV Efficiency (%)	38.6	29.2	40.2	30.7	53.4	46.9	56.2	49.6	55.8	49.2
Net Plant HHV Heat Rate (Btu/kWh)	8,849	11,691	8,490	11,116	6,385	7,277	6,068	6,884	6,113	6,928
Raw Water Withdrawal (gpm/MWnet)	10.0	16.1	9.3	15.0	4.1	7.3	3.6	6.6	3.7	6.7
Process Water Discharge (gpm/MWnet)	2.1	4.2	1.9	3.9	1.0	2.6	0.9	2.4	0.9	2.4
Raw Water Consumption (gpm/MWnet)	8.0	11.9	7.4	11.1	3.0	4.8	2.7	4.2	2.8	4.3
CO_2 Emissions (lb/MMBtu)	202	2	202	2	119	4	119	4	119	4
CO_2 Emissions (lb/MWh-gross)	1,693	20	1,628	19	743	24	707	23	713	23
CO_2 Emissions (lb/MWh-net)	1,790	24	1,718	23	757	26	719	25	725	25
SO_2 Emissions (lb/MMBtu)[B]	0.081	0.000	0.081	0.000	0.001	0.000	0.001	0.000	0.001	0.000
SO_2 Emissions (lb/MWh-gross)	0.675	0.000	0.649	0.000	0.006	0.000	0.006	0.000	0.006	0.000
NOx Emissions (lb/MMBtu)	0.084	0.072	0.087	0.075	0.003	0.003	0.003	0.003	0.003	0.003
NOx Emissions (lb/MWh-gross)	0.700	0.700	0.700	0.700	0.021	0.021	0.019	0.018	0.020	0.019
PM Emissions (lb/MMBtu)	0.011	0.009	0.011	0.010	0.003	0.000	0.002	0.000	0.003	0.000
PM Emissions (lb/MWh-gross)	0.090	0.090	0.090	0.090	0.017	0.000	0.014	0.000	0.016	0.000
Hg Emissions (lb/TBtu)	0.359	0.308	0.373	0.321	0.000	0.000	0.000	0.000	0.000	0.000
Hg Emissions (lb/MWh-gross)[C]	3.00×10^{-6}	3.00×10^{-6}	3.00×10^{-6}	3.00×10^{-6}	0.00×10^{-6}	0.00×10^{-6}	0.00×10^{-6}	0.00×10^{-6}	0.00×10^{-6}	0.00×10^{-6}

[A]The combustion turbine used in the 1x1 H-Class plant is larger and more advanced than that of the 2x1 H-Class plant
[B]Trace amounts of sulfur emissions may exist in the flue gas stream to the stack in capture cases
[C]The mercury capture units used in the PC cases were designed to attain the emissions target of 3.00×10^{-6} lb/MWh-gross

Exhibit ES-13. Cost summary for PC and NGCC cases with CO2 capture rates greater than 95 percent

Case Name[A]	PC				NGCC					
	SubC PC		SC PC		SOA 2023 F-Class		SOA 2023 1x1 H-Class[B]		SOA 2023 2x1 H-Class[B]	
	B11A	B11B.99	B12A	B12B.99	B31A	B31B.97	B32A.1	B32B.1.97	B32A.2	B32B.2.97
Total Plant Cost (2023$/kW)	2,471	4,363	2,584	4,433	1,051	2,271	993	2,199	876	2,086
Bare Erected Cost	1,822	3,090	1,906	3,146	756	1,531	714	1,480	630	1,393
Home Office Expenses	319	541	334	551	151	306	143	296	126	279
Project Contingency	331	608	345	616	144	341	136	331	119	316
Process Contingency	0	124	0	120	0	93	0	92	0	98
Total Overnight Cost (2023$/MM)	1,985	3,489	2,072	3,541	950	1,794	786	1,529	1,196	2,500
Total Overnight Cost (2023$/kW)	3,054	5,365	3,188	5,444	1,283	2,760	1,212	2,673	1,069	2,535
Owner's Costs	583	1,002	604	1,011	232	490	219	474	194	449
Total As-Spent Cost (2023$/kW)	3,704	6,506	3,866	6,602	1,517	3,265	1,433	3,162	1,265	2,999
FY COE ($/MWh) (excluding T&S)[C]	86.0	139.1	86.9	138.0	58.5	89.8	55.4	86.0	53.1	83.7
Capital Costs	38.3	67.3	40.0	68.3	15.7	33.8	14.8	32.7	13.1	31.0
Fixed Costs	11.1	18.6	11.6	18.8	4.7	9.8	4.5	9.5	3.9	8.8
Variable Costs	9.8	17.9	9.7	17.4	2.3	5.5	2.2	5.3	2.0	5.1
Fuel Costs	26.7	35.2	25.6	33.5	35.7	40.7	33.9	38.5	34.2	38.7
FY COE ($/MWh) (including T&S)[C]	86.0	149.6	86.9	148.3	58.5	94.5	55.4	90.8	53.1	87.8
CO_2 T&S Costs	N/A	10.6	N/A	10.3	N/A	4.7	N/A	4.9	N/A	4.1
LCOE ($/MWh) (excluding T&S)[C]	89.4	146.4	90.5	145.5	47.0	79.2	44.5	76.0	41.9	73.3
Capital Costs	38.3	67.3	40.0	68.3	15.7	33.8	14.8	32.7	13.1	31.0
Fixed Costs	14.9	24.8	15.5	25.1	6.3	13.1	6.0	12.7	5.1	11.8
Variable Costs	13.1	23.9	12.9	23.2	3.1	7.4	2.9	7.0	2.7	6.8
Fuel Costs	23.0	30.4	22.1	28.9	21.9	24.9	20.8	23.6	20.9	23.7
LCOE ($/MWh) (including T&S)[C]	89.4	160.5	90.5	159.2	47.0	85.4	44.5	82.5	41.9	78.9
CO_2 T&S Costs	N/A	14.1	N/A	13.7	N/A	6.2	N/A	6.5	N/A	5.5
Cost of CO_2 Captured (ex. T&S), $/tonne[D]	N/A	52.7	N/A	54.5	N/A	84.8	N/A	87.9	N/A	87.1
Cost of CO_2 Avoided (incl. T&S), $/tonne[D]	N/A	91.3	N/A	89.5	N/A	115.8	N/A	120.7	N/A	116.6

[A]Financing structures are presented in the QGESS report, "Cost Estimation Methodology for NETL Techno-economic Assessments" (NETL, 2025b)
[B]The combustion turbine used in the 1x1 H-Class plant is larger and more advanced than that of the 2x1 H-Class plant
[C]Varying incentives, such as tax credits, could impact the economics of the system
[D]Both the cost of CO_2 captured and cost of CO_2 avoided were calculated based on the non-capture SC PC Case B12A for all coal cases, and the analogous non-capture NGCC Cases (i.e., B31B cases use B31A as a reference, B32B.1 cases use B32A.1, and B32B.2 cases use B32A.2)

1 INTRODUCTION

This report presents an independent assessment of the cost and performance of select fossil energy power systems—pulverized coal (PC) and natural gas combined cycle (NGCC) plants—using a systematic, transparent technical and economic approach. This is Volume 1 of a five-volume series, which comprise the following reports:

- 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
- Volume 5: Natural Gas Electricity Generating Units for Flexible Operation

The cost and performance of fossil fuel-based generation technologies represented in this report (and the series at large) are important inputs to assessments and determinations of technology combinations to be utilized to meet the projected demands of future power markets. In addition to informing technology comparisons, the reference plant configurations found in this report provide perspective for regulators and policy makers. From a research and development perspective, this report is used to assess goals and metrics and to provide a consistent basis for comparing developing technologies.

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

- Capital and operating costs
- Overall energy efficiency
- Operational flexibility (e.g., ramp rate, turndown, start-up time)
- Fuel prices
- Project financial requirements
- Availability, reliability, and environmental performance
- Current and potential regulations governing air, water, and solid waste discharges from fossil-fueled power plants
- Specific site and application constraints and requirements

Fifteen[g] power plant configurations are analyzed in this report:

- Six PC power plant configurations—three subcritical (SubC) and three supercritical (SC) (four with [two 90 percent and two 95 percent] and two without CO_2 capture).
- Nine NGCC power plant configurations—three state-of-the-art 2023 F-Class combustion turbines, three state-of-the-art 2023 1x1 H-Class combustion turbines, and three state-

[g] Additional PC and NGCC cases that include CO_2 capture rates above 95 percent are reported in the appendices.

of-the-art 2023 2x1 H-Class combustion turbines (six with [three 90 percent and three 95 percent] and three without CO_2 capture).

An amine-based solvent system (Shell CANSOLV) is used for CO_2 capture in all cases.

Vendor quotes were obtained for the various NGCC plants within this report, reflecting 2023 F-Class, 1x1 H-Class, and 2x1 H-Class configurations. The combustion turbine used in the 1x1 H-Class plant is larger and more advanced than that of the 2x1 H-Class plant. The H-Class combustion turbines were selected to 1) provide an H-Class configuration (1x1) that was comparable in output to the PC plants, produced a volume of flue gas that could be treated with a single train CO_2 capture system, and represented the most advanced commercial offering; and 2) provide an H-Class configuration (2x1) and combustion turbine that was consistent with previous revisions of this study. The final assessment of performance and cost was determined independently by NETL and is not endorsed by the individual vendors.

For PC cases, existing costs were escalated to reflect a 2023-year dollar using the methodology outlined in NETL's current Quality Guidelines for Energy System Studies (QGESS) (NETL, 2025a).

1.1 CO_2 Capture Rates Above 95 Percent

Commercial-scale demonstration of solvent-based post-combustion CO_2 capture systems at power generation facilities (specifically PC plants) has shown the ability to capture 90 percent of the CO_2 in the flue gas stream (Greg Kennedy, n.d.) (Giannaris, et al., 2021). Moreover, field-testing of post-combustion CO_2 capture technology as well as vendor and industry feedback on projects currently in the planning stages (including front-end engineering and design projects sponsored by DOE) indicates that capture rates as high as 95 percent are feasible for both coal- and natural gas-fueled electricity generating units (NCCC, 2020b) (NCCC, 2020a) (OBrien, et al., 2022) (International CCS Knowledge Center, November). Given the breadth of publicly available information supporting the capability for post-combustion capture systems to remove greater than 90 percent of the CO_2 in the treated stream, cases for 90 percent and 95 percent capture on NGCC and PC are presented in the main body of this report.

It should be emphasized that technology suppliers (as reflected in vendor-supplied information provided to DOE for this study that included cost and performance estimates for >95 percent CCS [97 percent for NGCC and 99 percent for PC] study cases) as well as subject matter experts acknowledge and support that solvent-based post-combustion CO_2 capture technologies are capable of achieving CO_2 removal rates beyond 95 percent on low-purity streams representative of fossil-fueled combustion. Although technoeconomic analyses of deep decarbonization (≥ 99 percent) of combustion flue gas have been published by others, (Du, Gao, Rochelle, & Bhown, 2021) (IEAGHG, 2019) the relatively limited experience with design and operation of capture systems that can routinely, reliably, and economically achieve very high removal rates requires further study. Technoeconomic analyses of the higher capture rates (97 percent NGCC and 99 percent PC) are included in the appendices to this report.

1.2 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 2023 F-Class CT used to model the B31 cases comes in a standard size of 242 MW when operated at conditions set by ISO. Two CTs are used in the F-Class cases for a combined gross output of 484 MW. The state-of-the-art 2023 H-Class CT used to model the B32 1x1 cases comes in a standard size of 442 MW, whereas the H-Class CT used to model the B32 2x1 cases comes in a standard size of 380 MW, for a combined gross output of 759 MW, when operated at conditions set by ISO. In the combined cycle, an HRSG extracts heat from the CT exhaust to power a steam turbine. The overall combined cycle gross output ranges from 617 MW (B32B.1.95) to 1,137 MW (B32A.2).

The net output in the NGCC CO_2 capture cases is significantly reduced compared to the non-capture cases due to the high auxiliary power loads and significant extraction steam requirements of the CO_2 capture systems. The net output in NGCC cases varies from 575 MW (B32B.1.95) to 1,118 MW (B32A.2). The natural gas feed rate is 95,442 kg/hr (210,413 lb/hr) for the F-Class cases, 79,424 kg/hr (175,100 lb/hr) for the H-Class 1x1 cases, and 137,875 kg/hr (303,962 lb/hr) for the H-Class 2x1 cases.

All PC cases have a net output of 650 MW. When considering the NGCC cases net output, PC net output selection of 650 MW represents the most optimal midpoint for cross-technology results comparison to F-Class NGCC with CO_2 capture (654–658 MW-net) and 1x1 H-Class NGCC without CO_2 capture (649 MW-net). H-Class 2x1 NGCC with and without CO_2 capture (992–1,118 MW-net) represent the maximum net plant outputs for the cases considered in this report.

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, as well as the required extraction steam, to produce the desired net output.

The balance of this report is organized as follows:

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

Exhibit 1-1. Case descriptions

Case[A]	Plant Type	Steam Cycle[B], psig/°F/°F	Combustion Turbine	Boiler/HRSG Technology	Oxidant	Sulfur Removal	PM Control	NOx Control	CO_2 Separation	Capture Rate[C]	Process Water Treatment
B11A	PC	2400/1050/1050	N/A	SubC PC	Air	Wet FGD/ Gypsum	Baghouse	LNB with OFA and SCR	N/A	N/A	Spray dryer evaporator
B11B.90									CANSOLV	90%	
B11B.95										95%	
B12A		3500/1100/1100		SC PC[B]					N/A	N/A	
B12B.90									CANSOLV	90%	
B12B.95										95%	
B31A	NGCC	2494/1085/1085	2 x State-of-the-art 2023 F-Class	HRSG		N/A	N/A	LNB and SCR	N/A	N/A	N/A
B31B.90									CANSOLV	90%	
B31B.95										95%	
B32A.1		2501/1085/1085	1 x State-of-the-art 2023 H-Class						N/A	N/A	
B32B.1.90									CANSOLV	90%	
B32B.1.95										95%	
B32A.2		2494/1085/1085	2 x State-of-the-art 2023 H-Class						N/A	N/A	
B32A.2.90									CANSOLV	90%	
B32A.2.95										95%	

[A]All plants in this report are assumed to be located at a generic plant site in the midwestern United States

[B]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, particularly with respect to temperature (593°C [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 ultra-supercritical PC plants.

[C]The capture rates for all cases is based on the amount of carbon in the stack gas relative to the total carbon in, less unburned carbon present in ash (PC cases). 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 (NETL, 2025d).

Capital and operating costs were estimated by Black & Veatch based on simulation results using an in-house database and conceptual estimating models. The estimating models are based on a United States (U.S.) Gulf Coast location and the labor cost was adjusted using factors from PAS Inc (PAS, Inc., n.d.). PAS presents information for eight separate regions, with this study using a generic Midwest location, typical of Region 5 (IL, IN, MI, MN, OH, and WI). The costs within this report are based on non-union labor and would need to be re-evaluated for projects employing union labor.

Costs were further calibrated using a combination of adjusted vendor-furnished data and scaled estimates from previous design/build projects. The present revision relates costs in 2023 dollars. Ultimately, a first-year cost of electricity (FY COE) and a levelized cost of electricity (LCOE) were calculated for each of the cases and are 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 this report. 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 the midwestern United States, 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 (PC), acres	300
Size (NGCC), acres	100
Transportation	Rail or Highway
Ash (PC) Disposal	Off-Site
Water	50% Municipal and 50% Ground Water

Exhibit 2-2. Site ambient conditions

Parameter	Value
Elevation, m (ft)	0 (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	75.055
O_2	22.998
Ar	1.280
H_2O	0.616
CO_2	0.050
Total	100.00

[A]The cooling water temperature is the cooling tower cooling water exit temperature. This is set to 4.8°C (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 0.4 km (0.25 mi) to the fence line. The extra land could also provide for a rail loop if required (rail loop is not included in this report). In the NGCC cases it was assumed the plant proper occupies about 10 acres leaving a buffer of 0.24 km (0.15 mi) to the plant fence line.

The quality of plant makeup water will vary dramatically from source-to-source (municipal versus groundwater), as well as from site to site, and can be expected to vary significantly throughout any given site, particularly if ground water is utilized. In this study, 50 percent of the makeup water to the plants is sourced from a publicly owned treatment works (POTW), with the balance of the makeup water sourced from groundwater. The assumed design makeup water composition is provided in Exhibit 2-3.

The makeup water composition reported in the following table is based on water qualities from actual operations. The design concentration of each constituent is individually representative of a plant configuration comparable to those in this study. However, due to the interaction and interdependencies of each constituent and the multitude of potential species, the makeup water quality cannot be considered representative as a whole. The makeup water quality is intended to inform users of the contaminants likely present, and at what concentrations they may be expected, to facilitate appropriate equipment selection and design.

Exhibit 2-3. Design makeup water quality

Parameter	Groundwater (Range)	POTW Water (Range)	Makeup Water (Design Basis)
pH	6.6–7.9	7.1–8.0	7.4
Specific Conductance, µS/cm	1,096–1,484	1,150–1,629	1312
Turbidity, NTU		<50	<50
Total Dissolved Solids, ppm			906
M-Alkalinity as $CaCO_3$, ppm[A]	200–325	184–596	278
Sodium as Na, ppm	102–150	172–336	168
Chloride as Cl, ppm	73–100	205–275	157
Sulfate as SO_4, ppm	100–292	73–122	153
Calcium as Ca, ppm	106–160	71–117	106
Magnesium as Mg, ppm	39–75	19–33	40
Potassium as K, ppm	15–41	11–21	18
Silica as SiO_2, ppm	5–12	21–26	16
Nitrate as N, ppm	0.1–0.8	18–34	12
Total Phosphate as PO_4, ppm	0.1–0.2	1.3–6.1	1.6
Strontium as Sr, ppm	2.48–2.97	0.319–0.415	1.5
Fluoride as F, ppm	0.5–1.21	0.5–0.9	0.8
Boron as B, ppm	0.7–0.77		0.37
Iron as Fe, ppm	0.099–0.629	0.1	0.249
Barium as Ba, ppm	0.011–0.52	0.092–0.248	0.169
Aluminum as Al, ppm	0.068–0.1	0.1–0.107	0.098
Selenium as Se, ppm	0.02–0.15	0.0008	0.043
Lead as Pb, ppm	0.002–0.1		0.026
Arsenic as As, ppm	0.005–0.08		0.023
Copper as Cu, ppm	0.004–0.03	0.012–0.055	0.018
Nickel as Ni, ppm	0.02–0.05		0.018
Manganese as Mn, ppm	0.007–0.015	0.005–0.016	0.009
Zinc as Zn, ppm	0.005–0.024		0.009
Chromium as Cr, ppm	0.01–0.02		0.008
Cadmium as Cd, ppm	0.002–0.02		0.006
Silver as Ag, ppm	0.002–0.02		0.006
Mercury as Hg, ppm	0.0002–0.001		3E-04

[A]Alkalinity is reported as $CaCO_3$ equivalent, rather than the concentration of HCO_3. The concentration of HCO_3 can be obtained by dividing the alkalinity by 0.82.

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 gasifier and combustion turbines 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
- Weather delays
- Other local environmental concerns
- Noise regulations

2.2 COAL CHARACTERISTICS

The design coal is Illinois No. 6 with characteristics presented in Exhibit 2-4. The coal properties are from the 2019 revision of the QGESS report, "Detailed Coal Specifications" (NETL, 2019a).

Exhibit 2-4. Design coal

Rank	Bituminous	
Seam	Illinois No. 6	
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	**100.0**	**100.0**
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	0.15	0.17
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen[B]	7.02	7.91
Total	**100.0**	**100.0**
Heating Value		
	As Received	Dry
HHV, kJ/kg (Btu/lb)	27,113 (11,666)	30,506 (13,126)
LHV, kJ/kg (Btu/lb)	26,151 (11,252)	29,544 (12,712)

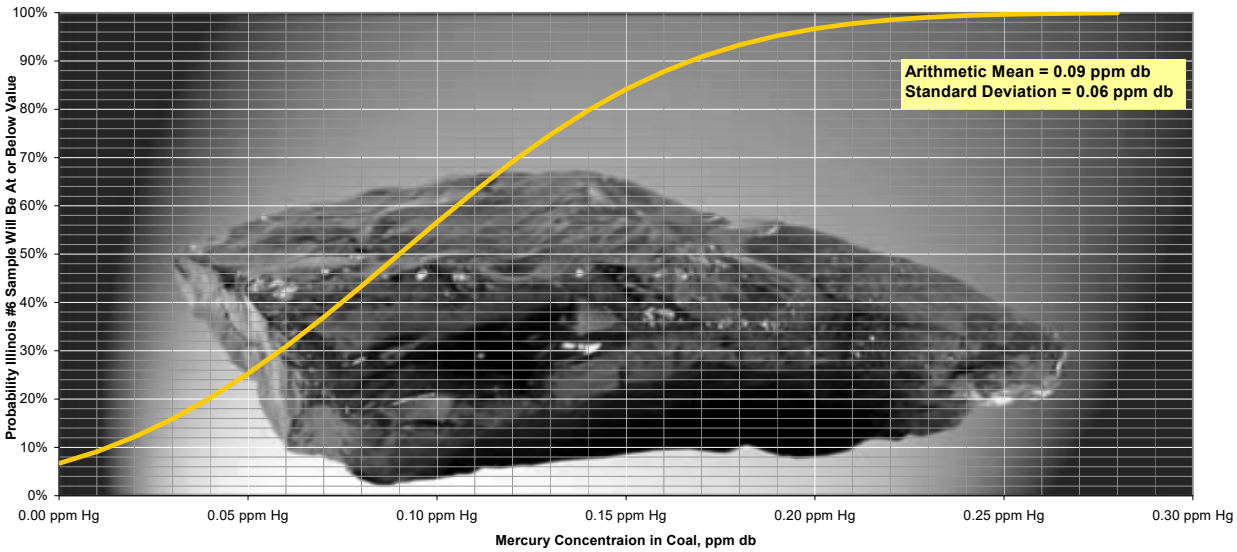
[A]The proximate analysis assumes sulfur as volatile matter.
[B]By difference.

The chlorine content of 34 samples of Illinois No. 6 coal has an arithmetic mean value of 1,671 ppmwd with a standard deviation of 1,189 ppmwd based on coal samples shipped by Illinois mines (Mining Media, 2004).

Based on the location of the Illinois No. 6 mine, along with the Herrin coal chlorine map published by the Illinois State Geological Survey (Prairie Research Institute, n.d.), it was determined that Illinois No. 6 coal could be expected to have a chlorine content of 0.1–0.2 percent, on a dry basis. Therefore, the coal chloride content for this report was assumed to be the arithmetic mean value of 1,671 ppmwd.

The mercury (Hg) 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 (Mining Media, 2004). Hence, as illustrated in Exhibit 2-5, there is a 50 percent probability that the Hg content in the Illinois No. 6 coal would not exceed 0.09 ppmwd. The coal Hg content for this report was assumed to be 0.15 ppmwd, which corresponds to the mean plus one standard deviation and encompasses about 84 percent of the samples. It was further assumed that all the coal Hg enters the gas phase and none leaves with the bottom ash in PC cases (NETL, 2002).

Exhibit 2-5. Probability distribution of mercury concentration in the Illinois No. 6 coal



Fuel costs used in this report are specified according to the 2025 QGESS report "Fuel Prices for Selected Feedstocks in NETL Studies" (NETL, 2025c). The current levelized coal price is $2.46/GJ ($2.60/MMBtu) on a higher heating value (HHV) basis for Illinois No. 6 bituminous coal delivered to the Midwest and reported in 2023 dollars (first-year coal price of $2.86/GJ [$3.01/MMBtu]). Fuel costs are levelized over an assumed 30-year plant operational period with an assumed on-line year of 2028 for PC cases.

2.3 NATURAL GAS CHARACTERISTICS

The composition of natural gas used as fuel in all NGCC cases is presented in Exhibit 2-6. The natural gas properties are from the 2019 revision of the QGESS report, "Specification for

Selected Feedstocks" (NETL, 2019b) including the addition of methanethiol (mercaptan) (Gas Research Institute, 1992).

Exhibit 2-6. 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	$5.74x10^{-6}$
	Total	100.0
	LHV	**HHV**
kJ/kg (Btu/lb)	47,201 (20,293)	52,295 (22,483)
MJ/scm (Btu/scf)	34.52 (927)	38.25 (1,027)

[A]The sulfur content of natural gas is primarily composed of added Mercaptan (methanethiol [CH_4S]) with trace levels of hydrogen sulfide (Gas Research Institute, 1992)
Note: Fuel composition is normalized, and heating values are calculated using Aspen

Fuel costs used in this report are specified according to the 2025 QGESS report, "Fuel Prices for Selected Feedstocks in NETL Studies" (NETL, 2025c). The current levelized natural gas price is $3.25/GJ ($3.42/MMBtu) on an HHV basis, delivered to the Midwest, and reported in 2023 U.S. dollars (first-year natural gas price of $5.30/GJ [$5.59/MMBtu]).[h] Fuel costs are levelized over an assumed 30-year plant operational period with an assumed on-line year of 2028 for NGCC cases.

2.4 Environmental Targets

2.4.1 Air Emissions Targets

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

- Hg and hydrochloric acid (HCl) limits were set by the April 2023 update to the Utility Mercury and Air Toxics Standards (MATS) for PC technologies (EPA, 2024c).
- 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 all technologies (EPA, 2024c), (EPA, 2018).

[h] The Energy Information Administration (EIA, n.d.) indicates relatively high volatility for natural gas, with the Henry hub spot price increasing to $7.83/GJ ($8.26/MMBtu) in May 2022. As these fluctuations are not captured by the reported cost uncertainty, the reader should adjust the reported costs if required by the end use of the data.

The regulations differentiate between low rank and non-low rank coal types based on their heating value. Coals with an HHV of greater than 19,300 kJ/kg (8,300 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 30,000 kJ/kg (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 2-7.

Exhibit 2-7. MATS and NSPS emission limits for SO_2, NOx, PM, Hg, and HCl

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] There is no federal emissions standard that sets a carbon monoxide (CO) emission limit for PC or NGCC plants. However, CO emissions are reported for NGCC cases based on vendor-reported emission rates.

These new regulations apply to PC technologies that began construction after May 3, 2011 (EPA, 2024c) and to NGCC technologies that began construction after February 18, 2005 (EPA, 2024c). Furthermore, these regulations state that (EPA, 2013)

> *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 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; 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 19,300 kJ/kg (8,300 Btu/lb) that is constructed and operates at or near the mine that produces such coal.

Unit designed for coal ≥ 19,300 kJ/kg (≥ 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 the Best Available Control Technology (BACT) determinations for new sources located in areas meeting ambient air quality standards (attainment areas) or Lowest Achievable Emission Rate technology for sources 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 Environmental Protection Agency's (EPA) Green Book Non-attainment Area Map, relatively few areas in the midwestern United States are classified as "non-attainment," so the plant site for this report was assumed to be in an attainment area (EPA, 2018).

2.4.2 Water Emissions Targets

EPA issued final Effluent Limitation Guidelines (ELG) and standards for the steam electric power generation point source category in May 2024, to strengthen controls on wastewater discharges (EPA, 2024a). The ELG are national technology-based NSPS derived from data collected from industry (existing source standards are not addressed in this report). They are intended to provide flexibility in implementation through use of technologies already installed and operating in the power industry. The federal standards established by this rule are the minimum discharge standards. As ELG are enforced under the National Pollutant Discharge Elimination System (EPA, n.d.), more stringent water quality-based standards may be established by the local permitting authority; however, these additional requirements were not considered in this report.

The final ELG rule established new wastewater categories and discharge limits and updated discharge requirements for existing wastewater categories. The following are the new or updated categories in the rule:

- FGD wastewater
- Fly ash transport water
- Bottom ash transport water
- Landfill leachate
- Flue gas mercury control wastewater
- Non-chemical metal cleaning wastewater

Non-chemical metal cleaning wastewater was established as a new wastewater category in the updated ELG. However, new limits were not established for this category; therefore, treatment of this stream has not been evaluated in this report.

The landfill of plant byproducts is assumed to be outside the scope of the plants considered in this study; therefore, landfill leachate is not evaluated in this report.

For the PC cases considered in this study, both fly ash and bottom ash handling systems are dry and do not result in a water stream requiring treatment under ELG. Similarly, the flue gas mercury control approach of combined sorbent injection followed by carbon injection does not generate a water stream for treatment. Therefore, only the FGD wastewater blowdown stream requires treatment in PC cases.

Intermittent discharges (e.g., chemical metal cleaning wastewater), coal pile runoff, low volume waste (e.g., boiler blowdown), and cooling tower blowdown were assumed to be compliant with all applicable regulations with no additional treatment beyond conventional considerations.

Under the assumptions established in this section, no additional control technology considerations are required for NGCC compliance with the ELG rule.

The applicable wastewater discharge limits for PC cases are shown in Exhibit 2-8.

Exhibit 2-8. New source treated FGD wastewater discharge limits (EPA, 2024a)

Effluent Characteristic	Long-Term Average	Daily Maximum Limit	Monthly Average Limit[A]
Arsenic, ppb	4.0	4	-
Mercury, ppt	17.8	39	24
Selenium, ppb	5.0	5	-
Total Dissolved Solids, ppm	14.9	50	24

[A]Monthly Average Limit refers to the highest allowable average of daily discharges over 30 consecutive days.

The limits are applied at the discharge, prior to commingling with other plant water systems.

2.4.3 Study Cases

2.4.3.1 PC

Exhibit 2-9 provides the emissions limits for PC plants as well as a summary of the control technology utilized to satisfy the limits.

Exhibit 2-9. Environmental targets for PC cases (EPA, 2012a) (EPA, 2024c) (EPA, 2018)

Pollutant	PC (lb/MWh-gross)	Control Technology
SO_2	1.00	Wet FGD
NOx	0.70	LNB, OFA, and SCR
PM (Filterable)	0.09	Fabric filter
Hg	$3x10^{-6}$	Co-benefit capture, dry sorbent injection[A], activated carbon injection
HCl	0.010	SO_2 surrogate[B]

[A]Limits sulfur trioxide (SO_3) levels and their detrimental effects on activated carbon injection
[B]SO_2 may be utilized as a surrogate for HCl measurement if the EGU utilizes wet FGD (EPA, 2012b)

It was assumed that low NOx burners (LNBs) and staged overfire air (OFA) would limit NOx production to 0.15 kg/GJ (0.35 lb/MMBtu), on a HHV basis, and that selective catalytic reduction (SCR) technology would be 75–79 percent efficient. By adjusting the ammonia (NH_3) flow rate and/or catalyst bed depth in the SCR, the NOx emissions limit was able to be met exactly.

The wet FGD was assumed to be 98 percent efficient, which results in SO_2 emissions below the NSPS SO_2 limit. Current technology allows wet 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 Hg removal efficiency required to meet the emission limit is approximately 97 percent in each case. It was assumed that the total Hg 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 Hg removal and the various systems involved.

Exhibit 2-10 provides the water discharge limits for PC plants, and a brief description of the control technology utilized to satisfy the limits follows.

Exhibit 2-10. Water discharge targets for PC cases (EPA, 2024a)

Effluent Characteristic	Long-term Average	Daily Maximum Limit	Monthly Average Limit[A]
Arsenic, ppb	4.0	4	-
Mercury, ppt	17.8	39	24
Selenium, ppb	5.0	5	-
Total Dissolved Solids, ppm	14.9	50	24

[A]Monthly Average Limit refers to the highest allowable average of daily discharges over 30 consecutive days.

A spray dryer is a technology commonly used in the power industry for FGD, which can be applied as a thermal evaporation process to treat wastewater. The feasibility of using a spray dryer evaporator as the sole treatment system in PC cases is limited by the flow rate of wastewater, as the cost and performance impact of the spray dryer increases with increasing wastewater flow rate. Section 3.1.10 provides a detailed discussion regarding the spray dryer as applied to the PC cases in this report.

2.4.3.2 NGCC

Exhibit 2-11 provides the emissions limits for NGCC plants as well as a summary of the control technology utilized to satisfy the limits.

Exhibit 2-11. Environmental targets for NGCC cases (EPA, 2012a) (EPA, 2024c) (EPA, 2018)

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 1.8 ppmv NOx emissions through the use of a dry low NOx (DLN) burner in the combustion turbine-generator (CTG)—the DLN burners reduce the emissions to about 25 ppmvd (GE Vernova, 2024b) (referenced to 15 percent O_2)—and an SCR (Davis & Black, October 2000).

While state-of-the-art 2023 F-Class and H-Class CTs alone produce NOx emissions below the limit shown in Exhibit 2-11, an SCR was included to ensure the plant met EPA's PSD program by installing BACT. The SCR system is designed for 94–95 percent NOx reduction while firing natural gas.

The total sulfur content of natural gas is typically limited by contract terms and industry practice to 0.25–1.00 gr/100 scf with the average total sulfur content being 0.34 gr/100 scf (Gas Research Institute, 1992). For this report, the natural gas was assumed to contain the average value of total sulfur of 0.34 gr/100 scf ($4.71x10^{-4}$ lb-S/MMBtu, on an HHV basis). It was also assumed that the added mercaptan (methanethiol [CH_4S]) was the sole contributor of sulfur to the natural gas. The CH_4S concentration of the natural gas is provided in Exhibit 2-6 as $5.74x10^{-6}$ percent by mole (mol%) ($7.09x10^{-4}$ lb-CH_4S/MMBtu, on an HHV basis).

The natural gas sulfur content results in SO_2 emissions for the non-capture case of 0.006 lb/MWh-gross. The CO_2 capture system removes virtually all SO_2 from the flue gas, resulting in zero (reported) emissions in the capture case.

The pipeline natural gas was assumed to contain no PM, Hg, or HCl.

Under the assumptions established in Section 2.4.2, no additional control technology considerations are required for compliance with the ELG rule.

2.4.4 Carbon Dioxide

The PC and NGCC cases all assume that all fuel-based carbon that is combusted (i.e., excluding unburned carbon in PC cases) is converted to CO_2 in the flue gas. While the CO emissions is reported in NGCC cases based on vendor specifications, the formation of CO is not modeled. Carbon dioxide is also generated from limestone in the FGD system. The nominal capture rate of each plant is defined by the amount of CO_2 that enters the capture plant (i.e., exiting the FGD system in PC cases and exiting the HRSG in NGCC cases). The non-capture plants report CO_2 emissions of 1,628–1,693 lb-CO_2/MWh-gross for PC cases, and 707–743 lb-CO_2/MWh-gross for

the NGCC cases. The CO_2 capture plant designs result in emissions ranging 94–195 lb-CO_2/MWh-gross and 38–79 lb-CO_2/MWh-gross for PC and NGCC plants, respectively.

On April 24, 2024, EPA issued a final rule (EPA, 2024b) regulating greenhouse gas emissions from fossil fuel-fired electric generating units that would be applicable to the coal and natural gas power plant configurations described in this report. The final rule includes different emissions standards based on technology, unit operating profiles (e.g., low, intermediate or base load operations) and compliance dates. The power plant configurations included here are evaluated as base load facilities operated at steady state full load (100% nameplate capacity). The PC plants described in this report could be expected to operate beyond 2039 and are assumed to be in compliance with the 2024 final rule.

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 CF 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 (GADS) (NERC, n.d.) 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 CF data, by fuel type and plant capacity.

The GADS database provides data on many plant operating characteristics. Two metrics are used in this report to evaluate existing plant availability and CFs (availability factor [AF] and equivalent availability factor [EAF]). The metrics are defined by the following equations.

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

Where:

PH – Period Hours (number of hours a unit was in the active state)

POH – Planned Outage Hours (sum of all hours experienced during Planned Outages and Planned Outage Extensions [the extension of maintenance or planned outage beyond initial Planned Outages])

FOH – Forced Outage Hours (sum of all hours experienced during Forced Outages)

MOH – Maintenance Outage Hours (sum of all hours experienced during Maintenance Outages and Maintenance Outage Extensions [the extension of Maintenance Outages])

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

Where:

EUDH – Equivalent Unplanned Derated Hours (the product of Unplanned Derated Hours [sum of all hours during Forced Deratings] and Size of Reduction [megawatts of derate], divided by Net Maximum Capacity [unit net megawatt output without derating])

EPDH – Equivalent Planned Derated Hours (the product of Planned Derated Hours [sum of all hours experienced during Planned Deratings and Scheduled Derating Extensions] and Size of Reduction, divided by Net Maximum Capacity)

ESEDH – Equivalent Seasonal Derated Hours (Net Maximum Capacity less Net Dependable Capacity [equivalent to the Net Maximum Capacity modified for seasonal limitations], multiplied by Available Hours [sum of all Service Hours, Reserve Shutdown Hours, Pumping Hours, and Synchronous Condensing Hours] and divided by Net Maximum Capacity)

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 2-12 presents GADS "coal primary" EAF data from the Units Reporting Events data files for the years 2011, 2014, 2015, and 2016. The number of generating units included in the 2011 and 2016 data is presented in Exhibit 2-13. As previously noted, the EAF is a representation of this study's definition of CF.

Exhibit 2-12. Coal unit equivalent availability factor

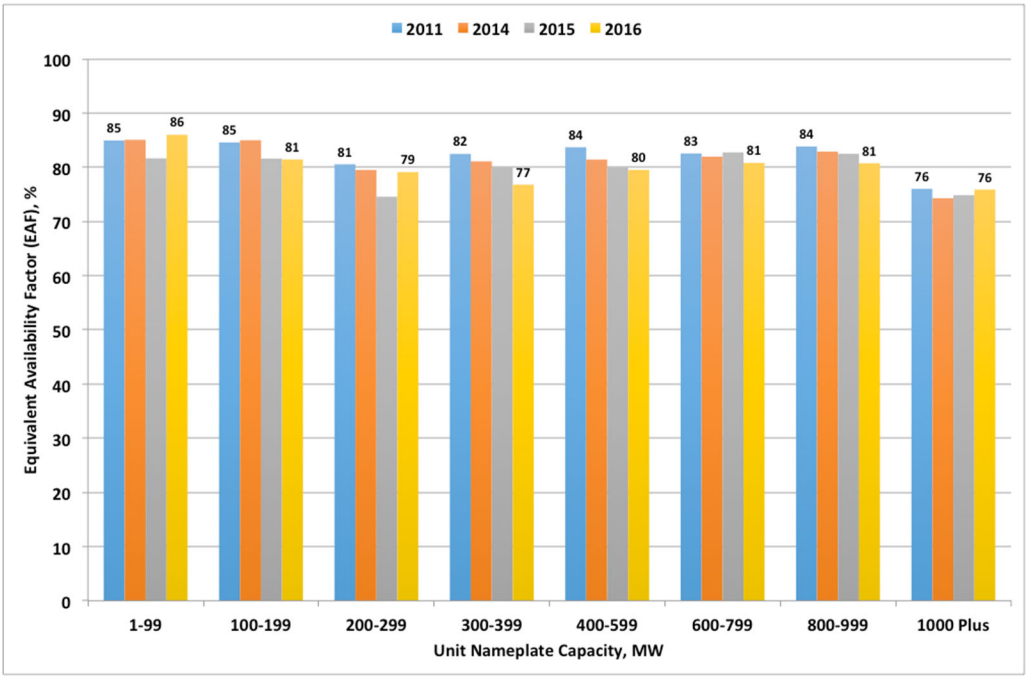


Exhibit 2-13. Number of coal units reporting in the 2011 and 2016 data

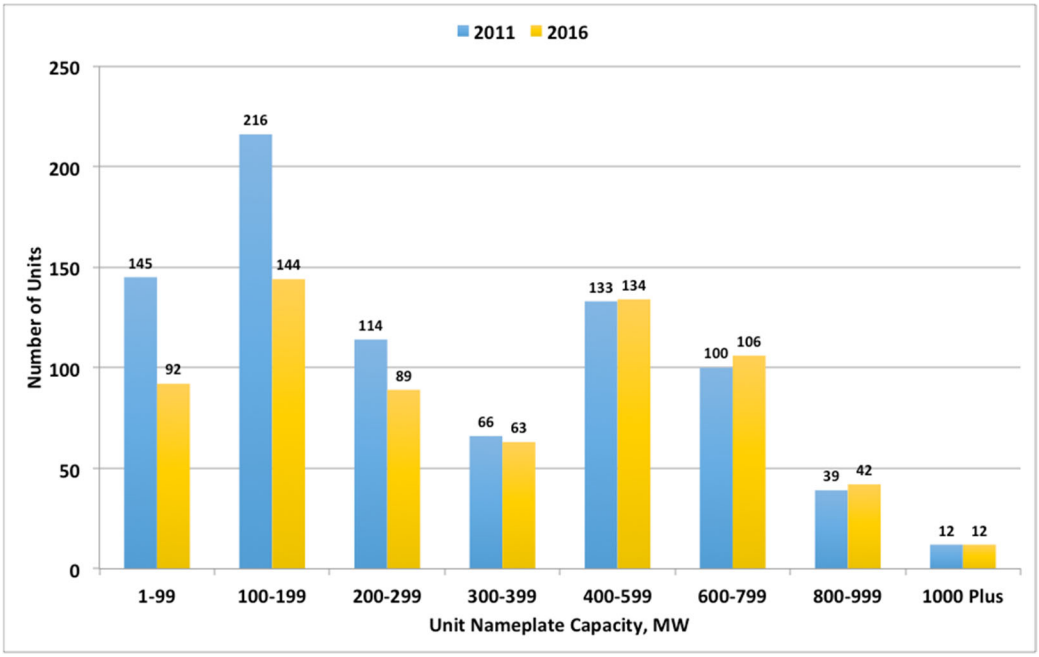
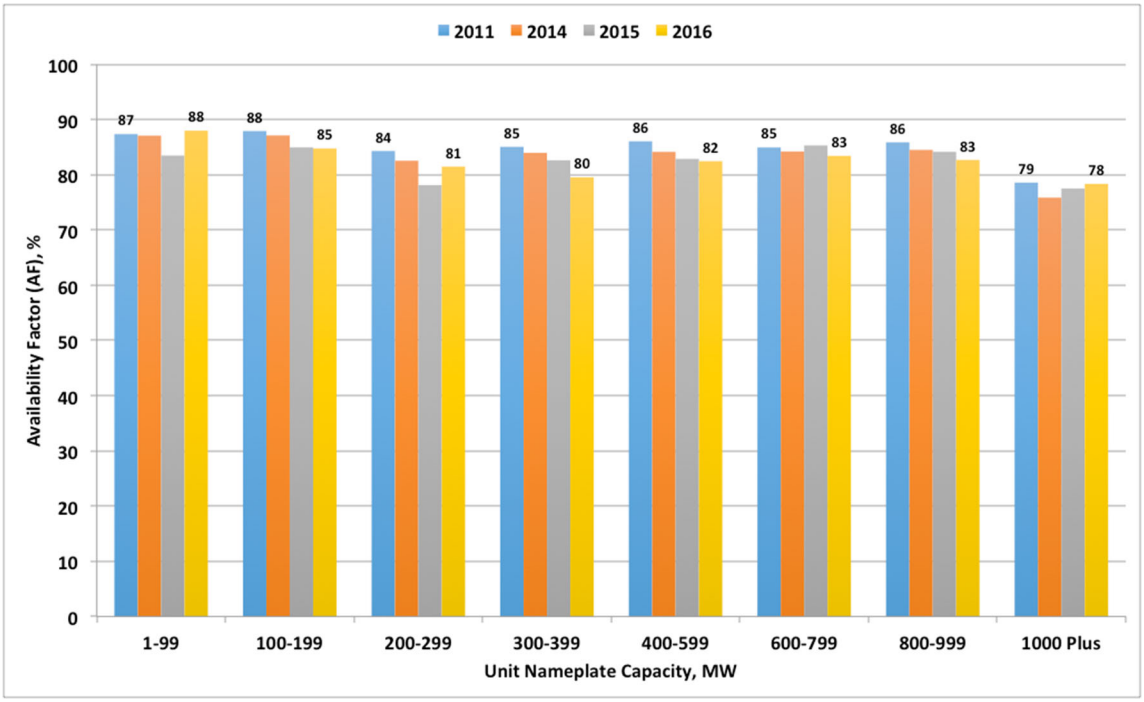


Exhibit 2-14 presents the GADS AF data for the same years (2011 through 2016).

Exhibit 2-14. Coal unit availability factor



The baseline study net PC unit capacity is 650 MW. The average EAF for coal-fired plants in the 600–799 MW size range was 83 percent in 2011 and declined to 81 percent in 2016.

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, and plants, to achieve high CFs. Exhibit 2-15 presents coal plants, with capacities greater than 300 MW, that achieved high CFs in 2017 (Ray, 2018).

Exhibit 2-15. Reported high-capacity factor coal units

Plant Name	Owner	State	Capacity, MW	Capacity Factor, %	Heat Rate, Btu/kWh
Dry Fork Station	Basin Electric	WY	393	94	10,593
Oak Grove	Luminant	TX	1,665	92	10,341
Twin Oaks	Luminant	TX	306	89	11,529
Milton R. Young	Minnkota Power Coop	ND	688	88	11,507
Wyodak	BHE	WY	336	87	12,249
Bonanza	Deseret G&T	UT	458	85	9,795
Rush Island	Ameren	MO	1,201	84	10,207
John W. Turk Jr.	SWEPCO	AR	609	83	9,089

In 2017 the top twenty coal plants, irrespective of nameplate capacity, achieved CFs in excess of 82 percent, with the top fifteen units achieving CFs of 85 percent or higher (Ray, 2018).

The GADS data show an average coal unit availability for all unit sizes greater than 80 percent and the 2017 plant level data show that coal units have demonstrated CFs greater than 85 percent. The current study costs are based on mature plant technology and market conditions that enable baseload operation. Based on a review of the available data, an 85 percent CF is selected for the PC units.

2.5.4 Capacity Factor for NGCC Plants

Similar data as used for coal units were reviewed for NGCC units. The GADS database reports an AF of 87.8 percent for 160 NGCC units in 2011, the same AF value for 277 NGCC units in 2016, and an AF of 85.97 percent for 309 NGCC units in 2023. The EAF reported for NGCC units in 2011 is 84.0 percent; in 2016 the EAF increased to 85.2 percent, and in 2023 the EAF decreased to 82.86 percent (NERC, n.d.). The 5-year data for 309 combined cycle plants (2019—2023) are 86.6 percent for AF and 83.38 percent for EAD. An 85 percent CF is selected for NGCC plants.

2.5.5 Capacity Factor for Plants with Carbon Capture

The addition of carbon capture and storage (CCS) adds extra equipment to the power plant. A solvent-based carbon capture technology is used in this report for all capture configurations. The capture and CO_2 compression technologies have commercial operating experience, albeit at smaller scale in the case of solvent systems, with demonstrated ability for high reliability. Given the report basis and use of commercial technology, the assumption is made that the CFs for a given plant with and without carbon capture are the same. Thus, the CF for PC and NGCC plants with capture is 85 percent.

2.5.6 Perspective

Reported unit data and reported plant experience support the capability to achieve the selected AFs 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 program with sufficient maintenance budget, 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 (Richwine, 2004).

Plant availability is determined by the plant technology, the capital cost invested in the plant (e.g., the design approach with respect to minimizing scheduled and unplanned maintenance), the maintenance requirements, the operating profile of the plant, 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. This report assumes that the plant design, plant maintenance, and electricity demand are consistent with the selected availability. Black & Veatch review of the maintenance allocation for the plants considered concluded that it was in accordance with expected maintenance allocations for comparable units in terms of the

specified sizes and CF. It is acknowledged that fewer fossil energy plants operate baseloaded in today's energy markets; however, the objective of the report is to compare technologies based on their performance and cost merits without imposing market forces that would impact CF.

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 85 percent for PC and NGCC 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 85–100 percent. It is assumed that the plants in this report will have yearly AFs above and below the selected value with the effective or levelized availability for the life of the plant being the selected value. The sensitivity of LCOE to CF is plotted in Exhibit 5-18.

2.6 Raw Water Withdrawal and Consumption

A water balance was performed for each case on the major water consumers in the process. The water demand, representing the total amount of water required for a particular process for each subsystem, was determined and internal recycle water recovered from various sources, such as condensate from flue gas (in PC 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 defined as the water removed from the ground or diverted from a POTW for use in the plant for all purposes, such as boiler feedwater (BFW) makeup, slurry preparation makeup, FGD system makeup, and cooling tower makeup. In this study, raw water was assumed to be provided 50 percent by a POTW and 50 percent from groundwater.

The difference between water withdrawal and process water discharge is defined as raw water consumption, which 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. Consumption represents the net impact of the process on the water source.

BFW blowdown was assumed to be treated and recycled to the cooling tower. The cooling tower blowdown, which is the largest consumer of raw water in all cases (Section 3.1.13), was assumed to be treated and returned to the water source.

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; engineering, procurement, and construction (EPC) contractor services; estimation of capital cost contingencies; owner's costs; cost estimate scope; economic assumptions; finance structures; FY COEs; and LCOEs are available in the 2025 revision of the QGESS report, "Cost Estimation

Methodology for NETL Techno-economic Assessments" (NETL, 2025b). Select portions are repeated in this report for completeness.

Capital Costs:

The capital cost estimates documented in this report reflect different uncertainty ranges depending on the technology considered, as shown in Exhibit 2-16.

Exhibit 2-16. Capital cost uncertainty ranges

Technology	Uncertainty Range	AACE Classification
PC	-15/+30	Class 4
NGCC	-15/+25	Class 4

PC and NGCC cases carry uncertainty ranges that fall within Association for the Advancement of Cost Engineering (AACE) Class 4 cost estimates (i.e., concept screening) (NETL, 2025b) (AACE International, 2003) (AACE International, 2005) based on the level of engineering design performed. Given the recent experience with NGCC plants, the NGCC uncertainty range is slightly smaller than PC. In all cases, this 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," supply chain improvements, vendor competition, and risk reduction benefits that result from serial deployments as well as from continuing research and development.

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 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 early deployments of PC and NGCC plants with CO_2 capture may incur costs higher than those reflected within this report.

Other Factors:

Actual reported project costs for all 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 and availability, seismic conditions, water quality, financing parameters, local environmental concerns, weather delays) that may make construction more costly. Such variations are not captured by the reported cost uncertainty.

Future Cost Trends:

Continuing research, development, and demonstration 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 here.

2.7.1 Capital Costs

As illustrated in Exhibit 2-17, 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 year in which all technology costs are expressed for comparison from a standard starting point. TASC is expressed in mixed, current-year dollars over the entire capital expenditure period, which is assumed in most NETL power 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.

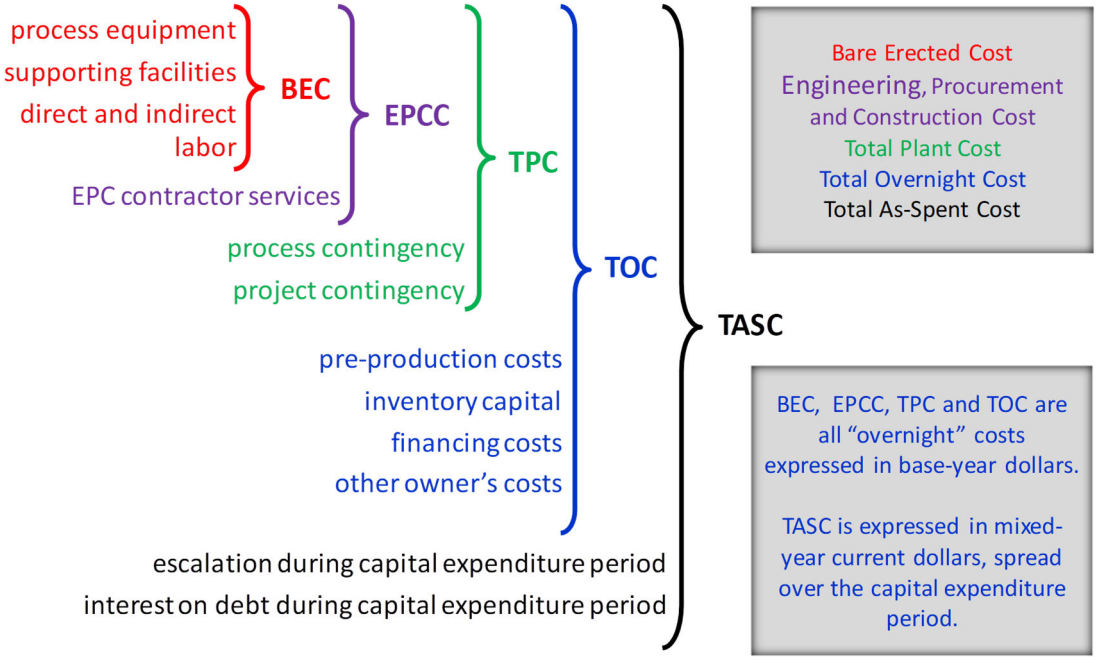
The Engineering, Procurement and Construction Cost (EPCC) comprises the BEC plus the cost of services provided by the EPC contractor. The EPC services include detailed design, contractor permitting (i.e., those permits that individual contractors must obtain to perform their scopes of work, as opposed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

The Total Plant Cost (TPC) comprises the EPCC plus project and process contingencies.

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 construction financing costs.

The Total As-Spent Cost (TASC) comprises the sum of all capital expenditures as they are incurred during the capital expenditure period for construction including their escalation. TASC also includes interest during construction, comprising interest on debt and a return on equity. TASC is expressed in mixed, current-year dollars over the capital expenditure period.

Exhibit 2-17. Capital cost levels and their elements



2.7.1.1 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).

2.7.1.2 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. CO_2 transport and storage (T&S) cost is not included in the reported capital cost or O&M costs but is treated separately and added to the COE.

2.7.1.3 Capital Cost Assumptions

Black & Veatch developed the capital cost estimates for each plant using the company's in-house database and conceptual estimating methodology for each of the specific technologies. This database and approach are maintained by Black & Veatch 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. Costs were further calibrated using a combination of adjusted vendor-furnished data and scaled estimates from previous design/build projects.

Other key estimate considerations include the following:

- Labor costs are based on Midwest, Merit Shop. The estimating models are based on a U.S. Gulf Coast location and the labor cost has been factored to a Midwest location. Labor cost data were sourced from recent projects and proprietary Black & Veatch in-house references/cost databases.
- The estimates are based on a competitive bidding environment, with adequate skilled craft labor available locally.
- Labor is based on a 50-hour workweek (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 based on Black & Veatch's historical experience in designing and building power projects. The cost, as a percentage of BEC, varies by technology; 17.5 percent for PC, and 20 percent for NGCC. The percentages were selected such that the final total cost calculated is representative of Black & Veatch's historical engineering/construction management costs for similar plant types. These costs consist of all home office engineering and procurement services as well as field construction management costs. Site staffing generally includes construction manager, resident engineer, scheduler, and personnel for project controls, document control, materials management, site safety, and field inspection.

2.7.1.4 Price Fluctuations

During the writing of this report, the prices of equipment and bulk materials fluctuated as a result of various market forces. Some reference quotes pre-dated the 2023-year cost basis while others may be considered more historical. All vendor quotes used to develop these estimates were adjusted to January 2023 dollars, accounting for the price fluctuations. Price indices, e.g., The Chemical Engineering Plant Cost Index (Chemical Engineering, 2024), Handy-Whitman Index (Whitman, Requardt & Associates, LLP, 2023), and Producer Price Indices (BLS, 2024a) (BLS, 2024b) (BLS, 2024c) (BLS, 2024d) (BLS, 2024g) (BLS, 2024e) (BLS, 2024f), were used as needed for these adjustments. While these indices provide a high-level estimate, it should be noted that the cost of individual equipment types may still deviate from the January 2023 reference point.

2.7.1.5 Cross-comparisons

In 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 cost trends.

In performing such a comparison, it is important to reference the technical parameters for each item, as these are the basis for establishing the costs. Scope or assumption differences can quickly explain any apparent anomalies. There are a number of cases where differences in design philosophy occur. Some key examples are as follows:

- In PC cases, the CANSOLV unit includes a pre-scrubber tower to reduce flue gas SO_2 content to 0.37 ppmv to limit solvent degradation. In NGCC cases, there is little SO_2 present in the flue gas; thus, a pre-scrubber is not required or included in the NGCC CANSOLV capital cost.
- In PC cases, a single boiler is required to produce the desired net plant output; however, in F-Class and 2x1 H-Class NGCC cases, two CTs and HRSGs are paired with a single steam turbine.

2.7.1.5.1 Process Contingency

Process contingencies were applied to the PC and NGCC estimates in this report, with justification provided, as follows:

- CANSOLV System: 17 percent on PC capture cases; 18 percent on NGCC capture cases—post-combustion capture process unproven at commercial scale for power plant applications.
- Instrumentation and Controls: 5 percent on most line-items in the PC and NGCC capture cases—integration issues.

2.7.1.6 Owner's Costs

The operation and maintenance (O&M) costs for each of the cases in the report were estimated by Black & Veatch using an in-house database. Costs were further calibrated using a combination of adjusted vendor-furnished data and scaled estimates from previous design/build projects.

Detailed explanation of the owner's costs is available in the 2025 revision of the QGESS report, "Cost Estimation Methodology for NETL Techno-economic Assessments" (NETL, 2025b). Owner's costs are split into three categories: pre-production costs, inventory capital, and other costs.

Pre-production allocations are expected to carry the specific plants through substantial completion, and to commercial operation. Substantial completion is intended to represent the transfer point of the facility from the EPC contractor (development entity) to the end user or owner, and is typically contingent on mutually acceptable equipment closeout, successful completion of facility-wide performance testing, and full closeout of commercial items.

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 versus gas-insulated. As a rule of thumb, a 345-kV switchyard (air-insulated, ring bus) would cost roughly $1,160,000 per breaker.

On-site only rails (excludes long runs) would be expected to cost $1,160,000–1,290,000 per mile (relatively level terrain) plus the costs of any switches/turnouts (approximately $65,000 each) and road crossings (approximately $390 per linear foot).

2.7.2 Operation and Maintenance Costs

The production costs or O&M pertain to those charges associated with operating and maintaining the power plants over their expected life, including the following:

- 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 the number of operators required for each technology. The average base labor rate used to determine annual cost is $45.04/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 (material and labor) was evaluated as a function of 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 energy 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 may be accounted for directly in the O&M tables or included with the equipment pricing in the capital cost. Where applicable, the O&M tables state where this cost is included on a case-by-case basis.

2.7.2.5 Waste Disposal

Waste quantities and disposal costs were determined/evaluated similarly to the consumables. In prior iterations of this report, the disposal cost for catalyst and chemicals was assumed to be included in the unit replacement cost, and thus, not explicitly shown. Only major waste streams, such as fly and bottom ash, were reported. In the current revision, chemical and catalyst waste streams are individually reported, in addition to others. Waste disposal costs were separated into two categories: non-hazardous and hazardous waste. Non-hazardous waste is disposed of at a rate of $51.48/tonne ($46.71/ton). Hazardous waste is disposed of at a rate of $108.39/tonne ($98.33/ton).

Some of the triethylene glycol (TEG) used in the CO_2 drying process is lost in the dryer vent. The contaminated water is condensed and sent to an off-site disposal facility, along with the thermal reclaimer unit waste produced by the CANSOLV system used in the PC and NGCC cases. Both waste streams are considered non-hazardous and the combined processing and disposal cost is $1.30/gal for the TEG and $250.00/ton for the thermal reclaimer unit waste.

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, 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 added capital should be included in the plant costs to produce a particular co-product. Ash may be a potential by-product in certain markets; however, due to the ACI in the PC cases, the fly ash may not be marketable. As stated above, these material streams are considered waste in this report with a concomitant disposal cost.

2.7.3 CO_2 Transport and Storage

The cost of CO_2 transport to, and storage in, a deep saline formation is estimated using the Office of Fossil Energy and Carbon Management (FECM)/NETL CO_2 Transport Cost Model and the FECM/NETL CO_2 Saline Storage Cost Model. All scenarios assume a single greenfield CO_2 pipeline project transports dense phase CO_2 to a single greenfield CO_2 saline storage project, and that both projects are designed and sized to be able to manage the maximum CO_2 mass flow rate of a single CO_2 point source engaged in CO_2 capture.

The transportation costs include taxes, financing, capital costs, and O&M costs. The capital costs include the costs for purchasing and installing the pipeline, a surge tank, a pipeline control system, and, if required, booster pumps along the pipeline to maintain the pressure above 1,200 psig. The O&M costs cover the maintenance of the pipeline and pumps and the cost of the electricity used to power the pumps.

The storage costs include the cost to drill and complete the necessary injection and monitoring well(s), financing costs, and costs for equipment and operation in compliance with EPA regulations for Class VI injection wells under the Underground Injection Control Program (EPA, 2017b) as well as compliance with monitoring and reporting requirements under subpart RR of the greenhouse gas reporting rule (EPA, 2017a).

Additional detail on development of these costs is available in the 2024 revision of the QGESS report, “Carbon Dioxide Transport and Storage Costs in NETL Studies” (NETL, 2024).

The cost to transport and store CO_2 varies with CO_2 flow rate, plant capacity factor, and plant location. Exhibit 2-18 provides the transport, storage, and total costs for each case within this study.

Exhibit 2-18. CO_2 transport and storage costs

Case	Transport Cost (2023 $/tonne)	Storage Cost (2023 $/tonne)	T&S First Year Breakeven CO_2 Cost[A] (2023 $/tonne)
B11B.90	2.25	7.48	9.73
B11B.95	2.33	7.90	10.23
B12B.90	2.35	7.65	10.00
B12B.95	2.21	8.08	10.29
B31B.90	4.07	8.77	12.84
B31B.95	3.88	8.55	12.43
B32B.1.90	4.56	9.65	14.21
B32B.1.95	4.35	9.38	13.73
B32B.2.90	3.30	8.70	12.00
B32B.2.95	3.12	8.48	11.60

[A]The sum of transport and storage costs

2.7.4 Cost Metrics

2.7.4.1 First-Year and Levelized Cost of Electricity

The FY COE is the revenue received by the generator per net MWh during the power plant's first year of operation. The nominal FY COE can be obtained from the following formula:

$$FY\ COE = \frac{FCR * TASC + OC_{Fix} + CF * (OC_{Var} + Fuel_{FY})}{CF * MWh}$$

Where:

FY COE – the first-year cost of electricity, $/MWh

FCR – fixed charge rate

TASC – total as spent capital, expressed in base year cost, $

OC_{Fix} – sum of all first-year-of-operation fixed annual operating costs, $/yr

CF – plant capacity factor, assumed to be constant over the operational period

OC_{Var} – sum of all first-year-of-operation variable annual operating costs at 100 percent CF, including consumable costs (excluding fuel) and offset by any byproduct revenues, $/yr

$Fuel_{FY}$ – first year fuel cost at 100 percent CF, $/yr

MWh – annual net megawatt-hours of electricity generated at 100 percent CF, MWh/yr

The LCOE is the amount of revenue required per net MWh during the power plant's operational life to meet all capital and operational costs. The nominal LCOE can be obtained using the same formula as the FY COE and multiplying the OC_{Fix} and OC_{Var} by a levelization factor and using a levelized cost of fuel. The method used to determine the fixed charge rate and levelization factors for O&M costs is found in the QGESS report, "Cost Estimation Methodology for NETL Techno-economic Assessments" (NETL, 2025b). The method used to determine the levelized coal and natural gas costs is found in the QGESS report, "Fuel Prices for Selected Feedstocks in NETL Studies" (NETL, 2025c).

2.7.4.2 Cost of CO_2 Captured and Avoided

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

$$Cost\ of\ CO_2\ Captured\ \left(\frac{\$}{tonne}\right) = \frac{(LCOE_{CCS} - LCOE_{Non\ CCS})}{CO_2\ Captured}$$

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

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

Where:

CCS – the capture plant for which the cost of CO_2 captured/avoided is being calculated (excluding T&S unless otherwise noted[i])

Non-CCS – the reference non-capture plant, as described below

LCOE – the levelized cost of electricity, reported in $/MWh

The CCS plant includes CO_2 compression to 15.3 MPa (2,215 psia)

For Cost of CO_2 Captured, the LCOE excludes T&S costs

For Cost of CO_2 Avoided, the LCOE 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 a greenfield coal-based power system with CCS, the reference non-capture plant used to calculate the cost of CO_2 captured/avoided is an SC PC plant without capture.

For a greenfield natural gas-based power system with CCS, the reference plant used to calculate the cost of CO_2 captured/avoided is an analogous non-capture natural gas-based plant.

[i] If a plant is selling the captured CO_2, which is the basis of the Cost of CO_2 Captured metric, the T&S costs are excluded as it is assumed that the buyer is responsible for transporting and storing (if necessary) the CO_2. However, if a plant is capturing the CO_2 to avoid a penalty, which is the basis of the Cost of CO_2 Avoided metric, then the CO_2 cannot be emitted and the plant will need to pay to transport and store the CO_2.

PULVERIZED COAL RANKINE CYCLE PLANTS

3 PULVERIZED COAL RANKINE CYCLE PLANTS

Six[j] PC-fired Rankine cycle power plant configurations were evaluated, and the results are presented in this section. Unless otherwise indicated, all units are reported on an HHV basis. Each design is based on a market-ready technology that is assumed to be commercially available at the time the project commences. All designs employ a one-on-one configuration comprising 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 650 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 allows a meaningful side-by-side comparison of the results. The boiler and steam turbine industry's 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.

The 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 United States with SubC and SC PC units at a nominal rating and firing Illinois No. 6 coal (WorleyParsons, June 2005). Based on the OEM responses, the following single-reheat steam conditions were selected for the study:

- For SubC cases (B11A, B11B.90, and B11B.95) – 16.5 MPa/566°C/566°C (2,400 psig/1,050°F/1,050°F)
- For SC cases (B12A, B12B.90, and B12B.95) – 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 believed the steam conditions above this range would be limited to low sulfur coal applications (such as Powder River Basin coal). 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 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.

[j] Additional PC cases that include CO_2 capture rates above 95 percent are reported in the appendices.

3.1 COMMON PROCESS AREAS FOR ALL PC CASES

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 day storage bins.

Operation Description – The coal is delivered to the site by 100-car unit trains comprising 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 3 cm x 0 (1.25" 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.

Brominated powdered activated carbon (PAC) is delivered to the site in 9-tonne (10-ton) batches by self-unloading pneumatic trucks. The carbon 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 carbon level in the silo is measured by system instrumentation.[k] More comprehensive description of the PAC system is provided in Section 3.1.6.2.

Hydrated lime is delivered and distributed in a manner very similar to that of the PAC. The hydrated lime is delivered in 11-tonne (12.5-ton) batches.[k] More comprehensive description of the hydrated lime system is provided in Section 3.1.6.1.

[k] The descriptions of PAC and hydrated lime unloading were sourced from a quote provided by United Conveyor Corporation (UCC) to NETL, unless otherwise noted. The information relates to a mercury control system designed by UCC.

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 is transferred from the storage pile to a reclaim hopper and conveyed to a day bin.

3.1.2 Steam Generator and Ancillaries

The steam generator for the SubC 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 water wall tubes, 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 SubC and SC steam conditions are equipped with LNBs and OFA. While it is assumed for the purposes of this report that the power plant is designed for operation as a baseload plant, some consideration for cycling from minimum to baseload are included, as the power plants within this report are based on supplier's standard designs.

3.1.2.1 Scope

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

- PC Combustor
- Drum-type evaporator (SubC only)
- Once-through type steam generator (SC only)
- Startup circuit, including integral separators (SC only)
- Water cooled furnace, dry bottom
- Three-stage superheater
- Reheater
- Economizer
- Spray type desuperheater
- Soot blower system
- Air preheaters (Ljungstrom type)
- Coal feeders and pulverizers
- Low NOx Coal burners and natural gas 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

3.1.2.2.1 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.

3.1.2.2.2 Steam Generation

For the SubC steam system, 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 and is routed to the HP turbine. Steam from the HP turbine returns to the steam generator as cold reheat and returns to the 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.

3.1.2.2.3 Main and Reheat Steam

The main steam system conveys HP steam, which exits the boiler superheater through a motor-operated stop/check valve and a motor-operated gate valve, to the HP turbine stop valves via a single line. The HP turbine receives HP steam from the steam generator, and the exhaust is routed back to the reheater in the steam generator. The reheater system conveys cold reheat steam from the HP turbine exhaust, through a motor-operated isolation gate valve and a flow control valve and enters the boiler reheater. The reheater system then conveys hot reheat steam exiting the boiler reheater outlet, through a motor-operated gate valve, to the IP turbine stop valves. The IP turbine exhaust is routed to the LP turbine where final steam expansion occurs before it is exhausted to a condenser. Along the steam turbine path, steam is extracted for feedwater and deaerator heating to improve Rankine cycle efficiency.

3.1.2.2.4 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.

3.1.2.2.5 Condensate

The function of the condensate system is to pump condensate from the condenser hotwell through the LP FW heaters to the deaerator. 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 (three in cases B12B.90 and B12B.95), 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 in the condenser neck. All remaining FW heaters are 100 percent capacity, shell and U-tube HXs. 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 the SubC PC capture cases return all process extraction steam (CO_2 capture and drying requirements) condensate to the deaerator, the SC PC capture cases require this condensate to be returned after the condenser upstream of the condensate polisher. This is required because 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 the SC capture cases (B12B.90 and B12B.95) require only three LP FW heaters rather than four, as the condensate return increases the FW temperature above that which would be exiting the first LP FW heater.

To account for any losses, makeup water is supplied to the condenser. The makeup water provides high-quality demineralized water for makeup to the steam cycle. The demineralizer is sized based on the requirements of the startup boiler.

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, reheater, economizer, SCR, and air preheater. The gases exit the steam generator at this point and flow to the DSI manifold, ACI manifold, fabric filter, ID fan, FGD system, and stack or post combustion carbon capture (PostCCC) system.

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 (Storm, October 1993). 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. Each hopper incorporates a dry seal trough and is of welded steel construction, lined with refractory and block insulation for personnel safety and heat retention. Each hopper is paired with a pneumatic bottom ash transport line and is fully isolatable, with shutoffs downstream of the screw feeder and upstream of the clinker grinder, for ease of maintenance.

The steam generator incorporates fly ash hoppers under the economizer outlet and air preheater outlet.

The description of the balance of the ash handling system is presented in Section 3.1.11.

3.1.2.6 Burners

A boiler of this capacity employs approximately 24–36 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.

Natural gas-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 50–150 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 boiler emissions to 0.15 kg/GJ (0.35 lb/MMBtu). This boiler NOx production rate is equivalent to production rates of 2.8–3.4 lb/MWh-gross across the six PC cases considered.

The second measure taken to reduce the NOx emissions is the installation of an SCR system prior to the air heater. SCR uses NH_3 and a catalyst to reduce NOx to nitrogen (N_2) and H_2O. The SCR system consists of three subsystems: reactor vessel, NH_3 storage and injection, and gas flow control. The SCR system is designed for 75–79 percent reduction with 2 ppmv NH_3 slip at the end of the catalyst life.

The SCR capital costs are reported separately from the boiler costs; the cost for the initial load of catalyst is broken out separately in the O&M cost table.

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 40–60 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 NH_3 to contact the NOx in the boiler exhaust gas, which flows down vertically through multiple catalyst layers. Flow distribution through the catalyst is important to help limit accumulation of ash in the catalyst. Sonic horns are used to help mitigate accumulation of ash on the catalyst.

NH_3 is mixed with dilution air before injection, and the mixture is injected into the gas path immediately prior to entering the reactor vessel, which is located between the economizer outlet and the air preheater inlet. The NH_3 injection grid is arranged into several sections and consists of multiple pipes with nozzles. The NH_3 flow rate into each injection grid section is controlled considering imbalances in the flue gas flow distribution.

The catalyst contained in the reactor vessel enhances the reaction between the NH_3 and the NOx in the gas. The catalyst consists of various active materials such as titanium dioxide, vanadium pentoxide, and tungsten trioxide. Catalysts in flue gases with high SO_2 levels are designed with inhibitors to reduce the conversion of SO_2 to SO_3. While the optimum inlet flue gas temperature range for the catalyst is 260–371°C (500–700°F), the typical operating range for vanadium/titanium-based catalysts in PC applications is 302–427°C (575–800°F), depending on the sulfur level of the coal, with higher sulfur coals requiring higher temperatures to prevent the formation of ammonium bisulfate in the catalyst. 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 NH_3 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 (Gansley, Love, Rader, & Lancaster, 2013). This system is discussed in detail in Section 3.1.6.

3.1.5 Particulate Control

The pulse-jet 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. Flue gas exits the baghouse and enters the ID fan suction.

The bag material is polyphenylensulfide with intrinsic Teflon Polytetrafluoroethylene coating (Wieslanger, 2000). The bags are rated for a continuous temperature of 180°C (356°F) and a peak temperature of 210°C (410°F). The baghouse is provided with an n+1 design, so a compartment can be taken offline for maintenance while maintaining particulate emission targets. 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 PM by approximately 17 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 (FHA, 2016). 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 calcium sulfate [$CaSO_4$] reaction product) will render the fly ash unsuitable for use in concrete mixtures.

3.1.6 Mercury Removal[l]

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

The fraction of chlorine, and other halogens in the coal, impacts the amount of mercury oxidized in the SCR and air preheater. As oxidized mercury is removed by the fabric filter and wet FGD, the chlorine content of the coal can have a significant impact on the mercury removal rate of the plant. Data presented by Reaction Engineering International suggest that as coal chlorine concentrations increase, up to 500 ppmwd, the fraction of oxidized mercury increases rapidly. However, the rate of mercury oxidation diminishes at chlorine concentrations above 500 ppmwd (Senior C. , 2005).

The rate of mercury oxidation is also affected by the NH_3 concentration. Since the SCR is operated more aggressively for NOx control, the NH_3 levels increase and the fraction of oxidized mercury decreases (Hinton, Jimenez, Dene, & Tyree, August 19-23, 2012).

In this study, it is assumed that 0.6 percent of the coal carbon is unreacted in the PC boiler (Babcock & Wilcox Company, 2015). This unburned carbon both promotes mercury oxidation and adsorbs mercury on the surface of the fabric filter. The unburned carbon, combined with the HCl in the flue gas, is sufficient to promote high levels of oxidized mercury and overall Hg removal in the plant (Senior & Johnson, 2005).

Depending on the chemistry in the wet FGD, a portion of the oxidized mercury that is captured by the scrubber could be reduced to elemental mercury and re-emitted. By minimizing the amount of mercury entering the wet FGD, and through careful operation of the scrubber, the risk of periodic spikes in mercury re-emissions can be minimized.

Wet FGD parameters such as oxidation reduction potential of the scrubber slurry, halogen concentration in the scrubber slurry, the form of Hg in the slurry (i.e., liquid or solid), and the effect of sulfite concentration was examined by Babcock & Wilcox Enterprises Inc. for their impact on mercury re-emissions. It was concluded that sulfite concentration in the slurry was the most cost-effective parameter that can be controlled as a strategy to minimize mercury re-emission (Gadgil, 2016).

Without mitigation, the concentration of SO_3 in the flue gas is estimated to be 59 ppmvd at the air preheater inlet. This elevated SO_3 concentration is the result of combusting a relatively high sulfur coal (2.82 wt%) and from oxidation of SO_2 across the SCR catalyst.

The presence of SO_3 significantly inhibits Hg adsorption, as SO_3 is preferentially adsorbed onto carbon. This effect was demonstrated in a testing program conducted at the Mercury Research Center using an electrostatic precipitator (ESP)-configured system with an ACI rate of 10 lb/MMacf upstream of the air preheater at 300°F, 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) (Pollack, October 26-

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

29, 2009). Therefore, DSI is included in the PC plant designs to reduce the SO_3 levels to approximately 5 ppmvd at the air preheater inlet, as discussed in Section 3.1.6.1.

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 83.8–98.8 percent (Memorandum from Robert Wayland to William H. Maxwell, May 31, 2006). 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.

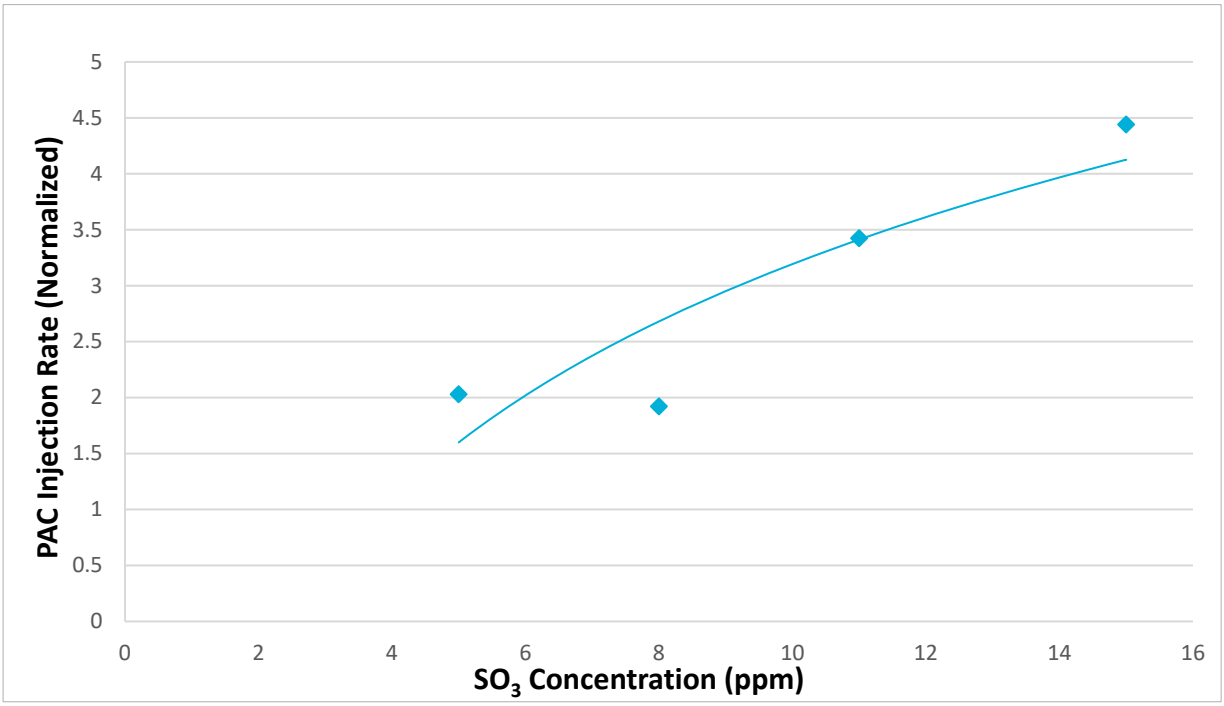
For PC boilers (as opposed to cyclones, stokers, fluidized beds, and 'others') with a fabric filter, SCR and wet FGD, the EMF is 0.1, which corresponds to a removal efficiency of 90 percent; (EPA, 2005) the average reduction in total Hg emissions developed from EPA's Information Collection Request (ICR) data on U.S. coal-fired boilers using bituminous coal, fabric filters, and wet FGD is 98 percent (Srivastava, Staudt, & Jozewicz, 2004). The referenced sources bound the co-benefit Hg capture for bituminous coal units employing SCR, a fabric filter, and a wet FGD system of 83.8–98 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 Hg removal rate required to comply with the Hg emission limit (Section 2.4.3.1) is calculated to be approximately 97–98 percent. Therefore, the potential co-benefit Hg capture rate (90 percent) of the systems utilized in the PC cases is not sufficient to achieve compliance with applicable regulations. A cost and performance estimate was obtained from United Conveyor Corporation (UCC), which applies ACI and DSI to increase the overall Hg removal rate in the plant.

3.1.6.1 Dry Sorbent Injection

Exhibit 3-1 provides data from a full-scale DSI/ACI test conducted by UCC on a midwestern coal-fired unit, which demonstrates the impact of SO_3 concentration (at the PAC injection point) on the PAC injection rate required to achieve a given Hg removal rate. The exhibit and data contained were supplied by UCC in the quote provided to NETL.

Exhibit 3-1. Effect of SO_3 concentration on PAC injection rate



As shown in Exhibit 3-1, higher SO_3 concentrations in the flue gas require significantly greater injection rates of PAC. Therefore, the DSI system considered in this report, with enhanced hydrated lime as the sorbent, targets an SO_3 concentration of 5 ppmvd at the air preheater inlet, with an SO_3 concentration of 2 ppmvd at the outlet of the fabric filter.

As the flue gas temperature must be maintained above the acid dew point temperature in the air preheater, locating the DSI point upstream of the air preheater allows for a lower operating temperature (289°F air preheater temperature with DSI upstream of the air preheater versus 337°F air preheater temperature with no DSI or DSI downstream of the air preheater) and higher overall plant efficiency, compared to a plant with no DSI or DSI downstream of the air preheater. Additionally, the reduction in operating temperature increases the Hg removal efficiency of carbon.

Since standard hydrated lime sorbents generally cannot achieve SO_3 removal rates greater than approximately 90 percent, the high level of SO_3 reduction required necessitates the use of an enhanced hydrated lime product to achieve the necessary Hg removal rate.

While DSI is included specifically to remove SO_3 from the flue gas, the enhanced hydrated lime also removes SO_2 and HCl, as shown in Exhibit 3-2. The rates shown are the total removal at the fabric filter outlet/FGD inlet, not the air preheater inlet.

Exhibit 3-2. Pollutant removal efficiency versus hydrated lime injection rate

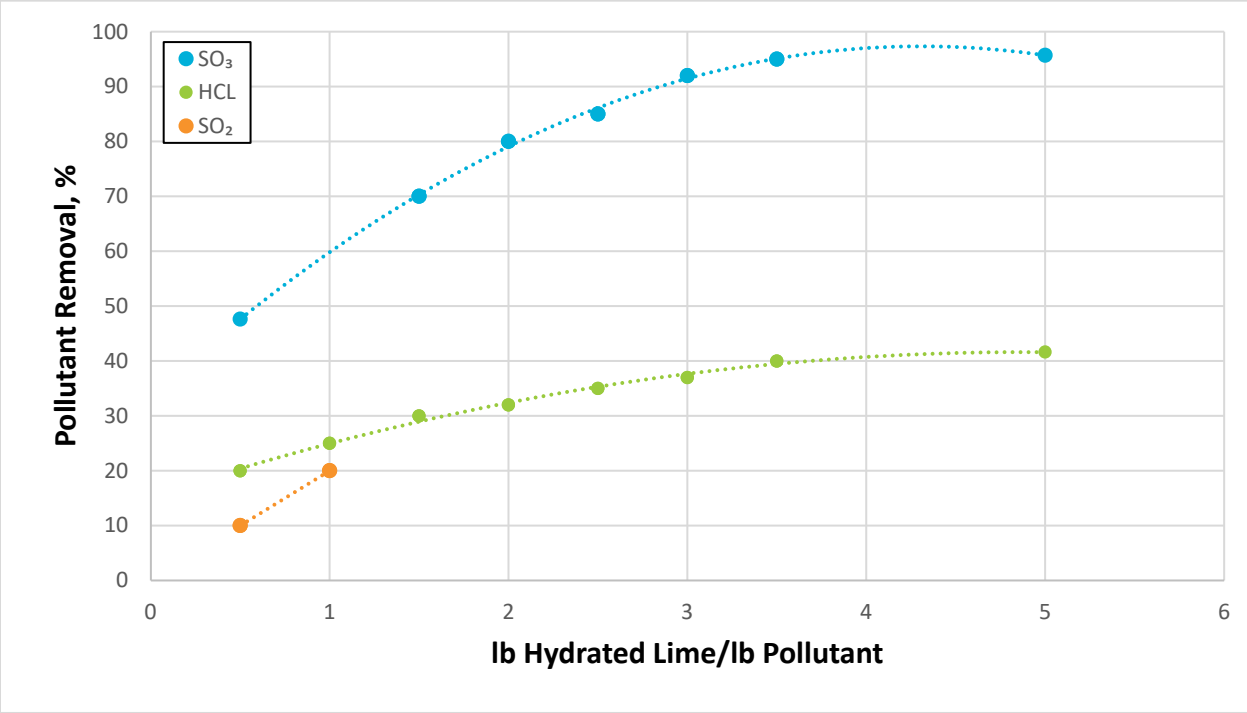


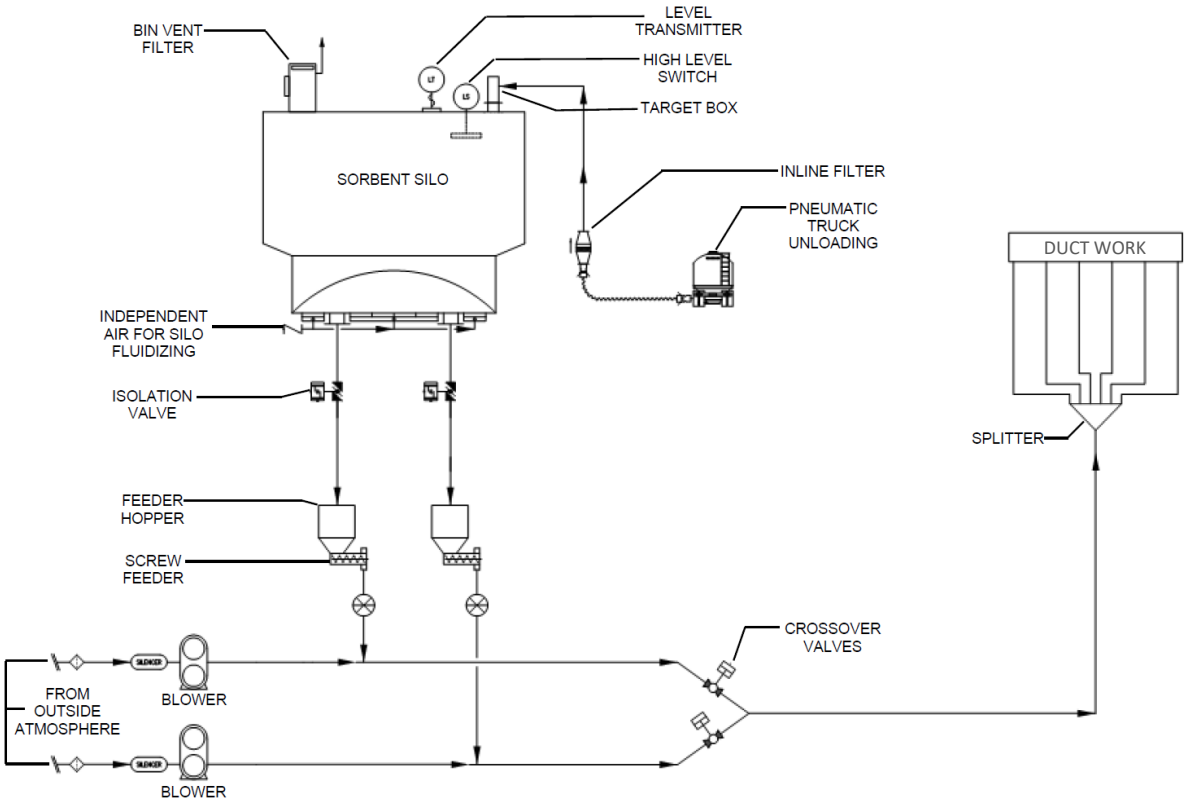
Exhibit 3-2 illustrates that approximately 3.5 lb of enhanced hydrated lime/lb of SO_3 is required to reduce the SO_3 concentration to 2 ppmvd at the outlet of the fabric filter (approximately 96.6 percent removal rate). At this injection rate, the enhanced hydrated lime is expected to also remove approximately 40 percent of HCl. The expected SO_2 reduction is very low, since SO_2 is a much weaker acid gas than SO_3 and HCl. In addition, the baseline SO_2 levels are far higher than either the SO_3 or HCl levels.

Operation Description – As shown in Exhibit 3-3, 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 sorbent is typically delivered in 11,340-kg (25,000-lb) batches by self-unloading pneumatic trucks equipped with manually operated discharge valves. The sorbent 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 sorbent level in the silo is measured by system instrumentation.

Silos are typically 14-ft diameter with skirt support, made of CS and are designed to be shipped in one piece. Storage silos are often aerated with dry air through a fluidizing system to ensure reliable feeding. Silos usually have two or more outlets and are equipped with weigh hoppers to provide loss-in-weight (LIW) monitoring and feed control.

Exhibit 3-3. Typical DSI process flow diagram



Used with permission from UCC

The silo roof equipment includes a bin vent filter, relief valve, and level transmitters. The bin vent filter is enabled when the unloading system is started to filter this airflow and vent it to the atmosphere.

Compressed air is delivered to the fluidizing stones located in the chisel bottom of the silo. The fluidizing of the material in conjunction with the 60-degree silo cone promotes mass flow of the sorbent out of the silo.

The fluidized sorbent 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 intake tee. The speed of the screw feeder determines the feed rate into the intake tee. Sorbent is fed through the intake tee directly into the conveying air stream.

Material fed from the storage silo typically discharges into one conveying line. The discharge of material is aided by the silo fluidizing system. Each silo discharge line has a CS weigh hopper equipped with load cells. The weigh hopper is vented via a small bin vent filter located on the weigh hopper. The material is metered from the weigh hopper using a variable speed rotary vane feeder.

The silo fluidizing system promotes constant fluid flow to the silo outlet by introducing air through a porous media. Cloth media is in trays on the silo floor and around the outlets. The pressure blower provides an air stream for conveying sorbent from the storage silo to a splitter

and lances for duct injection. Two 100-percent blowers are provided in a typical system for redundancy. Pressure blowers are on non-elevated common bases, and come complete with a v-belt motor, inlet filter, inlet and discharge silencers, discharge check valve, discharge relief valve, discharge pressure gauge, and pressure transmitter.

The conveying lines are mild steel and are provided with a combination of flange and groove-less Victaulic couplings. The conveying line after the splitter is made of a gum rubber material handling hose designed for abrasion resistance.

The DSI system is typically monitored and controlled by the DCS. The feed rate of the system can be adjusted in the following ways:

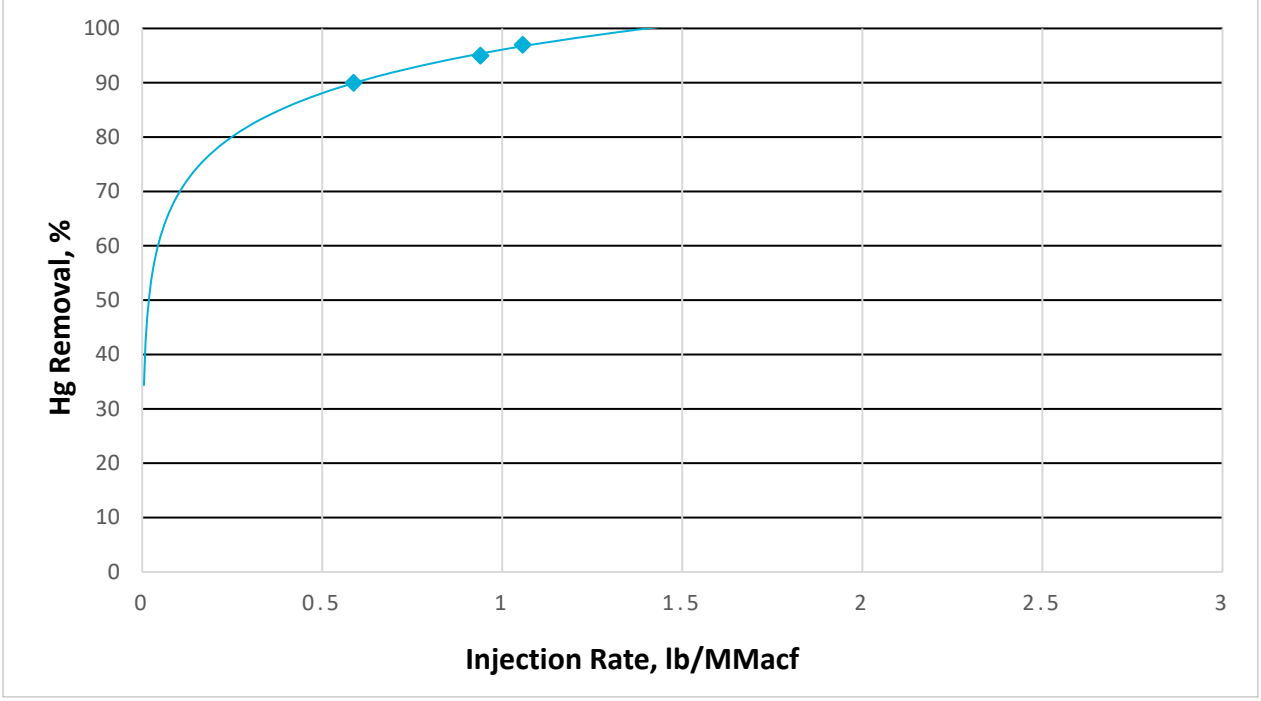
- Flat Rate (one continuous rate)
- Boiler Load Following (varies feed rate proportional to boiler load)
- Flue Gas Following (varies feed rate proportional to flue gas flow)

3.1.6.2 Activated Carbon Injection

By reducing the SO_3 with DSI (Section 3.1.6.1), most of the Hg will be oxidized in the SCR and removed in the fabric filter and wet FGD. Therefore, only a minimal amount of brominated PAC is injected upstream of the fabric filter to ensure the desired Hg emission rate is achieved.

Exhibit 3-4, provided by UCC, presents a typical performance curve for plants utilizing an SCR and a fabric filter firing bituminous coal. The points highlighted represent 90, 95, and 97 percent Hg removal.

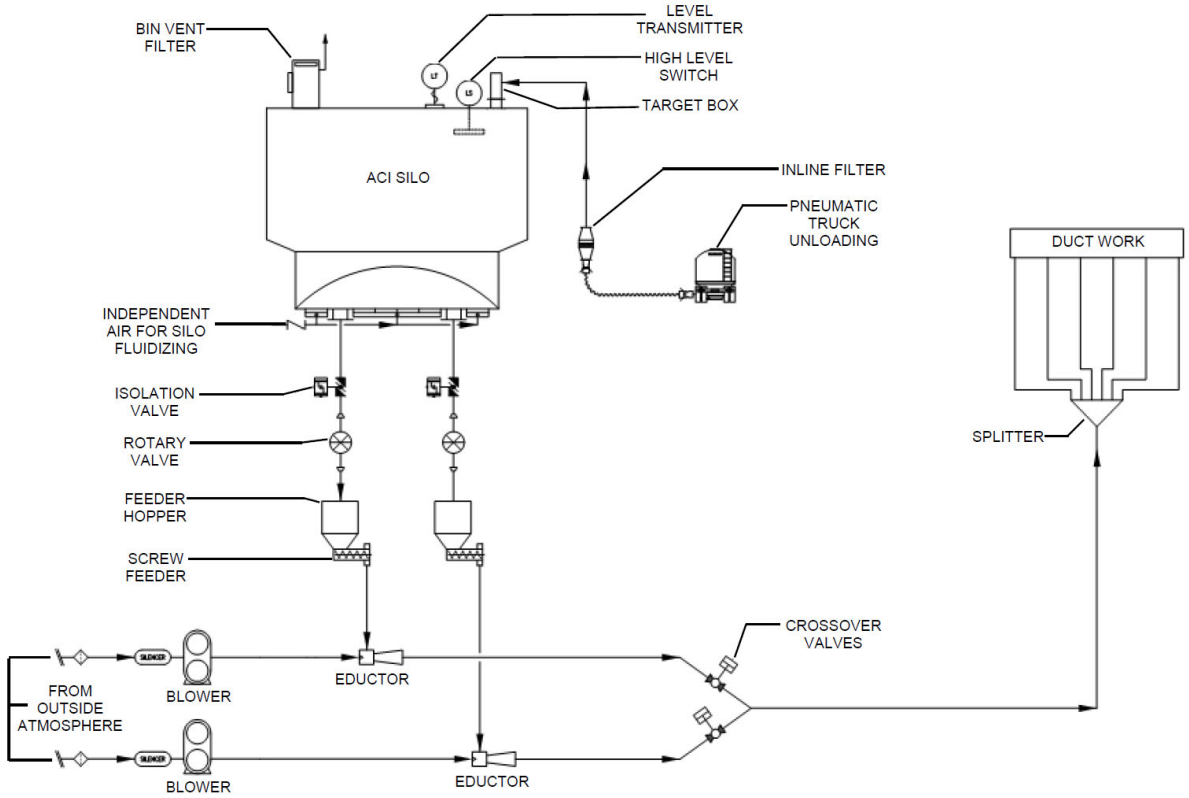
Exhibit 3-4. Mercury removal versus PAC injection rate for Case B12A



To meet the mercury emission limit, brominated PAC is injected at a rate of approximately 1.0 lb/MMacf in all PC cases.

Operation Description – As shown in Exhibit 3-5, the ACI system is based on dilute-phase, pneumatic conveying of activated carbon at a metered rate from a bulk storage silo to the flue gas ductwork where it mixes with the flue gas and absorbs Hg and SO_3, which is captured in the fabric filter.

Exhibit 3-5. Typical ACI injection process flow diagram



Used with permission from UCC

The activated carbon is typically delivered in 9,070-kg (20,000-lb) batches by self-unloading pneumatic trucks equipped with manually operated discharge valves. The carbon 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 carbon level in the silo is measured by system instrumentation.

Silos are typically 14-ft diameter with skirt support, made of CS and are designed to be shipped in one piece. Storage silos are often aerated with dry air through a fluidizing system to ensure reliable feeding. Silos usually have two or more outlets and are equipped with weigh hoppers to provide LIW monitoring and feed control.

The silo roof equipment includes a bin vent filter, relief valve, and level transmitters. The bin vent filter is enabled when the unloading system is started to filter this airflow and vent it to the atmosphere.

Compressed air is delivered to the fluidizing stones located in the chisel bottom of the silo. The fluidizing of the material in conjunction with the 60-degree silo cone promotes mass flow of the sorbent out of the silo.

The fluidized carbon 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. Carbon 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 carbon and air into the mixing zone directly downstream of the eductor discharge. The carbon is transported through the piping system and is distributed to an array of injection lances specifically designed to disperse the carbon across the cross section of the flue gas ductwork.

Material fed from the storage silo typically discharges into one conveying line. The discharge of material is aided by the silo fluidizing system. Each silo discharge line has a CS weigh hopper equipped with load cells. The weigh hopper is vented via a small bin vent filter located on the weigh hopper. The material is metered from the weigh hopper using a screw feeder.

The silo fluidizing systems promotes constant fluid flow to the silo outlet by introducing air through a porous media. Cloth media is in trays on the silo floor and around the outlets.

The pressure blower provides an air stream for conveying carbon from the storage silo to a splitter and lances for duct injection. Two 100 percent blowers are provided in a typical system for redundancy. Pressure blowers are on non-elevated common bases, and come complete with a v-belt motor, inlet filter, inlet and discharge silencers, discharge check valve, discharge relief valve, discharge pressure gauge, and pressure transmitter.

The conveying lines are mild steel and are provided with a combination of flange and groove-less Victaulic couplings. The conveying line after the splitter is made of a gum rubber material handling hose designed for abrasion resistance.

The ACI system is typically monitored and controlled by the DCS. The feed rate of the system can be adjusted in the following ways:

- Flat Rate (one continuous rate)
- Boiler Load Following (varies feed rate proportional to boiler load)
- Flue Gas Following (varies feed rate proportional to flue gas flow)
- Mercury Emission Following (varies feed rate to keep the Hg emission concentration below a given set point)

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 the PostCCC facility. Sulfur removal efficiency is 98 percent in the FGD unit for all cases. The PostCCC unit

includes a polishing scrubber designed to reduce the flue gas SO_2 concentration from about 34 ppmv at the FGD exit to approximately 0.37 ppmv prior to the PostCCC absorber to minimize formation of amine HSS during the CO_2 absorption process. The FGD removal efficiency of HCl is 99 percent for all cases. To minimize the required capacity and cost of specialized FGD wastewater treatment equipment, the FGD system is designed with materials capable of handling up to 20,000 ppm of chlorides.

While the PC cases of this study produce gypsum suitable for wallboard production, changes in coal or limestone characteristics or modifications to the wet FGD or dewatering system could impact the gypsum composition. Exhibit 3-6 provides the specification limits for gypsum used in wallboard and cement production, as well as typical characteristics of landfilled gypsum. The cases in this study do not consider a sale credit or a waste disposal cost for gypsum.

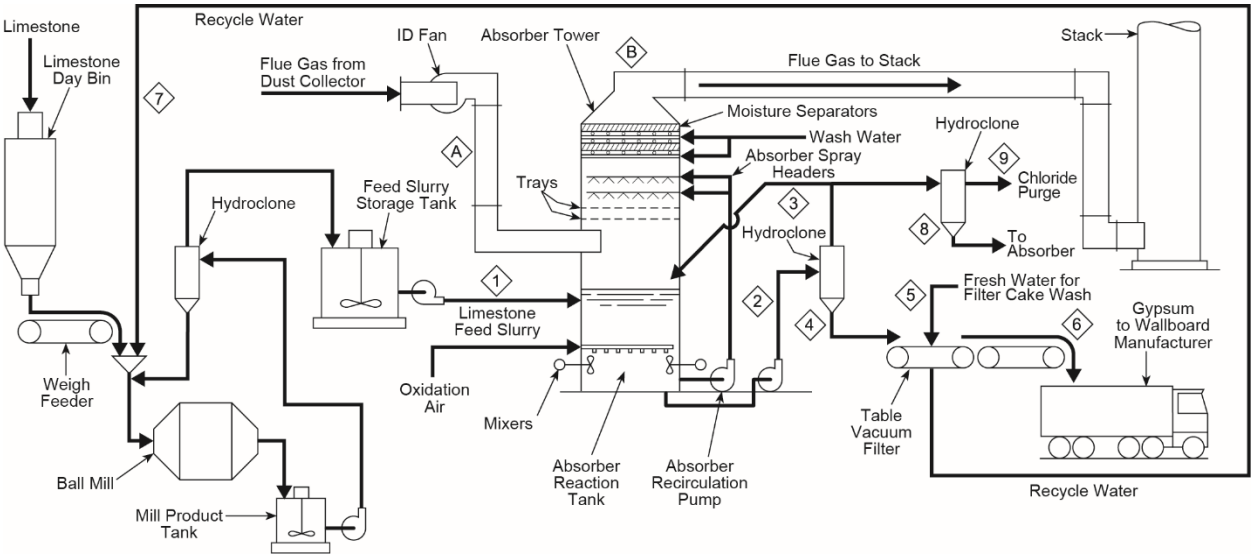
Exhibit 3-6. Typical disposal- and commercial-grade gypsum characteristics and limits

End Use	Disposal*	Wallboard	Cement
Moisture, % max	<20	<10	<14
$CaSO_4 \bullet 2H_2O$, % min	80–95+	>95	85–88
$CaSO_3 \bullet ½H_2O$, % max	<1–2+	0.5–1.0	
SiO_2, % max	<1–3+	1.0	2.0
Fe_2O_3, % max		1.5	1.0
Al_2O_3, % max			1.0
Fly ash, % max	<1–3+	1.0	
Total insolubles, % max	<5–20+	3.5	<15
Water soluble Cl^-, ppm max	2,000–50,000	100–120	50,000
Total dissolved solids, ppm max	5,000–150,000	600	
Mean particle size, µm	<20–90+	20–75	

* Disposal gypsum characteristics are based on a range of potential limestone supplies

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 PostCCC process inlet (cases B11B.90, B11B.95, B12B.90, and B12B.95). Exhibit 3-7 provides a process flow diagram of a typical wet limestone forced oxidation positive pressure absorber non-reheat FGD system (Babcock & Wilcox Company, 2015). The descriptions in Section 3.1.7.1 through Section 3.1.7.5 align with this diagram.

Exhibit 3-7. Wet flue gas desulfurization process flow diagram



Used with permission from Babcock & Wilcox

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.

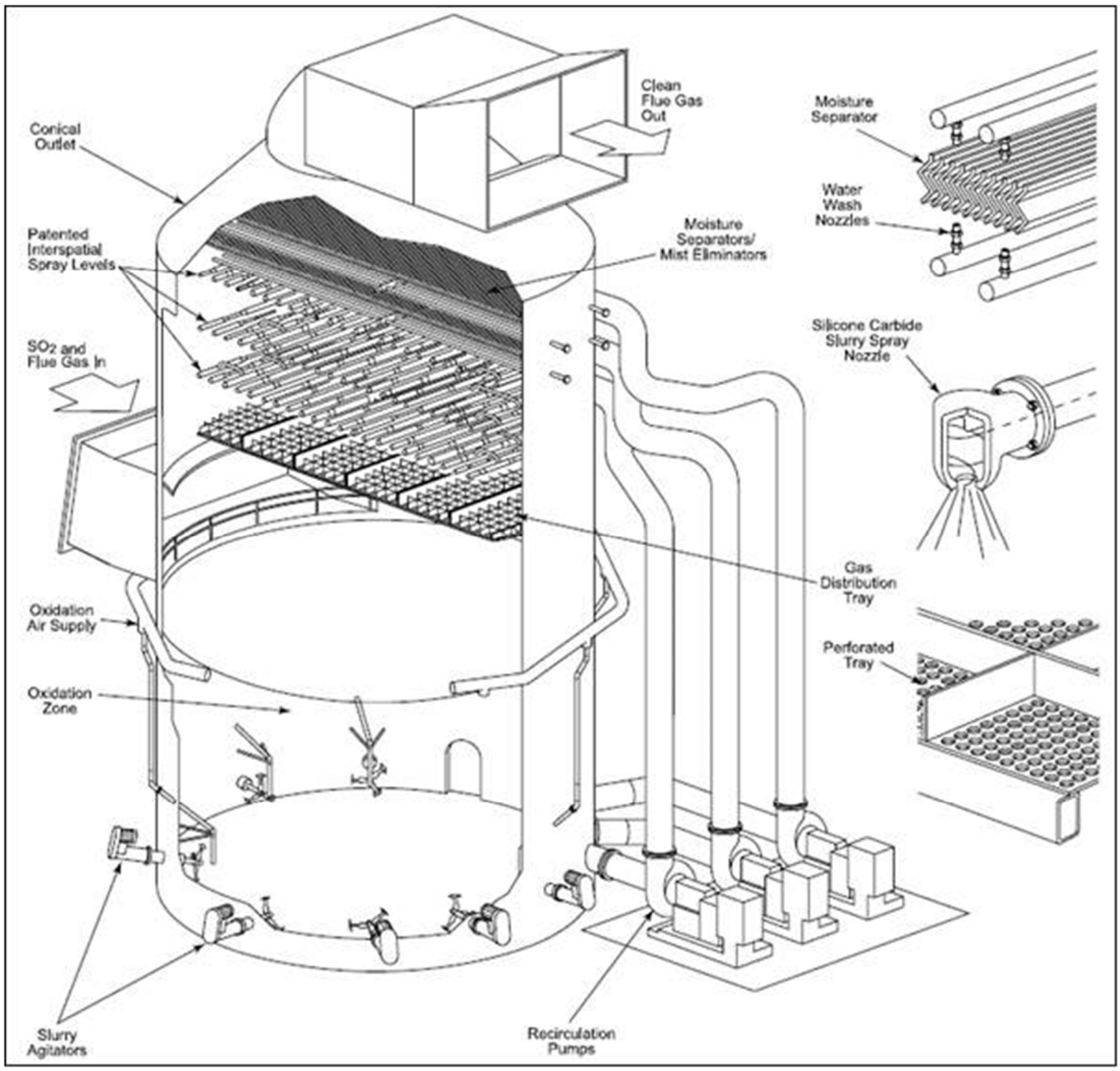
Operation Description – Each day bin supplies a 100 percent capacity ball mill via a weigh feeder. The wet ball mill accepts the limestone and grinds the limestone to 90 to 95 percent passing 325 mesh (44 microns). Water is added at the inlet to the ball mill to create limestone slurry. The reduced limestone slurry is then discharged into a mill product 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 feed slurry storage tank. Reagent distribution pumps direct slurry from the tank to the absorber module.

3.1.7.2 FGD Absorber Tower

The description of the FGD absorber tower follows Exhibit 3-7. Additional detail for the absorber tower cross section is presented in Exhibit 3-8 for reference (Babcock & Wilcox Company, 2015).

Exhibit 3-8. Cross section of the wet FGD absorber tower



Used with permission from Babcock & Wilcox

Upon entering the bottom of the absorber tower, 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 tower and is routed to the plant stack or PostCCC process.

The scrubbing slurry falls to the lower portion of the absorber tower, 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 (mixers) 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 tower 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 (not labeled in Exhibit 3-7). 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.

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 gas through the absorber 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 57°C (135°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 tower 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 tower 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 O_2 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 an overall limestone stoichiometry of 1.03. This system reduces the overall operating cost of the FGD process. The underflow from the hydrocyclone flows into the filter feed tank (not shown in Exhibit 3-7), from which it is pumped to a horizontal belt vacuum filter (represented as a table vacuum filter in Exhibit 3-7). 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 in.) 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 contains about 5 wt% solids, consisting of gypsum, fly ash, and limestone residues and is sent back to the absorber.

The remainder of the overflow is fed to a secondary hydrocyclone, where the resulting underflow is returned to the absorber and the overflow is blown down to the process water treatment system, for chloride control (represented as chloride purge in Exhibit 3-7). The flow to the secondary hydrocyclones is controlled to maintain a chloride concentration of 20,000 ppmw in the blowdown.

The underflow of the primary 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.

3.1.7.6 FGD Wastewater Quality

The blowdown stream from the FGD process must be treated under the ELG rule, as stated in Section 2.4.2. The design wastewater composition for the FGD process blowdown considered is provided in Exhibit 3-9. The design water quality is based on a survey of plants burning bituminous, high sulfur coal (EPA, 2009) (EPRI, 2006) and on internal information from Black & Veatch projects. Exhibit 3-9 includes a range of values, an average, and the final selected composition.

Exhibit 3-9. FGD process wastewater quality

Parameter	FGD Wastewater (Range)	FGD Wastewater (Average)	FGD Wastewater (Final)
pH	5.5–7.4	6.6	7.2
Chemical O_2 demand, ppm	304–1,060	682	350
Biological O_2 demand, ppm	21–1,370	422	500
Specific Conductance, µS/cm	5,990–32,000	9,595	32,000
Ammonia as N, ppm	1.5–31.5	8.4	10
Suspended Solids, ppm	4,970–25,300	13,888	15,000
Total Dissolved Solids, ppm	4,740–44,600	21,310	43,494
Chloride as Cl, ppm	832–28,800	9,966	20,000
Sulfate as SO_4, ppm	1,290–11,900	4,212	7,600
Calcium as Ca, ppm	751–5,370	2,791	5,370
Magnesium as Mg, ppm	176–7,000	2,728	6,000
Sodium as Na, ppm	59–5,340	998	2900
Boron (total), ppm	3.0–626	220	430
Potassium as K, ppm	35–684	226	250
M-Alkalinity as $CaCO_3$, ppm[1]	131–625	275	200
Iron (total), ppm	3.4–824	200	290
Aluminum (total), ppm	1.0–289	93	150
Silica as SiO_2, ppm	1–91	33	100
Manganese (total), ppm	1.58–225	32.1	60
Nitrate/Nitrite as N, ppm	1.0–54.5	20.5	30
Total Kjeldahl N_2, ppm	6.2–51.6	19.2	20
Carbon, ppm			8
Phosphorus, ppm	0.05–10.5	4.61	7
Nickel (total), ppm	0.447–6.0	2.05	5
Selenium (total), ppm	0.651–8.66	2.75	5
Zinc (total), ppm	0.31–9.04	3.23	6
Barium (total), ppm	0.588–11.900	3.330	5
Titanium (total), ppm	0.377–8.18	2.57	4
Vanadium (total), ppm	0.078–1.58	0.67	1.3
Fluorine, ppm			1
Arsenic (total), ppm	0.0599–3.000	0.799	1.4

Parameter	FGD Wastewater (Range)	FGD Wastewater (Average)	FGD Wastewater (Final)
Copper (total), ppm	0.0376–2.130	0.788	1.4
Lead (total), ppm	0.0312–4.000	0.896	1.3
Molybdenum (total), ppm	0.065–1.340	0.59	0.9
Mercury (total), ppm	0.0164–1.070	0.255	0.7
Chromium, ppm	0.176–1.380	0.777	1
Cobalt, ppm			0.1
Lithium, ppm			0.1
Beryllium (total), ppm	0.0036–3.000	0.438	0.140
Cadmium (total), ppm	0.00484–0.238	0.0728	0.140
Thallium (total), ppm	0.00633–0.300	0.0864	0.140
Antimony (total), ppm	0.00923–0.0518	0.0269	0.040
Uranium, ppm			0.03
Thorium, ppm			0.02
Tin, ppm			0.01

[1]Alkalinity is reported as $CaCO_3$ equivalent, rather than the concentration of HCO_3. The concentration of HCO_3 can be obtained by dividing the alkalinity by 0.82.

The wastewater composition reported in Exhibit 3-9 is based on water qualities from actual operations and adjusted to account for chloride. The design concentration of each constituent is individually representative of a plant configuration comparable to those in this study. However, due to the interaction and interdependencies of each constituent and the multitude of potential species, the wastewater quality cannot be considered representative as a whole. The wastewater quality is intended to inform users of the contaminants likely present, and at what concentrations they may be expected, to facilitate appropriate equipment selection and design.

The FGD process blowdown wastewater composition will be dependent on several factors, including composition of the coal, makeup water quality, flue gas treatment systems upstream of the FGD process, and other factors. The wastewater quality defined above will form the basis for discussion of the Spray Dryer Evaporator system, discussed in Section 3.1.10.

3.1.8 Post Combustion Carbon Capture [m]

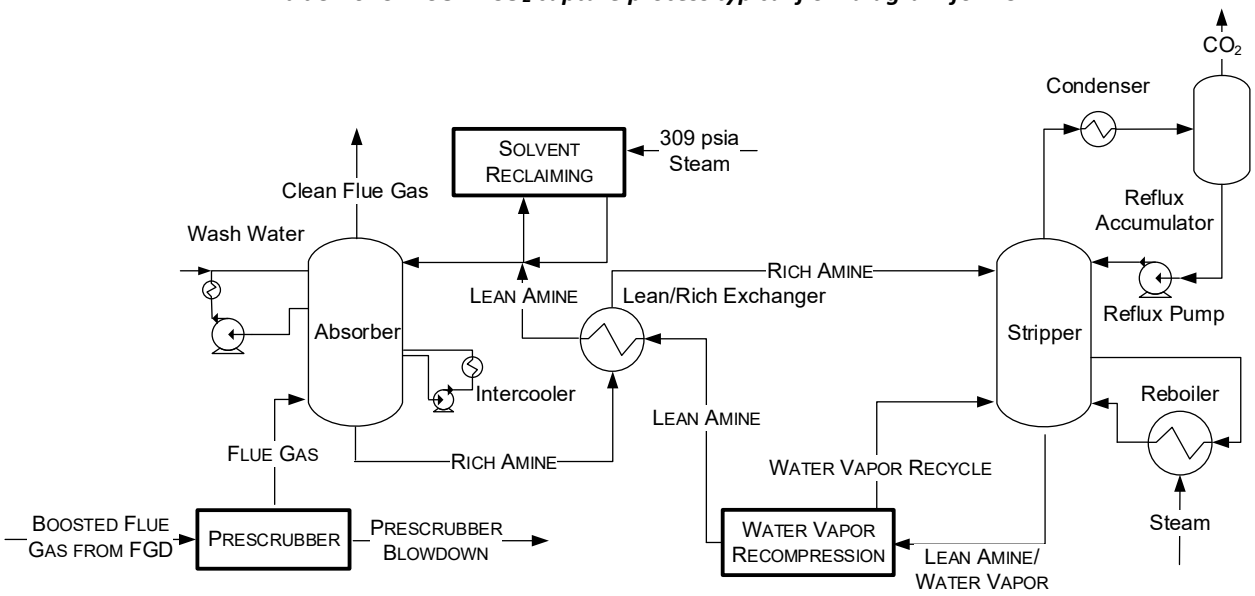
A PostCCC facility is used, along with a dryer and compressors, to remove, purify, and compress CO_2 in the flue gas exiting the FGD unit to a SC condition. In cases B11B.90 and B12B.90 90 percent of the CO_2 is removed; in cases B11B.95 and B12B.95, 95 percent of the CO_2 is removed. The flue gas exiting the FGD unit contains about 1 percent more CO_2 than the raw flue

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

gas because of the CO_2 liberated from the limestone in the FGD absorber tower. The PostCCC facility comprises the flue gas supply, pre-scrubber, CO_2 absorber, CO_2 stripper, and solvent reclaiming unit.

The CO_2 recovery process is based on data provided by Shell Catalyst & Technologies (SC&T) on their CANSOLV system in 2021 and is unchanged from Revision 4a of this report. A typical flowsheet is shown in Exhibit 3-10. This process is designed to recover high-purity CO_2 from LP streams that contain O_2, such as flue gas from coal-fired power plants, CT exhaust gas, and other waste gases.

Exhibit 3-10. CANSOLV CO_2 capture process typical flow diagram for PC



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 0.37 ppmv.

The exact composition of the direct contact cooler effluent and, therefore, the required treatment equipment, is unknown and not considered in this study. While this water may need to be treated before reuse, it is assumed suitable for recycle to the wet FGD. The balance of the effluent is discharged, rather than being recycled to the cooling tower, as it cannot be determined if there is a suitable treatment system available to prevent the cooling tower blowdown from being contaminated.

3.1.8.2 CO_2 Absorber Section

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

There are several packed sections in the CANSOLV absorber. The first few 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. Depending on the rate of capture specified for the case, 90 percent or more 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 HX to provide intercooling and limit water losses. The cooled amine is then sent back to the absorber just above the final packed section.

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 HX, 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 multiple parallel rich/lean HXs where heat from the lean amine is exchanged with the rich amine. The CANSOLV rich/lean solvent HXs are 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 HX after the rich/lean solvent HX where LP steam condensate from the regenerator reboiler or IP 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 indirectly uses LP steam to produce water vapor that flows upwards, counter-current to the rich amine flowing downward, and removes CO_2 from the amine. The CANSOLV regenerator reboiler is a Compabloc-type welded heat and block exchanger with a steam temperature approach of 20–30°C (68–86°F). Lean amine is collected in the stripper bottoms and flows to a flash vessel where water vapor is released. Simultaneously, the condensate leaving the reboiler flows to a separate flash vessel, and water vapor is released. The water vapor recovered from both flash vessels is combined, and then recompressed and injected into the bottom of the stripper to enhance stripping of CO_2 within the column, thus reducing the amount of reboiler steam otherwise required. The lean amine is then pumped through the same rich/lean HX to exchange heat from the lean amine to the rich amine and continues 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 0.2 MPa (29 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 LP steam is also dependent on the stripper top temperature. For the steady-state case described here, the LP steam requirement for the reboiler portion of the CANSOLV process is calculated as approximately 2.5 MJ/kg (1,070 Btu/lb) CO_2 for PC cases[n] and approximately 2.7 MJ/kg (1,160 Btu/lb) for NGCC cases, 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.

3.1.8.4.1 Thermal Reclaimer

The degradation products are removed in the thermal reclaimer by distilling a slipstream—taken from the lean amine exiting the lean amine flash vessel, and prior to the lean solvent pump—under vacuum conditions to separate the amine from the less volatile degradation products and non-volatile salts and ionic species. This process leaves the non-ionic degradation products and salts in the bottom, which are pumped to a storage tank, diluted and cooled with process water, and then disposed. The condensed amine and water are returned to the lean amine tank.

At large scale, the thermal reclaimer operation is typically continuous, while, at smaller scale, it can be designed to operate in batch mode.

3.1.9 CO_2 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 paper "Centrifugal Compressor Simulation User Manual" (CCSI, 2012). The design is assumed to be an eight-stage front-loaded centrifugal compressor with stage discharge pressures presented in Exhibit 3-11.

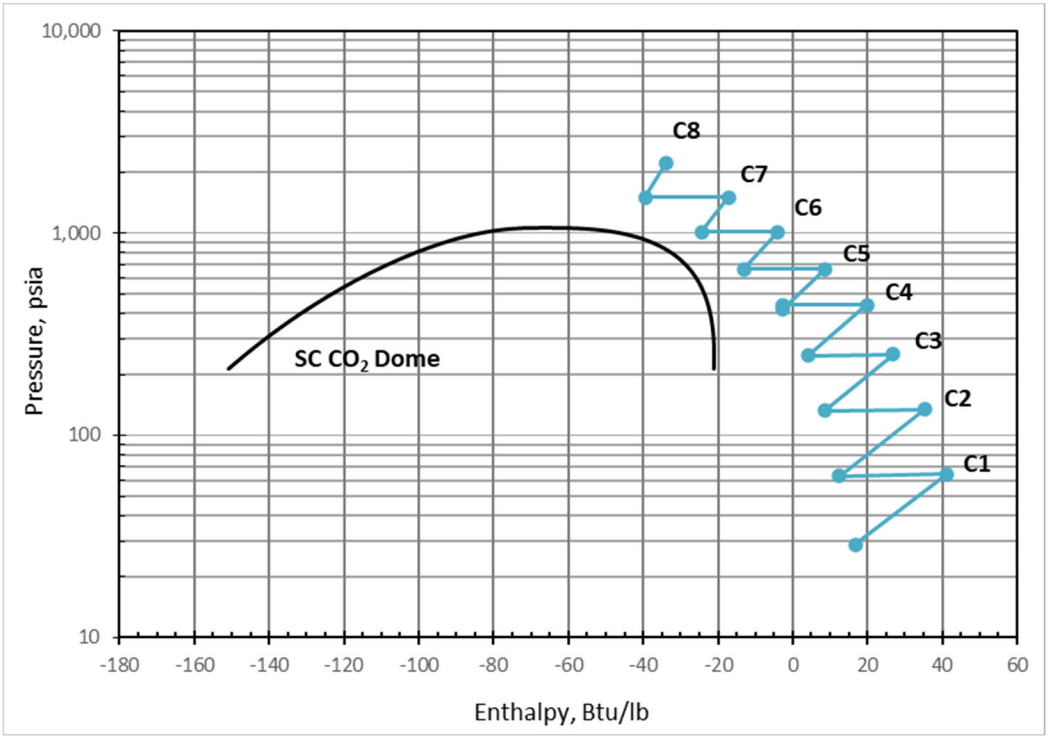
Exhibit 3-11. CO_2 compressor interstage pressures

Stage	Outlet Pressure, MPa (psia)	Stage Pressure Ratio
1	0.39 (56)	2.27
2	0.82 (119)	2.13
3	1.57 (227)	1.91
4	2.82 (410)	1.80
5	4.33 (628)	1.53
6	6.72 (975)	1.55
7	10.17 (1,475)	1.51
8	15.28 (2,217)	1.50

[n] Recent vendor feedback states that the PC reboiler energy requirement can be reduced to 2.4 MJ/kg (1,020 Btu/lb).

Intercooling is included for each stage with the first three stages including water knockout. CO_2 transportation and storage costs assume that the CO_2 enters the transport pipeline as a dense phase liquid; thus, a CO_2 product aftercooler is also included to cool the CO_2 to the pipeline inlet temperature of 30°C (86°F). Since all PC cases with CO_2 capture utilize the CANSOLV system and have identical CO_2 suction pressure, the enthalpy versus pressure operating profile shown in Exhibit 3-12 is representative of all cases. Data points representing compression stage discharge pressures are labeled with the compression stage number (e.g., C1). Intercooling temperatures for the final two intercooling stages (after compression stages six and seven) were selected to provide a suitable buffer between the compressor operating profile and SC CO_2 dome. The base assumption that cooling water is available at a temperature of 60°F from the cooling tower is not a limiting factor in selection of these two stages' intercooling temperatures. Enthalpy reference conditions are 0.01°C and 0.0006 MPa (32.02°F and 0.089 psia), the same as those used for stream table results. The CO_2 aftercooler is not represented in the compressor operating profile plot.

Exhibit 3-12. PC CO_2 compressor enthalpy versus pressure operating profile



A TEG dehydration unit is included between stages 4 and 5, operating at 2.82 MPa (409 psia), to reduce the moisture concentration of the CO_2 stream to the QGESS design point of 500 ppmv (NATCO Group Inc, 2009). The dryer is designed based on a paper published by the Norwegian University of Science and Technology (Bilsbak, 2009).

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.

Several alternatives to rejecting the heat of CO_2 compression to cooling water were investigated in a separate study (NETL, 2008). 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 lithium bromide-water (LiBr-H_2O) absorption refrigeration system, where water is the refrigerant. This configuration resulted in a net plant efficiency increase of 0.1 percentage points (absolute) and reduced the number of CO_2 compression stages necessary from eight to five.

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

3.1.10 Process Water Systems

3.1.10.1 Process Water Sources

As discussed in Section 2.4.2, the only system in the PC cases producing a wastewater stream that must be treated for compliance with the ELG rule is the wet FGD. A detailed process description of the wet FGD is provided in Section 3.1.7.

3.1.10.2 Process Water Treatment

The updated ELG rule established FGD wastewater as a new category, with discharge limits that must be met. The FGD wastewater is sourced from the overflow of the secondary hydrocyclone, as described in Section 3.1.7.3, with a composition described in Section 3.1.7.6.

The water recovered from the flue gas in PC cases with CO_2 capture is partially discharged from the plant. While the ELG rule does not regulate this water and therefore it does not need to be treated, the discharge of this water removes PC cases with CO_2 capture from qualifying for the ZLD designation.

A variety of technologies are currently installed at PC plants to treat FGD wastewater, including surface impoundments, chemical precipitation, biological treatment, ZLD operating practices, evaporation ponds, and constructed wetlands. Approximately 37 percent of PC plants currently utilize ZLD operating practices (EPA, 2015b) (EPA, 2009).

While multiple process configurations were assessed for feasibility of complying with the ELG, given this study's intention of maintaining general applicability of the cases presented, and the prevalence of utilizing ZLD operating practices in existing PC plants, systems that would enable ZLD were selected in all cases, specifically a spray dryer evaporator (SDE).

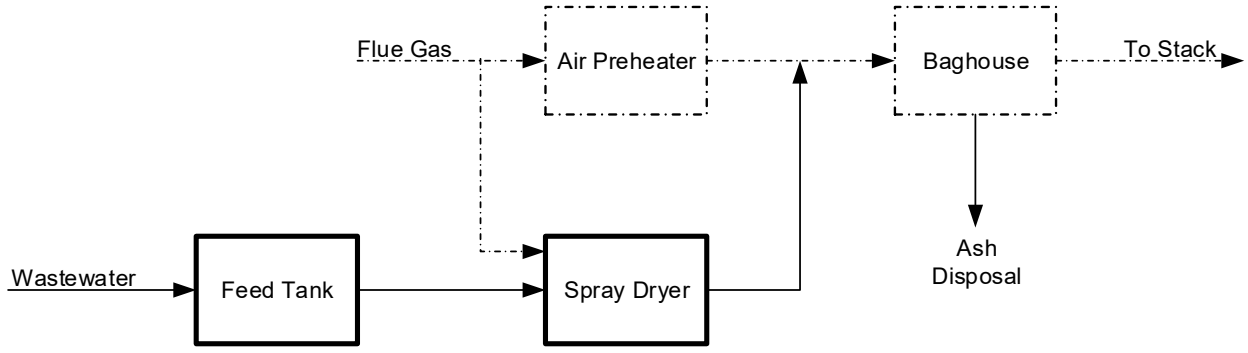
3.1.10.2.1 Spray Dryer Evaporator

A spray dryer is a technology commonly used in the power industry for FGD, which can also be applied as a thermal evaporation process to treat wastewater. An SDE has been constructed and is currently operating at Kansas City Power & Light's Iatan Plant Unit 2. Operation of the SDE has been described as straightforward, with periodic maintenance performed (Kansas City Power & Light, July 2017). The feasibility of using an SDE as the sole treatment system in PC cases is limited by the flow rate of wastewater, as the cost and performance impact of the spray dryer increases with increasing wastewater flow rate. Typically, a spray dryer for FGD wastewater is limited to approximately 150–200 gpm, depending on the flue gas conditions. As the system is designed based on flow rate, the solids concentration of the FGD wastewater does not impact the sizing of the system.

Spray dryers typically require a flue gas temperature above 316°C (600°F). A slipstream of flue gas is taken upstream of the air preheater for use as the heat source to evaporate the wastewater, which is sprayed into a tall cylindrical vessel using rotary atomizers. The heat from the slipstream is used to evaporate the wastewater, which contains dissolved and suspended solids, to produce a humidified gas stream containing additional suspended particulates. All the suspended particulates are assumed to exit the spray dryer vessel. The humidified gas stream is returned downstream of the air preheater and the combined flue gas passes through a baghouse, which removes most of the suspended solids.

Exhibit 3-13 provides a simplified BFD of the spray dryer evaporation process.

Exhibit 3-13. Spray dryer BFD



The atomizers and the spray dryer vessel are designed so that the wastewater mist droplets are evaporated before reaching the vessel wall. Therefore, the vessel is constructed of CS without concerns for corrosion. However, the wall metal temperature must be monitored to ensure there is no temperature drop, which is an indication that moisture is reaching the wall and can cause corrosion issues.

3.1.10.2.2 Alternative Treatment Methods

There are several alternative treatment options for compliance with the ELG rule, spanning a range of technology maturation on a technology readiness scale. Of the more mature routes, deep-well injection and evaporating ponds were also considered, and discussion is provided below.

Deep-well injection is a proven technology in municipal and industrial applications which discharges wastewater under pressure into underground porous rock formations through Class 1 wells. Strata of impermeable rock are used to protect underground sources of drinking water from the injected wastewater. A survey of the local geology is, therefore, required to determine the depth to which the well must be drilled and ultimately operated. Capital cost for the equipment and the electrical power consumed by the system would depend on the depth of the well. Disposal of wastewater by this method is regulated and requires that the facility apply for and receive a permit.

Based on the potentially adverse impacts to surface water and groundwater, geological and legal restrictions, and increasing disposal costs, deep well injection was excluded from further evaluation as a viable treatment option in this study.

Evaporation ponds can be constructed to dispose of wastewater if sufficient plot space is available, which is greatly impacted by local ambient conditions. A key determining factor in assessing the viability of an evaporation pond at a specific location is the difference between average rainfall and average evaporation at that location, as the pond needs to be large enough to contain the volume of the discharged wastewater, as well as rainwater. In addition, the pond must have enough surface area to allow for average evaporation rates to be equal to or greater than the total inflow of water.

Parts of the Midwest region could be considered a cold, semi-arid climate, which indicates that the summers can be either warm or hot, but the winters tend to be colder, compared to hot, semi-arid or hot, arid climates. Therefore, winter evaporation would be less available. Moreover, other parts of the Midwest region fall into humid, subtropical and humid, continental climate types. The humidity and higher rainfall averages compared to the arid climates are not favorable for the installation of evaporation ponds. Therefore, evaporation ponds were excluded from further evaluation as a viable treatment option in this study.

While both evaporating ponds and deep-well injection offer low-cost solutions with low auxiliary loads, neither option addresses water consumption, and in many regions of the country the availability of fresh water is limited—therefore, it is desirable to restrict the consumption of, and discharge into the available fresh water. By recycling what would otherwise be water discharge, the amount of water withdrawal required can be reduced considerably.

3.1.11 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), and dissolved solids from the SDE that are disposed of with the fly ash (discussed in Section 3.1.10.2.1). The scope of the system is from the baghouse hoppers, air heater and economizer hopper collectors, and bottom ash hoppers to the separate bottom ash/fly ash storage silos and truck filling stations. 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 PM by approximately 17 percent.

The bottom ash from the boiler is fed into a series of dry storage hoppers, each equipped with a clinker grinder. The clinker grinder is provided to break up any clinkers that may form. Accumulated bottom ash discharged from the hoppers passes through the clinker grinder, then to a screw feeder and finally to a pneumatic ash conveying system for transport to the bottom ash silos, which have a three-day retention time, before being transferred to trucks for offsite disposal.

Ash from the economizer hoppers is pneumatically conveyed to the fly ash storage silo(s) with a three-day storage capacity. Pyrites (rejected from the coal pulverizers) are conveyed using water on a periodic basis to the dewatering system (i.e., dewatering bins) for offsite removal by truck.

The wet sluicing for the pyrite system is not an explicit requirement of the National Fire Protection Association, but it is viewed as a risk mitigation measure to avoid accidental ignition of combustible materials clinging to the mill rejects. This can also come into effect when a mill trips and the contained solids need to be safely removed from the mills. Wet sluicing of the mill rejects further reduces potential ignition of this coal that is being swept from the mills. The water used for wet sluicing is regarded as low volume wastewater, which is not specifically regulated under the ELG rule, and is assumed to be treated for the pyrites within the plant's standard low volume wastewater treatment facility described in Section 3.1.14.5.

3.1.12 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).

The steam turbine is a tandem compound type, consisting of HP-IP-two double flow LP (four flow) sections enclosed in three casings, all connected to the generator by a common shaft, designed for condensing single reheat operation, and equipped with non-automatic extractions and four-flow exhaust. The turbine drives a H_2-cooled generator. The HP and IP sections are contained in a single span, opposed-flow casing, with the two double-flow LP sections in a separate casing each. The turbine has a direct current (DC) motor-operated emergency lube oil pump and redundant alternating current (AC) motor-operated main lube oil pumps (Gorman & Reinker, 1994). The exhaust pressure is 50.8 cm (2 in.) Hg in the single pressure condenser. There are eight extraction points for all non-capture plants and SubC capture plants, whereas there are seven extraction points for SC capture plants. The reason for the difference between

the capture and non-capture plants is discussed in Section 3.1.2.2.5. The condenser is two-shell, transverse, single pressure with divided waterbox for each shell.

Turbine bearings are lubricated by a closed-loop (CL), 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 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. The generator stator is cooled with a CL water system consisting of circulating pumps, shell and tube or plate and frame type HXs, filters, and deionizers, all skid-mounted. The generator rotor is cooled with a H_2 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 the conditions provided in Exhibit 3-14.

Exhibit 3-14. PC steam conditions

Steam Conditions		
Steam Parameter	**SubC**	**SC**
Main Pressure, MPa (psig)	16.5 (2,400)	24.1 (3,500)
Main Temperature, °C (°F)	566 (1,050)	593 (1,100)
Reheat Temperature, °C (°F)	566 (1,050)	593 (1,100)

The steam enters the turbine inlet, 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 the conditions provided in Exhibit 3-14. After passing through the IP section, the steam enters a crossover pipe, which transports the steam to the two double flow 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 exhaust moisture content ranging 9.4–9.6 percent.

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

3.1.13 Cooling System

3.1.13.1 Surface Condenser

The water-cooled surface 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 for plugging tubes. This can be done during normal operation at reduced load.

The condenser is equipped with an air extraction system to evacuate the condenser steam space for removal of non-condensable gases during steam turbine operation and to rapidly reduce the condenser pressure from atmospheric pressure before unit startup and admission of steam to the condenser.

3.1.13.2 Circulating Water System

The circulating water system (CWS) is a closed-cycle cooling water system that rejects heat through a wet cooling tower and supplies cooling water to the surface condenser to condense the main turbine exhaust steam. The system also supplies cooling water to the acid gas removal (AGR) plant and CO_2 compressors as required, and to the auxiliary cooling system.

The CWS consists of two 50 percent capacity vertical circulating water pumps (CWPs), a mechanical draft evaporative cooling tower, and CS cement-lined interconnecting piping. The pumps are single-stage vertical pumps. The piping system is equipped with butterfly isolation valves and all required expansion joints.

3.1.13.3 Auxiliary Cooling System

The auxiliary cooling system is a CL process that utilizes a higher quality water to remove heat from compressor intercoolers, oil coolers, and other ancillary equipment and transfers that heat to the main circulating cooling water system in plate and frame HXs. The heat transferred to the circulating water in the condenser and other applications is removed by a mechanical draft cooling tower.

3.1.13.4 Cooling Tower

The cooling tower is a multi-cell, wood frame, counterflow, mechanical draft, evaporative cooling tower.

The design ambient wet bulb temperature of 11°C (51.5°F) (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 (The Marley Cooling Tower Company, 1985):

- Evaporative losses of 0.8 percent of the circulating water flow rate per 5.5°C (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 was chosen for this report.

The cooling tower blowdown was assumed to be treated and returned to the water source.

It is assumed that makeup cooling water requires minimal pretreatment and all filtration and treatment of the circulating water are conducted on site.

3.1.14 Balance of Plant

The balance of plant components consists of the accessory electric plant, ducting and stack, buildings and structures, instrumentation and control, waste treatment, and miscellaneous systems as described below.

3.1.14.1 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.

3.1.14.2 Ducting and Stack

One stack is provided with a single fiberglass-reinforced plastic (FRP) liner. The stack is constructed of reinforced concrete and is 152 m (500 ft) high for adequate particulate dispersion. For cases with capture, a bypass system, consisting of a diverter damper and ducting, is included to route the flue gas from the wet FGD to the stack in case of failure or emergency shutdown of the PostCCC facility.

3.1.14.3 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 building
- Fire water pump house

3.1.14.4 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 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 and supervised manual procedures, with operator selection of modular automation routines available.

3.1.14.5 Wastewater Treatment

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 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.).

3.1.14.6 Miscellaneous Systems

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 a small auxiliary boiler; start-up fuel is assumed to be natural gas. Fuel oil is delivered by truck. All truck roadways and unloading stations inside the fence area are provided.

3.1.15 Performance Summary Metrics

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

3.1.15.1 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, fraction

BH – boiler thermal output, Btu

CH – coal thermal input, Btu

The heat transferred in the boiler is calculated in 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.

3.1.15.2 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, fraction

STP – steam turbine power, after generator losses, kWh

TI – thermal input, kWh

TC – thermal consumption, kWh

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).

3.1.15.3 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, B11B.90, and B11B.95, which are based on a SubC PC plant with a nominal net output of 650 MWe. All cases 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 three configurations is that cases B11B.90 and B11B.95 include CO_2 capture while Case B11A does not.

The balance of this section is organized as follows:

- Key Assumptions is a summary of study and modeling assumptions relevant to SubC PC cases.
- Sparing Philosophy is provided for all SubC PC cases.

- Process 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.
- 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.
- Major Equipment List provides an itemized list of major equipment for Case B11A with account codes that correspond to the cost accounts in the Cost Estimating section.
- Cost Estimating provides a summary of capital and operating costs for Case B11A.
- Process Description, Performance Results, Major Equipment List, and Cost Estimating are discussed for cases B11B.90 and B11B.95.

3.2.1 Key System Assumptions

System assumptions for cases B11A, B11B.90, and B11B.95, SubC PC with and without CO_2 capture, are compiled in Exhibit 3-15.

Exhibit 3-15. SubC PC plant study configuration matrix

	Case B11A w/o CO_2 Capture	Case B11B.90 w/ CO_2 Capture	Case B11B.95 w/ CO_2 Capture
Steam Cycle, MPa/°C/°C (psig/°F/°F)	16.5/566/566 (2,400/1,050/1,050)		
Coal	Illinois No. 6		
Condenser Pressure, mm Hg (in. Hg)	50.8 (2.0)		
Boiler Efficiency, HHV %	88.0		
Carbon Conversion, %	99.4		
Cooling Water to Condenser, °C (°F)	16 (60)		
Cooling Water from Condenser, °C (°F)	27 (80)		
Stack Temperature, °C (°F)	57 (135)	45 (113)	
SO_2 Control	Wet Limestone Forced Oxidation		
FGD Efficiency, %[A]	98	98[B, C]	
FGD Blowdown Treatment (Effluent Limitation Guidelines)	Spray dryer evaporator		
NOx Control	LNB w/OFA, SCR		
SCR Efficiency, %[A]	76.1	79.1	79.3
Ammonia Slip (end of catalyst life), ppmv	2		
Particulate Control	Fabric Filter		
Fabric Filter efficiency, %[A]	99.9		

	Case B11A w/o CO_2 Capture	Case B11B.90 w/ CO_2 Capture	Case B11B.95 w/ CO_2 Capture
Ash Distribution, Fly/Bottom, %	80/20		
SO_3 Control	DSI		
Mercury Control	Co-benefit Capture and ACI		
CO_2 Control	N/A	CANSOLV	
Overall Carbon Capture, %[A]	N/A	90	95
CO_2 Sequestration	N/A	Off-site Saline Formation	

[A]Removal efficiencies are based on the flue gas content.
[B]A SO_2 polishing step is included to meet more stringent SOx limits in the flue gas (0.37 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.

3.2.1.1 Balance of Plant

The balance of plant assumptions are common to all PC cases and are presented in Exhibit 3-16.

Exhibit 3-16. Balance of plant assumptions

Parameter	Value
Cooling System	Recirculating Wet Cooling Tower
Fuel and Other Storage	
Coal	30 days
Ash	3 days
Gypsum	30 days
Limestone	30 days
Hydrated lime	7 days
Activated carbon	7 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 Wastewater	
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

Parameter	Value
	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	Blowdown will be treated for chloride and metals and discharged

3.2.2 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 SubC PC boiler (1 x 100 percent)
- Two SCR reactors (2 x 50 percent)
- One DSI system (1 x 100 percent)
- One ACI system (1 x 100 percent)
- Two single-stage, in-line, multi-compartment fabric filters (2 x 50 percent)
- One wet limestone forced oxidation positive pressure absorber (1 x 100 percent)
- One steam turbine (1 x 100 percent)
- For cases B11B.90 and B11B.95, one CO_2 absorption system, consisting of an absorber, stripper, and ancillary equipment (1 x 100 percent) and two CO_2 compression systems (2 x 50 percent)

3.2.3 Case B11A – SubC PC Without CO_2 Capture Process Description

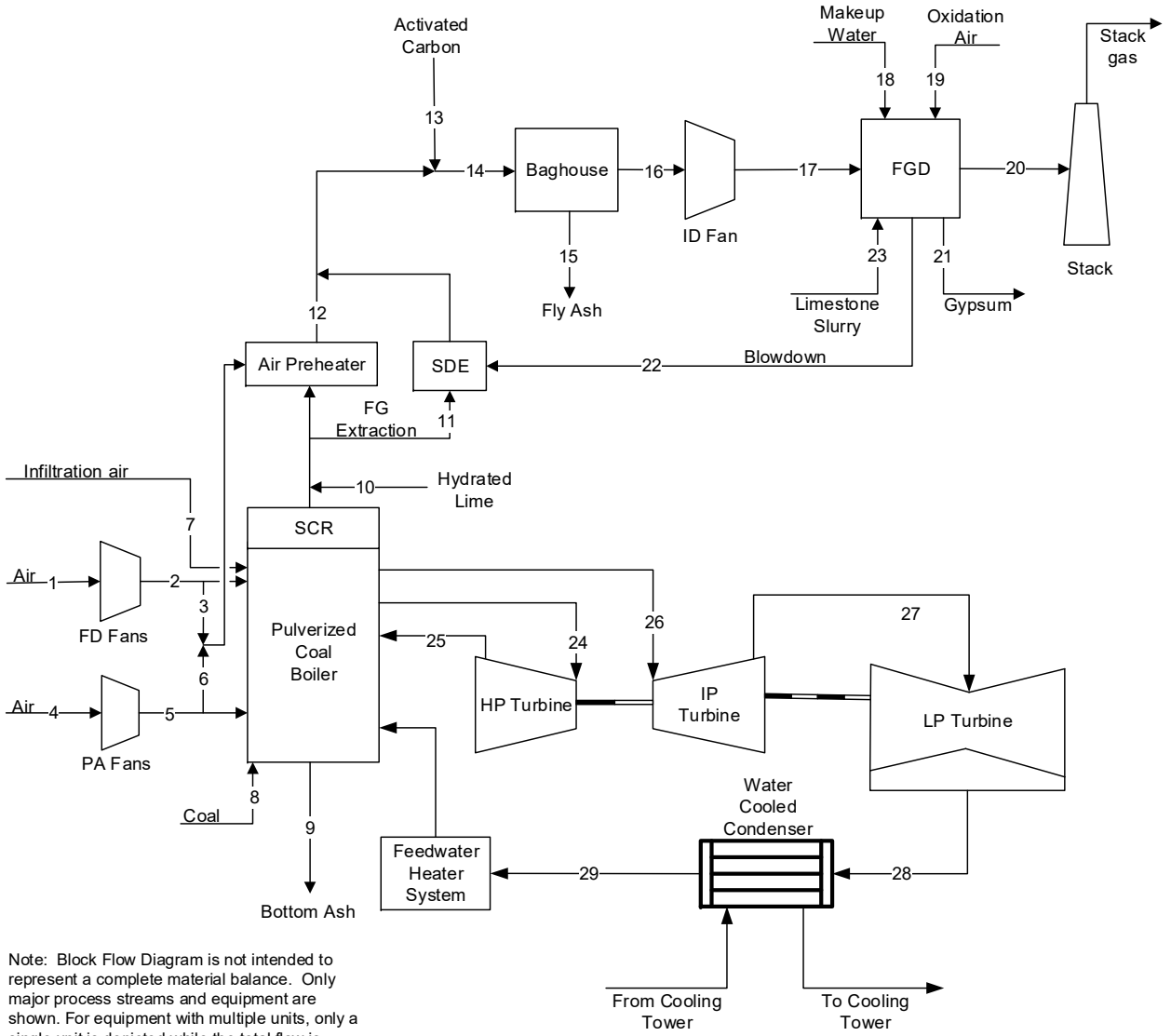
In this section the SubC PC process without CO_2 capture is described. The system description follows the BFD in Exhibit 3-17 and stream numbers reference the same exhibit. Exhibit 3-18 provides process data for the numbered streams in the BFD.

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 NH_3 is injected to reduce NOx compounds, followed by hydrated lime injection (stream 10) for the reduction of SO_3. A small

flue gas stream is extracted for use in the spray dryer evaporator (stream 11). The flue gas then passes through the combustion air preheater (where the air preheater leakages are introduced) and is cooled to 143°C (289°F) (stream 12) before PAC is injected (stream 13) for mercury reduction. The flue gas then passes through a fabric filter for particulate removal (stream 16). An ID fan provides the motive force for the flue gas (stream 17) to pass through the FGD unit and the plant stack. FGD inputs and outputs include makeup water (stream 18), oxidation air (stream 19), limestone slurry (stream 23) and product gypsum (stream 21). The clean, saturated flue gas exiting the FGD unit (stream 20) passes to the plant stack and is discharged to the atmosphere. The FGD blowdown (stream 22) is sent to the SDE where extracted flue gas (stream 11) is used to evaporate the FGD blowdown stream. The SDE outlet gas stream is recombined into the flue gas path after the air preheater, and before PAC injection.

Exhibit 3-17. Case B11A BFD, SubC 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. For equipment with multiple units, only a single unit is depicted while the total flow is reported.

Exhibit 3-18. Case B11A stream table, SubC unit without CO_2 capture

	1	2	3	4	5	6	7	8	9	10	11	12
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	0.0087	0.0088
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1457	0.1379
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	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000	0.0879	0.0837
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7318	0.7340
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0237	0.0336
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0020
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	60,980	60,980	1,806	18,732	18,732	2,578	1,348	0	0	1	4,018	81,515
V-L Flowrate (kg/hr)	1,759,698	1,759,698	52,120	540,561	540,561	74,394	38,896	0	0	12	119,511	2,420,545
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	223,673	4,509	1,219	965	18,528
Temperature (°C)	15	17	17	15	24	24	15	15	1,316	15	385	143
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg)[A]	30.23	32.49	32.49	30.23	38.98	38.98	30.23	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-95.31	-95.31	-97.58	-88.83	-88.83	-97.58	-2,119.02	1,267.06	-13,402.95	-2,261.17	-2,394.31
Density (kg/m^3)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	1,003.6	0.5	0.8
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015	29.742	29.694
V-L Flowrate (lb_{mol}/hr)	134,438	134,438	3,982	41,298	41,298	5,684	2,972	0	0	2	8,859	179,711
V-L Flowrate (lb/hr)	3,879,469	3,879,469	114,905	1,191,732	1,191,732	164,011	85,750	0	0	27	263,476	5,336,389
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	493,115	9,940	2,687	2,128	40,848
Temperature (°F)	59	63	63	59	75	75	59	59	2,400	59	726	289
Pressure (psia)	14.7	15.0	15.0	14.7	15.9	15.9	14.7	14.7	14.3	14.7	14.3	14.1
Steam Table Enthalpy (Btu/lb)[A]	13.0	14.0	14.0	13.0	16.8	16.8	13.0	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-41.0	-41.0	-42.0	-38.2	-38.2	-42.0	-911.0	544.7	-5,762.2	-972.1	-1,029.4
Density (lb/ft^3)	0.076	0.077	0.077	0.076	0.080	0.080	0.076	---	---	62.650	0.033	0.052

[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 3-18. Case B11A stream table, SubC unit without CO2 capture (continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.1372	0.0000	0.1372	0.1372	0.0000	0.0003	0.1245	0.0001	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	0.0000	0.0911	0.0000	0.0911	0.0911	0.9999	0.0099	0.1508	0.9998	0.9943	0.9999	1.0000
HCl	0.0000	0.0001	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.7281	0.0000	0.7281	0.7281	0.0000	0.7732	0.6803	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0329	0.0000	0.0329	0.0329	0.0000	0.2074	0.0363	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0020	0.0000	0.0020	0.0020	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.1158	0.0000	0.0000	0.0001	0.0000	0.0000	0.0001	0.0009	0.0001	0.0000
$CaCl_2$	0.0000	0.0001	0.8842	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0048	0.0000	0.0000
Total	0.0000	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_{mol}/hr)	0	86,215	5	86,209	86,209	5,037	3,609	96,375	203	681	2,805	103,895
V-L Flowrate (kg/hr)	0	2,552,647	552	2,552,082	2,552,082	90,763	104,139	2,769,828	3,656	12,591	50,543	1,871,700
Solids Flowrate (kg/hr)	49	19,734	19,747	0	0	0	0	0	32,887	192	21,637	0
Temperature (°C)	15	143	143	143	156	15	15	57	15	57	15	566
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	16.65
Steam Table Enthalpy (kJ/kg)[A]	---	---	---	287.58	302.09	-47.80	30.23	297.00	---	---	---	3,473.89
AspenPlus Enthalpy (kJ/kg)[B]	-6.79	-2,453.14	-1,066.09	-2,464.17	-2,449.66	-16,015.01	-97.58	-2,939.24	-12,513.34	-15,496.00	-14,994.25	-12,506.41
Density (kg/m^3)	---	0.8	2,150.2	0.8	0.9	1,003.7	1.2	1.1	878.3	979.5	1,003.7	47.7
V-L Molecular Weight	---	29.608	104.897	29.603	29.603	18.019	28.857	28.740	18.021	18.495	18.019	18.015
V-L Flowrate (lb_{mol}/hr)	0	190,070	12	190,059	190,059	11,105	7,956	212,470	447	1,501	6,184	229,050
V-L Flowrate (lb/hr)	0	5,627,624	1,217	5,626,378	5,626,378	200,098	229,587	6,106,425	8,060	27,759	111,429	4,126,393
Solids Flowrate (lb/hr)	108	43,506	43,535	0	0	0	0	0	72,504	423	47,701	0
Temperature (°F)	59	289	289	289	313	59	59	135	59	135	59	1,050
Pressure (psia)	14.7	14.1	14.1	13.9	15.3	14.7	14.7	14.8	14.7	14.7	14.7	2,414.7
Steam Table Enthalpy (Btu/lb)[A]	---	---	---	123.6	129.9	-20.5	13.0	127.7	---	---	---	1,493.5
AspenPlus Enthalpy (Btu/lb)[B]	-2.9	-1,054.7	-458.3	-1,059.4	-1,053.2	-6,885.2	-42.0	-1,263.6	-5,379.8	-6,662.1	-6,446.4	-5,376.8
Density (lb/ft^3)	---	0.052	134.232	0.051	0.055	62.658	0.076	0.067	54.833	61.145	62.658	2.975

[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 3-18. Case B11A stream table, SubC unit without CO2 capture (continued)

	25	26	27	28	29
V-L Mole Fraction					
Ar	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	96,973	96,973	82,051	65,522	83,314
V-L Flowrate (kg/hr)	1,746,999	1,746,999	1,478,180	1,180,392	1,500,921
Solids Flowrate (kg/hr)	0	0	0	0	0
Temperature (°C)	355	566	267	38	39
Pressure (MPa, abs)	4.28	4.19	0.52	0.01	1.32
Steam Table Enthalpy (kJ/kg)[A]	3,098.44	3,593.58	2,994.07	2,340.01	162.43
AspenPlus Enthalpy (kJ/kg)[B]	-12,881.86	-12,386.71	-12,986.23	-13,640.29	-15,817.87
Density (kg/m^3)	16.0	11.1	2.1	0.1	993.3
V-L Molecular Weight	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	213,789	213,789	180,893	144,451	183,675
V-L Flowrate (lb/hr)	3,851,475	3,851,475	3,258,829	2,602,318	3,308,965
Solids Flowrate (lb/hr)	0	0	0	0	0
Temperature (°F)	671	1,050	512	101	101
Pressure (psia)	620.5	608.1	75.0	1.0	190.7
Steam Table Enthalpy (Btu/lb)[A]	1,332.1	1,545.0	1,287.2	1,006.0	69.8
AspenPlus Enthalpy (Btu/lb)[B]	-5,538.2	-5,325.3	-5,583.1	-5,864.3	-6,800.5
Density (lb/ft^3)	1.000	0.692	0.132	0.003	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

3.2.4 Case B11A – Performance Results

The plant produces a net output of 650 MWe at a net plant efficiency of 38.6 percent (HHV basis). Overall performance for the plant is summarized in Exhibit 3-19. Exhibit 3-20 provides a detailed breakdown of the auxiliary power requirements.

Exhibit 3-19. Case B11A plant performance summary

Performance Summary	
Total Gross Power, MWe	**688**
CO_2 Capture/Removal Auxiliaries, kWe	–
CO_2 Compression, kWe	–
Balance of Plant, kWe	37,520
Total Auxiliaries, MWe	**38**
Net Power, MWe	**650**
HHV Net Plant Efficiency, %	38.6
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,336 (8,849)
LHV Net Plant Efficiency, %	40.0
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,005 (8,535)
HHV Boiler Efficiency, %	88.0
LHV Boiler Efficiency, %	91.3
Steam Turbine Cycle Efficiency, %	46.3
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,770 (7,365)
Condenser Duty, GJ/hr (MMBtu/hr)	2,793 (2,648)
CO_2 Capture Rate, %	–
AGR Cooling Duty, GJ/hr (MMBtu/hr)	–
As-Received Coal Feed, kg/hr (lb/hr)	223,673 (493,115)
Limestone Sorbent Feed, kg/hr (lb/hr)	21,637 (47,701)
HHV Thermal Input, kWt	1,685,945
LHV Thermal Input, kWt	1,626,114
Raw Water Withdrawal, (m^3/min)/MWnet (gpm/MWnet)	0.038 (10.0)
Raw Water Consumption, (m^3/min)/MWnet (gpm/MWnet)	0.030 (8.0)
Excess Air, %	20.3

Exhibit 3-20. Case B11A plant power summary

Power Summary	
Steam Turbine Power, MWe	688
Total Gross Power, MWe	**688**
Auxiliary Load Summary	
Activated Carbon Injection, kWe	30
Ash Handling, kWe	730
Baghouse, kWe	100
Circulating Water Pumps, kWe	5,700
CO_2 Capture/Removal Auxiliaries, kWe	–
CO_2 Compression, kWe	–
Coal Handling and Conveying, kWe	480
Condensate Pumps, kWe	720
Cooling Tower Fans, kWe	2,950
Dry Sorbent Injection, kWe	60
Flue Gas Desulfurizer, kWe	3,460
Forced Draft Fans, kWe	1,150
Ground Water Pumps, kWe	590
Induced Draft Fans, kWe	10,600
Miscellaneous Balance of Plant[A,B], kWe	2,250
Primary Air Fans, kWe	1,360
Pulverizers, kWe	3,350
SCR, kWe	40
Sorbent Handling & Reagent Preparation, kWe	1,040
Spray Dryer Evaporator, kWe	250
Steam Turbine Auxiliaries, kWe	500
Transformer Losses, kWe	2,160
Total Auxiliaries, MWe	**38**
Net Power, MWe	**650**

[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 are presented in Section 2.4. A summary of the plant air emissions for Case B11A is presented in Exhibit 3-21. SO_2 emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit 3-21. Case B11A air emissions

	kg/GJ (lb/MMBtu)[A]	tonne/year (ton/year)[B]	kg/MWh (lb/MWh)[C]
SO_2	0.035 (0.081)	1,567 (1,727)	0.306 (0.675)
NOx	0.036 (0.084)	1,626 (1,792)	0.318 (0.700)
Particulate	0.005 (0.011)	209 (230)	0.041 (0.090)
Hg	1.54E-7 (3.59E-7)	0.007 (0.008)	1.36E-6 (3.00E-6)
CO_2	87 (202)	3,931,031 (4,333,220)	768 (1,693)
CO_2[D]	–	–	812 (1,790)
	mg/Nm^3		
Particulate Concentration[E,F]	14.53		

[A]Based on thermal input on an HHV basis
[B]Calculations based on an 85 percent capacity factor
[C]Emissions based on gross power except where otherwise noted
[D]CO_2 emissions based on net power instead of gross power
[E]Concentration of particles in the flue gas after the baghouse
[F]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 boiler emissions are controlled to about 0.15 kg/GJ (0.35 lb/MMBtu) using LNBs and OFA. An SCR unit then further reduces the NOx concentration by 76.1 percent to 0.04 kg/GJ (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 97.2 percent.

CO_2 emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 3-22. 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, 20 percent of the unburned carbon remains in the bottom ash, the remaining unburned carbon is captured in the fabric filter, along with the PAC, and some carbon leaves as gypsum.

Exhibit 3-22. Case B11A carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	142,580 (314,335)	Stack Gas	144,083 (317,649)
Air (CO_2)	332 (733)	FGD Product	169 (373)
PAC	49 (108)	Baghouse	733 (1,617)
FGD Reagent	2,195 (4,840)	Bottom Ash	171 (377)
		CO_2 Product	–
		CO_2 Dryer Vent	–
		CO_2 Knockout	–
Total	**145,157 (320,016)**	**Total**	**145,157 (320,016)**

Exhibit 3-23 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 removed in the baghouse via hydrated lime, and sulfur emitted in the stack gas.

Exhibit 3-23. Case B11A sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	5,606 (12,360)	FGD Product	5,271 (11,620)
		Stack Gas	110 (241)
		Polishing Scrubber and Solvent Reclaiming	–
		Baghouse	226 (498)
Total	**5,606 (12,360)**	**Total**	**5,606 (12,360)**

Water demand, recycle, withdrawal, discharge, and consumption are defined and discussed in Section 2.6. Exhibit 3-24 shows the water balance for the plant.

Exhibit 3-24. 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 Process Makeup	1.5 (400)	–	1.5 (400)	–	1.5 (400)
FGD Slurry Water	0.8 (223)	–	0.8 (223)	–	0.8 (223)
CO_2 Drying	–	–	–	–	–
CO_2 Capture Recovery	–	–	–	–	–
CO_2 Compression KO	–	–	–	–	–
Deaerator Vent	–	–	–	0.1 (17)	-0.1 (-17)
Condenser Makeup	**0.4 (100)**	**–**	**0.4 (100)**	**–**	**0.4 (100)**
BFW Makeup	0.4 (100)	–	0.4 (100)	–	0.4 (100)
Cooling Tower	**22 (5,864)**	**0.3 (84)**	**22 (5,781)**	**5.0 (1,319)**	**17 (4,462)**
BFW Blowdown	–	0.3 (84)	-0.3 (-84)	–	-0.3 (-84)
Total	**25 (6,588)**	**0.3 (84)**	**25 (6,504)**	**5.1 (1,336)**	**20 (5,169)**

3.2.4.2 Energy and Mass Balance Diagrams

Energy and mass balance diagrams are shown for the PC boiler, FGD unit, and steam cycle of Case B11A in Exhibit 3-25 and Exhibit 3-26.

An overall plant energy balance is provided in tabular form in Exhibit 3-27. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-19) is calculated by multiplying the power out by a generator efficiency of 98.5 percent.

Exhibit 3-25. Case B11A energy and mass balance, SubC PC boiler without CO_2 capture

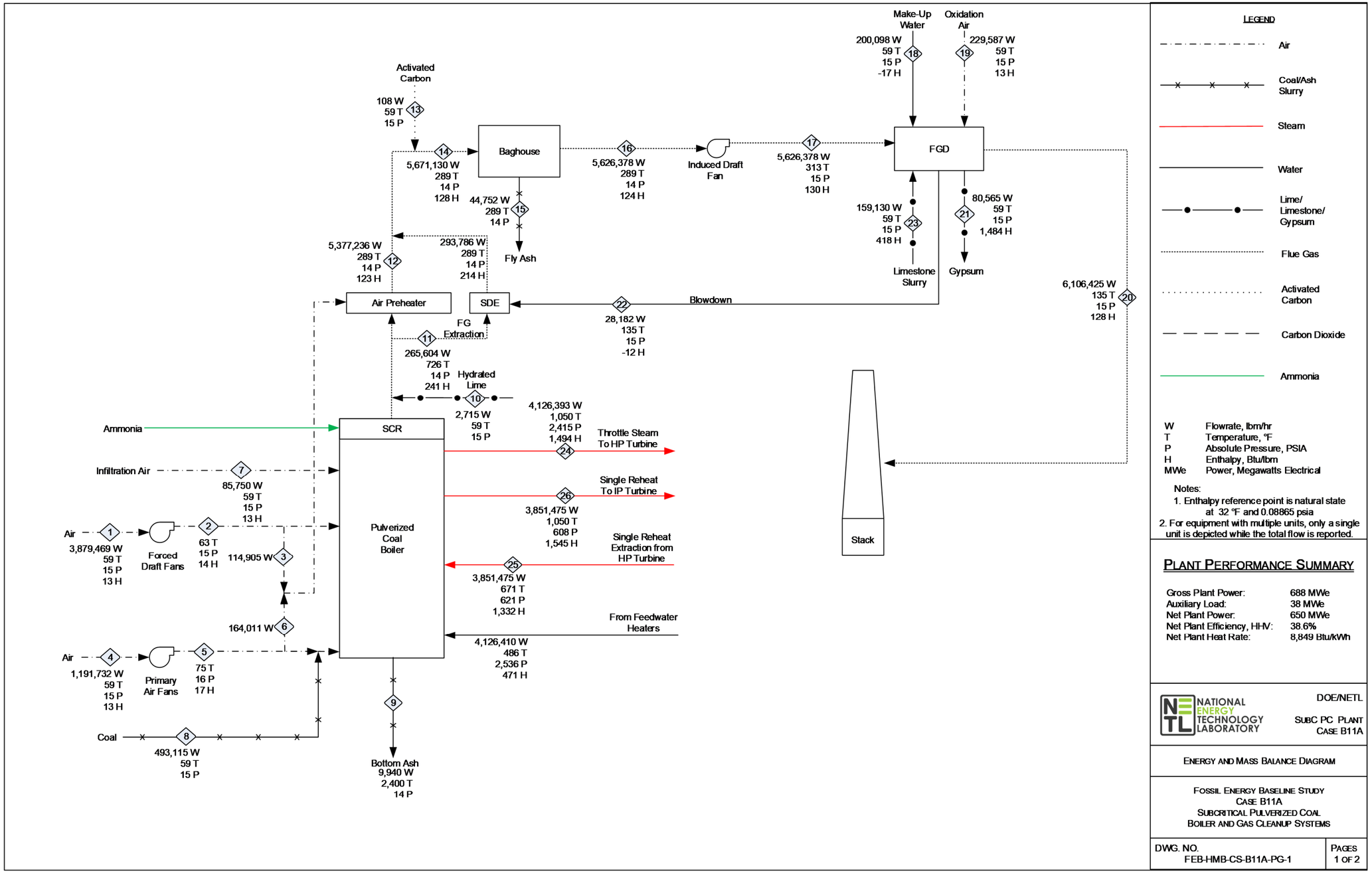


Exhibit 3-26. Case B11A energy and mass balance, SubC steam cycle

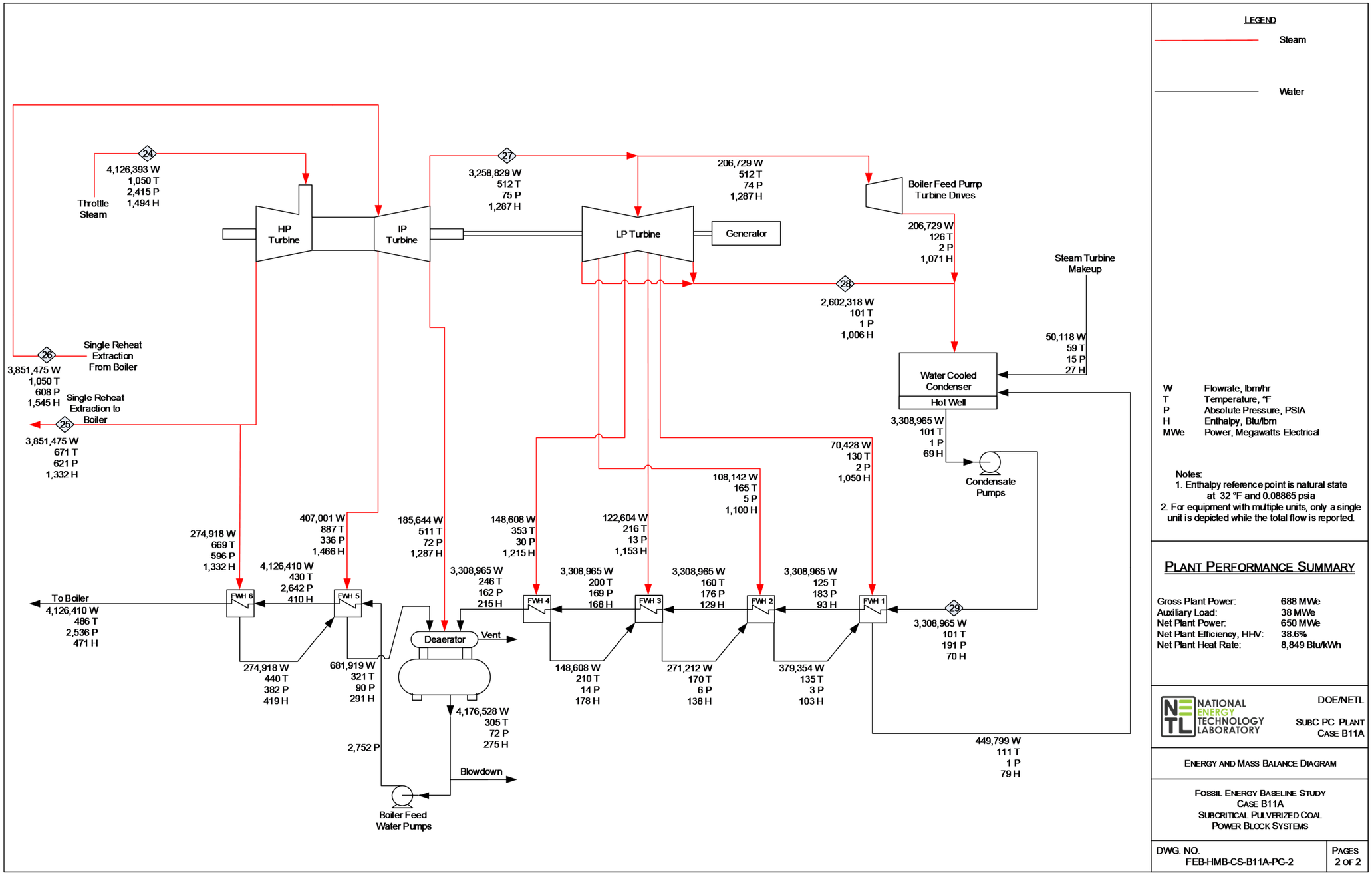


Exhibit 3-27. Case B11A overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, GJ/hr (MMBtu/hr)				
Coal	6,069 (5,753)	5.1 (4.8)	–	6,074 (5,757)
Air	–	71 (67)	–	71 (67)
Raw Water Makeup	–	93 (88)	–	93 (88)
Limestone	–	0.5 (0.4)	–	0.5 (0.4)
Auxiliary Power	–	–	135 (128)	135 (128)
TOTAL	**6,069 (5,753)**	**169 (160)**	**135 (128)**	**6,373 (6,041)**
Heat Out, GJ/hr (MMBtu/hr)				
Bottom Ash	–	5.7 (5.4)	–	5.7 (5.4)
Fly Ash	–	2.1 (2.0)	–	2.1 (2.0)
Stack Gas	–	823 (780)	–	823 (780)
Sulfur	–	–	–	–
Gypsum	–	2.1 (2.0)	–	2.1 (2.0)
Motor Losses and Design Allowances	–	–	40 (38)	40 (38)
Cooling Tower Load[A]	–	2,899 (2,748)	–	2,899 (2,748)
CO_2 Product Stream	–	–	–	–
AGR Effluent	–	–	–	–
Blowdown Streams and Deaerator Vent	–	14 (14)	–	14 (14)
Ambient Losses[B]	–	*141 (134)*	–	*141 (134)*
Power	–	–	2,475 (2,346)	2,475 (2,346)
TOTAL	**–**	**3,887 (3,684)**	**2,515 (2,384)**	**6,402 (6,068)**
Unaccounted Energy[C]	–	*-29 (-28)*	–	*-29 (-28)*

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

3.2.5 Case B11A – Major Equipment List

Major equipment items for the SubC PC plant without 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. Values reported in the equipment lists are rounded.

