NATIONAL ENERGY TECHNOLOGY LABORATORY

Assessment of Power Plants That Meet Proposed Greenhouse Gas Emission Performance Standards

November 5, 2009

DOE/NETL-401/110509

U.S. DEPARTMENT OF ENERGY

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ASSESSMENT OF POWER PLANTS THAT MEET PROPOSED GREENHOUSE GAS EMISSION PERFORMANCE STANDARDS

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FINAL REPORT

November 5, 2009

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LIST OF ACRONYMS AND ABBREVIATIONS

AACE	Association for the Advancement of Cost Engineering
AEO	Annual Energy Outlook
AGR	Acid gas removal
ANSI	American National Standards Institute
ASU	Air separation unit
BACT	Best available control technology
BART	Best available retrofit technology
BEC	Bare erected cost
BFD	Block flow diagram
Btu	British thermal unit
Btu/h	British thermal unit per hour
Btu/kWh	British thermal unit per kilowatt hour
Btu/lb	British thermal unit per pound
Btu/scf	British thermal unit per standard cubic foot
CAAA	Clean Air Act Amendments of 1990
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CCF	Capital Charge Factor
CDR	Carbon Dioxide Recovery
CF	Capacity factor
CFM	Cubic feet per minute
CFR	Code of Federal Regulations
cm	Centimeter
CO_2	Carbon dioxide
COE	Cost of electricity
COR	Contracting Officer's Representative
COS	Carbonyl sulfide
CRT	Cathode ray tube
CS	Carbon steel
CT	Combustion turbine
CTG	Combustion Turbine-Generator
CWT	Cold water temperature
dB	Decibel
DCS	Distributed control system
DI	De-ionized
Dia.	Diameter
DLN	Dry low NOx
DOE	Department of Energy
EAF	Equivalent availability factor
EIA	Energy Information Administration
EPA	Environmental Protection Agency

EPC	Engineer/Procure/Construct
EPRI	Electric Power Research Institute
EPCM	Engineering/Procurement/Construction Management
FERC	Federal Energy Regulatory Commission
FOAK	First of a kind
FRP	Fiberglass-reinforced plastic
ft	Foot, Feet
ft, w.g.	Feet of water gauge
GADS	Generating Availability Data System
gal	Gallon
GDP	Gross domestic product
gpm	Gallons per minute
GT	Gas turbine
h	Hour
H_2	Hydrogen
Hg	Mercury
HDPE	High density polyethylene
HHV	Higher heating value
hp	Horsepower
HP	High pressure
HRSG	Heat recovery steam generator
HVAC	Heating, ventilating, and air conditioning
HWT	Hot water temperature
Hz	Hertz
ICR	Information Collection Request
IEEE	Institute of Electrical and Electronics Engineers
IGCC	Integrated gasification combined cycle
IGVs	Inlet guide vanes
In. H_2O	Inches water
In. Hga	Inches mercury (absolute pressure)
In. W.C.	Inches water column
IOU	Investor-owned utility
IP	Intermediate pressure
IPM	Integrated Planning Model
IPP	Independent power producer
ISO	International Standards Organization
kg/GJ	Kilogram per gigajoule
kg/h	Kilogram per hour
kJ	Kilojoules
kJ/h	Kilojoules per hour
kJ/kg	Kilojoules per kilogram
KO	Knockout
kPa	Kilopascal absolute

kV	Kilovolt
kW	Kilowatt
kWe	Kilowatts electric
kWh	Kilowatt-hour
LAER	Lowest Achievable Emission Rate
lb	Pound
lb/h	Pounds per hour
lb/ft^2	Pounds per square foot
lb/MMBtu	Pounds per million British thermal units
lb/MWh	Pounds per megawatt hour
lb/TBtu	Pounds per trillion British thermal units
LCOE	Levelized cost of electricity
LF_{Fn}	Levelization factor for category n fixed operating cost
LF_{Vn}	Levelization factor for category n variable operating cost
LHV	Lower heating value
LNB	Low NOx burner
LP	Low pressure
lpm	Liters per minute
m	Meters
m/min	Meters per minute
m^3/min	Cubic meter per minute
MAF	Moisture and Ash Free
MCR	Maximum continuous rate
MDEA	Methyldiethanolamine
MHz	Megahertz
MJ/Nm^3	Megajoule per normal cubic meter
MMBtu	Million British thermal units (also shown as 10^6 Btu)
MMBtu/h	Million British thermal units (also shown as 10^6 Btu) per hour
MMkJ	Million kilojoules (also shown as 10^6 kJ)
MMkJ/h	Million kilojoules (also shown as 10^6 kJ) per hour
MNQC	Multi Nozzle Quiet Combustor
MPa	Megapascals
MVA	Mega volt-amps
MWe	Megawatts electric
MWh	Megawatt-hour
MWt	Megawatts thermal
N/A	Not applicable
NAAQS	National Ambient Air Quality Standards
NEMA	National Electrical Manufacturers Association
NERC	North American Electric Reliability Council
NETL	National Energy Technology Laboratory
NFPA	National Fire Protection Association
Nm^3	Normal cubic meter

NOx	Oxides of nitrogen
NSPS	New Source Performance Standards
NSR	New Source Review
O&M	Operation and maintenance
OC_{Fn}	Category n fixed operating cost for the initial year of operation
OC_{Vnq}	Category n variable operating cost for the initial year of operation
OD	Outside diameter
OP/VWO	Over pressure/valve wide open
OSHA	Occupational Safety and Health Administration
PF	Power Factor
PM	Particulate matter
PM_{10}	Particulate matter measuring 10 µm or less
POTW	Publicly Owned Treatment Works
ppm	Parts per million
ppmv	Parts per million volume
ppmvd	Parts per million volume, dry
PRB	Powder River Basin coal region
PSA	Pressure Swing Adsorption
PSD	Prevention of Significant Deterioration
psia	Pounds per square inch absolute
psid	Pounds per square inch differential
psig	Pounds per square inch gage
PTFE	Teflon (Polytetrafluoroethylene)
Qty	Quantity
RDS	Research and Development Solutions, LLC
RH	Reheater
scfh	Standard cubic feet per hour
scfm	Standard cubic feet per minute
Sch.	Schedule
scmh	Standard cubic meter per hour
SCOT	Shell Claus Off-gas Treating
SG	Specific gravity
SGC	Synthesis gas cooler
SGS	Sour gas shift
SO_2	Sulfur dioxide
SOx	Oxides of sulfur
SRU	Sulfur recovery unit
SS	Stainless steel
STG	Steam turbine generator
TCR	Total capital requirement
TEWAC	Totally Enclosed Water-to-Air Cooled
TGTU	Tail gas treating unit
Tonne	Metric Ton (1000 kg)

TPC	Total plant cost
TPD	Tons per day
TPH	Tons per hour
TPI	Total plant investment
TS&M	Transport, storage and monitoring
V-L	Vapor Liquid portion of stream (excluding solids)
vol%	Volume percent
WB	Wet bulb
wg	Water gauge
wt%	Weight percent
$/MMBtu	Dollars per million British thermal units
$/MMkJ	Dollars per million kilojoule

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EXECUTIVE SUMMARY

Revision 2 Updates

The technologies modeled in this study, namely integrated gasification combined cycle, subcritical pulverized coal and supercritical pulverized coal, are the subject of other ongoing systems analysis studies at the Department of Energy's National Energy Technology Laboratory. Vendor discussions that occurred as part of the other studies led to improved technology information that was incorporated into the Aspen models for this study. The updated models led to revised performance estimates, which were then used to update the cost estimates. The reference costs used for this study were also updated through efforts on other studies, and the most recent costs have been incorporated. In addition, owner's costs were added to the Total Plant Cost previously reported, and the capital component of levelized cost of electricity now includes owner's costs. The updated results are presented in the current revision (revision 2) of this report. Details of the modeling updates and cost methodology changes are included in the body of the report and are identified by italicized font.

Greenhouse gas (GHG) emissions continue to receive increased scrutiny because of their perceived relation to global warming. Numerous bills have been introduced in both the United States Senate and House of Representatives that would limit GHG emissions. The bills vary primarily in the economy sectors regulated, the extent of GHG reductions and the compliance year, but all represent reductions from the "business-as-usual" scenario. In June, 2009 the House of Representatives passed the American Clean Energy and Security Act of 2009 (H.R. 2454) which would limit GHG emissions starting as soon as 2012. The Senate has not yet acted on the House bill or any companion bill, but deliberations are ongoing. Adding to the legislative momentum for carbon regulation, in September, 2009 the Environmental Protection Agency proposed a rule that would limit future regulation of GHG emissions under the Clean Air Act to industrial facilities that emit 25,000 tons or more of carbon dioxide annually. The proposed rule would impact facilities such as power plants, refineries, and factories, which produce nearly 70 percent of domestic GHGs.

In addition to proposed Federal regulations, various states have proposed or enacted legislation to reduce GHG emissions. The most imminent regulations were enacted by the state of California and would limit GHG emissions from in-state energy producers or out-of-state producers supplying electricity to California to 1,100 lb CO_2/net-MWh [1]. A sampling of the legislation is provided in Section 1.1.

The objective of this report is to present the baseline cost and performance of greenfield integrated gasification combined cycle (IGCC) plants, greenfield supercritical (SC) pulverized coal (PC) plants, and retrofit subcritical PC plants that limit carbon dioxide (CO_2) emissions to the California standard of 1,100 lb CO_2/net-MWh and that achieve 90 percent CO_2 capture. For each plant type, three cases were modeled:

- Baseline performance with no CO_2 capture
- CO_2 emissions reduced to 1,100 lb CO_2/net-MWh

- CO_2 emissions reduced by 90 percent

The subcritical PC retrofit case was based on a generic plant site, but is representative of a western plant that could supply electricity to California and hence have to meet the 1,100 lb CO_2/net-MWh standard. The elevation used was 6,700 ft, which is the average elevation of Wyoming. For consistency between cases, this same elevation was used for all technologies. The fuel used in all nine cases was representative of a coal from the Powder River Basin (PRB) and has the same composition as the subbituminous coal used in an as yet unpublished NETL study entitled "Cost and Performance Baseline for Low-Rank Coal Fossil Energy Plants." The nine cases are summarized in Exhibit 1-1.

The cost and performance of the various fossil fuel-based technologies will most likely determine which combination of technologies will be utilized to meet the demands of the power market. Selection of new generation technologies will depend on many factors, including:

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

Nine power plant configurations were analyzed as listed in Exhibit 1-1. The list includes three IGCC cases utilizing Shell gasifiers each with and without CO_2 capture; six PC cases, three greenfield supercritical and three existing subcritical plants, each with and without CO_2 capture.

The methodology used information provided by the technology vendors (IGCC) and conventional models and existing plant information (PC) to perform steady-state simulations of the technology using the Aspen Plus (Aspen) modeling program. The resulting mass and energy balance results from the Aspen model were used to size major pieces of equipment. These equipment sizes formed the basis for cost estimating. Costs were scaled from estimates provided previously on similar technologies using PRB coal. The original estimates were developed through a combination of vendor quotes and scaled estimates from previous design/build projects. Performance and process limits were based upon published reports, information obtained from vendors and users of the technology, and cost and performance data from design/build utility projects. Baseline fuel costs for this analysis were determined using data from the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2007. The first year (2015) cost used is \$0.57/GJ (\$0.61/MMBtu) for coal (Montana Rosebud Powder River Basin) on a higher heating value (HHV) basis and in 2007 U.S. dollars.

All plant configurations were evaluated based on installation at a greenfield site, with the exception of the existing subcritical PC plant. Typically, greenfield plants are state-of-the-art plants with higher efficiencies than the existing average power plant population. Consequently, these plants would be expected to be near the top of the dispatch list, and the study capacity factor is chosen to reflect the maximum availability demonstrated for the specific plant type, i.e. 80 percent for IGCC and 85 percent for PC. A capacity factor of 85 percent was also used for the subcritical PC case to be consistent with the SC PC greenfield plant.

PERFORMANCE

Plant Output

The performance results are presented in Exhibit ES-1 and Exhibit ES-2. The net power output varies between technologies because the combustion turbines in the IGCC cases are manufactured in discrete sizes, but the boilers and steam turbines in the greenfield PC cases are readily available in a wide range of capacities. The net output in the subcritical retrofit PC plant is limited by the capacity of the existing boiler and steam turbine. The result is that all of the greenfield supercritical PC cases have a net output of 550 MW, the subcritical retrofit cases have net outputs ranging from 532 to 359 MW, and the IGCC cases have net outputs ranging from 502 to 401 MW.

The range in IGCC net output is caused by the increased elevation, the much higher auxiliary load imposed in the CO_2 capture cases primarily due to CO_2 compression, and the need for extraction steam in the water-gas shift reactions, which reduces steam turbine output. Higher auxiliary load and extraction steam requirements can be accommodated in the greenfield supercritical PC cases (larger boiler and steam turbine) but not in the IGCC or subcritical retrofit PC cases. For the IGCC cases or subcritical retrofit PC cases, it is impossible to maintain a constant net output from the steam cycle given the fixed input (combustion turbine for IGCC and existing boiler capacity for subcritical retrofit cases). In addition, the combustion turbine output increases with increasing capture levels because of the higher flue gas moisture content due to the higher hydrogen content of the syngas, while the mass flow remains relatively the same.

Energy Efficiency

The definition of Energy Penalty used in this study to evaluate the impact of energy losses due to the addition of CO_2 capture controls is the difference in net power plant efficiency expressed in absolute percentage points as shown in the following equation.

$$\text{Energy Penalty} = (\text{Net Power Plant Efficiency})_{\textit{no capture}} - (\text{Net Power Plant Efficiency})_{\textit{with capture}}$$

The net plant efficiency (HHV basis) for all 9 cases is shown in Exhibit ES-3.

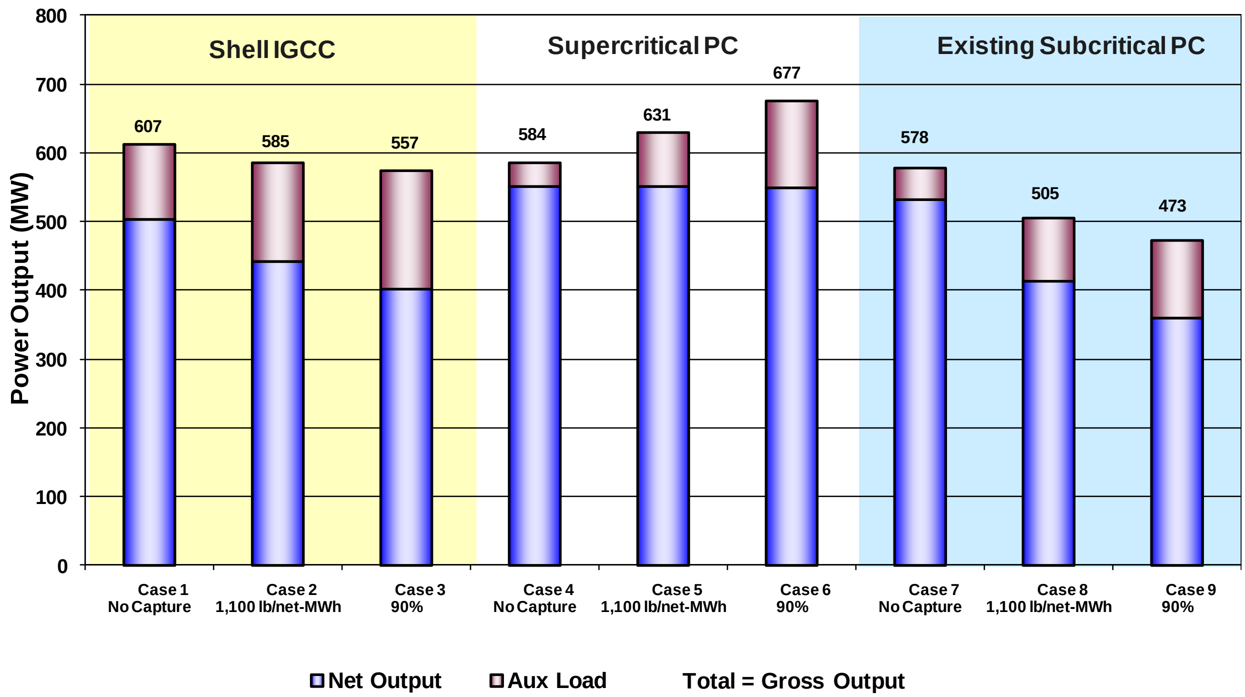
Exhibit ES-1 Performance Summary

		Shell IGCC			Supercritical PC			Existing Subcritical PC		
		Case 1 No Capture	Case 2 1,100 lb/MWh$_{net}$	Case 3 90%	Case 4 No Capture	Case 5 1,100 lb/MWh$_{net}$	Case 6 90%	Case 7 No Capture	Case 8 1,100 lb/MWh$_{net}$	Case 9 90%
Output										
Syngas Fuel Flow	(lbm/h)	709,921	425,936	216,381						
Combustion Turbine Generator	(kW)	372,500	377,000	380,600						
Main Steam Flow	(lbm/h)	1,290,732	919,549	942,596	3,640,595	4,366,633	5,136,290	3,924,635	3,924,075	3,925,353
Steam Turbine Generator	(kW)	240,400	208,000	192,900	585,300	629,800	675,500	577,800	476,800	432,000
Let Down Turbine Generator	(kW)					0	0		28,100	40,600
Total Gross Power	(kW)	612,900	585,000	573,500	585,300	629,800	675,500	577,800	504,900	472,600
Auxiliary Power Summary										
Base Plant Power	(kW)	28,360	28,760	30,040	32,750	40,920	49,880	43,010	48,590	51,120
Air Separation Unit	(kW)	81,290	90,830	98,160						
Flue Gas Cleanup	(kW)	880	9,520	18,200	2,540	14,510	26,550	2,760	15,570	21,310
CO_2 Compression	(kW)		13,130	25,960		24,340	49,170		28,200	40,780
Total Auxiliary Power	(kW)	110,530	142,240	172,360	35,290	79,770	125,600	45,770	92,360	113,210
Net Plant Output	(kW)	502,370	442,760	401,140	550,010	550,030	549,900	532,030	412,540	359,390
Boiler Efficiency (HHV)[1]	(fraction)				0.86	0.86	0.86	0.83	0.83	0.83
Coal Feed Rate	(lbm/h)	478,697	495,356	517,357	568,411	691,955	814,119	650,360	650,355	650,360
Coal Heat Input (HHV)	(10^6 Btu/h)	410	424	443	487	593	697	557	557	557
CO_2 Capture Efficiency	%	0	46	90	0	53	90	0	62	90
Net Plant Heat Rate (HHV)	(Btu/kWh)	8,160	9,581	11,045	8,851	10,774	12,679	10,469	13,501	15,498
Net Plant Thermal Effiecincy (HHV)	(%)	41.8	35.6	30.9	38.6	31.7	26.9	32.6	25.3	22.0
Energy Penalty[2]	(% Net Points)	-	6.2	10.9	-	6.9	11.7	-	7.3	10.6

[1] Boiler Heat Output/ ($C_{oal-HHV}$)