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	50 tonne (50 ton)	2	1
9	Feeder	Vibratory	180 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	180 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 - 9 tonne (10 ton) Feeder - 50 kg/hr (120 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 230 tonne (250 ton) Feeder - 1,350 kg/hr (2,990 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	91 tonne/hr (100 tph)	1	0
23	Limestone Conveyor No. 1	Belt	91 tonne/hr (100 tph)	1	0
24	Limestone Reclaim Hopper	N/A	18 tonne (20 ton)	1	0
25	Limestone Reclaim Feeder	Belt	72 tonne/hr (79 tph)	1	0
26	Limestone Conveyor No. 2	Belt	72 tonne/hr (79 tph)	1	0
27	Limestone Day Bin	w/ actuator	286 tonne (315 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	41 tonne/hr (45 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	41 tonne/hr (45 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	24 tonne/hr (26 tph)	1	1
4	Limestone Ball Mill	Rotary	24 tonne/hr (26 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	91,000 liters (24,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,510 lpm @ 10m H_2O (400 gpm @ 40 ft H_2O)	1	1
7	Hydrocyclone Classifier	4 active cyclones in a 5-cyclone bank	380 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	515,000 liters (136,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,070 lpm @ 9m H_2O (280 gpm @ 30 ft H_2O)	1	1

Case B11A – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,503,000 liters (396,900 gal)	2	0
2	Condensate Pumps	Vertical canned	13,900 lpm @ 200 m H_2O (3,660 gpm @ 500 ft H_2O)	2	1
3	Deaerator and Storage Tank	Horizontal spray type	1,042,000 kg/hr (2,297,000 lb/hr), 5 min. tank	2	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	17,000 lpm @ 2,300 m H_2O (4,600 gpm @ 7,500 ft H_2O)	2	2
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	5,100 lpm @ 2,300 m H_2O (1,400 gpm @ 7,500 ft H_2O)	2	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	410,000 kg/hr (910,000 lb/hr)	4	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	410,000 kg/hr (910,000 lb/hr)	4	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	410,000 kg/hr (910,000 lb/hr)	4	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	410,000 kg/hr (910,000 lb/hr)	4	0
10	HP Feedwater Heater 5	Horizontal U-tube	1,030,000 kg/hr (2,270,000 lb/hr)	2	0
11	HP Feedwater Heater 6	Horizontal U-tube	1,030,000 kg/hr (2,270,000 lb/hr)	2	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	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	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	6,600 lpm @ 20 m H_2O (1,740 gpm @ 60 ft H_2O)	2	1
21	Ground Water Pumps	Stainless steel, single suction	2,640 lpm @ 270 m H_2O (700 gpm @ 880 ft H_2O)	5	1
22	Filtered Water Pumps	Stainless steel, single suction	1,200 lpm @ 50 m H_2O (320 gpm @ 160 ft H_2O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	1,159,000 liter (306,200 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	770 lpm (200 gpm)	1	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
25	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
26	Process Water Treatment	Spray dryer evaporator	Flue Gas - 2,060 m3/min (72,700 acfm) @ 385°C (726°F) & 0.1 MPa (14 psia) Blowdown - 120 lpm (30 gpm) @ 19,995 ppmw Cl^-	2	1

Case B11A – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Subcritical, drum, wall-fired, low NOx burners, overfire air	2,060,000 kg/hr steam @ 16.5 MPa/566°C/566°C (4,540,000 lb/hr steam @ 2,400 psig/1,050°F/1,050°F)	1	0
2	Primary Air Fan	Centrifugal	297,000 kg/hr, 4,100 m^3/min @ 101 cm WG (655,000 lb/hr, 143,300 acfm @ 40 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	968,000 kg/hr, 13,200 m^3/min @ 26 cm WG (2,134,000 lb/hr, 466,000 acfm @ 10 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,404,000 kg/hr, 28,400 m^3/min @ 114 cm WG (3,095,000 lb/hr, 1,004,000 acfm @ 45 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	2,660,000 kg/hr (5,850,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	100 m^3/min @ 108 cm WG (3,500 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	109,000 liter (28,800 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	21 lpm @ 90 m H_2O (6 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	1,404,000 kg/hr (3,095,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	48,000 m^3/min (1,680,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	165,000 lpm @ 65 m H_2O (44,000 gpm @ 210 ft H_2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	4,570 lpm (1,210 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	780 m^3/min @ 0.3 MPa (27,600 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,150 lpm (300 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	36 tonne/hr (40 tph) of 50 wt% slurry	2	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
9	Filtrate Water Return Pumps	Horizontal centrifugal	700 lpm @ 13 m H_2O (180 gpm @ 40 ft H_2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	460,000 lpm (120,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	1,670 lpm @ 21 m H_2O (440 gpm @ 70 ft H_2O)	1	1
12	Activated Carbon Injectors	---	50 kg/hr (120 lb/hr)	1	0
13	Hydrated Lime Injectors	---	1,350 kg/hr (2,990 lb/hr)	1	0

Case B11A – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.4 m (21 ft) diameter	1	0

Case B11A – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	724 MW 16.5 MPa/566°C/566°C (2,400 psig/1,050°F/1,050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	800 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	3,070 GJ/hr (2,910 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	572,000 lpm @ 30 m (151,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 3,190 GJ/hr (3,020 MMBtu/hr) heat duty	1	0

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

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	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	20 m^3/min @ 0.2 MPa (708 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,320 tonne (1,450 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	120 tonne/hr (140 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, 760 MVA, 3-ph, 60 Hz	1	0
2	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 33 MVA, 3-ph, 60 Hz	1	1
3	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 6 MVA, 3-ph, 60 Hz	1	1
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
5	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
6	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
7	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 is described in Section 2.7. Exhibit 3-28 shows a detailed breakdown of the capital costs; Exhibit 3-29 shows the owner's costs, TOC, and TASC; Exhibit 3-30 shows the initial and annual O&M costs; and Exhibit 3-31 shows the COE breakdown.

For PC cases, existing costs were escalated to reflect a 2023-year dollar using the methodology outlined in NETL's current QGESS (NETL, 2025a).

The estimated TPC of the SubC PC boiler without CO_2 capture is $2,471/kW. No process contingency is included in this case because all elements of the technology are commercially proven. The project contingency is 13.4 percent of the TPC. The FY COE is $86.0/MWh and the LCOE is $89.4/MWh.

Exhibit 3-28. Case B11A total plant cost details

Case:	B11A – Subcritical PC without CO_2 Capture					Estimate Type:	Conceptual			
Plant Size (MW, net):	650					Cost Base:	Jan 2023			
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
1	Coal & Sorbent Handling										
1.1	Coal Receive & Unload	$1,410	$0	$493	$0	$1,903	$333	$0	$335	$2,571	$4
1.2	Coal Stackout & Reclaim	$4,629	$0	$803	$0	$5,432	$951	$0	$957	$7,340	$11
1.3	Coal Conveyors	$42,644	$0	$7,874	$0	$50,518	$8,841	$0	$8,904	$68,263	$105
1.4	Other Coal Handling	$5,930	$0	$967	$0	$6,897	$1,207	$0	$1,216	$9,320	$14
1.5	Sorbent Receive & Unload	$271	$0	$63	$0	$334	$58	$0	$59	$451	$1
1.6	Sorbent Stackout & Reclaim	$1,975	$0	$277	$0	$2,252	$394	$0	$397	$3,043	$5
1.7	Sorbent Conveyors	$2,991	$624	$561	$0	$4,177	$731	$0	$736	$5,644	$9
1.8	Other Sorbent Handling	$144	$32	$58	$0	$234	$41	$0	$41	$316	$0
1.9	Coal & Sorbent Handling Foundations	$0	$1,774	$1,892	$0	$3,666	$642	$0	$646	$4,954	$8
	Subtotal	**$59,995**	**$2,431**	**$12,987**	**$0**	**$75,413**	**$13,197**	**$0**	**$13,292**	**$101,902**	**$157**
2	Coal & Sorbent Preparation & Feed										
2.1	Coal Crushing & Drying	$3,006	$0	$448	$0	$3,454	$604	$0	$609	$4,667	$7
2.2	Prepared Coal Storage & Feed	$10,118	$0	$1,691	$0	$11,809	$2,066	$0	$2,081	$15,956	$25
2.5	Sorbent Preparation Equipment	$1,326	$55	$211	$0	$1,592	$279	$0	$281	$2,151	$3
2.6	Sorbent Storage & Feed	$2,223	$0	$651	$0	$2,874	$503	$0	$507	$3,883	$6
2.9	Coal & Sorbent Feed Foundation	$0	$846	$600	$0	$1,446	$253	$0	$255	$1,954	$3
	Subtotal	**$16,673**	**$901**	**$3,601**	**$0**	**$21,175**	**$3,706**	**$0**	**$3,732**	**$28,612**	**$44**
3	Feedwater & Miscellaneous BOP Systems										
3.1	Feedwater System	$4,514	$7,457	$3,015	$0	$14,985	$2,622	$0	$2,641	$20,249	$31
3.2	Water Makeup & Pretreating	$8,140	$784	$3,595	$0	$12,520	$2,191	$0	$2,942	$17,653	$27
3.3	Other Feedwater Subsystems	$3,324	$1,050	$807	$0	$5,182	$907	$0	$913	$7,002	$11
3.4	Service Water Systems	$2,536	$4,665	$12,216	$0	$19,416	$3,398	$0	$4,563	$27,377	$42
3.5	Other Boiler Plant Systems	$785	$287	$580	$0	$1,652	$289	$0	$291	$2,232	$3
3.6	Natural Gas Pipeline and Start-Up System	$4,548	$175	$106	$0	$4,829	$845	$0	$851	$6,525	$10
3.7	Waste Water Treatment Equipment	$11,549	$0	$5,517	$0	$17,065	$2,986	$0	$4,010	$24,062	$37
3.8	Spray Dryer Evaporator	$19,549	$0	$8,822	$0	$28,371	$4,965	$0	$6,667	$40,003	$62
3.9	Miscellaneous Plant Equipment	$257	$33	$102	$0	$392	$69	$0	$92	$553	$1
	Subtotal	**$55,201**	**$14,450**	**$34,760**	**$0**	**$104,411**	**$18,272**	**$0**	**$22,971**	**$145,654**	**$224**
4	Pulverized Coal Boiler & Accessories										
4.9	Pulverized Coal Boiler & Accessories	$243,187	$0	$129,030	$0	$372,217	$65,138	$0	$65,603	$502,959	$774
4.10	Selective Catalytic Reduction System	$33,906	$0	$17,245	$0	$51,150	$8,951	$0	$9,015	$69,117	$106
4.11	Boiler Balance of Plant	$1,745	$0	$926	$0	$2,671	$467	$0	$471	$3,609	$6
4.12	Primary Air System	$1,976	$0	$965	$0	$2,941	$515	$0	$518	$3,975	$6
4.13	Secondary Air System	$2,993	$0	$1,462	$0	$4,455	$780	$0	$785	$6,020	$9
4.14	Induced Draft Fans	$6,457	$0	$3,154	$0	$9,610	$1,682	$0	$1,694	$12,986	$20
4.15	Major Component Rigging	$103	$0	$53	$0	$156	$27	$0	$28	$211	$0
4.16	Boiler Foundations	$0	$453	$322	$0	$775	$136	$0	$137	$1,047	$2

Case:	B11A – Subcritical PC without CO_2 Capture					Estimate Type:	Conceptual			
Plant Size (MW, net):	650					Cost Base:	Jan 2023			
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
	Subtotal	**$290,368**	**$453**	**$153,156**	**$0**	**$443,977**	**$77,696**	**$0**	**$78,251**	**$599,923**	**$923**
5	**Flue Gas Cleanup**										
5.2	Wet FGD Absorber Vessels & Accessories	$85,687	$0	$15,471	$0	$101,159	$17,703	$0	$17,829	$136,691	$210
5.3	Other FGD	$1,354	$0	$881	$0	$2,235	$391	$0	$394	$3,020	$5
5.6	Mercury Removal (DSI/ACI)	$2,821	$648	$2,342	$0	$5,811	$1,017	$0	$1,024	$7,852	$12
5.9	Particulate Removal (Bag House & Accessories)	w/ 5.2	w/ 5.2	w/ 5.2	w/ 5.2	$0	$0	$0	$0	$0	$0
5.12	Gas Cleanup Foundations	$0	$219	$156	$0	$375	$66	$0	$66	$507	$1
5.13	Gypsum Dewatering System	$915	$0	$120	$0	$1,035	$181	$0	$182	$1,399	$2
	Subtotal	**$90,777**	**$867**	**$18,971**	**$0**	**$110,615**	**$19,358**	**$0**	**$19,496**	**$149,469**	**$230**
7	**Ductwork & Stack**										
7.3	Ductwork	$0	$918	$516	$0	$1,434	$251	$0	$253	$1,937	$3
7.4	Stack	$11,909	$0	$5,417	$0	$17,326	$3,032	$0	$3,054	$23,412	$36
7.5	Duct & Stack Foundations	$0	$270	$259	$0	$530	$93	$0	$124	$747	$1
	Subtotal	**$11,909**	**$1,188**	**$6,193**	**$0**	**$19,289**	**$3,376**	**$0**	**$3,431**	**$26,096**	**$40**
8	**Steam Turbine & Accessories**										
8.1	Steam Turbine Generator & Accessories	$72,041	$0	$7,113	$0	$79,154	$13,852	$0	$13,951	$106,957	$165
8.2	Steam Turbine Plant Auxiliaries	$1,638	$0	$3,058	$0	$4,696	$822	$0	$828	$6,345	$10
8.3	Condenser & Auxiliaries	$19,821	$0	$5,356	$0	$25,177	$4,406	$0	$4,437	$34,021	$52
8.4	Steam Piping	$47,736	$0	$13,678	$0	$61,414	$10,747	$0	$10,824	$82,986	$128
8.5	Turbine Generator Foundations	$0	$277	$370	$0	$648	$113	$0	$152	$913	$1
	Subtotal	**$141,236**	**$277**	**$29,575**	**$0**	**$171,089**	**$29,941**	**$0**	**$30,192**	**$231,222**	**$356**
9	**Cooling Water System**										
9.1	Cooling Towers	$18,382	$0	$4,450	$0	$22,832	$3,996	$0	$4,024	$30,851	$47
9.2	Circulating Water Pumps	$2,458	$0	$124	$0	$2,582	$452	$0	$455	$3,489	$5
9.3	Circulating Water System Auxiliaries	$16,230	$0	$1,674	$0	$17,905	$3,133	$0	$3,156	$24,194	$37
9.4	Circulating Water Piping	$0	$7,233	$5,297	$0	$12,530	$2,193	$0	$2,208	$16,931	$26
9.5	Make-up Water System	$1,422	$0	$1,424	$0	$2,847	$498	$0	$502	$3,846	$6
9.6	Component Cooling Water System	$1,080	$0	$700	$0	$1,779	$311	$0	$314	$2,404	$4
9.7	Circulating Water System Foundations	$0	$690	$927	$0	$1,618	$283	$0	$380	$2,281	$4
	Subtotal	**$39,572**	**$7,923**	**$14,596**	**$0**	**$62,091**	**$10,866**	**$0**	**$11,039**	**$83,996**	**$129**
10	**Ash & Spent Sorbent Handling Systems**										
10.6	Ash Storage Silos	$1,422	$0	$3,375	$0	$4,796	$839	$0	$845	$6,481	$10
10.7	Ash Transport & Feed Equipment	$4,836	$0	$3,720	$0	$8,556	$1,497	$0	$1,508	$11,561	$18
10.9	Ash/Spent Sorbent Foundation	$0	$950	$943	$0	$1,893	$331	$0	$445	$2,670	$4
	Subtotal	**$6,257**	**$950**	**$8,038**	**$0**	**$15,245**	**$2,668**	**$0**	**$2,798**	**$20,712**	**$32**
11	**Accessory Electric Plant**										
11.1	Generator Equipment	$3,597	$0	$1,992	$0	$5,589	$978	$0	$985	$7,552	$12
11.2	Station Service Equipment	$6,721	$0	$423	$0	$7,144	$1,250	$0	$1,259	$9,653	$15

Case:	B11A – Subcritical PC without CO_2 Capture									
Plant Size (MW, net):	650								Estimate Type:	Conceptual
									Cost Base:	Jan 2023
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
11.3	Switchgear & Motor Control	$10,433	$0	$1,329	$0	$11,762	$2,058	$0	$2,073	$15,893	$24
11.4	Conduit & Cable Tray	$0	$1,231	$2,869	$0	$4,099	$717	$0	$723	$5,539	$9
11.5	Wire & Cable	$0	$3,260	$4,712	$0	$7,972	$1,395	$0	$1,405	$10,772	$17
11.6	Protective Equipment	$79	$0	$201	$0	$280	$49	$0	$49	$378	$1
11.7	Standby Equipment	$1,127	$0	$763	$0	$1,890	$331	$0	$333	$2,554	$4
11.8	Main Power Transformers	$9,302	$0	$139	$0	$9,442	$1,652	$0	$1,664	$12,758	$20
11.9	Electrical Foundations	$0	$269	$552	$0	$821	$144	$0	$193	$1,157	$2
	Subtotal	**$31,260**	**$4,759**	**$12,980**	**$0**	**$48,999**	**$8,575**	**$0**	**$8,684**	**$66,258**	**$102**
12	Instrumentation & Control										
12.1	Pulverized Coal Boiler Control Equipment	$930	$0	$131	$0	$1,061	$186	$0	$187	$1,434	$2
12.3	Steam Turbine Control Equipment	$833	$0	$74	$0	$906	$159	$0	$160	$1,225	$2
12.5	Signal Processing Equipment	$1,056	$0	$148	$0	$1,204	$211	$0	$212	$1,627	$3
12.6	Control Boards, Panels, & Racks	$323	$0	$156	$0	$479	$84	$0	$84	$647	$1
12.7	Distributed Control System Equipment	$9,114	$0	$1,281	$0	$10,395	$1,819	$0	$1,832	$14,046	$22
12.8	Instrument Wiring & Tubing	$638	$498	$1,610	$0	$2,746	$481	$0	$484	$3,710	$6
12.9	Other Instrumentation & Controls Equipment	$785	$0	$1,432	$0	$2,217	$388	$0	$391	$2,996	$5
	Subtotal	**$13,679**	**$498**	**$4,832**	**$0**	**$19,009**	**$3,326**	**$0**	**$3,350**	**$25,685**	**$40**
13	Improvements to Site										
13.1	Site Preparation	$0	$540	$9,325	$0	$9,865	$1,726	$0	$2,318	$13,910	$21
13.2	Site Improvements	$0	$2,685	$2,869	$0	$5,554	$972	$0	$1,305	$7,831	$12
13.3	Site Facilities	$3,120	$0	$2,603	$0	$5,723	$1,001	$0	$1,345	$8,069	$12
	Subtotal	**$3,120**	**$3,225**	**$14,797**	**$0**	**$21,142**	**$3,700**	**$0**	**$4,968**	**$29,810**	**$46**
14	Buildings & Structures										
14.2	Boiler Building	$0	$15,100	$10,732	$0	$25,832	$4,521	$0	$4,553	$34,906	$54
14.3	Steam Turbine Building	$0	$20,989	$15,809	$0	$36,798	$6,440	$0	$6,486	$49,723	$76
14.4	Administration Building	$0	$1,364	$1,166	$0	$2,529	$443	$0	$446	$3,418	$5
14.5	Circulation Water Pumphouse	$0	$182	$117	$0	$299	$52	$0	$53	$404	$1
14.6	Water Treatment Buildings	$0	$508	$374	$0	$882	$154	$0	$155	$1,192	$2
14.7	Machine Shop	$0	$719	$391	$0	$1,110	$194	$0	$196	$1,499	$2
14.8	Warehouse	$0	$541	$438	$0	$979	$171	$0	$173	$1,323	$2
14.9	Other Buildings & Structures	$0	$378	$260	$0	$638	$112	$0	$112	$862	$1
14.10	Waste Treating Building & Structures	$0	$820	$2,013	$0	$2,833	$496	$0	$499	$3,828	$6
	Subtotal	**$0**	**$40,601**	**$31,299**	**$0**	**$71,900**	**$12,583**	**$0**	**$12,672**	**$97,155**	**$149**
	Total	**$760,047**	**$78,523**	**$345,785**	**$0**	**$1,184,355**	**$207,262**	**$0**	**$214,877**	**$1,606,494**	**$2,471**

Exhibit 3-29. Case B11A owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$10,914	$17
1 Month Maintenance Materials	$1,512	$2
1 Month Non-fuel Consumables	$2,228	$3
1 Month Waste Disposal	$935	$1
25% of 1 Months Fuel Cost at 100% CF	$3,164	$5
2% of TPC	$32,130	$49
Total	**$50,882**	**$78**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$28,838	$44
0.5% of TPC (spare parts)	$8,032	$12
Total	**$36,870**	**$57**
Other Costs		
Initial Cost for Catalyst and Chemicals	$4,982	$8
Land	$1,800	$3
Other Owner's Costs	$240,974	$371
Financing Costs	$43,375	$67
Total Overnight Costs (TOC)	**$1,985,378**	**$3,054**
TASC Multiplier (IOU, 33 year)	1.213	
Total As-Spent Cost (TASC)	**$2,407,722**	**$3,704**

Exhibit 3-30. Case B11A initial and annual operating and maintenance costs

Case:	B11A – Subcritical PC without CO_2 Capture				Cost Base:	Jan 2023
Plant Size (MW, net):	650	Heat Rate-net (Btu/kWh):	8,849		Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		45.04	**$/hour**	Skilled Operator:		2.0
Operating Labor Burden:		30.00	**% of base**	Operator:		9.0
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		2.0
				Total:		**14.0**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$7,180,746	$11.046
Maintenance Labor:					$10,281,561	$15.816
Administrative & Support Labor:					$4,365,577	$6.715
Property Taxes and Insurance:					$32,129,879	$49.424
Total:					**$53,957,763**	**$83.002**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$15,422,342	$3.186
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (gal/1000):	0	4,683	$2.30	$0	$3,341,687	$0.690
Makeup and Waste Water Treatment Chemicals (ton):	0	14.0	$660.00	$0	$2,856,484	$0.590
Brominated Activated Carbon (ton):	0	1.29	$2,547.97	$0	$1,023,454	$0.211
Enhanced Hydrated Lime (ton):	0	32.6	$391.63	$0	$3,957,945	$0.818
Limestone (ton):	0	572	$30.18	$0	$5,359,750	$1.107
Ammonia (19 wt%, ton):	0	54.9	$280.00	$0	$4,770,998	$0.986
SCR Catalyst (ft^3):	14,235	13.0	$350.00	$4,982,230	$1,411,632	$0.292
Subtotal:				**$4,982,230**	**$22,721,950**	**$4.694**
Waste Disposal						
Fly Ash (ton):	0	537	$46.71	$0	$7,781,725	$1.608
Bottom Ash (ton):	0	119	$46.71	$0	$1,728,502	$0.357
SCR Catalyst (ft^3):	0	13.0	$5.70	$0	$22,989	$0.005
Subtotal:				**$0**	**$9,533,217**	**$1.969**
By-Products						
Gypsum (ton):	0	870	$0.00	$0	$0	$0.000
Subtotal:				**$0**	**$0**	**$0.000**
Variable Operating Costs Total:				**$4,982,230**	**$47,677,509**	**$9.850**
Fuel Cost						
Illinois Number 6 (ton):	0	5,917	$70.32	$0	$129,103,668	$26.672
Total:				**$0**	**$129,103,668**	**$26.672**

Exhibit 3-31. Case B11A COE breakdown

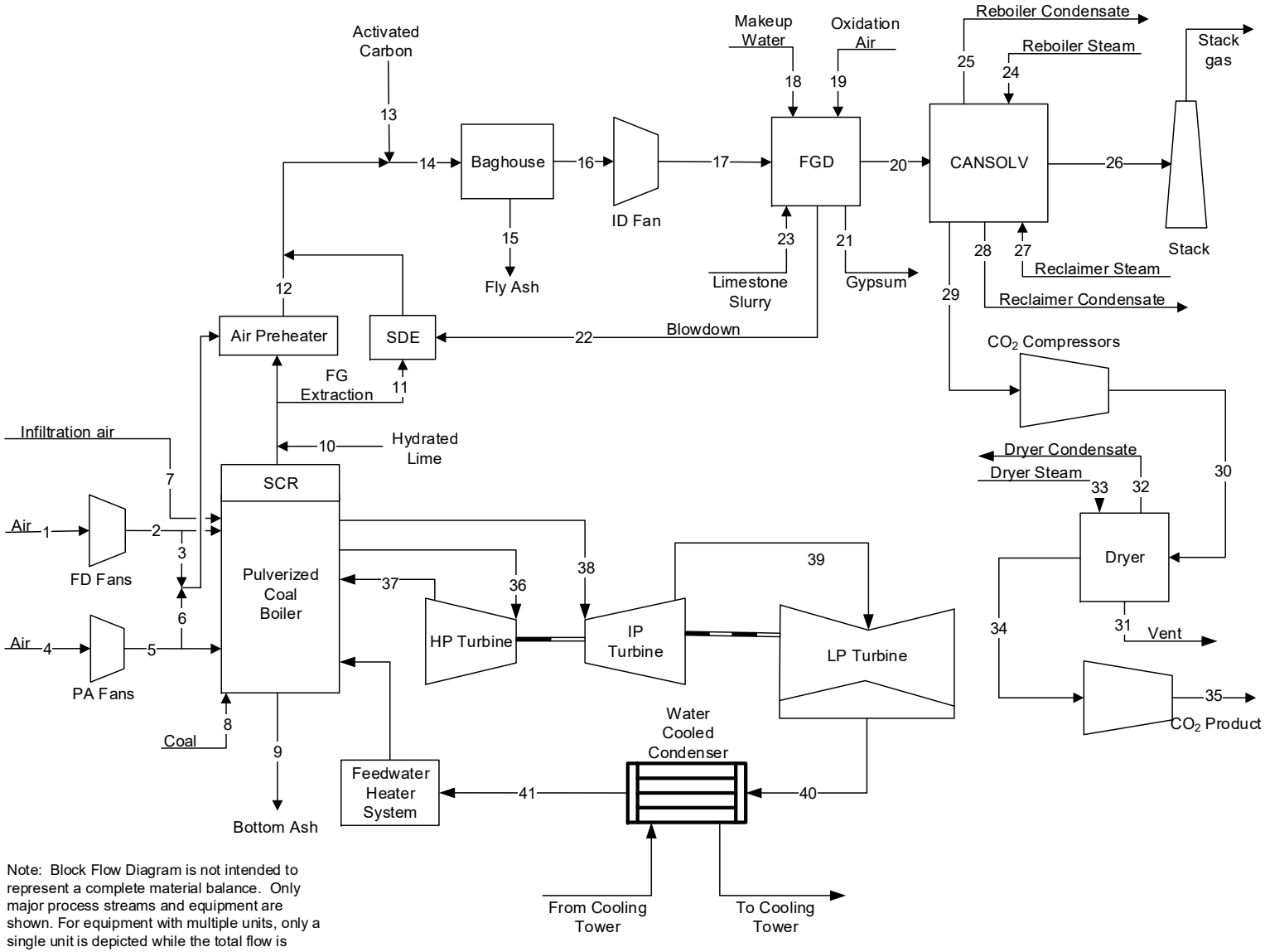
	FY COE		LCOE	
Component	Value, $/MWh	Percentage	Value, $/MWh	Percentage
Capital	38.3	45%	38.3	43%
Fixed	11.1	13%	14.9	17%
Variable	9.8	11%	13.1	15%
Fuel	26.7	31%	23.0	26%
Total (Excluding T&S)	**86.0**	**N/A**	**89.4**	**N/A**
CO_2 T&S	–	–	–	–
Total (Including T&S)	**86.0**	**N/A**	**89.4**	**N/A**

3.2.7 Case B11B.90 – SubC PC with 90% CO_2 Capture Process Description

The plant configuration and process description for Case B11B.90 are nearly the same as Case B11A, with the exception that a PostCCC facility was included to treat the flue gas stream. Since the process descriptions of the plant and PostCCC facility were provided in Section 3.2.3 and Section 3.1.8, respectively, they are not repeated here.

The BFD for Case B11B.90 is shown in Exhibit 3-32. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit 3-33. The modeling assumptions are presented in Section 3.2.1.

Exhibit 3-32. Case B11B.90 BFD, SubC unit with 90 percent CO_2 capture



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown. For equipment with multiple units, only a single unit is depicted while the total flow is reported.

Exhibit 3-33. Case B11B.90 stream table, SubC unit with 90 percent CO_2 capture

	1	2	3	4	5	6	7	8	9	10	11	12
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	0.0087	0.0088
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1457	0.1379
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	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000	0.0879	0.0837
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7318	0.7340
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0237	0.0336
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0020
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	78,024	78,024	2,311	23,968	23,968	3,299	1,725	0	0	1	5,141	104,299
V-L Flowrate (kg/hr)	2,251,529	2,251,529	66,687	691,646	691,646	95,187	49,767	0	0	16	152,916	3,097,080
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	286,189	5,769	1,560	1,235	23,707
Temperature (°C)	15	17	17	15	24	24	15	15	1,316	15	385	143
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg)[A]	30.23	32.49	32.49	30.23	38.98	38.98	30.23	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-95.31	-95.31	-97.58	-88.83	-88.83	-97.58	-2,119.02	1,267.06	-13,402.95	-2,261.17	-2,394.31
Density (kg/m^3)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	1,003.6	0.5	0.8
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015	29.742	29.694
V-L Flowrate (lb_{mol}/hr)	172,013	172,013	5,095	52,841	52,841	7,272	3,802	0	0	2	11,335	229,939
V-L Flowrate (lb/hr)	4,963,772	4,963,772	147,020	1,524,819	1,524,819	209,852	109,717	0	0	35	337,123	6,827,892
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	630,940	12,719	3,439	2,723	52,264
Temperature (°F)	59	63	63	59	75	75	59	59	2,400	59	726	289
Pressure (psia)	14.7	15.0	15.0	14.7	15.9	15.9	14.7	14.7	14.3	14.7	14.3	14.1
Steam Table Enthalpy (Btu/lb)[A]	13.0	14.0	14.0	13.0	16.8	16.8	13.0	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-41.0	-41.0	-42.0	-38.2	-38.2	-42.0	-911.0	544.7	-5,762.2	-972.1	-1,029.4
Density (lb/ft^3)	0.076	0.077	0.077	0.076	0.080	0.080	0.076	---	---	62.650	0.033	0.052

[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 3-33. Case B11B.90 stream table, SubC unit with 90 percent CO2 capture (continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.1372	0.0000	0.1372	0.1372	0.9999	0.0003	0.1245	0.0001	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	0.0000	0.0911	0.0000	0.0911	0.0911	0.0000	0.0099	0.1508	0.9998	0.9943	0.9999	1.0000
HCl	0.0000	0.0001	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.7281	0.0000	0.7281	0.7281	0.0000	0.7732	0.6803	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0329	0.0000	0.0329	0.0329	0.0000	0.2074	0.0363	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0020	0.0000	0.0020	0.0020	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.1158	0.0000	0.0000	1.0000	0.0000	0.0000	0.0001	0.0009	0.0001	0.0000
$CaCl_2$	0.0000	0.0001	0.8842	0.0000	0.0000		0.0000	0.0000	0.0000	0.0048	0.0000	0.0000
Total	0.0000	1.0000	1.0000	1.0000	1.0000	6,444	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
						116,116						
V-L Flowrate (kg_{mol}/hr)	0	110,311	7	110,305	110,305	0	4,617	123,311	260	871	3,589	35,464
V-L Flowrate (kg/hr)	0	3,266,106	706	3,265,384	3,265,384		133,245	3,543,988	4,678	16,110	64,670	638,896
Solids Flowrate (kg/hr)	63	25,250	25,267	0	0	15	0	0	42,080	245	27,684	0
						0.10						
Temperature (°C)	15	143	143	143	156	-47.80	15	57	15	57	15	266
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	-16,015.01	0.10	0.10	0.10	0.10	0.10	0.48
Steam Table Enthalpy (kJ/kg)[A]	---	---	---	287.58	302.09	1,003.7	30.23	297.00	---	---	---	2,994.07
AspenPlus Enthalpy (kJ/kg)[B]	-6.79	-2,453.14	-1,065.95	-2,464.17	-2,449.66	18.019	-97.58	-2,939.24	-12,513.34	-15,496.21	-14,994.25	-12,986.23
Density (kg/m^3)	---	0.8	2,150.2	0.8	0.9		1.2	1.1	878.3	979.4	1,003.7	2.0
V-L Molecular Weight	---	29.608	104.898	29.603	29.603	14,207	28.857	28.740	18.021	18.494	18.019	18.015
						255,993						
V-L Flowrate (lb_{mol}/hr)	0	243,195	15	243,180	243,180	0	10,180	271,854	572	1,920	7,913	78,185
V-L Flowrate (lb/hr)	0	7,200,532	1,556	7,198,939	7,198,939		293,755	7,813,157	10,313	35,517	142,573	1,408,525
Solids Flowrate (lb/hr)	138	55,666	55,703	0	0	59	0	0	92,769	541	61,033	0
						14.7						
Temperature (°F)	59	289	289	289	313	-20.5	59	135	59	135	59	511
Pressure (psia)	14.7	14.1	14.1	13.9	15.3	-6,885.2	14.7	14.8	14.7	14.7	14.7	70.0
Steam Table Enthalpy (Btu/lb)[A]	---	---	---	123.6	129.9	62.658	13.0	127.7	---	---	---	1,287.2
AspenPlus Enthalpy (Btu/lb)[B]	-2.9	-1,054.7	-458.3	-1,059.4	-1,053.2	0.0000	-42.0	-1,263.6	-5,379.8	-6,662.2	-6,446.4	-5,583.1
Density (lb/ft^3)	---	0.052	134.232	0.051	0.055	0.9999	0.076	0.067	54.833	61.145	62.658	0.123

[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 3-33. Case B11B.90 stream table, SubC unit with 90 percent CO2 capture (continued)

	25	26	27	28	29	30	31	32	33	34	35	36
V-L Mole Fraction												
Ar	0.0000	0.0101	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0156	0.0000	0.0000	0.9783	0.9975	0.0500	0.0000	0.0000	0.9995	0.9995	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	1.0000	0.0807	1.0000	1.0000	0.0217	0.0025	0.9500	1.0000	1.0000	0.0005	0.0005	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.8483	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0453	0.0000	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	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
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_{mol}/hr)	32,481	98,889	397	397	14,114	13,842	29	18	18	13,813	13,813	133,003
V-L Flowrate (kg/hr)	585,162	2,744,882	7,146	7,146	613,197	608,296	561	320	320	607,735	607,735	2,396,093
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	105	45	355	214	31	29	29	203	476	29	30	566
Pressure (MPa, abs)	0.12	0.10	4.28	2.04	0.17	2.81	2.81	1.64	2.42	2.68	15.27	16.65
Steam Table Enthalpy (kJ/kg)[A]	439.34	178.41	3,098.44	913.81	46.68	-3.05	137.94	863.65	3,408.95	-3.59	-231.09	3,473.89
AspenPlus Enthalpy (kJ/kg)[B]	-15,540.95	-903.21	-12,881.86	-15,066.49	-8,978.62	-8,972.51	-15,225.22	-15,116.65	-12,571.34	-8,967.15	-9,194.65	-12,506.41
Density (kg/m^3)	954.9	1.1	16.0	848.5	3.0	57.8	351.5	861.8	7.1	54.7	630.1	47.7
V-L Molecular Weight	18.015	27.757	18.015	18.015	43.445	43.945	19.315	18.015	18.015	43.997	43.997	18.015
V-L Flowrate (lb_{mol}/hr)	71,609	218,012	874	874	31,116	30,517	64	39	39	30,453	30,453	293,222
V-L Flowrate (lb/hr)	1,290,060	6,051,428	15,753	15,753	1,351,867	1,341,063	1,236	705	705	1,339,827	1,339,827	5,282,481
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	221	113	671	416	87	85	85	397	888	85	86	1,050
Pressure (psia)	17.4	14.8	620.5	296.6	24.7	407.6	407.6	237.4	350.5	389.1	2,214.7	2,414.7
Steam Table Enthalpy (Btu/lb)[A]	188.9	76.7	1,332.1	392.9	20.1	-1.3	59.3	371.3	1,465.6	-1.5	-99.4	1,493.5
AspenPlus Enthalpy (Btu/lb)[B]	-6,681.4	-388.3	-5,538.2	-6,477.4	-3,860.1	-3,857.5	-6,545.7	-6,499.0	-5,404.7	-3,855.2	-3,953.0	-5,376.8
Density (lb/ft^3)	59.612	0.067	1.000	52.968	0.184	3.609	21.943	53.801	0.446	3.416	39.338	2.975

[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 3-33. Case B11B.90 stream table, SubC unit with 90 percent CO2 capture (continued)

	37	38	39	40	41
V-L Mole Fraction					
Ar	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	123,745	123,745	103,920	51,884	73,055
V-L Flowrate (kg/hr)	2,229,310	2,229,310	1,872,154	934,712	1,316,103
Solids Flowrate (kg/hr)	0	0	0	0	0
Temperature (°C)	355	566	267	38	39
Pressure (MPa, abs)	4.28	4.19	0.52	0.01	1.32
Steam Table Enthalpy (kJ/kg)[A]	3,098.44	3,593.58	2,994.07	2,340.01	162.43
AspenPlus Enthalpy (kJ/kg)[B]	-12,881.86	-12,386.71	-12,986.23	-13,640.29	-15,817.87
Density (kg/m^3)	16.0	11.1	2.1	0.1	993.3
V-L Molecular Weight	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	272,812	272,812	229,105	114,386	161,058
V-L Flowrate (lb/hr)	4,914,787	4,914,787	4,127,393	2,060,687	2,901,511
Solids Flowrate (lb/hr)	0	0	0	0	0
Temperature (°F)	671	1,050	512	101	101
Pressure (psia)	620.5	608.1	75.0	1.0	190.7
Steam Table Enthalpy (Btu/lb)[A]	1,332.1	1,545.0	1,287.2	1,006.0	69.8
AspenPlus Enthalpy (Btu/lb)[B]	-5,538.2	-5,325.3	-5,583.1	-5,864.3	-6,800.5
Density (lb/ft^3)	1.000	0.692	0.132	0.003	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

3.2.8 Case B11B.90 – Performance Results

Overall plant performance is summarized in Exhibit 3-34; Exhibit 3-35 provides a detailed breakdown of the auxiliary power requirements.

The PostCCC facility and CO_2 compression combined account for over half of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for over 12 percent of the auxiliary load, largely due to the high cooling water demand of the PostCCC 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. By increasing the boiler and turbine/generator size to account for the greater auxiliary load imposed by the PostCCC facility and CO_2 compressors, a net output of 650 MW is maintained at a reduced net plant efficiency of 30.2 percent (HHV basis).

Exhibit 3-34. Case B11B.90 plant performance summary

Performance Summary	
Total Gross Power, MWe	**769**
CO_2 Capture/Removal Auxiliaries, kWe	18,800
CO_2 Compression, kWe	48,660
Balance of Plant, kWe	50,620
Total Auxiliaries, MWe	**118**
Net Power, MWe	**650**
HHV Net Plant Efficiency, %	30.2
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,940 (11,317)
LHV Net Plant Efficiency, %	31.3
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,516 (10,915)
HHV Boiler Efficiency, %	88.0
LHV Boiler Efficiency, %	91.3
Steam Turbine Cycle Efficiency, %	55.1
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	6,532 (6,191)
Condenser Duty, GJ/hr (MMBtu/hr)	2,312 (2,191)
CO_2 Capture Rate, %	90
AGR Duty, GJ/hr (MMBtu/hr)	2,162 (2,050)
As-Received Coal Feed, kg/hr (lb/hr)	286,189 (630,940)
Limestone Sorbent Feed, kg/hr (lb/hr)	27,684 (61,033)
HHV Thermal Input, kWt	2,157,162
LHV Thermal Input, kWt	2,080,609
Raw Water Withdrawal, (m^3/min)/MWnet (gpm/MWnet)	0.058 (15.3)
Raw Water Consumption, (m^3/min)/MWnet (gpm/MWnet)	0.043 (11.4)
Excess Air, %	20.3

Exhibit 3-35. Case B11B.90 plant power summary

Power Summary	
Steam Turbine Power, MWe	769
Total Gross Power, MWe	**769**
Auxiliary Load Summary	
Activated Carbon Injection, kWe	40
Ash Handling, kWe	940
Baghouse, kWe	120
Circulating Water Pumps, kWe	9,670
CO_2 Capture/Removal Auxiliaries, kWe	18,800
CO_2 Compression, kWe	48,660
Coal Handling and Conveying, kWe	540
Condensate Pumps, kWe	720
Cooling Tower Fans, kWe	5,000
Dry Sorbent Injection, kWe	80
Flue Gas Desulfurizer, kWe	4,420
Forced Draft Fans, kWe	1,470
Ground Water Pumps, kWe	900
Induced Draft Fans, kWe	13,570
Miscellaneous Balance of Plant[A,B], kWe	2,250
Primary Air Fans, kWe	1,740
Pulverizers, kWe	4,290
SCR, kWe	50
Sorbent Handling & Reagent Preparation, kWe	1,330
Spray Dryer Evaporator, kWe	320
Steam Turbine Auxiliaries, kWe	500
Transformer Losses, kWe	2,670
Total Auxiliaries, MWe	**118**
Net Power, MWe	**650**

[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 are presented in Section 2.4. A summary of the plant air emissions for Case B11B.90 is presented in Exhibit 3-36. SO_2 emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit 3-36. Case B11B.90 air emissions

	kg/GJ (lb/MMBtu)[A]	tonne/year (ton/year)[B]	kg/MWh (lb/MWh)[C]
SO_2	0.000 (0.000)	0 (0)	0.000 (0.000)
NOx	0.031 (0.073)	1,817 (2,003)	0.318 (0.700)
Particulate	0.004 (0.009)	234 (258)	0.041 (0.090)
Hg	1.35E-7 (3.13E-7)	0.008 (0.009)	1.36E-6 (3.00E-6)
CO_2	9 (20)	504,986 (556,652)	88 (195)
CO_2[D]	–	–	104 (230)
	mg/Nm^3		
Particulate Concentration[E,F]	12.69		

[A]Based on thermal input on an HHV basis
[B]Calculations based on an 85 percent capacity factor
[C]Emissions based on gross power except where otherwise noted
[D]CO_2 emissions based on net power instead of gross power
[E]Concentration of particles in the flue gas after the baghouse
[F]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 0.37 ppmv using a NaOH based polishing scrubber in the PostCCC facility. The remaining low concentration of SO_2 is essentially completely removed in the PostCCC absorber vessel resulting in very low SO_2 emissions (reported as zero here).

NOx boiler emissions are controlled to about 0.15 kg/GJ (0.35 lb/MMBtu) using LNBs and OFA. An SCR unit then further reduces the NOx concentration by 79.1 percent to 0.03 kg/GJ (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 97.6 percent.

The carbon balance for the plant is shown in Exhibit 3-37. 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 product from the CO_2 compression train; however, some CO_2 exits through the stack and the CO_2 dryer's vent, 20 percent of the unburned carbon remains in the bottom ash, the remaining unburned carbon is captured in the fabric filter, along with the PAC, and some carbon leaves as gypsum. The carbon conversion is assumed to be 99.4 percent.

Ninety percent of the CO_2 in the flue gas is removed in the PostCCC facility. The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in (minus unburnt carbon in the ash), represented by the following percentage:

$$1 - \frac{Carbon\ in\ Stack}{Total\ Carbon\ In - Unburnt\ Carbon} = \left(1 - \left(\frac{40{,}806}{409{,}459 - 2{,}413}\right)\right) * 100 = 90\%$$

Where the unburned carbon is equal to one minus the carbon conversion rate times the carbon in the coal:

$$(1 - Carbon\ Conversion) * Carbon\ in\ Coal = (1 - 0.994) * 402{,}191 = 2{,}413$$

Exhibit 3-37. Case B11B.90 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	182,431 (402,191)	Stack Gas	18,509 (40,806)
Air (CO_2)	425 (937)	FGD Product	216 (477)
PAC	63 (138)	Baghouse	938 (2,069)
FGD Reagent	2,809 (6,193)	Bottom Ash	219 (483)
		CO_2 Product	165,827 (365,586)
		CO_2 Dryer Vent	17 (38)
		CO_2 Knockout	0.5 (1.0)
Total	**185,728 (409,459)**	**Total**	**185,728 (409,459)**

Exhibit 3-38 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 removed in the polishing scrubber, and sulfur removed in the baghouse via hydrated lime.

Exhibit 3-38. Case B11B.90 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	7,173 (15,814)	FGD Product	6,744 (14,868)
		Stack Gas	0.0 (0.0)
		Polishing Scrubber and Solvent Reclaiming	140 (309)
		Baghouse	289 (637)
Total	**7,173 (15,814)**	**Total**	**7,173 (15,814)**

Water demand, recycle, withdrawal, discharge, and consumption are defined and discussed in Section 2.6. Exhibit 3-39 shows the overall water balance for the plant. The exhibit is presented in an identical manner as was for Case B11A. The only notable difference is the FGD makeup

water source. In CO_2 capture cases, a significant amount of water is recovered from the initial PostCCC facility cooling step. This water is assumed suitable to be used as FGD makeup, with the balance of the water from the PostCCC facility discharged.

Exhibit 3-39. Case B11B.90 water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m³/min (gpm)	m³/min (gpm)	m³/min (gpm)	m³/min (gpm)	m³/min (gpm)
FGD Process Makeup	1.9 (512)	1.9 (512)	–	–	–
FGD Slurry Water	1.1 (285)	1.1 (285)	–	–	–
CO_2 Drying	–	–	–	0.0 (2.5)	0.0 (-2.5)
CO_2 Capture Recovery	–	–	–	1.0 (258)	-1.0 (-258)
CO_2 Compression KO	–	–	–	0.1 (22)	-0.1 (-22)
Deaerator Vent	–	–	–	0.1 (21)	-0.1 (-21)
Condenser Makeup	**0.5 (128)**	**–**	**0.5 (128)**	**–**	**0.5 (128)**
BFW Makeup	0.5 (128)	–	0.5 (128)	–	0.5 (128)
Cooling Tower	**38 (9,952)**	**0.4 (107)**	**37 (9,845)**	**8.5 (2,238)**	**29 (7,607)**
BFW Blowdown	–	0.4 (107)	-0.4 (-107)	–	-0.4 (-107)
Total	**41 (10,877)**	**3.4 (904)**	**38 (9,973)**	**9.6 (2,542)**	**28 (7,431)**

3.2.8.2 Energy and Mass Balance Diagrams

Energy and mass balance diagrams are shown for the Case B11B.90 PC boiler, FGD unit, PostCCC system, and steam cycle in Exhibit 3-40 and Exhibit 3-41.

An overall plant energy balance is provided in tabular form in Exhibit 3-42. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-34) is calculated by multiplying the power out by a generator efficiency of 98.5 percent.

Exhibit 3-40. Case B11B.90 energy and mass balance, SubC PC boiler with CO_2 capture

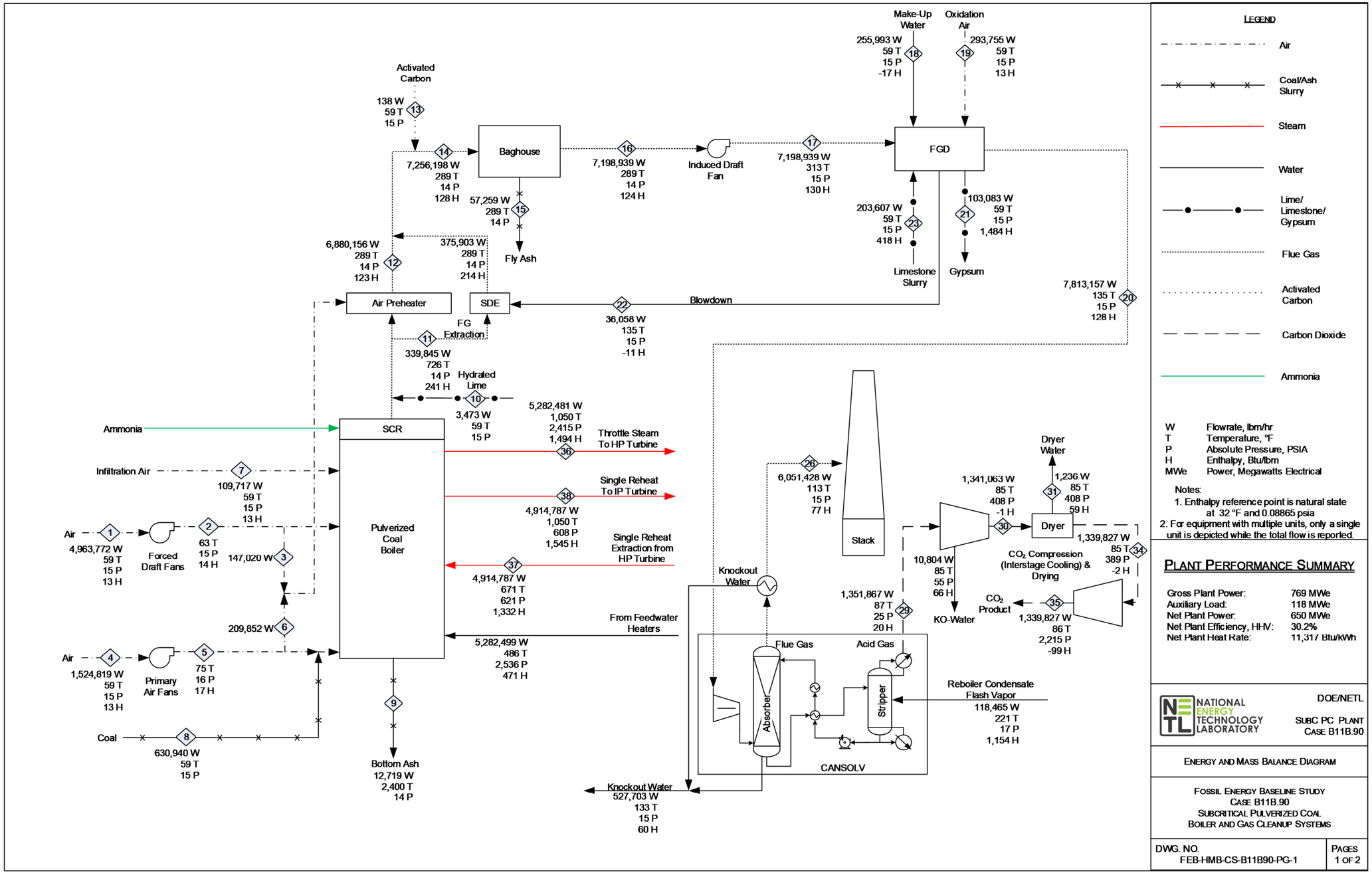


Exhibit 3-41. Case B11B.90 energy and mass balance, SubC steam cycle

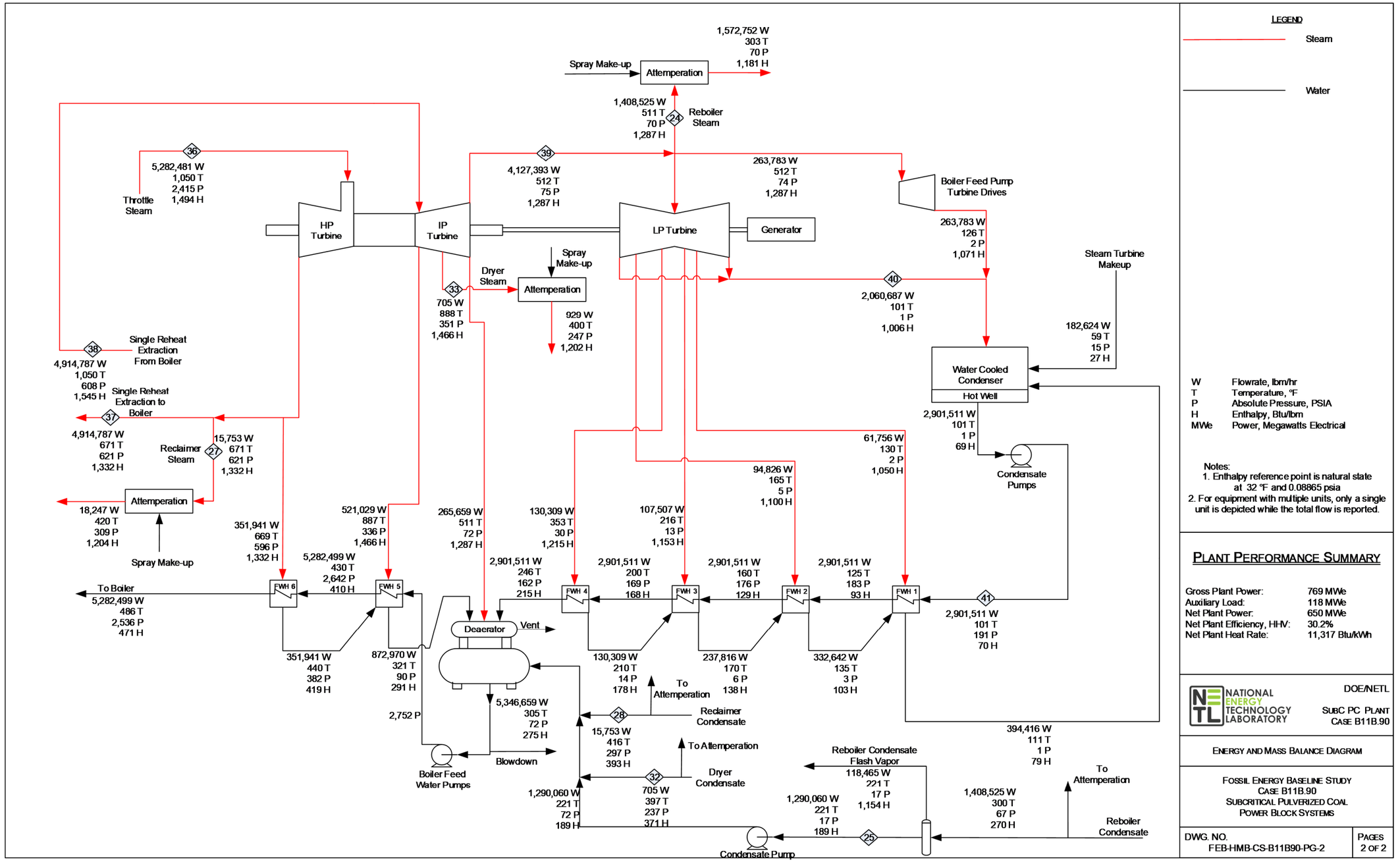


Exhibit 3-42. Case B11B.90 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, GJ/hr (MMBtu/hr)				
Coal	7,766 (7,361)	6.5 (6.1)	–	7,772 (7,367)
Air	–	90 (86)	–	90 (86)
Raw Water Makeup	–	142 (135)	–	142 (135)
Limestone	–	0.6 (0.6)	–	0.6 (0.6)
Auxiliary Power	–	–	425 (403)	425 (403)
TOTAL	**7,766 (7,361)**	**240 (227)**	**425 (403)**	**8,430 (7,990)**
Heat Out, GJ/hr (MMBtu/hr)				
Bottom Ash	–	7.4 (7.0)	–	7.4 (7.0)
Fly Ash	–	2.7 (2.5)	–	2.7 (2.5)
Stack Gas	–	490 (464)	–	490 (464)
Sulfur	2.6 (2.5)	0.0 (0.0)	–	2.6 (2.5)
Gypsum	–	2.7 (2.6)	–	2.7 (2.6)
Motor Losses and Design Allowances	–	–	51 (48)	51 (48)
Cooling Tower Load[A]	–	4,919 (4,663)	–	4,919 (4,663)
CO_2 Product Stream	–	-140 (-133)	–	-140 (-133)
AGR Effluent	–	56 (53)	–	56 (53)
Blowdown Streams and Deaerator Vent	–	18 (18)	–	18 (18)
Ambient Losses[B]	–	*181 (172)*	–	*181 (172)*
Power	–	–	2,767 (2,622)	2,767 (2,622)
TOTAL	**2.6 (2.5)**	**5,537 (5,248)**	**2,817 (2,670)**	**8,357 (7,921)**
Unaccounted Energy[C]	–	*73 (69)*	–	*73 (69)*

[A]Includes condenser, capture process, CO_2 compressor, and miscellaneous cooling loads
[B]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers
[C]By difference

3.2.9 Case B11B.90 – Major Equipment List

Major equipment items for the SubC 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. Values reported in the equipment lists are rounded.

Case B11B.90 – 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	60 tonne (70 ton)	2	1
9	Feeder	Vibratory	240 tonne/hr (260 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	470 tonne/hr (520 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	240 tonne (260 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	470 tonne/hr (520 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	470 tonne/hr (520 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	1,050 tonne (1,160 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 12 tonne (13 ton) Feeder - 70 kg/hr (150 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 290 tonne (320 ton) Feeder - 1,730 kg/hr (3,820 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	116 tonne/hr (128 tph)	1	0
23	Limestone Conveyor No. 1	Belt	116 tonne/hr (128 tph)	1	0
24	Limestone Reclaim Hopper	N/A	23 tonne (25 ton)	1	0
25	Limestone Reclaim Feeder	Belt	92 tonne/hr (101 tph)	1	0
26	Limestone Conveyor No. 2	Belt	92 tonne/hr (101 tph)	1	0
27	Limestone Day Bin	w/ actuator	365 tonne (403 ton)	2	0

Case B11B.90 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	52 tonne/hr (58 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	52 tonne/hr (58 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	30 tonne/hr (34 tph)	1	1
4	Limestone Ball Mill	Rotary	30 tonne/hr (34 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	115,800 liters (30,600 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,950 lpm @ 10m H_2O (510 gpm @ 40 ft H_2O)	1	1
7	Hydrocyclone Classifier	4 active cyclones in a 5-cyclone bank	490 lpm (130 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	658,000 liters (174,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,370 lpm @ 9m H_2O (360 gpm @ 30 ft H_2O)	1	1

Case B11B.90 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,924,000 liters (508,100 gal)	2	0
2	Condensate Pumps	Vertical canned	12,100 lpm @ 200 m H_2O (3,210 gpm @ 500 ft H_2O)	2	1
3	Deaerator and Storage Tank	Horizontal spray type	1,334,000 kg/hr (2,941,000 lb/hr), 5 min. tank	2	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	22,000 lpm @ 2,300 m H_2O (5,800 gpm @ 7,500 ft H_2O)	2	2
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	6,600 lpm @ 2,300 m H_2O (1,700 gpm @ 7,500 ft H_2O)	2	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	360,000 kg/hr (800,000 lb/hr)	4	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	360,000 kg/hr (800,000 lb/hr)	4	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	360,000 kg/hr (800,000 lb/hr)	4	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	360,000 kg/hr (800,000 lb/hr)	4	0
10	HP Feedwater Heater 5	Horizontal U-tube	1,320,000 kg/hr (2,910,000 lb/hr)	2	0
11	HP Feedwater Heater 6	Horizontal U-tube	1,320,000 kg/hr (2,910,000 lb/hr)	2	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	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	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	10,200 lpm @ 20 m H_2O (2,680 gpm @ 60 ft H_2O)	2	1
21	Ground Water Pumps	Stainless steel, single suction	4,060 lpm @ 270 m H_2O (1,070 gpm @ 880 ft H_2O)	5	1
22	Filtered Water Pumps	Stainless steel, single suction	1,560 lpm @ 50 m H_2O (410 gpm @ 160 ft H_2O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	1,499,000 liter (396,000 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	980 lpm (260 gpm)	1	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
25	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
26	Process Water Treatment	Spray dryer evaporator	Flue Gas - 2,630 m^3/min (93,100 acfm) @ 385°C (726°F) & 0.1 MPa (14 psia) Blowdown - 150 lpm (40 gpm) @ 19,983 ppmw Cl^-	2	1

Case B11B.90 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Subcritical, drum, wall-fired, low NOx burners, overfire air	2,640,000 kg/hr steam @ 16.5 MPa/566°C/566°C (5,810,000 lb/hr steam @ 2,400 psig/1,050°F/1,050°F)	1	0
2	Primary Air Fan	Centrifugal	380,000 kg/hr, 5,200 m^3/min @ 101 cm WG (839,000 lb/hr, 183,300 acfm @ 40 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	1,238,000 kg/hr, 16,900 m^3/min @ 26 cm WG (2,730,000 lb/hr, 597,000 acfm @ 10 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,796,000 kg/hr, 36,400 m^3/min @ 114 cm WG (3,959,000 lb/hr, 1,284,800 acfm @ 45 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	3,400,000 kg/hr (7,490,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	130 m^3/min @ 108 cm WG (4,700 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	145,000 liter (38,400 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	28 lpm @ 90 m H_2O (7 gpm @ 300 ft H_2O)	2	1

Case B11B.90 – 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	1,796,000 kg/hr (3,960,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	60,900 m^3/min (2,150,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	212,000 lpm @ 65 m H_2O (55,900 gpm @ 210 ft H_2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	5,850 lpm (1,540 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	1,000 m^3/min @ 0.3 MPa (35,320 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,460 lpm (390 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	46 tonne/hr (51 tph) of 50 wt% slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	890 lpm @ 13 m H_2O (240 gpm @ 40 ft H_2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	580,000 lpm (150,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	2,130 lpm @ 21 m H_2O (560 gpm @ 70 ft H_2O)	1	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
12	Activated Carbon Injectors	---	70 kg/hr (150 lb/hr)	1	0
13	Hydrated Lime Injectors	---	1,730 kg/hr (3,820 lb/hr)	1	0
14	CANSOLV	Amine-based CO_2 capture technology	3,898,000 kg/hr (8,594,000 lb/hr) 19.1 wt% CO_2 concentration	1	0
15	CANSOLV LP Condensate Pump	Centrifugal	1,368 lpm @ 1 m H_2O (361 gpm @ 3 ft H_2O)	1	1
16	CANSOLV IP Condensate Pump	Centrifugal	21 lpm @ 4.6 m H_2O (6 gpm @ 15 ft H_2O)	1	1
17	CO_2 Dryer	Triethylene glycol	Inlet: 175 m^3/min @ 2.8 MPa (6,193 acfm @ 408 psia) Outlet: 2.7 MPa (389 psia) Water Recovered: 561 kg/hr (1,236 lb/hr)	1	0
18	CO_2 Compressor	Integrally geared, multi-stage centrifugal	9.0 m^3/min @ 15.3 MPa, 82°C (312 acfm @ 2,217 psia, 180°F)	2	0
19	CO_2 Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 96 GJ/hr (91 MMBtu/hr)	1	0

Case B11B.90 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.4 m (21 ft) diameter	1	0

Case B11B.90 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	809 MW 16.5 MPa/566°C/566°C (2,400 psig/1,050°F/1,050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	900 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,540 GJ/hr (2,410 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0

Case B11B.90 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	971,000 lpm @ 30 m (256,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 5,410 GJ/hr (5,130 MMBtu/hr) heat duty	1	0

Case B11B.90 – Account 10: Ash and Spent Sorbent Handling System

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	–	6.3 tonne/hr (7 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	26 m^3/min @ 0.2 MPa (906 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,680 tonne (1,860 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	160 tonne/hr (170 tph)	1	0

Case B11B.90 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 760 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 27 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 55 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 19 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.90 – 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.90 – Cost Estimating

The cost estimating methodology is described in Section 2.7. Exhibit 3-43 shows a detailed breakdown of the capital costs; Exhibit 3-44 shows the owner's costs, TOC, and TASC; Exhibit 3-45 shows the initial and annual O&M costs; and Exhibit 3-46 shows the COE breakdown.

For PC cases, existing costs were escalated to reflect a 2023-year dollar using the methodology outlined in NETL's current QGESS (NETL, 2025a).

The estimated TPC of the SubC PC boiler with CO_2 capture is $4,177/kW. Process contingency represents 2.7 percent of the TPC and project contingency represents 13.9 percent of the TPC. The FY COE, including T&S costs of $9.1/MWh, is $142.7/MWh. The LCOE, including T&S costs of $12.1/MWh, is $152.7/MWh.

Exhibit 3-43. Case B11B.90 total plant cost details

Case:	B11B.90 – Subcritical PC with 90 Percent CO_2 Capture								Estimate Type:	Conceptual	
Plant Size (MW, net):	650								Cost Base:	Jan 2023	
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
1	Coal & Sorbent Handling										
1.1	Coal Receive & Unload	$1,643	$0	$574	$0	$2,217	$388	$0	$391	$2,996	$5
1.2	Coal Stackout & Reclaim	$5,393	$0	$936	$0	$6,329	$1,108	$0	$1,115	$8,552	$13
1.3	Coal Conveyors	$49,693	$0	$9,168	$0	$58,861	$10,301	$0	$10,374	$79,535	$122
1.4	Other Coal Handling	$6,908	$0	$1,128	$0	$8,035	$1,406	$0	$1,416	$10,858	$17
1.5	Sorbent Receive & Unload	$317	$0	$73	$0	$389	$68	$0	$69	$526	$1
1.6	Sorbent Stackout & Reclaim	$2,312	$0	$324	$0	$2,636	$461	$0	$465	$3,562	$5
1.7	Sorbent Conveyors	$3,504	$731	$659	$0	$4,893	$856	$0	$862	$6,612	$10
1.8	Other Sorbent Handling	$168	$38	$68	$0	$274	$48	$0	$48	$370	$1
1.9	Coal & Sorbent Handling Foundations	$0	$2,067	$2,204	$0	$4,271	$747	$0	$753	$5,772	$9
	Subtotal	**$69,937**	**$2,836**	**$15,133**	**$0**	**$87,906**	**$15,384**	**$0**	**$15,493**	**$118,783**	**$183**
2	Coal & Sorbent Preparation & Feed										
2.1	Coal Crushing & Drying	$3,537	$0	$527	$0	$4,064	$711	$0	$716	$5,492	$8
2.2	Prepared Coal Storage & Feed	$11,905	$0	$1,990	$0	$13,894	$2,432	$0	$2,449	$18,775	$29
2.5	Sorbent Preparation Equipment	$1,557	$65	$247	$0	$1,869	$327	$0	$329	$2,525	$4
2.6	Sorbent Storage & Feed	$2,607	$0	$766	$0	$3,372	$590	$0	$594	$4,557	$7
2.9	Coal & Sorbent Feed Foundation	$0	$992	$703	$0	$1,695	$297	$0	$299	$2,290	$4
	Subtotal	**$19,605**	**$1,056**	**$4,233**	**$0**	**$24,895**	**$4,357**	**$0**	**$4,388**	**$33,639**	**$52**
3	Feedwater & Miscellaneous BOP Systems										
3.1	Feedwater System	$5,339	$8,820	$3,567	$0	$17,726	$3,102	$0	$3,124	$23,952	$37
3.2	Water Makeup & Pretreating	$11,214	$1,081	$4,953	$0	$17,247	$3,018	$0	$4,053	$24,318	$37
3.3	Other Feedwater Subsystems	$4,144	$1,309	$1,006	$0	$6,459	$1,130	$0	$1,138	$8,727	$13
3.4	Service Water Systems	$3,568	$6,564	$17,190	$0	$27,322	$4,781	$0	$6,421	$38,524	$59
3.5	Other Boiler Plant Systems	$979	$358	$723	$0	$2,060	$361	$0	$363	$2,784	$4
3.6	Natural Gas Pipeline and Start-Up System	$5,155	$198	$120	$0	$5,473	$958	$0	$965	$7,396	$11
3.7	Waste Water Treatment Equipment	$18,537	$0	$8,855	$0	$27,391	$4,793	$0	$6,437	$38,622	$59
3.8	Spray Dryer Evaporator	$23,532	$0	$10,617	$0	$34,148	$5,976	$0	$8,025	$48,149	$74
3.9	Miscellaneous Plant Equipment	$274	$35	$108	$0	$417	$73	$0	$98	$587	$1
	Subtotal	**$72,740**	**$18,365**	**$47,138**	**$0**	**$138,243**	**$24,193**	**$0**	**$30,624**	**$193,060**	**$297**
4	Pulverized Coal Boiler & Accessories										
4.9	Pulverized Coal Boiler & Accessories	$294,980	$0	$156,510	$0	$451,490	$79,011	$0	$79,575	$610,075	$938
4.10	Selective Catalytic Reduction System	$40,212	$0	$20,452	$0	$60,664	$10,616	$0	$10,692	$81,972	$126
4.11	Boiler Balance of Plant	$2,068	$0	$1,097	$0	$3,166	$554	$0	$558	$4,278	$7
4.12	Primary Air System	$2,343	$0	$1,144	$0	$3,487	$610	$0	$615	$4,711	$7
4.13	Secondary Air System	$3,548	$0	$1,733	$0	$5,281	$924	$0	$931	$7,136	$11
4.14	Induced Draft Fans	$7,654	$0	$3,738	$0	$11,392	$1,994	$0	$2,008	$15,394	$24
4.15	Major Component Rigging	$123	$0	$63	$0	$185	$32	$0	$33	$251	$0
4.16	Boiler Foundations	$0	$537	$382	$0	$919	$161	$0	$162	$1,241	$2

Case:	B11B.90 – Subcritical PC with 90 Percent CO_2 Capture									
Plant Size (MW, net):	650									
Estimate Type:	Conceptual									
Cost Base:	Jan 2023									
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
	Subtotal	**$350,927**	**$537**	**$185,119**	**$0**	**$536,583**	**$93,902**	**$0**	**$94,573**	**$725,058**	**$1,115**
5	**Flue Gas Cleanup**										
5.1	CANSOLV CO_2 Removal System	$186,761	$83,403	$155,358	$0	$425,521	$74,466	$72,339	$100,157	$672,483	$1,034
5.2	Wet FGD Absorber Vessels & Accessories	$102,578	$0	$18,521	$0	$121,100	$21,192	$0	$21,344	$163,636	$252
5.3	Other FGD	$1,638	$0	$1,064	$0	$2,702	$473	$0	$476	$3,651	$6
5.4	CO_2 Compression & Drying	$58,866	$8,592	$15,251	$0	$82,709	$14,474	$0	$19,437	$116,620	$179
5.5	CO_2 Compressor Aftercooler	$649	$100	$219	$0	$968	$169	$0	$228	$1,365	$2
5.6	Mercury Removal (DSI/ACI)	$3,440	$790	$2,855	$0	$7,085	$1,240	$0	$1,249	$9,574	$15
5.9	Particulate Removal (Bag House & Accessories)	w/ 5.2	w/ 5.2	w/ 5.2	w/ 5.2	$0	$0	$0	$0	$0	$0
5.12	Gas Cleanup Foundations	$0	$267	$189	$0	$456	$80	$0	$80	$617	$1
5.13	Gypsum Dewatering System	$1,061	$0	$139	$0	$1,200	$210	$0	$212	$1,622	$2
	Subtotal	**$354,993**	**$93,152**	**$193,597**	**$0**	**$641,742**	**$112,305**	**$72,339**	**$143,182**	**$969,568**	**$1,491**
7	**Ductwork & Stack**										
7.3	Ductwork	$0	$986	$554	$0	$1,540	$269	$0	$271	$2,081	$3
7.4	Stack	$11,901	$0	$5,414	$0	$17,315	$3,030	$0	$3,052	$23,397	$36
7.5	Duct & Stack Foundations	$0	$274	$263	$0	$538	$94	$0	$126	$758	$1
	Subtotal	**$11,901**	**$1,260**	**$6,232**	**$0**	**$19,393**	**$3,394**	**$0**	**$3,450**	**$26,236**	**$40**
8	**Steam Turbine & Accessories**										
8.1	Steam Turbine Generator & Accessories	$77,725	$0	$7,821	$0	$85,546	$14,970	$0	$15,077	$115,593	$178
8.2	Steam Turbine Plant Auxiliaries	$1,771	$0	$3,308	$0	$5,079	$889	$0	$895	$6,863	$11
8.3	Condenser & Auxiliaries	$16,795	$0	$4,538	$0	$21,333	$3,733	$0	$3,760	$28,826	$44
8.4	Steam Piping	$56,745	$0	$16,260	$0	$73,005	$12,776	$0	$12,867	$98,648	$152
8.5	Turbine Generator Foundations	$0	$300	$401	$0	$701	$123	$0	$165	$988	$2
	Subtotal	**$153,036**	**$300**	**$32,327**	**$0**	**$185,663**	**$32,491**	**$0**	**$32,764**	**$250,918**	**$386**
9	**Cooling Water System**										
9.1	Cooling Towers	$27,130	$0	$6,568	$0	$33,698	$5,897	$0	$5,939	$45,535	$70
9.2	Circulating Water Pumps	$3,845	$0	$214	$0	$4,059	$710	$0	$715	$5,484	$8
9.3	Circulating Water System Auxiliaries	$22,635	$0	$2,334	$0	$24,968	$4,369	$0	$4,401	$33,739	$52
9.4	Circulating Water Piping	$0	$10,087	$7,388	$0	$17,474	$3,058	$0	$3,080	$23,612	$36
9.5	Make-up Water System	$1,756	$0	$1,758	$0	$3,514	$615	$0	$619	$4,748	$7
9.6	Component Cooling Water System	$1,506	$0	$975	$0	$2,481	$434	$0	$437	$3,352	$5
9.7	Circulating Water System Foundations	$0	$938	$1,259	$0	$2,197	$384	$0	$516	$3,098	$5
	Subtotal	**$56,871**	**$11,024**	**$20,495**	**$0**	**$88,391**	**$15,468**	**$0**	**$15,708**	**$119,568**	**$184**
10	**Ash & Spent Sorbent Handling Systems**										
10.6	Ash Storage Silos	$1,632	$0	$3,874	$0	$5,506	$964	$0	$970	$7,440	$11
10.7	Ash Transport & Feed Equipment	$5,551	$0	$4,271	$0	$9,822	$1,719	$0	$1,731	$13,272	$20
10.9	Ash/Spent Sorbent Foundation	$0	$1,092	$1,086	$0	$2,178	$381	$0	$512	$3,071	$5

Case:	B11B.90 – Subcritical PC with 90 Percent CO_2 Capture									
Plant Size (MW, net):	650								Estimate Type:	Conceptual
									Cost Base:	Jan 2023
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
	Subtotal	**$7,183**	**$1,092**	**$9,231**	**$0**	**$17,506**	**$3,064**	**$0**	**$3,213**	**$23,783**	**$37**
11	**Accessory Electric Plant**										
11.1	Generator Equipment	$3,833	$0	$2,122	$0	$5,955	$1,042	$0	$1,050	$8,046	$12
11.2	Station Service Equipment	$11,002	$0	$693	$0	$11,695	$2,047	$0	$2,061	$15,803	$24
11.3	Switchgear & Motor Control	$17,080	$0	$2,175	$0	$19,255	$3,370	$0	$3,394	$26,018	$40
11.4	Conduit & Cable Tray	$0	$2,015	$4,696	$0	$6,711	$1,174	$0	$1,183	$9,068	$14
11.5	Wire & Cable	$0	$5,336	$7,714	$0	$13,050	$2,284	$0	$2,300	$17,634	$27
11.6	Protective Equipment	$79	$0	$201	$0	$280	$49	$0	$49	$378	$1
11.7	Standby Equipment	$1,186	$0	$803	$0	$1,989	$348	$0	$351	$2,688	$4
11.8	Main Power Transformers	$10,056	$0	$151	$0	$10,206	$1,786	$0	$1,799	$13,791	$21
11.9	Electrical Foundations	$0	$290	$596	$0	$886	$155	$0	$208	$1,250	$2
	Subtotal	**$43,235**	**$7,641**	**$19,151**	**$0**	**$70,027**	**$12,255**	**$0**	**$12,394**	**$94,676**	**$146**
12	**Instrumentation & Control**										
12.1	Pulverized Coal Boiler Control Equipment	$1,080	$0	$152	$0	$1,231	$216	$0	$217	$1,664	$3
12.3	Steam Turbine Control Equipment	$965	$0	$87	$0	$1,052	$184	$0	$185	$1,421	$2
12.5	Signal Processing Equipment	$1,226	$0	$172	$0	$1,398	$245	$0	$246	$1,889	$3
12.6	Control Boards, Panels, & Racks	$375	$0	$180	$0	$555	$97	$28	$102	$782	$1
12.7	Distributed Control System Equipment	$10,578	$0	$1,487	$0	$12,065	$2,111	$603	$2,217	$16,997	$26
12.8	Instrument Wiring & Tubing	$741	$578	$1,869	$0	$3,187	$558	$159	$586	$4,490	$7
12.9	Other Instrumentation & Controls Equipment	$910	$0	$1,662	$0	$2,573	$450	$129	$473	$3,624	$6
	Subtotal	**$15,874**	**$578**	**$5,610**	**$0**	**$22,061**	**$3,861**	**$919**	**$4,026**	**$30,867**	**$47**
13	**Improvements to Site**										
13.1	Site Preparation	$0	$598	$10,289	$0	$10,888	$1,905	$0	$2,559	$15,352	$24
13.2	Site Improvements	$0	$2,963	$3,166	$0	$6,129	$1,073	$0	$1,440	$8,642	$13
13.3	Site Facilities	$3,443	$0	$2,873	$0	$6,315	$1,105	$0	$1,484	$8,905	$14
	Subtotal	**$3,443**	**$3,561**	**$16,328**	**$0**	**$23,332**	**$4,083**	**$0**	**$5,483**	**$32,898**	**$51**
14	**Buildings & Structures**										
14.2	Boiler Building	$0	$15,100	$10,732	$0	$25,832	$4,521	$0	$4,553	$34,906	$54
14.3	Steam Turbine Building	$0	$20,989	$15,809	$0	$36,798	$6,440	$0	$6,486	$49,723	$76
14.4	Administration Building	$0	$1,363	$1,166	$0	$2,529	$443	$0	$446	$3,418	$5
14.5	Circulation Water Pumphouse	$0	$250	$160	$0	$410	$72	$0	$72	$554	$1
14.6	Water Treatment Buildings	$0	$628	$463	$0	$1,092	$191	$0	$192	$1,475	$2
14.7	Machine Shop	$0	$720	$391	$0	$1,111	$194	$0	$196	$1,501	$2
14.8	Warehouse	$0	$541	$438	$0	$979	$171	$0	$173	$1,323	$2
14.9	Other Buildings & Structures	$0	$379	$261	$0	$641	$112	$0	$113	$866	$1
14.10	Waste Treating Building & Structures	$0	$840	$2,061	$0	$2,901	$508	$0	$511	$3,920	$6
	Subtotal	**$0**	**$40,810**	**$31,483**	**$0**	**$72,293**	**$12,651**	**$0**	**$12,742**	**$97,685**	**$150**
	Total	**$1,159,746**	**$182,212**	**$586,078**	**$0**	**$1,928,036**	**$337,406**	**$73,258**	**$378,040**	**$2,716,741**	**$4,177**

Exhibit 3-44. Case B11B.90 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$16,103	$25
1 Month Maintenance Materials	$2,557	$4
1 Month Non-fuel Consumables	$4,181	$6
1 Month Waste Disposal	$1,383	$2
25% of 1 Months Fuel Cost at 100% CF	$4,049	$6
2% of TPC	$54,335	$84
Total	**$82,607**	**$127**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$39,393	$61
0.5% of TPC (spare parts)	$13,584	$21
Total	**$52,977**	**$81**
Other Costs		
Initial Cost for Catalyst and Chemicals	$6,375	$10
Land	$1,800	$3
Other Owner's Costs	$407,511	$627
Financing Costs	$73,352	$113
Total Overnight Costs (TOC)	**$3,341,362**	**$5,137**
TASC Multiplier (IOU, 33 year)	1.213	
Total As-Spent Cost (TASC)	**$4,052,161**	**$6,230**

Exhibit 3-45. Case B11B.90 initial and annual operating and maintenance costs

Case:	B11B.90 – Subcritical PC with 90 Percent CO_2 Capture				Cost Base:	Jan 2023
Plant Size (MW, net):	650		Heat Rate-net (Btu/kWh):	11,317	Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		45.04	**$/hour**	Skilled Operator:		2.0
Operating Labor Burden:		30.00	**% of base**	Operator:		11.3
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		2.0
				Total:		**16.3**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$8,377,366	$12.880
Maintenance Labor:					$17,387,140	$26.732
Administrative & Support Labor:					$6,441,127	$9.903
Property Taxes and Insurance:					$54,334,812	$83.538
Total:					**$86,540,445**	**$133.053**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$26,080,710	$5.385
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	7,180	$2.30	$0	$5,123,819	$1.058
Makeup and Waste Water Treatment Chemicals (ton):	0	21.4	$660.00	$0	$4,379,856	$0.904
Brominated Activated Carbon (ton):	0	1.66	$2,547.97	$0	$1,309,508	$0.270
Enhanced Hydrated Lime (ton):	0	41.7	$391.63	$0	$5,064,182	$1.046
Limestone (ton):	0	732	$30.18	$0	$6,857,788	$1.416
Ammonia (19 wt%, ton):	0	73.1	$280.00	$0	$6,347,054	$1.311
SCR Catalyst (ft^3):	18,214	16.6	$350.00	$6,374,752	$1,806,180	$0.373
CO_2 Capture System Chemicals[A]:	Proprietary				$11,591,910	$2.394
Triethylene Glycol (gal):	w/equip.	63	$8.50	$0	$165,160	$0.034
Subtotal:				**$6,374,752**	**$42,645,455**	**$8.806**
Waste Disposal						
Fly Ash (ton):	0	687	$46.71	$0	$9,956,508	$2.056
Bottom Ash (ton):	0	153	$46.71	$0	$2,211,615	$0.457
SCR Catalyst (ft^3):	0	16.6	$5.70	$0	$29,415	$0.006
Triethylene Glycol (gal):	0	3,181	$1.30	$0	$1,282,859	$0.265
Thermal Reclaimer Unit Waste (ton):	0	8.07	$250.00	$0	$625,645	$0.129
Subtotal:				**$0**	**$14,106,042**	**$2.913**
By-Products						
Gypsum (ton):	0	1113	$0.00	$0	$0	$0.000
Subtotal:				**$0**	**$0**	**$0.000**
Variable Operating Costs Total:				**$6,374,752**	**$82,832,207**	**$17.103**
Fuel Cost						
Illinois Number 6 (ton):	0	7,571	$70.32	$0	$165,187,848	$34.108
Total:				**$0**	**$165,187,848**	**$34.108**

[A]CO_2 Capture System Chemicals includes NaOH and CANSOLV Solvent

Exhibit 3-46. Case B11B.90 COE breakdown

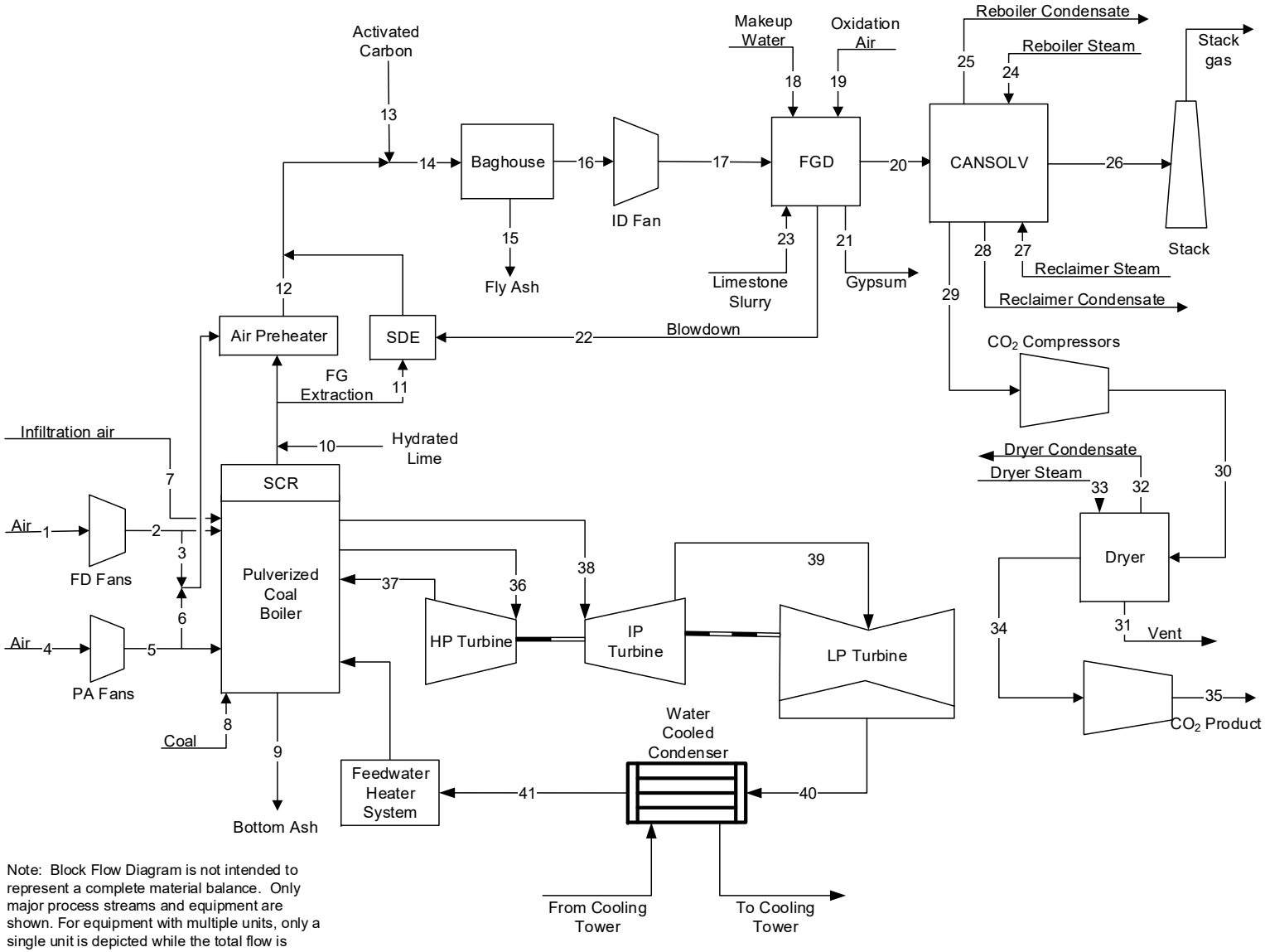
	FY COE		LCOE	
Component	**Value, $/MWh**	**Percentage**	**Value, $/MWh**	**Percentage**
Capital	64.5	45%	64.5	42%
Fixed	17.9	13%	23.9	16%
Variable	17.1	12%	22.8	15%
Fuel	34.1	24%	29.4	19%
Total (Excluding T&S)	**133.6**	**N/A**	**140.6**	**N/A**
CO_2 T&S	9.1	6%	12.1	8%
Total (Including T&S)	**142.7**	**N/A**	**152.7**	**N/A**

3.2.11 Case B11B.95 – SubC PC with 95% CO_2 Capture Process Description

The plant configuration and process description for Case B11B.95 are nearly the same as Case B11B.90, with the exception that the PostCCC facility captures 95, rather than 90, percent of the CO_2 in the flue gas. Since the process descriptions of the plant and PostCCC facility were provided in Section 3.2.3 and Section 3.1.8, respectively, they are not repeated here.

The BFD for Case B11B.95 is shown in Exhibit 3-47. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit 3-48. The modeling assumptions are presented in Section 3.2.1.

Exhibit 3-47. Case B11B.95 BFD, SubC unit with 95 percent CO_2 capture



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown. For equipment with multiple units, only a single unit is depicted while the total flow is reported.

Exhibit 3-48. Case B11B.95 stream table, SubC unit with 95 percent CO_2 capture

	1	2	3	4	5	6	7	8	9	10	11	12
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	0.0087	0.0088
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1457	0.1379
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	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000	0.0879	0.0837
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7318	0.7340
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0237	0.0336
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0020
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	79,245	79,245	2,347	24,343	24,343	3,350	1,752	0	0	1	5,222	105,932
V-L Flowrate (kg/hr)	2,286,782	2,286,782	67,731	702,476	702,476	96,678	50,546	0	0	16	155,310	3,145,573
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	290,670	5,859	1,584	1,254	24,078
Temperature (°C)	15	17	17	15	24	24	15	15	1,316	15	385	143
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg)[A]	30.23	32.49	32.49	30.23	38.98	38.98	30.23	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-95.31	-95.31	-97.58	-88.83	-88.83	-97.58	-2,119.02	1,267.06	-13,402.95	-2,261.17	-2,394.31
Density (kg/m^3)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	1,003.6	0.5	0.8
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015	29.742	29.694
V-L Flowrate (lb_{mol}/hr)	174,706	174,706	5,175	53,668	53,668	7,386	3,862	0	0	2	11,512	233,540
V-L Flowrate (lb/hr)	5,041,492	5,041,492	149,322	1,548,694	1,548,694	213,138	111,435	0	0	35	342,400	6,934,801
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	640,819	12,918	3,492	2,765	53,083
Temperature (°F)	59	63	63	59	75	75	59	59	2,400	59	726	289
Pressure (psia)	14.7	15.0	15.0	14.7	15.9	15.9	14.7	14.7	14.3	14.7	14.3	14.1
Steam Table Enthalpy (Btu/lb)[A]	13.0	14.0	14.0	13.0	16.8	16.8	13.0	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-41.0	-41.0	-42.0	-38.2	-38.2	-42.0	-911.0	544.7	-5,762.2	-972.1	-1,029.4
Density (lb/ft^3)	0.076	0.077	0.077	0.076	0.080	0.080	0.076	---	---	62.650	0.033	0.052

[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 3-48. Case B11B.95 stream table, SubC unit with 95 percent CO_2 capture (continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.1372	0.0000	0.1372	0.1372	0.0000	0.0003	0.1245	0.0001	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	0.0000	0.0911	0.0000	0.0911	0.0911	0.9999	0.0099	0.1508	0.9998	0.9943	0.9999	1.0000
HCl	0.0000	0.0001	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.7281	0.0000	0.7281	0.7281	0.0000	0.7732	0.6803	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0329	0.0000	0.0329	0.0329	0.0000	0.2074	0.0363	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0020	0.0000	0.0020	0.0020	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.1158	0.0000	0.0000	0.0001	0.0000	0.0000	0.0001	0.0009	0.0001	0.0000
$CaCl_2$	0.0000	0.0001	0.8842	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0048	0.0000	0.0000
Total	0.0000	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_{mol}/hr)	0	112,038	7	112,032	112,032	6,546	4,690	125,242	264	885	3,645	38,028
V-L Flowrate (kg/hr)	0	3,317,245	717	3,316,511	3,316,511	117,944	135,332	3,599,478	4,751	16,363	65,683	685,085
Solids Flowrate (kg/hr)	64	25,645	25,662	0	0	0	0	0	42,738	249	28,118	0
Temperature (°C)	15	143	143	143	156	15	15	57	15	57	15	266
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.48
Steam Table Enthalpy (kJ/kg)[A]	---	---	---	287.58	302.09	-47.80	30.23	297.00	---	---	---	2,994.07
AspenPlus Enthalpy (kJ/kg)[B]	-6.79	-2,453.14	-1,065.98	-2,464.17	-2,449.66	-16,015.01	-97.58	-2,939.24	-12,513.34	-15,496.18	-14,994.25	-12,986.23
Density (kg/m^3)	---	0.8	2,150.2	0.8	0.9	1,003.7	1.2	1.1	878.3	979.4	1,003.7	2.0
V-L Molecular Weight	---	29.608	104.898	29.603	29.603	18.019	28.857	28.740	18.021	18.494	18.019	18.015
V-L Flowrate (lb_{mol}/hr)	0	247,003	15	246,987	246,987	14,431	10,339	276,111	581	1,950	8,037	83,837
V-L Flowrate (lb/hr)	0	7,313,274	1,580	7,311,656	7,311,656	260,022	298,355	7,935,491	10,475	36,073	144,806	1,510,355
Solids Flowrate (lb/hr)	140	56,538	56,575	0	0	0	0	0	94,222	549	61,989	0
Temperature (°F)	59	289	289	289	313	59	59	135	59	135	59	511
Pressure (psia)	14.7	14.1	14.1	13.9	15.3	14.7	14.7	14.8	14.7	14.7	14.7	70.0
Steam Table Enthalpy (Btu/lb)[A]	---	---	---	123.6	129.9	-20.5	13.0	127.7	---	---	---	1,287.2
AspenPlus Enthalpy (Btu/lb)[B]	-2.9	-1,054.7	-458.3	-1,059.4	-1,053.2	-6,885.2	-42.0	-1,263.6	-5,379.8	-6,662.2	-6,446.4	-5,583.1
Density (lb/ft^3)	---	0.052	134.232	0.051	0.055	62.658	0.076	0.067	54.833	61.145	62.658	0.123

[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 3-48. Case B11B.95 stream table, SubC unit with 95 percent CO_2 capture (continued)

	25	26	27	28	29	30	31	32	33	34	35	36
V-L Mole Fraction												
Ar	0.0000	0.0102	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0079	0.0000	0.0000	0.9783	0.9975	0.0500	0.0000	0.0000	0.9995	0.9995	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	1.0000	0.0807	1.0000	1.0000	0.0217	0.0025	0.9500	1.0000	1.0000	0.0005	0.0005	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.8555	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0457	0.0000	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	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
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_{mol}/hr)	34,830	99,587	403	403	15,134	14,842	31	19	19	14,811	14,811	135,086
V-L Flowrate (kg/hr)	627,466	2,752,249	7,259	7,259	657,482	652,228	601	343	343	651,626	651,626	2,433,620
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	105	45	355	214	31	29	29	203	476	29	30	566
Pressure (MPa, abs)	0.12	0.10	4.28	2.04	0.17	2.81	2.81	1.64	2.42	2.68	15.27	16.65
Steam Table Enthalpy (kJ/kg)[A]	439.34	179.09	3,098.44	913.81	46.68	-3.05	137.94	863.65	3,408.95	-3.59	-231.09	3,473.89
AspenPlus Enthalpy (kJ/kg)[B]	-15,540.95	-797.41	-12,881.86	-15,066.49	-8,978.62	-8,972.51	-15,225.22	-15,116.65	-12,571.34	-8,967.15	-9,194.65	-12,506.41
Density (kg/m^3)	954.9	1.1	16.0	848.5	3.0	57.8	351.5	861.8	7.1	54.7	630.1	47.7
V-L Molecular Weight	18.015	27.637	18.015	18.015	43.445	43.945	19.315	18.015	18.015	43.997	43.997	18.015
V-L Flowrate (lb_{mol}/hr)	76,786	219,552	888	888	33,364	32,721	69	42	42	32,652	32,652	297,815
V-L Flowrate (lb/hr)	1,383,326	6,067,670	16,003	16,003	1,449,501	1,437,916	1,326	756	756	1,436,590	1,436,590	5,365,214
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	221	113	671	416	87	85	85	397	888	85	86	1,050
Pressure (psia)	17.4	14.8	620.5	296.6	24.7	407.6	407.6	237.4	350.5	389.1	2,214.7	2,414.7
Steam Table Enthalpy (Btu/lb)[A]	188.9	77.0	1,332.1	392.9	20.1	-1.3	59.3	371.3	1,465.6	-1.5	-99.4	1,493.5
AspenPlus Enthalpy (Btu/lb)[B]	-6,681.4	-342.8	-5,538.2	-6,477.4	-3,860.1	-3,857.5	-6,545.7	-6,499.0	-5,404.7	-3,855.2	-3,953.0	-5,376.8
Density (lb/ft^3)	59.612	0.066	1.000	52.968	0.184	3.609	21.943	53.801	0.446	3.416	39.338	2.975

[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 3-48. Case B11B.95 stream table, SubC unit with 95 percent CO_2 capture (continued)

	37	38	39	40	41
V-L Mole Fraction					
Ar	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	125,684	125,684	105,503	50,879	72,314
V-L Flowrate (kg/hr)	2,264,224	2,264,224	1,900,672	916,600	1,302,760
Solids Flowrate (kg/hr)	0	0	0	0	0
Temperature (°C)	355	566	267	38	39
Pressure (MPa, abs)	4.28	4.19	0.52	0.01	1.32
Steam Table Enthalpy (kJ/kg)[A]	3,098.44	3,593.58	2,994.07	2,340.01	162.43
AspenPlus Enthalpy (kJ/kg)[B]	-12,881.86	-12,386.71	-12,986.23	-13,640.29	-15,817.87
Density (kg/m^3)	16.0	11.1	2.1	0.1	993.3
V-L Molecular Weight	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	277,085	277,085	232,595	112,169	159,425
V-L Flowrate (lb/hr)	4,991,760	4,991,760	4,190,265	2,020,758	2,872,095
Solids Flowrate (lb/hr)	0	0	0	0	0
Temperature (°F)	671	1,050	512	101	101
Pressure (psia)	620.5	608.1	75.0	1.0	190.7
Steam Table Enthalpy (Btu/lb)[A]	1,332.1	1,545.0	1,287.2	1,006.0	69.8
AspenPlus Enthalpy (Btu/lb)[B]	-5,538.2	-5,325.3	-5,583.1	-5,864.3	-6,800.5
Density (lb/ft^3)	1.000	0.692	0.132	0.003	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

3.2.12 Case B11B.95 – Performance Results

Overall plant performance is summarized in Exhibit 3-49; Exhibit 3-50 provides a detailed breakdown of the auxiliary power requirements.

The PostCCC facility and CO_2 compression combined account for over half of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for 12 percent of the auxiliary load, largely due to the high cooling water demand of the PostCCC 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. By increasing the boiler and turbine/generator size to account for the greater auxiliary load imposed by the PostCCC facility and CO_2 compressors, a net output of 650 MW is maintained at a reduced net plant efficiency of 29.7 percent (HHV basis).

Exhibit 3-49. Case B11B.95 plant performance summary

Performance Summary	
Total Gross Power, MWe	**774**
CO_2 Capture/Removal Auxiliaries, kWe	20,200
CO_2 Compression, kWe	52,170
Balance of Plant, kWe	51,470
Total Auxiliaries, MWe	**124**
Net Power, MWe	**650**
HHV Net Plant Efficiency, %	29.7
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	12,128 (11,495)
LHV Net Plant Efficiency, %	30.8
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,697 (11,087)
HHV Boiler Efficiency, %	88.0
LHV Boiler Efficiency, %	91.3
Steam Turbine Cycle Efficiency, %	55.8
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	6,453 (6,116)
Condenser Duty, GJ/hr (MMBtu/hr)	2,277 (2,158)
CO_2 Capture Rate, %	95
AGR Duty, GJ/hr (MMBtu/hr)	2,288 (2,169)
As-Received Coal Feed, kg/hr (lb/hr)	290,670 (640,819)
Limestone Sorbent Feed, kg/hr (lb/hr)	28,118 (61,989)
HHV Thermal Input, kWt	2,190,938
LHV Thermal Input, kWt	2,113,187
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.059 (15.7)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.044 (11.7)
Excess Air, %	20.3

Exhibit 3-50. Case B11B.95 plant power summary

Power Summary	
Steam Turbine Power, MWe	774
Total Gross Power, MWe	**774**
Auxiliary Load Summary	
Activated Carbon Injection, kWe	40
Ash Handling, kWe	950
Baghouse, kWe	120
Circulating Water Pumps, kWe	9,900
CO_2 Capture/Removal Auxiliaries, kWe	20,200
CO_2 Compression, kWe	52,170
Coal Handling and Conveying, kWe	550
Condensate Pumps, kWe	720
Cooling Tower Fans, kWe	5,120
Dry Sorbent Injection, kWe	80
Flue Gas Desulfurizer, kWe	4,490
Forced Draft Fans, kWe	1,490
Ground Water Pumps, kWe	920
Induced Draft Fans, kWe	13,780
Miscellaneous Balance of Plant[A,B], kWe	2,250
Primary Air Fans, kWe	1,770
Pulverizers, kWe	4,360
SCR, kWe	50
Sorbent Handling & Reagent Preparation, kWe	1,350
Spray Dryer Evaporator, kWe	320
Steam Turbine Auxiliaries, kWe	500
Transformer Losses, kWe	2,710
Total Auxiliaries, MWe	**124**
Net Power, MWe	**650**

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

3.2.12.1 Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, and PM are presented in Section 2.4. A summary of the plant air emissions for Case B11B.95 is presented in Exhibit 3-51. SO_2 emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit 3-51. Case B11B.95 air emissions

	kg/GJ (lb/MMBtu)[A]	tonne/year (ton/year)[B]	kg/MWh (lb/MWh)[C]
SO_2	0.000 (0.000)	0 (0)	0.000 (0.000)
NOx	0.031 (0.072)	1,830 (2,018)	0.318 (0.700)
Particulate	0.004 (0.009)	235 (259)	0.041 (0.090)
Hg	1.34E-7 (3.11E-7)	0.008 (0.009)	1.36E-6 (3.00E-6)
CO_2	4 (10)	256,957 (283,247)	45 (98)
CO_2[D]	–	–	53 (117)
	mg/Nm^3		
Particulate Concentration[E,F]	12.59		

[A]Based on thermal input on an HHV basis
[B]Calculations based on an 85 percent capacity factor
[C]Emissions based on gross power except where otherwise noted
[D]CO_2 emissions based on net power instead of gross power
[E]Concentration of particles in the flue gas after the baghouse
[F]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 0.37 ppmv using a NaOH based polishing scrubber in the PostCCC facility. The remaining low concentration of SO_2 is essentially completely removed in the PostCCC absorber vessel resulting in very low SO_2 emissions (reported as zero here).

NOx boiler emissions are controlled to about 0.15 kg/GJ (0.35 lb/MMBtu) using LNBs and OFA. An SCR unit then further reduces the NOx concentration by 79.3 percent to 0.03 kg/GJ (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 97.6 percent.

The carbon balance for the plant is shown in Exhibit 3-52. 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 product from the CO_2 compression train; however, some CO_2 exits through the stack and CO_2 dryer's vent, 20 percent of the unburned carbon remains in the bottom ash, the remaining unburned carbon is captured in the fabric filter, along with the PAC, and some carbon leaves as gypsum. The carbon conversion is assumed to be 99.4 percent.

Ninety-five percent of the CO_2 in the flue gas is removed in PostCCC facility. The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in (minus unburnt carbon in the ash), represented by the following percentage:

$$1 - \frac{Carbon\ in\ Stack}{Total\ Carbon\ In - Unburnt\ Carbon} = \left(1 - \left(\frac{20{,}764}{415{,}870 - 2{,}451}\right)\right) * 100 = 95\%$$

Where the unburned carbon is equal to one minus the carbon conversion rate times the carbon in the coal:

$$(1 - Carbon\ Conversion) * Carbon\ in\ Coal = (1 - 0.994) * 408{,}488 = 2{,}451$$

Exhibit 3-52. Case B11B.95 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	185,287 (408,488)	Stack Gas	9,418 (20,764)
Air (CO_2)	432 (952)	FGD Product	220 (484)
PAC	64 (140)	Baghouse	953 (2,101)
FGD Reagent	2,853 (6,290)	Bottom Ash	222 (490)
		CO_2 Product	177,803 (391,989)
		CO_2 Dryer Vent	19 (41)
		CO_2 Knockout	0.5 (1.1)
Total	**188,636 (415,870)**	**Total**	**188,636 (415,870)**

Exhibit 3-53 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 removed in the polishing scrubber, and sulfur removed in the baghouse via hydrated lime.

Exhibit 3-53. Case B11B.95 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	7,285 (16,062)	FGD Product	6,850 (15,101)
		Stack Gas	–
		Polishing Scrubber and Solvent Reclaiming	142 (314)
		Baghouse	294 (647)
Total	**7,285 (16,062)**	**Total**	**7,285 (16,062)**

Water demand, recycle, withdrawal, discharge, and consumption are defined and discussed in Section 2.6. Exhibit 3-54 shows the overall water balance for the plant. The exhibit is presented in an identical manner as was for Case B11B.90. The only notable difference is the higher

capture rate. In CO_2 capture cases, a significant amount of water is recovered from the initial PostCCC facility cooling step. This water is assumed suitable to be used as FGD makeup, with the balance of the water from the PostCCC facility discharged.

Exhibit 3-54. Case B11B.95 water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m³/min (gpm)	m³/min (gpm)	m³/min (gpm)	m³/min (gpm)	m³/min (gpm)
FGD Process Makeup	2.0 (520)	2.0 (520)	–	–	–
FGD Slurry Water	1.1 (290)	1.1 (290)	–	–	–
CO_2 Drying	–	–	–	0.0 (2.7)	0.0 (-2.7)
CO_2 Capture Recovery	–	–	–	1.1 (280)	-1.1 (-280)
CO_2 Compression KO	–	–	–	0.1 (23)	-0.1 (-23)
Deaerator Vent	–	–	–	0.1 (22)	-0.1 (-22)
Condenser Makeup	**0.5 (130)**	**–**	**0.5 (130)**	**–**	**0.5 (130)**
BFW Makeup	0.5 (130)	–	0.5 (130)	–	0.5 (130)
Cooling Tower	**39 (10,186)**	**0.4 (109)**	**38 (10,077)**	**8.7 (2,291)**	**29 (7,786)**
BFW Blowdown	–	0.4 (109)	-0.4 (-109)	–	-0.4 (-109)
Total	**42 (11,126)**	**3.5 (918)**	**39 (10,207)**	**9.9 (2,618)**	**29 (7,589)**

3.2.12.2 Energy and Mass Balance Diagrams

Energy and mass balance diagrams are shown for the Case B11B.95 PC boiler, FGD unit, PostCCC system, and steam cycle in Exhibit 3-55 and Exhibit 3-56.

An overall plant energy balance is provided in tabular form in Exhibit 3-57. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-49) is calculated by multiplying the power out by a generator efficiency of 98.5 percent.

Exhibit 3-55. Case B11B.95 energy and mass balance, SubC PC boiler with CO_2 capture

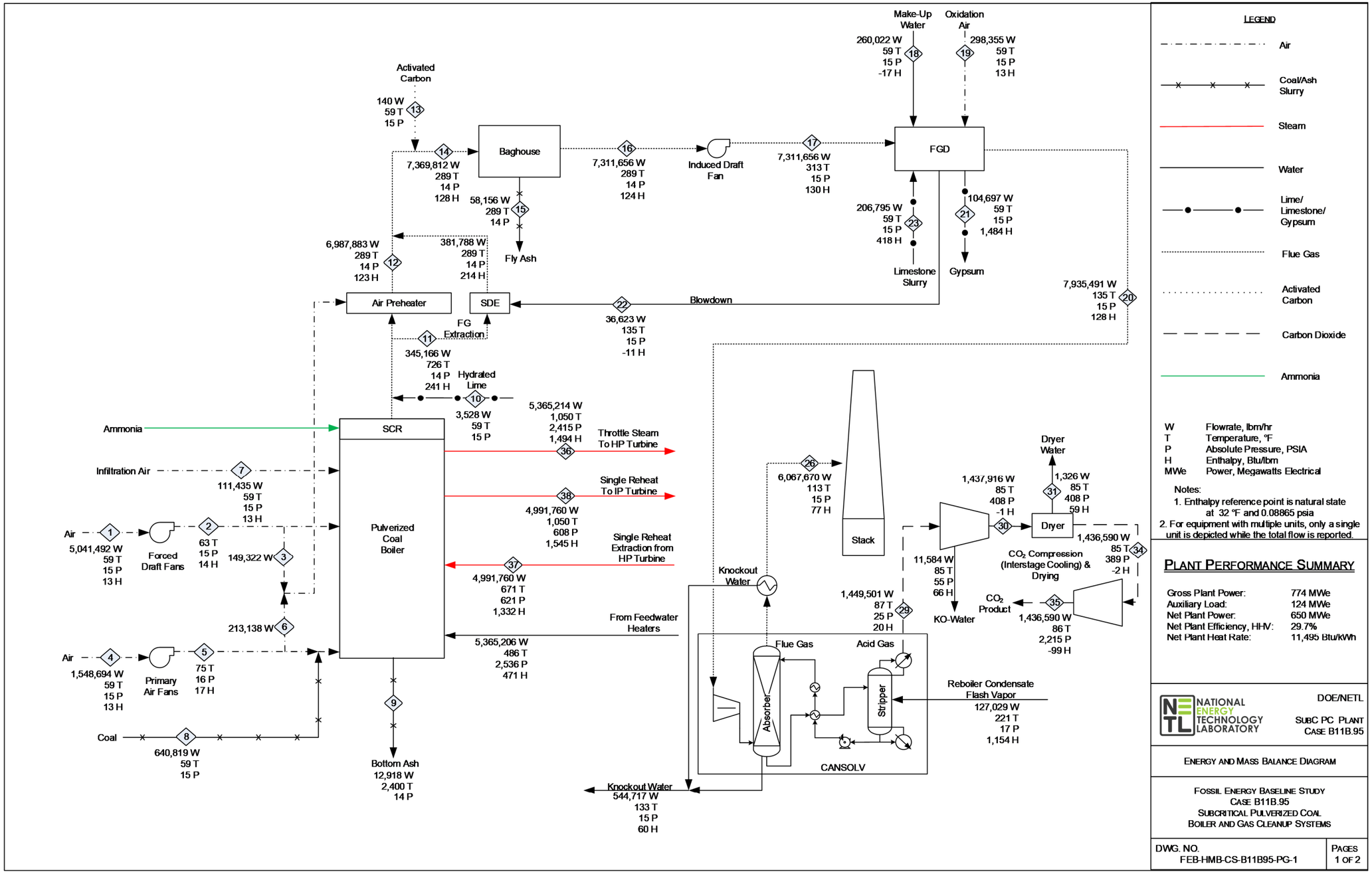


Exhibit 3-56. Case B11B.95 energy and mass balance, SubC steam cycle

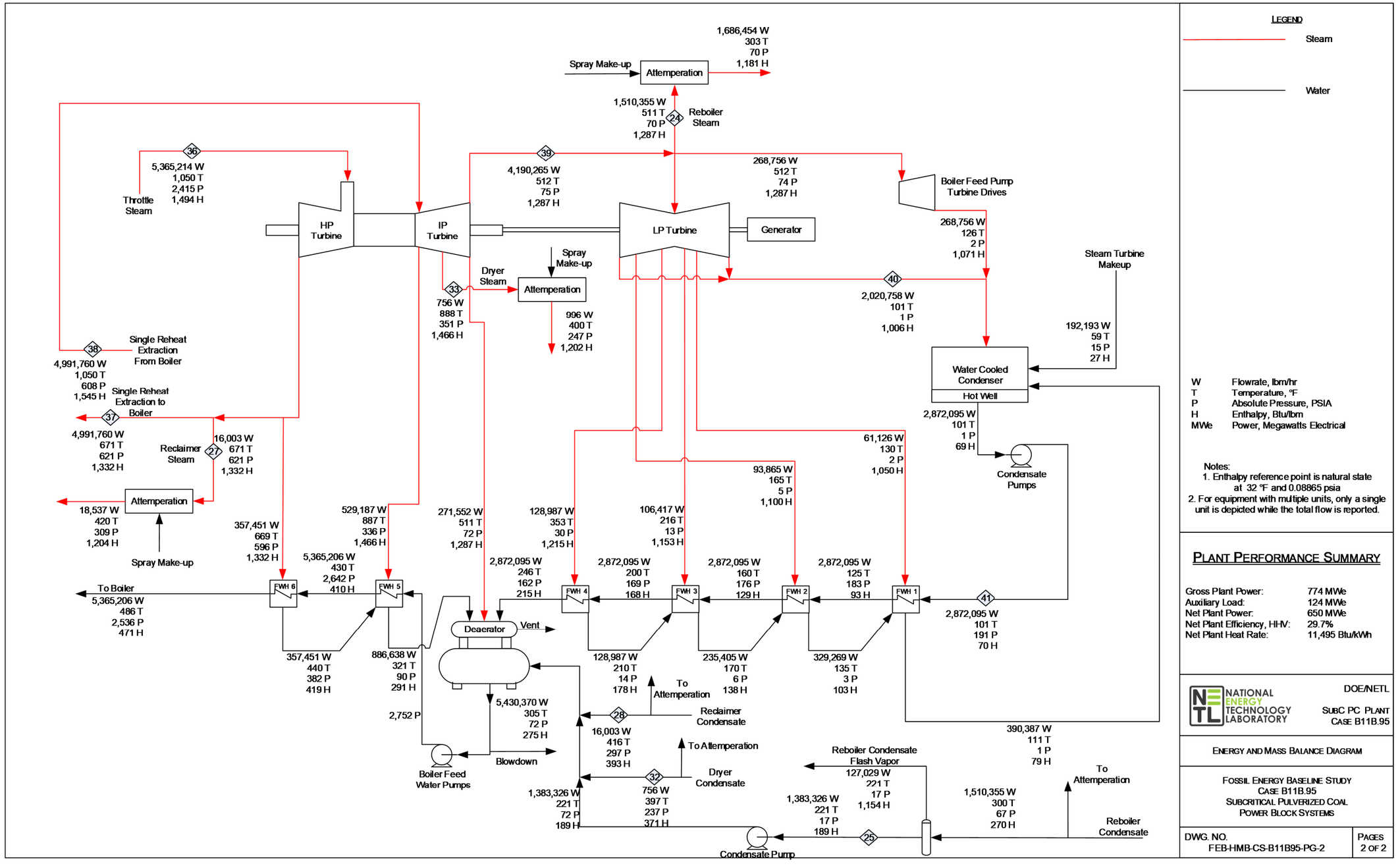


Exhibit 3-57. Case B11B.95 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, GJ/hr (MMBtu/hr)				
Coal	7,887 (7,476)	6.6 (6.2)	–	7,894 (7,482)
Air	–	92 (87)	–	92 (87)
Raw Water Makeup	–	145 (138)	–	145 (138)
Limestone	–	0.6 (0.6)	–	0.6 (0.6)
Auxiliary Power	–	–	446 (423)	446 (423)
TOTAL	**7,887 (7,476)**	**244 (232)**	**446 (423)**	**8,578 (8,130)**
Heat Out, GJ/hr (MMBtu/hr)				
Bottom Ash	–	7.5 (7.1)	–	7.5 (7.1)
Fly Ash	–	2.7 (2.6)	–	2.7 (2.6)
Stack Gas	–	493 (467)	–	493 (467)
Sulfur	2.7 (2.5)	0.0 (0.0)	–	2.7 (2.5)
Gypsum	–	2.8 (2.6)	–	2.8 (2.6)
Motor Losses and Design Allowances	–	–	52 (49)	52 (49)
Cooling Tower Load[A]	–	5,035 (4,772)	–	5,035 (4,772)
CO_2 Product Stream	–	-151 (-143)	–	-151 (-143)
AGR Effluent	–	58 (55)	–	58 (55)
Blowdown Streams and Deaerator Vent	–	19 (18)	–	19 (18)
Ambient Losses[B]	–	*184 (175)*	–	*184 (175)*
Power	–	–	2,787 (2,642)	2,787 (2,642)
TOTAL	**2.7 (2.5)**	**5,651 (5,356)**	**2,839 (2,691)**	**8,492 (8,049)**
Unaccounted Energy[C]	–	*85 (81)*	–	*85 (81)*

[A]Includes condenser, capture process, CO_2 compressor, and miscellaneous cooling loads
[B]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers
[C]By difference

3.2.13 Case B11B.95 – Major Equipment List

Major equipment items for the SubC 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. Values reported in the equipment lists are rounded.

Case B11B.95 – 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	60 tonne (70 ton)	2	1
9	Feeder	Vibratory	240 tonne/hr (260 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	480 tonne/hr (530 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	240 tonne (260 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	480 tonne/hr (530 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	480 tonne/hr (530 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	1,070 tonne (1,170 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 12 tonne (13 ton) Feeder - 70 kg/hr (150 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 300 tonne (330 ton) Feeder - 1,760 kg/hr (3,880 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	118 tonne/hr (130 tph)	1	0
23	Limestone Conveyor No. 1	Belt	118 tonne/hr (130 tph)	1	0
24	Limestone Reclaim Hopper	N/A	23 tonne (26 ton)	1	0
25	Limestone Reclaim Feeder	Belt	93 tonne/hr (102 tph)	1	0
26	Limestone Conveyor No. 2	Belt	93 tonne/hr (102 tph)	1	0
27	Limestone Day Bin	w/ actuator	371 tonne (409 ton)	2	0

Case B11B.95 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	53 tonne/hr (59 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	53 tonne/hr (59 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	31 tonne/hr (34 tph)	1	1
4	Limestone Ball Mill	Rotary	31 tonne/hr (34 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	120,000 liters (31,800 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	2,000 lpm @ 10m H_2O (530 gpm @ 40 ft H_2O)	1	1
7	Hydrocyclone Classifier	4 active cyclones in a 5-cyclone bank	500 lpm (130 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	669,000 liters (177,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,390 lpm @ 9m H_2O (370 gpm @ 30 ft H_2O)	1	1

Case B11B.95 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,954,000 liters (516,100 gal)	2	0
2	Condensate Pumps	Vertical canned	12,000 lpm @ 200 m H_2O (3,180 gpm @ 500 ft H_2O)	2	1
3	Deaerator and Storage Tank	Horizontal spray type	1,355,000 kg/hr (2,987,000 lb/hr), 5 min. tank	2	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	22,000 lpm @ 2,300 m H_2O (5,900 gpm @ 7,500 ft H_2O)	2	2
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	6,700 lpm @ 2,300 m H_2O (1,800 gpm @ 7,500 ft H_2O)	2	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	360,000 kg/hr (790,000 lb/hr)	4	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	360,000 kg/hr (790,000 lb/hr)	4	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	360,000 kg/hr (790,000 lb/hr)	4	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	360,000 kg/hr (790,000 lb/hr)	4	0
10	HP Feedwater Heater 5	Horizontal U-tube	1,340,000 kg/hr (2,950,000 lb/hr)	2	0
11	HP Feedwater Heater 6	Horizontal U-tube	1,340,000 kg/hr (2,950,000 lb/hr)	2	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	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	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	10,400 lpm @ 20 m H_2O (2,740 gpm @ 60 ft H_2O)	2	1
21	Ground Water Pumps	Stainless steel, single suction	4,160 lpm @ 270 m H_2O (1,100 gpm @ 880 ft H_2O)	5	1
22	Filtered Water Pumps	Stainless steel, single suction	1,600 lpm @ 50 m H_2O (420 gpm @ 160 ft H_2O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	1,519,000 liter (401,300 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	990 lpm (260 gpm)	1	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
25	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
26	Process Water Treatment	Spray dryer evaporator	Flue Gas - 2,680 m3/min (94,500 acfm) @ 385°C (726°F) & 0.1 MPa (14 psia) Blowdown - 160 lpm (40 gpm) @ 19,985 ppmw Cl^-	2	1

Case B11B.95 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Subcritical, drum, wall-fired, low NOx burners, overfire air	2,680,000 kg/hr steam @ 16.5 MPa/566°C/566°C (5,900,000 lb/hr steam @ 2,400 psig/1,050°F/1,050°F)	1	0
2	Primary Air Fan	Centrifugal	386,000 kg/hr, 5,300 m^3/min @ 101 cm WG (852,000 lb/hr, 186,200 acfm @ 40 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	1,258,000 kg/hr, 17,200 m^3/min @ 26 cm WG (2,773,000 lb/hr, 606,000 acfm @ 10 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,824,000 kg/hr, 36,900 m^3/min @ 114 cm WG (4,021,000 lb/hr, 1,305,000 acfm @ 45 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	3,450,000 kg/hr (7,610,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	130 m^3/min @ 108 cm WG (4,700 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	148,000 liter (39,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	28 lpm @ 90 m H_2O (7 gpm @ 300 ft H_2O)	2	1

Case B11B.95 – 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	1,824,000 kg/hr (4,022,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	61,800 m^3/min (2,180,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	215,000 lpm @ 65 m H_2O (56,800 gpm @ 210 ft H_2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	5,940 lpm (1,570 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	1,020 m^3/min @ 0.3 MPa (35,870 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,490 lpm (390 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	47 tonne/hr (52 tph) of 50 wt% slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	900 lpm @ 13 m H_2O (240 gpm @ 40 ft H_2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	590,000 lpm (160,000 gal)	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
11	Process Makeup Water Pumps	Horizontal centrifugal	2,170 lpm @ 21 m H_2O (570 gpm @ 70 ft H_2O)	1	1
12	Activated Carbon Injectors	---	70 kg/hr (150 lb/hr)	1	0
13	Hydrated Lime Injectors	---	1,760 kg/hr (3,880 lb/hr)	1	0
14	CANSOLV	Amine-based CO_2 capture technology	3,959,000 kg/hr (8,729,000 lb/hr) 19.1 wt% CO_2 concentration	1	0
15	CANSOLV LP Condensate Pump	Centrifugal	1,466 lpm @ 1 m H_2O (387 gpm @ 3 ft H_2O)	1	1
16	CANSOLV IP Condensate Pump	Centrifugal	21 lpm @ 4.6 m H_2O (6 gpm @ 15 ft H_2O)	1	1
17	CO_2 Dryer	Triethylene glycol	Inlet: 188 m^3/min @ 2.8 MPa (6,640 acfm @ 408 psia) Outlet: 2.7 MPa (389 psia) Water Recovered: 601 kg/hr (1,326 lb/hr)	1	0
18	CO_2 Compressor	Integrally geared, multi-stage centrifugal	9.0 m^3/min @ 15.3 MPa, 82°C (335 acfm @ 2,217 psia, 180°F)	2	0
19	CO_2 Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 103 GJ/hr (97 MMBtu/hr)	1	0

Case B11B.95 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.4 m (21 ft) diameter	1	0

Case B11B.95 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	815 MW 16.5 MPa/566°C/566°C (2,400 psig/1,050°F/1,050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	910 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,500 GJ/hr (2,370 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0

Case B11B.95 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	994,000 lpm @ 30 m (262,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 5,540 GJ/hr (5,250 MMBtu/hr) heat duty	1	0

Case B11B.95 – Account 10: Ash and Spent Sorbent Handling System

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	–	6.4 tonne/hr (7.1 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	26 m^3/min @ 0.2 MPa (920 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,710 tonne (1,890 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	160 tonne/hr (180 tph)	1	0

Case B11B.95 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 760 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 29 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 56 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 20 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.95 – 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

3.2.14 Case B11B.95 – Cost Estimating

The cost estimating methodology is described in Section 2.7. Exhibit 3-58 shows a detailed breakdown of the capital costs; Exhibit 3-59 shows the owner's costs, TOC, and TASC; Exhibit 3-60 shows the initial and annual O&M costs; and Exhibit 3-61 shows the COE breakdown.

For PC cases, existing costs were escalated to reflect a 2023-year dollar using the methodology outlined in NETL's current QGESS (NETL, 2025a).

The estimated TPC of the SubC PC boiler with CO_2 capture is $4,258/kW. Process contingency represents 2.7 percent of the TPC and project contingency represents 13.9 percent of the TPC. The FY COE, including T&S costs of $10.3/MWh, is $146.3/MWh. The LCOE, including T&S costs of $13.7/MWh, is $156.9/MWh.

Exhibit 3-58. Case B11B.95 total plant cost details

Case:	B11B.95 – Subcritical PC with 95 Percent CO_2 Capture					Estimate Type:	Conceptual			
Plant Size (MW, net):	650					Cost Base:	Jan 2023			
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
1	Coal & Sorbent Handling										
1.1	Coal Receive & Unload	$1,659	$0	$580	$0	$2,239	$392	$0	$395	$3,025	$5
1.2	Coal Stackout & Reclaim	$5,446	$0	$945	$0	$6,390	$1,118	$0	$1,126	$8,635	$13
1.3	Coal Conveyors	$50,174	$0	$9,257	$0	$59,430	$10,400	$0	$10,475	$80,305	$123
1.4	Other Coal Handling	$6,974	$0	$1,139	$0	$8,113	$1,420	$0	$1,430	$10,963	$17
1.5	Sorbent Receive & Unload	$320	$0	$73	$0	$393	$69	$0	$69	$531	$1
1.6	Sorbent Stackout & Reclaim	$2,335	$0	$328	$0	$2,663	$466	$0	$469	$3,598	$6
1.7	Sorbent Conveyors	$3,539	$738	$665	$0	$4,942	$865	$0	$871	$6,678	$10
1.8	Other Sorbent Handling	$170	$38	$68	$0	$277	$48	$0	$49	$374	$1
1.9	Coal & Sorbent Handling Foundations	$0	$2,087	$2,226	$0	$4,313	$755	$0	$760	$5,828	$9
	Subtotal	**$70,616**	**$2,864**	**$15,280**	**$0**	**$88,760**	**$15,533**	**$0**	**$15,644**	**$119,936**	**$184**
2	Coal & Sorbent Preparation & Feed										
2.1	Coal Crushing & Drying	$3,573	$0	$533	$0	$4,106	$719	$0	$724	$5,548	$9
2.2	Prepared Coal Storage & Feed	$12,028	$0	$2,010	$0	$14,038	$2,457	$0	$2,474	$18,968	$29
2.5	Sorbent Preparation Equipment	$1,573	$65	$250	$0	$1,888	$330	$0	$333	$2,551	$4
2.6	Sorbent Storage & Feed	$2,633	$0	$774	$0	$3,407	$596	$0	$600	$4,603	$7
2.9	Coal & Sorbent Feed Foundation	$0	$1,001	$710	$0	$1,712	$300	$0	$302	$2,313	$4
	Subtotal	**$19,807**	**$1,067**	**$4,277**	**$0**	**$25,150**	**$4,401**	**$0**	**$4,433**	**$33,984**	**$52**
3	Feedwater & Miscellaneous BOP Systems										
3.1	Feedwater System	$5,396	$8,914	$3,605	$0	$17,914	$3,135	$0	$3,157	$24,206	$37
3.2	Water Makeup & Pretreating	$11,411	$1,100	$5,040	$0	$17,550	$3,071	$0	$4,124	$24,746	$38
3.3	Other Feedwater Subsystems	$4,201	$1,327	$1,020	$0	$6,549	$1,146	$0	$1,154	$8,849	$14
3.4	Service Water Systems	$3,635	$6,687	$17,512	$0	$27,834	$4,871	$0	$6,541	$39,246	$60
3.5	Other Boiler Plant Systems	$993	$363	$734	$0	$2,089	$366	$0	$368	$2,823	$4
3.6	Natural Gas Pipeline and Start-Up System	$5,196	$200	$121	$0	$5,517	$965	$0	$972	$7,455	$11
3.7	Waste Water Treatment Equipment	$18,941	$0	$9,048	$0	$27,989	$4,898	$0	$6,577	$39,464	$61
3.8	Spray Dryer Evaporator	$23,807	$0	$10,741	$0	$34,549	$6,046	$0	$8,119	$48,714	$75
3.9	Miscellaneous Plant Equipment	$275	$35	$109	$0	$418	$73	$0	$98	$590	$1
	Subtotal	**$73,855**	**$18,625**	**$47,929**	**$0**	**$140,409**	**$24,572**	**$0**	**$31,112**	**$196,092**	**$302**
4	Pulverized Coal Boiler & Accessories										
4.9	Pulverized Coal Boiler & Accessories	$298,577	$0	$158,419	$0	$456,996	$79,974	$0	$80,545	$617,515	$949
4.10	Selective Catalytic Reduction System	$40,647	$0	$20,673	$0	$61,320	$10,731	$0	$10,808	$82,858	$127
4.11	Boiler Balance of Plant	$2,091	$0	$1,109	$0	$3,200	$560	$0	$564	$4,324	$7
4.12	Primary Air System	$2,368	$0	$1,156	$0	$3,524	$617	$0	$621	$4,762	$7
4.13	Secondary Air System	$3,586	$0	$1,752	$0	$5,338	$934	$0	$941	$7,213	$11
4.14	Induced Draft Fans	$7,736	$0	$3,778	$0	$11,515	$2,015	$0	$2,029	$15,559	$24
4.15	Major Component Rigging	$124	$0	$63	$0	$187	$33	$0	$33	$253	$0
4.16	Boiler Foundations	$0	$543	$386	$0	$928	$162	$0	$164	$1,255	$2

Case:	B11B.95 – Subcritical PC with 95 Percent CO_2 Capture					Estimate Type:	Conceptual			
Plant Size (MW, net):	650					Cost Base:	Jan 2023			
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
	Subtotal	**$355,129**	**$543**	**$187,336**	**$0**	**$543,008**	**$95,026**	**$0**	**$95,705**	**$733,740**	**$1,128**
5	**Flue Gas Cleanup**										
5.1	CANSOLV CO_2 Removal System	$194,767	$86,461	$161,055	$0	$442,283	$77,400	$75,188	$104,102	$698,973	$1,075
5.2	Wet FGD Absorber Vessels & Accessories	$103,748	$0	$18,733	$0	$122,481	$21,434	$0	$21,587	$165,503	$254
5.3	Other FGD	$1,658	$0	$1,077	$0	$2,734	$478	$0	$482	$3,695	$6
5.4	CO_2 Compression & Drying	$61,421	$8,964	$15,913	$0	$86,299	$15,102	$0	$20,280	$121,682	$187
5.5	CO_2 Compressor Aftercooler	$688	$106	$232	$0	$1,026	$180	$0	$241	$1,447	$2
5.6	Mercury Removal (DSI/ACI)	$3,483	$800	$2,891	$0	$7,174	$1,255	$0	$1,264	$9,693	$15
5.9	Particulate Removal (Bag House & Accessories)	w/ 5.2	w/ 5.2	w/ 5.2	w/ 5.2	$0	$0	$0	$0	$0	$0
5.12	Gas Cleanup Foundations	$0	$270	$192	$0	$462	$81	$0	$81	$624	$1
5.13	Gypsum Dewatering System	$1,071	$0	$141	$0	$1,212	$212	$0	$214	$1,637	$3
	Subtotal	**$366,836**	**$96,602**	**$200,232**	**$0**	**$663,671**	**$116,142**	**$75,188**	**$148,252**	**$1,003,253**	**$1,543**
7	**Ductwork & Stack**										
7.3	Ductwork	$0	$990	$557	$0	$1,547	$271	$0	$273	$2,090	$3
7.4	Stack	$11,906	$0	$5,416	$0	$17,323	$3,031	$0	$3,053	$23,407	$36
7.5	Duct & Stack Foundations	$0	$275	$264	$0	$538	$94	$0	$126	$759	$1
	Subtotal	**$11,906**	**$1,265**	**$6,237**	**$0**	**$19,408**	**$3,396**	**$0**	**$3,452**	**$26,257**	**$40**
8	**Steam Turbine & Accessories**										
8.1	Steam Turbine Generator & Accessories	$78,128	$0	$7,861	$0	$85,989	$15,048	$0	$15,156	$116,193	$179
8.2	Steam Turbine Plant Auxiliaries	$1,781	$0	$3,325	$0	$5,106	$894	$0	$900	$6,899	$11
8.3	Condenser & Auxiliaries	$16,578	$0	$4,479	$0	$21,057	$3,685	$0	$3,711	$28,453	$44
8.4	Steam Piping	$57,366	$0	$16,438	$0	$73,803	$12,916	$0	$13,008	$99,727	$153
8.5	Turbine Generator Foundations	$0	$302	$403	$0	$705	$123	$0	$166	$993	$2
	Subtotal	**$153,852**	**$302**	**$32,507**	**$0**	**$186,660**	**$32,665**	**$0**	**$32,940**	**$252,266**	**$388**
9	**Cooling Water System**										
9.1	Cooling Towers	$27,614	$0	$6,685	$0	$34,299	$6,002	$0	$6,045	$46,346	$71
9.2	Circulating Water Pumps	$3,923	$0	$218	$0	$4,141	$725	$0	$730	$5,595	$9
9.3	Circulating Water System Auxiliaries	$22,968	$0	$2,368	$0	$25,337	$4,434	$0	$4,466	$34,236	$53
9.4	Circulating Water Piping	$0	$10,235	$7,497	$0	$17,732	$3,103	$0	$3,125	$23,960	$37
9.5	Make-up Water System	$1,776	$0	$1,778	$0	$3,554	$622	$0	$626	$4,802	$7
9.6	Component Cooling Water System	$1,528	$0	$990	$0	$2,518	$441	$0	$444	$3,402	$5
9.7	Circulating Water System Foundations	$0	$950	$1,276	$0	$2,227	$390	$0	$523	$3,140	$5
	Subtotal	**$57,809**	**$11,186**	**$20,812**	**$0**	**$89,807**	**$15,716**	**$0**	**$15,959**	**$121,482**	**$187**
10	**Ash & Spent Sorbent Handling Systems**										
10.6	Ash Storage Silos	$1,646	$0	$3,908	$0	$5,554	$972	$0	$979	$7,505	$12
10.7	Ash Transport & Feed Equipment	$5,600	$0	$4,308	$0	$9,908	$1,734	$0	$1,746	$13,388	$21
10.9	Ash/Spent Sorbent Foundation	$0	$1,101	$1,096	$0	$2,197	$385	$0	$516	$3,098	$5
	Subtotal	**$7,246**	**$1,101**	**$9,312**	**$0**	**$17,659**	**$3,090**	**$0**	**$3,242**	**$23,991**	**$37**

Case:	B11B.95 – Subcritical PC with 95 Percent CO_2 Capture								Estimate Type:	Conceptual
Plant Size (MW, net):	650								Cost Base:	Jan 2023
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	Accessory Electric Plant										
11.1	Generator Equipment	$3,849	$0	$2,131	$0	$5,980	$1,046	$0	$1,054	$8,080	$12
11.2	Station Service Equipment	$11,230	$0	$707	$0	$11,937	$2,089	$0	$2,104	$16,130	$25
11.3	Switchgear & Motor Control	$17,433	$0	$2,220	$0	$19,653	$3,439	$0	$3,464	$26,556	$41
11.4	Conduit & Cable Tray	$0	$2,057	$4,793	$0	$6,850	$1,199	$0	$1,207	$9,256	$14
11.5	Wire & Cable	$0	$5,446	$7,873	$0	$13,320	$2,331	$0	$2,348	$17,999	$28
11.6	Protective Equipment	$79	$0	$201	$0	$280	$49	$0	$49	$378	$1
11.7	Standby Equipment	$1,190	$0	$806	$0	$1,996	$349	$0	$352	$2,697	$4
11.8	Main Power Transformers	$10,108	$0	$151	$0	$10,259	$1,795	$0	$1,808	$13,863	$21
11.9	Electrical Foundations	$0	$291	$599	$0	$891	$156	$0	$209	$1,256	$2
	Subtotal	**$43,889**	**$7,795**	**$19,483**	**$0**	**$71,166**	**$12,454**	**$0**	**$12,595**	**$96,215**	**$148**
12	Instrumentation & Control										
12.1	Pulverized Coal Boiler Control Equipment	$1,086	$0	$153	$0	$1,239	$217	$0	$218	$1,674	$3
12.3	Steam Turbine Control Equipment	$971	$0	$88	$0	$1,058	$185	$0	$187	$1,430	$2
12.5	Signal Processing Equipment	$1,233	$0	$173	$0	$1,407	$246	$0	$248	$1,901	$3
12.6	Control Boards, Panels, & Racks	$377	$0	$182	$0	$559	$98	$28	$103	$787	$1
12.7	Distributed Control System Equipment	$10,643	$0	$1,497	$0	$12,140	$2,124	$607	$2,231	$17,102	$26
12.8	Instrument Wiring & Tubing	$745	$581	$1,880	$0	$3,207	$561	$160	$589	$4,518	$7
12.9	Other Instrumentation & Controls Equipment	$916	$0	$1,673	$0	$2,589	$453	$129	$476	$3,647	$6
	Subtotal	**$15,972**	**$581**	**$5,645**	**$0**	**$22,198**	**$3,885**	**$925**	**$4,051**	**$31,059**	**$48**
13	Improvements to Site										
13.1	Site Preparation	$0	$601	$10,329	$0	$10,929	$1,913	$0	$2,568	$15,411	$24
13.2	Site Improvements	$0	$2,974	$3,178	$0	$6,153	$1,077	$0	$1,446	$8,675	$13
13.3	Site Facilities	$3,456	$0	$2,884	$0	$6,339	$1,109	$0	$1,490	$8,939	$14
	Subtotal	**$3,456**	**$3,575**	**$16,391**	**$0**	**$23,421**	**$4,099**	**$0**	**$5,504**	**$33,024**	**$51**
14	Buildings & Structures										
14.2	Boiler Building	$0	$15,100	$10,732	$0	$25,832	$4,521	$0	$4,553	$34,906	$54
14.3	Steam Turbine Building	$0	$20,989	$15,809	$0	$36,798	$6,440	$0	$6,486	$49,723	$76
14.4	Administration Building	$0	$1,363	$1,166	$0	$2,529	$443	$0	$446	$3,418	$5
14.5	Circulation Water Pumphouse	$0	$253	$162	$0	$415	$73	$0	$73	$561	$1
14.6	Water Treatment Buildings	$0	$636	$469	$0	$1,105	$193	$0	$195	$1,493	$2
14.7	Machine Shop	$0	$720	$391	$0	$1,111	$194	$0	$196	$1,501	$2
14.8	Warehouse	$0	$541	$438	$0	$979	$171	$0	$173	$1,323	$2
14.9	Other Buildings & Structures	$0	$379	$261	$0	$641	$112	$0	$113	$866	$1
14.10	Waste Treating Building & Structures	$0	$841	$2,064	$0	$2,904	$508	$0	$512	$3,924	$6
	Subtotal	**$0**	**$40,821**	**$31,493**	**$0**	**$72,314**	**$12,655**	**$0**	**$12,745**	**$97,715**	**$150**
	Total	**$1,180,372**	**$186,327**	**$596,932**	**$0**	**$1,963,631**	**$343,635**	**$76,113**	**$385,635**	**$2,769,015**	**$4,258**

Exhibit 3-59. Case B11B.95 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$16,312	$25
1 Month Maintenance Materials	$2,606	$4
1 Month Non-fuel Consumables	$4,276	$7
1 Month Waste Disposal	$1,413	$2
25% of 1 Months Fuel Cost at 100% CF	$4,112	$6
2% of TPC	$55,380	$85
Total	**$84,099**	**$129**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$40,061	$62
0.5% of TPC (spare parts)	$13,845	$21
Total	**$53,906**	**$83**
Other Costs		
Initial Cost for Catalyst and Chemicals	$6,475	$10
Land	$1,800	$3
Other Owner's Costs	$415,352	$639
Financing Costs	$74,763	$115
Total Overnight Costs (TOC)	**$3,405,410**	**$5,236**
TASC Multiplier (IOU, 33 year)	1.213	
Total As-Spent Cost (TASC)	**$4,129,833**	**$6,350**

Exhibit 3-60. Case B11B.95 initial and annual operating and maintenance costs

Case:	B11B.95 – Subcritical PC with 95 Percent CO_2 Capture				Cost Base:	Jan 2023
Plant Size (MW, net):	650	Heat Rate-net (Btu/kWh):	11,495		Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		45.04	**$/hour**	Skilled Operator:		2.0
Operating Labor Burden:		30.00	**% of base**	Operator:		11.3
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		2.0
				Total:		16.3
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$8,377,366	$12.881
Maintenance Labor:					$17,721,693	$27.249
Administrative & Support Labor:					$6,524,765	$10.033
Property Taxes and Insurance:					$55,380,290	$85.153
Total:					**$88,004,114**	**$135.316**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$26,582,539	$5.489
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	7,349	$2.30	$0	$5,244,244	$1.083
Makeup and Waste Water Treatment Chemicals (ton):	0	21.9	$660.00	$0	$4,482,796	$0.926
Brominated Activated Carbon (ton):	0	1.68	$2,547.97	$0	$1,330,011	$0.275
Enhanced Hydrated Lime (ton):	0	42.3	$391.63	$0	$5,143,474	$1.062
Limestone (ton):	0	744	$30.18	$0	$6,965,164	$1.438
Ammonia (19 wt%, ton):	0	74.4	$280.00	$0	$6,460,237	$1.334
SCR Catalyst (ft^3):	18,499	16.9	$350.00	$6,474,564	$1,834,460	$0.379
CO_2 Capture System Chemicals[A]:	Proprietary				$11,976,713	$2.473
Triethylene Glycol (gal):	w/equip.	67	$8.50	$0	$177,088	$0.037
Subtotal:				**$6,474,564**	**$43,614,188**	**$9.006**
Waste Disposal						
Fly Ash (ton):	0	698	$46.71	$0	$10,112,442	$2.088
Bottom Ash (ton):	0	155	$46.71	$0	$2,246,243	$0.464
SCR Catalyst (ft^3):	0	16.9	$5.70	$0	$29,875	$0.006
Triethylene Glycol (gal):	0	3,410	$1.30	$0	$1,375,509	$0.284
Thermal Reclaimer Unit Waste (ton):	0	8.35	$250.00	$0	$647,468	$0.134
Subtotal:				**$0**	**$14,411,537**	**$2.976**
By-Products						
Gypsum (ton):	0	1131	$0.00	$0	$0	$0.000
Subtotal:				**$0**	**$0**	**$0.000**
Variable Operating Costs Total:				**$6,474,564**	**$84,608,265**	**$17.472**
Fuel Cost						
Illinois Number 6 (ton):	0	7,690	$70.32	$0	$167,774,279	$34.646
Total:				**$0**	**$167,774,279**	**$34.646**

[A]CO_2 Capture System Chemicals includes NaOH and CANSOLV Solvent

Exhibit 3-61. Case B11B.95 COE breakdown

	FY COE		LCOE	
Component	**Value, $/MWh**	**Percentage**	**Value, $/MWh**	**Percentage**
Capital	65.7	45%	65.7	42%
Fixed	18.2	12%	24.3	15%
Variable	17.5	12%	23.3	15%
Fuel	34.6	24%	29.9	19%
Total (Excluding T&S)	**136.0**	**N/A**	**143.2**	**N/A**
CO_2 T&S	10.3	7%	13.7	9%
Total (Including T&S)	**146.3**	**N/A**	**156.9**	**N/A**

3.3 SUPERCRITICAL PC CASES

This section contains an evaluation of plant designs for cases B12A, B12B.90, and B12B.95, which are based on a SC PC plant with a nominal net output of 650 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 three plants is that cases B12B.90 and B12B.95 include CO_2 capture while Case B12A does not.

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

- Key Assumptions for SC PC cases
- Sparing Philosophy for SC PC cases
- Process Description for Case B12A
- Performance Results for Case B12A
- Major Equipment List for Case B12A
- Cost Estimating for Case B12A
- Process Description, Performance Results, Major Equipment List, and Cost Estimating for cases B12B.90 and B12B.95

3.3.1 Key System Assumptions

System assumptions for cases B12A, B12B.90, and B12B.95, SC PC with and without CO_2 capture, are compiled in Exhibit 3-62.

Exhibit 3-62. SC PC plant study configuration matrix

	Case B12A w/o CO_2 Capture	Case B12B.90 w/ CO_2 Capture	Case B12B.95 w/ CO_2 Capture
Steam Cycle, MPa/°C/°C (psig/°F/°F)	24.1/593/593 (3,500/1,100/1,100)		
Coal	Illinois No. 6		
Condenser Pressure, mm Hg (in. Hg)	50.8 (2.0)		
Boiler Efficiency, HHV %	88.0		
Carbon Conversion, %	99.4		
Cooling Water to Condenser, °C (°F)	16 (60)		
Cooling Water from Condenser, °C (°F)	27 (80)		
Stack Temperature, °C (°F)	57 (135)	45 (113)	
SO_2 Control	Wet Limestone Forced Oxidation		
FGD Efficiency, %[A]	98	98[B, C]	
FGD Blowdown Treatment (Effluent Limitation Guidelines)	Spray dryer evaporator		
NOx Control	LNB w/OFA, SCR		
SCR Efficiency, %[A]	75.1	78.2	78.4
Ammonia Slip (end of catalyst life), ppmv	2		
Particulate Control	Fabric Filter		
Fabric Filter efficiency, %[A]	99.9		
Ash Distribution, Fly/Bottom, %	80/20		
SO_3 Control	DSI		
Mercury Control	Co-benefit Capture and ACI		
CO_2 Control	N/A	CANSOLV	
Overall Carbon Capture, %[A]	N/A	90	95
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 (0.37 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

3.3.1.1 Balance of Plant

The balance of plant assumptions are common to all PC cases and are presented in Exhibit 3-16.

3.3.2 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 SC PC boiler (1 x 100 percent)
- Two SCR reactors (2 x 50 percent)
- One DSI system (1 x 100 percent)
- One ACI system (1 x 100 percent)
- Two single-stage, in-line, multi-compartment fabric filters (2 x 50 percent)
- One wet limestone forced oxidation positive pressure absorber (1 x 100 percent)
- One steam turbine (1 x 100 percent)
- For case B12B.90 and B12B.95, one CO_2 absorption system, consisting of an absorber, stripper, and ancillary equipment (1 x 100 percent) and two CO_2 compression systems (2 x 50 percent)

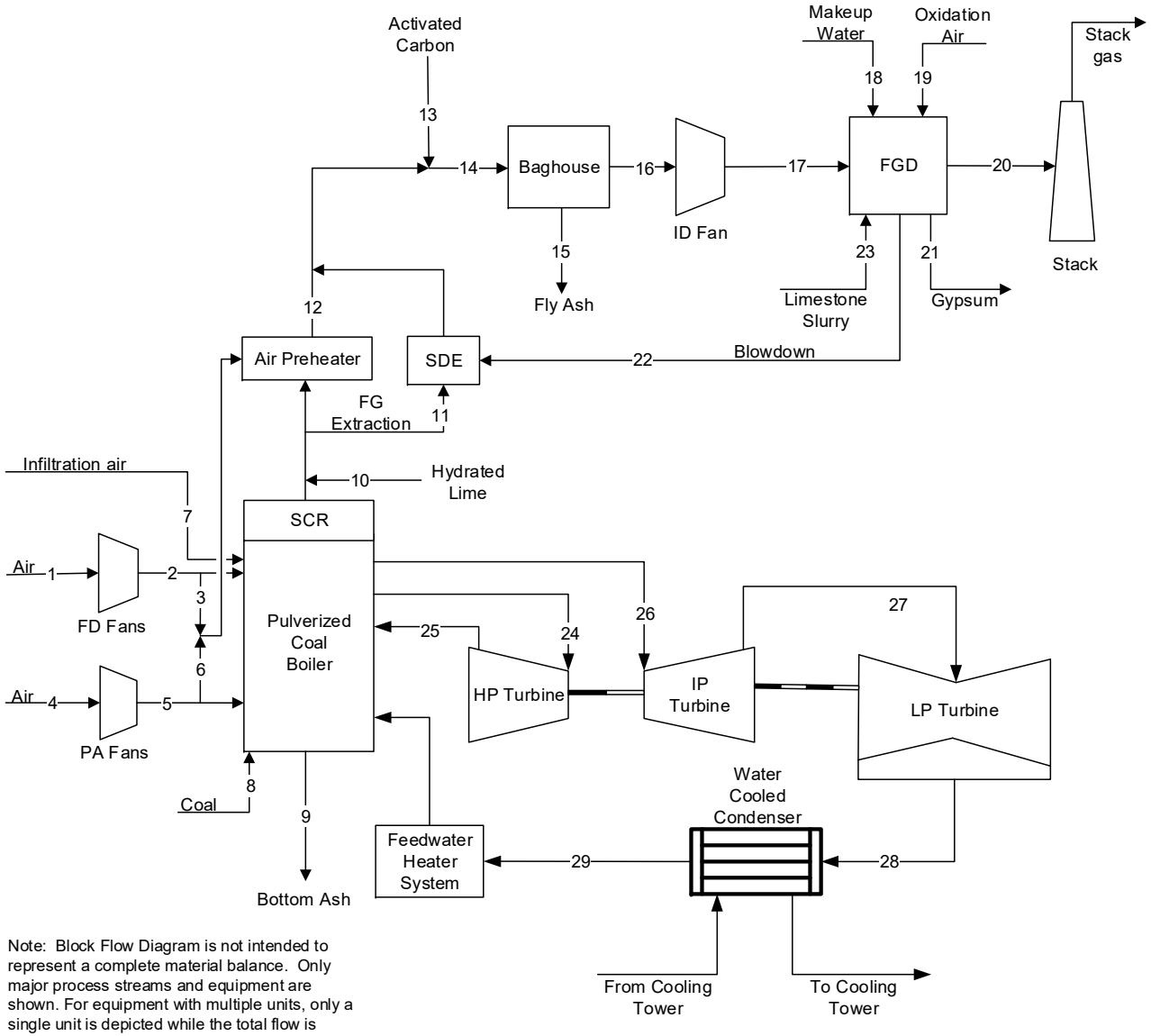
3.3.3 Case B12A – SC PC Without CO_2 Capture Process Description

In this section, the SC PC process without CO_2 capture is described. The system description is nearly identical to the SubC PC case without CO_2 capture but is repeated here for completeness. The description follows the BFD in Exhibit 3-63 and stream numbers reference the same exhibit. Exhibit 3-64 provides 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. A small flue gas stream is extracted for use in the SDE (stream 11). The flue gas then passes through the combustion air preheater (where the air preheater leakages are introduced) and is cooled to 143°C (289°F) (stream 12) before PAC is injected (stream 13) for mercury reduction. The flue gas then passes through a fabric filter for particulate removal (stream 16). An ID fan provides the motive force for the flue gas (stream 17) to pass through the FGD unit and the plant stack. FGD inputs and outputs include makeup water (stream 18), oxidation air (stream 19), limestone slurry (stream 23), and product gypsum (stream 21). The clean, saturated flue gas exiting the FGD unit (stream 20) passes to the plant stack and is discharged to the atmosphere. The FGD blowdown (stream 22) is sent to the SDE where extracted flue gas (stream 11) is used to evaporate the FGD blowdown stream. The SDE outlet gas stream is recombined into the flue gas path after the air preheater, and before PAC injection.

Exhibit 3-63. Case B12A BFD, SC 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. For equipment with multiple units, only a single unit is depicted while the total flow is reported.

Exhibit 3-64. Case B12A stream table, SC unit without CO_2 capture

	1	2	3	4	5	6	7	8	9	10	11	12
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	0.0087	0.0088
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1457	0.1379
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	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000	0.0879	0.0837
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7318	0.7340
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0237	0.0336
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0020
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	58,499	58,499	1,733	17,970	17,970	2,473	1,293	0	0	1	3,855	78,199
V-L Flowrate (kg/hr)	1,688,112	1,688,112	50,000	518,570	518,570	71,368	37,313	0	0	12	114,649	2,322,076
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	214,574	4,326	1,169	926	17,774
Temperature (°C)	15	17	17	15	24	24	15	15	1,316	15	385	143
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg)[A]	30.23	32.49	32.49	30.23	38.98	38.98	30.23	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-95.31	-95.31	-97.58	-88.83	-88.83	-97.58	-2,119.02	1,267.06	-13,402.95	-2,261.17	-2,394.31
Density (kg/m^3)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	1,003.6	0.5	0.8
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015	29.742	29.694
V-L Flowrate (lb_{mol}/hr)	128,969	128,969	3,820	39,618	39,618	5,452	2,851	0	0	1	8,498	172,400
V-L Flowrate (lb/hr)	3,721,650	3,721,650	110,230	1,143,252	1,143,252	157,339	82,262	0	0	26	252,758	5,119,302
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	473,055	9,536	2,578	2,041	39,186
Temperature (°F)	59	63	63	59	75	75	59	59	2,400	59	726	289
Pressure (psia)	14.7	15.0	15.0	14.7	15.9	15.9	14.7	14.7	14.3	14.7	14.3	14.1
Steam Table Enthalpy (Btu/lb)[A]	13.0	14.0	14.0	13.0	16.8	16.8	13.0	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-41.0	-41.0	-42.0	-38.2	-38.2	-42.0	-911.0	544.7	-5,762.2	-972.1	-1,029.4
Density (lb/ft^3)	0.076	0.077	0.077	0.076	0.080	0.080	0.076	---	---	62.650	0.033	0.052

[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 3-64. Case B12A stream table, SC unit without CO2 capture (continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.1372	0.0000	0.1372	0.1372	0.0000	0.0003	0.1245	0.0001	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	0.0000	0.0911	0.0000	0.0911	0.0911	0.9999	0.0099	0.1508	0.9998	0.9943	0.9999	1.0000
HCl	0.0000	0.0001	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.7281	0.0000	0.7281	0.7281	0.0000	0.7732	0.6803	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0329	0.0000	0.0329	0.0329	0.0000	0.2074	0.0363	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0020	0.0000	0.0020	0.0020	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.1158	0.0000	0.0000	0.0001	0.0000	0.0000	0.0001	0.0009	0.0001	0.0000
$CaCl_2$	0.0000	0.0001	0.8842	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0048	0.0000	0.0000
Total	0.0000	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_{mol}/hr)	0	82,707	5	82,702	82,702	4,832	3,462	92,454	195	653	2,691	104,862
V-L Flowrate (kg/hr)	0	2,448,804	529	2,448,262	2,448,262	87,072	99,902	2,657,150	3,507	12,079	48,487	1,889,118
Solids Flowrate (kg/hr)	47	18,931	18,944	0	0	0	0	0	31,549	184	20,757	0
Temperature (°C)	15	143	143	143	156	15	15	57	15	57	15	593
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	24.23
Steam Table Enthalpy (kJ/kg)[A]	---	---	---	287.58	302.09	-47.80	30.23	297.00	---	---	---	3,477.96
AspenPlus Enthalpy (kJ/kg)[B]	-6.79	-2,453.14	-1,066.10	-2,464.17	-2,449.66	-16,015.01	-97.58	-2,939.24	-12,513.34	-15,496.00	-14,994.25	-12,502.33
Density (kg/m^3)	---	0.8	2,150.2	0.8	0.9	1,003.7	1.2	1.1	878.3	979.5	1,003.7	69.2
V-L Molecular Weight	---	29.608	104.897	29.603	29.603	18.019	28.857	28.740	18.021	18.495	18.019	18.015
V-L Flowrate (lb_{mol}/hr)	0	182,338	11	182,327	182,327	10,654	7,632	203,826	429	1,440	5,933	231,181
V-L Flowrate (lb/hr)	0	5,398,689	1,167	5,397,494	5,397,494	191,961	220,247	5,858,012	7,732	26,630	106,896	4,164,793
Solids Flowrate (lb/hr)	104	41,736	41,764	0	0	0	0	0	69,555	406	45,761	0
Temperature (°F)	59	289	289	289	313	59	59	135	59	135	59	1,100
Pressure (psia)	14.7	14.1	14.1	13.9	15.3	14.7	14.7	14.8	14.7	14.7	14.7	3,514.7
Steam Table Enthalpy (Btu/lb)[A]	---	---	---	123.6	129.9	-20.5	13.0	127.7	---	---	---	1,495.3
AspenPlus Enthalpy (Btu/lb)[B]	-2.9	-1,054.7	-458.3	-1,059.4	-1,053.2	-6,885.2	-42.0	-1,263.6	-5,379.8	-6,662.1	-6,446.4	-5,375.0
Density (lb/ft^3)	---	0.052	134.232	0.051	0.055	62.658	0.076	0.067	54.833	61.145	62.658	4.319

[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 3-64. Case B12A stream table, SC unit without CO2 capture (continued)

	25	26	27	28	29
V-L Mole Fraction					
Ar	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	87,665	87,665	75,546	57,259	75,757
V-L Flowrate (kg/hr)	1,579,312	1,579,312	1,360,986	1,031,543	1,364,788
Solids Flowrate (kg/hr)	0	0	0	0	0
Temperature (°C)	342	593	270	38	39
Pressure (MPa, abs)	4.90	4.80	0.52	0.01	1.32
Steam Table Enthalpy (kJ/kg)[A]	3,049.81	3,652.36	3,000.14	2,343.61	162.43
AspenPlus Enthalpy (kJ/kg)[B]	-12,930.48	-12,327.93	-12,980.15	-13,636.69	-15,817.87
Density (kg/m^3)	19.2	12.3	2.1	0.1	993.3
V-L Molecular Weight	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	193,269	193,269	166,551	126,235	167,016
V-L Flowrate (lb/hr)	3,481,788	3,481,788	3,000,461	2,274,164	3,008,843
Solids Flowrate (lb/hr)	0	0	0	0	0
Temperature (°F)	648	1,100	517	101	101
Pressure (psia)	710.8	696.6	75.0	1.0	190.7
Steam Table Enthalpy (Btu/lb)[A]	1,311.2	1,570.2	1,289.8	1,007.6	69.8
AspenPlus Enthalpy (Btu/lb)[B]	-5,559.1	-5,300.1	-5,580.5	-5,862.7	-6,800.5
Density (lb/ft^3)	1.197	0.768	0.131	0.003	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

3.3.4 Case B12A – Performance Results

The plant produces a net output of 650 MWe at a net plant efficiency of 40.2 percent (HHV basis). Overall performance for the plant is summarized in Exhibit 3-65; Exhibit 3-66 provides a detailed breakdown of the auxiliary power requirements.

Exhibit 3-65. Case B12A plant performance summary

Performance Summary	
Total Gross Power, MWe	**686**
CO_2 Capture/Removal Auxiliaries, kWe	–
CO_2 Compression, kWe	–
Balance of Plant, kWe	35,950
Total Auxiliaries, MWe	**36**
Net Power, MWe	**650**
HHV Net Plant Efficiency, %	40.2
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,957 (8,490)
LHV Net Plant Efficiency, %	41.7
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,639 (8,188)
HHV Boiler Efficiency, %	88.0
LHV Boiler Efficiency, %	91.3
Steam Turbine Cycle Efficiency, %	48.2
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,471 (7,081)
Condenser Duty, GJ/hr (MMBtu/hr)	2,592 (2,457)
CO_2 Capture Rate, %	–
AGR Duty, GJ/hr (MMBtu/hr)	–
As-Received Coal Feed, kg/hr (lb/hr)	214,574 (473,055)
Limestone Sorbent Feed, kg/hr (lb/hr)	20,757 (45,761)
HHV Thermal Input, kWt	1,617,359
LHV Thermal Input, kWt	1,559,963
Raw Water Withdrawal, (m^3/min)/MWnet (gpm/MWnet)	0.035 (9.3)
Raw Water Consumption, (m^3/min)/MWnet (gpm/MWnet)	0.028 (7.4)
Excess Air, %	20.3

Exhibit 3-66. Case B12A plant power summary

Power Summary	
Steam Turbine Power, MWe	686
Total Gross Power, MWe	**686**
Auxiliary Load Summary	
Activated Carbon Injection, kWe	30
Ash Handling, kWe	700
Baghouse, kWe	90
Circulating Water Pumps, kWe	5,300
CO_2 Capture/Removal Auxiliaries, kWe	–
CO_2 Compression, kWe	–
Coal Handling and Conveying, kWe	470
Condensate Pumps, kWe	660
Cooling Tower Fans, kWe	2,740
Dry Sorbent Injection, kWe	60
Flue Gas Desulfurizer, kWe	3,320
Forced Draft Fans, kWe	1,100
Ground Water Pumps, kWe	500
Induced Draft Fans, kWe	10,230
Miscellaneous Balance of Plant[A,B], kWe	2,250
Primary Air Fans, kWe	1,310
Pulverizers, kWe	3,220
SCR, kWe	30
Sorbent Handling & Reagent Preparation, kWe	1,000
Spray Dryer Evaporator, kWe	240
Steam Turbine Auxiliaries, kWe	500
Transformer Losses, kWe	2,150
Total Auxiliaries, MWe	**36**
Net Power, MWe	**650**

[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 are presented in Section 2.4. A summary of the plant air emissions for Case B12A is presented in Exhibit 3-67. SO_2 emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit 3-67. Case B12A air emissions

	kg/GJ (lb/MMBtu)[A]	tonne/year (ton/year)[B]	kg/MWh (lb/MWh)[C]
SO_2	0.035 (0.081)	1,503 (1,657)	0.294 (0.649)
NOx	0.037 (0.087)	1,622 (1,788)	0.318 (0.700)
Particulate	0.005 (0.011)	209 (230)	0.041 (0.090)
Hg	1.60E-7 (3.73E-7)	0.007 (0.008)	1.36E-6 (3.00E-6)
CO_2	87 (202)	3,771,114 (4,156,942)	738 (1,628)
CO_2[D]	–	–	779 (1,718)
	mg/Nm^3		
Particulate Concentration[E,F]	15.11		

[A]Based on thermal input on an HHV basis
[B]Calculations based on an 85 percent capacity factor
[C]Emissions based on gross power except where otherwise noted
[D]CO_2 emissions based on net power instead of gross power
[E]Concentration of particles in the flue gas after the baghouse
[F]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 boiler emissions are controlled to about 0.15 kg/GJ (0.35 lb/MMBtu) using LNBs and OFA. An SCR unit then further reduces the NOx concentration by 75.1 percent to 0.04 kg/GJ (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 97.1 percent.

CO_2 emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 3-68. 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, 20 percent of the unburned carbon remains in the bottom ash, the remaining unburned carbon is captured in the fabric filter, along with the PAC, and some carbon leaves as gypsum.

Exhibit 3-68. Case B12A carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	136,780 (301,548)	Stack Gas	138,222 (304,727)
Air (CO_2)	319 (703)	FGD Product	162 (358)
PAC	47 (104)	Baghouse	703 (1,551)
FGD Reagent	2,106 (4,643)	Bottom Ash	164 (362)
		CO_2 Product	–
		CO_2 Dryer Vent	–
		CO_2 Knockout	–
Total	**139,252 (306,997)**	**Total**	**139,252 (306,997)**

Exhibit 3-69 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 removed in the baghouse via hydrated lime, and sulfur emitted in the stack gas.

Exhibit 3-69. Case B12A sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	5,378 (11,857)	FGD Product	5,056 (11,147)
		Stack Gas	105 (232)
		Polishing Scrubber and Solvent Reclaiming	–
		Baghouse	217 (478)
Total	**5,378 (11,857)**	**Total**	**5,378 (11,857)**

Water demand, recycle, withdrawal, discharge, and consumption are defined and discussed in Section 2.6. Exhibit 3-70 shows the overall water balance for the plant.

Exhibit 3-70. 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 Process Makeup	1.5 (384)	–	1.5 (384)	–	1.5 (384)
FGD Slurry Water	0.8 (214)		0.8 (214)	–	0.8 (214)
CO_2 Drying	–	–	–	–	–
CO_2 Capture Recovery	–	–	–	–	–

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m³/min (gpm)	m³/min (gpm)	m³/min (gpm)	m³/min (gpm)	m³/min (gpm)
CO_2 Compression KO	–	–	–	–	–
Deaerator Vent	–	–	–	0.1 (17)	-0.1 (-17)
Condenser Makeup	**0.1 (17)**	**–**	**0.1 (17)**	**–**	**0.1 (17)**
BFW Makeup	0.1 (17)	–	0.1 (17)	–	0.1 (17)
Cooling Tower	**21 (5,458)**	**–**	**21 (5,458)**	**4.6 (1,227)**	**16 (4,230)**
BFW Blowdown	–	–	–	–	–
Total	**23 (6,072)**	–	**23 (6,072)**	**4.7 (1,244)**	**18 (4,828)**

3.3.4.2 Energy and Mass Balance Diagrams

Energy and mass balance diagrams are is shown for the Case B12A PC boiler, FGD unit and steam cycle in Exhibit 3-71 and Exhibit 3-72.

An overall plant energy balance is provided in tabular form in Exhibit 3-73. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-65) is calculated by multiplying the power out by a generator efficiency of 98.5 percent.

Exhibit 3-71. Case B12A energy and mass balance, SC PC boiler without CO_2 capture

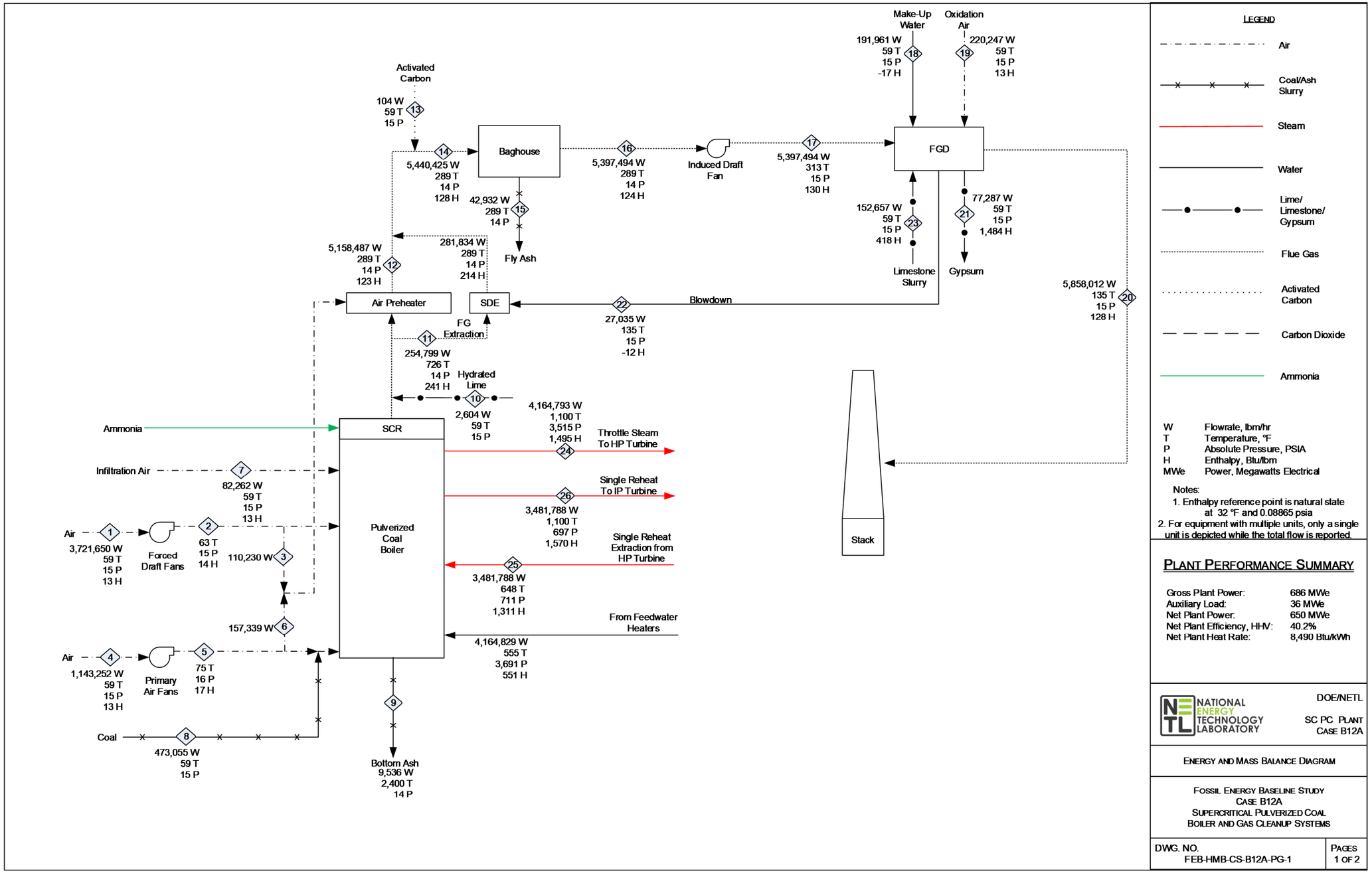


Exhibit 3-72. Case B12A energy and mass balance, SC steam cycle

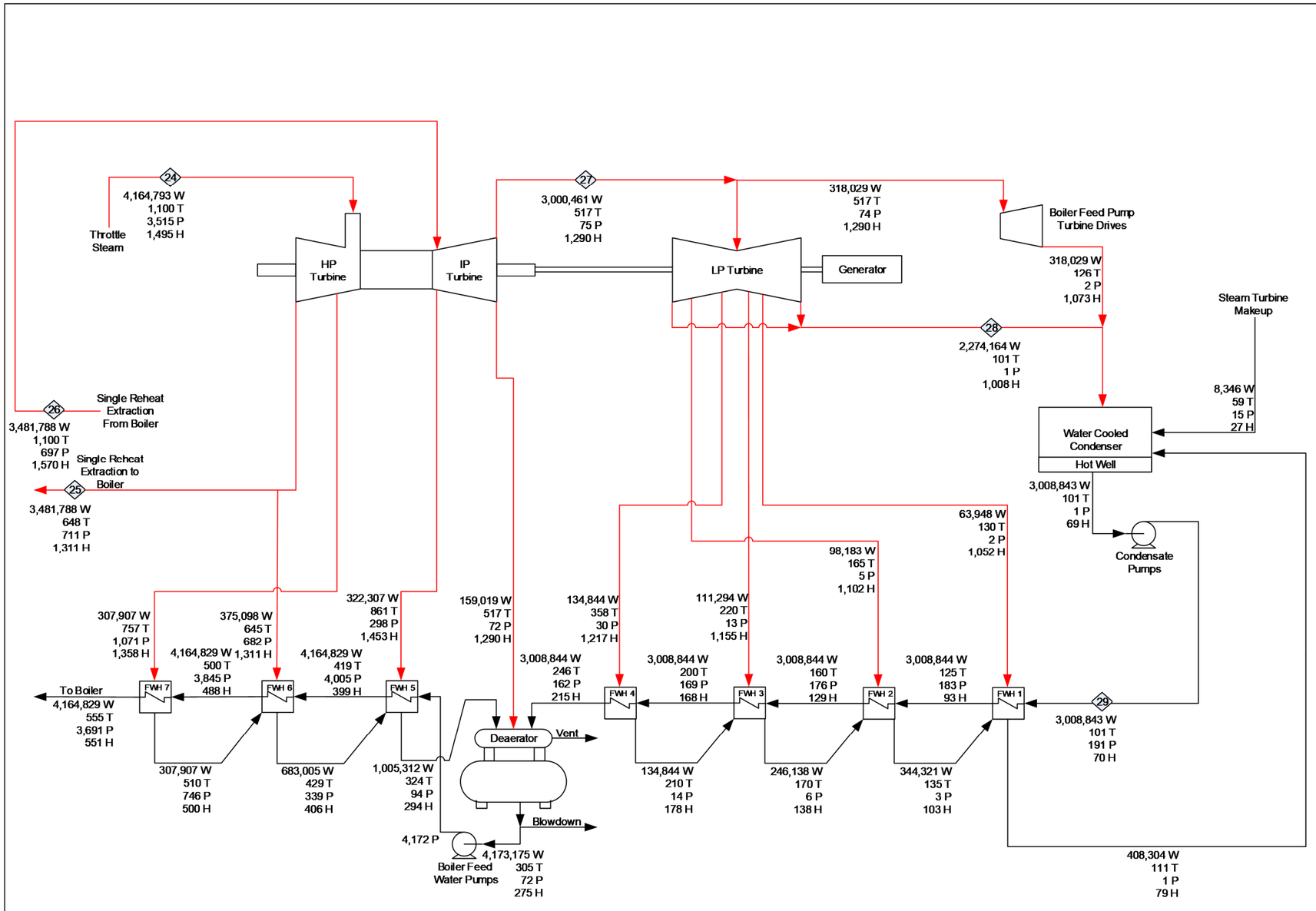


Exhibit 3-73. Case B12A overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, GJ/hr (MMBtu/hr)				
Coal	5,822 (5,519)	4.9 (4.6)	–	5,827 (5,523)
Air	–	68 (64)	–	68 (64)
Raw Water Makeup	–	86 (82)	–	86 (82)
Limestone	–	0.5 (0.4)	–	0.5 (0.4)
Auxiliary Power	–	–	129 (123)	129 (123)
TOTAL	**5,822 (5,519)**	**160 (151)**	**129 (123)**	**6,111 (5,793)**
Heat Out, GJ/hr (MMBtu/hr)				
Bottom Ash	–	5.5 (5.2)	–	5.5 (5.2)
Fly Ash	–	2.0 (1.9)	–	2.0 (1.9)
Stack Gas	–	789 (748)	–	789 (748)
Sulfur	–	–	–	–
Gypsum	–	2.0 (1.9)	–	2.0 (1.9)
Motor Losses and Design Allowances	–	–	40 (38)	40 (38)
Cooling Tower Load[A]	–	2,698 (2,557)	–	2,698 (2,557)
CO_2 Product Stream	–	–	–	–
AGR Effluent	–	–	–	–
Blowdown Streams and Deaerator Vent	–	2.4 (2.3)	–	2.4 (2.3)
Ambient Losses[B]	–	*137 (130)*	–	*137 (130)*
Power	–	–	2,470 (2,341)	2,470 (2,341)
TOTAL	**–**	**3,636 (3,446)**	**2,510 (2,379)**	**6,145 (5,825)**
Unaccounted Energy[C]	–	*-34 (-32)*	–	*-34 (-32)*

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

3.3.5 Case B12A – Major Equipment List

Major equipment items for the SC PC plant without 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. Values reported in the equipment lists are rounded.

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 (50 ton)	2	1
9	Feeder	Vibratory	180 tonne/hr (200 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	350 tonne/hr (390 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	180 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	350 tonne/hr (390 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	350 tonne/hr (390 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	790 tonne (870 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 9 tonne (10 ton) Feeder - 50 kg/hr (110 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 220 tonne (240 ton) Feeder - 1,300 kg/hr (2,860 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	87 tonne/hr (96 tph)	1	0
23	Limestone Conveyor No. 1	Belt	87 tonne/hr (96 tph)	1	0
24	Limestone Reclaim Hopper	N/A	17 tonne (19 ton)	1	0
25	Limestone Reclaim Feeder	Belt	69 tonne/hr (76 tph)	1	0
26	Limestone Conveyor No. 2	Belt	69 tonne/hr (76 tph)	1	0
27	Limestone Day Bin	w/ actuator	274 tonne (302 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	39 tonne/hr (43 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	39 tonne/hr (43 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	23 tonne/hr (25 tph)	1	1
4	Limestone Ball Mill	Rotary	23 tonne/hr (25 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	89,000 liters (23,400 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,460 lpm @ 10m H_2O (390 gpm @ 40 ft H_2O)	1	1
7	Hydrocyclone Classifier	4 active cyclones in a 5-cyclone bank	370 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	494,000 liters (130,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,030 lpm @ 9m H_2O (270 gpm @ 30 ft H_2O)	1	1

Case B12A – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	250,000 liters (66,100 gal)	2	0
2	Condensate Pumps	Vertical canned	12,600 lpm @ 200 m H_2O (3,330 gpm @ 500 ft H_2O)	2	1
3	Deaerator and Storage Tank	Horizontal spray type	1,041,000 kg/hr (2,295,000 lb/hr), 5 min. tank	2	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	17,000 lpm @ 3,500 m H_2O (4,600 gpm @ 11,400 ft H_2O)	2	2
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	5,200 lpm @ 3,500 m H_2O (1,400 gpm @ 11,400 ft H_2O)	2	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	380,000 kg/hr (830,000 lb/hr)	4	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	380,000 kg/hr (830,000 lb/hr)	4	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	380,000 kg/hr (830,000 lb/hr)	4	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	380,000 kg/hr (830,000 lb/hr)	4	0
10	HP Feedwater Heater 5	Horizontal U-tube	1,040,000 kg/hr (2,290,000 lb/hr)	2	0
11	HP Feedwater Heater 6	Horizontal U-tube	1,040,000 kg/hr (2,290,000 lb/hr)	2	0
12	HP Feedwater heater 7	Horizontal U-tube	1,040,000 kg/hr (2,290,000 lb/hr)	2	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	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	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	6,100 lpm @ 20 m H_2O (1,620 gpm @ 60 ft H_2O)	2	1
22	Ground Water Pumps	Stainless steel, single suction	2,460 lpm @ 270 m H_2O (650 gpm @ 880 ft H_2O)	5	1
23	Filtered Water Pumps	Stainless steel, single suction	1,000 lpm @ 50 m H_2O (250 gpm @ 160 ft H_2O)	2	1
24	Filtered Water Tank	Vertical, cylindrical	919,000 liter (242,900 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
27	Process Water Treatment	Spray dryer evaporator	Flue Gas - 1,980 m^3/min (69,800 acfm) @ 385°C (726°F) & 0.1 MPa (14 psia) Blowdown - 110 lpm (30 gpm) @ 19,996 ppmw Cl^-	2	1

Case B12A – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, once-through, wall-fired, low NOx burners, overfire air	2,080,000 kg/hr steam @ 24.1 MPa/593°C/593°C (4,580,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	285,000 kg/hr, 3,900 m^3/min @ 101 cm WG (629,000 lb/hr, 137,400 acfm @ 40 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	928,000 kg/hr, 12,700 m^3/min @ 26 cm WG (2,047,000 lb/hr, 447,000 acfm @ 10 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,347,000 kg/hr, 27,300 m^3/min @ 114 cm WG (2,969,000 lb/hr, 963,000 acfm @ 45 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	2,550,000 kg/hr (5,620,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	90 m^3/min @ 108 cm WG (3,300 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	103,000 liter (27,300 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	20 lpm @ 90 m H_2O (5 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	1,347,000 kg/hr (2,969,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	46,000 m^3/min (1,612,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	159,000 lpm @ 65 m H_2O (42,000 gpm @ 210 ft H_2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	4,380 lpm (1,160 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	750 m^3/min @ 0.3 MPa (26,480 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,100 lpm (290 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	35 tonne/hr (38 tph) of 50 wt% slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	670 lpm @ 13 m H_2O (180 gpm @ 40 ft H_2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	440,000 lpm (120,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	1,600 lpm @ 21 m H_2O (420 gpm @ 70 ft H_2O)	1	1
12	Activated Carbon Injectors	---	50 kg/hr (110 lb/hr)	1	0
13	Hydrated Lime Injectors	---	1,300 kg/hr (2,860 lb/hr)	1	0

Case B12A – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.3 m (21 ft) diameter	1	0

Case B12A – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	722 MW 24.1 MPa/593°C/593°C (3,500 psig/1,100°F/1,100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	800 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,850 GJ/hr (2,700 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	532,000 lpm @ 30 m (141,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 2,970 GJ/hr (2,810 MMBtu/hr) heat duty	1	0

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

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 (5.2 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	19 m^3/min @ 0.2 MPa (679 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,260 tonne (1,390 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	120 tonne/hr (130 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, 760 MVA, 3-ph, 60 Hz	1	0
N/A	N/A	N/A	N/A	N/A	N/A
2	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 32 MVA, 3-ph, 60 Hz	1	1
3	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 6 MVA, 3-ph, 60 Hz	1	1
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
5	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
6	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
7	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 – Cost Estimating

The cost estimating methodology is described in Section 2.7. Exhibit 3-74 shows a detailed breakdown of the capital costs; Exhibit 3-75 shows the owner's costs, TOC, and TASC; Exhibit 3-76 shows the initial and annual O&M costs; and Exhibit 3-77 shows the COE breakdown.

For PC cases, existing costs were escalated to reflect a 2023-year dollar using the methodology outlined in NETL's current QGESS (NETL, 2025a).

The estimated TPC of the SC PC boiler without CO_2 capture is $2,584/kW. No process contingency was included in this case because all elements of the technology are commercially proven. The project contingency is 13.4 percent of the TPC. The FY COE is $86.9/MWh and the LCOE is $90.5/MWh.

Exhibit 3-74. Case B12A total plant cost details

Case:	B12A – Supercritical PC without CO_2 Capture					Estimate Type:	Conceptual			
Plant Size (MW, net):	650					Cost Base:	Jan 2023			
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
1	Coal & Sorbent Handling										
1.1	Coal Receive & Unload	$1,374	$0	$480	$0	$1,855	$325	$0	$327	$2,506	$4
1.2	Coal Stackout & Reclaim	$4,512	$0	$783	$0	$5,295	$927	$0	$933	$7,155	$11
1.3	Coal Conveyors	$41,567	$0	$7,668	$0	$49,236	$8,616	$0	$8,678	$66,530	$102
1.4	Other Coal Handling	$5,780	$0	$942	$0	$6,722	$1,176	$0	$1,185	$9,083	$14
1.5	Sorbent Receive & Unload	$262	$0	$60	$0	$322	$56	$0	$57	$435	$1
1.6	Sorbent Stackout & Reclaim	$1,923	$0	$270	$0	$2,193	$384	$0	$386	$2,963	$5
1.7	Sorbent Conveyors	$2,912	$606	$546	$0	$4,064	$711	$0	$716	$5,492	$8
1.8	Other Sorbent Handling	$140	$32	$56	$0	$228	$40	$0	$40	$308	$0
1.9	Coal & Sorbent Handling Foundations	$0	$1,729	$1,844	$0	$3,573	$625	$0	$630	$4,827	$7
	Subtotal	**$58,471**	**$2,366**	**$12,650**	**$0**	**$73,487**	**$12,860**	**$0**	**$12,952**	**$99,299**	**$153**
2	Coal & Sorbent Preparation & Feed										
2.1	Coal Crushing & Drying	$2,925	$0	$436	$0	$3,361	$588	$0	$592	$4,541	$7
2.2	Prepared Coal Storage & Feed	$9,844	$0	$1,644	$0	$11,488	$2,010	$0	$2,025	$15,523	$24
2.5	Sorbent Preparation Equipment	$1,291	$54	$205	$0	$1,550	$271	$0	$273	$2,094	$3
2.6	Sorbent Storage & Feed	$2,162	$0	$635	$0	$2,797	$489	$0	$493	$3,779	$6
2.9	Coal & Sorbent Feed Foundation	$0	$824	$585	$0	$1,408	$246	$0	$248	$1,903	$3
	Subtotal	**$16,222**	**$877**	**$3,505**	**$0**	**$20,604**	**$3,606**	**$0**	**$3,631**	**$27,840**	**$43**
3	Feedwater & Miscellaneous BOP Systems										
3.1	Feedwater System	$4,552	$7,520	$3,041	$0	$15,113	$2,645	$0	$2,664	$20,422	$31
3.2	Water Makeup & Pretreating	$7,810	$753	$3,449	$0	$12,013	$2,102	$0	$2,823	$16,938	$26
3.3	Other Feedwater Subsystems	$3,389	$1,071	$823	$0	$5,283	$924	$0	$931	$7,138	$11
3.4	Service Water Systems	$2,388	$4,393	$11,505	$0	$18,286	$3,200	$0	$4,297	$25,784	$40
3.5	Other Boiler Plant Systems	$802	$293	$592	$0	$1,686	$295	$0	$297	$2,279	$4
3.6	Natural Gas Pipeline and Start-Up System	$4,332	$167	$101	$0	$4,600	$805	$0	$811	$6,215	$10
3.7	Waste Water Treatment Equipment	$11,019	$0	$5,263	$0	$16,282	$2,849	$0	$3,826	$22,958	$35
3.8	Spray Dryer Evaporator	$19,120	$0	$8,629	$0	$27,749	$4,856	$0	$6,521	$39,126	$60
3.9	Miscellaneous Plant Equipment	$287	$36	$114	$0	$437	$77	$0	$103	$616	$1
	Subtotal	**$53,699**	**$14,233**	**$33,517**	**$0**	**$101,449**	**$17,754**	**$0**	**$22,273**	**$141,476**	**$218**
4	Pulverized Coal Boiler & Accessories										
4.9	Pulverized Coal Boiler & Accessories	$289,428	$0	$133,986	$0	$423,414	$74,097	$0	$74,627	$572,138	$880
4.10	Selective Catalytic Reduction System	$34,656	$0	$15,423	$0	$50,078	$8,764	$0	$8,826	$67,669	$104
4.11	Boiler Balance of Plant	$1,939	$0	$898	$0	$2,837	$497	$0	$500	$3,834	$6
4.12	Primary Air System	$2,022	$0	$862	$0	$2,884	$505	$0	$508	$3,897	$6
4.13	Secondary Air System	$3,063	$0	$1,305	$0	$4,368	$764	$0	$770	$5,903	$9
4.14	Induced Draft Fans	$6,607	$0	$2,816	$0	$9,423	$1,649	$0	$1,661	$12,733	$20
4.15	Major Component Rigging	$106	$0	$47	$0	$153	$27	$0	$27	$207	$0
4.16	Boiler Foundations	$0	$440	$313	$0	$753	$132	$0	$133	$1,018	$2

Case:	B12A – Supercritical PC without CO_2 Capture								Estimate Type:	Conceptual
Plant Size (MW, net):	650								Cost Base:	Jan 2023
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
	Subtotal	**$337,821**	**$440**	**$155,649**	**$0**	**$493,911**	**$86,434**	**$0**	**$87,052**	**$667,397**	**$1,027**
5	**Flue Gas Cleanup**										
5.2	Wet FGD Absorber Vessels & Accessories	$83,129	$0	$15,009	$0	$98,138	$17,174	$0	$17,297	$132,609	$204
5.3	Other FGD	$1,311	$0	$853	$0	$2,164	$379	$0	$381	$2,924	$4
5.6	Mercury Removal (DSI/ACI)	$2,756	$633	$2,288	$0	$5,677	$993	$0	$1,001	$7,671	$12
5.9	Particulate Removal (Bag House & Accessories)	w/ 5.2	w/ 5.2	w/ 5.2	w/ 5.2	$0	$0	$0	$0	$0	$0
5.12	Gas Cleanup Foundations	$0	$212	$151	$0	$363	$64	$0	$64	$491	$1
5.13	Gypsum Dewatering System	$897	$0	$118	$0	$1,015	$178	$0	$179	$1,371	$2
	Subtotal	**$88,093**	**$845**	**$18,419**	**$0**	**$107,357**	**$18,787**	**$0**	**$18,922**	**$145,066**	**$223**
7	**Ductwork & Stack**										
7.3	Ductwork	$0	$907	$510	$0	$1,417	$248	$0	$250	$1,914	$3
7.4	Stack	$11,880	$0	$5,404	$0	$17,284	$3,025	$0	$3,046	$23,355	$36
7.5	Duct & Stack Foundations	$0	$270	$259	$0	$529	$93	$0	$124	$745	$1
	Subtotal	**$11,880**	**$1,177**	**$6,173**	**$0**	**$19,229**	**$3,365**	**$0**	**$3,420**	**$26,015**	**$40**
8	**Steam Turbine & Accessories**										
8.1	Steam Turbine Generator & Accessories	$81,393	$0	$7,795	$0	$89,188	$15,608	$0	$15,719	$120,515	$185
8.2	Steam Turbine Plant Auxiliaries	$1,843	$0	$3,446	$0	$5,289	$926	$0	$932	$7,147	$11
8.3	Condenser & Auxiliaries	$18,402	$0	$4,973	$0	$23,375	$4,091	$0	$4,120	$31,586	$49
8.4	Steam Piping	$54,205	$0	$15,533	$0	$69,738	$12,204	$0	$12,291	$94,234	$145
8.5	Turbine Generator Foundations	$0	$312	$417	$0	$730	$128	$0	$171	$1,029	$2
	Subtotal	**$155,844**	**$312**	**$32,164**	**$0**	**$188,320**	**$32,956**	**$0**	**$33,234**	**$254,510**	**$392**
9	**Cooling Water System**										
9.1	Cooling Towers	$17,439	$0	$4,221	$0	$21,660	$3,791	$0	$3,818	$29,268	$45
9.2	Circulating Water Pumps	$2,314	$0	$114	$0	$2,428	$425	$0	$428	$3,281	$5
9.3	Circulating Water System Auxiliaries	$15,508	$0	$1,609	$0	$17,117	$2,995	$0	$3,017	$23,129	$36
9.4	Circulating Water Piping	$0	$6,915	$5,065	$0	$11,980	$2,097	$0	$2,111	$16,188	$25
9.5	Make-up Water System	$1,363	$0	$1,364	$0	$2,726	$477	$0	$481	$3,684	$6
9.6	Component Cooling Water System	$1,032	$0	$669	$0	$1,701	$298	$0	$300	$2,299	$4
9.7	Circulating Water System Foundations	$0	$662	$890	$0	$1,552	$272	$0	$365	$2,189	$3
	Subtotal	**$37,656**	**$7,578**	**$13,931**	**$0**	**$59,165**	**$10,354**	**$0**	**$10,519**	**$80,038**	**$123**
10	**Ash & Spent Sorbent Handling Systems**										
10.6	Ash Storage Silos	$1,388	$0	$3,298	$0	$4,686	$820	$0	$826	$6,332	$10
10.7	Ash Transport & Feed Equipment	$4,725	$0	$3,634	$0	$8,359	$1,463	$0	$1,473	$11,295	$17
10.9	Ash/Spent Sorbent Foundation	$0	$928	$922	$0	$1,850	$324	$0	$435	$2,608	$4
	Subtotal	**$6,112**	**$928**	**$7,854**	**$0**	**$14,895**	**$2,607**	**$0**	**$2,734**	**$20,235**	**$31**
11	**Accessory Electric Plant**										
11.1	Generator Equipment	$3,592	$0	$1,989	$0	$5,581	$977	$0	$984	$7,542	$12
11.2	Station Service Equipment	$6,598	$0	$415	$0	$7,014	$1,227	$0	$1,236	$9,478	$15
11.3	Switchgear & Motor Control	$10,243	$0	$1,304	$0	$11,548	$2,021	$0	$2,035	$15,604	$24

Case:	B12A – Supercritical PC without CO_2 Capture								Estimate Type:	Conceptual
Plant Size (MW, net):	650								Cost Base:	Jan 2023
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
11.4	Conduit & Cable Tray	$0	$1,208	$2,816	$0	$4,025	$704	$0	$709	$5,439	$8
11.5	Wire & Cable	$0	$3,200	$4,626	$0	$7,826	$1,370	$0	$1,379	$10,576	$16
11.6	Protective Equipment	$79	$0	$201	$0	$280	$49	$0	$49	$378	$1
11.7	Standby Equipment	$1,126	$0	$763	$0	$1,888	$330	$0	$333	$2,551	$4
11.8	Main Power Transformers	$9,287	$0	$139	$0	$9,426	$1,650	$0	$1,661	$12,737	$20
11.9	Electrical Foundations	$0	$268	$551	$0	$819	$143	$0	$193	$1,155	$2
	Subtotal	**$30,926**	**$4,677**	**$12,806**	**$0**	**$48,408**	**$8,471**	**$0**	**$8,580**	**$65,460**	**$101**
12	**Instrumentation & Control**										
12.1	Pulverized Coal Boiler Control Equipment	$925	$0	$130	$0	$1,055	$185	$0	$186	$1,426	$2
12.3	Steam Turbine Control Equipment	$831	$0	$71	$0	$902	$158	$0	$159	$1,219	$2
12.5	Signal Processing Equipment	$1,050	$0	$148	$0	$1,198	$210	$0	$211	$1,618	$2
12.6	Control Boards, Panels, & Racks	$321	$0	$155	$0	$476	$83	$0	$84	$643	$1
12.7	Distributed Control System Equipment	$9,062	$0	$1,274	$0	$10,336	$1,809	$0	$1,822	$13,966	$21
12.8	Instrument Wiring & Tubing	$635	$495	$1,601	$0	$2,731	$478	$0	$481	$3,690	$6
12.9	Other Instrumentation & Controls Equipment	$780	$0	$1,424	$0	$2,205	$386	$0	$389	$2,979	$5
	Subtotal	**$13,604**	**$495**	**$4,803**	**$0**	**$18,901**	**$3,308**	**$0**	**$3,331**	**$25,540**	**$39**
13	**Improvements to Site**										
13.1	Site Preparation	$0	$546	$9,412	$0	$9,958	$1,743	$0	$2,340	$14,041	$22
13.2	Site Improvements	$0	$2,711	$2,895	$0	$5,606	$981	$0	$1,317	$7,904	$12
13.3	Site Facilities	$3,149	$0	$2,627	$0	$5,776	$1,011	$0	$1,357	$8,144	$13
	Subtotal	**$3,149**	**$3,256**	**$14,935**	**$0**	**$21,340**	**$3,735**	**$0**	**$5,015**	**$30,090**	**$46**
14	**Buildings & Structures**										
14.2	Boiler Building	$0	$15,101	$10,733	$0	$25,834	$4,521	$0	$4,553	$34,908	$54
14.3	Steam Turbine Building	$0	$20,990	$15,810	$0	$36,801	$6,440	$0	$6,486	$49,727	$76
14.4	Administration Building	$0	$1,364	$1,166	$0	$2,529	$443	$0	$446	$3,418	$5
14.5	Circulation Water Pumphouse	$0	$174	$112	$0	$287	$50	$0	$51	$387	$1
14.6	Water Treatment Buildings	$0	$486	$358	$0	$844	$148	$0	$149	$1,140	$2
14.7	Machine Shop	$0	$720	$390	$0	$1,110	$194	$0	$196	$1,500	$2
14.8	Warehouse	$0	$541	$439	$0	$979	$171	$0	$173	$1,323	$2
14.9	Other Buildings & Structures	$0	$379	$260	$0	$639	$112	$0	$113	$864	$1
14.10	Waste Treating Building & Structures	$0	$817	$2,004	$0	$2,821	$494	$0	$497	$3,812	$6
	Subtotal	**$0**	**$40,571**	**$31,272**	**$0**	**$71,843**	**$12,573**	**$0**	**$12,662**	**$97,078**	**$149**
	Total	**$813,476**	**$77,756**	**$347,676**	**$0**	**$1,238,908**	**$216,809**	**$0**	**$224,326**	**$1,680,043**	**$2,584**

Exhibit 3-75. Case B12A owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$11,208	$17
1 Month Maintenance Materials	$1,581	$2
1 Month Non-fuel Consumables	$2,116	$3
1 Month Waste Disposal	$897	$1
25% of 1 Months Fuel Cost at 100% CF	$3,036	$5
2% of TPC	$33,601	$52
Total	**$52,438**	**$81**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$27,639	$43
0.5% of TPC (spare parts)	$8,400	$13
Total	**$36,039**	**$55**
Other Costs		
Initial Cost for Catalyst and Chemicals	$4,780	$7
Land	$1,800	$3
Other Owner's Costs	$252,006	$388
Financing Costs	$45,361	$70
Total Overnight Costs (TOC)	**$2,072,467**	**$3,188**
TASC Multiplier (IOU, 33 year)	1.213	
Total As-Spent Cost (TASC)	**$2,513,337**	**$3,866**

Exhibit 3-76. Case B12A initial and annual operating and maintenance costs

Case:	B12A –Supercritical PC without CO_2 Capture				Cost Base:	Jan 2023
Plant Size (MW, net):	650	Heat Rate-net (Btu/kWh):	8,490		Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		45.04	**$/hour**	Skilled Operator:		2.0
Operating Labor Burden:		30.00	**% of base**	Operator:		9.0
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		2.0
				Total:		**14.0**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$7,180,746	$11.046
Maintenance Labor:					$10,752,273	$16.541
Administrative & Support Labor:					$4,483,255	$6.897
Property Taxes and Insurance:					$33,600,853	$51.690
Total:					**$56,017,127**	**$86.174**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$16,128,409	$3.332
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	4,372	$2.30	$0	$3,119,717	$0.645
Makeup and Waste Water Treatment Chemicals (lbs):	0	13.0	$660.00	$0	$2,666,743	$0.551
Brominated Activated Carbon (ton):	0	1.24	$2,547.97	$0	$981,820	$0.203
Enhanced Hydrated Lime (ton):	0	31.3	$391.63	$0	$3,796,934	$0.784
Limestone (ton):	0	549	$30.18	$0	$5,141,712	$1.062
Ammonia (19 wt%, ton):	0	52.0	$280.00	$0	$4,519,425	$0.934
SCR Catalyst (ft^3):	13,656	12.5	$350.00	$4,779,550	$1,354,206	$0.280
Subtotal:				**$4,779,550**	**$21,580,557**	**$4.459**
Waste Disposal						
Fly Ash (ton):	0	515	$46.71	$0	$7,465,166	$1.542
Bottom Ash (ton):	0	114	$46.71	$0	$1,658,186	$0.343
SCR Catalyst (ft^3):	0	12.5	$5.70	$0	$22,054	$0.005
Subtotal:				**$0**	**$9,145,406**	**$1.889**
By-Products						
Gypsum (ton)	0	835	$0.00	$0	$0	$0.000
Subtotal:				**$0**	**$0**	**$0.000**
Variable Operating Costs Total:				**$4,779,550**	**$46,854,372**	**$9.680**
						Fuel Cost
Illinois Number 6 (ton):	0	5,677	$70.32	$0	$123,851,654	$25.588
Total:				**$0**	**$123,851,654**	**$25.588**

Exhibit 3-77. Case B12A COE breakdown

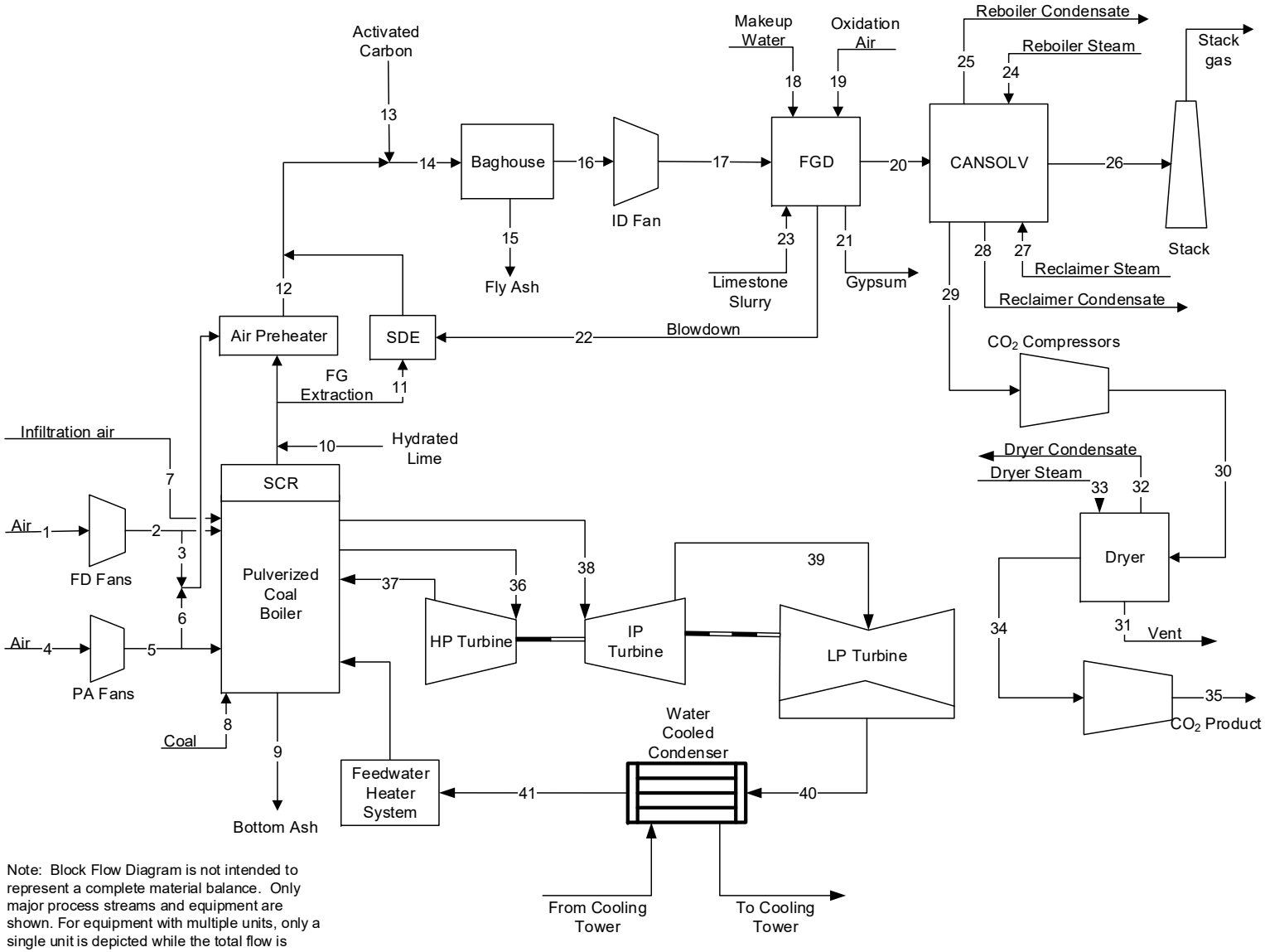
	FY COE		LCOE	
Component	Value, $/MWh	Percentage	Value, $/MWh	Percentage
Capital	40.0	46%	40.0	44%
Fixed	11.6	13%	15.5	17%
Variable	9.7	11%	12.9	14%
Fuel	25.6	29%	22.1	24%
Total (Excluding T&S)	**86.9**	**N/A**	**90.5**	**N/A**
CO_2 T&S	–	–	–	–
Total (Including T&S)	**86.9**	**N/A**	**90.5**	**N/A**

3.3.7 Case B12B.90 – SC PC with 90% CO_2 Capture Process Description

The plant configuration and process description for Case B12B.90 are nearly the same as Case B12A, with the exception that a PostCCC facility was included to treat the flue gas stream. Since the process descriptions of the plant and PostCCC facility were provided in Section 3.3.3 and Section 3.1.8, respectively, they are not repeated here.

The BFD for Case B12B.90 is shown in Exhibit 3-78. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit 3-79. The modeling assumptions are presented in Section 3.3.1.

Exhibit 3-78. Case B12B.90 BFD, SC unit with 90 percent CO_2 capture



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown. For equipment with multiple units, only a single unit is depicted while the total flow is reported.

Exhibit 3-79. Case B12B.90 stream table, SC unit with 90 percent CO_2 capture

	1	2	3	4	5	6	7	8	9	10	11	12
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	0.0087	0.0088
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1457	0.1379
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	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000	0.0879	0.0837
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7318	0.7340
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0237	0.0336
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0020
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	74,297	74,297	2,201	22,823	22,823	3,141	1,642	0	0	1	4,896	99,317
V-L Flowrate (kg/hr)	2,143,977	2,143,977	63,502	658,607	658,607	90,640	47,389	0	0	15	145,610	2,949,138
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	272,519	5,494	1,485	1,176	22,574
Temperature (°C)	15	17	17	15	24	24	15	15	1,316	15	385	143
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg)[A]	30.23	32.49	32.49	30.23	38.98	38.98	30.23	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-95.31	-95.31	-97.58	-88.83	-88.83	-97.58	-2,119.02	1,267.06	-13,402.95	-2,261.17	-2,394.31
Density (kg/m^3)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	1,003.6	0.5	0.8
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015	29.742	29.694
V-L Flowrate (lb_{mol}/hr)	163,796	163,796	4,851	50,316	50,316	6,925	3,620	0	0	2	10,793	218,956
V-L Flowrate (lb/hr)	4,726,660	4,726,660	139,997	1,451,980	1,451,980	199,828	104,476	0	0	33	321,016	6,501,737
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	600,801	12,111	3,274	2,593	49,768
Temperature (°F)	59	63	63	59	75	75	59	59	2,400	59	726	289
Pressure (psia)	14.7	15.0	15.0	14.7	15.9	15.9	14.7	14.7	14.3	14.7	14.3	14.1
Steam Table Enthalpy (Btu/lb)[A]	13.0	14.0	14.0	13.0	16.8	16.8	13.0	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-41.0	-41.0	-42.0	-38.2	-38.2	-42.0	-911.0	544.7	-5,762.2	-972.1	-1,029.4
Density (lb/ft^3)	0.076	0.077	0.077	0.076	0.080	0.080	0.076	---	---	62.650	0.033	0.052

[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 3-79. Case B12B.90 stream table, SC unit with 90 percent CO2 capture (continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.1372	0.0000	0.1372	0.1372	0.0000	0.0003	0.1245	0.0001	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	0.0000	0.0911	0.0000	0.0911	0.0911	0.9999	0.0099	0.1508	0.9998	0.9943	0.9999	1.0000
HCl	0.0000	0.0001	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.7281	0.0000	0.7281	0.7281	0.0000	0.7732	0.6803	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0329	0.0000	0.0329	0.0329	0.0000	0.2074	0.0363	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0020	0.0000	0.0020	0.0020	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.1158	0.0000	0.0000	0.0001	0.0000	0.0000	0.0001	0.0009	0.0001	0.0000
$CaCl_2$	0.0000	0.0001	0.8842	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0048	0.0000	0.0000
Total	0.0000	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_{mol}/hr)	0	105,042	6	105,035	105,035	6,136	4,397	117,421	247	829	3,418	33,684
V-L Flowrate (kg/hr)	0	3,110,089	672	3,109,401	3,109,401	110,565	126,880	3,374,697	4,455	15,341	61,581	606,834
Solids Flowrate (kg/hr)	60	24,043	24,060	0	0	0	0	0	40,069	233	26,362	0
Temperature (°C)	15	143	143	143	156	15	15	57	15	57	15	269
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.48
Steam Table Enthalpy (kJ/kg)[A]	---	---	---	287.58	302.09	-47.80	30.23	297.00	---	---	---	3,000.14
AspenPlus Enthalpy (kJ/kg)[B]	-6.79	-2,453.14	-1,065.96	-2,464.17	-2,449.66	-16,015.01	-97.58	-2,939.24	-12,513.34	-15,496.14	-14,994.25	-12,980.15
Density (kg/m^3)	---	0.8	2,150.2	0.8	0.9	1,003.7	1.2	1.1	878.3	979.5	1,003.7	2.0
V-L Molecular Weight	---	29.608	104.898	29.603	29.603	18.019	28.857	28.740	18.021	18.495	18.019	18.015
V-L Flowrate (lb_{mol}/hr)	0	231,578	14	231,564	231,564	13,528	9,693	258,868	545	1,829	7,535	74,261
V-L Flowrate (lb/hr)	0	6,856,573	1,482	6,855,055	6,855,055	243,754	279,723	7,439,934	9,821	33,821	135,763	1,337,840
Solids Flowrate (lb/hr)	131	53,007	53,042	0	0	0	0	0	88,338	515	58,118	0
Temperature (°F)	59	289	289	289	313	59	59	135	59	135	59	516
Pressure (psia)	14.7	14.1	14.1	13.9	15.3	14.7	14.7	14.8	14.7	14.7	14.7	70.0
Steam Table Enthalpy (Btu/lb)[A]	---	---	---	123.6	129.9	-20.5	13.0	127.7	---	---	---	1,289.8
AspenPlus Enthalpy (Btu/lb)[B]	-2.9	-1,054.7	-458.3	-1,059.4	-1,053.2	-6,885.2	-42.0	-1,263.6	-5,379.8	-6,662.1	-6,446.4	-5,580.5
Density (lb/ft^3)	---	0.052	134.232	0.051	0.055	62.658	0.076	0.067	54.833	61.145	62.658	0.122

[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 3-79. Case B12B.90 stream table, SC unit with 90 percent CO2 capture (continued)

	25	26	27	28	29	30	31	32	33	34	35	36
V-L Mole Fraction												
Ar	0.0000	0.0101	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0156	0.0000	0.0000	0.9783	0.9975	0.0500	0.0000	0.0000	0.9995	0.9995	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	1.0000	0.0807	1.0000	1.0000	0.0217	0.0025	0.9500	1.0000	1.0000	0.0005	0.0005	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.8483	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0453	0.0000	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	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
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_{mol}/hr)	30,851	94,165	386	386	13,440	13,181	28	17	17	13,153	13,153	133,266
V-L Flowrate (kg/hr)	555,796	2,613,763	6,959	6,959	583,905	579,239	534	307	307	578,705	578,705	2,400,833
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	105	45	342	214	31	29	29	203	461	29	30	593
Pressure (MPa, abs)	0.12	0.10	4.90	2.04	0.17	2.81	2.81	1.64	2.14	2.68	15.27	24.23
Steam Table Enthalpy (kJ/kg)[A]	439.34	178.41	3,049.81	913.81	46.68	-3.05	137.94	863.65	3,379.61	-3.59	-231.09	3,477.96
AspenPlus Enthalpy (kJ/kg)[B]	-15,540.95	-903.21	-12,930.48	-15,066.49	-8,978.62	-8,972.51	-15,225.22	-15,116.65	-12,600.69	-8,967.15	-9,194.65	-12,502.33
Density (kg/m^3)	954.9	1.1	19.2	848.5	3.0	57.8	351.5	861.8	6.4	54.7	630.1	69.2
V-L Molecular Weight	18.015	27.757	18.015	18.015	43.445	43.945	19.315	18.015	18.015	43.997	43.997	18.015
V-L Flowrate (lb_{mol}/hr)	68,016	207,598	852	852	29,630	29,059	61	38	38	28,998	28,998	293,802
V-L Flowrate (lb/hr)	1,225,320	5,762,360	15,343	15,343	1,287,291	1,277,003	1,177	677	677	1,275,825	1,275,825	5,292,930
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	221	113	648	416	87	85	85	397	862	85	86	1,100
Pressure (psia)	17.4	14.8	710.8	296.6	24.7	407.6	407.6	237.4	310.1	389.1	2,214.7	3,514.7
Steam Table Enthalpy (Btu/lb)[A]	188.9	76.7	1,311.2	392.9	20.1	-1.3	59.3	371.3	1,453.0	-1.5	-99.4	1,495.3
AspenPlus Enthalpy (Btu/lb)[B]	-6,681.4	-388.3	-5,559.1	-6,477.4	-3,860.1	-3,857.5	-6,545.7	-6,499.0	-5,417.3	-3,855.2	-3,953.0	-5,375.0
Density (lb/ft^3)	59.612	0.067	1.197	52.968	0.184	3.609	21.943	53.801	0.402	3.416	39.338	4.319

[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 3-79. Case B12B.90 stream table, SC unit with 90 percent CO2 capture (continued)

	31	32	33	34	35	36	37	38	39	40	41
V-L Mole Fraction											
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0500	0.0000	0.0000	0.9995	0.9995	0.0000	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
H_2O	0.9500	1.0000	1.0000	0.0005	0.0005	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.0000	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	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	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	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
V-L Flowrate (kg_{mol}/hr)	28	17	17	13,153	13,153	133,266	111,025	111,025	95,607	42,151	65,023
V-L Flowrate (kg/hr)	534	307	307	578,705	578,705	2,400,833	2,000,151	2,000,151	1,722,380	759,359	1,171,406
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	29	203	461	29	30	593	342	593	270	38	39
Pressure (MPa, abs)	2.81	1.64	2.14	2.68	15.27	24.23	4.90	4.80	0.52	0.01	1.26
Steam Table Enthalpy (kJ/kg)[A]	137.94	863.65	3,379.61	-3.59	-231.09	3,477.96	3,049.81	3,652.36	3,000.14	2,343.61	162.36
AspenPlus Enthalpy (kJ/kg)[B]	-15,225.22	-15,116.65	-12,600.69	-8,967.15	-9,194.65	-12,502.33	-12,930.48	-12,327.93	-12,980.15	-13,636.69	-15,817.93
Density (kg/m^3)	351.5	861.8	6.4	54.7	630.1	69.2	19.2	12.3	2.1	0.1	993.3
V-L Molecular Weight	19.315	18.015	18.015	43.997	43.997	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	61	38	38	28,998	28,998	293,802	244,769	244,769	210,776	92,927	143,351
V-L Flowrate (lb/hr)	1,177	677	677	1,275,825	1,275,825	5,292,930	4,409,577	4,409,577	3,797,197	1,674,099	2,582,509
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	85	397	862	85	86	1,100	648	1,100	517	101	101
Pressure (psia)	407.6	237.4	310.1	389.1	2,214.7	3,514.7	710.8	696.6	75.0	1.0	183.1
Steam Table Enthalpy (Btu/lb)[A]	59.3	371.3	1,453.0	-1.5	-99.4	1,495.3	1,311.2	1,570.2	1,289.8	1,007.6	69.8
AspenPlus Enthalpy (Btu/lb)[B]	-6,545.7	-6,499.0	-5,417.3	-3,855.2	-3,953.0	-5,375.0	-5,559.1	-5,300.1	-5,580.5	-5,862.7	-6,800.5
Density (lb/ft^3)	21.943	53.801	0.402	3.416	39.338	4.319	1.197	0.768	0.131	0.003	62.009

[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

3.3.8 Case B12B.90 – Performance Results

Overall plant performance is summarized in Exhibit 3-80; Exhibit 3-81 provides a detailed breakdown of the auxiliary power requirements.

The PostCCC facility and CO_2 compression combined account for over half of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for 12 percent of the auxiliary load, largely due to the high cooling water demand of the PostCCC 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. By increasing the boiler and turbine/generator size to account for the greater auxiliary load imposed by the PostCCC facility and CO_2 compressors, a net output of 650 MW is maintained at a reduced net plant efficiency of 31.7 percent (HHV basis).

Exhibit 3-80. Case B12B.90 plant performance summary

Performance Summary	
Total Gross Power, MWe	**763**
CO_2 Capture/Removal Auxiliaries, kWe	17,900
CO_2 Compression, kWe	46,330
Balance of Plant, kWe	48,270
Total Auxiliaries, MWe	**113**
Net Power, MWe	**650**
HHV Net Plant Efficiency, %	31.7
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,371 (10,778)
LHV Net Plant Efficiency, %	32.8
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	10,968 (10,396)
HHV Boiler Efficiency, %	88.0
LHV Boiler Efficiency, %	91.3
Steam Turbine Cycle Efficiency, %	57.4
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	6,267 (5,940)
Condenser Duty, GJ/hr (MMBtu/hr)	2,100 (1,990)
CO_2 Capture Rate, %	90
AGR Duty, GJ/hr (MMBtu/hr)	2,059 (1,952)
As-Received Coal Feed, kg/hr (lb/hr)	272,519 (600,801)
Limestone Sorbent Feed, kg/hr (lb/hr)	26,362 (58,118)
HHV Thermal Input, kWt	2,054,118
LHV Thermal Input, kWt	1,981,222
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})	0.040 (10.6)
Excess Air, %	20.3

Exhibit 3-81. Case B12B.90 plant power summary

Power Summary	
Steam Turbine Power, MWe	763
Total Gross Power, MWe	**763**
Auxiliary Load Summary	
Activated Carbon Injection, kWe	40
Ash Handling, kWe	890
Baghouse, kWe	120
Circulating Water Pumps, kWe	9,020
CO_2 Capture/Removal Auxiliaries, kWe	17,900
CO_2 Compression, kWe	46,330
Coal Handling and Conveying, kWe	530
Condensate Pumps, kWe	790
Cooling Tower Fans, kWe	4,670
Dry Sorbent Injection, kWe	80
Flue Gas Desulfurizer, kWe	4,210
Forced Draft Fans, kWe	1,400
Ground Water Pumps, kWe	840
Induced Draft Fans, kWe	12,920
Miscellaneous Balance of Plant[A,B], kWe	2,250
Primary Air Fans, kWe	1,660
Pulverizers, kWe	4,090
SCR, kWe	50
Sorbent Handling & Reagent Preparation, kWe	1,270
Spray Dryer Evaporator, kWe	300
Steam Turbine Auxiliaries, kWe	500
Transformer Losses, kWe	2,640
Total Auxiliaries, MWe	**113**
Net Power, MWe	**650**

[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 are presented in Section 2.4. A summary of the plant air emissions for Case B12B.90 is presented in Exhibit 3-82. SO_2 emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit 3-82. Case B12B.90 air emissions

	kg/GJ (lb/MMBtu)[A]	tonne/year (ton/year)[B]	kg/MWh (lb/MWh)[C]
SO_2	0.000 (0.000)	0 (0)	0.000 (0.000)
NOx	0.033 (0.076)	1,803 (1,988)	0.318 (0.700)
Particulate	0.004 (0.010)	232 (256)	0.041 (0.090)
Hg	1.40E-7 (3.26E-7)	0.008 (0.009)	1.36E-6 (3.00E-6)
CO_2	9 (20)	480,864 (530,061)	85 (187)
CO_2[D]	–	–	99 (219)
	mg/Nm^3		
Particulate Concentration[E,F]	13.23		

[A]Based on thermal input on an HHV basis
[B]Calculations based on an 85 percent capacity factor
[C]Emissions based on gross power except where otherwise noted
[D]CO_2 emissions based on net power instead of gross power
[E]Concentration of particles in the flue gas after the baghouse
[F]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 0.37 ppmv using a NaOH based polishing scrubber in the PostCCC facility. The remaining low concentration of SO_2 is essentially completely removed in the PostCCC absorber vessel resulting in very low SO_2 emissions (reported as zero here).

NOx emissions are controlled to about 0.15 kg/GJ (0.35 lb/MMBtu) using LNBs and OFA. An SCR unit then further reduces the NOx concentration by 78.2 percent to 0.03 kg/GJ (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 97.5 percent.

The carbon balance for the plant is shown in Exhibit 3-83. 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 product from the CO_2 compression train; however, some CO_2 exits through the stack and the CO_2 dryer's vent, 20 percent of the unburned carbon remains in the bottom ash, the remaining unburned carbon is captured in the fabric filter, along with the PAC, and some carbon leaves as gypsum. The carbon conversion is assumed to be 99.4 percent.

Ninety percent of the CO_2 in the flue gas is removed in PostCCC facility. The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in (minus unburnt carbon in the ash), represented by the following percentage:

$$1 - \frac{Carbon\ in\ Stack}{Total\ Carbon\ In - Unburnt\ Carbon} = \left(1 - \left(\frac{38{,}856}{389{,}900 - 2{,}298}\right)\right) * 100 = 90\%$$

Where the unburned carbon is equal to one minus the carbon conversion rate times the carbon in the coal:

$$(1 - Carbon\ Conversion) * Carbon\ in\ Coal = (1 - 0.994) * 382{,}979 = 2{,}298$$

Exhibit 3-83. Case B12B.90 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	173,716 (382,979)	Stack Gas	17,625 (38,856)
Air (CO_2)	405 (893)	FGD Product	206 (454)
PAC	60 (131)	Baghouse	893 (1,970)
FGD Reagent	2,675 (5,897)	Bottom Ash	208 (460)
		CO_2 Product	157,906 (348,122)
		CO_2 Dryer Vent	17 (37)
		CO_2 Knockout	0.4 (1.0)
Total	**176,856 (389,900)**	**Total**	**176,856 (389,900)**

Exhibit 3-84 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 removed in the polishing scrubber, and sulfur removed in the baghouse via hydrated lime.

Exhibit 3-84. Case B12B.90 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	6,830 (15,059)	FGD Product	6,422 (14,158)
		Stack Gas	0 (0)
		Polishing Scrubber and Solvent Reclaiming	133 (294)
		Baghouse	275 (607)
Total	**6,830 (15,059)**	**Total**	**6,830 (15,059)**

Water demand, recycle, withdrawal, discharge, and consumption are defined and discussed in Section 2.6. Exhibit 3-85 shows the overall water balance for the plant. The exhibit is presented in an identical manner as for Case B12A. The only notable difference is the FGD makeup water

source. In CO_2 capture cases, a significant amount of water is recovered from the initial PostCCC facility cooling step. This water is assumed suitable to be used as FGD makeup, with the balance of the water from the PostCCC facility discharged.

Exhibit 3-85. Case B12B.90 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 Process Makeup	1.8 (488)	1.8 (488)	–	–	–
FGD Slurry Water	1.0 (272)	1.0 (272)	–	–	–
CO_2 Drying	–	–	–	0.0 (2.4)	0.0 (-2.4)
CO_2 Capture Recovery	–	–	–	0.9 (245)	-0.9 (-245)
CO_2 Compression KO	–	–	–	0.1 (21)	-0.1 (-21)
Deaerator Vent	–	–	–	0.1 (21)	-0.1 (-21)
Condenser Makeup	**0.1 (21)**	**–**	**0.1 (21)**	**–**	**0.1 (21)**
BFW Makeup	0.1 (21)	–	0.1 (21)	–	0.1 (21)
Cooling Tower	**35 (9,281)**	**–**	**35 (9,281)**	**7.9 (2,087)**	**27 (7,194)**
BFW Blowdown	–	–	–	–	–
Total	**38 (10,061)**	**2.9 (759)**	**35 (9,302)**	**9.0 (2,377)**	**26 (6,925)**

3.3.8.2 Energy and Mass Balance Diagrams

Energy and mass balance diagrams are shown for the Case B12B.90 PC boiler, FGD unit, PostCCC system, and steam cycle in Exhibit 3-86 and Exhibit 3-87.

An overall plant energy balance is provided in tabular form in Exhibit 3-88. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-80) is calculated by multiplying the power out by a generator efficiency of 98.5 percent.

Exhibit 3-86. Case B12B.90 energy and mass balance, SC PC boiler with CO_2 capture

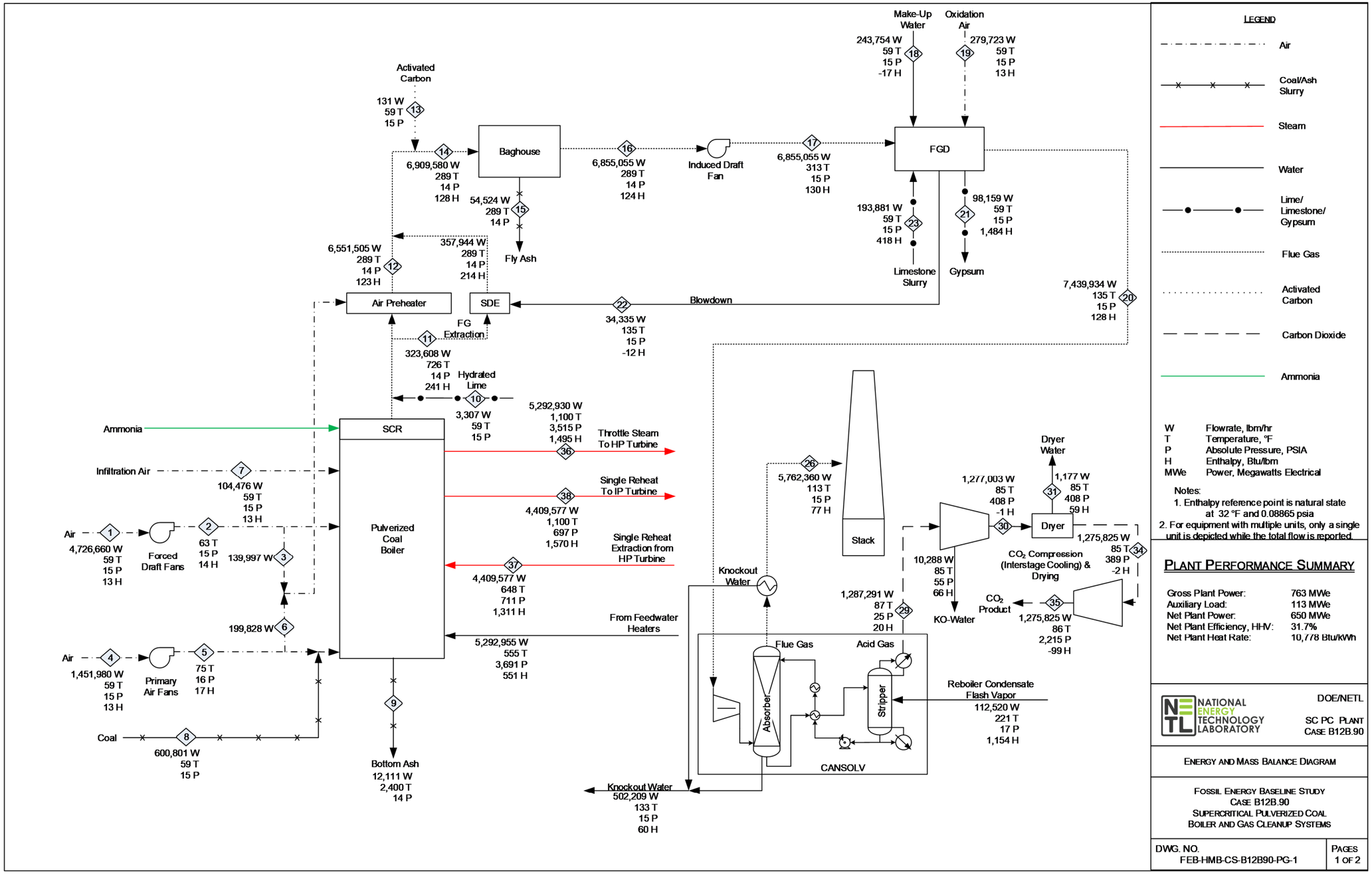


Exhibit 3-87. Case B12B.90 energy and mass balance, SC steam cycle

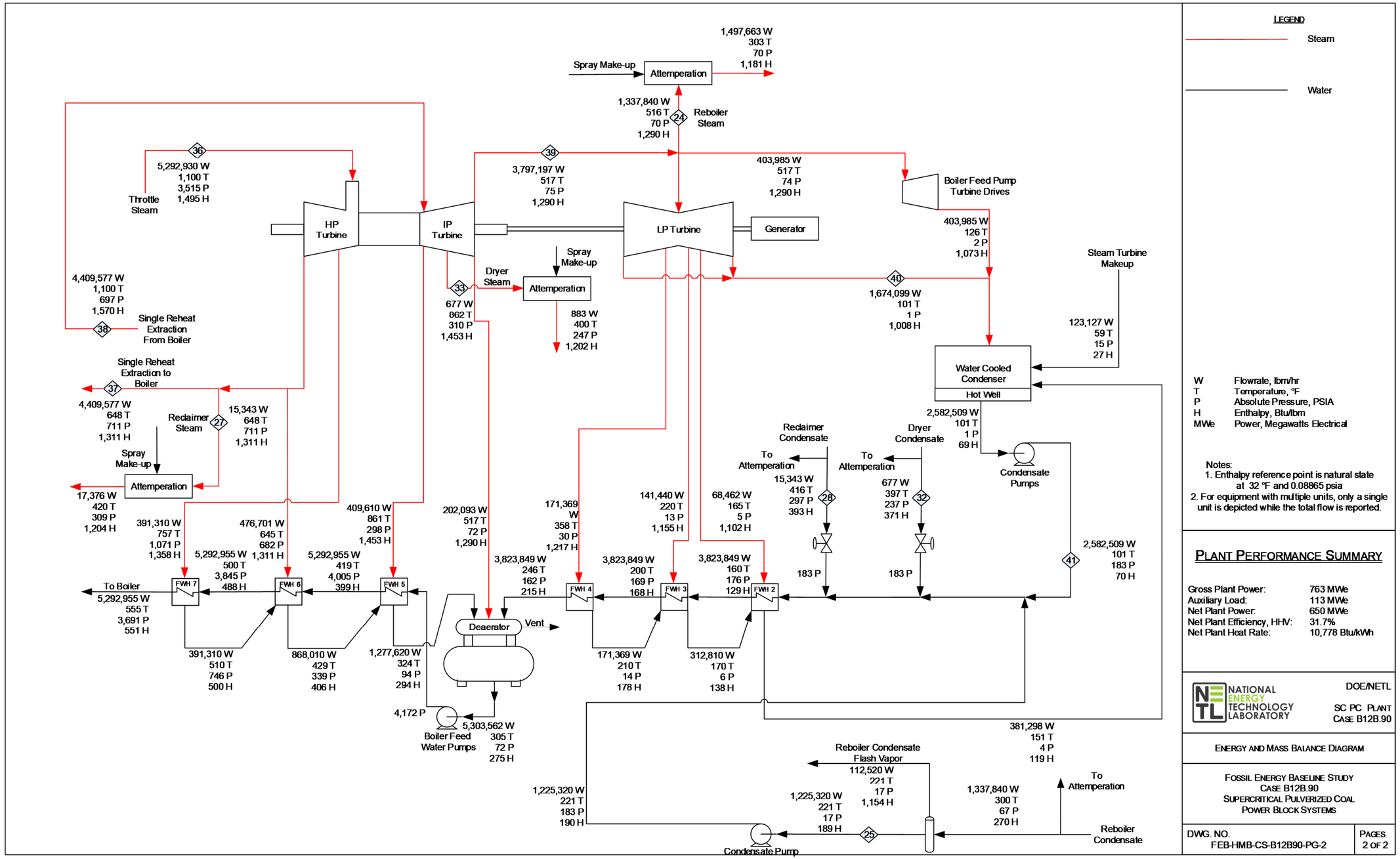


Exhibit 3-88. Case B12B.90 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, GJ/hr (MMBtu/hr)				
Coal	7,395 (7,009)	6.2 (5.9)	–	7,401 (7,015)
Air	–	86 (82)	–	86 (82)
Raw Water Makeup	–	132 (125)	–	132 (125)
Limestone	–	0.6 (0.5)	–	0.6 (0.5)
Auxiliary Power	–	–	405 (384)	405 (384)
TOTAL	**7,395 (7,009)**	**225 (214)**	**405 (384)**	**8,025 (7,606)**
Heat Out, GJ/hr (MMBtu/hr)				
Bottom Ash	–	7.0 (6.6)	–	7.0 (6.6)
Fly Ash	–	2.5 (2.4)	–	2.5 (2.4)
Stack Gas	–	466 (442)	–	466 (442)
Sulfur	2.5 (2.4)	0.0 (0.0)	–	2.5 (2.4)
Gypsum	–	2.6 (2.5)	–	2.6 (2.5)
Motor Losses and Design Allowances	–	–	50 (47)	50 (47)
Cooling Tower Load[A]	–	4,588 (4,348)	–	4,588 (4,348)
CO_2 Product Stream	–	-134 (-127)	–	-134 (-127)
AGR Effluent	–	53 (51)	–	53 (51)
Blowdown Streams and Deaerator Vent	–	3.1 (2.9)	–	3.1 (2.9)
Ambient Losses[B]	–	*175 (166)*	–	*175 (166)*
Power	–	–	2,746 (2,603)	2,746 (2,603)
TOTAL	**2.5 (2.4)**	**5,164 (4,895)**	**2,796 (2,650)**	**7,963 (7,547)**
Unaccounted Energy[C]	–	*62 (59)*	–	*62 (59)*

[A]Includes condenser, capture process, CO_2 compressor, and miscellaneous cooling loads
[B]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers
[C]By difference

3.3.9 Case B12B.90 – 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. Values reported in the equipment lists are rounded.

Case B12B.90 – 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	60 tonne (60 ton)	2	1
9	Feeder	Vibratory	220 tonne/hr (250 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	450 tonne/hr (500 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	220 tonne (250 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	450 tonne/hr (500 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	450 tonne/hr (500 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	1,000 tonne (1,100 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 11 tonne (12 ton) Feeder - 70 kg/hr (140 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 280 tonne (310 ton) Feeder - 1,650 kg/hr (3,640 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	111 tonne/hr (122 tph)	1	0
23	Limestone Conveyor No. 1	Belt	111 tonne/hr (122 tph)	1	0
24	Limestone Reclaim Hopper	N/A	22 tonne (24 ton)	1	0
25	Limestone Reclaim Feeder	Belt	87 tonne/hr (96 tph)	1	0
26	Limestone Conveyor No. 2	Belt	87 tonne/hr (96 tph)	1	0
27	Limestone Day Bin	w/ actuator	348 tonne (384 ton)	2	0

Case B12B.90 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	50 tonne/hr (55 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	50 tonne/hr (55 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	29 tonne/hr (32 tph)	1	1
4	Limestone Ball Mill	Rotary	29 tonne/hr (32 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	114,000 liters (30,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,890 lpm @ 10 m H_2O (500 gpm @ 40 ft H_2O)	1	1
7	Hydrocyclone Classifier	4 active cyclones in a 5-cyclone bank	470 lpm (130 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	627,000 liters (166,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,310 lpm @ 9 m H_2O (350 gpm @ 30 ft H_2O)	1	1

Case B12B.90 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	318,000 liters (84,000 gal)	2	0
2	Condensate Pumps	Vertical canned	10,800 lpm @ 200 m H_2O (2,860 gpm @ 500 ft H_2O)	2	1
3	Deaerator and Storage Tank	Horizontal spray type	1,323,000 kg/hr (2,917,000 lb/hr), 5 min. tank	2	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	22,000 lpm @ 3,500 m H_2O (5,900 gpm @ 11,400 ft H_2O)	2	2
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	6,600 lpm @ 3,500 m H_2O (1,700 gpm @ 11,400 ft H_2O)	2	0
6	LP Feedwater Heater 2A/2B	Horizontal U-tube	480,000 kg/hr (1,050,000 lb/hr)	4	0
7	LP Feedwater Heater 3A/3B	Horizontal U-tube	480,000 kg/hr (1,050,000 lb/hr)	4	0
8	LP Feedwater Heater 4A/4B	Horizontal U-tube	480,000 kg/hr (1,050,000 lb/hr)	4	0
9	HP Feedwater Heater 5	Horizontal U-tube	1,320,000 kg/hr (2,910,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	1,320,000 kg/hr (2,910,000 lb/hr)	2	0
11	HP Feedwater Heater 7	Horizontal U-tube	1,320,000 kg/hr (2,910,000 lb/hr)	2	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	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
14	Service Air Compressors	Flooded screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
15	Instrument Air Dryers	Duplex, regenerative	28 m3/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	9,400 lpm @ 20 m H_2O (2,490 gpm @ 60 ft H_2O)	2	1
21	Ground Water Pumps	Stainless steel, single suction	3,770 lpm @ 270 m H_2O (1,000 gpm @ 880 ft H_2O)	5	1
22	Filtered Water Pumps	Stainless steel, single suction	1,200 lpm @ 50 m H_2O (310 gpm @ 160 ft H_2O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	1,139,000 liter (301,000 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	330 lpm (90 gpm)	1	1
25	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
26	Process Water Treatment	Spray dryer evaporator	Flue Gas - 2,510 m3/min (88,600 acfm) @ 385°C (726°F) & 0.1 MPa (14 psia) Blowdown - 150 lpm (40 gpm) @ 19,990 ppmw Cl^-	2	1

Case B12B.90 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, once-through, wall-fired, low NOx burners, overfire air	2,640,000 kg/hr steam @ 24.1 MPa/593°C/593°C (5,820,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	362,000 kg/hr, 4,900 m^3/min @ 101 cm WG (799,000 lb/hr, 174,600 acfm @ 40 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	1,179,000 kg/hr, 16,100 m^3/min @ 26 cm WG (2,600,000 lb/hr, 568,000 acfm @ 10 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,710,000 kg/hr, 34,600 m^3/min @ 114 cm WG (3,770,000 lb/hr, 1,223,000 acfm @ 45 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	3,230,000 kg/hr (7,130,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	120 m^3/min @ 108 cm WG (4,400 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	137,000 liter (36,100 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	26 lpm @ 90 m H_2O (7 gpm @ 300 ft H_2O)	2	1

Case B12B.90 – 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	1,711,000 kg/hr (3,771,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	58,000 m^3/min (2,050,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	201,000 lpm @ 65 m H_2O (53,200 gpm @ 210 ft H_2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	5,570 lpm (1,470 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	950 m^3/min @ 0.3 MPa (33,630 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,390 lpm (370 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	44 tonne/hr (49 tph) of 50 wt% slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	850 lpm @ 13 m H_2O (220 gpm @ 40 ft H_2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	550,000 lpm (150,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	2,030 lpm @ 21 m H_2O (540 gpm @ 70 ft H_2O)	1	1
12	Activated Carbon Injectors	---	70 kg/hr (140 lb/hr)	1	0
13	Hydrated Lime Injectors	---	1,650 kg/hr (3,640 lb/hr)	1	0
14	CANSOLV	Amine-based CO_2 capture technology	3,712,000 kg/hr (8,184,000 lb/hr) 19.1 wt% CO_2 concentration	1	0
15	CANSOLV LP Condensate Pump	Centrifugal	1,331 lpm @ 1 m H_2O (352 gpm @ 3 ft H_2O)	1	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
16	CANSOLV IP Condensate Pump	Centrifugal	17 lpm @ 4.6 m H_2O (5 gpm @ 15 ft H_2O)	1	1
17	CO_2 Dryer	Triethylene glycol	Inlet: 167 m^3/min @ 2.8 MPa (5,897 acfm @ 408 psia) Outlet: 2.7 MPa (389 psia) Water Recovered: 534 kg/hr (1,177 lb/hr)	1	0
18	CO_2 Compressor	Integrally geared, multi-stage centrifugal	8.0 m^3/min @ 15.3 MPa, 82°C (297 acfm @ 2,217 psia, 180°F)	2	0
19	CO_2 Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 91 GJ/hr (86 MMBtu/hr)	1	0

Case B12B.90 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.2 m (20 ft) diameter	1	0

Case B12B.90 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	803 MW 24.1 MPa/593°C/593°C (3,500 psig/1,100°F/1,100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	890 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,310 GJ/hr (2,190 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0

Case B12B.90 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	905,000 lpm @ 30 m (239,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 5,050 GJ/hr (4,780 MMBtu/hr) heat duty	1	0

Case B12B.90 – Account 10: Ash and Spent Sorbent Handling System

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	–	6.0 tonne/hr (6.7 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	24 m^3/min @ 0.2 MPa (862 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,600 tonne (1,770 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	150 tonne/hr (160 tph)	1	0

Case B12B.90 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 760 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 26 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 52 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 18 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.90 – 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.90 – Cost Estimating

The cost estimating methodology is described in Section 2.7. Exhibit 3-89 shows a detailed breakdown of the capital costs; Exhibit 3-90 shows the owner's costs, TOC, and TASC; Exhibit 3-91 shows the initial and annual O&M costs; and Exhibit 3-92 shows the COE breakdown.

For PC cases, existing costs were escalated to reflect a 2023-year dollar using the methodology outlined in NETL's current QGESS (NETL, 2025a).

The estimated TPC of the SC PC boiler with CO_2 capture is $4,254/kW. Process contingency represents 2.6 percent of the TPC and project contingency represents 13.9 percent of the TPC. The FY COE, including T&S costs of $8.9/MWh, is $141.7/MWh. The LCOE, including T&S costs of $11.9/MWh, is $151.9/MWh.

Exhibit 3-89. Case B12B.90 total plant cost details

Case:	B12B.90 – Supercritical PC with 90 Percent CO_2 Capture					Estimate Type:	Conceptual			
Plant Size (MW, net):	650					Cost Base:	Jan 2023			
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
1	Coal & Sorbent Handling										
1.1	Coal Receive & Unload	$1,594	$0	$557	$0	$2,151	$376	$0	$379	$2,906	$4
1.2	Coal Stackout & Reclaim	$5,232	$0	$908	$0	$6,140	$1,074	$0	$1,082	$8,296	$13
1.3	Coal Conveyors	$48,211	$0	$8,898	$0	$57,109	$9,994	$0	$10,065	$77,168	$119
1.4	Other Coal Handling	$6,698	$0	$1,093	$0	$7,791	$1,363	$0	$1,373	$10,528	$16
1.5	Sorbent Receive & Unload	$306	$0	$71	$0	$377	$66	$0	$66	$510	$1
1.6	Sorbent Stackout & Reclaim	$2,241	$0	$314	$0	$2,556	$447	$0	$450	$3,453	$5
1.7	Sorbent Conveyors	$3,396	$709	$638	$0	$4,742	$830	$0	$836	$6,408	$10
1.8	Other Sorbent Handling	$163	$37	$66	$0	$266	$47	$0	$47	$359	$1
1.9	Coal & Sorbent Handling Foundations	$0	$2,124	$2,264	$0	$4,388	$768	$0	$773	$5,929	$9
	Subtotal	**$67,841**	**$2,869**	**$14,809**	**$0**	**$85,519**	**$14,966**	**$0**	**$15,072**	**$115,557**	**$178**
2	Coal & Sorbent Preparation & Feed										
2.1	Coal Crushing & Drying	$3,425	$0	$510	$0	$3,935	$689	$0	$694	$5,317	$8
2.2	Prepared Coal Storage & Feed	$11,527	$0	$1,926	$0	$13,453	$2,354	$0	$2,371	$18,178	$28
2.5	Sorbent Preparation Equipment	$1,508	$63	$240	$0	$1,810	$317	$0	$319	$2,446	$4
2.6	Sorbent Storage & Feed	$2,528	$0	$740	$0	$3,267	$572	$0	$576	$4,415	$7
2.9	Coal & Sorbent Feed Foundation	$0	$960	$681	$0	$1,641	$287	$0	$289	$2,218	$3
	Subtotal	**$18,987**	**$1,023**	**$4,097**	**$0**	**$24,107**	**$4,219**	**$0**	**$4,249**	**$32,574**	**$50**
3	Feedwater & Miscellaneous BOP Systems										
3.1	Feedwater System	$5,373	$8,876	$3,589	$0	$17,838	$3,122	$0	$3,144	$24,104	$37
3.2	Water Makeup & Pretreating	$10,655	$1,027	$4,706	$0	$16,388	$2,868	$0	$3,851	$23,107	$36
3.3	Other Feedwater Subsystems	$4,194	$1,325	$1,018	$0	$6,537	$1,144	$0	$1,152	$8,833	$14
3.4	Service Water Systems	$3,365	$6,191	$16,213	$0	$25,769	$4,510	$0	$6,056	$36,334	$56
3.5	Other Boiler Plant Systems	$995	$364	$735	$0	$2,094	$367	$0	$369	$2,830	$4
3.6	Natural Gas Pipeline and Start-Up System	$4,869	$187	$114	$0	$5,170	$905	$0	$911	$6,986	$11
3.7	Waste Water Treatment Equipment	$17,487	$0	$8,353	$0	$25,840	$4,522	$0	$6,072	$36,434	$56
3.8	Spray Dryer Evaporator	$22,884	$0	$10,326	$0	$33,210	$5,812	$0	$7,804	$46,827	$72
3.9	Miscellaneous Plant Equipment	$305	$39	$121	$0	$464	$81	$0	$109	$654	$1
	Subtotal	**$70,128**	**$18,008**	**$45,175**	**$0**	**$133,311**	**$23,329**	**$0**	**$29,469**	**$186,109**	**$286**
4	Pulverized Coal Boiler & Accessories										
4.9	Pulverized Coal Boiler & Accessories	$347,672	$0	$160,949	$0	$508,621	$89,009	$0	$89,645	$687,275	$1,057
4.10	Selective Catalytic Reduction System	$40,890	$0	$18,198	$0	$59,088	$10,340	$0	$10,414	$79,843	$123
4.11	Boiler Balance of Plant	$2,287	$0	$1,059	$0	$3,346	$586	$0	$590	$4,521	$7
4.12	Primary Air System	$2,385	$0	$1,016	$0	$3,401	$595	$0	$599	$4,596	$7
4.13	Secondary Air System	$3,612	$0	$1,539	$0	$5,152	$902	$0	$908	$6,961	$11
4.14	Induced Draft Fans	$7,792	$0	$3,321	$0	$11,113	$1,945	$0	$1,959	$15,016	$23
4.15	Major Component Rigging	$125	$0	$56	$0	$181	$32	$0	$32	$244	$0
4.16	Boiler Foundations	$0	$519	$369	$0	$888	$155	$0	$157	$1,200	$2

Case:	B12B.90 – Supercritical PC with 90 Percent CO_2 Capture										
Plant Size (MW, net):	650										
Estimate Type:	Conceptual										
Cost Base:	Jan 2023										
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
	Subtotal	**$404,764**	**$519**	**$186,507**	**$0**	**$591,790**	**$103,563**	**$0**	**$104,303**	**$799,656**	**$1,230**
5	**Flue Gas Cleanup**										
5.1	CANSOLV CO_2 Removal System	$180,748	$80,989	$150,861	$0	$412,598	$72,205	$70,142	$97,115	$652,060	$1,003
5.2	Wet FGD Absorber Vessels & Accessories	$98,978	$0	$17,871	$0	$116,849	$20,449	$0	$20,595	$157,892	$243
5.3	Other FGD	$1,577	$0	$1,025	$0	$2,602	$455	$0	$459	$3,516	$5
5.4	CO_2 Compression & Drying	$56,930	$8,309	$14,978	$0	$80,216	$14,038	$0	$18,851	$113,105	$174
5.5	CO_2 Compressor Aftercooler	$625	$97	$211	$0	$933	$163	$0	$219	$1,315	$2
5.6	Mercury Removal (DSI/ACI)	$3,323	$763	$2,758	$0	$6,843	$1,198	$0	$1,206	$9,247	$14
5.9	Particulate Removal (Bag House & Accessories)	w/ 5.2	w/ 5.2	w/ 5.2	w/ 5.2	$0	$0	$0	$0	$0	$0
5.12	Gas Cleanup Foundations	$0	$257	$182	$0	$439	$77	$0	$77	$593	$1
5.13	Gypsum Dewatering System	$1,030	$0	$135	$0	$1,166	$204	$0	$205	$1,575	$2
	Subtotal	**$343,211**	**$90,414**	**$188,021**	**$0**	**$621,646**	**$108,788**	**$70,142**	**$138,727**	**$939,303**	**$1,444**
7	**Ductwork & Stack**										
7.3	Ductwork	$0	$972	$546	$0	$1,518	$266	$0	$268	$2,051	$3
7.4	Stack	$11,867	$0	$5,398	$0	$17,265	$3,021	$0	$3,043	$23,329	$36
7.5	Duct & Stack Foundations	$0	$273	$263	$0	$536	$94	$0	$126	$756	$1
	Subtotal	**$11,867**	**$1,245**	**$6,207**	**$0**	**$19,319**	**$3,381**	**$0**	**$3,436**	**$26,136**	**$40**
8	**Steam Turbine & Accessories**										
8.1	Steam Turbine Generator & Accessories	$87,480	$0	$8,562	$0	$96,042	$16,807	$0	$16,927	$129,777	$200
8.2	Steam Turbine Plant Auxiliaries	$1,985	$0	$3,712	$0	$5,697	$997	$0	$1,004	$7,698	$12
8.3	Condenser & Auxiliaries	$14,750	$0	$3,986	$0	$18,736	$3,279	$0	$3,302	$25,317	$39
8.4	Steam Piping	$64,109	$0	$18,370	$0	$82,479	$14,434	$0	$14,537	$111,450	$171
8.5	Turbine Generator Foundations	$0	$337	$450	$0	$787	$138	$0	$185	$1,109	$2
	Subtotal	**$168,325**	**$337**	**$35,079**	**$0**	**$203,740**	**$35,655**	**$0**	**$35,955**	**$275,350**	**$423**
9	**Cooling Water System**										
9.1	Cooling Towers	$25,782	$0	$6,241	$0	$32,023	$5,604	$0	$5,644	$43,271	$67
9.2	Circulating Water Pumps	$3,613	$0	$209	$0	$3,822	$669	$0	$674	$5,164	$8
9.3	Circulating Water System Auxiliaries	$21,674	$0	$2,229	$0	$23,903	$4,183	$0	$4,213	$32,299	$50
9.4	Circulating Water Piping	$0	$9,656	$7,072	$0	$16,728	$2,927	$0	$2,948	$22,603	$35
9.5	Make-up Water System	$1,678	$0	$1,680	$0	$3,357	$587	$0	$592	$4,536	$7
9.6	Component Cooling Water System	$1,442	$0	$933	$0	$2,375	$416	$0	$419	$3,209	$5
9.7	Circulating Water System Foundations	$0	$901	$1,210	$0	$2,110	$369	$0	$496	$2,976	$5
	Subtotal	**$54,188**	**$10,557**	**$19,573**	**$0**	**$84,318**	**$14,756**	**$0**	**$14,985**	**$114,059**	**$175**
10	**Ash & Spent Sorbent Handling Systems**										
10.6	Ash Storage Silos	$1,588	$0	$3,770	$0	$5,359	$938	$0	$944	$7,241	$11
10.7	Ash Transport & Feed Equipment	$5,401	$0	$4,155	$0	$9,556	$1,672	$0	$1,684	$12,913	$20
10.9	Ash/Spent Sorbent Foundation	$0	$1,060	$1,055	$0	$2,115	$370	$0	$497	$2,982	$5
	Subtotal	**$6,989**	**$1,060**	**$8,981**	**$0**	**$17,029**	**$2,980**	**$0**	**$3,126**	**$23,135**	**$36**

Case:	B12B.90 – Supercritical PC with 90 Percent CO_2 Capture										
Plant Size (MW, net):	650								Estimate Type:	Conceptual	
									Cost Base:	Jan 2023	
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	Accessory Electric Plant										
11.1	Generator Equipment	$3,816	$0	$2,113	$0	$5,929	$1,038	$0	$1,045	$8,012	$12
11.2	Station Service Equipment	$10,776	$0	$679	$0	$11,455	$2,005	$0	$2,019	$15,478	$24
11.3	Switchgear & Motor Control	$16,729	$0	$2,130	$0	$18,859	$3,300	$0	$3,324	$25,484	$39
11.4	Conduit & Cable Tray	$0	$1,974	$4,600	$0	$6,573	$1,150	$0	$1,159	$8,882	$14
11.5	Wire & Cable	$0	$5,227	$7,555	$0	$12,782	$2,237	$0	$2,253	$17,272	$27
11.6	Protective Equipment	$79	$0	$201	$0	$280	$49	$0	$49	$378	$1
11.7	Standby Equipment	$1,182	$0	$801	$0	$1,983	$347	$0	$349	$2,679	$4
11.8	Main Power Transformers	$10,003	$0	$150	$0	$10,153	$1,777	$0	$1,789	$13,719	$21
11.9	Electrical Foundations	$0	$288	$593	$0	$882	$154	$0	$207	$1,243	$2
	Subtotal	**$42,586**	**$7,488**	**$18,822**	**$0**	**$68,896**	**$12,057**	**$0**	**$12,195**	**$93,148**	**$143**
12	Instrumentation & Control										
12.1	Pulverized Coal Boiler Control Equipment	$1,073	$0	$151	$0	$1,224	$214	$0	$216	$1,654	$3
12.3	Steam Turbine Control Equipment	$961	$0	$84	$0	$1,046	$183	$0	$184	$1,413	$2
12.5	Signal Processing Equipment	$1,218	$0	$171	$0	$1,389	$243	$0	$245	$1,877	$3
12.6	Control Boards, Panels, & Racks	$373	$0	$179	$0	$552	$97	$28	$101	$777	$1
12.7	Distributed Control System Equipment	$10,512	$0	$1,478	$0	$11,990	$2,098	$599	$2,203	$16,890	$26
12.8	Instrument Wiring & Tubing	$736	$574	$1,857	$0	$3,167	$554	$158	$582	$4,462	$7
12.9	Other Instrumentation & Controls Equipment	$905	$0	$1,652	$0	$2,557	$447	$128	$470	$3,602	$6
	Subtotal	**$15,778**	**$574**	**$5,573**	**$0**	**$21,925**	**$3,837**	**$913**	**$4,001**	**$30,676**	**$47**
13	Improvements to Site										
13.1	Site Preparation	$0	$602	$10,332	$0	$10,934	$1,914	$0	$2,570	$15,418	$24
13.2	Site Improvements	$0	$2,975	$3,180	$0	$6,155	$1,077	$0	$1,446	$8,679	$13
13.3	Site Facilities	$3,457	$0	$2,884	$0	$6,341	$1,110	$0	$1,490	$8,941	$14
	Subtotal	**$3,457**	**$3,577**	**$16,397**	**$0**	**$23,431**	**$4,100**	**$0**	**$5,506**	**$33,038**	**$51**
14	Buildings & Structures										
14.2	Boiler Building	$0	$15,114	$10,742	$0	$25,856	$4,525	$0	$4,557	$34,938	$54
14.3	Steam Turbine Building	$0	$21,008	$15,824	$0	$36,832	$6,446	$0	$6,492	$49,769	$77
14.4	Administration Building	$0	$1,364	$1,167	$0	$2,531	$443	$0	$446	$3,421	$5
14.5	Circulation Water Pumphouse	$0	$240	$154	$0	$394	$69	$0	$69	$532	$1
14.6	Water Treatment Buildings	$0	$600	$442	$0	$1,042	$182	$0	$184	$1,408	$2
14.7	Machine Shop	$0	$720	$391	$0	$1,111	$194	$0	$196	$1,501	$2
14.8	Warehouse	$0	$542	$438	$0	$980	$172	$0	$173	$1,324	$2
14.9	Other Buildings & Structures	$0	$378	$260	$0	$639	$112	$0	$113	$863	$1
14.10	Waste Treating Building & Structures	$0	$837	$2,050	$0	$2,887	$505	$0	$509	$3,901	$6
	Subtotal	**$0**	**$40,803**	**$31,468**	**$0**	**$72,272**	**$12,648**	**$0**	**$12,738**	**$97,657**	**$150**
	Total	**$1,208,120**	**$178,475**	**$580,707**	**$0**	**$1,967,303**	**$344,278**	**$71,055**	**$383,763**	**$2,766,399**	**$4,254**

Exhibit 3-90. Case B12B.90 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$16,301	$25
1 Month Maintenance Materials	$2,604	$4
1 Month Non-fuel Consumables	$3,956	$6
1 Month Waste Disposal	$1,317	$2
25% of 1 Months Fuel Cost at 100% CF	$3,855	$6
2% of TPC	$55,328	$85
Total	**$83,362**	**$128**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$37,481	$58
0.5% of TPC (spare parts)	$13,832	$21
Total	**$51,313**	**$79**
Other Costs		
Initial Cost for Catalyst and Chemicals	$6,070	$9
Land	$1,800	$3
Other Owner's Costs	$414,960	$638
Financing Costs	$74,693	$115
Total Overnight Costs (TOC)	**$3,398,597**	**$5,226**
TASC Multiplier (IOU, 33 year)	1.213	
Total As-Spent Cost (TASC)	**$4,121,571**	**$6,338**

Exhibit 3-91. Case B12B.90 initial and annual operating and maintenance costs

Case:	B12B.90 – Supercritical PC with 90 Percent CO_2 Capture				Cost Base:	Jan 2023
Plant Size (MW, net):	650	Heat Rate-net (Btu/kWh):	10,778		Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		45.04	**$/hour**	Skilled Operator:		2.0
Operating Labor Burden:		30.00	**% of base**	Operator:		11.3
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		2.0
				Total:		**16.3**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$8,377,366	$12.882
Maintenance Labor:					$17,704,953	$27.226
Administrative & Support Labor:					$6,520,580	$10.027
Property Taxes and Insurance:					$55,327,979	$85.081
Total:					**$87,930,878**	**$135.216**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$26,557,430	$5.485
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	6,698	$2.30	$0	$4,779,183	$0.987
Makeup and Waste Water Treatment Chemicals (ton):	0	20.0	$660.00	$0	$4,085,260	$0.844
Brominated Activated Carbon (ton):	0	1.58	$2,547.97	$0	$1,246,954	$0.258
Enhanced Hydrated Lime (ton):	0	39.7	$391.63	$0	$4,822,273	$0.996
Limestone (ton):	0	697	$30.18	$0	$6,530,202	$1.349
Ammonia (19 wt%, ton):	0	68.8	$280.00	$0	$5,976,268	$1.234
SCR Catalyst (ft^3):	17,344	15.8	$350.00	$6,070,239	$1,719,901	$0.355
CO_2 Capture System Chemicals[A]:	Proprietary				$11,038,182	$2.280
Triethylene Glycol (gal):	w/equip.	60	$8.50	$0	$157,270	$0.032
Subtotal:				**$6,070,239**	**$40,355,494**	**$8.334**
Waste Disposal						
Fly Ash (ton):	0	654	$46.71	$0	$9,480,940	$1.958
Bottom Ash (ton):	0	145	$46.71	$0	$2,105,969	$0.435
SCR Catalyst (ft^3):	0	15.8	$5.70	$0	$28,010	$0.006
Triethylene Glycol (gal):	0	3,029	$1.30	$0	$1,221,579	$0.252
Thermal Reclaimer Unit Waste (ton):	0	7.68	$250.00	$0	$595,759	$0.123
Subtotal:				**$0**	**$13,432,257**	**$2.774**
By-Products						
Gypsum (ton):	0	1060	$0.00	$0	$0	$0.000
Subtotal:				**$0**	**$0**	**$0.000**
Variable Operating Costs Total:				**$6,070,239**	**$80,345,181**	**$16.593**
Fuel Cost						
Illinois Number 6 (ton):	0	7,210	$70.32	$0	$157,297,066	$32.485
Total:				**$0**	**$157,297,066**	**$32.485**

[A]CO_2 Capture System Chemicals includes NaOH and CANSOLV Solvent

Exhibit 3-92. Case B12B.90 COE breakdown

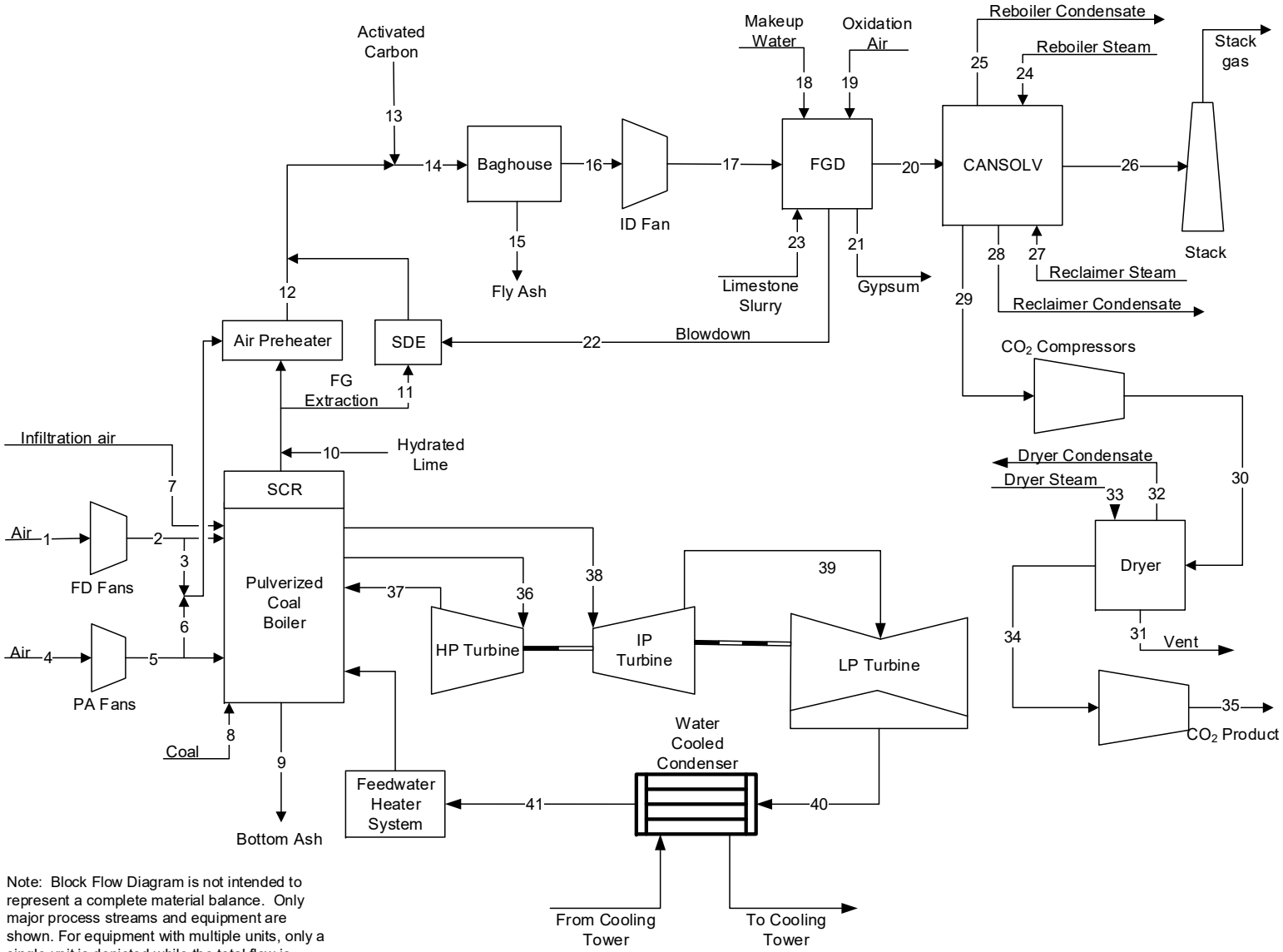
	FY COE		LCOE	
Component	Value, $/MWh	Percentage	Value, $/MWh	Percentage
Capital	65.6	46%	65.6	43%
Fixed	18.2	13%	24.2	16%
Variable	16.6	12%	22.2	15%
Fuel	32.5	23%	28.0	18%
Total (Excluding T&S)	**132.8**	**N/A**	**140.0**	**N/A**
CO_2 T&S	8.9	6%	11.9	8%
Total (Including T&S)	**141.7**	**N/A**	**151.9**	**N/A**

3.3.11 Case B12B.95 – SC PC with 95% CO_2 Capture Process Description

The plant configuration and process description for Case B12B.95 are nearly the same as Case B12B.90, with the exception that the PostCCC facility captures 95, rather than 90, percent of the CO_2 in the flue gas. Since the process descriptions of the plant and PostCCC facility were provided in Section 3.3.3 and Section 3.1.8, respectively, they are not repeated here.

The BFD for Case B12B.95 is shown in Exhibit 3-93. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit 3-94. The modeling assumptions are presented in Section 3.3.1.

Exhibit 3-93. Case B12B.95 BFD, SC unit with 95 percent CO_2 capture



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown. For equipment with multiple units, only a single unit is depicted while the total flow is reported.

Exhibit 3-94. Case B12B.95 stream table, SC unit with 95 percent CO_2 capture

	1	2	3	4	5	6	7	8	9	10	11	12
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	0.0087	0.0088
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1457	0.1379
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	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000	0.0879	0.0837
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7318	0.7340
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0237	0.0336
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0020
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	75,402	75,402	2,233	23,163	23,163	3,188	1,667	0	0	1	4,969	100,794
V-L Flowrate (kg/hr)	2,175,880	2,175,880	64,447	668,408	668,408	91,989	48,095	0	0	15	147,779	2,993,021
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	276,574	5,575	1,507	1,194	22,910
Temperature (°C)	15	17	17	15	24	24	15	15	1,316	15	385	143
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg)[A]	30.23	32.49	32.49	30.23	38.98	38.98	30.23	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-95.31	-95.31	-97.58	-88.83	-88.83	-97.58	-2,119.02	1,267.06	-13,402.95	-2,261.17	-2,394.31
Density (kg/m^3)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	1,003.6	0.5	0.8
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015	29.742	29.694
V-L Flowrate (lb_{mol}/hr)	166,234	166,234	4,924	51,065	51,065	7,028	3,674	0	0	2	10,954	222,214
V-L Flowrate (lb/hr)	4,796,995	4,796,995	142,081	1,473,587	1,473,587	202,801	106,031	0	0	34	325,796	6,598,482
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	609,741	12,291	3,323	2,631	50,508
Temperature (°F)	59	63	63	59	75	75	59	59	2,400	59	726	289
Pressure (psia)	14.7	15.0	15.0	14.7	15.9	15.9	14.7	14.7	14.3	14.7	14.3	14.1
Steam Table Enthalpy (Btu/lb)[A]	13.0	14.0	14.0	13.0	16.8	16.8	13.0	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-41.0	-41.0	-42.0	-38.2	-38.2	-42.0	-911.0	544.7	-5,762.2	-972.1	-1,029.4
Density (lb/ft^3)	0.076	0.077	0.077	0.076	0.080	0.080	0.076	---	---	62.650	0.033	0.052

[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 3-94. Case B12B.95 stream table, SC unit with 95 percent CO_2 capture (continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.1372	0.0000	0.1372	0.1372	0.0000	0.0003	0.1245	0.0001	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	0.0000	0.0911	0.0000	0.0911	0.0911	0.9999	0.0099	0.1508	0.9998	0.9943	0.9999	1.0000
HCl	0.0000	0.0001	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.7281	0.0000	0.7281	0.7281	0.0000	0.7732	0.6803	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0329	0.0000	0.0329	0.0329	0.0000	0.2074	0.0363	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0020	0.0000	0.0020	0.0020	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.1158	0.0000	0.0000	0.0001	0.0000	0.0000	0.0001	0.0009	0.0001	0.0000
$CaCl_2$	0.0000	0.0001	0.8842	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0048	0.0000	0.0000
Total	0.0000	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_{mol}/hr)	0	106,605	7	106,598	106,598	6,228	4,462	119,168	251	842	3,469	36,090
V-L Flowrate (kg/hr)	0	3,156,369	682	3,155,670	3,155,670	112,215	128,768	3,424,914	4,521	15,569	62,497	650,164
Solids Flowrate (kg/hr)	61	24,401	24,418	0	0	0	0	0	40,666	237	26,754	0
Temperature (°C)	15	143	143	143	156	15	15	57	15	57	15	269
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.48
Steam Table Enthalpy (kJ/kg)[A]	---	---	---	287.58	302.09	-47.80	30.23	297.00	---	---	---	3,000.14
AspenPlus Enthalpy (kJ/kg)[B]	-6.79	-2,453.14	-1,065.93	-2,464.17	-2,449.66	-16,015.01	-97.58	-2,939.24	-12,513.34	-15,496.23	-14,994.25	-12,980.15
Density (kg/m^3)	---	0.8	2,150.2	0.8	0.9	1,003.7	1.2	1.1	878.3	979.4	1,003.7	2.0
V-L Molecular Weight	---	29.608	104.898	29.603	29.603	18.019	28.857	28.740	18.021	18.494	18.019	18.015
V-L Flowrate (lb_{mol}/hr)	0	235,024	14	235,009	235,009	13,730	9,838	262,720	553	1,856	7,647	79,564
V-L Flowrate (lb/hr)	0	6,958,602	1,504	6,957,062	6,957,062	247,391	283,886	7,550,643	9,967	34,324	137,783	1,433,366
Solids Flowrate (lb/hr)	133	53,795	53,832	0	0	0	0	0	89,653	522	58,983	0
Temperature (°F)	59	289	289	289	313	59	59	135	59	135	59	516
Pressure (psia)	14.7	14.1	14.1	13.9	15.3	14.7	14.7	14.8	14.7	14.7	14.7	70.0
Steam Table Enthalpy (Btu/lb)[A]	---	---	---	123.6	129.9	-20.5	13.0	127.7	---	---	---	1,289.8
AspenPlus Enthalpy (Btu/lb)[B]	-2.9	-1,054.7	-458.3	-1,059.4	-1,053.2	-6,885.2	-42.0	-1,263.6	-5,379.8	-6,662.2	-6,446.4	-5,580.5
Density (lb/ft^3)	---	0.052	134.232	0.051	0.055	62.658	0.076	0.067	54.833	61.145	62.658	0.122

[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 3-94. Case B12B.95 stream table, SC unit with 95 percent CO_2 capture (continued)

	25	26	27	28	29	30	31	32	33	34	35	36
V-L Mole Fraction												
Ar	0.0000	0.0102	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0079	0.0000	0.0000	0.9783	0.9975	0.0500	0.0000	0.0000	0.9995	0.9995	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	1.0000	0.0807	1.0000	1.0000	0.0217	0.0025	0.9500	1.0000	1.0000	0.0005	0.0005	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.8555	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0457	0.0000	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	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
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_{mol}/hr)	33,054	94,758	392	392	14,400	14,122	30	18	18	14,092	14,092	135,250
V-L Flowrate (kg/hr)	595,482	2,618,773	7,064	7,064	625,596	620,597	572	330	330	620,024	620,024	2,436,565
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	105	45	342	214	31	29	29	203	461	29	30	593
Pressure (MPa, abs)	0.12	0.10	4.90	2.04	0.17	2.81	2.81	1.64	2.14	2.68	15.27	24.23
Steam Table Enthalpy (kJ/kg)[A]	439.34	179.09	3,049.81	913.81	46.68	-3.05	137.94	863.65	3,379.61	-3.59	-231.09	3,477.96
AspenPlus Enthalpy (kJ/kg)[B]	-15,540.95	-797.41	-12,930.48	-15,066.49	-8,978.62	-8,972.51	-15,225.22	-15,116.65	-12,600.69	-8,967.15	-9,194.65	-12,502.33
Density (kg/m^3)	954.9	1.1	19.2	848.5	3.0	57.8	351.5	861.8	6.4	54.7	630.1	69.2
V-L Molecular Weight	18.015	27.637	18.015	18.015	43.445	43.945	19.315	18.015	18.015	43.997	43.997	18.015
V-L Flowrate (lb_{mol}/hr)	72,872	208,905	864	864	31,746	31,134	65	40	40	31,069	31,069	298,175
V-L Flowrate (lb/hr)	1,312,812	5,773,406	15,573	15,573	1,379,204	1,368,181	1,262	728	728	1,366,920	1,366,920	5,371,707
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	221	113	648	416	87	85	85	397	862	85	86	1,100
Pressure (psia)	17.4	14.8	710.8	296.6	24.7	407.6	407.6	237.4	310.1	389.1	2,214.7	3,514.7
Steam Table Enthalpy (Btu/lb)[A]	188.9	77.0	1,311.2	392.9	20.1	-1.3	59.3	371.3	1,453.0	-1.5	-99.4	1,495.3
AspenPlus Enthalpy (Btu/lb)[B]	-6,681.4	-342.8	-5,559.1	-6,477.4	-3,860.1	-3,857.5	-6,545.7	-6,499.0	-5,417.3	-3,855.2	-3,953.0	-5,375.0
Density (lb/ft^3)	59.612	0.066	1.197	52.968	0.184	3.609	21.943	53.801	0.402	3.416	39.338	4.319

[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 3-94. Case B12B.95 stream table, SC unit with 95 percent CO_2 capture (continued)

	37	38	39	40	41
V-L Mole Fraction					
Ar	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	112,678	112,678	97,029	41,067	64,246
V-L Flowrate (kg/hr)	2,029,920	2,029,920	1,747,998	739,838	1,157,402
Solids Flowrate (kg/hr)	0	0	0	0	0
Temperature (°C)	342	593	270	38	39
Pressure (MPa, abs)	4.90	4.80	0.52	0.01	1.26
Steam Table Enthalpy (kJ/kg)[A]	3,049.81	3,652.36	3,000.14	2,343.61	162.36
AspenPlus Enthalpy (kJ/kg)[B]	-12,930.48	-12,327.93	-12,980.15	-13,636.69	-15,817.93
Density (kg/m^3)	19.2	12.3	2.1	0.1	993.3
V-L Molecular Weight	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	248,412	248,412	213,911	90,538	141,637
V-L Flowrate (lb/hr)	4,475,208	4,475,208	3,853,675	1,631,063	2,551,634
Solids Flowrate (lb/hr)	0	0	0	0	0
Temperature (°F)	648	1,100	517	101	101
Pressure (psia)	710.8	696.6	75.0	1.0	183.1
Steam Table Enthalpy (Btu/lb)[A]	1,311.2	1,570.2	1,289.8	1,007.6	69.8
AspenPlus Enthalpy (Btu/lb)[B]	-5,559.1	-5,300.1	-5,580.5	-5,862.7	-6,800.5
Density (lb/ft^3)	1.197	0.768	0.131	0.003	62.009

[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

3.3.12 Case B12B.95 – Performance Results

Overall plant performance is summarized in Exhibit 3-95; Exhibit 3-96 provides a detailed breakdown of the auxiliary power requirements.

The PostCCC facility and CO_2 compression combined account for over half of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for 11 percent of the auxiliary load, largely due to the high cooling water demand of the PostCCC 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. By increasing the boiler and turbine/generator size to account for the greater auxiliary load imposed by the PostCCC facility and CO_2 compressors, a net output of 650 MW is maintained at a reduced net plant efficiency of 31.2 percent (HHV basis).

Exhibit 3-95. Case B12B.95 plant performance summary

Performance Summary	
Total Gross Power, MWe	**768**
CO_2 Capture/Removal Auxiliaries, kWe	19,200
CO_2 Compression, kWe	49,640
Balance of Plant, kWe	49,030
Total Auxiliaries, MWe	**118**
Net Power, MWe	**650**
HHV Net Plant Efficiency, %	31.2
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,540 (10,938)
LHV Net Plant Efficiency, %	32.3
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,131 (10,550)
HHV Boiler Efficiency, %	88.0
LHV Boiler Efficiency, %	91.3
Steam Turbine Cycle Efficiency, %	58.2
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	6,189 (5,866)
Condenser Duty, GJ/hr (MMBtu/hr)	2,064 (1,956)
CO_2 Capture Rate, %	95
AGR Duty, GJ/hr (MMBtu/hr)	2,177 (2,064)
As-Received Coal Feed, kg/hr (lb/hr)	276,574 (609,741)
Limestone Sorbent Feed, kg/hr (lb/hr)	26,754 (58,983)
HHV Thermal Input, kWt	2,084,684
LHV Thermal Input, kWt	2,010,703
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.055 (14.6)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.041 (10.9)
Excess Air, %	20.3

Exhibit 3-96. Case B12B.95 plant power summary

Power Summary	
Steam Turbine Power, MWe	768
Total Gross Power, MWe	**768**
Auxiliary Load Summary	
Activated Carbon Injection, kWe	40
Ash Handling, kWe	910
Baghouse, kWe	120
Circulating Water Pumps, kWe	9,230
CO_2 Capture/Removal Auxiliaries, kWe	19,200
CO_2 Compression, kWe	49,640
Coal Handling and Conveying, kWe	530
Condensate Pumps, kWe	800
Cooling Tower Fans, kWe	4,770
Dry Sorbent Injection, kWe	80
Flue Gas Desulfurizer, kWe	4,270
Forced Draft Fans, kWe	1,420
Ground Water Pumps, kWe	860
Induced Draft Fans, kWe	13,110
Miscellaneous Balance of Plant[A,B], kWe	2,250
Primary Air Fans, kWe	1,680
Pulverizers, kWe	4,150
SCR, kWe	50
Sorbent Handling & Reagent Preparation, kWe	1,290
Spray Dryer Evaporator, kWe	300
Steam Turbine Auxiliaries, kWe	500
Transformer Losses, kWe	2,670
Total Auxiliaries, MWe	**118**
Net Power, MWe	**650**

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

3.3.12.1 Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, and PM are presented in Section 2.4. A summary of the plant air emissions for Case B12B.95 is presented in Exhibit 3-97. SO_2 emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit 3-97. Case B12B.95 air emissions

	kg/GJ (lb/MMBtu)[A]	tonne/year (ton/year)[B]	kg/MWh (lb/MWh)[C]
SO_2	0.000 (0.000)	0 (0)	0.000 (0.000)
NOx	0.033 (0.076)	1,816 (2,002)	0.318 (0.700)
Particulate	0.004 (0.010)	234 (257)	0.041 (0.090)
Hg	1.39E-7 (3.24E-7)	0.008 (0.009)	1.36E-6 (3.00E-6)
CO_2	4 (10)	244,496 (269,510)	43 (94)
CO_2[D]	–	–	50 (111)
	mg/Nm³		
Particulate Concentration[E,F]	13.13		

[A]Based on thermal input on an HHV basis
[B]Calculations based on an 85 percent capacity factor
[C]Emissions based on gross power except where otherwise noted
[D]CO_2 emissions based on net power instead of gross power
[E]Concentration of particles in the flue gas after the baghouse
[F]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 0.37 ppmv using a NaOH based polishing scrubber in the PostCCC facility. The remaining low concentration of SO_2 is essentially completely removed in the PostCCC absorber vessel resulting in very low SO_2 emissions (reported as zero here).

NOx emissions are controlled to about 0.15 kg/GJ (0.35 lb/MMBtu) using LNBs and OFA. An SCR unit then further reduces the NOx concentration by 78.4 percent to 0.03 kg/GJ (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 97.5 percent.

The carbon balance for the plant is shown in Exhibit 3-98. 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 product from the CO_2 compression train; however, some CO_2 exits through the stack and the CO_2 dryer's vent, 20 percent of the unburned carbon remains in the bottom ash, the remaining unburned carbon is captured in the

fabric filter, along with the PAC, and some carbon leaves as gypsum. The carbon conversion is assumed to be 99.4 percent.

Ninety-five percent of the CO_2 in the flue gas is removed in PostCCC facility. The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in (minus unburnt carbon in the ash), represented by the following percentage:

$$1 - \frac{Carbon\ in\ Stack}{Total\ Carbon\ In - Unburnt\ Carbon} = \left(1 - \left(\frac{19{,}757}{395{,}702 - 2{,}332}\right)\right) * 100 = 95\%$$

Where the unburned carbon is equal to one minus the carbon conversion rate times the carbon in the coal:

$$(1 - Carbon\ Conversion) * Carbon\ in\ Coal = (1 - 0.994) * 388{,}678 = 2{,}332$$

Exhibit 3-98. Case B12B.95 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	176,301 (388,678)	Stack Gas	8,961 (19,757)
Air (CO_2)	411 (906)	FGD Product	209 (461)
PAC	61 (133)	Baghouse	907 (1,999)
FGD Reagent	2,715 (5,985)	Bottom Ash	212 (466)
		CO_2 Product	169,180 (372,979)
		CO_2 Dryer Vent	18 (39)
		CO_2 Knockout	0.5 (1.1)
Total	**179,487 (395,702)**	**Total**	**179,487 (395,702)**

Exhibit 3-99 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 removed in the polishing scrubber, and sulfur removed in the baghouse via hydrated lime.

Exhibit 3-99. Case B12B.95 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	6,932 (15,283)	FGD Product	6,517 (14,368)
		Stack Gas	0 (0)
		Polishing Scrubber and Solvent Reclaiming	135 (299)
		Baghouse	279 (616)
Total	**6,932 (15,283)**	**Total**	**6,932 (15,283)**

Water demand, recycle, withdrawal, discharge, and consumption are defined and discussed in Section 2.6. Exhibit 3-100 shows the overall water balance for the plant. The exhibit is presented in an identical manner as for Case B12A. The only notable difference is the FGD makeup water source. In CO_2 capture cases, a significant amount of water is recovered from the initial PostCCC facility cooling step. This water is assumed suitable to be used as FGD makeup, with the balance of the water from the PostCCC facility discharged.

Exhibit 3-100. Case B12B.95 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 Process Makeup	1.9 (495)	1.9 (495)	–	–	–
FGD Slurry Water	1.0 (276)	1.0 (276)	–	–	–
CO_2 Drying	–	–	–	0.0 (2.5)	0.0 (-2.5)
CO_2 Capture Recovery	–	–	–	1.0 (266)	-1.0 (-266)
CO_2 Compression KO	–	–	–	0.1 (22)	-0.1 (-22)
Deaerator Vent	–	–	–	0.1 (22)	-0.1 (-22)
Condenser Makeup	**0.1 (22)**	**–**	**0.1 (22)**	**–**	**0.1 (22)**
BFW Makeup	0.1 (22)	–	0.1 (22)	–	0.1 (22)
Cooling Tower	**36 (9,494)**	**–**	**36 (9,494)**	**8.1 (2,135)**	**28 (7,359)**
BFW Blowdown	–	–	–	–	–
Total	**39 (10,286)**	**2.9 (770)**	**36 (9,516)**	**9.3 (2,447)**	**27 (7,069)**

3.3.12.2 Energy and Mass Balance Diagrams

Energy and mass balance diagrams are shown for the Case B12B.95 PC boiler, FGD unit, PostCCC system, and steam cycle in Exhibit 3-101 and Exhibit 3-102.

An overall plant energy balance is provided in tabular form in Exhibit 3-103. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-95) is calculated by multiplying the power out by a generator efficiency of 98.5 percent.

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Exhibit 3-101. Case B12B.95 energy and mass balance, SC PC boiler with CO_2 capture

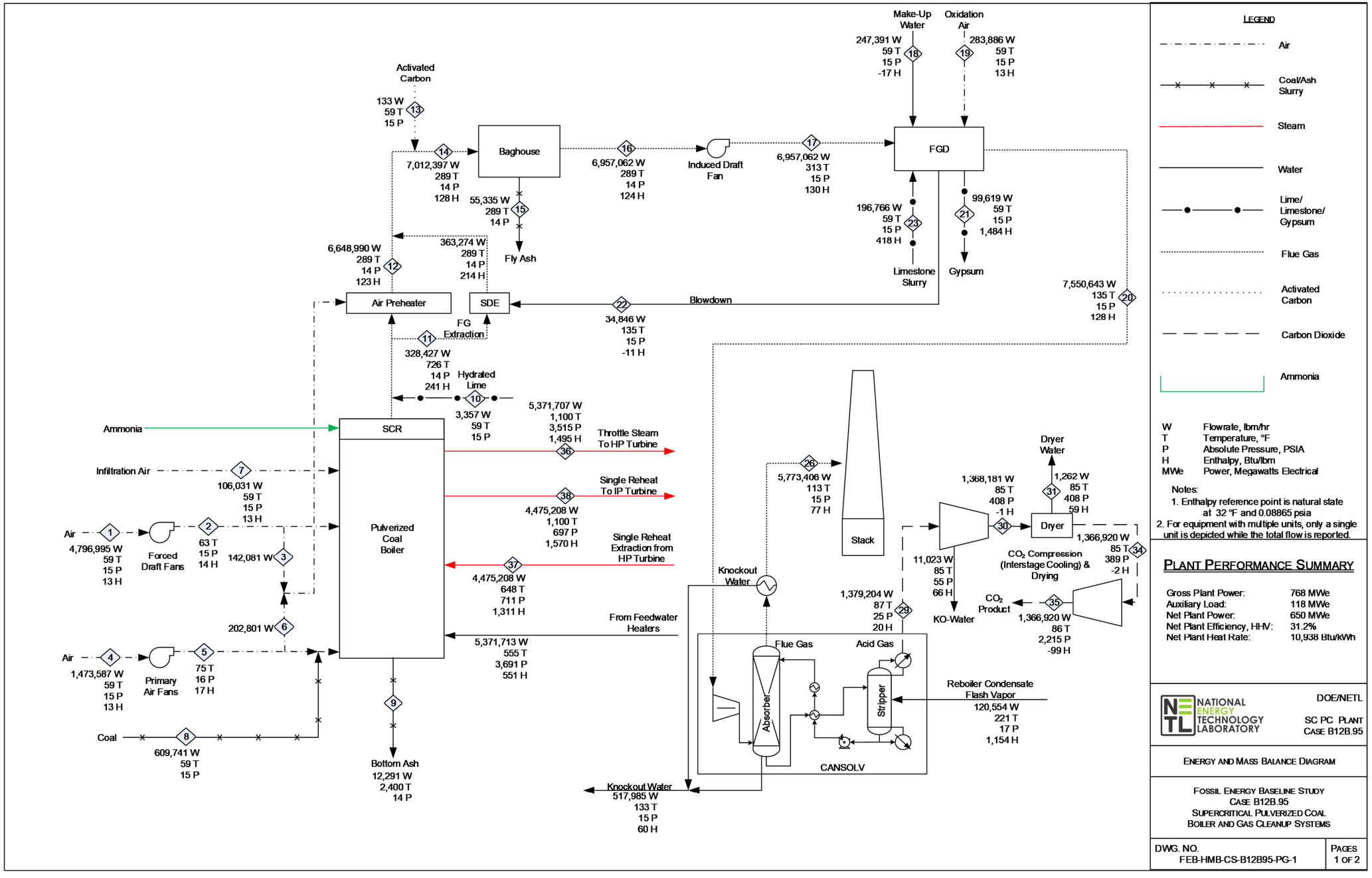


Exhibit 3-102. Case B12B.95 energy and mass balance, SC steam cycle

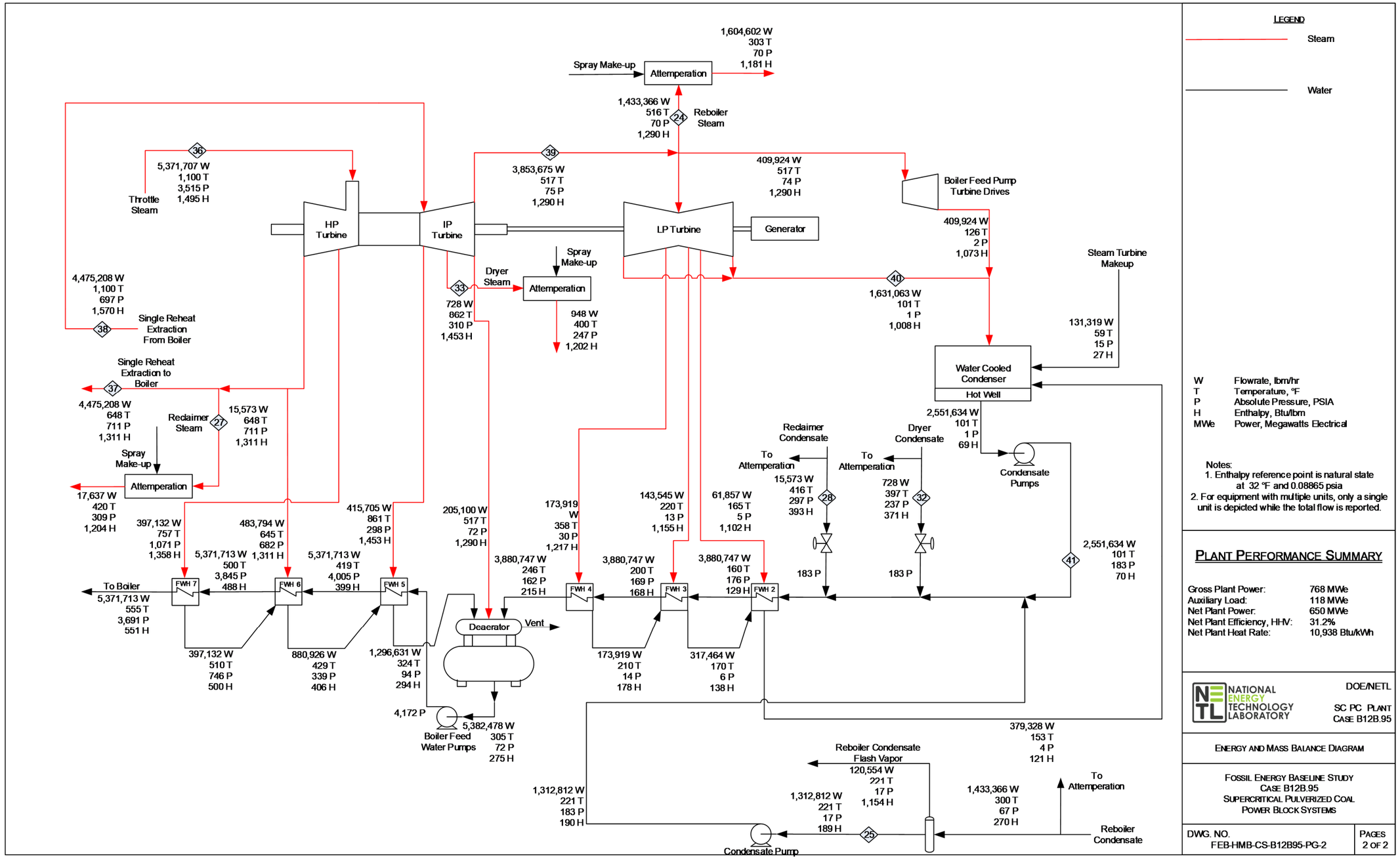


Exhibit 3-103. Case B12B.95 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, GJ/hr (MMBtu/hr)				
Coal	7,505 (7,113)	6.3 (5.9)	–	7,511 (7,119)
Air	–	87 (83)	–	87 (83)
Raw Water Makeup	–	135 (128)	–	135 (128)
Limestone	–	0.6 (0.6)	–	0.6 (0.6)
Auxiliary Power	–	–	424 (402)	424 (402)
TOTAL	**7,505 (7,113)**	**230 (218)**	**424 (402)**	**8,159 (7,733)**
Heat Out, GJ/hr (MMBtu/hr)				
Bottom Ash	–	7.1 (6.7)	–	7.1 (6.7)
Fly Ash	–	2.6 (2.4)	–	2.6 (2.4)
Stack Gas	–	469 (445)	–	469 (445)
Sulfur	2.5 (2.4)	0.0 (0.0)	–	2.5 (2.4)
Gypsum	–	2.6 (2.5)	–	2.6 (2.5)
Motor Losses and Design Allowances	–	–	51 (48)	51 (48)
Cooling Tower Load[A]	–	4,693 (4,448)	–	4,693 (4,448)
CO_2 Product Stream	–	-143 (-136)	–	-143 (-136)
AGR Effluent	–	55 (52)	–	55 (52)
Blowdown Streams and Deaerator Vent	–	3.1 (2.9)	–	3.1 (2.9)
Ambient Losses[B]	–	*178 (168)*	–	*178 (168)*
Power	–	–	2,766 (2,621)	2,766 (2,621)
TOTAL	**2.5 (2.4)**	**5,267 (4,992)**	**2,816 (2,669)**	**8,086 (7,664)**
Unaccounted Energy[C]	–	*73 (70)*	–	*73 (70)*

[A]Includes condenser, capture process, CO_2 compressor, and miscellaneous cooling loads
[B]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers
[C]By difference

3.3.13 Case B12B.95 – 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. Values reported in the equipment lists are rounded.

Case B12B.95 – 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	60 tonne (60 ton)	2	1
9	Feeder	Vibratory	230 tonne/hr (250 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	460 tonne/hr (500 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	230 tonne (250 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	460 tonne/hr (500 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	460 tonne/hr (500 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	1,010 tonne (1,120 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 11 tonne (12 ton) Feeder - 70 kg/hr (150 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 280 tonne (310 ton) Feeder - 1,670 kg/hr (3,690 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	112 tonne/hr (124 tph)	1	0
23	Limestone Conveyor No. 1	Belt	112 tonne/hr (124 tph)	1	0
24	Limestone Reclaim Hopper	N/A	22 tonne (24 ton)	1	0
25	Limestone Reclaim Feeder	Belt	88 tonne/hr (97 tph)	1	0
26	Limestone Conveyor No. 2	Belt	88 tonne/hr (97 tph)	1	0
27	Limestone Day Bin	w/ actuator	353 tonne (389 ton)	2	0

Case B12B.95 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	51 tonne/hr (56 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	51 tonne/hr (56 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	29 tonne/hr (32 tph)	1	1
4	Limestone Ball Mill	Rotary	29 tonne/hr (32 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	114,000 liters (30,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,890 lpm @ 10 m H_2O (500 gpm @ 40 ft H_2O)	1	1
7	Hydrocyclone Classifier	4 active cyclones in a 5-cyclone bank	470 lpm (130 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	636,000 liters (168,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,330 lpm @ 9 m H_2O (350 gpm @ 30 ft H_2O)	1	1

Case B12B.95 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	323,000 liters (85,300 gal)	2	0
2	Condensate Pumps	Vertical canned	10,700 lpm @ 200 m H_2O (2,820 gpm @ 500 ft H_2O)	2	1
3	Deaerator and Storage Tank	Horizontal spray type	1,343,000 kg/hr (2,960,000 lb/hr), 5 min. tank	2	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	22,000 lpm @ 3,500 m H_2O (5,900 gpm @ 11,400 ft H_2O)	2	2
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	6,700 lpm @ 3,500 m H_2O (1,800 gpm @ 11,400 ft H_2O)	2	0
6	LP Feedwater Heater 2A/2B	Horizontal U-tube	480,000 kg/hr (1,070,000 lb/hr)	4	0
7	LP Feedwater Heater 3A/3B	Horizontal U-tube	480,000 kg/hr (1,070,000 lb/hr)	4	0
8	LP Feedwater Heater 4A/4B	Horizontal U-tube	480,000 kg/hr (1,070,000 lb/hr)	4	0
9	HP Feedwater Heater 5	Horizontal U-tube	1,340,000 kg/hr (2,950,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	1,340,000 kg/hr (2,950,000 lb/hr)	2	0
11	HP Feedwater Heater 7	Horizontal U-tube	1,340,000 kg/hr (2,950,000 lb/hr)	2	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	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
14	Service Air Compressors	Flooded screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
15	Instrument Air Dryers	Duplex, regenerative	28 m3/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	9,600 lpm @ 20 m H_2O (2,540 gpm @ 60 ft H_2O)	2	1
21	Ground Water Pumps	Stainless steel, single suction	3,850 lpm @ 270 m H_2O (1,020 gpm @ 880 ft H_2O)	5	1
22	Filtered Water Pumps	Stainless steel, single suction	1,200 lpm @ 50 m H_2O (310 gpm @ 160 ft H_2O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	1,139,000 liter (301,000 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	330 lpm (90 gpm)	1	1
25	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
26	Process Water Treatment	Spray dryer evaporator	Flue Gas - 2,550 m3/min (89,900 acfm) @ 385°C (726°F) & 0.1 MPa (14 psia) Blowdown - 150 lpm (40 gpm) @ 19,982 ppmw Cl^-	2	1

Case B12B.95 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, once-through, wall-fired, low NOx burners, overfire air	2,680,000 kg/hr steam @ 24.1 MPa/593°C/593°C (5,910,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	368,000 kg/hr, 5,000 m^3/min @ 101 cm WG (810,000 lb/hr, 177,200 acfm @ 40 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	1,197,000 kg/hr, 16,300 m^3/min @ 26 cm WG (2,638,000 lb/hr, 577,000 acfm @ 10 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,736,000 kg/hr, 35,200 m^3/min @ 114 cm WG (3,826,000 lb/hr, 1,242,000 acfm @ 45 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	3,280,000 kg/hr (7,240,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	130 m^3/min @ 108 cm WG (4,500 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	139,000 liter (36,700 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	27 lpm @ 90 m H_2O (7 gpm @ 300 ft H_2O)	2	1

Case B12B.95 – 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	1,736,000 kg/hr (3,827,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	58,800 m^3/min (2,080,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	204,000 lpm @ 65 m H_2O (54,000 gpm @ 210 ft H_2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	5,650 lpm (1,490 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	970 m^3/min @ 0.3 MPa (34,130 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,410 lpm (370 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	45 tonne/hr (49 tph) of 50 wt% slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	860 lpm @ 13 m H_2O (230 gpm @ 40 ft H_2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	560,000 lpm (150,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	2,060 lpm @ 21 m H_2O (540 gpm @ 70 ft H_2O)	1	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
12	Activated Carbon Injectors	---	70 kg/hr (150 lb/hr)	1	0
13	Hydrated Lime Injectors	---	1,670 kg/hr (3,690 lb/hr)	1	0
14	CANSOLV	Amine-based CO_2 capture technology	3,767,000 kg/hr (8,306,000 lb/hr) 19.1 wt% CO_2 concentration	1	0
15	CANSOLV LP Condensate Pump	Centrifugal	1,426 lpm @ 1 m H_2O (377 gpm @ 3 ft H_2O)	1	1
16	CANSOLV IP Condensate Pump	Centrifugal	17 lpm @ 4.6 m H_2O (5 gpm @ 15 ft H_2O)	1	1
17	CO_2 Dryer	Triethylene glycol	Inlet: 179 m^3/min @ 2.8 MPa (6,318 acfm @ 408 psia) Outlet: 2.7 MPa (389 psia) Water Recovered: 572 kg/hr (1,262 lb/hr)	1	0
18	CO_2 Compressor	Integrally geared, multi-stage centrifugal	9.0 m^3/min @ 15.3 MPa, 82°C (319 acfm @ 2,217 psia, 180°F)	2	0
19	CO_2 Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 98 GJ/hr (93 MMBtu/hr)	1	0

Case B12B.95 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.3 m (21 ft) diameter	1	0

Case B12B.95 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	809 MW 24.1 MPa/593°C/593°C (3,500 psig/1,100°F/1,100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	900 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,270 GJ/hr (2,150 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0

Case B12B.95 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	926,000 lpm @ 30 m (245,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 5,160 GJ/hr (4,890 MMBtu/hr) heat duty	1	0

Case B12B.95 – Account 10: Ash and Spent Sorbent Handling System

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	–	6.1 tonne/hr (6.8 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	25 m^3/min @ 0.2 MPa (875 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,630 tonne (1,790 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	150 tonne/hr (170 tph)	1	0

Case B12B.95 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 760 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 28 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 54 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 19 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.95 – 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

3.3.14 Case B12B.95 – Cost Estimating

The cost estimating methodology is described in Section 2.7. Exhibit 3-104 shows a detailed breakdown of the capital costs; Exhibit 3-105 shows the owner's costs, TOC, and TASC; Exhibit 3-106 shows the initial and annual O&M costs; and Exhibit 3-107 shows the COE breakdown.

For PC cases, existing costs were escalated to reflect a 2023-year dollar using the methodology outlined in NETL's current QGESS (NETL, 2025a).

The estimated TPC of the SC PC boiler with CO_2 capture is $4,331/kW. Process contingency represents 2.6 percent of the TPC and project contingency represents 13.9 percent of the TPC. The FY COE, including T&S costs of $9.8/MWh, is $145.0/MWh. The LCOE, including T&S costs of $13.1/MWh, is $155.6/MWh.

Exhibit 3-104. Case B12B.95 total plant cost details

Case:	B12B.95 – Supercritical PC with 95 Percent CO_2 Capture					Estimate Type:			Conceptual	
Plant Size (MW, net):	650					Cost Base:			Jan 2023	
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
1	Coal & Sorbent Handling										
1.1	Coal Receive & Unload	$1,608	$0	$562	$0	$2,171	$380	$0	$383	$2,933	$5
1.2	Coal Stackout & Reclaim	$5,280	$0	$916	$0	$6,196	$1,084	$0	$1,092	$8,372	$13
1.3	Coal Conveyors	$48,654	$0	$8,980	$0	$57,634	$10,086	$0	$10,158	$77,878	$120
1.4	Other Coal Handling	$6,760	$0	$1,103	$0	$7,863	$1,376	$0	$1,386	$10,624	$16
1.5	Sorbent Receive & Unload	$309	$0	$72	$0	$381	$67	$0	$67	$515	$1
1.6	Sorbent Stackout & Reclaim	$2,263	$0	$317	$0	$2,580	$452	$0	$455	$3,486	$5
1.7	Sorbent Conveyors	$3,429	$716	$644	$0	$4,788	$838	$0	$844	$6,470	$10
1.8	Other Sorbent Handling	$165	$37	$66	$0	$268	$47	$0	$47	$362	$1
1.9	Coal & Sorbent Handling Foundations	$0	$2,143	$2,285	$0	$4,428	$775	$0	$780	$5,984	$9
	Subtotal	**$68,468**	**$2,896**	**$14,945**	**$0**	**$86,309**	**$15,104**	**$0**	**$15,211**	**$116,625**	**$179**
2	Coal & Sorbent Preparation & Feed										
2.1	Coal Crushing & Drying	$3,458	$0	$515	$0	$3,974	$695	$0	$700	$5,369	$8
2.2	Prepared Coal Storage & Feed	$11,640	$0	$1,945	$0	$13,585	$2,377	$0	$2,394	$18,356	$28
2.5	Sorbent Preparation Equipment	$1,522	$63	$242	$0	$1,827	$320	$0	$322	$2,469	$4
2.6	Sorbent Storage & Feed	$2,552	$0	$747	$0	$3,299	$577	$0	$581	$4,458	$7
2.9	Coal & Sorbent Feed Foundation	$0	$969	$688	$0	$1,657	$290	$0	$292	$2,239	$3
	Subtotal	**$19,172**	**$1,033**	**$4,137**	**$0**	**$24,342**	**$4,260**	**$0**	**$4,290**	**$32,892**	**$51**
3	Feedwater & Miscellaneous BOP Systems										
3.1	Feedwater System	$5,428	$8,967	$3,626	$0	$18,021	$3,154	$0	$3,176	$24,351	$37
3.2	Water Makeup & Pretreating	$10,833	$1,044	$4,784	$0	$16,661	$2,916	$0	$3,915	$23,493	$36
3.3	Other Feedwater Subsystems	$4,249	$1,343	$1,032	$0	$6,623	$1,159	$0	$1,167	$8,950	$14
3.4	Service Water Systems	$3,427	$6,304	$16,510	$0	$26,241	$4,592	$0	$6,167	$36,999	$57
3.5	Other Boiler Plant Systems	$1,009	$369	$745	$0	$2,122	$371	$0	$374	$2,868	$4
3.6	Natural Gas Pipeline and Start-Up System	$4,905	$189	$114	$0	$5,208	$911	$0	$918	$7,037	$11
3.7	Waste Water Treatment Equipment	$17,852	$0	$8,527	$0	$26,379	$4,616	$0	$6,199	$37,194	$57
3.8	Spray Dryer Evaporator	$23,140	$0	$10,441	$0	$33,581	$5,877	$0	$7,891	$47,349	$73
3.9	Miscellaneous Plant Equipment	$306	$39	$121	$0	$466	$82	$0	$109	$657	$1
	Subtotal	**$71,147**	**$18,254**	**$45,901**	**$0**	**$135,302**	**$23,678**	**$0**	**$29,917**	**$188,897**	**$290**
4	Pulverized Coal Boiler & Accessories										
4.9	Pulverized Coal Boiler & Accessories	$351,598	$0	$162,766	$0	$514,364	$90,014	$0	$90,657	$695,035	$1,069
4.10	Selective Catalytic Reduction System	$41,310	$0	$18,385	$0	$59,695	$10,447	$0	$10,521	$80,663	$124
4.11	Boiler Balance of Plant	$2,311	$0	$1,070	$0	$3,380	$592	$0	$596	$4,568	$7
4.12	Primary Air System	$2,409	$0	$1,027	$0	$3,436	$601	$0	$606	$4,643	$7
4.13	Secondary Air System	$3,649	$0	$1,555	$0	$5,204	$911	$0	$917	$7,032	$11
4.14	Induced Draft Fans	$7,872	$0	$3,355	$0	$11,226	$1,965	$0	$1,979	$15,170	$23
4.15	Major Component Rigging	$126	$0	$56	$0	$182	$32	$0	$32	$247	$0

Case:	B12B.95 – Supercritical PC with 95 Percent CO_2 Capture									
Plant Size (MW, net):	650					Estimate Type:	Conceptual			
						Cost Base:	Jan 2023			
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
4.16	Boiler Foundations	$0	$524	$373	$0	$897	$157	$0	$158	$1,212	$2
	Subtotal	**$409,276**	**$524**	**$188,586**	**$0**	**$598,386**	**$104,718**	**$0**	**$105,466**	**$808,570**	**$1,243**
5	Flue Gas Cleanup										
5.1	CANSOLV CO_2 Removal System	$188,382	$83,920	$156,322	$0	$428,624	$75,009	$72,866	$100,887	$677,386	$1,042
5.2	Wet FGD Absorber Vessels & Accessories	$100,051	$0	$18,065	$0	$118,116	$20,670	$0	$20,818	$159,604	$245
5.3	Other FGD	$1,595	$0	$1,036	$0	$2,632	$461	$0	$464	$3,556	$5
5.4	CO_2 Compression & Drying	$59,377	$8,666	$15,622	$0	$83,665	$14,641	$0	$19,661	$117,968	$181
5.5	CO_2 Compressor Aftercooler	$662	$102	$223	$0	$988	$173	$0	$232	$1,393	$2
5.6	Mercury Removal (DSI/ACI)	$3,361	$772	$2,790	$0	$6,923	$1,211	$0	$1,220	$9,354	$14
5.9	Particulate Removal (Bag House & Accessories)	w/ 5.2	w/ 5.2	w/ 5.2	w/ 5.2	$0	$0	$0	$0	$0	$0
5.12	Gas Cleanup Foundations	$0	$260	$184	$0	$444	$78	$0	$78	$600	$1
5.13	Gypsum Dewatering System	$1,039	$0	$137	$0	$1,176	$206	$0	$207	$1,589	$2
	Subtotal	**$354,467**	**$93,720**	**$194,378**	**$0**	**$642,566**	**$112,449**	**$72,866**	**$143,568**	**$971,449**	**$1,494**
7	Ductwork & Stack										
7.3	Ductwork	$0	$976	$549	$0	$1,525	$267	$0	$269	$2,060	$3
7.4	Stack	$11,871	$0	$5,400	$0	$17,271	$3,022	$0	$3,044	$23,338	$36
7.5	Duct & Stack Foundations	$0	$274	$263	$0	$537	$94	$0	$126	$757	$1
	Subtotal	**$11,871**	**$1,250**	**$6,211**	**$0**	**$19,333**	**$3,383**	**$0**	**$3,439**	**$26,155**	**$40**
8	Steam Turbine & Accessories										
8.1	Steam Turbine Generator & Accessories	$87,913	$0	$8,604	$0	$96,517	$16,891	$0	$17,011	$130,419	$201
8.2	Steam Turbine Plant Auxiliaries	$1,995	$0	$3,730	$0	$5,725	$1,002	$0	$1,009	$7,736	$12
8.3	Condenser & Auxiliaries	$14,488	$0	$3,915	$0	$18,402	$3,220	$0	$3,243	$24,866	$38
8.4	Steam Piping	$64,776	$0	$18,561	$0	$83,337	$14,584	$0	$14,688	$112,609	$173
8.5	Turbine Generator Foundations	$0	$338	$452	$0	$790	$138	$0	$186	$1,115	$2
	Subtotal	**$169,172**	**$338**	**$35,262**	**$0**	**$204,772**	**$35,835**	**$0**	**$36,138**	**$276,745**	**$426**
9	Cooling Water System										
9.1	Cooling Towers	$26,236	$0	$6,351	$0	$32,588	$5,703	$0	$5,744	$44,034	$68
9.2	Circulating Water Pumps	$3,684	$0	$213	$0	$3,897	$682	$0	$687	$5,266	$8
9.3	Circulating Water System Auxiliaries	$21,987	$0	$2,261	$0	$24,247	$4,243	$0	$4,274	$32,764	$50
9.4	Circulating Water Piping	$0	$9,795	$7,174	$0	$16,969	$2,970	$0	$2,991	$22,929	$35
9.5	Make-up Water System	$1,696	$0	$1,698	$0	$3,395	$594	$0	$598	$4,587	$7
9.6	Component Cooling Water System	$1,462	$0	$947	$0	$2,409	$422	$0	$425	$3,256	$5
9.7	Circulating Water System Foundations	$0	$913	$1,226	$0	$2,138	$374	$0	$503	$3,015	$5
	Subtotal	**$55,066**	**$10,708**	**$19,870**	**$0**	**$85,643**	**$14,988**	**$0**	**$15,220**	**$115,851**	**$178**
10	Ash & Spent Sorbent Handling Systems										
10.6	Ash Storage Silos	$1,602	$0	$3,802	$0	$5,403	$946	$0	$952	$7,301	$11
10.7	Ash Transport & Feed Equipment	$5,446	$0	$4,190	$0	$9,635	$1,686	$0	$1,698	$13,020	$20
10.9	Ash/Spent Sorbent Foundation	$0	$1,068	$1,064	$0	$2,132	$373	$0	$501	$3,006	$5

Case:	B12B.95 – Supercritical PC with 95 Percent CO_2 Capture									
Plant Size (MW, net):	650					Estimate Type:	Conceptual			
						Cost Base:	Jan 2023			
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
	Subtotal	**$7,047**	**$1,068**	**$9,055**	**$0**	**$17,171**	**$3,005**	**$0**	**$3,152**	**$23,327**	**$36**
11	**Accessory Electric Plant**										
11.1	Generator Equipment	$3,832	$0	$2,122	$0	$5,953	$1,042	$0	$1,049	$8,045	$12
11.2	Station Service Equipment	$10,995	$0	$692	$0	$11,687	$2,045	$0	$2,060	$15,792	$24
11.3	Switchgear & Motor Control	$17,068	$0	$2,173	$0	$19,241	$3,367	$0	$3,391	$26,000	$40
11.4	Conduit & Cable Tray	$0	$2,013	$4,693	$0	$6,706	$1,174	$0	$1,182	$9,062	$14
11.5	Wire & Cable	$0	$5,332	$7,708	$0	$13,041	$2,282	$0	$2,298	$17,621	$27
11.6	Protective Equipment	$79	$0	$201	$0	$280	$49	$0	$49	$378	$1
11.7	Standby Equipment	$1,186	$0	$803	$0	$1,989	$348	$0	$351	$2,688	$4
11.8	Main Power Transformers	$10,053	$0	$151	$0	$10,203	$1,786	$0	$1,798	$13,787	$21
11.9	Electrical Foundations	$0	$290	$596	$0	$886	$155	$0	$208	$1,249	$2
	Subtotal	**$43,212**	**$7,636**	**$19,140**	**$0**	**$69,987**	**$12,248**	**$0**	**$12,387**	**$94,622**	**$145**
12	**Instrumentation & Control**										
12.1	Pulverized Coal Boiler Control Equipment	$1,079	$0	$152	$0	$1,231	$215	$0	$217	$1,664	$3
12.3	Steam Turbine Control Equipment	$967	$0	$85	$0	$1,052	$184	$0	$185	$1,422	$2
12.5	Signal Processing Equipment	$1,225	$0	$172	$0	$1,398	$245	$0	$246	$1,889	$3
12.6	Control Boards, Panels, & Racks	$375	$0	$180	$0	$555	$97	$28	$102	$782	$1
12.7	Distributed Control System Equipment	$10,576	$0	$1,487	$0	$12,063	$2,111	$603	$2,217	$16,993	$26
12.8	Instrument Wiring & Tubing	$741	$578	$1,868	$0	$3,186	$558	$159	$586	$4,489	$7
12.9	Other Instrumentation & Controls Equipment	$911	$0	$1,662	$0	$2,573	$450	$129	$473	$3,624	$6
	Subtotal	**$15,874**	**$578**	**$5,606**	**$0**	**$22,058**	**$3,860**	**$919**	**$4,026**	**$30,862**	**$47**
13	**Improvements to Site**										
13.1	Site Preparation	$0	$604	$10,370	$0	$10,974	$1,920	$0	$2,579	$15,473	$24
13.2	Site Improvements	$0	$2,986	$3,191	$0	$6,177	$1,081	$0	$1,452	$8,710	$13
13.3	Site Facilities	$3,470	$0	$2,895	$0	$6,364	$1,114	$0	$1,496	$8,974	$14
	Subtotal	**$3,470**	**$3,590**	**$16,456**	**$0**	**$23,516**	**$4,115**	**$0**	**$5,526**	**$33,157**	**$51**
14	**Buildings & Structures**										
14.2	Boiler Building	$0	$15,114	$10,742	$0	$25,856	$4,525	$0	$4,557	$34,938	$54
14.3	Steam Turbine Building	$0	$21,008	$15,824	$0	$36,832	$6,446	$0	$6,492	$49,769	$77
14.4	Administration Building	$0	$1,364	$1,167	$0	$2,531	$443	$0	$446	$3,421	$5
14.5	Circulation Water Pumphouse	$0	$243	$156	$0	$399	$70	$0	$70	$540	$1
14.6	Water Treatment Buildings	$0	$607	$447	$0	$1,054	$184	$0	$186	$1,424	$2
14.7	Machine Shop	$0	$720	$391	$0	$1,111	$194	$0	$196	$1,501	$2
14.8	Warehouse	$0	$542	$438	$0	$980	$172	$0	$173	$1,324	$2
14.9	Other Buildings & Structures	$0	$378	$260	$0	$639	$112	$0	$113	$863	$1
14.10	Waste Treating Building & Structures	$0	$838	$2,052	$0	$2,890	$506	$0	$509	$3,905	$6
	Subtotal	**$0**	**$40,814**	**$31,478**	**$0**	**$72,292**	**$12,651**	**$0**	**$12,741**	**$97,685**	**$150**
	Total	**$1,228,242**	**$182,409**	**$591,026**	**$0**	**$2,001,677**	**$350,293**	**$73,785**	**$391,082**	**$2,816,837**	**$4,331**

Exhibit 3-105. Case B12B.95 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$16,503	$25
1 Month Maintenance Materials	$2,651	$4
1 Month Non-fuel Consumables	$4,043	$6
1 Month Waste Disposal	$1,344	$2
25% of 1 Months Fuel Cost at 100% CF	$3,913	$6
2% of TPC	$56,337	$87
Total	**$84,792**	**$130**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$38,087	$59
0.5% of TPC (spare parts)	$14,084	$22
Total	**$52,172**	**$80**
Other Costs		
Initial Cost for Catalyst and Chemicals	$6,161	$9
Land	$1,800	$3
Other Owner's Costs	$422,525	$650
Financing Costs	$76,055	$117
Total Overnight Costs (TOC)	**$3,460,341**	**$5,321**
TASC Multiplier (IOU, 33 year)	1.213	
Total As-Spent Cost (TASC)	**$4,196,449**	**$6,453**

Exhibit 3-106. Case B12B.95 initial and annual operating and maintenance costs

Case:	B12B.95 – Supercritical PC with 95 Percent CO_2 Capture				Cost Base:	Jan 2023
Plant Size (MW, net):	650	Heat Rate-net (Btu/kWh):	10,938		Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		45.04	**$/hour**	Skilled Operator:		2.0
Operating Labor Burden:		30.00	**% of base**	Operator:		11.3
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		2.0
				Total:		**16.3**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$8,377,366	$12.882
Maintenance Labor:					$18,027,755	$27.721
Administrative & Support Labor:					$6,601,280	$10.151
Property Taxes and Insurance:					$56,336,733	$86.628
Total:					**$89,343,134**	**$137.381**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$27,041,632	$5.584
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	6,851	$2.30	$0	$4,888,824	$1.010
Makeup and Waste Water Treatment Chemicals (ton):	0	20.4	$660.00	$0	$4,178,982	$0.863
Brominated Activated Carbon (ton):	0	1.60	$2,547.97	$0	$1,265,510	$0.261
Enhanced Hydrated Lime (ton):	0	40.3	$391.63	$0	$4,894,031	$1.011
Limestone (ton):	0	708	$30.18	$0	$6,627,374	$1.369
Ammonia (19 wt%, ton):	0	70.0	$280.00	$0	$6,078,170	$1.255
SCR Catalyst (ft^3):	17,602	16.1	$350.00	$6,160,567	$1,745,494	$0.360
CO_2 Capture System Chemicals[A]:	Proprietary				$11,395,874	$2.353
Triethylene Glycol (gal):	w/equip.	64	$8.50	$0	$168,500	$0.035
Subtotal:				**$6,160,567**	**$41,242,757**	**$8.517**
Waste Disposal						
Fly Ash (ton):	0	664	$46.71	$0	$9,621,965	$1.987
Bottom Ash (ton):	0	147	$46.71	$0	$2,137,307	$0.441
SCR Catalyst (ft^3):	0	16.1	$5.70	$0	$28,427	$0.006
Triethylene Glycol (gal):	0	3,245	$1.30	$0	$1,308,801	$0.270
Thermal Reclaimer Unit Waste (ton):	0	7.94	$250.00	$0	$616,068	$0.127
Subtotal:				**$0**	**$13,712,567**	**$2.832**
By-Products						
Gypsum (ton):	0	1076	$0.00	$0	$0	$0.000
Subtotal:				**$0**	**$0**	**$0.000**
Variable Operating Costs Total:				**$6,160,567**	**$81,996,956**	**$16.933**
Fuel Cost						
Illinois Number 6 (ton):	0	7,317	$70.32	$0	$159,637,718	$32.967
Total:				**$0**	**$159,637,718**	**$32.967**

[A]CO_2 Capture System Chemicals includes NaOH and CANSOLV Solvent

Exhibit 3-107. Case B12B.95 COE breakdown

	FY COE		LCOE	
Component	**Value, $/MWh**	**Percentage**	**Value, $/MWh**	**Percentage**
Capital	66.8	46%	66.8	43%
Fixed	18.5	13%	24.6	16%
Variable	16.9	12%	22.6	15%
Fuel	33.0	23%	28.4	18%
Total (Excluding T&S)	**135.1**	**N/A**	**142.5**	**N/A**
CO_2 T&S	9.8	7%	13.1	8%
Total (Including T&S)	**145.0**	**N/A**	**155.6**	**N/A**

3.4 PC Case Summary

The performance and cost results of the six PC plant configurations are summarized in Exhibit 3-108.

Exhibit 3-108. Estimated performance and cost results for PC cases

Pulverized Coal Boiler						
	SubC PC			SC PC		
Case	B11A	B11B.90	B11B.95	B12A	B12B.90	B12B.95
PERFORMANCE						
CO_2 Capture Rate (%)	0	90	95	0	90	95
Capacity Factor (%)	85	85	85	85	85	85
Gross Power Output (MWe)	688	769	774	686	763	768
Auxiliary Power Requirement (MWe)	38	118	124	36	113	118
Net Power Output (MWe)	650	650	650	650	650	650
Coal Flow Rate (lb/hr)	493,115	630,940	640,819	473,055	600,801	609,741
Natural Gas Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A
HHV Thermal Input (kW_t)	1,685,945	2,157,162	2,190,938	1,617,359	2,054,118	2,084,684
Net Plant HHV Efficiency (%)	38.6	30.2	29.7	40.2	31.7	31.2
Net Plant HHV Heat Rate (Btu/kWh)	8,849	11,317	11,495	8,490	10,778	10,938
Raw Water Withdrawal (gpm/MWnet)	10.0	15.3	15.7	9.3	14.3	14.6
Process Water Discharge (gpm/MWnet)	2.1	3.9	4.0	1.9	3.7	3.8
Raw Water Consumption (gpm/MWnet)	8.0	11.4	11.7	7.4	10.6	10.9
CO_2 Emissions (lb/MMBtu)	202	20	10	202	20	10
CO_2 Emissions (lb/MWh-gross)	1,693	195	98	1,628	187	94
CO_2 Emissions (lb/MWh-net)	1,790	230	117	1,718	219	111
SO_2 Emissions (lb/MMBtu)	0.081	0.000	0.000	0.081	0.000	0.000
SO_2 Emissions (lb/MWh-gross)	0.675	0.000	0.000	0.649	0.000	0.000
NOx Emissions (lb/MMBtu)	0.084	0.073	0.072	0.087	0.076	0.076
NOx Emissions (lb/MWh-gross)	0.700	0.700	0.700	0.700	0.700	0.700
PM Emissions (lb/MMBtu)	0.011	0.009	0.009	0.011	0.010	0.010
PM Emissions (lb/MWh-gross)	0.090	0.090	0.090	0.090	0.090	0.090
Hg Emissions (lb/TBtu)	0.359	0.313	0.311	0.373	0.326	0.324
Hg Emissions (lb/MWh-gross)	$3.00x10^{-6}$	$3.00x10^{-6}$	$3.00x10^{-6}$	$3.00x10^{-6}$	$3.00x10^{-6}$	$3.00x10^{-6}$

Pulverized Coal Boiler						
	SubC PC			SC PC		
Case	B11A	B11B.90	B11B.95	B12A	B12B.90	B12B.95
COST						
Total Plant Cost (2023$/kW)	2,471	4,177	4,258	2,584	4,254	4,331
Bare Erected Cost	1,822	2,964	3,019	1,906	3,025	3,078
Home Office Expenses	319	519	528	334	529	539
Project Contingency	331	581	593	345	590	601
Process Contingency	0	113	117	0	109	113
Total Overnight Cost (2023$/MM)	1,985	3,341	3,405	2,072	3,399	3,460
Total Overnight Cost (2023$/kW)	3,054	5,137	5,236	3,188	5,226	5,321
Owner's Costs	583	960	979	604	972	990
Total As-Spent Cost (2023$/kW)	3,704	6,230	6,350	3,866	6,338	6,453
FY COE ($/MWh) (excluding T&S)[A]	86.0	133.6	136.0	86.9	132.8	135.1
Capital Costs	38.3	64.5	65.7	40.0	65.6	66.8
Fixed Costs	11.1	17.9	18.2	11.6	18.2	18.5
Variable Costs	9.8	17.1	17.5	9.7	16.6	16.9
Fuel Costs	26.7	34.1	34.6	25.6	32.5	33.0
FY COE ($/MWh) (including T&S)[A]	86.0	142.7	146.3	86.9	141.7	145.0
CO_2 T&S Costs	N/A	9.1	10.3	N/A	8.9	9.8
LCOE ($/MWh) (excluding T&S)[A]	89.4	140.6	143.2	90.5	140.0	142.5
Capital Costs	38.3	64.5	65.7	40.0	65.6	66.8
Fixed Costs	14.9	23.9	24.3	15.5	24.2	24.6
Variable Costs	13.1	22.8	23.3	12.9	22.2	22.6
Fuel Costs	23.0	29.4	29.9	22.1	28.0	28.4
LCOE ($/MWh) (including T&S)[A]	89.4	152.7	156.9	90.5	151.9	155.6
CO_2 T&S Costs	N/A	12.1	13.7	N/A	11.9	13.1
Cost of CO_2 Captured (ex. T&S), $/tonne[B]	N/A	53.6	52.6	N/A	55.7	54.5
Cost of CO_2 Avoided (incl. T&S), $/tonne[B]	N/A	92.3	91.5	N/A	90.4	89.3

[A]Varying incentives, such as tax credits, could impact the economics of the system

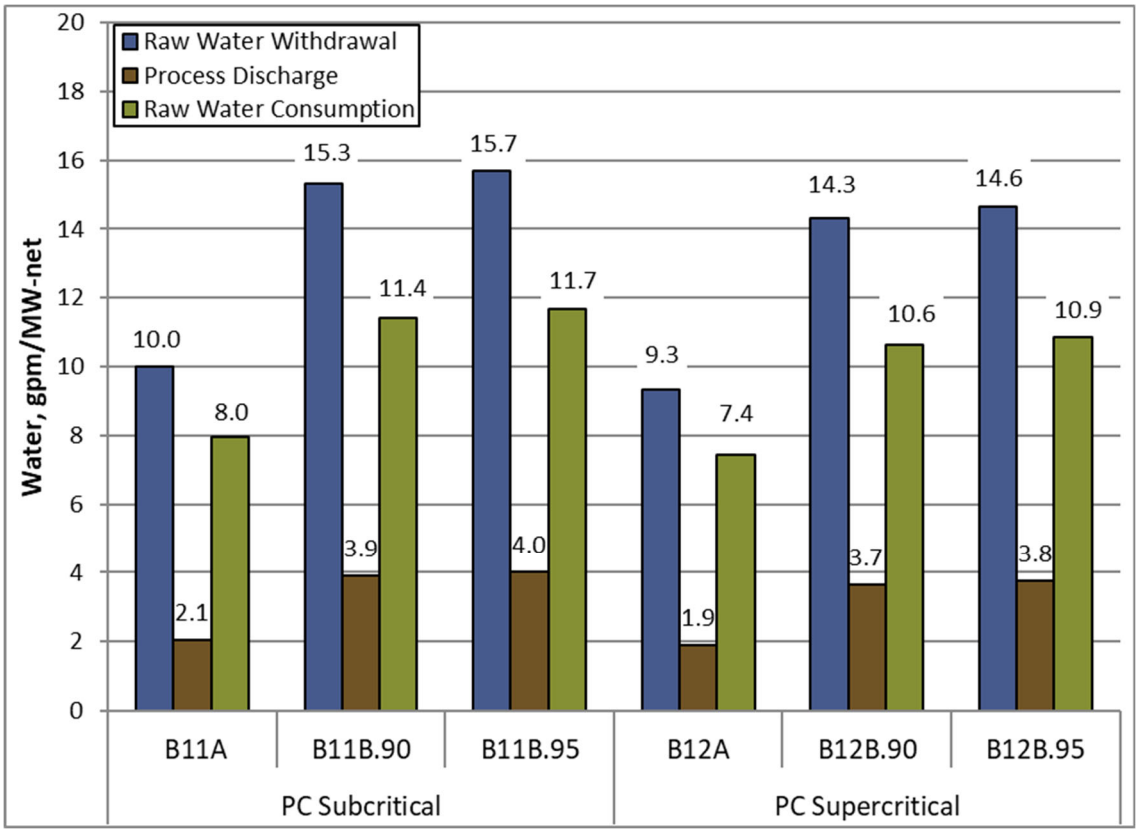
[B]Both the cost of CO_2 captured and cost of CO_2 avoided were calculated based on the non-capture SC PC Case B12A for all coal cases

The following observations can be made regarding plant performance:

- The addition of 90 percent CO_2 capture results in an HHV efficiency penalty of 8.4 percentage points (21.8 percent), relative to the non-capture case (B11A) in the SubC PC case (B11B.90). For the SC PC case (B12B.90), the addition of 90 percent CO_2 capture results in an HHV efficiency penalty of 8.5 percentage points (21.2 percent), relative to the non-capture case (B12A). 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 81 MW in the SubC PC case and by 77 MW in the SC PC case. In addition to the negative impact of the auxiliary load increase, steam is extracted prior to the LP section of the steam cycle for CO_2 capture solvent regeneration. The use of this steam in the reboiler, rather than passing through the LP steam turbine section and generating power, also contributes to the efficiency penalty.
    - The addition of 95 percent CO_2 capture (B11B.95 and B12B.95) results in an HHV efficiency penalty of 0.5 percentage points (1.5–1.6 percent), relative to the 90 percent capture cases (B11B.90 and B12B.90). The auxiliary load increases by 6 MW between cases B11B.90 and B11B.95 and by 5 MW between cases B12B.90 and B12B.95.
- The SO_2 emissions for non-capture cases are nearly identical, with the SubC PC emissions being higher than SC when normalized by gross output because of the lower HHV 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 normalized by gross output, are greater for SubC PC cases than SC PC cases because of the lower HHV efficiency.
- Emissions of Hg, HCl, PM, NOx, and SO_2 are all at or below the applicable federal regulatory limits currently in effect for PC technology.
    - Since the PC cases utilize a wet FGD system, SO_2 emissions could be used as a surrogate for HCl (EPA, 2012b). 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.
- For the PC cases in this study, the FGD wastewater blowdown flow rate range to be treated by the SDE spans 209–283 lpm (55–75 gpm). The approximate performance impact of implementing the SDE across the six PC cases is a 0.25–0.27 percentage point decrease in the HHV net plant efficiency. This is due primarily to the diversion of warm flue gas away from the air preheater and to the evaporator, with an additional minor impact resulting from the small auxiliary load required by the SDE.

The normalized water withdrawal, process discharge and raw water consumption are shown in Exhibit 3-109 for each of the PC cases.

Exhibit 3-109. Raw water withdrawal and consumption in PC cases



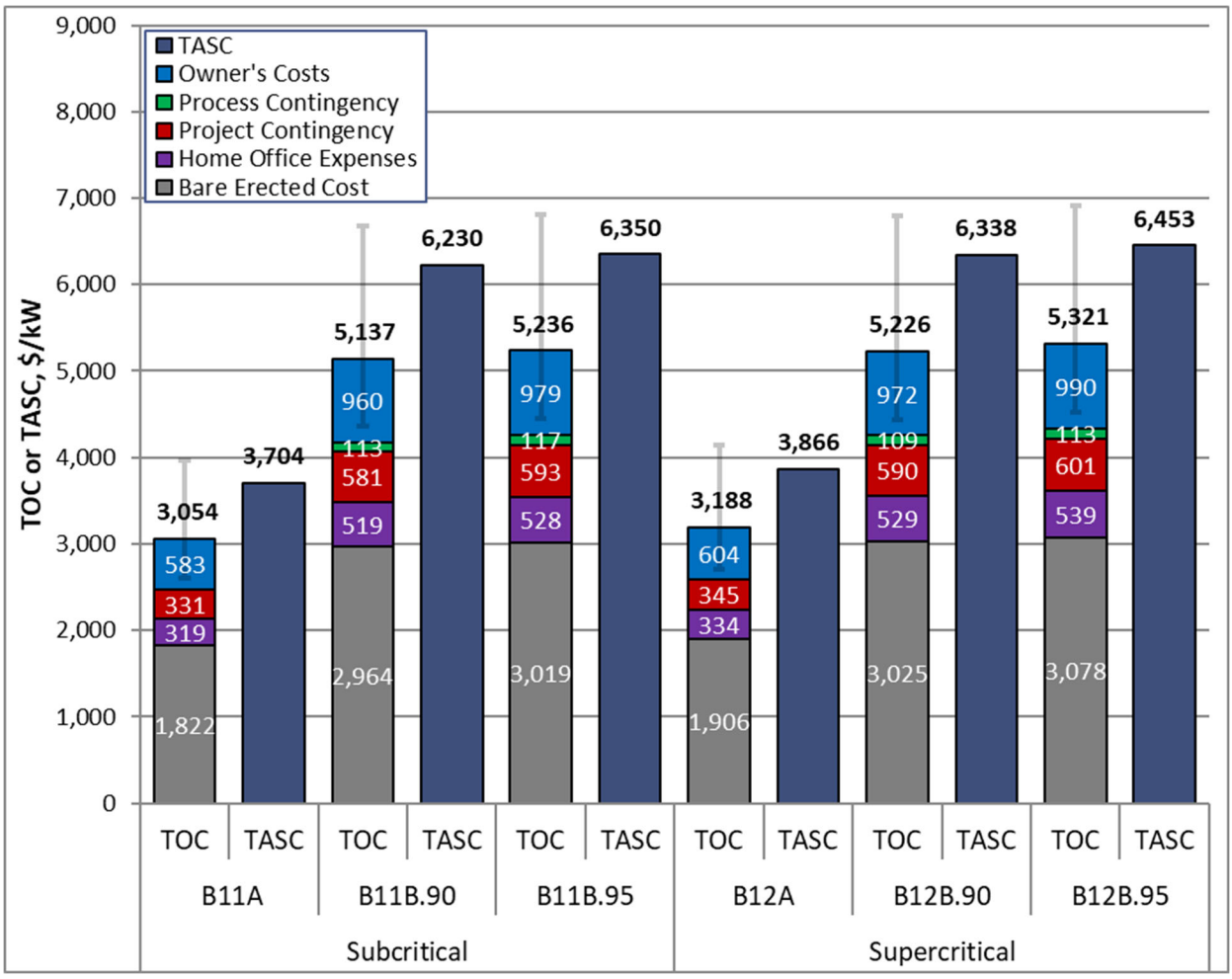
Raw water consumption for all cases is dominated by cooling tower makeup requirements, which accounts for about 86–88 percent of raw water in non-capture cases and 99 percent in CO_2 capture cases. The amount of raw water consumption in the CO_2 capture cases is greatly increased by the cooling water requirements of the capture process. Cooling water is required to:

- Reduce the flue gas temperature from 57°C (135°F) (FGD exit temperature) to 31°C (87°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 heat of CO_2 absorption through absorber tower intercoolers
- Remove the heat input from the auxiliary electric loads
- Remove heat in the CO_2 compressor intercoolers
- Cool the CO_2 product stream exiting the CO_2 compressor to the target specification of 30°C (86°F)

In the CO_2 capture cases, a portion of the additional water recovered from the flue gas as it is cooled to the absorber temperature is used as FGD makeup, and the remainder is discharged.

The components of TOC and TASC are shown for each PC case in Exhibit 3-110.

Exhibit 3-110. Plant capital cost for PC cases



The PC capital cost estimate accuracy provides an AACE Class 4 range of -15 percent/+30 percent. The error bars included in Exhibit 3-110 represent the potential TOC range relative to the maximum and minimum of the capital cost uncertainty range.

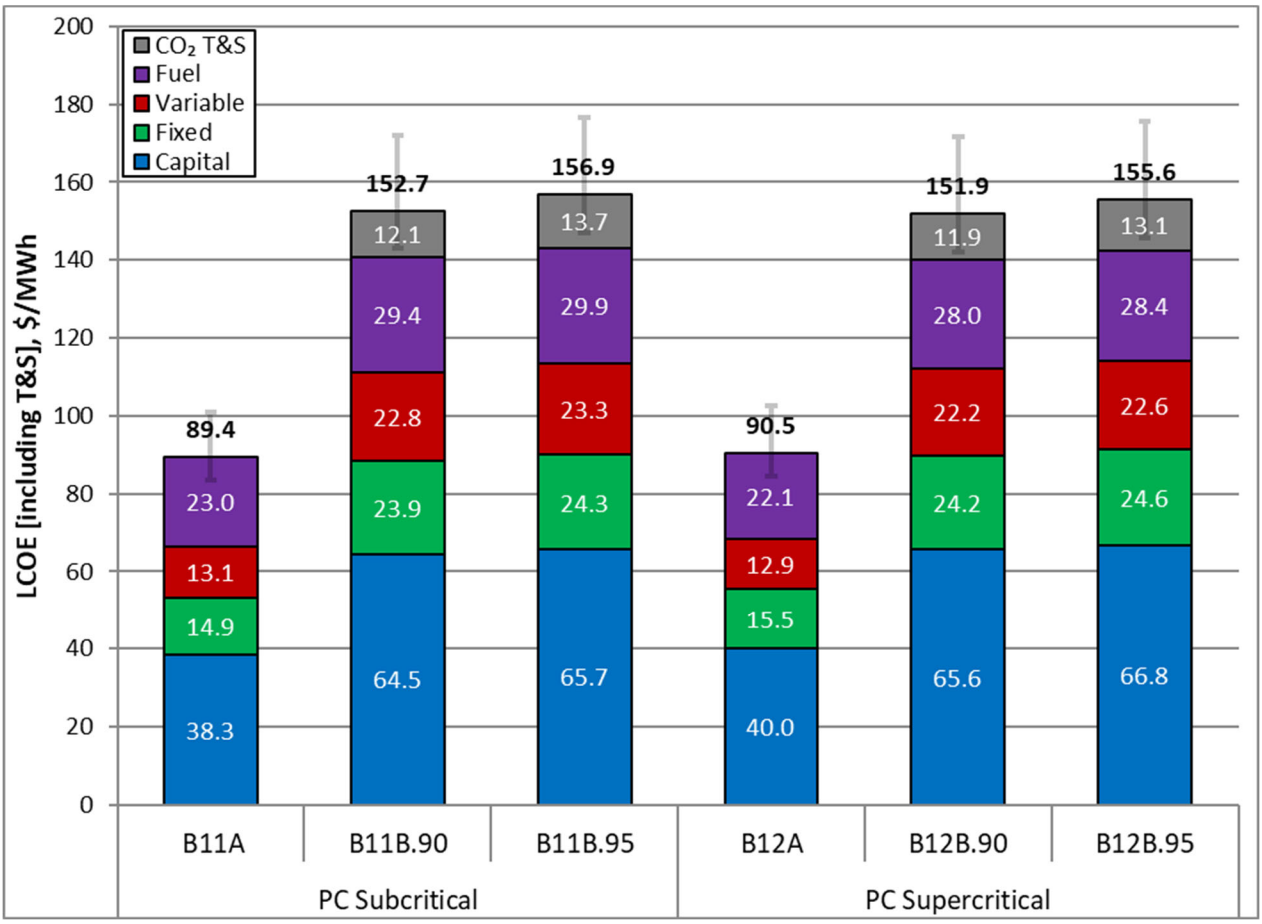
The following observations about normalized TOC ($/kW) can be made:

- When comparing SubC and SC PC cases with equivalent rates of CO_2 capture, the difference in TOCs is within the accuracy of this report.
- The TOC of the non-capture SC PC (Case B12A) is 4.4 percent greater than non-capture SubC PC (Case B11A). The TOC of SC PC with 90 percent CO_2 capture (Case B12B.90) is 1.7 percent greater than SubC PC with 90 percent CO_2 capture (Case B11B.90). The TOC of SC PC with 95 percent CO_2 capture (Case B12B.95) is 1.6 percent greater than SubC PC with 95 percent CO_2 capture (Case B11B.95).
- The TOC penalty for adding 90 percent CO_2 capture to SubC PC is 68 percent and is 64 percent for SC PC. The TOC penalty for adding 95 percent CO_2 capture to SubC PC is 71 percent and is 67 percent for SC PC.