[2] Percentage points decrease in efficiency due to CO_2 capture

Exhibit ES-2 Power Output Summary

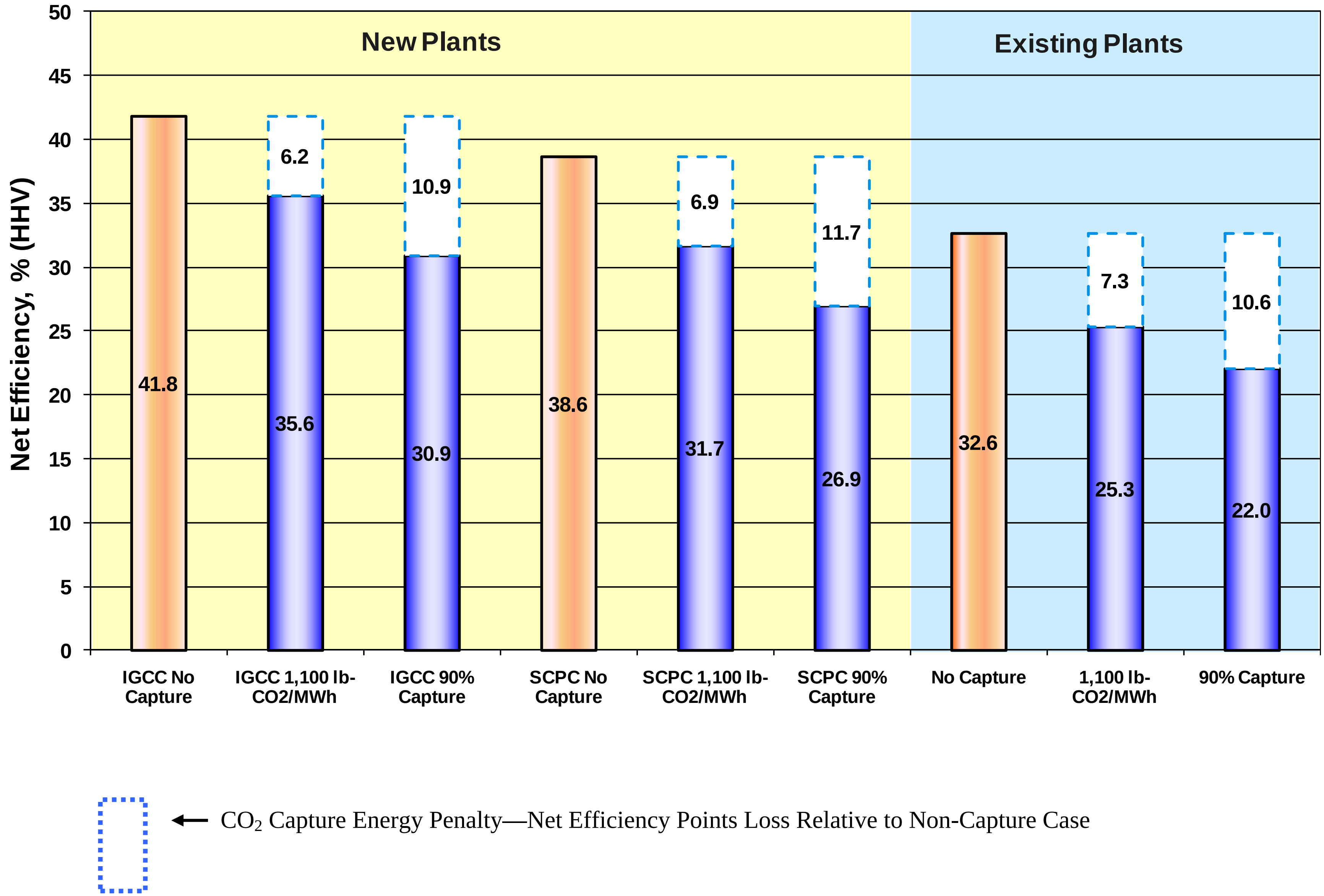


<u>Performance Highlights</u>:

- The IGCC no-capture case has the <u>highest</u> net efficiency of the technologies modeled in this study with an efficiency of 41.8 percent. The energy penalty for the 1,100 lb/net-MWh CO_2 emission level is smallest for IGCC and highest for the retrofit subcritical PC case.
- The new SCPC no-capture case has a lower net efficiency compared to the new IGCC no-capture case, and the CO_2 Capture Energy Penalty for the SCPC cases is <u>higher</u> at 6.9 and 11.7 net efficiency points lost relative to the SCPC no-capture case for the 1,100 lb CO_2/net-MWh case and 90 percent capture case, respectively, *resulting in lower net power plant efficiencies compared to the IGCC power plants equipped with CO_2 capture.*
- The estimated efficiency of the existing subcritical PC using Montana Rosebud PRB coal is 32.6 percent. There is a 7.3 percent penalty to achieve the 1,100 lb/net-MWh CO_2 emission limit and 10.6 percent penalty for the 90 percent capture case. The retrofit cases have the lowest efficiency for each of the three cases, but the smallest energy penalty for the 90 percent capture case.

Exhibit ES-3 Net Plant Efficiency (HHV Basis)

Subbituminous PRB Coal at 6,700 feet elevation



Water Use

Three water values are presented for each case in Exhibit ES-4 and Exhibit ES-5: raw water withdrawal, process water discharge and raw water consumption. Each of these values is normalized by net plant output for Exhibit ES-4.

Exhibit ES-5 shows absolute water withdrawal and consumption. Water demand represents the total amount of water required for a particular process. Some water is recovered within the process, primarily as coal moisture from the drying process and syngas condensate (IGCC cases) or flue gas condensate (PC cases), and that water is re-used as internal recycle. Raw water withdrawal is the difference between water demand and internal recycle. Some water is returned to the source, namely sour water stripper blowdown (IGCC cases) and cooling tower blowdown (IGCC and PC cases). The difference between raw water withdrawal and water returned to the source (process discharge) is raw water consumption, which represents the net impact on the water source.

The largest consumer of water in the plant is the makeup to the cooling system. The greenfield plants (IGCC and supercritical PC) use parallel wet (50 percent)/dry (50 percent) cooling. The existing subcritical PC uses only an evaporative cooling tower. The difference in cooling systems has a significant impact on water consumption.

Water Usage Highlights:

- In all cases the primary water consumer is cooling tower makeup, which ranges from 60 to 94 percent of the total raw water consumption.
- For the non-capture cases, IGCC has the least amount of raw water withdrawal and consumption, followed by the new SCPC and existing subcritical PC. The relative total raw water consumption is 4.0: 1.6: 1.0 normalized by net power output (gpm/MWnet) (subcritical PC: SCPC: IGCC). The relative results are as expected due to the cooling systems employed and the higher steam turbine output in the PC cases. These factors combined result in higher condenser duties, higher cooling water requirements and ultimately higher cooling water makeup.
- Among the CO_2 capture cases, raw water consumption increases (relative to non-capture cases) much more dramatically for the PC than for IGCC cases because of the large cooling water demand of the CO_2 scrubbing process which results in much greater cooling water makeup requirements. Comparing the 1,100 lb CO_2/net-MWh emission limit cases, the relative raw water consumption is 3.6 : 1.7 : 1.0 normalized by net power output (subcritical PC: SCPC: IGCC)—meaning that the SCPC plant has a net consumption that is 1.7 times greater than the IGCC plant at the same capture rate. The relative raw water consumption comparison for the 90 percent capture cases follows the same trend.
- CO_2 capture increases the absolute raw water consumption of the subcritical PC retrofit cases by the least amount of the technologies evaluated: a maximum of 30 percent at the 90 percent capture level. The primary reason for the small increase is the reduction in condenser duty, which mostly offsets the increase in duty due to the Econamine process. The consequence is a significant reduction in net plant power output. With the addition of CO_2 capture, supercritical PC raw water consumption increases by 208 percent and IGCC by 106 percent. The substantial increase in the SC PC case is driven by the high Econamine water requirement and the increase in size of the steam turbine to maintain a constant net output. Hence the steam turbine condenser duty remains high and the Econamine cooling load is simply additive.

Exhibit ES-4 Normalized Water Withdrawal and Consumption

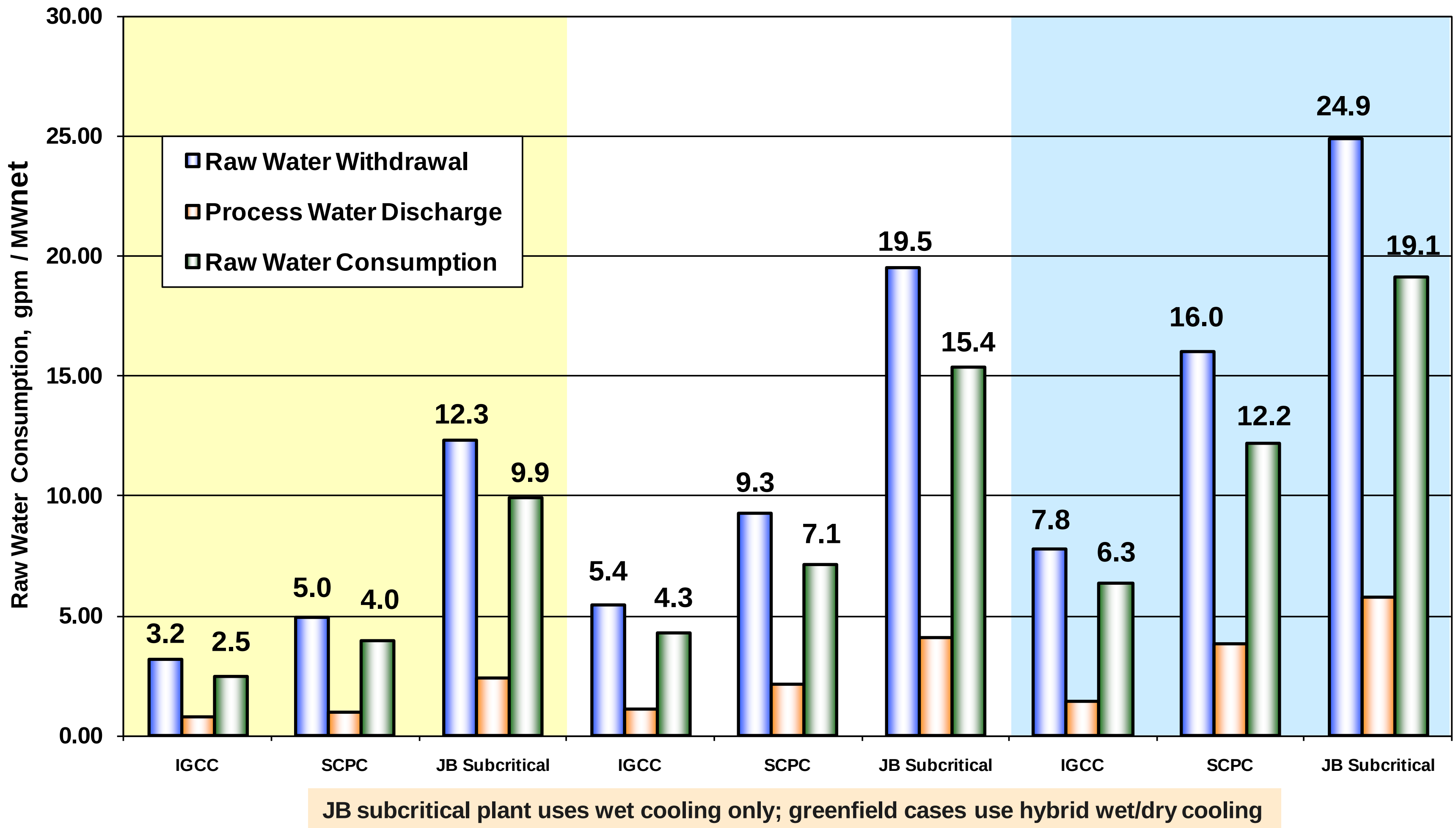
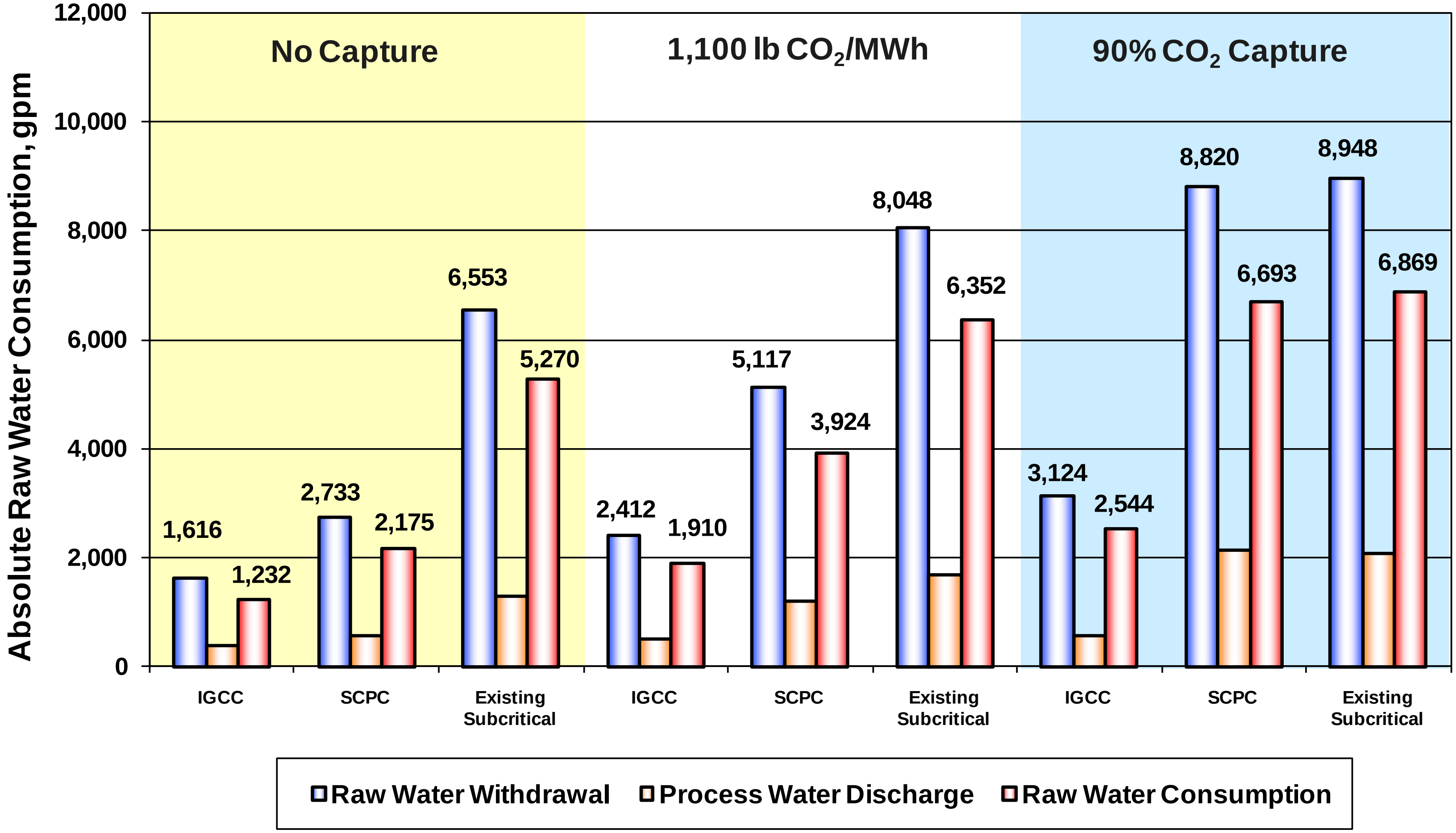


Exhibit ES-5 Absolute Water Demand and Usage



COST RESULTS

Total Plant Cost

The total plant cost (TPC) for each technology was determined through a combination of vendor quotes and scaled estimates from previous design/build projects. For the existing subcritical retrofit PC plant, the cost was determined through the use of a Best Available Retrofit Technology (BART) analysis and scaled estimates. TPC includes all equipment, materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). *Owner's costs, including preproduction costs, inventory capital, initial cost for catalyst and chemicals, land, financing costs and other owner's costs were added to TPC to generate total overnight cost (TOC). Property taxes and insurance were included in the fixed operating costs as an additional owner's cost. TOC was used to calculate the capital component of the levelized cost of electricity (LCOE). A factor was applied to TOC to convert to total as spent cost (TASC), which includes interest and escalation during the construction period. The inclusion of owner's costs increases the TPC by about 18 percent for each of the cases modeled.*

The cost estimates carry an accuracy of ±30 percent, consistent with the screening study level of design engineering applied to the various cases in this study. The value of the study lies not in the absolute accuracy of the individual case results but in the fact that all cases were evaluated under the same set of technical and economic assumptions. This consistency of approach allows meaningful comparisons among the cases evaluated.

Project contingencies were added to the Engineering/Procurement/Construction Management (EPCM) capital accounts to cover project uncertainty and the cost of any additional equipment that would result from a detailed design. The contingencies represent costs that are expected to occur. Each bare erected cost (BEC) account was evaluated against the level of estimate detail and field experience to determine project contingency. Process contingency was added to cost account items that were deemed to be first-of-a-kind or posed significant risk due to lack of operating experience. The cost accounts that received a process contingency include:

- Gasifiers and Syngas Coolers – 15 percent on all IGCC cases – next-generation commercial offering and integration with the power island.
- Two Stage Selexol – 20 percent on all IGCC capture cases – lack of operating experience at commercial scale in IGCC service.
- Mercury Removal – 5 percent on all IGCC cases – minimal commercial scale experience in IGCC applications.
- CO_2 Removal System – 20 percent on all PC capture cases - post-combustion process unproven at commercial scale for power plant applications.
- Combustion Turbine Generator – 5 percent on all IGCC non-capture cases – syngas firing and ASU integration; 10 percent on all IGCC capture cases – high hydrogen firing.
- Instrumentation and Controls – 5 percent on all IGCC accounts and 5 percent on the PC capture cases – integration issues.

The TPC, TOC and TASC for the nine power plant configurations are shown in Exhibit ES-6 in June 2007 dollars. The normalized TOC for each technology is shown in Exhibit ES-7.