- 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 PC plants increases by 81 MW (SubC) and 77 MW (SC) with the addition of 90 percent CO_2 capture to maintain the net output at 650 MW. For 95 percent capture, the gross power increases by 87 MW (SubC) and 82 MW (SC). The increased gross output results in higher coal flow rate and consequently higher costs for all cost accounts in the estimate.

The LCOE is shown for the six PC cases in Exhibit 3-111.

Exhibit 3-111. LCOE for PC cases



Note: Financial assumptions are presented in the QGESS report, "Cost Estimation Methodology for NETL Techno-economic Assessments" (NETL, 2025b)

Similar to Exhibit 3-110, the error bars included in Exhibit 3-111 represent the potential LCOE range relative to the maximum and minimum capital cost uncertainty ranges. The LCOE ranges presented are not reflective of other changes, such as variation in fuel price, labor price, CF, or other factors. As an example, if Case B11B.90 capital costs were determined to be at the high end of the uncertainty range (+30 percent), then the LCOE result would be $172.1/MWh.

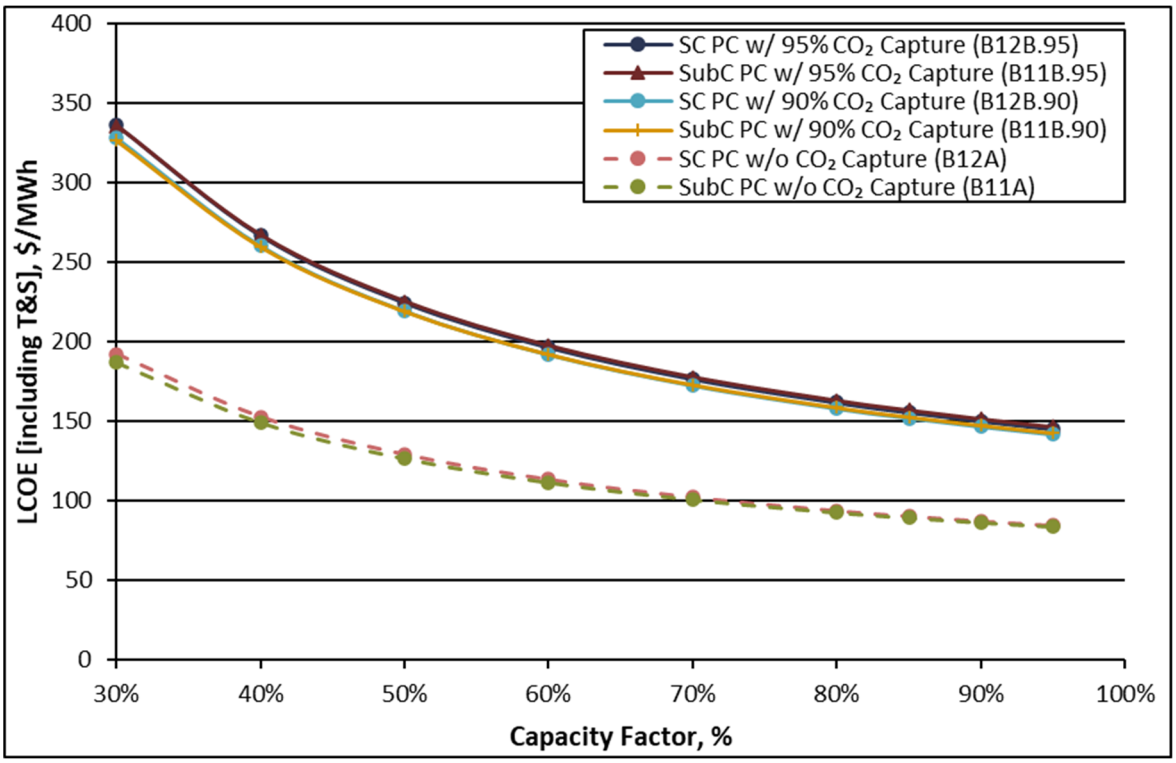
Conversely, if at the low end of the uncertainty range (-15 percent), the LCOE result would be $143.1/MWh.

The following observations can be made:

- In all cases, the LCOE (including T&S) is dominated by the capital cost component (42–44 percent) followed by the fuel cost component (18–26 percent). Capital charges and fuel costs combined represent 61 to 69 percent of the LCOE, including T&S.
- In the non-capture cases, the increase in capital cost in the SC case is almost offset by the efficiency gain so that the LCOE for SC PC is only 1.2 percent more than SubC despite having a 4.4 percent greater TOC.
- The delta between the LCOE of the non-capture SubC PC case and the non-capture SC PC case is well within the limits of the study accuracy. The same is true of the CO_2 capture cases.
- The PC cases incur a 68—71 percent increase in LCOE (including T&S costs) due to the addition of 90 percent CO_2 capture.
- The addition of 95 percent CO_2 capture to the SubC PC cases results in an additional LCOE penalty of $4.1/MWh (2.7 percent) in Case B11B.95, compared to Case B11B.90 (including T&S costs). For the SCPC cases, the addition of 95 percent CO_2 capture results in an additional LCOE penalty of $3.7/MWh (2.4 percent) in Case B12B.95, compared to Case B12B.90 (including T&S costs).
- CO_2 T&S costs add $12–14/MWh to the LCOE, which accounts for 8–9 percent of the total LCOE.

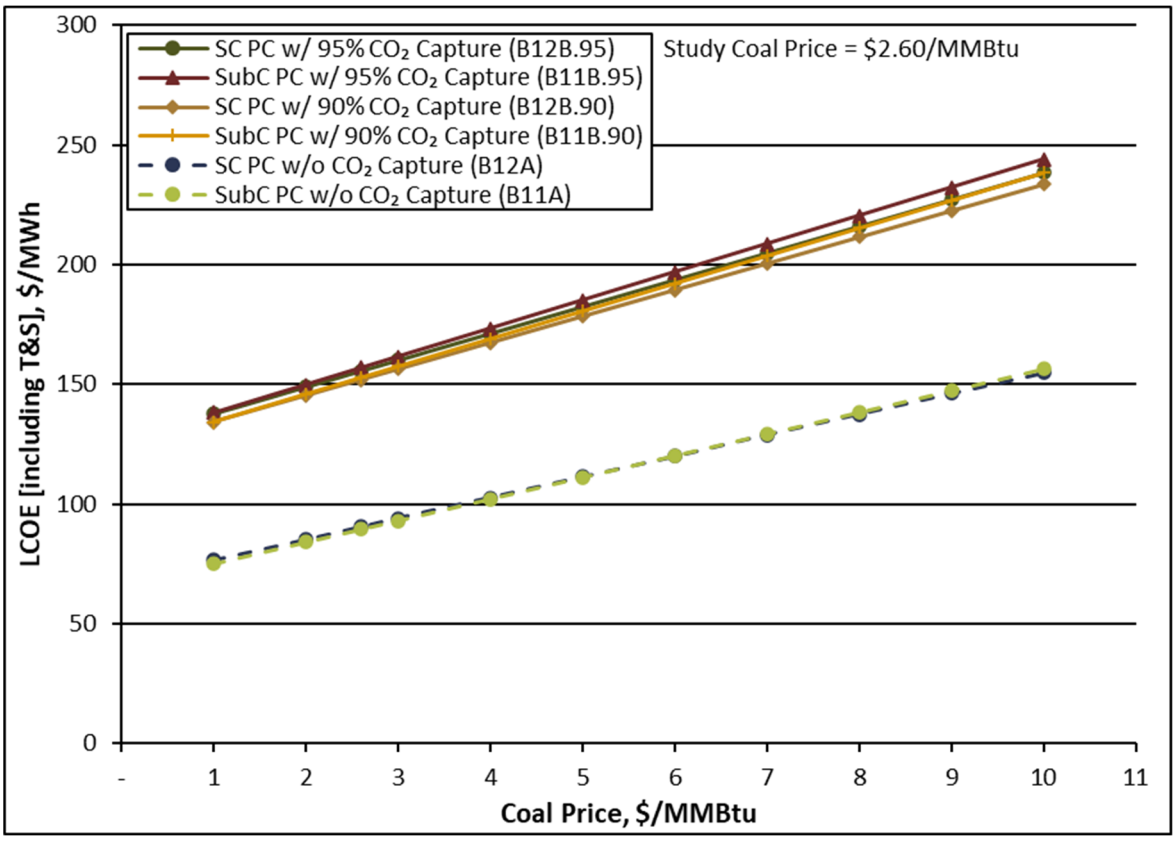
The sensitivity of LCOE to CF for the PC cases is shown in Exhibit 3-112. Implicit in the curves is the assumption that a CF of greater than 85 percent can be achieved without the expenditure of additional capital and capacity factors less than 85 percent do not result in lower capital or operating costs. The SubC and SC cases are nearly identical making it difficult to distinguish between the two lines. The LCOE increases more rapidly at low CF because the relatively high capital component is spread over fewer kWh of generation.

Exhibit 3-112. Sensitivity of LCOE to capacity factor for PC cases



The sensitivity of LCOE to levelized fuel costs for the PC cases is shown in Exhibit 3-113. A doubling of coal levelized price from $2.46/GJ to $4.93/GJ ($2.60/MMBtu to $5.20/MMBtu) results in an LCOE increase of about 25-26 percent in the non-capture cases and 19-20 percent in the CO_2 capture cases.

Exhibit 3-113. Sensitivity of LCOE to coal price for PC cases



The cost of CO_2 captured and avoided, shown in Exhibit 3-114 and Exhibit 3-115, respectively, were calculated using the methodology presented in Section 2.7.4.2, with the SC PC case (B12A) used as the non-capture reference case. Comparing the SubC and SC PC cases, the cost of CO_2 captured and cost of CO_2 avoided differs by 3.6–3.8 percent and 2.1–2.4 percent, respectively.

Exhibit 3-114. Breakdown of cost of CO_2 captured in PC cases

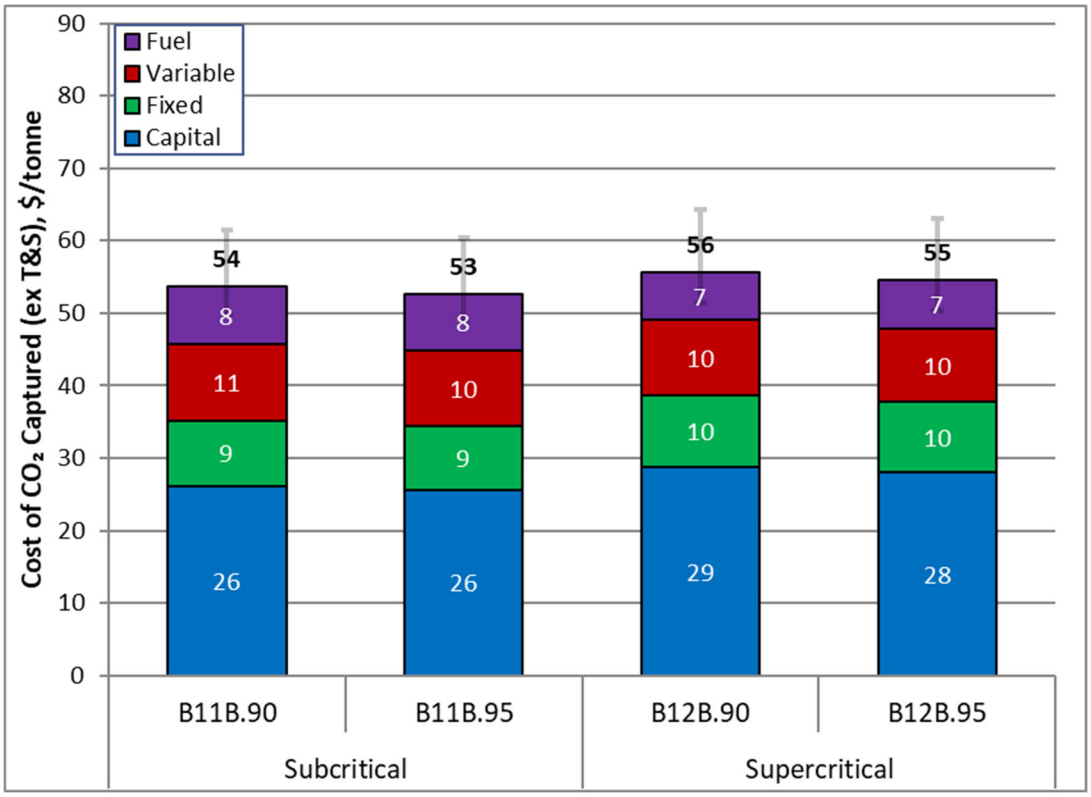
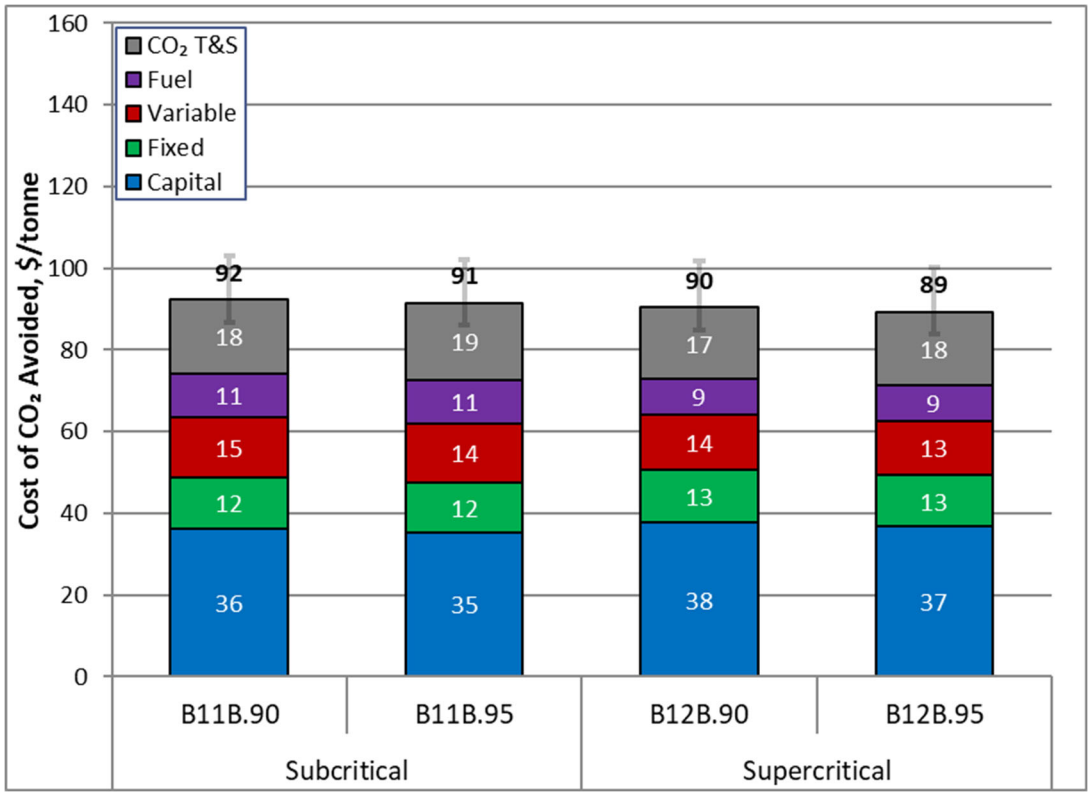


Exhibit 3-115. Breakdown of cost of CO_2 avoided in PC cases



NATURAL GAS COMBINED CYCLE PLANTS

4 NATURAL GAS COMBINED CYCLE PLANTS

Nine[o] NGCC power plant configurations were evaluated, and the results are presented in this section. Unless otherwise indicated, all units are reported on an HHV basis. Each design is based on a market-ready technology that is assumed to be commercially available at the time the project commences. The 2023 F-Class design consists of two state-of-the-art CTGs, two HRSGs, and one STG in a multi-shaft 2x2x1 configuration. The two 2023 H-Class designs consist of either 1) one state-of-the-art CTG, one HRSG, and one STG on a single-shaft 1x1x1 configuration or 2) two state-of-the-art CTGs, two HRSGs, and one STG in a multi-shaft 2x2x1 configuration.

The combustion turbine used in the 1x1 H-Class plant is larger and more advanced than that of the 2x1 H-Class plant. The H-Class combustion turbines were selected to 1) provide an H-Class configuration (1x1) that was comparable in output to the PC plants, produced a volume of flue gas that could be treated with a single train CO_2 capture system, and represented the most advanced commercial offering; and 2) provide an H-Class configuration (2x1) and combustion turbine that was consistent with previous revisions of this study.

The NGCC cases are evaluated with and without CO_2 capture on a common thermal input basis. The NGCC designs that include a PostCCC facility have a smaller plant net output resulting from the additional auxiliary loads and steam extraction associated with the PostCCC facility and CO_2 compressors. The gross output of the NGCC cases was largely governed by the characteristic output of the commercially available CT. Hence, evaluation of the NGCC designs on a common net output basis for capture and non-capture cases was not practicable.

The Rankine cycle portion of each case uses a single reheat subcritical steam cycle with steam conditions of 17.2 MPaG/585°C/585°C (2,494 psig/1,085°F/1,085°F) in the F-Class cases, 17.2 MPaG/585°C/585°C (2,501 psig/1,085°F/1,085°F) in the 1x1 H-Class cases, and 17.2 MPaG/585°C/585°C (2,494 psig/1,085°F/1,085°F) in the 2x1 H-Class cases.

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

4.1 COMMON PROCESS AREAS FOR ALL NGCC CASES

The nine NGCC cases are nearly identical in configuration, with the exception that Case B31A, B32A.1 and B32A.1.2 do not include CO_2 capture, whereas the remaining cases do. As detailed descriptions of the 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.

4.1.1 Natural Gas Supply System

It was assumed that a natural gas main with adequate capacity is near to the site fence line (within 16 km [10 mi]) and that a suitable right-of-way is available to install a branch line to the

[o] Additional NGCC cases that include CO_2 capture rates above 95 percent are reported in the appendices.

site. For the purposes of this report, it was also assumed that the gas will be delivered to the plant custody transfer point at sufficient pressure such that natural gas is available at the turbine inlet at either 3.0 MPa (430 psia) and 27°C (80°F), which matches the state-of-the-art 2023 F-Class fuel system requirements or 3.8 MPa (550 psia and 27°C (80°F), which matches the state-of-the-art 2023 H-Class fuel system requirements. Hence, neither a pressure reducing station, nor a fuel booster compressor is required. It is further assumed that the cost of the natural gas remains constant at either pressure to help maintain consistency across cases. In reality, one may require a pressure let down or booster, impacting the price of natural gas. A sensitivity to natural gas price is included in this study, which covers both fluctuations in natural gas price and the variation in natural price resulting from deviation described above (e.g., booster station requirement).

As discussed in Section 2.3, it was assumed that the natural gas has an added mercaptan composition of 5.74×10^{-6} mol% (Gas Research Institute, 1992).

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 Steam Generator and Ancillaries

Steam is generated with an HRSG in all NGCC Plants. The HRSG tubes typically comprise finned tubing. The high-temperature portions are type P91, P92, or P22 ferritic alloy material; the low-temperature portions (less than 399°C [750°F]) are CS. Each HRSG exhausts directly to the stack.

The power plants within this report are based on supplier's standard designs. While this report assumes that the power plants are operated as baseload units, NGCC plants are not typically operated as baseload units. Hence, the standard design includes some consideration for daily or weekly cycling.

The following subsections describe the operation of the steam generator.

4.1.2.1 Feedwater and Steam

4.1.2.1.1 Feedwater

The function of the FW system is to pump the various FW streams from the LP evaporator to their respective steam drums. Two 100 percent capacity motor-driven feed pumps are provided per each HRSG (total of four pumps for the F-Class plants and two pumps for the H-Class plants). The FW pumps are equipped with an interstage takeoff to provide IP FW. Each pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines discharging back to the LP drum. The recirculation flow is controlled by automatic or pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with strainers.

4.1.2.1.2 Steam Generation

The HRSG is configured with HP, IP, and LP steam drums, and superheater, reheater, evaporator, 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 585°C (1,085°F). The IP drum is supplied with FW by an interstage bleed from the HP boiler feed pump to generate IP steam, which passes to the superheater section for heating to 585°C (1,085°F). Steam from the LP drum passes to the superheater section for heating to 304°C (579°F) in the F-Class cases and 300°C (572°F) in the H-Class cases.

4.1.2.1.2.1 Main and Reheat Steam

Main, IP, and LP steam exit 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 HP turbine exhaust is conveyed through a motor-operated isolation gate valve and reheated to 585°C (1,085°F) before being combined with the IP steam. The combined stream passes through a motor-operated gate valve to the IP turbines. The LP steam passes through a motor-operated isolation gate valve before being combined with the IP turbine exhaust and conveyed to the LP turbines.

4.1.2.2 Condensate

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

The system consists of one main condenser, one motor-driven vertical multistage condensate pump, 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 discharge header through a pump discharge line with a check valve and a gate valve. A minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pump.

Condensate from all process extraction steam (e.g., CO_2 capture and drying requirements) is returned to the hotwell of the deaerating-type condenser. A condensate polisher is required because the NGCC cases do not have a blowdown.

Deaerating condenser losses are assumed to be 0.2 percent of the total flowrate. To account for these losses, makeup water is supplied to the condenser. The makeup water provides high-quality demineralized water for makeup to the HRSG cycle. The demineralizer is sized based on the requirements of the startup boiler.

4.1.3 NOx Control System

Two measures are taken to reduce the NOx. The first is a DLN burner in the CTG (GE Power, 2017). The DLN burners reduce the emissions to about 25 ppmvd at 15 percent O_2 (assumed to be 100 percent NO).

While state-of-the-art 2023 F-Class and 2023 H-Class CTs alone produce NOx emissions below the limits described in Section 2.4.3.2, an SCR was included as a second measure to ensure the plant met EPA's PSD program by installing the BACT. SCR uses NH_3 and a catalyst to reduce NOx to N_2 and H_2O. The SCR system consists of a reactor duct and NH_3 storage and injection system. The SCR system is designed for 94–95 percent NOx reduction with 5 ppmv NH_3 slip at the end of the catalyst life (Davis & Black, October 2000).

The SCR unit cost accounts for less than 1 percent of the overall TPC for all capture and non-capture cases. The SCR capital costs are reported separately from the HRSG costs; the cost for the initial load of catalyst is broken out separately in the O&M cost table.

4.1.3.1 SCR Operation Description

The HRSG duct and NH_3 distribution system are designed to allow proper retention time for the NH_3 to contact the NOx in the flue gas. 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.

NH_3 is mixed with dilution air before injection, and the mixture is injected into the gas path approximately eight feet upstream of the SCR catalyst, which is located inside the HRSG between the HP and IP sections. The NH_3 injection grid is arranged into several sections and consists of multiple pipes with nozzles (holes). The NH_3 flow rate into each injection grid section is controlled considering imbalances in the flue gas flow distribution across the HRSG.

The catalyst contained in the reactor enhances the reaction between the NH_3 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 260–371°C (500–700°F). The flue gas temperature entering the SCR catalyst is controlled by the pressure in the HP evaporator. This study assumes that the flue gas distribution is acceptable for the SCR system to meet the guarantee requirements without the use of a flue gas distribution grid.

The NH_3 storage and injection system consists of unloading facilities, bulk storage tank, vaporizers, dilution air skid, and injection grid.

4.1.4 Post Combustion Carbon Capture

A PostCCC facility is used, along with a dryer and compressors, to remove, purify, and compress CO_2 in the flue gas exiting the HRSG to a SC condition. In cases B31B.90, B32B.1.90, and B32B.2.90, 90 percent of the CO_2 is removed; in Cases B31B.95, B32B.1.95, and B32B.2.95, 95 percent of the CO_2 is removed. It is assumed that all the carbon in the natural gas is converted to CO_2. The PostCCC facility comprises flue gas supply, direct contact cooler, CO_2 absorber, CO_2 stripper, and solvent reclaiming unit.

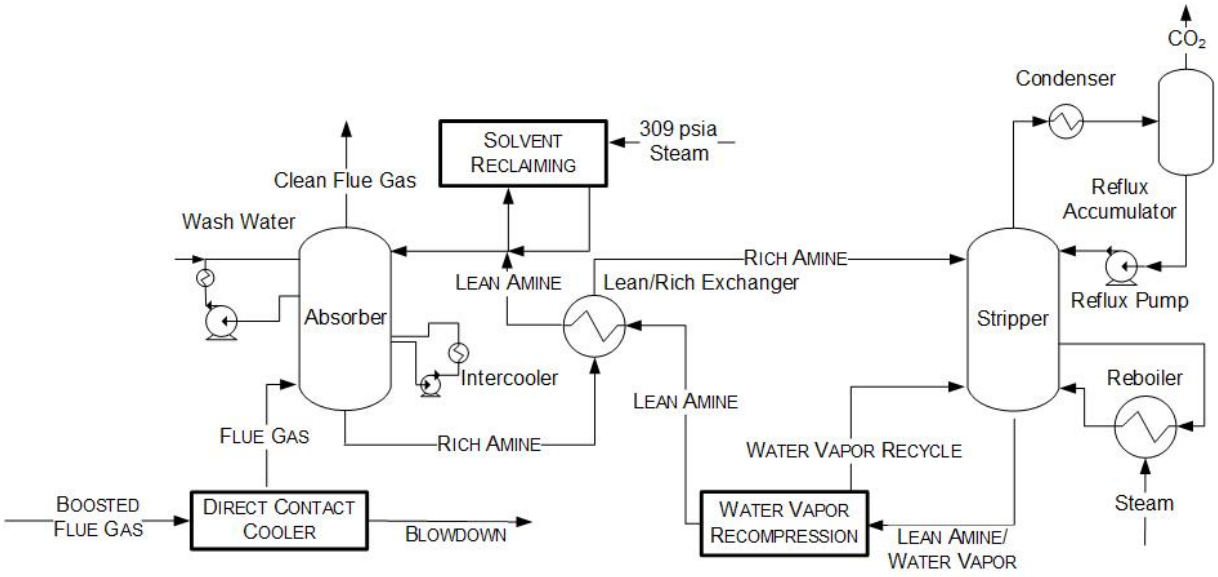
The PostCCC facility designed for NGCC cases is based on the SC&T CANSOLV system, described in Section 3.1.8 for the PC-specific application, but with the following differences:

- 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 pre-scrubber used in the PC cases.
- For the steady-state cases described here, the LP steam requirement for the reboiler only is calculated as approximately 2.4 MJ/kg (1,050 Btu/lb) CO_2 for the CANSOLV process.

The CO_2 recovery process is based on data provided by SC&T on their CANSOLV system in 2021 and is unchanged from Revision 4a of this report.

A diagram of the CANSOLV CO_2 capture process for the NGCC application is provided in Exhibit 4-1.

Exhibit 4-1. CANSOLV CO_2 capture process typical flow diagram for NGCC



The NGCC quote is based on a volumetric flow rate of 4.6 million m^3/hr (162 million ft^3/hr) with a CO_2 concentration of 3.9 mol% and the PC quote is based on a volumetric flow rate of 2.8 million m^3/hr (99 million ft^3/hr) with a CO_2 concentration of 12.9 mol%. Due to the higher volumetric flow rate and lower CO_2 concentration of the NGCC case, compared to the PC case, the quoted CO_2 absorber volume was 34-35 percent larger in the NGCC case than the PC case. However, due to the lower CO_2 content of the NGCC flue gas, the quoted NGCC CO_2 stripper is only 42 percent of the volume of the quoted PC CO_2 stripper.

As the 2x1 H-Class cases in this report have a significantly larger flue gas volumetric flow (5.6 million m^3/hr [196–197 million ft^3/hr]) than the quoted NGCC case, it was assumed that a single absorber would not be economical due to the resulting absorber diameter. Therefore, the 2x1 H-Class cases include two parallel CO_2 capture trains, each treating 50 percent of the flue gas. This configuration leads to significantly greater capital costs, and consequently higher LCOEs, than would be associated with a single train system. It is anticipated that if demand for large-scale CO_2 capture systems is demonstrated, vendors may develop alternative designs that would

allow for single-train systems that are more economical. One such example may be the use of two absorbers in parallel within a single train, with the intention to reduce the diameter of each absorber. In this configuration, the balance of equipment is common to both absorbers, rather than having duplicate equipment for each absorber, as is done in a two-train system.

The CANSOLV system in the NGCC cases discharges CO_2 at the same temperature and pressure as that in the PC cases; as such, the enthalpy versus pressure operating profile presented for PC cases in Exhibit 3-12 in Section 3.1.9 is also representative of the CO_2 compressor for the NGCC cases with capture.

4.1.5 Power Generation

4.1.5.1 Steam Turbine

The steam turbine is designed for long-term operation (90 days or more) at MCR with throttle control valves 95 percent open.

The steam turbine is a tandem compound type, consisting of HP-IP-double-flow LP sections enclosed in two casings, all connected to the generator by a common shaft, designed for condensing single reheat operation and double-flow exhaust. The turbine drives a H_2-cooled generator. The HP and IP sections are contained in a single span, opposed-flow casing, with the LP section in a separate casing. The turbine has a DC motor-operated emergency lube oil pump and redundant AC motor-operated main lube oil pumps (Gorman & Reinker, 1994). The exhaust pressure is 50.8 mm (2.0 in.) Hg in the single pressure condenser. The condenser is two-shell, transverse, single pressure with divided waterbox for each shell.

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 produces power at 18 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. The generator stator and rotor are hydrogen cooled. Hydrogen is circulated through the generator using fans mounted on the generator rotor shaft and cooled with a finned-tubed, water-cooled heat exchanger.

4.1.5.1.1 Steam Turbine 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 HRSG passes through the stop valves and control valves and enters the turbine at the conditions provided in Exhibit 4-2.

Exhibit 4-2. NGCC steam conditions

Steam Conditions			
Steam Parameter	**F-Class**	**1x1 H-Class**	**2x1 H-Class**
Main Pressure, MPa (psig)	17.2 (2,494)	17.2 (2,501)	17.2 (2,494)
Main Temperature, °C (°F)	585 (1,085)	585 (1,085)	585 (1,085)
Reheat Pressure, MPa (psig)	3.7 (543)	3.6 (521)	3.7 (542)
Reheat Temperature, °C (°F)	585 (1,085)	585 (1,085)	585 (1,085)

The steam enters the turbine inlet, flows through the HP turbine, and returns to the HRSG for reheating. The reheat steam flows through the reheat stop valves and intercept valves and is combined with steam from the IP superheater before entering the IP turbine at the conditions provided in Exhibit 4-2. After passing through the IP turbine, the steam enters a crossover pipe, which transports the steam to the double flow LP turbines. A branch line equipped with a stop valve and a control valve conveys LP steam from the HRSG LP superheater to a tie-in at the crossover line. The steam divides into two paths and flows through the LP turbines exhausting into the condenser. The last stages of the LP turbines operate as condensing turbines with an exhaust moisture content ranging 8.0–9.6 percent.

The sliding pressure turbine is designed to operate at variable inlet steam pressure over the load range.

4.1.5.2 Combustion Turbine

The CTGs are representative of state-of-the-art, natural gas fired 2023 F-Class and H-Class turbines. The F-Class configuration uses two CTGs in all cases, whereas the H-Class cases are configured with either one CTG or two CTGs. These machines are axial flow, single spool, constant speed units, with variable IGVs, and dry LNB combustion systems.

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 4-3.

Exhibit 4-3. Combustion turbine typical scope of supply

System	System Scope
Engine Assembly	Coupling to Generator, Water Mist 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, Turbine Rotor Cooler
Walk-in Acoustical Enclosure	HVAC, Lighting, and Water Mist Fire Protection System
Mechanical Package	HVAC, Lighting, Air Compressor for Pneumatic System, Fire Protection Systems
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
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, FM-200 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, Inlet Silencer and Exhaust Acoustic Treatment, Pressure and Temperature Ports and Instrumentation
NG Fuel System	Gas Valves Including Vent, Throttle and Trip Valves, Gas Filter/Separator, Gas Supply Instruments and Instrument Panel
Starting System	Enclosure, Static Start System, Turning Gear, and Clutch Assembly
Generator	Static Exciter and Excitation Transformer, Line Termination Enclosure with Current Transformers, Voltage Transformers, Surge Arrestors, and Surge Capacitors, Neutral Cubicle with Current Transformer, 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, Grounding System Connectors
Generator Cooling	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 18 kV, 3-phase, 60 Hz, constructed to meet American National Standards Institute and National Electrical Manufacturers Association standards for turbine-driven synchronous generators. The generator is H_2 cooled, complete with excitation system, cooling, and protective relaying.

4.1.5.2.1 Combustion Turbine Class Comparison

The current combustion turbine market for natural gas applications offers multiple class size options, supplied by several different OEMs. In general, the class (e.g., F-Class) is delineated by combustion turbine output. Advanced-class combustion turbines, such as the H- or J-Class will have higher outputs, and higher efficiencies, than the F-Class. Exhibit 4-4 compares parameter values for currently offered F- and H-Class combustion turbines based on public literature, for simple cycle and 2x1 combined cycle configurations (GE Vernova, 2024c) (GE Vernova, 2024a) (Modern Power Systems, 2014).

Exhibit 4-4. F- versus H-Class combustion turbines

Parameter	F-Class	H-Class
Simple Cycle		
Combustion Turbine Net Output, MW	239	384
Combustion Turbine Net Efficiency (LHV), %	38.5	42.6
Turbine Inlet Temperature, °F	2,300-2,600	>2,600
Ramp Rate, MW/min	40	60
Startup Time (RR Hot), min	21	21
Combined Cycle Configuration		
Combined Cycle Net Output, MW	762	1148
Combined Cycle Net Efficiency (LHV), %	60.5	63.6
Ramp Rate, MW/min	80	120
Startup Time (RR Hot), min	25	<30

Comparing the F- and H-Class 2x1 combined cycle configurations, the H-Class can offer an LHV net plant efficiency advantage of 3.1 percentage points and an additional net output of 386 MW.

As is stated throughout this report, the objective of the cases presented is to provide a consistent and transparent analysis methodology that is robust enough to allow for technology comparison on an equivalent basis. One of the mechanisms to facilitate comparison is to consider plants on a comparable net electrical output basis. The PC cases presented in Section 3 consider a fixed 650 MW net output. This was selected to maintain comparability with F-Class NGCC cases.

As larger, higher efficiency NGCC machines are deployed and currently operating in the market today, a 2x1 H-Class was included in the prior revision of this report and, for consistency, updated for this revision. However, due to the high power output of the H-Class combustion turbine, a 1x1 H-Class configuration has been added to this revision to provide an advanced combustion turbine configuration at a more comparable output to PC and F-Class cases. The combustion turbine used in the 1x1 H-Class plant is larger and more advanced than that of the 2x1 H-Class plant.

4.1.6 Cooling System

The cooling system is identical for all cases in this study and is described in Section 3.1.13.

4.1.7 Balance of Plant

The balance of plant components consists of the accessory electric plant, ducting and stack, buildings and structures, instrumentation and control, wastewater treatment, and miscellaneous systems as described below.

4.1.7.1 Accessory Electric Plant

The accessory electric plant is identical for all cases in this study and is described in Section 3.1.14.1.

4.1.7.2 Ducting and Stack

One stack is provided for each CTG. The stack is fabricated from CS plate materials and epoxy coated. The stack for the NGCC cases is assumed to be 46 m (150 ft) high. For cases with capture, a bypass system, consisting of a diverter damper and ducting, is included to route the flue gas from the HRSG outlet to the stack in case of failure or emergency shutdown of the PostCCC facility.

4.1.7.3 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:

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
6. Continuous emissions monitoring building
7. Guard house
8. Electrical equipment building

4.1.7.4 Instrumentation and Control

The instrumentation and control system is identical for all cases in this study and is described in Section 3.1.14.4.

4.1.7.5 Wastewater Treatment

The wastewater treatment is identical for all cases in this study and is described in Section 3.1.14.5.

4.1.7.6 Miscellaneous Systems

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.

4.1.8 Performance Summary Metrics

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

4.1.8.1 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, fraction

CTP – combustion turbine power, after generator losses, kWh

TI – thermal input to turbines, kWh

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 the units to kW.

4.1.8.2 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, fraction

STP – steam turbine power, after generator losses, kWh

TI – thermal input to the HRSG, kWh

TC – thermal consumption, kWh

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.

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

4.1.8.3 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 F-CLASS NGCC CASES

This section contains an evaluation of plant designs for F-Class NGCC cases based on a 2x1 plant (cases B31A, B31B.90, and B31B.95), consisting of two state-of-the-art 2023 F-Class combustion turbines with an ISO base rating of 239 MW each and one single reheat subcritical steam cycle 17.2 MPaG/585°C/585°C (2,494 psig/1,085°F/1,085°F). Cases B31A, B31B.90, and B31B.95 are similar, differing only in the degree of CO_2 capture, with B31A including no CO_2 capture, B31B.90 including 90 percent CO_2 capture, and B31B.95 including 95 percent CO_2 capture.

The balance of this section is organized as follows:

- Key System Assumptions is a summary of study and modeling assumptions relevant to F-Class NGCC cases.
- Sparing Philosophy is provided for F-Class NGCC cases.
- Process 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 F-Class cases are discussed further in this section.
- Performance Results provides the main modeling results from Case B31A, including the performance summary, environmental performance, carbon balance, water balance, energy and mass balance diagrams, and energy balance table.
- Major Equipment List provides an itemized list of major equipment for Case B31A with account codes that correspond to the cost accounts in the Cost Estimating section.
- Cost Estimating provides a summary of capital and operating costs for Case B31A.
- Process Description, Performance Results, Major Equipment List, and Cost Estimating are discussed for cases B31B.90 and B31B.95.

4.2.1 Key System Assumptions

System assumptions for cases B31A, B31B.90, and B31B.95, NGCC with and without CO_2 capture, are compiled in Exhibit 4-5.

Exhibit 4-5. NGCC F-Class plant study configuration matrix

	Case B31A w/o CO_2 Capture	Case B31B.90 w/ CO_2 Capture	Case B31B.95 w/ CO_2 Capture
Steam Cycle, MPaG/°C/°C (psig/°F/°F)	17.2/585/585 (2,494/1,085/1,085)		
Fuel	Natural Gas		
Fuel Pressure at Plant Battery Limit, MPa (psia)	3.0 (430)		
Condenser Pressure, mm Hg (in. Hg)	50.8 (2.0)		
Cooling Water to Condenser, °C (°F)	16 (60)		
Cooling Water from Condenser, °C (°F)	27 (80)		
Stack Temperature, °C (°F)	79 (174)	38 (100)	38 (100)
SO_2 Control	Low Sulfur Fuel		
NOx Control	LNB and SCR		
SCR Efficiency, %[A]	94.2	94.7	94.7
Ammonia Slip (End of Catalyst Life), ppmv	5		
Particulate Control	N/A		
Mercury Control	N/A		
CO Control	N/A		
CO_2 Control	N/A	CANSOLV	
Overall Carbon Capture, %[A]	N/A	90	95
CO_2 Sequestration	N/A	Off-site Saline Formation	

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

4.2.1.1 Balance of Plant

The balance of plant assumptions are common to all F-Class NGCC cases and are presented in Exhibit 4-6.

Exhibit 4-6. F-Class NGCC balance of plant assumptions

Parameter	Value
Cooling System	Recirculating Wet Cooling Tower
Fuel and Other Storage	
Natural Gas	Pipeline supply at 3.0 MPa (430 psia) and 27°C (80°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

Parameter	Value
Steam and CT Generators	18,000 V
Grid Interconnection Voltage	345 kV
Water and Wastewater	
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	Blowdown is treated for chloride and metals and discharged.

4.2.2 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:

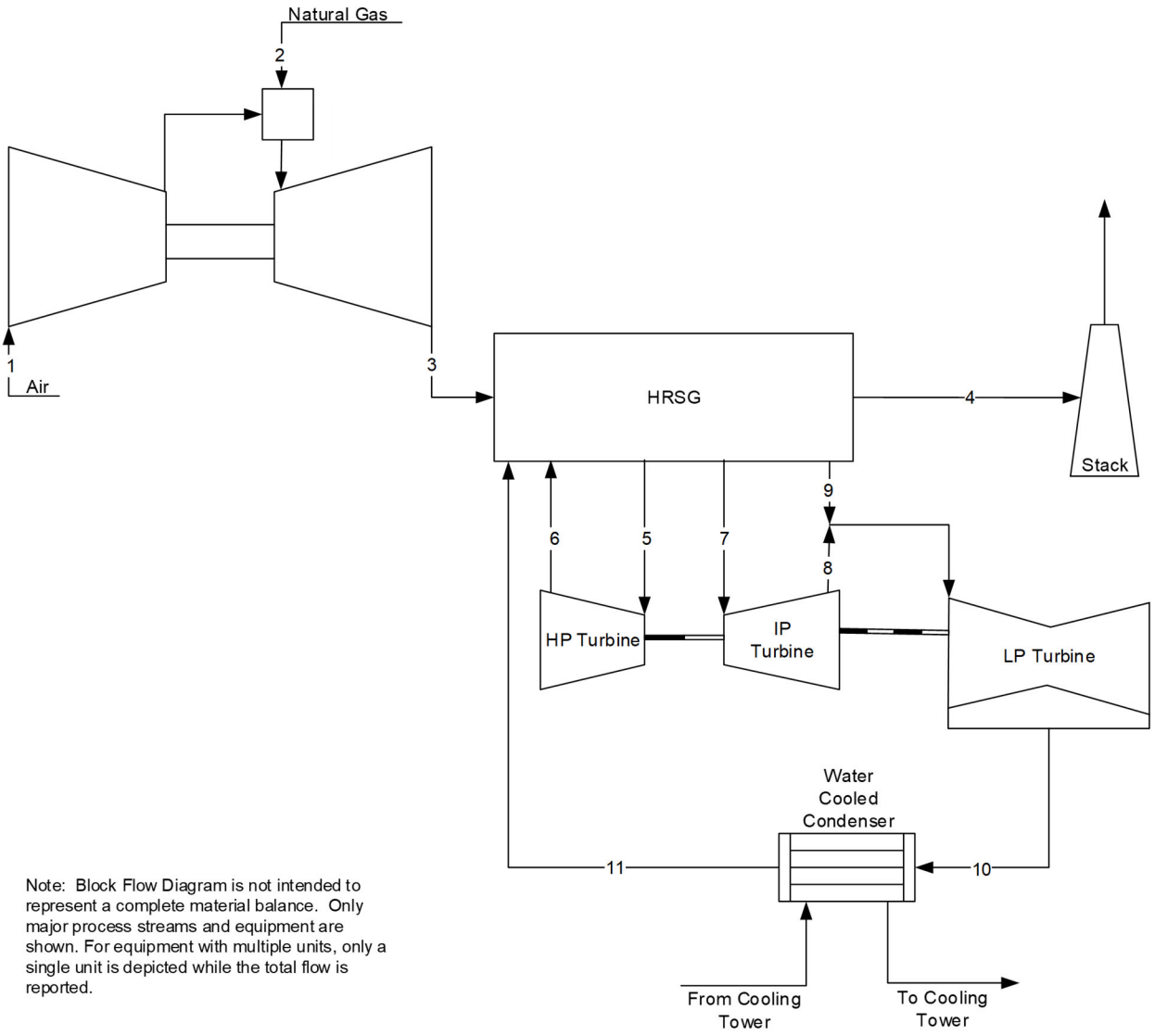
- Two state-of-the-art 2023 F-Class CTGs (2 x 50 percent)
- Two 3-pressure reheat HRSGs with self-supporting stacks and SCR systems (2 x 50 percent)
- One 3-pressure reheat, triple-admission STG (1 x 100 percent)
- For Cases B31B.90 and B31B.95, one CO_2 absorption system, consisting of an absorber, stripper, and ancillary equipment (1 x 100 percent) and two CO_2 compression systems (2 x 50 percent)

4.2.3 Case B31A – NGCC Without CO_2 Capture Process Description

In this section, the F-Class NGCC process without CO_2 capture is described. The description follows the BFD in Exhibit 4-7 and stream numbers reference the same exhibit. Exhibit 4-8 provides 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 (not depicted) and compressed before being combined with natural gas (stream 2) in the dry LNB, which is operated to control the rotor inlet (not depicted) temperature at 1,427°C (2,600°F). The flue gas exits the turbine at 652°C (1,206°F) (stream 3) and passes into the HRSG. The HRSG generates both the main steam (stream 5) and reheat steam (stream 7) for the steam turbine. Flue gas (stream 4) exits the HRSG at 79°C (174°F) and passes to the plant stack.

Exhibit 4-7. Case B31A BFD, 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. For equipment with multiple units, only a single unit is depicted while the total flow is reported.

Exhibit 4-8. Case B31A stream table, NGCC without CO_2 capture

	1	2	3	4	5	6	7	8	9	10	11
V-L Mole Fraction											
Ar	0.0092	0.0000	0.0089	0.0089	0.0000	0.0000	0.0000	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	0.0000	0.0000
CH_4S	0.0000	0.0000	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	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	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	0.0000	0.0000
CO_2	0.0003	0.0100	0.0425	0.0425	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0000	0.0906	0.0906	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.7732	0.0160	0.7416	0.7416	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2074	0.0000	0.1164	0.1164	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	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
V-L Flowrate (kg_{mol}/hr)	130,449	5,508	136,117	136,117	30,101	29,232	31,946	32,780	3,842	36,622	36,657
V-L Flowrate (kg/hr)	3,764,363	95,442	3,859,805	3,859,805	542,286	526,630	575,515	590,534	69,218	659,752	660,390
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	27	652	79	585	364	585	300	304	38	38
Pressure (MPa, abs)	0.10	2.96	0.11	0.10	17.30	4.13	3.84	0.52	0.51	0.01	0.01
Steam Table Enthalpy (kJ/kg)[A]	30.23	21.97	872.29	226.68	3,520.51	3,124.08	3,641.17	3,062.57	3,071.95	2,375.86	160.78
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-4,487.26	-660.40	-1,306.01	-12,459.78	-12,856.21	-12,339.12	-12,917.72	-12,908.34	-13,604.44	-15,819.51
Density (kg/m^3)	1.2	22.1	0.4	1.0	48.1	15.1	9.9	2.0	1.9	0.1	992.8
V-L Molecular Weight	28.857	17.328	28.357	28.357	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	287,591	12,143	300,086	300,086	66,362	64,446	70,429	72,267	8,471	80,737	80,815
V-L Flowrate (lb/hr)	8,299,000	210,413	8,509,413	8,509,413	1,195,537	1,161,020	1,268,793	1,301,904	152,600	1,454,504	1,455,910
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	80	1,206	174	1,085	687	1,085	571	579	101	101
Pressure (psia)	14.7	430.0	15.3	14.8	2,509.2	598.5	557.6	75.0	73.5	1.0	1.0
Steam Table Enthalpy (Btu/lb)[A]	13.0	9.4	375.0	97.5	1,513.5	1,343.1	1,565.4	1,316.7	1,320.7	1,021.4	69.1
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-1,929.2	-283.9	-561.5	-5,356.7	-5,527.2	-5,304.9	-5,553.6	-5,549.6	-5,848.9	-6,801.2
Density (lb/ft^3)	0.076	1.380	0.024	0.062	3.002	0.943	0.618	0.124	0.120	0.003	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

4.2.4 Case B31A – Performance Results

The plant produces a net output of 741 MW at a net plant efficiency of 53.4 percent (HHV basis). Overall plant performance is summarized in Exhibit 4-9; Exhibit 4-10 provides a detailed breakdown of the auxiliary power requirements.

Exhibit 4-9. Case B31A plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	484
Steam Turbine Power, MWe	272
Total Gross Power, MWe	**755**
CO_2 Capture/Removal Auxiliaries, kWe	–
CO_2 Compression, kWe	–
Balance of Plant, kWe	14,056
Total Auxiliaries, MWe	**14**
Net Power, MWe	**741**
HHV Net Plant Efficiency, %	53.4
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,736 (6,385)
HHV Combustion Turbine Efficiency, %	34.9
LHV Net Plant Efficiency, %	59.2
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,080 (5,763)
LHV Combustion Turbine Efficiency, %	38.6
Steam Turbine Cycle Efficiency, %	39.2
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	9,178 (8,700)
CO_2 Capture Rate, %	–
Condenser Duty, GJ/hr (MMBtu/hr)	1,461 (1,385)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	–
Natural Gas Feed Flow, kg/hr (lb/hr)	95,442 (210,413)
HHV Thermal Input, kWt	1,386,417
LHV Thermal Input, kWt	1,251,379
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.015 (4.1)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.011 (3.0)

Exhibit 4-10. Case B31A plant power summary

Power Summary	
Combustion Turbine Power, MWe	484
Steam Turbine Power, MWe	272
Total Gross Power, MWe	**755**
Auxiliary Load Summary	
Circulating Water Pumps, kWe	2,920
Combustion Turbine Auxiliaries, kWe	1,240
Condensate Pumps, kWe	550
Cooling Tower Fans, kWe	1,510
CO_2 Capture/Removal Auxiliaries, kWe	–
CO_2 Compression, kWe	–
Feedwater Pumps, kWe	4,440
Ground Water Pumps, kWe	270
Miscellaneous Balance of Plant[A], kWe	580
SCR, kWe	6
Steam Turbine Auxiliaries, kWe	240
Transformer Losses, kWe	2,300
Total Auxiliaries, MWe	**14**
Net Power, MWe	**741**

[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 are presented in Section 2.4. A summary of the plant air emissions for Case B31A is presented in Exhibit 4-11.

Exhibit 4-11. Case B31A air emissions

	kg/GJ (lb/MMBtu)[A]	tonne/year (ton/year)[B]	kg/MWh (lb/MWh)[C]
SO_2	0.000 (0.001)	15 (17)	0.003 (0.006)
NOx	0.001 (0.003)	55 (60)	0.010 (0.021)
Particulate	0.001 (0.003)	44 (49)	0.008 (0.017)
Hg	0.00E+0 (0.00E+0)	0.000 (0.000)	0.00E+0 (0.00E+0)
CO	0.009 (0.020)	317 (350)	0.056 (0.124)
CO_2	51 (119)	1,894,743 (2,088,597)	337 (743)
CO_2[D]	–	–	343 (757)

[A]Based on thermal input on an HHV basis
[B]Calculations based on an 85 percent capacity factor
[C]Emissions based on gross power except where otherwise noted
[D]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 domestic average value of total sulfur of 0.34 gr/100 scf ($4.71x10^{-4}$ lb-S/MMBtu) (Gas Research Institute, 1992). It was also assumed that the added 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 1.8 ppmv NOx emissions using a DLN burner in the CTG and an SCR. The DLN burners reduce the emissions to about 25 ppmvd (at 15 percent O_2) (GE Vernova, 2024b) and the SCR system is designed for an additional 94.2 percent NOx reduction (Davis & Black, October 2000).

The pipeline natural gas was assumed to contain no Hg or HCl, resulting in zero emissions.

The state-of-the-art 2023 F-Class gas turbine achieves approximately 9.0 ppmvd (at 15 percent O_2) CO and 1.5 ppmw PM emissions. The production of PM is a result of system inefficiencies and is not produced or emitted in any significant amount.

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

The carbon balance for the plant is shown in Exhibit 4-12. The carbon input to the plant consists of carbon in the natural gas and carbon in the air. Carbon leaves the plant as CO_2 through the stack.

Exhibit 4-12. Case B31A carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	68,936 (151,977)	Stack Gas	69,448 (153,106)
Air (CO_2)	512 (1,129)	CO_2 Product	–
		CO_2 Knockout	–
Total	**69,448 (153,106)**	**Total**	**69,448 (153,106)**

As shown in Exhibit 4-13, the sulfur content of the natural gas is insignificant, entirely comprising CH_4S (used as an odorant) (Gas Research Institute, 1992). All sulfur in the natural gas is emitted in the stack gas.

Exhibit 4-13. Case B31A sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	1.0 (2.2)	Stack Gas	1.0 (2.2)
		Solvent Reclaiming	–
Total	**1.0 (2.2)**	**Total**	**1.0 (2.2)**

Water demand, recycle, withdrawal, discharge, and consumption are defined and discussed in Section 2.6. Exhibit 4-14 shows the water balance for the plant.

Exhibit 4-14. Case B31A water balance

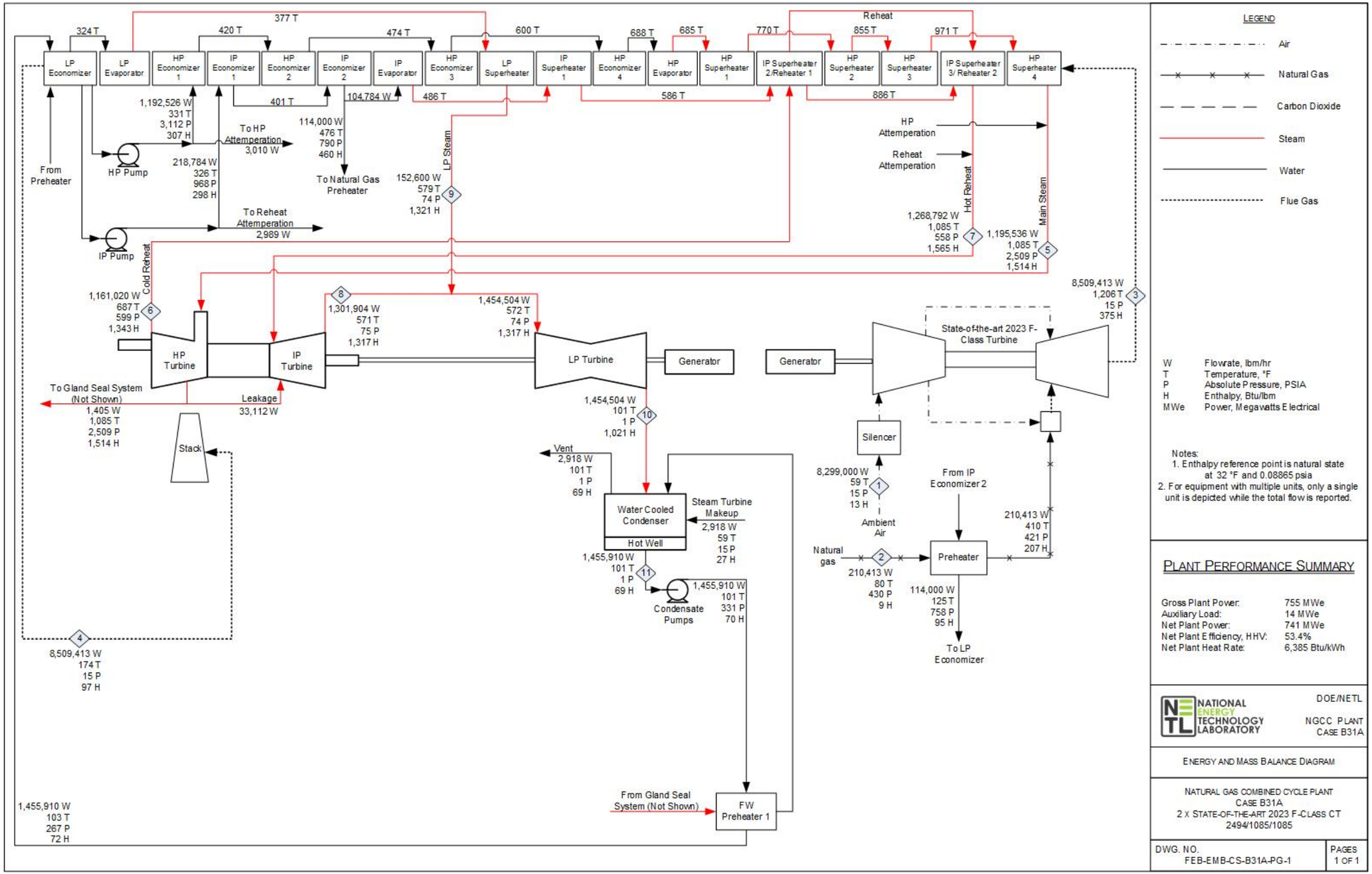
Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m³/min (gpm)	m³/min (gpm)	m³/min (gpm)	m³/min (gpm)	m³/min (gpm)
CO_2 Capture System Makeup	–	–	–	–	–
CO_2 Capture Recovery	–	–	–	–	–
CO_2 Compression Recovery	–	–	–	–	–
Deaerator Vent	–	–	–	0.0 (5.8)	0.0 (-5.8)
Condenser Makeup	**0.0 (5.8)**	**–**	**0.0 (5.8)**	**–**	**0.0 (5.8)**
BFW Makeup	0.0 (5.8)	–	0.0 (5.8)	–	0.0 (5.8)
Cooling Tower	**11 (2,999)**	**–**	**11 (2,999)**	**2.8 (749)**	**8.5 (2,250)**
Total	**11 (3,005)**	**–**	**11 (3,005)**	**2.9 (755)**	**8.5 (2,250)**

4.2.4.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for Case B31A in Exhibit 4-15.

An overall plant energy balance is provided in tabular form in Exhibit 4-16. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-9) is calculated by multiplying the power out by the generator efficiency: 98.5 percent for the CT and 97.5 percent for the steam turbine.

Exhibit 4-15. Case B31A energy and mass balance, NGCC without CO_2 capture



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Exhibit 4-16. Case B31A overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, GJ/hr (MMBtu/hr)				
Natural Gas	4,991 (4,731)	5.9 (5.6)	–	4,997 (4,736)
Air	–	114 (108)	–	114 (108)
Raw Water Makeup	–	43 (41)	–	43 (41)
Auxiliary Power	–	–	51 (48)	51 (48)
TOTAL	**4,991 (4,731)**	**163 (154)**	**51 (48)**	**5,204 (4,933)**
Heat Out, GJ/hr (MMBtu/hr)				
Stack Gas	–	875 (829)	–	875 (829)
Sulfur	–	–	–	–
Motor Losses and Design Allowances	–	–	64 (60)	64 (60)
Cooling Tower Load[A]	–	1,488 (1,410)	–	1,488 (1,410)
CO_2 Product Stream	–	–	–	–
AGR Effluent	–	–	–	–
Dryer Effluent	–	–	–	–
Deaerator Vent	–	0.2 (0.2)	–	0.2 (0.2)
Ambient Losses[B]	–	*42 (39)*	–	42 (39)
Power	–	–	2,718 (2,576)	2,718 (2,576)
TOTAL	**–**	**2,404 (2,279)**	**2,782 (2,637)**	**5,186 (4,915)**
Unaccounted Energy[C]	**–**	*18 (17)*	–	*18 (17)*

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

4.2.5 Case B31A – Major Equipment List

Major equipment items for the F-Class NGCC plant without 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. Values reported in the equipment lists are rounded.

Case B31A – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	87,000 liters (23,000 gal)	2	0
2	Condensate Pumps	Vertical canned	12,190 lpm @ 280 m H_2O (3,220 gpm @ 920 ft H_2O)	1	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP Water: 5,010 lpm @ 2,430 m H_2O (1,320 gpm @ 7,970 ft H_2O) IP Water: 930 lpm @ 610 m H_2O (250 gpm @ 1,990 ft H_2O)	2	2
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 GJ/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	3,800 lpm @ 110 m H_2O (1,000 gpm @ 350 ft H_2O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,600 lpm @ 80 m H_2O (700 gpm @ 250 ft H_2O)	1	1
11	Municipal Water Pumps	Stainless steel, single suction	3,200 lpm @ 20 m H_2O (850 gpm @ 60 ft H_2O)	2	1
12	Ground Water Pumps	Stainless steel, single suction	3,200 lpm @ 20 m H_2O (850 gpm @ 60 ft H_2O)	2	1
13	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H_2O (40 gpm @ 160 ft H_2O)	2	1
14	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
15	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0
16	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
17	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	79 m^3/min @ 3.0 MPa (2,795 acfm @ 430 psia) 39 cm (16 in) standard wall pipe	16 km (10 mile)	0
18	Gas Metering Station	–	79 m^3/min (2,795 acfm)	1	0

Case B31A – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	2023 Advanced F-Class w/ dry low-NOx burner	240 MW	2	0
2	Combustion Turbine Generator	Hydrogen Cooled	280 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	2	0

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

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Epoxy-coated CS plate	46 m (150 ft) high x 5.6 m (18 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section	Main Steam: 290,000 kg/hr, 17.2 MPa/585°C (639,000 lb/hr, 2,494 psig/1,085°F) Reheat Steam: 317,000 kg/hr, 3.7 MPa/585°C (698,000 lb/hr, 543 psig/1,085°F)	2	0
3	SCR Reactor	–	2,120,000 kg/hr (4,680,000 lb/hr)	2	0
4	SCR Catalyst	–	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	20 m^3/min @ 108 cm WG (600 scfm @ 42 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	3.6 lpm @ 90 m H_2O (0.9 gpm @ 300 ft H_2O)	2	1
7	Ammonia Storage Tank	Horizontal tank	103,000 liter (27,000 gal)	1	0

Case B31A – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	286 MW 17.2 MPa/585°C/585°C (2,494 psig/1,085°F/1,085°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	340 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Two pass, divided waterbox including vacuum pumps and integrated deaerator	1,610 GJ/hr (1,520 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	293,000 lpm @ 30 m (77,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 1,640 GJ/hr (1,550 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	18 kV/345 kV, 280 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	18 kV/345 kV, 320 MVA, 3-ph, 60 Hz	1	0
3	Medium Voltage Transformer	Oil-filled	18 kV/4.16 kV, 11 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 2 MVA, 3-ph, 60 Hz	1	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	2	0
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	1	0
7	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
8	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
9	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 is described in Section 2.7. Exhibit 4-17 shows a detailed breakdown of the capital costs; Exhibit 4-18 shows the owner's costs, TOC, and TASC; Exhibit 4-19 shows the initial and annual O&M costs; and Exhibit 4-20 shows the COE breakdown.

The estimated TPC of the F-Class NGCC without CO_2 capture is $1,051/kW. No process contingency was included in this case because all elements of the technology are commercially proven. The project contingency is 13.7 percent of TPC. The FY COE is $58.5/MWh and the LCOE is $47.0/MWh.

Exhibit 4-17. Case B31A total plant cost details

Case:	B31A– NGCC F-Class (2x1) without CO_2 capture					Estimate Type:	Conceptual			
Plant Size (MW, net):	741					Cost Base:	Jan 2023			
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	$2,491	$4,270	$1,831	$0	$8,591	$1,718	$0	$1,546	$11,856	$16
3.2	Water Makeup & Pretreating	$5,272	$527	$2,479	$0	$8,278	$1,656	$0	$1,987	$11,920	$16
3.3	Other Feedwater Subsystems	$1,417	$465	$379	$0	$2,261	$452	$0	$407	$3,120	$4
3.4	Service Water Systems	$1,600	$3,054	$8,207	$0	$12,861	$2,572	$0	$3,087	$18,520	$25
3.5	Other Boiler Plant Systems	$330	$120	$263	$0	$714	$143	$0	$128	$985	$1
3.6	NG Pipeline and Start-Up System	$12,945	$557	$347	$0	$13,848	$2,770	$0	$2,493	$19,111	$26
3.7	Waste Water Treatment Equipment	$7,394	$0	$3,973	$0	$11,367	$2,273	$0	$2,728	$16,369	$22
3.9	Miscellaneous Plant Equipment	$19,384	$2,542	$8,637	$0	$30,563	$6,113	$0	$7,335	$44,011	$59
	Subtotal	**$50,833**	**$11,535**	**$26,116**	**$0**	**$88,484**	**$17,697**	**$0**	**$19,711**	**$125,892**	**$170**
6	Combustion Turbine & Accessories										
6.1	Combustion Turbine Generator	$109,737	$0	$7,005	$0	$116,742	$23,348	$0	$21,014	$161,104	$217
6.3	Combustion Turbine Accessories	$3,106	$0	$191	$0	$3,297	$659	$0	$593	$4,549	$6
6.4	Compressed Air Piping	$0	$1,181	$227	$0	$1,407	$281	$0	$253	$1,942	$3
6.5	Combustion Turbine Foundations	$0	$1,064	$1,160	$0	$2,224	$445	$0	$534	$3,202	$4
	Subtotal	**$112,843**	**$2,244**	**$8,582**	**$0**	**$123,670**	**$24,734**	**$0**	**$22,394**	**$170,798**	**$231**
7	HRSG, Ductwork, & Stack										
7.1	HRSG	$65,396	$0	$16,349	$0	$81,745	$16,349	$0	$14,714	$112,808	$152
7.2	HRSG Accessories	$16,381	$0	$3,060	$0	$19,441	$3,888	$0	$3,499	$26,828	$36
7.3	Ductwork	$0	$1,492	$816	$0	$2,308	$462	$0	$415	$3,185	$4
7.4	Stack	$5,158	$0	$964	$0	$6,122	$1,224	$0	$1,102	$8,448	$11
7.5	HRSG, Ductwork, & Stack Foundations	$0	$1,037	$821	$0	$1,859	$372	$0	$446	$2,676	$4
7.6	Selective Catalytic Reduction System	$1,991	$837	$1,023	$0	$3,851	$770	$0	$693	$5,314	$7
	Subtotal	**$88,927**	**$3,366**	**$23,032**	**$0**	**$115,325**	**$23,065**	**$0**	**$20,870**	**$159,259**	**$215**
8	Steam Turbine & Accessories										
8.1	Steam Turbine Generator & Accessories	$51,751	$0	$7,578	$0	$59,330	$11,866	$0	$10,679	$81,875	$111
8.2	Steam Turbine Plant Auxiliaries	$174	$0	$400	$0	$574	$115	$0	$103	$792	$1
8.3	Condenser & Auxiliaries	$10,875	$0	$5,218	$0	$16,092	$3,218	$0	$2,897	$22,207	$30
8.4	Steam Piping	$13,635	$0	$4,685	$0	$18,320	$3,664	$0	$3,298	$25,282	$34
8.5	Turbine Generator Foundations	$0	$1,783	$2,488	$0	$4,271	$854	$0	$1,025	$6,150	$8
	Subtotal	**$76,434**	**$1,783**	**$20,369**	**$0**	**$98,587**	**$19,717**	**$0**	**$18,002**	**$136,306**	**$184**
9	Cooling Water System										
9.1	Cooling Towers	$11,261	$0	$3,012	$0	$14,273	$2,855	$0	$2,569	$19,697	$27
9.2	Circulating Water Pumps	$1,432	$0	$76	$0	$1,508	$302	$0	$272	$2,082	$3
9.3	Circulating Water System Auxiliaries	$10,852	$0	$1,296	$0	$12,148	$2,430	$0	$2,187	$16,764	$23
9.4	Circulating Water Piping	$0	$3,233	$2,429	$0	$5,662	$1,132	$0	$1,019	$7,814	$11
9.5	Make-up Water System	$415	$0	$443	$0	$858	$172	$0	$154	$1,184	$2
9.6	Component Cooling Water System	$477	$0	$304	$0	$780	$156	$0	$140	$1,077	$1
9.7	Circulating Water System Foundations	$0	$748	$1,065	$0	$1,813	$363	$0	$435	$2,611	$4

Case:	B31A– NGCC F-Class (2x1) without CO_2 capture						Estimate Type:		Conceptual	
Plant Size (MW, net):	741						Cost Base:		Jan 2023	
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
	Subtotal	**$24,437**	**$3,981**	**$8,625**	**$0**	**$37,043**	**$7,409**	**$0**	**$6,777**	**$51,229**	**$69**
	11					**Accessory Electric Plant**					
11.1	Generator Equipment	$3,573	$0	$2,227	$0	$5,800	$1,160	$0	$1,044	$8,004	$11
11.2	Station Service Equipment	$4,124	$0	$292	$0	$4,417	$883	$0	$795	$6,095	$8
11.3	Switchgear & Motor Control	$6,774	$0	$844	$0	$7,618	$1,524	$0	$1,371	$10,513	$14
11.4	Conduit & Cable Tray	$0	$1,423	$3,389	$0	$4,812	$962	$0	$866	$6,640	$9
11.5	Wire & Cable	$0	$2,124	$3,138	$0	$5,262	$1,052	$0	$947	$7,262	$10
11.6	Protective Equipment	$288	$0	$718	$0	$1,005	$201	$0	$181	$1,387	$2
11.7	Standby Equipment	$1,037	$0	$687	$0	$1,724	$345	$0	$310	$2,379	$3
11.8	Main Power Transformers	$7,379	$0	$152	$0	$7,531	$1,506	$0	$1,356	$10,393	$14
11.9	Electrical Foundations	$0	$125	$284	$0	$409	$82	$0	$98	$589	$1
	Subtotal	**$23,174**	**$3,672**	**$11,732**	**$0**	**$38,578**	**$7,716**	**$0**	**$6,969**	**$53,263**	**$72**
	12					**Instrumentation & Control**					
12.1	NGCC Control Equipment	$252	$0	$159	$0	$412	$82	$0	$74	$568	$1
12.2	Combustion Turbine Control Equipment	$416	$0	$262	$0	$678	$136	$0	$122	$935	$1
12.3	Steam Turbine Control Equipment	$405	$0	$255	$0	$659	$132	$0	$119	$910	$1
12.4	Other Major Component Control Equipment	$679	$0	$428	$0	$1,107	$221	$0	$199	$1,527	$2
12.5	Signal Processing Equipment	$566	$0	$17	$0	$583	$117	$0	$105	$804	$1
12.6	Control Boards, Panels, & Racks	$150	$0	$90	$0	$240	$48	$0	$43	$332	$0
12.7	Distributed Control System Equipment	$8,317	$0	$251	$0	$8,567	$1,713	$0	$1,542	$11,823	$16
12.8	Instrument Wiring & Tubing	$823	$658	$2,175	$0	$3,656	$731	$0	$658	$5,045	$7
12.9	Other I&C Equipment	$570	$0	$1,090	$0	$1,660	$332	$0	$299	$2,291	$3
	Subtotal	**$12,176**	**$658**	**$4,727**	**$0**	**$17,561**	**$3,512**	**$0**	**$3,161**	**$24,235**	**$33**
	13					**Improvements to Site**					
13.1	Site Preparation	$0	$710	$12,735	$0	$13,445	$2,689	$0	$3,227	$19,361	$26
13.2	Site Improvements	$0	$2,285	$2,548	$0	$4,834	$967	$0	$1,160	$6,960	$9
13.3	Site Facilities	$2,192	$0	$1,942	$0	$4,135	$827	$0	$992	$5,954	$8
	Subtotal	**$2,192**	**$2,996**	**$17,226**	**$0**	**$22,414**	**$4,483**	**$0**	**$5,379**	**$32,276**	**$44**
	14					**Buildings & Structures**					
14.1	Combustion Turbine Area	$0	$556	$216	$0	$772	$154	$0	$139	$1,066	$1
14.3	Steam Turbine Building	$0	$5,680	$5,554	$0	$11,235	$2,247	$0	$2,022	$15,504	$21
14.4	Administration Building	$0	$592	$295	$0	$887	$177	$0	$160	$1,224	$2
14.5	Circulation Water Pumphouse	$0	$92	$33	$0	$125	$25	$0	$22	$172	$0
14.6	Water Treatment Buildings	$0	$556	$373	$0	$929	$186	$0	$167	$1,282	$2
14.7	Machine Shop	$0	$886	$416	$0	$1,302	$260	$0	$234	$1,797	$2
14.8	Warehouse	$0	$689	$306	$0	$994	$199	$0	$179	$1,372	$2
14.9	Other Buildings & Structures	$0	$504	$269	$0	$773	$155	$0	$139	$1,066	$1
14.10	Waste Treating Building & Structures	$0	$641	$841	$0	$1,482	$296	$0	$267	$2,045	$3
	Subtotal	**$0**	**$10,197**	**$8,303**	**$0**	**$18,500**	**$3,700**	**$0**	**$3,330**	**$25,529**	**$34**
	Total	**$391,017**	**$40,431**	**$128,713**	**$0**	**$560,161**	**$112,032**	**$0**	**$106,592**	**$778,785**	**$1,051**

Exhibit 4-18. Case B31A owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$5,302	$7
1 Month Maintenance Materials	$870	$1
1 Month Non-fuel Consumables	$394	$1
1 Month Waste Disposal	$1	$0
25% of 1 Months Fuel Cost at 100% CF	$4,824	$7
2% of TPC	$15,576	$21
Total	**$26,966**	**$36**
Inventory Capital		
60-day supply of consumables at 100% CF	$420	$1
0.5% of TPC (spare parts)	$3,894	$5
Total	**$4,314**	**$6**
Other Costs		
Initial Cost for Catalyst and Chemicals	$1,944	$3
Land	$600	$1
Other Owner's Costs	$116,818	$158
Financing Costs	$21,027	$28
Total Overnight Costs (TOC)	**$950,454**	**$1,283**
TASC Multiplier (IOU, 33 year)	1.183	
Total As-Spent Cost (TASC)	**$1,124,337**	**$1,517**

Exhibit 4-19. Case B31A initial and annual operating and maintenance costs

Case:	B31A – NGCC F-Class (2x1) Without CO_2 Capture				Cost Base:	Jan 2023
Plant Size (MW, net):	741	Heat Rate-net (Btu/kWh):	6,385		Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		45.04	**$/hour**	Skilled Operator:	1.0	
Operating Labor Burden:		30.00	**% of base**	Operator:	2.0	
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:	1.0	
				Lab Techs, etc.:	1.0	
				Total:	**5.0**	
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$2,564,552	$3.461
Maintenance Labor:					$5,918,769	$7.988
Administrative & Support Labor:					$2,120,830	$2.862
Property Taxes and Insurance:					$15,575,708	$21.021
Total:					**$26,179,860**	**$35.333**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$8,878,154	$1.609
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	2,164	$2.30	$0	$1,543,934	$0.280
Makeup and Waste Water Treatment Chemicals (ton):	0	6.4	$660.00	$0	$1,319,760	$0.239
Ammonia (19 wt%, ton):	0	9.4	$280.00	$0	$820,484	$0.149
SCR Catalyst (ft^3):	5,555	3.0	$350.00	$1,944,340	$330,538	$0.060
Subtotal:				**$1,944,340**	**$4,014,716**	**$0.728**
Waste Disposal						
SCR Catalyst (ft^3):	0	3.0	$5.70	$0	$5,383	$0.001
Subtotal:				**$0**	**$5,383**	**$0.001**
Variable Operating Costs Total:				**$1,944,340**	**$12,898,252**	**$2.338**
Fuel Cost						
Natural Gas (MMBtu):	0	113,536	$5.59	$0	$196,806,494	$35.672
Total:				**$0**	**$196,806,494**	**$35.672**

Exhibit 4-20. Case B31A COE breakdown

	FY COE		LCOE	
Component	**Value, $/MWh**	**Percentage**	**Value, $/MWh**	**Percentage**
Capital	15.7	27%	15.7	33%
Fixed	4.7	8%	6.3	13%
Variable	2.3	4%	3.1	7%
Fuel	35.7	61%	21.9	46%
Total (Excluding T&S)	**58.5**	**N/A**	**47.0**	**N/A**
CO_2 T&S	–	–	–	–
Total (Including T&S)	**58.5**	**N/A**	**47.0**	**N/A**

4.2.7 Case B31B.90 – NGCC with 90% CO_2 Capture Process Description

The plant configuration and process description for Case B31B.90 are nearly the same as Case B31A, with the exception that a PostCCC facility was included to treat the flue gas stream. Since the process descriptions of the plant and PostCCC facility were provided in Section 4.2.3 and Section 3.1.8, respectively, with differences between the facilities used in NGCC and PC cases noted in Section 4.1.4, they are not repeated here.

The BFD for Case B31B.90 is shown in Exhibit 4-21. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit 4-22. The modeling assumptions are presented in Section 4.2.1.

Exhibit 4-21. Case B31B.90 BFD, NGCC with 90 percent CO_2 capture

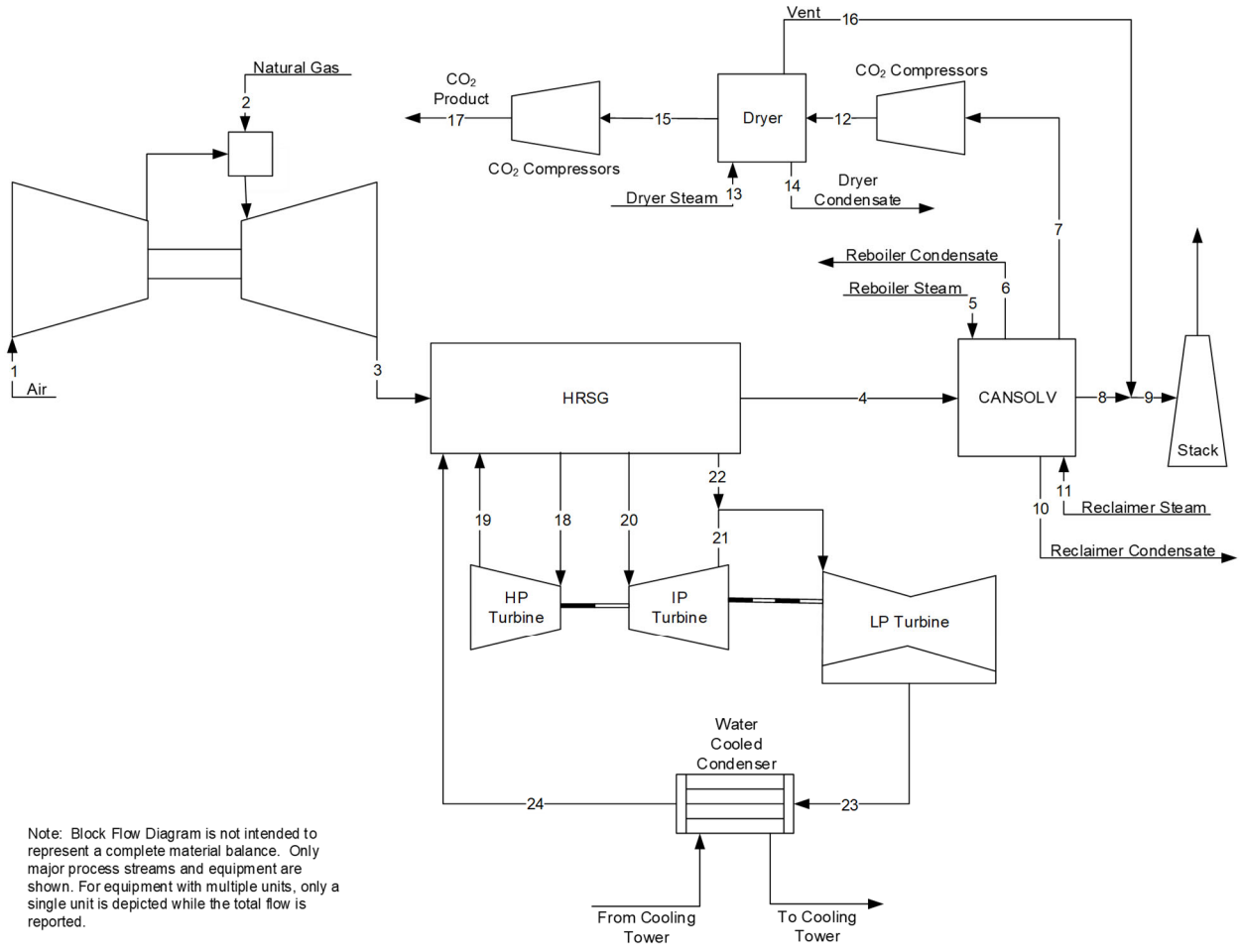


Exhibit 4-22. Case B31B.90 stream table, NGCC with 90 percent CO_2 capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0000	0.0089	0.0089	0.0000	0.0000	0.0000	0.0096	0.0096	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	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	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	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	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	0.0000	0.0000	0.0000
CO_2	0.0003	0.0100	0.0425	0.0425	0.0000	0.0000	0.9796	0.0046	0.0046	0.0000	0.0000	0.9957
H_2O	0.0099	0.0000	0.0906	0.0906	1.0000	1.0000	0.0204	0.0550	0.0550	1.0000	1.0000	0.0043
N_2	0.7732	0.0160	0.7416	0.7416	0.0000	0.0000	0.0000	0.8045	0.8045	0.0000	0.0000	0.0000
O_2	0.2074	0.0000	0.1164	0.1164	0.0000	0.0000	0.0000	0.1263	0.1263	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	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_{mol}/hr)	130,449	5,508	136,117	136,117	14,072	12,889	5,312	125,477	125,478	132	132	5,226
V-L Flowrate (kg/hr)	3,764,363	95,442	3,859,805	3,859,805	253,516	232,194	230,966	3,532,859	3,532,906	2,371	2,371	229,425
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	27	652	93	300	105	29	38	38	214	364	29
Pressure (MPa, abs)	0.10	2.96	0.11	0.10	0.51	0.12	0.17	0.10	0.10	2.04	4.13	2.81
Steam Table Enthalpy (kJ/kg)[A]	30.23	21.97	872.29	242.34	3,062.57	439.34	45.99	127.19	127.19	913.81	3,124.08	-1.10
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-4,487.26	-660.40	-1,290.35	-12,917.73	-15,540.95	-8,977.01	-523.67	-523.78	-15,066.49	-12,856.21	-8,976.01
Density (kg/m^3)	1.2	22.1	0.4	0.9	1.9	954.9	3.0	1.1	1.1	848.5	15.1	57.8
V-L Molecular Weight	28.857	17.328	28.357	28.357	18.015	18.015	43.481	28.155	28.155	18.015	18.015	43.897
V-L Flowrate (lb_{mol}/hr)	287,591	12,143	300,086	300,086	31,024	28,415	11,711	276,630	276,633	290	290	11,522
V-L Flowrate (lb/hr)	8,299,000	210,413	8,509,413	8,509,413	558,908	511,901	509,193	7,788,621	7,788,725	5,226	5,226	505,795
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	80	1,206	200	571	221	85	100	100	416	687	85
Pressure (psia)	14.7	430.0	15.3	14.8	73.5	17.4	24.7	14.8	14.8	296.6	598.5	407.6
Steam Table Enthalpy (Btu/lb)[A]	13.0	9.4	375.0	104.2	1,316.7	188.9	19.8	54.7	54.7	392.9	1,343.1	-0.5
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-1,929.2	-283.9	-554.8	-5,553.6	-6,681.4	-3,859.4	-225.1	-225.2	-6,477.4	-5,527.2	-3,859.0
Density (lb/ft^3)	0.076	1.380	0.024	0.059	0.121	59.612	0.185	0.069	0.069	52.968	0.943	3.607

[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 4-22. Case B31B.90 stream table, NGCC with 90 percent CO2 capture (continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0000	0.0000	0.0000	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	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	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	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	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	0.0000	0.0000	0.0000
CO_2	0.0000	0.0000	0.9995	0.9704	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	0.0005	0.0296	0.0005	1.0000	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	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	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	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_{mol}/hr)	8	8	5,205	1	5,205	30,131	29,261	31,830	32,664	3,842	22,434	36,681
V-L Flowrate (kg/hr)	136	136	229,018	47	229,018	542,824	527,152	573,419	588,453	69,218	404,155	660,816
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	364	203	29	28	30	585	364	585	300	304	38	38
Pressure (MPa, abs)	4.13	1.64	2.68	0.10	15.27	17.30	4.13	3.84	0.52	0.51	0.01	0.01
Steam Table Enthalpy (kJ/kg)[A]	3,124.08	863.65	-3.59	56.47	-231.09	3,520.51	3,124.08	3,641.17	3,062.57	3,071.95	2,376.21	160.78
AspenPlus Enthalpy (kJ/kg)[B]	-12,856.21	-15,116.65	-8,967.15	-8,994.77	-9,194.65	-12,459.78	-12,856.21	-12,339.12	-12,917.73	-12,908.34	-13,604.08	-15,819.51
Density (kg/m^3)	15.1	861.8	54.7	1.8	630.1	48.1	15.1	9.9	2.0	1.9	0.1	992.8
V-L Molecular Weight	18.015	18.015	43.997	43.240	43.997	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	17	17	11,476	2	11,476	66,428	64,510	70,172	72,012	8,471	49,459	80,867
V-L Flowrate (lb/hr)	299	299	504,899	103	504,899	1,196,721	1,162,170	1,264,173	1,297,318	152,600	891,010	1,456,849
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	687	397	85	83	86	1,085	687	1,085	571	579	101	101
Pressure (psia)	598.5	237.4	389.1	14.8	2,214.7	2,509.2	598.5	557.6	75.0	73.5	1.0	1.0
Steam Table Enthalpy (Btu/lb)[A]	1,343.1	371.3	-1.5	24.3	-99.4	1,513.5	1,343.1	1,565.4	1,316.7	1,320.7	1,021.6	69.1
AspenPlus Enthalpy (Btu/lb)[B]	-5,527.2	-6,499.0	-3,855.2	-3,867.1	-3,953.0	-5,356.7	-5,527.2	-5,304.9	-5,553.6	-5,549.6	-5,848.7	-6,801.2
Density (lb/ft^3)	0.943	53.801	3.416	0.110	39.338	3.002	0.943	0.618	0.124	0.120	0.003	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

4.2.8 Case B31B.90 – Performance Results

Overall plant performance is summarized in Exhibit 4-23; Exhibit 4-24 provides a detailed breakdown of the auxiliary power requirements.

The PostCCC facility and CO_2 compression combined account for 66 percent of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for 14 percent of the auxiliary load, largely due to the high cooling water demand of the PostCCC facility and CO_2 compressors.

Unlike the PC cases, which utilize boilers and steam turbines that can be produced at nearly any desired output, the gross outputs of the NGCC cases are fixed by the available size of the CTs. As such, the net outputs of the capture cases are reduced due to the greater auxiliary load imposed by the PostCCC facility and CO_2 compressors, relative to a non-capture case. The plant produces a net output of 658 MW at a net plant efficiency of 47.5 percent (HHV basis).

Exhibit 4-23. Case B31B.90 plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	484
Steam Turbine Power, MWe	224
Total Gross Power, MWe	**707**
CO_2 Capture/Removal Auxiliaries, kWe	13,900
CO_2 Compression, kWe	18,320
Balance of Plant, kWe	16,626
Total Auxiliaries, MWe	**49**
Net Power, MWe	**658**
HHV Net Plant Efficiency, %	47.5
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	7,582 (7,187)
HHV Combustion Turbine Efficiency, %	34.9
LHV Net Plant Efficiency, %	52.6
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,844 (6,487)
LHV Combustion Turbine Efficiency, %	38.6
Steam Turbine Cycle Efficiency, %	46.0
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,833 (7,425)
CO_2 Capture Rate, %	90
Condenser Duty, GJ/hr (MMBtu/hr)	899 (852)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	1,225 (1,161)
Natural Gas Feed Flow, kg/hr (lb/hr)	95,442 (210,413)
HHV Thermal Input, kWt	1,386,417
LHV Thermal Input, kWt	1,251,379
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.027 (7.1)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.017 (4.6)

Exhibit 4-24. Case B31B.90 plant power summary

Power Summary	
Combustion Turbine Power, MWe	484
Steam Turbine Power, MWe	224
Total Gross Power, MWe	**707**
Auxiliary Load Summary	
Circulating Water Pumps, kWe	4,470
Combustion Turbine Auxiliaries, kWe	1,240
Condensate Pumps, kWe	630
Cooling Tower Fans, kWe	2,310
CO_2 Capture/Removal Auxiliaries, kWe	13,900
CO_2 Compression, kWe	18,320
Feedwater Pumps, kWe	4,450
Ground Water Pumps, kWe	430
Miscellaneous Balance of Plant[A], kWe	580
SCR, kWe	6
Steam Turbine Auxiliaries, kWe	240
Transformer Losses, kWe	2,270
Total Auxiliaries, MWe	**49**
Net Power, MWe	**658**

[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 are presented in Section 2.4. A summary of the plant air emissions for Case B31B.90 is presented in Exhibit 4-25.

Exhibit 4-25. Case B31B.90 air emissions

	kg/GJ (lb/MMBtu)[A]	tonne/year (ton/year)[B]	kg/MWh (lb/MWh)[C]
SO_2	0.000 (0.000)	0 (0)	0.000 (0.000)
NOx	0.001 (0.003)	50 (56)	0.010 (0.021)
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	0.000 (0.000)	0 (0)	0.000 (0.000)
CO_2	5 (12)	189,819 (209,240)	36 (79)
CO_2[D]	–	–	39 (85)

[A]Based on thermal input on an HHV basis
[B]Calculations based on an 85 percent capacity factor
[C]Emissions based on gross power except where otherwise noted
[D]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 domestic average value of total sulfur of 0.34 gr/100 scf ($4.71x10^{-4}$ lb-S/MMBtu) (Gas Research Institute, 1992). It was also assumed that the added 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 1.8 ppmv NOx emissions using a DLN burner in the CTG and an SCR. The DLN burners reduce the emissions to about 25 ppmvd (at 15 percent O_2) (GE Vernova, 2024b) and the SCR system is designed for an additional 94.7 percent NOx reduction (Davis & Black, October 2000).

The pipeline natural gas was assumed to contain no Hg or HCl, resulting in zero emissions.

The state-of-the-art 2023 F-Class gas turbine achieves approximately 9.0 ppmvd (at 15 percent O_2) CO and 1.5 ppmw PM emissions. The production of PM is a result of system inefficiencies and is not produced or emitted in any significant amount. Any CO or PM present in the flue gas is assumed to interact with, and be removed by, the PostCCC system solvent.

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

The carbon balance for the plant is shown in Exhibit 4-26. The carbon input to the plant consists of carbon in the natural gas and carbon in the air. Carbon leaves the plant mostly as CO_2 product from the CO_2 compression train; however, some carbon exits through the stack as CO_2.

Ninety percent of the CO_2 in the flue gas is removed in the PostCCC facility. 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 percentage:

$$1 - \frac{Carbon\ in\ Stack}{Total\ Carbon\ In} = \left(1 - \left(\frac{15{,}338}{153{,}106}\right)\right) * 100 = 90\%$$

Exhibit 4-26. Case B31B.90 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	68,936 (151,977)	Stack Gas	6,957 (15,338)
Air (CO_2)	512 (1,129)	CO_2 Product	62,490 (137,767)
		CO_2 Knockout	0.1 (0.3)
Total	**69,448 (153,106)**	**Total**	**69,448 (153,106)**

As shown in Exhibit 4-27, the sulfur content of the natural gas is insignificant, entirely comprising CH_4S (used as an odorant) (Gas Research Institute, 1992). All sulfur in the natural gas is assumed to react with the PostCCC system solvent and is removed from the solvent during solvent reclaiming as a waste stream.

Exhibit 4-27. Case B31B.90 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	1.0 (2.2)	Stack Gas	0.0 (0.0)
		Solvent Reclaiming	1.0 (2.2)
Total	**1.0 (2.2)**	**Total**	**1.0 (2.2)**

Water demand, recycle, withdrawal, discharge, and consumption are defined and discussed in Section 2.6. Exhibit 4-28 shows the overall water balance for the plant.

Exhibit 4-28. Case B31B.90 water balance

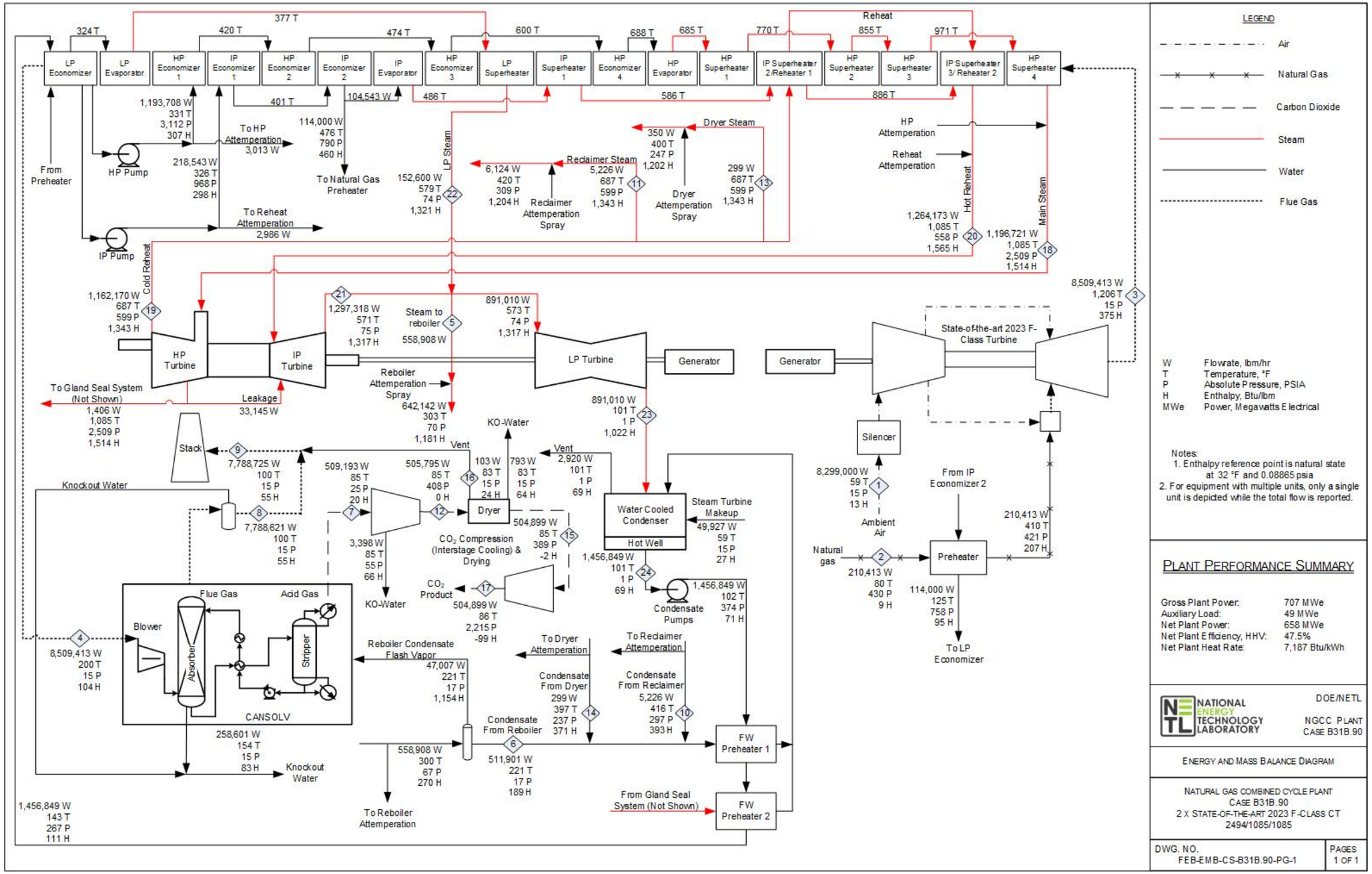
Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)
CO_2 Capture System Makeup	–	–	–	–	–
CO_2 Capture Recovery	–	–	–	2.0 (515)	-2.0 (-515)
CO_2 Compression Recovery	–	–	–	0.0 (6.8)	0.0 (-6.8)
Deaerator Vent	–	–	–	0.0 (5.8)	0.0 (-5.8)
Condenser Makeup	**0.4 (100)**	**–**	**0.4 (100)**	**–**	**0.4 (100)**
BFW Makeup	0.4 (100)	–	0.4 (100)	–	0.4 (100)
Cooling Tower	**17 (4,594)**	**–**	**17 (4,594)**	**4.3 (1,148)**	**13 (3,446)**
Total	**18 (4,694)**	**–**	**18 (4,694)**	**6.3 (1,676)**	**11 (3,018)**

4.2.8.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for Case B31B.90 in Exhibit 4-29.

An overall plant energy balance is provided in tabular form in Exhibit 4-30. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-23) is calculated by multiplying the power out by the generator efficiency: 98.5 percent for the CT and 97.5 percent for the steam turbine.

Exhibit 4-29. Case B31B.90 energy and mass balance, NGCC with CO_2 capture



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Exhibit 4-30. Case B31B.90 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, GJ/hr (MMBtu/hr)				
Natural Gas	4,991 (4,731)	5.9 (5.6)	–	4,997 (4,736)
Air	–	114 (108)	–	114 (108)
Raw Water Makeup	–	67 (64)	–	67 (64)
Auxiliary Power	–	–	176 (167)	176 (167)
TOTAL	**4,991 (4,731)**	**187 (177)**	**176 (167)**	**5,354 (5,074)**
Heat Out, GJ/hr (MMBtu/hr)				
Stack Gas	–	449 (426)	–	449 (426)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Motor Losses and Design Allowances	–	–	62 (58)	62 (58)
Cooling Tower Load[A]	–	2,279 (2,160)	–	2,279 (2,160)
CO_2 Product Stream	–	-53 (-50)	–	-53 (-50)
AGR Effluent	–	33 (32)	–	33 (32)
Dryer Effluent	–	0.0 (0.0)	–	0.0 (0.0)
Deaerator Vent	–	0.2 (0.2)	–	0.2 (0.2)
Ambient Losses[B]	–	*44 (42)*	–	44 (42)
Power	–	–	2,546 (2,413)	2,546 (2,413)
TOTAL	**0.0 (0.0)**	**2,753 (2,609)**	**2,607 (2,471)**	**5,360 (5,081)**
Unaccounted Energy[C]	–	*-6.6 (-6.2)*	–	*-6.6 (-6.2)*

[A]Includes condenser, capture process, CO_2 compressor, and miscellaneous cooling loads
[B]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers
[C]By difference

4.2.9 Case B31B.90 – Major Equipment List

Major equipment items for the F-Class NGCC plant with 90 percent 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. Values reported in the equipment lists are rounded.

Case B31B.90 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,492,000 liters (394,000 gal)	2	0
2	Condensate Pumps	Vertical canned	12,200 lpm @ 320 m H_2O (3,220 gpm @ 1,040 ft H_2O)	1	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP Water: 5,010 lpm @ 2,430 m H_2O (1,320 gpm @ 7,970 ft H_2O) IP Water: 930 lpm @ 610 m H_2O (250 gpm @ 1,990 ft H_2O)	2	2
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 GJ/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	3,800 lpm @ 110 m H_2O (1,000 gpm @ 350 ft H_2O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,600 lpm @ 80 m H_2O (700 gpm @ 250 ft H_2O)	1	1
11	Municipal Water Pumps	Stainless steel, single suction	4,900 lpm @ 20 m H_2O (1,290 gpm @ 60 ft H_2O)	2	1
12	Ground Water Pumps	Stainless steel, single suction	4,900 lpm @ 20 m H_2O (1,290 gpm @ 60 ft H_2O)	2	1
13	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H_2O (40 gpm @ 160 ft H_2O)	2	1
14	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
15	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0
16	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
17	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	79 m^3/min @ 3.0 MPa (2,795 acfm @ 430 psia) 39 cm (16 in) standard wall pipe	16 km (10 mile)	0
18	Gas Metering Station	–	79 m^3/min (2,795 acfm)	1	0

Case B31B.90 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Cansolv	Amine-based CO_2 capture technology	4,246,000 kg/hr (9,360,000 lb/hr) 6.6 wt% CO_2 concentration	1	0
2	Cansolv LP Condensate Pump	Centrifugal	690 lpm @ 1.0 m H_2O (180 gpm @ 3.4 ft H_2O)	1	1
3	Cansolv HP Condensate Pump	Centrifugal	7.6 lpm @ 4.6 m H_2O (2.0 gpm @ 15.0 ft H_2O)	1	1
4	CO_2 Dryer	Triethylene glycol	Inlet: 66 m^3/min @ 2.8 MPa (2,337 acfm @ 408 psia) Outlet: 2.7 MPa (389 psia) Water Removed: 360 kg/hr (795 lb/hr)	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
5	CO_2 Compressor	Integrally geared, multi-stage centrifugal	3 m^3/min @ 15.3 MPa, 82°C (118 acfm @ 2,217 psia, 180°F)	2	0
6	CO_2 Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 36 GJ/hr (34 MMBtu/hr)	2	0

Case B31B.90 – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	2023 Advanced F-Class w/ dry low-NOx burner	240 MW	2	0
2	Combustion Turbine Generator	Hydrogen Cooled	280 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	2	0

Case B31B.90 – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Epoxy-coated CS plate	46 m (150 ft) high x 5.0 m (17 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section	Main Steam: 290,000 kg/hr, 17.2 MPa/585°C (639,000 lb/hr, 2,494 psig/1,085°F) Reheat Steam: 315,000 kg/hr, 3.7 MPa/585°C (695,000 lb/hr, 543 psig/1,085°F)	2	0
3	SCR Reactor	–	2,120,000 kg/hr (4,680,000 lb/hr)	2	0
4	SCR Catalyst	–	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	20 m^3/min @ 108 cm WG (600 scfm @ 42 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	3.6 lpm @ 90 m H_2O (1.0 gpm @ 300 ft H_2O)	2	1
7	Ammonia Storage Tank	Horizontal tank	104,000 liter (27,000 gal)	1	0

Case B31B.90 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	235 MW 17.2 MPa/585°C/585°C (2,494 psig/1,085°F/1,085°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	280 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Two pass, divided waterbox including vacuum pumps and integrated deaerator	990 GJ/hr (940 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.90 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	448,000 lpm @ 30 m (118,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 2,510 GJ/hr (2,380 MMBtu/hr) heat duty	1	0

Case B31B.90 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	18 kV/345 kV, 280 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	18 kV/345 kV, 220 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 10 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	18 kV/4.16 kV, 24 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 8 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 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.90 – 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.90 – Cost Estimating

The cost estimating methodology is described in Section 2.7. Exhibit 4-31 shows a detailed breakdown of the capital costs; Exhibit 4-32 shows the owner's costs, TOC, and TASC; Exhibit 4-33 shows the initial and annual O&M costs; and Exhibit 4-34 shows the COE breakdown.

The estimated TPC of the NGCC with CO_2 capture is $2,180/kW. Process contingency represents 3.9 percent of the TPC and project contingency represents 15.0 percent of the TPC. The FY COE, including T&S costs of $4.5/MWh, is $91.8/MWh. The LCOE, including T&S costs of $6.0/MWh, is $82.7/MWh.

Exhibit 4-31. Case B31B.90 total plant cost details

Case:	B31B.90 – NGCC F-Class (2x1) with 90 Percent CO_2 Capture									
Plant Size (MW, net):	658									
Estimate Type:	Conceptual									
Cost Base:	Jan 2023									
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	$2,492	$4,273	$1,833	$0	$8,598	$1,720	$0	$1,548	$11,865	$18
3.2	Water Makeup & Pretreating	$7,235	$724	$3,403	$0	$11,361	$2,272	$0	$2,727	$16,360	$25
3.3	Other Feedwater Subsystems	$1,418	$465	$379	$0	$2,262	$452	$0	$407	$3,122	$5
3.4	Service Water Systems	$2,196	$4,192	$11,264	$0	$17,651	$3,530	$0	$4,236	$25,418	$39
3.5	Other Boiler Plant Systems	$331	$120	$263	$0	$714	$143	$0	$129	$986	$1
3.6	NG Pipeline and Start-Up System	$12,945	$557	$347	$0	$13,848	$2,770	$0	$2,493	$19,111	$29
3.7	Waste Water Treatment Equipment	$13,022	$0	$6,997	$0	$20,019	$4,004	$0	$4,805	$28,828	$44
3.9	Miscellaneous Plant Equipment	$19,384	$2,542	$8,637	$0	$30,563	$6,113	$0	$7,335	$44,011	$67
	Subtotal	**$59,024**	**$12,872**	**$33,122**	**$0**	**$105,018**	**$21,004**	**$0**	**$23,679**	**$149,700**	**$227**
5	Flue Gas Cleanup										
5.1	CANSOLV CO_2 Removal System	$130,015	$62,752	$116,890	$0	$309,658	$61,932	$55,738	$85,466	$512,793	$779
5.4	CO_2 Compression & Drying	$33,450	$5,018	$13,134	$0	$51,601	$10,320	$0	$12,384	$74,306	$113
5.5	CO_2 Compressor Aftercooler	$283	$45	$115	$0	$443	$89	$0	$106	$638	$1
5.12	Gas Cleanup Foundations	$0	$481	$492	$0	$973	$195	$0	$233	$1,401	$2
	Subtotal	**$163,748**	**$68,296**	**$130,631**	**$0**	**$362,675**	**$72,535**	**$55,738**	**$98,190**	**$589,138**	**$895**
6	Combustion Turbine & Accessories										
6.1	Combustion Turbine Generator	$109,737	$0	$7,005	$0	$116,742	$23,348	$0	$21,014	$161,104	$245
6.3	Combustion Turbine Accessories	$3,106	$0	$191	$0	$3,297	$659	$0	$593	$4,549	$7
6.4	Compressed Air Piping	$0	$1,181	$227	$0	$1,407	$281	$0	$253	$1,942	$3
6.5	Combustion Turbine Foundations	$0	$1,064	$1,160	$0	$2,224	$445	$0	$534	$3,202	$5
	Subtotal	**$112,843**	**$2,244**	**$8,582**	**$0**	**$123,670**	**$24,734**	**$0**	**$22,394**	**$170,798**	**$259**
7	HRSG, Ductwork, & Stack										
7.1	HRSG	$64,281	$0	$16,070	$0	$80,351	$16,070	$0	$14,463	$110,885	$168
7.2	HRSG Accessories	$16,102	$0	$3,008	$0	$19,109	$3,822	$0	$3,440	$26,371	$40
7.3	Ductwork	$0	$1,293	$707	$0	$1,999	$400	$0	$360	$2,759	$4
7.4	Stack	$4,469	$0	$835	$0	$5,304	$1,061	$0	$955	$7,320	$11
7.5	HRSG, Ductwork, & Stack Foundations	$0	$899	$712	$0	$1,610	$322	$0	$386	$2,319	$4
7.6	Selective Catalytic Reduction System	$1,991	$837	$1,023	$0	$3,851	$770	$0	$693	$5,314	$8
	Subtotal	**$86,843**	**$3,028**	**$22,354**	**$0**	**$112,225**	**$22,445**	**$0**	**$20,297**	**$154,967**	**$235**
8	Steam Turbine & Accessories										
8.1	Steam Turbine Generator & Accessories	$44,308	$0	$6,488	$0	$50,796	$10,159	$0	$9,143	$70,099	$106
8.2	Steam Turbine Plant Auxiliaries	$151	$0	$347	$0	$498	$100	$0	$90	$687	$1
8.3	Condenser & Auxiliaries	$7,374	$0	$3,538	$0	$10,912	$2,182	$0	$1,964	$15,058	$23
8.4	Steam Piping	$13,646	$0	$4,689	$0	$18,335	$3,667	$0	$3,300	$25,303	$38
8.5	Turbine Generator Foundations	$0	$1,548	$2,159	$0	$3,707	$741	$0	$890	$5,337	$8
	Subtotal	**$65,479**	**$1,548**	**$17,222**	**$0**	**$84,248**	**$16,850**	**$0**	**$15,387**	**$116,485**	**$177**
9	Cooling Water System										
9.1	Cooling Towers	$15,244	$0	$4,077	$0	$19,321	$3,864	$0	$3,478	$26,663	$41

Case:	B31B.90 – NGCC F-Class (2x1) with 90 Percent CO_2 Capture								Estimate Type:	Conceptual
Plant Size (MW, net):	658								Cost Base:	Jan 2023
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
9.2	Circulating Water Pumps	$1,947	$0	$104	$0	$2,051	$410	$0	$369	$2,830	$4
9.3	Circulating Water System Auxiliaries	$13,273	$0	$1,585	$0	$14,858	$2,972	$0	$2,674	$20,504	$31
9.4	Circulating Water Piping	$0	$4,175	$3,138	$0	$7,313	$1,463	$0	$1,316	$10,092	$15
9.5	Make-up Water System	$495	$0	$528	$0	$1,023	$205	$0	$184	$1,412	$2
9.6	Component Cooling Water System	$615	$0	$392	$0	$1,008	$202	$0	$181	$1,391	$2
9.7	Circulating Water System Foundations	$0	$966	$1,376	$0	$2,342	$468	$0	$562	$3,373	$5
	Subtotal	**$31,574**	**$5,141**	**$11,200**	**$0**	**$47,915**	**$9,583**	**$0**	**$8,765**	**$66,264**	**$101**
11	**Accessory Electric Plant**										
11.1	Generator Equipment	$3,437	$0	$2,143	$0	$5,580	$1,116	$0	$1,004	$7,700	$12
11.2	Station Service Equipment	$9,153	$0	$649	$0	$9,802	$1,960	$0	$1,764	$13,527	$21
11.3	Switchgear & Motor Control	$15,034	$0	$1,874	$0	$16,908	$3,382	$0	$3,043	$23,333	$35
11.4	Conduit & Cable Tray	$0	$3,158	$7,521	$0	$10,679	$2,136	$0	$1,922	$14,737	$22
11.5	Wire & Cable	$0	$4,715	$6,964	$0	$11,679	$2,336	$0	$2,102	$16,117	$24
11.6	Protective Equipment	$638	$0	$1,593	$0	$2,231	$446	$0	$402	$3,079	$5
11.7	Standby Equipment	$1,004	$0	$666	$0	$1,670	$334	$0	$301	$2,305	$4
11.8	Main Power Transformers	$7,036	$0	$145	$0	$7,181	$1,436	$0	$1,293	$9,909	$15
11.9	Electrical Foundations	$0	$119	$271	$0	$391	$78	$0	$94	$563	$1
	Subtotal	**$36,303**	**$7,992**	**$21,825**	**$0**	**$66,120**	**$13,224**	**$0**	**$11,925**	**$91,270**	**$139**
12	**Instrumentation & Control**										
12.1	NGCC Control Equipment	$292	$0	$184	$0	$475	$95	$0	$86	$656	$1
12.2	Combustion Turbine Control Equipment	$480	$0	$303	$0	$783	$157	$0	$141	$1,080	$2
12.3	Steam Turbine Control Equipment	$467	$0	$295	$0	$762	$152	$0	$137	$1,051	$2
12.4	Other Major Component Control Equipment	$784	$0	$494	$0	$1,278	$256	$64	$240	$1,838	$3
12.5	Signal Processing Equipment	$654	$0	$20	$0	$673	$135	$0	$121	$929	$1
12.6	Control Boards, Panels, & Racks	$173	$0	$105	$0	$278	$56	$14	$52	$399	$1
12.7	Distributed Control System Equipment	$9,607	$0	$290	$0	$9,897	$1,979	$495	$1,856	$14,227	$22
12.8	Instrument Wiring & Tubing	$950	$760	$2,513	$0	$4,223	$845	$211	$792	$6,071	$9
12.9	Other I&C Equipment	$658	$0	$1,259	$0	$1,918	$384	$96	$360	$2,756	$4
	Subtotal	**$14,066**	**$760**	**$5,461**	**$0**	**$20,287**	**$4,057**	**$880**	**$3,784**	**$29,007**	**$44**
13	**Improvements to Site**										
13.1	Site Preparation	$0	$925	$16,586	$0	$17,511	$3,502	$0	$4,203	$25,216	$38
13.2	Site Improvements	$0	$2,976	$3,319	$0	$6,295	$1,259	$0	$1,511	$9,065	$14
13.3	Site Facilities	$2,855	$0	$2,530	$0	$5,385	$1,077	$0	$1,292	$7,754	$12
	Subtotal	**$2,855**	**$3,901**	**$22,435**	**$0**	**$29,191**	**$5,838**	**$0**	**$7,006**	**$42,035**	**$64**
14	**Buildings & Structures**										
14.1	Combustion Turbine Area	$0	$556	$216	$0	$772	$154	$0	$139	$1,066	$2
14.3	Steam Turbine Building	$0	$5,056	$4,944	$0	$9,999	$2,000	$0	$1,800	$13,799	$21
14.4	Administration Building	$0	$579	$288	$0	$867	$173	$0	$156	$1,197	$2
14.5	Circulation Water Pumphouse	$0	$130	$47	$0	$177	$35	$0	$32	$244	$0
14.6	Water Treatment Buildings	$0	$675	$453	$0	$1,128	$226	$0	$203	$1,557	$2
14.7	Machine Shop	$0	$867	$407	$0	$1,274	$255	$0	$229	$1,758	$3

Case:		B31B.90 – NGCC F-Class (2x1) with 90 Percent CO_2 Capture					Estimate Type:			Conceptual	
Plant Size (MW, net):		658					Cost Base:			Jan 2023	
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
14.8	Warehouse	$0	$674	$299	$0	$973	$195	$0	$175	$1,342	$2
14.9	Other Buildings & Structures	$0	$493	$263	$0	$756	$151	$0	$136	$1,043	$2
14.10	Waste Treating Building & Structures	$0	$1,130	$1,480	$0	$2,610	$522	$0	$470	$3,602	$5
	Subtotal	**$0**	**$10,159**	**$8,397**	**$0**	**$18,556**	**$3,711**	**$0**	**$3,340**	**$25,608**	**$39**
	Total	**$572,735**	**$115,941**	**$281,230**	**$0**	**$969,906**	**$193,981**	**$56,618**	**$214,767**	**$1,435,272**	**$2,180**

Exhibit 4-32. Case B31B.90 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$8,848	$13
1 Month Maintenance Materials	$1,604	$2
1 Month Non-fuel Consumables	$823	$1
1 Month Waste Disposal	$105	$0
25% of 1 Months Fuel Cost at 100% CF	$4,824	$7
2% of TPC	$28,705	$44
Total	**$44,909**	**$68**
Inventory Capital		
60-day supply of consumables at 100% CF	$1,108	$2
0.5% of TPC (spare parts)	$7,176	$11
Total	**$8,284**	**$13**
Other Costs		
Initial Cost for Catalyst and Chemicals	$1,944	$3
Land	$600	$1
Other Owner's Costs	$215,291	$327
Financing Costs	$38,752	$59
Total Overnight Costs (TOC)	**$1,745,053**	**$2,651**
TASC Multiplier (IOU, 33 year)	1.183	
Total As-Spent Cost (TASC)	**$2,064,306**	**$3,136**

Exhibit 4-33. Case B31B.90 initial and annual operating and maintenance costs

Case:	B31B.90 – NGCC F-Class (2x1) with 90 Percent CO_2 Capture				Cost Base:	Jan 2023
Plant Size (MW, net):	658	Heat Rate-net (Btu/kWh):		7,187	Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		45.04	**$/hour**	Skilled Operator:		1.0
Operating Labor Burden:		30.00	**% of base**	Operator:		3.3
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		1.0
				Total:		**6.3**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$3,248,262	$4.935
Maintenance Labor:					$10,908,070	$16.571
Administrative & Support Labor:					$3,539,083	$5.376
Property Taxes and Insurance:					$28,705,447	$43.608
Total:					**$46,400,861**	**$70.491**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$16,362,105	$3.338
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	3,380	$2.30	$0	$2,411,568	$0.492
Makeup and Waste Water Treatment Chemicals (ton):	0	10.1	$660.00	$0	$2,061,415	$0.421
Ammonia (19 wt%, ton):	0	9.5	$280.00	$0	$824,429	$0.168
SCR Catalyst (ft^3):	5,555	3.0	$350.00	$1,944,340	$330,538	$0.067
CO_2 Capture System Chemicals[A]:	Proprietary				$2,644,960	$0.540
Triethylene Glycol (gal):	w/equip.	45.4	$8.50	$0	$119,771	$0.024
Subtotal:				**$1,944,340**	**$8,392,680**	**$1.712**
Waste Disposal						
SCR Catalyst (ft^3):	0	3.0	$5.70	$0	$5,383	$0.001
Triethylene Glycol (gal):	0	2,303	$1.30	$0	$928,873	$0.190
Thermal Reclaimer Unit Waste (ton):	0	1.8	$250.00	$0	$138,925	$0.028
Subtotal:				**$0**	**$1,073,182**	**$0.219**
Variable Operating Costs Total:				**$1,944,340**	**$25,827,967**	**$5.270**
Fuel Cost						
Natural Gas (MMBtu):	0	113,536	$5.59	$0	$196,806,494	$40.153
Total:				**$0**	**$196,806,494**	**$40.153**

[A]CO_2 Capture System Chemicals includes NaOH and CANSOLV Solvent

Exhibit 4-34. Case B31B.90 COE breakdown

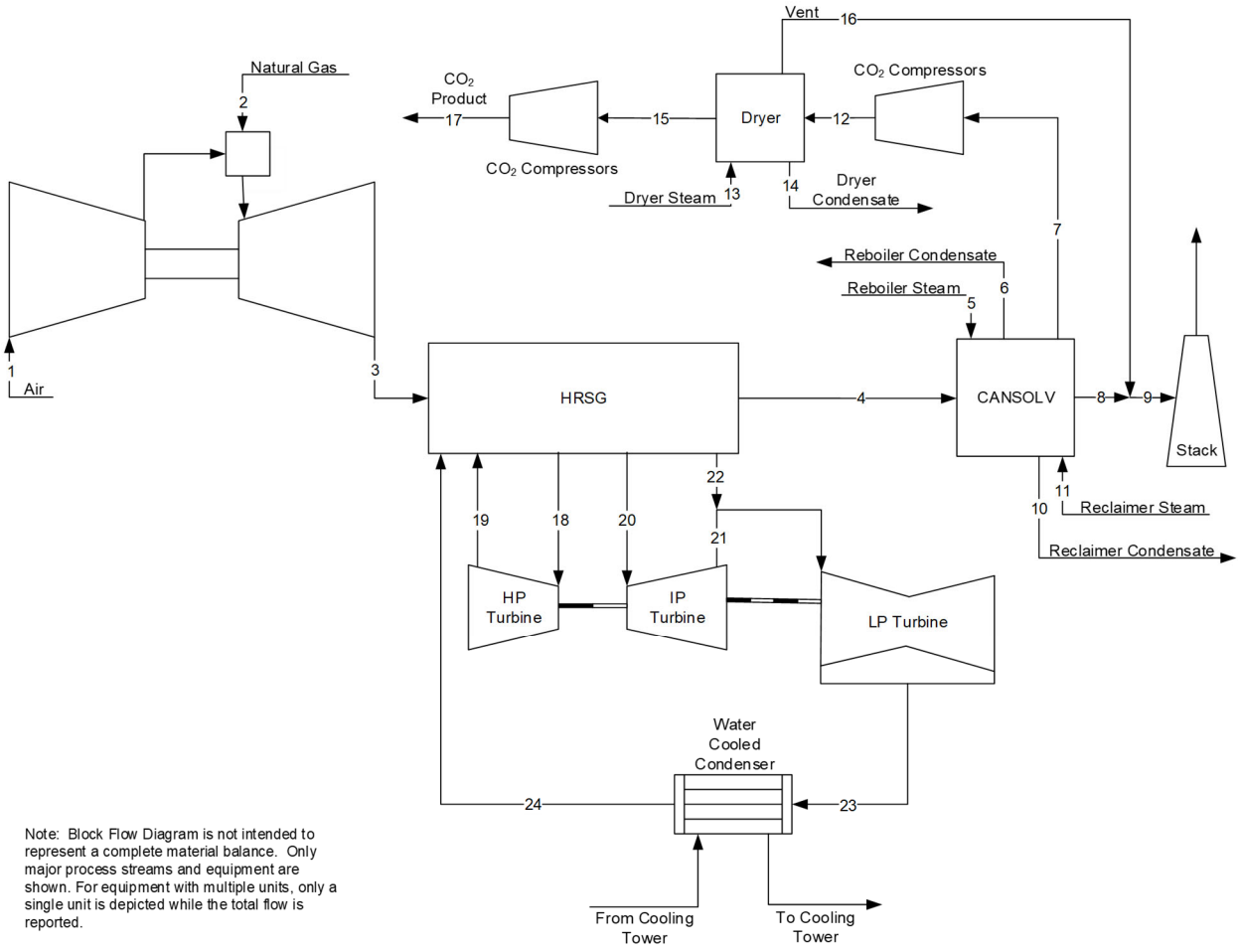
	FY COE		LCOE	
Component	Value, $/MWh	Percentage	Value, $/MWh	Percentage
Capital	32.5	35%	32.5	39%
Fixed	9.5	10%	12.6	15%
Variable	5.3	6%	7.0	9%
Fuel	40.2	44%	24.6	30%
Total (Excluding T&S)	**87.3**	**N/A**	**76.7**	**N/A**
CO_2 T&S	4.5	5%	6.0	7%
Total (Including T&S)	**91.8**	**N/A**	**82.7**	**N/A**

4.2.11 Case B31B.95 – NGCC with 95% CO_2 Capture Process Description

The plant configuration and process description for Case B31B.95 are the same as Case B31B.90, with the exception that the PostCCC facility captures 95, rather than 90, percent of the CO_2 in the flue gas. Since the process descriptions of the plant and PostCCC facility were provided in Section 4.2.3 and Section 3.1.8, respectively, with differences between the facilities used in NGCC and PC cases noted in Section 4.1.4, they are not repeated here.

The BFD for Case B31B.95 is shown in Exhibit 4-35. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit 4-36. The modeling assumptions are presented in Section 4.2.1.

Exhibit 4-35. Case B31B.95 BFD, NGCC with 95 percent CO_2 capture



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown. For equipment with multiple units, only a single unit is depicted while the total flow is reported.

Exhibit 4-36. Case B31B.95 stream table, NGCC with 95 percent CO_2 capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0000	0.0089	0.0089	0.0000	0.0000	0.0000	0.0096	0.0096	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	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	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	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	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	0.0000	0.0000	0.0000
CO_2	0.0003	0.0100	0.0425	0.0425	0.0000	0.0000	0.9796	0.0023	0.0023	0.0000	0.0000	0.9957
H_2O	0.0099	0.0000	0.0906	0.0906	1.0000	1.0000	0.0204	0.0550	0.0550	1.0000	1.0000	0.0043
N_2	0.7732	0.0160	0.7416	0.7416	0.0000	0.0000	0.0000	0.8065	0.8064	0.0000	0.0000	0.0000
O_2	0.2074	0.0000	0.1164	0.1164	0.0000	0.0000	0.0000	0.1266	0.1266	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	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_{mol}/hr)	130,449	5,508	136,117	136,117	14,853	13,604	5,607	125,171	125,172	132	132	5,517
V-L Flowrate (kg/hr)	3,764,363	95,442	3,859,805	3,859,805	267,581	245,076	243,798	3,519,832	3,519,881	2,370	2,370	242,171
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	27	652	94	300	105	29	38	38	214	364	29
Pressure (MPa, abs)	0.10	2.96	0.11	0.10	0.51	0.12	0.17	0.10	0.10	2.04	4.13	2.81
Steam Table Enthalpy (kJ/kg)[A]	30.23	21.97	872.29	243.19	3,062.57	439.34	45.99	127.32	127.32	913.81	3,124.08	-1.10
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-4,487.26	-660.40	-1,289.50	-12,917.73	-15,540.95	-8,977.01	-492.16	-492.28	-15,066.49	-12,856.21	-8,976.01
Density (kg/m^3)	1.2	22.1	0.4	0.9	1.9	954.9	3.0	1.1	1.1	848.5	15.1	57.8
V-L Molecular Weight	28.857	17.328	28.357	28.357	18.015	18.015	43.481	28.120	28.120	18.015	18.015	43.897
V-L Flowrate (lb_{mol}/hr)	287,591	12,143	300,086	300,086	32,745	29,991	12,361	275,956	275,958	290	290	12,162
V-L Flowrate (lb/hr)	8,299,000	210,413	8,509,413	8,509,413	589,915	540,300	537,482	7,759,901	7,760,010	5,226	5,226	533,895
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	80	1,206	202	571	221	85	100	100	416	687	85
Pressure (psia)	14.7	430.0	15.3	14.8	73.5	17.4	24.7	14.8	14.8	296.6	598.5	407.6
Steam Table Enthalpy (Btu/lb)[A]	13.0	9.4	375.0	104.6	1,316.7	188.9	19.8	54.7	54.7	392.9	1,343.1	-0.5
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-1,929.2	-283.9	-554.4	-5,553.6	-6,681.4	-3,859.4	-211.6	-211.6	-6,477.4	-5,527.2	-3,859.0
Density (lb/ft^3)	0.076	1.380	0.024	0.059	0.121	59.612	0.185	0.069	0.069	52.968	0.943	3.607

[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 4-36. Case B31B.95 stream table, NGCC with 95 percent CO_2 capture (continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0000	0.0000	0.0000	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	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	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	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	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	0.0000	0.0000	0.0000
CO_2	0.0000	0.0000	0.9995	0.9704	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	0.0005	0.0296	0.0005	1.0000	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	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	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	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_{mol}/hr)	8	8	5,495	1	5,495	30,131	29,261	31,829	32,664	3,842	21,653	36,681
V-L Flowrate (kg/hr)	143	143	241,741	49	241,741	542,825	527,153	573,413	588,447	69,218	390,084	660,817
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	364	203	29	28	30	585	364	585	300	304	38	38
Pressure (MPa, abs)	4.13	1.64	2.68	0.10	15.27	17.30	4.13	3.84	0.52	0.51	0.01	0.01
Steam Table Enthalpy (kJ/kg)[A]	3,124.08	863.65	-3.59	56.47	-231.09	3,520.51	3,124.08	3,641.17	3,062.57	3,071.95	2,376.25	160.78
AspenPlus Enthalpy (kJ/kg)[B]	-12,856.21	-15,116.65	-8,967.15	-8,994.77	-9,194.65	-12,459.78	-12,856.21	-12,339.12	-12,917.73	-12,908.34	-13,604.05	-15,819.51
Density (kg/m^3)	15.1	861.8	54.7	1.8	630.1	48.1	15.1	9.9	2.0	1.9	0.1	992.8
V-L Molecular Weight	18.015	18.015	43.997	43.240	43.997	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	18	18	12,113	3	12,113	66,428	64,510	70,172	72,011	8,471	47,737	80,868
V-L Flowrate (lb/hr)	316	316	532,949	109	532,949	1,196,725	1,162,174	1,264,159	1,297,304	152,600	859,989	1,456,852
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	687	397	85	83	86	1,085	687	1,085	571	579	101	101
Pressure (psia)	598.5	237.4	389.1	14.8	2,214.7	2,509.2	598.5	557.6	75.0	73.5	1.0	1.0
Steam Table Enthalpy (Btu/lb)[A]	1,343.1	371.3	-1.5	24.3	-99.4	1,513.5	1,343.1	1,565.4	1,316.7	1,320.7	1,021.6	69.1
AspenPlus Enthalpy (Btu/lb)[B]	-5,527.2	-6,499.0	-3,855.2	-3,867.1	-3,953.0	-5,356.7	-5,527.2	-5,304.9	-5,553.6	-5,549.6	-5,848.7	-6,801.2
Density (lb/ft^3)	0.943	53.801	3.416	0.110	39.338	3.002	0.943	0.618	0.124	0.120	0.003	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

4.2.12 Case B31B.95 – Performance Results

Overall plant performance is summarized in Exhibit 4-37; Exhibit 4-38 provides a detailed breakdown of the auxiliary power requirements.

The PostCCC facility and CO_2 compression combined account for 67 percent of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for 13 percent of the auxiliary load, largely due to the high cooling water demand of the PostCCC facility and CO_2 compressors.

Unlike the PC cases, which utilize boilers and steam turbines that can be produced at nearly any desired output, the gross outputs of the NGCC cases are fixed by the available size of the CTs. As such, the net outputs of the capture cases are reduced due to the greater auxiliary load imposed by the PostCCC facility and CO_2 compressors, relative to a non-capture case. The plant produces a net output of 654 MW at a net plant efficiency of 47.2 percent (HHV basis).

Exhibit 4-37. Case B31B.95 plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	484
Steam Turbine Power, MWe	221
Total Gross Power, MWe	**705**
CO_2 Capture/Removal Auxiliaries, kWe	14,700
CO_2 Compression, kWe	19,340
Balance of Plant, kWe	16,676
Total Auxiliaries, MWe	**51**
Net Power, MWe	**654**
HHV Net Plant Efficiency, %	47.2
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	7,634 (7,236)
HHV Combustion Turbine Efficiency, %	34.9
LHV Net Plant Efficiency, %	52.2
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,891 (6,531)
LHV Combustion Turbine Efficiency, %	38.6
Steam Turbine Cycle Efficiency, %	46.5
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,741 (7,337)
CO_2 Capture Rate, %	95
Condenser Duty, GJ/hr (MMBtu/hr)	868 (823)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	1,264 (1,198)
Natural Gas Feed Flow, kg/hr (lb/hr)	95,442 (210,413)
HHV Thermal Input, kWt	1,386,417
LHV Thermal Input, kWt	1,251,379
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})	0.018 (4.6)

Exhibit 4-38. Case B31B.95 plant power summary

Power Summary	
Combustion Turbine Power, MWe	484
Steam Turbine Power, MWe	221
Total Gross Power, MWe	**705**
Auxiliary Load Summary	
Circulating Water Pumps, kWe	4,500
Combustion Turbine Auxiliaries, kWe	1,240
Condensate Pumps, kWe	630
Cooling Tower Fans, kWe	2,330
CO_2 Capture/Removal Auxiliaries, kWe	14,700
CO_2 Compression, kWe	19,340
Feedwater Pumps, kWe	4,450
Ground Water Pumps, kWe	430
Miscellaneous Balance of Plant[A], kWe	580
SCR, kWe	6
Steam Turbine Auxiliaries, kWe	240
Transformer Losses, kWe	2,270
Total Auxiliaries, MWe	**51**
Net Power, MWe	**654**

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

4.2.12.1 Environmental Performance

The environmental targets for emissions of NOx, SO_2, and PM are presented in Section 2.4. A summary of the plant air emissions for Case B31B.95 is presented in Exhibit 4-39.

Exhibit 4-39. Case B31B.95 air emissions

	kg/GJ (lb/MMBtu)[A]	tonne/year (ton/year)[B]	kg/MWh (lb/MWh)[C]
SO_2	0.000 (0.000)	0 (0)	0.000 (0.000)
NOx	0.001 (0.003)	50 (55)	0.010 (0.021)
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	0.000 (0.000)	0 (0)	0.000 (0.000)
CO_2	3 (6)	95,101 (104,831)	18 (40)
CO_2[D]	-	-	20 (43)

[A]Based on thermal input on an HHV basis
[B]Calculations based on an 85 percent capacity factor
[C]Emissions based on gross power except where otherwise noted
[D]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 domestic average value of total sulfur of 0.34 gr/100 scf ($4.71x10^{-4}$ lb-S/MMBtu) (Gas Research Institute, 1992). It was also assumed that the added 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 1.8 ppmv NOx emissions using a DLN burner in the CTG and an SCR. The DLN burners reduce the emissions to about 25 ppmvd (at 15 percent O_2) (GE Vernova, 2024b) and the SCR system is designed for an additional 94.7 percent NOx reduction (Davis & Black, October 2000).

The pipeline natural gas was assumed to contain no Hg or HCl, resulting in zero emissions.

The state-of-the-art 2023 F-Class gas turbine achieves approximately 9.0 ppmvd (at 15 percent O_2) CO and 1.5 ppmw PM emissions. The production of PM is a result of system inefficiencies and is not produced or emitted in any significant amount. Any CO or PM present in the flue gas is assumed to interact with, and be removed by, the PostCCC system solvent.

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

The carbon balance for the plant is shown in Exhibit 4-40. The carbon input to the plant consists of carbon in the natural gas and carbon in the air. Carbon leaves the plant mostly as CO_2 product from the CO_2 compression train; however, some carbon exits through the stack as CO_2.

Ninety five percent of the CO_2 in the flue gas is removed in the PostCCC facility. 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 percentage:

$$1 - \frac{Carbon\ in\ Stack}{Total\ Carbon\ In} = \left(1 - \left(\frac{7{,}685}{153{,}106}\right)\right) * 100 = 95\%$$

Exhibit 4-40. Case B31B.95 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	68,936 (151,977)	Stack Gas	3,486 (7,685)
Air (CO_2)	512 (1,129)	CO_2 Product	65,962 (145,421)
		CO_2 Knockout	0.1 (0.3)
Total	**69,448 (153,106)**	**Total**	**69,448 (153,106)**

As shown in Exhibit 4-41, the sulfur content of the natural gas is insignificant, entirely comprising CH_4S (used as an odorant) (Gas Research Institute, 1992). All sulfur in the natural gas is assumed to react with the PostCCC system solvent and is removed from the solvent during solvent reclaiming as a waste stream.

Exhibit 4-41. Case B31B.95 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	1.0 (2.2)	Stack Gas	0.0 (0.0)
		Solvent Reclaiming	1.0 (2.2)
Total	1.0 (2.2)	**Total**	1.0 (2.2)

Water demand, recycle, withdrawal, discharge, and consumption are defined and discussed in Section 2.6. Exhibit 4-42 shows the overall water balance for the plant.

Exhibit 4-42. Case B31B.95 water balance

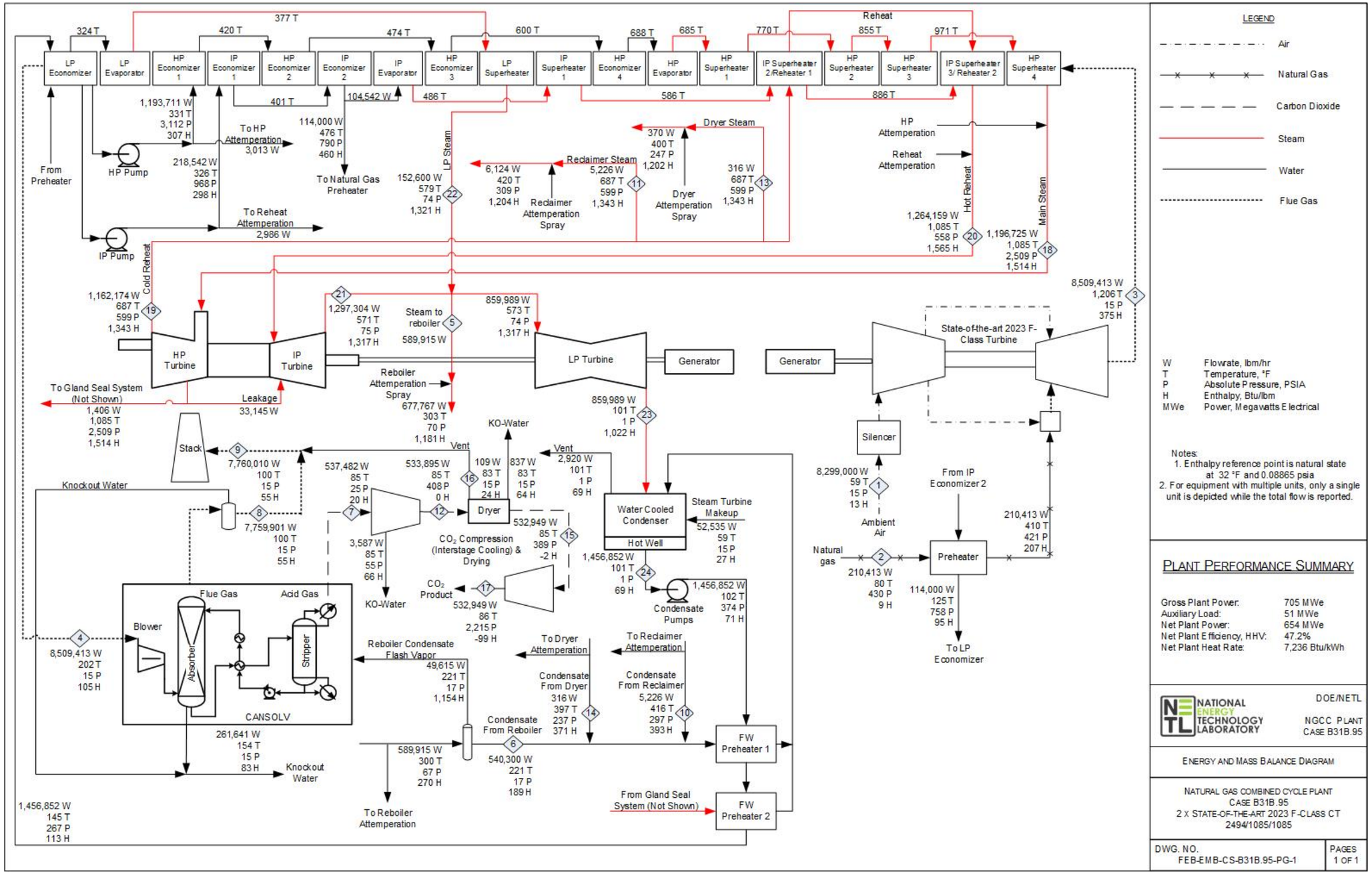
Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)
CO_2 Capture System Makeup	–	–	–	–	–
CO_2 Capture Recovery	–	–	–	2.0 (521)	-2.0 (-521)
CO_2 Compression Recovery	–	–	–	0.0 (7.1)	0.0 (-7.1)
Deaerator Vent	–	–	–	0.0 (5.8)	0.0 (-5.8)
Condenser Makeup	**0.4 (105)**	**–**	**0.4 (105)**	**–**	**0.4 (105)**
BFW Makeup	0.4 (105)	–	0.4 (105)	–	0.4 (105)
Cooling Tower	**18 (4,624)**	**–**	**18 (4,624)**	**4.4 (1,156)**	**13 (3,469)**
Total	**18 (4,729)**	**–**	**18 (4,729)**	**6.4 (1,690)**	**12 (3,039)**

4.2.12.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for Case B31B.95 Exhibit 4-43. An overall plant energy balance is provided in tabular form in Exhibit 4-44. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-37) is calculated by multiplying the power out by the generator efficiency: 98.5 percent for the CT and 97.5 percent for the steam turbine.

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Exhibit 4-43. Case B31B.95 energy and mass balance, NGCC with CO_2 capture



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Exhibit 4-44. Case B31B.95 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, GJ/hr (MMBtu/hr)				
Natural Gas	4,991 (4,731)	5.9 (5.6)	–	4,997 (4,736)
Air	–	114 (108)	–	114 (108)
Raw Water Makeup	–	68 (64)	–	68 (64)
Auxiliary Power	–	–	183 (173)	183 (173)
TOTAL	**4,991 (4,731)**	**187 (177)**	**183 (173)**	**5,361 (5,081)**
Heat Out, GJ/hr (MMBtu/hr)				
Stack Gas	–	448 (425)	–	448 (425)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Motor Losses and Design Allowances	–	–	61 (58)	61 (58)
Cooling Tower Load[A]	–	2,294 (2,174)	–	2,294 (2,174)
CO_2 Product Stream	–	-56 (-53)	–	-56 (-53)
AGR Effluent	–	34 (32)	–	34 (32)
Dryer Effluent	–	0.0 (0.0)	–	0.0 (0.0)
Deaerator Vent	–	0.2 (0.2)	–	0.2 (0.2)
Ambient Losses[B]	–	*44 (42)*	–	44 (42)
Power	–	–	2,536 (2,404)	2,536 (2,404)
TOTAL	**0.0 (0.0)**	**2,764 (2,620)**	**2,598 (2,462)**	**5,362 (5,082)**
Unaccounted Energy[C]	–	*-1.0 (-1.0)*	–	*-1.0 (-1.0)*

[A]Includes condenser, capture process, CO_2 compressor, and miscellaneous cooling loads
[B]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers
[C]By difference

4.2.13 Case B31B.95 – Major Equipment List

Major equipment items for the F-Class NGCC plant with 95 percent 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 4.2.14. 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. Values reported in the equipment lists are rounded.

Case B31B.95 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,570,000 liters (415,000 gal)	2	0
2	Condensate Pumps	Vertical canned	12,200 lpm @ 320 m H_2O (3,220 gpm @ 1,040 ft H_2O)	1	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP Water: 5,010 lpm @ 2,430 m H_2O (1,320 gpm @ 7,970 ft H_2O) IP Water: 930 lpm @ 610 m H_2O (250 gpm @ 1,990 ft H_2O)	2	2
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 GJ/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	3,800 lpm @ 110 m H_2O (1,000 gpm @ 350 ft H_2O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,600 lpm @ 80 m H_2O (700 gpm @ 250 ft H_2O)	1	1
11	Municipal Water Pumps	Stainless steel, single suction	4,900 lpm @ 20 m H_2O (1,290 gpm @ 60 ft H_2O)	2	1
12	Ground Water Pumps	Stainless steel, single suction	4,900 lpm @ 20 m H_2O (1,290 gpm @ 60 ft H_2O)	2	1
13	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H_2O (40 gpm @ 160 ft H_2O)	2	1
14	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
15	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0
16	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
17	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	79 m^3/min @ 3.0 MPa (2,795 acfm @ 430 psia) 39 cm (16 in) standard wall pipe	16 km (10 mile)	0
18	Gas Metering Station	–	79 m^3/min (2,795 acfm)	1	0

Case B31B.95 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Cansolv	Amine-based CO_2 capture technology	4,246,000 kg/hr (9,360,000 lb/hr) 6.6 wt% CO_2 concentration	1	0
2	Cansolv LP Condensate Pump	Centrifugal	730 lpm @ 1.0 m H_2O (190 gpm @ 3.4 ft H_2O)	1	1
3	Cansolv HP Condensate Pump	Centrifugal	7.6 lpm @ 4.6 m H_2O (2.0 gpm @ 15.0 ft H_2O)	1	1
4	CO_2 Dryer	Triethylene glycol	Inlet: 70 m^3/min @ 2.8 MPa (2,467 acfm @ 408 psia) Outlet: 2.7 MPa (389 psia) Water Removed: 380 kg/hr (839 lb/hr)	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
5	CO_2 Compressor	Integrally geared, multi-stage centrifugal	4 m^3/min @ 15.3 MPa, 82°C (124 acfm @ 2,217 psia, 180°F)	2	0
6	CO_2 Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 38 GJ/hr (36 MMBtu/hr)	2	0

Case B31B.95 – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	2023 Advanced F-Class w/ dry low-NOx burner	240 MW	2	0
2	Combustion Turbine Generator	Hydrogen Cooled	280 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	2	0

Case B31B.95 – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Epoxy-coated CS plate	46 m (150 ft) high x 5.0 m (17 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section	Main Steam: 290,000 kg/hr, 17.2 MPa/585°C (639,000 lb/hr, 2,494 psig/1,085°F) Reheat Steam: 315,000 kg/hr, 3.7 MPa/585°C (695,000 lb/hr, 543 psig/1,085°F)	2	0
3	SCR Reactor	–	2,120,000 kg/hr (4,680,000 lb/hr)	2	0
4	SCR Catalyst	–	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	20 m^3/min @ 108 cm WG (600 scfm @ 42 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	3.6 lpm @ 90 m H_2O (1.0 gpm @ 300 ft H_2O)	2	1
7	Ammonia Storage Tank	Horizontal tank	104,000 liter (27,000 gal)	1	0

Case B31B.95 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	233 MW 17.2 MPa/585°C/585°C (2,494 psig/1,085°F/1,085°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	270 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Two pass, divided waterbox including vacuum pumps and integrated deaerator	960 GJ/hr (910 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.95 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	451,000 lpm @ 30 m (119,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 2,520 GJ/hr (2,390 MMBtu/hr) heat duty	1	0

Case B31B.95 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	18 kV/345 kV, 280 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	18 kV/345 kV, 210 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 11 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	18 kV/4.16 kV, 24 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 8 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 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.95 – 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

4.2.14 Case B31B.95 – Cost Estimating

The cost estimating methodology is described in Section 2.7. Exhibit 4-45 shows a detailed breakdown of the capital costs; Exhibit 4-46 shows the owner's costs, TOC, and TASC; Exhibit 4-47 shows the initial and annual O&M costs; and Exhibit 4-48 shows the COE breakdown.

The estimated TPC of the NGCC with CO_2 capture is $2,235/kW. Process contingency represents 4.0 percent of the TPC and project contingency represents 15.0 percent of the TPC. The FY COE, including T&S costs of $4.6/MWh, is $93.4/MWh. The LCOE, including T&S costs of $6.1/MWh, is $84.3/MWh.

Exhibit 4-45. Case B31B.95 total plant cost details

Case:	B31B.95 – NGCC F-Class (2x1) with 95 Percent CO_2 Capture					Estimate Type:	Conceptual			
Plant Size (MW, net):	654					Cost Base:	Jan 2023			
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	$2,492	$4,273	$1,833	$0	$8,598	$1,720	$0	$1,548	$11,865	$18
3.2	Water Makeup & Pretreating	$7,274	$727	$3,421	$0	$11,422	$2,284	$0	$2,741	$16,448	$25
3.3	Other Feedwater Subsystems	$1,418	$465	$379	$0	$2,262	$452	$0	$407	$3,122	$5
3.4	Service Water Systems	$2,207	$4,214	$11,324	$0	$17,745	$3,549	$0	$4,259	$25,553	$39
3.5	Other Boiler Plant Systems	$331	$120	$263	$0	$714	$143	$0	$129	$986	$2
3.6	NG Pipeline and Start-Up System	$12,945	$557	$347	$0	$13,848	$2,770	$0	$2,493	$19,111	$29
3.7	Waste Water Treatment Equipment	$13,099	$0	$7,039	$0	$20,137	$4,027	$0	$4,833	$28,998	$44
3.9	Miscellaneous Plant Equipment	$19,384	$2,542	$8,637	$0	$30,563	$6,113	$0	$7,335	$44,011	$67
	Subtotal	**$59,151**	**$12,898**	**$33,242**	**$0**	**$105,290**	**$21,058**	**$0**	**$23,744**	**$150,093**	**$230**
5	Flue Gas Cleanup										
5.1	CANSOLV CO_2 Removal System	$135,785	$65,058	$121,185	$0	$322,028	$64,406	$57,965	$88,880	$533,278	$816
5.4	CO_2 Compression & Drying	$34,872	$5,231	$13,692	$0	$53,795	$10,759	$0	$12,911	$77,465	$118
5.5	CO_2 Compressor Aftercooler	$295	$47	$120	$0	$462	$92	$0	$111	$665	$1
5.12	Gas Cleanup Foundations	$0	$497	$508	$0	$1,005	$201	$0	$241	$1,448	$2
	Subtotal	**$170,952**	**$70,833**	**$135,505**	**$0**	**$377,290**	**$75,458**	**$57,965**	**$102,143**	**$612,856**	**$937**
6	Combustion Turbine & Accessories										
6.1	Combustion Turbine Generator	$109,737	$0	$7,005	$0	$116,742	$23,348	$0	$21,014	$161,104	$246
6.3	Combustion Turbine Accessories	$3,106	$0	$191	$0	$3,297	$659	$0	$593	$4,549	$7
6.4	Compressed Air Piping	$0	$1,181	$227	$0	$1,407	$281	$0	$253	$1,942	$3
6.5	Combustion Turbine Foundations	$0	$1,064	$1,160	$0	$2,224	$445	$0	$534	$3,202	$5
	Subtotal	**$112,843**	**$2,244**	**$8,582**	**$0**	**$123,670**	**$24,734**	**$0**	**$22,394**	**$170,798**	**$261**
7	HRSG, Ductwork, & Stack										
7.1	HRSG	$64,221	$0	$16,055	$0	$80,276	$16,055	$0	$14,450	$110,781	$169
7.2	HRSG Accessories	$16,087	$0	$3,005	$0	$19,092	$3,818	$0	$3,436	$26,346	$40
7.3	Ductwork	$0	$1,290	$706	$0	$1,996	$399	$0	$359	$2,755	$4
7.4	Stack	$4,462	$0	$833	$0	$5,295	$1,059	$0	$953	$7,307	$11
7.5	HRSG, Ductwork, & Stack Foundations	$0	$897	$710	$0	$1,607	$321	$0	$386	$2,315	$4
7.6	Selective Catalytic Reduction System	$1,991	$837	$1,023	$0	$3,851	$770	$0	$693	$5,314	$8
	Subtotal	**$86,760**	**$3,024**	**$22,332**	**$0**	**$112,117**	**$22,423**	**$0**	**$20,277**	**$154,817**	**$237**
8	Steam Turbine & Accessories										
8.1	Steam Turbine Generator & Accessories	$43,895	$0	$6,428	$0	$50,323	$10,065	$0	$9,058	$69,446	$106
8.2	Steam Turbine Plant Auxiliaries	$149	$0	$344	$0	$494	$99	$0	$89	$682	$1
8.3	Condenser & Auxiliaries	$7,170	$0	$3,440	$0	$10,610	$2,122	$0	$1,910	$14,642	$22
8.4	Steam Piping	$13,646	$0	$4,689	$0	$18,335	$3,667	$0	$3,300	$25,303	$39
8.5	Turbine Generator Foundations	$0	$1,534	$2,141	$0	$3,675	$735	$0	$882	$5,292	$8
	Subtotal	**$64,861**	**$1,534**	**$17,043**	**$0**	**$83,438**	**$16,688**	**$0**	**$15,239**	**$115,365**	**$176**
9	Cooling Water System										
9.1	Cooling Towers	$15,314	$0	$4,096	$0	$19,410	$3,882	$0	$3,494	$26,786	$41

Case:	B31B.95 – NGCC F-Class (2x1) with 95 Percent CO_2 Capture								Estimate Type:	Conceptual
Plant Size (MW, net):	654								Cost Base:	Jan 2023
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
9.2	Circulating Water Pumps	$1,956	$0	$104	$0	$2,060	$412	$0	$371	$2,843	$4
9.3	Circulating Water System Auxiliaries	$13,325	$0	$1,591	$0	$14,916	$2,983	$0	$2,685	$20,584	$31
9.4	Circulating Water Piping	$0	$4,192	$3,150	$0	$7,342	$1,468	$0	$1,322	$10,132	$15
9.5	Make-up Water System	$497	$0	$530	$0	$1,027	$205	$0	$185	$1,418	$2
9.6	Component Cooling Water System	$618	$0	$394	$0	$1,012	$202	$0	$182	$1,396	$2
9.7	Circulating Water System Foundations	$0	$970	$1,382	$0	$2,351	$470	$0	$564	$3,386	$5
	Subtotal	**$31,710**	**$5,162**	**$11,247**	**$0**	**$48,119**	**$9,624**	**$0**	**$8,803**	**$66,545**	**$102**
11	Accessory Electric Plant										
11.1	Generator Equipment	$3,430	$0	$2,138	$0	$5,568	$1,114	$0	$1,002	$7,684	$12
11.2	Station Service Equipment	$9,376	$0	$665	$0	$10,041	$2,008	$0	$1,807	$13,856	$21
11.3	Switchgear & Motor Control	$15,400	$0	$1,919	$0	$17,319	$3,464	$0	$3,117	$23,901	$37
11.4	Conduit & Cable Tray	$0	$3,235	$7,704	$0	$10,939	$2,188	$0	$1,969	$15,096	$23
11.5	Wire & Cable	$0	$4,830	$7,134	$0	$11,963	$2,393	$0	$2,153	$16,509	$25
11.6	Protective Equipment	$654	$0	$1,632	$0	$2,285	$457	$0	$411	$3,154	$5
11.7	Standby Equipment	$1,003	$0	$665	$0	$1,667	$333	$0	$300	$2,301	$4
11.8	Main Power Transformers	$7,017	$0	$145	$0	$7,161	$1,432	$0	$1,289	$9,882	$15
11.9	Electrical Foundations	$0	$119	$271	$0	$390	$78	$0	$94	$561	$1
	Subtotal	**$36,879**	**$8,184**	**$22,271**	**$0**	**$67,333**	**$13,467**	**$0**	**$12,143**	**$92,943**	**$142**
12	Instrumentation & Control										
12.1	NGCC Control Equipment	$298	$0	$188	$0	$486	$97	$0	$88	$671	$1
12.2	Combustion Turbine Control Equipment	$491	$0	$309	$0	$801	$160	$0	$144	$1,105	$2
12.3	Steam Turbine Control Equipment	$478	$0	$301	$0	$779	$156	$0	$140	$1,075	$2
12.4	Other Major Component Control Equipment	$802	$0	$505	$0	$1,307	$261	$65	$245	$1,879	$3
12.5	Signal Processing Equipment	$669	$0	$20	$0	$689	$138	$0	$124	$951	$1
12.6	Control Boards, Panels, & Racks	$177	$0	$107	$0	$284	$57	$14	$53	$408	$1
12.7	Distributed Control System Equipment	$9,826	$0	$296	$0	$10,123	$2,025	$506	$1,898	$14,551	$22
12.8	Instrument Wiring & Tubing	$972	$777	$2,570	$0	$4,319	$864	$216	$810	$6,209	$9
12.9	Other I&C Equipment	$673	$0	$1,288	$0	$1,961	$392	$98	$368	$2,819	$4
	Subtotal	**$14,386**	**$777**	**$5,586**	**$0**	**$20,749**	**$4,150**	**$900**	**$3,870**	**$29,669**	**$45**
13	Improvements to Site										
13.1	Site Preparation	$0	$932	$16,716	$0	$17,649	$3,530	$0	$4,236	$25,414	$39
13.2	Site Improvements	$0	$3,000	$3,345	$0	$6,345	$1,269	$0	$1,523	$9,136	$14
13.3	Site Facilities	$2,878	$0	$2,550	$0	$5,427	$1,085	$0	$1,303	$7,815	$12
	Subtotal	**$2,878**	**$3,932**	**$22,611**	**$0**	**$29,421**	**$5,884**	**$0**	**$7,061**	**$42,366**	**$65**
14	Buildings & Structures										
14.1	Combustion Turbine Area	$0	$556	$216	$0	$772	$154	$0	$139	$1,066	$2
14.3	Steam Turbine Building	$0	$5,020	$4,909	$0	$9,930	$1,986	$0	$1,787	$13,703	$21
14.4	Administration Building	$0	$578	$288	$0	$866	$173	$0	$156	$1,195	$2
14.5	Circulation Water Pumphouse	$0	$131	$47	$0	$178	$36	$0	$32	$246	$0
14.6	Water Treatment Buildings	$0	$679	$455	$0	$1,133	$227	$0	$204	$1,564	$2
14.7	Machine Shop	$0	$866	$406	$0	$1,272	$254	$0	$229	$1,755	$3

Case:		B31B.95 – NGCC F-Class (2x1) with 95 Percent CO_2 Capture					Estimate Type:			Conceptual	
Plant Size (MW, net):		654					Cost Base:			Jan 2023	
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
14.8	Warehouse	$0	$673	$299	$0	$971	$194	$0	$175	$1,340	$2
14.9	Other Buildings & Structures	$0	$492	$263	$0	$755	$151	$0	$136	$1,041	$2
14.10	Waste Treating Building & Structures	$0	$1,136	$1,489	$0	$2,625	$525	$0	$473	$3,623	$6
	Subtotal	**$0**	**$10,131**	**$8,372**	**$0**	**$18,503**	**$3,701**	**$0**	**$3,331**	**$25,534**	**$39**
	Total	**$580,420**	**$118,719**	**$286,791**	**$0**	**$985,931**	**$197,186**	**$58,865**	**$219,005**	**$1,460,986**	**$2,235**

Exhibit 4-46. Case B31B.95 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$8,970	$14
1 Month Maintenance Materials	$1,633	$2
1 Month Non-fuel Consumables	$838	$1
1 Month Waste Disposal	$111	$0
25% of 1 Months Fuel Cost at 100% CF	$4,824	$7
2% of TPC	$29,220	$45
Total	**$45,595**	**$70**
Inventory Capital		
60-day supply of consumables at 100% CF	$1,135	$2
0.5% of TPC (spare parts)	$7,305	$11
Total	**$8,440**	**$13**
Other Costs		
Initial Cost for Catalyst and Chemicals	$1,944	$3
Land	$600	$1
Other Owner's Costs	$219,148	$335
Financing Costs	$39,447	$60
Total Overnight Costs (TOC)	**$1,776,160**	**$2,717**
TASC Multiplier (IOU, 33 year)	1.183	
Total As-Spent Cost (TASC)	**$2,101,104**	**$3,214**

Exhibit 4-47. Case B31B.95 initial and annual operating and maintenance costs

Case:	B31B.95 – NGCC F-Class (2x1) with 95 Percent CO_2 Capture				Cost Base:	Jan 2023
Plant Size (MW, net):	654	Heat Rate-net (Btu/kWh):		7,236	Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		45.04	**$/hour**	Skilled Operator:		1.0
Operating Labor Burden:		30.00	**% of base**	Operator:		3.3
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		1.0
				Total:		**6.3**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$3,248,262	$4.968
Maintenance Labor:					$11,103,497	$16.983
Administrative & Support Labor:					$3,587,940	$5.488
Property Taxes and Insurance:					$29,219,730	$44.693
Total:					**$47,159,429**	**$72.133**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$16,655,246	$3.421
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	3,405	$2.30	$0	$2,429,675	$0.499
Makeup and Waste Water Treatment Chemicals (ton):	0	10.1	$660.00	$0	$2,076,894	$0.427
Ammonia (19 wt%, ton):	0	9.5	$280.00	$0	$824,542	$0.169
SCR Catalyst (ft^3):	5,555	3.0	$350.00	$1,944,340	$330,538	$0.068
CO_2 Capture System Chemicals[A]:	Proprietary				$2,760,516	$0.567
Triethylene Glycol (gal):	w/equip.	47.9	$8.50	$0	$126,425	$0.026
Subtotal:				**$1,944,340**	**$8,548,590**	**$1.756**
Waste Disposal						
SCR Catalyst (ft^3):	0	3.0	$5.70	$0	$5,383	$0.001
Triethylene Glycol (gal):	0	2,431	$1.30	$0	$980,477	$0.201
Thermal Reclaimer Unit Waste (ton):	0	1.9	$250.00	$0	$145,246	$0.030
Subtotal:				**$0**	**$1,131,107**	**$0.232**
Variable Operating Costs Total:				**$1,944,340**	**$26,334,943**	**$5.410**
Fuel Cost						
Natural Gas (MMBtu):	0	113,536	$5.59	$0	$196,806,494	$40.428
Total:				**$0**	**$196,806,494**	**$40.428**

[A]CO_2 Capture System Chemicals includes NaOH and CANSOLV Solvent

Exhibit 4-48. Case B31B.95 COE breakdown

	FY COE		LCOE	
Component	Value, $/MWh	Percentage	Value, $/MWh	Percentage
Capital	33.3	36%	33.3	39%
Fixed	9.7	10%	12.9	15%
Variable	5.4	6%	7.2	9%
Fuel	40.4	43%	24.8	29%
Total (Excluding T&S)	**88.8**	**N/A**	**78.2**	**N/A**
CO_2 T&S	4.6	5%	6.1	7%
Total (Including T&S)	**93.4**	**N/A**	**84.3**	**N/A**

4.3 1x1 H-Class NGCC Cases

This section contains an evaluation of plant designs for H-Class NGCC cases based on a 1x1 plant (cases B32A.1, B32B.1.90, and B32B.1.95), consisting of one state-of-the-art 2023 H-Class combustion turbine with an ISO base rating of 430 MW and one single reheat subcritical steam cycle 17.2 MPaG/585°C/585°C (2,501 psig/1,085°F/1,085°F). Unlike the F-Class and 2x1 H-Class cases, the 1x1 H-Class cases are configured with a single-shaft for both the combustion turbine and steam turbine with a common generator. Cases B32A.1, B32B.1.90, and B32B.1.95 are similar, differing only in the degree of CO_2 capture, with B32A.1 including no CO_2 capture, B32B.1.90 including 90 percent CO_2 capture, and B32B.1.95 including 95 percent CO_2 capture.

The balance of this section is organized as follows:

- Key System Assumptions is a summary of study and modeling assumptions relevant to H-Class NGCC cases.
- Sparing Philosophy is provided for 1x1 H-Class NGCC cases.
- Process Description provides an overview of the technology operation as applied to Case B32A.1. The systems that are common to all NGCC cases were covered in Section 4.1 and only features that are unique to 1x1 H-Class cases are discussed further in this section.
- Performance Results provides the main modeling results from Case B32A.1, including the performance summary, environmental performance, carbon balance, water balance, energy and mass balance diagrams, and energy balance table.
- Major Equipment List provides an itemized list of major equipment for Case B32A.1 with account codes that correspond to the cost accounts in the Cost Estimating section.
- Cost Estimating provides a summary of capital and operating costs for Case B32A.1.
- Process Description, Performance Results, Major Equipment List, and Cost Estimating are discussed for cases B32B.1.90 and B32B.1.95.

4.3.1 Key System Assumptions

System assumptions for cases B32A.1, B32B.1.90, and B32B.1.95, NGCC with and without CO_2 capture, are compiled in Exhibit 4-49.

Exhibit 4-49. NGCC 1x1 H-Class plant study configuration matrix

	Case B32A.1 w/o CO_2 Capture	Case B32B.1.90 w/ CO_2 Capture	Case B32B.1.95 w/ CO_2 Capture
Steam Cycle, MPaG/°C/°C (psig/°F/°F)	17.2/585/585 (2,501/1,085/1,085)		
Fuel	Natural Gas		
Fuel Pressure at Plant Battery Limit, MPa (psia)	3.8 (550)		
Condenser Pressure, mm Hg (in. Hg)	50.8 (2.0)		
Cooling Water to Condenser, °C (°F)	16 (60)		
Cooling Water from Condenser, °C (°F)	27 (80)		
Stack Temperature, °C (°F)	78 (172)	38 (100)	38 (100)
SO_2 Control	Low Sulfur Fuel		
NOx Control	LNB and SCR		
SCR Efficiency, %[A]	94.7	95.1	95.2
Ammonia Slip (End of Catalyst Life), ppmv	5		
Particulate Control	N/A		
Mercury Control	N/A		
CO Control	N/A		
CO_2 Control	N/A	CANSOLV	
Overall Carbon Capture, %[A]	N/A	90	95
CO_2 Sequestration	N/A	Off-site Saline Formation	

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

4.3.1.1 Balance of Plant

The balance of plant assumptions are common to all H-Class NGCC cases and are presented in Exhibit 4-50. The assumptions in Exhibit 4-50 are identical to those presented for the F-Class cases, with the exception that the H-Class cases assume a higher natural gas pipeline supply pressure (3.8 MPa [550 psia] versus 3.0 MPa [430 psia]).

Exhibit 4-50. NGCC balance of plant assumptions

Parameter	Value
Cooling System	Recirculating Wet Cooling Tower
Fuel and Other Storage	

Parameter	Value
Natural Gas	Pipeline supply at 3.8 MPa (550 psia) and 27°C (80°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	18,000 V
Grid Interconnection voltage	345 kV
Water and Wastewater	
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	Blowdown is treated for chloride and metals and discharged.

4.3.2 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:

- One state-of-the-art 2023 H-Class CTG (1 x 100 percent)
- One 3-pressure reheat HRSGs with self-supporting stacks and SCR systems (1 x 100 percent)
- One 3-pressure reheat, triple-admission STG (1 x 100 percent)
- For cases B32B.1.90 and B32B.1.95, one CO_2 absorption system, consisting of an absorber, stripper, and ancillary equipment (1 x 100 percent) and two CO_2 compression systems (2 x 50 percent)

4.3.3 Case B32A.1 – NGCC Without CO_2 Capture Process Description

In this section, the H-Class NGCC process without CO_2 capture is described. The description follows the BFD in Exhibit 4-51 and stream numbers reference the same exhibit. Exhibit 4-52 provides process data for the numbered streams in the BFD.

Ambient air (stream 1) is supplied to an inlet filter (not depicted) and compressed before being combined with natural gas (stream 2) in the dry LNB, which is operated to control the rotor inlet (not depicted) temperature at 1,544°C (2,812°F). The flue gas exits the turbine at 663°C (1,226°F) (stream 3) and passes into the HRSG. The HRSG generates both the main steam (stream 5) and reheat steam (stream 7) for the steam turbine. Flue gas (stream 4) exits the HRSG at 78°C (172°F) and passes to the plant stack.

Exhibit 4-51. Case B32A.1 BFD, NGCC without CO_2 capture

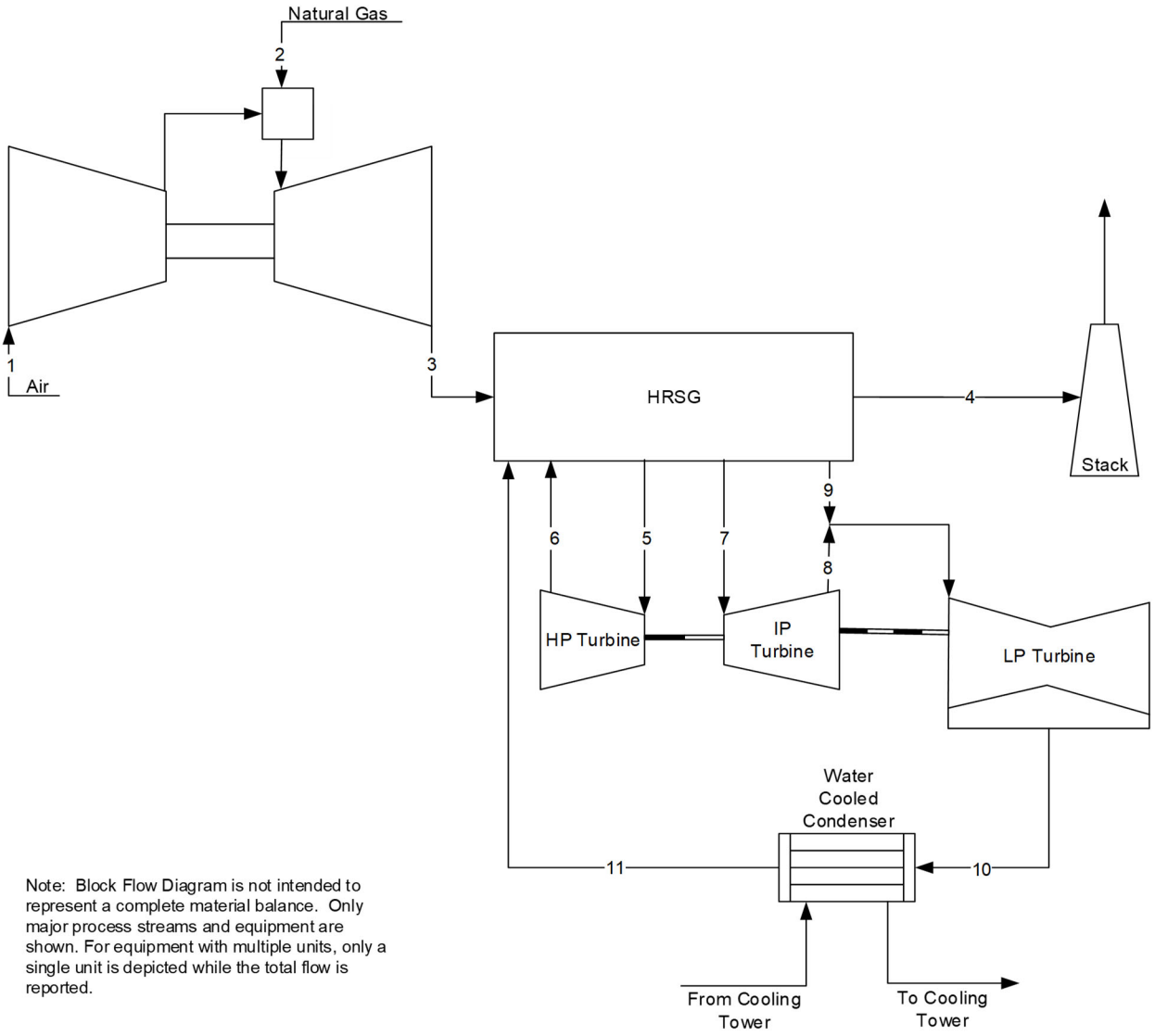


Exhibit 4-52. Case B32A.1 stream table, NGCC without CO_2 capture

	1	2	3	4	5	6	7	8	9	10	11
V-L Mole Fraction											
Ar	0.0092	0.0000	0.0088	0.0088	0.0000	0.0000	0.0000	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	0.0000	0.0000
CH_4S	0.0000	0.0000	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	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	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	0.0000	0.0000
CO_2	0.0003	0.0100	0.0462	0.0462	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0000	0.0977	0.0977	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.7732	0.0160	0.7389	0.7389	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2074	0.0000	0.1085	0.1085	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	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
V-L Flowrate (kg_{mol}/hr)	99,469	4,584	104,186	104,186	23,923	23,527	25,268	25,631	2,855	28,487	28,522
V-L Flowrate (kg/hr)	2,870,378	79,424	2,949,802	2,949,802	430,984	423,840	455,204	461,756	51,437	513,193	513,830
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	27	663	78	585	362	585	299	300	38	38
Pressure (MPa, abs)	0.10	3.79	0.11	0.10	17.35	4.06	3.69	0.52	0.51	0.01	0.01
Steam Table Enthalpy (kJ/kg)[A]	30.23	12.48	900.09	237.13	3,520.05	3,119.49	3,642.32	3,060.24	3,063.55	2,358.22	160.78
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-4,496.75	-757.48	-1,420.45	-12,460.24	-12,860.81	-12,337.98	-12,920.06	-12,916.74	-13,622.08	-15,819.51
Density (kg/m^3)	1.2	28.8	0.4	1.0	48.2	14.9	9.5	2.0	1.9	0.1	992.8
V-L Molecular Weight	28.857	17.328	28.313	28.313	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	219,292	10,105	229,690	229,690	52,742	51,868	55,706	56,507	6,295	62,802	62,880
V-L Flowrate (lb/hr)	6,328,100	175,100	6,503,200	6,503,200	950,157	934,408	1,003,553	1,017,998	113,400	1,131,398	1,132,802
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	80	1,226	172	1,085	683	1,085	569	572	101	101
Pressure (psia)	14.7	550.0	15.4	14.8	2,516.2	589.1	535.6	75.0	73.5	1.0	1.0
Steam Table Enthalpy (Btu/lb)[A]	13.0	5.4	387.0	101.9	1,513.4	1,341.1	1,565.9	1,315.7	1,317.1	1,013.9	69.1
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-1,933.3	-325.7	-610.7	-5,356.9	-5,529.2	-5,304.4	-5,554.6	-5,553.2	-5,856.4	-6,801.2
Density (lb/ft^3)	0.076	1.799	0.024	0.062	3.011	0.932	0.593	0.124	0.121	0.003	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

4.3.4 Case B32A.1 – Performance Results

The plant produces a net output of 649 MW at a net plant efficiency of 56.2 percent (HHV basis). Overall plant performance is summarized in Exhibit 4-53; Exhibit 4-54 provides a detailed breakdown of the auxiliary power requirements.

Exhibit 4-53. Case B32A.1 plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	442
Steam Turbine Power, MWe	218
Total Gross Power, MWe	**660**
CO_2 Capture/Removal Auxiliaries, kWe	–
CO_2 Compression, kWe	–
Balance of Plant, kWe	11,085
Total Auxiliaries, MWe	**11**
Net Power, MWe	**649**
HHV Net Plant Efficiency, %	56.2
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,402 (6,068)
HHV Combustion Turbine Efficiency, %	38.3
LHV Net Plant Efficiency, %	62.3
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	5,778 (5,477)
LHV Combustion Turbine Efficiency, %	42.4
Steam Turbine Cycle Efficiency, %	40.2
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	8,954 (8,487)
CO_2 Capture Rate, %	–
Condenser Duty, GJ/hr (MMBtu/hr)	1,128 (1,069)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	–
Natural Gas Feed Flow, kg/hr (lb/hr)	79,424 (175,100)
HHV Thermal Input, kWt	1,153,739
LHV Thermal Input, kWt	1,041,363
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.014 (3.6)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.010 (2.7)

Exhibit 4-54. Case B32A.1 plant power summary

Power Summary	
Combustion Turbine Power, MWe	442
Steam Turbine Power, MWe	218
Total Gross Power, MWe	**660**
Auxiliary Load Summary	
Circulating Water Pumps, kWe	2,260
Combustion Turbine Auxiliaries, kWe	820
Condensate Pumps, kWe	460
Cooling Tower Fans, kWe	1,170
CO_2 Capture/Removal Auxiliaries, kWe	–
CO_2 Compression, kWe	–
Feedwater Pumps, kWe	3,490
Ground Water Pumps, kWe	210
Miscellaneous Balance of Plant[A], kWe	510
SCR, kWe	5
Steam Turbine Auxiliaries, kWe	160
Transformer Losses, kWe	2,000
Total Auxiliaries, MWe	**11**
Net Power, MWe	**649**

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

4.3.4.1 Environmental Performance

The environmental targets for emissions of NOx, SO_2, and PM are presented in Section 2.4. A summary of the plant air emissions for Case B32A.1 is presented in Exhibit 4-55.

Exhibit 4-55. Case B32A.1 air emissions

	kg/GJ (lb/MMBtu)[A]	tonne/year (ton/year)[B]	kg/MWh (lb/MWh)[C]
SO_2	0.000 (0.001)	13 (14)	0.003 (0.006)
NOx	0.001 (0.003)	42 (46)	0.009 (0.019)
Particulate	0.001 (0.002)	30 (33)	0.006 (0.014)
Hg	0.00E+0 (0.00E+0)	0.000 (0.000)	0.00E+0 (0.00E+0)
CO	0.009 (0.020)	264 (291)	0.054 (0.118)
CO_2	51 (119)	1,575,781 (1,737,001)	321 (707)
CO_2[D]	-	-	326 (719)

[A]Based on thermal input on an HHV basis
[B]Calculations based on an 85 percent capacity factor
[C]Emissions based on gross power except where otherwise noted
[D]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 domestic average value of total sulfur of 0.34 gr/100 scf ($4.71x10^{-4}$ lb-S/MMBtu) (Gas Research Institute, 1992). It was also assumed that the added 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 1.8 ppmv NOx emissions using a DLN burner in the CTG and an SCR. The DLN burners reduce the emissions to about 25 ppmvd (at 15 percent O_2) (GE Vernova, 2024b) and the SCR system is designed for an additional 94.7 percent NOx reduction (Davis & Black, October 2000).

The pipeline natural gas was assumed to contain no Hg or HCl, resulting in zero emissions.

The state-of-the-art 2023 H-Class gas turbine achieves approximately 9.0 ppmvd (at 15 percent O_2) CO and 1.4 ppmw PM emissions. The production of PM is a result of system inefficiencies and is not produced or emitted in any significant amount.

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

The carbon balance for the plant is shown in Exhibit 4-56. The carbon input to the plant consists of carbon in the natural gas and carbon in the air. Carbon leaves the plant as CO_2 through the stack.

Exhibit 4-56. Case B32A.1 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	57,366 (126,471)	Stack Gas	57,757 (127,332)
Air (CO_2)	390 (861)	CO_2 Product	–
		CO_2 Knockout	–
Total	**57,757 (127,332)**	**Total**	**57,757 (127,332)**

As shown in Exhibit 4-57, the sulfur content of the natural gas is insignificant, entirely comprising CH_4S (used as an odorant) (Gas Research Institute, 1992). All sulfur in the natural gas is emitted in the stack gas.

Exhibit 4-57. Case B32A.1 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	0.8 (1.9)	Stack Gas	0.8 (1.9)
		Solvent Reclaiming	–
Total	**0.8 (1.9)**	**Total**	**0.8 (1.9)**

Water demand, recycle, withdrawal, discharge, and consumption are defined and discussed in Section 2.6. Exhibit 4-58 shows the water balance for the plant.

Exhibit 4-58. Case B32A.1 water balance

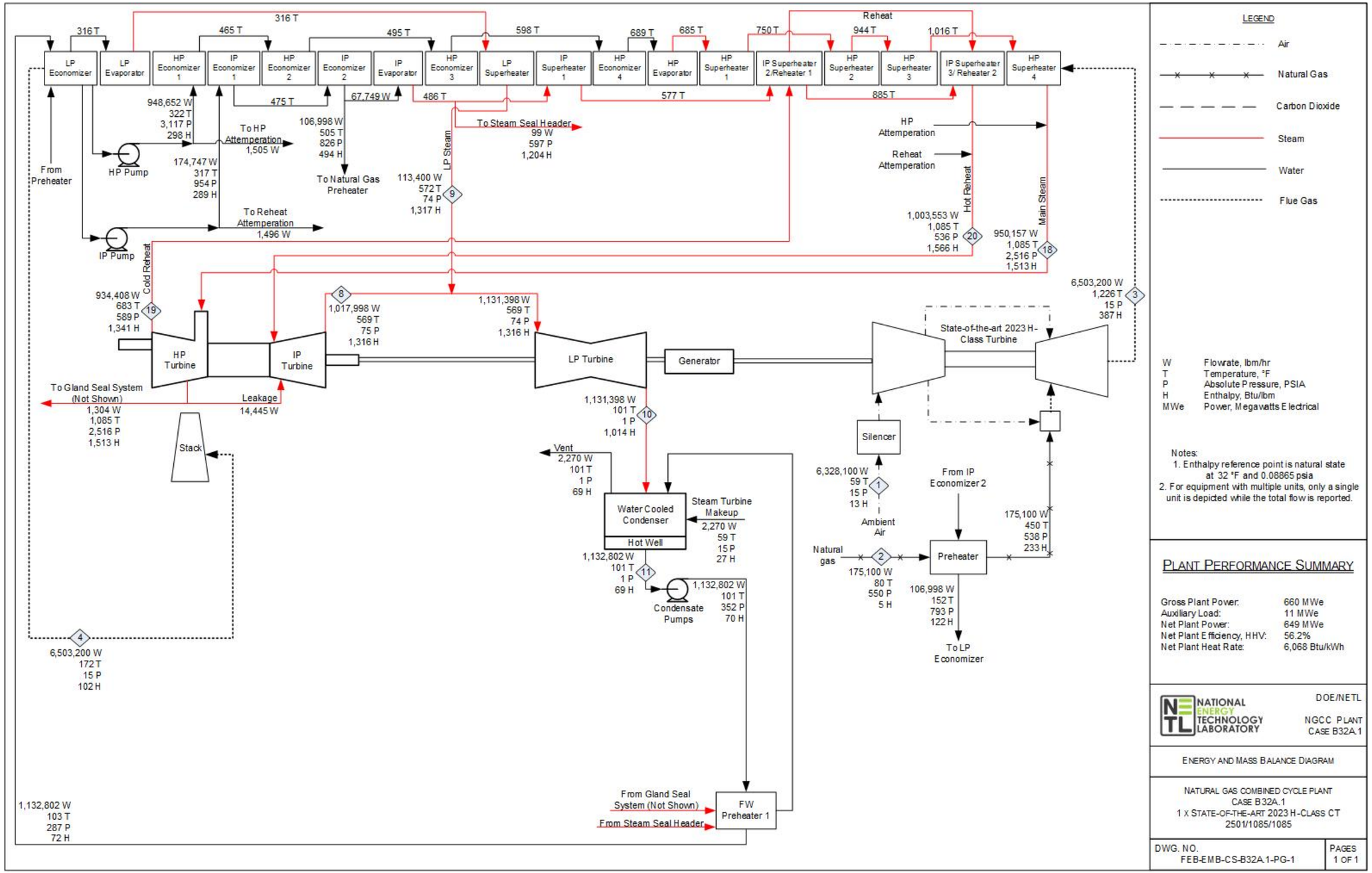
Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m³/min (gpm)	m³/min (gpm)	m³/min (gpm)	m³/min (gpm)	m³/min (gpm)
CO_2 Capture System Makeup	–	–	–	–	–
CO_2 Capture Recovery	–	–	–	–	–
CO_2 Compression Recovery	–	–	–	–	–
Deaerator Vent	–	–	–	0.0 (4.5)	0.0 (-4.5)
Condenser Makeup	**0.0 (4.5)**	**–**	**0.0 (4.5)**	**–**	**0.0 (4.5)**
BFW Makeup	0.0 (4.5)	–	0.0 (4.5)	–	0.0 (4.5)
Cooling Tower	**8.8 (2,327)**	**–**	**8.8 (2,327)**	**2.2 (581)**	**6.6 (1,745)**
Total	**8.8 (2,331)**	**–**	**8.8 (2,331)**	**2.2 (586)**	**6.6 (1,745)**

4.3.4.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for Case B32A.1 in Exhibit 4-59.

An overall plant energy balance is provided in tabular form in Exhibit 4-60. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-53) is calculated by multiplying the power out by the generator efficiency: 98.5 percent for the CT and 98.5 percent for the steam turbine.

Exhibit 4-59. Case B32A.1 energy and mass balance, NGCC without CO_2 capture



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Exhibit 4-60. Case B32A.1 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, GJ/hr (MMBtu/hr)				
Natural Gas	4,153 (3,937)	4.9 (4.7)	–	4,158 (3,941)
Air	–	87 (82)	–	87 (82)
Raw Water Makeup	–	33 (32)	–	33 (32)
Auxiliary Power	–	–	40 (38)	40 (38)
TOTAL	**4,153 (3,937)**	**125 (118)**	**40 (38)**	**4,318 (4,093)**
Heat Out, GJ/hr (MMBtu/hr)				
Stack Gas	–	699 (663)	–	699 (663)
Sulfur	–	–	–	–
Motor Losses and Design Allowances	–	–	47 (44)	47 (44)
Cooling Tower Load[A]	–	1,154 (1,094)	–	1,154 (1,094)
CO_2 Product Stream	–	–	–	–
AGR Effluent	–	–	–	–
Dryer Effluent	–	–	–	–
Deaerator Vent	–	0.2 (0.2)	–	0.2 (0.2)
Ambient Losses[B]	–	*34 (32)*	–	34 (32)
Power	–	–	2,376 (2,252)	2,376 (2,252)
TOTAL	–	**1,888 (1,789)**	**2,422 (2,296)**	**4,310 (4,085)**
Unaccounted Energy[C]	–	*8.5 (8.1)*	–	*8.5 (8.1)*

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

4.3.5 Case B32A.1 – Major Equipment List

Major equipment items for the 1x1 H-Class NGCC plant without 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 4.3.6. 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. Values reported in the equipment lists are rounded.

Case B32A.1 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	68,000 liters (18,000 gal)	2	0
2	Condensate Pumps	Vertical canned	9,490 lpm @ 300 m H_2O (2,510 gpm @ 980 ft H_2O)	1	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP Water: 3,980 lpm @ 2,420 m H_2O (1,050 gpm @ 7,930 ft H_2O) IP Water: 740 lpm @ 580 m H_2O (190 gpm @ 1,890 ft H_2O)	2	2
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 GJ/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	3,800 lpm @ 110 m H_2O (1,000 gpm @ 350 ft H_2O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,600 lpm @ 80 m H_2O (700 gpm @ 250 ft H_2O)	1	1
11	Municipal Water Pumps	Stainless steel, single suction	2,500 lpm @ 20 m H_2O (660 gpm @ 60 ft H_2O)	2	1
12	Ground Water Pumps	Stainless steel, single suction	2,500 lpm @ 20 m H_2O (660 gpm @ 60 ft H_2O)	2	1
13	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H_2O (40 gpm @ 160 ft H_2O)	2	1
14	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
15	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0
16	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
17	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	51 m^3/min @ 3.8 MPa (1,784 acfm @ 550 psia) 39 cm (16 in) standard wall pipe	16 km (10 mile)	0
18	Gas Metering Station	–	51 m^3/min (1,784 acfm)	1	0

Case B32A.1 – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	2023 Advanced H-Class w/ dry low-NOx burner	440 MW	1	0
2	Combustion Turbine Generator	Hydrogen Cooled	520 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	1	0

Case B32A.1 – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Epoxy-coated CS plate	46 m (150 ft) high x 6.9 m (23 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section	Main Steam: 466,000 kg/hr, 17.2 MPa/585°C (1,028,000 lb/hr, 2,502 psig/1,085°F) Reheat Steam: 501,000 kg/hr, 3.6 MPa/585°C (1,104,000 lb/hr, 521 psig/1,085°F)	1	0
3	SCR Reactor	–	3,240,000 kg/hr (7,150,000 lb/hr)	1	0
4	SCR Catalyst	–	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	30 m^3/min @ 108 cm WG (1,010 scfm @ 42 in WG)	1	1
6	Ammonia Feed Pump	Centrifugal	6.0 lpm @ 90 m H_2O (1.6 gpm @ 300 ft H_2O)	1	1
7	Ammonia Storage Tank	Horizontal tank	86,000 liter (23,000 gal)	1	0

Case B32A.1 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	230 MW 17.2 MPa/585°C/585°C (2,502 psig/1,085°F/1,085°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	270 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Two pass, divided waterbox including vacuum pumps and integrated deaerator	1,240 GJ/hr (1,180 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	1	0

Case B32A.1 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	227,000 lpm @ 30 m (60,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 1,270 GJ/hr (1,200 MMBtu/hr) heat duty	1	0

Case B32A.1 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	18 kV/345 kV, 520 MVA, 3-ph, 60 Hz	1	0
2	STG Transformer	Oil-filled	18 kV/345 kV, 260 MVA, 3-ph, 60 Hz	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
3	Medium Voltage Transformer	Oil-filled	18 kV/4.16 kV, 9 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 2 MVA, 3-ph, 60 Hz	1	1
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	1	0
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	1	0
7	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
8	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
9	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B32A.1 – 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

4.3.6 Case B32A.1 – Cost Estimating

The cost estimating methodology is described in Section 2.7. Exhibit 4-61 shows a detailed breakdown of the capital costs; Exhibit 4-62 shows the owner's costs, TOC, and TASC; Exhibit 4-63 shows the initial and annual O&M costs; and Exhibit 4-64 shows the COE breakdown.

The estimated TPC of the NGCC without CO_2 capture is $993/kW. No process contingency was included in this case because all elements of the technology are commercially proved. The project contingency is 13.7 percent of TPC. The FY COE is $55.4/MWh and the LCOE is $44.5/MWh.

Exhibit 4-61. Case B32A.1 total plant cost details

Case:		B32A.1 – NGCC H-Class (1x1) without CO_2 Capture					Estimate Type:			Conceptual	
Plant Size (MW, net):		649					Cost Base:			Jan 2023	
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	$2,111	$3,619	$1,552	$0	$7,282	$1,456	$0	$1,311	$10,049	$15
3.2	Water Makeup & Pretreating	$4,402	$440	$2,070	$0	$6,912	$1,382	$0	$1,659	$9,954	$15
3.3	Other Feedwater Subsystems	$1,201	$394	$321	$0	$1,916	$383	$0	$345	$2,644	$4
3.4	Service Water Systems	$1,336	$2,550	$6,853	$0	$10,739	$2,148	$0	$2,577	$15,464	$24
3.5	Other Boiler Plant Systems	$280	$102	$223	$0	$605	$121	$0	$109	$835	$1
3.6	NG Pipeline and Start-Up System	$9,455	$407	$253	$0	$10,115	$2,023	$0	$1,821	$13,959	$22
3.7	Waste Water Treatment Equipment	$6,174	$0	$3,318	$0	$9,492	$1,898	$0	$2,278	$13,668	$21
3.9	Miscellaneous Plant Equipment	$13,782	$1,807	$6,141	$0	$21,730	$4,346	$0	$5,215	$31,291	$48
	Subtotal	**$38,741**	**$9,319**	**$20,731**	**$0**	**$68,791**	**$13,758**	**$0**	**$15,315**	**$97,864**	**$151**
6	Combustion Turbine & Accessories										
6.1	Combustion Turbine Generator	$93,216	$0	$5,950	$0	$99,166	$19,833	$0	$17,850	$136,849	$211
6.3	Combustion Turbine Accessories	$2,269	$0	$139	$0	$2,408	$482	$0	$433	$3,323	$5
6.4	Compressed Air Piping	$0	$862	$166	$0	$1,028	$206	$0	$185	$1,418	$2
6.5	Combustion Turbine Foundations	$0	$998	$1,089	$0	$2,087	$417	$0	$501	$3,005	$5
	Subtotal	**$95,484**	**$1,860**	**$7,344**	**$0**	**$104,688**	**$20,938**	**$0**	**$18,969**	**$144,595**	**$223**
7	HRSG, Ductwork, & Stack										
7.1	HRSG	$49,511	$0	$12,378	$0	$61,889	$12,378	$0	$11,140	$85,407	$132
7.2	HRSG Accessories	$13,825	$0	$2,582	$0	$16,407	$3,281	$0	$2,953	$22,642	$35
7.3	Ductwork	$0	$1,234	$675	$0	$1,909	$382	$0	$344	$2,635	$4
7.4	Stack	$4,268	$0	$797	$0	$5,065	$1,013	$0	$912	$6,990	$11
7.5	HRSG, Ductwork, & Stack Foundations	$0	$858	$680	$0	$1,538	$308	$0	$369	$2,214	$3
7.6	Selective Catalytic Reduction System	$1,637	$688	$841	$0	$3,166	$633	$0	$570	$4,369	$7
	Subtotal	**$69,241**	**$2,780**	**$17,953**	**$0**	**$89,974**	**$17,995**	**$0**	**$16,288**	**$124,257**	**$192**
8	Steam Turbine & Accessories										
8.1	Steam Turbine Generator & Accessories	$42,805	$0	$6,268	$0	$49,073	$9,815	$0	$8,833	$67,721	$104
8.2	Steam Turbine Plant Auxiliaries	$148	$0	$341	$0	$490	$98	$0	$88	$676	$1
8.3	Condenser & Auxiliaries	$9,238	$0	$4,432	$0	$13,670	$2,734	$0	$2,461	$18,865	$29
8.4	Steam Piping	$11,268	$0	$3,872	$0	$15,140	$3,028	$0	$2,725	$20,893	$32
8.5	Turbine Generator Foundations	$0	$1,521	$2,122	$0	$3,643	$729	$0	$874	$5,247	$8
	Subtotal	**$63,459**	**$1,521**	**$17,036**	**$0**	**$82,016**	**$16,403**	**$0**	**$14,982**	**$113,401**	**$175**
9	Cooling Water System										
9.1	Cooling Towers	$9,403	$0	$2,515	$0	$11,918	$2,384	$0	$2,145	$16,447	$25
9.2	Circulating Water Pumps	$1,193	$0	$64	$0	$1,256	$251	$0	$226	$1,734	$3
9.3	Circulating Water System Auxiliaries	$9,318	$0	$1,113	$0	$10,431	$2,086	$0	$1,878	$14,395	$22
9.4	Circulating Water Piping	$0	$2,776	$2,086	$0	$4,862	$972	$0	$875	$6,709	$10
9.5	Make-up Water System	$357	$0	$380	$0	$737	$147	$0	$133	$1,016	$2
9.6	Component Cooling Water System	$409	$0	$261	$0	$670	$134	$0	$121	$924	$1
9.7	Circulating Water System Foundations	$0	$642	$915	$0	$1,557	$311	$0	$374	$2,242	$3

Case:	B32A.1 – NGCC H-Class (1x1) without CO_2 Capture					Estimate Type:	Conceptual			
Plant Size (MW, net):	649					Cost Base:	Jan 2023			
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
	Subtotal	**$20,680**	**$3,418**	**$7,333**	**$0**	**$31,431**	**$6,286**	**$0**	**$5,751**	**$43,468**	**$67**
11	**Accessory Electric Plant**										
11.1	Generator Equipment	$3,300	$0	$2,057	$0	$5,357	$1,071	$0	$964	$7,393	$11
11.2	Station Service Equipment	$3,543	$0	$251	$0	$3,794	$759	$0	$683	$5,236	$8
11.3	Switchgear & Motor Control	$5,819	$0	$725	$0	$6,544	$1,309	$0	$1,178	$9,031	$14
11.4	Conduit & Cable Tray	$0	$1,222	$2,911	$0	$4,133	$827	$0	$744	$5,704	$9
11.5	Wire & Cable	$0	$1,825	$2,696	$0	$4,520	$904	$0	$814	$6,238	$10
11.6	Protective Equipment	$247	$0	$617	$0	$864	$173	$0	$155	$1,192	$2
11.7	Standby Equipment	$972	$0	$644	$0	$1,616	$323	$0	$291	$2,230	$3
11.8	Main Power Transformers	$6,715	$0	$138	$0	$6,853	$1,371	$0	$1,234	$9,458	$15
11.9	Electrical Foundations	$0	$114	$259	$0	$372	$74	$0	$89	$536	$1
	Subtotal	**$20,596**	**$3,161**	**$10,298**	**$0**	**$34,054**	**$6,811**	**$0**	**$6,152**	**$47,017**	**$72**
12	**Instrumentation & Control**										
12.1	NGCC Control Equipment	$223	$0	$141	$0	$364	$73	$0	$65	$502	$1
12.2	Combustion Turbine Control Equipment	$367	$0	$231	$0	$599	$120	$0	$108	$826	$1
12.3	Steam Turbine Control Equipment	$357	$0	$225	$0	$583	$117	$0	$105	$804	$1
12.4	Other Major Component Control Equipment	$600	$0	$378	$0	$978	$196	$0	$176	$1,349	$2
12.5	Signal Processing Equipment	$500	$0	$15	$0	$515	$103	$0	$93	$711	$1
12.6	Control Boards, Panels, & Racks	$132	$0	$80	$0	$212	$42	$0	$38	$293	$0
12.7	Distributed Control System Equipment	$7,349	$0	$221	$0	$7,570	$1,514	$0	$1,363	$10,447	$16
12.8	Instrument Wiring & Tubing	$727	$581	$1,922	$0	$3,230	$646	$0	$581	$4,458	$7
12.9	Other I&C Equipment	$503	$0	$963	$0	$1,467	$293	$0	$264	$2,024	$3
	Subtotal	**$10,759**	**$581**	**$4,177**	**$0**	**$15,518**	**$3,104**	**$0**	**$2,793**	**$21,415**	**$33**
13	**Improvements to Site**										
13.1	Site Preparation	$0	$649	$11,633	$0	$12,281	$2,456	$0	$2,948	$17,685	$27
13.2	Site Improvements	$0	$2,087	$2,328	$0	$4,415	$883	$0	$1,060	$6,358	$10
13.3	Site Facilities	$2,003	$0	$1,774	$0	$3,777	$755	$0	$906	$5,439	$8
	Subtotal	**$2,003**	**$2,736**	**$15,735**	**$0**	**$20,473**	**$4,095**	**$0**	**$4,914**	**$29,482**	**$45**
14	**Buildings & Structures**										
14.1	Combustion Turbine Area	$0	$530	$206	$0	$736	$147	$0	$133	$1,016	$2
14.3	Steam Turbine Building	$0	$4,985	$4,874	$0	$9,859	$1,972	$0	$1,775	$13,606	$21
14.4	Administration Building	$0	$565	$282	$0	$847	$169	$0	$152	$1,169	$2
14.5	Circulation Water Pumphouse	$0	$74	$27	$0	$101	$20	$0	$18	$140	$0
14.6	Water Treatment Buildings	$0	$471	$315	$0	$786	$157	$0	$141	$1,084	$2
14.7	Machine Shop	$0	$846	$398	$0	$1,244	$249	$0	$224	$1,717	$3
14.8	Warehouse	$0	$658	$292	$0	$950	$190	$0	$171	$1,311	$2
14.9	Other Buildings & Structures	$0	$481	$257	$0	$738	$148	$0	$133	$1,019	$2
14.10	Waste Treating Building & Structures	$0	$536	$702	$0	$1,238	$248	$0	$223	$1,708	$3
	Subtotal	**$0**	**$9,147**	**$7,353**	**$0**	**$16,500**	**$3,300**	**$0**	**$2,970**	**$22,769**	**$35**
	Total	**$320,963**	**$34,524**	**$107,959**	**$0**	**$463,446**	**$92,689**	**$0**	**$88,133**	**$644,269**	**$993**

Exhibit 4-62. Case B32A.1 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$4,343	$7
1 Month Maintenance Materials	$720	$1
1 Month Non-fuel Consumables	$310	$0
1 Month Waste Disposal	$0	$0
25% of 1 Months Fuel Cost at 100% CF	$4,014	$6
2% of TPC	$12,885	$20
Total	**$22,272**	**$34**
Inventory Capital		
60-day supply of consumables at 100% CF	$335	$1
0.5% of TPC (spare parts)	$3,221	$5
Total	**$3,557**	**$5**
Other Costs		
Initial Cost for Catalyst and Chemicals	$1,488	$2
Land	$600	$1
Other Owner's Costs	$96,640	$149
Financing Costs	$17,395	$27
Total Overnight Costs (TOC)	**$786,221**	**$1,212**
TASC Multiplier (IOU, 33 year)	1.183	
Total As-Spent Cost (TASC)	**$930,058**	**$1,433**

Exhibit 4-63. Case B32A.1 initial and annual operating and maintenance costs

Case:	B32A.1 – NGCC H–Class (1x1) without CO_2 Capture				Cost Base:	Jan 2023
Plant Size (MW, net):	649	Heat Rate-net (Btu/kWh):	6,068		Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		45.04	**$/hour**	Skilled Operator:		1.0
Operating Labor Burden:		30.00	**% of base**	Operator:		1.0
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		1.0
				Total:		**4.0**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$2,051,642	$3.162
Maintenance Labor:					$4,896,441	$7.547
Administrative & Support Labor:					$1,737,021	$2.677
Property Taxes and Insurance:					$12,885,371	$19.860
Total:					**$21,570,474**	**$33.246**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$7,344,661	$1.520
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	1,678	$2.30	$0	$1,197,664	$0.248
Makeup and Waste Water Treatment Chemicals (ton):	0	5.0	$660.00	$0	$1,023,767	$0.212
Ammonia (19 wt%, ton):	0	7.9	$280.00	$0	$685,745	$0.142
SCR Catalyst (ft^3):	4,252	2.3	$350.00	$1,488,225	$252,998	$0.052
Subtotal:				**$1,488,225**	**$3,160,174**	**$0.654**
Waste Disposal						
SCR Catalyst (ft^3):	0	2.3	$5.70	$0	$4,120	$0.001
Subtotal:				**$0**	**$4,120**	**$0.001**
Variable Operating Costs Total:				**$1,488,225**	**$10,508,956**	**$2.175**
Fuel Cost						
Natural Gas (MMBtu):	0	94,481	$5.59	$0	$163,777,048	$33.901
Total:				**$0**	**$163,777,048**	**$33.901**

Exhibit 4-64. Case B32A.1 COE breakdown

	FY COE		LCOE	
Component	**Value, $/MWh**	**Percentage**	**Value, $/MWh**	**Percentage**
Capital	14.8	27%	14.8	33%
Fixed	4.5	8%	6.0	13%
Variable	2.2	4%	2.9	7%
Fuel	33.9	61%	20.8	47%
Total (Excluding T&S)	**55.4**	**N/A**	**44.5**	**N/A**
CO_2 T&S	–	–	–	–
Total (Including T&S)	**55.4**	**N/A**	**44.5**	**N/A**

4.3.7 Case B32B.1.90 – NGCC with 90% CO_2 Capture Process Description

The plant configuration and process description for Case B32B.1.90 are nearly the same as Case B32A.1, with the exception that a PostCCC facility was included to treat the flue gas stream. Since the process descriptions of the plant and PostCCC facility were provided in Section 4.3.3 and Section 3.1.8, respectively, with differences between the facilities used in NGCC and PC cases noted in Section 4.1.4, they are not repeated here.

The BFD for Case B32B.1.90 is shown in Exhibit 4-65. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit 4-66. The modeling assumptions are presented in Section 4.3.1.

Exhibit 4-65. Case B32B.1.90 BFD, NGCC with 90 percent CO_2 capture

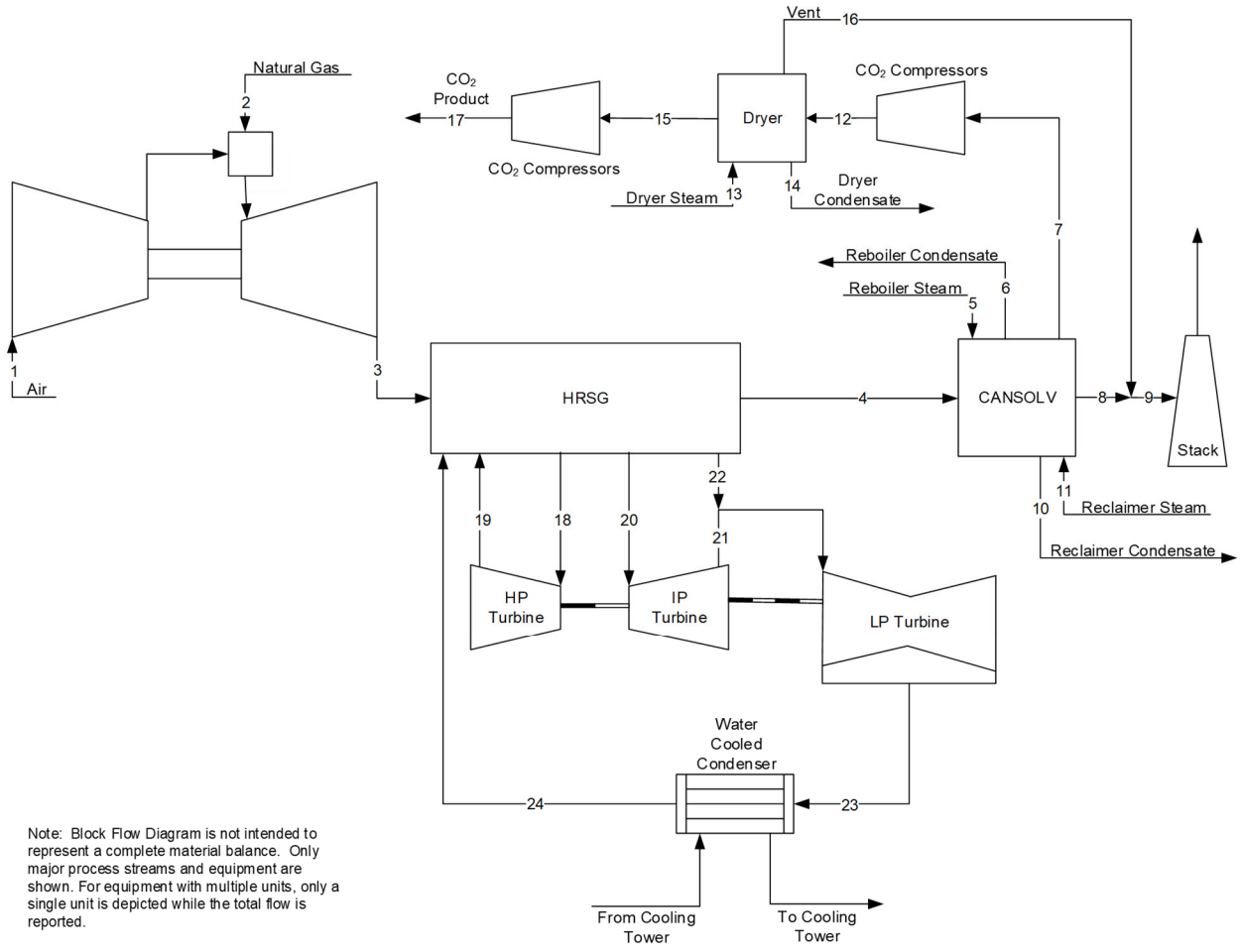


Exhibit 4-66. Case B32B.1.90 stream table, NGCC with 90 percent CO_2 capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0000	0.0088	0.0088	0.0000	0.0000	0.0000	0.0097	0.0097	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	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	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	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	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	0.0000	0.0000	0.0000
CO_2	0.0003	0.0100	0.0462	0.0462	0.0000	0.0000	0.9796	0.0051	0.0051	0.0000	0.0000	0.9957
H_2O	0.0099	0.0000	0.0977	0.0977	1.0000	1.0000	0.0204	0.0550	0.0550	1.0000	1.0000	0.0043
N_2	0.7732	0.0160	0.7389	0.7389	0.0000	0.0000	0.0000	0.8111	0.8111	0.0000	0.0000	0.0000
O_2	0.2074	0.0000	0.1085	0.1085	0.0000	0.0000	0.0000	0.1191	0.1191	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	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_{mol}/hr)	99,469	4,584	104,186	104,186	11,715	10,729	4,418	94,901	94,902	110	110	4,347
V-L Flowrate (kg/hr)	2,870,378	79,424	2,949,802	2,949,802	211,041	193,291	192,085	2,670,031	2,670,070	1,976	1,976	190,803
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	27	663	94	298	105	29	38	38	214	362	29
Pressure (MPa, abs)	0.10	3.79	0.11	0.10	0.51	0.12	0.17	0.10	0.10	2.04	4.06	2.81
Steam Table Enthalpy (kJ/kg)[A]	30.23	12.48	900.09	254.17	3,060.23	439.34	45.99	127.28	127.28	913.81	3,119.49	-1.10
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-4,496.75	-757.48	-1,403.41	-12,920.06	-15,540.95	-8,977.01	-530.47	-530.60	-15,066.49	-12,860.81	-8,976.01
Density (kg/m^3)	1.2	28.8	0.4	0.9	1.9	954.9	3.0	1.1	1.1	848.5	14.9	57.8
V-L Molecular Weight	28.857	17.328	28.313	28.313	18.015	18.015	43.481	28.135	28.135	18.015	18.015	43.897
V-L Flowrate (lb_{mol}/hr)	219,292	10,105	229,690	229,690	25,826	23,654	9,739	209,220	209,222	242	242	9,583
V-L Flowrate (lb/hr)	6,328,100	175,100	6,503,200	6,503,200	465,266	426,134	423,475	5,886,411	5,886,497	4,355	4,355	420,649
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	80	1,226	200	569	221	85	100	100	416	683	85
Pressure (psia)	14.7	550.0	15.4	14.8	73.5	17.4	24.7	14.8	14.8	296.6	589.1	407.6
Steam Table Enthalpy (Btu/lb)[A]	13.0	5.4	387.0	109.3	1,315.7	188.9	19.8	54.7	54.7	392.9	1,341.1	-0.5
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-1,933.3	-325.7	-603.4	-5,554.6	-6,681.4	-3,859.4	-228.1	-228.1	-6,477.4	-5,529.2	-3,859.0
Density (lb/ft^3)	0.076	1.799	0.024	0.059	0.121	59.612	0.185	0.069	0.069	52.968	0.932	3.607

[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 4-66. Case B32B.1.90 stream table, NGCC with 90 percent CO_2 capture (cont'd)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0000	0.0000	0.0000	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	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	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	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	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	0.0000	0.0000	0.0000
CO_2	0.0000	0.0000	0.9995	0.9704	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	0.0005	0.0296	0.0005	1.0000	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	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	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	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_{mol}/hr)	6	6	4,329	1	4,329	23,948	23,551	25,172	25,536	2,855	16,676	28,542
V-L Flowrate (kg/hr)	113	113	190,465	39	190,465	431,421	424,270	453,474	460,032	51,437	300,429	514,196
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	362	203	29	28	30	585	362	585	299	300	38	38
Pressure (MPa, abs)	4.06	1.64	2.68	0.10	15.27	17.35	4.06	3.69	0.52	0.51	0.01	0.01
Steam Table Enthalpy (kJ/kg)[A]	3,119.49	863.65	-3.59	56.47	-231.09	3,520.05	3,119.49	3,642.32	3,060.23	3,063.55	2,358.35	160.78
AspenPlus Enthalpy (kJ/kg)[B]	-12,860.81	-15,116.65	-8,967.15	-8,994.77	-9,194.65	-12,460.24	-12,860.81	-12,337.98	-12,920.06	-12,916.74	-13,621.94	-15,819.51
Density (kg/m^3)	14.9	861.8	54.7	1.8	630.1	48.2	14.9	9.5	2.0	1.9	0.1	992.8
V-L Molecular Weight	18.015	18.015	43.997	43.240	43.997	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	14	14	9,544	2	9,544	52,795	51,920	55,494	56,297	6,295	36,765	62,925
V-L Flowrate (lb/hr)	249	249	419,904	86	419,904	951,121	935,356	999,738	1,014,198	113,400	662,332	1,133,607
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	683	397	85	83	86	1,085	683	1,085	569	572	101	101
Pressure (psia)	589.1	237.4	389.1	14.8	2,214.7	2,516.2	589.1	535.6	75.0	73.5	1.0	1.0
Steam Table Enthalpy (Btu/lb)[A]	1,341.1	371.3	-1.5	24.3	-99.4	1,513.4	1,341.1	1,565.9	1,315.7	1,317.1	1,013.9	69.1
AspenPlus Enthalpy (Btu/lb)[B]	-5,529.2	-6,499.0	-3,855.2	-3,867.1	-3,953.0	-5,356.9	-5,529.2	-5,304.4	-5,554.6	-5,553.2	-5,856.4	-6,801.2
Density (lb/ft^3)	0.932	53.801	3.416	0.110	39.338	3.011	0.932	0.593	0.124	0.121	0.003	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

4.3.8 Case B32B.1.90 – Performance Results

Overall plant performance is summarized in Exhibit 4-67; Exhibit 4-68 provides a detailed breakdown of the auxiliary power requirements.

The PostCCC facility and CO_2 compression combined accounts for 67 percent of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for 14 percent of the auxiliary load, largely due to the high cooling water demand of the PostCCC facility and CO_2 compressors.

Unlike the PC cases, which utilize boilers and steam turbines that can be produced at nearly any desired output, the gross outputs of the NGCC cases are fixed by the available size of the CTs. As such, the net outputs of the capture cases are reduced due to the greater auxiliary load imposed by the PostCCC facility and CO_2 compressors, relative to a non-capture case. The plant produces a net output of 579 MW at a net plant efficiency of 50.2 percent (HHV basis).

Exhibit 4-67. Case B32B.1.90 plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	442
Steam Turbine Power, MWe	177
Total Gross Power, MWe	**619**
CO_2 Capture/Removal Auxiliaries, kWe	11,500
CO_2 Compression, kWe	15,240
Balance of Plant, kWe	13,225
Total Auxiliaries, MWe	**40**
Net Power, MWe	**579**
HHV Net Plant Efficiency, %	50.2
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	7,176 (6,801)
HHV Combustion Turbine Efficiency, %	38.3
LHV Net Plant Efficiency, %	55.6
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,477 (6,139)
LHV Combustion Turbine Efficiency, %	42.4
Steam Turbine Cycle Efficiency, %	47.6
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,557 (7,163)
CO_2 Capture Rate, %	90
Condenser Duty, GJ/hr (MMBtu/hr)	663 (629)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	1,019 (966)
Natural Gas Feed Flow, kg/hr (lb/hr)	79,424 (175,100)
HHV Thermal Input, kWt	1,153,739
LHV Thermal Input, kWt	1,041,363
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.024 (6.5)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.015 (4.1)

Exhibit 4-68. Case B32B.1.90 plant power summary

Power Summary	
Combustion Turbine Power, MWe	442
Steam Turbine Power, MWe	177
Total Gross Power, MWe	**619**
Auxiliary Load Summary	
Circulating Water Pumps, kWe	3,560
Combustion Turbine Auxiliaries, kWe	820
Condensate Pumps, kWe	520
Cooling Tower Fans, kWe	1,840
CO_2 Capture/Removal Auxiliaries, kWe	11,500
CO_2 Compression, kWe	15,240
Feedwater Pumps, kWe	3,490
Ground Water Pumps, kWe	340
Miscellaneous Balance of Plant[A], kWe	510
SCR, kWe	5
Steam Turbine Auxiliaries, kWe	160
Transformer Losses, kWe	1,980
Total Auxiliaries, MWe	**40**
Net Power, MWe	**579**

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

4.3.8.1 Environmental Performance

The environmental targets for emissions of NOx, SO_2, and PM are presented in Section 2.4. A summary of the plant air emissions for Case B32B.1.90 is presented in Exhibit 4-69.

Exhibit 4-69. Case B32B.1.90 air emissions

	kg/GJ (lb/MMBtu)[A]	tonne/yr (ton/year)[B]	kg/MWh (lb/MWh)[C]
SO_2	0.000 (0.000)	0 (0)	0.000 (0.000)
NOx	0.001 (0.003)	38 (42)	0.008 (0.018)
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	0.000 (0.000)	0 (0)	0.000 (0.000)
CO_2	5 (12)	157,865 (174,016)	34 (76)
CO_2[D]	-	-	37 (81)

[A]Based on thermal input on an HHV basis
[B]Calculations based on an 85 percent capacity factor
[C]Emissions based on gross power except where otherwise noted
[D]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 domestic average value of total sulfur of 0.34 gr/100 scf ($4.71x10^{-4}$ lb-S/MMBtu) (Gas Research Institute, 1992). It was also assumed that the added 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 1.8 ppmv NOx emissions using a DLN burner in the CTG and an SCR. The DLN burners reduce the emissions to about 25 ppmvd (at 15 percent O_2) (GE Vernova, 2024b) and the SCR system is designed for an additional 95.1 percent NOx reduction (Davis & Black, October 2000).

The pipeline natural gas was assumed to contain no Hg or HCl, resulting in zero emissions.

The state-of-the-art 2023 H-Class gas turbine achieves approximately 9.0 ppmvd (at 15 percent O_2) CO and 1.4 ppmw PM emissions. The production of PM is a result of system inefficiencies and is not produced or emitted in any significant amount. Any CO or PM present in the flue gas is assumed to interact with, and be removed by, the PostCCC system solvent.

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

The carbon balance for the plant is shown in Exhibit 4-70. The carbon input to the plant consists of carbon in the natural gas and carbon in the air. Carbon leaves the plant mostly as CO_2 product from the CO_2 compression train; however, some carbon exits through the stack as CO_2.

Ninety percent of the CO_2 in the flue gas is removed in the PostCCC facility. 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 percentage:

$$1 - \frac{Carbon\ in\ Stack}{Total\ Carbon\ In} = \left(1 - \left(\frac{12{,}756}{127{,}332}\right)\right) * 100 = 90\%$$

Exhibit 4-70. Case B32B.1.90 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	57,366 (126,471)	Stack Gas	5,786 (12,756)
Air (CO_2)	390 (861)	CO_2 Product	51,970 (114,575)
		CO_2 Knockout	0.1 (0.2)
Total	**57,757 (127,332)**	**Total**	**57,757 (127,332)**

As shown in Exhibit 4-71, the sulfur content of the natural gas is insignificant, entirely comprising CH_4S (used as an odorant) (Gas Research Institute, 1992). All sulfur in the natural gas is assumed to react with the PostCCC system solvent and is removed from the solvent during solvent reclaiming as a waste stream.

Exhibit 4-71. Case B32B.1.90 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	0.8 (1.9)	Stack Gas	0.0 (0.0)
		Solvent Reclaiming	0.8 (1.9)
Total	**0.8 (1.9)**	**Total**	**0.8 (1.9)**

Water demand, recycle, withdrawal, discharge, and consumption are defined and discussed in Section 2.6. Exhibit 4-72 shows the overall water balance for the plant.

Exhibit 4-72. Case B32B.1.90 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 Capture System Makeup	–	–	–	–	–
CO_2 Capture Recovery	–	–	–	1.8 (463)	-1.8 (-463)
CO_2 Compression Recovery	–	–	–	0.0 (5.6)	0.0 (-5.6)
Deaerator Vent	–	–	–	0.0 (4.5)	0.0 (-4.5)
Condenser Makeup	**0.3 (83)**	**–**	**0.3 (83)**	**–**	**0.3 (83)**
BFW Makeup	0.3 (83)	–	0.3 (83)	–	0.3 (83)
Cooling Tower	**14 (3,660)**	**–**	**14 (3,660)**	**3.5 (915)**	**10 (2,745)**
Total	**14 (3,742)**	**–**	**14 (3,742)**	**5.3 (1,388)**	**8.9 (2,354)**

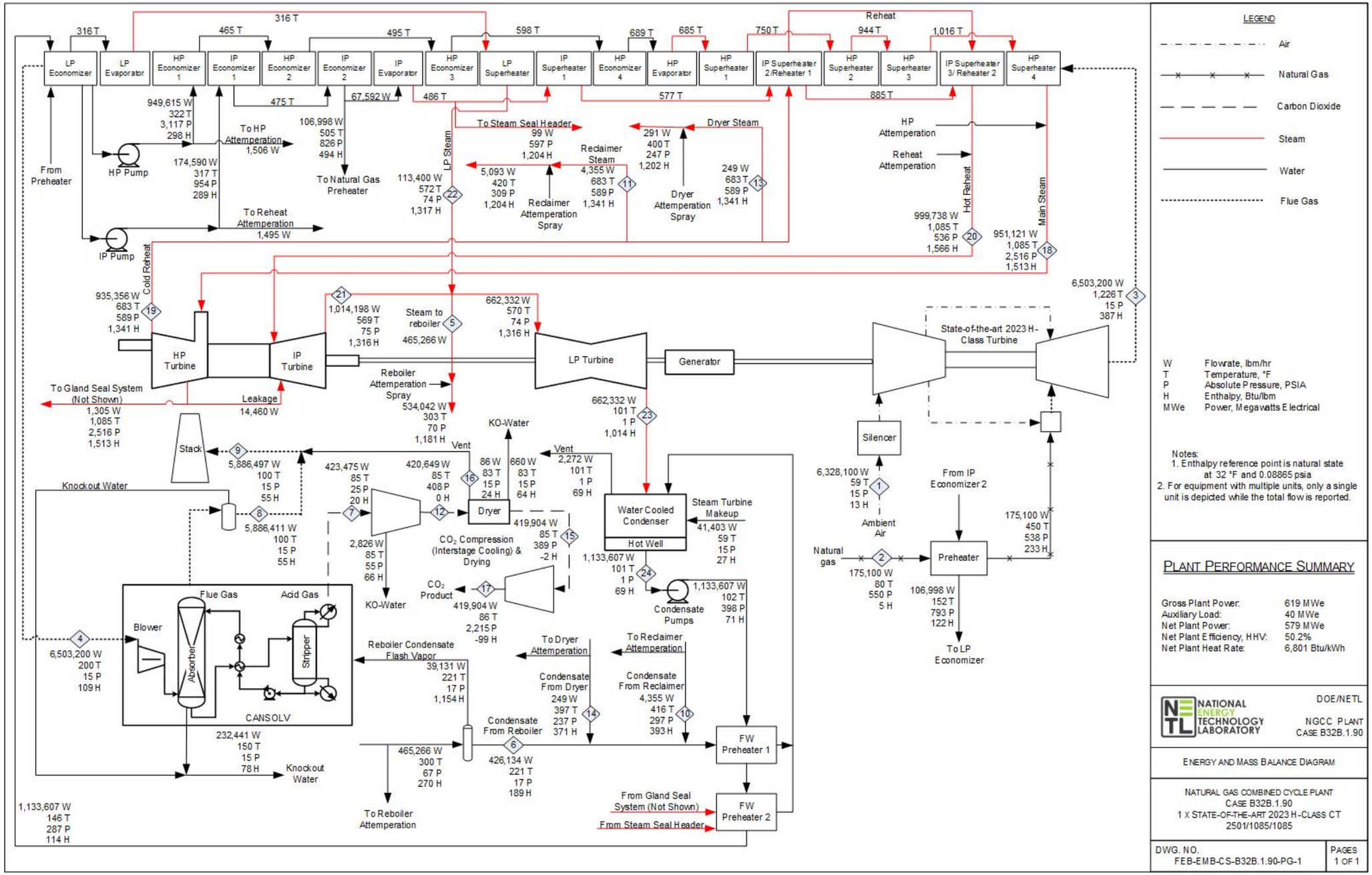
4.3.8.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for Case B32B.1.90 in Exhibit 4-73.

An overall plant energy balance is provided in tabular form in Exhibit 4-74. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-67) is calculated by multiplying the power out by the generator efficiency: 98.5 percent for the CT and 98.5 percent for the steam turbine.

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Exhibit 4-73. Case B32B.1.90 energy and mass balance, NGCC with CO_2 capture



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Exhibit 4-74. Case B32B.1.90 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, GJ/hr (MMBtu/hr)				
Natural Gas	4,153 (3,937)	4.9 (4.7)	–	4,158 (3,941)
Air	–	87 (82)	–	87 (82)
Raw Water Makeup	–	53 (51)	–	53 (51)
Auxiliary Power	–	–	144 (136)	144 (136)
TOTAL	**4,153 (3,937)**	**145 (138)**	**144 (136)**	**4,442 (4,211)**
Heat Out, GJ/hr (MMBtu/hr)				
Stack Gas	–	340 (322)	–	340 (322)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Motor Losses and Design Allowances	–	–	46 (44)	46 (44)
Cooling Tower Load[A]	–	1,815 (1,721)	–	1,815 (1,721)
CO_2 Product Stream	–	-44 (-42)	–	-44 (-42)
AGR Effluent	–	29 (27)	–	29 (27)
Dryer Effluent	–	0.0 (0.0)	–	0.0 (0.0)
Deaerator Vent	–	0.2 (0.2)	–	0.2 (0.2)
Ambient Losses[B]	–	*36 (34)*	–	36 (34)
Power	–	–	2,228 (2,111)	2,228 (2,111)
TOTAL	**0.0 (0.0)**	**2,177 (2,063)**	**2,274 (2,155)**	**4,450 (4,218)**
Unaccounted Energy[C]	–	*-7.8 (-7.4)*	–	*-7.8 (-7.4)*

[A]Includes condenser, capture process, CO_2 compressor, and miscellaneous cooling loads
[B]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers
[C]By difference

4.3.9 Case B32B.1.90 – Major Equipment List

Major equipment items for the 1x1 H-Class NGCC plant with 90 percent 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 4.3.10. 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. Values reported in the equipment lists are rounded.

Case B32B.1.90 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,237,000 liters (327,000 gal)	2	0
2	Condensate Pumps	Vertical canned	9,490 lpm @ 340 m H_2O (2,510 gpm @ 1,110 ft H_2O)	1	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP Water: 3,980 lpm @ 2,420 m H_2O (1,050 gpm @ 7,930 ft H_2O) IP Water: 740 lpm @ 580 m H_2O (190 gpm @ 1,890 ft H_2O)	2	2
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 GJ/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	3,800 lpm @ 110 m H_2O (1,000 gpm @ 350 ft H_2O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,600 lpm @ 80 m H_2O (700 gpm @ 250 ft H_2O)	1	1
11	Municipal Water Pumps	Stainless steel, single suction	3,900 lpm @ 20 m H_2O (1,030 gpm @ 60 ft H_2O)	2	1
12	Ground Water Pumps	Stainless steel, single suction	3,900 lpm @ 20 m H_2O (1,030 gpm @ 60 ft H_2O)	2	1
13	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H_2O (40 gpm @ 160 ft H_2O)	2	1
14	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
15	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0
16	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
17	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	51 m^3/min @ 3.8 MPa (1,784 acfm @ 550 psia) 39 cm (16 in) standard wall pipe	16 km (10 mile)	0
18	Gas Metering Station	–	51 m^3/min (1,784 acfm)	1	0

Case B32B.1.90 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Cansolv	Amine-based CO_2 capture technology	3,245,000 kg/hr (7,154,000 lb/hr) 7.2 wt% CO_2 concentration	1	0
2	Cansolv LP Condensate Pump	Centrifugal	570 lpm @ 1.0 m H_2O (150 gpm @ 3.4 ft H_2O)	1	1
3	Cansolv HP Condensate Pump	Centrifugal	6.1 lpm @ 4.6 m H_2O (1.6 gpm @ 15.0 ft H_2O)	1	1
4	CO_2 Dryer	Triethylene glycol	Inlet: 55 m^3/min @ 2.8 MPa (1,944 acfm @ 408 psia) Outlet: 2.7 MPa (389 psia) Water Removed: 300 kg/hr (661 lb/hr)	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
5	CO_2 Compressor	Integrally geared, multi-stage centrifugal	3 m^3/min @ 15.3 MPa, 82°C (98 acfm @ 2,217 psia, 180°F)	2	0
6	CO_2 Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 30 GJ/hr (28 MMBtu/hr)	2	0

Case B32B.1.90 – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	2023 Advanced H-Class w/ dry low-NOx burner	440 MW	1	0
2	Combustion Turbine Generator	Hydrogen Cooled	520 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	1	0

Case B32B.1.90 – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Epoxy-coated CS plate	46 m (150 ft) high x 6.2 m (20 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section	Main Steam: 467,000 kg/hr, 17.2 MPa/585°C (1,029,000 lb/hr, 2,502 psig/1,085°F) Reheat Steam: 499,000 kg/hr, 3.6 MPa/585°C (1,100,000 lb/hr, 521 psig/1,085°F)	1	0
3	SCR Reactor	–	3,240,000 kg/hr (7,150,000 lb/hr)	1	0
4	SCR Catalyst	–	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	30 m^3/min @ 108 cm WG (1,010 scfm @ 42 in WG)	1	1
6	Ammonia Feed Pump	Centrifugal	6.0 lpm @ 90 m H_2O (1.6 gpm @ 300 ft H_2O)	1	1
7	Ammonia Storage Tank	Horizontal tank	87,000 liter (23,000 gal)	1	0

Case B32B.1.90 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	187 MW 17.2 MPa/585°C/585°C (2,502 psig/1,085°F/1,085°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	220 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Two pass, divided waterbox including vacuum pumps and integrated deaerator	730 GJ/hr (690 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	1	0

Case B32B.1.90 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	357,000 lpm @ 30 m (94,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 2,000 GJ/hr (1,890 MMBtu/hr) heat duty	1	0

Case B32B.1.90 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	18 kV/345 kV, 520 MVA, 3-ph, 60 Hz	1	0
2	STG Transformer	Oil-filled	18 kV/345 kV, 170 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	18 kV/4.16 kV, 19 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 6 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	1	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 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 B32B.1.90 – 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

4.3.10 Case B32B.1.90 – Cost Estimating

The cost estimating methodology is described in Section 2.7. Exhibit 4-75 shows a detailed breakdown of the capital costs; Exhibit 4-76 shows the owner's costs, TOC, and TASC; Exhibit 4-77 shows the initial and annual O&M costs; and Exhibit 4-78 shows the COE breakdown.

The estimated TPC of the NGCC with CO_2 capture is $2,111/kW. Process contingency represents 4.1 percent of the TPC and project contingency represents 15.0 percent of the TPC. The FY COE, including T&S costs of $4.7/MWh, is $88.3/MWh. The LCOE, including T&S costs of $6.2/MWh, is $79.9/MWh.

Exhibit 4-75. Case B32B.1.90 total plant cost details

Case:	B32B.1.90 – NGCC H-Class (1x1) with 90 Percent CO_2 Capture									
Plant Size (MW, net):	579							Cost Base:	Jan 2023	
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	$2,112	$3,621	$1,553	$0	$7,287	$1,457	$0	$1,312	$10,056	$17
3.2	Water Makeup & Pretreating	$6,160	$616	$2,897	$0	$9,673	$1,935	$0	$2,322	$13,930	$24
3.3	Other Feedwater Subsystems	$1,202	$394	$321	$0	$1,917	$383	$0	$345	$2,646	$5
3.4	Service Water Systems	$1,869	$3,569	$9,590	$0	$15,029	$3,006	$0	$3,607	$21,641	$37
3.5	Other Boiler Plant Systems	$280	$102	$223	$0	$605	$121	$0	$109	$835	$1
3.6	NG Pipeline and Start-Up System	$9,455	$407	$253	$0	$10,115	$2,023	$0	$1,821	$13,959	$24
3.7	Waste Water Treatment Equipment	$11,390	$0	$6,120	$0	$17,510	$3,502	$0	$4,202	$25,214	$44
3.9	Miscellaneous Plant Equipment	$13,782	$1,807	$6,141	$0	$21,730	$4,346	$0	$5,215	$31,291	$54
	Subtotal	**$46,251**	**$10,516**	**$27,099**	**$0**	**$83,867**	**$16,773**	**$0**	**$18,933**	**$119,573**	**$207**
5	Flue Gas Cleanup										
5.1	CANSOLV CO_2 Removal System	$113,610	$55,148	$102,726	$0	$271,484	$54,297	$48,867	$74,930	$449,577	$777
5.4	CO_2 Compression & Drying	$29,024	$4,354	$11,396	$0	$44,773	$8,955	$0	$10,746	$64,473	$111
5.5	CO_2 Compressor Aftercooler	$246	$39	$100	$0	$385	$77	$0	$92	$554	$1
5.12	Gas Cleanup Foundations	$0	$430	$440	$0	$869	$174	$0	$209	$1,252	$2
	Subtotal	**$142,879**	**$59,971**	**$114,661**	**$0**	**$317,511**	**$63,502**	**$48,867**	**$85,976**	**$515,857**	**$891**
6	Combustion Turbine & Accessories										
6.1	Combustion Turbine Generator	$93,216	$0	$5,950	$0	$99,166	$19,833	$0	$17,850	$136,849	$236
6.3	Combustion Turbine Accessories	$2,269	$0	$139	$0	$2,408	$482	$0	$433	$3,323	$6
6.4	Compressed Air Piping	$0	$862	$166	$0	$1,028	$206	$0	$185	$1,418	$2
6.5	Combustion Turbine Foundations	$0	$998	$1,089	$0	$2,087	$417	$0	$501	$3,005	$5
	Subtotal	**$95,484**	**$1,860**	**$7,344**	**$0**	**$104,688**	**$20,938**	**$0**	**$18,969**	**$144,595**	**$250**
7	HRSG, Ductwork, & Stack										
7.1	HRSG	$48,617	$0	$12,154	$0	$60,771	$12,154	$0	$10,939	$83,864	$145
7.2	HRSG Accessories	$13,575	$0	$2,536	$0	$16,111	$3,222	$0	$2,900	$22,233	$38
7.3	Ductwork	$0	$1,063	$581	$0	$1,644	$329	$0	$296	$2,269	$4
7.4	Stack	$3,676	$0	$687	$0	$4,362	$872	$0	$785	$6,020	$10
7.5	HRSG, Ductwork, & Stack Foundations	$0	$739	$585	$0	$1,324	$265	$0	$318	$1,907	$3
7.6	Selective Catalytic Reduction System	$1,637	$688	$841	$0	$3,166	$633	$0	$570	$4,369	$8
	Subtotal	**$67,505**	**$2,490**	**$17,384**	**$0**	**$87,379**	**$17,476**	**$0**	**$15,808**	**$120,663**	**$208**
8	Steam Turbine & Accessories										
8.1	Steam Turbine Generator & Accessories	$36,229	$0	$5,305	$0	$41,534	$8,307	$0	$7,476	$57,317	$99
8.2	Steam Turbine Plant Auxiliaries	$127	$0	$293	$0	$421	$84	$0	$76	$580	$1
8.3	Condenser & Auxiliaries	$6,043	$0	$2,900	$0	$8,943	$1,789	$0	$1,610	$12,341	$21
8.4	Steam Piping	$11,277	$0	$3,875	$0	$15,153	$3,031	$0	$2,727	$20,911	$36
8.5	Turbine Generator Foundations	$0	$1,306	$1,823	$0	$3,129	$626	$0	$751	$4,506	$8
	Subtotal	**$53,677**	**$1,306**	**$14,196**	**$0**	**$69,180**	**$13,836**	**$0**	**$12,640**	**$95,656**	**$165**

Case:	B32B.1.90 – NGCC H-Class (1x1) with 90 Percent CO_2 Capture								Estimate Type:	Conceptual
Plant Size (MW, net):	579								Cost Base:	Jan 2023

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
9	Cooling Water System										
9.1	Cooling Towers	$12,971	$0	$3,469	$0	$16,440	$3,288	$0	$2,959	$22,687	$39
9.2	Circulating Water Pumps	$1,653	$0	$88	$0	$1,741	$348	$0	$313	$2,402	$4
9.3	Circulating Water System Auxiliaries	$11,580	$0	$1,383	$0	$12,963	$2,593	$0	$2,333	$17,888	$31
9.4	Circulating Water Piping	$0	$3,643	$2,738	$0	$6,380	$1,276	$0	$1,148	$8,805	$15
9.5	Make-up Water System	$427	$0	$455	$0	$882	$176	$0	$159	$1,216	$2
9.6	Component Cooling Water System	$537	$0	$342	$0	$879	$176	$0	$158	$1,213	$2
9.7	Circulating Water System Foundations	$0	$843	$1,201	$0	$2,044	$409	$0	$490	$2,943	$5
	Subtotal	**$27,167**	**$4,486**	**$9,675**	**$0**	**$41,328**	**$8,266**	**$0**	**$7,562**	**$57,155**	**$99**
11	Accessory Electric Plant										
11.1	Generator Equipment	$3,177	$0	$1,981	$0	$5,158	$1,032	$0	$928	$7,118	$12
11.2	Station Service Equipment	$8,050	$0	$571	$0	$8,621	$1,724	$0	$1,552	$11,896	$21
11.3	Switchgear & Motor Control	$13,222	$0	$1,648	$0	$14,870	$2,974	$0	$2,677	$20,521	$35
11.4	Conduit & Cable Tray	$0	$2,778	$6,614	$0	$9,392	$1,878	$0	$1,691	$12,961	$22
11.5	Wire & Cable	$0	$4,147	$6,125	$0	$10,271	$2,054	$0	$1,849	$14,174	$24
11.6	Protective Equipment	$561	$0	$1,401	$0	$1,962	$392	$0	$353	$2,708	$5
11.7	Standby Equipment	$942	$0	$625	$0	$1,567	$313	$0	$282	$2,162	$4
11.8	Main Power Transformers	$6,408	$0	$132	$0	$6,540	$1,308	$0	$1,177	$9,026	$16
11.9	Electrical Foundations	$0	$109	$247	$0	$356	$71	$0	$85	$512	$1
	Subtotal	**$32,361**	**$7,033**	**$19,343**	**$0**	**$58,737**	**$11,747**	**$0**	**$10,594**	**$81,078**	**$140**
12	Instrumentation & Control										
12.1	NGCC Control Equipment	$259	$0	$163	$0	$422	$84	$0	$76	$582	$1
12.2	Combustion Turbine Control Equipment	$426	$0	$268	$0	$694	$139	$0	$125	$958	$2
12.3	Steam Turbine Control Equipment	$414	$0	$261	$0	$675	$135	$0	$122	$932	$2
12.4	Other Major Component Control Equipment	$695	$0	$438	$0	$1,133	$227	$57	$212	$1,629	$3
12.5	Signal Processing Equipment	$580	$0	$17	$0	$597	$119	$0	$107	$824	$1
12.6	Control Boards, Panels, & Racks	$154	$0	$93	$0	$246	$49	$12	$46	$354	$1
12.7	Distributed Control System Equipment	$8,518	$0	$257	$0	$8,774	$1,755	$439	$1,645	$12,613	$22
12.8	Instrument Wiring & Tubing	$842	$674	$2,228	$0	$3,744	$749	$187	$702	$5,382	$9
12.9	Other I&C Equipment	$583	$0	$1,117	$0	$1,700	$340	$85	$319	$2,444	$4
	Subtotal	**$12,470**	**$674**	**$4,842**	**$0**	**$17,986**	**$3,597**	**$780**	**$3,354**	**$25,717**	**$44**
13	Improvements to Site										
13.1	Site Preparation	$0	$857	$15,363	$0	$16,219	$3,244	$0	$3,893	$23,356	$40
13.2	Site Improvements	$0	$2,757	$3,074	$0	$5,831	$1,166	$0	$1,399	$8,396	$15
13.3	Site Facilities	$2,645	$0	$2,343	$0	$4,988	$998	$0	$1,197	$7,183	$12
	Subtotal	**$2,645**	**$3,614**	**$20,780**	**$0**	**$27,038**	**$5,408**	**$0**	**$6,489**	**$38,935**	**$67**
14	Buildings & Structures										
14.1	Combustion Turbine Area	$0	$530	$206	$0	$736	$147	$0	$133	$1,016	$2
14.3	Steam Turbine Building	$0	$4,399	$4,301	$0	$8,700	$1,740	$0	$1,566	$12,006	$21
14.4	Administration Building	$0	$553	$276	$0	$829	$166	$0	$149	$1,144	$2

Case:		B32B.1.90 – NGCC H-Class (1x1) with 90 Percent CO_2 Capture					Estimate Type:			Conceptual	
Plant Size (MW, net):		579					Cost Base:			Jan 2023	
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
14.5	Circulation Water Pumphouse	$0	$108	$39	$0	$147	$29	$0	$26	$203	$0
14.6	Water Treatment Buildings	$0	$573	$384	$0	$958	$192	$0	$172	$1,321	$2
14.7	Machine Shop	$0	$828	$389	$0	$1,217	$243	$0	$219	$1,680	$3
14.8	Warehouse	$0	$644	$286	$0	$929	$186	$0	$167	$1,283	$2
14.9	Other Buildings & Structures	$0	$471	$251	$0	$722	$144	$0	$130	$997	$2
14.10	Waste Treating Building & Structures	$0	$988	$1,295	$0	$2,283	$457	$0	$411	$3,150	$5
	Subtotal	**$0**	**$9,094**	**$7,427**	**$0**	**$16,521**	**$3,304**	**$0**	**$2,974**	**$22,799**	**$39**
	Total	**$480,440**	**$101,044**	**$242,751**	**$0**	**$824,235**	**$164,847**	**$49,647**	**$183,299**	**$1,222,028**	**$2,111**

Exhibit 4-76. Case B32B.1.90 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$7,514	$13
1 Month Maintenance Materials	$1,366	$2
1 Month Non-fuel Consumables	$667	$1
1 Month Waste Disposal	$87	$0
25% of 1 Months Fuel Cost at 100% CF	$4,014	$7
2% of TPC	$24,441	$42
Total	**$38,090**	**$66**
Inventory Capital		
60-day supply of consumables at 100% CF	$908	$2
0.5% of TPC (spare parts)	$6,110	$11
Total	**$7,018**	**$12**
Other Costs		
Initial Cost for Catalyst and Chemicals	$1,488	$3
Land	$600	$1
Other Owner's Costs	$183,304	$317
Financing Costs	$32,995	$57
Total Overnight Costs (TOC)	**$1,485,523**	**$2,566**
TASC Multiplier (IOU, 33 year)	1.183	
Total As-Spent Cost (TASC)	**$1,757,295**	**$3,036**

Exhibit 4-77. Case B32B.1.90 initial and annual operating and maintenance costs

Case:	B32B.1.90 – NGCC H-Class (1x1) with 90 Percent CO_2 Capture				Cost Base:	Jan 2023
Plant Size (MW, net):	579	Heat Rate-net (Btu/kWh):		6,801	Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		45.04	**$/hour**	Skilled Operator:		1.0
Operating Labor Burden:		30.00	**% of base**	Operator:		2.3
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		1.0
				Total:		**5.3**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$2,735,351	$4.726
Maintenance Labor:					$9,287,409	$16.045
Administrative & Support Labor:					$3,005,690	$5.193
Property Taxes and Insurance:					$24,440,551	$42.224
Total:					**$39,469,002**	**$68.187**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$13,931,114	$3.232
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	2,694	$2.30	$0	$1,922,678	$0.446
Makeup and Waste Water Treatment Chemicals (ton):	0	8.0	$660.00	$0	$1,643,511	$0.381
Ammonia (19 wt%, ton):	0	7.9	$280.00	$0	$689,187	$0.160
SCR Catalyst (ft^3):	4,252	2.3	$350.00	$1,488,225	$252,998	$0.059
CO_2 Capture System Chemicals[A]:	Proprietary				$2,199,706	$0.510
Triethylene Glycol (gal):	w/equip.	37.8	$8.50	$0	$99,609	$0.023
Subtotal:				**$1,488,225**	**$6,807,690**	**$1.580**
Waste Disposal						
SCR Catalyst (ft^3):	0	2.3	$5.70	$0	$4,120	$0.001
Triethylene Glycol (gal):	0	1,915	$1.30	$0	$772,506	$0.179
Thermal Reclaimer Unit Waste (ton):	0	1.5	$250.00	$0	$115,539	$0.027
Subtotal:				**$0**	**$892,165**	**$0.207**
Variable Operating Costs Total:				**$1,488,225**	**$21,630,969**	**$5.019**
Fuel Cost						
Natural Gas (MMBtu):	0	94,481	$5.59	$0	$163,777,048	$37.999
Total:				**$0**	**$163,777,048**	**$37.999**

[A]CO_2 Capture System Chemicals includes sodium hydroxide and CANSOLV solvent

Exhibit 4-78. Case B32B.1.90 COE breakdown

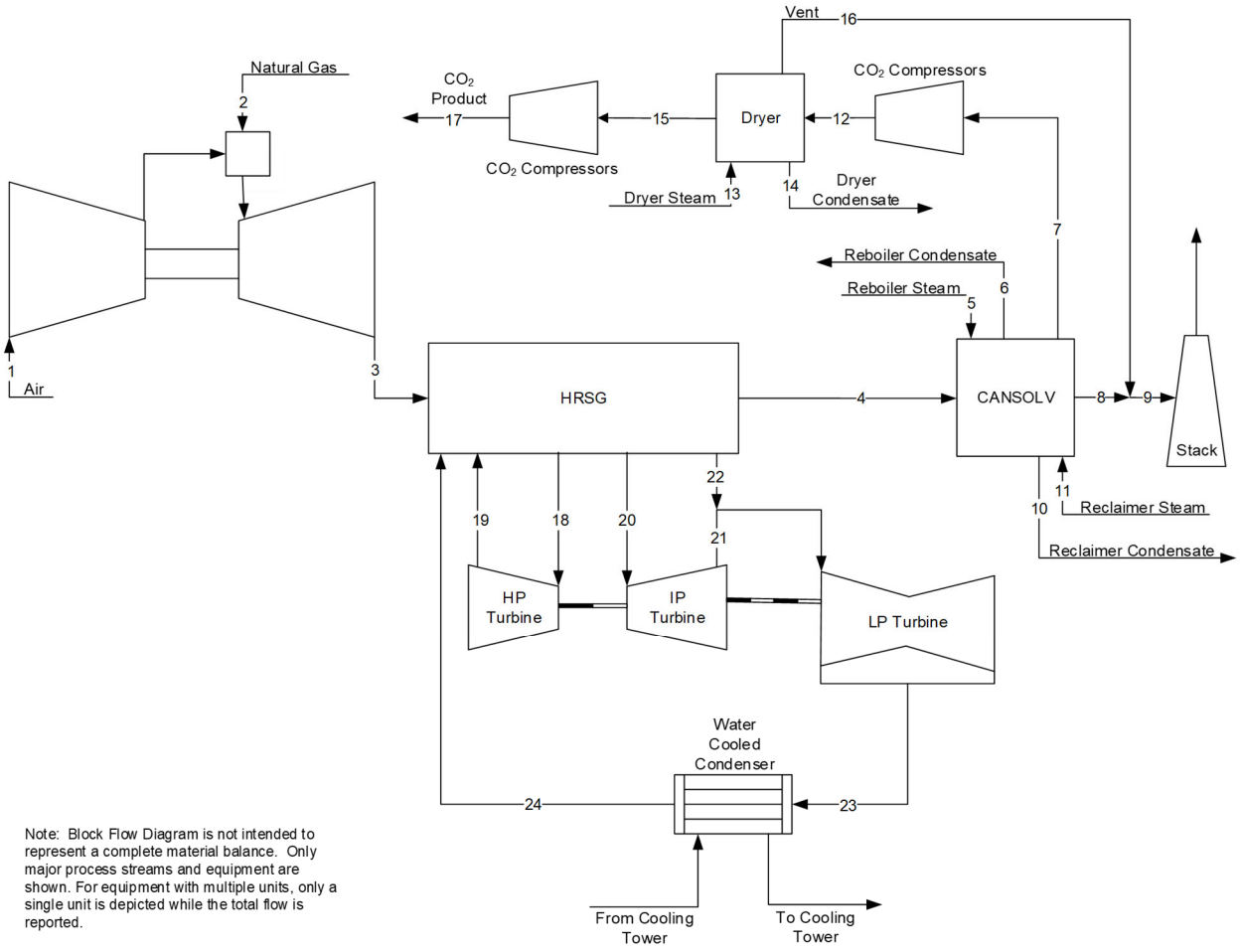
	FY COE		LCOE	
Component	Value, $/MWh	Percentage	Value, $/MWh	Percentage
Capital	31.4	36%	31.4	39%
Fixed	9.2	10%	12.2	15%
Variable	5.0	6%	6.7	8%
Fuel	38.0	43%	23.3	29%
Total (Excluding T&S)	**83.6**	**N/A**	**73.6**	**N/A**
CO_2 T&S	4.7	5%	6.2	8%
Total (Including T&S)	**88.3**	**N/A**	**79.9**	**N/A**

4.3.11 Case B32B.1.95 – NGCC with 95% CO_2 Capture Process Description

The plant configuration and process description for Case B32B.1.95 are the same as Case B32B.1.90, with the exception that the PostCCC facility captures 95, rather than 90, percent of the CO_2 in the flue gas. Since the process descriptions of the plant and PostCCC facility were provided in Section 4.3.3 and Section 3.1.8, respectively, with differences between the facilities used in NGCC and PC cases noted in Section 4.1.4, they are not repeated here.

The BFD for Case B32B.1.95 is shown in Exhibit 4-79. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit 4-80. The modeling assumptions are presented in Section 4.3.1.

Exhibit 4-79. Case B32B.1.95 BFD, NGCC with 95 percent CO_2 capture



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown. For equipment with multiple units, only a single unit is depicted while the total flow is reported.

Exhibit 4-80. Case B32B.1.95 stream table, NGCC with 95 percent CO_2 capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0000	0.0088	0.0088	0.0000	0.0000	0.0000	0.0097	0.0097	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	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	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	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	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	0.0000	0.0000	0.0000
CO_2	0.0003	0.0100	0.0462	0.0462	0.0000	0.0000	0.9796	0.0025	0.0026	0.0000	0.0000	0.9957
H_2O	0.0099	0.0000	0.0977	0.0977	1.0000	1.0000	0.0204	0.0550	0.0550	1.0000	1.0000	0.0043
N_2	0.7732	0.0160	0.7389	0.7389	0.0000	0.0000	0.0000	0.8133	0.8133	0.0000	0.0000	0.0000
O_2	0.2074	0.0000	0.1085	0.1085	0.0000	0.0000	0.0000	0.1194	0.1194	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	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_{mol}/hr)	99,469	4,584	104,186	104,186	12,364	11,325	4,663	94,646	94,647	110	110	4,588
V-L Flowrate (kg/hr)	2,870,378	79,424	2,949,802	2,949,802	222,750	204,015	202,757	2,659,197	2,659,238	1,976	1,976	201,404
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	27	663	94	298	105	29	38	38	214	362	29
Pressure (MPa, abs)	0.10	3.79	0.11	0.10	0.51	0.12	0.17	0.10	0.10	2.04	4.06	2.81
Steam Table Enthalpy (kJ/kg)[A]	30.23	12.48	900.09	255.09	3,060.23	439.34	45.99	127.43	127.43	913.81	3,119.49	-1.10
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-4,496.75	-757.48	-1,402.49	-12,920.06	-15,540.95	-8,977.01	-495.82	-495.95	-15,066.49	-12,860.81	-8,976.01
Density (kg/m^3)	1.2	28.8	0.4	0.9	1.9	954.9	3.0	1.1	1.1	848.5	14.9	57.8
V-L Molecular Weight	28.857	17.328	28.313	28.313	18.015	18.015	43.481	28.096	28.096	18.015	18.015	43.897
V-L Flowrate (lb_{mol}/hr)	219,292	10,105	229,690	229,690	27,259	24,966	10,280	208,659	208,662	242	242	10,115
V-L Flowrate (lb/hr)	6,328,100	175,100	6,503,200	6,503,200	491,079	449,776	447,002	5,862,525	5,862,616	4,355	4,355	444,019
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	80	1,226	202	569	221	85	100	100	416	683	85
Pressure (psia)	14.7	550.0	15.4	14.8	73.5	17.4	24.7	14.8	14.8	296.6	589.1	407.6
Steam Table Enthalpy (Btu/lb)[A]	13.0	5.4	387.0	109.7	1,315.7	188.9	19.8	54.8	54.8	392.9	1,341.1	-0.5
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-1,933.3	-325.7	-603.0	-5,554.6	-6,681.4	-3,859.4	-213.2	-213.2	-6,477.4	-5,529.2	-3,859.0
Density (lb/ft^3)	0.076	1.799	0.024	0.059	0.121	59.612	0.185	0.069	0.069	52.968	0.932	3.607

[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 4-80. Case B32B.1.95 stream table, NGCC with 95 percent CO_2 capture (cont'd)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0000	0.0000	0.0000	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	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	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	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	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	0.0000	0.0000	0.0000
CO_2	0.0000	0.0000	0.9995	0.9704	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	0.0005	0.0296	0.0005	1.0000	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	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	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	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_{mol}/hr)	7	7	4,570	1	4,570	23,948	23,551	25,171	25,535	2,855	16,026	28,542
V-L Flowrate (kg/hr)	120	120	201,047	41	201,047	431,425	424,274	453,470	460,029	51,437	288,716	514,199
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	362	203	29	28	30	585	362	585	299	300	38	38
Pressure (MPa, abs)	4.06	1.64	2.68	0.10	15.27	17.35	4.06	3.69	0.52	0.51	0.01	0.01
Steam Table Enthalpy (kJ/kg)[A]	3,119.49	863.65	-3.59	56.47	-231.09	3,520.05	3,119.49	3,642.32	3,060.23	3,063.55	2,358.36	160.78
AspenPlus Enthalpy (kJ/kg)[B]	-12,860.81	-15,116.65	-8,967.15	-8,994.77	-9,194.65	-12,460.24	-12,860.81	-12,337.98	-12,920.06	-12,916.74	-13,621.93	-15,819.51
Density (kg/m^3)	14.9	861.8	54.7	1.8	630.1	48.2	14.9	9.5	2.0	1.9	0.1	992.8
V-L Molecular Weight	18.015	18.015	43.997	43.240	43.997	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	15	15	10,074	2	10,074	52,796	51,921	55,493	56,296	6,295	35,332	62,925
V-L Flowrate (lb/hr)	265	265	443,232	91	443,232	951,129	935,363	999,730	1,014,189	113,400	636,511	1,133,614
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	683	397	85	83	86	1,085	683	1,085	569	572	101	101
Pressure (psia)	589.1	237.4	389.1	14.8	2,214.7	2,516.2	589.1	535.6	75.0	73.5	1.0	1.0
Steam Table Enthalpy (Btu/lb)[A]	1,341.1	371.3	-1.5	24.3	-99.4	1,513.4	1,341.1	1,565.9	1,315.7	1,317.1	1,013.9	69.1
AspenPlus Enthalpy (Btu/lb)[B]	-5,529.2	-6,499.0	-3,855.2	-3,867.1	-3,953.0	-5,356.9	-5,529.2	-5,304.4	-5,554.6	-5,553.2	-5,856.4	-6,801.2
Density (lb/ft^3)	0.932	53.801	3.416	0.110	39.338	3.011	0.932	0.593	0.124	0.121	0.003	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

4.3.12 Case B32B.1.95 – Performance Results

Overall plant performance is summarized in Exhibit 4-81; Exhibit 4-82 provides a detailed breakdown of the auxiliary power requirements.

The PostCCC facility and CO_2 compression combined account for 68 percent of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for 13 percent of the auxiliary load, largely due to the high cooling water demand of the PostCCC facility and CO_2 compressors.

Unlike the PC cases, which utilize boilers and steam turbines that can be produced at nearly any desired output, the gross outputs of the NGCC cases are fixed by the available size of the CTs. As such, the net outputs of the capture cases are reduced due to the greater auxiliary load imposed by the PostCCC facility and CO_2 compressors, relative to a non-capture case. The plant produces a net output of 575 MW at a net plant efficiency of 49.8 percent (HHV basis).

Exhibit 4-81. Case B32B.1.95 plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	442
Steam Turbine Power, MWe	175
Total Gross Power, MWe	**617**
CO_2 Capture/Removal Auxiliaries, kWe	12,300
CO_2 Compression, kWe	16,080
Balance of Plant, kWe	13,245
Total Auxiliaries, MWe	**42**
Net Power, MWe	**575**
HHV Net Plant Efficiency, %	49.8
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	7,225 (6,848)
HHV Combustion Turbine Efficiency, %	38.3
LHV Net Plant Efficiency, %	55.2
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,521 (6,181)
LHV Combustion Turbine Efficiency, %	42.4
Steam Turbine Cycle Efficiency, %	48.2
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,463 (7,073)
CO_2 Capture Rate, %	95
Condenser Duty, GJ/hr (MMBtu/hr)	638 (605)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	1,051 (996)
Natural Gas Feed Flow, kg/hr (lb/hr)	79,424 (175,100)
HHV Thermal Input, kWt	1,153,739
LHV Thermal Input, kWt	1,041,363
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.025 (6.6)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.016 (4.1)

Exhibit 4-82. Case B32B.1.95 plant power summary

Power Summary	
Combustion Turbine Power, MWe	442
Steam Turbine Power, MWe	175
Total Gross Power, MWe	**617**
Auxiliary Load Summary	
Circulating Water Pumps, kWe	3,580
Combustion Turbine Auxiliaries, kWe	820
Condensate Pumps, kWe	520
Cooling Tower Fans, kWe	1,850
CO_2 Capture/Removal Auxiliaries, kWe	12,300
CO_2 Compression, kWe	16,080
Feedwater Pumps, kWe	3,490
Ground Water Pumps, kWe	340
Miscellaneous Balance of Plant[A], kWe	510
SCR, kWe	5
Steam Turbine Auxiliaries, kWe	160
Transformer Losses, kWe	1,970
Total Auxiliaries, MWe	**42**
Net Power, MWe	**575**

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

4.3.12.1 Environmental Performance

The environmental targets for emissions of NOx, SO_2, and PM are presented in Section 2.4. A summary of the plant air emissions for Case B32B.1.95 is presented in Exhibit 4-83.

Exhibit 4-83. Case B32B.1.95 air emissions

	kg/GJ (lb/MMBtu)[A]	tonne/year (ton/year)[B]	kg/MWh (lb/MWh)[C]
SO_2	0.000 (0.000)	0 (0)	0.000 (0.000)
NOx	0.001 (0.003)	38 (42)	0.008 (0.018)
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	0.000 (0.000)	0 (0)	0.000 (0.000)
CO_2	3 (6)	79,092 (87,184)	17 (38)
CO_2[D]	-	-	18 (41)

[A]Based on thermal input on an HHV basis
[B]Calculations based on an 85 percent capacity factor
[C]Emissions based on gross power except where otherwise noted
[D]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 domestic average value of total sulfur of 0.34 gr/100 scf ($4.71x10^{-4}$ lb-S/MMBtu) (Gas Research Institute, 1992). It was also assumed that the added 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 1.8 ppmv NOx emissions using a DLN burner in the CTG and an SCR. The DLN burners reduce the emissions to about 25 ppmvd (at 15 percent O_2) (GE Vernova, 2024b) and the SCR system is designed for an additional 95.2 percent NOx reduction (Davis & Black, October 2000).

The pipeline natural gas was assumed to contain no Hg or HCl, resulting in zero emissions.

The state-of-the-art 2023 H-Class gas turbine achieves approximately 9.0 ppmvd (at 15 percent O_2) CO and 1.4 ppmw PM emissions. The production of PM is a result of system inefficiencies and is not produced or emitted in any significant amount. Any CO or PM present in the flue gas is assumed to interact with, and be removed by, the PostCCC system solvent.

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

The carbon balance for the plant is shown in Exhibit 4-84. The carbon input to the plant consists of carbon in the natural gas and carbon in the air. Carbon leaves the plant mostly as CO_2 product from the CO_2 compression train; however, some carbon exits through the stack as CO_2.

Ninety five percent of the CO_2 in the flue gas is removed in the PostCCC facility. 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 percentage:

$$1 - \frac{Carbon\ in\ Stack}{Total\ Carbon\ In} = \left(1 - \left(\frac{6{,}391}{127{,}332}\right)\right) * 100 = 95\%$$

Exhibit 4-84. Case B32B.1.95 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	57,366 (126,471)	Stack Gas	2,899 (6,391)
Air (CO_2)	390 (861)	CO_2 Product	54,858 (120,940)
		CO_2 Knockout	0.1 (0.2)
Total	**57,757 (127,332)**	**Total**	**57,757 (127,332)**

As shown in Exhibit 4-85, the sulfur content of the natural gas is insignificant, entirely comprising CH_4S (used as an odorant) (Gas Research Institute, 1992). All sulfur in the natural gas is assumed to react with the PostCCC system solvent and is removed from the solvent during solvent reclaiming as a waste stream.

Exhibit 4-85. Case B32B.1.95 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	0.8 (1.9)	Stack Gas	0.0 (0.0)
		Solvent Reclaiming	0.8 (1.9)
Total	**0.8 (1.9)**	**Total**	**0.8 (1.9)**

Water demand, recycle, withdrawal, discharge, and consumption are defined and discussed in Section 2.6. Exhibit 4-86 shows the overall water balance for the plant.

Exhibit 4-86. Case B32B.1.95 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 Capture System Makeup	–	–	–	–	–
CO_2 Capture Recovery	–	–	–	1.8 (468)	-1.8 (-468)
CO_2 Compression Recovery	–	–	–	0.0 (5.9)	0.0 (-5.9)
Deaerator Vent	–	–	–	0.0 (4.5)	0.0 (-4.5)
Condenser Makeup	**0.3 (87)**	**–**	**0.3 (87)**	**–**	**0.3 (87)**
BFW Makeup	0.3 (87)	–	0.3 (87)	–	0.3 (87)
Cooling Tower	**14 (3,685)**	**–**	**14 (3,685)**	**3.5 (921)**	**10 (2,764)**
Total	**14 (3,772)**	**–**	**14 (3,772)**	**5.3 (1,400)**	**9.0 (2,372)**

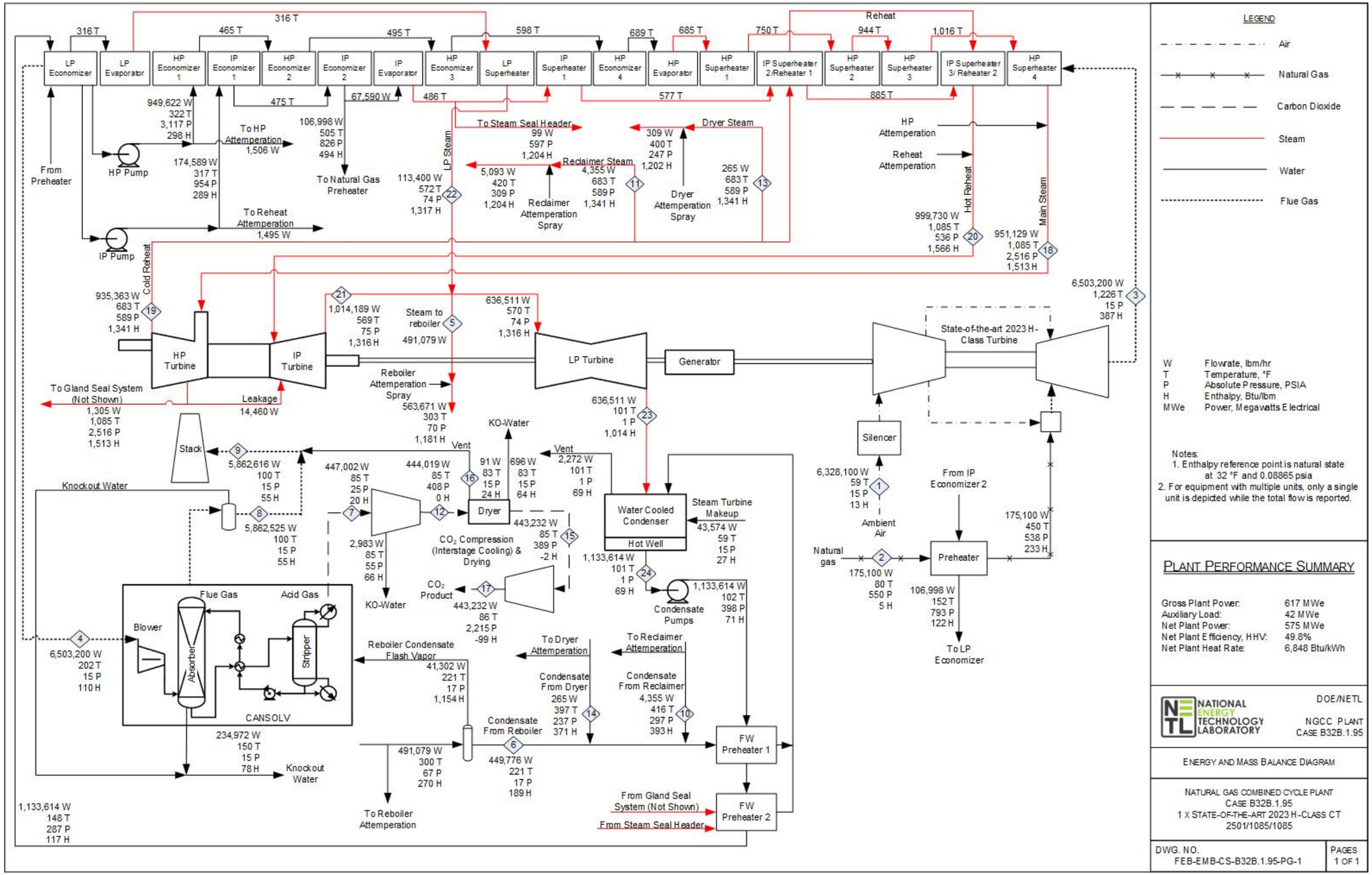
4.3.12.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for Case B32B.1.95 in Exhibit 4-87.

An overall plant energy balance is provided in tabular form in Exhibit 4-88. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-81) is calculated by multiplying the power out by the generator efficiency: 98.5 percent for the CT and 98.5 percent for the steam turbine.

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Exhibit 4-87. Case B32B.1.95 energy and mass balance, NGCC with CO_2 capture



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Exhibit 4-88. Case B32B.1.95 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, GJ/hr (MMBtu/hr)				
Natural Gas	4,153 (3,937)	4.9 (4.7)	–	4,158 (3,941)
Air	–	87 (82)	–	87 (82)
Raw Water Makeup	–	54 (51)	–	54 (51)
Auxiliary Power	–	–	150 (142)	150 (142)
TOTAL	**4,153 (3,937)**	**146 (138)**	**150 (142)**	**4,449 (4,217)**
Heat Out, GJ/hr (MMBtu/hr)				
Stack Gas	–	339 (321)	–	339 (321)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Motor Losses and Design Allowances	–	–	46 (44)	46 (44)
Cooling Tower Load[A]	–	1,828 (1,732)	–	1,828 (1,732)
CO_2 Product Stream	–	-46 (-44)	–	-46 (-44)
AGR Effluent	–	29 (28)	–	29 (28)
Dryer Effluent	–	0.0 (0.0)	–	0.0 (0.0)
Deaerator Vent	–	0.2 (0.2)	–	0.2 (0.2)
Ambient Losses[B]	–	*36 (34)*	–	36 (34)
Power	–	–	2,219 (2,104)	2,219 (2,104)
TOTAL	**0.0 (0.0)**	**2,186 (2,072)**	**2,265 (2,147)**	**4,451 (4,219)**
Unaccounted Energy[C]	–	*-2.6 (-2.4)*	–	*-2.6 (-2.4)*

[A]Includes condenser, capture process, CO_2 compressor, and miscellaneous cooling loads
[B]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers
[C]By difference

4.3.13 Case B32B.1.95 – Major Equipment List

Major equipment items for the 1x1 H-Class NGCC plant with 95 percent 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 4.3.14. 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. Values reported in the equipment lists are rounded.

Case B32B.1.95 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,302,000 liters (344,000 gal)	2	0
2	Condensate Pumps	Vertical canned	9,490 lpm @ 340 m H_2O (2,510 gpm @ 1,110 ft H_2O)	1	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP Water: 3,980 lpm @ 2,420 m H_2O (1,050 gpm @ 7,930 ft H_2O) IP Water: 740 lpm @ 580 m H_2O (190 gpm @ 1,890 ft H_2O)	2	2
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 GJ/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	3,800 lpm @ 110 m H_2O (1,000 gpm @ 350 ft H_2O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,600 lpm @ 80 m H_2O (700 gpm @ 250 ft H_2O)	1	1
11	Municipal Water Pumps	Stainless steel, single suction	3,900 lpm @ 20 m H_2O (1,040 gpm @ 60 ft H_2O)	2	1
12	Ground Water Pumps	Stainless steel, single suction	3,900 lpm @ 20 m H_2O (1,040 gpm @ 60 ft H_2O)	2	1
13	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H_2O (40 gpm @ 160 ft H_2O)	2	1
14	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
15	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0
16	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
17	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	51 m^3/min @ 3.8 MPa (1,784 acfm @ 550 psia) 39 cm (16 in) standard wall pipe	16 km (10 mile)	0
18	Gas Metering Station	–	51 m^3/min (1,784 acfm)	1	0

Case B32B.1.95 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Cansolv	Amine-based CO_2 capture technology	3,245,000 kg/hr (7,154,000 lb/hr) 7.2 wt% CO_2 concentration	1	0
2	Cansolv LP Condensate Pump	Centrifugal	600 lpm @ 1.0 m H_2O (160 gpm @ 3.4 ft H_2O)	1	1
3	Cansolv HP Condensate Pump	Centrifugal	6.1 lpm @ 4.6 m H_2O (1.6 gpm @ 15.0 ft H_2O)	1	1
4	CO_2 Dryer	Triethylene glycol	Inlet: 58 m^3/min @ 2.8 MPa (2,052 acfm @ 408 psia) Outlet: 2.7 MPa (389 psia) Water Removed: 316 kg/hr (697 lb/hr)	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
5	CO_2 Compressor	Integrally geared, multi-stage centrifugal	3 m^3/min @ 15.3 MPa, 82°C (103 acfm @ 2,217 psia, 180°F)	2	0
6	CO_2 Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 32 GJ/hr (30 MMBtu/hr)	2	0

Case B32B.1.95 – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	2023 Advanced H-Class w/ dry low-NOx burner	440 MW	1	0
2	Combustion Turbine Generator	Hydrogen Cooled	520 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	1	0

Case B32B.1.95 – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Epoxy-coated CS plate	46 m (150 ft) high x 6.2 m (20 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section	Main Steam: 467,000 kg/hr, 17.2 MPa/585°C (1,029,000 lb/hr, 2,502 psig/1,085°F) Reheat Steam: 499,000 kg/hr, 3.6 MPa/585°C (1,100,000 lb/hr, 521 psig/1,085°F)	1	0
3	SCR Reactor	–	3,240,000 kg/hr (7,150,000 lb/hr)	1	0
4	SCR Catalyst	–	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	30 m^3/min @ 108 cm WG (1,010 scfm @ 42 in WG)	1	1
6	Ammonia Feed Pump	Centrifugal	6.0 lpm @ 90 m H_2O (1.6 gpm @ 300 ft H_2O)	1	1
7	Ammonia Storage Tank	Horizontal tank	87,000 liter (23,000 gal)	1	0

Case B32B.1.95 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	184 MW 17.2 MPa/585°C/585°C (2,502 psig/1,085°F/1,085°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	220 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Two pass, divided waterbox including vacuum pumps and integrated deaerator	700 GJ/hr (670 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	1	0

Case B32B.1.95 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	359,000 lpm @ 30 m (95,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 2,010 GJ/hr (1,910 MMBtu/hr) heat duty	1	0

Case B32B.1.95 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	18 kV/345 kV, 520 MVA, 3-ph, 60 Hz	1	0
2	STG Transformer	Oil-filled	18 kV/345 kV, 170 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 9 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	18 kV/4.16 kV, 20 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 7 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	1	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 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 B32B.1.95 – 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

4.3.14 Case B32B.1.95 – Cost Estimating

The cost estimating methodology is described in Section 2.7. Exhibit 4-89 shows a detailed breakdown of the capital costs; Exhibit 4-90 shows the owner's costs, TOC, and TASC; Exhibit 4-91 shows the initial and annual O&M costs; and Exhibit 4-92 shows the COE breakdown.

The estimated TPC of the NGCC with CO_2 capture is $2,165/kW. Process contingency represents 4.1 percent of the TPC and project contingency represents 15.0 percent of the TPC. The FY COE, including T&S costs of $4.8/MWh, is $89.8/MWh. The LCOE, including T&S costs of $6.4/MWh, is $81.5/MWh.

Exhibit 4-89. Case B32B.1.95 total plant cost details

Case:	B32B.1.95 – NGCC H-Class (1x1) with 95 Percent CO_2 Capture									
Plant Size (MW, net):	575							Cost Base:	Jan 2023	
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	$2,112	$3,621	$1,553	$0	$7,287	$1,457	$0	$1,312	$10,056	$17
3.2	Water Makeup & Pretreating	$6,195	$619	$2,913	$0	$9,728	$1,946	$0	$2,335	$14,008	$24
3.3	Other Feedwater Subsystems	$1,202	$394	$321	$0	$1,917	$383	$0	$345	$2,646	$5
3.4	Service Water Systems	$1,880	$3,589	$9,644	$0	$15,113	$3,023	$0	$3,627	$21,763	$38
3.5	Other Boiler Plant Systems	$280	$102	$223	$0	$605	$121	$0	$109	$835	$1
3.6	NG Pipeline and Start-Up System	$9,455	$407	$253	$0	$10,115	$2,023	$0	$1,821	$13,959	$24
3.7	Waste Water Treatment Equipment	$11,458	$0	$6,157	$0	$17,615	$3,523	$0	$4,228	$25,365	$44
3.9	Miscellaneous Plant Equipment	$13,782	$1,807	$6,141	$0	$21,730	$4,346	$0	$5,215	$31,291	$54
	Subtotal	**$46,365**	**$10,540**	**$27,206**	**$0**	**$84,110**	**$16,822**	**$0**	**$18,991**	**$119,924**	**$209**
5	Flue Gas Cleanup										
5.1	CANSOLV CO_2 Removal System	$118,613	$57,176	$106,503	$0	$282,291	$56,458	$50,812	$77,912	$467,475	$813
5.4	CO_2 Compression & Drying	$30,257	$4,539	$11,880	$0	$46,677	$9,335	$0	$11,202	$67,214	$117
5.5	CO_2 Compressor Aftercooler	$256	$41	$104	$0	$401	$80	$0	$96	$577	$1
5.12	Gas Cleanup Foundations	$0	$444	$454	$0	$899	$180	$0	$216	$1,294	$2
	Subtotal	**$149,126**	**$62,199**	**$118,942**	**$0**	**$330,268**	**$66,054**	**$50,812**	**$89,427**	**$536,560**	**$933**
6	Combustion Turbine & Accessories										
6.1	Combustion Turbine Generator	$93,216	$0	$5,950	$0	$99,166	$19,833	$0	$17,850	$136,849	$238
6.3	Combustion Turbine Accessories	$2,269	$0	$139	$0	$2,408	$482	$0	$433	$3,323	$6
6.4	Compressed Air Piping	$0	$862	$166	$0	$1,028	$206	$0	$185	$1,418	$2
6.5	Combustion Turbine Foundations	$0	$998	$1,089	$0	$2,087	$417	$0	$501	$3,005	$5
	Subtotal	**$95,484**	**$1,860**	**$7,344**	**$0**	**$104,688**	**$20,938**	**$0**	**$18,969**	**$144,595**	**$252**
7	HRSG, Ductwork, & Stack										
7.1	HRSG	$48,568	$0	$12,142	$0	$60,710	$12,142	$0	$10,928	$83,780	$146
7.2	HRSG Accessories	$13,562	$0	$2,533	$0	$16,095	$3,219	$0	$2,897	$22,211	$39
7.3	Ductwork	$0	$1,061	$580	$0	$1,641	$328	$0	$295	$2,265	$4
7.4	Stack	$3,669	$0	$685	$0	$4,354	$871	$0	$784	$6,009	$10
7.5	HRSG, Ductwork, & Stack Foundations	$0	$738	$584	$0	$1,322	$264	$0	$317	$1,903	$3
7.6	Selective Catalytic Reduction System	$1,637	$688	$841	$0	$3,166	$633	$0	$570	$4,369	$8
	Subtotal	**$67,436**	**$2,487**	**$17,366**	**$0**	**$87,289**	**$17,458**	**$0**	**$15,791**	**$120,538**	**$210**
8	Steam Turbine & Accessories										
8.1	Steam Turbine Generator & Accessories	$35,853	$0	$5,250	$0	$41,103	$8,221	$0	$7,398	$56,722	$99
8.2	Steam Turbine Plant Auxiliaries	$126	$0	$290	$0	$417	$83	$0	$75	$575	$1
8.3	Condenser & Auxiliaries	$5,856	$0	$2,810	$0	$8,666	$1,733	$0	$1,560	$11,960	$21
8.4	Steam Piping	$11,277	$0	$3,875	$0	$15,153	$3,031	$0	$2,728	$20,911	$36
8.5	Turbine Generator Foundations	$0	$1,294	$1,805	$0	$3,099	$620	$0	$744	$4,463	$8
	Subtotal	**$53,112**	**$1,294**	**$14,031**	**$0**	**$68,438**	**$13,688**	**$0**	**$12,505**	**$94,630**	**$165**
9	Cooling Water System										
9.1	Cooling Towers	$13,034	$0	$3,486	$0	$16,521	$3,304	$0	$2,974	$22,798	$40

Case:	B32B.1.95 – NGCC H-Class (1x1) with 95 Percent CO_2 Capture					Estimate Type:	Conceptual			
Plant Size (MW, net):	575					Cost Base:	Jan 2023			
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
9.2	Circulating Water Pumps	$1,661	$0	$88	$0	$1,750	$350	$0	$315	$2,414	$4
9.3	Circulating Water System Auxiliaries	$11,628	$0	$1,389	$0	$13,016	$2,603	$0	$2,343	$17,963	$31
9.4	Circulating Water Piping	$0	$3,658	$2,749	$0	$6,407	$1,281	$0	$1,153	$8,841	$15
9.5	Make-up Water System	$429	$0	$457	$0	$886	$177	$0	$159	$1,222	$2
9.6	Component Cooling Water System	$539	$0	$344	$0	$883	$177	$0	$159	$1,218	$2
9.7	Circulating Water System Foundations	$0	$846	$1,206	$0	$2,052	$410	$0	$492	$2,955	$5
	Subtotal	**$27,291**	**$4,504**	**$9,718**	**$0**	**$41,514**	**$8,303**	**$0**	**$7,596**	**$57,412**	**$100**
	11	**Accessory Electric Plant**									
11.1	Generator Equipment	$3,170	$0	$1,976	$0	$5,146	$1,029	$0	$926	$7,102	$12
11.2	Station Service Equipment	$8,262	$0	$586	$0	$8,848	$1,770	$0	$1,593	$12,210	$21
11.3	Switchgear & Motor Control	$13,571	$0	$1,691	$0	$15,262	$3,052	$0	$2,747	$21,062	$37
11.4	Conduit & Cable Tray	$0	$2,851	$6,789	$0	$9,640	$1,928	$0	$1,735	$13,303	$23
11.5	Wire & Cable	$0	$4,256	$6,286	$0	$10,542	$2,108	$0	$1,898	$14,548	$25
11.6	Protective Equipment	$576	$0	$1,438	$0	$2,014	$403	$0	$363	$2,779	$5
11.7	Standby Equipment	$940	$0	$624	$0	$1,564	$313	$0	$282	$2,158	$4
11.8	Main Power Transformers	$6,391	$0	$132	$0	$6,523	$1,305	$0	$1,174	$9,002	$16
11.9	Electrical Foundations	$0	$108	$246	$0	$355	$71	$0	$85	$511	$1
	Subtotal	**$32,912**	**$7,215**	**$19,768**	**$0**	**$59,895**	**$11,979**	**$0**	**$10,802**	**$82,676**	**$144**
	12	**Instrumentation & Control**									
12.1	NGCC Control Equipment	$265	$0	$167	$0	$432	$86	$0	$78	$596	$1
12.2	Combustion Turbine Control Equipment	$436	$0	$275	$0	$711	$142	$0	$128	$981	$2
12.3	Steam Turbine Control Equipment	$425	$0	$268	$0	$692	$138	$0	$125	$955	$2
12.4	Other Major Component Control Equipment	$712	$0	$449	$0	$1,161	$232	$58	$218	$1,669	$3
12.5	Signal Processing Equipment	$594	$0	$18	$0	$612	$122	$0	$110	$844	$1
12.6	Control Boards, Panels, & Racks	$157	$0	$95	$0	$252	$50	$13	$47	$363	$1
12.7	Distributed Control System Equipment	$8,728	$0	$263	$0	$8,991	$1,798	$450	$1,686	$12,925	$22
12.8	Instrument Wiring & Tubing	$863	$691	$2,283	$0	$3,837	$767	$192	$719	$5,515	$10
12.9	Other I&C Equipment	$598	$0	$1,144	$0	$1,742	$348	$87	$327	$2,504	$4
	Subtotal	**$12,778**	**$691**	**$4,961**	**$0**	**$18,430**	**$3,686**	**$799**	**$3,437**	**$26,353**	**$46**
	13	**Improvements to Site**									
13.1	Site Preparation	$0	$864	$15,488	$0	$16,352	$3,270	$0	$3,925	$23,547	$41
13.2	Site Improvements	$0	$2,779	$3,099	$0	$5,879	$1,176	$0	$1,411	$8,465	$15
13.3	Site Facilities	$2,666	$0	$2,362	$0	$5,029	$1,006	$0	$1,207	$7,241	$13
	Subtotal	**$2,666**	**$3,643**	**$20,950**	**$0**	**$27,259**	**$5,452**	**$0**	**$6,542**	**$39,254**	**$68**
	14	**Buildings & Structures**									
14.1	Combustion Turbine Area	$0	$530	$206	$0	$736	$147	$0	$133	$1,016	$2
14.3	Steam Turbine Building	$0	$4,364	$4,268	$0	$8,632	$1,726	$0	$1,554	$11,912	$21
14.4	Administration Building	$0	$553	$275	$0	$828	$166	$0	$149	$1,142	$2
14.5	Circulation Water Pumphouse	$0	$108	$39	$0	$148	$30	$0	$27	$204	$0
14.6	Water Treatment Buildings	$0	$576	$386	$0	$962	$192	$0	$173	$1,328	$2
14.7	Machine Shop	$0	$827	$388	$0	$1,216	$243	$0	$219	$1,678	$3

Case:		B32B.1.95 – NGCC H-Class (1x1) with 95 Percent CO_2 Capture					Estimate Type:			Conceptual	
Plant Size (MW, net):		575					Cost Base:			Jan 2023	
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
14.8	Warehouse	$0	$643	$285	$0	$928	$186	$0	$167	$1,281	$2
14.9	Other Buildings & Structures	$0	$470	$251	$0	$721	$144	$0	$130	$995	$2
14.10	Waste Treating Building & Structures	$0	$994	$1,303	$0	$2,297	$459	$0	$413	$3,169	$6
	Subtotal	**$0**	**$9,066**	**$7,402**	**$0**	**$16,468**	**$3,294**	**$0**	**$2,964**	**$22,726**	**$40**
	Total	**$487,171**	**$103,500**	**$247,688**	**$0**	**$838,359**	**$167,672**	**$51,612**	**$187,025**	**$1,244,667**	**$2,165**

Exhibit 4-90. Case B32B.1.95 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$7,622	$13
1 Month Maintenance Materials	$1,391	$2
1 Month Non-fuel Consumables	$680	$1
1 Month Waste Disposal	$92	$0
25% of 1 Months Fuel Cost at 100% CF	$4,014	$7
2% of TPC	$24,893	$43
Total	**$38,693**	**$67**
Inventory Capital		
60-day supply of consumables at 100% CF	$931	$2
0.5% of TPC (spare parts)	$6,223	$11
Total	**$7,154**	**$12**
Other Costs		
Initial Cost for Catalyst and Chemicals	$1,488	$3
Land	$600	$1
Other Owner's Costs	$186,700	$325
Financing Costs	$33,606	$58
Total Overnight Costs (TOC)	**$1,512,908**	**$2,632**
TASC Multiplier (IOU, 33 year)	1.183	
Total As-Spent Cost (TASC)	**$1,789,691**	**$3,113**

Exhibit 4-91. Case B32B.1.95 initial and annual operating and maintenance costs

Case:	B32B.1.95 – NGCC H-Class (1x1) with 95 Percent CO_2 Capture				Cost Base:	Jan 2023
Plant Size (MW, net):	575	Heat Rate-net (Btu/kWh):		6,848	Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor					**Operating Labor Requirements per Shift**	
Operating Labor Rate (base):		45.04	**$/hour**	Skilled Operator:	1.0	
Operating Labor Burden:		30.00	**% of base**	Operator:	2.3	
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:	1.0	
				Lab Techs, etc.:	1.0	
				Total:	**5.3**	
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$2,735,351	$4.758
Maintenance Labor:					$9,459,471	$16.455
Administrative & Support Labor:					$3,048,706	$5.303
Property Taxes and Insurance:					$24,893,345	$43.302
Total:					**$40,136,873**	**$69.818**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$14,189,207	$3.315
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	2,716	$2.30	$0	$1,937,928	$0.453
Makeup and Waste Water Treatment Chemicals (ton):	0	8.1	$660.00	$0	$1,656,547	$0.387
Ammonia (19 wt%, ton):	0	7.9	$280.00	$0	$689,282	$0.161
SCR Catalyst (ft^3):	4,252	2.3	$350.00	$1,488,225	$252,998	$0.059
CO_2 Capture System Chemicals[A]:	Proprietary				$2,295,809	$0.536
Triethylene Glycol (gal):	w/equip.	39.9	$8.50	$0	$105,143	$0.025
Subtotal:				**$1,488,225**	**$6,937,707**	**$1.621**
Waste Disposal						
SCR Catalyst (ft^3):	0	2.3	$5.70	$0	$4,120	$0.001
Triethylene Glycol (gal):	0	2,022	$1.30	$0	$815,423	$0.190
Thermal Reclaimer Unit Waste (ton):	0	1.6	$250.00	$0	$120,796	$0.028
Subtotal:				**$0**	**$940,339**	**$0.220**
Variable Operating Costs Total:				**$1,488,225**	**$22,067,252**	**$5.155**
Fuel Cost						
Natural Gas (MMBtu):	0	94,481	$5.59	$0	$163,777,048	$38.261
Total:				**$0**	**$163,777,048**	**$38.261**

[A]CO_2 Capture System Chemicals includes sodium hydroxide and CANSOLV solvent

Exhibit 4-92. Case B32B.1.95 COE breakdown

	FY COE		LCOE	
Component	Value, $/MWh	Percentage	Value, $/MWh	Percentage
Capital	32.2	36%	32.2	40%
Fixed	9.4	10%	12.5	15%
Variable	5.2	6%	6.9	8%
Fuel	38.3	43%	23.5	29%
Total (Excluding T&S)	**85.0**	**N/A**	**75.1**	**N/A**
CO_2 T&S	4.8	5%	6.4	8%
Total (Including T&S)	**89.8**	**N/A**	**81.5**	**N/A**

4.4 2x1 H-Class NGCC Cases

This section contains an evaluation of plant designs for H-Class NGCC cases based on a 2x1 plant (cases B32A.2, B32B.2.90, and B32B.2.95), consisting of two state-of-the-art 2023 H-Class combustion turbines with an ISO base rating of 384 MW and one single reheat subcritical steam cycle 17.2 MPaG/585°C/585°C (2,494 psig/1,085°F/1,085°F). Cases B32A.2, B32B.2.90, and B32B.2.95 are similar, differing only in the degree of CO_2 capture, with B32A.2 including no CO_2 capture, B32B.2.90 including 90 percent CO_2 capture, and B32B.2.95 including 95 percent CO_2 capture.

The balance of this section is organized as follows:

- Key System Assumptions is a summary of study and modeling assumptions relevant to H-Class NGCC cases.
- Sparing Philosophy is provided for 2x1 H-Class NGCC cases.
- Process Description provides an overview of the technology operation as applied to Case B32A.2. The systems that are common to all NGCC cases were covered in Section 4.1 and only features that are unique to 2x1 H-Class cases are discussed further in this section.
- Performance Results provides the main modeling results from Case B32A.2, including the performance summary, environmental performance, carbon balance, water balance, energy and mass balance diagrams, and energy balance table.
- Major Equipment List provides an itemized list of major equipment for Case B32A.2 with account codes that correspond to the cost accounts in the Cost Estimating section.
- Cost Estimating provides a summary of capital and operating costs for Case B32A.2.
- Process Description, Performance Results, Major Equipment List, and Cost Estimating are discussed for cases B32B.2.90 and B32B.2.95.

4.4.1 Key System Assumptions

System assumptions for cases B32A.2, B32B.2.90, and B32B.2.95, NGCC with and without CO_2 capture, are compiled in Exhibit 4-93.

Exhibit 4-93. NGCC 2x1 H-Class plant study configuration matrix

	Case B32A.2 w/o CO_2 Capture	Case B32B.2.90 w/ CO_2 Capture	Case B32B.2.95 w/ CO_2 Capture
Steam Cycle, MPaG/°C/°C (psig/°F/°F)	17.2/585/585 (2,494/1,085/1,085)		
Fuel	Natural Gas		
Fuel Pressure at Plant Battery Limit, MPa (psia)	3.8 (550)		
Condenser Pressure, mm Hg (in. Hg)	50.8 (2.0)		
Cooling Water to Condenser, °C (°F)	16 (60)		
Cooling Water from Condenser, °C (°F)	27 (80)		
Stack Temperature, °C (°F)	76 (169)	38 (100)	38 (100)
SO_2 Control	Low Sulfur Fuel		
NOx Control	LNB and SCR		
SCR Efficiency, %[A]	94.5	95.0	95.0
Ammonia Slip (End of Catalyst Life), ppmv	5		
Particulate Control	N/A		
Mercury Control	N/A		
CO Control	N/A		
CO_2 Control	N/A	CANSOLV	
Overall Carbon Capture, %[A]	N/A	90	95
CO_2 Sequestration	N/A	Off-site Saline Formation	

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

4.4.1.1 Balance of Plant

The balance of plant assumptions are common to all H-Class NGCC cases and are presented in Exhibit 4-94. The assumptions in Exhibit 4-94 are identical to those presented for the F-Class cases, with the exception that the H-Class cases assume a higher natural gas pipeline supply pressure (3.8 MPa [550 psia] versus 3.0 MPa [430 psia]).

Exhibit 4-94. NGCC balance of plant assumptions

Parameter	Value
Cooling System	Recirculating Wet Cooling Tower
Fuel and Other Storage	
Natural Gas	Pipeline supply at 3.8 MPa (550 psia) and 27°C (80°F)
Plant Distribution Voltage	
Motors below 1 hp	110/220 V

Parameter	Value
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	18,000 V
Grid Interconnection voltage	345 kV
Water and Wastewater	
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	Blowdown is treated for chloride and metals and discharged.

4.4.2 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 2023 H-Class CTG (2 x 50 percent)
- Two 3-pressure reheat HRSGs with self-supporting stacks and SCR systems (2 x 50 percent)
- One 3-pressure reheat, triple-admission STG (1 x 100 percent)
- For cases B32B.2.90 and B32B.2.95, two CO_2 absorption systems, consisting of an absorber, stripper, and ancillary equipment (2 x 50 percent) and two CO_2 compression systems (2 x 50 percent)

4.4.3 Case B32A.2 – NGCC Without CO_2 Capture Process Description

In this section, the H-Class NGCC process without CO_2 capture is described. The description follows the BFD in Exhibit 4-95 and stream numbers reference the same exhibit. Exhibit 4-96 provides process data for the numbered streams in the BFD.

Ambient air (stream 1) is supplied to an inlet filter (not depicted) and compressed before being combined with natural gas (stream 2) in the dry LNB, which is operated to control the rotor inlet

(not depicted) temperature at 1,544°C (2,812°F). The flue gas exits the turbine at 653°C (1,208°F) (stream 3) and passes into the HRSG. The HRSG generates both the main steam (stream 5) and reheat steam (stream 7) for the steam turbine. Flue gas (stream 4) exits the HRSG at 76°C (169°F) and passes to the plant stack.

Exhibit 4-95. Case B32A.2 BFD, NGCC without CO_2 capture

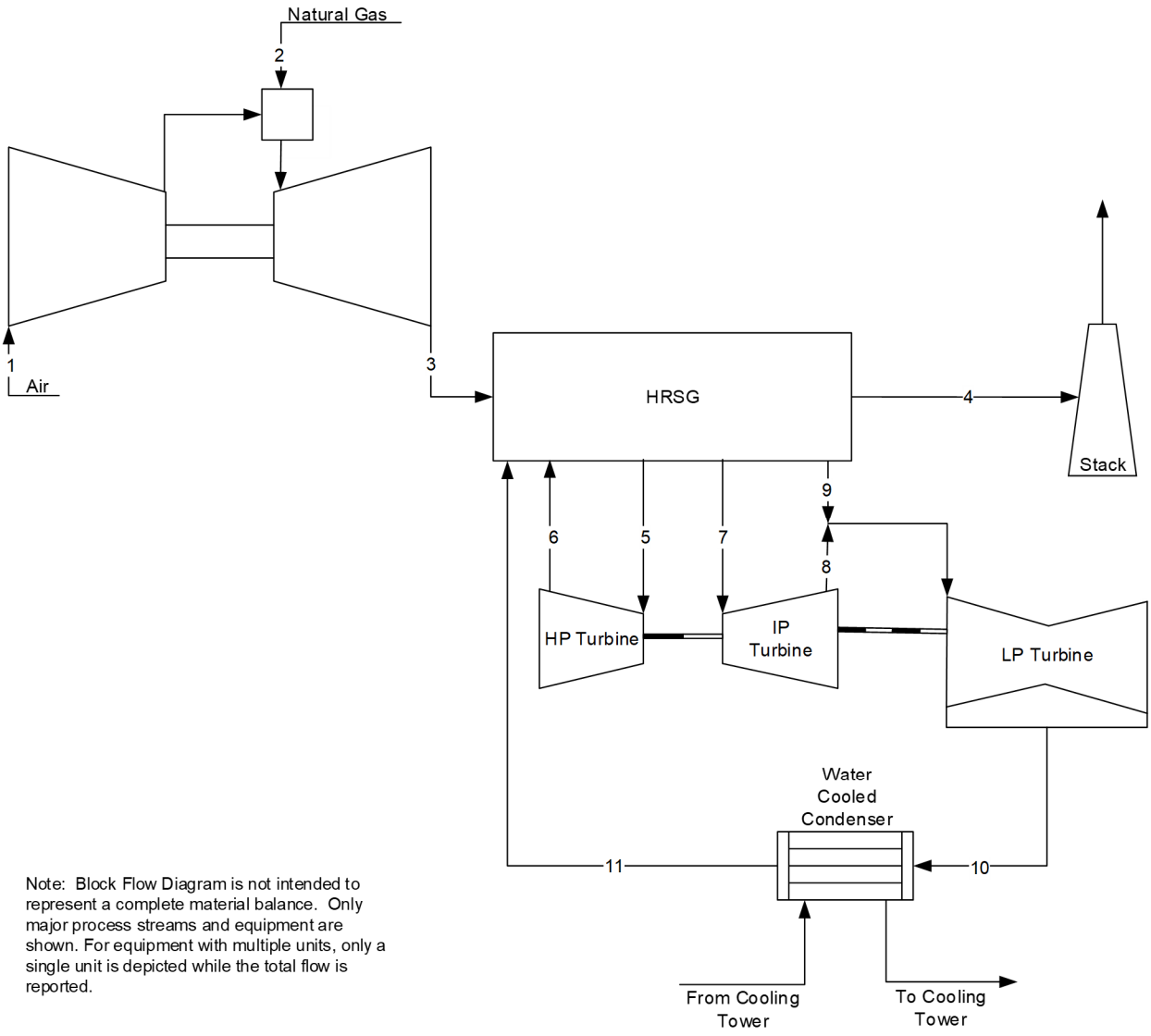


Exhibit 4-96. Case B32A.2 stream table, NGCC without CO_2 capture

	1	2	3	4	5	6	7	8	9	10	11
V-L Mole Fraction											
Ar	0.0092	0.0000	0.0088	0.0088	0.0000	0.0000	0.0000	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	0.0000	0.0000
CH_4S	0.0000	0.0000	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	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	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	0.0000	0.0000
CO_2	0.0003	0.0100	0.0447	0.0447	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0000	0.0949	0.0949	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.7732	0.0160	0.7399	0.7399	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2074	0.0000	0.1116	0.1116	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	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
V-L Flowrate (kg_{mol}/hr)	178,633	7,957	186,821	186,821	41,174	40,770	44,315	44,684	5,688	50,372	50,407
V-L Flowrate (kg/hr)	5,154,805	137,875	5,292,680	5,292,680	741,762	734,477	798,349	804,997	102,467	907,463	908,101
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	27	653	76	585	360	585	300	303	38	38
Pressure (MPa, abs)	0.10	3.79	0.11	0.10	17.30	4.12	3.84	0.52	0.51	0.01	0.01
Steam Table Enthalpy (kJ/kg)[A]	30.23	12.48	882.51	230.66	3,520.56	3,113.70	3,641.20	3,064.29	3,070.57	2,376.82	160.78
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-4,496.75	-725.35	-1,377.19	-12,459.74	-12,866.59	-12,339.10	-12,916.01	-12,909.72	-13,603.47	-15,819.51
Density (kg/m^3)	1.2	28.8	0.4	1.0	48.1	15.2	9.9	2.0	1.9	0.1	992.8
V-L Molecular Weight	28.857	17.328	28.330	28.330	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	393,818	17,542	411,869	411,869	90,773	89,882	97,698	98,512	12,539	111,051	111,129
V-L Flowrate (lb/hr)	11,364,400	303,962	11,668,362	11,668,362	1,635,306	1,619,244	1,760,057	1,774,714	225,900	2,000,614	2,002,020
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	80	1,208	169	1,085	680	1,085	573	578	101	101
Pressure (psia)	14.7	550.0	15.3	14.8	2,508.5	598.0	557.1	75.0	73.5	1.0	1.0
Steam Table Enthalpy (Btu/lb)[A]	13.0	5.4	379.4	99.2	1,513.6	1,338.7	1,565.4	1,317.4	1,320.1	1,021.8	69.1
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-1,933.3	-311.8	-592.1	-5,356.7	-5,531.6	-5,304.9	-5,552.9	-5,550.2	-5,848.4	-6,801.2
Density (lb/ft^3)	0.076	1.799	0.024	0.062	3.001	0.951	0.617	0.123	0.120	0.003	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

4.4.4 Case B32A.2 – Performance Results

The plant produces a net output of 1,118 MW at a net plant efficiency of 55.8 percent (HHV basis). Overall plant performance is summarized in Exhibit 4-97; Exhibit 4-98 provides a detailed breakdown of the auxiliary power requirements.

Exhibit 4-97. Case B32A.2 plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	759
Steam Turbine Power, MWe	378
Total Gross Power, MWe	**1,137**
CO_2 Capture/Removal Auxiliaries, kWe	–
CO_2 Compression, kWe	–
Balance of Plant, kWe	18,979
Total Auxiliaries, MWe	**19**
Net Power, MWe	**1,118**
HHV Net Plant Efficiency, %	55.8
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,450 (6,113)
HHV Combustion Turbine Efficiency, %	37.9
LHV Net Plant Efficiency, %	61.8
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	5,821 (5,518)
LHV Combustion Turbine Efficiency, %	42.0
Steam Turbine Cycle Efficiency, %	39.4
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	9,137 (8,660)
CO_2 Capture Rate, %	–
Condenser Duty, GJ/hr (MMBtu/hr)	2,011 (1,906)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	–
Natural Gas Feed Flow, kg/hr (lb/hr)	137,875 (303,962)
HHV Thermal Input, kWt	2,002,815
LHV Thermal Input, kWt	1,807,738
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.014 (3.7)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.010 (2.8)

Exhibit 4-98. Case B32A.2 plant power summary

Power Summary	
Combustion Turbine Power, MWe	759
Steam Turbine Power, MWe	378
Total Gross Power, MWe	**1,137**
Auxiliary Load Summary	
Circulating Water Pumps, kWe	4,000
Combustion Turbine Auxiliaries, kWe	1,270
Condensate Pumps, kWe	930
Cooling Tower Fans, kWe	2,070
CO_2 Capture/Removal Auxiliaries, kWe	–
CO_2 Compression, kWe	–
Feedwater Pumps, kWe	5,750
Ground Water Pumps, kWe	370
Miscellaneous Balance of Plant[A], kWe	880
SCR, kWe	9
Steam Turbine Auxiliaries, kWe	250
Transformer Losses, kWe	3,450
Total Auxiliaries, MWe	**19**
Net Power, MWe	**1,118**

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

4.4.4.1 Environmental Performance

The environmental targets for emissions of NOx, SO_2, and PM are presented in Section 2.4. A summary of the plant air emissions for Case B32A.2 is presented in Exhibit 4-99.

Exhibit 4-99. Case B32A.2 air emissions

	kg/GJ (lb/MMBtu)[A]	tonne/year (ton/year)[B]	kg/MWh (lb/MWh)[C]
SO_2	0.000 (0.001)	22 (24)	0.003 (0.006)
NOx	0.001 (0.003)	75 (83)	0.009 (0.020)
Particulate	0.001 (0.003)	60 (66)	0.007 (0.016)
Hg	0.00E+0 (0.00E+0)	0.000 (0.000)	0.00E+0 (0.00E+0)
CO	0.009 (0.020)	458 (505)	0.054 (0.119)
CO_2	51 (119)	2,736,090 (3,016,023)	323 (713)
CO_2[D]	-	-	329 (725)

[A]Based on thermal input on an HHV basis
[B]Calculations based on an 85 percent capacity factor
[C]Emissions based on gross power except where otherwise noted
[D]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 domestic average value of total sulfur of 0.34 gr/100 scf ($4.71x10^{-4}$ lb-S/MMBtu) (Gas Research Institute, 1992). It was also assumed that the added 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 1.8 ppmv NOx emissions using a DLN burner in the CTG and an SCR. The DLN burners reduce the emissions to about 25 ppmvd (at 15 percent O_2) (GE Vernova, 2024b) and the SCR system is designed for an additional 94.5 percent NOx reduction (Davis & Black, October 2000).

The pipeline natural gas was assumed to contain no Hg or HCl, resulting in zero emissions.

The state-of-the-art 2023 H-Class gas turbine achieves approximately 9.0 ppmvd (at 15 percent O_2) CO and 1.5 ppmw PM emissions. The production of PM is a result of system inefficiencies and is not produced or emitted in any significant amount.

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

The carbon balance for the plant is shown in Exhibit 4-100. The carbon input to the plant consists of carbon in the natural gas and carbon in the air. Carbon leaves the plant as CO_2 through the stack.

Exhibit 4-100. Case B32A.2 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	99,584 (219,546)	Stack Gas	100,285 (221,091)
Air (CO_2)	701 (1,545)	CO_2 Product	–
		CO_2 Knockout	–
Total	**100,285 (221,091)**	**Total**	**100,285 (221,091)**

As shown in Exhibit 4-101, the sulfur content of the natural gas is insignificant, entirely comprising CH_4S (used as an odorant) (Gas Research Institute, 1992). All sulfur in the natural gas is emitted in the stack gas.

Exhibit 4-101. Case B32A.2 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	1.5 (3.2)	Stack Gas	1.5 (3.2)
		Solvent Reclaiming	–
Total	**1.5 (3.2)**	**Total**	**1.5 (3.2)**

Water demand, recycle, withdrawal, discharge, and consumption are defined and discussed in Section 2.6. Exhibit 4-102 shows the water balance for the plant.

Exhibit 4-102. Case B32A.2 water balance

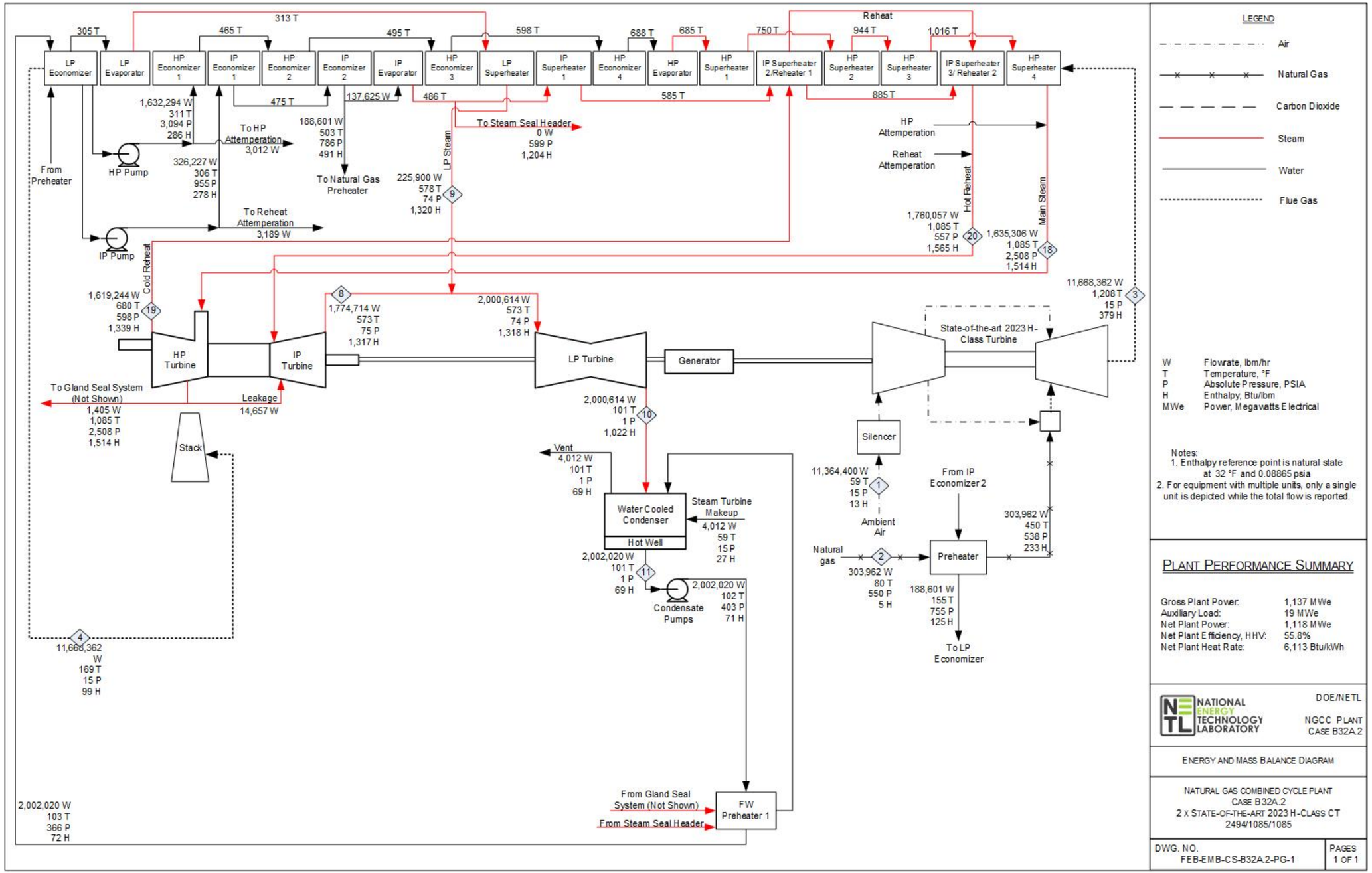
Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m³/min (gpm)	m³/min (gpm)	m³/min (gpm)	m³/min (gpm)	m³/min (gpm)
CO_2 Capture System Makeup	–	–	–	–	–
CO_2 Capture Recovery	–	–	–	–	–
CO_2 Compression Recovery	–	–	–	–	–
Deaerator Vent	–	–	–	0.0 (8.0)	0.0 (-8.0)
Condenser Makeup	**0.0 (8.0)**	**–**	**0.0 (8.0)**	**–**	**0.0 (8.0)**
BFW Makeup	0.0 (8.0)	–	0.0 (8.0)	–	0.0 (8.0)
Cooling Tower	**16 (4,107)**	**–**	**16 (4,107)**	**3.9 (1,026)**	**12 (3,081)**
Total	**16 (4,115)**	**–**	**16 (4,115)**	**3.9 (1,034)**	**12 (3,081)**

4.4.4.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for Case B32A.2 in Exhibit 4-103.

An overall plant energy balance is provided in tabular form in Exhibit 4-104. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-97) is calculated by multiplying the power out by the generator efficiency: 99.6 percent for the CT and 98.0 percent for the steam turbine.

Exhibit 4-103. Case B32A.2 energy and mass balance, NGCC without CO_2 capture



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Exhibit 4-104. Case B32A.2 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, GJ/hr (MMBtu/hr)				
Natural Gas	7,210 (6,834)	8.6 (8.1)	–	7,219 (6,842)
Air	–	156 (148)	–	156 (148)
Raw Water Makeup	–	59 (56)	–	59 (56)
Auxiliary Power	–	–	68 (65)	68 (65)
TOTAL	**7,210 (6,834)**	**223 (212)**	**68 (65)**	**7,502 (7,110)**
Heat Out, GJ/hr (MMBtu/hr)				
Stack Gas	–	1,221 (1,157)	–	1,221 (1,157)
Sulfur	–	–	–	–
Motor Losses and Design Allowances	–	–	56 (53)	56 (53)
Cooling Tower Load[A]	–	2,037 (1,931)	–	2,037 (1,931)
CO_2 Product Stream	–	–	–	–
AGR Effluent	–	–	–	–
Dryer Effluent	–	–	–	–
Deaerator Vent	–	0.3 (0.3)	–	0.3 (0.3)
Ambient Losses[B]	–	*58 (55)*	–	58 (55)
Power	–	–	4,093 (3,879)	4,093 (3,879)
TOTAL	**–**	**3,317 (3,144)**	**4,149 (3,933)**	**7,466 (7,076)**
Unaccounted Energy[C]	**–**	*36 (34)*	–	*36 (34)*

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

4.4.5 Case B32A.2 – Major Equipment List

Major equipment items for the 2x1 H-Class NGCC plant without 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 4.3.6. 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. Values reported in the equipment lists are rounded.

Case B32A.2 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	120,000 liters (32,000 gal)	2	0
2	Condensate Pumps	Vertical canned	16,760 lpm @ 340 m H_2O (4,430 gpm @ 1,120 ft H_2O)	1	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP Water: 6,850 lpm @ 2,330 m H_2O (1,810 gpm @ 7,650 ft H_2O) IP Water: 1,380 lpm @ 510 m H_2O (360 gpm @ 1,680 ft H_2O)	2	2
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 GJ/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	3,800 lpm @ 110 m H_2O (1,000 gpm @ 350 ft H_2O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,600 lpm @ 80 m H_2O (700 gpm @ 250 ft H_2O)	1	1
11	Municipal Water Pumps	Stainless steel, single suction	4,400 lpm @ 20 m H_2O (1,150 gpm @ 60 ft H_2O)	2	1
12	Ground Water Pumps	Stainless steel, single suction	4,400 lpm @ 20 m H_2O (1,150 gpm @ 60 ft H_2O)	2	1
13	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H_2O (40 gpm @ 160 ft H_2O)	2	1
14	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
15	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0
16	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
17	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	88 m^3/min @ 3.8 MPa (3,098 acfm @ 550 psia) 39 cm (16 in) standard wall pipe	16 km (10 mile)	0
18	Gas Metering Station	–	88 m^3/min (3,098 acfm)	1	0

Case B32A.2 – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	2023 Advanced H-Class w/ dry low-NOx burner	380 MW	2	0
2	Combustion Turbine Generator	Hydrogen Cooled	450 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	2	0

Case B32A.2 – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Epoxy-coated CS plate	46 m (150 ft) high x 6.5 m (21 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section	Main Steam: 404,000 kg/hr, 17.2 MPa/585°C (891,000 lb/hr, 2,494 psig/1,085°F) Reheat Steam: 439,000 kg/hr, 3.7 MPa/585°C (968,000 lb/hr, 542 psig/1,085°F)	2	0
3	SCR Reactor	–	2,910,000 kg/hr (6,420,000 lb/hr)	2	0
4	SCR Catalyst	–	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	20 m^3/min @ 108 cm WG (870 scfm @ 42 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	5.2 lpm @ 90 m H_2O (1.4 gpm @ 300 ft H_2O)	2	1
7	Ammonia Storage Tank	Horizontal tank	150,000 liter (39,000 gal)	1	0

Case B32A.2 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	397 MW 17.2 MPa/585°C/585°C (2,494 psig/1,085°F/1,085°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	470 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Two pass, divided waterbox including vacuum pumps and integrated deaerator	2,210 GJ/hr (2,100 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 B32A.2 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	401,000 lpm @ 30 m (106,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 2,240 GJ/hr (2,120 MMBtu/hr) heat duty	1	0

Case B32A.2 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	18 kV/345 kV, 450 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	18 kV/345 kV, 450 MVA, 3-ph, 60 Hz	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
3	Medium Voltage Transformer	Oil-filled	18 kV/4.16 kV, 15 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 3 MVA, 3-ph, 60 Hz	1	1
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	2	0
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	1	0
7	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
8	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
9	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B32A.2 – 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

4.4.6 Case B32A.2 – Cost Estimating

The cost estimating methodology is described in Section 2.7. Exhibit 4-105 shows a detailed breakdown of the capital costs; Exhibit 4-106 shows the owner's costs, TOC, and TASC; Exhibit 4-107 shows the initial and annual O&M costs; and Exhibit 4-108 shows the COE breakdown.

The estimated TPC of the NGCC without CO_2 capture is $876/kW. No process contingency was included in this case because all elements of the technology are commercially proved. The project contingency is 13.6 percent of TPC. The FY COE is $53.1/MWh and the LCOE is $41.9/MWh.

Exhibit 4-105. Case B32A.2 total plant cost details

Case:		B32A.2 – NGCC H-Class (2x1) without CO_2 Capture					Estimate Type:			Conceptual	
Plant Size (MW, net):		1,118					Cost Base:			Jan 2023	
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	$3,121	$5,350	$2,295	$0	$10,765	$2,153	$0	$1,938	$14,856	$13
3.2	Water Makeup & Pretreating	$6,590	$659	$3,099	$0	$10,348	$2,070	$0	$2,484	$14,901	$13
3.3	Other Feedwater Subsystems	$1,776	$582	$475	$0	$2,833	$567	$0	$510	$3,909	$3
3.4	Service Water Systems	$2,000	$3,818	$10,259	$0	$16,077	$3,215	$0	$3,858	$23,151	$21
3.5	Other Boiler Plant Systems	$414	$151	$330	$0	$894	$179	$0	$161	$1,234	$1
3.6	NG Pipeline and Start-Up System	$13,910	$598	$372	$0	$14,881	$2,976	$0	$2,679	$20,536	$18
3.7	Waste Water Treatment Equipment	$9,243	$0	$4,967	$0	$14,210	$2,842	$0	$3,410	$20,463	$18
3.9	Miscellaneous Plant Equipment	$20,959	$2,749	$9,338	$0	$33,045	$6,609	$0	$7,931	$47,585	$43
	Subtotal	**$58,012**	**$13,906**	**$31,135**	**$0**	**$103,053**	**$20,611**	**$0**	**$22,970**	**$146,635**	**$131**
6	Combustion Turbine & Accessories										
6.1	Combustion Turbine Generator	$143,815	$0	$9,180	$0	$152,995	$30,599	$0	$27,539	$211,133	$189
6.3	Combustion Turbine Accessories	$3,337	$0	$205	$0	$3,542	$708	$0	$638	$4,889	$4
6.4	Compressed Air Piping	$0	$1,269	$244	$0	$1,512	$302	$0	$272	$2,087	$2
6.5	Combustion Turbine Foundations	$0	$1,459	$1,591	$0	$3,050	$610	$0	$732	$4,392	$4
	Subtotal	**$147,152**	**$2,727**	**$11,220**	**$0**	**$161,100**	**$32,220**	**$0**	**$29,181**	**$222,500**	**$199**
7	HRSG, Ductwork, & Stack										
7.1	HRSG	$85,770	$0	$21,442	$0	$107,212	$21,442	$0	$19,298	$147,953	$132
7.2	HRSG Accessories	$20,570	$0	$3,842	$0	$24,413	$4,883	$0	$4,394	$33,689	$30
7.3	Ductwork	$0	$1,851	$1,012	$0	$2,864	$573	$0	$515	$3,952	$4
7.4	Stack	$6,401	$0	$1,196	$0	$7,597	$1,519	$0	$1,367	$10,484	$9
7.5	HRSG, Ductwork, & Stack Foundations	$0	$1,287	$1,019	$0	$2,306	$461	$0	$554	$3,321	$3
7.6	Selective Catalytic Reduction System	$2,472	$1,039	$1,270	$0	$4,781	$956	$0	$861	$6,598	$6
	Subtotal	**$115,214**	**$4,177**	**$29,782**	**$0**	**$149,173**	**$29,835**	**$0**	**$26,990**	**$205,997**	**$184**
8	Steam Turbine & Accessories										
8.1	Steam Turbine Generator & Accessories	$68,367	$0	$10,012	$0	$78,379	$15,676	$0	$14,108	$108,163	$97
8.2	Steam Turbine Plant Auxiliaries	$221	$0	$509	$0	$730	$146	$0	$131	$1,008	$1
8.3	Condenser & Auxiliaries	$14,646	$0	$7,027	$0	$21,673	$4,335	$0	$3,901	$29,908	$27
8.4	Steam Piping	$17,683	$0	$6,077	$0	$23,760	$4,752	$0	$4,277	$32,788	$29
8.5	Turbine Generator Foundations	$0	$2,269	$3,165	$0	$5,434	$1,087	$0	$1,304	$7,824	$7
	Subtotal	**$100,917**	**$2,269**	**$26,789**	**$0**	**$129,975**	**$25,995**	**$0**	**$23,722**	**$179,692**	**$161**
9	Cooling Water System										
9.1	Cooling Towers	$14,077	$0	$3,765	$0	$17,843	$3,569	$0	$3,212	$24,623	$22
9.2	Circulating Water Pumps	$1,796	$0	$96	$0	$1,892	$378	$0	$340	$2,610	$2
9.3	Circulating Water System Auxiliaries	$13,104	$0	$1,565	$0	$14,669	$2,934	$0	$2,640	$20,244	$18
9.4	Circulating Water Piping	$0	$3,904	$2,934	$0	$6,837	$1,367	$0	$1,231	$9,436	$8
9.5	Make-up Water System	$501	$0	$534	$0	$1,036	$207	$0	$186	$1,430	$1
9.6	Component Cooling Water System	$575	$0	$367	$0	$942	$188	$0	$170	$1,300	$1
9.7	Circulating Water System Foundations	$0	$903	$1,287	$0	$2,190	$438	$0	$526	$3,153	$3

Case:	B32A.2 – NGCC H-Class (2x1) without CO_2 Capture					Estimate Type:	Conceptual			
Plant Size (MW, net):	1,118					Cost Base:	Jan 2023			
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
	Subtotal	**$30,055**	**$4,807**	**$10,547**	**$0**	**$45,409**	**$9,082**	**$0**	**$8,305**	**$62,796**	**$56**
11	**Accessory Electric Plant**										
11.1	Generator Equipment	$4,549	$0	$2,836	$0	$7,384	$1,477	$0	$1,329	$10,190	$9
11.2	Station Service Equipment	$4,998	$0	$354	$0	$5,353	$1,071	$0	$963	$7,386	$7
11.3	Switchgear & Motor Control	$8,210	$0	$1,023	$0	$9,233	$1,847	$0	$1,662	$12,741	$11
11.4	Conduit & Cable Tray	$0	$1,725	$4,107	$0	$5,831	$1,166	$0	$1,050	$8,047	$7
11.5	Wire & Cable	$0	$2,575	$3,803	$0	$6,377	$1,275	$0	$1,148	$8,801	$8
11.6	Protective Equipment	$349	$0	$870	$0	$1,218	$244	$0	$219	$1,681	$2
11.7	Standby Equipment	$1,262	$0	$837	$0	$2,098	$420	$0	$378	$2,895	$3
11.8	Main Power Transformers	$9,847	$0	$203	$0	$10,050	$2,010	$0	$1,809	$13,869	$12
11.9	Electrical Foundations	$0	$166	$378	$0	$545	$109	$0	$131	$784	$1
	Subtotal	**$29,214**	**$4,466**	**$14,410**	**$0**	**$48,090**	**$9,618**	**$0**	**$8,689**	**$66,397**	**$59**
12	**Instrumentation & Control**										
12.1	NGCC Control Equipment	$310	$0	$195	$0	$505	$101	$0	$91	$696	$1
12.2	Combustion Turbine Control Equipment	$509	$0	$321	$0	$831	$166	$0	$150	$1,146	$1
12.3	Steam Turbine Control Equipment	$496	$0	$313	$0	$809	$162	$0	$146	$1,116	$1
12.4	Other Major Component Control Equipment	$832	$0	$524	$0	$1,357	$271	$0	$244	$1,872	$2
12.5	Signal Processing Equipment	$694	$0	$21	$0	$715	$143	$0	$129	$986	$1
12.6	Control Boards, Panels, & Racks	$184	$0	$111	$0	$295	$59	$0	$53	$407	$0
12.7	Distributed Control System Equipment	$10,196	$0	$307	$0	$10,503	$2,101	$0	$1,891	$14,494	$13
12.8	Instrument Wiring & Tubing	$1,008	$807	$2,667	$0	$4,482	$896	$0	$807	$6,185	$6
12.9	Other I&C Equipment	$698	$0	$1,337	$0	$2,035	$407	$0	$366	$2,808	$3
	Subtotal	**$14,927**	**$807**	**$5,796**	**$0**	**$21,530**	**$4,306**	**$0**	**$3,875**	**$29,711**	**$27**
13	**Improvements to Site**										
13.1	Site Preparation	$0	$758	$13,584	$0	$14,342	$2,868	$0	$3,442	$20,653	$18
13.2	Site Improvements	$0	$2,438	$2,718	$0	$5,156	$1,031	$0	$1,237	$7,425	$7
13.3	Site Facilities	$2,339	$0	$2,072	$0	$4,411	$882	$0	$1,059	$6,351	$6
	Subtotal	**$2,339**	**$3,195**	**$18,375**	**$0**	**$23,909**	**$4,782**	**$0**	**$5,738**	**$34,428**	**$31**
14	**Buildings & Structures**										
14.1	Combustion Turbine Area	$0	$707	$274	$0	$981	$196	$0	$177	$1,354	$1
14.3	Steam Turbine Building	$0	$6,924	$6,770	$0	$13,693	$2,739	$0	$2,465	$18,897	$17
14.4	Administration Building	$0	$680	$339	$0	$1,019	$204	$0	$183	$1,407	$1
14.5	Circulation Water Pumphouse	$0	$118	$43	$0	$162	$32	$0	$29	$223	$0
14.6	Water Treatment Buildings	$0	$685	$459	$0	$1,144	$229	$0	$206	$1,578	$1
14.7	Machine Shop	$0	$1,018	$478	$0	$1,497	$299	$0	$269	$2,066	$2
14.8	Warehouse	$0	$792	$351	$0	$1,143	$229	$0	$206	$1,577	$1
14.9	Other Buildings & Structures	$0	$579	$309	$0	$888	$178	$0	$160	$1,226	$1
14.10	Waste Treating Building & Structures	$0	$802	$1,051	$0	$1,853	$371	$0	$333	$2,557	$2
	Subtotal	**$0**	**$12,305**	**$10,075**	**$0**	**$22,380**	**$4,476**	**$0**	**$4,028**	**$30,884**	**$28**
	Total	**$497,830**	**$48,659**	**$158,129**	**$0**	**$704,618**	**$140,924**	**$0**	**$133,498**	**$979,039**	**$876**

Exhibit 4-106. Case B32A.2 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$6,253	$6
1 Month Maintenance Materials	$1,094	$1
1 Month Non-fuel Consumables	$545	$0
1 Month Waste Disposal	$1	$0
25% of 1 Months Fuel Cost at 100% CF	$6,968	$6
2% of TPC	$19,581	$18
Total	**$34,443**	**$31**
Inventory Capital		
60-day supply of consumables at 100% CF	$587	$1
0.5% of TPC (spare parts)	$4,895	$4
Total	**$5,483**	**$5**
Other Costs		
Initial Cost for Catalyst and Chemicals	$2,669	$2
Land	$600	$1
Other Owner's Costs	$146,856	$131
Financing Costs	$26,434	$24
Total Overnight Costs (TOC)	**$1,195,523**	**$1,069**
TASC Multiplier (IOU, 33 year)	1.183	
Total As-Spent Cost (TASC)	**$1,414,241**	**$1,265**

Exhibit 4-107. Case B32A.2 initial and annual operating and maintenance costs

Case:	B32A.2 – NGCC H–Class (2x1) without CO_2 Capture				Cost Base:	Jan 2023
Plant Size (MW, net):	1,118	Heat Rate-net (Btu/kWh):	6,113		Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		45.04	**$/hour**	Skilled Operator:		1.0
Operating Labor Burden:		30.00	**% of base**	Operator:		2.0
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		1.0
				Total:		**5.0**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$2,564,552	$2.294
Maintenance Labor:					$7,440,700	$6.656
Administrative & Support Labor:					$2,501,313	$2.237
Property Taxes and Insurance:					$19,580,789	$17.515
Total:					**$32,087,355**	**$28.703**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$11,161,050	$1.341
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	2,963	$2.30	$0	$2,114,255	$0.254
Makeup and Waste Water Treatment Chemicals (ton):	0	8.8	$660.00	$0	$1,807,272	$0.217
Ammonia (19 wt%, ton):	0	13.7	$280.00	$0	$1,188,466	$0.143
SCR Catalyst (ft^3):	7,625	4.2	$350.00	$2,668,610	$453,664	$0.055
Subtotal:				**$2,668,610**	**$5,563,657**	**$0.668**
Waste Disposal						
SCR Catalyst (ft^3):	0	4.2	$5.70	$0	$7,388	$0.001
Subtotal:				**$0**	**$7,388**	**$0.001**
Variable Operating Costs Total:				**$2,668,610**	**$16,732,095**	**$2.010**
Fuel Cost						
Natural Gas (MMBtu):	0	164,013	$5.59	$0	$284,306,142	$34.155
Total:				**$0**	**$284,306,142**	**$34.155**

Exhibit 4-108. Case B32A.2 COE breakdown

	FY COE		LCOE	
Component	**Value, $/MWh**	**Percentage**	**Value, $/MWh**	**Percentage**
Capital	13.1	25%	13.1	31%
Fixed	3.9	7%	5.1	12%
Variable	2.0	4%	2.7	6%
Fuel	34.2	64%	20.9	50%
Total (Excluding T&S)	**53.1**	**N/A**	**41.9**	**N/A**
CO_2 T&S	–	–	–	–
Total (Including T&S)	**53.1**	**N/A**	**41.9**	**N/A**

4.4.7 Case B32B.2.90 – NGCC with 90% CO_2 Capture Process Description

The plant configuration and process description for Case B32B.2.90 are nearly the same as Case B32A.2, with the exception that a PostCCC facility was included to treat the flue gas stream. Since the process descriptions of the plant and PostCCC facility were provided in Section 4.3.3 and Section 3.1.8, respectively, with differences between the facilities used in NGCC and PC cases noted in Section 4.1.4, they are not repeated here.

The BFD for Case B32B.2.90 is shown in Exhibit 4-109. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit 4-110. The modeling assumptions are presented in Section 4.3.1.

Exhibit 4-109. Case B32B.2.90 BFD, NGCC with 90 percent CO_2 capture

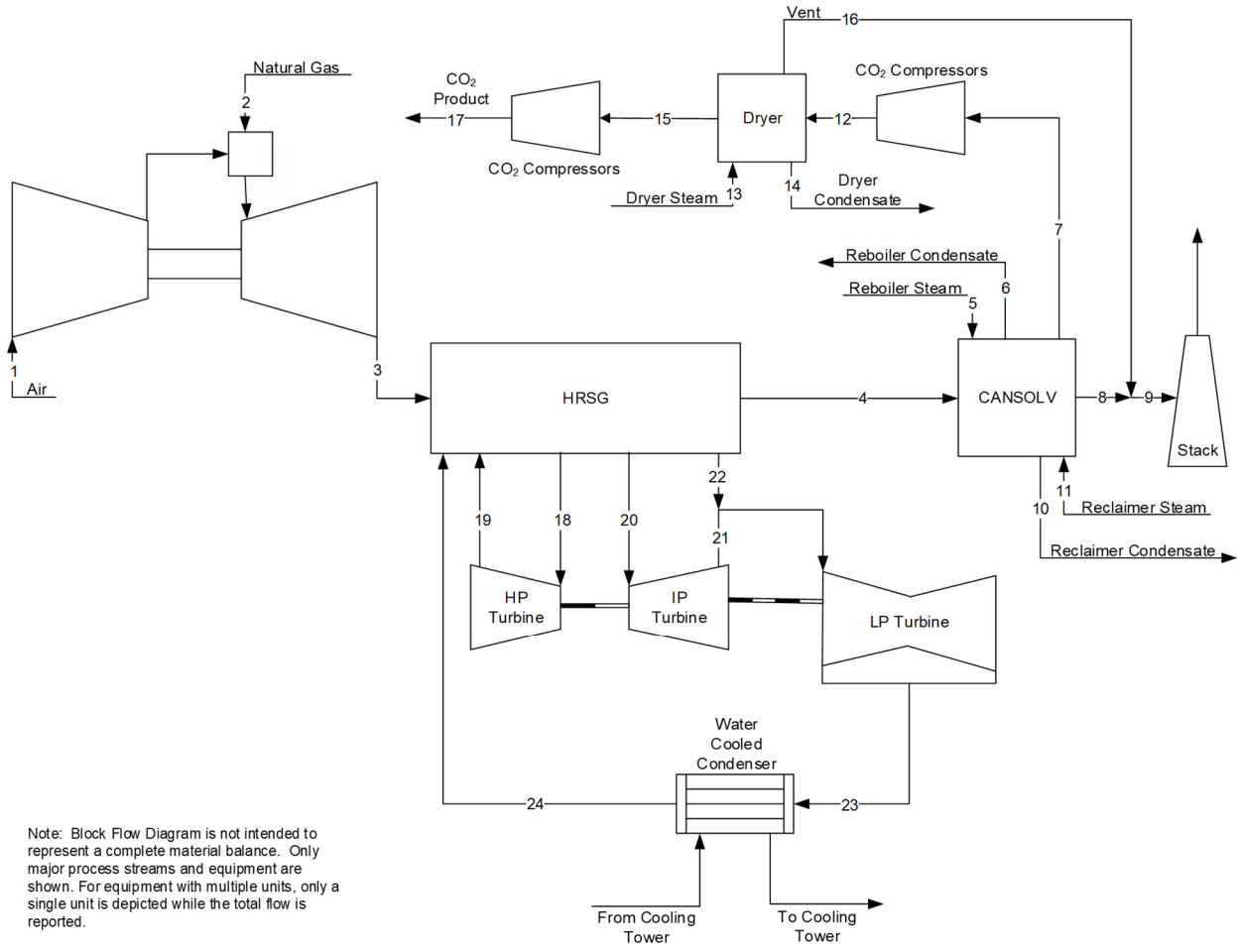


Exhibit 4-110. Case B32B.2.90 stream table, NGCC with 90 percent CO_2 capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0000	0.0088	0.0088	0.0000	0.0000	0.0000	0.0097	0.0097	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	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	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	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	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	0.0000	0.0000	0.0000
CO_2	0.0003	0.0100	0.0447	0.0447	0.0000	0.0000	0.9796	0.0049	0.0049	0.0000	0.0000	0.9957
H_2O	0.0099	0.0000	0.0949	0.0949	1.0000	1.0000	0.0204	0.0550	0.0550	1.0000	1.0000	0.0043
N_2	0.7732	0.0160	0.7399	0.7399	0.0000	0.0000	0.0000	0.8085	0.8085	0.0000	0.0000	0.0000
O_2	0.2074	0.0000	0.1116	0.1116	0.0000	0.0000	0.0000	0.1220	0.1220	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	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_{mol}/hr)	178,633	7,957	186,821	186,821	20,307	18,599	7,671	170,985	170,987	191	191	7,547
V-L Flowrate (kg/hr)	5,154,805	137,875	5,292,680	5,292,680	365,830	335,062	333,525	4,812,065	4,812,132	3,439	3,439	331,299
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	27	653	91	300	105	29	38	38	214	360	29
Pressure (MPa, abs)	0.10	3.79	0.11	0.10	0.51	0.12	0.17	0.10	0.10	2.04	4.12	2.81
Steam Table Enthalpy (kJ/kg)[A]	30.23	12.48	882.51	247.14	3,064.28	439.34	45.99	127.24	127.24	913.81	3,113.70	-1.10
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-4,496.75	-725.35	-1,360.72	-12,916.01	-15,540.95	-8,977.01	-527.74	-527.86	-15,066.49	-12,866.59	-8,976.01
Density (kg/m^3)	1.2	28.8	0.4	1.0	1.9	954.9	3.0	1.1	1.1	848.5	15.2	57.8
V-L Molecular Weight	28.857	17.328	28.330	28.330	18.015	18.015	43.481	28.143	28.143	18.015	18.015	43.897
V-L Flowrate (lb_{mol}/hr)	393,818	17,542	411,869	411,869	44,769	41,003	16,911	376,958	376,962	421	421	16,639
V-L Flowrate (lb/hr)	11,364,400	303,962	11,668,362	11,668,362	806,518	738,685	735,297	10,608,787	10,608,936	7,582	7,582	730,390
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	80	1,208	196	573	221	85	100	100	416	680	85
Pressure (psia)	14.7	550.0	15.3	14.8	73.5	17.4	24.7	14.8	14.8	296.6	598.0	407.6
Steam Table Enthalpy (Btu/lb)[A]	13.0	5.4	379.4	106.3	1,317.4	188.9	19.8	54.7	54.7	392.9	1,338.7	-0.5
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-1,933.3	-311.8	-585.0	-5,552.9	-6,681.4	-3,859.4	-226.9	-226.9	-6,477.4	-5,531.6	-3,859.0
Density (lb/ft^3)	0.076	1.799	0.024	0.059	0.121	59.612	0.185	0.069	0.069	52.968	0.951	3.607

[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 4-110. Case B32B.2.90 stream table, NGCC with 90 percent CO_2 capture (cont'd)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0000	0.0000	0.0000	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	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	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	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	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	0.0000	0.0000	0.0000
CO_2	0.0000	0.0000	0.9995	0.9704	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	0.0005	0.0296	0.0005	1.0000	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	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	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	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_{mol}/hr)	11	11	7,517	2	7,517	41,216	40,812	44,148	44,518	5,688	29,899	50,443
V-L Flowrate (kg/hr)	197	197	330,712	68	330,712	742,524	735,231	795,347	802,001	102,467	538,638	908,742
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	360	203	29	28	30	585	360	585	300	303	38	38
Pressure (MPa, abs)	4.12	1.64	2.68	0.10	15.27	17.30	4.12	3.84	0.52	0.51	0.01	0.01
Steam Table Enthalpy (kJ/kg)[A]	3,113.70	863.65	-3.59	56.47	-231.09	3,520.56	3,113.70	3,641.20	3,064.28	3,070.57	2,377.10	160.78
AspenPlus Enthalpy (kJ/kg)[B]	-12,866.59	-15,116.65	-8,967.15	-8,994.77	-9,194.65	-12,459.74	-12,866.59	-12,339.10	-12,916.01	-12,909.72	-13,603.19	-15,819.51
Density (kg/m^3)	15.2	861.8	54.7	1.8	630.1	48.1	15.2	9.9	2.0	1.9	0.1	992.8
V-L Molecular Weight	18.015	18.015	43.997	43.240	43.997	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	24	24	16,572	3	16,572	90,867	89,974	97,331	98,145	12,539	65,916	111,207
V-L Flowrate (lb/hr)	434	434	729,095	149	729,095	1,636,986	1,620,907	1,753,439	1,768,111	225,900	1,187,493	2,003,434
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	680	397	85	83	86	1,085	680	1,085	573	578	101	101
Pressure (psia)	598.0	237.4	389.1	14.8	2,214.7	2,508.5	598.0	557.1	75.0	73.5	1.0	1.0
Steam Table Enthalpy (Btu/lb)[A]	1,338.7	371.3	-1.5	24.3	-99.4	1,513.6	1,338.7	1,565.4	1,317.4	1,320.1	1,022.0	69.1
AspenPlus Enthalpy (Btu/lb)[B]	-5,531.6	-6,499.0	-3,855.2	-3,867.1	-3,953.0	-5,356.7	-5,531.6	-5,304.9	-5,552.9	-5,550.2	-5,848.3	-6,801.2
Density (lb/ft^3)	0.951	53.801	3.416	0.110	39.338	3.001	0.951	0.617	0.123	0.120	0.003	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

4.4.8 Case B32B.2.90 – Performance Results

Overall plant performance is summarized in Exhibit 4-111; Exhibit 4-112 provides a detailed breakdown of the auxiliary power requirements.

The PostCCC facility and CO_2 compression combined accounts for 67 percent of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for 14 percent of the auxiliary load, largely due to the high cooling water demand of the PostCCC facility and CO_2 compressors.

Unlike the PC cases, which utilize boilers and steam turbines that can be produced at nearly any desired output, the gross outputs of the NGCC cases are fixed by the available size of the CTs. As such, the net outputs of the capture cases are reduced due to the greater auxiliary load imposed by the PostCCC facility and CO_2 compressors, relative to a non-capture case. The plant produces a net output of 998 MW at a net plant efficiency of 49.8 percent (HHV basis).

Exhibit 4-111. Case B32B.2.90 plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	759
Steam Turbine Power, MWe	308
Total Gross Power, MWe	**1,067**
CO_2 Capture/Removal Auxiliaries, kWe	20,000
CO_2 Compression, kWe	26,460
Balance of Plant, kWe	22,699
Total Auxiliaries, MWe	**69**
Net Power, MWe	**998**
HHV Net Plant Efficiency, %	49.8
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	7,223 (6,846)
HHV Combustion Turbine Efficiency, %	37.9
LHV Net Plant Efficiency, %	55.2
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,519 (6,179)
LHV Combustion Turbine Efficiency, %	42.0
Steam Turbine Cycle Efficiency, %	46.6
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,728 (7,325)
CO_2 Capture Rate, %	90
Condenser Duty, GJ/hr (MMBtu/hr)	1,199 (1,137)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	1,770 (1,677)
Natural Gas Feed Flow, kg/hr (lb/hr)	137,875 (303,962)
HHV Thermal Input, kWt	2,002,815
LHV Thermal Input, kWt	1,807,738
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.025 (6.6)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.016 (4.2)

Exhibit 4-112. Case B32B.2.90 plant power summary

Power Summary	
Combustion Turbine Power, MWe	759
Steam Turbine Power, MWe	308
Total Gross Power, MWe	**1,067**
Auxiliary Load Summary	
Circulating Water Pumps, kWe	6,240
Combustion Turbine Auxiliaries, kWe	1,270
Condensate Pumps, kWe	1,050
Cooling Tower Fans, kWe	3,230
CO_2 Capture/Removal Auxiliaries, kWe	20,000
CO_2 Compression, kWe	26,460
Feedwater Pumps, kWe	5,770
Ground Water Pumps, kWe	590
Miscellaneous Balance of Plant[A], kWe	880
SCR, kWe	9
Steam Turbine Auxiliaries, kWe	250
Transformer Losses, kWe	3,410
Total Auxiliaries, MWe	**69**
Net Power, MWe	**998**

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

4.4.8.1 Environmental Performance

The environmental targets for emissions of NOx, SO_2, and PM are presented in Section 2.4. A summary of the plant air emissions for Case B32B.2.90 is presented in Exhibit 4-113.

Exhibit 4-113. Case B32B.2.90 air emissions

	kg/GJ (lb/MMBtu)[A]	tonne/yr (ton/year)[B]	kg/MWh (lb/MWh)[C]
SO_2	0.000 (0.000)	0 (0)	0.000 (0.000)
NOx	0.001 (0.003)	69 (76)	0.009 (0.019)
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	0.000 (0.000)	0 (0)	0.000 (0.000)
CO_2	5 (12)	274,107 (302,151)	34 (76)
CO_2[D]	-	-	37 (81)

[A]Based on thermal input on an HHV basis
[B]Calculations based on an 85 percent capacity factor
[C]Emissions based on gross power except where otherwise noted
[D]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 domestic average value of total sulfur of 0.34 gr/100 scf ($4.71x10^{-4}$ lb-S/MMBtu) (Gas Research Institute, 1992). It was also assumed that the added 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 1.8 ppmv NOx emissions using a DLN burner in the CTG and an SCR. The DLN burners reduce the emissions to about 25 ppmvd (at 15 percent O_2) (GE Vernova, 2024b) and the SCR system is designed for an additional 95.0 percent NOx reduction (Davis & Black, October 2000).