Exhibit ES-6 Plant Costs

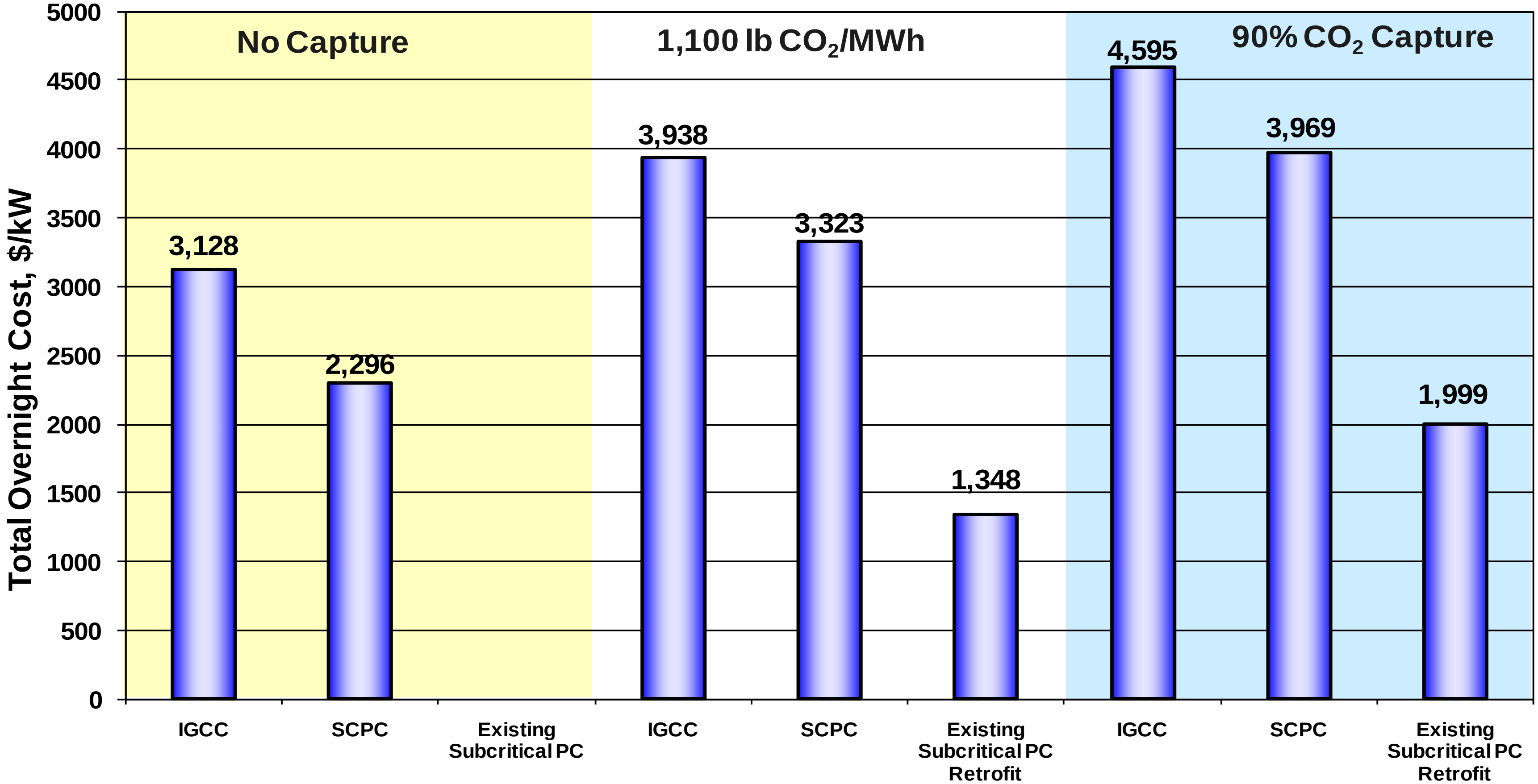
Study Case	Net Plant Output	Total Plant Cost (TPC)		Total Over Night Cost (TOC)		Total As-Spent Cost (TASC)[1]	
	kW	1000$	$/kW_{net}$	1000$	$/kW_{net}$	1000$	$/kW_{net}$
Case 1, IGCC w/o CO_2 Capture	502,370	1,290,415	2,569	1,571,409	3,128	1,791,407	3,566
Case 2, IGCC w/ 1,100 lb/MWh_{net} CO_2 Capture	442,760	1,432,055	3,234	1,743,413	3,938	1,987,490	4,489
Case 3, IGCC w/ 90% CO_2 Capture	401,140	1,513,013	3,772	1,843,305	4,595	2,101,368	5,238
Case 4, SCPC w/o CO_2 Capture	550,010	1,036,345	1,884	1,262,625	2,296	1,357,322	2,468
Case 5, SCPC w/ 1,100 lb/MWh_{net} CO_2 Capture	550,030	1,501,061	2,729	1,827,611	3,323	1,970,165	3,582
Case 6, SCPC w/ 90% CO_2 Capture	549,900	1,792,301	3,259	2,182,729	3,969	2,352,982	4,279
Case 7, Existing Subcritical PC w/o CO_2 Capture	532,030	0	0	0	0	0	0
Case 8, Existing Subcritical PC Retrofit w/ 1,100 lb/MWh_{net} CO_2 Capture	412,540	458,271	1,111	555,992	1,348	599,360	1,453
Case 9, Existing Subcritical PC Retrofit w/ 90% CO_2 Capture	359,390	591,983	1,647	718,587	1,999	774,637	2,155

[1] Construction duration for the greenfield cases is 5 years and for the retrofit cases is 3 years.

<u>Capital Cost Highlights</u>:

- Retrofitting the existing subcritical PC plant with CO_2 capture designed to meet a CO_2 emissions limit of 1,100 lb/net-MWh has a TOC of \$1,348/kW$_e$ and one designed for 90% CO_2 capture has a TOC of \$1,999/kW$_e$. The retrofit cost for an existing plant is 59 percent lower than a greenfield application at an emissions limit of 1,100 lb CO_2/net-MWh and 50 percent less at 90 percent CO_2 capture primarily because of the assumption that the subcritical PC plant is paid for and the cost of capital pertains only to the carbon capture and sequestration portion of the plant, while in the greenfield cases the cost of capital pertains to the total plant cost.
- If New Source Review (NSR) is triggered, the existing subcritical PC retrofit plant could require SCR. The retrofit with SCR designed to meet a CO_2 emissions limit of 1,100 lb/net-MWh and 90% CO_2 capture will have a TOC of \$1,717/ kW$_e$ and \$2,430/ kW$_e$, respectively. Even with SCR, the TOC of the retrofit cases is less than greenfield plants with CO_2 capture for equivalent emissions reduction primarily because of the assumption that the original subcritical PC plant capital cost has been paid.
- Comparing the greenfield IGCC and PC cases <u>without</u> CO_2 capture, the supercritical PC has the lowest TOC at \$2,296/kW$_e$ followed by IGCC with a cost of \$3,128/kW$_e$. The IGCC cost is 36 percent greater than the supercritical PC cost.
- Comparing the greenfield IGCC and PC cases <u>with</u> CO_2 capture, the supercritical PC has the lowest TOC at \$3,323/kW$_e$ at an emissions level of 1,100 lb CO_2/net-MWh and \$3,969/kW$_e$ at a capture level of 90 percent. The corresponding IGCC cases have a TOC of \$3,938/kW$_e$ and \$4,595/kW$_e$.
- A new IGCC power plant built with CO_2 capture designed to meet a CO_2 emissions limit of 1,100 lb/net-MWh will add \$810/kW$_e$ in incremental capital cost. The same IGCC power plant designed for 90% CO_2 capture will have an incremental cost of \$1,467/kW$_e$.
- A new SCPC power plant built with CO_2 capture designed to meet a CO_2 emissions limit of 1,100 lb/net-MWh will add \$1,027/kW$_e$ in incremental capital cost and one designed for 90% CO_2 capture will have an incremental cost of \$1,673/kW$_e$.

Exhibit ES-7 Total Overnight Cost, 2007 Dollars



Note: Compared to the Greenfield IGCC and SCPC power plants, the capital cost for the subcritical PC no capture case is zero (assumes the original plant costs are paid). The capital costs for the new IGCC and PC power plants are total (base plant + capture); whereas the capital cost for the subcritical PC retrofit is for the CO_2 capture process only.

Levelized Cost of Electricity (LCOE)

The current dollar, 30-year LCOE was calculated for each case using the economic parameters shown in Exhibit ES-8. The cases were divided into three categories, all undertaken at an investor owned utility: high risk projects with a five year construction duration (all IGCC cases and greenfield SC PC capture cases); low risk projects with a five year construction duration (greenfield SC PC non-capture case); and high risk projects with a three year duration (retrofit PC capture cases). High risk projects are those in which commercial scale operating experience is limited. The IGCC cases (with and without CO_2 capture) and the PC cases with CO_2 capture were considered to be high risk. The non-capture PC case was considered to be low risk.

Exhibit ES-8 Economic Parameters Used to Calculate LCOE

	High Risk (5 year construction period)	Low Risk (5 year construction period)	High Risk (3 year construction period)
Capital Charge Factor	0.1773	0.1691	0.1567
General Levelization Factor	1.443	1.4299	1.4101

The LCOE results are shown in Exhibit ES-9 with the capital cost fixed operating cost, variable operating cost, fuel cost and TS&M cost shown separately. When carbon capture is implemented, the net power output of the subcritical PC plant decreases to 413 MW and 359 MW for the 1,100 lb/net-MWh and 90 percent capture cases, respectively. The current electricity cost for the subcritical PC plant was estimated to be $19/MWh using the Energy Velocity Database. An estimated cost for the plant property taxes and insurance was added to the fixed O&M costs for a total current cost of electricity of $26.29/MWh. The current cost was levelized using the same factor applied to the retrofit cases yielding an LCOE of $33.78/MWh.

LCOE Cost Highlights:

- By virtue of having the intitial plant capital investment paid off, the subcritical PC retrofit case has the lowest LCOE of all cases.
- Comparing the greenfield IGCC and PC cases without CO_2 capture, the LCOE of the PC case is 32 percent lower than the IGCC case.
- Comparing the greenfield IGCC and PC cases with CO_2 capture, the supercritical PC has the lowest LCOE at $120.01/MWh at a capture level to meet a CO_2 emissions level of 1,100 lb/net-MWh and $143.89/MWh at a capture level of 90 percent. The LCOEs of the SCPC cases are 20 percent and 18 percent lower than the corresponding IGCC cases. For reference, the Energy Information Administration reports the average residential retail price of electricity in 2007 was $106.5/MWh.

Exhibit ES-9 Levelized Cost of Electricity for Power Plants

Study Case	Levelized Cost of Electricity ($/MWh)						Incremental COE[a] (¢/kWh)	Increase COE[a] (%)[a]
	Capital	Fixed O&M	Variable O&M	Fuel	TS&M	Total		
Case 1, IGCC w/o CO_2 Capture	79.13	20.17	11.41	7.13	0.00	117.84	-	-
Case 2, IGCC w/ 1,100 lb/MWh_{net} CO_2 Capture	99.62	24.57	13.33	8.37	3.49	149.38	31.54	26.8%
Case 3, IGCC w/ 90% CO_2 Capture	116.25	28.39	15.85	9.65	4.72	174.86	57.02	48.4%
Case 4, SCPC w/o CO_2 Capture	52.13	12.86	7.21	7.66	0.00	79.86	-	-
Case 5, SCPC w/ 1,100 lb/MWh_{net} CO_2 Capture	79.12	17.96	10.38	9.41	3.13	120.01	40.15	50.3%
Case 6, SCPC w/ 90% CO_2 Capture	94.52	20.84	13.09	11.07	4.37	143.89	64.02	80.2%
Case 7, Existing Subcritical PC w/o CO_2 Capture	0	13.16	1.48	19.14	0	33.78	-	-
Case 8, Existing Subcritical PC Retrofit w/ 1,100 lb/MWh_{net} CO_2 Capture	28.36	22.44	5.53	24.69	3.79	84.81	51.03	151%
Case 9, Existing Subcritical PC Retrofit w/ 90% CO_2 Capture	42.08	28.09	7.89	28.34	5.24	111.64	77.86	230%

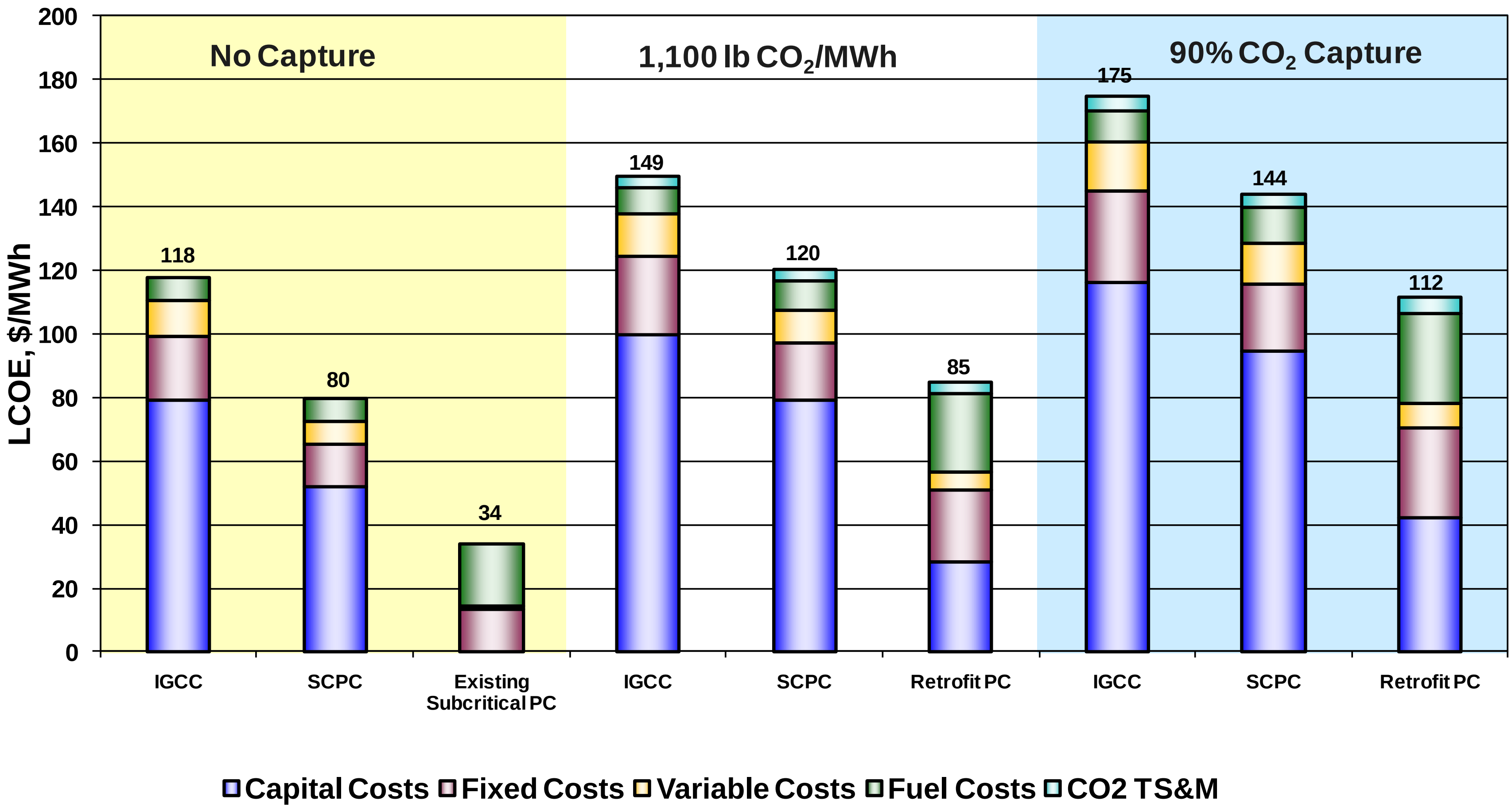
[a]Relative to non-capture case for each respective technology

The TS&M in the costs assume the CO_2 is transported 50 miles via pipeline to a geological sequestration field, injected into a saline formation at a depth of 4,055 ft and monitored for 30 years during plant life and 50 years following for a total of 80 years. These values are shown in Exhibit ES-10. The Total Levelized Costs of Electricity including TS&M are shown in Exhibit ES-11.

Exhibit ES-10 Levelized Cost of Electricity for CO_2 Transport, Storage, and Monitoring

Study Case	30 yr Levelized Costs ($/MWh)			
	CO_2 Transport	CO_2 Storage	CO_2 Monitoring	TS&M Total
Case 2, IGCC w/ 1,100 lb/MWh_{net} CO_2 Capture	2.62	0.42	0.40	3.45
Case 3, IGCC w/ 90% CO_2 Capture	3.34	0.47	0.91	4.72
Case 5, SCPC w/ 1,100 lb/MWh_{net} CO_2 Capture	2.29	0.32	0.52	3.13
Case 6, SCPC w/ 90% CO_2 Capture	2.90	0.41	1.05	4.37
Case 8, Existing Subcritical PC Retrofit w/ 1,100 lb/MWh_{net} CO_2 Capture	2.72	0.39	0.68	3.79
Case 9, Existing Subcritical PC Retrofit w/ 90% CO_2 Capture	3.53	0.57	1.14	5.24

Exhibit ES-11 LCOE By Cost Component



CO_2 Mitigation Cost

The cost of CO_2 capture was calculated in two ways, the cost of CO_2 removed and the cost of CO_2 avoided, as illustrated in Equations 1 and 2, respectively.

$$Removal\ Cost = \frac{\{LCOE_{with\ removal} - LCOE_{w/o\ removal}\}\ \$/MWh}{\{CO_2\ \ removed\}\ tons/MWh} \qquad \text{(Equation-1)}$$

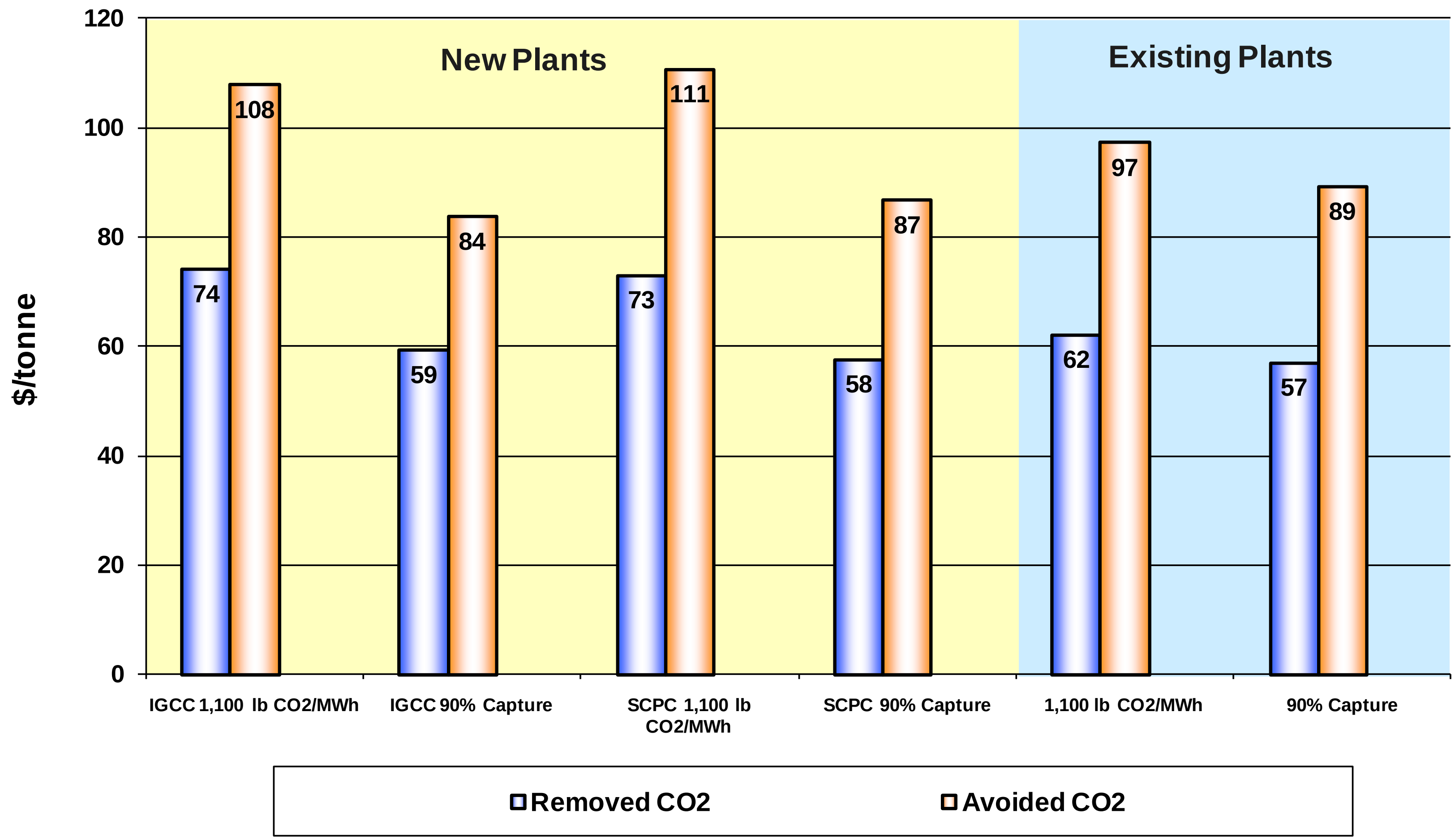
$$Avoided\ Cost = \frac{\{LCOE_{with\ removal} - LCOE_{w/o\ removal}\}\ \$/MWh}{\{Emissions_{w/o\ removal} - Emissions_{with\ removal}\}\ tons/MWh} \qquad \text{(Equation-2)}$$

The LCOE with CO_2 removal includes the costs of capture and compression as well as TS&M costs. The resulting removal and avoided costs are shown in Exhibit ES-12 for each of the six capture technologies modeled.