The pipeline natural gas was assumed to contain no Hg or HCl, resulting in zero emissions.

The state-of-the-art 2023 H-Class gas turbine achieves approximately 9.0 ppmvd (at 15 percent O_2) CO and 1.5 ppmw PM emissions. The production of PM is a result of system inefficiencies and is not produced or emitted in any significant amount. Any CO or PM present in the flue gas is assumed to interact with, and be removed by, the PostCCC system solvent.

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

The carbon balance for the plant is shown in Exhibit 4-114. The carbon input to the plant consists of carbon in the natural gas and carbon in the air. Carbon leaves the plant mostly as CO_2 product from the CO_2 compression train; however, some carbon exits through the stack as CO_2.

Ninety percent of the CO_2 in the flue gas is removed in the PostCCC facility. 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 percentage:

$$1 - \frac{Carbon\ in\ Stack}{Total\ Carbon\ In} = \left(1 - \left(\frac{22{,}149}{221{,}091}\right)\right) * 100 = 90\%$$

Exhibit 4-114. Case B32B.2.90 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	99,584 (219,546)	Stack Gas	10,047 (22,149)
Air (CO_2)	701 (1,545)	CO_2 Product	90,238 (198,941)
		CO_2 Knockout	0.2 (0.4)
Total	**100,285 (221,091)**	**Total**	**100,285 (221,091)**

As shown in Exhibit 4-115, the sulfur content of the natural gas is insignificant, entirely comprising CH_4S (used as an odorant) (Gas Research Institute, 1992). All sulfur in the natural gas is assumed to react with the PostCCC system solvent and is removed from the solvent during solvent reclaiming as a waste stream.

Exhibit 4-115. Case B32B.2.90 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	1.5 (3.2)	Stack Gas	0.0 (0.0)
		Solvent Reclaiming	1.5 (3.2)
Total	**1.5 (3.2)**	**Total**	**1.5 (3.2)**

Water demand, recycle, withdrawal, discharge, and consumption are defined and discussed in Section 2.6. Exhibit 4-116 shows the overall water balance for the plant.

Exhibit 4-116. Case B32B.2.90 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 Capture System Makeup	–	–	–	–	–
CO_2 Capture Recovery	–	–	–	3.0 (782)	-3.0 (-782)
CO_2 Compression Recovery	–	–	–	0.0 (9.8)	0.0 (-9.8)
Deaerator Vent	–	–	–	0.0 (8.0)	0.0 (-8.0)
Condenser Makeup	**0.5 (143)**	**–**	**0.5 (143)**	**–**	**0.5 (143)**
BFW Makeup	0.5 (143)	–	0.5 (143)	–	0.5 (143)
Cooling Tower	**24 (6,411)**	**–**	**24 (6,411)**	**6.1 (1,602)**	**18 (4,809)**
Total	**25 (6,554)**	**–**	**25 (6,554)**	**9.1 (2,401)**	**16 (4,153)**

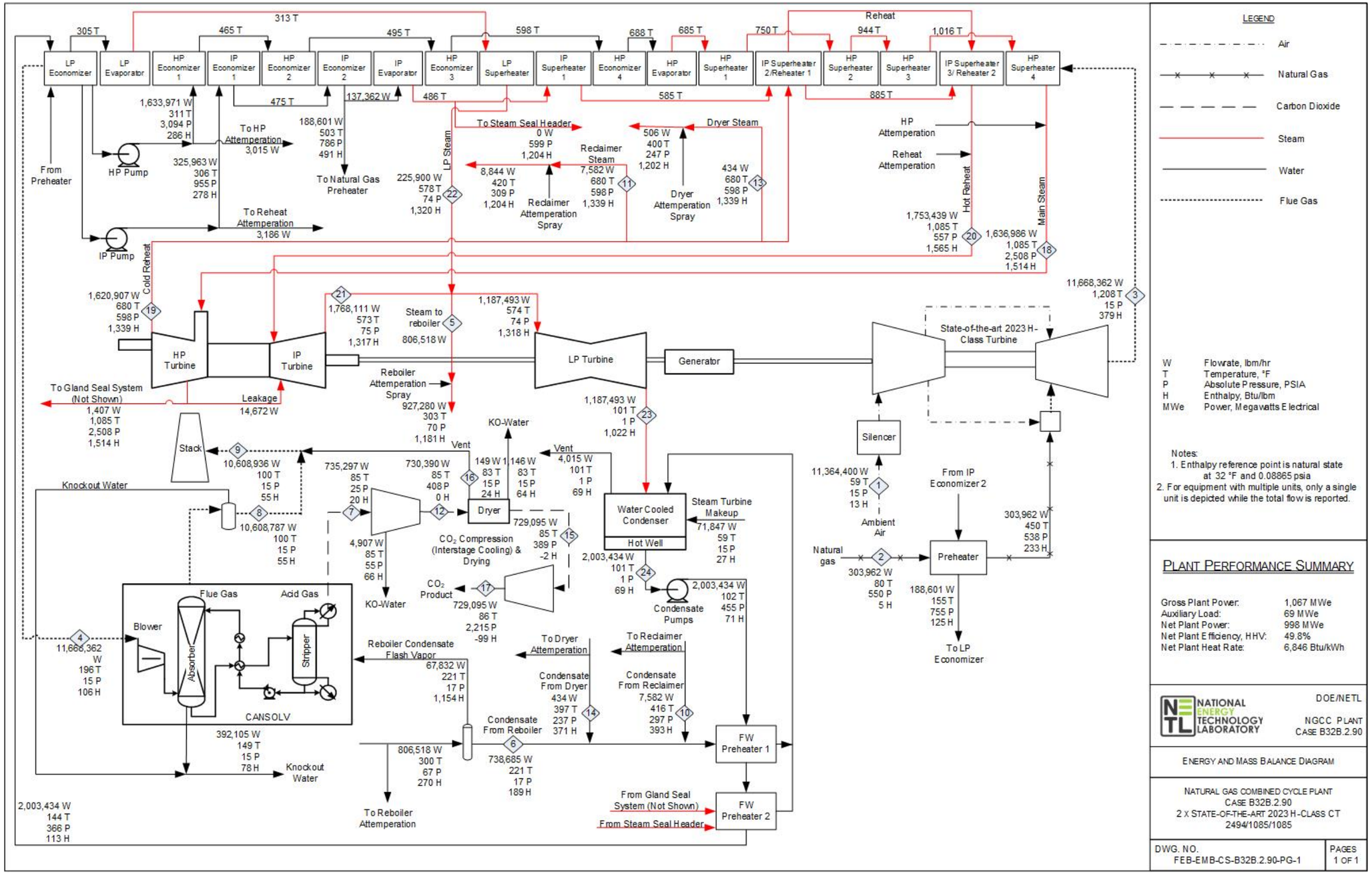
4.4.8.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for Case B32B.2.90 in Exhibit 4-117.

An overall plant energy balance is provided in tabular form in Exhibit 4-118. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-111) is calculated by multiplying the power out by the generator efficiency: 99.6 percent for the CT and 98.0 percent for the steam turbine.

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Exhibit 4-117. Case B32B.2.90 energy and mass balance, NGCC with CO_2 capture



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Exhibit 4-118. Case B32B.2.90 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, GJ/hr (MMBtu/hr)				
Natural Gas	7,210 (6,834)	8.6 (8.1)	–	7,219 (6,842)
Air	–	156 (148)	–	156 (148)
Raw Water Makeup	–	94 (89)	–	94 (89)
Auxiliary Power	–	–	249 (236)	249 (236)
TOTAL	**7,210 (6,834)**	**258 (245)**	**249 (236)**	**7,717 (7,314)**
Heat Out, GJ/hr (MMBtu/hr)				
Stack Gas	–	612 (580)	–	612 (580)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Motor Losses and Design Allowances	–	–	54 (52)	54 (52)
Cooling Tower Load[A]	–	3,180 (3,014)	–	3,180 (3,014)
CO_2 Product Stream	–	-76 (-72)	–	-76 (-72)
AGR Effluent	–	49 (46)	–	49 (46)
Dryer Effluent	–	0.1 (0.1)	–	0.1 (0.1)
Deaerator Vent	–	0.3 (0.3)	–	0.3 (0.3)
Ambient Losses[B]	–	*62 (59)*	–	62 (59)
Power	–	–	3,843 (3,642)	3,843 (3,642)
TOTAL	**0.0 (0.0)**	**3,827 (3,628)**	**3,897 (3,694)**	**7,724 (7,321)**
Unaccounted Energy[C]	**–**	*-7.3 (-6.9)*	–	*-7.3 (-6.9)*

[A]Includes condenser, capture process, CO_2 compressor, and miscellaneous cooling loads
[B]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers
[C]By difference

4.4.9 Case B32B.2.90 – Major Equipment List

Major equipment items for the 2x1 H-Class NGCC plant with 90 percent 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 4.3.10. 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. Values reported in the equipment lists are rounded.

Case B32B.2.90 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	2,147,000 liters (567,000 gal)	2	0
2	Condensate Pumps	Vertical canned	16,780 lpm @ 390 m H_2O (4,430 gpm @ 1,270 ft H_2O)	1	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP Water: 6,850 lpm @ 2,330 m H_2O (1,810 gpm @ 7,650 ft H_2O) IP Water: 1,380 lpm @ 510 m H_2O (360 gpm @ 1,680 ft H_2O)	2	2
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 GJ/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	3,800 lpm @ 110 m H_2O (1,000 gpm @ 350 ft H_2O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,600 lpm @ 80 m H_2O (700 gpm @ 250 ft H_2O)	1	1
11	Municipal Water Pumps	Stainless steel, single suction	6,800 lpm @ 20 m H_2O (1,790 gpm @ 60 ft H_2O)	2	1
12	Ground Water Pumps	Stainless steel, single suction	6,800 lpm @ 20 m H_2O (1,790 gpm @ 60 ft H_2O)	2	1
13	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H_2O (40 gpm @ 160 ft H_2O)	2	1
14	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
15	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0
16	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
17	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	88 m^3/min @ 3.8 MPa (3,098 acfm @ 550 psia) 39 cm (16 in) standard wall pipe	16 km (10 mile)	0
18	Gas Metering Station	–	88 m^3/min (3,098 acfm)	1	0

Case B32B.2.90 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Cansolv	Amine-based CO_2 capture technology	2,911,000 kg/hr (6,418,000 lb/hr) 6.9 wt% CO_2 concentration	2	0
2	Cansolv LP Condensate Pump	Centrifugal	1,000 lpm @ 1.0 m H_2O (260 gpm @ 3.4 ft H_2O)	1	1
3	Cansolv HP Condensate Pump	Centrifugal	10.6 lpm @ 4.6 m H_2O (2.8 gpm @ 15.0 ft H_2O)	1	1
4	CO_2 Dryer	Triethylene glycol	Inlet: 96 m^3/min @ 2.8 MPa (3,375 acfm @ 408 psia) Outlet: 2.7 MPa (389 psia) Water Removed: 520 kg/hr (1,147 lb/hr)	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
5	CO_2 Compressor	Integrally geared, multi-stage centrifugal	5 m^3/min @ 15.3 MPa, 82°C (170 acfm @ 2,217 psia, 180°F)	2	0
6	CO_2 Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 52 GJ/hr (49 MMBtu/hr)	2	0

Case B32B.2.90 – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	2023 Advanced H-Class w/ dry low-NOx burner	380 MW	2	0
2	Combustion Turbine Generator	Hydrogen Cooled	450 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	2	0

Case B32B.2.90 – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Epoxy-coated CS plate	46 m (150 ft) high x 5.9 m (19 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section	Main Steam: 404,000 kg/hr, 17.2 MPa/585°C (891,000 lb/hr, 2,494 psig/1,085°F) Reheat Steam: 437,000 kg/hr, 3.7 MPa/585°C (964,000 lb/hr, 542 psig/1,085°F)	2	0
3	SCR Reactor	–	2,910,000 kg/hr (6,420,000 lb/hr)	2	0
4	SCR Catalyst	–	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	20 m^3/min @ 108 cm WG (880 scfm @ 42 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	5.2 lpm @ 90 m H_2O (1.4 gpm @ 300 ft H_2O)	2	1
7	Ammonia Storage Tank	Horizontal tank	150,000 liter (40,000 gal)	1	0

Case B32B.2.90 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	324 MW 17.2 MPa/585°C/585°C (2,494 psig/1,085°F/1,085°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	380 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Two pass, divided waterbox including vacuum pumps and integrated deaerator	1,320 GJ/hr (1,250 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 B32B.2.90 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	625,000 lpm @ 30 m (165,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 3,500 GJ/hr (3,320 MMBtu/hr) heat duty	1	0

Case B32B.2.90 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	18 kV/345 kV, 450 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	18 kV/345 kV, 300 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 15 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	18 kV/4.16 kV, 33 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 11 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 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 B32B.2.90 – 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

4.4.10 Case B32B.2.90 – Cost Estimating

The cost estimating methodology is described in Section 2.7. Exhibit 4-119 shows a detailed breakdown of the capital costs; Exhibit 4-120 shows the owner's costs, TOC, and TASC; Exhibit 4-121 shows the initial and annual O&M costs; and Exhibit 4-122 shows the COE breakdown.

The estimated TPC of the NGCC with CO_2 capture is $1,998/kW. Process contingency represents 4.6 percent of the TPC and project contingency represents 15.1 percent of the TPC. The FY COE, including T&S costs of $4.0/MWh, is $85.3/MWh. The LCOE, including T&S costs of $5.3/MWh, is $76.3/MWh.

As discussed in Section 4.1.4, the 2x1 H-Class cases use two parallel CO_2 capture trains due to the high volumetric flow rate of flue gas produced. A high-level estimate of a dual-absorber, single-train CO_2 capture system suggests that the TPC of the 90 percent CO_2 capture system may be reduced by 17 percent, relative to the two-train configuration, which would reduce the LCOE by 4 percent to $73.2/MWh.[p]

[p] As of the publication of this report, no commercial builds have been demonstrated with this design. The estimated cost impact does not reflect any vendor input.

Exhibit 4-119. Case B32B.2.90 total plant cost details

Case:		B32B.2.90 – NGCC H-Class (2x1) with 90 Percent CO_2 Capture					Estimate Type:			Conceptual	
Plant Size (MW, net):		998					Cost Base:			Jan 2023	
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	$3,123	$5,354	$2,296	$0	$10,773	$2,155	$0	$1,939	$14,867	$15
3.2	Water Makeup & Pretreating	$9,171	$917	$4,313	$0	$14,400	$2,880	$0	$3,456	$20,737	$21
3.3	Other Feedwater Subsystems	$1,777	$583	$475	$0	$2,835	$567	$0	$510	$3,912	$4
3.4	Service Water Systems	$2,783	$5,313	$14,277	$0	$22,373	$4,475	$0	$5,369	$32,217	$32
3.5	Other Boiler Plant Systems	$414	$151	$330	$0	$895	$179	$0	$161	$1,235	$1
3.6	NG Pipeline and Start-Up System	$13,910	$598	$372	$0	$14,881	$2,976	$0	$2,679	$20,536	$21
3.7	Waste Water Treatment Equipment	$16,809	$0	$9,032	$0	$25,841	$5,168	$0	$6,202	$37,212	$37
3.9	Miscellaneous Plant Equipment	$20,959	$2,749	$9,338	$0	$33,045	$6,609	$0	$7,931	$47,585	$48
	Subtotal	**$68,946**	**$15,664**	**$40,434**	**$0**	**$125,043**	**$25,009**	**$0**	**$28,247**	**$178,300**	**$179**
5	Flue Gas Cleanup										
5.1	CANSOLV CO_2 Removal System	$208,676	$101,916	$189,843	$0	$500,435	$100,087	$90,078	$138,120	$828,720	$830
5.4	CO_2 Compression & Drying	$44,388	$6,659	$17,429	$0	$68,476	$13,695	$0	$16,434	$98,605	$99
5.5	CO_2 Compressor Aftercooler	$376	$60	$153	$0	$588	$118	$0	$141	$847	$1
5.12	Gas Cleanup Foundations	$0	$602	$616	$0	$1,217	$243	$0	$292	$1,753	$2
	Subtotal	**$253,440**	**$109,236**	**$208,039**	**$0**	**$570,716**	**$114,143**	**$90,078**	**$154,987**	**$929,925**	**$932**
6	Combustion Turbine & Accessories										
6.1	Combustion Turbine Generator	$143,815	$0	$9,180	$0	$152,995	$30,599	$0	$27,539	$211,133	$212
6.3	Combustion Turbine Accessories	$3,337	$0	$205	$0	$3,542	$708	$0	$638	$4,889	$5
6.4	Compressed Air Piping	$0	$1,269	$244	$0	$1,512	$302	$0	$272	$2,087	$2
6.5	Combustion Turbine Foundations	$0	$1,459	$1,591	$0	$3,050	$610	$0	$732	$4,392	$4
	Subtotal	**$147,152**	**$2,727**	**$11,220**	**$0**	**$161,100**	**$32,220**	**$0**	**$29,181**	**$222,500**	**$223**
7	HRSG, Ductwork, & Stack										
7.1	HRSG	$84,246	$0	$21,062	$0	$105,308	$21,062	$0	$18,955	$145,325	$146
7.2	HRSG Accessories	$20,205	$0	$3,774	$0	$23,979	$4,796	$0	$4,316	$33,091	$33
7.3	Ductwork	$0	$1,605	$878	$0	$2,483	$497	$0	$447	$3,427	$3
7.4	Stack	$5,550	$0	$1,037	$0	$6,587	$1,317	$0	$1,186	$9,090	$9
7.5	HRSG, Ductwork, & Stack Foundations	$0	$1,116	$884	$0	$2,000	$400	$0	$480	$2,880	$3
7.6	Selective Catalytic Reduction System	$2,472	$1,039	$1,270	$0	$4,781	$956	$0	$861	$6,598	$7
	Subtotal	**$112,474**	**$3,760**	**$28,904**	**$0**	**$145,138**	**$29,028**	**$0**	**$26,245**	**$200,410**	**$201**
8	Steam Turbine & Accessories										
8.1	Steam Turbine Generator & Accessories	$58,100	$0	$8,508	$0	$66,608	$13,322	$0	$11,989	$91,919	$92
8.2	Steam Turbine Plant Auxiliaries	$190	$0	$439	$0	$629	$126	$0	$113	$869	$1
8.3	Condenser & Auxiliaries	$9,686	$0	$4,648	$0	$14,334	$2,867	$0	$2,580	$19,781	$20
8.4	Steam Piping	$17,698	$0	$6,082	$0	$23,780	$4,756	$0	$4,280	$32,816	$33
8.5	Turbine Generator Foundations	$0	$1,956	$2,728	$0	$4,684	$937	$0	$1,124	$6,745	$7
	Subtotal	**$85,675**	**$1,956**	**$22,405**	**$0**	**$110,035**	**$22,007**	**$0**	**$20,087**	**$152,130**	**$152**
9	Cooling Water System										
9.1	Cooling Towers	$19,312	$0	$5,165	$0	$24,477	$4,895	$0	$4,406	$33,779	$34

Case:	B32B.2.90 – NGCC H-Class (2x1) with 90 Percent CO_2 Capture					Estimate Type:	Conceptual			
Plant Size (MW, net):	998					Cost Base:	Jan 2023			
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
9.2	Circulating Water Pumps	$2,475	$0	$132	$0	$2,607	$521	$0	$469	$3,597	$4
9.3	Circulating Water System Auxiliaries	$16,210	$0	$1,936	$0	$18,146	$3,629	$0	$3,266	$25,041	$25
9.4	Circulating Water Piping	$0	$5,099	$3,832	$0	$8,931	$1,786	$0	$1,608	$12,325	$12
9.5	Make-up Water System	$600	$0	$639	$0	$1,239	$248	$0	$223	$1,710	$2
9.6	Component Cooling Water System	$752	$0	$479	$0	$1,231	$246	$0	$222	$1,698	$2
9.7	Circulating Water System Foundations	$0	$1,180	$1,681	$0	$2,861	$572	$0	$687	$4,119	$4
	Subtotal	**$39,348**	**$6,279**	**$13,864**	**$0**	**$59,491**	**$11,898**	**$0**	**$10,880**	**$82,270**	**$82**
11	Accessory Electric Plant										
11.1	Generator Equipment	$4,383	$0	$2,732	$0	$7,115	$1,423	$0	$1,281	$9,818	$10
11.2	Station Service Equipment	$11,435	$0	$811	$0	$12,245	$2,449	$0	$2,204	$16,898	$17
11.3	Switchgear & Motor Control	$18,782	$0	$2,341	$0	$21,122	$4,224	$0	$3,802	$29,149	$29
11.4	Conduit & Cable Tray	$0	$3,945	$9,396	$0	$13,341	$2,668	$0	$2,401	$18,410	$18
11.5	Wire & Cable	$0	$5,890	$8,700	$0	$14,590	$2,918	$0	$2,626	$20,134	$20
11.6	Protective Equipment	$797	$0	$1,990	$0	$2,787	$557	$0	$502	$3,846	$4
11.7	Standby Equipment	$1,224	$0	$812	$0	$2,035	$407	$0	$366	$2,809	$3
11.8	Main Power Transformers	$9,408	$0	$194	$0	$9,602	$1,920	$0	$1,728	$13,250	$13
11.9	Electrical Foundations	$0	$159	$362	$0	$521	$104	$0	$125	$751	$1
	Subtotal	**$46,028**	**$9,995**	**$27,336**	**$0**	**$83,358**	**$16,672**	**$0**	**$15,036**	**$115,066**	**$115**
12	Instrumentation & Control										
12.1	NGCC Control Equipment	$359	$0	$226	$0	$586	$117	$0	$105	$808	$1
12.2	Combustion Turbine Control Equipment	$591	$0	$373	$0	$964	$193	$0	$174	$1,331	$1
12.3	Steam Turbine Control Equipment	$576	$0	$363	$0	$939	$188	$0	$169	$1,295	$1
12.4	Other Major Component Control Equipment	$966	$0	$609	$0	$1,575	$315	$79	$295	$2,264	$2
12.5	Signal Processing Equipment	$805	$0	$24	$0	$830	$166	$0	$149	$1,145	$1
12.6	Control Boards, Panels, & Racks	$213	$0	$129	$0	$342	$68	$17	$64	$492	$0
12.7	Distributed Control System Equipment	$11,836	$0	$357	$0	$12,193	$2,439	$610	$2,286	$17,527	$18
12.8	Instrument Wiring & Tubing	$1,171	$937	$3,096	$0	$5,203	$1,041	$260	$976	$7,479	$7
12.9	Other I&C Equipment	$811	$0	$1,552	$0	$2,362	$472	$118	$443	$3,396	$3
	Subtotal	**$17,329**	**$937**	**$6,728**	**$0**	**$24,993**	**$4,999**	**$1,084**	**$4,661**	**$35,737**	**$36**
13	Improvements to Site										
13.1	Site Preparation	$0	$1,029	$18,444	$0	$19,473	$3,895	$0	$4,673	$28,041	$28
13.2	Site Improvements	$0	$3,310	$3,691	$0	$7,000	$1,400	$0	$1,680	$10,081	$10
13.3	Site Facilities	$3,175	$0	$2,813	$0	$5,988	$1,198	$0	$1,437	$8,623	$9
	Subtotal	**$3,175**	**$4,338**	**$24,948**	**$0**	**$32,461**	**$6,492**	**$0**	**$7,791**	**$46,744**	**$47**
14	Buildings & Structures										
14.1	Combustion Turbine Area	$0	$707	$274	$0	$981	$196	$0	$177	$1,354	$1
14.3	Steam Turbine Building	$0	$6,128	$5,992	$0	$12,120	$2,424	$0	$2,182	$16,726	$17
14.4	Administration Building	$0	$666	$332	$0	$998	$200	$0	$180	$1,377	$1
14.5	Circulation Water Pumphouse	$0	$171	$62	$0	$233	$47	$0	$42	$321	$0
14.6	Water Treatment Buildings	$0	$834	$559	$0	$1,393	$279	$0	$251	$1,922	$2
14.7	Machine Shop	$0	$997	$468	$0	$1,465	$293	$0	$264	$2,022	$2

Case:		B32B.2.90 – NGCC H-Class (2x1) with 90 Percent CO_2 Capture					Estimate Type:			Conceptual	
Plant Size (MW, net):		998					Cost Base:			Jan 2023	
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
14.8	Warehouse	$0	$775	$344	$0	$1,119	$224	$0	$201	$1,544	$2
14.9	Other Buildings & Structures	$0	$567	$303	$0	$869	$174	$0	$156	$1,200	$1
14.10	Waste Treating Building & Structures	$0	$1,458	$1,911	$0	$3,369	$674	$0	$606	$4,649	$5
	Subtotal	**$0**	**$12,302**	**$10,245**	**$0**	**$22,547**	**$4,509**	**$0**	**$4,058**	**$31,114**	**$31**
	Total	**$773,567**	**$167,194**	**$394,122**	**$0**	**$1,334,883**	**$266,977**	**$91,162**	**$301,174**	**$1,994,196**	**$1,998**

Exhibit 4-120. Case B32B.2.90 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$11,503	$12
1 Month Maintenance Materials	$2,229	$2
1 Month Non-fuel Consumables	$1,165	$1
1 Month Waste Disposal	$152	$0
25% of 1 Months Fuel Cost at 100% CF	$6,968	$7
2% of TPC	$39,884	$40
Total	**$61,901**	**$62**
Inventory Capital		
60-day supply of consumables at 100% CF	$1,581	$2
0.5% of TPC (spare parts)	$9,971	$10
Total	**$11,552**	**$12**
Other Costs		
Initial Cost for Catalyst and Chemicals	$2,669	$3
Land	$600	$1
Other Owner's Costs	$299,129	$300
Financing Costs	$53,843	$54
Total Overnight Costs (TOC)	**$2,423,891**	**$2,428**
TASC Multiplier (IOU, 33 year)	1.183	
Total As-Spent Cost (TASC)	**$2,867,335**	**$2,872**

Exhibit 4-121. Case B32B.2.90 initial and annual operating and maintenance costs

Case:	B32B.2.90 – NGCC H-Class (2x1) with 90 Percent CO_2 Capture				Cost Base:	Jan 2023
Plant Size (MW, net):	998	Heat Rate-net (Btu/kWh):	6,846		Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		45.04	**$/hour**	Skilled Operator:		1.0
Operating Labor Burden:		30.00	**% of base**	Operator:		3.3
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		1.0
				Total:		**6.3**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$3,248,262	$3.254
Maintenance Labor:					$15,155,892	$15.183
Administrative & Support Labor:					$4,601,038	$4.609
Property Taxes and Insurance:					$39,883,926	$39.954
Total:					**$62,889,118**	**$63.000**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$22,733,838	$3.059
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	4,719	$2.30	$0	$3,367,356	$0.453
Makeup and Waste Water Treatment Chemicals (ton):	0	14.1	$660.00	$0	$2,878,426	$0.387
Ammonia (19 wt%, ton):	0	13.7	$280.00	$0	$1,194,337	$0.161
SCR Catalyst (ft^3):	7,625	4.2	$350.00	$2,668,610	$453,664	$0.061
CO_2 Capture System Chemicals[A]:	Proprietary				$3,819,435	$0.514
Triethylene Glycol (gal):	w/equip.	65.6	$8.50	$0	$172,955	$0.023
Subtotal:				**$2,668,610**	**$11,886,172**	**$1.599**
Waste Disposal						
SCR Catalyst (ft^3):	0	4.2	$5.70	$0	$7,388	$0.001
Triethylene Glycol (gal):	0	3,326	$1.30	$0	$1,341,333	$0.180
Thermal Reclaimer Unit Waste (ton):	0	2.6	$250.00	$0	$200,614	$0.027
Subtotal:				**$0**	**$1,549,335**	**$0.208**
Variable Operating Costs Total:				**$2,668,610**	**$36,169,345**	**$4.866**
Fuel Cost						
Natural Gas (MMBtu):	0	164,013	$5.59	$0	$284,306,142	$38.250
Total:				**$0**	**$284,306,142**	**$38.250**

[A]CO_2 Capture System Chemicals includes sodium hydroxide and CANSOLV solvent

Exhibit 4-122. Case B32B.2.90 COE breakdown

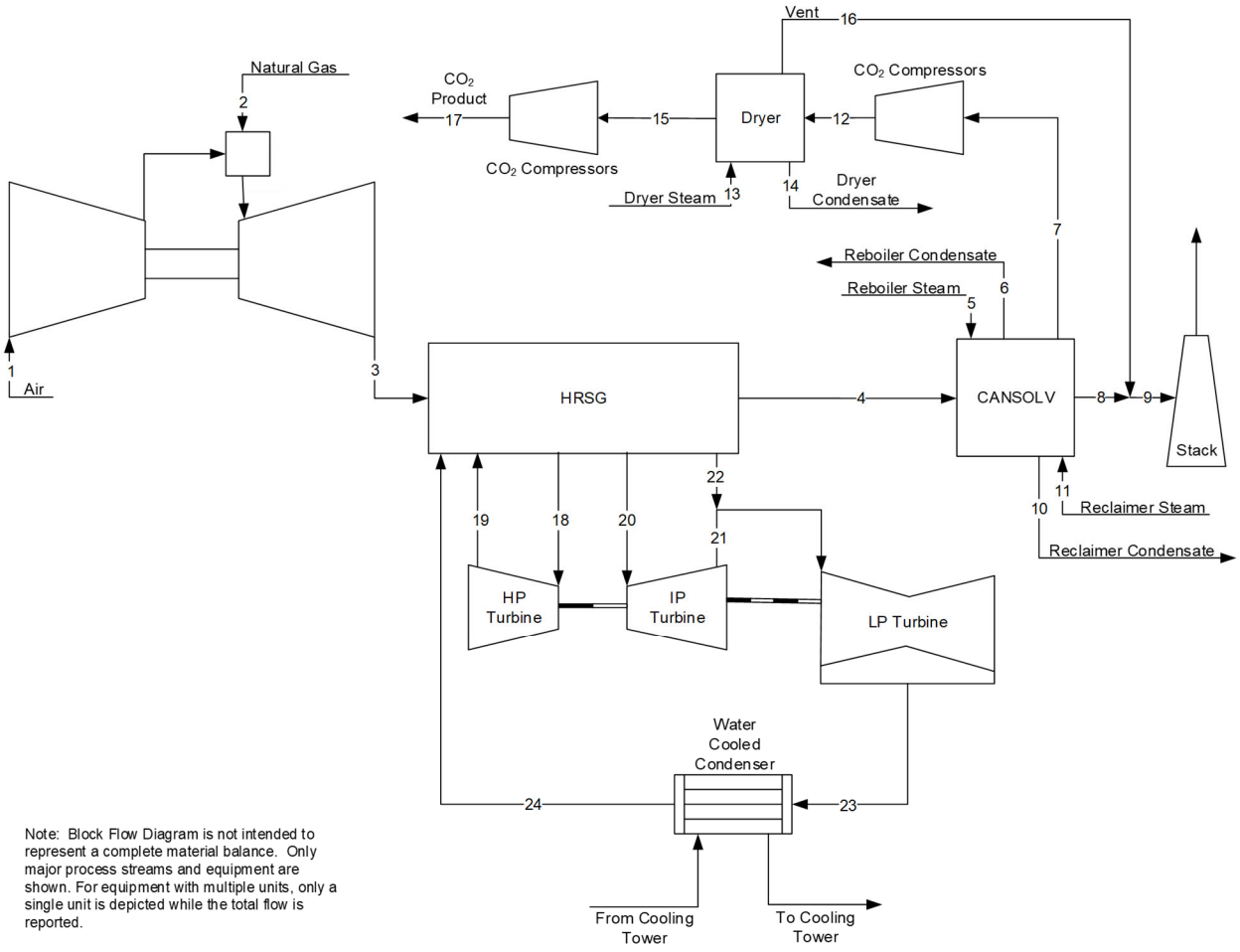
	FY COE		LCOE	
Component	Value, $/MWh	Percentage	Value, $/MWh	Percentage
Capital	29.7	35%	29.7	39%
Fixed	8.5	10%	11.3	15%
Variable	4.9	6%	6.5	9%
Fuel	38.2	45%	23.4	31%
Total (Excluding T&S)	**81.3**	**N/A**	**71.0**	**N/A**
CO_2 T&S	4.0	5%	5.3	7%
Total (Including T&S)	**85.3**	**N/A**	**76.3**	**N/A**

4.4.11 Case B32B.2.95 – NGCC with 95% CO_2 Capture Process Description

The plant configuration and process description for Case B32B.2.95 are the same as Case B32B.2.90, with the exception that the PostCCC facility captures 95, rather than 90, percent of the CO_2 in the flue gas. Since the process descriptions of the plant and PostCCC facility were provided in Section 4.3.3 and Section 3.1.8, respectively, with differences between the facilities used in NGCC and PC cases noted in Section 4.1.4, they are not repeated here.

The BFD for Case B32B.2.95 is shown in Exhibit 4-123. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit 4-124. The modeling assumptions are presented in Section 4.3.1.

Exhibit 4-123. Case B32B.2.95 BFD, NGCC with 95 percent CO_2 capture



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown. For equipment with multiple units, only a single unit is depicted while the total flow is reported.

Exhibit 4-124. Case B32B.2.95 stream table, NGCC with 95 percent CO_2 capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0000	0.0088	0.0088	0.0000	0.0000	0.0000	0.0097	0.0097	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	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	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	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	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	0.0000	0.0000	0.0000
CO_2	0.0003	0.0100	0.0447	0.0447	0.0000	0.0000	0.9796	0.0024	0.0025	0.0000	0.0000	0.9957
H_2O	0.0099	0.0000	0.0949	0.0949	1.0000	1.0000	0.0204	0.0550	0.0550	1.0000	1.0000	0.0043
N_2	0.7732	0.0160	0.7399	0.7399	0.0000	0.0000	0.0000	0.8106	0.8106	0.0000	0.0000	0.0000
O_2	0.2074	0.0000	0.1116	0.1116	0.0000	0.0000	0.0000	0.1223	0.1223	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	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_{mol}/hr)	178,633	7,957	186,821	186,821	21,433	19,631	8,097	170,544	170,545	191	191	7,966
V-L Flowrate (kg/hr)	5,154,805	137,875	5,292,680	5,292,680	386,126	353,651	352,054	4,793,252	4,793,324	3,439	3,439	349,705
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	27	653	92	300	105	29	38	38	214	360	29
Pressure (MPa, abs)	0.10	3.79	0.11	0.10	0.51	0.12	0.17	0.10	0.10	2.04	4.12	2.81
Steam Table Enthalpy (kJ/kg)[A]	30.23	12.48	882.51	248.03	3,064.28	439.34	45.99	127.39	127.39	913.81	3,113.70	-1.10
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-4,496.75	-725.35	-1,359.83	-12,916.01	-15,540.95	-8,977.01	-494.35	-494.48	-15,066.49	-12,866.59	-8,976.01
Density (kg/m^3)	1.2	28.8	0.4	1.0	1.9	954.9	3.0	1.1	1.1	848.5	15.2	57.8
V-L Molecular Weight	28.857	17.328	28.330	28.330	18.015	18.015	43.481	28.106	28.106	18.015	18.015	43.897
V-L Flowrate (lb_{mol}/hr)	393,818	17,542	411,869	411,869	47,252	43,278	17,850	375,984	375,988	421	421	17,563
V-L Flowrate (lb/hr)	11,364,400	303,962	11,668,362	11,668,362	851,262	779,666	776,146	10,567,313	10,567,470	7,582	7,582	770,967
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	80	1,208	198	573	221	85	100	100	416	680	85
Pressure (psia)	14.7	550.0	15.3	14.8	73.5	17.4	24.7	14.8	14.8	296.6	598.0	407.6
Steam Table Enthalpy (Btu/lb)[A]	13.0	5.4	379.4	106.6	1,317.4	188.9	19.8	54.8	54.8	392.9	1,338.7	-0.5
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-1,933.3	-311.8	-584.6	-5,552.9	-6,681.4	-3,859.4	-212.5	-212.6	-6,477.4	-5,531.6	-3,859.0
Density (lb/ft^3)	0.076	1.799	0.024	0.059	0.121	59.612	0.185	0.069	0.069	52.968	0.951	3.607

[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 4-124. Case B32B.2.95 stream table, NGCC with 95 percent CO_2 capture (cont'd)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0000	0.0000	0.0000	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	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	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	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	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	0.0000	0.0000	0.0000
CO_2	0.0000	0.0000	0.9995	0.9704	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	0.0005	0.0296	0.0005	1.0000	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	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	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	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_{mol}/hr)	12	12	7,934	2	7,934	41,217	40,812	44,148	44,517	5,688	28,772	50,443
V-L Flowrate (kg/hr)	208	208	349,085	71	349,085	742,528	735,235	795,339	801,994	102,467	518,334	908,745
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	360	203	29	28	30	585	360	585	300	303	38	38
Pressure (MPa, abs)	4.12	1.64	2.68	0.10	15.27	17.30	4.12	3.84	0.52	0.51	0.01	0.01
Steam Table Enthalpy (kJ/kg)[A]	3,113.70	863.65	-3.59	56.47	-231.09	3,520.56	3,113.70	3,641.20	3,064.28	3,070.57	2,377.13	160.78
AspenPlus Enthalpy (kJ/kg)[B]	-12,866.59	-15,116.65	-8,967.15	-8,994.77	-9,194.65	-12,459.74	-12,866.59	-12,339.10	-12,916.01	-12,909.72	-13,603.16	-15,819.51
Density (kg/m^3)	15.2	861.8	54.7	1.8	630.1	48.1	15.2	9.9	2.0	1.9	0.1	992.8
V-L Molecular Weight	18.015	18.015	43.997	43.240	43.997	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	25	25	17,492	4	17,492	90,867	89,974	97,330	98,144	12,539	63,431	111,208
V-L Flowrate (lb/hr)	458	458	769,601	158	769,601	1,636,993	1,620,915	1,753,422	1,768,093	225,900	1,142,732	2,003,440
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	680	397	85	83	86	1,085	680	1,085	573	578	101	101
Pressure (psia)	598.0	237.4	389.1	14.8	2,214.7	2,508.5	598.0	557.1	75.0	73.5	1.0	1.0
Steam Table Enthalpy (Btu/lb)[A]	1,338.7	371.3	-1.5	24.3	-99.4	1,513.6	1,338.7	1,565.4	1,317.4	1,320.1	1,022.0	69.1
AspenPlus Enthalpy (Btu/lb)[B]	-5,531.6	-6,499.0	-3,855.2	-3,867.1	-3,953.0	-5,356.7	-5,531.6	-5,304.9	-5,552.9	-5,550.2	-5,848.3	-6,801.2
Density (lb/ft^3)	0.951	53.801	3.416	0.110	39.338	3.001	0.951	0.617	0.123	0.120	0.003	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

4.4.12 Case B32B.2.95 – Performance Results

Overall plant performance is summarized in Exhibit 4-125; Exhibit 4-126 provides a detailed breakdown of the auxiliary power requirements.

The PostCCC facility and CO_2 compression combined account for 68 percent of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for 13 percent of the auxiliary load, largely due to the high cooling water demand of the PostCCC facility and CO_2 compressors.

Unlike the PC cases, which utilize boilers and steam turbines that can be produced at nearly any desired output, the gross outputs of the NGCC cases are fixed by the available size of the CTs. As such, the net outputs of the capture cases are reduced due to the greater auxiliary load imposed by the PostCCC facility and CO_2 compressors, relative to a non-capture case. The plant produces a net output of 992 MW at a net plant efficiency of 49.5 percent (HHV basis).

Exhibit 4-125. Case B32B.2.95 plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	759
Steam Turbine Power, MWe	304
Total Gross Power, MWe	**1,064**
CO_2 Capture/Removal Auxiliaries, kWe	21,300
CO_2 Compression, kWe	27,930
Balance of Plant, kWe	22,769
Total Auxiliaries, MWe	**72**
Net Power, MWe	**992**
HHV Net Plant Efficiency, %	49.5
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	7,271 (6,892)
HHV Combustion Turbine Efficiency, %	37.9
LHV Net Plant Efficiency, %	54.9
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,563 (6,221)
LHV Combustion Turbine Efficiency, %	42.0
Steam Turbine Cycle Efficiency, %	47.2
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,631 (7,233)
CO_2 Capture Rate, %	95
Condenser Duty, GJ/hr (MMBtu/hr)	1,155 (1,094)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	1,825 (1,730)
Natural Gas Feed Flow, kg/hr (lb/hr)	137,875 (303,962)
HHV Thermal Input, kWt	2,002,815
LHV Thermal Input, kWt	1,807,738
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.025 (6.7)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.016 (4.2)

Exhibit 4-126. Case B32B.2.95 plant power summary

Power Summary	
Combustion Turbine Power, MWe	759
Steam Turbine Power, MWe	304
Total Gross Power, MWe	**1,064**
Auxiliary Load Summary	
Circulating Water Pumps, kWe	6,280
Combustion Turbine Auxiliaries, kWe	1,270
Condensate Pumps, kWe	1,050
Cooling Tower Fans, kWe	3,250
CO_2 Capture/Removal Auxiliaries, kWe	21,300
CO_2 Compression, kWe	27,930
Feedwater Pumps, kWe	5,770
Ground Water Pumps, kWe	600
Miscellaneous Balance of Plant[A], kWe	880
SCR, kWe	9
Steam Turbine Auxiliaries, kWe	250
Transformer Losses, kWe	3,410
Total Auxiliaries, MWe	**72**
Net Power, MWe	**992**

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

4.4.12.1 Environmental Performance

The environmental targets for emissions of NOx, SO_2, and PM are presented in Section 2.4. A summary of the plant air emissions for Case B32B.2.95 is presented in Exhibit 4-127.

Exhibit 4-127. Case B32B.2.95 air emissions

	kg/GJ (lb/MMBtu)[A]	tonne/year (ton/year)[B]	kg/MWh (lb/MWh)[C]
SO_2	0.000 (0.000)	0 (0)	0.000 (0.000)
NOx	0.001 (0.003)	69 (76)	0.009 (0.019)
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	0.000 (0.000)	0 (0)	0.000 (0.000)
CO_2	3 (6)	137,330 (151,381)	17 (38)
CO_2[D]	-	-	19 (41)

[A]Based on thermal input on an HHV basis
[B]Calculations based on an 85 percent capacity factor
[C]Emissions based on gross power except where otherwise noted
[D]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 domestic average value of total sulfur of 0.34 gr/100 scf ($4.71x10^{-4}$ lb-S/MMBtu) (Gas Research Institute, 1992). It was also assumed that the added 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 1.8 ppmv NOx emissions using a DLN burner in the CTG and an SCR. The DLN burners reduce the emissions to about 25 ppmvd (at 15 percent O_2) (GE Vernova, 2024b) and the SCR system is designed for an additional 95.0 percent NOx reduction (Davis & Black, October 2000).

The pipeline natural gas was assumed to contain no Hg or HCl, resulting in zero emissions.

The state-of-the-art 2023 H-Class gas turbine achieves approximately 9.0 ppmvd (at 15 percent O_2) CO and 1.5 ppmw PM emissions. The production of PM is a result of system inefficiencies and is not produced or emitted in any significant amount. Any CO or PM present in the flue gas is assumed to interact with, and be removed by, the PostCCC system solvent.

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

The carbon balance for the plant is shown in Exhibit 4-128. The carbon input to the plant consists of carbon in the natural gas and carbon in the air. Carbon leaves the plant mostly as CO_2 product from the CO_2 compression train; however, some carbon exits through the stack as CO_2.

Ninety five percent of the CO_2 in the flue gas is removed in the PostCCC facility. 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 percentage:

$$1 - \frac{Carbon\ in\ Stack}{Total\ Carbon\ In} = \left(1 - \left(\frac{11{,}097}{221{,}091}\right)\right) * 100 = 95\%$$

Exhibit 4-128. Case B32B.2.95 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	99,584 (219,546)	Stack Gas	5,034 (11,097)
Air (CO_2)	701 (1,545)	CO_2 Product	95,252 (209,994)
		CO_2 Knockout	0.2 (0.4)
Total	**100,285 (221,091)**	**Total**	**100,285 (221,091)**

As shown in Exhibit 4-129, the sulfur content of the natural gas is insignificant, entirely comprising CH_4S (used as an odorant) (Gas Research Institute, 1992). All sulfur in the natural gas is assumed to react with the PostCCC system solvent and is removed from the solvent during solvent reclaiming as a waste stream.

Exhibit 4-129. Case B32B.2.95 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	1.5 (3.2)	Stack Gas	0.0 (0.0)
		Solvent Reclaiming	1.5 (3.2)
Total	**1.5 (3.2)**	**Total**	**1.5 (3.2)**

Water demand, recycle, withdrawal, discharge, and consumption are defined and discussed in Section 2.6. Exhibit 4-130 shows the overall water balance for the plant.

Exhibit 4-130. Case B32B.2.95 water balance

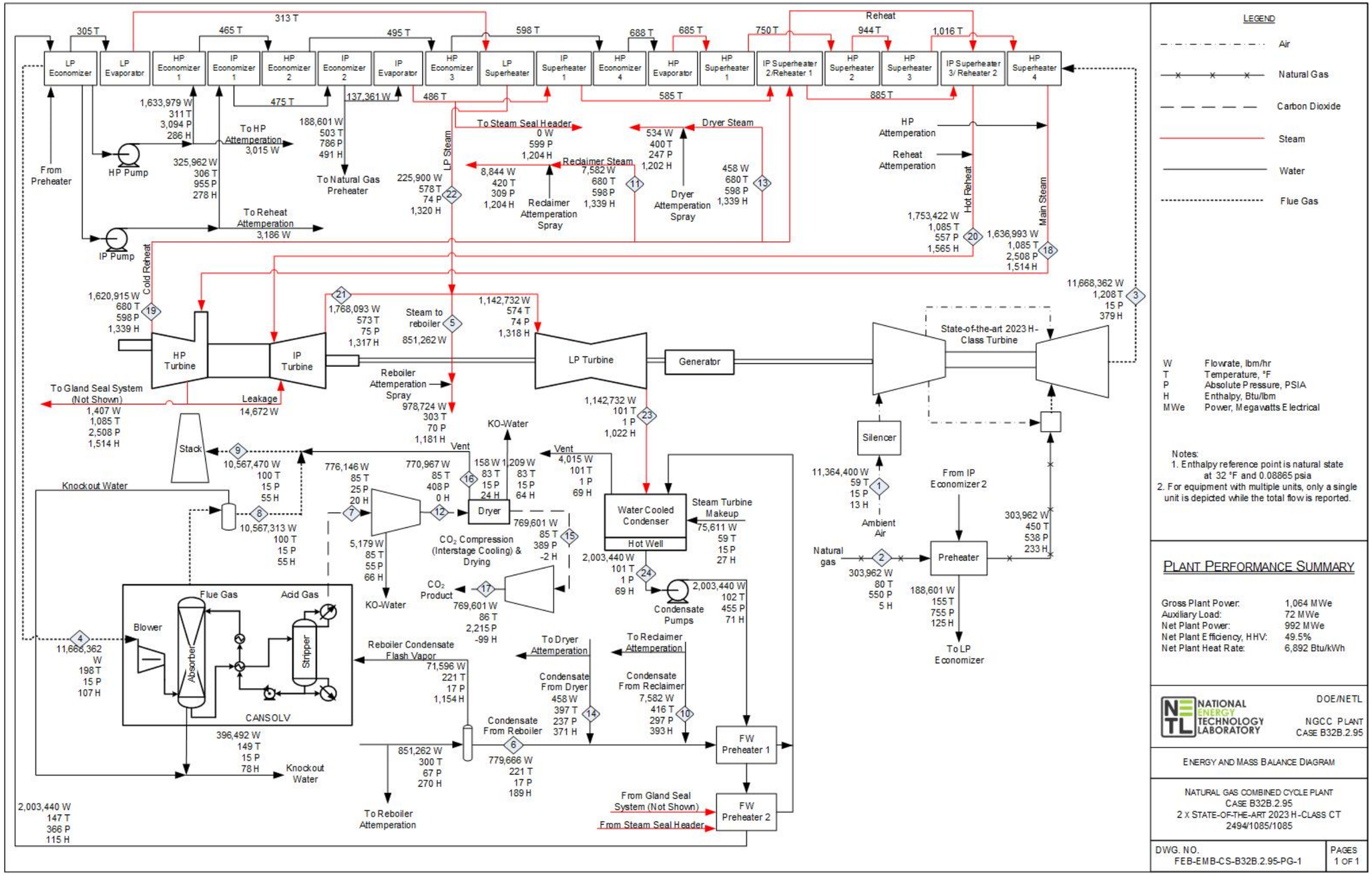
Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)
CO_2 Capture System Makeup	–	–	–	–	–
CO_2 Capture Recovery	–	–	–	3.0 (790)	-3.0 (-790)
CO_2 Compression Recovery	–	–	–	0.0 (10)	0.0 (-10)
Deaerator Vent	–	–	–	0.0 (8.0)	0.0 (-8.0)
Condenser Makeup	**0.6 (151)**	**–**	**0.6 (151)**	**–**	**0.6 (151)**
BFW Makeup	0.6 (151)	–	0.6 (151)	–	0.6 (151)
Cooling Tower	**24 (6,454)**	**–**	**24 (6,454)**	**6.1 (1,613)**	**18 (4,842)**
Total	**25 (6,605)**	**–**	**25 (6,605)**	**9.2 (2,421)**	**16 (4,184)**

4.4.12.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for Case B32B.2.95 in Exhibit 4-131.

An overall plant energy balance is provided in tabular form in Exhibit 4-132. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-125) is calculated by multiplying the power out by the generator efficiency: 99.6 percent for the CT and 98.0 percent for the steam turbine.

Exhibit 4-131. Case B32B.2.95 energy and mass balance, NGCC with CO_2 capture



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Exhibit 4-132. Case B32B.2.95 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, GJ/hr (MMBtu/hr)				
Natural Gas	7,210 (6,834)	8.6 (8.1)	–	7,219 (6,842)
Air	–	156 (148)	–	156 (148)
Raw Water Makeup	–	94 (89)	–	94 (89)
Auxiliary Power	–	–	259 (246)	259 (246)
TOTAL	**7,210 (6,834)**	**259 (245)**	**259 (246)**	**7,728 (7,325)**
Heat Out, GJ/hr (MMBtu/hr)				
Stack Gas	–	611 (579)	–	611 (579)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Motor Losses and Design Allowances	–	–	54 (52)	54 (52)
Cooling Tower Load[A]	–	3,201 (3,034)	–	3,201 (3,034)
CO_2 Product Stream	–	-81 (-76)	–	-81 (-76)
AGR Effluent	–	49 (47)	–	49 (47)
Dryer Effluent	–	0.1 (0.1)	–	0.1 (0.1)
Deaerator Vent	–	0.3 (0.3)	–	0.3 (0.3)
Ambient Losses[B]	–	*63 (59)*	–	63 (59)
Power	–	–	3,829 (3,629)	3,829 (3,629)
TOTAL	**0.0 (0.0)**	**3,843 (3,643)**	**3,883 (3,681)**	**7,727 (7,324)**
Unaccounted Energy[C]	–	*1.3 (1.2)*	–	*1.3 (1.2)*

[A]Includes condenser, capture process, CO_2 compressor, and miscellaneous cooling loads
[B]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers
[C]By difference

4.4.13 Case B32B.2.95 – Major Equipment List

Major equipment items for the 2x1 H-Class NGCC plant with 95 percent 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 4.3.14. 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. Values reported in the equipment lists are rounded.

Case B32B.2.95 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	2,259,000 liters (597,000 gal)	2	0
2	Condensate Pumps	Vertical canned	16,780 lpm @ 390 m H_2O (4,430 gpm @ 1,270 ft H_2O)	1	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP Water: 6,850 lpm @ 2,330 m H_2O (1,810 gpm @ 7,650 ft H_2O) IP Water: 1,380 lpm @ 510 m H_2O (360 gpm @ 1,680 ft H_2O)	2	2
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 GJ/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	3,800 lpm @ 110 m H_2O (1,000 gpm @ 350 ft H_2O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,600 lpm @ 80 m H_2O (700 gpm @ 250 ft H_2O)	1	1
11	Municipal Water Pumps	Stainless steel, single suction	6,800 lpm @ 20 m H_2O (1,800 gpm @ 60 ft H_2O)	2	1
12	Ground Water Pumps	Stainless steel, single suction	6,800 lpm @ 20 m H_2O (1,800 gpm @ 60 ft H_2O)	2	1
13	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H_2O (40 gpm @ 160 ft H_2O)	2	1
14	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
15	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0
16	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
17	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	88 m^3/min @ 3.8 MPa (3,098 acfm @ 550 psia) 39 cm (16 in) standard wall pipe	16 km (10 mile)	0
18	Gas Metering Station	–	88 m^3/min (3,098 acfm)	1	0

Case B32B.2.95 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Cansolv	Amine-based CO_2 capture technology	2,911,000 kg/hr (6,418,000 lb/hr) 6.9 wt% CO_2 concentration	2	0
2	Cansolv LP Condensate Pump	Centrifugal	1,060 lpm @ 1.0 m H_2O (280 gpm @ 3.4 ft H_2O)	1	1
3	Cansolv HP Condensate Pump	Centrifugal	10.6 lpm @ 4.6 m H_2O (2.8 gpm @ 15.0 ft H_2O)	1	1
4	CO_2 Dryer	Triethylene glycol	Inlet: 101 m^3/min @ 2.8 MPa (3,562 acfm @ 408 psia) Outlet: 2.7 MPa (389 psia) Water Removed: 549 kg/hr (1,211 lb/hr)	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
5	CO_2 Compressor	Integrally geared, multi-stage centrifugal	5 m^3/min @ 15.3 MPa, 82°C (179 acfm @ 2,217 psia, 180°F)	2	0
6	CO_2 Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 55 GJ/hr (52 MMBtu/hr)	2	0

Case B32B.2.95 – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	2023 Advanced H-Class w/ dry low-NOx burner	380 MW	2	0
2	Combustion Turbine Generator	Hydrogen Cooled	450 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	2	0

Case B32B.2.95 – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Epoxy-coated CS plate	46 m (150 ft) high x 5.9 m (19 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section	Main Steam: 404,000 kg/hr, 17.2 MPa/585°C (892,000 lb/hr, 2,494 psig/1,085°F) Reheat Steam: 437,000 kg/hr, 3.7 MPa/585°C (964,000 lb/hr, 542 psig/1,085°F)	2	0
3	SCR Reactor	–	2,910,000 kg/hr (6,420,000 lb/hr)	2	0
4	SCR Catalyst	–	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	20 m^3/min @ 108 cm WG (880 scfm @ 42 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	5.2 lpm @ 90 m H_2O (1.4 gpm @ 300 ft H_2O)	2	1
7	Ammonia Storage Tank	Horizontal tank	150,000 liter (40,000 gal)	1	0

Case B32B.2.95 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	320 MW 17.2 MPa/585°C/585°C (2,494 psig/1,085°F/1,085°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	380 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Two pass, divided waterbox including vacuum pumps and integrated deaerator	1,270 GJ/hr (1,200 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 B32B.2.95 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	630,000 lpm @ 30 m (166,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 3,520 GJ/hr (3,340 MMBtu/hr) heat duty	1	0

Case B32B.2.95 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	18 kV/345 kV, 450 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	18 kV/345 kV, 290 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 16 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	18 kV/4.16 kV, 34 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 11 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 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 B32B.2.95 – 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

4.4.14 Case B32B.2.95 – Cost Estimating

The cost estimating methodology was described in Section 2.7. Exhibit 4-133 shows a detailed breakdown of the capital costs; Exhibit 4-134 shows the owner's costs, TOC, and TASC; Exhibit 4-135 shows the initial and annual O&M costs; and Exhibit 4-136 shows the COE breakdown.

The estimated TPC of the NGCC with CO_2 capture is $2,051/kW. Process contingency represents 4.7 percent of the TPC and project contingency represents 15.1 percent of the TPC. The FY COE, including T&S costs of $4.1/MWh, is $86.8/MWh. The LCOE, including T&S costs of $5.5/MWh, is $77.8/MWh.

As discussed in Section 4.1.4, the 2x1 H-Class cases use two parallel CO_2 capture trains due to the high volumetric flow rate of flue gas produced. A high-level estimate of a dual-absorber, single-train CO_2 capture system suggests that the TPC of the 95 percent CO_2 capture system may be reduced by 17 percent, relative to the two-train configuration, which would reduce the LCOE by 4 percent to $74.6/MWh.[q]

[q] As of the publication of this report, no commercial builds have been demonstrated with this design. The estimated cost impact does not reflect any vendor input.

Exhibit 4-133. Case B32B.2.95 total plant cost details

Case:	B32B.2.95 – NGCC H-Class (2x1) with 95 Percent CO_2 Capture									
Plant Size (MW, net):	992					Estimate Type:			Conceptual	
						Cost Base:			Jan 2023	
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	$3,123	$5,354	$2,296	$0	$10,773	$2,155	$0	$1,939	$14,867	$15
3.2	Water Makeup & Pretreating	$9,221	$922	$4,337	$0	$14,480	$2,896	$0	$3,475	$20,851	$21
3.3	Other Feedwater Subsystems	$1,777	$583	$475	$0	$2,835	$567	$0	$510	$3,912	$4
3.4	Service Water Systems	$2,798	$5,342	$14,356	$0	$22,496	$4,499	$0	$5,399	$32,394	$33
3.5	Other Boiler Plant Systems	$414	$151	$330	$0	$895	$179	$0	$161	$1,235	$1
3.6	NG Pipeline and Start-Up System	$13,910	$598	$372	$0	$14,881	$2,976	$0	$2,679	$20,536	$21
3.7	Waste Water Treatment Equipment	$16,909	$0	$9,086	$0	$25,995	$5,199	$0	$6,239	$37,433	$38
3.9	Miscellaneous Plant Equipment	$20,959	$2,749	$9,338	$0	$33,045	$6,609	$0	$7,931	$47,585	$48
	Subtotal	**$69,112**	**$15,698**	**$40,590**	**$0**	**$125,400**	**$25,080**	**$0**	**$28,333**	**$178,813**	**$180**
5	Flue Gas Cleanup										
5.1	CANSOLV CO_2 Removal System	$217,779	$105,662	$196,821	$0	$520,263	$104,053	$93,647	$143,593	$861,555	$869
5.4	CO_2 Compression & Drying	$46,275	$6,942	$18,169	$0	$71,387	$14,277	$0	$17,133	$102,797	$104
5.5	CO_2 Compressor Aftercooler	$392	$62	$159	$0	$613	$123	$0	$147	$883	$1
5.12	Gas Cleanup Foundations	$0	$622	$636	$0	$1,258	$252	$0	$302	$1,812	$2
	Subtotal	**$264,447**	**$113,288**	**$215,786**	**$0**	**$593,521**	**$118,704**	**$93,647**	**$161,174**	**$967,047**	**$975**
6	Combustion Turbine & Accessories										
6.1	Combustion Turbine Generator	$143,815	$0	$9,180	$0	$152,995	$30,599	$0	$27,539	$211,133	$213
6.3	Combustion Turbine Accessories	$3,337	$0	$205	$0	$3,542	$708	$0	$638	$4,889	$5
6.4	Compressed Air Piping	$0	$1,269	$244	$0	$1,512	$302	$0	$272	$2,087	$2
6.5	Combustion Turbine Foundations	$0	$1,459	$1,591	$0	$3,050	$610	$0	$732	$4,392	$4
	Subtotal	**$147,152**	**$2,727**	**$11,220**	**$0**	**$161,100**	**$32,220**	**$0**	**$29,181**	**$222,500**	**$224**
7	HRSG, Ductwork, & Stack										
7.1	HRSG	$84,164	$0	$21,041	$0	$105,205	$21,041	$0	$18,937	$145,182	$146
7.2	HRSG Accessories	$20,185	$0	$3,770	$0	$23,955	$4,791	$0	$4,312	$33,059	$33
7.3	Ductwork	$0	$1,602	$876	$0	$2,479	$496	$0	$446	$3,420	$3
7.4	Stack	$5,540	$0	$1,035	$0	$6,575	$1,315	$0	$1,184	$9,074	$9
7.5	HRSG, Ductwork, & Stack Foundations	$0	$1,114	$882	$0	$1,996	$399	$0	$479	$2,874	$3
7.6	Selective Catalytic Reduction System	$2,472	$1,039	$1,270	$0	$4,781	$956	$0	$861	$6,598	$7
	Subtotal	**$112,362**	**$3,755**	**$28,875**	**$0**	**$144,991**	**$28,998**	**$0**	**$26,218**	**$200,208**	**$202**
8	Steam Turbine & Accessories										
8.1	Steam Turbine Generator & Accessories	$57,526	$0	$8,424	$0	$65,950	$13,190	$0	$11,871	$91,011	$92
8.2	Steam Turbine Plant Auxiliaries	$189	$0	$435	$0	$624	$125	$0	$112	$861	$1
8.3	Condenser & Auxiliaries	$9,397	$0	$4,508	$0	$13,905	$2,781	$0	$2,503	$19,189	$19
8.4	Steam Piping	$17,698	$0	$6,082	$0	$23,780	$4,756	$0	$4,280	$32,817	$33
8.5	Turbine Generator Foundations	$0	$1,938	$2,704	$0	$4,642	$928	$0	$1,114	$6,684	$7
	Subtotal	**$84,810**	**$1,938**	**$22,153**	**$0**	**$108,901**	**$21,780**	**$0**	**$19,881**	**$150,562**	**$152**
9	Cooling Water System										
9.1	Cooling Towers	$19,405	$0	$5,190	$0	$24,595	$4,919	$0	$4,427	$33,941	$34

Case:	B32B.2.95 – NGCC H-Class (2x1) with 95 Percent CO_2 Capture								Estimate Type:	Conceptual
Plant Size (MW, net):	992								Cost Base:	Jan 2023
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
9.2	Circulating Water Pumps	$2,487	$0	$132	$0	$2,619	$524	$0	$471	$3,615	$4
9.3	Circulating Water System Auxiliaries	$16,276	$0	$1,944	$0	$18,220	$3,644	$0	$3,280	$25,143	$25
9.4	Circulating Water Piping	$0	$5,120	$3,848	$0	$8,968	$1,794	$0	$1,614	$12,375	$12
9.5	Make-up Water System	$602	$0	$642	$0	$1,245	$249	$0	$224	$1,718	$2
9.6	Component Cooling Water System	$755	$0	$481	$0	$1,236	$247	$0	$222	$1,705	$2
9.7	Circulating Water System Foundations	$0	$1,185	$1,687	$0	$2,872	$574	$0	$689	$4,136	$4
	Subtotal	**$39,524**	**$6,305**	**$13,925**	**$0**	**$59,754**	**$11,951**	**$0**	**$10,928**	**$82,633**	**$83**
11	**Accessory Electric Plant**										
11.1	Generator Equipment	$4,373	$0	$2,726	$0	$7,100	$1,420	$0	$1,278	$9,798	$10
11.2	Station Service Equipment	$11,733	$0	$832	$0	$12,565	$2,513	$0	$2,262	$17,339	$17
11.3	Switchgear & Motor Control	$19,272	$0	$2,402	$0	$21,673	$4,335	$0	$3,901	$29,909	$30
11.4	Conduit & Cable Tray	$0	$4,048	$9,641	$0	$13,689	$2,738	$0	$2,464	$18,891	$19
11.5	Wire & Cable	$0	$6,044	$8,927	$0	$14,971	$2,994	$0	$2,695	$20,659	$21
11.6	Protective Equipment	$818	$0	$2,042	$0	$2,860	$572	$0	$515	$3,947	$4
11.7	Standby Equipment	$1,222	$0	$810	$0	$2,032	$406	$0	$366	$2,804	$3
11.8	Main Power Transformers	$9,383	$0	$193	$0	$9,577	$1,915	$0	$1,724	$13,216	$13
11.9	Electrical Foundations	$0	$159	$361	$0	$520	$104	$0	$125	$749	$1
	Subtotal	**$46,801**	**$10,251**	**$27,934**	**$0**	**$84,986**	**$16,997**	**$0**	**$15,329**	**$117,312**	**$118**
12	**Instrumentation & Control**										
12.1	NGCC Control Equipment	$368	$0	$232	$0	$600	$120	$0	$108	$828	$1
12.2	Combustion Turbine Control Equipment	$606	$0	$382	$0	$988	$198	$0	$178	$1,363	$1
12.3	Steam Turbine Control Equipment	$590	$0	$372	$0	$962	$192	$0	$173	$1,327	$1
12.4	Other Major Component Control Equipment	$990	$0	$624	$0	$1,613	$323	$81	$302	$2,319	$2
12.5	Signal Processing Equipment	$825	$0	$25	$0	$850	$170	$0	$153	$1,173	$1
12.6	Control Boards, Panels, & Racks	$219	$0	$132	$0	$350	$70	$18	$66	$504	$1
12.7	Distributed Control System Equipment	$12,126	$0	$365	$0	$12,491	$2,498	$625	$2,342	$17,956	$18
12.8	Instrument Wiring & Tubing	$1,199	$959	$3,171	$0	$5,330	$1,066	$266	$999	$7,662	$8
12.9	Other I&C Equipment	$831	$0	$1,590	$0	$2,420	$484	$121	$454	$3,479	$4
	Subtotal	**$17,752**	**$959**	**$6,892**	**$0**	**$25,604**	**$5,121**	**$1,110**	**$4,775**	**$36,611**	**$37**
13	**Improvements to Site**										
13.1	Site Preparation	$0	$1,038	$18,605	$0	$19,642	$3,928	$0	$4,714	$28,285	$29
13.2	Site Improvements	$0	$3,338	$3,723	$0	$7,061	$1,412	$0	$1,695	$10,168	$10
13.3	Site Facilities	$3,203	$0	$2,838	$0	$6,040	$1,208	$0	$1,450	$8,698	$9
	Subtotal	**$3,203**	**$4,376**	**$25,165**	**$0**	**$32,744**	**$6,549**	**$0**	**$7,859**	**$47,152**	**$48**
14	**Buildings & Structures**										
14.1	Combustion Turbine Area	$0	$707	$274	$0	$981	$196	$0	$177	$1,354	$1
14.3	Steam Turbine Building	$0	$6,083	$5,948	$0	$12,030	$2,406	$0	$2,165	$16,602	$17
14.4	Administration Building	$0	$665	$331	$0	$996	$199	$0	$179	$1,375	$1
14.5	Circulation Water Pumphouse	$0	$172	$62	$0	$234	$47	$0	$42	$323	$0
14.6	Water Treatment Buildings	$0	$838	$562	$0	$1,399	$280	$0	$252	$1,931	$2
14.7	Machine Shop	$0	$996	$468	$0	$1,463	$293	$0	$263	$2,019	$2

Case:		B32B.2.95 – NGCC H-Class (2x1) with 95 Percent CO_2 Capture					Estimate Type:			Conceptual	
Plant Size (MW, net):		992					Cost Base:			Jan 2023	
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
14.8	Warehouse	$0	$774	$343	$0	$1,117	$223	$0	$201	$1,542	$2
14.9	Other Buildings & Structures	$0	$566	$302	$0	$868	$174	$0	$156	$1,198	$1
14.10	Waste Treating Building & Structures	$0	$1,467	$1,922	$0	$3,389	$678	$0	$610	$4,677	$5
	Subtotal	**$0**	**$12,267**	**$10,213**	**$0**	**$22,479**	**$4,496**	**$0**	**$4,046**	**$31,022**	**$31**
	Total	**$785,163**	**$171,565**	**$402,752**	**$0**	**$1,359,480**	**$271,896**	**$94,758**	**$307,724**	**$2,033,858**	**$2,051**

Exhibit 4-134. Case B32B.2.95 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$11,691	$12
1 Month Maintenance Materials	$2,273	$2
1 Month Non-fuel Consumables	$1,187	$1
1 Month Waste Disposal	$160	$0
25% of 1 Months Fuel Cost at 100% CF	$6,968	$7
2% of TPC	$40,677	$41
Total	**$62,957**	**$63**
Inventory Capital		
60-day supply of consumables at 100% CF	$1,620	$2
0.5% of TPC (spare parts)	$10,169	$10
Total	**$11,790**	**$12**
Other Costs		
Initial Cost for Catalyst and Chemicals	$2,669	$3
Land	$600	$1
Other Owner's Costs	$305,079	$308
Financing Costs	$54,914	$55
Total Overnight Costs (TOC)	**$2,471,866**	**$2,493**
TASC Multiplier (IOU, 33 year)	1.183	
Total As-Spent Cost (TASC)	**$2,924,087**	**$2,949**

Exhibit 4-135. Case B32B.2.95 initial and annual operating and maintenance costs

Case:	B32B.2.95 – NGCC H-Class (2x1) with 95 Percent CO_2 Capture				Cost Base:	Jan 2023
Plant Size (MW, net):	992	Heat Rate-net (Btu/kWh):		6,892	Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor					**Operating Labor Requirements per Shift**	
Operating Labor Rate (base):		45.04	**$/hour**	Skilled Operator:	1.0	
Operating Labor Burden:		30.00	**% of base**	Operator:	3.3	
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:	1.0	
				Lab Techs, etc.:	1.0	
				Total:	**6.3**	
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$3,248,262	$3.276
Maintenance Labor:					$15,457,318	$15.588
Administrative & Support Labor:					$4,676,395	$4.716
Property Taxes and Insurance:					$40,677,152	$41.022
Total:					**$64,059,127**	**$64.602**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$23,185,977	$3.140
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	4,756	$2.30	$0	$3,393,516	$0.460
Makeup and Waste Water Treatment Chemicals (ton):	0	14.2	$660.00	$0	$2,900,788	$0.393
Ammonia (19 wt%, ton):	0	13.8	$280.00	$0	$1,194,501	$0.162
SCR Catalyst (ft^3):	7,625	4.2	$350.00	$2,668,610	$453,664	$0.061
CO_2 Capture System Chemicals[A]:	Proprietary				$3,986,303	$0.540
Triethylene Glycol (gal):	w/equip.	69.2	$8.50	$0	$182,564	$0.025
Subtotal:				**$2,668,610**	**$12,111,336**	**$1.640**
Waste Disposal						
SCR Catalyst (ft^3):	0	4.2	$5.70	$0	$7,388	$0.001
Triethylene Glycol (gal):	0	3,510	$1.30	$0	$1,415,851	$0.192
Thermal Reclaimer Unit Waste (ton):	0	2.7	$250.00	$0	$209,742	$0.028
Subtotal:				**$0**	**$1,632,981**	**$0.221**
Variable Operating Costs Total:				**$2,668,610**	**$36,930,294**	**$5.002**
Fuel Cost						
Natural Gas (MMBtu):	0	164,013	$5.59	$0	$284,306,142	$38.506
Total:				**$0**	**$284,306,142**	**$38.506**

[A] CO_2 Capture System Chemicals includes sodium hydroxide and CANSOLV solvent

Exhibit 4-136. Case B32B.2.95 COE breakdown

	FY COE		LCOE	
Component	**Value, $/MWh**	**Percentage**	**Value, $/MWh**	**Percentage**
Capital	30.5	35%	30.5	39%
Fixed	8.7	10%	11.6	15%
Variable	5.0	6%	6.7	9%
Fuel	38.5	44%	23.6	30%
Total (Excluding T&S)	**82.7**	**N/A**	**72.4**	**N/A**
CO_2 T&S	4.1	5%	5.5	7%
Total (Including T&S)	**86.8**	**N/A**	**77.8**	**N/A**

4.5 NGCC Case Summary

The performance and cost results of the nine NGCC plant configurations modeled in this report are summarized in Exhibit 4-137.

Exhibit 4-137. Estimated performance and cost results for NGCC cases

NGCC									
Configuration	SOA 2023 F-Class			SOA 2023 H-Class (1x1)[A]			SOA 2023 H-Class (2x1)[A]		
Case	B31A	B31B.90	B31B.95	B32A.1	B32B.1.90	B32B.1.95	B32A.2	B32B.2.90	B32B.2.95
PERFORMANCE									
CO_2 Capture Rate (%)	0	90	95	0	90	95	0	90	95
Capacity Factor (%)	85	85	85	85	85	85	85	85	85
Gross Power Output (MWe)	755	707	705	660	619	617	1,137	1,067	1,064
Auxiliary Power Requirement (MWe)	14	49	51	11	40	42	19	69	72
Net Power Output (MWe)	741	658	654	649	579	575	1,118	998	992
Coal Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Natural Gas Flow Rate (lb/hr)	210,413	210,413	210,413	175,100	175,100	175,100	303,962	303,962	303,962
HHV Thermal Input (kW_t)	1,386,417	1,386,417	1,386,417	1,153,739	1,153,739	1,153,739	2,002,815	2,002,815	2,002,815
Net Plant HHV Efficiency (%)	53.4	47.5	47.2	56.2	50.2	49.8	55.8	49.8	49.5
Net Plant HHV Heat Rate (Btu/kWh)	6,385	7,187	7,236	6,068	6,801	6,848	6,113	6,846	6,892
Raw Water Withdrawal (gpm/MWnet)	4.1	7.1	7.2	3.6	6.5	6.6	3.7	6.6	6.7
Process Water Discharge (gpm/MWnet)	1.0	2.5	2.6	0.9	2.4	2.4	0.9	2.4	2.4
Raw Water Consumption (gpm/MWnet)	3.0	4.6	4.6	2.7	4.1	4.1	2.8	4.2	4.2
CO_2 Emissions (lb/MMBtu)	119	12	6	119	12	6	119	12	6
CO_2 Emissions (lb/MWh-gross)	743	79	40	707	76	38	713	76	38
CO_2 Emissions (lb/MWh-net)	757	85	43	719	81	41	725	81	41
SO_2 Emissions (lb/MMBtu)	0.001	0.000	0.000	0.001	0.000	0.000	0.001	0.000	0.000
SO_2 Emissions (lb/MWh-gross)	0.006	0.000	0.000	0.006	0.000	0.000	0.006	0.000	0.000
NOx Emissions (lb/MMBtu)	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
NOx Emissions (lb/MWh-gross)	0.021	0.021	0.021	0.019	0.018	0.018	0.020	0.019	0.019
PM Emissions (lb/MMBtu)	0.003	0.000	0.000	0.002	0.000	0.000	0.003	0.000	0.000
PM Emissions (lb/MWh-gross)	0.017	0.000	0.000	0.014	0.000	0.000	0.016	0.000	0.000
Hg Emissions (lb/TBtu)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Hg Emissions (lb/MWh-gross)	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$

NGCC									
Configuration	SOA 2023 F-Class			SOA 2023 H-Class (1x1)[A]			SOA 2023 H-Class (2x1)[A]		
Case	B31A	B31B.90	B31B.95	B32A.1	B32B.1.90	B32B.1.95	B32A.2	B32B.2.90	B32B.2.95
COST									
Total Plant Cost (2023$/kW)	1,051	2,180	2,235	993	2,111	2,165	876	1,998	2,051
Bare Erected Cost	756	1,473	1,508	714	1,424	1,458	630	1,337	1,371
Home Office Expenses	151	295	302	143	285	292	126	267	274
Project Contingency	144	326	335	136	317	325	119	302	310
Process Contingency	0	86	90	0	86	90	0	91	96
Total Overnight Cost (2023$/MM)	950	1,745	1,776	786	1,486	1,513	1,196	2,424	2,472
Total Overnight Cost (2023$/kW)	1,283	2,651	2,717	1,212	2,566	2,632	1,069	2,428	2,493
Owner's Costs	232	471	482	219	455	467	194	430	442
Total As-Spent Cost (2023$/kW)	1,517	3,136	3,214	1,433	3,036	3,113	1,265	2,872	2,949
FY COE ($/MWh) (excluding T&S)[B]	58.5	87.3	88.8	55.4	83.6	85.0	53.1	81.3	82.7
Capital Costs	15.7	32.5	33.3	14.8	31.4	32.2	13.1	29.7	30.5
Fixed Costs	4.7	9.5	9.7	4.5	9.2	9.4	3.9	8.5	8.7
Variable Costs	2.3	5.3	5.4	2.2	5.0	5.2	2.0	4.9	5.0
Fuel Costs	35.7	40.2	40.4	33.9	38.0	38.3	34.2	38.2	38.5
FY COE ($/MWh) (including T&S)[B]	58.5	91.8	93.4	55.4	88.3	89.8	53.1	85.3	86.8
CO_2 T&S Costs	N/A	4.5	4.6	N/A	4.7	4.8	N/A	4.0	4.1
LCOE ($/MWh) (excluding T&S)[B]	47.0	76.7	78.2	44.5	73.6	75.1	41.9	71.0	72.4
Capital Costs	15.7	32.5	33.3	14.8	31.4	32.2	13.1	29.7	30.5
Fixed Costs	6.3	12.6	12.9	6.0	12.2	12.5	5.1	11.3	11.6
Variable Costs	3.1	7.0	7.2	2.9	6.7	6.9	2.7	6.5	6.7
Fuel Costs	21.9	24.6	24.8	20.8	23.3	23.5	20.9	23.4	23.6
LCOE ($/MWh) (including T&S)[B]	47.0	82.7	84.3	44.5	79.9	81.5	41.9	76.3	77.8
CO_2 T&S Costs	N/A	6.0	6.1	N/A	6.2	6.4	N/A	5.3	5.5
Cost of CO_2 Captured (ex. T&S), $/tonne[C]	N/A	85.4	84.3	N/A	88.6	87.5	N/A	87.9	86.7
Cost of CO_2 Avoided (incl. T&S), $/tonne[C]	N/A	117.1	115.2	N/A	122.3	120.3	N/A	117.9	116.0

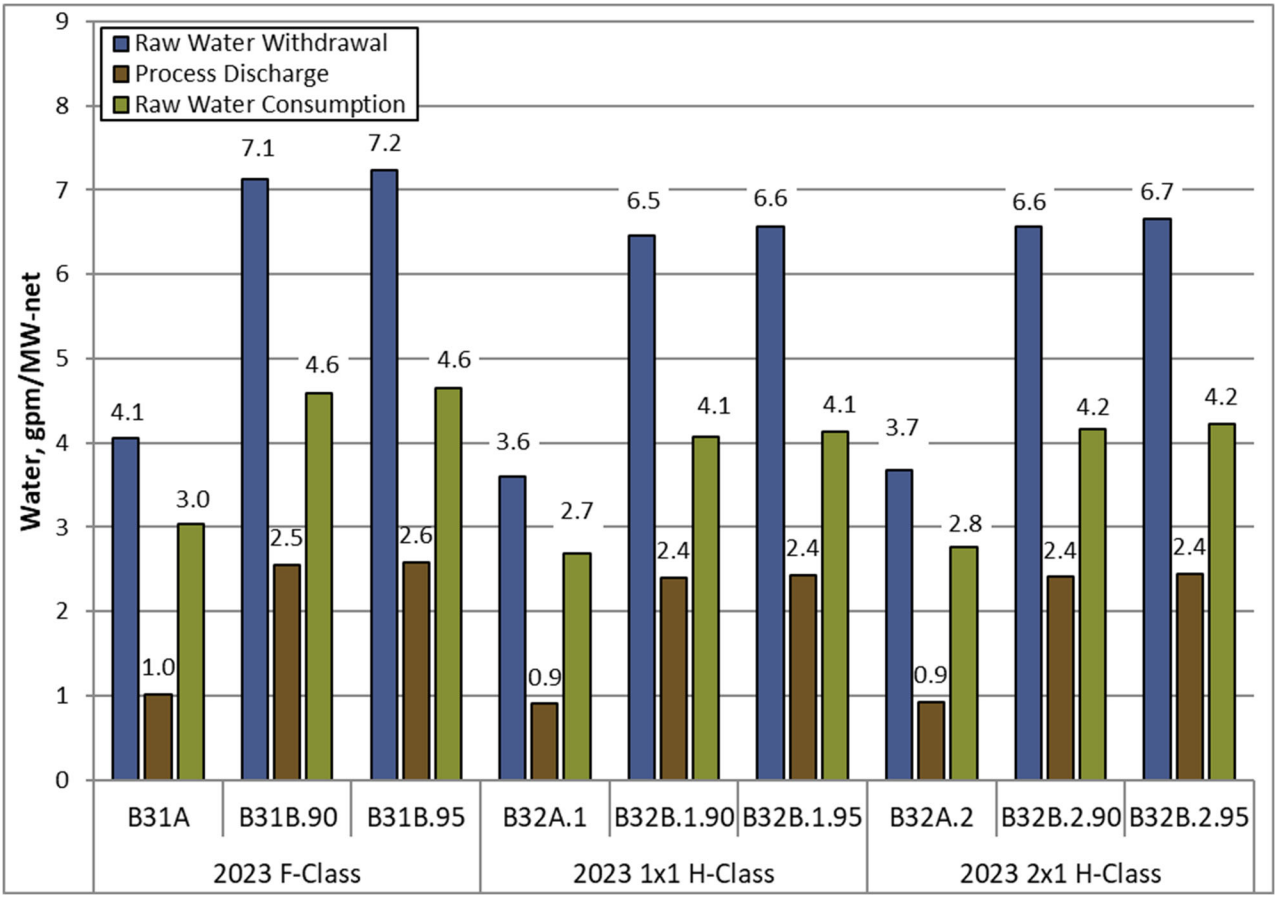
[A]The combustion turbine used in the 1x1 H-Class plant is larger and more advanced than that of the 2x1 H-Class plant
[B]Varying incentives, such as tax credits, could impact the economics of the system
[C]The cost of CO_2 captured and cost of CO_2 avoided were calculated based on the analogous non-capture case (i.e. B31B cases use B31A as a reference, B32B.1 cases use B32A.1, and B32B.2 cases use B32A.2)

The following observations can be made regarding plant performance with reference to Exhibit 4-137:

- The HHV net plant efficiency of the 1x1 H-Class case (B32A.1) is the highest of the non-capture cases at 56.2 percent, followed by the 2x1 H-Class case (B32A.2) at 55.8 percent and the F-Class case (B31A) at 53.4 percent.
    - Gas Turbine World provides estimated performance for a state-of-the-art 2023 F-Class turbine operated on natural gas in a combined cycle mode, and the reported efficiency is 60.5 percent (LHV basis) (Gas Turbine World, 2024). In addition, Gas Turbine World provides estimated performance for a state-of-the-art 2023 H-Class turbine operated on natural gas in a combined cycle mode, and the reported efficiency is 63.9 percent (LHV basis) for 1x1 configurations and 64.0 percent (LHV basis) for 2x1 configurations (Gas Turbine World, 2024). Adjusting the result from this report to an LHV basis results in an efficiency of 59.2 percent for the F-Class non-capture case (B31A), 62.3 percent for the 1x1 H-Class non-capture case (B32A.1), and 61.8 percent for the 2x1 H-Class non-capture case (B32A.2). It should be noted that the combustion turbine used in the 1x1 H-Class plant in this study is larger and more advanced than that of the 2x1 H-Class plant, as discussed in Section 4.
- The HHV efficiency penalty to add 90 percent CO_2 capture ranges 6.0–6.1 percentage points (10.7–11.2 percent), relative to the non-capture cases. The efficiency reduction is caused by the reduction in steam turbine output and increase in auxiliary loads.
    - The steam turbine output is reduced due to the extraction of steam for use in the CO_2 capture system (primarily the reboiler). Adding 90 percent CO_2 capture results in a 48, 41, and 70 MW decrease in steam turbine output compared to the non-capture case for F-Class, 1x1 H-Class, and 2x1 H-Class, respectively.
    - The auxiliary load increases due to the additional power requirements 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. Adding 90 percent CO_2 capture results in a 35, 29, and 50 MW increase in auxiliary load compared to the non-capture case for F-Class, 1x1 H-Class, and 2x1 H-Class, respectively.
- Relative to the 90 percent capture cases, the addition of 95 percent CO_2 capture results in an HHV efficiency penalty of 0.3 percentage points (0.7 percent) for F- (B31B.95) and H-Class (B32B.1.95 and B32B.2.95) cases.
- Natural gas contains no Hg or chloride, and PM, NOx, and SO_2 emissions are all at or below the applicable federal regulatory limits currently in effect for NGCC technology.

The normalized water withdrawal, process discharge, and raw water consumption are shown in Exhibit 4-138.

Exhibit 4-138. Raw water withdrawal and consumption in NGCC cases



Raw water consumption for all cases is dominated by cooling tower makeup requirements, which accounts for over 99 percent of raw water makeup in non-capture cases and 98 percent of raw water makeup 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:

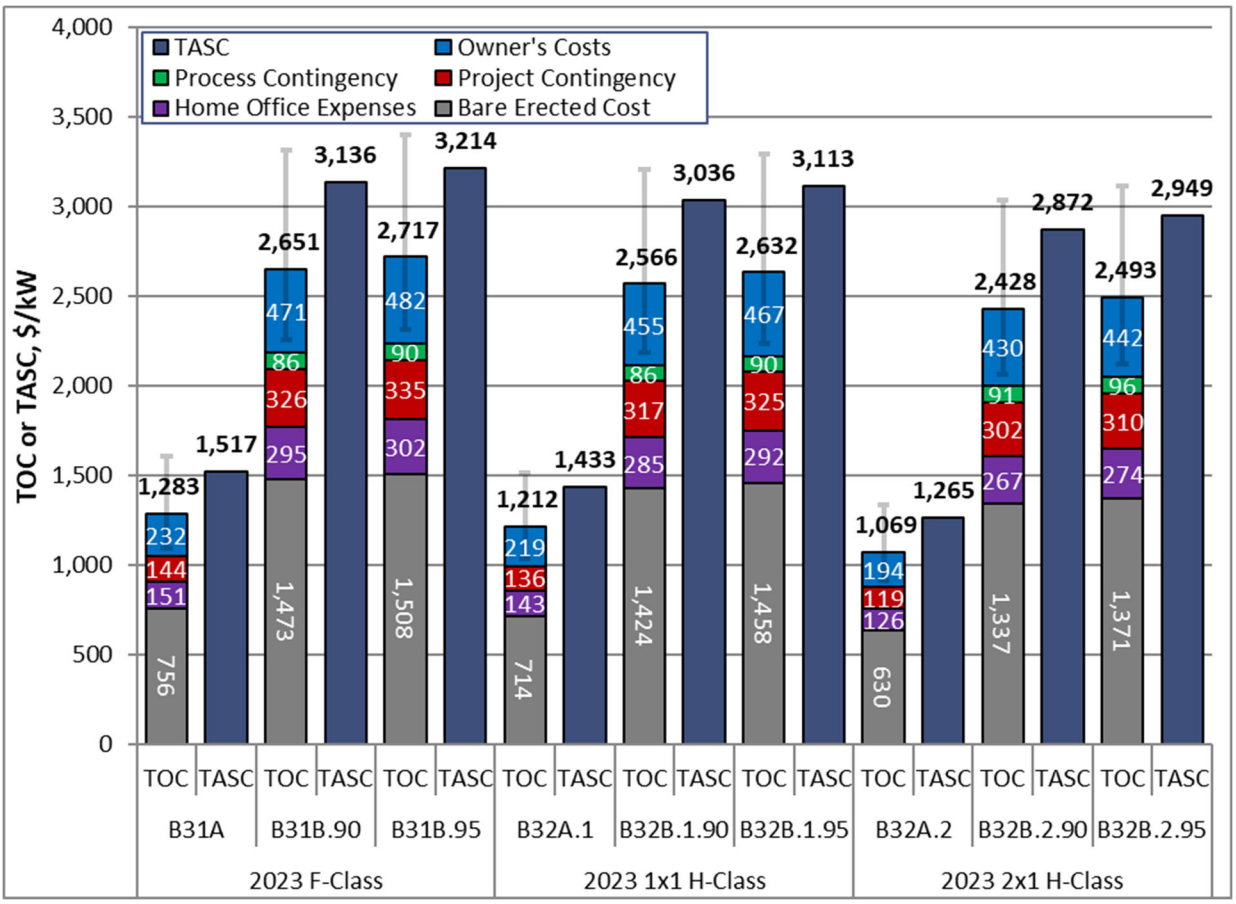
- Reduce the temperature of the flue gas exiting the HRSG from 91–94°C (196–202°F) to the CO_2 absorber operating temperature of 31°C (88°F), which also requires condensing water from the flue gas that comes from the HRSG
- Remove the heat input by the stripping steam to cool the solvent
- Remove heat of CO_2 absorption through absorber tower intercoolers
- Remove the heat input from the auxiliary electric loads
- Remove heat in the CO_2 compressor intercoolers
- Cool the CO_2 product stream exiting the CO_2 compressor to the target specification of 30°C (86°F)

The following observation can be made:

- Normalized water withdrawal increases 76–85 percent and normalized raw water consumption increases 51–53 percent in the CO_2 capture cases. The high cooling water demand of the capture process results in a large increase in cooling tower makeup requirements.

The components of TOC and TASC are shown for the NGCC cases in Exhibit 4-139. The addition of CO_2 capture more than doubles the TOC of the NGCC plant.

Exhibit 4-139. Plant capital cost for NGCC cases



The NGCC capital cost estimate accuracy provides an AACE Class 4 range of -15 percent/+25 percent. The error bars included in Exhibit 4-139 represent the potential TOC range relative to the maximum and minimum of the capital cost uncertainty range.

The following observations about normalized TOC ($/kW) can be made:

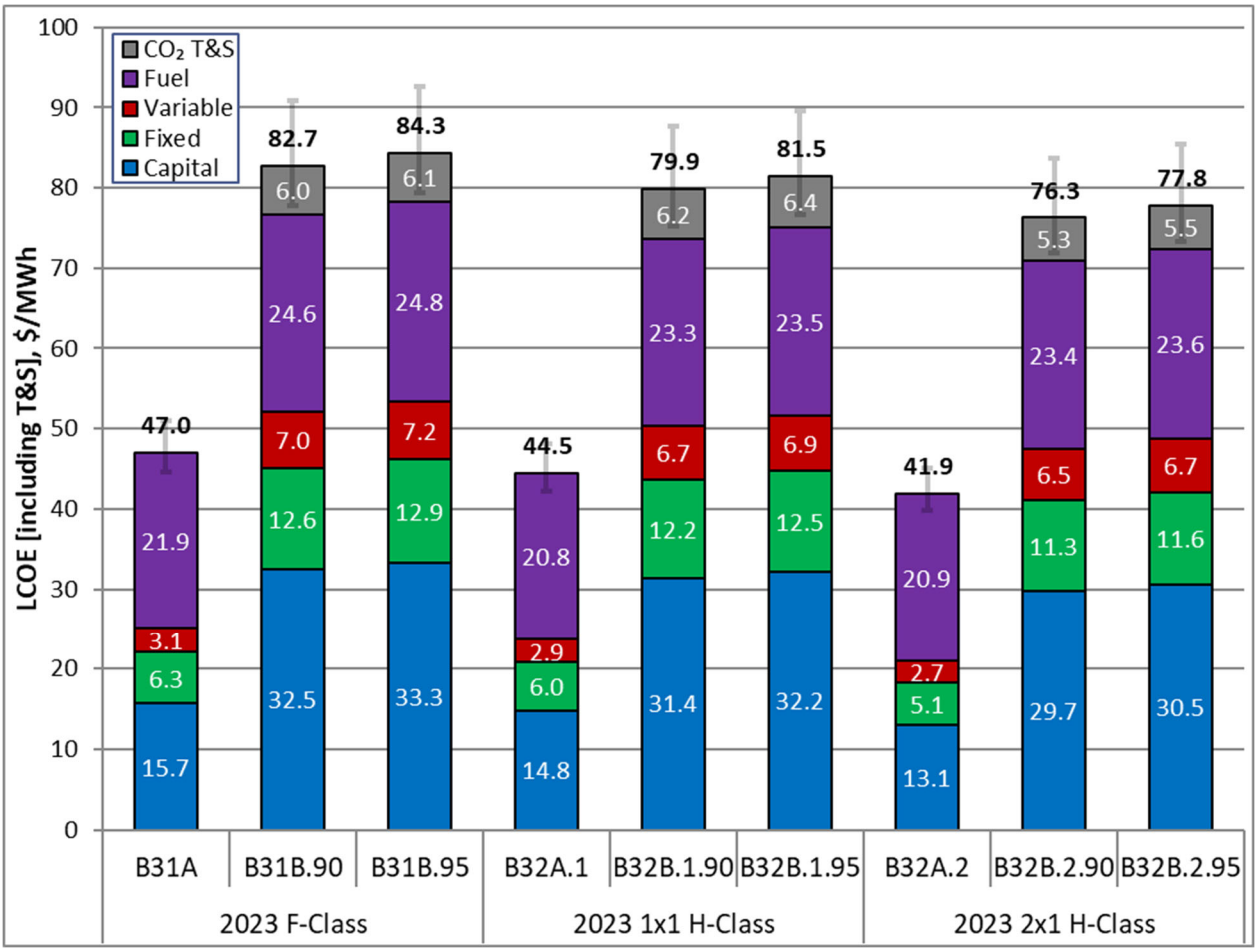
- The H-Class 2x1 configuration has the lowest normalized TOC for capture and non-capture cases, with the 1x1 H-Class and F-Class being 6–13 percent and 9–20 percent greater, respectively.
    - The TOCs of the non-capture H-Class cases are lower than the non-capture F-Class case (B31A) by 5.5 percent in the 1x1 configuration (B32A.1) and 16.6 percent in the 2x1 configuration (B32A.2).

  - The TOCs of the 90 percent CO_2 capture H-Class cases are lower than the F-Class case (B31B.90) by 3.2 percent in the 1x1 configuration (B32B.1.90) and 8.4 percent in the 2x1 configuration (B32B.2.90).
  - The TOCs of the 95 percent CO_2 capture H-Class cases are lower than the F-Class case (B31B.95) by 3.1 percent in the 1x1 configuration (B32B.1.95) and 8.2 percent in the 2x1 configuration (B32B.2.95).

- The TOC penalty for adding 90 percent CO_2 capture is 107 percent in the F-Class case (B31B.90), 112 percent in the 1x1 H-Class case (B32B.1.90), and 127 percent in the 2x1 H-Class case (B32B.2.90). The TOC penalty for adding 95 percent CO_2 capture is 112 percent in the F-Class case (B31B.95), 117 percent in the 1x1 H-Class case (B32B.1.95), and 133 percent in the 2x1 H-Class case (B32B.2.95). 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.
  - The 2x1 H-Class cases have a higher TOC penalty for adding CO_2 capture due to the need to use two parallel trains, compared to the single train used in F-Class and 1x1 H-Class cases (discussed in Section 4.1.4).

The LCOE is shown for the NGCC cases in Exhibit 4-140 (including T&S in the capture cases).

Exhibit 4-140. LCOE of NGCC cases



Similar to Exhibit 4-139, the error bars included in Exhibit 4-140 represent the potential LCOE range relative to the maximum and minimum capital cost uncertainty ranges. The LCOE ranges presented are not reflective of other changes, such as variation in fuel price, labor price, CF, or other factors. As an example, if Case B31B.90 capital costs were determined to be at the high end of the uncertainty range (+25 percent), then the LCOE result would be $90.8/MWh. Conversely, if at the low end of the uncertainty range (-15 percent), the LCOE result would be $77.8/MWh.

The following observations can be made:

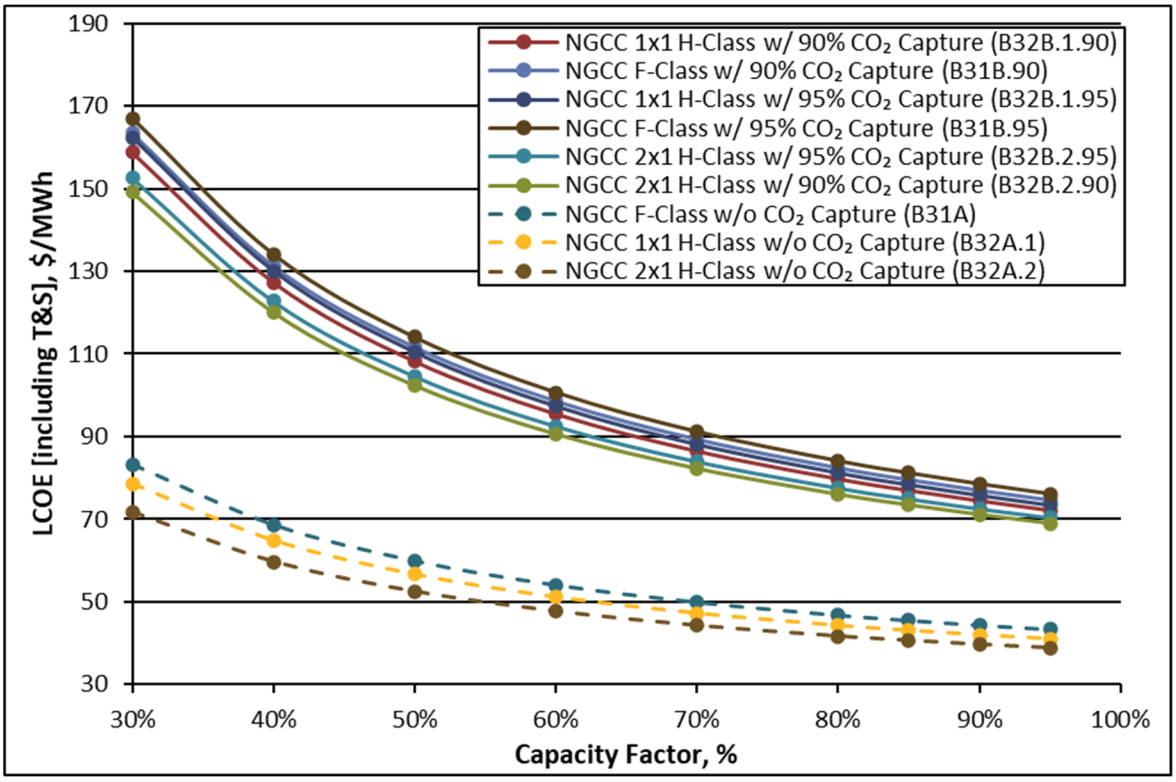
- Fuel costs represent the largest fraction of LCOE in non-capture cases, representing 46–50 percent of the total. In cases with CO_2 capture, capital costs represent the largest fraction of LCOE (including T&S costs), representing 39–40 percent of the total. The CO_2 T&S component represents 7–8 percent of the total LCOE in the CO_2 capture cases.
- The NGCC cases incur a 76–82 percent increase in LCOE (including T&S costs) due to the addition of 90 percent CO_2 capture.

- The addition of 95 percent CO_2 capture results in an additional LCOE (including T&S costs) penalty of $1.6/MWh (2 percent), compared to cases with 90 percent CO_2 capture.
- CO_2 T&S costs add $5–6/MWh to the LCOE, which accounts for 7–8 percent of the total LCOE.

As discussed in Section 4.1.4, the 2x1 H-Class cases (B32B.2.90 and B32B.2.95) use two parallel CO_2 capture trains due to the high volumetric flow rate of flue gas produced. A high-level estimate of a dual-absorber, single-train CO_2 capture system suggests that the TPC of the CO_2 capture system may be reduced by 17 percent in both cases, relative to the two-train configuration, which would reduce the LCOE by 4 percent in both cases.[r]

The sensitivity of LCOE to CF for the NGCC cases is shown in Exhibit 4-141. Implicit in the curves is the assumption that a CF of greater than 85 percent can be achieved without the expenditure of additional capital and capacity factors less than 85 percent do not result in lower capital or operating costs. The LCOE increases more rapidly at low CF because the capital component is spread over fewer kWh of generation.

Exhibit 4-141. Sensitivity of LCOE to capacity factor in NGCC cases

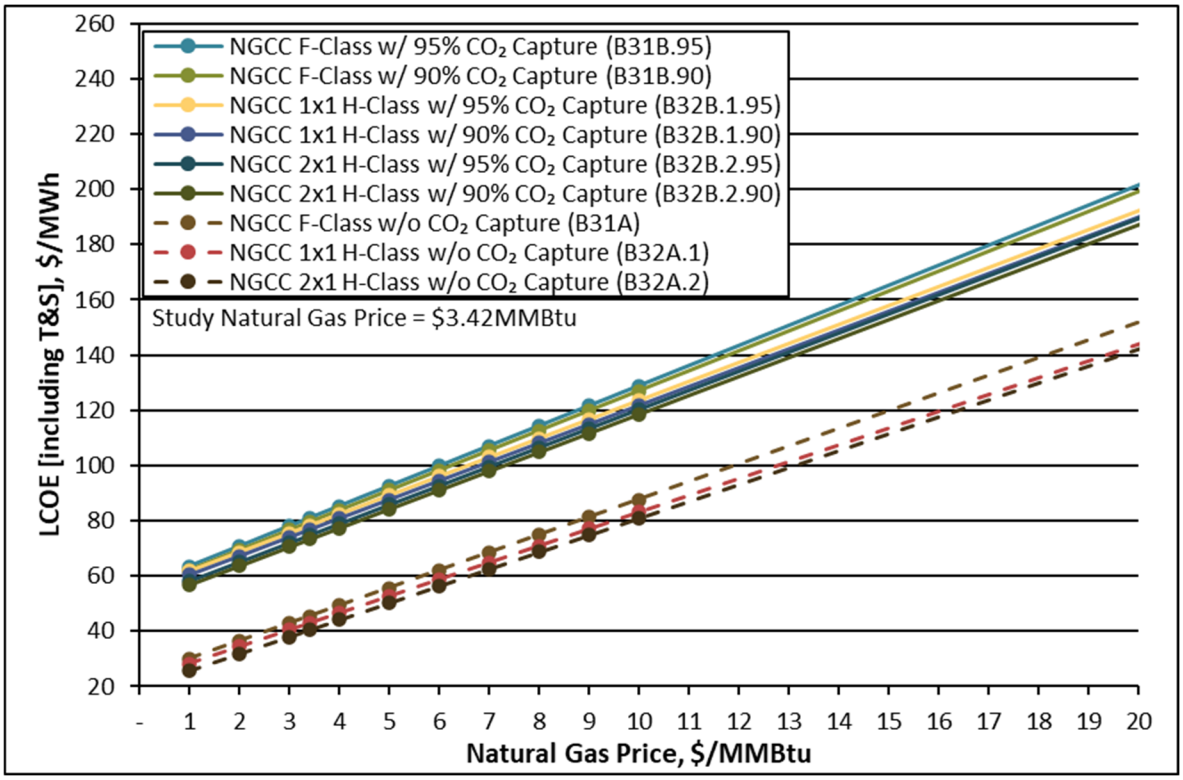


The sensitivity of LCOE to levelized fuel costs for the NGCC cases is shown in Exhibit 4-142. A 33 percent increase in natural gas levelized price (from $3.25 to $4.32/GJ [$3.42 to $4.55/MMBtu])

[r] As of the publication of this report, no commercial builds have been demonstrated with this design. The estimated cost impact does not reflect any vendor input.

results in an LCOE increase of 15–17 percent in the non-capture cases and 10 percent in the CO_2 capture cases. Because of the higher capital cost in the CO_2 capture case, the impact of fuel price changes is diminished.

Exhibit 4-142. Sensitivity of LCOE to fuel price in NGCC cases



The cost of CO_2 captured and avoided, shown in Exhibit 4-143 and Exhibit 4-144, respectively, were calculated using the methodology presented in Section 2.7.4.2 using the analogous non-capture reference case (Cases B31A, B32A.1, and B32A.2). The cost of CO_2 captured is $84–89/tonne ($76–80/ton) and the cost of CO_2 avoided is $115–122/tonne ($104–111/ton).

Exhibit 4-143. Breakdown of cost of CO_2 captured in NGCC cases

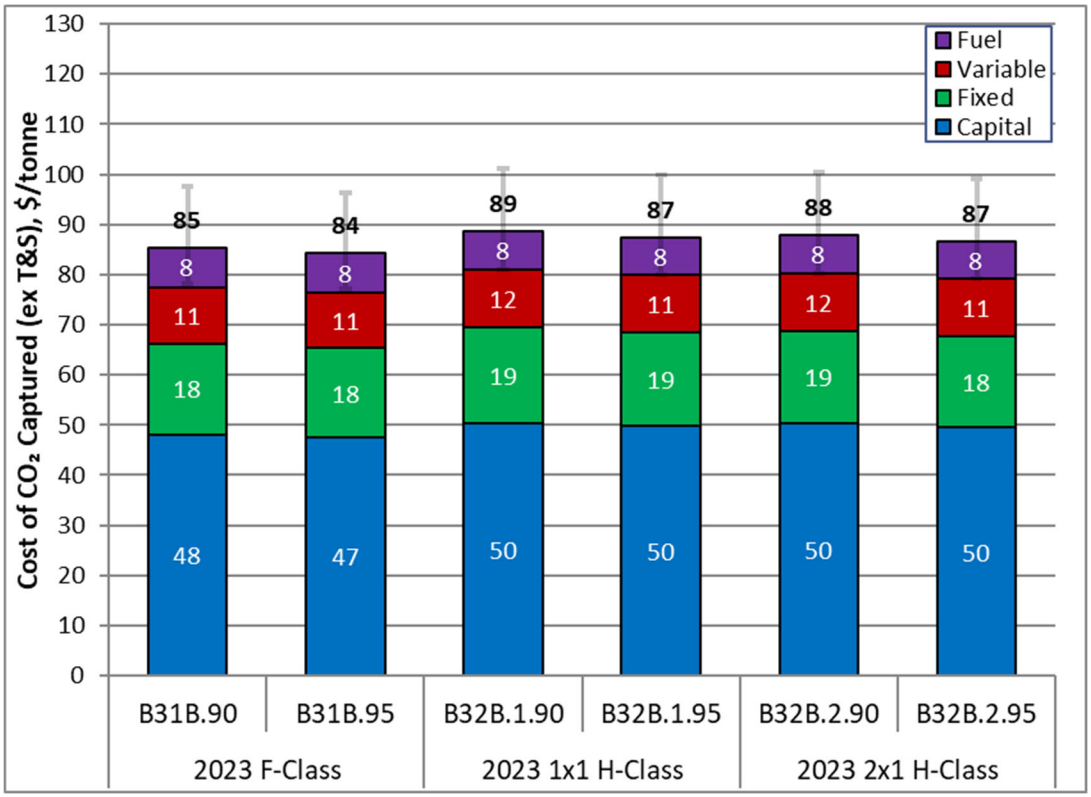
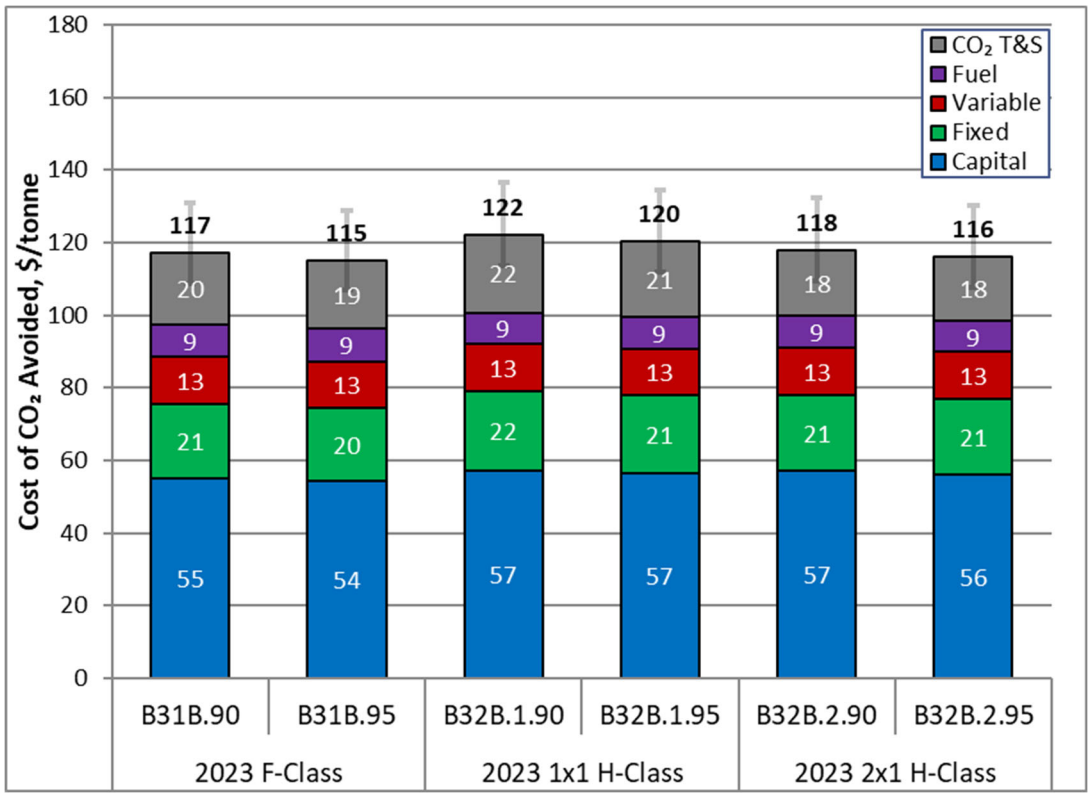


Exhibit 4-144. Breakdown of cost of CO_2 avoided in NGCC cases



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 RESULTS

Exhibit 5-1 provides a summary of the performance and environmental profile for PC and NGCC cases.

Exhibit 5-1. Performance summary and environmental profile for all cases

Case Name	PC						NGCC								
	SubC PC			SC PC			SOA 2023 F-Class			SOA 2023 1x1 H-Class[A]			SOA 2023 2x1 H-Class[A]		
	B11A	B11B.90	B11B.95	B12A	B12B.90	B12B.95	B31A	B31B.90	B31B.95	B32A.1	B32B.1.90	B32B.1.95	B32A.2	B32B.2.90	B32B.2.95
CO_2 Capture Rate (%)	0	90	95	0	90	95	0	90	95	0	90	95	0	90	95
Capacity Factor (%)	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Gross Power Output (MWe)	688	769	774	686	763	768	755	707	705	660	619	617	1,137	1,067	1,064
Auxiliary Power Requirement (MWe)	38	118	124	36	113	118	14	49	51	11	40	42	19	69	72
Net Power Output (MWe)	650	650	650	650	650	650	741	658	654	649	579	575	1,118	998	992
Coal Flow Rate (lb/hr)	493,115	630,940	640,819	473,055	600,801	609,741	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Natural Gas Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A	210,413	210,413	210,413	175,100	175,100	175,100	303,962	303,962	303,962
HHV Thermal Input (kWt)	1,685,945	2,157,162	2,190,938	1,617,359	2,054,118	2,084,684	1,386,417	1,386,417	1,386,417	1,153,739	1,153,739	1,153,739	2,002,815	2,002,815	2,002,815
Net Plant HHV Efficiency (%)	38.6	30.2	29.7	40.2	31.7	31.2	53.4	47.5	47.2	56.2	50.2	49.8	55.8	49.8	49.5
Net Plant HHV Heat Rate (Btu/kWh)	8,849	11,317	11,495	8,490	10,778	10,938	6,385	7,187	7,236	6,068	6,801	6,848	6,113	6,846	6,892
Raw Water Withdrawal (gpm/MWnet)	10.0	15.3	15.7	9.3	14.3	14.6	4.1	7.1	7.2	3.6	6.5	6.6	3.7	6.6	6.7
Process Water Discharge (gpm/MWnet)	2.1	3.9	4.0	1.9	3.7	3.8	1.0	2.5	2.6	0.9	2.4	2.4	0.9	2.4	2.4
Raw Water Consumption (gpm/MWnet)	8.0	11.4	11.7	7.4	10.6	10.9	3.0	4.6	4.6	2.7	4.1	4.1	2.8	4.2	4.2
CO_2 Emissions (lb/MMBtu)	202	20	10	202	20	10	119	12	6	119	12	6	119	12	6
CO_2 Emissions (lb/MWh-gross)	1,693	195	98	1,628	187	94	743	79	40	707	76	38	713	76	38
CO_2 Emissions (lb/MWh-net)	1,790	230	117	1,718	219	111	757	85	43	719	81	41	725	81	41
SO_2 Emissions (lb/MMBtu)[B]	0.081	0.000	0.000	0.081	0.000	0.000	0.001	0.000	0.000	0.001	0.000	0.000	0.001	0.000	0.000
SO_2 Emissions (lb/MWh-gross)	0.675	0.000	0.000	0.649	0.000	0.000	0.006	0.000	0.000	0.006	0.000	0.000	0.006	0.000	0.000
NOx Emissions (lb/MMBtu)	0.084	0.073	0.072	0.087	0.076	0.076	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
NOx Emissions (lb/MWh-gross)	0.700	0.700	0.700	0.700	0.700	0.700	0.021	0.021	0.021	0.019	0.018	0.018	0.020	0.019	0.019
PM Emissions (lb/MMBtu)	0.011	0.009	0.009	0.011	0.010	0.010	0.003	0.000	0.000	0.002	0.000	0.000	0.003	0.000	0.000
PM Emissions (lb/MWh-gross)	0.090	0.090	0.090	0.090	0.090	0.090	0.017	0.000	0.000	0.014	0.000	0.000	0.016	0.000	0.000
Hg Emissions (lb/TBtu)	0.359	0.313	0.311	0.373	0.326	0.324	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Hg Emissions (lb/MWh-gross)[C]	$3.00x10^{-6}$	$3.00x10^{-6}$	$3.00x10^{-6}$	$3.00x10^{-6}$	$3.00x10^{-6}$	$3.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$

[A] The combustion turbine used in the 1x1 H-Class plant is larger and more advanced than that of the 2x1 H-Class plant
[B] Trace amounts of sulfur emissions may exist in the flue gas stream to the stack in capture cases
[C] The mercury capture units used in PC cases were designed to attain the emissions target of $3.00x10^{-6}$ lb/MWh-gross

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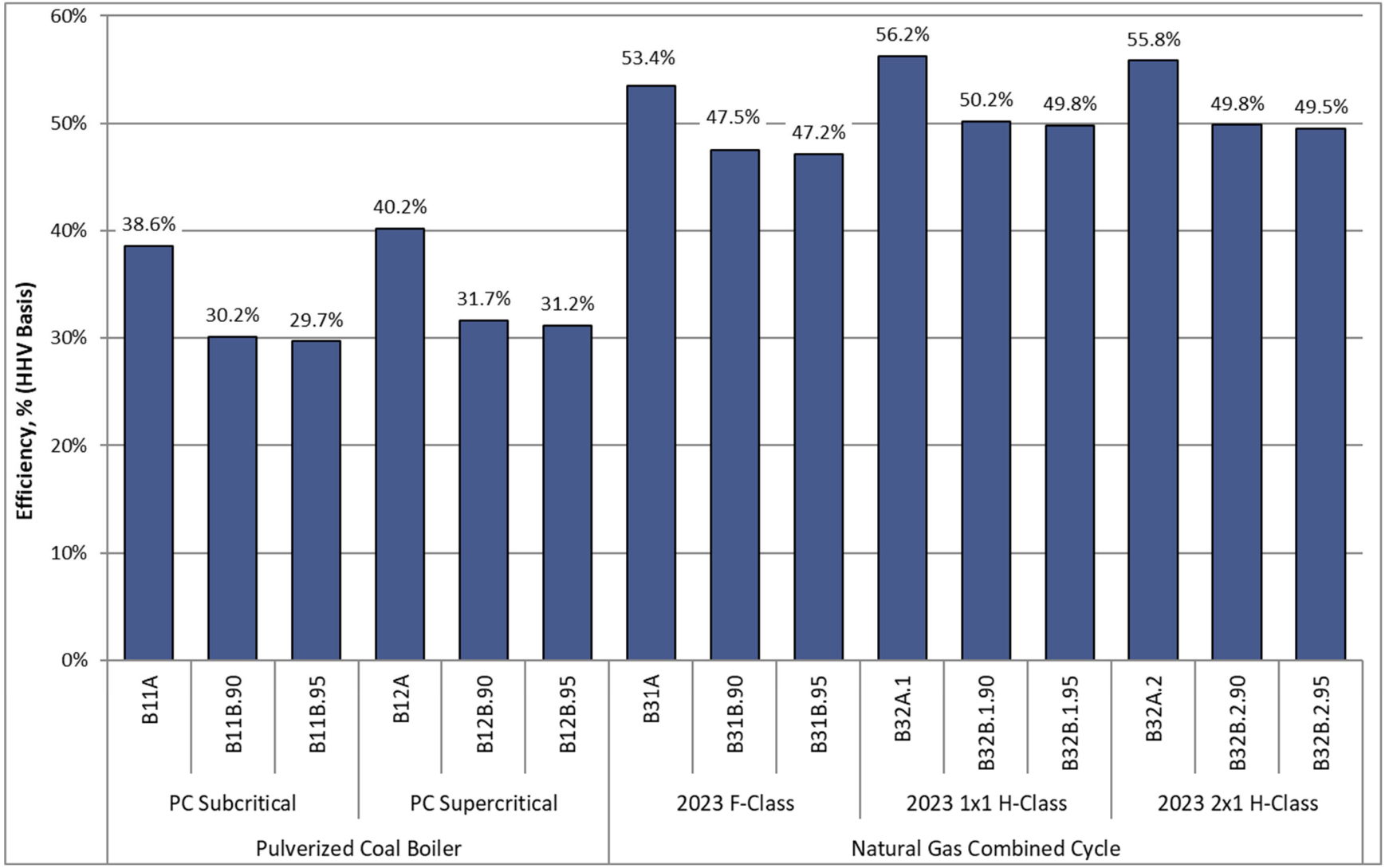
5.1.1 Energy Efficiency

A graph of the net plant efficiency (HHV basis) is provided in Exhibit 5-2. The primary conclusions that can be drawn are as follows:

- The 1x1 H-Class NGCC cases have the highest HHV net plant efficiency of all the technologies, both without CO_2 capture (56.2 percent in Case B32A.1) and with CO_2 capture (50.2 and 49.8 percent at 90 percent [Case B32B.1.90] and 95 percent [Case B32B.1.95] CO_2 capture rates, respectively). The next highest non-NGCC case efficiency is the non-capture SC PC case (B12A), with an efficiency of 40.2 percent.
- When comparing cases with similar rates of CO_2 capture, the HHV net plant efficiency of the SC PC cases are 1.5–1.6 percentage points higher than those of SubC PC cases. Similarly, the 2x1 H-Class cases have HHV efficiencies 2.4 percentage points higher than F-Class cases and the 1x1 H-Class cases have HHV efficiencies 2.7–2.8 percentage points higher than F-Class cases:
    - The combustion turbine used in the 1x1 H-Class plant is larger and more advanced than that of the 2x1 H-Class plant. The H-Class combustion turbines were selected to 1) provide an H-Class configuration (1x1) that was comparable in output to the PC plants, produced a volume of flue gas that could be treated with a single train CO_2 capture system, and represented the most advanced commercial offering; and 2) provide an H-Class configuration (2x1) and combustion turbine that was consistent with previous revisions of this study.
- For the PC cases, adding 90 percent CO_2 capture results in an HHV efficiency penalty of 8.4 percentage points (21.8 percent), relative to the non-capture case (B11A) for the SubC PC case (B11B.90) and 8.5 percentage points (21.2 percent), relative to the non-capture case (B12A) for the SC PC case (B12B.90).
- The addition of 95 percent CO_2 capture in PC cases (B11B.95 and B12B.95) results in an HHV efficiency penalty of 0.5 percentage points (1.5–1.6 percent), relative to the 90 percent capture cases (B11B.90 and B12B.90).
- For the NGCC cases, adding 90 percent CO_2 capture results in an HHV efficiency penalty of 6 percentage points (11 percent), relative to the non-capture cases (B31A, B32A.1, and B32A.2), for the F-Class case (B31B.90) and H-Class cases (B32B.1.90 and B32B.2.90).
- The addition of 95 percent CO_2 capture in NGCC cases (B31B.95, B32B.1.95, and B32B.2.95) results in an HHV efficiency penalty of 0.3 percentage points (0.7 percent) for F- and H-Class cases, relative to the 90 percent capture cases (B31B.90, B32B.1.90, and B32B.2.90).
- The energy penalty for adding CO_2 capture is less in NGCC cases than in PC cases 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 (13.7 kg/GJ) [HHV] of heat input and coal contains 55 lb/MMBtu (23.6 kg/GJ) [HHV]).

- 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 56–60 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 (4–5 vol% versus 12 vol% for PC)—concentration of CO_2 is the driving force for capture from the flue gas in the amine system, and the lower concentration requires more energy (steam and auxiliary load) from the base plant to reach the capture target.

Exhibit 5-2. Net plant efficiency (HHV basis)



Sankey diagrams for PC and NGCC cases, both without and with 90 percent CO_2 capture, are shown in Exhibit 5-3 through Exhibit 5-7. Discussion and cross-technology comparisons follow the exhibits.

Exhibit 5-3. SubC PC Sankey diagram with and without CO_2 capture

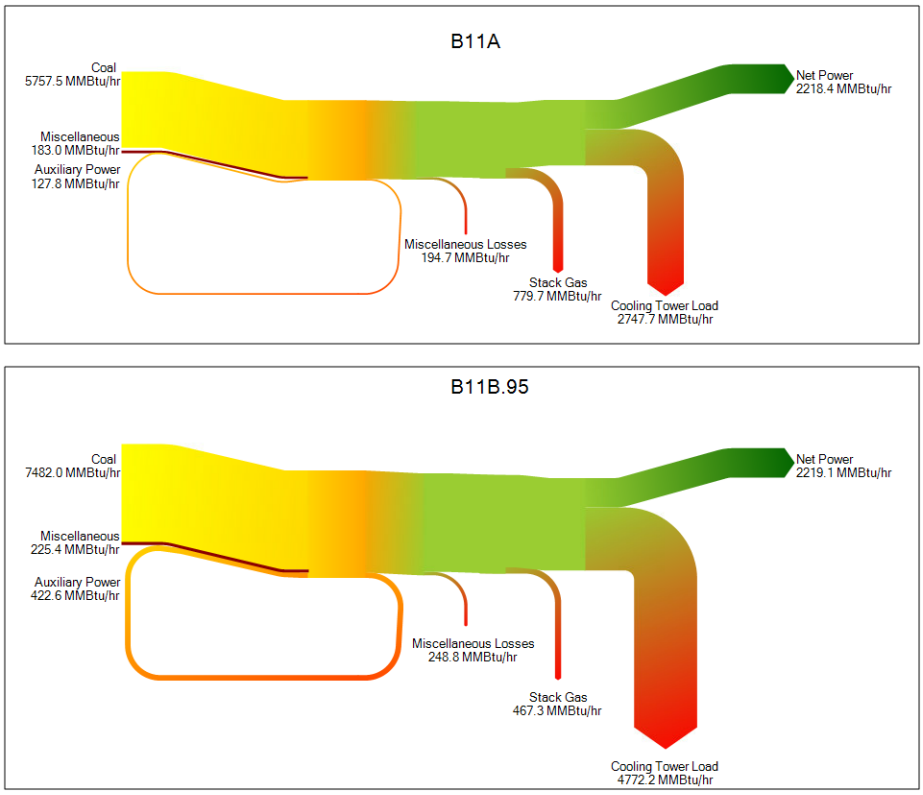


Exhibit 5-4. SC PC Sankey diagram with and without CO_2 capture

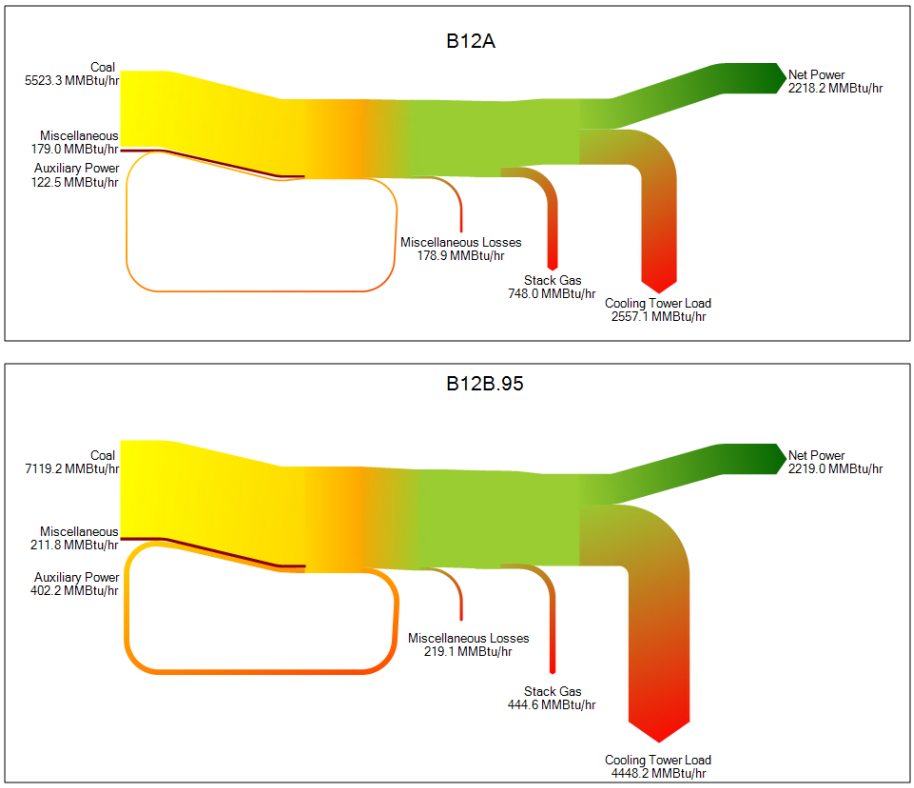


Exhibit 5-5. NGCC F-Class Sankey diagram with and without CO_2 capture

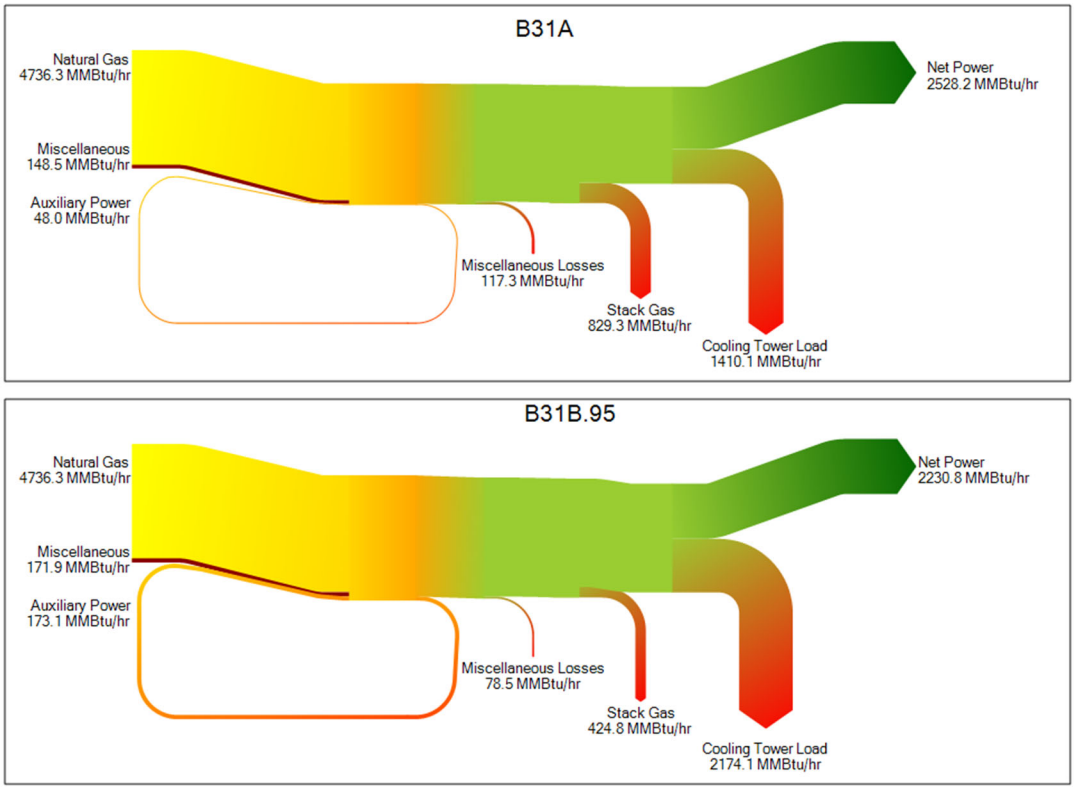


Exhibit 5-6. NGCC 1x1 H-Class Sankey diagram with and without CO_2 capture

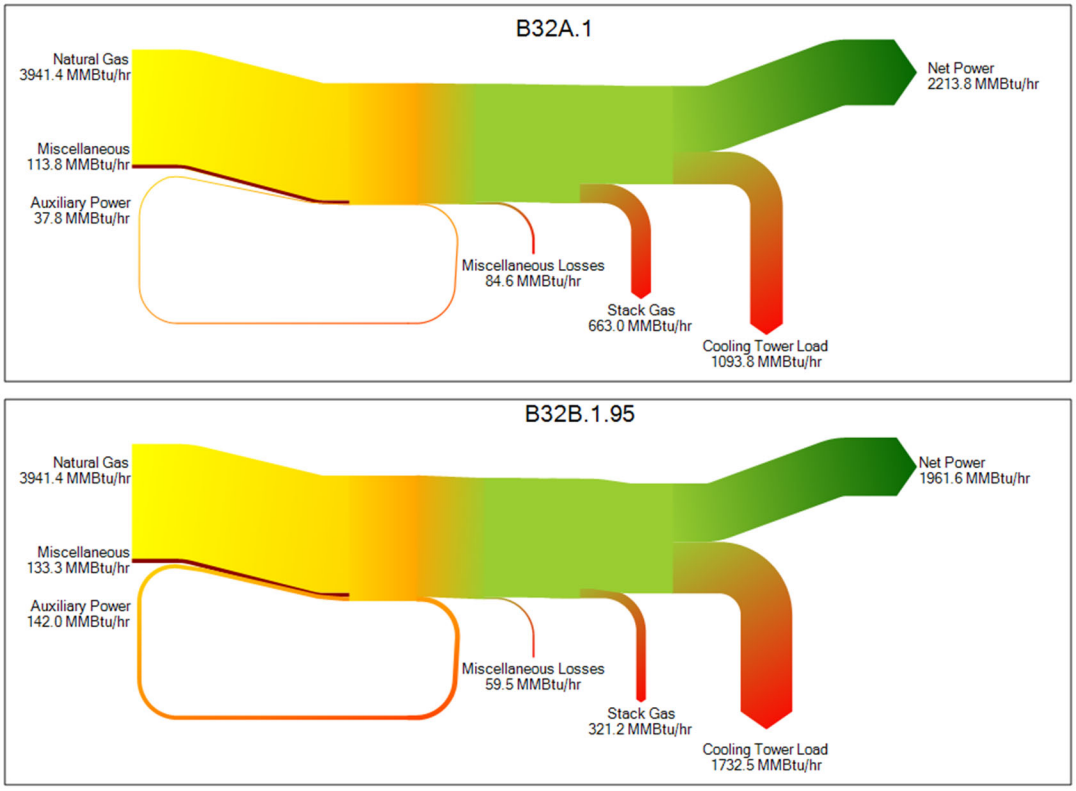
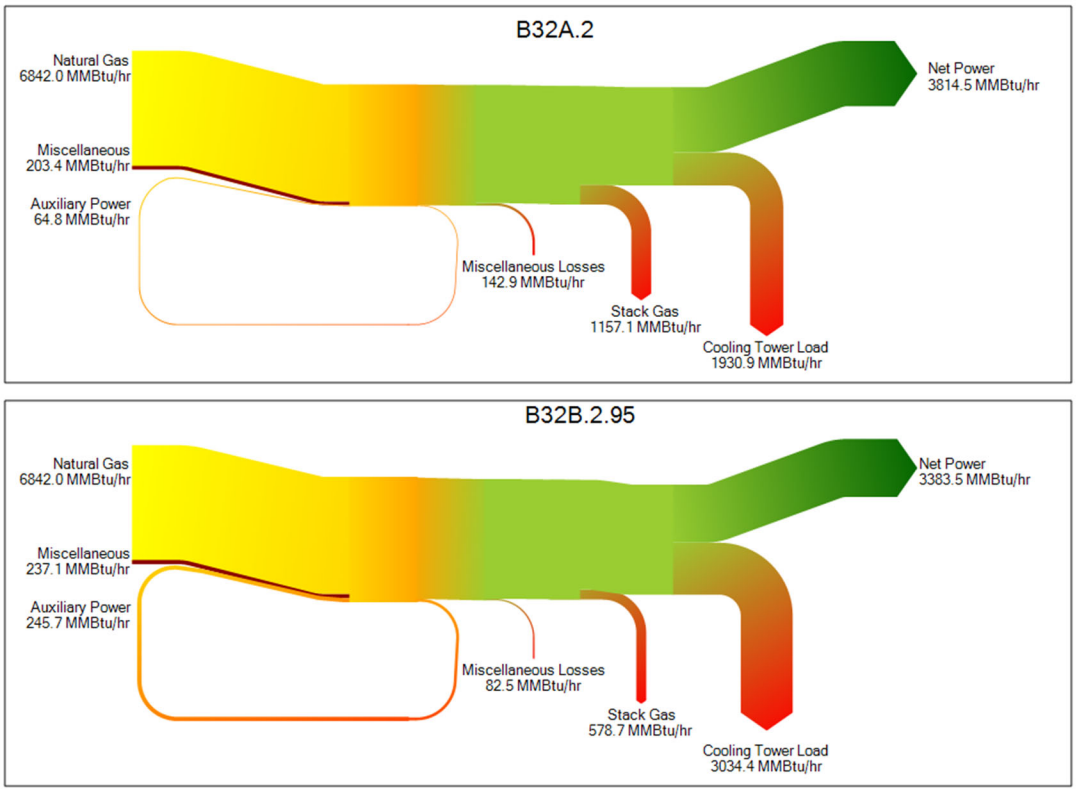


Exhibit 5-7. NGCC 2x1 H-Class Sankey diagram with and without CO_2 capture



The miscellaneous losses category is used to simplify the diagrams for the numerous, but relatively small, heat outlet streams, and includes different items across the two technology types. In PC cases, this category includes bottom and fly ash, sulfur, gypsum, blowdown streams, deaerator vent, ambient losses, CO_2 product, AGR effluent, and others. In NGCC cases, this category includes deaerator vent, ambient losses, CO_2 product, AGR effluent, and others.

In comparing the Sankey diagram results of PC and NGCC cases, several observations can be made:

- The size of the Rankine cycle (output basis) in PC plants is larger than NGCC, which contributes to the larger cooling tower load observed in PC plants. The addition of CO_2 capture impacts additional load on the cooling tower, thus creating an even larger cooling tower load for PC cases with capture as compared to NGCC cases with capture.
- In PC cases, the miscellaneous losses are larger in capture cases than non-capture cases because the coal feed rate is increased to maintain a constant net power output, which results in higher ash and gypsum production, ambient losses, stack flow rate, blowdowns, etc. Conversely, in NGCC cases, the miscellaneous losses are lower in capture cases than non-capture cases because the natural gas feed rate is held constant instead of the net power output and the CO_2 product from the capture cases has a negative enthalpy relative to the reference conditions.

5.1.2 Environmental Emissions

Estimated emissions of Hg, HCl, PM, NOx, and SO_2 are all at or below the applicable regulatory limits currently in effect for all cases. Emissions results for each case were provided in Exhibit 5-1.

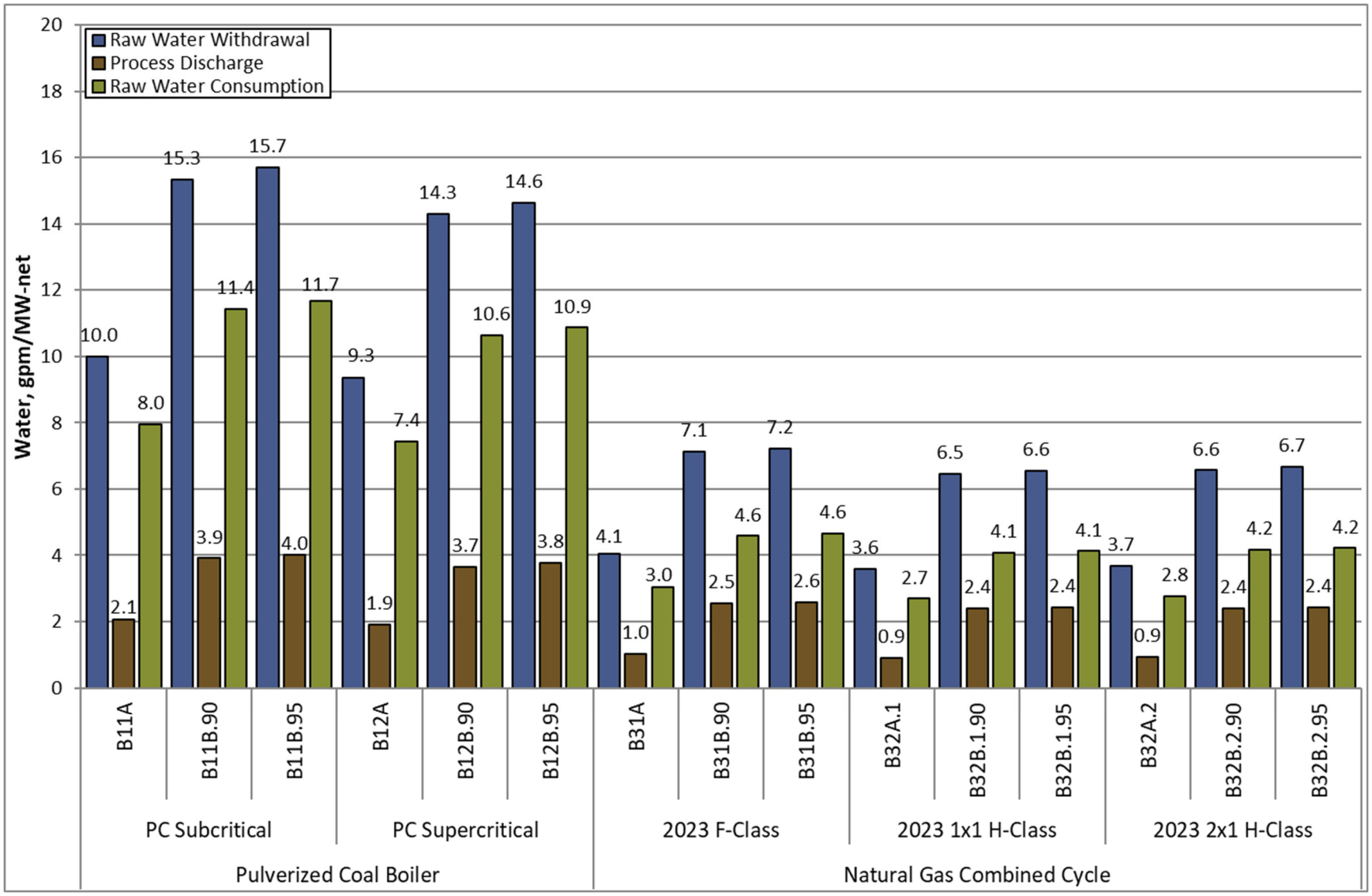
Natural gas does not contain Hg, PM, or HCl, which makes its environmental profile more attractive compared to PC cases. In this report, it was assumed that the only sulfur present in natural gas is from the addition of the odorant, mercaptan. This results in an SO_2 emission rate below the regulatory limits without any further control.

For the PC cases, the FGD wastewater blowdown flow rate range to be treated by the SDE for ELG compliance spans 209–283 lpm (55–75 gpm). The approximate performance impact of implementing the SDE across the six PC cases is a 0.25–0.27 percentage point decrease in the HHV net plant efficiency. This is due primarily to the diversion of warm flue gas away from the air preheater and to the evaporator, with an additional minor impact resulting from the small auxiliary load required by the SDE.

5.1.3 Water Use

Three water values are presented for each technology in Exhibit 5-8: raw water withdrawal, process discharge, and raw water consumption. Each value is normalized by net output.

Exhibit 5-8. Raw water withdrawal and consumption



The primary conclusions that can be drawn are as follows:

- NGCC has the lowest raw water consumption of all cases for both non-capture and CO_2 capture cases. The results are expected given the higher steam turbine output in the PC cases, which results in higher condenser duties and consequently higher cooling water demand.
- 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. On a normalized basis, raw water consumption increases by 51–53 percent for the NGCC cases and 43–47 percent for the PC cases.

5.2 COST RESULTS

Cost results for all PC and NGCC cases are presented in Exhibit 5-9.

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Exhibit 5-9. Cost summary for all cases

Case Name[A]	PC						NGCC								
	SubC PC			SC PC			SOA 2023 F-Class			SOA 2023 1x1 H-Class[B]			SOA 2023 2x1 H-Class[B]		
	B11A	B11B.90	B11B.95	B12A	B12B.90	B12B.95	B31A	B31B.90	B31B.95	B32A.1	B32B.1.90	B32B.1.95	B32A.2	B32B.2.90	B32B.2.95
Total Plant Cost (2023$/kW)	2,471	4,177	4,258	2,584	4,254	4,331	1,051	2,180	2,235	993	2,111	2,165	876	1,998	2,051
Bare Erected Cost	1,822	2,964	3,019	1,906	3,025	3,078	756	1,473	1,508	714	1,424	1,458	630	1,337	1,371
Home Office Expenses	319	519	528	334	529	539	151	295	302	143	285	292	126	267	274
Project Contingency	331	581	593	345	590	601	144	326	335	136	317	325	119	302	310
Process Contingency	0	113	117	0	109	113	0	86	90	0	86	90	0	91	96
Total Overnight Cost (2023$/MM)	1,985	3,341	3,405	2,072	3,399	3,460	950	1,745	1,776	786	1,486	1,513	1,196	2,424	2,472
Total Overnight Cost (2023$/kW)	3,054	5,137	5,236	3,188	5,226	5,321	1,283	2,651	2,717	1,212	2,566	2,632	1,069	2,428	2,493
Owner's Costs	583	960	979	604	972	990	232	471	482	219	455	467	194	430	442
Total As-Spent Cost (2023$/kW)	3,704	6,230	6,350	3,866	6,338	6,453	1,517	3,136	3,214	1,433	3,036	3,113	1,265	2,872	2,949
FY COE ($/MWh) (excluding T&S)[C]	86.0	133.6	136.0	86.9	132.8	135.1	58.5	87.3	88.8	55.4	83.6	85.0	53.1	81.3	82.7
Capital Costs	38.3	64.5	65.7	40.0	65.6	66.8	15.7	32.5	33.3	14.8	31.4	32.2	13.1	29.7	30.5
Fixed Costs	11.1	17.9	18.2	11.6	18.2	18.5	4.7	9.5	9.7	4.5	9.2	9.4	3.9	8.5	8.7
Variable Costs	9.8	17.1	17.5	9.7	16.6	16.9	2.3	5.3	5.4	2.2	5.0	5.2	2.0	4.9	5.0
Fuel Costs	26.7	34.1	34.6	25.6	32.5	33.0	35.7	40.2	40.4	33.9	38.0	38.3	34.2	38.2	38.5
FY COE ($/MWh) (including T&S)[C]	86.0	142.7	146.3	86.9	141.7	145.0	58.5	91.8	93.4	55.4	88.3	89.8	53.1	85.3	86.8
CO_2 T&S Costs	N/A	9.1	10.3	N/A	8.9	9.8	N/A	4.5	4.6	N/A	4.7	4.8	N/A	4.0	4.1
LCOE ($/MWh) (excluding T&S)[C]	89.4	140.6	143.2	90.5	140.0	142.5	47.0	76.7	78.2	44.5	73.6	75.1	41.9	71.0	72.4
Capital Costs	38.3	64.5	65.7	40.0	65.6	66.8	15.7	32.5	33.3	14.8	31.4	32.2	13.1	29.7	30.5
Fixed Costs	14.9	23.9	24.3	15.5	24.2	24.6	6.3	12.6	12.9	6.0	12.2	12.5	5.1	11.3	11.6
Variable Costs	13.1	22.8	23.3	12.9	22.2	22.6	3.1	7.0	7.2	2.9	6.7	6.9	2.7	6.5	6.7
Fuel Costs	23.0	29.4	29.9	22.1	28.0	28.4	21.9	24.6	24.8	20.8	23.3	23.5	20.9	23.4	23.6
LCOE ($/MWh) (including T&S)[C]	89.4	152.7	156.9	90.5	151.9	155.6	47.0	82.7	84.3	44.5	79.9	81.5	41.9	76.3	77.8
CO_2 T&S Costs	N/A	12.1	13.7	N/A	11.9	13.1	N/A	6.0	6.1	N/A	6.2	6.4	N/A	5.3	5.5
Cost of CO_2 Captured (ex. T&S), $/tonne[D]	N/A	53.6	52.6	N/A	55.7	54.5	N/A	85.4	84.3	N/A	88.6	87.5	N/A	87.9	86.7
Cost of CO_2 Avoided (incl. T&S), $/tonne[D]	N/A	92.3	91.5	N/A	90.4	89.3	N/A	117.1	115.2	N/A	122.3	120.3	N/A	117.9	116.0

[A]The combustion turbine used in the 1x1 H-Class plant is larger and more advanced than that of the 2x1 H-Class plant
[B]Financing structures are presented in the QGESS report, "Cost Estimation Methodology for NETL Techno-economic Assessments" (NETL, 2025b)
[C]Varying incentives, such as tax credits, could impact the economics of the system
[D]Both the cost of CO_2 captured and cost of CO_2 avoided were calculated based on the non-capture SC PC Case B12A for all coal cases, and the analogous non-capture NGCC Cases (i.e., B31B cases use B31A as a reference, B32B.1 cases use B32A.1, and B32B.2 cases use B32A.2)

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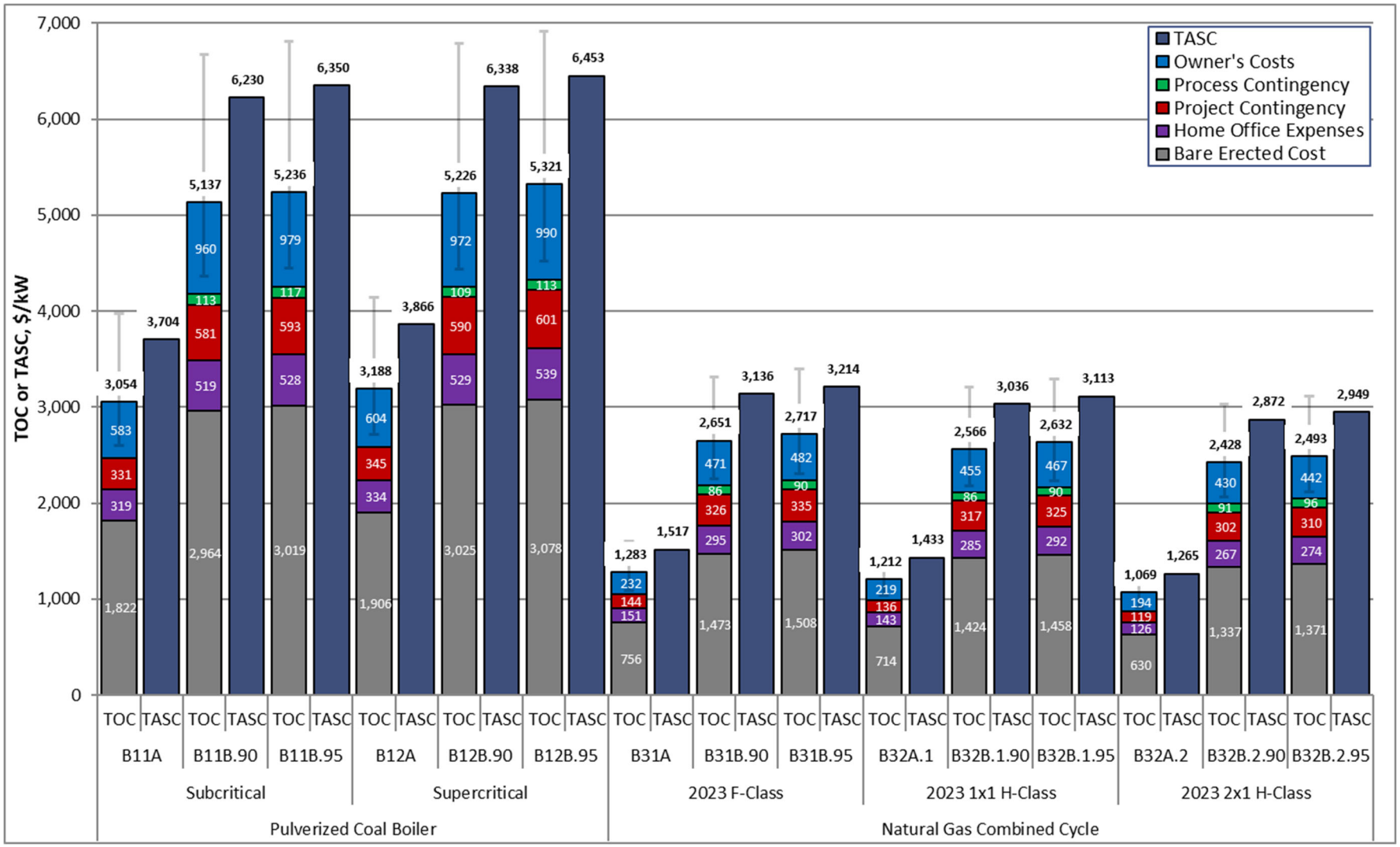
5.2.1 TOC and TASC

In Exhibit 5-10, the normalized components of TOC and TASC are shown for each technology. As described previously in the technology summary sections, each technology carries with it a different uncertainty range for the capital cost estimate. The error bars included in Exhibit 5-10 represent the potential TOC range relative to the maximum and minimum of the capital cost uncertainty range.

The following observations about normalized TOC can be made:

- NGCC 2x1 H-Class capital costs are 34 percent of the SC PC capital costs for non-capture cases (B32A.2 vs B12A), 46 percent of the SC PC capital costs for the 90 percent capture cases (B32B.2.90 vs B12B.90), and 47 percent of the SC PC capital costs for the 95 percent capture cases (B32B.2.95 vs B12B.95), on a $/kW basis.
    - The NGCC cost advantage over PC is partially enabled by the lack of emission control equipment necessary for adherence to current regulations.
- The addition of CO_2 capture technology significantly impacts the TOC of all technologies, with the greatest impact demonstrated on NGCC cases. On a $/kW basis, the increase from the addition of CO_2 capture technology spans the range of 64–71 percent for PC cases (68–71 percent for SubC PC and 64–67 percent for SC PC) and 107–133 percent for NGCC cases (107–112 percent for F-Class, 112–117 percent for 1x1 H-Class, and 127–133 percent for 2x1 H-Class).
    - The 2x1 H-Class cases have a higher TOC penalty for adding CO_2 capture due to the need for two parallel trains, compared to the single train used in F-Class and 1x1 H-Class cases (discussed in Section 4.1.4).

Exhibit 5-10. Plant capital costs



5.2.2 LCOE

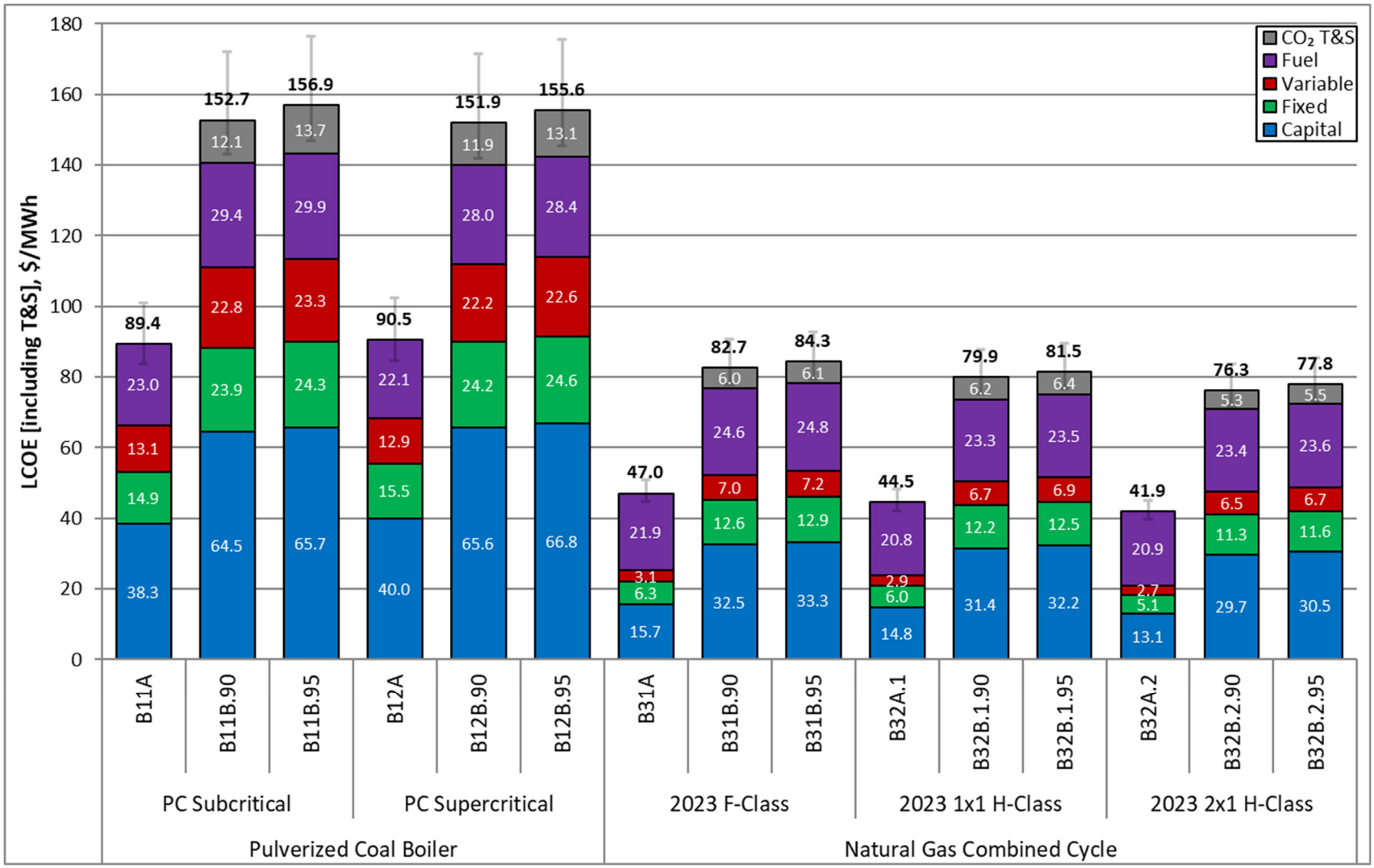
A graph of the LCOE by cost component is provided in Exhibit 5-11. As described previously in the technology summary sections, each technology carries with it a different uncertainty range for the capital cost estimate. The error bars included in Exhibit 5-11 represent the potential LCOE range relative to the maximum and minimum of the capital cost uncertainty range. The LCOE ranges presented are not reflective of other parameter changes, such as variation in fuel price, labor price, CF, or other factors. The primary observations that can be made are as follows:

- In PC cases, the LCOE (including T&S) is dominated by the capital cost component (42–44 percent) followed by the fuel cost component (18–26 percent).
- In NGCC cases, fuel costs represent the largest fraction of LCOE in non-capture cases, representing 46–50 percent of the total. In cases with CO_2 capture, capital costs represent the largest fraction of LCOE (including T&S), representing 39–40 percent of the total.
- The CO_2 T&S LCOE component represents 7–9 percent of the total LCOE across the cases with CO_2 capture considered in this study.

As discussed in Section 4.1.4, the 2x1 H-Class cases (B32B.2.90 and B32B.2.95) use two parallel CO_2 capture trains due to the high volumetric flow rate of flue gas produced. A high-level estimate of a dual-absorber, single-train CO_2 capture system suggests that the TPC of the CO_2 capture system may be reduced by 17 percent in both cases, relative to the two-train configuration, which would reduce the LCOE by 4 percent in both cases.[s]

[s] As of the publication of this report, no commercial builds have been demonstrated with this design. The estimated cost impact does not reflect any vendor input.

Exhibit 5-11. LCOE by cost component



Note: Financing structures are presented in the QGESS report, "Cost Estimation Methodology for NETL Techno-economic Assessments" (NETL, 2025b)

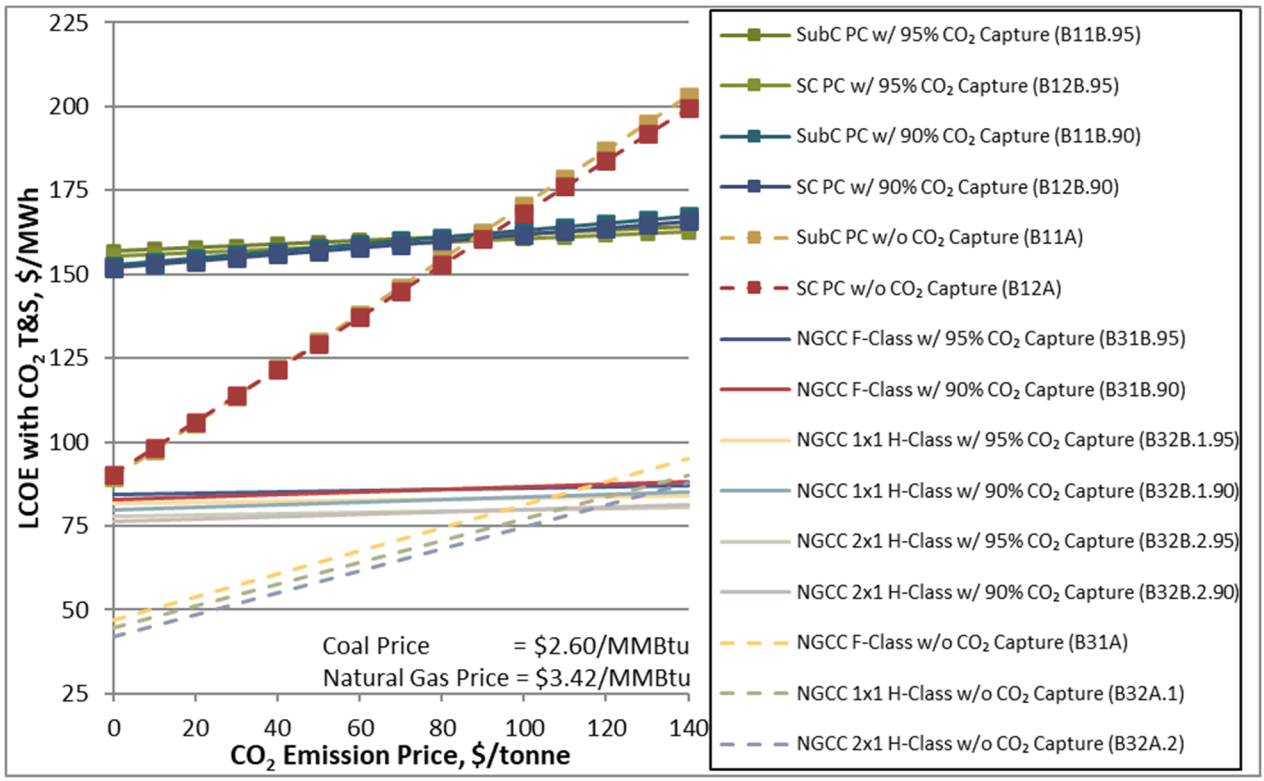
5.2.3 CO_2 Emission Price Impact

If future legislation assigns a cost to carbon emissions, all 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 for 90 and 95 percent capture cases is shown in Exhibit 5-12 as the intersection of the lines of CO_2 capture PC cases with the line for the SC PC non-capture case, and the intersection of the lines of NGCC CO_2 capture cases with the lines for the analogous NGCC non-capture cases. For example, the cost of CO_2 avoided is $89–92/tonne ($81–84/ton) for PC and $115–122/tonne ($104–111/ton) for NGCC.

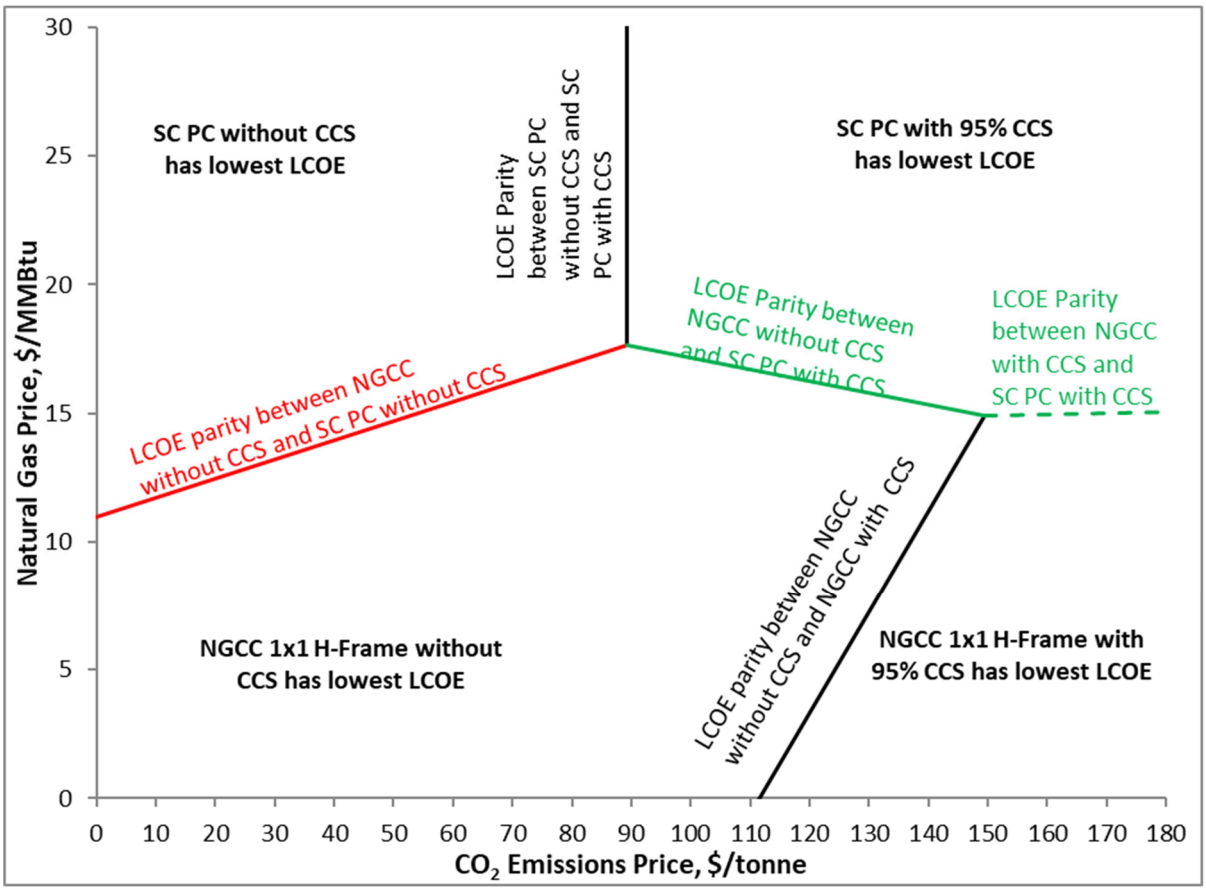
The curves in Exhibit 5-12 represent the study design conditions (CF) and levelized fuel prices used for each technology; namely an 85 percent CF and $2.46/GJ ($2.60/MMBtu) for coal and $3.25/GJ ($3.42/MMBtu) for natural gas.

Exhibit 5-12. Impact of carbon emissions price on study technologies



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 5-13. The lines in the plot represent cost parity between different pairs of technologies. Where cases include CO_2 capture, the reference cases include 95 percent capture.

Exhibit 5-13. Lowest cost power generation options at various NG and CO_2 emissions prices for NGCC and PC



The plot demonstrates the following points:

- Non-capture plants are the low-cost option below a CO_2 price of $89.3/tonne ($81.1/ton).
- NGCC is preferred when natural gas prices are below $11.0/MMBtu (and a CF of 85 percent). SC PC plants are preferred when natural gas prices are above $17.6/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 for capture plant configurations. The plant gate CO_2 sales price will ultimately depend on a number of factors, such as the varying performance of a CO_2 EOR flood, 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 relative to a defined reference non-capture plant.

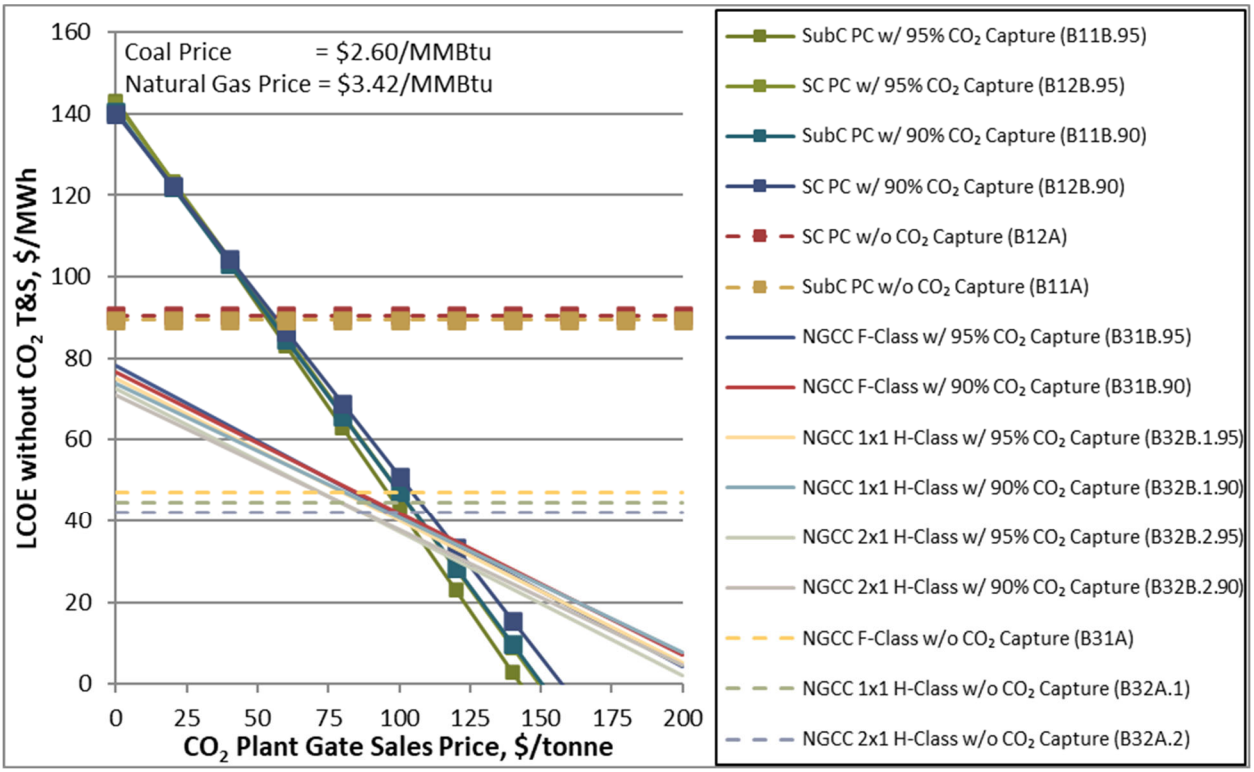
The industry CO_2 sales price for EOR varies from $17/ton to $50/ton (Martin, Johnson, Stolberg, Zhang, & Young, 2017) with an average price of $40/ton, as of 2019 (Moskal & Nuñez-López, 2019). A general rule of thumb used in academic work for estimating the CO_2 price for EOR is that one million cubic feet of CO_2 will cost approximately 2 percent of a barrel of Western Texas

Intermediate oil, which results in a CO_2 sales price of $24.86/ton(Martin, Johnson, Stolberg, Zhang, & Young, 2017). For qualifying facilities, a $54/ton ($60/tonne) tax credit is available for CO_2 geologically sequestered with EOR through Section 45Q (CRS, 2023).