CO_2 Mitigation Cost Highlights:

- The total cost of CO_2 avoided meeting a 1,100 lb/net-MWh CO_2 emissions limit was estimated to be $108/tonne ($98/ton) for a new IGCC, $111/tonne ($100/ton) for a new SCPC, and $97/tonne ($88/ton) to retrofit the existing subcritical PC plant. At the 90 percent carbon capture level, the avoided cost was estimated to be $84/tonne ($76/ton) for a new IGCC, $87/tonne ($79/ton) for a new SCPC, and $89/tonne ($81/ton) to retrofit the subcritical PC plant.
- The CO_2 avoided costs are lowest for the existing subcritical PC plant at an emission level of 1,100 lb CO_2/net-MWh primarily because there is no capital cost associated with the power plant itself (CO_2 capture only) and because of the shorter construction duration (3 years versus 5 years for the greenfield plants). At 90 percent capture the reduction in net output offsets the capital cost savings and the existing PC plant has a slightly higher CO_2 avoided cost compared to greenfield SCPC and IGCC.
- The cost of CO_2 removed is 16 percent lower for the subcritical PC retrofit case compared to the greenfield PC and IGCC cases at a CO_2 emission limit of 1,100 lb/net-MWh.
- The cost of CO_2 removed is fairly constant for all technologies at the 90 percent capture level, ranging from $57-$59/tonne ($52-$54/ton).
- The normalized cost of CO_2 removed and avoided is lower for 90 percent capture cases compared to 1,100 lb/net-MWh cases mainly because of economies of scale. The size of CO_2 capture equipment increases in proportion to the amount of CO_2 captured, but the costs increase less than proportionately.

Exhibit ES-12 CO_2 Mitigation Cost



ENVIRONMENTAL PERFORMANCE

The environmental targets for each power plant scenario are summarized in Exhibit ES-13 and emission rates of SO_2, NOx, PM, Hg and CO_2 are shown graphically in Exhibit ES-14 through Exhibit ES-16. Targets were chosen on the basis of the environmental regulations that would most likely apply to plants built in 2015.

Exhibit ES-13 Study Environmental Targets

Pollutant	IGCC	Supercritical PC	Existing Subcritical Plant	Subcritical Retrofit Plant
SO_2	0.0128 lb/MMBtu	0.085 lb/MMBtu	0.256 lb/MMBtu	0.054 lb/MMBtu
NOx	15 ppmv (dry) @ 15% O_2	0.070 lb/MMBtu	0.45 lb/MMBtu	0.24 lb/MMBtu
PM (Filterable)	0.0071 lb/MMBtu	0.013 lb/MMBtu	0.027 lb/MMBtu	0.027 lb/MMBtu
Hg	>90% capture	0.70 lb/TBtu	6.00 lb/TBtu	6.00 lb/TBtu
CO_2	Three CO_2 emission levels were evaluated in this analysis for each case. Baseline—no CO_2 controls California Standard—1,100 lbCO_2/MWh-net Maximum Study Capture—90% CO_2 Capture			

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

- IGCC cases use the EPRI targets established in their CoalFleet for Tomorrow work as documented in the CoalFleet User Design Basis Specification for Coal-Based Integrated Gasification Combined Cycle (IGCC) Power Plants: Version 4.
- Supercritical PC cases are based on best available control technology.
- The Existing Subcritical Plant environmental targets are based on typical subcritical PC emissions and the Subcritical Retrofit Plant is based on upgrades required to accommodate CO_2 capture.

Exhibit ES-14 Criteria Pollutant Emissions

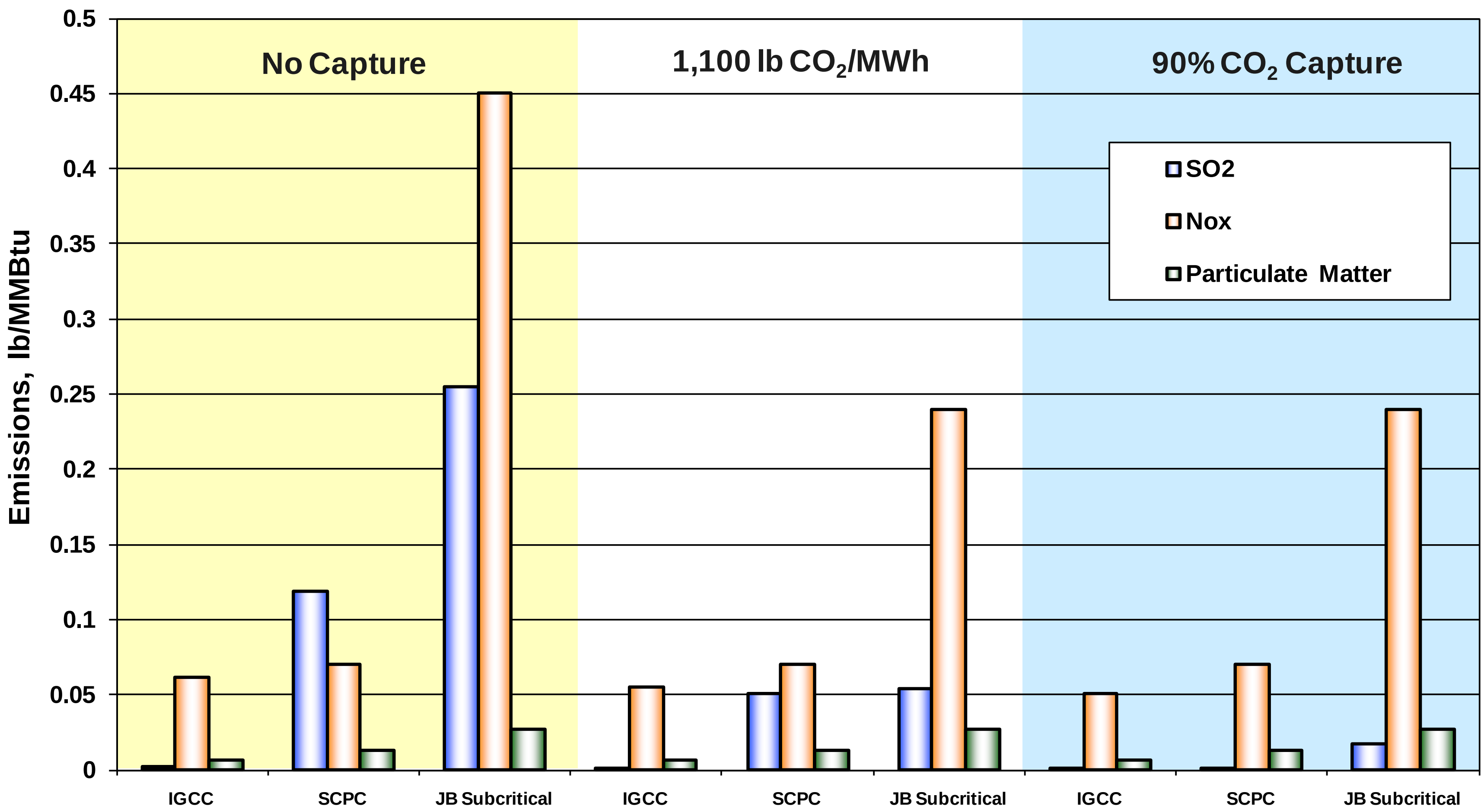


Exhibit ES-15 Mercury Emissions Rates

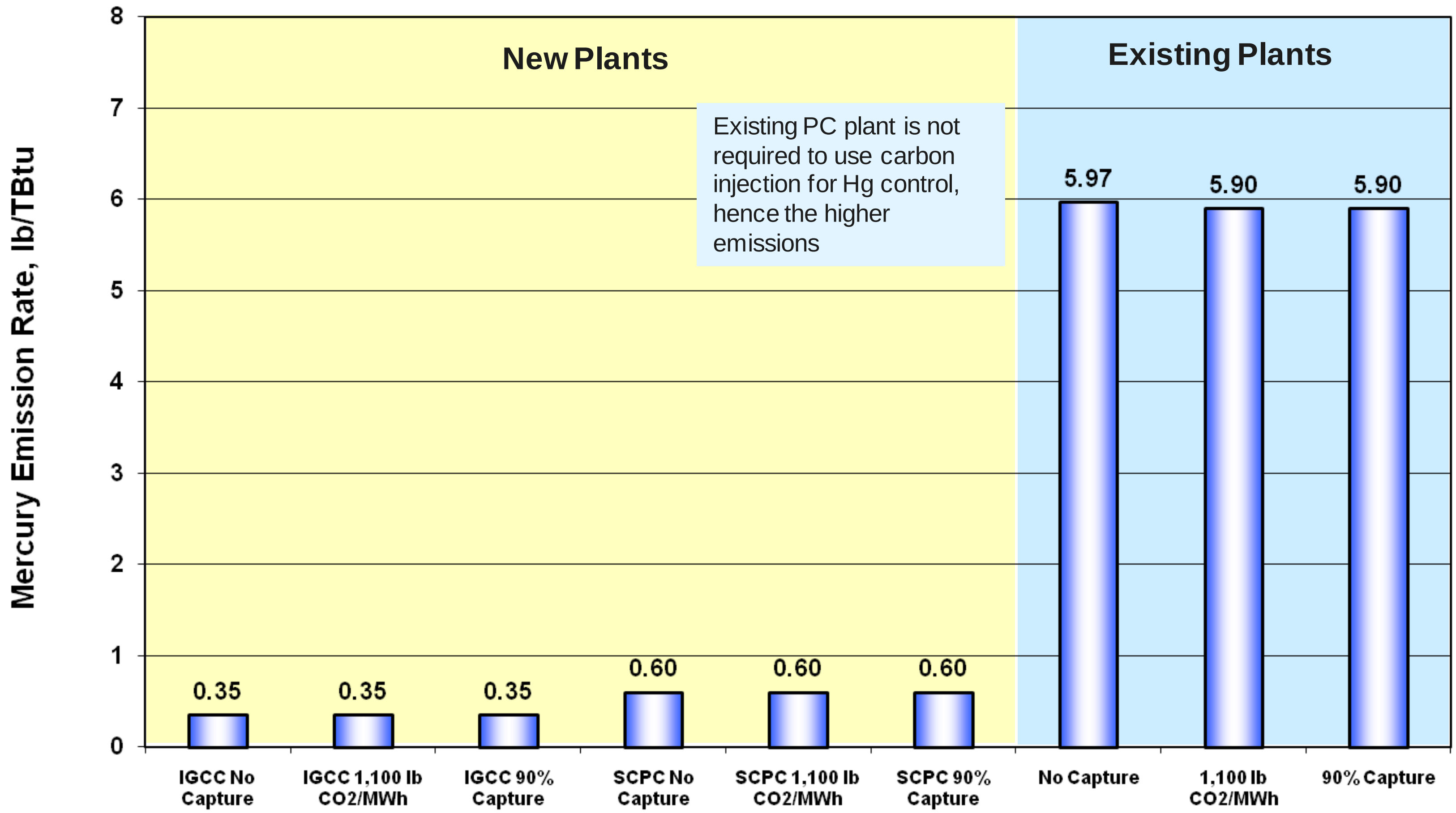
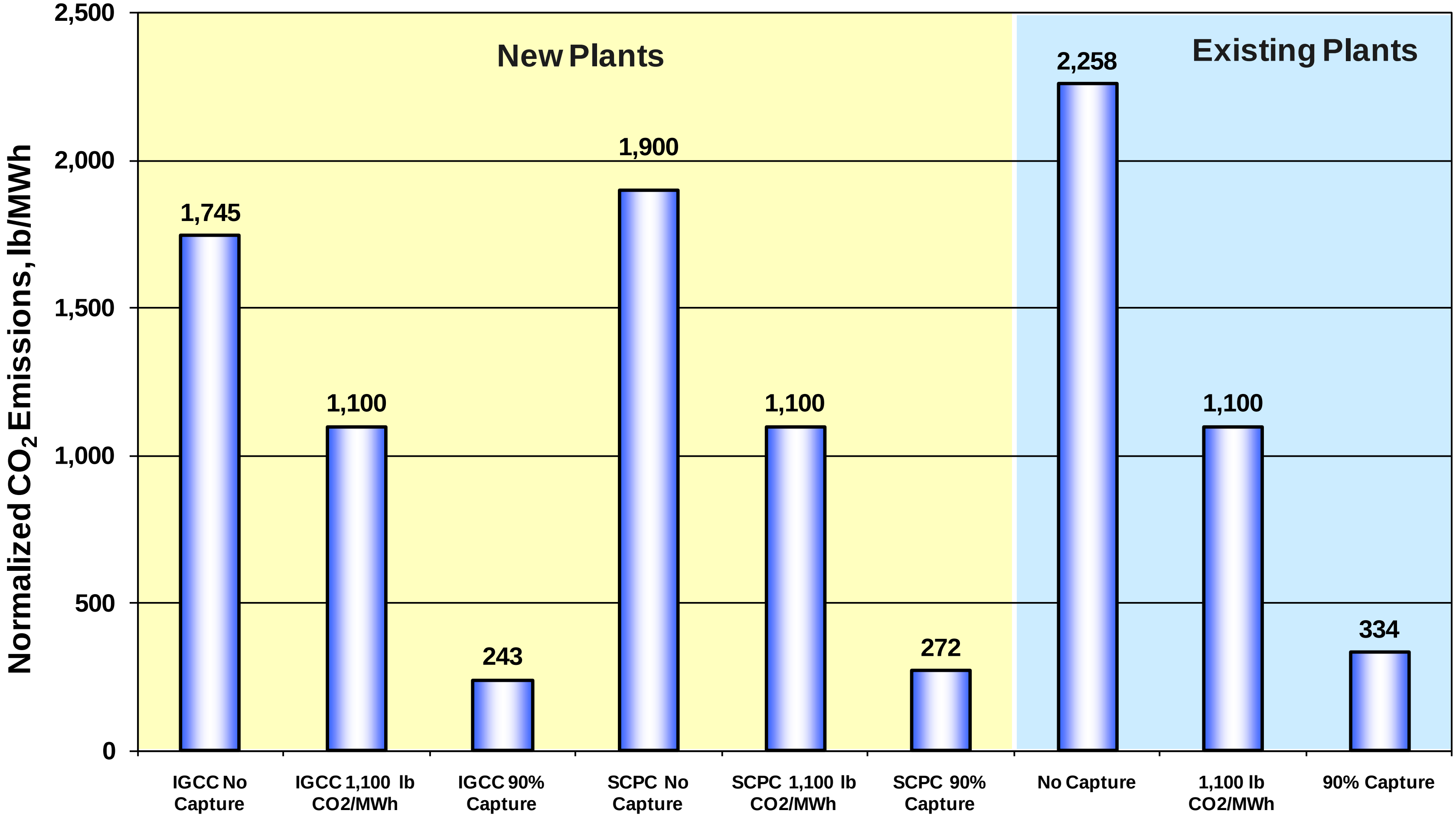


Exhibit ES-16 CO_2 Emissions Normalized By Net Power Output



<u>Emission Key Findings</u>:

- The IGCC baseline plant generates the lowest criteria pollutant emissions (NO_x, SO_x, PM, and mercury), followed by supercritical PC and then existing subcritical PC.
- In cases with no carbon capture, IGCC emits 8.2 percent less CO_2 than supercritical PC and 23 percent less CO_2 than existing subcritical PC per unit of net output. The relative emissions are indicative of the net efficiencies of each technology.
- In the IGCC cases the nominal 90 percent CO_2 reduction was accomplished by adding two sour gas shift (SGS) reactors to convert CO to CO_2 and using a two-stage Selexol process with a second stage CO_2 removal efficiency of up to 95 percent, which resulted in 90 percent reduction of CO_2 in the syngas. This number was supported by vendor quotes. In the 1,100 lb CO_2/net-MWh capture case, the 2 gasifier trains each have 1 SGS reactor with a bypass to achieve the emission limit, which resulted in 46 percent carbon capture.

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1. INTRODUCTION

Revision 2 Updates

The technologies modeled in this study, namely integrated gasification combined cycle, subcritical pulverized coal and supercritical pulverized coal, are the subject of other ongoing systems analysis studies at the Department of Energy's National Energy Technology Laboratory. Vendor discussions that occurred as part of the other studies led to improved technology information that was incorporated into the Aspen models for this study. The updated models led to revised performance estimates, which were then used to update the cost estimates. The reference costs used for this study were also updated through efforts on other studies, and the most recent costs have been incorporated. In addition, owner's costs were added to the Total Plant Cost previously reported, and the capital component of levelized cost of electricity now includes owner's costs. The updated results are presented in the current revision (revision 2) of this report. Details of the modeling updates and cost methodology changes are identified throughout the report by the use of italicized font.

Greenhouse gas (GHG) emissions continue to receive increased scrutiny because of their perceived relation to global warming. Over the past several years, numerous bills have been introduced in both the United States Senate and House of Representatives that would limit GHG emissions. The bills vary primarily in the economy sectors regulated, the extent of GHG reductions and the compliance year, but all represent reductions from the "business-as-usual" scenario. *In June, 2009, the American Clean Energy and Security Act of 2009 (H.R. 2454) was passed by the House of Representatives. The bill requires that GHG emissions from regulated sources be reduced to 97 percent of 2005 levels by 2012; to 83 percent by 2020; to 58 percent by 2030; and to 17 percent by 2050 [2]. While the bill has not yet come to a vote in the Senate, it continues to be debated and similar bills are also under consideration. Adding to the legislative momentum for carbon regulation, in September, 2009 the Environmental Protection Agency proposed a rule that would limit future regulation of GHG emissions under the Clean Air Act to industrial facilities that emit 25,000 tons or more of carbon dioxide annually. The proposed rule would impact facilities such as power plants, refineries, and factories, which produce nearly 70 percent of domestic GHGs.* In addition to proposed Federal regulations, various states have proposed or enacted legislation to reduce GHG emissions. A sampling of the legislation is provided in Section 1.1.

The objective of this report is to present the baseline cost and performance of greenfield integrated gasification combined cycle (IGCC) plants, greenfield supercritical (SC) pulverized coal (PC) plants, and retrofit subcritical PC plants that limit carbon dioxide (CO_2) emissions to various levels. For each plant type, three cases were modeled:

- Baseline performance with no CO_2 capture
- CO_2 emissions reduced to 1,100 lb/net-MWh
- CO_2 emissions reduced by 90 percent

The intermediate value of 1,100 lb/net-MWh was chosen to match the recent interim California standard established in January 2007 [1].

The fuel used in all nine cases was representative of a coal from the Powder River Basin (PRB). The nine cases are summarized in Exhibit 1-1.

Generating Unit Configurations

The three IGCC cases are each comprised of two advanced F-class turbines and a single steam turbine. The advanced F-class turbine comes in a standard size of 232 MW when operated on syngas at ISO conditions. Because these cases are operated at elevations greater than sea level (2,042 m [6,700 ft]), the output is reduced from the turbine's ISO condition potential. In the combined cycle, a heat recovery steam generator extracts heat from the combustion turbine exhaust to power a steam turbine. However, the carbon capture cases consume more extraction steam than the non-capture cases, thus reducing the steam turbine output. In addition, the capture cases have a higher auxiliary load requirement than non-capture cases, which serves to further reduce net plant output. Although the gross combustion turbine output increases with increasing levels of carbon capture, the net plant output decreases as CO_2 capture increases because of the higher auxiliary loads and the increased extraction steam requirement for the water-gas shift reactions. The gross combustion turbine output increases because the syngas has a higher heat of combustion (Btu/lb) with increase capture levels, while maintaining a relatively similar mass flow. The resulting net output ranges from 504 MW for Case 1 (no capture) to 396 MW for Case 3 (90% CO_2 capture).

The three greenfield SC PC cases are all modeled to maintain a nominal net output of 550 MW. The increased auxiliary loads due to CO_2 capture plus the extraction steam required for amine regeneration result in higher gross outputs for the capture cases, ranging from 584 MW for Case 4 (no capture) to 677 MW in Case 6 (90% CO_2 capture).

Since the boiler heat input (coal flowrate and boiler size), and therefore the amount of steam generated, is a fixed quantity in the existing subcritical power plant, the gross and net output are both decreased when retrofitted for CO_2 capture. The extraction steam required to regenerate the amine solvent in the capture cases causes a de-rating to the existing steam turbine and the higher auxiliary loads (i.e. CO_2 compression) further reduces the net output. The baseline case or 'current state" is Case 7 and has a net power output equal to 532 MW. When the plant is retrofitted with 90 percent CO_2 capture (Case 9) the net power output is reduced to 359 MW (a 33% reduction or 173 MW loss of power to the grid).

1.1 GHG EMISSION STANDARDS

The United States continues to progress towards restrictions of greenhouse gas (GHG) emissions, including carbon dioxide (CO_2). In 1992, the United States ratified the United Nations' Framework Convention on Climate Change (UNFCCC), which called on industrialized countries to take the lead in reducing greenhouse gas emissions. The UNFCCC did not include mandatory reductions, but set an ultimate objective of stabilizing greenhouse gas concentrations "at a level that would prevent dangerous anthropogenic interference with the climate system." The convention requires precise and regularly updated inventories of greenhouse gas emissions from industrialized countries. The "base year" for tabulating greenhouse gas emissions was set as 1990.

The first addition to the treaty, the Kyoto Protocol, was adopted in 1997. The United States chose not to ratify the Kyoto Protocol, which called for legally binding commitments by developed countries to reduce their greenhouse gas emissions. Instead, the domestic initiatives have focused on voluntary reductions in the growth of GHG emissions per unit of gross domestic product (GDP) and the development of advanced technologies to improve energy efficiency and control GHG emissions reliably and cost-effectively.

Many bills were introduced in the 109th and 110th Congresses with the goal of reducing emissions of GHG. During the 111th Congress, the House of Representatives passed H.R. 2454 which includes provisions for reducing GHG emissions from regulated sources. While the Senate has yet to act on H.R. 2454 or any companion bills, momentum continues to gather for climate change legislation. A sampling of bills that were previously proposed along with a summary of H.R. 2454 are shown below to illustrate the format that climate change legislation may ultimately take [2,3,4,5,6].

- *H.R. 2454 (introduced by Representatives Waxman and Markey and passed by the House of Representatives in June 2009) would require reduction of greenhouse gases from regulated sources to 97 percent of 2005 levels by 2012; to 83 percent by 2020; to 58 percent by 2030; and to 17 percent by 2050.*
- S. 342 (introduced by Senators McCain and Lieberman) and H.R. 759 (introduced by Representatives Gilchrest and Oliver) would cap emissions of CO_2 in the year 2010 based on the affected facilities' 2000 emissions (for any entity that emits from a single facility more than 10,000 metric tons of GHG annually [CO_2 equivalent]). The legislation would be implemented through an expansive allowance trading program that would allow cross-sector trading, increases in carbon sequestration and limited acquisition of allowances from foreign sources.
- S. 150 (introduced by Senator Jeffords) would require electric generating facilities producing 15 MW or greater to meet an aggregate CO_2 emissions cap in the year 2010. The national emissions cap would be set at 1990 emissions levels for electric generating facilities and would be implemented through a tradable allowance program.
- S. 730 (introduced by Senator Leahy) is the same as S. 150 except that trading is restricted to within a single facility, not across different sites.
- H.R. 1451 (introduced by Representative Waxman) is essentially the same as S. 150 with regard to CO_2 emissions.
- H.R. 1873 (introduced by Representative Bass) would set a CO_2 cap in 2010 at the projected 2006 levels, declining to actual 2001 levels in 2015.
- H.R. 1590 (introduced by Representative Waxman and also called The Safe Climate Act of 2007) freezes domestic GHG emissions in 2010 at 2009 levels. Beginning in 2011, it would cut emissions by roughly 2 percent per year, reaching 1990 emission levels by 2020. After 2020, it would cut emissions by roughly 5 percent per year. By 2050, emissions would be 80 percent lower than in 1990.
- S. 280 (introduced by Senator Lieberman) would cap emissions of the six greenhouse gases specified in the United Nations Framework Convention on Climate Change, at reduced levels, form the electric generation, transportation, industrial, and commercial sectors. The initial cap would restrict 2012 emissions from the affected facility to their 2004 emission levels. The cap steadily declines until it is equal to one-third of the facilities' 2004 level.
- S. 317 (introduced by Senator Feinstein) would cap GHG emissions from electric generators over 25 MW. Beginning in 2011, affected generators would be capped at their

- 2006 levels, declining to 2001 levels by 2015. After that, the emission cap would decline 1% annually until 2020, when the rate of decline would increase to 1.5%.
- The Low Carbon Economy Act of 2007 (introduced by Senators Bingaman and Specter) would require economy-wide CO_2 emissions to be reduced to 2006 levels by 2020. Following that, the bill proposes to achieve reductions to 1990 levels by 2030 and at least 60 percent below current levels by 2050. The bill also contains a "safety valve" provision, which allows entities to purchase climate change credits at a relatively low cost in early years, to allow time for carbon sequestration technologies to be developed.

While GHG limits continue to be debated at a national level, many state and local governments have already passed climate change legislation. Twenty-five states have passed Renewable Portfolio Standards (RPS) and two other states have voluntary standards. Seventeen states have established GHG emission targets [7].

In 2006, the California Legislature passed Assembly Bill 32 (the Global Warming Solutions Act of 2006), which mandates that California must reduce its GHG emissions to 2000 levels by 2010 and to 1990 levels by 2020. Senate Bill No. 1368 further required that, "On or before February 1, 2007, the commission, through a rulemaking proceeding, and in consultation with the Energy Commission and the State Air Resources Board, shall establish a greenhouse gases emission performance standard for all baseload generation of load-serving entities, at a rate of emissions of greenhouse gases that is no higher than the rate of emissions of greenhouse gases for combined-cycle natural gas baseload generation."

In response to Senate Bill No. 1368, on January 25, 2007 the California Public Utilities Commission adopted an interim GHG Emissions Performance Standard. The level established is 1,100 lb CO_2/net-MWh for all new long-term commitments for baseload generation that serves California consumers. "New long-term commitment" refers to new plant investments (new construction), new or renewal contracts with a term of five years or more, or major investments by the utility in its existing baseload power plants. The clause "baseload generation that serves California consumers" also makes it applicable to imported power supplies.

The California GHG Emissions Performance Standard provided the impetus for this study. The results provide an overview of the cost and performance impacts that such a standard will have on new and existing coal-fired power plants.

The balance of this report is organized as follows:

- Chapter 2 provides the basis for technical, environmental and cost evaluations.
- Chapter 3 describes the systems of all three greenfield Shell IGCC cases.
- Chapter 4 provides the results of the three greenfield Shell IGCC cases.
- Chapter 5 describes the systems common to all six PC cases.
- Chapter 6 describes the results of the supercritical PC cases.

- Chapter 7 describes the results of the existing subcritical PC retrofit.
- Chapter 8 provides the conclusions that summarize the major differences for all nine cases.
- Chapter 9 contains the reference list.

Exhibit 1-1 Summary of Cases

Case	Power Plant Type	Steam Cycle, psig/°F/°F	Oxidant	Sulfur Removal	PM Control	NOx Control	CO_2 Capture	Capture Level	CO_2 Storage[c]
1	**NEW IGCC** Shell Gasifier 2 x Advanced F Class Combustion Turbines	1800/1048/1048	95 mol% O_2	Sulfinol with Claus Plant	Cyclone, barrier filter and scrubber	N_2 dilution	Case 1—IGCC No CO_2 Capture		
2		1800/1020/1020[a]		Selexol with Claus Plant			Selexol 2nd Stage added	1,100 lb/net-MWh	Off-Site
3		1800/996/996[a]						90%	
4	**NEW PULVERIZED COAL** Supercritical	3500/1100/1100	Air	Spray Dryer Absorber	Baghouse	LNB w/OFA and SCR	Case 4—PC No CO_2 Capture		
5							Amine Scrubbing	1,100 lb/net-MWh	Off-Site
6								90%	
7	**EXISTING PULVERIZED COAL** Subcritical	2400/1000/1000	Air	Existing Wet FGD/ Sodium based	ESP	OFA and 'retro' LNB	Case 7—Existing PC No CO_2 Capture		
8				Upgrade[b] Existing Wet FGD/ Sodium based		OFA and Reconfigure LNB	Amine Scrubbing	1,100 lb/net-MWh	Off-Site
9								90%	

ESP = Electrostatic Precipitator, OFA = Overfired air, LNB = Low NOx Burners

[a]For the IGCC w/CO_2 capture cases, the steam conditions are lowered due to a lower temperature flue gas exiting the combustion turbine.
[b]Upgrade existing Wet FGD by removing the internal bypass and modifying the stack to handle wet operation. This increases efficiency from 85% to 92% to decrease the sulfur concentration entering the CO_2 scrubbing process.
[c]Transported 50 miles via pipeline to a geologic sequestration field for injection into a saline formation

2. GENERAL EVALUATION BASIS

For each of the plant configurations in this study an AspenPlus model was developed and used to generate material and energy balances, which in turn were 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 creating factored capital and operating cost estimates. Cost estimates were generated for the greenfield Shell IGCC and SCPC cases (on PRB coal) from a previous study and those costs were used as the scaling basis. The original cost estimates were based on simulation results and through a combination of vendor quotes, scaled estimates from previous design/build projects, or a combination of the two. Ultimately, a constant dollar, 30-year levelized cost of electricity (LCOE) was calculated for each of the cases and is reported as the revenue requirement figure-of-merit.

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. The performance of the subcritical PC plant was based on a suite of publicly available data, including a report published by the Energy Information Administration (EIA) and a Best Available Retrofit Technology (BART) report [8].

The balance of this chapter documents the design basis, environmental targets and cost assumptions used in the study.

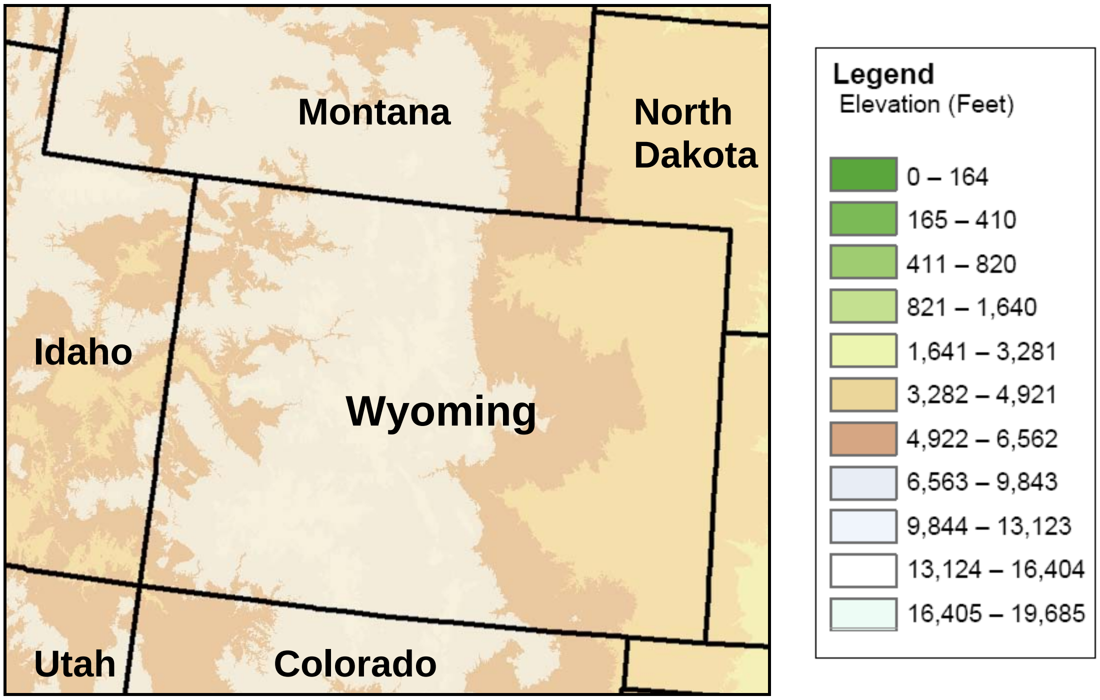
2.1 SITE CHARACTERISTICS

The plants are located in Wyoming, U.S. The ambient conditions for the site are shown in Exhibit 2-1. The average elevation of the state of Wyoming is 6,700 ft and was the basis for the elevation chosen for this study. A topographical map of the state of Wyoming is shown in Exhibit 2-2.

Exhibit 2-1 Site Ambient Conditions for All Cases

Elevation, m (ft)	2,042 (6,700)
Barometric Pressure, MPa (psia)	0.08 (11.4)
Design Ambient Temperature, Dry Bulb, °C (°F)	5.6 (42)
Design Ambient Temperature, Wet Bulb, °C (°F)	2.8 (37)
Design Ambient Relative Humidity, %	62

Exhibit 2-2 Topographical Map of Wyoming



The assumed site characteristics are shown in Exhibit 2-3.

Exhibit 2-3 Site Characteristics

Location	Wyoming, USA
Topography	Level
Size, acres	300
Ash/Slag Disposal	Off Site
Water Source	Municipal (50%) / Groundwater (50%) for Cases 1-6 Green River for Cases 7-9
CO_2 Storage	Compressed to 15.3 MPa (2,215 psia), transported 80 kilometers (50 miles) and sequestered in a saline formation at a depth of 1,239 meters (4,055 feet)

The land area for all greenfield cases (PC and IGCC) assumes 30 acres are required for the plant proper and the balance provides a buffer of approximately 0.25 miles to the fence line. Sufficient land area for additional controls, including CO_2 capture and compression, is assumed available in the retrofit PC cases.

In all cases it was assumed that the steam turbine is enclosed in a turbine building and the boiler in the PC cases is also enclosed, but the gasifier in the IGCC cases is not enclosed.

The following design parameters are considered site-specific, and are not quantified for this study. 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
- Fire protection
- Local code height requirements
- Noise regulations – Impact on site and surrounding area

2.2 COAL CHARACTERISTICS

The design coal is a subbituminous PRB coal from Montana. The coals properties are from NETL's Coal Quality Guidelines and are shown in Exhibit 2-4 [9].

The first year cost of coal used in this study is \$0.57/GJ (\$0.61/MMBtu). The first year coal cost is the EIA projected cost of Montana Rosebud PRB coal for 2015 in 2005 dollars. This cost is then scaled to 2007 dollars. The projected 2015 coal cost was used to correspond with the start-up date for the greenfield IGCC and SCPC cases, but is applied to all cases to enable comparison. The costs were determined using the following information from the Energy Information Administration's (EIA) 2007 Annual Energy Outlook (AEO):

- The 2015 minemouth cost of PRB coal in 2005 dollars, \$10.85/tonne (\$9.84/ton), was obtained from Supplemental Table 113 of the EIA's 2007 AEO for western Montana medium-sulfur subbituminous coal.
- The plants are assumed to be minemouth so transportation costs are zero.
- The 2015 cost of PRB coal was escalated to 2007 dollars using the gross domestic product (GDP) chain-type price index from AEO 2007, resulting in a price of \$11.43/tonne (\$10.37/ton) or \$0.57/GJ (\$0.61/MMBtu) [10]. (Note: The PRB coal cost conversion of \$10.37/ton to dollars per million Btu results in \$0.6053/MMBtu which was used in calculations, but only two decimal places are shown in the report.)

2.3 ENVIRONMENTAL TARGETS

The current federal regulation governing new fossil-fuel fired electric utility steam generating units is the New Source Performance Standards (NSPS) as amended in February 2006 and shown in Exhibit 2-5, which represents the minimum level of control that would be required for a new fossil energy plant.

Exhibit 2-4 Montana Rosebud PRB, Area D, Western Energy Co. Mine, Subbituminous Design Coal Analysis

Proximate Analysis	**Dry Basis, %**	**As Received, %**
Moisture	0.0	25.77
Ash	11.04	8.19
Volatile Matter	40.87	30.34
Fixed Carbon	48.09	35.70
Total	100.0	100.0
Ultimate Analysis	**Dry Basis, %**	**As Received, %**
Carbon	67.45	50.07
Hydrogen	4.56	3.38
Nitrogen	0.96	0.71
Sulfur	0.98	0.73
Chlorine	0.01	0.01
Ash	11.03	8.19
Moisture	0.00	25.77
Oxygen (Note A)	15.01	11.14
Total	100.0	100.0
Heating Value	**Dry Basis, (Dulong Calc.)**	**As Received, %**
HHV, kJ/kg	26,787	19,920
HHV, Btu/lb	11,516	8,564
LHV, kJ/kg	25,810	19,195
LHV, Btu/lb	11,096	8,252
Hardgrove Grindability Index	57	
Ash Mineral Analysis		**%**
Silica	SiO_2	38.09
Aluminum Oxide	Al_2O_3	16.73
Iron Oxide	Fe_2O_3	6.46
Titanium Dioxide	TiO_2	0.72
Calcium Oxide	CaO	16.56
Magnesium Oxide	MgO	4.25
Sodium Oxide	Na_2O	0.54
Potassium Oxide	K_2O	0.38
Sulfur Trioxide	SO_3	15.08
Phosphorous Pentoxide	P_2O_5	0.35
Barium Oxide	Ba_2O	0.00
Strontium Oxide	SrO	0.00
Unknown	---	0.84
	Total	100.0
Trace Components		**ppmd**
Mercury (Note B)	Hg	0.081

Notes: A. By Difference
B. Mercury value is the mean plus one standard deviation using EPA's ICR data

Exhibit 2-5 Standards of Performance for Electric Utility Steam Generating Units Built, Reconstructed, or Modified After February 28, 2005

	New Units		Reconstructed Units		Modified Units	
	Emission Limit	% Reduction	Emission Limit (lb/MMBtu)	% Reduction	Emission Limit (lb/MMBtu)	% Reduction
PM	0.015 lb/MMBtu	99.9	0.015	99.9	0.015	99.8
SO_2	1.4 lb/MWh[1]	95	0.15	95	0.15	90
NOx	1.0 lb/MWh[1]	N/A	0.11	N/A	0.15	N/A

[1]Gross MWh output

The new NSPS standards apply to units with the capacity to generate greater than 73 MW of power by burning fossil fuels, as well as cogeneration units that sell more than 25 MW of power and more than one-third of their potential output capacity to any utility power distribution system. The rule also applies to combined cycle, including IGCC plants, and combined heat and power combustion turbines that burn 75 percent or more synthetic-coal gas. In cases where both an emission limit and a percent reduction are presented, the unit has the option of meeting one or the other. All limits with the unit lb/MWh are based on gross power output.