The cost of CO_2 captured is shown in Exhibit 5-14 as the intersection of the lines of CO_2 capture PC cases with the line for the SC PC non-capture case, and the intersection of the lines of NGCC CO_2 capture cases with the lines for the analogous NGCC non-capture cases. For example, when looking at the exhibit, the cost of CO_2 captured is $53–56/tonne ($48–51/ton) for PC and $84–89/tonne ($76–80/ton) for NGCC.

The curves in Exhibit 5-14 represent the study design conditions (CF) and fuel prices used for each technology; namely an 85 percent CF (PC/NGCC) and $2.46/GJ ($2.60/MMBtu) for coal and $3.25/GJ ($3.42/MMBtu) for natural gas.

Exhibit 5-14. Impact of carbon sales price on study technologies

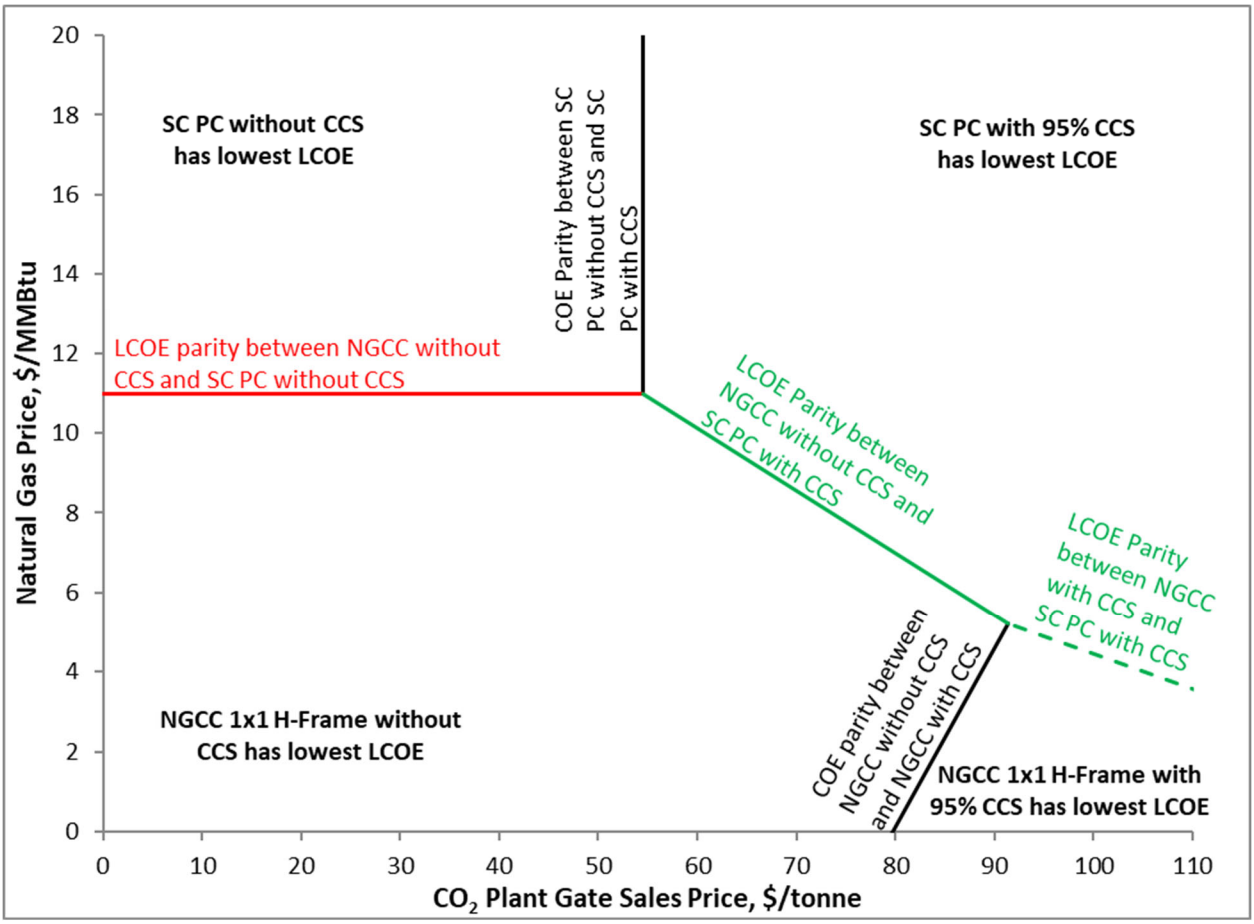


One of the important conclusions that can be drawn from the plot is that at a CO_2 sales price of approximately $96–110/tonne ($87–100/ton), the costs of PC with CO_2 capture cases are equal to those of the NGCC without CO_2 capture. At a CO_2 sales price of approximately $102–126/tonne ($93–114/ton), the costs of PC with CO_2 capture cases are equal to those of the NGCC with CO_2 capture. Above $126/tonne ($114/ton), the PC capture cases are lower cost options than the NGCC capture case.

As with CO_2 emission pricing shown previously, 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 5-15. The lines in the plot represent LCOE parity between different pairs of technologies.

Exhibit 5-15. Lowest cost power generation options at various NG and CO_2 sales prices for NGCC and PC



The plot demonstrates the following points:

- Non-capture plants are the low-cost option below a CO_2 price of $54.5/tonne ($49.5/ton).
- NGCC is preferred when natural gas prices are below $11.0/MMBtu with a CO_2 sale price below $54.5/tonne ($49.5/ton) (and a CF 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 $5.2/MMBtu at $91.4/tonne ($83.0/ton).

5.3 SENSITIVITIES

Exhibit 5-16 shows the LCOE sensitivity to natural gas costs for NGCC 1x1 H-Class cases, compared to SC PC cases, with 95 percent capture and without CCS. The bands for the coal cases represent a variance in coal price from $1.85–3.08/GJ ($1.95–3.25/MMBtu) (±25 percent of the base study value of $2.46/GJ [$2.60/MMBtu]). This sensitivity highlights regions of

competitiveness for NGCC with SC PC, with and without CCS, as a function of the delivered natural gas price. As an example, at a coal cost of $2.60/MMBtu, the LCOE of the non-capture SC PC case equals non-capture NGCC at a natural gas price of approximately $11/MMBtu. For the same comparison with capture cases, SC PC is competitive with NGCC at a natural gas price of approximately $14/MMBtu. It should be noted that this comparison does not include additional valuation for the cost of CO_2 captured/avoided. These costs could impact the price at which natural gas and coal cases are equal, given a scenario where the CO_2 captured is sold or stored to reduce the cost of emissions.

Exhibit 5-16. LCOE sensitivity to natural gas costs

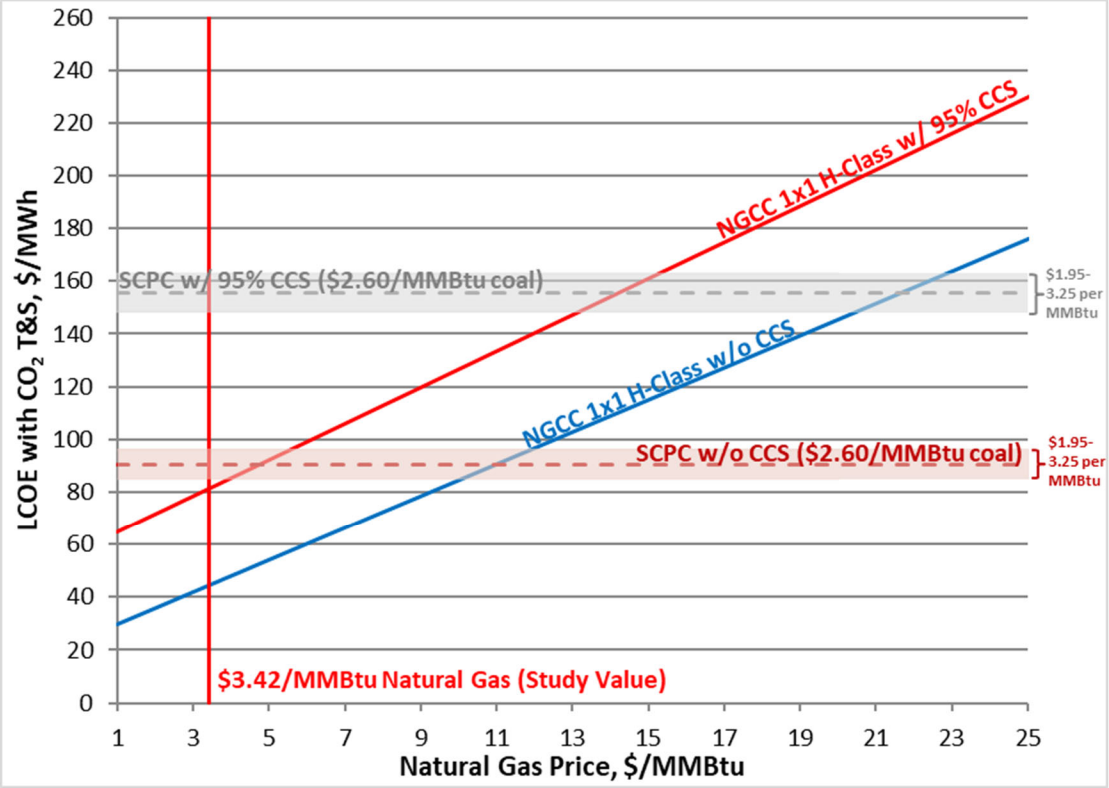
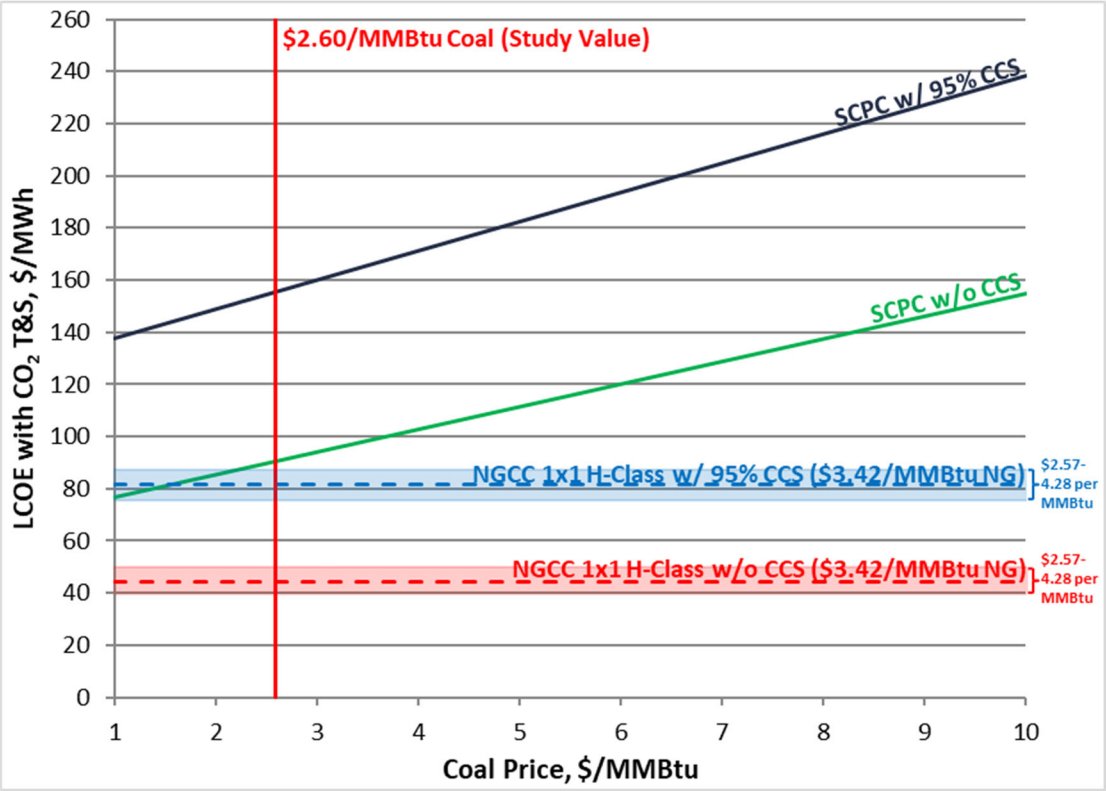


Exhibit 5-17 shows the LCOE sensitivity to coal costs for SC PC cases, compared to NGCC 1x1 H-Class cases, with 95 percent capture and without CCS. The bands for the natural gas cases represent a variance in natural gas price of $2.43–4.06/GJ ($2.57–4.28/MMBtu) (±25 percent of the base study value of $3.25/GJ [$3.42/MMBtu]). Similar to Exhibit 5-16, this sensitivity highlights regions of competitiveness for NGCC with SC PC, with and without CCS, as a function of the delivered coal price. As an example, at a natural gas cost of $3.42/MMBtu, the LCOE of the capture NGCC 1x1 H-Class case equals non-capture SC PC at a coal price of approximately $1.5/MMBtu. It should be noted that this comparison does not include additional valuation for the cost of CO_2 captured/avoided. These costs could impact the price at which natural gas and coal cases are equal, given a scenario where the CO_2 captured is sold or stored to reduce the cost of emissions.

Exhibit 5-17. LCOE sensitivity to coal costs

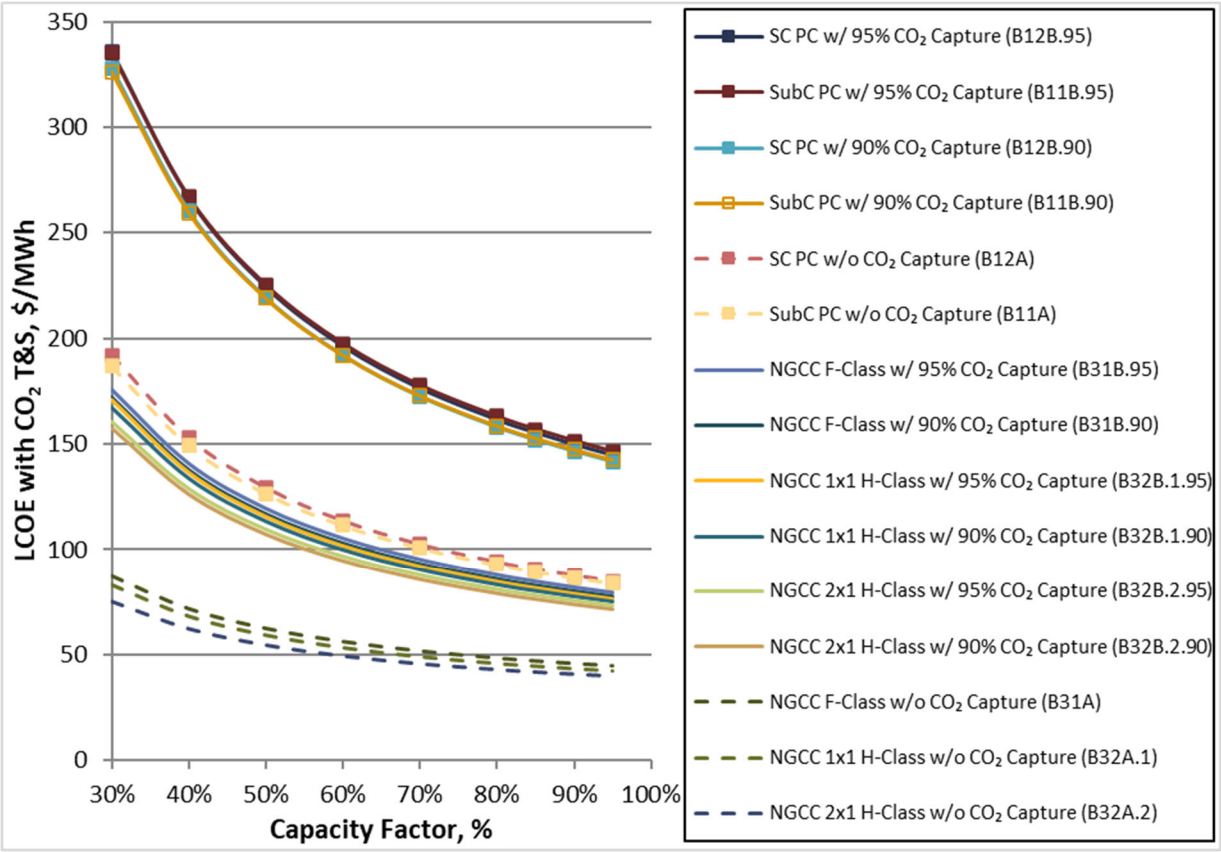


In Exhibit 5-18, the sensitivity of LCOE to CF is shown for all technologies. The curves are relatively tightly grouped by technology, and whether CO_2 capture is included or not. The CF is plotted from 30 to 95 percent. The baseline CF is 85 percent for both PC and NGCC technologies. The curves plotted in Exhibit 5-18 assume that the CF could be extended to 95 percent with no additional capital equipment and that lower capacity factors do not result in capital cost savings.

Technologies with high capital cost (e.g., PC cases with CO_2 capture) show a greater increase in LCOE with decreased CF. Conversely, NGCC without CO_2 capture is relatively flat because the LCOE is dominated by fuel charges, which decrease as the CF decreases. Conclusions that can be drawn from Exhibit 5-18 include:

- At any CF shown, NGCC has the lowest LCOE out of the non-capture cases.
- The LCOE 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.
- The LCOE of all NGCC with CO_2 capture cases remains below that of the PC cases without CO_2 capture at all CFs.

Exhibit 5-18. LCOE sensitivity to capacity factor



The next series of sensitivities illustrates the impact of various financial parameters on LCOE, cost of CO_2 capture, and cost of CO_2 avoided for SC PC and NGCC cases with and without CCS. In Exhibit 5-19, Exhibit 5-20, and Exhibit 5-21 the sensitivity of LCOE and cost of CO_2 capture/cost of CO_2 avoided to debt-to-equity (D:E) ratio is plotted. Since the baseline required return on equity (6.9 percent) is greater than the baseline cost of debt (4.5 percent), the LCOE of the more capital-intensive technologies increases more rapidly as the D:E ratio decreases. The impact of D:E ratio on cost of CO_2 capture and cost of CO_2 avoided for PC and NGCC cases is similar (on a relative basis) because the change in D:E ratio impacts the capture plant and non-capture reference plant in a consistent manner.

The sensitivity of LCOE, cost of CO_2 capture, and cost of CO_2 avoided to effective tax rate is plotted in Exhibit 5-22, Exhibit 5-23, and Exhibit 5-24. The tax rate impact is relatively small for all technologies, but similar to D:E ratio, the more capital-intensive technologies are impacted to a greater extent. The most capital-intensive technology plotted, SC PC with 95 percent CO_2 capture, has an LCOE increase of 6.6 percent as the effective tax rate increases from 0 to 40 percent. The least capital-intensive technology plotted, NGCC without CCS, experiences a 5.3 percent increase in LCOE over the same effective tax rate range. The relative impact of effective tax rate on cost of CO_2 capture and cost of CO_2 avoided is similar for all four technologies plotted, ranging 6.3–9.3 percent, with the greatest impact on the cost of CO_2 captured in NGCC cases as the tax rate increases from 0 to 40 percent.

Exhibit 5-19. LCOE sensitivity to debt-to-equity ratio

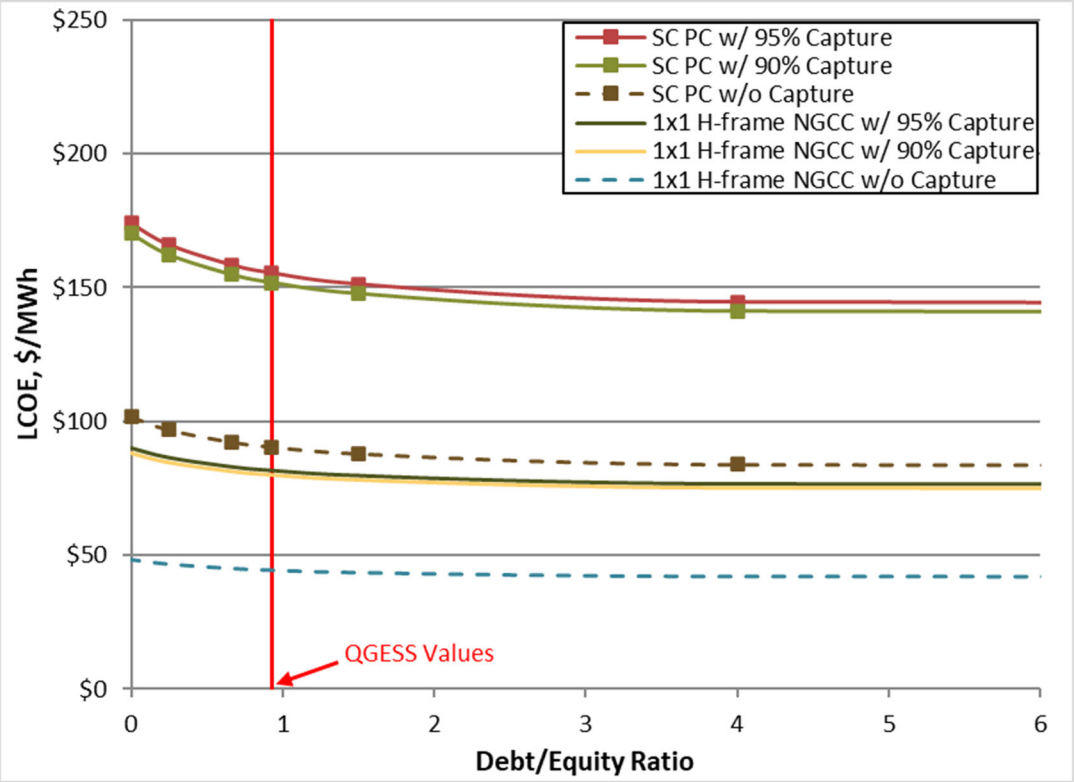


Exhibit 5-20. Cost of CO_2 captured sensitivity to debt-to-equity ratio

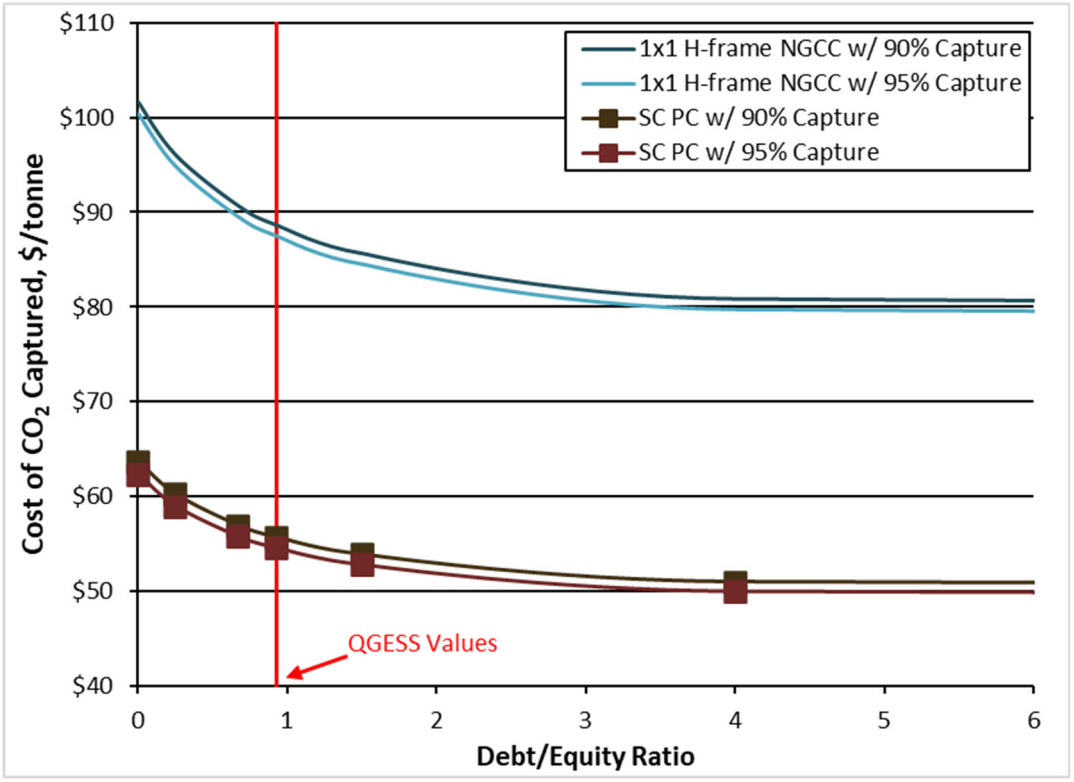


Exhibit 5-21. Cost of CO_2 avoided sensitivity to debt-to-equity ratio

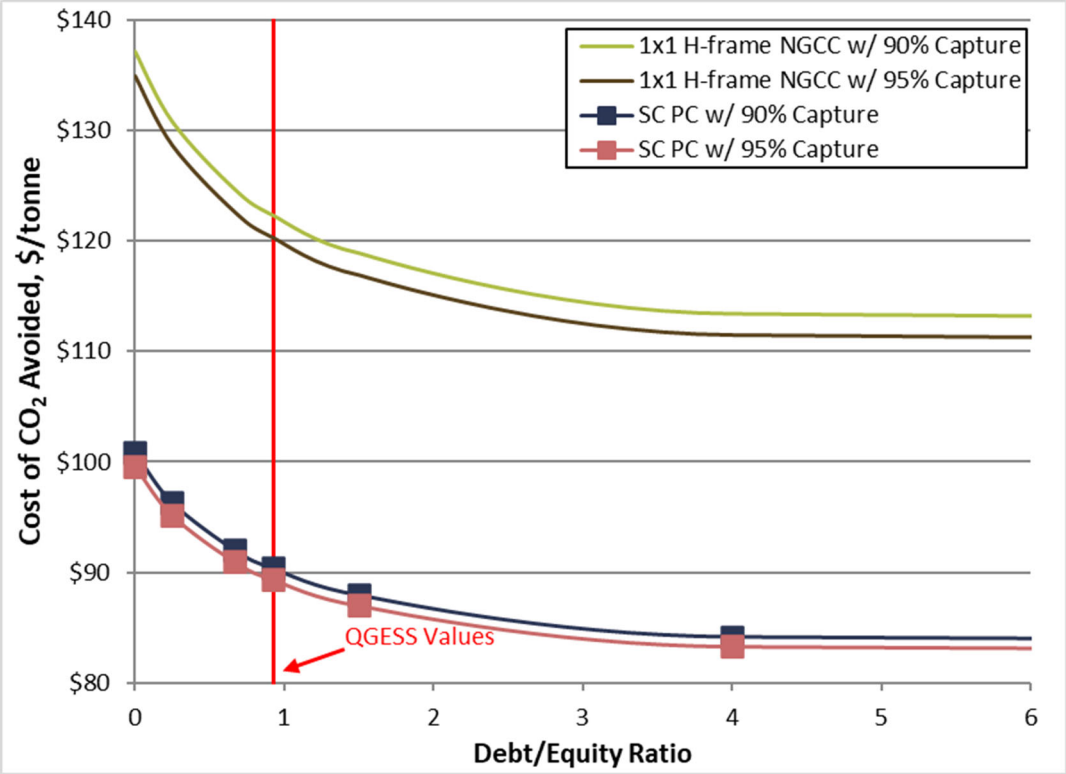


Exhibit 5-22. LCOE sensitivity to effective tax rate

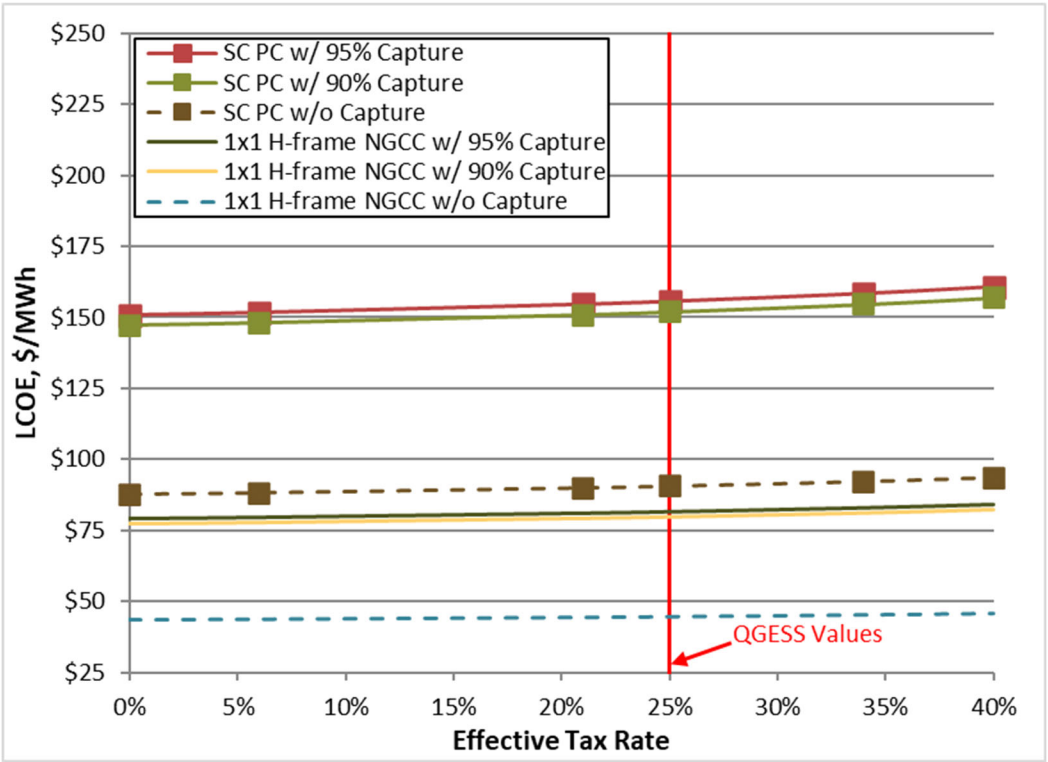


Exhibit 5-23. Cost of CO_2 captured sensitivity to effective tax rate

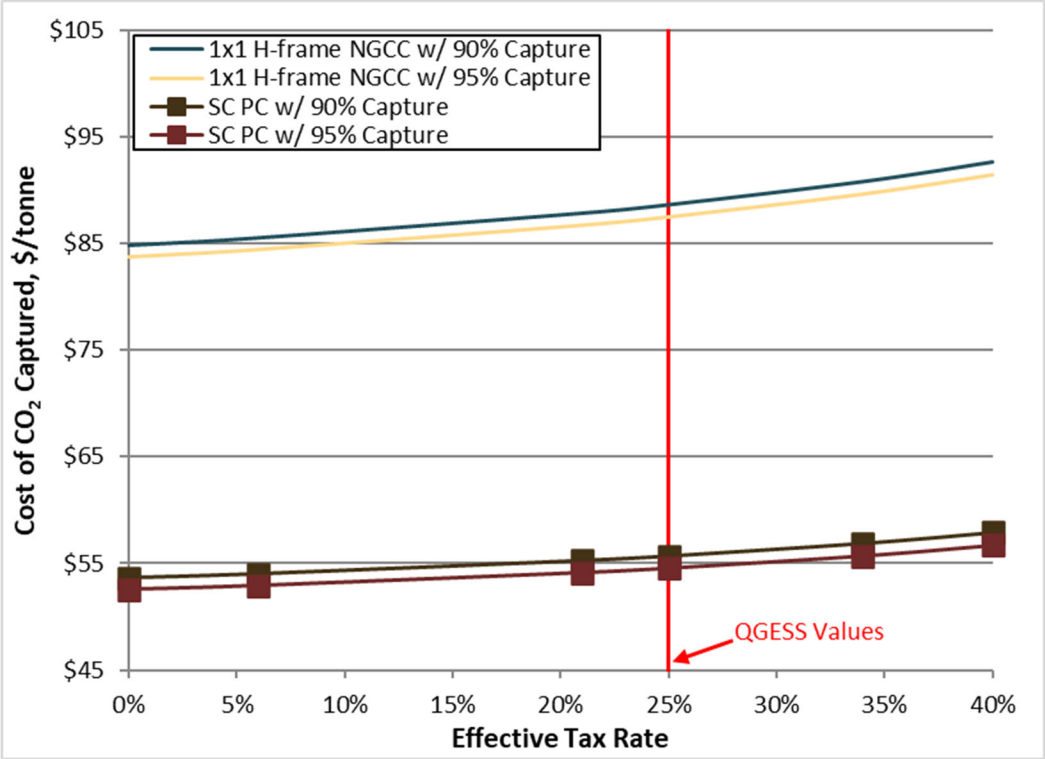
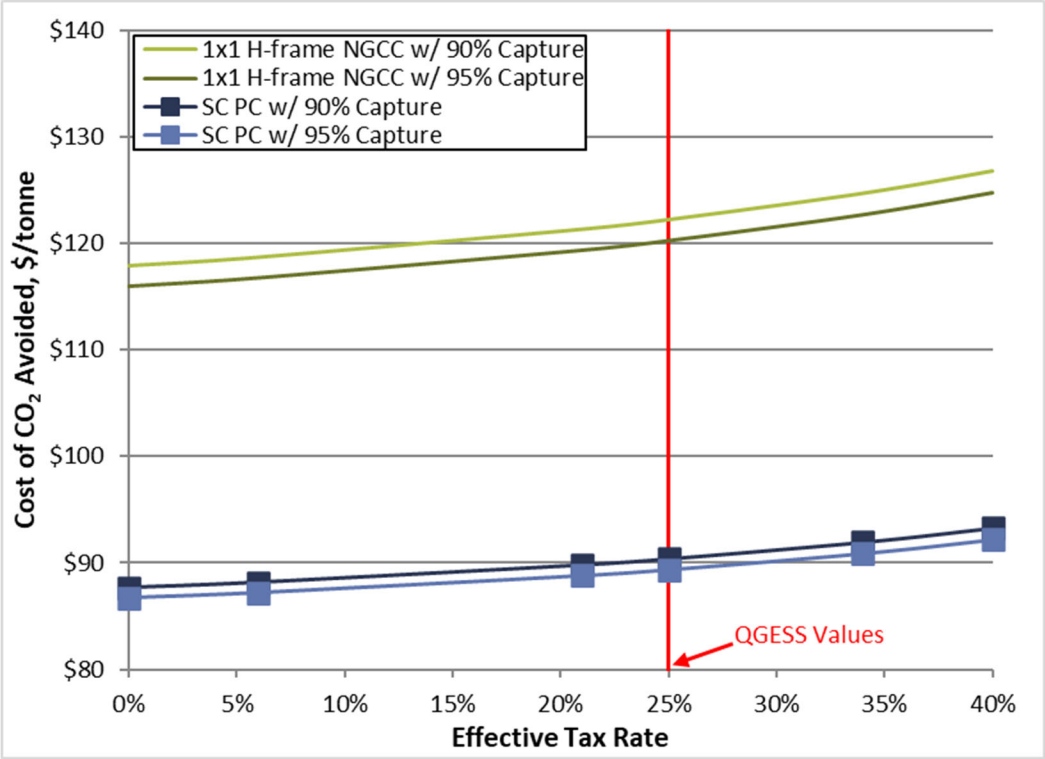


Exhibit 5-24. Cost of CO_2 avoided sensitivity to effective tax rate



The sensitivity of LCOE, cost of CO_2 capture, and cost of CO_2 avoided to interest rate on debt is plotted in Exhibit 5-25, Exhibit 5-26, and Exhibit 5-27 and the sensitivity to return on equity is plotted in Exhibit 5-28, Exhibit 5-29, and Exhibit 5-30. The trends for both sensitivities are consistent with the D:E ratio sensitivity. LCOE increases more rapidly for more capital-intensive projects than less capital-intensive projects as the debt interest rate increases and the required return on equity increases. The impact of debt interest rate and return on equity on cost of CO_2 capture and cost of CO_2 avoided for PC and NGCC cases is similar (on a relative basis), as was the case with the D:E ratio sensitivity.

Exhibit 5-25. LCOE sensitivity to interest rate on debt

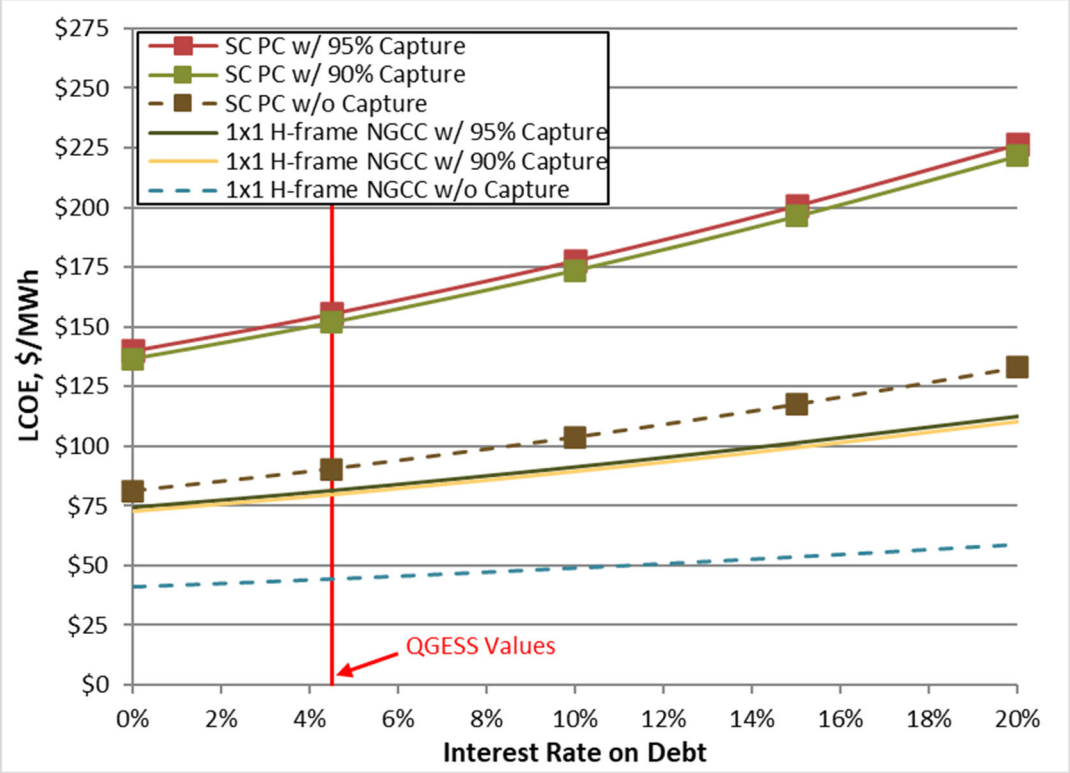


Exhibit 5-26. Cost of CO_2 capture sensitivity to interest rate on debt

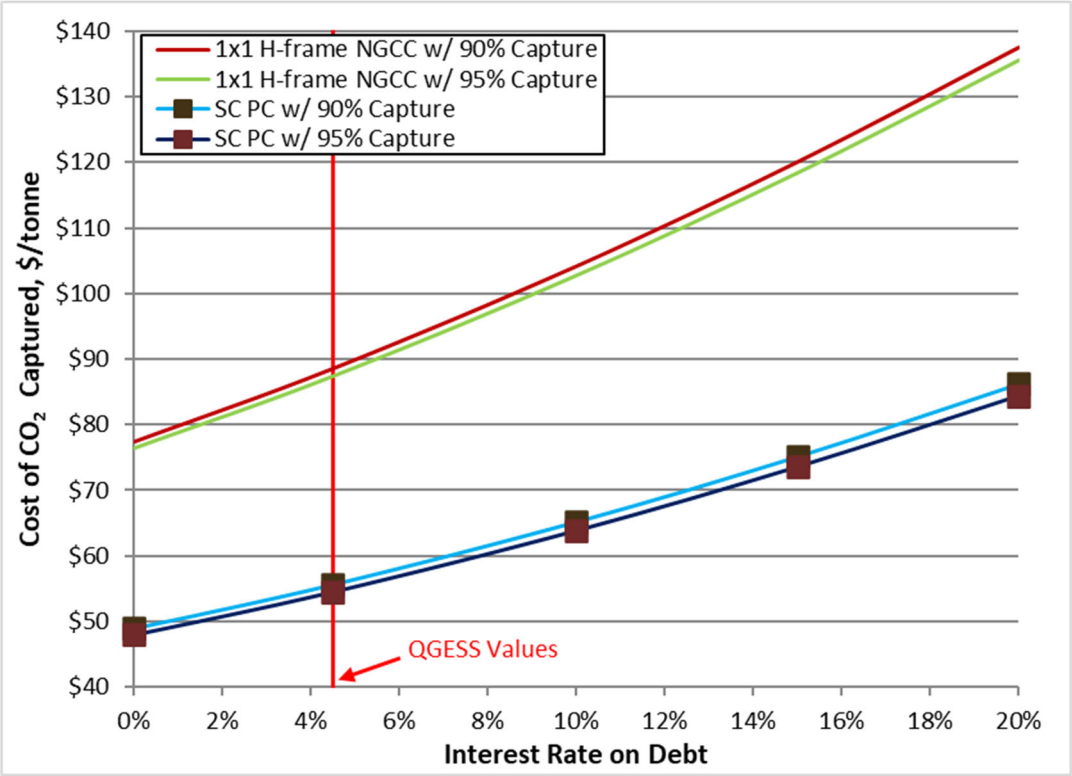


Exhibit 5-27. Cost of CO_2 avoided sensitivity to interest rate on debt

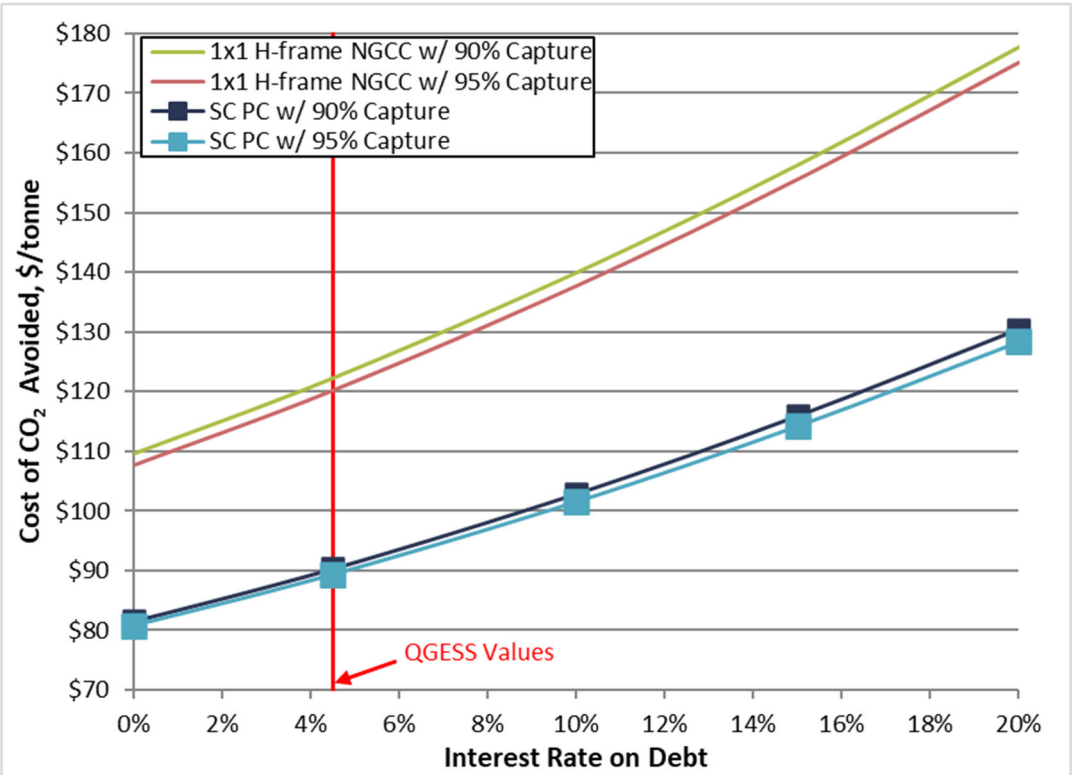


Exhibit 5-28. LCOE sensitivity to return on equity

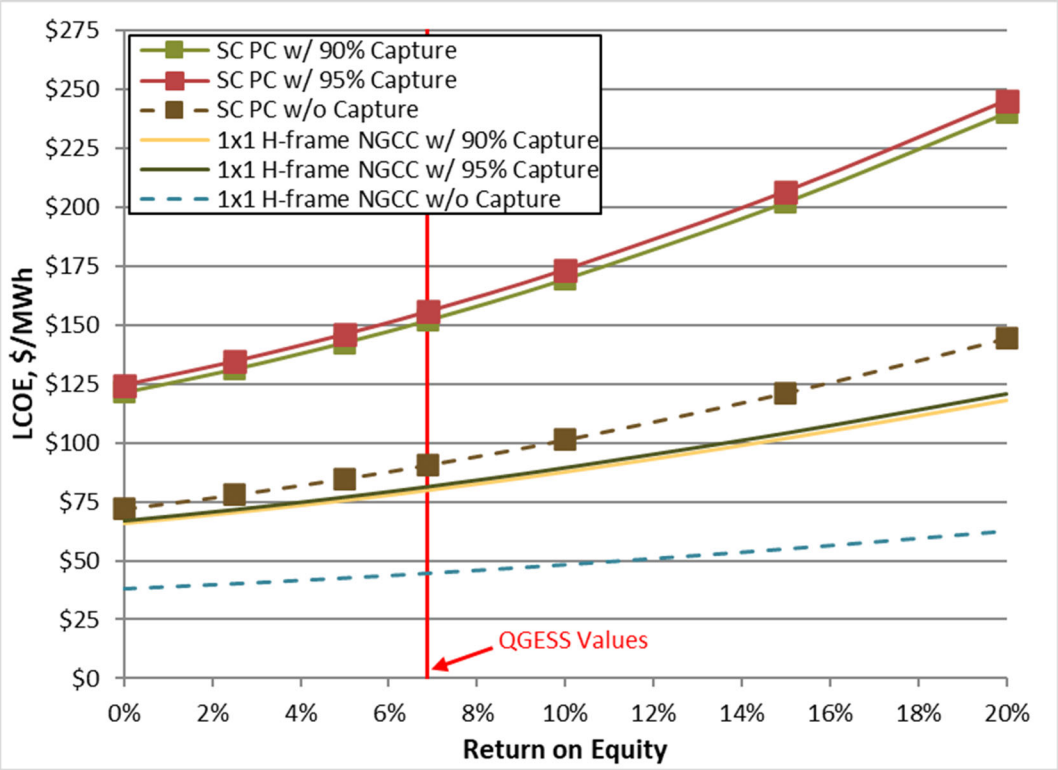


Exhibit 5-29. Cost of CO_2 capture sensitivity to return on equity

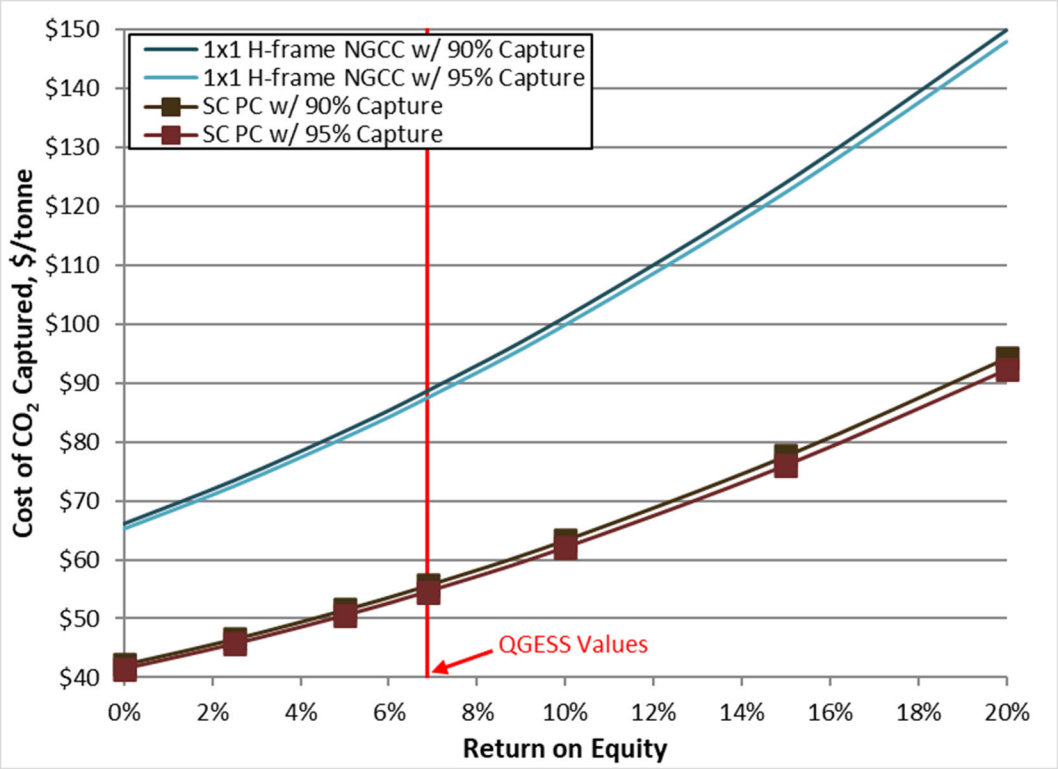
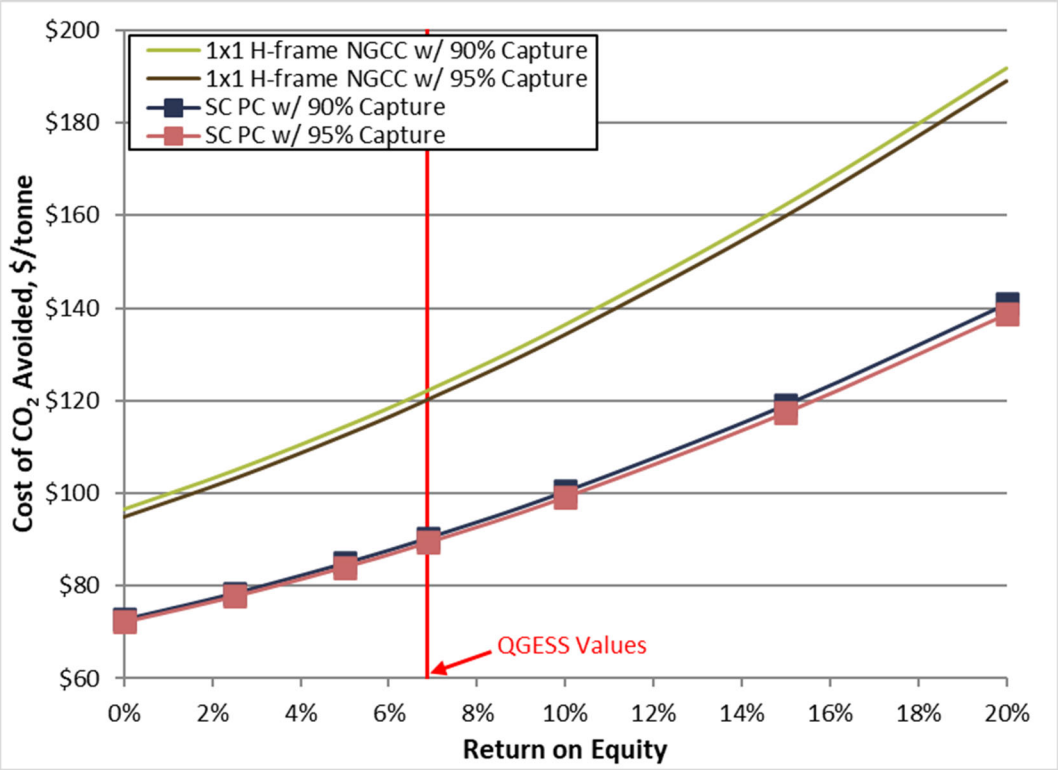
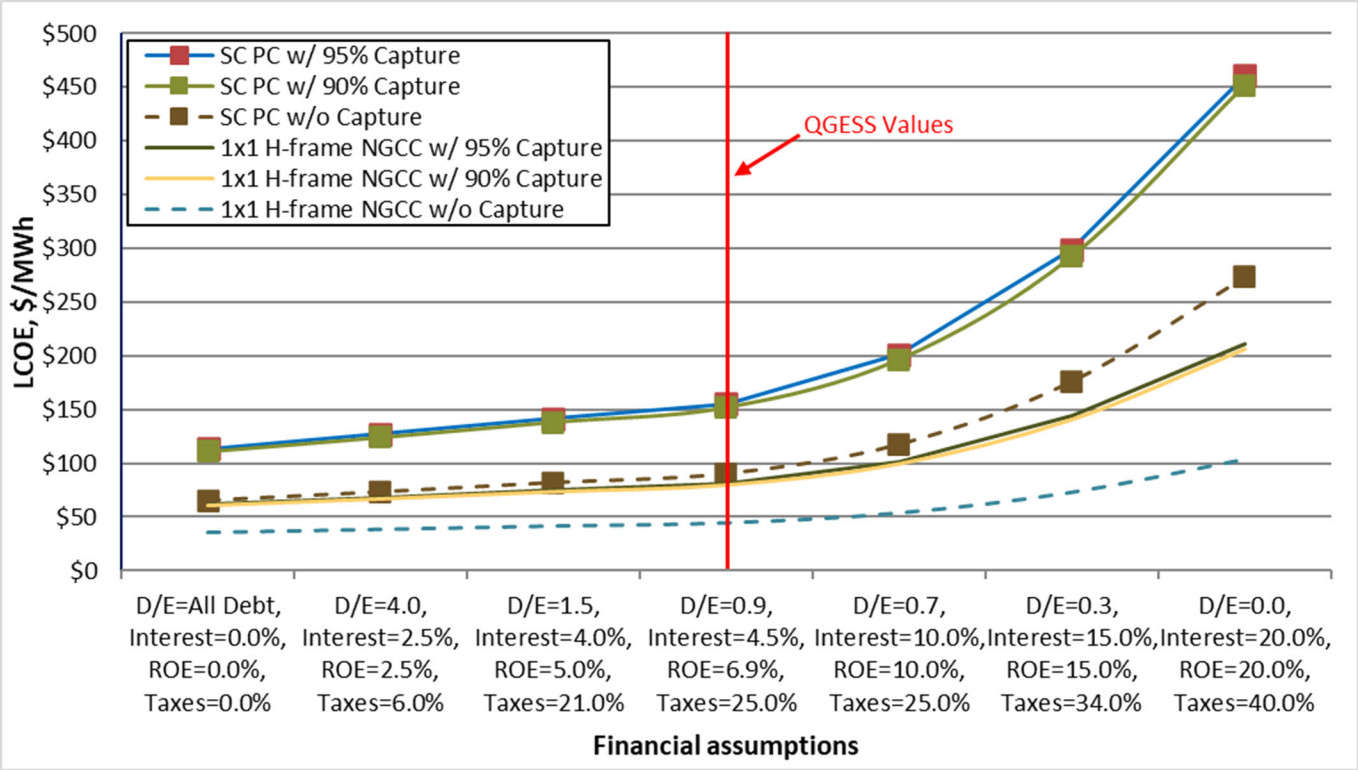


Exhibit 5-30. Cost of CO_2 avoided sensitivity to return on equity



The final sensitivity examines the impact of multiple simultaneous financial parameter variations (Exhibit 5-31). At one extreme, it is assumed that the project is financed with all debt at a zero percent interest rate and with a zero percent tax rate. At the other extreme, 100 percent equity financing with a 20 percent required return on equity and a 40 percent effective tax rate is assumed. Five additional scenarios between these two extremes are also considered, including the baseline scenario of a D:E ratio of 0.9, an interest rate of 4.5 percent, a required return on equity of 6.9 percent, and an effective tax rate of 25.0 percent. This sensitivity illustrates the significant impact that financial parameter assumptions can have on LCOE. Using SC PC with 90 percent CCS (B12B.90) as an example, the LCOE ranges $111–452/MWh at the two extremes and is $151.9/MWh at the baseline conditions. The impact on the less capital-intensive H-Class NGCC without CCS (B32A.1) is less extreme, but still impactful. The range of LCOE at the two extreme scenarios is $36–104/MWh with the baseline condition resulting in an LCOE of $44.5/MWh.

Exhibit 5-31. LCOE sensitivity to combined financial parameters



5.4 Comparison to Revision 4a

This revision updated the cost year basis from 2018 to 2023 for all cases; however, the methods used for PC differed from that of NGCC. As there has been little development or deployments of PC plants in the United States since the publication of Revision 4a, no new quotes were obtained for these cases, rather, the costs were escalated using various indices, as discussed in Section 2.7.1.4. Conversely, as NGCC plants continue to be deployed and combustion turbines used in NGCC plants continue to be developed, new quotes were obtained for the F- and H-Class cases, excluding the CO_2 capture system. The costs were then developed by Black & Veatch for Cases B31B.95, B32B.1.95, and B32B.2.95, with the escalation to 2023 dollars based on in-house data of recent build projects. The balance of the NGCC cases were scaled in accordance with NETL's QGESS reports.[t] (NETL, 2025a) The CO_2 capture system used in the NGCC cases is consistent with Revision 4a, scaled and escalated using the QGESS methodology (NETL, 2025a).

The 2x1 H-Class cases use the same type of combustion turbine as those in Revision 4a, but reflect the improved output and efficiency of 2023 commercial offerings. In addition, a 1x1 H-Class case has been added that uses a more advanced version of the combustion turbine, with even higher output and efficiency than the version used in the 2x1 H-Class cases. As discussed

[t]As specified in the QGESS report, "Capital Cost Scaling Methodology: Revision 4b Report" (NETL, 2025a), scaled costs should use the same technology basis as the reference (e.g., If developing cooling tower costs for a PC plant, the reference cooling tower cost should be from a PC case).

in Section 4.1.5.2.1, the 1x1 configuration of the advanced H-Class combustion turbine was used to provide a more comparable output to PC and F-Class cases.

As stated in Section 4.1.4, the 2x1 H-Class cases in this report have a significantly larger flue gas volumetric flow than the quoted NGCC case. As such, it was assumed that a single absorber would not be economical due to the large diameter of the absorber. It is anticipated that if demand for large-scale CO_2 capture systems is demonstrated, vendors may develop alternative designs that would allow for single-train systems that are more economical. One such example may be the use of two absorbers in parallel, with the intention to reduce the diameter of each absorber. As of the publication of this report, no commercial builds have been demonstrated with this design; therefore, the 2x1 H-Class cases within this report include two parallel CO_2 capture trains, each treating 50 percent of the flue gas, rather than the single 100 percent CO_2 capture train used in Revision 4a. To demonstrate the potential cost impact of alternative designs a high-level estimate of a dual-absorber, single-train CO_2 capture system was developed for each of the 2x1 H-Class cases with CO_2 capture (B32B.2.90 and B32B.2.95).[u]

Relative to Revision 4a, the TEG makeup rate has decreased by 90 percent and the disposal rate of TEG has increased by 5 times. The revised makeup and disposal rates reflect guidance from Black & Veatch informed by recent build projects. As stated in Section 2.7.2.5, the disposal rate reflects the fact that some of the TEG used in the drying process is lost in the dryer vent, contaminating the condensed water, which in turn must be disposed of. The TEG waste product, along with the thermal reclaimer unit waste, is sent to an off-site disposal facility, where it is solidified (e.g., mixed with ash) and landfilled. The additional processing fee increases the disposal cost of triethylene glycol from $0.43/gal to $1.30/gal and thermal reclaimer unit waste from $46.71/ton to $250.00/ton.

Previous revisions of this report assumed a CO_2 T&S cost of $10/tonne-$CO_2$ for each case, whereas this revision calculated specific per unit costs for each case dependent on the CO_2 flow rate and plant capacity factor based on the methodology described in NETL's QGESS reports (NETL, 2024) with the resulting unit costs reported in Section 2.7.3.

This report also uses a different method for calculating the cost of electricity than that of Revision 4a, reporting COE on a nominal (aka current dollar), rather than real (aka constant dollar), basis. FY COE is also reported, in addition to LCOE. The financial structure used to estimate the capital charge factor and levelization factors within the calculations of FY COE and LCOE are those specified for the power industry in the 2025 revision of the QGESS report, "Cost Estimation Methodology for NETL Techno-economic Assessments," which was updated to reflect publicly available 2023 financial data and trends (NETL, 2025b).

Comparing the results reported herein to those of Revision 4a, the following can be observed:

- For F-Class NGCC cases, the HHV efficiency reduced by 0.1–0.2 percentage points and the net plant output increased by 13–14 MW.
- For 2x1 H-Class NGCC cases, the HHV efficiency increased by 0.7–0.8 percentage points and the net plant output increased by 114–126 MW.

[u]The estimated cost impact does not reflect any vendor input.

- While the 1x1 H-Class NGCC cases produce 302–343 MW-net less than the 2x1 H-Class NGCC cases reported in Revision 4a, the net plant efficiency of the 1x1 H-Class NGCC cases is 1.1–1.2 percentage points higher than the H-Class cases reported in Revision 4a.
- The TOC, on a $/kW basis, increased by 23 percent in the PC cases, 29–35 percent in the F-Class NGCC cases, and 10–26 percent in the 2x1 H-Class NGCC cases.
    - In 2x1 H-Class NGCC cases, the TOC of the CO_2 capture cases increased significantly more than the non-capture cases (26 percent versus 10 percent), on a $/kW basis, due to the shift from single train capture assumed in Revision 4a to parallel train capture assumed in this report.
- The LCOE increased by 40–42 percent in PC cases, 9–22 percent in F-Class NGCC cases, and -2–18 percent in 2x1 H-Class NGCC cases.
    - Despite the increase in costs when going from 2018 to 2023 dollars due to inflation, the LCOE of the non-capture 2x1 H-Class NGCC case decreased by 5 percent relative to Rev4a due to the reduced levelized fuel price ($3.42/MMBtu versus $4.42/MMBtu), increased net plant output (1,118 MWh versus 992 MWh), and higher net plant efficiency (55.8 percent versus 55.1 percent).
    - The LCOEs of the 2x1 H-Class cases with CO_2 capture increase to a lesser extent than the F-Class cases due to the reduction in F-Class net plant efficiency (0.2 percentage points), but are not a reduction relative to Revision 4a due to the increased capital associated with the CO_2 capture system, which diminishes the impact of the reduced levelized fuel price.

6 REVISION CONTROL

The initial issue of this report was published in May 2007, and updated revisions were published in November 2010, July 2015, and September 2019. Since the reissue date, updates have been made to various report sections. These modifications were made for clarification and aesthetic purposes as well as to bring all costs to the current year dollar basis.

Exhibit 6-1 contains information that was 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 Exhibit ES-1 and Exhibit 1-1 since they no longer exist	Synthetic natural gas 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”	N/A
		Added Supplemental Chapter 7 “Dry and Parallel Cooling”	N/A
		Added Supplemental Chapter 8 “GEP IGCC in Quench-Only Configuration with CO_2 Capture”	N/A

Revision Number	Revision Date	Description of Change	Comments
		Added Supplemental Chapter 9 "Sensitivity to MEA System Performance and Cost Bituminous Baseline Case B12B A"	N/A
		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 SC 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 LCOE)
		Updated report tables, figures, and text to reflect the revision 2 changes	N/A
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	N/A
2b	7/13/2015	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	N/A

Revision Number	Revision Date	Description of Change	Comments
		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	N/A
		Incorporated the Supplemental Chapter 8 "GEP IGCC in Quench-Only Configuration with CO_2 Capture" into the body of the report	The supplemental chapter was broken down and the information regarding the case describe within it is presented similar to cases B5A and B5B in Section 3.4.12
		Removed Supplemental Chapter 9 "Sensitivity to MEA System Performance and Cost Bituminous Baseline Case 12A"	N/A
		Updated the environmental targets to current limits published by EPA and presented in Section 2.3	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 CFs used for each technology type
		Removed portions of Section 2.7 concerning cost estimating methodology	Many QGESS reports 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 reports has been removed and references have been inserted that provide the QGESS report title and revision notation
		Added Cost of CO_2 Captured methodology and results	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
		Removed Section 2.7	N/A
		Updated Section 3.1.4 to reflect the use of a dual carbon bed	N/A
		Updated Section 3.1.5	Superfluous information has been removed and the remaining information has been re-organized, especially concerning AGR/gasifier pairings used in non-capture cases
		Improved the BFD depiction of the HRSGs	N/A
		Updated all cases to a new case naming convention	Example: Revision 2's Case 1 is now Case B5A

		Updated performance tables	Major updates include:
			• Table is split into two sections
			  ○ Performance summary
			  ○ Plant power and auxiliary load breakdown
			  ○ O_2:Coal ratio
			  ○ Cold gas efficiency
			  ○ Combustion turbine efficiency
			  ○ Steam turbine efficiency and heat rate
			  ○ LHV basis efficiency and heat rate

Revision Number	Revision Date	Description of Change	Comments
		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
		Completed updating case economic results	Major updates included: • Updated to 2011-year dollars • Revised the engineering and construction management costs • Added NG supply line • Updated the T&S costing methodology • Updated fuel prices
		Updated report tables, figures, and text to reflect the Revision 2b changes	N/A
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	N/A
		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	N/A
		Removed Supplemental Chapter 9 “Sensitivity to MEA System Performance and Cost Bituminous Baseline Case 12A”	
		Updated the environmental targets to current limits published by EPA and presented in Section 2.3	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 CFs used for each technology type
		Removed portions of Section 2.7 concerning cost estimating methodology	Many QGESS reports 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

Revision Number	Revision Date	Description of Change	Comments
			reports has been removed and references have been inserted that provide the QGESS report 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	
		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	Example: Revision 2's Case 9 is now Case B11A

		Performance tables have been updated	Major updates include:
			• Table is split into two sections
			  ○ Performance summary
			  ○ Plant power and auxiliary load breakdown
			• PC
			  ○ Steam generator efficiency
			  ○ Excess air
			  ○ Steam turbine cycle efficiency and heat rate
			  ○ LHV basis efficiency and heat rate
			• NGCC
			  ○ Combustion turbine efficiency
			  ○ Steam turbine efficiency and heat rate
			  ○ 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
		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

Revision Number	Revision Date	Description of Change	Comments
			• 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 percent 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	
4	9/24/2019	Volumes 1a (PC and NGCC) and 1b (IGCC) have been recombined into one report (Volume 1 – Rev4)	• IGCC case updates began with the internal Rev4-Performance Only report • PC and NGCC began with the Rev3 report
		Updated syngas scrubber performance and added vacuum flash, brine concentration, and a crystallizer	Added Section 3.1.12 to cover process water sources, define the ZLD methodology, and provide the technology descriptions of the systems used to achieve ZLD
		Added secondary sour water stripper	Secondary sour water stripper is used to remove ammonia from the ZLD condensate prior to being used as steam for the gasifiers
		Removed sour water stripper from Cases B5B and B5B-Q	sour water stripper only treats excess process water from the process water drum. These cases do not have any excess
		Reduced the chloride content of the coal	Added discussion of chloride content of coal to Section 2.2
		Updated the HHV/LHV calculation method for natural gas	Aspen QVALGRS/QVALNET stream property data used to calculate natural gas heating values
		Updated air separation unit technology description in Section 3.1.2	New information was acquired for air separation unit performance

Revision Number	Revision Date	Description of Change	Comments
		Updated water gas shift technology description in Section 3.1.3	New information was acquired for water gas shift performance
		Updated Selexol technology description in Section 3.1.5.4	New information was acquired for Selexol performance
		Updated COS hydrolysis technology description in Section 3.1.5.1	New information was acquired for COS hydrolysis performance
		Updated CO_2 compression and drying system technology description	New information was acquired for compression and drying performance. Sections updated are • Section 3.1.6 • Section 4.1.9
		Updated gasifier specific technology descriptions to reflect changes made to the common process areas (Section 3)	Sections updated are • Section 3.2.4 • Section 3.2.8 • Section 3.3.4 • Section 3.3.8 • Section 3.4.4 • Section 3.4.8 • Section 3.4.12
		Added chloride control to the plant study configuration matrices	N/A
		Updated performance of the steam cycle	New information was acquired for steam turbine performance for IGCC cases
		Updated NGCC combustion turbine and steam turbine description	New information was acquired for performance. Sections updated are • Section 5.1.2 • Section 5.1.3 • Section 5.1.4 • Section 5.1.6 • Section 5.1.7 • Section 5.1.10
		Updated Shell CANSOLV system description for PC and NGCC	New information was acquired for performance. Sections updated are • Section 4.1.8 • Section 5.1.5
		Updated the PC target net plant output to 650 MW-net	New PC net output provides comparable basis for PC and NGCC capture cases (NGCC w/ capture is 646 MW-net)

Revision Number	Revision Date	Description of Change	Comments
		Added spray dryer evaporator for PC cases	Added Section 4.1.10 to cover process water sources and provide the technology descriptions of the spray dryer evaporator
		Updated PC mercury control system descriptions	New information was acquired for performance. Sections updated are • Section 4.1.6
		Additional Aspen model updates	Major Aspen model updates included: • CO_2 compressor product water target updated to 500 ppmv H_2O • Increased CO_2 compressor intercooling temperatures for final two stages of intercooling • All NOx assumed to be NO (previously considered split of NO and NO_2) • Carbon extent of reaction in PC cases adjusted from 1.0 to 0.994 for bituminous PC cases • DSI/ACI modeled in Aspen • PC boiler block split to allow for ELG spray dryer evaporator flue gas extraction • FGD HCl removal efficiency updated to 99 percent • FGD oxidation air stoichiometric ratio increased to 4.0 • Set excess O_2 prior to the air preheater to 2.6 volume percent-dry for all PC cases • Added IGCC mercury bed preheater
		Energy balance updated to report a Cooling Tower line item	Rather than split out Acid Gas Removal, Condenser, and Non-Condenser cooling loads, all three are summed in the Cooling Tower line item. The AGR cooling duty is reported separately in the Performance Summary table under the Condenser cooling duty
		PC with CO_2 capture cases water balance updated to recycle capture system water recovered as FGD make-up; balance of water recovered sent to discharge	N/A
		Updated fixed auxiliary loads	Steam turbine, Gas turbine, and Miscellaneous Balance of Plant fixed auxiliary loads were updated
		Updated performance data throughout the report to reflect new performance results obtained from changes previously stated in this revision	
		Completed updating case economic results	Major updates included: • Reporting results in 2018-year dollars • Updating the T&S costing methodology • Reverting to LCOE result, but with updated methodology • Updating fuel prices • Re-costing of cases based on the updated performance results • Revised the engineering and construction management costs, as well as some contingencies

Revision Number	Revision Date	Description of Change	Comments
			• Updating cost estimates based on recently obtained vendor quotes
4a	2/14/2021	Updated air separation unit costs for IGCC cases	New information was acquired for air separation unit costs. IGCC performance was unchanged.
		Updated CANSOLV CO_2 capture cost and performance for PC and NGCC cases	Major updates include: • CANSOLV performance in PC cases • Capture system costs in PC cases • NGCC capture system description was changed to reflect current CANSOLV quote • NGCC capture system performance and cost updates
		Added cases for capture greater than 90 percent for PC and NGCC technologies	Updated CANSOLV quote included cost and performance for 95 percent and max capture (97 percent for NGCC and 99 percent for PC) cases. This data was utilized to form new higher capture cases reflective of the same base technology as 90 percent capture cases.
		Added H-Class NGCC cases	2017 7HA.02 turbine vendor data was utilized to develop H-Class cases comparable to the F-Class cases. • Section 5.3
		Miscellaneous PC performance updates	Minor updates included: • Adjusted the APH inlet temperature and added an additional pressure drop of 7 in w.c. for the SCR • Added explicit calculations for dew point temperature of H_2SO_4 plus a 29° F temperature approach at the APH exit • Pressure drop across the boiler block was adjusted to maintain the expected total pressure drop • Equations for motor losses for the ST were corrected to accurately reflect the impact of motor efficiencies in the energy balances
		Miscellaneous NGCC performance updates	Minor updates included: • Adjusted the location of the HP-IP reheat mixing block in the Aspen models • Adjusted streams to account for variances in modeling due to the addition of blocks for H-Class NGCC and updated capture system. This resulted in small changes through additional initialization values and conversion factors
4b	9/23/2024	Added 1x1 H-Class NGCC cases	• Cost and performance based on recently obtained vendor quote • Added Sections 5.3 and B.2 to report the results • Updated Sections 5.1 and 5.5 to include the technology descriptions and results analysis associated with the new cases
		Updated F-Class and H-Class NGCC cases	• Cost and performance based on recently obtained vendor quotes • Combustion turbine, HRSG, and steam turbine model sections were updated to reflect quoted performance, including the combustion turbine efficiency, combustion turbine generator efficiency, natural gas feed rate, air feed rate, air compression ratio, bleed air disposition, turbine inlet temperature, combustion turbine exhaust temperature, NOx

Revision Number	Revision Date	Description of Change	Comments
			uncontrolled emissions, HRSG approach temperatures, HRSG exit temperature, steam turbine efficiency, steam turbine generator efficiency, steam turbine pressure profile, steam turbine temperature profile, etc. • Sections 5.1, 5.2, 5.4, and 5.5 were updated to reflect new technology descriptions and results analysis

		Additional model updates	• Converted to Aspen V12 for NGCC and PC cases (IGCC cases remain in V10)
			• For NGCC cases:
			  • A BFW water makeup stream has been added to the water balance to account for the water extracted from the steam cycle for the CO_2 capture system
			  • The vent from the CO_2 dryer has been connected to the stack
			  • Added a knockout drum at CO_2 outlet of AGR
			  • Updated the cooling tower water supply temperature based on the Arden Buck equation
			  • Updated parameters associated with the cooling tower based on psychrometric data (Inlet air enthalpy, outlet air enthalpy, inlet air humidity ratio, outlet air humidity ratio, outlet air specific volume)
			  • Updated the energy balance calculations for natural gas to use the inlet temperature instead of dry bulb temperature
			  • Revised the CO_2 drying system's process discharge in the mass balance to only account for the water in the stream. The water is now condensed out.
			  • Added the flow rate of the AGR steam extraction for the mechanical vapor recompressor to the calculation for water recovered from the AGR in the water balance
			  • Corrected the calculation for raw water pump flow
			  • Updated the water balance calculations to remove the assumption of 10% of cooling tower blowdown being discharged to an ash pond
			  • Updated the water density to be reflective of plant ambient conditions

		Updated economic results	Major updates include:
			  • Reported results in 2023-year dollars
			  • Updated the T&S costing methodology
			  • Added FY COE results
			  • Updated LCOE methodology to reflect current QGESS documentation
			  • Updated fuel prices to reflect current QGESS documentation
			  • Decreased TEG makeup rate to CO_2 dryer
			  • Increased TEG waste disposal rate
			  • Added a processing fee for TEG and thermal reclaimer unit waste
			  • Updated the CO_2 capture system for 2x1 H-Class cases to use two parallel trains
			  • Re-costed of NGCC cases to reflect recently obtained vendor quotes and the updated performance associated with the new vendor quotes

Revision Number	Revision Date	Description of Change	Comments
			Minor updates include: • Coal price and natural gas sensitivity equations were updated to account for the fuel price impact to owner's costs • Updated the 60-day supply calculation to exclude natural gas and those that are done in batch (e.g., SCR, water gas shift) • Corrected the stack costs of NGCC cases - Rev4 and 4a estimated the stack based on PC plant designs • Corrected the TASC/TOC factors to use the 3-year construction distribution for NGCC cases

		Report updates	• Added Section 6.4, a comparison to Rev4a assumptions and results
			• Removed the sulfur content of coal from the proximate analysis shown in Exhibit 2-4
			• Revised the text in the balance of plant assumption tables regarding the disposition of cooling tower blowdown for consistency across technologies
			• Revised the carbon removal calculation reported in each performance results section to exclude the bottom ash carbon value and instead include the unburned carbon content of bottom and fly ash for all PC cases
			• Updated the SC boiler type in Account 4 equipment list from drum to once-through
			• Section 2.6 was updated to consolidate text from elsewhere, align with other baseline series volumes, and move the discussion of the cooling tower to Section 3.1.12.
			• Section 2.7.1.5 was updated to reflect the cost escalation method used in this update for PC and IGCC cases.
			• Updated Section 2.7.2.5 to include a discussion on the TEG waste disposal assumptions
			• Section 2.7.3 was updated to reflect the T&S methodology used in this report and to list the T&S costs for each case.
			• Section 2.7.4 was updated to reflect the revised methodology for calculating LCOE, as well as a discussion of the FY COE methodology
			• All IGCC cases were removed from the report, including all discussions of IGCC technology and systems throughout the report.
			• For PC cases:
			  • The Circulating Water System was revised and moved to Section 3.1.13, along with the Auxiliary Cooling System
			  • The Accessory Electric Plant section was moved to Section 3.1.14
			  • Waste treatment/miscellaneous systems have been split up into separate subsections
			  • The text following the water balance tables in each case has been moved to Section 2.6
			  • The Extraction Steam section (3.1.2.2.4) was moved to come before the Condensate section (3.1.2.2.5)

Revision Number	Revision Date	Description of Change	Comments

			• The post combustion carbon capture section (3.1.8) was updated for consistency with other Baseline volumes and to accurately reflect the design and assumptions within this report
			• For NGCC cases:
			  • Sections were reorganized consistent with the changes listed for PC cases
			  • Several sections were reorganized and/or revised for consistency with other Baseline volumes and for clarity, including Section 5.1.2, 5.1.5, and 5.1.7

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7 REFERENCES

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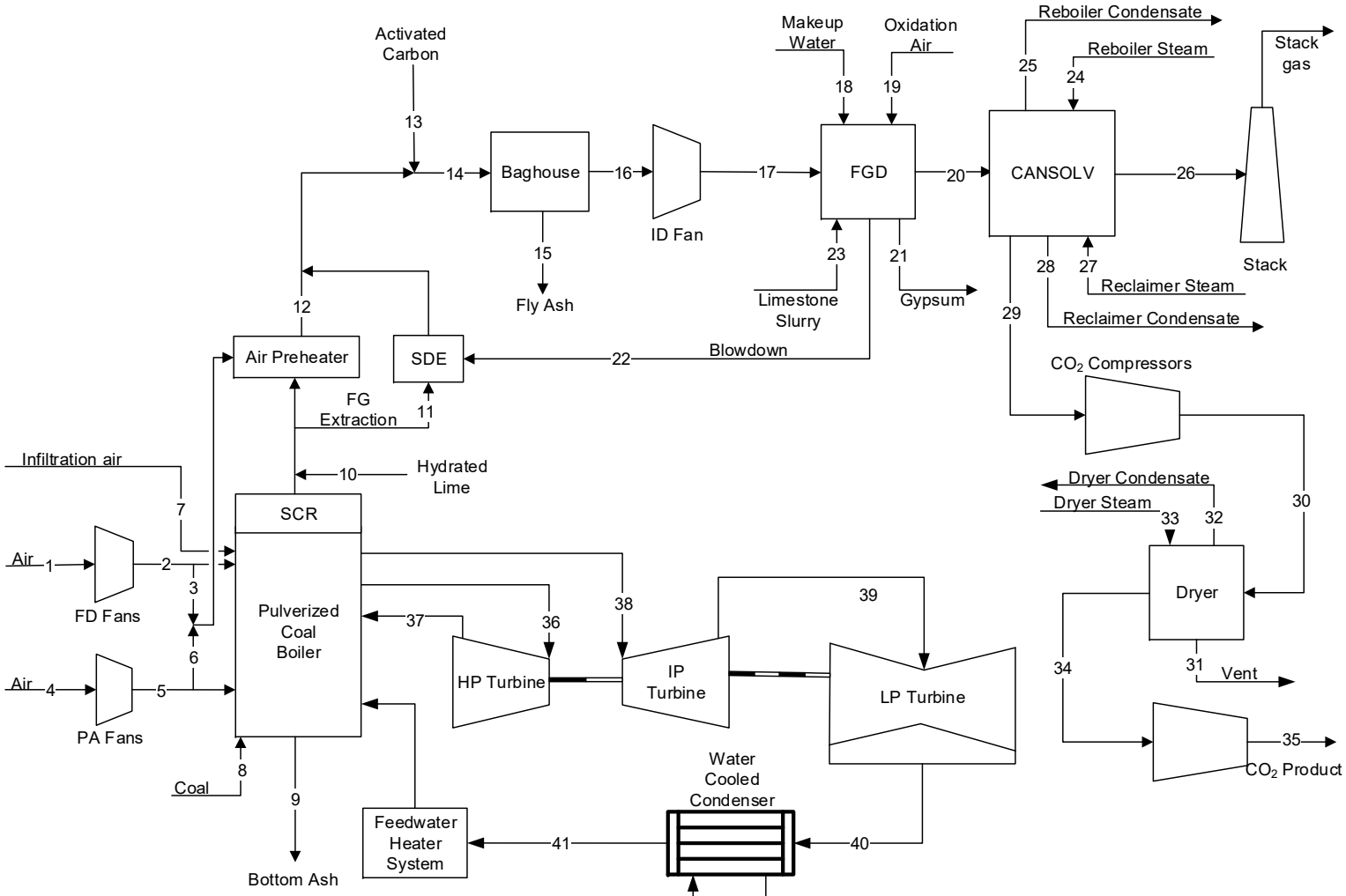
APPENDIX A: PC WITH 99% CO_2 CAPTURE

A.1 CASE B11B.99 – SUBC PC WITH 99% CO_2 CAPTURE PROCESS DESCRIPTION

The plant configuration and process description for Case B11B.99 are nearly the same as Case B11B.90, with the exception of 99 percent capture. Since the process descriptions of the plant and post combustion carbon capture (PostCCC) facility were provided in Section 3.2.3 and Section 3.1.8, respectively, they are not repeated here.

The block flow diagram (BFD) for Case B11B.99 is shown in Exhibit A-1. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit A-2. The modeling assumptions are presented in Section 3.2.1.

Exhibit A-1. Case B11B.99 BFD, SubC unit with 99 percent CO_2 capture



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown. For equipment with multiple units, only a single unit is depicted while the total flow is reported.

Exhibit A-2. Case B11B.99 stream table, SubC unit with 99 percent CO_2 capture

	1	2	3	4	5	6	7	8	9	10	11	12
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	0.0087	0.0088
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1457	0.1379
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	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000	0.0879	0.0837
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7318	0.7340
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0237	0.0336
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0020
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	80,607	80,607	2,387	24,762	24,762	3,408	1,782	0	0	1	5,312	107,752
V-L Flowrate (kg/hr)	2,326,082	2,326,082	68,895	714,548	714,548	98,339	51,415	0	0	16	157,980	3,199,630
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	295,666	5,960	1,611	1,276	24,492
Temperature (°C)	15	17	17	15	24	24	15	15	1,316	15	385	143
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg)[A]	30.23	32.49	32.49	30.23	38.98	38.98	30.23	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-95.31	-95.31	-97.58	-88.83	-88.83	-97.58	-2,119.02	1,267.06	-13,402.95	-2,261.17	-2,394.31
Density (kg/m^3)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	1,003.6	0.5	0.8
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015	29.742	29.694
V-L Flowrate (lb_{mol}/hr)	177,709	177,709	5,263	54,590	54,590	7,513	3,928	0	0	2	11,710	237,553
V-L Flowrate (lb/hr)	5,128,133	5,128,133	151,888	1,575,309	1,575,309	216,801	113,350	0	0	36	348,286	7,053,978
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	651,832	13,140	3,552	2,813	53,995
Temperature (°F)	59	63	63	59	75	75	59	59	2,400	59	726	289
Pressure (psia)	14.7	15.0	15.0	14.7	15.9	15.9	14.7	14.7	14.3	14.7	14.3	14.1
Steam Table Enthalpy (Btu/lb)[A]	13.0	14.0	14.0	13.0	16.8	16.8	13.0	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-41.0	-41.0	-42.0	-38.2	-38.2	-42.0	-911.0	544.7	-5,762.2	-972.1	-1,029.4
Density (lb/ft^3)	0.076	0.077	0.077	0.076	0.080	0.080	0.076	---	---	62.650	0.033	0.052

[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 A-2. Case B11B.99 stream table, SubC unit with 99 percent CO_2 capture (continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.1372	0.0000	0.1372	0.1372	0.0000	0.0003	0.1245	0.0001	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	0.0000	0.0911	0.0000	0.0911	0.0911	0.9999	0.0099	0.1508	0.9998	0.9943	0.9999	1.0000
HCl	0.0000	0.0001	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.7281	0.0000	0.7281	0.7281	0.0000	0.7732	0.6803	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0329	0.0000	0.0329	0.0329	0.0000	0.2074	0.0363	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0020	0.0000	0.0020	0.0020	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.1158	0.0000	0.0000	0.0001	0.0000	0.0000	0.0001	0.0009	0.0001	0.0000
$CaCl_2$	0.0000	0.0001	0.8842	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0048	0.0000	0.0000
Total	0.0000	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_{mol}/hr)	0	113,964	7	113,957	113,957	6,658	4,770	127,394	268	900	3,708	41,091
V-L Flowrate (kg/hr)	0	3,374,254	729	3,373,508	3,373,508	119,965	137,657	3,661,337	4,833	16,644	66,812	740,259
Solids Flowrate (kg/hr)	65	26,086	26,103	0	0	0	0	0	43,473	253	28,601	0
Temperature (°C)	15	143	143	143	156	15	15	57	15	57	15	266
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.48
Steam Table Enthalpy (kJ/kg)[A]	---	---	---	287.58	302.09	-47.80	30.23	297.00	---	---	---	2,994.07
AspenPlus Enthalpy (kJ/kg)[B]	-6.79	-2,453.14	-1,065.96	-2,464.17	-2,449.66	-16,015.01	-97.58	-2,939.24	-12,513.34	-15,496.21	-14,994.25	-12,986.23
Density (kg/m^3)	---	0.8	2,150.2	0.8	0.9	1,003.7	1.2	1.1	878.3	979.4	1,003.7	2.0
V-L Molecular Weight	---	29.608	104.898	29.603	29.603	18.019	28.857	28.740	18.021	18.494	18.019	18.015
V-L Flowrate (lb_{mol}/hr)	0	251,247	15	251,232	251,232	14,678	10,517	280,856	591	1,984	8,175	90,589
V-L Flowrate (lb/hr)	0	7,438,957	1,607	7,437,311	7,437,311	264,477	303,482	8,071,867	10,655	36,693	147,294	1,631,992
Solids Flowrate (lb/hr)	143	57,509	57,548	0	0	0	0	0	95,841	559	63,054	0
Temperature (°F)	59	289	289	289	313	59	59	135	59	135	59	511
Pressure (psia)	14.7	14.1	14.1	13.9	15.3	14.7	14.7	14.8	14.7	14.7	14.7	70.0
Steam Table Enthalpy (Btu/lb)[A]	---	---	---	123.6	129.9	-20.5	13.0	127.7	---	---	---	1,287.2
AspenPlus Enthalpy (Btu/lb)[B]	-2.9	-1,054.7	-458.3	-1,059.4	-1,053.2	-6,885.2	-42.0	-1,263.6	-5,379.8	-6,662.2	-6,446.4	-5,583.1
Density (lb/ft^3)	---	0.052	134.232	0.051	0.055	62.658	0.076	0.067	54.833	61.145	62.658	0.123

[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 A-2. Case B11B.99 stream table, SubC unit with 99 percent CO_2 capture (continued)

	25	26	27	28	29	30	31	32	33	34	35	36
V-L Mole Fraction												
Ar	0.0000	0.0103	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0016	0.0000	0.0000	0.9783	0.9975	0.0500	0.0000	0.0000	0.9995	0.9995	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	1.0000	0.0807	1.0000	1.0000	0.0217	0.0025	0.9500	1.0000	1.0000	0.0005	0.0005	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.8614	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0460	0.0000	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	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
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_{mol}/hr)	37,635	100,609	410	410	16,042	15,733	33	20	20	15,700	15,700	137,407
V-L Flowrate (kg/hr)	677,999	2,770,628	7,383	7,383	696,950	691,380	637	363	363	690,742	690,742	2,475,431
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	105	45	355	214	31	29	29	203	476	29	30	566
Pressure (MPa, abs)	0.12	0.10	4.28	2.04	0.17	2.81	2.81	1.64	2.42	2.68	15.27	16.65
Steam Table Enthalpy (kJ/kg)[A]	439.34	179.65	3,098.44	913.81	46.68	-3.05	137.94	863.65	3,408.95	-3.59	-231.09	3,473.89
AspenPlus Enthalpy (kJ/kg)[B]	-15,540.95	-710.95	-12,881.86	-15,066.49	-8,978.62	-8,972.51	-15,225.22	-15,116.65	-12,571.34	-8,967.15	-9,194.65	-12,506.41
Density (kg/m^3)	954.9	1.1	16.0	848.5	3.0	57.8	351.5	861.8	7.1	54.7	630.1	47.7
V-L Molecular Weight	18.015	27.539	18.015	18.015	43.445	43.945	19.315	18.015	18.015	43.997	43.997	18.015
V-L Flowrate (lb_{mol}/hr)	82,970	221,804	903	903	35,366	34,685	73	44	44	34,612	34,612	302,931
V-L Flowrate (lb/hr)	1,494,733	6,108,188	16,277	16,277	1,536,511	1,524,231	1,405	801	801	1,522,826	1,522,826	5,457,392
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	221	113	671	416	87	85	85	397	888	85	86	1,050
Pressure (psia)	17.4	14.8	620.5	296.6	24.7	407.6	407.6	237.4	350.5	389.1	2,214.7	2,414.7
Steam Table Enthalpy (Btu/lb)[A]	188.9	77.2	1,332.1	392.9	20.1	-1.3	59.3	371.3	1,465.6	-1.5	-99.4	1,493.5
AspenPlus Enthalpy (Btu/lb)[B]	-6,681.4	-305.7	-5,538.2	-6,477.4	-3,860.1	-3,857.5	-6,545.7	-6,499.0	-5,404.7	-3,855.2	-3,953.0	-5,376.8
Density (lb/ft^3)	59.612	0.066	1.000	52.968	0.184	3.609	21.943	53.801	0.446	3.416	39.338	2.975

[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 A-2. Case B11B.99 stream table, SubC unit with 99 percent CO_2 capture (continued)

	37	38	39	40	41
V-L Mole Fraction					
Ar	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	127,843	127,843	107,263	49,602	71,297
V-L Flowrate (kg/hr)	2,303,125	2,303,125	1,932,365	893,599	1,284,442
Solids Flowrate (kg/hr)	0	0	0	0	0
Temperature (°C)	355	566	267	38	39
Pressure (MPa, abs)	4.28	4.19	0.52	0.01	1.32
Steam Table Enthalpy (kJ/kg)[A]	3,098.44	3,593.58	2,994.07	2,340.01	162.43
AspenPlus Enthalpy (kJ/kg)[B]	-12,881.86	-12,386.71	-12,986.23	-13,640.29	-15,817.87
Density (kg/m^3)	16.0	11.1	2.1	0.1	993.3
V-L Molecular Weight	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	281,845	281,845	236,473	109,354	157,184
V-L Flowrate (lb/hr)	5,077,521	5,077,521	4,260,136	1,970,050	2,831,710
Solids Flowrate (lb/hr)	0	0	0	0	0
Temperature (°F)	671	1,050	512	101	101
Pressure (psia)	620.5	608.1	75.0	1.0	190.7
Steam Table Enthalpy (Btu/lb)[A]	1,332.1	1,545.0	1,287.2	1,006.0	69.8
AspenPlus Enthalpy (Btu/lb)[B]	-5,538.2	-5,325.3	-5,583.1	-5,864.3	-6,800.5
Density (lb/ft^3)	1.000	0.692	0.132	0.003	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

A.1.1 Case B11B.99 – Performance Results

Overall plant performance is summarized in Exhibit A-3; Exhibit A-4 provides a detailed breakdown of the auxiliary power requirements.

The PostCCC facility, including carbon dioxide (CO_2) compression, accounts for over half of the auxiliary plant load. The cooling water system (CWS) (cooling water pumps [CWPs] and cooling tower fan) accounts for over 12 percent of the auxiliary load, largely due to the high cooling water demand of the PostCCC facility and CO_2 compressors.

Unlike the natural gas combined cycle (NGCC) cases where gross output was fixed by the available size of the combustion turbines (CTs), the pulverized coal (PC) cases utilize boilers and steam turbines that can be procured at nearly any desired output. By increasing the boiler and turbine/generator size to account for the greater auxiliary load imposed by the PostCCC facility and CO_2 compressors, a net output of 650 MW is maintained at a reduced net plant efficiency of 29.2 percent (higher heating value [HHV] basis).

Exhibit A-3. Case B11B.99 plant performance summary

Performance Summary	
Total Gross Power, MWe	**780**
CO_2 Capture/Removal Auxiliaries, kWe	21,900
CO_2 Compression, kWe	55,300
Balance of Plant, kWe	52,440
Total Auxiliaries, MWe	**130**
Net Power, MWe	**650**
HHV Net Plant Efficiency, %	29.2
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	12,334 (11,691)
LHV Net Plant Efficiency, %	30.3
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,897 (11,276)
HHV Boiler Efficiency, %	88.0
LHV Boiler Efficiency, %	91.3
Steam Turbine Cycle Efficiency, %	56.6
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	6,358 (6,026)
Condenser Duty, GJ/hr (MMBtu/hr)	2,231 (2,115)
CO_2 Capture Rate, %	99
AGR Duty, GJ/hr (MMBtu/hr)	2,443 (2,316)
As-Received Coal Feed, kg/hr (lb/hr)	295,666 (651,832)
Limestone Sorbent Feed, kg/hr (lb/hr)	28,601 (63,054)
HHV Thermal Input, kWt	2,228,591
LHV Thermal Input, kWt	2,149,503
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.061 (16.1)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.045 (11.9)
Excess Air, %	20.3

Exhibit A-4. Case B11B.99 plant power summary

Power Summary	
Steam Turbine Power, MWe	780
Total Gross Power, MWe	**780**
Auxiliary Load Summary	
Activated Carbon Injection, kWe	40
Ash Handling, kWe	970
Baghouse, kWe	130
Circulating Water Pumps, kWe	10,160
CO_2 Capture/Removal Auxiliaries, kWe	21,900
CO_2 Compression, kWe	55,300
Coal Handling and Conveying, kWe	550
Condensate Pumps, kWe	720
Cooling Tower Fans, kWe	5,250
Dry Sorbent Injection, kWe	80
Flue Gas Desulfurizer, kWe	4,570
Forced Draft Fans, kWe	1,520
Ground Water Pumps, kWe	950
Induced Draft Fans, kWe	14,020
Miscellaneous Balance of Plant[A,B], kWe	2,250
Primary Air Fans, kWe	1,800
Pulverizers, kWe	4,430
SCR, kWe	50
Sorbent Handling & Reagent Preparation, kWe	1,380
Spray Dryer Evaporator, kWe	330
Steam Turbine Auxiliaries, kWe	500
Transformer Losses, kWe	2,740
Total Auxiliaries, MWe	**130**
Net Power, MWe	**650**

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

A.1.1.1 Environmental Performance

The environmental targets for emissions of mercury (Hg), nitrogen oxide (NOx), sulfur dioxide (SO_2), and particulate matter (PM) are presented in Section 2.4. A summary of the plant air emissions for Case B11B.99 is presented in Exhibit A-5. SO_2 emissions are utilized as a surrogate for hydrochloric acid (HCl) emissions; therefore, HCl is not reported.

Exhibit A-5. Case B11B.99 air emissions

	kg/GJ (lb/MMBtu)[A]	tonne/year (ton/year)[B]	kg/MWh (lb/MWh)[C]
SO_2	0.000 (0.000)	0 (0)	0.000 (0.000)
NOx	0.031 (0.072)	1,844 (2,033)	0.318 (0.700)
Particulate	0.004 (0.009)	237 (261)	0.041 (0.090)
Hg	1.32E-7 (3.08E-7)	0.008 (0.009)	1.36E-6 (3.00E-6)
CO_2	1 (2)	53,522 (58,998)	9 (20)
CO_2[D]	–	–	11 (24)
	mg/Nm^3		
Particulate Concentration[E,F]	12.47		

[A]Based on thermal input on an HHV basis
[B]Calculations based on an 85 percent capacity factor
[C]Emissions based on gross power except where otherwise noted
[D]CO_2 emissions based on net power instead of gross power
[E]Concentration of particles in the flue gas after the baghouse
[F]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 0.37 ppmv using a sodium hydroxide (NaOH)-based polishing scrubber in the PostCCC facility. The remaining low concentration of SO_2 is essentially completely removed in the PostCCC absorber vessel resulting in very low SO_2 emissions (reported as zero here).

NOx boiler emissions are controlled to about 0.15 kg/GJ (0.35 lb/MMBtu) using low NOx burners (LNBs) and overfire air (OFA). A selective catalytic reduction (SCR) unit then further reduces the NOx concentration by 79.5 percent to 0.03 kg/GJ (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, activated carbon injection [ACI], fabric filter, dry sorbent injection [DSI], and wet flue gas desulfurization [FGD]) is 97.6 percent.

Ninety-nine percent of the CO_2 in the flue gas is removed in PostCCC facility.

The carbon balance for the plant is shown in Exhibit A-6. The carbon input to the plant consists of carbon in the coal, carbon in the air, powdered activated carbon (PAC), and carbon in the limestone reagent used in the FGD absorber. Carbon leaves the plant mostly as CO_2 product from the CO_2 compression train; however, some CO_2 exits through the stack, 20 percent of the unburned carbon remains in the bottom ash, the remaining unburned carbon is captured in the fabric filter, along with the PAC, and some carbon 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 (minus unburnt carbon in the ash), represented by the following fraction:

$$1 - \frac{Carbon\ in\ Stack}{Total\ Carbon\ In - Unburnt\ Carbon} = \left(1 - \left(\frac{4{,}325}{423{,}017 - 2{,}493}\right) *\right) 100 = 99\%$$

Where the unburned carbon is equal to one minus the carbon conversion rate times the carbon in the coal:

$$(1 - Carbon\ Conversion) * Carbon\ in\ Coal = (1 - 0.994) * 415{,}508 = 2{,}493$$

Exhibit A-6. Case B11B.99 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	188,471 (415,508)	Stack Gas	1,962 (4,325)
Air (CO_2)	439 (968)	FGD Product	223 (493)
PAC	65 (143)	Baghouse	969 (2,137)
FGD Reagent	2,902 (6,398)	Bottom Ash	226 (499)
		CO_2 Product	188,476 (415,519)
		CO_2 Dryer Vent	20 (44)
		CO_2 Knockout	0.5 (1.2)
Total	**191,877 (423,017)**	**Total**	**191,877 (423,017)**

Exhibit A-7 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 removed in the polishing scrubber, and sulfur removed in the baghouse.

Exhibit A-7. Case B11B.99 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	7,411 (16,338)	FGD Product	6,967 (15,360)
		Stack Gas	–
		Polishing Scrubber and Solvent Reclaiming	145 (319)
		Baghouse	299 (658)
Total	**7,411 (16,338)**	**Total**	**7,411 (16,338)**

Exhibit A-8 shows the overall water balance for the plant. The exhibit is presented in an identical manner as was for Case B11A. The only notable difference is the FGD makeup water source. In CO_2 capture cases, a significant amount of water is recovered from the initial PostCCC facility cooling step. This water is assumed suitable to be used as FGD makeup, with the balance of the water from the PostCCC facility discharged.

Exhibit A-8. Case B11B.99 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 Process Makeup	2.0 (529)	2.0 (529)	–	–	–
FGD Slurry Water	1.1 (295)	1.1 (295)	–	–	–
CO_2 Drying	–	–	–	0.0 (2.8)	0.0 (-2.8)
CO_2 Capture Recovery	–	–	–	1.2 (304)	-1.2 (-304)
CO_2 Compression KO	–	–	–	0.1 (25)	-0.1 (-25)
Deaerator Vent	–	–	–	0.1 (22)	-0.1 (-22)
Condenser Makeup	**0.5 (133)**	**–**	**0.5 (133)**	**–**	**0.5 (133)**
BFW Makeup	0.5 (133)	–	0.5 (133)	–	0.5 (133)
Cooling Tower	**40 (10,450)**	**0.4 (110)**	**39 (10,340)**	**8.9 (2,350)**	**30 (7,990)**
BFW Blowdown	–	0.4 (110)	-0.4 (-110)	–	-0.4 (-110)
Total	**43 (11,406)**	**3.5 (934)**	**40 (10,472)**	**10 (2,704)**	29 (7,769)

A.1.1.2 Energy and Mass Balance Diagrams

Energy and mass balance diagrams are shown for the Case B11B.99 PC boiler, the FGD unit, PostCCC system and steam cycle in Exhibit A-9 and Exhibit A-10.

An overall plant energy balance is provided in tabular form in Exhibit A-11. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit A-3) is calculated by multiplying the power out by a generator efficiency of 98.5 percent.

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Exhibit A-9. Case B11B.99 energy and mass balance, SubC PC boiler with CO_2 capture

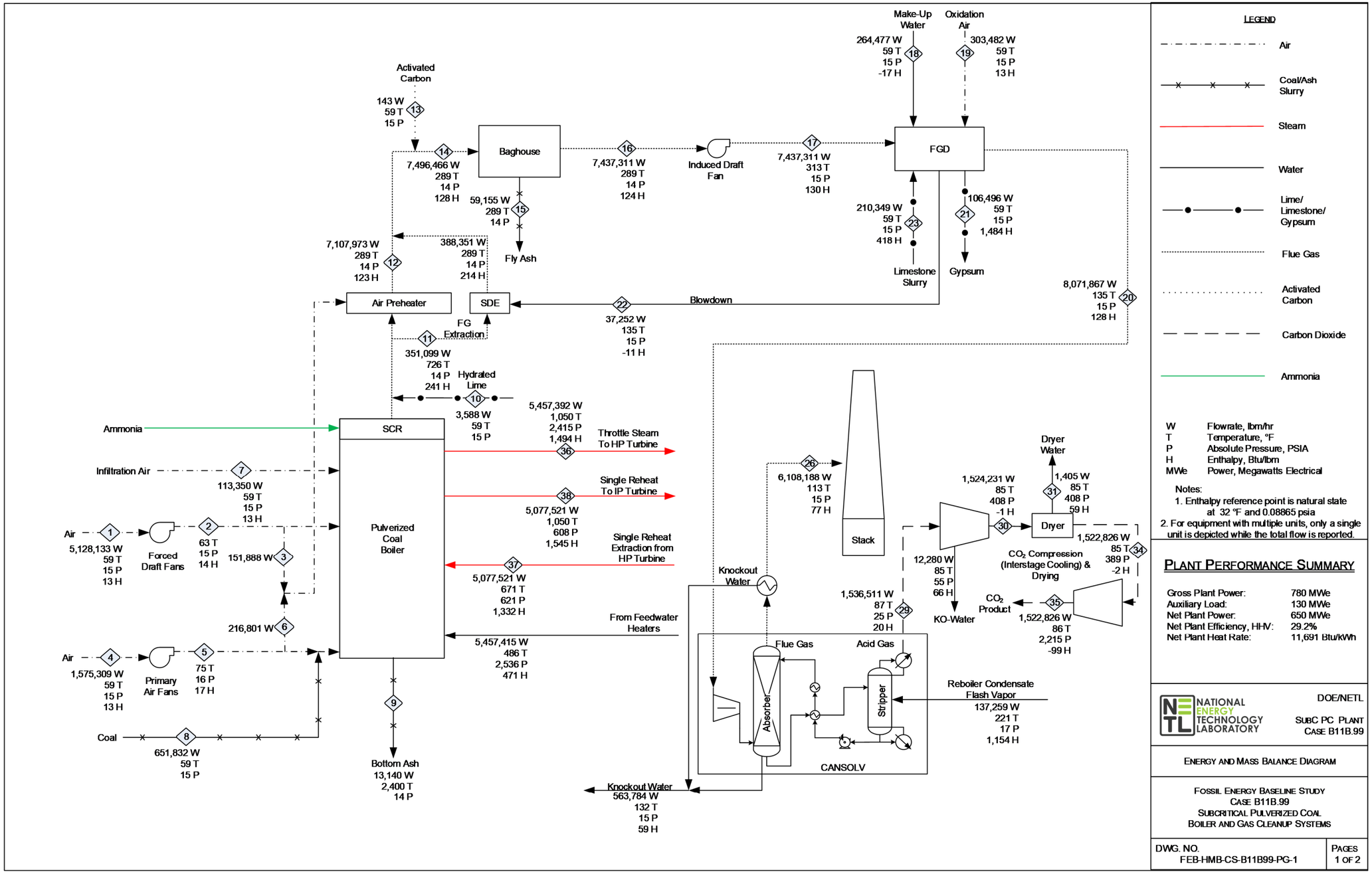


Exhibit A-10. Case B11B.99 energy and mass balance, SubC steam cycle

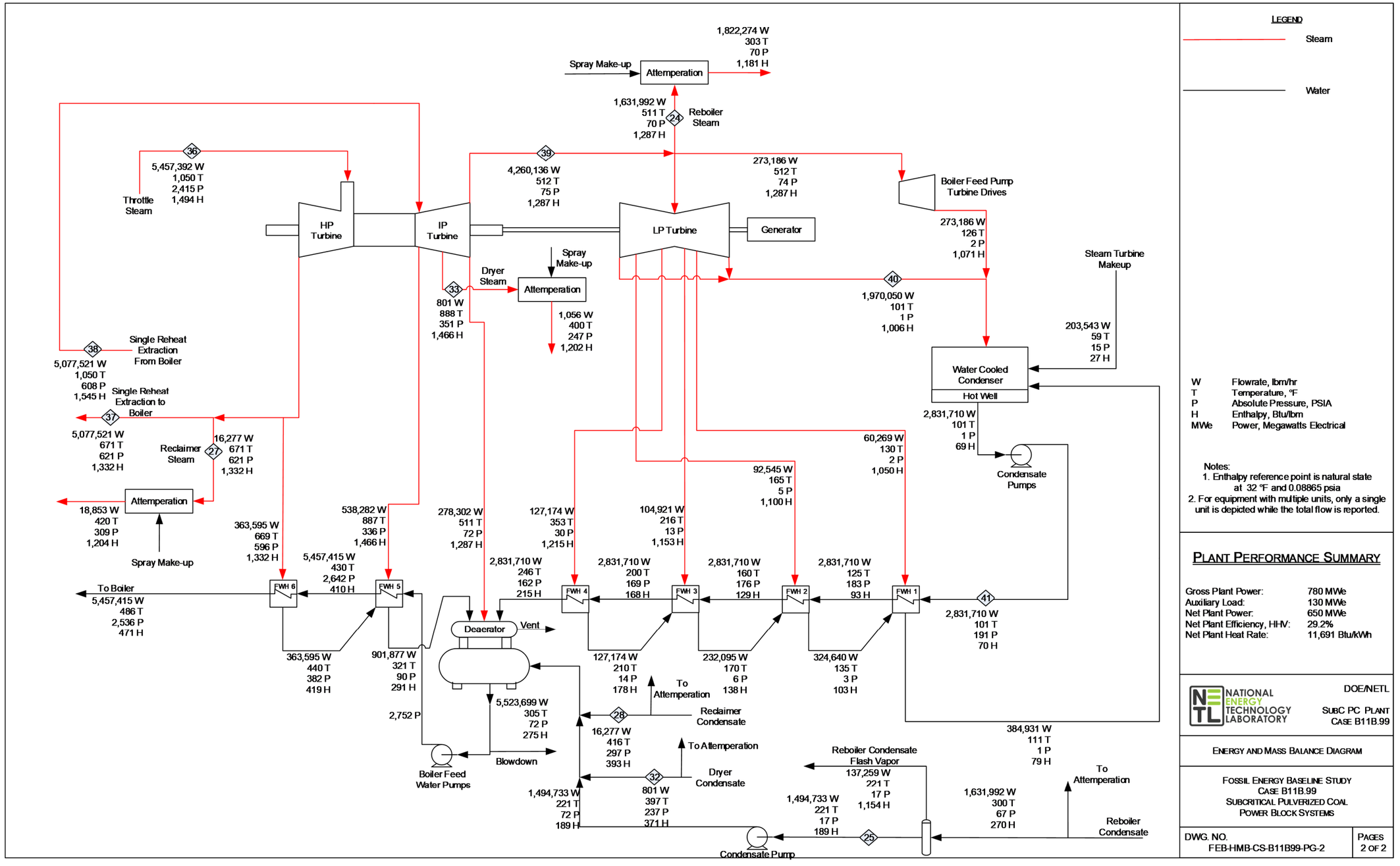


Exhibit A-11. Case B11B.99 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, GJ/hr (MMBtu/hr)				
Coal	8,023 (7,604)	6.7 (6.4)	–	8,030 (7,611)
Air	–	93 (89)	–	93 (89)
Raw Water Makeup	–	149 (141)	–	149 (141)
Limestone	–	0.6 (0.6)	–	0.6 (0.6)
Auxiliary Power	–	–	467 (442)	467 (442)
TOTAL	**8,023 (7,604)**	**250 (237)**	**467 (442)**	**8,739 (8,283)**
Heat Out, GJ/hr (MMBtu/hr)				
Bottom Ash	–	7.6 (7.2)	–	7.6 (7.2)
Fly Ash	–	2.7 (2.6)	–	2.7 (2.6)
Stack Gas	–	498 (472)	–	498 (472)
Sulfur	2.7 (2.6)	0.0 (0.0)	–	2.7 (2.6)
Gypsum	–	2.8 (2.7)	–	2.8 (2.7)
Motor Losses and Design Allowances	–	–	52 (49)	52 (49)
Cooling Tower Load[A]	–	5,166 (4,896)	–	5,166 (4,896)
CO_2 Product Stream	–	-160 (-151)	–	-160 (-151)
AGR Effluent	–	59 (56)	–	59 (56)
Blowdown Streams and Deaerator Vent	–	19 (18)	–	19 (18)
Ambient Losses[B]	–	187 (178)	–	187 (178)
Power	–	–	2,808 (2,662)	2,808 (2,662)
TOTAL	**2.7 (2.6)**	**5,783 (5,481)**	**2,860 (2,711)**	**8,646 (8,195)**
Unaccounted Energy[C]	–	*93 (89)*	–	*93 (89)*

[A]Includes condenser, capture process, CO_2 compressor, and miscellaneous cooling loads
[B]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers
[C]By difference

A.1.2 Case B11B.99 – Major Equipment List

Major equipment items for the subcritical (SubC) 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 A.1.3. 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. Values reported in the equipment lists are rounded.

Case B11B.99 – 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	60 tonne (70 ton)	2	1
9	Feeder	Vibratory	240 tonne/hr (270 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	490 tonne/hr (540 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	240 tonne (270 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	490 tonne/hr (540 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	490 tonne/hr (540 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	1,080 tonne (1,200 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 12 tonne (13 ton) Feeder - 70 kg/hr (160 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 300 tonne (330 ton) Feeder - 1,790 kg/hr (3,950 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	120 tonne/hr (132 tph)	1	0
23	Limestone Conveyor No. 1	Belt	120 tonne/hr (132 tph)	1	0
24	Limestone Reclaim Hopper	N/A	24 tonne (26 ton)	1	0
25	Limestone Reclaim Feeder	Belt	94 tonne/hr (104 tph)	1	0
26	Limestone Conveyor No. 2	Belt	94 tonne/hr (104 tph)	1	0
27	Limestone Day Bin	w/ actuator	378 tonne (416 ton)	2	0

Case B11B.99 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	54 tonne/hr (60 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	54 tonne/hr (60 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	31 tonne/hr (35 tph)	1	1
4	Limestone Ball Mill	Rotary	31 tonne/hr (35 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	120,000 liters (31,800 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	2,000 lpm @ 10m H_2O (530 gpm @ 40 ft H_2O)	1	1
7	Hydrocyclone Classifier	4 active cyclones in a 5-cyclone bank	500 lpm (130 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	680,000 liters (180,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,420 lpm @ 9m H_2O (370 gpm @ 30 ft H_2O)	1	1

Case B11B.99 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,987,000 liters (525,000 gal)	2	0
2	Condensate Pumps	Vertical canned	11,900 lpm @ 200 m H_2O (3,130 gpm @ 500 ft H_2O)	2	1
3	Deaerator and Storage Tank	Horizontal spray type	1,378,000 kg/hr (3,038,000 lb/hr), 5 min. tank	2	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	23,000 lpm @ 2,300 m H_2O (6,000 gpm @ 7,500 ft H_2O)	2	2
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	6,800 lpm @ 2,300 m H_2O (1,800 gpm @ 7,500 ft H_2O)	2	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	350,000 kg/hr (780,000 lb/hr)	4	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	350,000 kg/hr (780,000 lb/hr)	4	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	350,000 kg/hr (780,000 lb/hr)	4	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	350,000 kg/hr (780,000 lb/hr)	4	0
10	HP Feedwater Heater 5	Horizontal U-tube	1,360,000 kg/hr (3,000,000 lb/hr)	2	0
11	HP Feedwater Heater 6	Horizontal U-tube	1,360,000 kg/hr (3,000,000 lb/hr)	2	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	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	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	10,700 lpm @ 20 m H_2O (2,810 gpm @ 60 ft H_2O)	2	1
21	Ground Water Pumps	Stainless steel, single suction	4,260 lpm @ 270 m H_2O (1,130 gpm @ 880 ft H_2O)	5	1
22	Filtered Water Pumps	Stainless steel, single suction	1,600 lpm @ 50 m H_2O (420 gpm @ 160 ft H_2O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	1,539,000 liter (406,600 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	1,010 lpm (270 gpm)	1	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
25	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
26	Process Water Treatment	Spray dryer evaporator	Flue Gas - 2,720 m3/min (96,100 acfm) @ 385°C (726°F) & 0.1 MPa (14 psia) Blowdown - 160 lpm (40 gpm) @ 19,982 ppmw Cl^-	2	1

Case B11B.99 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Subcritical, drum, wall-fired, low NOx burners, overfire air	2,720,000 kg/hr steam @ 16.5 MPa/566°C/566°C (6,000,000 lb/hr steam @ 2,400 psig/1,050°F/1,050°F)	1	0
2	Primary Air Fan	Centrifugal	393,000 kg/hr, 5,400 m^3/min @ 101 cm WG (866,000 lb/hr, 189,400 acfm @ 40 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	1,279,000 kg/hr, 17,500 m^3/min @ 26 cm WG (2,820,000 lb/hr, 617,000 acfm @ 10 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,855,000 kg/hr, 37,600 m^3/min @ 114 cm WG (4,091,000 lb/hr, 1,327,000 acfm @ 45 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	3,510,000 kg/hr (7,740,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	140 m^3/min @ 108 cm WG (4,800 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	151,000 liter (39,800 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	29 lpm @ 90 m H_2O (8 gpm @ 300 ft H_2O)	2	1

Case B11B.99 – 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	1,856,000 kg/hr (4,091,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	62,900 $m^3$3/min (2,220,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	219,000 lpm @ 65 m H_2O (57,700 gpm @ 210 ft H_2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	6,040 lpm (1,600 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	1,030 m^3/min @ 0.3 MPa (36,490 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,510 lpm (400 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	48 tonne/hr (53 tph) of 50 wt% slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	920 lpm @ 13 m H_2O (240 gpm @ 40 ft H_2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	600,000 lpm (160,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	2,200 lpm @ 21 m H_2O (580 gpm @ 70 ft H_2O)	1	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
12	Activated Carbon Injectors	---	70 kg/hr (160 lb/hr)	1	0
13	Hydrated Lime Injectors	---	1,790 kg/hr (3,950 lb/hr)	1	0
14	CANSOLV	Amine-based CO_2 capture technology	4,027,000 kg/hr (8,879,000 lb/hr) 19.1 wt% CO_2 concentration	1	0
15	CANSOLV LP Condensate Pump	Centrifugal	1,585 lpm @ 1 m H_2O (419 gpm @ 3 ft H_2O)	1	1
16	CANSOLV IP Condensate Pump	Centrifugal	22 lpm @ 4.6 m H_2O (6 gpm @ 15 ft H_2O)	1	1
17	CO_2 Dryer	Triethylene glycol	Inlet: 199 m^3/min @ 2.8 MPa (7,039 acfm @ 408 psia) Outlet: 2.7 MPa (389 psia) Water Recovered: 637 kg/hr (1,405 lb/hr)	1	0
18	CO_2 Compressor	Integrally geared, multi-stage centrifugal	10.0 m^3/min @ 15.3 MPa, 82°C (355 acfm @ 2,217 psia, 180°F)	2	0
19	CO_2 Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 109 GJ/hr (103 MMBtu/hr)	1	0

Case B11B.99 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.5 m (21 ft) diameter	1	0

Case B11B.99 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	821 MW 16.5 MPa/566°C/566°C (2,400 psig/1,050°F/1,050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	910 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,450 GJ/hr (2,330 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0

Case B11B.99 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	1,019,000 lpm @ 30 m (269,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 5,680 GJ/hr (5,390 MMBtu/hr) heat duty	1	0

Case B11B.99 – Account 10: Ash and Spent Sorbent Handling System

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	–	6.6 tonne/hr (7.2 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	26 m^3/min @ 0.2 MPa (936 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,740 tonne (1,920 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	160 tonne/hr (180 tph)	1	0

Case B11B.99 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 760 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 31 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 58 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 21 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.99 – 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

A.1.3 Case B11B.99 – Cost Estimating

The cost estimating methodology was described in Section 2.7. Exhibit A-12 shows a detailed breakdown of the capital costs; Exhibit A-13 shows the owner's costs, total overnight cost (TOC), and total as-spent cost (TASC); Exhibit A-14 shows the initial and annual operation and maintenance (O&M) costs; and Exhibit A-15 shows the cost of electricity (COE) breakdown.

For PC cases, existing costs were escalated to reflect a 2023-year dollar using the methodology outlined in NETL's current Quality Guidelines for Energy System Studies (QGESS) (NETL, 2025a).

The estimated total plant cost (TPC) of the SubC PC boiler with CO_2 capture is $4,363/kW. Process contingency represents 2.8 percent of the TPC and project contingency represents 13.9 percent of the TPC. The first-year (FY) COE, including transport and storage (T&S) costs of $10.6/MWh,[v] is $149.6/MWh. The levelized cost of electricity (LCOE), including T&S costs of $14.1/MWh, is $160.5/MWh.

[v] T&S costs for this case are based on a first-year break-even CO_2 price of $9.96/tonne.

Exhibit A-12. Case B11B.99 total plant cost details

Case:	B11B.99 – Subcritical PC with 99 Percent CO_2 Capture					Estimate Type:	Conceptual			
Plant Size (MW, net):	650					Cost Base:	Jan 2023			
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
1	Coal & Sorbent Handling										
1.1	Coal Receive & Unload	$1,676	$0	$586	$0	$2,262	$396	$0	$399	$3,057	$5
1.2	Coal Stackout & Reclaim	$5,503	$0	$955	$0	$6,458	$1,130	$0	$1,138	$8,726	$13
1.3	Coal Conveyors	$50,706	$0	$9,355	$0	$60,062	$10,511	$0	$10,586	$81,158	$125
1.4	Other Coal Handling	$7,049	$0	$1,151	$0	$8,199	$1,435	$0	$1,445	$11,079	$17
1.5	Sorbent Receive & Unload	$323	$0	$74	$0	$397	$70	$0	$70	$537	$1
1.6	Sorbent Stackout & Reclaim	$2,361	$0	$331	$0	$2,692	$471	$0	$474	$3,637	$6
1.7	Sorbent Conveyors	$3,577	$746	$672	$0	$4,996	$874	$0	$881	$6,751	$10
1.8	Other Sorbent Handling	$172	$39	$69	$0	$280	$49	$0	$49	$378	$1
1.9	Coal & Sorbent Handling Foundations	$0	$2,109	$2,249	$0	$4,358	$763	$0	$768	$5,889	$9
	Subtotal	**$71,368**	**$2,895**	**$15,443**	**$0**	**$89,705**	**$15,698**	**$0**	**$15,810**	**$121,214**	**$186**
2	Coal & Sorbent Preparation & Feed										
2.1	Coal Crushing & Drying	$3,614	$0	$539	$0	$4,153	$727	$0	$732	$5,611	$9
2.2	Prepared Coal Storage & Feed	$12,164	$0	$2,033	$0	$14,196	$2,484	$0	$2,502	$19,183	$29
2.5	Sorbent Preparation Equipment	$1,590	$66	$253	$0	$1,909	$334	$0	$336	$2,579	$4
2.6	Sorbent Storage & Feed	$2,662	$0	$782	$0	$3,445	$603	$0	$607	$4,655	$7
2.9	Coal & Sorbent Feed Foundation	$0	$1,012	$718	$0	$1,731	$303	$0	$305	$2,339	$4
	Subtotal	**$20,030**	**$1,078**	**$4,325**	**$0**	**$25,433**	**$4,451**	**$0**	**$4,483**	**$34,366**	**$53**
3	Feedwater & Miscellaneous BOP Systems										
3.1	Feedwater System	$5,459	$9,018	$3,647	$0	$18,123	$3,171	$0	$3,194	$24,488	$38
3.2	Water Makeup & Pretreating	$11,632	$1,121	$5,137	$0	$17,891	$3,131	$0	$4,204	$25,226	$39
3.3	Other Feedwater Subsystems	$4,265	$1,348	$1,035	$0	$6,649	$1,164	$0	$1,172	$8,984	$14
3.4	Service Water Systems	$3,710	$6,826	$17,875	$0	$28,411	$4,972	$0	$6,677	$40,060	$62
3.5	Other Boiler Plant Systems	$1,008	$368	$745	$0	$2,122	$371	$0	$374	$2,867	$4
3.6	Natural Gas Pipeline and Start-Up System	$5,241	$202	$122	$0	$5,565	$974	$0	$981	$7,520	$12
3.7	Waste Water Treatment Equipment	$19,392	$0	$9,263	$0	$28,655	$5,015	$0	$6,734	$40,403	$62
3.8	Spray Dryer Evaporator	$24,114	$0	$10,880	$0	$34,993	$6,124	$0	$8,223	$49,340	$76
3.9	Miscellaneous Plant Equipment	$276	$35	$109	$0	$420	$73	$0	$99	$592	$1
	Subtotal	**$75,097**	**$18,917**	**$48,814**	**$0**	**$142,828**	**$24,995**	**$0**	**$31,658**	**$199,481**	**$307**
4	Pulverized Coal Boiler & Accessories										
4.9	Pulverized Coal Boiler & Accessories	$302,571	$0	$160,538	$0	$463,108	$81,044	$0	$81,623	$625,775	$962
4.10	Selective Catalytic Reduction System	$41,129	$0	$20,918	$0	$62,047	$10,858	$0	$10,936	$83,841	$129
4.11	Boiler Balance of Plant	$2,115	$0	$1,122	$0	$3,238	$567	$0	$571	$4,375	$7
4.12	Primary Air System	$2,396	$0	$1,170	$0	$3,566	$624	$0	$628	$4,818	$7
4.13	Secondary Air System	$3,629	$0	$1,772	$0	$5,401	$945	$0	$952	$7,298	$11
4.14	Induced Draft Fans	$7,828	$0	$3,823	$0	$11,651	$2,039	$0	$2,053	$15,743	$24
4.15	Major Component Rigging	$125	$0	$64	$0	$190	$33	$0	$33	$256	$0
4.16	Boiler Foundations	$0	$549	$390	$0	$939	$164	$0	$166	$1,269	$2

Case:	B11B.99 – Subcritical PC with 99 Percent CO_2 Capture										
Plant Size (MW, net):	650										
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
	Subtotal	**$359,793**	**$549**	**$189,798**	**$0**	**$550,140**	**$96,275**	**$0**	**$96,962**	**$743,377**	**$1,143**
5	**Flue Gas Cleanup**										
5.1	CANSOLV CO_2 Removal System	$207,219	$91,311	$170,089	$0	$468,620	$82,008	$79,665	$110,301	$740,595	$1,139
5.2	Wet FGD Absorber Vessels & Accessories	$105,047	$0	$18,967	$0	$124,014	$21,702	$0	$21,858	$167,574	$258
5.3	Other FGD	$1,680	$0	$1,091	$0	$2,770	$485	$0	$488	$3,743	$6
5.4	CO_2 Compression & Drying	$63,643	$9,289	$16,489	$0	$89,421	$15,649	$0	$21,014	$126,084	$194
5.5	CO_2 Compressor Aftercooler	$722	$111	$243	$0	$1,077	$188	$0	$253	$1,518	$2
5.6	Mercury Removal (DSI/ACI)	$3,531	$811	$2,930	$0	$7,272	$1,273	$0	$1,282	$9,827	$15
5.9	Particulate Removal (Bag House & Accessories)	w/ 5.2	w/ 5.2	w/ 5.2	w/ 5.2	$0	$0	$0	$0	$0	$0
5.12	Gas Cleanup Foundations	$0	$274	$194	$0	$468	$82	$0	$83	$633	$1
5.13	Gypsum Dewatering System	$1,082	$0	$142	$0	$1,224	$214	$0	$216	$1,654	$3
	Subtotal	**$382,924**	**$101,796**	**$210,146**	**$0**	**$694,867**	**$121,602**	**$79,665**	**$155,494**	**$1,051,628**	**$1,617**
7	**Ductwork & Stack**										
7.3	Ductwork	$0	$995	$559	$0	$1,555	$272	$0	$274	$2,101	$3
7.4	Stack	$11,914	$0	$5,420	$0	$17,333	$3,033	$0	$3,055	$23,422	$36
7.5	Duct & Stack Foundations	$0	$275	$264	$0	$539	$94	$0	$127	$760	$1
	Subtotal	**$11,914**	**$1,270**	**$6,243**	**$0**	**$19,427**	**$3,400**	**$0**	**$3,456**	**$26,282**	**$40**
8	**Steam Turbine & Accessories**										
8.1	Steam Turbine Generator & Accessories	$78,544	$0	$7,903	$0	$86,447	$15,128	$0	$15,236	$116,812	$180
8.2	Steam Turbine Plant Auxiliaries	$1,790	$0	$3,343	$0	$5,133	$898	$0	$905	$6,937	$11
8.3	Condenser & Auxiliaries	$16,289	$0	$4,402	$0	$20,691	$3,621	$0	$3,647	$27,958	$43
8.4	Steam Piping	$58,054	$0	$16,635	$0	$74,689	$13,071	$0	$13,164	$100,923	$155
8.5	Turbine Generator Foundations	$0	$303	$405	$0	$708	$124	$0	$166	$999	$2
	Subtotal	**$154,677**	**$303**	**$32,688**	**$0**	**$187,669**	**$32,842**	**$0**	**$33,118**	**$253,629**	**$390**
9	**Cooling Water System**										
9.1	Cooling Towers	$28,158	$0	$6,817	$0	$34,974	$6,120	$0	$6,164	$47,259	$73
9.2	Circulating Water Pumps	$4,010	$0	$223	$0	$4,233	$741	$0	$746	$5,720	$9
9.3	Circulating Water System Auxiliaries	$23,343	$0	$2,407	$0	$25,750	$4,506	$0	$4,538	$34,794	$53
9.4	Circulating Water Piping	$0	$10,402	$7,619	$0	$18,021	$3,154	$0	$3,176	$24,351	$37
9.5	Make-up Water System	$1,799	$0	$1,800	$0	$3,599	$630	$0	$634	$4,863	$7
9.6	Component Cooling Water System	$1,553	$0	$1,006	$0	$2,559	$448	$0	$451	$3,457	$5
9.7	Circulating Water System Foundations	$0	$965	$1,296	$0	$2,260	$396	$0	$531	$3,187	$5
	Subtotal	**$58,862**	**$11,367**	**$21,167**	**$0**	**$91,396**	**$15,994**	**$0**	**$16,241**	**$123,631**	**$190**
10	**Ash & Spent Sorbent Handling Systems**										
10.6	Ash Storage Silos	$1,662	$0	$3,945	$0	$5,608	$981	$0	$988	$7,577	$12
10.7	Ash Transport & Feed Equipment	$5,653	$0	$4,349	$0	$10,003	$1,750	$0	$1,763	$13,516	$21
10.9	Ash/Spent Sorbent Foundation	$0	$1,112	$1,106	$0	$2,218	$388	$0	$521	$3,128	$5
	Subtotal	**$7,316**	**$1,112**	**$9,401**	**$0**	**$17,828**	**$3,120**	**$0**	**$3,273**	**$24,221**	**$37**

Case:	B11B.99 – Subcritical PC with 99 Percent CO_2 Capture						Estimate Type:	Conceptual			
Plant Size (MW, net):	650						Cost Base:	Jan 2023			
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	Accessory Electric Plant										
11.1	Generator Equipment	$3,866	$0	$2,140	$0	$6,006	$1,051	$0	$1,059	$8,115	$12
11.2	Station Service Equipment	$11,453	$0	$721	$0	$12,174	$2,130	$0	$2,146	$16,450	$25
11.3	Switchgear & Motor Control	$17,780	$0	$2,264	$0	$20,044	$3,508	$0	$3,533	$27,084	$42
11.4	Conduit & Cable Tray	$0	$2,097	$4,889	$0	$6,986	$1,223	$0	$1,231	$9,440	$15
11.5	Wire & Cable	$0	$5,555	$8,030	$0	$13,585	$2,377	$0	$2,394	$18,356	$28
11.6	Protective Equipment	$79	$0	$201	$0	$280	$49	$0	$49	$378	$1
11.7	Standby Equipment	$1,194	$0	$809	$0	$2,003	$351	$0	$353	$2,707	$4
11.8	Main Power Transformers	$10,162	$0	$152	$0	$10,314	$1,805	$0	$1,818	$13,937	$21
11.9	Electrical Foundations	$0	$293	$602	$0	$895	$157	$0	$210	$1,263	$2
	Subtotal	**$44,533**	**$7,945**	**$19,809**	**$0**	**$72,287**	**$12,650**	**$0**	**$12,793**	**$97,730**	**$150**
12	Instrumentation & Control										
12.1	Pulverized Coal Boiler Control Equipment	$1,093	$0	$154	$0	$1,247	$218	$0	$220	$1,684	$3
12.3	Steam Turbine Control Equipment	$976	$0	$88	$0	$1,065	$186	$0	$188	$1,439	$2
12.5	Signal Processing Equipment	$1,241	$0	$174	$0	$1,415	$248	$0	$249	$1,912	$3
12.6	Control Boards, Panels, & Racks	$380	$0	$183	$0	$562	$98	$28	$103	$792	$1
12.7	Distributed Control System Equipment	$10,707	$0	$1,506	$0	$12,212	$2,137	$611	$2,244	$17,204	$26
12.8	Instrument Wiring & Tubing	$750	$585	$1,892	$0	$3,226	$565	$161	$593	$4,545	$7
12.9	Other Instrumentation & Controls Equipment	$922	$0	$1,683	$0	$2,604	$456	$130	$479	$3,669	$6
	Subtotal	**$16,068**	**$585**	**$5,679**	**$0**	**$22,331**	**$3,908**	**$930**	**$4,075**	**$31,244**	**$48**
13	Improvements to Site										
13.1	Site Preparation	$0	$604	$10,379	$0	$10,983	$1,922	$0	$2,581	$15,485	$24
13.2	Site Improvements	$0	$2,989	$3,194	$0	$6,182	$1,082	$0	$1,453	$8,717	$13
13.3	Site Facilities	$3,473	$0	$2,898	$0	$6,370	$1,115	$0	$1,497	$8,982	$14
	Subtotal	**$3,473**	**$3,592**	**$16,470**	**$0**	**$23,535**	**$4,119**	**$0**	**$5,531**	**$33,185**	**$51**
14	Buildings & Structures										
14.2	Boiler Building	$0	$15,100	$10,732	$0	$25,832	$4,521	$0	$4,553	$34,906	$54
14.3	Steam Turbine Building	$0	$20,989	$15,809	$0	$36,798	$6,440	$0	$6,486	$49,723	$76
14.4	Administration Building	$0	$1,363	$1,166	$0	$2,529	$443	$0	$446	$3,418	$5
14.5	Circulation Water Pumphouse	$0	$257	$165	$0	$422	$74	$0	$74	$570	$1
14.6	Water Treatment Buildings	$0	$644	$475	$0	$1,119	$196	$0	$197	$1,512	$2
14.7	Machine Shop	$0	$720	$391	$0	$1,111	$194	$0	$196	$1,501	$2
14.8	Warehouse	$0	$541	$438	$0	$979	$171	$0	$173	$1,323	$2
14.9	Other Buildings & Structures	$0	$379	$261	$0	$641	$112	$0	$113	$866	$1
14.10	Waste Treating Building & Structures	$0	$842	$2,066	$0	$2,908	$509	$0	$513	$3,929	$6
	Subtotal	**$0**	**$40,835**	**$31,504**	**$0**	**$72,339**	**$12,659**	**$0**	**$12,750**	**$97,748**	**$150**
	Total	**$1,206,054**	**$192,245**	**$611,485**	**$0**	**$2,009,784**	**$351,712**	**$80,596**	**$395,644**	**$2,837,736**	**$4,363**

Exhibit A-13. Case B11B.99 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$16,587	$26
1 Month Maintenance Materials	$2,671	$4
1 Month Non-fuel Consumables	$4,393	$7
1 Month Waste Disposal	$1,445	$2
25% of 1 Months Fuel Cost at 100% CF	$4,183	$6
2% of TPC	$56,755	$87
Total	**$86,034**	**$132**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$40,828	$63
0.5% of TPC (spare parts)	$14,189	$22
Total	**$55,017**	**$85**
Other Costs		
Initial Cost for Catalyst and Chemicals	$6,586	$10
Land	$1,800	$3
Other Owner's Costs	$425,660	$654
Financing Costs	$76,619	$118
Total Overnight Costs (TOC)	**$3,489,452**	**$5,365**
TASC Multiplier (IOU, 33 year)	1.213	
Total As-Spent Cost (TASC)	**$4,231,753**	**$6,506**

Exhibit A-14. Case B11B.99 initial and annual operating and maintenance costs

Case:	B11B.99 – Subcritical PC with 99 Percent CO_2 Capture				Cost Base:	Jan 2023
Plant Size (MW, net):	650	Heat Rate-net (Btu/kWh):	11,691		Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		45.04	**$/hour**	Skilled Operator:		2.0
Operating Labor Burden:		30.00	**% of base**	Operator:		11.3
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		2.0
				Total:		16.3
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$8,377,366	$12.879
Maintenance Labor:					$18,161,511	$27.921
Administrative & Support Labor:					$6,634,719	$10.200
Property Taxes and Insurance:					$56,754,720	$87.253
Total:					**$89,928,316**	**$138.253**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$27,242,266	$5.625
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	7,540	$2.30	$0	$5,380,462	$1.111
Makeup and Waste Water Treatment Chemicals (ton):	0	22.5	$660.00	$0	$4,599,236	$0.950
Brominated Activated Carbon (ton):	0	1.71	$2,547.97	$0	$1,352,868	$0.279
Enhanced Hydrated Lime (ton):	0	43.1	$391.63	$0	$5,231,868	$1.080
Limestone (ton):	0	757	$30.18	$0	$7,084,864	$1.463
Ammonia (19 wt%, ton):	0	75.8	$280.00	$0	$6,587,401	$1.360
SCR Catalyst (ft^3):	18,817	17.2	$350.00	$6,585,834	$1,865,986	$0.385
CO_2 Capture System Chemicals[A]:	Proprietary				$12,522,567	$2.586
Triethylene Glycol (gal):	w/equip.	71	$8.50	$0	$187,718	$0.039
Subtotal:				**$6,585,834**	**$44,812,971**	**$9.253**
Waste Disposal						
Fly Ash (ton)	0	710	$46.71	$0	$10,286,203	$2.124
Bottom Ash (ton)	0	158	$46.71	$0	$2,284,846	$0.472
SCR Catalyst (ft^3):	0	17.2	$5.70	$0	$30,389	$0.006
Triethylene Glycol (gal):	0	3,615	$1.30	$0	$1,458,078	$0.301
Thermal Reclaimer Unit Waste (ton):	0	8.77	$250.00	$0	$680,477	$0.140
Subtotal:				**$0**	**$14,739,992**	**$3.043**
By-Products						
Gypsum (ton)	0	1150	$0.00	$0	$0	$0.000
Subtotal:				**$0**	**$0**	**$0.000**
Variable Operating Costs Total:				**$6,585,834**	**$86,795,229**	**$17.921**
Fuel Cost						
Illinois Number 6 (ton):	0	7,822	$70.32	$0	$170,657,578	$35.236
Total:				**$0**	**$170,657,578**	**$35.236**

[A]CO_2 Capture System Chemicals includes NaOH and CANSOLV Solvent

Exhibit A-15. Case B11B.99 COE breakdown

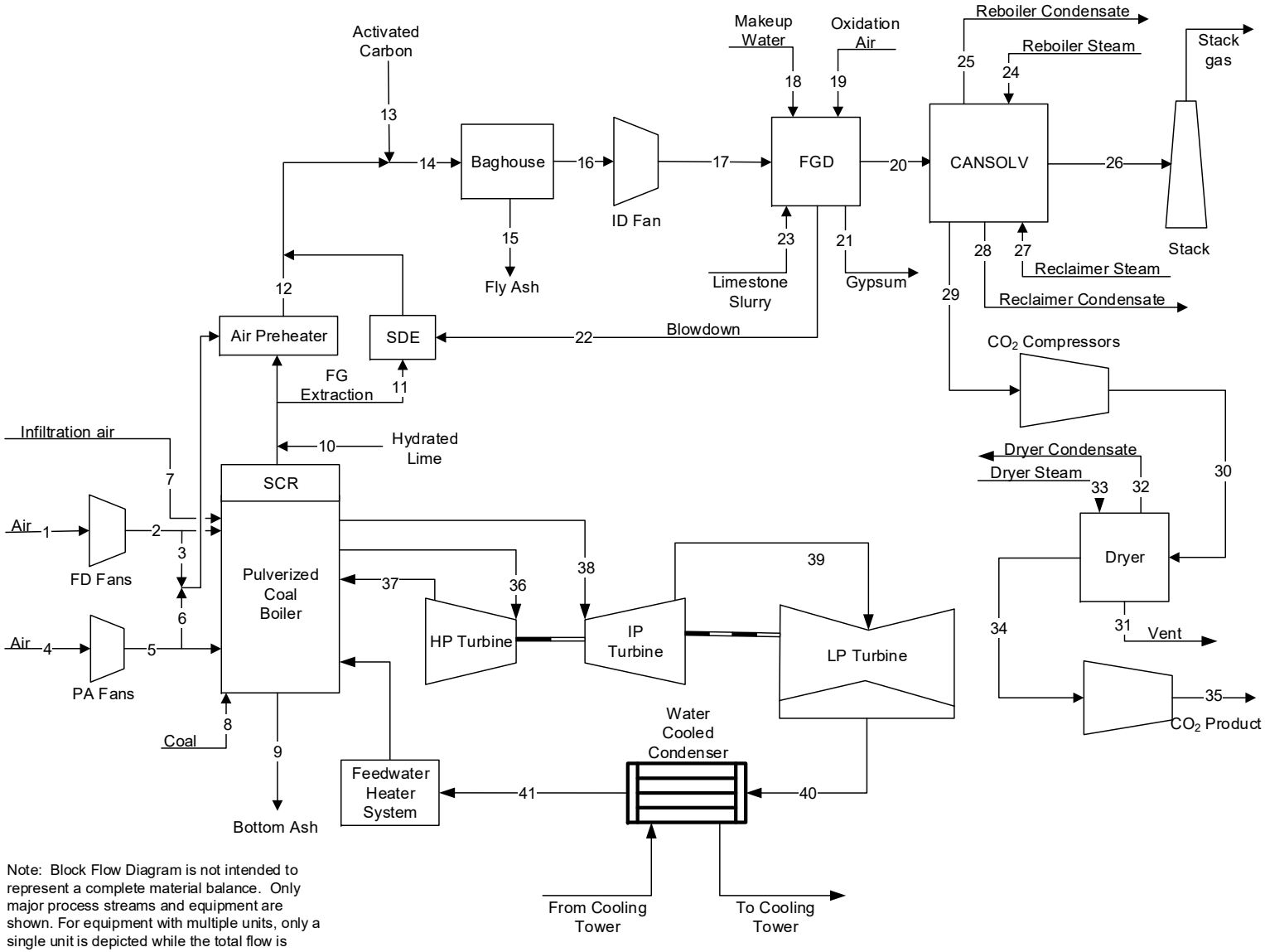
	FY COE		LCOE	
Component	Value, $/MWh	Percentage	Value, $/MWh	Percentage
Capital	67.3	45%	67.3	42%
Fixed	18.6	12%	24.8	15%
Variable	17.9	12%	23.9	15%
Fuel	35.2	24%	30.4	19%
Total (Excluding T&S)	**139.1**	**N/A**	**146.4**	**N/A**
CO_2 T&S	10.6	7%	14.1	9%
Total (Including T&S)	**149.6**	**N/A**	**160.5**	**N/A**

A.2 Case B12B.99 – SC PC with 99% CO_2 Capture Process Description

The plant configuration and process description for Case B12B.99 are nearly the same as Case B12B.90, with the exception of 99 percent capture. Since the process descriptions of the plant and PostCCC facility were provided in Section 3.3.3 and Section 3.1.8, respectively, they are not repeated here.

The BFD for Case B12B.99 is shown in Exhibit A-16. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit A-17. The modeling assumptions are presented in Section 3.3.1.

Exhibit A-16. Case B12B.99 BFD, SC unit with 99 percent CO_2 capture



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown. For equipment with multiple units, only a single unit is depicted while the total flow is reported.

Exhibit A-17. Case B12B.99 stream table, SC unit with 99 percent CO_2 capture

	1	2	3	4	5	6	7	8	9	10	11	12
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	0.0087	0.0088
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1457	0.1379
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	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000	0.0879	0.0837
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0001
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7318	0.7340
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0237	0.0336
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0020
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	76,638	76,638	2,270	23,542	23,542	3,240	1,694	0	0	1	5,050	102,446
V-L Flowrate (kg/hr)	2,211,534	2,211,534	65,503	679,360	679,360	93,497	48,883	0	0	15	150,200	3,042,064
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	281,106	5,667	1,532	1,213	23,286
Temperature (°C)	15	17	17	15	24	24	15	15	1,316	15	385	143
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg)[A]	30.23	32.49	32.49	30.23	38.98	38.98	30.23	---	---	---	---	---
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-95.31	-95.31	-97.58	-88.83	-88.83	-97.58	-2,119.02	1,267.06	-13,402.95	-2,261.17	-2,394.31
Density (kg/m^3)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	1,003.6	0.5	0.8
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015	29.742	29.694
V-L Flowrate (lb_{mol}/hr)	168,957	168,957	5,004	51,902	51,902	7,143	3,735	0	0	2	11,134	225,855
V-L Flowrate (lb/hr)	4,875,597	4,875,597	144,409	1,497,732	1,497,732	206,125	107,768	0	0	34	331,134	6,706,604
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	619,732	12,493	3,378	2,674	51,336
Temperature (°F)	59	63	63	59	75	75	59	59	2,400	59	726	289
Pressure (psia)	14.7	15.0	15.0	14.7	15.9	15.9	14.7	14.7	14.3	14.7	14.3	14.1
Steam Table Enthalpy (Btu/lb)[A]	13.0	14.0	14.0	13.0	16.8	16.8	13.0	---	---	---	---	---
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-41.0	-41.0	-42.0	-38.2	-38.2	-42.0	-911.0	544.7	-5,762.2	-972.1	-1,029.4
Density (lb/ft^3)	0.076	0.077	0.077	0.076	0.080	0.080	0.076	---	---	62.650	0.033	0.052

[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 A-17. Case B12B.99 stream table, SC unit with 99 percent CO_2 capture (continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0092	0.0081	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.1372	0.0000	0.1372	0.1372	0.0000	0.0003	0.1245	0.0001	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	0.0000	0.0911	0.0000	0.0911	0.0911	0.9999	0.0099	0.1508	0.9998	0.9943	0.9999	1.0000
HCl	0.0000	0.0001	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.7281	0.0000	0.7281	0.7281	0.0000	0.7732	0.6803	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0329	0.0000	0.0329	0.0329	0.0000	0.2074	0.0363	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0020	0.0000	0.0020	0.0020	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.1158	0.0000	0.0000	0.0001	0.0000	0.0000	0.0001	0.0009	0.0001	0.0000
$CaCl_2$	0.0000	0.0001	0.8842	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0048	0.0000	0.0000
Total	0.0000	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_{mol}/hr)	0	108,352	7	108,345	108,345	6,330	4,535	121,121	255	856	3,525	38,969
V-L Flowrate (kg/hr)	0	3,208,088	693	3,207,378	3,207,378	114,053	130,878	3,481,034	4,595	15,824	63,521	702,030
Solids Flowrate (kg/hr)	62	24,801	24,818	0	0	0	0	0	41,332	241	27,192	0
Temperature (°C)	15	143	143	143	156	15	15	57	15	57	15	269
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.48
Steam Table Enthalpy (kJ/kg)[A]	---	---	---	287.58	302.09	-47.80	30.23	297.00	---	---	---	3,000.14
AspenPlus Enthalpy (kJ/kg)[B]	-6.79	-2,453.14	-1,065.96	-2,464.17	-2,449.66	-16,015.01	-97.58	-2,939.24	-12,513.34	-15,496.21	-14,994.25	-12,980.15
Density (kg/m^3)	---	0.8	2,150.2	0.8	0.9	1,003.7	1.2	1.1	878.3	979.4	1,003.7	2.0
V-L Molecular Weight	---	29.608	104.898	29.603	29.603	18.019	28.857	28.740	18.021	18.494	18.019	18.015
V-L Flowrate (lb_{mol}/hr)	0	238,875	15	238,860	238,860	13,955	9,999	267,025	562	1,886	7,772	85,911
V-L Flowrate (lb/hr)	0	7,072,624	1,528	7,071,059	7,071,059	251,444	288,537	7,674,367	10,130	34,886	140,041	1,547,711
Solids Flowrate (lb/hr)	136	54,677	54,714	0	0	0	0	0	91,121	531	59,949	0
Temperature (°F)	59	289	289	289	313	59	59	135	59	135	59	516
Pressure (psia)	14.7	14.1	14.1	13.9	15.3	14.7	14.7	14.8	14.7	14.7	14.7	70.0
Steam Table Enthalpy (Btu/lb)[A]	---	---	---	123.6	129.9	-20.5	13.0	127.7	---	---	---	1,289.8
AspenPlus Enthalpy (Btu/lb)[B]	-2.9	-1,054.7	-458.3	-1,059.4	-1,053.2	-6,885.2	-42.0	-1,263.6	-5,379.8	-6,662.2	-6,446.4	-5,580.5
Density (lb/ft^3)	---	0.052	134.232	0.051	0.055	62.658	0.076	0.067	54.833	61.145	62.658	0.122

[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 A-17. Case B12B.99 stream table, SC unit with 99 percent CO_2 capture (continued)

	25	26	27	28	29	30	31	32	33	34	35	36
V-L Mole Fraction												
Ar	0.0000	0.0103	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0016	0.0000	0.0000	0.9783	0.9975	0.0500	0.0000	0.0000	0.9995	0.9995	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	1.0000	0.0807	1.0000	1.0000	0.0217	0.0025	0.9500	1.0000	1.0000	0.0005	0.0005	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.8614	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0460	0.0000	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	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
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_{mol}/hr)	35,691	95,654	399	399	15,252	14,958	31	19	19	14,927	14,927	137,466
V-L Flowrate (kg/hr)	642,985	2,634,187	7,179	7,179	662,628	657,333	606	350	350	656,726	656,726	2,476,484
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	105	45	342	214	31	29	29	203	461	29	30	593
Pressure (MPa, abs)	0.12	0.10	4.90	2.04	0.17	2.81	2.81	1.64	2.14	2.68	15.27	24.23
Steam Table Enthalpy (kJ/kg)[A]	439.34	179.65	3,049.81	913.81	46.68	-3.05	137.94	863.65	3,379.61	-3.59	-231.09	3,477.96
AspenPlus Enthalpy (kJ/kg)[B]	-15,540.95	-710.95	-12,930.48	-15,066.49	-8,978.62	-8,972.51	-15,225.22	-15,116.65	-12,600.69	-8,967.15	-9,194.65	-12,502.33
Density (kg/m^3)	954.9	1.1	19.2	848.5	3.0	57.8	351.5	861.8	6.4	54.7	630.1	69.2
V-L Molecular Weight	18.015	27.539	18.015	18.015	43.445	43.945	19.315	18.015	18.015	43.997	43.997	18.015
V-L Flowrate (lb_{mol}/hr)	78,685	210,881	879	879	33,625	32,977	69	43	43	32,908	32,908	303,060
V-L Flowrate (lb/hr)	1,417,540	5,807,389	15,828	15,828	1,460,845	1,449,170	1,336	771	771	1,447,834	1,447,834	5,459,713
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	221	113	648	416	87	85	85	397	862	85	86	1,100
Pressure (psia)	17.4	14.8	710.8	296.6	24.7	407.6	407.6	237.4	310.1	389.1	2,214.7	3,514.7
Steam Table Enthalpy (Btu/lb)[A]	188.9	77.2	1,311.2	392.9	20.1	-1.3	59.3	371.3	1,453.0	-1.5	-99.4	1,495.3
AspenPlus Enthalpy (Btu/lb)[B]	-6,681.4	-305.7	-5,559.1	-6,477.4	-3,860.1	-3,857.5	-6,545.7	-6,499.0	-5,417.3	-3,855.2	-3,953.0	-5,375.0
Density (lb/ft^3)	59.612	0.066	1.197	52.968	0.184	3.609	21.943	53.801	0.402	3.416	39.338	4.319

[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 A-17. Case B12B.99 stream table, SC unit with 99 percent CO_2 capture (continued)

	37	38	39	40	41
V-L Mole Fraction					
Ar	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000
SO_3	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	114,524	114,524	98,617	39,687	63,202
V-L Flowrate (kg/hr)	2,063,176	2,063,176	1,776,620	714,965	1,138,608
Solids Flowrate (kg/hr)	0	0	0	0	0
Temperature (°C)	342	593	270	38	39
Pressure (MPa, abs)	4.90	4.80	0.52	0.01	1.26
Steam Table Enthalpy (kJ/kg)[A]	3,049.81	3,652.36	3,000.14	2,343.61	162.36
AspenPlus Enthalpy (kJ/kg)[B]	-12,930.48	-12,327.93	-12,980.15	-13,636.69	-15,817.93
Density (kg/m^3)	19.2	12.3	2.1	0.1	993.3
V-L Molecular Weight	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	252,481	252,481	217,414	87,494	139,337
V-L Flowrate (lb/hr)	4,548,524	4,548,524	3,916,776	1,576,229	2,510,200
Solids Flowrate (lb/hr)	0	0	0	0	0
Temperature (°F)	648	1,100	517	101	101
Pressure (psia)	710.8	696.6	75.0	1.0	183.1
Steam Table Enthalpy (Btu/lb)[A]	1,311.2	1,570.2	1,289.8	1,007.6	69.8
AspenPlus Enthalpy (Btu/lb)[B]	-5,559.1	-5,300.1	-5,580.5	-5,862.7	-6,800.5
Density (lb/ft^3)	1.197	0.768	0.131	0.003	62.009

[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

A.2.1 Case B12B.99 – Performance Results

Overall plant performance is summarized in Exhibit A-18; Exhibit A-19 provides a detailed breakdown of the auxiliary power requirements.

The PostCCC facility, including CO_2 compression, accounts for over half of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for over 12 percent of the auxiliary load, largely due to the high cooling water demand of the PostCCC 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. By increasing the boiler and turbine/generator size to account for the greater auxiliary load imposed by the PostCCC facility and CO_2 compressors, a net output of 650 MW is maintained at a reduced net plant efficiency of 30.7 percent (HHV basis).

Exhibit A-18. Case B12B.99 plant performance summary

Performance Summary	
Total Gross Power, MWe	**774**
CO_2 Capture/Removal Auxiliaries, kWe	20,800
CO_2 Compression, kWe	52,580
Balance of Plant, kWe	49,900
Total Auxiliaries, MWe	**123**
Net Power, MWe	**650**
HHV Net Plant Efficiency, %	30.7
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,728 (11,116)
LHV Net Plant Efficiency, %	31.8
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,311 (10,721)
HHV Boiler Efficiency, %	88.0
LHV Boiler Efficiency, %	91.3
Steam Turbine Cycle Efficiency, %	59.1
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	6,096 (5,777)
Condenser Duty, GJ/hr (MMBtu/hr)	2,017 (1,912)
CO_2 Capture Rate, %	99
AGR Duty, GJ/hr (MMBtu/hr)	2,323 (2,202)
As-Received Coal Feed, kg/hr (lb/hr)	281,106 (619,732)
Limestone Sorbent Feed, kg/hr (lb/hr)	27,192 (59,949)
HHV Thermal Input, kWt	2,118,843
LHV Thermal Input, kWt	2,043,650
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.057 (15.0)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.042 (11.1)
Excess Air, %	20.3

Exhibit A-19. Case B12B.99 plant power summary

Power Summary	
Steam Turbine Power, MWe	774
Total Gross Power, MWe	**774**
Auxiliary Load Summary	
Activated Carbon Injection, kWe	40
Ash Handling, kWe	920
Baghouse, kWe	120
Circulating Water Pumps, kWe	9,460
CO_2 Capture/Removal Auxiliaries, kWe	20,800
CO_2 Compression, kWe	52,580
Coal Handling and Conveying, kWe	540
Condensate Pumps, kWe	810
Cooling Tower Fans, kWe	4,890
Dry Sorbent Injection, kWe	80
Flue Gas Desulfurizer, kWe	4,340
Forced Draft Fans, kWe	1,440
Ground Water Pumps, kWe	880
Induced Draft Fans, kWe	13,330
Miscellaneous Balance of Plant[A,B], kWe	2,250
Primary Air Fans, kWe	1,710
Pulverizers, kWe	4,210
SCR, kWe	50
Sorbent Handling & Reagent Preparation, kWe	1,310
Spray Dryer Evaporator, kWe	310
Steam Turbine Auxiliaries, kWe	500
Transformer Losses, kWe	2,710
Total Auxiliaries, MWe	**123**
Net Power, MWe	**650**

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

A.2.1.1 Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, and PM are presented in Section 2.3. A summary of the plant air emissions for Case B12B.99 is presented in Exhibit A-20. SO_2 emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit A-20. Case B12B.99 air emissions

	kg/GJ (lb/MMBtu)[A]	tonne/year (ton/year)[B]	kg/MWh (lb/MWh)[C]
SO_2	0.000 (0.000)	0 (0)	0.000 (0.000)
NOx	0.032 (0.075)	1,829 (2,016)	0.318 (0.700)
Particulate	0.004 (0.010)	235 (259)	0.041 (0.090)
Hg	1.38E-7 (3.21E-7)	0.008 (0.009)	1.36E-6 (3.00E-6)
CO_2	1 (2)	50,886 (56,092)	9 (19)
CO_2[D]	–	–	11 (23)
	mg/Nm^3		
Particulate Concentration[E,F]	13.01		

[A]Based on thermal input on an HHV basis
[B]Calculations based on an 85 percent capacity factor
[C]Emissions based on gross power except where otherwise noted
[D]CO_2 emissions based on net power instead of gross power
[E]Concentration of particles in the flue gas after the baghouse
[F]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 0.37 ppmv using a NaOH based polishing scrubber in the PostCCC facility. The remaining low concentration of SO_2 is essentially completely removed in the PostCCC absorber vessel resulting in very low SO_2 emissions (reported as zero here).

NOx emissions are controlled to about 0.15 kg/GJ (0.35 lb/MMBtu) using LNBs and OFA. An SCR unit then further reduces the NOx concentration by 78.6 percent to 0.03 kg/GJ (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 97.5 percent.

Ninety-nine percent of the CO_2 in the flue gas is removed in PostCCC 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 product from the CO_2 compression train; however, some CO_2 exits through the stack, 20 percent of the unburned

carbon remains in the bottom ash, the remaining unburned carbon is captured in the fabric filter, along with the PAC, and some carbon leaves as gypsum. The carbon balance is given in Exhibit A-21. The carbon capture efficiency is defined as one minus the amount of carbon in the stack gas relative to the total carbon in (minus unburnt carbon in the ash), represented by the following fraction:

$$1 - \frac{Carbon\ in\ Stack}{Total\ Carbon\ In - Unburnt\ Carbon} = \left(1 - \left(\frac{4{,}112}{402{,}186 - 2{,}370}\right)\right) * 100 = 99\%$$

Where the unburned carbon is equal to one minus the carbon conversion rate times the carbon in the coal:

$$(1 - Carbon\ Conversion) * Carbon\ in\ Coal = (1 - 0.994) * 395{,}046 = 2{,}370$$

Exhibit A-21. Case B12B.99 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	179,190 (395,046)	Stack Gas	1,865 (4,112)
Air (CO_2)	418 (921)	FGD Product	212 (468)
PAC	62 (136)	Baghouse	922 (2,032)
FGD Reagent	2,759 (6,083)	Bottom Ash	215 (474)
		CO_2 Product	179,195 (395,057)
		CO_2 Dryer Vent	19 (42)
		CO_2 Knockout	0.5 (1.1)
Total	**182,428 (402,186)**	**Total**	**182,428 (402,186)**

Exhibit A-22 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 A-22. Case B12B.99 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	7,046 (15,533)	FGD Product	6,624 (14,604)
		Stack Gas	0 (0)
		Polishing Scrubber and Solvent Reclaiming	138 (303)
		Baghouse	284 (626)
Total	**7,046 (15,533)**	**Total**	**7,046 (15,533)**

Exhibit A-23 shows the overall water balance for the plant. The exhibit is presented in an identical manner as for Case B12A. The only notable difference is the FGD makeup water source. In CO_2 capture cases, a significant amount of water is recovered from the initial PostCCC facility cooling step. This water is assumed suitable to be used as FGD makeup, with the balance of the water from the PostCCC facility discharged.

Exhibit A-23. Case B12B.99 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 Process Makeup	1.9 (503)	1.9 (503)	–	–	–
FGD Slurry Water	1.1 (280)	1.1 (280)	–	–	–
CO_2 Drying	–	–	–	0.0 (2.7)	0.0 (-2.7)
CO_2 Capture Recovery	–	–	–	1.1 (288)	-1.1 (-288)
CO_2 Compression KO	–	–	–	0.1 (23)	-0.1 (-23)
Deaerator Vent	–	–	–	0.1 (22)	-0.1 (-22)
Condenser Makeup	**0.1 (22)**	**–**	**0.1 (22)**	**–**	**0.1 (22)**
BFW Makeup	0.1 (22)	–	0.1 (22)	–	0.1 (22)
Cooling Tower	**37 (9,735)**	**–**	**37 (9,735)**	**8.3 (2,189)**	**29 (7,546)**
BFW Blowdown	–	–	–	–	–
Total	**40 (10,540)**	**3.0 (783)**	**37 (9,757)**	**9.6 (2,526)**	**27 (7,231)**

A.2.1.2 Energy and Mass Balance Diagrams

Energy and mass balance diagrams are shown for the Case B12B.99 PC boiler, the FGD unit, PostCCC system, and steam cycle in Exhibit A-24 and Exhibit A-25.

An overall plant energy balance is provided in tabular form in Exhibit A-26. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit A-18) is calculated by multiplying the power out by a generator efficiency of 98.5 percent.

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Exhibit A-24. Case B12B.99 energy and mass balance, SC PC boiler with CO_2 capture

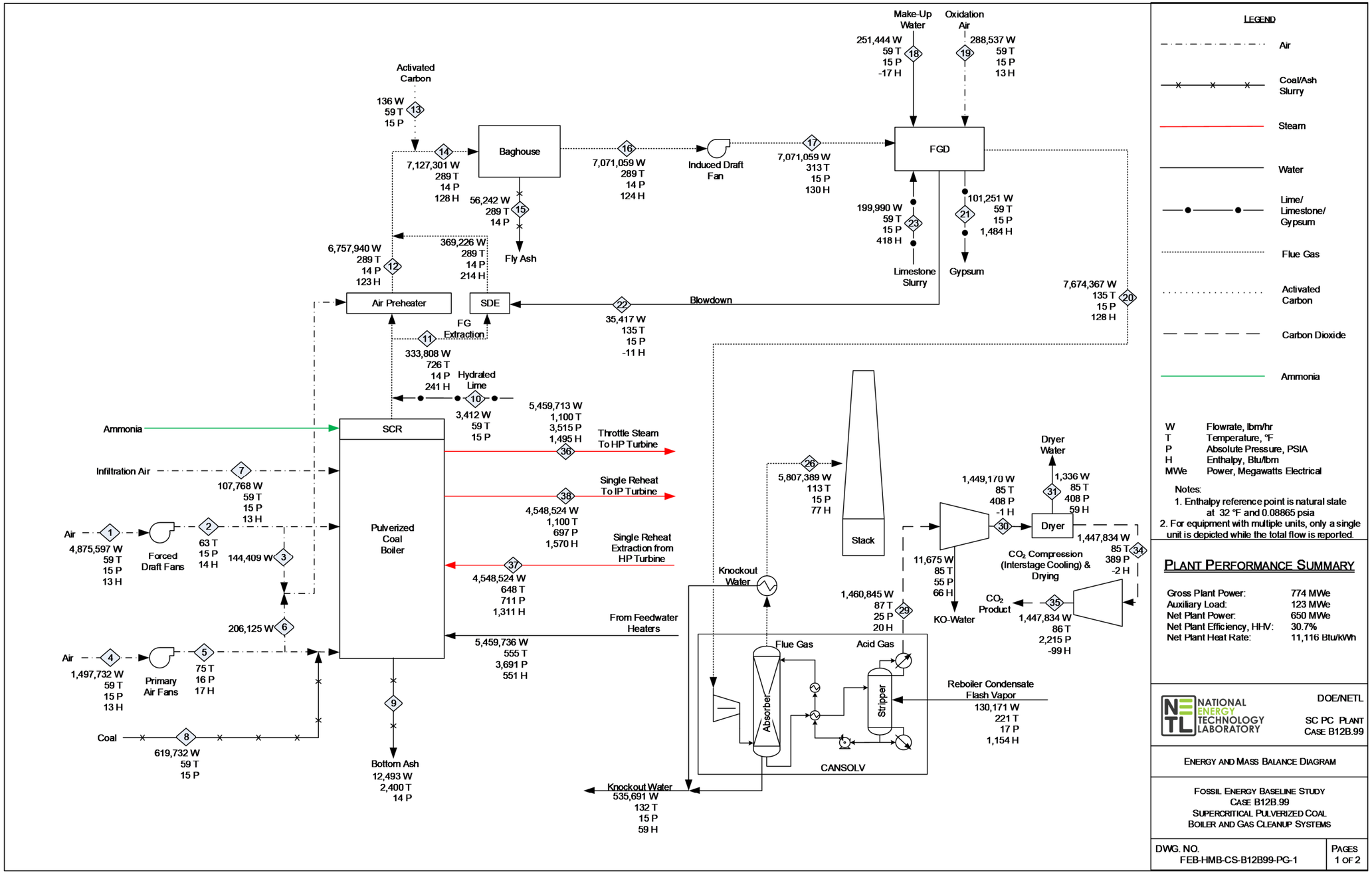


Exhibit A-25. Case B12B.99 energy and mass balance, SC steam cycle

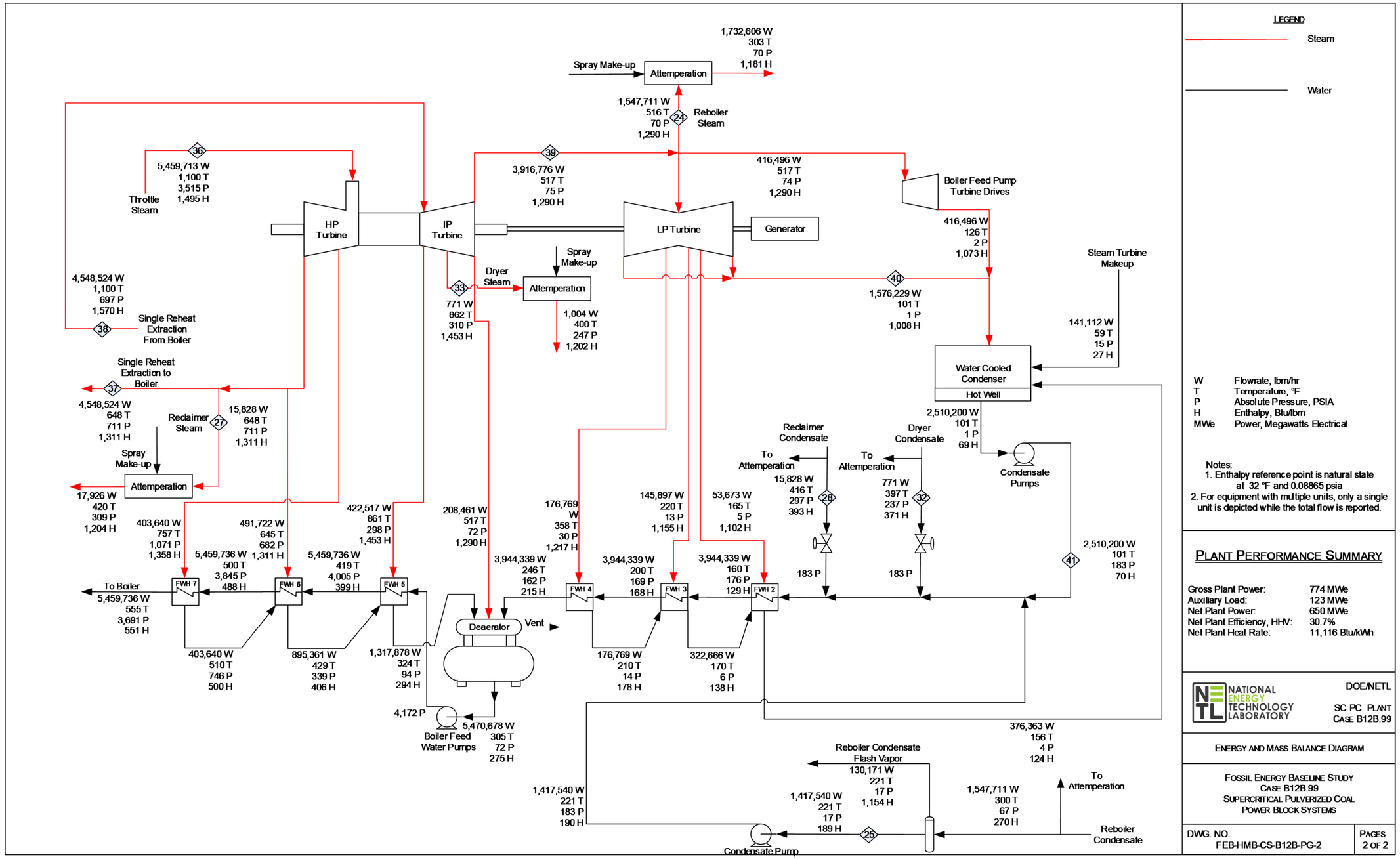


Exhibit A-26. Case B12B.99 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, GJ/hr (MMBtu/hr)				
Coal	7,628 (7,230)	6.4 (6.0)	–	7,634 (7,236)
Air	–	89 (84)	–	89 (84)
Raw Water Makeup	–	139 (132)	–	139 (132)
Limestone	–	0.6 (0.6)	–	0.6 (0.6)
Auxiliary Power	–	–	444 (421)	444 (421)
TOTAL	**7,628 (7,230)**	**235 (222)**	**444 (421)**	**8,306 (7,873)**
Heat Out, GJ/hr (MMBtu/hr)				
Bottom Ash	–	7.2 (6.8)	–	7.2 (6.8)
Fly Ash	–	2.6 (2.5)	–	2.6 (2.5)
Stack Gas	–	473 (449)	–	473 (449)
Sulfur	2.6 (2.4)	0.0 (0.0)	–	2.6 (2.4)
Gypsum	–	2.7 (2.5)	–	2.7 (2.5)
Motor Losses and Design Allowances	–	–	51 (49)	51 (49)
Cooling Tower Load[A]	–	4,812 (4,561)	–	4,812 (4,561)
CO_2 Product Stream	–	-152 (-144)	–	-152 (-144)
AGR Effluent	–	56 (53)	–	56 (53)
Blowdown Streams and Deaerator Vent	–	3.1 (3.0)	–	3.1 (3.0)
Ambient Losses[B]	–	180 (171)	–	180 (171)
Power	–	–	2,785 (2,640)	2,785 (2,640)
TOTAL	**2.6 (2.4)**	**5,386 (5,105)**	**2,837 (2,689)**	**8,226 (7,796)**
Unaccounted Energy[C]	–	*81 (76)*	–	*81 (76)*

[A]Includes condenser, capture process, CO_2 compressor, and miscellaneous cooling loads
[B]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers
[C]By difference

A.2.2 Case B12B.99 – Major Equipment List

Major equipment items for the supercritical (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 A.2.3. 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. Values reported in the equipment lists are rounded.