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 Best Available Control Technology (BACT) determinations for new sources being located in areas meeting ambient air quality standards (attainment areas), or Lowest Achievable Emission Rate (LAER) technology for sources being located in areas not meeting ambient air quality standards (non-attainment areas). Environmental area designation varies by county and can be established only for a specific site location. Based on the Environmental Protection Agency (EPA) Green Book Non-attainment Area Map relatively few areas in the Western U.S. are classified as "non-attainment" so the greenfield plant site for this study was assumed to be in an attainment area [11].

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

The Clean Air Mercury Rule (CAMR) established NSPS limits for Hg emissions. While CAMR is no longer legally binding, it is used as a reference until new regulations are established. The

IGCC limits are independent of coal type and the PC limits are dependent on the type of coal used. The applicable limit for IGCC cases in this study is 20 x 10^{-6} lb/MWh. The applicable limit for the PC cases is 97 x 10^{-6} lb/MWh. The NSPS limits, based on gross output, are shown in Exhibit 2-6.

Exhibit 2-6 NSPS Mercury Emission Limits

Coal Type / Technology	Hg Emission Limit
Bituminous/ PC	20 x 10^{-6} lb/MWh
Subbituminous (wet units)/ PC	66 x 10^{-6} lb/MWh
Subbituminous (dry units)/ PC	**97 x 10^{-6} lb/MWh**
Lignite/ PC	175 x 10^{-6} lb/MWh
Coal refuse/ PC	16 x 10^{-6} lb/MWh
All coals/ IGCC	**20 x 10^{-6} lb/MWh**

The coal mercury concentration used for this study was determined from the Environmental Protection Agency's (EPA) Information Collection Request (ICR) database. The ICR database has 137 records of Montana Rosebud subbituminous coal with an average Hg concentration of 0.056 ppm (dry) and a standard deviation of 0.025 ppm. The mercury value in Exhibit 2-4 is the mean plus one standard deviation, or 0.081 ppm (dry) [12]. It was further assumed that all of the coal Hg enters the gas phase and none leaves with the bottom ash or slag.

2.3.1 IGCC Environmental Targets

The IGCC environmental targets were chosen to match the Electric Power Research Institute's (EPRI) design basis for their CoalFleet for Tomorrow Initiative and are shown in Exhibit 2-7 [13]. The design targets were established specifically for bituminous coal, but are applied to subbituminous as well. Because of the lower coal sulfur content in the Montana Rosebud PRB coal, actual SO_2 emissions in this study are substantially lower than the environmental target. EPRI notes that these are design targets and are not to be used for permitting values.

Exhibit 2-7 IGCC Environmental Targets

Pollutant	Environmental Target	NSPS Limit[1]	Control Technology
NOx	15 ppmv (dry) @ 15% O_2	1.0 lb/MWh (0.117 lb/MMBtu)	Low NOx burners and syngas nitrogen dilution
SO_2	0.0128 lb/MMBtu	1.4 lb/MWh (0.163 lb/MMBtu)	Sulfinol—non capture cases Selexol—capture cases
Particulate Matter (Filterable)	0.0071 lb/MMBtu	0.015 lb/MMBtu	Full quench (capture cases), water scrubber, and cyclones
Mercury	> 90% capture	20×10^{-6} lb/MWh (2.3 lb/TBtu)	Carbon bed

[1] The NSPS value in parentheses is calculated based on an average heat rate of 8,570 Btu/kWh from the two non-CO_2 capture gasifier cases.

IGCC Emissions Design Assumptions

1. **NOx:** Based on published vendor literature, it was assumed that low NOx burners (LNB) and nitrogen dilution can achieve 15 ppmv (dry) at 15 percent O_2, and that value was used for all IGCC cases [14, 15].
2. **SO_2:** To achieve an environmental target of 0.0128 lb/MMBtu of SO_2 (see Exhibit 2-7) requires approximately 28 ppmv sulfur in the sweet syngas. The acid gas removal (AGR) process requires a sulfur capture efficiency of about 99.7 percent to reach the environmental target using bituminous coal with a sulfur content of 2.51 percent. Vendor data on the AGR processes used in this study indicate that this level of sulfur removal is possible, resulting in substantially lower SO_2 emissions because of the lower coal sulfur content. In the CO_2 capture cases, the two-stage Selexol process was designed for just over 90 percent CO_2 removal, which results in a sulfur capture of greater than 99.7 percent due to co-sequestration of some sulfur containing compounds.
3. **PM:** Most of the coal ash is removed from the gasifier as slag. The ash that remains entrained in the syngas is captured in the downstream equipment, including the syngas scrubber and a cyclone and either ceramic or metallic candle filters. The environmental target of 0.0071 lb/MMBtu filterable particulates can be achieved with this combination of particulate control devices so that it was assumed the environmental target was met exactly.
4. **Mercury:** The environmental target for mercury capture is greater than 90 percent. Based on experience at the Eastman Chemical plant, where syngas from a GEE gasifier is treated, the actual mercury removal efficiency used is 95 percent. Sulfur-impregnated activated carbon is used by Eastman as the adsorbent in the packed beds operated at 30°C (86°F) and 6.2 MPa (900 psig). Mercury removal between 90 and 95 percent has been reported with a bed life of 18 to 24 months. Removal efficiencies may be even higher, but at 95 percent the measurement precision limit was reached. Eastman has yet to experience any mercury contamination in its product [16]. Mercury removals of greater

than 99 percent can be achieved by the use of dual beds, i.e., two beds in series. However, this study assumes that the use of sulfur-impregnated carbon in a single carbon bed achieves 95 percent reduction of mercury emissions which meets the environmental target and NSPS limits in all cases.

2.3.2 Pulverized Coal Environmental Targets

Best available control technology (BACT) was applied to the greenfield supercritical PC cases, and the resulting emissions were compared to NSPS limits and recent permit averages. Since the BACT results met or exceeded the NSPS requirements and the average of recent permits, they were used as the environmental targets. The average of recent permits is comprised of 8 units at 5 locations. The 5 plants include Elm Road Generating Station, Longview Power, Prairie State, Thoroughbred and Cross.

The existing subcritical PC plant used in this study does not, and is not required to, meet the NSPS limits. However, Best Available Retrofit Technology (BART) for SO_2 and NOx control was applied to the subcritical PC cases retrofitted for CO_2 capture because of the amine-based system limits on those pollutants [8]. In addition, it was assumed that the retrofit modifications for the existing subcritical PC plant would not trigger New Source Review (NSR) environmental standards because additional capacity and subsequent emissions rates are not increased. Per U.S.C. §7411(a), NSR is only applicable when "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source which results in the emissions of any air pollutant not previously emitted." However, in the event that NSR is triggered and selective catalytic reduction (SCR) needs to be implemented for NOx control, a sensitivity case was added to determine the impact on costs. The environmental targets for the greenfield supercritical PC plant and the existing subcritical PC plant are shown in Exhibit 2-8.

Pulverized Coal Emission Control Design Assumptions

1. **NOx:** In the new SCPC cases, the NOx emissions exiting the boiler equipped with low NOx burners and overfire air would be 0.20 lb/MMBtu . Adding an SCR unit would further reduce the NOx by 65 percent, resulting in the emission of 0.070 lb/MMBtu.

   The current subcritical PC plant NOx emissions are 0.45 lb/MMBtu. With the implementation of new LNBs and improved OFA the emissions would be reduced to 0.24 lb/MMBtu according to the CH2MHill Bart Analysis [8]. This level of control was assumed to meet the amine-based CO_2 capture NO_2 limit.

   With the addition of SCR to the subcritical PC retrofit, the NOx emissions would be further reduced to 0.070 lb/MMBtu.

2. **SO_2:** The lime-based spray dry absorber utilized in the new SCPC cases was assumed to be 93 percent efficient which results in SO_2 emissions of 0.119 lb/MMBtu for the non-capture case (Case 4). Current technology allows flue gas desulfurization (FGD) removal efficiencies in excess of 99 percent, but based on NSPS requirements and recent permit averages, such high removal efficiency is not necessary.

Exhibit 2-8 Environmental Targets for Pulverized Coal Cases

Pollutant	Environmental Target	NSPS Limit	Average of Recent Permits	Control Technology
NOx				
New SCPC	0.07 lb/MMBtu	1.0 lb/MWh (0.111 lb/MMBtu)	0.08 lb/MMBtu	LNB, OFA, SCR
Existing Plant	0.45 lb/MMBtu			OFA and 'retro' LNB
Existing Plant CO_2 Retrofit[1]	0.24 lb/MMBtu			New LNB, Improved OFA
SO_2				
New SCPC	0.119 lb/MMBtu	1.4 lb/MWh (0.156 lb/MMBtu)	0.16 lb/MMBtu	Dry lime-based spray dry absorber
Existing Plant	0.255 lb/MMBtu			Wet soda ash scrubber
Existing Plant CO_2 Retrofit[1]	0.017 lb/MMBtu			Upgraded wet soda ash scrubber
Particulate Matter				
New SCPC	0.0150 lb/MMBtu	0.0150 lb/MMBtu	0.017 lb/MMBtu	Fabric filter
Existing Plant	0.0270 lb/MMBtu			ESP
Existing Plant CO_2 Retrofit[1]	0.0270 lb/MMBtu			ESP
Mercury				
New SCPC	0.70 lb/TBtu	97×10^{-6} lb/MWh (11 lb/TBtu)	2.49 lb/TBtu	Co-benefit capture plus carbon injection
Existing Plant	6.00 lb/TBtu			Co-benefit capture
Existing Plant CO_2 Retrofit[1]	6.00 lb/TBtu			Co-benefit capture

[1]Both 1,100 lb/net-MWh and 90 percent CO_2 capture cases

LNB: Low NOx Burners
OFA: Over-fired Air
SCR: Selective Catalytic Reduction

The wet soda ash scrubber utilized in the existing subcritical retrofit PC case was assumed to be 85 percent efficient for (Case 7), which results in SO_2 emissions of 0.255 lb/MMBtu. SO_2 emissions for this technology are currently greater than NSPS limits. Should NSPS requirements become relevant, the wet soda ash scrubber would have to be modified to meet NSPS limits.

In the CO_2 capture cases, the Econamine system employs a polishing scrubber to reduce the flue gas SO_2 concentration to 10 ppmv entering the CO_2 absorber. This results in SO_2 emissions of 0.017 lb/MMBtu for the new SCPC and existing plant 90 percent CO_2 capture cases. In the 1,100 lb CO_2/net-MWh PC cases, the SO_2 emissions increase because a portion of the flue gas is bypassed around the Econamine system polishing scrubber. The SO_2 emissions at this capture level are 0.068 lb/MMBtu for the SCPC case (Case 5) and 0.054 lb/MMBtu for the subcritical retrofit PC case (Case 8).

3. **<u>PM</u>:** In new SCPC cases, a fabric filter will remove 99.97 percent of the entering particulate. In the existing subcritical PC cases, the ESP will remove 99.65 percent. There is an 80/20 split between fly ash and bottom ash in all PC cases. The result is the emission of 0.0150 lb/MMBtu for supercritical PC cases and 0.0270 lb/MMBtu for the existing subcritical PC cases. The SCPC technology meets NSPS and recent permit average requirements. PM emissions from the existing subcritical PC are currently greater than NSPS limits. Should NSPS requirements become relevant, the ESP would have to be replaced by a baghouse.

4. **<u>Mercury</u>:** 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 [17]. The EMF is simply one minus the removal efficiency. Based on the IPM estimates, mercury control was assumed to occur through 15 percent co-benefit capture for the fabric filter, dry FGD scrubber, and SCR in the new supercritical PC cases. Activated carbon injection provides an additional 90 percent reduction for a total Hg environmental target for the new SCPC of 0.70 lb/TBtu. In the subcritical PC plant, the co-benefit capture is assumed to be 16 percent with a wet FGD, a cold-side ESP, and no post-combustion NOx control. The estimated Hg emissions for the existing subcritical PC plant are 6.00 lb/TBtu. With the addition of SCR to the subcritical PC retrofit, the mercury emissions would be further reduced to 2.39 lb/TBtu because of the increased co-benefit capture.

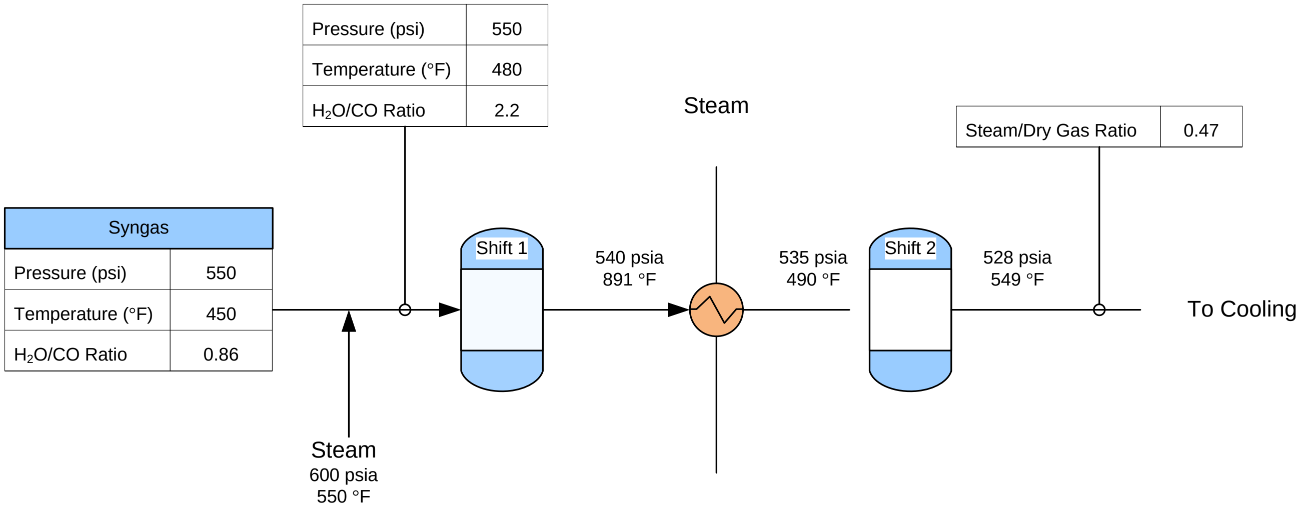
2.3.3 <u>Carbon Dioxide</u>

Carbon dioxide (CO_2) is not currently regulated nationally, but the California Public Utilities Commission adopted an interim GHG Emissions Performance Standard of 1,100 lb CO_2/net-MWh for carbon dioxide.

For the IGCC cases that have CO_2 capture, the emissions benchmarks are a nominal 90 percent overall carbon capture and an emissions limit equal to 1,100 lb CO_2/net-MWh. These are based on carbon input from the coal and excluding carbon that exits the gasifier with the slag. For the 90 percent capture case, two water gas shift (WGS) reactors were used with a Selexol CO_2 removal efficiency of 90.1 percent (based on a vendor quote and a given syngas CO_2

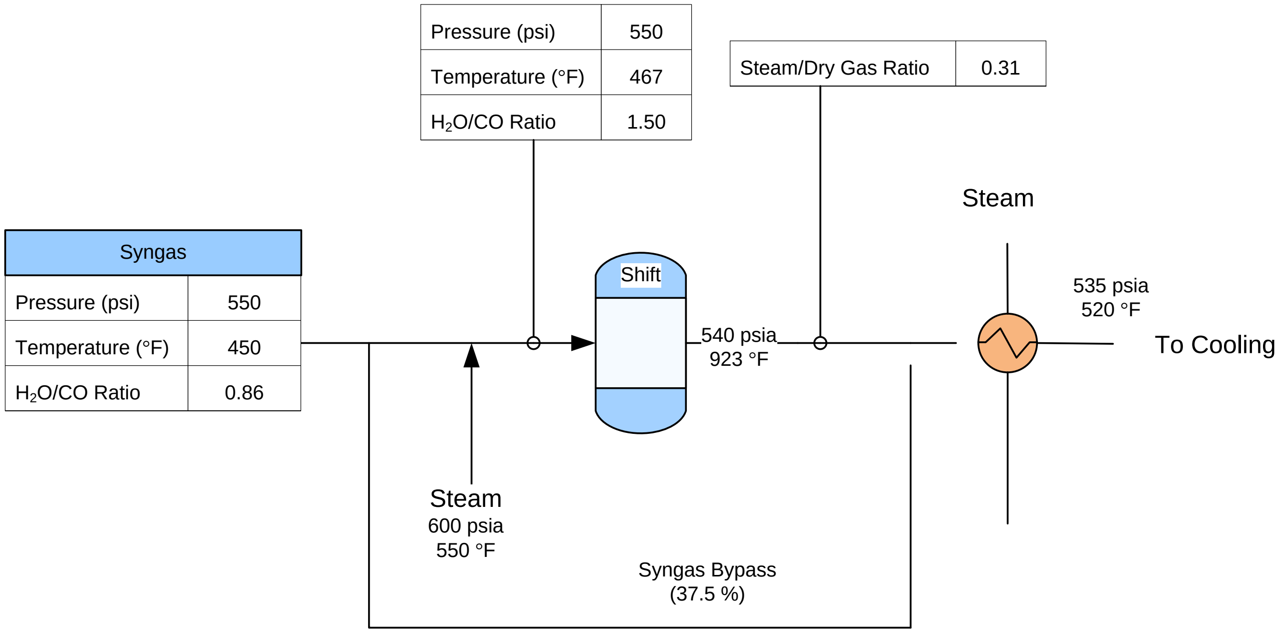
concentration). In addition, to achieve 90 percent CO_2 capture, shift steam had to be increased above the minimum value of 0.30 (steam: dry gas at shift outlet) to 0.47 in order to increase conversion to CO_2 as shown in Exhibit 2-9.

Exhibit 2-9 IGCC with 90 Percent CO_2 Capture WGS Process



For the IGCC case that meets the 1,100 lb CO_2/net-MWh emission standard, a partial flue gas bypass around a single water gas shift reactor was implemented and the shift steam was reduced to near the minimum value of 0.30:1 (steam: dry gas) as shown in Exhibit 2-10. To achieve the CO_2 emissions target of 1,100 lb CO_2/net-MWh, 50 percent removal was required.

Exhibit 2-10 IGCC with Partial WGS to Meet 1,100 lb/net-MWh CO_2 Emission Limit



For the SCPC cases that have CO_2 capture, it is assumed that all of the fuel carbon is converted to CO_2 in the flue gas. Ninety percent of the CO_2 entering the Econamine FG Plus unit from the FGD is subsequently captured. For the 1,100 lb CO_2/net-MWh cases, a partial flue gas bypass is implemented to reduce the amount of CO_2 entering the Econamine unit to achieve the desired emission limit.

The cost of CO_2 capture was calculated in two ways, the cost of CO_2 removed and the cost of CO_2 avoided, as illustrated in Equations 1 and 2, respectively. The cost of electricity in the CO_2 capture cases includes transport, storage and monitoring (TS&M) as well as capture and compression.

$$(1) \qquad Removal\ Cost = \frac{\{LCOE_{with\ removal} - LCOE_{w/o\ removal}\}\ \$/MWh}{\{CO_2\ removed\}\ tons/MWh}$$

$$(2) \qquad Avoided\ Cost = \frac{\{LCOE_{with\ removal} - LCOE_{w/o\ removal}\}\ \$/MWh}{\{Emissions_{w/o\ removal} - Emissions_{with\ removal}\}\ tons/MWh}$$

2.4 CO_2 TRANSPORT AND STORAGE

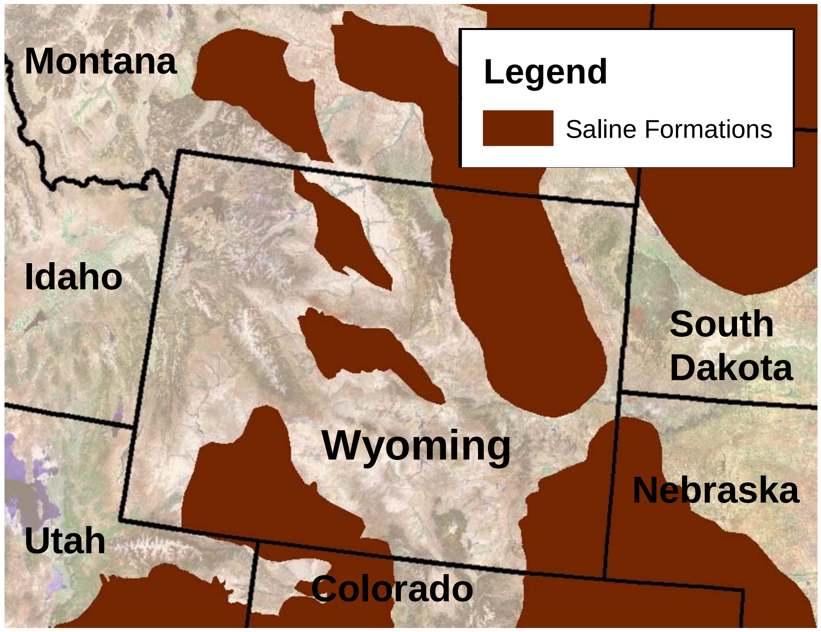
CO_2 is compressed to a pressure of 15.3 MPa (2,215 psia) in preparation for sequestration. The CO_2 product gas composition varies in the cases presented, but is expected to meet the specification described in Exhibit 2-11.

Exhibit 2-11 CO_2 Pipeline Specification

Parameter	Units	Parameter Value
Inlet Pressure	MPa (psia)	15.3 (2,215)
Outlet Pressure	MPa (psia)	10.4 (1,515)
Inlet Temperature	°C (°F)	26 (79)
N_2 Concentration	ppmv	< 300
O_2 Concentration	ppmv	< 40
Ar Concentration	ppmv	< 10

The CO_2 is transported 50 miles via pipeline to a geologic sequestration field for injection into a saline formation. Exhibit 2-12 shows the possible saline formations in Wyoming and the surrounding areas that could be used for CO_2 sequestration.

Exhibit 2-12 Saline Formations of Wyoming and Surrounding States



The CO_2 is transported and injected as a supercritical fluid in order to avoid two-phase flow and achieve maximum efficiency [18]. The pipeline is assumed to have an outlet pressure (above the supercritical pressure) of 10.4 MPa (1,515 psia) with no recompression along the way. Accordingly, CO_2 flow in the pipeline was modeled to determine the pipe diameter that results in a pressure drop of 4.8 MPa (700 psi) over a 50 mile pipeline length [19]. (Although not explored in this study, the use of boost compressors and a smaller pipeline diameter could possibly reduce capital costs for sufficiently long pipelines.) The diameter of the injection pipe will be of sufficient size that frictional losses during injection are minimal and no booster compression is required at the well-head in order to achieve an appropriate down-hole pressure.

The saline formation is at a depth of 4,055 ft and has a permeability of 22 millidarcy (a measure of permeability defined as roughly 10^{-12} Darcy) and formation pressure of 8.4 MPa (1,220 psig) [20]. This is considered an average storage site and requires roughly one injection well for each 10,320 short tons of CO_2 injected per day [20]. The assumed aquifer characteristics are tabulated in Exhibit 2-13.

Exhibit 2-13 Deep Saline Aquifer Specifications

Parameter	Units	Base Case
Pressure	MPa (psi)	8.4 (1,220)
Thickness	m (ft)	161 (530)
Depth	m (ft)	1,236 (4,055)
Permeability md		22

Parameter	Units	Base Case
Pipeline Distance	km (miles)	80 (50)
Injection Rate per Well	Tonne (ton) CO_2/day	9,360 (10,320)

2.5 CAPACITY FACTOR

This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore, capacity factor and availability are assumed to be equal. The availability for PC cases was determined using the Generating Availability Data System (GADS) for the North American Electric Reliability Council [21]. Input from EPRI and their work on the CoalFleet for Tomorrow Initiative were used to set the IGCC case capacity factor.

NERC defines an equivalent availability factor (EAF), which is essentially a measure of plant capacity factor 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 study's definition of capacity factor.

The average EAF for pulverized coal-fired plants in the 400-599 MW size range was 84.9 percent in 2004 and averaged 83.9 percent from 2000-2004. Given that many plants of this size range are older, the EAF was rounded up to 85 percent and that value was used as the greenfield supercritical PC plant capacity factor. The BART analysis of the existing subcritical PC plant uses 90 percent for the capacity factor, but 85 percent was used in this study to be consistent with the greenfield supercritical PC cases.

EPRI examined the historical forced and scheduled outage times for IGCCs and concluded that the reliability factor (which looks at forced or unscheduled outage time only) for a single train IGCC (no spares) would be about 90 percent [22]. To get the availability factor, one has to deduct the scheduled outage time. In reality the scheduled outage time differs from gasifier technology-to-gasifier technology, but the differences are relatively small and would have minimal impact on the capacity factor, so for this study it was assumed to be constant at a 30-day planned outage per year (or two 15-day outages). The planned outage would amount to 8.2 percent of the year, so the availability factor would be (90 percent - 8.2 percent), or 81.2 percent.

There are four operating IGCC's worldwide that use a solid feedstock and are primarily power producers (Polk, Wabash, Buggenum and Puertollano). A 2006 report by Higman et al. examined the reliability of these IGCC power generation units and concluded that typical annual on-stream times are around 80 percent [23]. The capacity factor would be somewhat less than the on-stream time since most plants operate at less than full load for some portion of the operating year. Given the results of the EPRI study and the Higman paper, a capacity factor of 80 percent was chosen for IGCC with no spare gasifier required.

The addition of CO_2 capture to each technology was assumed not to impact the capacity factor. This assumption was made to enable a comparison based on the impact of capital and variable operating costs only. Any reduction in assumed capacity factor would further increase the levelized cost of electricity (LCOE) for the CO_2 capture cases.

2.6 RAW WATER WITHDRAWAL AND CONSUMPTION

A water balance was performed for each case on the major water consumers in the process. The total water demand for each subsystem was determined. The internal recycle water available from various sources like boiler feedwater blowdown, moisture recovered from the coal in the drying process (IGCC cases only), and condensate from syngas was applied to offset the water demand. The difference between demand and recycle is raw water withdrawal.

In the greenfield cases, raw water makeup was assumed to be provided 50 percent by a publicly owned treatment works (POTW) and 50 percent from groundwater. In the existing subcritical PC cases, raw water is obtained from the Green River. Raw water withdrawal is defined as the water metered from a water source and used in the plant processes for any and all purposes, such as cooling tower makeup, boiler feedwater makeup, ash handling makeup, syngas humidification, and quench system makeup. Withdrawal represents the gross impact of the process on the water source.

Some water from the process can be treated and returned to the source, referred to as process discharge. The main source of process discharge is cooling tower blowdown with smaller amounts from the sour water stripper in the IGCC cases. It was assumed that 90 percent of the cooling tower blowdown could be returned to the source, and the remaining 10 percent would be sent to the ash ponds to evaporate. Similarly, 90 percent of the sour water stripper blowdown is recycled as process discharge and the balance is sent to the slag pile. The difference between raw water withdrawal and process discharge is raw water consumption and represents the net impact on the water source.

The largest consumer of raw water in all cases is cooling tower makeup. The IGCC and supercritical PC cases utilize a parallel cooling system with half of the turbine exhaust steam condensed in an air-cooled condenser and half in a water-cooled condenser. The subcritical PC retrofit cases utilize a water-cooled condenser only. The cooling water is provided by a mechanical draft, evaporative cooling tower, and all process blowdown streams were assumed to be treated and recycled to the cooling tower. The design ambient wet bulb temperature of 3°C (37°F) (Exhibit 2-1) was used to achieve a cooling water temperature of 9°C (48°F), using an approach of 6°C (11°F). The cooling water range was assumed to be 11°C (20°F). The cooling tower makeup rate was determined using the following [24]:

- Evaporative losses of 0.8 percent of the circulating water flow rate per 10°F of range
- Drift losses of 0.001 percent of the circulating water flow rate
- Blowdown losses were calculated as follows:
    - Blowdown Losses = Evaporative Losses / (Cycles of Concentration - 1)

Where cycles of concentration are a measure of water quality, and a mid-range value of 4 was chosen for this study.

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, raw water withdrawal by difference, process discharge, and raw water consumption. The existing subcritical PC plant water balance was calculated using the same methodology as the greenfield cases.

2.7 COST ESTIMATING METHODOLOGY

The cost estimates for this project were derived from previous estimates on similar plant types and sizes. The original estimates were done for an ongoing DOE project by WorleyParsons Group Inc. (WorleyParsons) that included a Shell IGCC using PRB coal with and without CO_2 capture and a supercritical PC plant using PRB coal with and without CO_2 capture. WorleyParsons estimated the Total Plant Cost (TPC) and the Operation and Maintenance (O&M) costs for each technology. The estimates have an accuracy of ±30 percent.

The costing methodology used by WorleyParsons for the baseline estimates is described below. At the end of this section the methodology used to scale the WorleyParsons estimates is described.

WorleyParsons used an in-house database and conceptual estimating models for the capital cost and O&M cost estimates. Costs were further calibrated using a combination of adjusted vendor-furnished and actual cost data from recent design and design/build projects.

The capital costs for each cost account were reviewed by comparing individual accounts across each of the similar technologies to ensure an accurate representation of the relative cost differences between the cases and accounts. All capital costs are presented as "overnight costs" expressed in June 2007 dollars.

Capital costs are presented at the TPC level. TPC includes:

- Equipment (complete with initial chemical and catalyst loadings),
- Materials,
- Labor (direct and indirect),
- Engineering and construction management, and
- Contingencies (process and project).

Owner's costs were subsequently calculated and added to the TPC, the result of which is Total Overnight Cost (TOC). Additionally, financing costs were estimated and added to TOC to provide Total As-Spent Cost (TASC). The levelized cost of electricity was calculated using TOC.

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).

Non-CO_2 Capture Plant Maturity

The non-capture IGCC cases are based on commercial offerings; however, there have been very limited sales of these units so far. These non-CO_2-capture IGCC plant costs are less mature in the learning curve than PC plants, and the costs listed reflect the "next commercial offering" level of cost rather than mature n^{th}-of-a-kind cost. Thus, each of these cases reflects the expected cost for the next commercial sale of each of these respective technologies.

CO_2 Removal Maturity

The pre-combustion CO_2 removal technology for the IGCC capture cases has a stronger commercial experience base than post-combustion technologies for PC plants. Pre-combustion CO_2 removal from syngas streams has been proven in chemical processes with similar conditions to that in IGCC plants, but has not been demonstrated in IGCC applications. While no commercial IGCC plant yet uses CO_2 removal technology in commercial service, there are currently IGCC plants with CO_2 capture well along in the planning stages.

While the post-combustion technology for the PC plants has been practiced at smaller scale, it has never been practiced at a scale equivalent to that required in this study. There are domestic amine-based CO_2 capture systems operating on coal-derived flue gas at scales ranging from 150-800 TPD [25]. Plants in this study will capture on average 11,500 TPD. Consequently the CO_2 capture cases are treated as first-of-a-kind (FOAK).

Contracting Strategy

The estimates are based on an Engineering/Procurement/Construction Management (EPCM) approach utilizing multiple subcontracts. This approach provides the Owner with greater control of the project, while minimizing, if not eliminating most of the risk premiums typically included in an Engineer/Procure/Construct (EPC) contract price.

In a traditional lump sum EPC contract, the Contractor assumes all risk for performance, schedule, and cost. However, as a result of current market conditions, EPC contractors appear more reluctant to assume that overall level of risk. Rather, the current trend appears to be a modified EPC approach where much of the risk remains with the Owner. Where Contractors are willing to accept the risk in EPC type lump-sum arrangements, it is reflected in the project cost. In today's market, Contractor premiums for accepting these risks, particularly performance risk, can be substantial and increase the overall project costs dramatically.

The EPCM approach used as the basis for the estimates here is anticipated to be the most cost effective approach for the Owner. While the Owner retains the risks and absorbs higher project management costs, the risks become reduced with time, as there is better scope definition at the time of contract award(s).

Estimate Scope

The estimates represent a complete power plant facility on a generic site. Site-specific considerations such as unusual soil conditions, special seismic zone requirements, or unique local conditions such as accessibility, local regulatory requirements are not considered in the estimates.

The estimate 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. The single exception to the fence line limit is in the CO_2 capture cases where costs are included for TS&M of the CO_2.

Labor costs are based on Merit Shop (non-union), in a competitive bidding environment.

Capital Costs

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

Key equipment costs for each of the cases were calibrated to reflect recent quotations and/or purchase orders for other ongoing in-house power or process projects. These include, but are not limited to the following equipment:

- Pulverized Coal Boilers
- Combustion Turbine Generators
- Steam Turbine Generators
- Circulating Water Pumps and Drivers
- Cooling Towers
- Condensers
- Air Separation Units (partial)
- Main Transformers

Other key estimate considerations include the following:

- Labor costs are based on Midwest, Merit Shop using factors from PAS, Inc. [26]. PAS presents information for eight separate regions. Previous studies used a generic

Midwestern site, typical of Region 5 (IL, IN, MI, MN, OH, WI). The weighted average rate for Region 8 (CO, MT, ND, SD, UT, WY) is within less than one-half of one percent of that for Region 5. The difference is inconsequential so the same rates used in other NETL studies were maintained in this study.

- The estimates are based on a competitive bidding environment, with adequate skilled craft labor available locally.
- Labor is based on a 50-hour work-week (5-10s). No additional incentives such as per-diems 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. Current indications are that regional craft shortages are likely over the next several years. The types and amounts of incentives will vary based on project location and timing relative to other work. The cost impact resulting from an inadequate local work force can be significant.
- 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.
- Costs are limited to within the “fence line,” terminating at the high voltage side of the main power transformers with the exception of costs included for TS&M of CO_2 in all capture cases.
- Engineering and Construction Management were estimated as a percent of bare erected cost. These costs consist of all home office engineering and procurement services as well as field construction management costs. Site staffing generally includes a construction manager, resident engineer, scheduler, and personnel for project controls, document control, materials management, site safety and field inspection.
- All capital costs are presented as “Overnight Costs” in June 2007 dollars. Escalation to period-of-performance is specifically excluded.

Price Escalation

A significant change in power plant cost occurred in recent years due to the significant increases in the pricing of equipment and bulk materials. This estimate includes these increases. All vendor quotes used to develop these estimates were received within the last three years. The price escalation of vendor quotes incorporated a vendor survey of actual and projected pricing increases from 2004 through mid-2007 that WorleyParsons conducted for a recent project. The results of that survey were used to validate/recalibrate the corresponding escalation factors used in the conceptual estimating models.

Cross-comparisons

In all technology comparison studies, the relative differences in costs are often more significant than the absolute level of TPC. This requires cross-account comparison between technologies to review the consistency of the direction of the costs. As noted above, the capital costs were reviewed and compared across each of the similar technologies to ensure that a consistent representation of the relative cost differences is reflected in the estimates.

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

- The combustion turbines for the IGCC capture cases include an additional cost for firing a high hydrogen content fuel.
- The Shell gasifier syngas cooling configuration is different between the CO_2-capture and non-CO_2-capture cases, resulting in a significant differential in thermal duty between the syngas coolers for the two cases.

Exclusions

The capital cost estimate includes all anticipated costs for equipment and materials, installation labor, professional services (Engineering and Construction Management), and contingency. The following items are extremely project and site specific and are therefore excluded from the capital costs:

- Escalation to period-of-performance
- Owner's costs – these are accounted for separately and are described below.
- Site specific considerations – including but not limited to seismic zone, accessibility, local regulatory requirements, excessive rock, piles and laydown space
- Labor incentives in excess of a 5-day/10-hour work week
- Additional premiums associated with an EPC contracting approach

Contingency

Both the project contingency and process contingency costs represent costs that are expected to be spent in the development and execution of the project that are not yet fully reflected in the design. It is industry practice to include project contingency in the TPC to cover project uncertainty and the cost of any additional equipment that would result during detailed design. Likewise, the estimates include process contingency to cover the cost of any additional equipment that would be required as a result of continued technology development.

Project Contingency

Project contingencies were added to each of the capital accounts to cover project uncertainty and the cost of any additional equipment that could result from detailed design. The project contingencies represent costs that are expected to occur. Each bare erected cost account was evaluated against the level of estimate detail, field experience, and the basis for the equipment pricing to define project contingency.

The capital cost estimates associated with the plant designs in this study were derived from various sources which include prior conceptual designs and actual design and construction of both process and power plants.

The Association for the Advancement of Cost Engineering (AACE) International recognizes five classes of estimates. On the surface, the level of project definition of the cases evaluated in this study would appear to fall under an AACE International Class 5 Estimate, associated with less than 2 percent project definition, and based on preliminary design methodology. However, the study cases are actually more in line with the AACE International Class 4 Estimate, which is associated with equipment factoring, parametric modeling, historical relationship factors, and broad unit cost data.

Based on the AACE International contingency guidelines as presented in NETL's "Quality Guidelines for Energy System Studies" it would appear that the overall project contingencies for the subject cases should be in the range of 30 to 40 percent [27]. However, such contingencies are believed to be too high when the basis for the cost numbers is considered. The costs have been extrapolated from an extensive data base of project costs (estimated, quoted, and actual), based on both conceptual and detailed designs for the various technologies. This information has been used to calibrate the costs in the current studies, thus improving the quality of the overall estimates. As such, the overall project contingencies should be more in the range of 15 to 20 percent with the capture cases being higher than the non-capture cases.

Process Contingency

Process contingency is intended to compensate for uncertainties arising as a result of the state of technology development. Process contingencies have been applied to the estimates as follows:

- Gasifiers and Syngas Coolers – 15 percent on all cases – next-generation commercial offering and integration with the power island
- Two Stage Selexol – 20 percent on all capture cases - unproven technology at commercial scale in IGCC service
- CO_2 Removal System – 20 percent on all PC capture cases – post-combustion process unproven at commercial scale for power plant applications
- Mercury Removal – 5 percent on all cases – minimal commercial scale experience in IGCC applications
- Combustion Turbine Generator – 5 percent on all non-capture cases – syngas firing and ASU integration; 10 percent on all capture cases – high hydrogen firing.
- Instrumentation and Controls – 5 percent on all accounts

AACE International provides standards for process contingency relative to technology status; from commercial technology at 0 to 5 percent to new technology with little or no test data at 40 percent. The process contingencies as applied in this study are consistent with the AACE International standards.