Case B12B.99 – 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	60 tonne (60 ton)	2	1
9	Feeder	Vibratory	230 tonne/hr (260 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	460 tonne/hr (510 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	230 tonne (260 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	460 tonne/hr (510 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	460 tonne/hr (510 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	1,030 tonne (1,140 ton)	3	0
19	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 11 tonne (13 ton) Feeder - 70 kg/hr (150 lb/hr)	1	0
20	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 290 tonne (320 ton) Feeder - 1,700 kg/hr (3,750 lb/hr)	1	0
21	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
22	Limestone Feeder	Belt	114 tonne/hr (126 tph)	1	0
23	Limestone Conveyor No. 1	Belt	114 tonne/hr (126 tph)	1	0
24	Limestone Reclaim Hopper	N/A	22 tonne (25 ton)	1	0
25	Limestone Reclaim Feeder	Belt	90 tonne/hr (99 tph)	1	0
26	Limestone Conveyor No. 2	Belt	90 tonne/hr (99 tph)	1	0
27	Limestone Day Bin	w/ actuator	359 tonne (396 ton)	2	0

Case B12B.99 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	52 tonne/hr (57 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	52 tonne/hr (57 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	30 tonne/hr (33 tph)	1	1
4	Limestone Ball Mill	Rotary	30 tonne/hr (33 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	116,000 liters (30,600 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,950 lpm @ 10m H_2O (510 gpm @ 40 ft H_2O)	1	1
7	Hydrocyclone Classifier	4 active cyclones in a 5-cyclone bank	490 lpm (130 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	647,000 liters (171,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,350 lpm @ 9m H_2O (360 gpm @ 30 ft H_2O)	1	1

Case B12B.99 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	328,000 liters (86,700 gal)	2	0
2	Condensate Pumps	Vertical canned	10,500 lpm @ 200 m H_2O (2,780 gpm @ 500 ft H_2O)	2	1
3	Deaerator and Storage Tank	Horizontal spray type	1,365,000 kg/hr (3,009,000 lb/hr), 5 min. tank	2	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	23,000 lpm @ 3,500 m H_2O (6,000 gpm @ 11,400 ft H_2O)	2	2
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	6,800 lpm @ 3,500 m H_2O (1,800 gpm @ 11,400 ft H_2O)	2	0
6	LP Feedwater Heater 2A/2B	Horizontal U-tube	490,000 kg/hr (1,080,000 lb/hr)	4	0
7	LP Feedwater Heater 3A/3B	Horizontal U-tube	490,000 kg/hr (1,080,000 lb/hr)	4	0
8	LP Feedwater Heater 4A/4B	Horizontal U-tube	490,000 kg/hr (1,080,000 lb/hr)	4	0
9	HP Feedwater Heater 5	Horizontal U-tube	1,360,000 kg/hr (3,000,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	1,360,000 kg/hr (3,000,000 lb/hr)	2	0
11	HP Feedwater Heater 7	Horizontal U-tube	1,360,000 kg/hr (3,000,000 lb/hr)	2	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	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
14	Service Air Compressors	Flooded screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
15	Instrument Air Dryers	Duplex, regenerative	28 m3/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	9,900 lpm @ 20 m H_2O (2,610 gpm @ 60 ft H_2O)	2	1
21	Ground Water Pumps	Stainless steel, single suction	3,950 lpm @ 270 m H_2O (1,040 gpm @ 880 ft H_2O)	5	1
22	Filtered Water Pumps	Stainless steel, single suction	1,200 lpm @ 50 m H_2O (320 gpm @ 160 ft H_2O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	1,159,000 liter (306,200 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	330 lpm (90 gpm)	1	1
25	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
26	Process Water Treatment	Spray dryer evaporator	Flue Gas - 2,590 m3/min (91,400 acfm) @ 385°C (726°F) & 0.1 MPa (14 psia) Blowdown - 150 lpm (40 gpm) @ 19,982 ppmw Cl^-	2	1

Case B12B.99 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, once-through, wall-fired, low NOx burners, overfire air	2,720,000 kg/hr steam @ 24.1 MPa/593°C/593°C (6,010,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	374,000 kg/hr, 5,100 m^3/min @ 101 cm WG (824,000 lb/hr, 180,100 acfm @ 40 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	1,216,000 kg/hr, 16,600 m^3/min @ 26 cm WG (2,682,000 lb/hr, 586,000 acfm @ 10 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,764,000 kg/hr, 35,700 m^3/min @ 114 cm WG (3,889,000 lb/hr, 1,262,000 acfm @ 45 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	3,340,000 kg/hr (7,360,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	130 m^3/min @ 108 cm WG (4,500 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	142,000 liter (37,400 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	27 lpm @ 90 m H_2O (7 gpm @ 300 ft H_2O)	2	1

Case B12B.99 – 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	1,764,000 kg/hr (3,890,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	59,800 m^3/min (2,110,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	208,000 lpm @ 65 m H_2O (54,900 gpm @ 210 ft H_2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	5,740 lpm (1,520 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	980 m^3/min @ 0.3 MPa (34,690 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,440 lpm (380 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	45 tonne/hr (50 tph) of 50 wt% slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	870 lpm @ 13 m H_2O (230 gpm @ 40 ft H_2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	570,000 lpm (150,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	2,090 lpm @ 21 m H_2O (550 gpm @ 70 ft H_2O)	1	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
12	Activated Carbon Injectors	---	70 kg/hr (150 lb/hr)	1	0
13	Hydrated Lime Injectors	---	1,700 kg/hr (3,750 lb/hr)	1	0
14	CANSOLV	Amine-based CO_2 capture technology	3,829,000 kg/hr (8,442,000 lb/hr) 19.1 wt% CO_2 concentration	1	0
15	CANSOLV LP Condensate Pump	Centrifugal	1,540 lpm @ 1 m H_2O (407 gpm @ 3 ft H_2O)	1	1
16	CANSOLV IP Condensate Pump	Centrifugal	17 lpm @ 4.6 m H_2O (5 gpm @ 15 ft H_2O)	1	1
17	CO_2 Dryer	Triethylene glycol	Inlet: 190 m^3/min @ 2.8 MPa (6,692 acfm @ 408 psia) Outlet: 2.7 MPa (389 psia) Water Recovered: 606 kg/hr (1,336 lb/hr)	1	0
18	CO_2 Compressor	Integrally geared, multi-stage centrifugal	10.0 m^3/min @ 15.3 MPa, 82°C (337 acfm @ 2,217 psia, 180°F)	2	0
19	CO_2 Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 103 GJ/hr (98 MMBtu/hr)	1	0

Case B12B.99 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 6.3 m (21 ft) diameter	1	0

Case B12B.99 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	814 MW 24.1 MPa/593°C/593°C (3,500 psig/1,100°F/1,100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	900 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 (2,100 MMBtu/hr), Inlet water temperature: 16°C (60°F), Water temperature rise: 11°C (20°F)	1	0

Case B12B.99 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	950,000 lpm @ 30 m (251,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb/16°C (60°F) CWT/ 27°C (80°F) HWT/ 5,290 GJ/hr (5,020 MMBtu/hr) heat duty	1	0

Case B12B.99 – Account 10: Ash and Spent Sorbent Handling System

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	–	6.2 tonne/hr (6.9 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	24	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	25 m^3/min @ 0.2 MPa (890 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	1,650 tonne (1,820 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	150 tonne/hr (170 tph)	1	0

Case B12B.99 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 760 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 29 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 55 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 20 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.99 – 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

A.2.3 Case B12B.99 – Cost Estimating

The cost estimating methodology was described in Section 2.7. Exhibit A-27 shows a detailed breakdown of the capital costs; Exhibit A-28 shows the owner's costs, TOC, and TASC; Exhibit A-29 shows the initial and annual O&M costs; and Exhibit A-30 shows the COE breakdown.

For PC cases, existing costs were escalated to reflect a 2023-year dollar using the methodology outlined in NETL's current QGESS (NETL, 2025a).

The estimated TPC of the SC PC boiler with CO_2 capture is $4,433/kW. Process contingency represents 2.7 percent of the TPC and project contingency represents 13.9 percent of the TPC. The FY COE, including T&S costs of $10.3/MWh,[w] is $148.3/MWh. The LCOE, including T&S costs of $13.7/MWh, is $159.2/MWh.

[w] T&S costs for this case are based on a first-year break-even CO_2 price of $10.18/tonne.

Exhibit A-27. Case B12B.99 total plant cost details

Case:	B12B.99 – Supercritical PC with 99 Percent CO_2 Capture					Estimate Type:	Conceptual			
Plant Size (MW, net):	650					Cost Base:	Jan 2023			
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
1	Coal & Sorbent Handling										
1.1	Coal Receive & Unload	$1,625	$0	$568	$0	$2,193	$384	$0	$386	$2,963	$5
1.2	Coal Stackout & Reclaim	$5,334	$0	$925	$0	$6,259	$1,095	$0	$1,103	$8,457	$13
1.3	Coal Conveyors	$49,147	$0	$9,071	$0	$58,218	$10,188	$0	$10,261	$78,667	$121
1.4	Other Coal Handling	$6,828	$0	$1,114	$0	$7,942	$1,390	$0	$1,400	$10,732	$17
1.5	Sorbent Receive & Unload	$312	$0	$72	$0	$385	$67	$0	$68	$520	$1
1.6	Sorbent Stackout & Reclaim	$2,286	$0	$321	$0	$2,607	$456	$0	$459	$3,523	$5
1.7	Sorbent Conveyors	$3,465	$723	$651	$0	$4,839	$847	$0	$853	$6,539	$10
1.8	Other Sorbent Handling	$166	$38	$67	$0	$271	$47	$0	$48	$366	$1
1.9	Coal & Sorbent Handling Foundations	$0	$2,165	$2,308	$0	$4,473	$783	$0	$788	$6,044	$9
	Subtotal	**$69,164**	**$2,926**	**$15,097**	**$0**	**$87,187**	**$15,258**	**$0**	**$15,366**	**$117,810**	**$181**
2	Coal & Sorbent Preparation & Feed										
2.1	Coal Crushing & Drying	$3,496	$0	$521	$0	$4,016	$703	$0	$708	$5,427	$8
2.2	Prepared Coal Storage & Feed	$11,765	$0	$1,966	$0	$13,731	$2,403	$0	$2,420	$18,554	$29
2.5	Sorbent Preparation Equipment	$1,538	$64	$245	$0	$1,847	$323	$0	$326	$2,496	$4
2.6	Sorbent Storage & Feed	$2,579	$0	$755	$0	$3,334	$583	$0	$588	$4,505	$7
2.9	Coal & Sorbent Feed Foundation	$0	$979	$695	$0	$1,674	$293	$0	$295	$2,262	$3
	Subtotal	**$19,379**	**$1,043**	**$4,181**	**$0**	**$24,603**	**$4,305**	**$0**	**$4,336**	**$33,244**	**$51**
3	Feedwater & Miscellaneous BOP Systems										
3.1	Feedwater System	$5,489	$9,068	$3,667	$0	$18,224	$3,189	$0	$3,212	$24,625	$38
3.2	Water Makeup & Pretreating	$11,033	$1,063	$4,873	$0	$16,969	$2,970	$0	$3,988	$23,926	$37
3.3	Other Feedwater Subsystems	$4,311	$1,362	$1,047	$0	$6,720	$1,176	$0	$1,184	$9,080	$14
3.4	Service Water Systems	$3,496	$6,432	$16,844	$0	$26,772	$4,685	$0	$6,291	$37,749	$58
3.5	Other Boiler Plant Systems	$1,024	$374	$756	$0	$2,154	$377	$0	$380	$2,910	$4
3.6	Natural Gas Pipeline and Start-Up System	$4,944	$190	$115	$0	$5,250	$919	$0	$925	$7,093	$11
3.7	Waste Water Treatment Equipment	$18,258	$0	$8,722	$0	$26,980	$4,721	$0	$6,340	$38,041	$58
3.8	Spray Dryer Evaporator	$23,423	$0	$10,569	$0	$33,993	$5,949	$0	$7,988	$47,929	$74
3.9	Miscellaneous Plant Equipment	$307	$39	$122	$0	$468	$82	$0	$110	$659	$1
	Subtotal	**$72,286**	**$18,528**	**$46,714**	**$0**	**$137,529**	**$24,067**	**$0**	**$30,419**	**$192,015**	**$295**
4	Pulverized Coal Boiler & Accessories										
4.9	Pulverized Coal Boiler & Accessories	$355,967	$0	$164,789	$0	$520,756	$91,132	$0	$91,783	$703,672	$1,082
4.10	Selective Catalytic Reduction System	$41,778	$0	$18,593	$0	$60,371	$10,565	$0	$10,640	$81,576	$125
4.11	Boiler Balance of Plant	$2,337	$0	$1,082	$0	$3,418	$598	$0	$602	$4,619	$7
4.12	Primary Air System	$2,436	$0	$1,038	$0	$3,475	$608	$0	$612	$4,695	$7
4.13	Secondary Air System	$3,690	$0	$1,573	$0	$5,263	$921	$0	$928	$7,112	$11
4.14	Induced Draft Fans	$7,961	$0	$3,392	$0	$11,353	$1,987	$0	$2,001	$15,341	$24
4.15	Major Component Rigging	$128	$0	$57	$0	$185	$32	$0	$33	$249	$0
4.16	Boiler Foundations	$0	$530	$377	$0	$907	$159	$0	$160	$1,226	$2

Case:	B12B.99 – Supercritical PC with 99 Percent CO_2 Capture						Estimate Type:	Conceptual			
Plant Size (MW, net):	650						Cost Base:	Jan 2023			
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
	Subtotal	**$414,297**	**$530**	**$190,901**	**$0**	**$605,728**	**$106,002**	**$0**	**$106,760**	**$818,490**	**$1,258**
5	**Flue Gas Cleanup**										
5.1	CANSOLV CO_2 Removal System	$200,296	$88,586	$165,013	$0	$453,894	$79,432	$77,162	$106,835	$717,323	$1,103
5.2	Wet FGD Absorber Vessels & Accessories	$101,245	$0	$18,281	$0	$119,526	$20,917	$0	$21,066	$161,509	$248
5.3	Other FGD	$1,615	$0	$1,049	$0	$2,665	$466	$0	$470	$3,601	$6
5.4	CO_2 Compression & Drying	$61,498	$8,976	$16,180	$0	$86,654	$15,164	$0	$20,364	$122,182	$188
5.5	CO_2 Compressor Aftercooler	$694	$107	$234	$0	$1,036	$181	$0	$243	$1,461	$2
5.6	Mercury Removal (DSI/ACI)	$3,404	$781	$2,825	$0	$7,011	$1,227	$0	$1,236	$9,473	$15
5.9	Particulate Removal (Bag House & Accessories)	w/ 5.2	w/ 5.2	w/ 5.2	w/ 5.2	$0	$0	$0	$0	$0	$0
5.12	Gas Cleanup Foundations	$0	$263	$187	$0	$450	$79	$0	$79	$607	$1
5.13	Gypsum Dewatering System	$1,049	$0	$138	$0	$1,187	$208	$0	$209	$1,604	$2
	Subtotal	**$369,802**	**$98,714**	**$203,906**	**$0**	**$672,422**	**$117,674**	**$77,162**	**$150,503**	**$1,017,760**	**$1,565**
7	**Ductwork & Stack**										
7.3	Ductwork	$0	$981	$551	$0	$1,532	$268	$0	$270	$2,070	$3
7.4	Stack	$11,878	$0	$5,403	$0	$17,281	$3,024	$0	$3,046	$23,351	$36
7.5	Duct & Stack Foundations	$0	$274	$263	$0	$537	$94	$0	$126	$757	$1
	Subtotal	**$11,878**	**$1,255**	**$6,217**	**$0**	**$19,350**	**$3,386**	**$0**	**$3,442**	**$26,178**	**$40**
8	**Steam Turbine & Accessories**										
8.1	Steam Turbine Generator & Accessories	$88,353	$0	$8,647	$0	$97,001	$16,975	$0	$17,096	$131,072	$202
8.2	Steam Turbine Plant Auxiliaries	$2,005	$0	$3,749	$0	$5,754	$1,007	$0	$1,014	$7,775	$12
8.3	Condenser & Auxiliaries	$14,145	$0	$3,822	$0	$17,968	$3,144	$0	$3,167	$24,279	$37
8.4	Steam Piping	$65,517	$0	$18,773	$0	$84,290	$14,751	$0	$14,856	$113,897	$175
8.5	Turbine Generator Foundations	$0	$340	$454	$0	$794	$139	$0	$187	$1,120	$2
	Subtotal	**$170,020**	**$340**	**$35,446**	**$0**	**$205,806**	**$36,016**	**$0**	**$36,320**	**$278,143**	**$428**
9	**Cooling Water System**										
9.1	Cooling Towers	$26,748	$0	$6,475	$0	$33,224	$5,814	$0	$5,856	$44,893	$69
9.2	Circulating Water Pumps	$3,764	$0	$218	$0	$3,982	$697	$0	$702	$5,381	$8
9.3	Circulating Water System Auxiliaries	$22,337	$0	$2,297	$0	$24,634	$4,311	$0	$4,342	$33,286	$51
9.4	Circulating Water Piping	$0	$9,951	$7,288	$0	$17,239	$3,017	$0	$3,038	$23,294	$36
9.5	Make-up Water System	$1,717	$0	$1,719	$0	$3,437	$601	$0	$606	$4,644	$7
9.6	Component Cooling Water System	$1,486	$0	$962	$0	$2,448	$428	$0	$431	$3,307	$5
9.7	Circulating Water System Foundations	$0	$926	$1,244	$0	$2,170	$380	$0	$510	$3,059	$5
	Subtotal	**$56,053**	**$10,877**	**$20,203**	**$0**	**$87,133**	**$15,248**	**$0**	**$15,485**	**$117,865**	**$181**
10	**Ash & Spent Sorbent Handling Systems**										
10.6	Ash Storage Silos	$1,616	$0	$3,837	$0	$5,453	$954	$0	$961	$7,368	$11
10.7	Ash Transport & Feed Equipment	$5,495	$0	$4,228	$0	$9,724	$1,702	$0	$1,714	$13,139	$20
10.9	Ash/Spent Sorbent Foundation	$0	$1,078	$1,073	$0	$2,152	$377	$0	$506	$3,034	$5
	Subtotal	**$7,112**	**$1,078**	**$9,138**	**$0**	**$17,328**	**$3,032**	**$0**	**$3,180**	**$23,541**	**$36**

Case:	B12B.99 – Supercritical PC with 99 Percent CO_2 Capture					Estimate Type:	Conceptual			
Plant Size (MW, net):	650					Cost Base:	Jan 2023			
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	Accessory Electric Plant										
11.1	Generator Equipment	$3,847	$0	$2,130	$0	$5,978	$1,046	$0	$1,054	$8,077	$12
11.2	Station Service Equipment	$11,209	$0	$706	$0	$11,915	$2,085	$0	$2,100	$16,100	$25
11.3	Switchgear & Motor Control	$17,401	$0	$2,216	$0	$19,616	$3,433	$0	$3,457	$26,506	$41
11.4	Conduit & Cable Tray	$0	$2,053	$4,784	$0	$6,837	$1,196	$0	$1,205	$9,238	$14
11.5	Wire & Cable	$0	$5,436	$7,859	$0	$13,295	$2,327	$0	$2,343	$17,965	$28
11.6	Protective Equipment	$79	$0	$201	$0	$280	$49	$0	$49	$378	$1
11.7	Standby Equipment	$1,190	$0	$806	$0	$1,996	$349	$0	$352	$2,696	$4
11.8	Main Power Transformers	$10,103	$0	$151	$0	$10,254	$1,795	$0	$1,807	$13,856	$21
11.9	Electrical Foundations	$0	$291	$599	$0	$890	$156	$0	$209	$1,255	$2
	Subtotal	**$43,828**	**$7,780**	**$19,452**	**$0**	**$71,061**	**$12,436**	**$0**	**$12,577**	**$96,073**	**$148**
12	Instrumentation & Control										
12.1	Pulverized Coal Boiler Control Equipment	$1,086	$0	$153	$0	$1,238	$217	$0	$218	$1,673	$3
12.3	Steam Turbine Control Equipment	$973	$0	$85	$0	$1,058	$185	$0	$187	$1,430	$2
12.5	Signal Processing Equipment	$1,233	$0	$173	$0	$1,406	$246	$0	$248	$1,900	$3
12.6	Control Boards, Panels, & Racks	$377	$0	$181	$0	$558	$98	$28	$103	$787	$1
12.7	Distributed Control System Equipment	$10,638	$0	$1,495	$0	$12,133	$2,123	$607	$2,229	$17,093	$26
12.8	Instrument Wiring & Tubing	$745	$581	$1,879	$0	$3,205	$561	$160	$589	$4,515	$7
12.9	Other Instrumentation & Controls Equipment	$916	$0	$1,672	$0	$2,588	$453	$129	$475	$3,645	$6
	Subtotal	**$15,967**	**$581**	**$5,639**	**$0**	**$22,187**	**$3,883**	**$924**	**$4,049**	**$31,043**	**$48**
13	Improvements to Site										
13.1	Site Preparation	$0	$607	$10,418	$0	$11,025	$1,929	$0	$2,591	$15,545	$24
13.2	Site Improvements	$0	$3,000	$3,206	$0	$6,206	$1,086	$0	$1,458	$8,750	$13
13.3	Site Facilities	$3,486	$0	$2,908	$0	$6,394	$1,119	$0	$1,503	$9,015	$14
	Subtotal	**$3,486**	**$3,607**	**$16,532**	**$0**	**$23,624**	**$4,134**	**$0**	**$5,552**	**$33,310**	**$51**
14	Buildings & Structures										
14.2	Boiler Building	$0	$15,114	$10,742	$0	$25,856	$4,525	$0	$4,557	$34,938	$54
14.3	Steam Turbine Building	$0	$21,008	$15,824	$0	$36,832	$6,446	$0	$6,492	$49,769	$77
14.4	Administration Building	$0	$1,364	$1,167	$0	$2,531	$443	$0	$446	$3,421	$5
14.5	Circulation Water Pumphouse	$0	$247	$158	$0	$405	$71	$0	$71	$548	$1
14.6	Water Treatment Buildings	$0	$614	$453	$0	$1,067	$187	$0	$188	$1,442	$2
14.7	Machine Shop	$0	$720	$391	$0	$1,111	$194	$0	$196	$1,501	$2
14.8	Warehouse	$0	$542	$438	$0	$980	$172	$0	$173	$1,324	$2
14.9	Other Buildings & Structures	$0	$378	$260	$0	$639	$112	$0	$113	$863	$1
14.10	Waste Treating Building & Structures	$0	$839	$2,055	$0	$2,894	$506	$0	$510	$3,910	$6
	Subtotal	**$0**	**$40,827**	**$31,488**	**$0**	**$72,315**	**$12,655**	**$0**	**$12,746**	**$97,716**	**$150**
	Total	**$1,253,270**	**$188,086**	**$604,915**	**$0**	**$2,046,272**	**$358,098**	**$78,086**	**$400,734**	**$2,883,189**	**$4,433**

Exhibit A-28. Case B12B.99 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$16,769	$26
1 Month Maintenance Materials	$2,714	$4
1 Month Non-fuel Consumables	$3,372	$5
1 Month Waste Disposal	$1,374	$2
25% of 1 Months Fuel Cost at 100% CF	$3,977	$6
2% of TPC	$57,664	$89
Total	**$85,869**	**$132**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$38,787	$60
0.5% of TPC (spare parts)	$14,416	$22
Total	**$53,203**	**$82**
Other Costs		
Initial Cost for Catalyst and Chemicals	$6,262	$10
Land	$1,800	$3
Other Owner's Costs	$432,478	$665
Financing Costs	$77,846	$120
Total Overnight Costs (TOC)	**$3,540,647**	**$5,444**
TASC Multiplier (IOU, 33 year)	1.213	
Total As-Spent Cost (TASC)	**$4,293,839**	**$6,602**

Exhibit A-29. Case B12B.99 initial and annual operating and maintenance costs

Case:	B12B.99 – Supercritical PC with 99 Percent CO_2 Capture				Cost Base:	Jan 2023
Plant Size (MW, net):	650	Heat Rate-net (Btu/kWh):	11,116		Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		45.04	**$/hour**	Skilled Operator:		2.0
Operating Labor Burden:		30.00	**% of base**	Operator:		11.3
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		2.0
				Total:		**16.3**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$8,377,366	$12.880
Maintenance Labor:					$18,452,409	$28.370
Administrative & Support Labor:					$6,707,444	$10.312
Property Taxes and Insurance:					$57,663,778	$88.656
Total:					**$91,200,997**	**$140.219**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$27,678,614	$5.715
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	7,025	$2.30	$0	$5,012,956	$1.035
Makeup and Waste Water Treatment Chemicals (ton):	0	20.9	$660.00	$0	$4,285,091	$0.885
Brominated Activated Carbon (ton):	0	1.63	$2,547.97	$0	$1,286,246	$0.266
Enhanced Hydrated Lime (ton):	0	40.9	$391.63	$0	$4,974,223	$1.027
Limestone (ton):	0	719	$30.18	$0	$6,735,969	$1.391
Ammonia (19 wt%, ton):	0	71.3	$280.00	$0	$6,193,215	$1.279
SCR Catalyst (ft^3):	17,890	16.3	$350.00	$6,261,513	$1,774,095	$0.366
CO_2 Capture System Chemicals[A]:	Proprietary				$11,905,883	$2.458
Triethylene Glycol (gal):	w/equip.	68	$8.50	$0	$178,474	$0.037
Subtotal:				**$6,261,513**	**$42,346,152**	**$8.744**
Waste Disposal						
Fly Ash (ton)	0	675	$46.71	$0	$9,779,654	$2.019
Bottom Ash (ton)	0	150	$46.71	$0	$2,172,328	$0.449
SCR Catalyst (ft^3):	0	16.3	$5.70	$0	$28,892	$0.006
Triethylene Glycol (gal):	0	3,437	$1.30	$0	$1,386,274	$0.286
Thermal Reclaimer Unit Waste (ton):	0	8.34	$250.00	$0	$646,966	$0.134
Subtotal:				**$0**	**$14,014,115**	**$2.894**
By-Products						
Gypsum (ton)	0	1093	$0.00	$0	$0	$0.000
Subtotal:				**$0**	**$0**	**$0.000**
Variable Operating Costs Total:				**$6,261,513**	**$84,038,881**	**$17.353**
Fuel Cost						
Illinois Number 6 (ton):	0	7,437	$70.32	$0	$162,253,507	$33.502
Total:				**$0**	**$162,253,507**	**$33.502**

[A]CO_2 Capture System Chemicals includes NaOH and CANSOLV Solvent

Exhibit A-30. Case B12B.99 COE breakdown

	FY COE		LCOE	
Component	**Value, $/MWh**	**Percentage**	**Value, $/MWh**	**Percentage**
Capital	68.3	46%	68.3	43%
Fixed	18.8	13%	25.1	16%
Variable	17.4	12%	23.2	15%
Fuel	33.5	23%	28.9	18%
Total (Excluding T&S)	**138.0**	**N/A**	**145.5**	**N/A**
CO_2 T&S	10.3	7%	13.7	9%
Total (Including T&S)	**148.3**	**N/A**	**159.2**	**N/A**

APPENDIX B: NGCC WITH 97% CO_2 CAPTURE

B.1 CASE B31B.97 – F-CLASS NGCC WITH 97% CO_2 CAPTURE PROCESS DESCRIPTION

The plant configuration and process description for Case B31B.97 are the same as Case B31B.90, with the exception that the carbon dioxide recovery (PostCCC) facility captures 97, rather than 90, percent of the carbon dioxide (CO_2) in the flue gas. Since the process descriptions of the plant and PostCCC facility were provided in Section 4.2.3 and Section 3.1.8, respectively, with differences between the facilities used in natural gas combined cycle (NGCC) and pulverized coal (PC) cases noted in Section 4.1.4, they are not repeated here.

The block flow diagram (BFD) for Case B31B.97 is shown in Exhibit B-1. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit B-2. The modeling assumptions are presented in Section 4.2.1.

Exhibit B-1. Case B31B.97 BFD, NGCC with 97 percent CO_2 capture

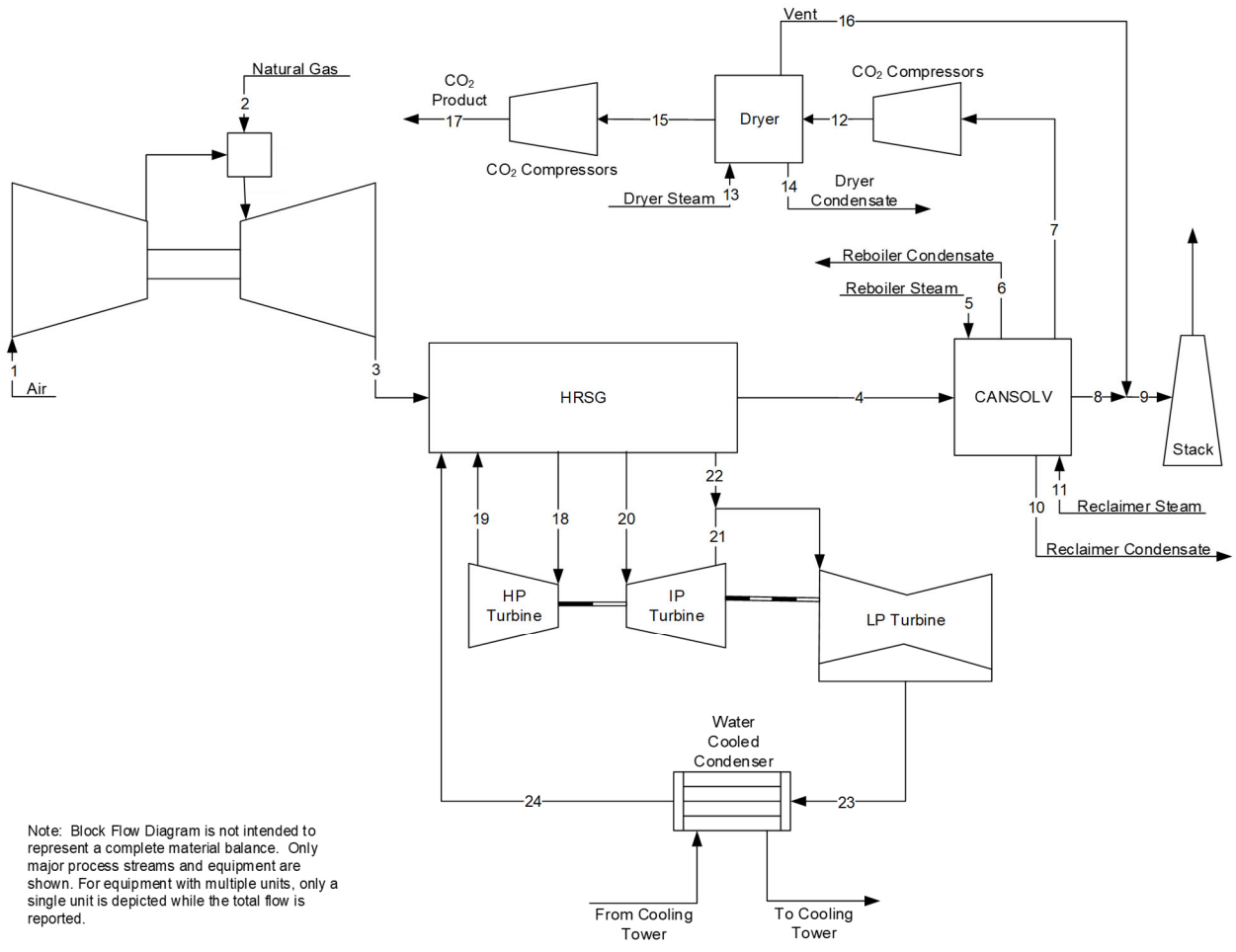


Exhibit B-2. Case B31B.97 stream table, NGCC with 97 percent CO_2 capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0000	0.0089	0.0089	0.0000	0.0000	0.0000	0.0096	0.0096	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	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	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	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	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	0.0000	0.0000	0.0000
CO_2	0.0003	0.0100	0.0425	0.0425	0.0000	0.0000	0.9796	0.0014	0.0014	0.0000	0.0000	0.9957
H_2O	0.0099	0.0000	0.0906	0.0906	1.0000	1.0000	0.0204	0.0582	0.0582	1.0000	1.0000	0.0043
N_2	0.7732	0.0160	0.7416	0.7416	0.0000	0.0000	0.0000	0.8045	0.8045	0.0000	0.0000	0.0000
O_2	0.2074	0.0000	0.1164	0.1164	0.0000	0.0000	0.0000	0.1263	0.1263	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	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_{mol}/hr)	130,449	5,508	136,117	136,117	15,560	14,251	5,725	125,469	125,471	132	132	5,633
V-L Flowrate (kg/hr)	3,764,363	95,442	3,859,805	3,859,805	280,310	256,735	248,930	3,522,196	3,522,247	2,371	2,371	247,269
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	27	652	95	300	105	29	39	39	214	364	29
Pressure (MPa, abs)	0.10	2.96	0.11	0.10	0.51	0.12	0.17	0.10	0.10	2.04	4.13	2.81
Steam Table Enthalpy (kJ/kg)[A]	30.23	21.97	872.29	243.95	3,062.57	439.34	45.99	133.68	133.67	913.81	3,124.08	-1.10
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-4,487.26	-660.40	-1,288.74	-12,917.73	-15,540.95	-8,977.01	-506.24	-506.36	-15,066.49	-12,856.21	-8,976.01
Density (kg/m^3)	1.2	22.1	0.4	0.9	1.9	954.9	3.0	1.1	1.1	848.5	15.1	57.8
V-L Molecular Weight	28.857	17.328	28.357	28.357	18.015	18.015	43.481	28.072	28.072	18.015	18.015	43.897
V-L Flowrate (lb_{mol}/hr)	287,591	12,143	300,086	300,086	34,303	31,418	12,622	276,613	276,615	290	290	12,418
V-L Flowrate (lb/hr)	8,299,000	210,413	8,509,413	8,509,413	617,978	566,003	548,797	7,765,113	7,765,225	5,226	5,226	545,135
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	80	1,206	203	571	221	85	102	102	416	687	85
Pressure (psia)	14.7	430.0	15.3	14.8	73.5	17.4	24.7	14.8	14.8	296.6	598.5	407.6
Steam Table Enthalpy (Btu/lb)[A]	13.0	9.4	375.0	104.9	1,316.7	188.9	19.8	57.5	57.5	392.9	1,343.1	-0.5
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-1,929.2	-283.9	-554.1	-5,553.6	-6,681.4	-3,859.4	-217.6	-217.7	-6,477.4	-5,527.2	-3,859.0
Density (lb/ft^3)	0.076	1.380	0.024	0.059	0.121	59.612	0.185	0.069	0.069	52.968	0.943	3.607

[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 B-2. Case B31B.97 stream table, NGCC with 97 percent CO_2 capture (continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0000	0.0000	0.0000	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	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	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	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	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	0.0000	0.0000	0.0000
CO_2	0.0000	0.0000	0.9995	0.9704	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	0.0005	0.0296	0.0005	1.0000	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	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	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	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_{mol}/hr)	8	8	5,610	1	5,610	30,131	29,261	31,829	32,664	3,842	20,946	36,681
V-L Flowrate (kg/hr)	146	146	246,831	51	246,831	542,826	527,154	573,410	588,445	69,218	377,353	660,817
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	364	203	29	28	30	585	364	585	300	304	38	38
Pressure (MPa, abs)	4.13	1.64	2.68	0.10	15.27	17.30	4.13	3.84	0.52	0.51	0.01	0.01
Steam Table Enthalpy (kJ/kg)[A]	3,124.08	863.65	-3.59	56.47	-231.09	3,520.51	3,124.08	3,641.17	3,062.57	3,071.95	2,376.28	160.78
AspenPlus Enthalpy (kJ/kg)[B]	-12,856.21	-15,116.65	-8,967.15	-8,994.77	-9,194.65	-12,459.78	-12,856.21	-12,339.12	-12,917.73	-12,908.34	-13,604.01	-15,819.51
Density (kg/m^3)	15.1	861.8	54.7	1.8	630.1	48.1	15.1	9.9	2.0	1.9	0.1	992.8
V-L Molecular Weight	18.015	18.015	43.997	43.240	43.997	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	18	18	12,368	3	12,368	66,428	64,511	70,171	72,011	8,471	46,179	80,868
V-L Flowrate (lb/hr)	322	322	544,169	111	544,169	1,196,726	1,162,175	1,264,154	1,297,298	152,600	831,920	1,456,853
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	687	397	85	83	86	1,085	687	1,085	571	579	101	101
Pressure (psia)	598.5	237.4	389.1	14.8	2,214.7	2,509.2	598.5	557.6	75.0	73.5	1.0	1.0
Steam Table Enthalpy (Btu/lb)[A]	1,343.1	371.3	-1.5	24.3	-99.4	1,513.5	1,343.1	1,565.4	1,316.7	1,320.7	1,021.6	69.1
AspenPlus Enthalpy (Btu/lb)[B]	-5,527.2	-6,499.0	-3,855.2	-3,867.1	-3,953.0	-5,356.7	-5,527.2	-5,304.9	-5,553.6	-5,549.6	-5,848.7	-6,801.2
Density (lb/ft^3)	0.943	53.801	3.416	0.110	39.338	3.002	0.943	0.618	0.124	0.120	0.003	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

B.1.1 Case B31B.97 – Performance Results

Overall plant performance is summarized in Exhibit B-3; Exhibit B-4 provides a detailed breakdown of the auxiliary power requirements.

The PostCCC facility and CO_2 compression combined account for 68 percent of the auxiliary plant load. The circulating water system (CWS) (circulating water pumps [CWPs] and cooling tower fan) accounts for 13 percent of the auxiliary load, largely due to the high cooling water demand of the PostCCC facility and CO_2 compressors.

Unlike the PC cases, which utilize boilers and steam turbines that can be produced at nearly any desired output, the gross outputs of the NGCC cases are fixed by the available size of the combustion turbines (CTs). As such, the net outputs of the capture cases are reduced due to the greater auxiliary load imposed by the PostCCC facility and CO_2 compressors, relative to a non-capture case. The plant produces a net output of 650 MW at a net plant efficiency of 46.9 percent (higher heating value [HHV] basis).

Exhibit B-3. Case B31B.97 plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	484
Steam Turbine Power, MWe	219
Total Gross Power, MWe	**702**
CO_2 Capture/Removal Auxiliaries, kWe	15,600
CO_2 Compression, kWe	19,750
Balance of Plant, kWe	16,696
Total Auxiliaries, MWe	**52**
Net Power, MWe	**650**
HHV Net Plant Efficiency, %	46.9
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	7,678 (7,277)
HHV Combustion Turbine Efficiency, %	34.9
LHV Net Plant Efficiency, %	51.9
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,930 (6,569)
LHV Combustion Turbine Efficiency, %	38.6
Steam Turbine Cycle Efficiency, %	47.0
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,658 (7,258)
CO_2 Capture Rate, %	97
Condenser Duty, GJ/hr (MMBtu/hr)	840 (796)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	1,301 (1,233)
Natural Gas Feed Flow, kg/hr (lb/hr)	95,442 (210,413)
HHV Thermal Input, kWt	1,386,417
LHV Thermal Input, kWt	1,251,379
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.028 (7.3)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.018 (4.8)

Exhibit B-4. Case B31B.97 plant power summary

Power Summary	
Combustion Turbine Power, MWe	484
Steam Turbine Power, MWe	219
Total Gross Power, MWe	**702**
Auxiliary Load Summary	
Circulating Water Pumps, kWe	4,520
Combustion Turbine Auxiliaries, kWe	1,240
Condensate Pumps, kWe	630
Cooling Tower Fans, kWe	2,340
CO_2 Capture/Removal Auxiliaries, kWe	15,600
CO_2 Compression, kWe	19,750
Feedwater Pumps, kWe	4,450
Ground Water Pumps, kWe	430
Miscellaneous Balance of Plant[A], kWe	580
SCR, kWe	6
Steam Turbine Auxiliaries, kWe	240
Transformer Losses, kWe	2,260
Total Auxiliaries, MWe	**52**
Net Power, MWe	**650**

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

B.1.1.1 Environmental Performance

The environmental targets for emissions of nitrogen oxide (NOx), sulfur dioxide (SO_2), and particulate matter (PM) are presented in Section 2.4. A summary of the plant air emissions for Case B31B.97 is presented in Exhibit B-5.

Exhibit B-5. Case B31B.97 air emissions

	kg/GJ (lb/MMBtu)[A]	tonne/year (ton/year)[B]	kg/MWh (lb/MWh)[C]
SO_2	0.000 (0.000)	0 (0)	0.000 (0.000)
NOx	0.001 (0.003)	50 (56)	0.010 (0.021)
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	0.000 (0.000)	0 (0)	0.000 (0.000)
CO_2	2 (4)	57,214 (63,068)	11 (24)
CO_2[D]	-	-	12 (26)

[A]Based on thermal input on an HHV basis
[B]Calculations based on an 85 percent capacity factor
[C]Emissions based on gross power except where otherwise noted
[D]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 domestic average value of total sulfur of 0.34 gr/100 scf ($4.71x10^{-4}$ lb-S/MMBtu) (Gas Research Institute, 1992). It was also assumed that the added methanethiol (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 1.8 ppmv NOx emissions using a dry low-NOx (DLN) burner in the combustion turbine generator (CTG) and selective catalytic reduction (SCR). The DLN burners reduce the emissions to about 25 ppmvd (at 15 percent oxygen [$O_{2]}$) (GE Vernova, 2024b) and the SCR system is designed for an additional 94.7 percent NOx reduction (Davis & Black, October 2000).

The pipeline natural gas was assumed to contain no mercury (Hg) or hydrochloric acid (HCl), resulting in zero emissions.

The state-of-the-art 2023 F-Class gas turbine achieves approximately 9.0 ppmvd (at 15 percent O_2) CO and 1.5 ppmw PM emissions. The production of PM is a result of system inefficiencies and is not produced or emitted in any significant amount. Any carbon monoxide (CO) or PM present in the flue gas is assumed to interact with, and be removed by, the PostCCC system solvent.

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

The carbon balance for the plant is shown in Exhibit B-6. The carbon input to the plant consists of carbon in the natural gas and carbon in the air. Carbon leaves the plant mostly as CO_2 product from the CO_2 compression train; however, some carbon exits through the stack as CO_2.

Ninety seven percent of the CO_2 in the flue gas is removed in the PostCCC facility. 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 percentage:

$$1 - \frac{Carbon\ in\ Stack}{Total\ Carbon\ In} = \left(1 - \left(\frac{4{,}623}{153{,}106}\right)\right) * 100 = 97\%$$

Exhibit B-6. Case B31B.97 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	68,936 (151,977)	Stack Gas	2,097 (4,623)
Air (CO_2)	512 (1,129)	CO_2 Product	67,350 (148,482)
		CO_2 Knockout	0.1 (0.3)
Total	**69,448 (153,106)**	**Total**	**69,448 (153,106)**

As shown in Exhibit B-7, the sulfur content of the natural gas is insignificant, entirely comprising CH_4S (used as an odorant) (Gas Research Institute, 1992). All sulfur in the natural gas is assumed

to react with the PostCCC system solvent and is removed from the solvent during solvent reclaiming as a waste stream.

Exhibit B-7. Case B31B.97 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	1.0 (2.2)	Stack Gas	0.0 (0.0)
		Solvent Reclaiming	1.0 (2.2)
Total	**1.0 (2.2)**	**Total**	**1.0 (2.2)**

Water demand, recycle, withdrawal, discharge, and consumption are defined and discussed in Section 2.6. Exhibit B-8 shows the overall water balance for the plant.

Exhibit B-8. Case B31B.97 water balance

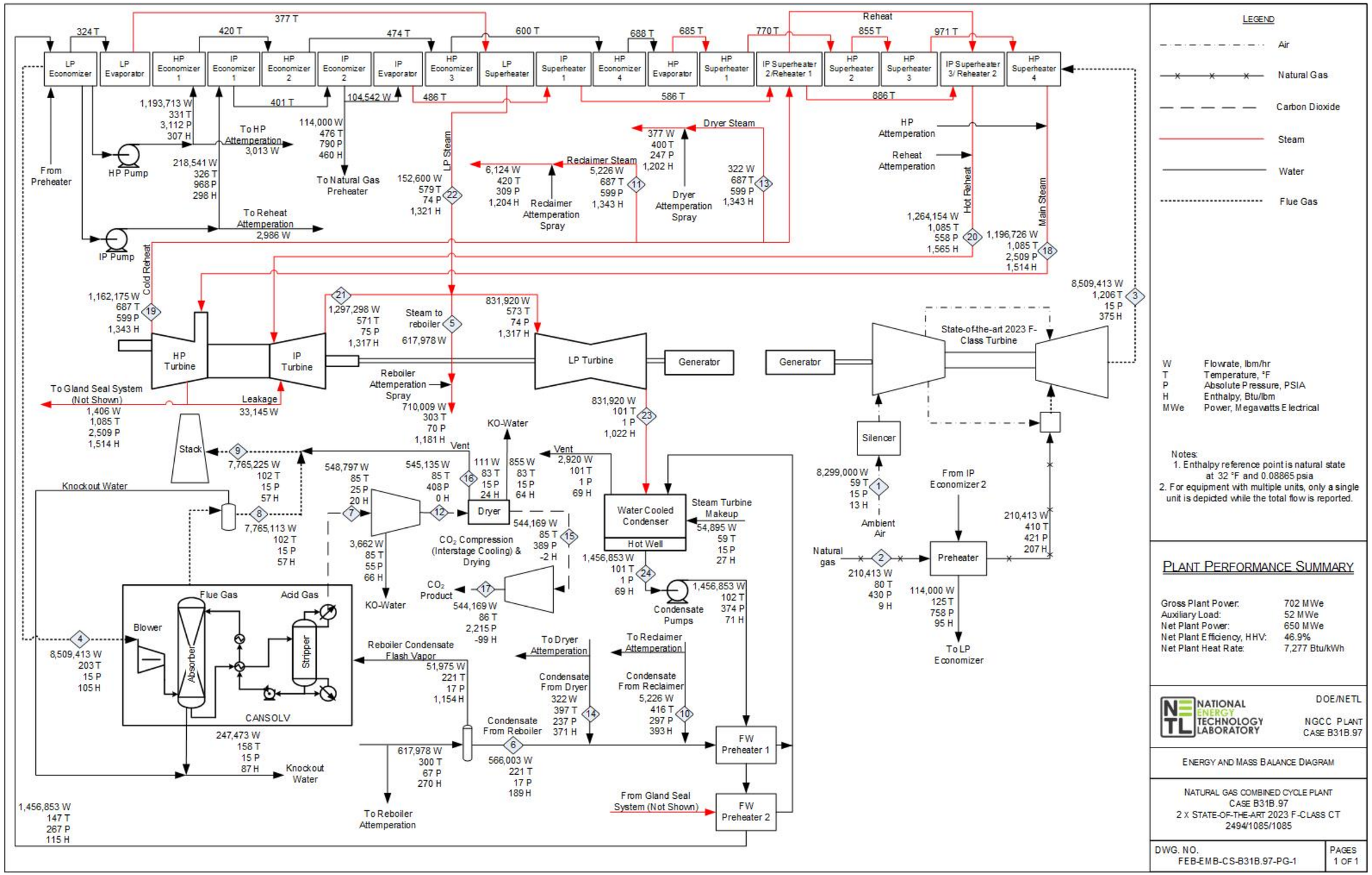
Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)	m^3/min (gpm)
CO_2 Capture System Makeup	–	–	–	–	–
CO_2 Capture Recovery	–	–	–	1.9 (493)	-1.9 (-493)
CO_2 Compression Recovery	–	–	–	0.0 (7.3)	0.0 (-7.3)
Deaerator Vent	–	–	–	0.0 (5.8)	0.0 (-5.8)
Condenser Makeup	**0.4 (109)**	**–**	**0.4 (109)**	**–**	**0.4 (109)**
BFW Makeup	0.4 (109)	–	0.4 (109)	–	0.4 (109)
Cooling Tower	18 (4,648)	–	18 (4,648)	4.4 (1,162)	13 (3,487)
Total	**18 (4,758)**	**–**	**18 (4,758)**	**6.3 (1,668)**	**12 (3,090)**

B.1.1.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for Case B31B.97 in Exhibit B-9.

An overall plant energy balance is provided in tabular form in Exhibit B-10. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit B-3) is calculated by multiplying the power out by the generator efficiency: 98.5 percent for the CT and 97.5 percent for the steam turbine.

Exhibit B-9. Case B31B.97 energy and mass balance, NGCC with CO_2 capture



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Exhibit B-10. Case B31B.97 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, GJ/hr (MMBtu/hr)				
Natural Gas	4,991 (4,731)	5.9 (5.6)	–	4,997 (4,736)
Air	–	114 (108)	–	114 (108)
Raw Water Makeup	–	68 (64)	–	68 (64)
Auxiliary Power	–	–	187 (178)	187 (178)
TOTAL	**4,991 (4,731)**	**188 (178)**	**187 (178)**	**5,366 (5,086)**
Heat Out, GJ/hr (MMBtu/hr)				
Stack Gas	–	471 (446)	–	471 (446)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Motor Losses and Design Allowances	–	–	61 (58)	61 (58)
Cooling Tower Load[A]	–	2,306 (2,185)	–	2,306 (2,185)
CO_2 Product Stream	–	-57 (-54)	–	-57 (-54)
AGR Effluent	–	33 (31)	–	33 (31)
Dryer Effluent	–	0.0 (0.0)	–	0.0 (0.0)
Deaerator Vent	–	0.2 (0.2)	–	0.2 (0.2)
Ambient Losses[B]	–	*44 (42)*	–	44 (42)
Power	–	–	2,528 (2,396)	2,528 (2,396)
TOTAL	**0.0 (0.0)**	**2,797 (2,651)**	**2,589 (2,454)**	**5,386 (5,105)**
Unaccounted Energy[C]	–	*-20 (-19)*	–	*-20 (-19)*

[A]Includes condenser, capture process, CO_2 compressor, and miscellaneous cooling loads
[B]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers
[C]By difference

B.1.2 Case B31B.97 – Major Equipment List

Major equipment items for the F-Class NGCC plant with 97 percent 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 B.1.3. 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. Values reported in the equipment lists are rounded.

Case B31B.97 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,640,000 liters (433,000 gal)	2	0
2	Condensate Pumps	Vertical canned	12,200 lpm @ 320 m H_2O (3,220 gpm @ 1,040 ft H_2O)	1	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP Water: 5,010 lpm @ 2,430 m H_2O (1,320 gpm @ 7,970 ft H_2O) IP Water: 930 lpm @ 610 m H_2O (250 gpm @ 1,990 ft H_2O)	2	2
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 GJ/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	3,800 lpm @ 110 m H_2O (1,000 gpm @ 350 ft H_2O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,600 lpm @ 80 m H_2O (700 gpm @ 250 ft H_2O)	1	1
11	Municipal Water Pumps	Stainless steel, single suction	4,900 lpm @ 20 m H_2O (1,300 gpm @ 60 ft H_2O)	2	1
12	Ground Water Pumps	Stainless steel, single suction	4,900 lpm @ 20 m H_2O (1,300 gpm @ 60 ft H_2O)	2	1
13	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H_2O (40 gpm @ 160 ft H_2O)	2	1
14	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
15	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0
16	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
17	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	79 m^3/min @ 3.0 MPa (2,795 acfm @ 430 psia) 39 cm (16 in) standard wall pipe	16 km (10 mile)	0
18	Gas Metering Station	–	79 m^3/min (2,795 acfm)	1	0

Case B31B.97 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Cansolv	Amine-based CO_2 capture technology	4,246,000 kg/hr (9,360,000 lb/hr) 6.6 wt% CO_2 concentration	1	0
2	Cansolv LP Condensate Pump	Centrifugal	760 lpm @ 1.0 m H_2O (200 gpm @ 3.4 ft H_2O)	1	1
3	Cansolv HP Condensate Pump	Centrifugal	7.6 lpm @ 4.6 m H_2O (2.0 gpm @ 15.0 ft H_2O)	1	1
4	CO_2 Dryer	Triethylene glycol	Inlet: 71 m^3/min @ 2.8 MPa (2,519 acfm @ 408 psia) Outlet: 2.7 MPa (389 psia) Water Removed: 388 kg/hr (856 lb/hr)	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
5	CO_2 Compressor	Integrally geared, multi-stage centrifugal	4 m^3/min @ 15.3 MPa, 82°C (127 acfm @ 2,217 psia, 180°F)	2	0
6	CO_2 Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 39 GJ/hr (37 MMBtu/hr)	2	0

Case B31B.97 – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	2023 Advanced F class w/ dry low-NOx burner	240 MW	2	0
2	Combustion Turbine Generator	Hydrogen Cooled	280 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	2	0

Case B31B.97 – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Epoxy-coated CS plate	46 m (150 ft) high x 5.0 m (17 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section	Main Steam: 290,000 kg/hr, 17.2 MPa/585°C (639,000 lb/hr, 2,494 psig/1,085°F) Reheat Steam: 315,000 kg/hr, 3.7 MPa/585°C (695,000 lb/hr, 543 psig/1,085°F)	2	0
3	SCR Reactor	–	2,120,000 kg/hr (4,680,000 lb/hr)	2	0
4	SCR Catalyst	–	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	20 m^3/min @ 108 cm WG (600 scfm @ 42 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	3.6 lpm @ 90 m H_2O (1.0 gpm @ 300 ft H_2O)	2	1
7	Ammonia Storage Tank	Horizontal tank	104,000 liter (27,000 gal)	1	0

Case B31B.97 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	230 MW 17.2 MPa/585°C/585°C (2,494 psig/1,085°F/1,085°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	270 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Two pass, divided waterbox including vacuum pumps and integrated deaerator	920 GJ/hr (880 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.97 – 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

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 2,540 GJ/hr (2,400 MMBtu/hr) heat duty	1	0

Case B31B.97 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	18 kV/345 kV, 280 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	18 kV/345 kV, 210 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 11 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	18 kV/4.16 kV, 25 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 8 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 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.97 – 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

B.1.3 Case B31B.97 – Cost Estimating

The cost estimating methodology was described in Section 2.7. Exhibit B-11 shows a detailed breakdown of the capital costs; Exhibit B-12 shows the owner's costs, total overnight cost (TOC), and total as-spent cost (TASC); Exhibit B-13 shows the initial and annual operation and maintenance (O&M) costs; and Exhibit B-14 shows the cost of electricity (COE) breakdown.

The estimated total plant cost (TPC) of the NGCC with CO_2 capture is $2,271/kW. Process contingency represents 4.1 percent of the TPC and project contingency represents 15.0 percent of the TPC. The first year (FY) COE, including transport and storage (T&S) costs of $4.7/MWh[x], is $94.5/MWh. The LCOE, including T&S costs of $6.2/MWh, is $85.4/MWh.

[x] T&S costs for this case are based on a first-year break-even CO_2 price of $12.26/tonne.

Exhibit B-11. Case B31B.97 total plant cost details

Case:	B31B.97 – NGCC F-Class (2x1) with 97 Percent CO_2 Capture					Estimate Type:	Conceptual			
Plant Size (MW, net):	650					Cost Base:	Jan 2023			
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	$2,492	$4,273	$1,833	$0	$8,598	$1,720	$0	$1,548	$11,865	$18
3.2	Water Makeup & Pretreating	$7,305	$730	$3,435	$0	$11,471	$2,294	$0	$2,753	$16,518	$25
3.3	Other Feedwater Subsystems	$1,418	$465	$379	$0	$2,262	$452	$0	$407	$3,122	$5
3.4	Service Water Systems	$2,217	$4,232	$11,373	$0	$17,821	$3,564	$0	$4,277	$25,663	$39
3.5	Other Boiler Plant Systems	$331	$120	$263	$0	$714	$143	$0	$129	$986	$2
3.6	NG Pipeline and Start-Up System	$12,945	$557	$347	$0	$13,848	$2,770	$0	$2,493	$19,111	$29
3.7	Waste Water Treatment Equipment	$12,977	$0	$6,973	$0	$19,950	$3,990	$0	$4,788	$28,728	$44
3.9	Miscellaneous Plant Equipment	$19,384	$2,542	$8,637	$0	$30,563	$6,113	$0	$7,335	$44,011	$68
	Subtotal	**$59,069**	**$12,919**	**$33,239**	**$0**	**$105,228**	**$21,046**	**$0**	**$23,729**	**$150,002**	**$231**
	5	**Flue Gas Cleanup**									
5.1	CANSOLV CO_2 Removal System	$139,062	$66,658	$124,166	$0	$329,887	$65,977	$59,380	$91,049	$546,292	$840
5.4	CO_2 Compression & Drying	$35,436	$5,316	$13,913	$0	$54,665	$10,933	$0	$13,120	$78,717	$121
5.5	CO_2 Compressor Aftercooler	$300	$48	$122	$0	$470	$94	$0	$113	$676	$1
5.12	Gas Cleanup Foundations	$0	$503	$515	$0	$1,018	$204	$0	$244	$1,466	$2
	Subtotal	**$174,798**	**$72,525**	**$138,716**	**$0**	**$386,039**	**$77,208**	**$59,380**	**$104,525**	**$627,152**	**$965**
	6	**Combustion Turbine & Accessories**									
6.1	Combustion Turbine Generator	$109,737	$0	$7,005	$0	$116,742	$23,348	$0	$21,014	$161,104	$248
6.3	Combustion Turbine Accessories	$3,106	$0	$191	$0	$3,297	$659	$0	$593	$4,549	$7
6.4	Compressed Air Piping	$0	$1,181	$227	$0	$1,407	$281	$0	$253	$1,942	$3
6.5	Combustion Turbine Foundations	$0	$1,064	$1,160	$0	$2,224	$445	$0	$534	$3,202	$5
	Subtotal	**$112,843**	**$2,244**	**$8,582**	**$0**	**$123,670**	**$24,734**	**$0**	**$22,394**	**$170,798**	**$263**
	7	**HRSG, Ductwork, & Stack**									
7.1	HRSG	$64,166	$0	$16,042	$0	$80,208	$16,042	$0	$14,437	$110,687	$170
7.2	HRSG Accessories	$16,073	$0	$3,002	$0	$19,075	$3,815	$0	$3,434	$26,324	$40
7.3	Ductwork	$0	$1,295	$708	$0	$2,004	$401	$0	$361	$2,765	$4
7.4	Stack	$4,479	$0	$837	$0	$5,316	$1,063	$0	$957	$7,336	$11
7.5	HRSG, Ductwork, & Stack Foundations	$0	$901	$713	$0	$1,614	$323	$0	$387	$2,324	$4
7.6	Selective Catalytic Reduction System	$1,991	$837	$1,023	$0	$3,851	$770	$0	$693	$5,314	$8
	Subtotal	**$86,709**	**$3,033**	**$22,325**	**$0**	**$112,067**	**$22,413**	**$0**	**$20,269**	**$154,749**	**$238**
	8	**Steam Turbine & Accessories**									
8.1	Steam Turbine Generator & Accessories	$43,513	$0	$6,372	$0	$49,886	$9,977	$0	$8,979	$68,842	$106
8.2	Steam Turbine Plant Auxiliaries	$148	$0	$342	$0	$490	$98	$0	$88	$676	$1
8.3	Condenser & Auxiliaries	$6,985	$0	$3,351	$0	$10,336	$2,067	$0	$1,860	$14,263	$22
8.4	Steam Piping	$13,646	$0	$4,689	$0	$18,335	$3,667	$0	$3,300	$25,303	$39
8.5	Turbine Generator Foundations	$0	$1,522	$2,124	$0	$3,646	$729	$0	$875	$5,250	$8
	Subtotal	**$64,292**	**$1,522**	**$16,878**	**$0**	**$82,693**	**$16,539**	**$0**	**$15,103**	**$114,335**	**$176**

Case:	B31B.97 – NGCC F-Class (2x1) with 97 Percent CO_2 Capture						Estimate Type:		Conceptual	
Plant Size (MW, net):	650						Cost Base:		Jan 2023	
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
	9	Cooling Water System									
9.1	Cooling Towers	$15,370	$0	$4,111	$0	$19,481	$3,896	$0	$3,507	$26,884	$41
9.2	Circulating Water Pumps	$1,963	$0	$105	$0	$2,068	$414	$0	$372	$2,854	$4
9.3	Circulating Water System Auxiliaries	$13,366	$0	$1,596	$0	$14,962	$2,992	$0	$2,693	$20,648	$32
9.4	Circulating Water Piping	$0	$4,205	$3,160	$0	$7,364	$1,473	$0	$1,326	$10,163	$16
9.5	Make-up Water System	$502	$0	$535	$0	$1,038	$208	$0	$187	$1,432	$2
9.6	Component Cooling Water System	$620	$0	$395	$0	$1,015	$203	$0	$183	$1,400	$2
9.7	Circulating Water System Foundations	$0	$973	$1,386	$0	$2,359	$472	$0	$566	$3,397	$5
	Subtotal	**$31,822**	**$5,177**	**$11,288**	**$0**	**$48,287**	**$9,657**	**$0**	**$8,833**	**$66,778**	**$103**
	11	Accessory Electric Plant									
11.1	Generator Equipment	$3,423	$0	$2,134	$0	$5,557	$1,111	$0	$1,000	$7,668	$12
11.2	Station Service Equipment	$9,533	$0	$676	$0	$10,208	$2,042	$0	$1,837	$14,087	$22
11.3	Switchgear & Motor Control	$15,657	$0	$1,951	$0	$17,609	$3,522	$0	$3,170	$24,300	$37
11.4	Conduit & Cable Tray	$0	$3,289	$7,833	$0	$11,122	$2,224	$0	$2,002	$15,348	$24
11.5	Wire & Cable	$0	$4,910	$7,253	$0	$12,163	$2,433	$0	$2,189	$16,785	$26
11.6	Protective Equipment	$665	$0	$1,659	$0	$2,324	$465	$0	$418	$3,207	$5
11.7	Standby Equipment	$1,001	$0	$664	$0	$1,665	$333	$0	$300	$2,297	$4
11.8	Main Power Transformers	$6,999	$0	$144	$0	$7,144	$1,429	$0	$1,286	$9,858	$15
11.9	Electrical Foundations	$0	$119	$270	$0	$389	$78	$0	$93	$560	$1
	Subtotal	**$37,278**	**$8,318**	**$22,583**	**$0**	**$68,179**	**$13,636**	**$0**	**$12,296**	**$94,110**	**$145**
	12	Instrumentation & Control									
12.1	NGCC Control Equipment	$303	$0	$191	$0	$494	$99	$0	$89	$682	$1
12.2	Combustion Turbine Control Equipment	$499	$0	$314	$0	$813	$163	$0	$146	$1,122	$2
12.3	Steam Turbine Control Equipment	$485	$0	$306	$0	$791	$158	$0	$142	$1,092	$2
12.4	Other Major Component Control Equipment	$814	$0	$513	$0	$1,328	$266	$66	$249	$1,909	$3
12.5	Signal Processing Equipment	$679	$0	$20	$0	$700	$140	$0	$126	$965	$1
12.6	Control Boards, Panels, & Racks	$180	$0	$109	$0	$288	$58	$14	$54	$415	$1
12.7	Distributed Control System Equipment	$9,980	$0	$301	$0	$10,281	$2,056	$514	$1,928	$14,779	$23
12.8	Instrument Wiring & Tubing	$987	$790	$2,610	$0	$4,387	$877	$219	$823	$6,306	$10
12.9	Other I&C Equipment	$684	$0	$1,308	$0	$1,992	$398	$100	$373	$2,863	$4
	Subtotal	**$14,612**	**$790**	**$5,673**	**$0**	**$21,074**	**$4,215**	**$914**	**$3,930**	**$30,133**	**$46**
	13	Improvements to Site									
13.1	Site Preparation	$0	$937	$16,792	$0	$17,728	$3,546	$0	$4,255	$25,529	$39
13.2	Site Improvements	$0	$3,013	$3,360	$0	$6,373	$1,275	$0	$1,530	$9,178	$14
13.3	Site Facilities	$2,891	$0	$2,561	$0	$5,452	$1,090	$0	$1,308	$7,851	$12
	Subtotal	**$2,891**	**$3,950**	**$22,713**	**$0**	**$29,554**	**$5,911**	**$0**	**$7,093**	**$42,557**	**$65**
	14	Buildings & Structures									
14.1	Combustion Turbine Area	$0	$556	$216	$0	$772	$154	$0	$139	$1,066	$2
14.3	Steam Turbine Building	$0	$4,988	$4,877	$0	$9,865	$1,973	$0	$1,776	$13,613	$21
14.4	Administration Building	$0	$578	$288	$0	$865	$173	$0	$156	$1,194	$2

Case:		B31B.97 – NGCC F-Class (2x1) with 97 Percent CO_2 Capture					Estimate Type:			Conceptual	
Plant Size (MW, net):		650					Cost Base:			Jan 2023	
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
14.5	Circulation Water Pumphouse	$0	$131	$48	$0	$179	$36	$0	$32	$247	$0
14.6	Water Treatment Buildings	$0	$686	$460	$0	$1,146	$229	$0	$206	$1,581	$2
14.7	Machine Shop	$0	$865	$406	$0	$1,271	$254	$0	$229	$1,753	$3
14.8	Warehouse	$0	$672	$298	$0	$970	$194	$0	$175	$1,339	$2
14.9	Other Buildings & Structures	$0	$491	$262	$0	$754	$151	$0	$136	$1,040	$2
14.10	Waste Treating Building & Structures	$0	$1,126	$1,475	$0	$2,601	$520	$0	$468	$3,589	$6
	Subtotal	**$0**	**$10,092**	**$8,330**	**$0**	**$18,422**	**$3,684**	**$0**	**$3,316**	**$25,423**	**$39**
	Total	**$584,314**	**$120,571**	**$290,328**	**$0**	**$995,212**	**$199,042**	**$60,293**	**$221,489**	**$1,476,037**	**$2,271**

Exhibit B-12. Case B31B.97 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$9,041	$14
1 Month Maintenance Materials	$1,650	$3
1 Month Non-fuel Consumables	$852	$1
1 Month Waste Disposal	$114	$0
25% of 1 Months Fuel Cost at 100% CF	$4,824	$7
2% of TPC	$29,521	$45
Total	**$46,001**	**$71**
Inventory Capital		
60-day supply of consumables at 100% CF	$1,161	$2
0.5% of TPC (spare parts)	$7,380	$11
Total	**$8,541**	**$13**
Other Costs		
Initial Cost for Catalyst and Chemicals	$1,944	$3
Land	$600	$1
Other Owner's Costs	$221,406	$341
Financing Costs	$39,853	$61
Total Overnight Costs (TOC)	**$1,794,382**	**$2,760**
TASC Multiplier (IOU, 33 year)	1.183	
Total As-Spent Cost (TASC)	**$2,122,659**	**$3,265**

Exhibit B-13. Case B31B.97 initial and annual operating and maintenance costs

Case:	B31B.97 – NGCC F-Class (2x1) with 97 Percent CO_2 Capture				Cost Base:	Jan 2023
Plant Size (MW, net):	650	Heat Rate-net (Btu/kWh):	7,277		Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		45.04	**$/hour**	Skilled Operator:		1.0
Operating Labor Burden:		30.00	**% of base**	Operator:		3.3
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		1.0
				Total:		**6.3**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$3,248,262	$4.997
Maintenance Labor:					$11,217,880	$17.257
Administrative & Support Labor:					$3,616,535	$5.563
Property Taxes and Insurance:					$29,520,737	$45.413
Total:					**$47,603,415**	**$73.230**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$16,826,820	$3.476
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	3,425	$2.30	$0	$2,444,337	$0.505
Makeup and Waste Water Treatment Chemicals (ton):	0	10.2	$660.00	$0	$2,089,427	$0.432
Ammonia (19 wt%, ton):	0	9.5	$280.00	$0	$824,431	$0.170
SCR Catalyst (ft^3):	5,555	3.0	$350.00	$1,944,340	$330,538	$0.068
CO_2 Capture System Chemicals[A]:	Proprietary				$2,876,723	$0.594
Triethylene Glycol (gal):	w/equip.	48.9	$8.50	$0	$129,087	$0.027
Subtotal:				**$1,944,340**	**$8,694,543**	**$1.796**
Waste Disposal						
SCR Catalyst (ft^3):	0	3.0	$5.70	$0	$5,383	$0.001
Triethylene Glycol (gal):	0	2,482	$1.30	$0	$1,001,119	$0.207
Thermal Reclaimer Unit Waste (ton):	0	2.0	$250.00	$0	$151,558	$0.031
Subtotal:				**$0**	**$1,158,060**	**$0.239**
Variable Operating Costs Total:				**$1,944,340**	**$26,679,423**	**$5.512**
Fuel Cost						
Natural Gas (MMBtu):	0	113,536	$5.59	$0	$196,806,494	$40.660
Total:				**$0**	**$196,806,494**	**$40.660**

[A]CO_2 Capture System Chemicals includes NaOH and CANSOLV Solvent

Exhibit B-14. Case B31B.97 COE breakdown

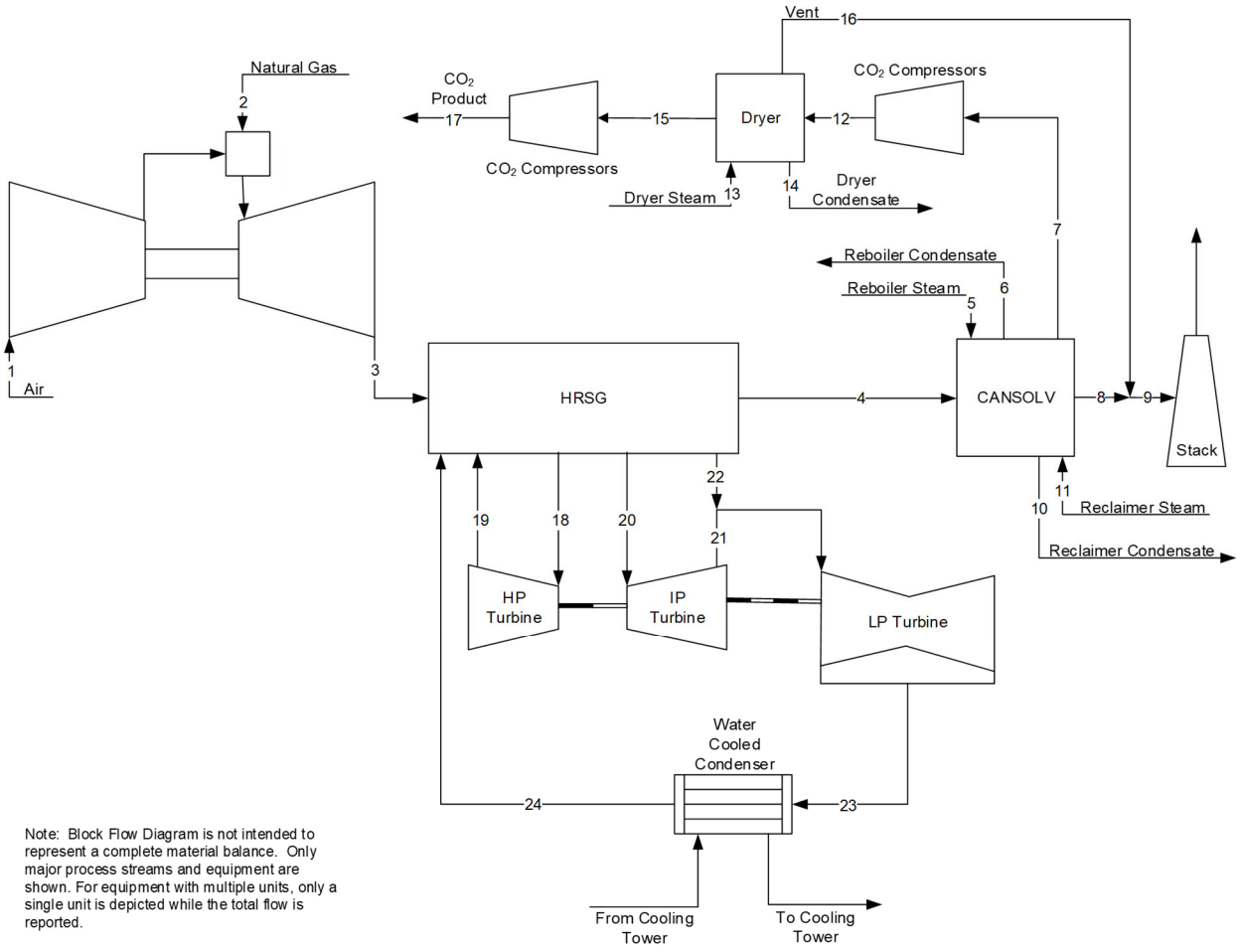
	FY COE		LCOE	
Component	Value, $/MWh	Percentage	Value, $/MWh	Percentage
Capital	33.8	36%	33.8	40%
Fixed	9.8	10%	13.1	15%
Variable	5.5	6%	7.4	9%
Fuel	40.7	43%	24.9	29%
Total (Excluding T&S)	**89.8**	**N/A**	**79.2**	**N/A**
CO_2 T&S	4.7	5%	6.2	7%
Total (Including T&S)	**94.5**	**N/A**	**85.4**	**N/A**

B.2 Case B32B.1.97 – 1x1 H-Class NGCC with 97% CO_2 Capture Process Description

The plant configuration and process description for Case B32B.1.97 is the same as Case B32B.1.90, with the exception that the PostCCC facility captures 97, rather than 90, percent of the CO_2 in the flue gas. Since the process descriptions of the plant and PostCCC facility were provided in Section 4.2.3 and Section 3.1.8, respectively, with differences between the facilities used in NGCC and PC cases noted in Section 4.1.4, they are not repeated here.

The BFD for Case B32B.1.97 is shown in Exhibit B-15. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit B-16. The modeling assumptions are presented in Section 4.3.1.

Exhibit B-15. Case B32B.1.97 BFD, NGCC with 97 percent CO_2 capture



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown. For equipment with multiple units, only a single unit is depicted while the total flow is reported.

Exhibit B-16. Case B32B.1.97 stream table, NGCC with 97 percent CO_2 capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0000	0.0088	0.0088	0.0000	0.0000	0.0000	0.0097	0.0097	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	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	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	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	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	0.0000	0.0000	0.0000
CO_2	0.0003	0.0100	0.0462	0.0462	0.0000	0.0000	0.9796	0.0015	0.0015	0.0000	0.0000	0.9957
H_2O	0.0099	0.0000	0.0977	0.0977	1.0000	1.0000	0.0204	0.0582	0.0582	1.0000	1.0000	0.0043
N_2	0.7732	0.0160	0.7389	0.7389	0.0000	0.0000	0.0000	0.8115	0.8115	0.0000	0.0000	0.0000
O_2	0.2074	0.0000	0.1085	0.1085	0.0000	0.0000	0.0000	0.1191	0.1191	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	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_{mol}/hr)	99,469	4,584	104,186	104,186	12,953	11,863	4,761	94,862	94,863	110	110	4,685
V-L Flowrate (kg/hr)	2,870,378	79,424	2,949,802	2,949,802	233,346	213,721	207,025	2,660,590	2,660,632	1,976	1,976	205,644
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	27	663	95	298	105	29	39	39	214	362	29
Pressure (MPa, abs)	0.10	3.79	0.11	0.10	0.51	0.12	0.17	0.10	0.10	2.04	4.06	2.81
Steam Table Enthalpy (kJ/kg)[A]	30.23	12.48	900.09	255.92	3,060.23	439.34	45.99	133.80	133.80	913.81	3,119.49	-1.10
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-4,496.75	-757.48	-1,401.65	-12,920.06	-15,540.95	-8,977.01	-508.65	-508.78	-15,066.49	-12,860.81	-8,976.01
Density (kg/m^3)	1.2	28.8	0.4	0.9	1.9	954.9	3.0	1.1	1.1	848.5	14.9	57.8
V-L Molecular Weight	28.857	17.328	28.313	28.313	18.015	18.015	43.481	28.047	28.047	18.015	18.015	43.897
V-L Flowrate (lb_{mol}/hr)	219,292	10,105	229,690	229,690	28,556	26,154	10,497	209,136	209,138	242	242	10,328
V-L Flowrate (lb/hr)	6,328,100	175,100	6,503,200	6,503,200	514,441	471,173	456,412	5,865,598	5,865,691	4,355	4,355	453,367
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	80	1,226	203	569	221	85	102	102	416	683	85
Pressure (psia)	14.7	550.0	15.4	14.8	73.5	17.4	24.7	14.8	14.8	296.6	589.1	407.6
Steam Table Enthalpy (Btu/lb)[A]	13.0	5.4	387.0	110.0	1,315.7	188.9	19.8	57.5	57.5	392.9	1,341.1	-0.5
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-1,933.3	-325.7	-602.6	-5,554.6	-6,681.4	-3,859.4	-218.7	-218.7	-6,477.4	-5,529.2	-3,859.0
Density (lb/ft^3)	0.076	1.799	0.024	0.059	0.121	59.612	0.185	0.069	0.069	52.968	0.932	3.607

[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 B-16. Case B32B.1.97 stream table, NGCC with 97 percent CO_2 capture (cont'd)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0000	0.0000	0.0000	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	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	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	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	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	0.0000	0.0000	0.0000
CO_2	0.0000	0.0000	0.9995	0.9704	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	0.0005	0.0296	0.0005	1.0000	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	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	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	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_{mol}/hr)	7	7	4,666	1	4,666	23,947	23,550	25,171	25,535	2,855	15,437	28,542
V-L Flowrate (kg/hr)	122	122	205,279	42	205,279	431,416	424,265	453,461	460,020	51,437	278,111	514,191
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	362	203	29	28	30	585	362	585	299	300	38	38
Pressure (MPa, abs)	4.06	1.64	2.68	0.10	15.27	17.35	4.06	3.69	0.52	0.51	0.01	0.01
Steam Table Enthalpy (kJ/kg)[A]	3,119.49	863.65	-3.59	56.47	-231.09	3,520.05	3,119.49	3,642.32	3,060.23	3,063.55	2,358.38	160.78
AspenPlus Enthalpy (kJ/kg)[B]	-12,860.81	-15,116.65	-8,967.15	-8,994.77	-9,194.65	-12,460.24	-12,860.81	-12,337.98	-12,920.06	-12,916.74	-13,621.92	-15,819.51
Density (kg/m^3)	14.9	861.8	54.7	1.8	630.1	48.2	14.9	9.5	2.0	1.9	0.1	992.8
V-L Molecular Weight	18.015	18.015	43.997	43.240	43.997	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	15	15	10,286	2	10,286	52,795	51,920	55,492	56,295	6,295	34,034	62,924
V-L Flowrate (lb/hr)	269	269	452,563	93	452,563	951,110	935,345	999,710	1,014,169	113,400	613,129	1,133,598
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	683	397	85	83	86	1,085	683	1,085	569	572	101	101
Pressure (psia)	589.1	237.4	389.1	14.8	2,214.7	2,516.2	589.1	535.6	75.0	73.5	1.0	1.0
Steam Table Enthalpy (Btu/lb)[A]	1,341.1	371.3	-1.5	24.3	-99.4	1,513.4	1,341.1	1,565.9	1,315.7	1,317.1	1,013.9	69.1
AspenPlus Enthalpy (Btu/lb)[B]	-5,529.2	-6,499.0	-3,855.2	-3,867.1	-3,953.0	-5,356.9	-5,529.2	-5,304.4	-5,554.6	-5,553.2	-5,856.4	-6,801.2
Density (lb/ft^3)	0.932	53.801	3.416	0.110	39.338	3.011	0.932	0.593	0.124	0.121	0.003	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

B.2.1 Case B32B.1.97 – Performance Results

Overall plant performance is summarized in Exhibit B-17; Exhibit B-18 provides a detailed breakdown of the auxiliary power requirements.

The PostCCC facility and CO_2 compression combined account for 69 percent of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for 13 percent of the auxiliary load, largely due to the high cooling water demand of the PostCCC facility and CO_2 compressors.

Unlike the PC cases, which utilize boilers and steam turbines that can be produced at nearly any desired output, the gross outputs of the NGCC cases are fixed by the available size of the CTs. As such, the net outputs of the capture cases are reduced due to the greater auxiliary load imposed by the PostCCC facility and CO_2 compressors, relative to a non-capture case. The plant produces a net output of 572 MW at a net plant efficiency of 49.6 percent (HHV basis).

Exhibit B-17. Case B32B.1.97 plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	442
Steam Turbine Power, MWe	173
Total Gross Power, MWe	**615**
CO_2 Capture/Removal Auxiliaries, kWe	12,900
CO_2 Compression, kWe	16,420
Balance of Plant, kWe	13,275
Total Auxiliaries, MWe	**43**
Net Power, MWe	**572**
HHV Net Plant Efficiency, %	49.6
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	7,263 (6,884)
HHV Combustion Turbine Efficiency, %	38.3
LHV Net Plant Efficiency, %	54.9
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,555 (6,213)
LHV Combustion Turbine Efficiency, %	42.4
Steam Turbine Cycle Efficiency, %	48.8
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,372 (6,987)
CO_2 Capture Rate, %	97
Condenser Duty, GJ/hr (MMBtu/hr)	615 (583)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	1,082 (1,026)
Natural Gas Feed Flow, kg/hr (lb/hr)	79,424 (175,100)
HHV Thermal Input, kWt	1,153,739
LHV Thermal Input, kWt	1,041,363
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.025 (6.6)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.016 (4.2)

Exhibit B-18. Case B32B.1.97 plant power summary

Power Summary	
Combustion Turbine Power, MWe	442
Steam Turbine Power, MWe	173
Total Gross Power, MWe	**615**
Auxiliary Load Summary	
Circulating Water Pumps, kWe	3,600
Combustion Turbine Auxiliaries, kWe	820
Condensate Pumps, kWe	520
Cooling Tower Fans, kWe	1,860
CO_2 Capture/Removal Auxiliaries, kWe	12,900
CO_2 Compression, kWe	16,420
Feedwater Pumps, kWe	3,490
Ground Water Pumps, kWe	340
Miscellaneous Balance of Plant,[A] kWe	510
SCR, kWe	5
Steam Turbine Auxiliaries, kWe	160
Transformer Losses, kWe	1,970
Total Auxiliaries, MWe	**43**
Net Power, MWe	**572**

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

B.2.1.1 Environmental Performance

The environmental targets for emissions of NOx, SO_2, and PM are presented in Section 2.4. A summary of the plant air emissions for Case B32B.1.97 is presented in Exhibit B-19.

Exhibit B-19. Case B32B.1.97 air emissions

	kg/GJ (lb/MMBtu)[A]	tonne/year (ton/year)[B]	kg/MWh (lb/MWh)[C]
SO_2	0.000 (0.000)	0 (0)	0.000 (0.000)
NOx	0.001 (0.003)	38 (42)	0.008 (0.018)
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	0.000 (0.000)	0 (0)	0.000 (0.000)
CO_2	2 (4)	47,583 (52,451)	10 (23)
CO_2[D]	-	-	11 (25)

[A]Based on thermal input on an HHV basis
[B]Calculations based on an 85 percent capacity factor
[C]Emissions based on gross power except where otherwise noted
[D]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 domestic average value of total sulfur of 0.34 gr/100 scf ($4.71x10^{-4}$ lb-S/MMBtu) (Gas Research Institute, 1992). It was also assumed that the added 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 1.8 ppmv NOx emissions using a DLN burner in the CTG and an SCR. The DLN burners reduce the emissions to about 25 ppmvd (at 15 percent O_2) (GE Vernova, 2024b) and the SCR system is designed for an additional 95.1 percent NOx reduction (Davis & Black, October 2000).

The pipeline natural gas was assumed to contain no Hg or HCl, resulting in zero emissions.

The state-of-the-art 2023 H-Class gas turbine achieves approximately 9.0 ppmvd (at 15 percent O_2) CO and 1.4 ppmw PM emissions. The production of PM is a result of system inefficiencies and is not produced or emitted in any significant amount. Any CO or PM present in the flue gas is assumed to interact with, and be removed by, the PostCCC system solvent.

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

The carbon balance for the plant is shown in Exhibit B-20. The carbon input to the plant consists of carbon in the natural gas and carbon in the air. Carbon leaves the plant mostly as CO_2 product from the CO_2 compression train; however, some carbon exits through the stack as CO_2.

Ninety seven percent of the CO_2 in the flue gas is removed in the PostCCC facility. 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 percentage:

$$1 - \frac{Carbon\ in\ Stack}{Total\ Carbon\ In} = \left(1 - \left(\frac{3{,}845}{127{,}332}\right)\right) * 100 = 97\%$$

Exhibit B-20. Case B32B.1.97 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	57,366 (126,471)	Stack Gas	1,744 (3,845)
Air (CO_2)	390 (861)	CO_2 Product	56,013 (123,487)
		CO_2 Knockout	0.1 (0.2)
Total	**57,757 (127,332)**	**Total**	**57,757 (127,332)**

As shown in Exhibit B-21, the sulfur content of the natural gas is insignificant, entirely comprising CH_4S (used as an odorant) (Gas Research Institute, 1992). All sulfur in the natural gas is assumed to react with the PostCCC system solvent and is removed from the solvent during solvent reclaiming as a waste stream.

Exhibit B-21. Case B32B.1.97 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	0.8 (1.9)	Stack Gas	0.0 (0.0)
		Solvent Reclaiming	0.8 (1.9)
Total	**0.8 (1.9)**	**Total**	**0.8 (1.9)**

Water demand, recycle, withdrawal, discharge, and consumption are defined and discussed in Section 2.6. Exhibit B-22 shows the overall water balance for the plant.

Exhibit B-22. Case B32B.1.97 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 Capture System Makeup	–	–	–	–	–
CO_2 Capture Recovery	–	–	–	1.7 (447)	-1.7 (-447)
CO_2 Compression Recovery	–	–	–	0.0 (6.1)	0.0 (-6.1)
Deaerator Vent	–	–	–	0.0 (4.5)	0.0 (-4.5)
Condenser Makeup	**0.3 (91)**	**–**	**0.3 (91)**	**–**	**0.3 (91)**
BFW Makeup	0.3 (91)	–	0.3 (91)	–	0.3 (91)
Cooling Tower	14 (3,705)	–	14 (3,705)	3.5 (926)	11 (2,779)
Total	**14 (3,796)**	**–**	**14 (3,796)**	**5.2 (1,384)**	**9.1 (2,412)**

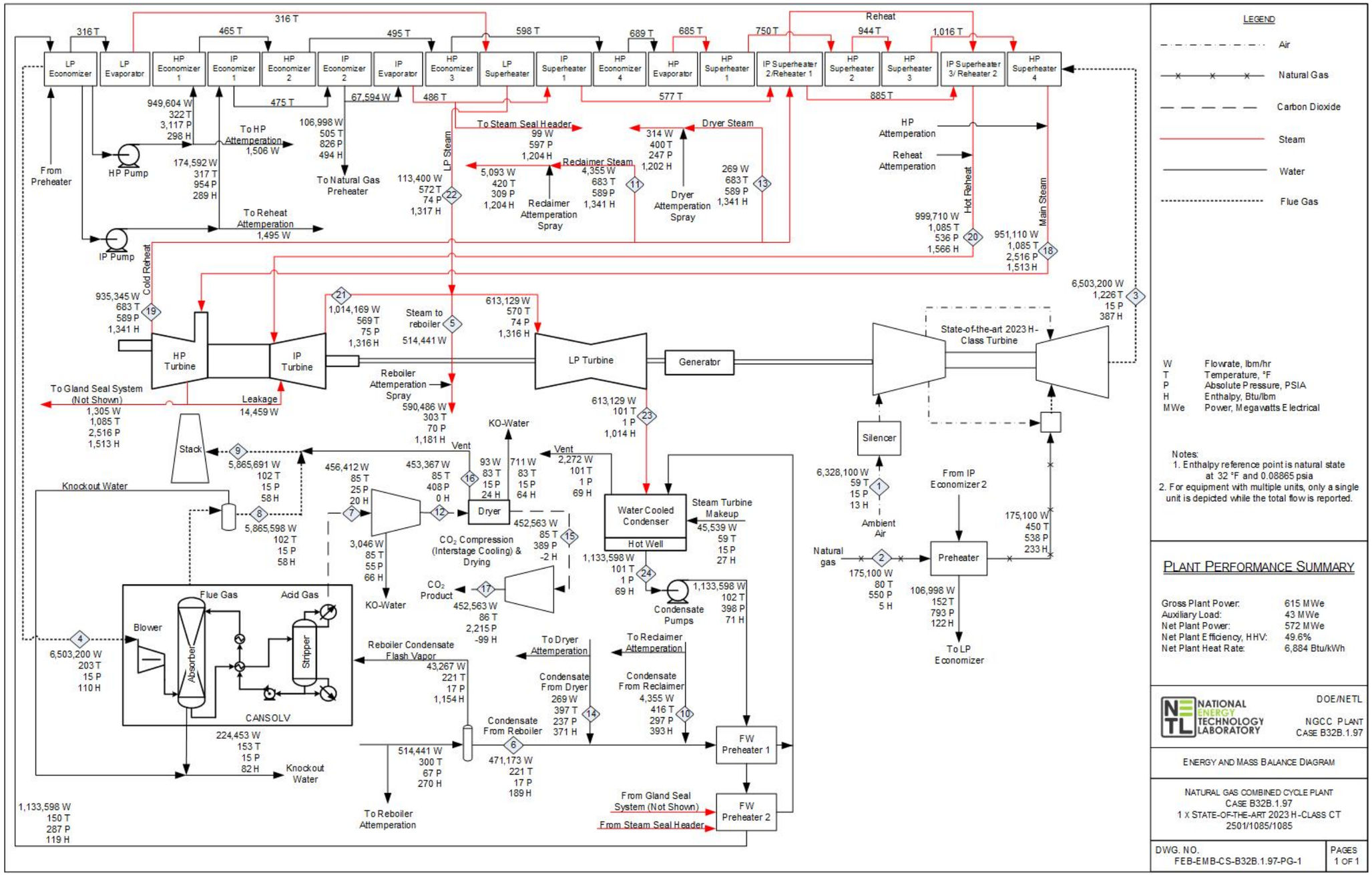
B.2.1.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for Case B32B.1.97 in Exhibit B-23.

An overall plant energy balance is provided in tabular form in Exhibit B-24. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals is (shown in Exhibit B-17) calculated by multiplying the power out by the generator efficiency: 98.5 percent for the CT and 98.5 percent for the steam turbine.

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Exhibit B-23. Case B32B.1.97 energy and mass balance, NGCC with CO_2 capture



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Exhibit B-24. Case B32B.1.97 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, GJ/hr (MMBtu/hr)				
Natural Gas	4,153 (3,937)	4.9 (4.7)	–	4,158 (3,941)
Air	–	87 (82)	–	87 (82)
Raw Water Makeup	–	54 (51)	–	54 (51)
Auxiliary Power	–	–	153 (145)	153 (145)
TOTAL	**4,153 (3,937)**	**146 (138)**	**153 (145)**	**4,453 (4,220)**
Heat Out, GJ/hr (MMBtu/hr)				
Stack Gas	–	356 (337)	–	356 (337)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Motor Losses and Design Allowances	–	–	46 (44)	46 (44)
Cooling Tower Load[A]	–	1,838 (1,742)	–	1,838 (1,742)
CO_2 Product Stream	–	-47 (-45)	–	-47 (-45)
AGR Effluent	–	29 (27)	–	29 (27)
Dryer Effluent	–	0.0 (0.0)	–	0.0 (0.0)
Deaerator Vent	–	0.2 (0.2)	–	0.2 (0.2)
Ambient Losses[B]	–	*36 (34)*	–	36 (34)
Power	–	–	2,212 (2,097)	2,212 (2,097)
TOTAL	**0.0 (0.0)**	**2,212 (2,096)**	**2,258 (2,140)**	**4,470 (4,237)**
Unaccounted Energy[C]	–	*-17 (-16)*	–	*-17 (-16)*

[A]Includes condenser, capture process, CO_2 compressor, and miscellaneous cooling loads
[B]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers
[C]By difference

B.2.2 Case B32B.1.97 – Major Equipment List

Major equipment items for the 1x1 H-Class NGCC plant with 97 percent 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 B.3.3. 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. Values reported in the equipment lists are rounded.

Case B32B.1.97 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,361,000 liters (359,000 gal)	2	0
2	Condensate Pumps	Vertical canned	9,490 lpm @ 340 m H_2O (2,510 gpm @ 1,110 ft H_2O)	1	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP Water: 3,980 lpm @ 2,420 m H_2O (1,050 gpm @ 7,930 ft H_2O) IP Water: 740 lpm @ 580 m H_2O (190 gpm @ 1,890 ft H_2O)	2	2
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 GJ/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	3,800 lpm @ 110 m H_2O (1,000 gpm @ 350 ft H_2O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,600 lpm @ 80 m H_2O (700 gpm @ 250 ft H_2O)	1	1
11	Municipal Water Pumps	Stainless steel, single suction	3,900 lpm @ 20 m H_2O (1,040 gpm @ 60 ft H_2O)	2	1
12	Ground Water Pumps	Stainless steel, single suction	3,900 lpm @ 20 m H_2O (1,040 gpm @ 60 ft H_2O)	2	1
13	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H_2O (40 gpm @ 160 ft H_2O)	2	1
14	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
15	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0
16	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
17	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	51 m^3/min @ 3.8 MPa (1,784 acfm @ 550 psia) 39 cm (16 in) standard wall pipe	16 km (10 mile)	0
18	Gas Metering Station	–	51 m^3/min (1,784 acfm)	1	0

Case B32B.1.97 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Cansolv	Amine-based CO_2 capture technology	3,245,000 kg/hr (7,154,000 lb/hr) 7.2 wt% CO_2 concentration	1	0
2	Cansolv LP Condensate Pump	Centrifugal	630 lpm @ 1.0 m H_2O (170 gpm @ 3.4 ft H_2O)	1	1
3	Cansolv HP Condensate Pump	Centrifugal	6.1 lpm @ 4.6 m H_2O (1.6 gpm @ 15.0 ft H_2O)	1	1
4	CO_2 Dryer	Triethylene glycol	Inlet: 59 m^3/min @ 2.8 MPa (2,095 acfm @ 408 psia) Outlet: 2.7 MPa (389 psia) Water Removed: 323 kg/hr (712 lb/hr)	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
5	CO_2 Compressor	Integrally geared, multi-stage centrifugal	3 m^3/min @ 15.3 MPa, 82°C (105 acfm @ 2,217 psia, 180°F)	2	0
6	CO_2 Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 32 GJ/hr (31 MMBtu/hr)	2	0

Case B32B.1.97 – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	2023 Advanced H-Class w/ dry low-NOx burner	440 MW	1	0
2	Combustion Turbine Generator	Hydrogen Cooled	520 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	1	0

Case B32B.1.97 – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Epoxy-coated CS plate	46 m (150 ft) high x 6.2 m (20 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section	Main Steam: 467,000 kg/hr, 17.2 MPa/585°C (1,029,000 lb/hr, 2,502 psig/1,085°F) Reheat Steam: 499,000 kg/hr, 3.6 MPa/585°C (1,100,000 lb/hr, 521 psig/1,085°F)	1	0
3	SCR Reactor	–	3,240,000 kg/hr (7,150,000 lb/hr)	1	0
4	SCR Catalyst	–	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	30 m^3/min @ 108 cm WG (1,010 scfm @ 42 in WG)	1	1
6	Ammonia Feed Pump	Centrifugal	6.0 lpm @ 90 m H_2O (1.6 gpm @ 300 ft H_2O)	1	1
7	Ammonia Storage Tank	Horizontal tank	87,000 liter (23,000 gal)	1	0

Case B32B.1.97 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	182 MW 17.2 MPa/585°C/585°C (2,502 psig/1,085°F/1,085°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	210 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Two pass, divided waterbox including vacuum pumps and integrated deaerator	680 GJ/hr (640 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	1	0

Case B32B.1.97 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	361,000 lpm @ 30 m (95,000 gpm @ 100 ft)	2	1

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 2,020 GJ/hr (1,920 MMBtu/hr) heat duty	1	0

Case B32B.1.97 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	18 kV/345 kV, 520 MVA, 3-ph, 60 Hz	1	0
2	STG Transformer	Oil-filled	18 kV/345 kV, 160 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 9 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	18 kV/4.16 kV, 20 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 7 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	1	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 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 B32B.1.97 – 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

B.2.3 Case B32B.1.97 – Cost Estimating

The cost estimating methodology was described in Section 2.7. Exhibit B-25 shows a detailed breakdown of the capital costs; Exhibit B-26 shows the owner's costs, TOC, and TASC; Exhibit B-27 shows the initial and annual O&M costs; and Exhibit B-28 shows the COE breakdown.

The estimated TPC of the NGCC with CO_2 capture is $2,199/kW. Process contingency represents 4.2 percent of the TPC and project contingency represents 15.0 percent of the TPC. The FY COE, including T&S costs of $4.9/MWh,[y] is $90.8/MWh. The LCOE, including T&S costs of $6.5/MWh, is $82.5/MWh.

[y] T&S costs for this case are based on a first-year break-even CO_2 price of $13.55/tonne.

Exhibit B-25. Case B32B.1.97 total plant cost details

Case:	B32B.1.97 – NGCC H-Class (1x1) with 97 Percent CO_2 Capture						Estimate Type:		Conceptual	
Plant Size (MW, net):	572						Cost Base:		Jan 2023	
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	$2,112	$3,621	$1,553	$0	$7,287	$1,457	$0	$1,312	$10,056	$18
3.2	Water Makeup & Pretreating	$6,223	$622	$2,926	$0	$9,772	$1,954	$0	$2,345	$14,071	$25
3.3	Other Feedwater Subsystems	$1,202	$394	$321	$0	$1,917	$383	$0	$345	$2,646	$5
3.4	Service Water Systems	$1,888	$3,605	$9,688	$0	$15,181	$3,036	$0	$3,644	$21,861	$38
3.5	Other Boiler Plant Systems	$280	$102	$223	$0	$605	$121	$0	$109	$835	$1
3.6	NG Pipeline and Start-Up System	$9,455	$407	$253	$0	$10,115	$2,023	$0	$1,821	$13,959	$24
3.7	Waste Water Treatment Equipment	$11,366	$0	$6,107	$0	$17,473	$3,495	$0	$4,194	$25,161	$44
3.9	Miscellaneous Plant Equipment	$13,782	$1,807	$6,141	$0	$21,730	$4,346	$0	$5,215	$31,291	$55
	Subtotal	**$46,309**	**$10,559**	**$27,213**	**$0**	**$84,081**	**$16,816**	**$0**	**$18,984**	**$119,881**	**$210**
	5	**Flue Gas Cleanup**									
5.1	CANSOLV CO_2 Removal System	$121,481	$58,584	$109,126	$0	$289,190	$57,838	$52,054	$79,816	$478,899	$837
5.4	CO_2 Compression & Drying	$30,747	$4,612	$12,072	$0	$47,431	$9,486	$0	$11,384	$68,301	$119
5.5	CO_2 Compressor Aftercooler	$260	$41	$106	$0	$407	$81	$0	$98	$587	$1
5.12	Gas Cleanup Foundations	$0	$450	$460	$0	$910	$182	$0	$218	$1,310	$2
	Subtotal	**$152,488**	**$63,687**	**$121,764**	**$0**	**$337,939**	**$67,588**	**$52,054**	**$91,516**	**$549,097**	**$960**
	6	**Combustion Turbine & Accessories**									
6.1	Combustion Turbine Generator	$93,216	$0	$5,950	$0	$99,166	$19,833	$0	$17,850	$136,849	$239
6.3	Combustion Turbine Accessories	$2,269	$0	$139	$0	$2,408	$482	$0	$433	$3,323	$6
6.4	Compressed Air Piping	$0	$862	$166	$0	$1,028	$206	$0	$185	$1,418	$2
6.5	Combustion Turbine Foundations	$0	$998	$1,089	$0	$2,087	$417	$0	$501	$3,005	$5
	Subtotal	**$95,484**	**$1,860**	**$7,344**	**$0**	**$104,688**	**$20,938**	**$0**	**$18,969**	**$144,595**	**$253**
	7	**HRSG, Ductwork, & Stack**									
7.1	HRSG	$48,524	$0	$12,131	$0	$60,656	$12,131	$0	$10,918	$83,705	$146
7.2	HRSG Accessories	$13,549	$0	$2,531	$0	$16,080	$3,216	$0	$2,894	$22,191	$39
7.3	Ductwork	$0	$1,065	$582	$0	$1,648	$330	$0	$297	$2,274	$4
7.4	Stack	$3,683	$0	$688	$0	$4,371	$874	$0	$787	$6,032	$11
7.5	HRSG, Ductwork, & Stack Foundations	$0	$741	$586	$0	$1,327	$265	$0	$318	$1,911	$3
7.6	Selective Catalytic Reduction System	$1,637	$688	$841	$0	$3,166	$633	$0	$570	$4,369	$8
	Subtotal	**$67,394**	**$2,494**	**$17,360**	**$0**	**$87,247**	**$17,449**	**$0**	**$15,784**	**$120,481**	**$211**
	8	**Steam Turbine & Accessories**									
8.1	Steam Turbine Generator & Accessories	$35,524	$0	$5,202	$0	$40,727	$8,145	$0	$7,331	$56,203	$98
8.2	Steam Turbine Plant Auxiliaries	$125	$0	$288	$0	$413	$83	$0	$74	$570	$1
8.3	Condenser & Auxiliaries	$5,686	$0	$2,728	$0	$8,414	$1,683	$0	$1,515	$11,611	$20
8.4	Steam Piping	$11,277	$0	$3,875	$0	$15,153	$3,031	$0	$2,727	$20,911	$37
8.5	Turbine Generator Foundations	$0	$1,283	$1,790	$0	$3,073	$615	$0	$738	$4,426	$8
	Subtotal	**$52,612**	**$1,283**	**$13,884**	**$0**	**$67,779**	**$13,556**	**$0**	**$12,385**	**$93,720**	**$164**

Case:	B32B.1.97 – NGCC H-Class (1x1) with 97 Percent CO_2 Capture						Estimate Type:	Conceptual		
Plant Size (MW, net):	572						Cost Base:	Jan 2023		
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
	9					**Cooling Water System**					
9.1	Cooling Towers	$13,085	$0	$3,500	$0	$16,585	$3,317	$0	$2,985	$22,887	$40
9.2	Circulating Water Pumps	$1,668	$0	$89	$0	$1,756	$351	$0	$316	$2,424	$4
9.3	Circulating Water System Auxiliaries	$11,666	$0	$1,393	$0	$13,059	$2,612	$0	$2,351	$18,022	$32
9.4	Circulating Water Piping	$0	$3,670	$2,758	$0	$6,428	$1,286	$0	$1,157	$8,870	$16
9.5	Make-up Water System	$433	$0	$462	$0	$894	$179	$0	$161	$1,234	$2
9.6	Component Cooling Water System	$541	$0	$345	$0	$886	$177	$0	$159	$1,222	$2
9.7	Circulating Water System Foundations	$0	$849	$1,210	$0	$2,059	$412	$0	$494	$2,965	$5
	Subtotal	**$27,392**	**$4,519**	**$9,755**	**$0**	**$41,667**	**$8,333**	**$0**	**$7,624**	**$57,623**	**$101**
	11					**Accessory Electric Plant**					
11.1	Generator Equipment	$3,164	$0	$1,972	$0	$5,136	$1,027	$0	$925	$7,088	$12
11.2	Station Service Equipment	$8,385	$0	$594	$0	$8,980	$1,796	$0	$1,616	$12,392	$22
11.3	Switchgear & Motor Control	$13,773	$0	$1,716	$0	$15,489	$3,098	$0	$2,788	$21,375	$37
11.4	Conduit & Cable Tray	$0	$2,893	$6,890	$0	$9,783	$1,957	$0	$1,761	$13,501	$24
11.5	Wire & Cable	$0	$4,319	$6,380	$0	$10,699	$2,140	$0	$1,926	$14,765	$26
11.6	Protective Equipment	$585	$0	$1,459	$0	$2,044	$409	$0	$368	$2,821	$5
11.7	Standby Equipment	$939	$0	$623	$0	$1,562	$312	$0	$281	$2,155	$4
11.8	Main Power Transformers	$6,376	$0	$131	$0	$6,507	$1,301	$0	$1,171	$8,980	$16
11.9	Electrical Foundations	$0	$108	$246	$0	$354	$71	$0	$85	$510	$1
	Subtotal	**$33,221**	**$7,321**	**$20,012**	**$0**	**$60,554**	**$12,111**	**$0**	**$10,921**	**$83,586**	**$146**
	12					**Instrumentation & Control**					
12.1	NGCC Control Equipment	$269	$0	$169	$0	$438	$88	$0	$79	$604	$1
12.2	Combustion Turbine Control Equipment	$442	$0	$279	$0	$721	$144	$0	$130	$995	$2
12.3	Steam Turbine Control Equipment	$430	$0	$271	$0	$702	$140	$0	$126	$968	$2
12.4	Other Major Component Control Equipment	$722	$0	$455	$0	$1,177	$235	$59	$221	$1,693	$3
12.5	Signal Processing Equipment	$602	$0	$18	$0	$620	$124	$0	$112	$856	$1
12.6	Control Boards, Panels, & Racks	$159	$0	$96	$0	$256	$51	$13	$48	$368	$1
12.7	Distributed Control System Equipment	$8,850	$0	$267	$0	$9,116	$1,823	$456	$1,709	$13,105	$23
12.8	Instrument Wiring & Tubing	$875	$700	$2,314	$0	$3,890	$778	$194	$729	$5,592	$10
12.9	Other I&C Equipment	$606	$0	$1,160	$0	$1,766	$353	$88	$331	$2,539	$4
	Subtotal	**$12,956**	**$700**	**$5,030**	**$0**	**$18,687**	**$3,737**	**$810**	**$3,485**	**$26,719**	**$47**
	13					**Improvements to Site**					
13.1	Site Preparation	$0	$868	$15,560	$0	$16,428	$3,286	$0	$3,943	$23,656	$41
13.2	Site Improvements	$0	$2,792	$3,114	$0	$5,906	$1,181	$0	$1,417	$8,504	$15
13.3	Site Facilities	$2,679	$0	$2,373	$0	$5,052	$1,010	$0	$1,212	$7,275	$13
	Subtotal	**$2,679**	**$3,660**	**$21,047**	**$0**	**$27,386**	**$5,477**	**$0**	**$6,573**	**$39,435**	**$69**
	14					**Buildings & Structures**					
14.1	Combustion Turbine Area	$0	$530	$206	$0	$736	$147	$0	$133	$1,016	$2
14.3	Steam Turbine Building	$0	$4,335	$4,238	$0	$8,573	$1,715	$0	$1,543	$11,830	$21
14.4	Administration Building	$0	$552	$275	$0	$827	$165	$0	$149	$1,141	$2

Case:		B32B.1.97 – NGCC H-Class (1x1) with 97 Percent CO_2 Capture					Estimate Type:			Conceptual	
Plant Size (MW, net):		572					Cost Base:			Jan 2023	
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
14.5	Circulation Water Pumphouse	$0	$109	$40	$0	$148	$30	$0	$27	$205	$0
14.6	Water Treatment Buildings	$0	$583	$390	$0	$973	$195	$0	$175	$1,343	$2
14.7	Machine Shop	$0	$826	$388	$0	$1,214	$243	$0	$219	$1,676	$3
14.8	Warehouse	$0	$642	$285	$0	$927	$185	$0	$167	$1,280	$2
14.9	Other Buildings & Structures	$0	$470	$251	$0	$720	$144	$0	$130	$994	$2
14.10	Waste Treating Building & Structures	$0	$986	$1,292	$0	$2,278	$456	$0	$410	$3,144	$5
	Subtotal	**$0**	**$9,032**	**$7,365**	**$0**	**$16,397**	**$3,279**	**$0**	**$2,952**	**$22,628**	**$40**
	Total	**$490,536**	**$105,115**	**$250,774**	**$0**	**$846,425**	**$169,285**	**$52,864**	**$189,192**	**$1,257,766**	**$2,199**

Exhibit B-26. Case B32B.1.97 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$7,684	$13
1 Month Maintenance Materials	$1,406	$2
1 Month Non-fuel Consumables	$692	$1
1 Month Waste Disposal	$94	$0
25% of 1 Months Fuel Cost at 100% CF	$4,014	$7
2% of TPC	$25,155	$44
Total	**$39,046**	**$68**
Inventory Capital		
60-day supply of consumables at 100% CF	$952	$2
0.5% of TPC (spare parts)	$6,289	$11
Total	**$7,241**	**$13**
Other Costs		
Initial Cost for Catalyst and Chemicals	$1,488	$3
Land	$600	$1
Other Owner's Costs	$188,665	$330
Financing Costs	$33,960	$59
Total Overnight Costs (TOC)	**$1,528,766**	**$2,673**
TASC Multiplier (IOU, 33 year)	1.183	
Total As-Spent Cost (TASC)	**$1,808,450**	**$3,162**

Exhibit B-27. Case B32B.1.97 initial and annual operating and maintenance costs

Case:	B32B.1.97 –NGCC H–Class (1x1) with 97 Percent CO_2 Capture				Cost Base:	Jan 2023
Plant Size (MW, net):	572	Heat Rate-net (Btu/kWh):		6,884	Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		45.04	**$/hour**	Skilled Operator:		1.0
Operating Labor Burden:		30.00	**% of base**	Operator:		2.3
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		1.0
				Total:		**5.3**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$2,735,351	$4.783
Maintenance Labor:					$9,559,025	$16.714
Administrative & Support Labor:					$3,073,594	$5.374
Property Taxes and Insurance:					$25,155,330	$43.985
Total:					**$40,523,301**	**$70.857**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$14,338,538	$3.367
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	2,733	$2.30	$0	$1,950,275	$0.458
Makeup and Waste Water Treatment Chemicals (ton):	0	8.1	$660.00	$0	$1,667,101	$0.391
Ammonia (19 wt%, ton):	0	7.9	$280.00	$0	$689,202	$0.162
SCR Catalyst (ft^3):	4,252	2.3	$350.00	$1,488,225	$252,998	$0.059
CO_2 Capture System Chemicals[A]:	Proprietary				$2,392,454	$0.562
Triethylene Glycol (gal):	w/equip.	40.7	$8.50	$0	$107,356	$0.025
Subtotal:				**$1,488,225**	**$7,059,387**	**$1.658**
Waste Disposal						
SCR Catalyst (ft^3):	0	2.3	$5.70	$0	$4,120	$0.001
Triethylene Glycol (gal):	0	2,064	$1.30	$0	$832,590	$0.196
Thermal Reclaimer Unit Waste (ton):	0	1.6	$250.00	$0	$126,044	$0.030
Subtotal:				**$0**	**$962,755**	**$0.226**
Variable Operating Costs Total:				**$1,488,225**	**$22,360,680**	**$5.251**
Fuel Cost						
Natural Gas (MMBtu):	0	94,481	$5.59	$0	$163,777,048	$38.460
Total:				**$0**	**$163,777,048**	**$38.460**

[A]CO_2 Capture System Chemicals includes sodium hydroxide and CANSOLV solvent

Exhibit B-28. Case B32B.1.97 COE breakdown

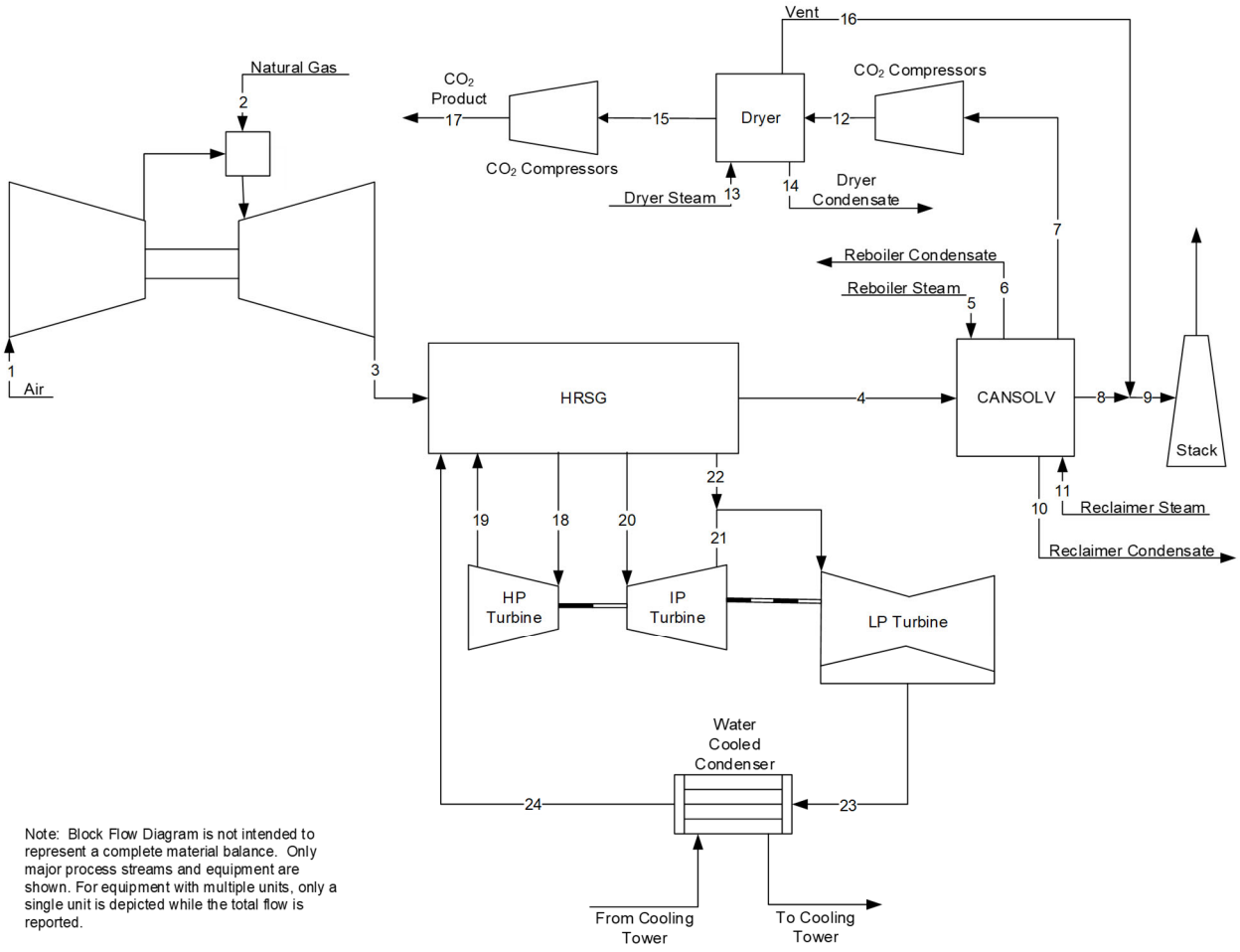
	FY COE		LCOE	
Component	**Value, $/MWh**	**Percentage**	**Value, $/MWh**	**Percentage**
Capital	32.7	36%	32.7	40%
Fixed	9.5	10%	12.7	15%
Variable	5.3	6%	7.0	8%
Fuel	38.5	42%	23.6	29%
Total (Excluding T&S)	**86.0**	**N/A**	**76.0**	**N/A**
CO_2 T&S	4.9	5%	6.5	8%
Total (Including T&S)	**90.8**	**N/A**	**82.5**	**N/A**

B.3 Case B32B.2.97 – 2x1 H-Class NGCC with 97% CO_2 Capture Process Description

The plant configuration and process description for Case B32B.2.97 is the same as Case B32B.2.90, with the exception that the PostCCC facility captures 97, rather than 90, percent of the CO_2 in the flue gas. Since the process descriptions of the plant and PostCCC facility were provided in Section 4.2.3 and Section 3.1.8, respectively, with differences between the facilities used in NGCC and PC cases noted in Section 4.1.4, they are not repeated here.

The BFD for Case B32B.2.97 is shown in Exhibit B-29. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit B-30. The modeling assumptions are presented in Section 4.3.1.

Exhibit B-29. Case B32B.2.97 BFD, NGCC with 97 percent CO_2 capture



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown. For equipment with multiple units, only a single unit is depicted while the total flow is reported.

Exhibit B-30. Case B32B.2.97 stream table, NGCC with 97 percent CO_2 capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0000	0.0088	0.0088	0.0000	0.0000	0.0000	0.0097	0.0097	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	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	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	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	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	0.0000	0.0000	0.0000
CO_2	0.0003	0.0100	0.0447	0.0447	0.0000	0.0000	0.9796	0.0015	0.0015	0.0000	0.0000	0.9957
H_2O	0.0099	0.0000	0.0949	0.0949	1.0000	1.0000	0.0204	0.0582	0.0582	1.0000	1.0000	0.0043
N_2	0.7732	0.0160	0.7399	0.7399	0.0000	0.0000	0.0000	0.8087	0.8087	0.0000	0.0000	0.0000
O_2	0.2074	0.0000	0.1116	0.1116	0.0000	0.0000	0.0000	0.1220	0.1220	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	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_{mol}/hr)	178,633	7,957	186,821	186,821	22,453	20,564	8,267	170,940	170,941	191	191	8,134
V-L Flowrate (kg/hr)	5,154,805	137,875	5,292,680	5,292,680	404,495	370,474	359,466	4,796,048	4,796,121	3,439	3,439	357,067
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	27	653	93	300	105	29	39	39	214	360	29
Pressure (MPa, abs)	0.10	3.79	0.11	0.10	0.51	0.12	0.17	0.10	0.10	2.04	4.12	2.81
Steam Table Enthalpy (kJ/kg)[A]	30.23	12.48	882.51	248.83	3,064.28	439.34	45.99	133.75	133.75	913.81	3,113.70	-1.10
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-4,496.75	-725.35	-1,359.03	-12,916.01	-15,540.95	-8,977.01	-507.68	-507.81	-15,066.49	-12,866.59	-8,976.01
Density (kg/m^3)	1.2	28.8	0.4	0.9	1.9	954.9	3.0	1.1	1.1	848.5	15.2	57.8
V-L Molecular Weight	28.857	17.328	28.330	28.330	18.015	18.015	43.481	28.057	28.057	18.015	18.015	43.897
V-L Flowrate (lb_{mol}/hr)	393,818	17,542	411,869	411,869	49,500	45,337	18,226	376,857	376,861	421	421	17,933
V-L Flowrate (lb/hr)	11,364,400	303,962	11,668,362	11,668,362	891,758	816,756	792,486	10,573,477	10,573,638	7,582	7,582	787,198
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	80	1,208	199	573	221	85	102	102	416	680	85
Pressure (psia)	14.7	550.0	15.3	14.8	73.5	17.4	24.7	14.8	14.8	296.6	598.0	407.6
Steam Table Enthalpy (Btu/lb)[A]	13.0	5.4	379.4	107.0	1,317.4	188.9	19.8	57.5	57.5	392.9	1,338.7	-0.5
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-1,933.3	-311.8	-584.3	-5,552.9	-6,681.4	-3,859.4	-218.3	-218.3	-6,477.4	-5,531.6	-3,859.0
Density (lb/ft^3)	0.076	1.799	0.024	0.059	0.121	59.612	0.185	0.069	0.069	52.968	0.951	3.607

[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 B-30. Case B32B.2.97 stream table, NGCC with 97 percent CO_2 capture (cont'd)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0000	0.0000	0.0000	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	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	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	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	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	0.0000	0.0000	0.0000
CO_2	0.0000	0.0000	0.9995	0.9704	0.9995	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	1.0000	0.0005	0.0296	0.0005	1.0000	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	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	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	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_{mol}/hr)	12	12	8,101	2	8,101	41,217	40,812	44,148	44,517	5,688	27,752	50,443
V-L Flowrate (kg/hr)	212	212	356,434	73	356,434	742,529	735,236	795,335	801,990	102,467	499,962	908,746
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	360	203	29	28	30	585	360	585	300	303	38	38
Pressure (MPa, abs)	4.12	1.64	2.68	0.10	15.27	17.30	4.12	3.84	0.52	0.51	0.01	0.01
Steam Table Enthalpy (kJ/kg)[A]	3,113.70	863.65	-3.59	56.47	-231.09	3,520.56	3,113.70	3,641.20	3,064.28	3,070.57	2,377.16	160.78
AspenPlus Enthalpy (kJ/kg)[B]	-12,866.59	-15,116.65	-8,967.15	-8,994.77	-9,194.65	-12,459.74	-12,866.59	-12,339.10	-12,916.01	-12,909.72	-13,603.14	-15,819.51
Density (kg/m^3)	15.2	861.8	54.7	1.8	630.1	48.1	15.2	9.9	2.0	1.9	0.1	992.8
V-L Molecular Weight	18.015	18.015	43.997	43.240	43.997	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	26	26	17,860	4	17,860	90,867	89,975	97,329	98,144	12,539	61,183	111,208
V-L Flowrate (lb/hr)	468	468	785,803	161	785,803	1,636,995	1,620,917	1,753,413	1,768,085	225,900	1,102,227	2,003,442
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	680	397	85	83	86	1,085	680	1,085	573	578	101	101
Pressure (psia)	598.0	237.4	389.1	14.8	2,214.7	2,508.5	598.0	557.1	75.0	73.5	1.0	1.0
Steam Table Enthalpy (Btu/lb)[A]	1,338.7	371.3	-1.5	24.3	-99.4	1,513.6	1,338.7	1,565.4	1,317.4	1,320.1	1,022.0	69.1
AspenPlus Enthalpy (Btu/lb)[B]	-5,531.6	-6,499.0	-3,855.2	-3,867.1	-3,953.0	-5,356.7	-5,531.6	-5,304.9	-5,552.9	-5,550.2	-5,848.3	-6,801.2
Density (lb/ft^3)	0.951	53.801	3.416	0.110	39.338	3.001	0.951	0.617	0.123	0.120	0.003	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

B.3.1 Case B32B.2.97 – Performance Results

Overall plant performance is summarized in Exhibit B-31; Exhibit B-32 provides a detailed breakdown of the auxiliary power requirements.

The PostCCC facility and CO_2 compression combined account for 69 percent of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for 13 percent of the auxiliary load, largely due to the high cooling water demand of the PostCCC facility and CO_2 compressors.

Unlike the PC cases, which utilize boilers and steam turbines that can be produced at nearly any desired output, the gross outputs of the NGCC cases are fixed by the available size of the CTs. As such, the net outputs of the capture cases are reduced due to the greater auxiliary load imposed by the PostCCC facility and CO_2 compressors, relative to a non-capture case. The plant produces a net output of 986 MW at a net plant efficiency of 49.2 percent (HHV basis).

Exhibit B-31. Case B32B.2.97 plant performance summary

Performance Summary	
Combustion Turbine Power, MWe	759
Steam Turbine Power, MWe	301
Total Gross Power, MWe	**1,060**
CO_2 Capture/Removal Auxiliaries, kWe	22,500
CO_2 Compression, kWe	28,520
Balance of Plant, kWe	22,809
Total Auxiliaries, MWe	**74**
Net Power, MWe	**986**
HHV Net Plant Efficiency, %	49.2
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	7,310 (6,928)
HHV Combustion Turbine Efficiency, %	37.9
LHV Net Plant Efficiency, %	54.6
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	6,598 (6,253)
LHV Combustion Turbine Efficiency, %	42.0
Steam Turbine Cycle Efficiency, %	47.7
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,541 (7,148)
CO_2 Capture Rate, %	97
Condenser Duty, GJ/hr (MMBtu/hr)	1,114 (1,056)
AGR Cooling Duty, GJ/hr (MMBtu/hr)	1,879 (1,781)
Natural Gas Feed Flow, kg/hr (lb/hr)	137,875 (303,962)
HHV Thermal Input, kWt	2,002,815
LHV Thermal Input, kWt	1,807,738
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.026 (6.7)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.016 (4.3)

Exhibit B-32. Case B32B.2.97 plant power summary

Power Summary	
Combustion Turbine Power, MWe	759
Steam Turbine Power, MWe	301
Total Gross Power, MWe	**1,060**
Auxiliary Load Summary	
Circulating Water Pumps, kWe	6,310
Combustion Turbine Auxiliaries, kWe	1,270
Condensate Pumps, kWe	1,050
Cooling Tower Fans, kWe	3,270
CO_2 Capture/Removal Auxiliaries, kWe	22,500
CO_2 Compression, kWe	28,520
Feedwater Pumps, kWe	5,770
Ground Water Pumps, kWe	600
Miscellaneous Balance of Plant,[A] kWe	880
SCR, kWe	9
Steam Turbine Auxiliaries, kWe	250
Transformer Losses, kWe	3,400
Total Auxiliaries, MWe	**74**
Net Power, MWe	**986**

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

B.2.1.1 Environmental Performance

The environmental targets for emissions of NOx, SO_2, and PM are presented in Section 2.4. A summary of the plant air emissions for Case B32B.2.97 is presented in Exhibit B-33.

Exhibit B-33. Case B32B.2.97 air emissions

	kg/GJ (lb/MMBtu)[A]	tonne/year (ton/year)[B]	kg/MWh (lb/MWh)[C]
SO_2	0.000 (0.000)	0 (0)	0.000 (0.000)
NOx	0.001 (0.003)	69 (76)	0.009 (0.019)
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	0.000 (0.000)	0 (0)	0.000 (0.000)
CO_2	2 (4)	82,619 (91,072)	10 (23)
CO_2[D]	-	-	11 (25)

[A]Based on thermal input on an HHV basis
[B]Calculations based on an 85 percent capacity factor
[C]Emissions based on gross power except where otherwise noted
[D]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 domestic average value of total sulfur of 0.34 gr/100 scf ($4.71x10^{-4}$ lb-S/MMBtu) (Gas Research Institute, 1992). It was also assumed that the added 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 1.8 ppmv NOx emissions using a DLN burner in the CTG and an SCR. The DLN burners reduce the emissions to about 25 ppmvd (at 15 percent O_2) (GE Vernova, 2024b) and the SCR system is designed for an additional 95.0 percent NOx reduction (Davis & Black, October 2000).

The pipeline natural gas was assumed to contain no Hg or HCl, resulting in zero emissions.

The state-of-the-art 2023 H-Class gas turbine achieves approximately 9.0 ppmvd (at 15 percent O_2) CO and 1.5 ppmw PM emissions. The production of PM is a result of system inefficiencies and is not produced or emitted in any significant amount. Any CO or PM present in the flue gas is assumed to interact with, and be removed by, the PostCCC system solvent.

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

The carbon balance for the plant is shown in Exhibit B-34. The carbon input to the plant consists of carbon in the natural gas and carbon in the air. Carbon leaves the plant mostly as CO_2 product from the CO_2 compression train; however, some carbon exits through the stack as CO_2.

Ninety seven percent of the CO_2 in the flue gas is removed in the PostCCC facility. 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 percentage:

$$1 - \frac{Carbon\ in\ Stack}{Total\ Carbon\ In} = \left(1 - \left(\frac{6{,}676}{221{,}091}\right)\right) * 100 = 97\%$$

Exhibit B-34. Case B32B.2.97 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	99,584 (219,546)	Stack Gas	3,028 (6,676)
Air (CO_2)	701 (1,545)	CO_2 Product	97,257 (214,415)
		CO_2 Knockout	0.2 (0.4)
Total	**100,285 (221,091)**	**Total**	**100,285 (221,091)**

As shown in Exhibit B-35, the sulfur content of the natural gas is insignificant, entirely comprising CH_4S (used as an odorant) (Gas Research Institute, 1992). All sulfur in the natural gas is assumed to react with the PostCCC system solvent and is removed from the solvent during solvent reclaiming as a waste stream.

Exhibit B-35. Case B32B.2.97 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Natural Gas	1.5 (3.2)	Stack Gas	0.0 (0.0)
		Solvent Reclaiming	1.5 (3.2)
Total	**1.5 (3.2)**	**Total**	**1.5 (3.2)**

Water demand, recycle, withdrawal, discharge, and consumption are defined and discussed in Section 2.6. Exhibit B-36 shows the overall water balance for the plant.

Exhibit B-36. Case B32B.2.97 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 Capture System Makeup	–	–	–	–	–
CO_2 Capture Recovery	–	–	–	2.8 (752)	-2.8 (-752)
CO_2 Compression Recovery	–	–	–	0.0 (11)	0.0 (-11)
Deaerator Vent	–	–	–	0.0 (8.0)	0.0 (-8.0)
Condenser Makeup	**0.6 (157)**	**–**	**0.6 (157)**	**–**	**0.6 (157)**
BFW Makeup	0.6 (157)	–	0.6 (157)	–	0.6 (157)
Cooling Tower	25 (6,489)	–	25 (6,489)	6.1 (1,621)	18 (4,867)
Total	**25 (6,646)**	**–**	**25 (6,646)**	**9.1 (2,392)**	**16 (4,254)**

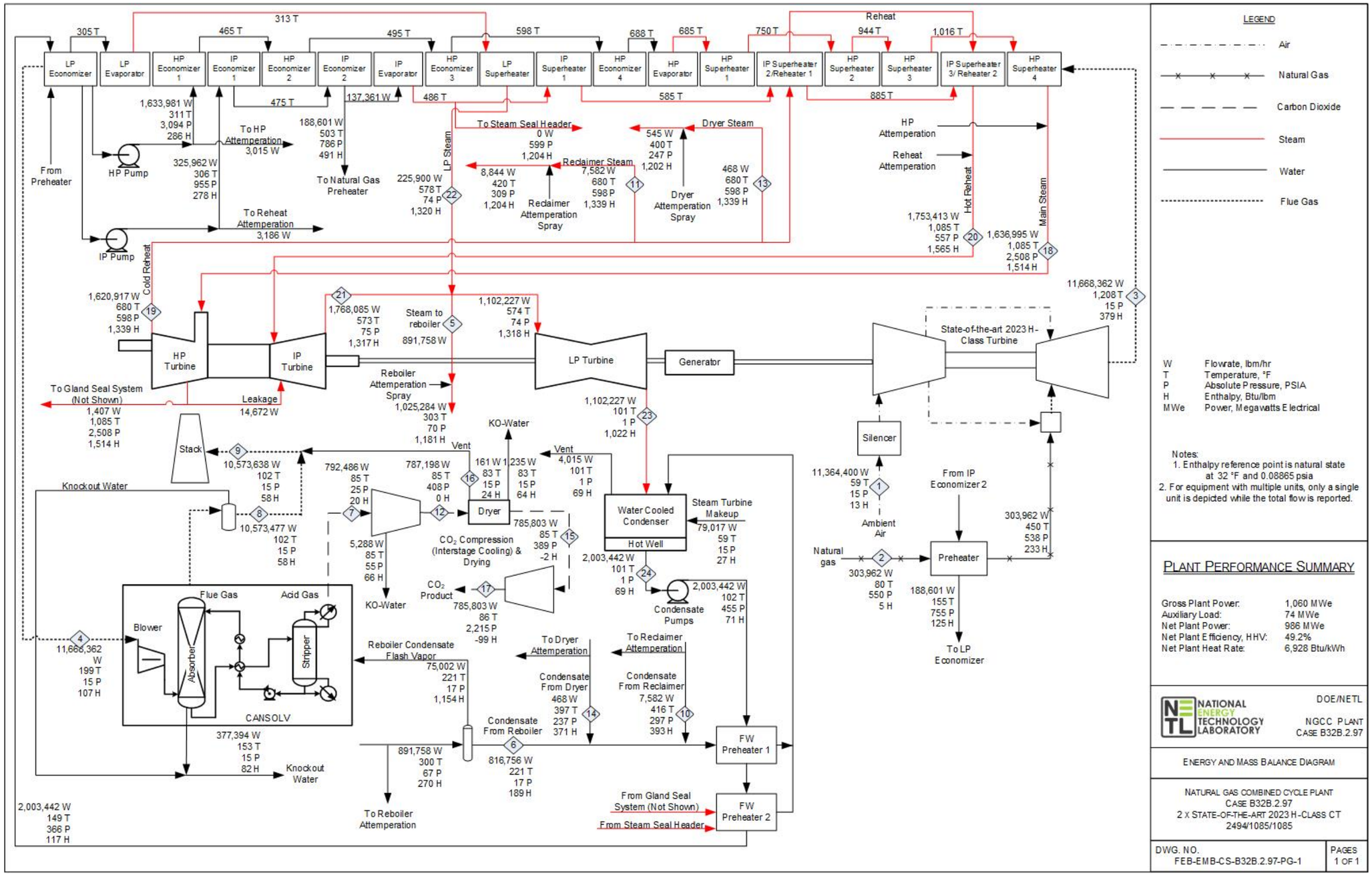
B.2.1.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for Case B32B.2.97 in Exhibit B-37.

An overall plant energy balance is provided in tabular form in Exhibit B-38. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals is (shown in Exhibit B-31) calculated by multiplying the power out by the generator efficiency: 99.6 percent for the CT and 98.0 percent for the steam turbine.

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Exhibit B-37. Case B32B.2.97 energy and mass balance, NGCC with CO_2 capture



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Exhibit B-38. Case B32B.2.97 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In, GJ/hr (MMBtu/hr)				
Natural Gas	7,210 (6,834)	8.6 (8.1)	–	7,219 (6,842)
Air	–	156 (148)	–	156 (148)
Raw Water Makeup	–	95 (90)	–	95 (90)
Auxiliary Power	–	–	266 (252)	266 (252)
TOTAL	**7,210 (6,834)**	**259 (246)**	**266 (252)**	**7,735 (7,332)**
Heat Out, GJ/hr (MMBtu/hr)				
Stack Gas	–	641 (608)	–	641 (608)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Motor Losses and Design Allowances	–	–	54 (51)	54 (51)
Cooling Tower Load[A]	–	3,219 (3,051)	–	3,219 (3,051)
CO_2 Product Stream	–	-82 (-78)	–	-82 (-78)
AGR Effluent	–	48 (46)	–	48 (46)
Dryer Effluent	–	0.1 (0.1)	–	0.1 (0.1)
Deaerator Vent	–	0.3 (0.3)	–	0.3 (0.3)
Ambient Losses[B]	–	*63 (59)*	–	63 (59)
Power	–	–	3,817 (3,618)	3,817 (3,618)
TOTAL	**0.0 (0.0)**	**3,889 (3,686)**	**3,871 (3,669)**	**7,760 (7,355)**
Unaccounted Energy[C]	–	*-24 (-23)*	–	*-24 (-23)*

[A]Includes condenser, capture process, CO_2 compressor, and miscellaneous cooling loads
[B]Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the combustor, reheater, superheater, and transformers
[C]By difference

B.3.2 Case B32B.2.97 – Major Equipment List

Major equipment items for the 2x1 H-Class NGCC plant with 97 percent 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 B.3.3. 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. Values reported in the equipment lists are rounded.

Case B32B.2.97 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	2,361,000 liters (624,000 gal)	2	0
2	Condensate Pumps	Vertical canned	16,780 lpm @ 390 m H_2O (4,430 gpm @ 1,270 ft H_2O)	1	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP Water: 6,850 lpm @ 2,330 m H_2O (1,810 gpm @ 7,650 ft H_2O) IP Water: 1,380 lpm @ 510 m H_2O (360 gpm @ 1,680 ft H_2O)	2	2
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 GJ/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	3,800 lpm @ 110 m H_2O (1,000 gpm @ 350 ft H_2O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,600 lpm @ 80 m H_2O (700 gpm @ 250 ft H_2O)	1	1
11	Municipal Water Pumps	Stainless steel, single suction	6,800 lpm @ 20 m H_2O (1,810 gpm @ 60 ft H_2O)	2	1
12	Ground Water Pumps	Stainless steel, single suction	6,800 lpm @ 20 m H_2O (1,810 gpm @ 60 ft H_2O)	2	1
13	Filtered Water Pumps	Stainless steel, single suction	150 lpm @ 50 m H_2O (40 gpm @ 160 ft H_2O)	2	1
14	Filtered Water Tank	Vertical, cylindrical	145,000 liter (38,000 gal)	1	0
15	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	330 lpm (90 gpm)	1	0
16	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
17	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	88 m^3/min @ 3.8 MPa (3,098 acfm @ 550 psia) 39 cm (16 in) standard wall pipe	16 km (10 mile)	0
18	Gas Metering Station	–	88 m^3/min (3,098 acfm)	1	0

Case B32B.2.97 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Cansolv	Amine-based CO_2 capture technology	2,911,000 kg/hr (6,418,000 lb/hr) 6.9 wt% CO_2 concentration	2	0
2	Cansolv LP Condensate Pump	Centrifugal	1,110 lpm @ 1.0 m H_2O (290 gpm @ 3.4 ft H_2O)	1	1
3	Cansolv HP Condensate Pump	Centrifugal	10.6 lpm @ 4.6 m H_2O (2.8 gpm @ 15.0 ft H_2O)	1	1
4	CO_2 Dryer	Triethylene glycol	Inlet: 103 m^3/min @ 2.8 MPa (3,637 acfm @ 408 psia) Outlet: 2.7 MPa (389 psia) Water Removed: 561 kg/hr (1,237 lb/hr)	1	0

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
5	CO_2 Compressor	Integrally geared, multi-stage centrifugal	5 m^3/min @ 15.3 MPa, 82°C (183 acfm @ 2,217 psia, 180°F)	2	0
6	CO_2 Aftercooler	Shell and tube heat exchanger	Outlet: 15.3 MPa, 30°C (2,215 psia, 86°F) Duty: 56 GJ/hr (53 MMBtu/hr)	2	0

Case B32B.2.97 – Account 6: Combustion Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Combustion Turbine	2023 Advanced H-Class w/ dry low-NOx burner	380 MW	2	0
2	Combustion Turbine Generator	Hydrogen Cooled	450 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	2	0

Case B32B.2.97 – Account 7: HRSG, Ductwork, and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Epoxy-coated CS plate	46 m (150 ft) high x 5.9 m (19 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section	Main Steam: 404,000 kg/hr, 17.2 MPa/585°C (892,000 lb/hr, 2,494 psig/1,085°F) Reheat Steam: 437,000 kg/hr, 3.7 MPa/585°C (964,000 lb/hr, 542 psig/1,085°F)	2	0
3	SCR Reactor	–	2,910,000 kg/hr (6,420,000 lb/hr)	2	0
4	SCR Catalyst	–	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	20 m^3/min @ 108 cm WG (880 scfm @ 42 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	5.2 lpm @ 90 m H_2O (1.4 gpm @ 300 ft H_2O)	2	1
7	Ammonia Storage Tank	Horizontal tank	150,000 liter (40,000 gal)	1	0

Case B32B.2.97 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	317 MW 17.2 MPa/585°C/585°C (2,494 psig/1,085°F/1,085°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	370 MVA @ 0.85 p.f., 18 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Two pass, divided waterbox including vacuum pumps and integrated deaerator	1,230 GJ/hr (1,160 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 B32B.2.97 – Account 9: Cooling Water System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	633,000 lpm @ 30 m (167,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (52°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 3,540 GJ/hr (3,360 MMBtu/hr) heat duty	1	0

Case B32B.2.97 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	18 kV/345 kV, 450 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	18 kV/345 kV, 290 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 16 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	18 kV/4.16 kV, 35 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 12 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	18 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 B32B.2.97 – 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

B.3.3 Case B32B.2.97 – Cost Estimating

The cost estimating methodology was described in Section 2.7. Exhibit B-39 shows a detailed breakdown of the capital costs; Exhibit B-40 shows the owner's costs, TOC, and TASC; Exhibit B-41 shows the initial and annual O&M costs; and Exhibit B-42 shows the COE breakdown.

The estimated TPC of the NGCC with CO_2 capture is $2,086/kW. Process contingency represents 4.7 percent of the TPC and project contingency represents 15.1 percent of the TPC. The FY COE,

including T&S costs of $4.1/MWh,[z] is $87.8/MWh. The LCOE, including T&S costs of $5.5/MWh, is $78.9/MWh.

As discussed in Section 4.1.4, the 2x1 H-Class cases use two parallel CO_2 capture trains due to the high volumetric flow rate of flue gas produced. A high-level estimate of a dual-absorber, single-train CO_2 capture system suggests that the TPC of the 97 percent CO_2 capture system may be reduced by 17 percent, relative to the two-train configuration, which would reduce the LCOE by 4 percent to $75.5/MWh.[aa]

[z] T&S costs for this case are based on a first-year break-even CO_2 price of $11.45/tonne.

[aa] As of the publication of this report, no commercial builds have been demonstrated with this design. The estimated cost impact does not reflect any vendor input.

Exhibit B-39. Case B32B.2.97 total plant cost details

Case:	B32B.2.97 – NGCC H-Class (2x1) with 97 Percent CO_2 Capture						Estimate Type:		Conceptual	
Plant Size (MW, net):	986						Cost Base:		Jan 2023	
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	$3,123	$5,354	$2,296	$0	$10,773	$2,155	$0	$1,939	$14,867	$15
3.2	Water Makeup & Pretreating	$9,262	$926	$4,356	$0	$14,544	$2,909	$0	$3,491	$20,943	$21
3.3	Other Feedwater Subsystems	$1,777	$583	$475	$0	$2,835	$567	$0	$510	$3,912	$4
3.4	Service Water Systems	$2,811	$5,366	$14,419	$0	$22,596	$4,519	$0	$5,423	$32,538	$33
3.5	Other Boiler Plant Systems	$414	$151	$330	$0	$895	$179	$0	$161	$1,235	$1
3.6	NG Pipeline and Start-Up System	$13,910	$598	$372	$0	$14,881	$2,976	$0	$2,679	$20,536	$21
3.7	Waste Water Treatment Equipment	$16,764	$0	$9,008	$0	$25,772	$5,154	$0	$6,185	$37,111	$38
3.9	Miscellaneous Plant Equipment	$20,959	$2,749	$9,338	$0	$33,045	$6,609	$0	$7,931	$47,585	$48
	Subtotal	**$69,020**	**$15,726**	**$40,595**	**$0**	**$125,340**	**$25,068**	**$0**	**$28,319**	**$178,727**	**$181**
	5	**Flue Gas Cleanup**									
5.1	CANSOLV CO_2 Removal System	$223,048	$108,263	$201,666	$0	$532,978	$106,596	$95,936	$147,102	$882,611	$895
5.4	CO_2 Compression & Drying	$47,024	$7,054	$18,463	$0	$72,541	$14,508	$0	$17,410	$104,459	$106
5.5	CO_2 Compressor Aftercooler	$398	$63	$162	$0	$623	$125	$0	$150	$897	$1
5.12	Gas Cleanup Foundations	$0	$630	$644	$0	$1,274	$255	$0	$306	$1,835	$2
	Subtotal	**$270,470**	**$116,011**	**$220,935**	**$0**	**$607,416**	**$121,483**	**$95,936**	**$164,967**	**$989,802**	**$1,003**
	6	**Combustion Turbine & Accessories**									
6.1	Combustion Turbine Generator	$143,815	$0	$9,180	$0	$152,995	$30,599	$0	$27,539	$211,133	$214
6.3	Combustion Turbine Accessories	$3,337	$0	$205	$0	$3,542	$708	$0	$638	$4,889	$5
6.4	Compressed Air Piping	$0	$1,269	$244	$0	$1,512	$302	$0	$272	$2,087	$2
6.5	Combustion Turbine Foundations	$0	$1,459	$1,591	$0	$3,050	$610	$0	$732	$4,392	$4
	Subtotal	**$147,152**	**$2,727**	**$11,220**	**$0**	**$161,100**	**$32,220**	**$0**	**$29,181**	**$222,500**	**$226**
	7	**HRSG, Ductwork, & Stack**									
7.1	HRSG	$84,089	$0	$21,022	$0	$105,111	$21,022	$0	$18,920	$145,054	$147
7.2	HRSG Accessories	$20,167	$0	$3,767	$0	$23,934	$4,787	$0	$4,308	$33,029	$33
7.3	Ductwork	$0	$1,609	$880	$0	$2,488	$498	$0	$448	$3,434	$3
7.4	Stack	$5,562	$0	$1,039	$0	$6,601	$1,320	$0	$1,188	$9,109	$9
7.5	HRSG, Ductwork, & Stack Foundations	$0	$1,118	$886	$0	$2,004	$401	$0	$481	$2,886	$3
7.6	Selective Catalytic Reduction System	$2,472	$1,039	$1,270	$0	$4,781	$956	$0	$861	$6,598	$7
	Subtotal	**$112,291**	**$3,766**	**$28,863**	**$0**	**$144,920**	**$28,984**	**$0**	**$26,206**	**$200,109**	**$203**
	8	**Steam Turbine & Accessories**									
8.1	Steam Turbine Generator & Accessories	$57,011	$0	$8,349	$0	$65,360	$13,072	$0	$11,765	$90,197	$91
8.2	Steam Turbine Plant Auxiliaries	$187	$0	$431	$0	$619	$124	$0	$111	$854	$1
8.3	Condenser & Auxiliaries	$9,133	$0	$4,382	$0	$13,514	$2,703	$0	$2,433	$18,650	$19
8.4	Steam Piping	$17,698	$0	$6,082	$0	$23,780	$4,756	$0	$4,280	$32,817	$33
8.5	Turbine Generator Foundations	$0	$1,922	$2,682	$0	$4,604	$921	$0	$1,105	$6,629	$7
	Subtotal	**$84,029**	**$1,922**	**$21,925**	**$0**	**$107,877**	**$21,575**	**$0**	**$19,694**	**$149,146**	**$151**

Case:	B32B.2.97 – NGCC H-Class (2x1) with 97 Percent CO_2 Capture								Estimate Type:	Conceptual
Plant Size (MW, net):	986								Cost Base:	Jan 2023
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
	9					Cooling Water System					
9.1	Cooling Towers	$19,478	$0	$5,210	$0	$24,688	$4,938	$0	$4,444	$34,069	$35
9.2	Circulating Water Pumps	$2,496	$0	$133	$0	$2,629	$526	$0	$473	$3,628	$4
9.3	Circulating Water System Auxiliaries	$16,328	$0	$1,950	$0	$18,278	$3,656	$0	$3,290	$25,223	$26
9.4	Circulating Water Piping	$0	$5,136	$3,860	$0	$8,996	$1,799	$0	$1,619	$12,415	$13
9.5	Make-up Water System	$609	$0	$649	$0	$1,257	$251	$0	$226	$1,735	$2
9.6	Component Cooling Water System	$757	$0	$482	$0	$1,240	$248	$0	$223	$1,711	$2
9.7	Circulating Water System Foundations	$0	$1,189	$1,693	$0	$2,881	$576	$0	$692	$4,149	$4
	Subtotal	**$39,668**	**$6,325**	**$13,977**	**$0**	**$59,970**	**$11,994**	**$0**	**$10,967**	**$82,931**	**$84**
	11					Accessory Electric Plant					
11.1	Generator Equipment	$4,365	$0	$2,721	$0	$7,086	$1,417	$0	$1,276	$9,779	$10
11.2	Station Service Equipment	$11,923	$0	$845	$0	$12,768	$2,554	$0	$2,298	$17,620	$18
11.3	Switchgear & Motor Control	$19,584	$0	$2,441	$0	$22,024	$4,405	$0	$3,964	$30,394	$31
11.4	Conduit & Cable Tray	$0	$4,114	$9,797	$0	$13,911	$2,782	$0	$2,504	$19,197	$19
11.5	Wire & Cable	$0	$6,142	$9,072	$0	$15,213	$3,043	$0	$2,738	$20,994	$21
11.6	Protective Equipment	$831	$0	$2,075	$0	$2,906	$581	$0	$523	$4,011	$4
11.7	Standby Equipment	$1,220	$0	$809	$0	$2,029	$406	$0	$365	$2,800	$3
11.8	Main Power Transformers	$9,361	$0	$193	$0	$9,554	$1,911	$0	$1,720	$13,185	$13
11.9	Electrical Foundations	$0	$158	$360	$0	$519	$104	$0	$124	$747	$1
	Subtotal	**$47,285**	**$10,414**	**$28,312**	**$0**	**$86,011**	**$17,202**	**$0**	**$15,513**	**$118,726**	**$120**
	12					Instrumentation & Control					
12.1	NGCC Control Equipment	$374	$0	$236	$0	$609	$122	$0	$110	$841	$1
12.2	Combustion Turbine Control Equipment	$615	$0	$388	$0	$1,003	$201	$0	$181	$1,384	$1
12.3	Steam Turbine Control Equipment	$599	$0	$377	$0	$976	$195	$0	$176	$1,347	$1
12.4	Other Major Component Control Equipment	$1,005	$0	$633	$0	$1,638	$328	$82	$307	$2,354	$2
12.5	Signal Processing Equipment	$838	$0	$25	$0	$863	$173	$0	$155	$1,191	$1
12.6	Control Boards, Panels, & Racks	$222	$0	$134	$0	$356	$71	$18	$67	$511	$1
12.7	Distributed Control System Equipment	$12,310	$0	$371	$0	$12,681	$2,536	$634	$2,378	$18,228	$18
12.8	Instrument Wiring & Tubing	$1,217	$974	$3,219	$0	$5,411	$1,082	$271	$1,015	$7,778	$8
12.9	Other I&C Equipment	$843	$0	$1,614	$0	$2,457	$491	$123	$461	$3,532	$4
	Subtotal	**$18,022**	**$974**	**$6,997**	**$0**	**$25,993**	**$5,199**	**$1,127**	**$4,848**	**$37,166**	**$38**
	13					Improvements to Site					
13.1	Site Preparation	$0	$1,043	$18,699	$0	$19,742	$3,948	$0	$4,738	$28,428	$29
13.2	Site Improvements	$0	$3,355	$3,742	$0	$7,097	$1,419	$0	$1,703	$10,220	$10
13.3	Site Facilities	$3,219	$0	$2,852	$0	$6,071	$1,214	$0	$1,457	$8,742	$9
	Subtotal	**$3,219**	**$4,398**	**$25,293**	**$0**	**$32,910**	**$6,582**	**$0**	**$7,898**	**$47,390**	**$48**
	14					Buildings & Structures					
14.1	Combustion Turbine Area	$0	$707	$274	$0	$981	$196	$0	$177	$1,354	$1
14.3	Steam Turbine Building	$0	$6,042	$5,908	$0	$11,949	$2,390	$0	$2,151	$16,490	$17
14.4	Administration Building	$0	$664	$331	$0	$995	$199	$0	$179	$1,374	$1
14.5	Circulation Water Pumphouse	$0	$172	$63	$0	$235	$47	$0	$42	$324	$0

Case:	B32B.2.97 – NGCC H-Class (2x1) with 97 Percent CO_2 Capture					Estimate Type:	Conceptual			
Plant Size (MW, net):	986					Cost Base:	Jan 2023			
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
14.6	Water Treatment Buildings	$0	$847	$568	$0	$1,415	$283	$0	$255	$1,953	$2
14.7	Machine Shop	$0	$995	$467	$0	$1,462	$292	$0	$263	$2,017	$2
14.8	Warehouse	$0	$773	$343	$0	$1,116	$223	$0	$201	$1,540	$2
14.9	Other Buildings & Structures	$0	$565	$302	$0	$867	$173	$0	$156	$1,197	$1
14.10	Waste Treating Building & Structures	$0	$1,454	$1,906	$0	$3,360	$672	$0	$605	$4,637	$5
	Subtotal	**$0**	**$12,220**	**$10,161**	**$0**	**$22,381**	**$4,476**	**$0**	**$4,029**	**$30,886**	**$31**
	Total	**$791,156**	**$174,482**	**$408,278**	**$0**	**$1,373,916**	**$274,783**	**$97,063**	**$311,622**	**$2,057,384**	**$2,086**

Exhibit B-40. Case B32B.2.97 owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$11,803	$12
1 Month Maintenance Materials	$2,299	$2
1 Month Non-fuel Consumables	$1,208	$1
1 Month Waste Disposal	$164	$0
25% of 1 Months Fuel Cost at 100% CF	$6,968	$7
2% of TPC	$41,148	$42
Total	**$63,590**	**$64**
Inventory Capital		
60-day supply of consumables at 100% CF	$1,658	$2
0.5% of TPC (spare parts)	$10,287	$10
Total	**$11,945**	**$12**
Other Costs		
Initial Cost for Catalyst and Chemicals	$2,669	$3
Land	$600	$1
Other Owner's Costs	$308,608	$313
Financing Costs	$55,549	$56
Total Overnight Costs (TOC)	**$2,500,344**	**$2,535**
TASC Multiplier (IOU, 33 year)	1.183	
Total As-Spent Cost (TASC)	**$2,957,775**	**$2,999**

Exhibit B-41. Case B32B.2.97 initial and annual operating and maintenance costs

Case:	B32B.2.97 –NGCC H–Class (2x1) with 97 Percent CO_2 Capture				Cost Base:	Jan 2023
Plant Size (MW, net):	986	Heat Rate-net (Btu/kWh):		6,928	Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		45.04	**$/hour**	Skilled Operator:		1.0
Operating Labor Burden:		30.00	**% of base**	Operator:		3.3
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		1.0
				Total:		**6.3**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$3,248,262	$3.293
Maintenance Labor:					$15,636,118	$15.852
Administrative & Support Labor:					$4,721,095	$4.786
Property Taxes and Insurance:					$41,147,680	$41.716
Total:					**$64,753,155**	**$65.648**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$23,454,177	$3.193
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (/1000 gallons):	0	4,785	$2.30	$0	$3,414,697	$0.465
Makeup and Waste Water Treatment Chemicals (ton):	0	14.3	$660.00	$0	$2,918,894	$0.397
Ammonia (19 wt%, ton):	0	13.7	$280.00	$0	$1,194,354	$0.163
SCR Catalyst (ft^3):	7,625	4.2	$350.00	$2,668,610	$453,664	$0.062
CO_2 Capture System Chemicals[A]:	Proprietary				$4,154,112	$0.566
Triethylene Glycol (gal):	w/equip.	70.7	$8.50	$0	$186,407	$0.025
Subtotal:				**$2,668,610**	**$12,322,127**	**$1.678**
Waste Disposal						
SCR Catalyst (ft^3):	0	4.2	$5.70	$0	$7,388	$0.001
Triethylene Glycol (gal):	0	3,584	$1.30	$0	$1,445,658	$0.197
Thermal Reclaimer Unit Waste (ton):	0	2.8	$250.00	$0	$218,856	$0.030
Subtotal:				**$0**	**$1,671,903**	**$0.228**
Variable Operating Costs Total:				**$2,668,610**	**$37,448,207**	**$5.099**
Fuel Cost						
Natural Gas (MMBtu):	0	164,013	$5.59	$0	$284,306,142	$38.710
Total:				**$0**	**$284,306,142**	**$38.710**

[A]CO_2 Capture System Chemicals includes sodium hydroxide and CANSOLV solvent

Exhibit B-42. Case B32B.2.97 COE breakdown

	FY COE		LCOE	
Component	**Value, $/MWh**	**Percentage**	**Value, $/MWh**	**Percentage**
Capital	31.0	35%	31.0	39%
Fixed	8.8	10%	11.8	15%
Variable	5.1	6%	6.8	9%
Fuel	38.7	44%	23.7	30%
Total (Excluding T&S)	**83.7**	**N/A**	**73.3**	**N/A**
CO_2 T&S	4.1	5%	5.5	7%
Total (Including T&S)	**87.8**	**N/A**	**78.9**	**N/A**

APPENDIX C: SUMMARY OF CAPTURE RATES ABOVE 95 PERCENT

Commercial-scale demonstration of solvent-based post-combustion carbon dioxide (CO_2) capture systems at power generation facilities (specifically pulverized coal [PC] plants) has shown the ability to capture 90 percent of the CO_2 in the flue gas stream (Greg Kennedy, n.d.) (Giannaris, et al., 2021). Moreover, field-testing of post-combustion CO_2 capture technology as well as vendor and industry feedback on projects currently in the planning stages (including front-end engineering design projects sponsored by the Department of Energy [DOE]) indicates that capture rates as high as 95 percent are feasible for both coal- and natural gas-fueled electricity generating units (NCCC, 2020b) (NCCC, 2020a) (OBrien, et al., 2022) (International CCS Knowledge Center, November). Given the breadth of publicly-available information supporting the capability for post-combustion capture systems to remove greater than 90 percent of the CO_2 in the treated stream, cases for 90 percent and 95 percent capture on natural gas combined cycle (NGCC) and PC are presented in the main body of this report.

It should be emphasized that technology suppliers (as reflected in vendor-supplied information provided to DOE for this study that included cost and performance estimates for >95 percent carbon capture and storage [CCS] [97 percent for NGCC and 99 percent for PC] study cases) as well as subject matter experts acknowledge and support that solvent-based post-combustion CO_2 capture technologies are capable of achieving CO_2 removal rates beyond 95 percent on low-purity streams representative of fossil-fueled combustion. Although technoeconomic analyses of deep decarbonization (≥ 99 percent) of combustion flue gas have been published by others, (Du, Gao, Rochelle, & Bhown, 2021) (IEAGHG, 2019) the relatively limited experience with design and operation of capture systems that can routinely, reliably, and economically achieve very high removal rates requires further study. Technoeconomic analyses of the higher capture rates (97 percent NGCC and 99 percent PC) are included in the appendices to this report. The performance and environmental profile summaries for PC and NGCC cases with CO_2 capture rates greater than 95 percent are shown in Exhibit C-1; the primary conclusions that can be drawn are as follows:

- The emissions of mercury (Hg), hydrochloric acid (HCl), particulate matter (PM), nitrogen oxide (NOx), and sulfur dioxide (SO_2) are all at or below the applicable federal regulatory limits currently in effect for PC and NGCC technologies (natural gas contains no Hg or chloride).
- For the PC cases, adding a CO_2 capture system results in a 9 percentage point (24 percent) reduction in efficiency, compared to the non-capture PC cases. For the NGCC cases, the addition of a CO_2 capture system results in a 7 percentage point (12 percent) reduction in efficiency, compared to non-capture NGCC cases.

The cost results for PC and NGCC cases with CO_2 capture rates greater than 95 percent are shown in Exhibit C-2; the primary cost conclusions that can be drawn are as follows:

- The addition of CO_2 capture increases the total overnight costs (TOC) by 71–76 percent for PC cases and 115–137 for NGCC cases.

- The addition of CO_2 capture increases the levelized cost of electricity (LCOE), including transport and storage (T&S), by 76–80 percent for PC cases and 82–88 percent for NGCC cases.
    - As discussed in Section 4.1.4, the 2x1 H-Class case B32B.2.97 uses two parallel CO_2 capture trains due to the high volumetric flow rate of flue gas produced. A high-level estimate of a dual-absorber, single-train CO_2 capture system suggests that the total plant cost (TPC) of the CO_2 capture system may be reduced by 17 percent, relative to the two-train configuration, which would reduce the LCOE by 4 percent.[bb]
- For PC cases, CO_2 T&S costs add $14/MWh to the LCOE, which accounts for 9 percent of the total LCOE. For NGCC cases, CO_2 T&S costs add $6/MWh to the LCOE, which accounts for 7–8 percent of the total LCOE.

[bb] As of the publication of this report, no commercial builds have been demonstrated with this design. The estimated cost impact does not reflect any vendor input.

Exhibit C-1. Performance summary and environmental profile for PC and NGCC cases with CO_2 capture rates greater than 95 percent

Case Name	PC				NGCC					
	SubC PC		SC PC		SOA 2023 F-Class		SOA 2023 1x1 H-Class[A]		SOA 2023 2x1 H-Class[A]	
	B11A	B11B.99	B12A	B12B.99	B31A	B31B.97	B32A.1	B32B.1.97	B32A.2	B32B.2.97
CO_2 Capture Rate (%)	0	99	0	99	0	97	0	97	0	97
Capacity Factor (%)	85	85	85	85	85	85	85	85	85	85
Gross Power Output (MWe)	688	780	686	774	755	702	660	615	1,137	1,060
Auxiliary Power Requirement (MWe)	38	130	36	123	14	52	11	43	19	74
Net Power Output (MWe)	650	650	650	650	741	650	649	572	1,118	986
Coal Flow Rate (lb/hr)	493,115	651,832	473,055	619,732	N/A	N/A	N/A	N/A	N/A	N/A
Natural Gas Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	210,413	210,413	175,100	175,100	303,962	303,962
HHV Thermal Input (kWt)	1,685,945	2,228,591	1,617,359	2,118,843	1,386,417	1,386,417	1,153,739	1,153,739	2,002,815	2,002,815
Net Plant HHV Efficiency (%)	38.6	29.2	40.2	30.7	53.4	46.9	56.2	49.6	55.8	49.2
Net Plant HHV Heat Rate (Btu/kWh)	8,849	11,691	8,490	11,116	6,385	7,277	6,068	6,884	6,113	6,928
Raw Water Withdrawal (gpm/MWnet)	10.0	16.1	9.3	15.0	4.1	7.3	3.6	6.6	3.7	6.7
Process Water Discharge (gpm/MWnet)	2.1	4.2	1.9	3.9	1.0	2.6	0.9	2.4	0.9	2.4
Raw Water Consumption (gpm/MWnet)	8.0	11.9	7.4	11.1	3.0	4.8	2.7	4.2	2.8	4.3
CO_2 Emissions (lb/MMBtu)	202	2	202	2	119	4	119	4	119	4
CO_2 Emissions (lb/MWh-gross)	1,693	20	1,628	19	743	24	707	23	713	23
CO_2 Emissions (lb/MWh-net)	1,790	24	1,718	23	757	26	719	25	725	25
SO_2 Emissions (lb/MMBtu)[B]	0.081	0.000	0.081	0.000	0.001	0.000	0.001	0.000	0.001	0.000
SO_2 Emissions (lb/MWh-gross)	0.675	0.000	0.649	0.000	0.006	0.000	0.006	0.000	0.006	0.000
NOx Emissions (lb/MMBtu)	0.084	0.072	0.087	0.075	0.003	0.003	0.003	0.003	0.003	0.003
NOx Emissions (lb/MWh-gross)	0.700	0.700	0.700	0.700	0.021	0.021	0.019	0.018	0.020	0.019
PM Emissions (lb/MMBtu)	0.011	0.009	0.011	0.010	0.003	0.000	0.002	0.000	0.003	0.000
PM Emissions (lb/MWh-gross)	0.090	0.090	0.090	0.090	0.017	0.000	0.014	0.000	0.016	0.000
Hg Emissions (lb/TBtu)	0.359	0.308	0.373	0.321	0.000	0.000	0.000	0.000	0.000	0.000
Hg Emissions (lb/MWh-gross)[C]	$3.00x10^{-6}$	$3.00x10^{-6}$	$3.00x10^{-6}$	$3.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$	$0.00x10^{-6}$

[A]The combustion turbine used in the 1x1 H-Class plant is larger and more advanced than that of the 2x1 H-Class plant
[B]Trace amounts of sulfur emissions may exist in the flue gas stream to the stack in capture cases
[C]The mercury capture units used in the PC cases were designed to attain the emissions target of $3.00x10^{-6}$ lb/MWh-gross

Exhibit C-2. Cost summary for PC and NGCC cases with CO_2 capture rates greater than 95 percent

Case Name[A]	PC				NGCC					
	SubC PC		SC PC		SOA 2023 F-Class		SOA 2023 1x1 H-Class[B]		SOA 2023 2x1 H-Class[B]	
	B11A	B11B.99	B12A	B12B.99	B31A	B31B.97	B32A.1	B32B.1.97	B32A.2	B32B.2.97
Total Plant Cost (2023$/kW)	2,471	4,363	2,584	4,433	1,051	2,271	993	2,199	876	2,086
Bare Erected Cost	1,822	3,090	1,906	3,146	756	1,531	714	1,480	630	1,393
Home Office Expenses	319	541	334	551	151	306	143	296	126	279
Project Contingency	331	608	345	616	144	341	136	331	119	316
Process Contingency	0	124	0	120	0	93	0	92	0	98
Total Overnight Cost (2023$/MM)	1,985	3,489	2,072	3,541	950	1,794	786	1,529	1,196	2,500
Total Overnight Cost (2023$/kW)	3,054	5,365	3,188	5,444	1,283	2,760	1,212	2,673	1,069	2,535
Owner's Costs	583	1,002	604	1,011	232	490	219	474	194	449
Total As-Spent Cost (2023$/kW)	3,704	6,506	3,866	6,602	1,517	3,265	1,433	3,162	1,265	2,999
FY COE ($/MWh) (excluding T&S)[C]	86.0	139.1	86.9	138.0	58.5	89.8	55.4	86.0	53.1	83.7
Capital Costs	38.3	67.3	40.0	68.3	15.7	33.8	14.8	32.7	13.1	31.0
Fixed Costs	11.1	18.6	11.6	18.8	4.7	9.8	4.5	9.5	3.9	8.8
Variable Costs	9.8	17.9	9.7	17.4	2.3	5.5	2.2	5.3	2.0	5.1
Fuel Costs	26.7	35.2	25.6	33.5	35.7	40.7	33.9	38.5	34.2	38.7
FY COE ($/MWh) (including T&S)[C]	86.0	149.6	86.9	148.3	58.5	94.5	55.4	90.8	53.1	87.8
CO_2 T&S Costs	N/A	10.6	N/A	10.3	N/A	4.7	N/A	4.9	N/A	4.1
LCOE ($/MWh) (excluding T&S)[C]	89.4	146.4	90.5	145.5	47.0	79.2	44.5	76.0	41.9	73.3
Capital Costs	38.3	67.3	40.0	68.3	15.7	33.8	14.8	32.7	13.1	31.0
Fixed Costs	14.9	24.8	15.5	25.1	6.3	13.1	6.0	12.7	5.1	11.8
Variable Costs	13.1	23.9	12.9	23.2	3.1	7.4	2.9	7.0	2.7	6.8
Fuel Costs	23.0	30.4	22.1	28.9	21.9	24.9	20.8	23.6	20.9	23.7
LCOE ($/MWh) (including T&S)[C]	89.4	160.5	90.5	159.2	47.0	85.4	44.5	82.5	41.9	78.9
CO_2 T&S Costs	N/A	14.1	N/A	13.7	N/A	6.2	N/A	6.5	N/A	5.5
Cost of CO_2 Captured (ex. T&S), $/tonne[D]	N/A	52.7	N/A	54.5	N/A	84.8	N/A	87.9	N/A	87.1
Cost of CO_2 Avoided (incl. T&S), $/tonne[D]	N/A	91.3	N/A	89.5	N/A	115.8	N/A	120.7	N/A	116.6

[A]Financing structures are presented in the QGESS report, "Cost Estimation Methodology for NETL Techno-economic Assessments" (NETL, 2025b)
[B]The combustion turbine used in the 1x1 H-Class plant is larger and more advanced than that of the 2x1 H-Class plant
[C]Varying incentives, such as tax credits, could impact the economics of the system
[D]Both the cost of CO_2 captured and cost of CO_2 avoided were calculated based on the non-capture SC PC Case B12A for all coal cases, and the analogous non-capture NGCC Cases (i.e., B31B cases use B31A as a reference, B32B.1 cases use B32A.1, and B32B.2 cases use B32A.2)

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