All contingencies included in the TPC, both project and process, represent costs that are expected to be spent in the development and execution of the project.

Operations and Maintenance (O&M)

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

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

There are two components of O&M costs; fixed O&M, which is independent of power generation, and variable O&M, which is proportional to power generation.

Operating Labor

Operating labor cost was determined based on the number of operators required for each specific case. The average base labor rate used to determine annual cost is $34.65/hr [26]. The associated labor burden is estimated at 30 percent of the base labor rate.

Maintenance Material and Labor

Maintenance cost was evaluated on the basis of relationships of maintenance cost to initial capital cost. This represents a weighted analysis in which the individual cost relationships were considered for each major plant component or section. The exception to this is the maintenance cost for the combustion turbines, which is calculated as a function of operating hours.

Administrative and Support Labor

Labor administration and overhead charges are assessed at rate of 25 percent of the burdened operation and maintenance labor.

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

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

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

Waste Disposal

Waste quantities and disposal costs were determined similarly to the consumables. The slag from the IGCC cases is considered a waste with a disposal cost of $16.23/ton. The carbon used for mercury control is considered a hazardous waste with disposal cost of $834/ton.

Co-Products and By-Products (Other than CO_2)

IGCC Cases

By-product quantities were also determined similarly to the consumables. However, due to the variable marketability of these by-products, specifically sulfur, no credit was taken for its potential saleable value. Nor were any of the cases penalized for their potential disposal cost. That is, for this evaluation, it is assumed that the by-product or co-product value simply offset disposal costs, for a net zero in operating costs. Similarly slag is a potential by-product in certain markets and would have potential marketability. However, slag is also considered a waste in this study with a concomitant disposal cost.

PC Cases

Due to the variable marketability of these by-products (bottom ash and fly ash co-mingled with flue gas desulfurization (FGD) products) no credit was taken for potential saleable value.

It should be noted that by-product credits and/or disposal costs could potentially be an additional determining factor in the choice of technology for some companies and in selecting some sites. A high local value of the product can establish whether or not added capital should be included in the plant costs to produce a particular co-product. Ash is a potential by-product in certain markets and would have potential marketability. However, since in these cases the fly ash contains mercury from carbon injection and FGD byproducts, it was assumed to be a waste material rather than a saleable byproduct. Similarly the bottom ash was considered a waste with both materials having a concomitant disposal cost of $17.89/tonne ($16.23/ton).

Owner's Costs

The owner's costs included in the TOC cost estimate are shown in Exhibit 2-14.

Exhibit 2-14 Owner's Costs Included in TOC

Owner's Cost	***Comprised of***
Preproduction Costs	• *6 months operating, maintenance, and administrative & support labor* • *1 month maintenance materials* • *1 month non-fuel consumables* • *1 month of waste disposal costs* • *25% of one month's fuel cost @ 100% capacity factor* • *2% of TPC*
Inventory Capital	• *60 day supply of fuel and consumables @100% capacity factor* • *0.5% of TPC (spare parts)*
Land	• *$3,000/acre (300 acres for greenfield IGCC and PC)*
Financing Costs	• *2.7% of TPC*
Other Owner's Costs	• *15% of TPC*
Initial Cost for Catalyst and Chemicals	• *All initial fills not included in BEC*
Prepaid Royalties	• *Not included in owner's costs (included with BEC)*
Taxes & Insurance	• *2% of TPC (Fixed O&M cost)*
AFUDC and Escalation	• *Varies based on levelization period and financing scenario* • *33-yr IOU high risk: TASC = TOC *1.078* • *33-yr IOU low risk: TASC = TOC * 1.075* • *35-yr IOU high risk: TASC = TOC * 1.140* • *35-yr IOU low risk: TASC = TOC * 1.134*

The category labeled "Other Owner's Costs" includes the following:

- *Preliminary feasibility studies, including a Front-End Engineering Design (FEED) study*
- *Economic development (costs for incentivizing local collaboration and support)*
- *Construction and/or improvement of roads and/or railroad spurs outside of site boundary.*
- *Legal fees*
- *Permitting costs*
- *Owner's engineering (staff paid by owner to give third-party advice and to help the owner oversee/evaluate the work of the EPC contractor and other contractors)*

- *Owner's contingency: sometimes called "management reserve", these are funds to cover costs relating to delayed startup, fluctuations in equipment costs, unplanned labor incentives in excess of a five-day/ten-hour-per-day work week*

Cost items excluded from "Other Owner's Costs" include:

- *EPC Risk Premiums: Costs estimates are based on an Engineering Procurement Construction Management (EPCM) approach utilizing multiple subcontracts, in which the owner assumes project risks for performance, schedule and cost. This approach provides the owner with greater control of the project, while minimizing, if not eliminating most of the risk premiums typically included in a lump-sum, "turnkey" Engineer/Procure/Construct (EPC) contract, under which the EPC contractor assumes some or all of the project risks. The EPCM approach used as the basis for the estimates here is anticipated to be the most cost effective approach for the owner.*
- *Transmission interconnection: the cost of interconnecting with power transmission infrastructure beyond the plant busbar.*
- *Taxes on capital costs: all capital costs are assumed to be exempt from state and local taxes.*
- *Unusual site improvements: normal costs associated with improvements to the plant site are included in the bare erected cost, assuming that the site is level and requires no environmental remediation. Unusual costs associated with the following design parameters are excluded: flood plain considerations, existing soil/site conditions, water discharges and reuse, rainfall/snowfall criteria, seismic design, buildings/enclosures, fire protection, local code height requirements, noise regulations.*

CO_2 Transport, Storage and Monitoring

For those cases that feature CO_2 capture, the capital and operating costs for CO_2 TS&M were independently estimated by NETL. Those costs were converted to a levelized cost of electricity (LCOE) and combined with the plant capital and operating costs to produce an overall LCOE.

The transport and storage (T&S) capital and operating costs were assessed using metrics published in a DOE sponsored report entitled *Economic Evaluation of CO_2 Storage and Sink Enhancement Options* [28]. These costs were escalated from the 1999-year dollars described in the report to June 2007-year dollars using cost indices appropriate to that cost type. Capital costs were escalated using the Chemical Engineering Plant Cost Index Report and operating costs were escalated using the U.S. Bureau of Labor Statistics (BLS) Producer Price Indices (PPI) for the oil and gas industry.

Capital costs were levelized over a 30-year period and include both a 30 percent process contingency factor and a 20 percent project contingency factor in accordance with NETL's Systems Analysis Guidelines [29].

T&S costs are also assessed in terms of removed or avoided emissions cost, which requires power plant specific information such as plant efficiency, capacity factor, and emission rates.

Monitoring costs were evaluated based on the methodology set forth in the IEA Greenhouse Gas R&D Programme's *Overview of Monitoring Projects for Geologic Storage Projects* report [30]. In this scenario, operational monitoring of the CO_2 plume occurs over thirty years and closure monitoring occurs for the following fifty years (for a total of eighty years). Operational and closure monitoring costs are assumed to be proportional to the plume size plus a fixed cost, with closure monitoring costs evaluated at half the value of the operational costs. The present value of the life-cycle costs is assessed at a 10 percent discount rate and a capital fund is set up to pay for these costs over the eighty year monitoring cycle.

High pressure (2,200 psig) CO_2 is provided at the power plant gate and is transported via pipeline to a geologic storage site where it can be safely sequestered. It is transported and injected as a supercritical fluid in order to avoid two-phase flow and achieve maximum efficiency [28]. A minimum pipeline outlet pressure of 1,500 psig is utilized in order to ensure the CO_2 exiting the pipeline is supercritical and the pipeline is sized such that no recompression stations are needed. Utilizing this large pressure drop also minimizes the pipeline diameter required, and therefore transport capital cost.

The storage site evaluated is a saline aquifer at a depth of 4,055 feet with a permeability of 22 md and down-hole pressure of 1,220 psig [28] as shown in Exhibit 2-13. This is considered an average storage site and requires roughly one injection well for each 10,300 tons of CO_2 injected per day [28].

Exhibit 2-15 and Exhibit 2-16 detail the T&S cost metrics for the deep, saline aquifer described above. Transport capital costs are directly dependent on both pipeline length and diameter and constitute a significant portion of the overall transport, storage, and monitoring costs. Specific costs will be site specific based on right-of-way, topography, and other issues, but in this study the basis costs outlined in this section will be used. Costs from the *Economic Evaluation of CO_2 Storage and Sink Enhancement Options* were escalated from $33,000/inch-Diameter/mile in 1999-year dollars to $47,175/inch-Diameter/mile in June-2007 dollars using the Chemical Engineering Plant Cost Index for piping, valves and fittings.

Exhibit 2-15 Transport (Pipeline) Costs

Cost Type	Units	Cost
Capital	$/inch-Diameter/mile	$47,175
Fixed O&M	$/mile/year	$8,350

The order of magnitude of this cost appears to be valid based on a recent testimony from Ronald T. Evans, Senior Vice President of Denbury Resources, Inc. to the U.S. Senate Committee on Energy and Natural Resources. In his testimony, Mr. Evans states that pipeline costs have dramatically increased in recent years and of the three CO_2 pipelines Denbury has constructed in recent years, the costs have ranged from $30,000//inch-Diameter/mile in 2006, $55,000/inch-Diameter/mile in 2007 and an approximate $100,000/inch-Diameter/mile for a planned pipeline

[31]. With regards to the latter $100,000/inch-Diameter/mile pipeline, he states that issues such as route obstacles and terrain inflate the cost of that particular pipeline. However, it provides a data point that shows the $47,175/inch-Diameter/mile figure used in this study is a reasonable cost metric [31].

The fixed O&M costs related to transport are inclusive of pipeline maintenance and monitoring and constitute a large portion of the combined transport and storage costs. These costs were escalated using the Support Activities for Oil and Gas Operations BLS PPI [32]. No variable O&M costs were assessed [28].

Storage costs include initial site assessment, injection wells, and associated injection well equipment. The site assessment cost is a fixed cost and was escalated using the Drilling Oil and Gas Wells BLS PPI [32].

Exhibit 2-16 Geological Storage Costs

Cost Type	Units	Cost
Capital		
Initial Site Assessment	$	$4,931,547
Injection Wells	$/injection well (*see formula*)[1,2]	$\$189{,}242 \times e^{0.0008 \times well-depth}$
Injection Equipment	$/injection well (*see formula*)[2]	$\$92{,}916 \times \left(\frac{7{,}389}{280 \times \#\,of\ injection\ wells} \right)^{0.5}$
O&M		
Normal Daily Expenses (Fixed O&M)	$/injection well	$11,086
Consumables (Variable O&M)	$/injection well	$29,619
Surface Maintenance (Fixed O&M)	*see formula*	$\$22{,}504 \times \left(\frac{7{,}389}{280 \times \#\,of\ injection\ wells} \right)^{0.5}$

Subsurface Maintenance (Fixed O&M)	$/ft-depth/inject. well	$2.07

[1]The units for the "well depth" term in the formula are meters of depth.
[2]The formulas at right describe the cost per injection well and in each case the number of injection wells should be multiplied the formula in order to determine the overall capital cost.

The injection well and well equipment costs are a function of the number of wells. The number of injection wells is largely determined by reservoir characteristics such as Permeability, Downhole Injection Pressure Differential, and Thickness which can result in significantly different storage costs. The Downhole Injection Pressure Differential is the difference between the reservoir pressure and the CO_2 pressure at the bottom of the well hole. The pressure differential can be changed by manipulating the injection pressure. These costs were evaluated based on what is considered to be an average storage site, as described in Table 1.

The storage fixed O&M costs consist of Normal Daily Expenses, Surface Maintenance, and Subsurface Maintenance costs, with Surface Maintenance comprising the largest portion of costs. Consumables represent the only variable O&M cost. All storage O&M Costs were escalated using the Support Activities for Oil and Gas Operations BLS [32].

Levelized Cost of Electricity

The revenue requirement method of performing an economic analysis of a prospective power plant has been widely used in the electric utility industry. This method permits the incorporation of the various dissimilar components for a potential new plant into a single value that can be compared to various alternatives. The revenue requirement figure-of-merit in this report is cost of electricity (COE) levelized over a 30 year period and expressed in $/MWh (numerically equivalent to mills/kWh). The 30-year LCOE was calculated using a simplified model derived from the NETL Power Systems Financial Model [33].

The equation used to calculate LCOE is as follows:

$$LCOE_P = \frac{(CCF_P)(TPC) + (LF_P)[(OC_{F1}) + (OC_{F2}) + \ldots] + (CF)(LF_P)[(OC_{V1}) + (OC_{V2}) + \ldots]}{(CF)(MWh)}$$

where

$LCOE_P$ = levelized cost of electricity over P years, $/MWh

P = levelization period (e.g., 10, 20 or 30 years)

CCF_P = capital charge factor for a levelization period of P years

TPC = total plant cost, $

LF = levelization factor

OC_{Fn} = category n fixed operating cost for the initial year of operation (but expressed in "first-year-of-construction" year dollars)

CF = plant capacity factor

OC_{Vn} = category n variable operating cost at 100 percent capacity factor for the initial year of operation (but expressed in "first-year-of-construction" year dollars)

MWh = annual net megawatt-hours of power generated at 100 percent capacity factor

All costs are expressed in June 2007 dollars, and the resulting LCOE is also expressed in June 2007 year dollars.

In CO_2 capture cases, the LCOE for TS&M costs was added to the LCOE calculated using the above equation to generate a total cost including CO_2 capture, sequestration and subsequent monitoring.

Although their useful life is usually well in excess of thirty years, a thirty-year levelization period is typically used for large energy conversion plants and is the levelization period used in this study.

The technologies modeled in this study were categorized as investor owned utility (IOU) high risk except for the SC PC and subcritical PC non-capture cases, which were categorized as low risk. The resulting capital charge factor and levelization factors are shown in Exhibit 2-17. The levelization factors assume a nominal 3 percent escalation for all cost categories.

Exhibit 2-17 Economic Parameters for LCOE Calculation

	High Risk (5 year construction period)	*Low Risk (5 year construction period)*	*High Risk (3 year construction period)*
Capital Charge Factor	*0.1773*	*0.1691*	*0.1567*
General Levelization Factor	*1.443*	*1.4299*	*1.4101*

The economic assumptions used to derive the capital charge factors are shown in Exhibit 2-18. The difference between the high risk and low risk categories is manifested in the debt-to-equity ratio and the weighted cost of capital. The values used to generate the capital charge factors and levelization factors in this study are shown in Exhibit 2-19.

Exhibit 2-18 Parameter Assumptions for Capital Charge Factors

Parameter	***Value***
Income Tax Rate	*38% (Effective 34% Federal, 6% State)*
Repayment Term of Debt	*15 years*
Grace Period on Debt Repayment	*0 years*
Debt Reserve Fund	*None*
Capital Depreciation	*20 years, 150% declining balance*
Working Capital	*zero for all parameters*
Plant Economic Life	*30 years*
Investment Tax Credit	*0%*
Tax Holiday	*0 years*
All other additional capital costs ($)	*0*
Capital Cost Escalation During Construction (nominal annual rate)	*3.6%*[1]
Construction Duration	*5 years (greenfield) / 3 years (retrofit)*

[1] *A nominal average annual rate of 3.6 percent is assumed for escalation of capital costs during construction. This rate is equivalent to the nominal average annual escalation rate for process plant construction costs between 1947 and 2008 according to the Chemical Engineering Plant Cost Index.*

Exhibit 2-19 Financial Structure for Investor Owned Utility High and Low Risk Projects

Type of Security	***% of Total***	***Current (Nominal) Dollar Cost***	***Weighted Current (Nominal) Cost***	***After Tax Weighted Cost of Capital***
Low Risk				
Debt	*50*	*4.5%*	*2.25%*	
Equity	*50*	*12%*	*6%*	
Total			*8.25%*	*7.39%*
High Risk				
Debt	*45*	*5.5%*	*2.475%*	
Equity	*55*	*12%*	*6.6%*	
Total			*9.075%*	*8.13%*

Cost Scaling Procedures

The WorleyParsons estimates were scaled for this study as described below.

Total Plant Cost

Each cost subaccount was scaled using an appropriate process parameter and a scaling exponent derived from the WorleyParsons baseline estimates. For example, each Coal Handling subaccount was scaled based on coal feed rate using an exponent of 0.62 as follows:

Scaled Cost = Reference Cost x (Scaled coal feed rate / Reference coal feed rate)$^{0.62}$

In total, 25 process parameters were used to scale the IGCC costs, 15 parameters were used to scale the greenfield SC PC costs and 7 parameters were required to scale the subcritical PC plant retrofit costs. Additional cost data for the subcritical plant was derived from the recent CH2MHill BART analysis of Unit 4 [8].

The TPC for Case 7, the existing subcritical PC plant, was assumed to be zero. The TPC for the CO_2 retrofit cases (8 and 9) included the Econamine FG Plus process and ancillary components that were scaled based on incremental process requirements above existing plant capacity. For example, in Case 8 the circulating water flow rate requirement increased by 81,000 gpm over the current plant capacity. The cost accounts related to the circulating water flow (circulating water pumps, circulating water system auxiliaries, circulating water piping and component cooling water systems and circulating water systems and foundations) were scaled from the reference estimate based on the incremental flow requirement and the appropriate scaling exponent.

The CH2MHill BART analysis provided costs for the new low NOx burners and the required upgrades to the flue gas desulfurization system. These costs were used directly in subaccount 4.2 (LNB's and OFA) and subaccount 5.1 (Absorber Vessel and Accessories) [8]. The SCR costs were also taken from the BART analysis in the sensitivity case that assumed NSR would be activated.

O & M Costs

The O&M costs for the greenfield IGCC and SC PC cases were calculated using the same staffing requirements, labor rates, labor burdens, overhead charges, waste disposal costs and commodity unit costs as in the reference cases estimated previously by WorleyParsons. The maintenance labor and material costs were calculated by maintaining the same percentage of bare erected cost as used in the reference estimates.

The existing subcritical PC retrofit plant O&M costs were obtained from Global Energy Decisions' Energy Velocity Database [34]. The O&M costs represent the marginal cost of electricity exclusive of any capital charges. The database provided the fuel component of the O&M costs and the total O&M costs. By difference the total of the variable and fixed O&M costs was calculated. The magnitude of the fixed O&M costs indicated that property taxes and insurance were excluded. To be consistent with the greenfield cases, an estimate of taxes and insurance was made and applied to the fixed operating cost. The estimate was based on 2 percent of the TPC, and the TPC was estimated by multiplying the ratio of the gross power output to the 0.7 power using the corresponding greenfield PC case.

The existing subcritical PC retrofit O&M costs in the CO_2 retrofit cases include the baseline costs from the Energy Velocity Database plus the additional costs incurred from retrofit of the CO_2 capture technology. The additional O&M costs include the following:

- One additional skilled operator and 1.3 additional operators (represents the delta between capture and non-capture in the SC PC cases)
- Maintenance labor and maintenance materials calculated as a percentage of the bare erected cost of the CO_2 capture technology and ancillary equipment
- Additional raw water makeup at a cost of $1.22/1000 gallons (obtained from the BART analysis)
- Additional water treatment chemicals estimated at the same relative makeup rate as the SC PC cases (on the incremental makeup water only)
- Makeup chemicals required by the Econamine FG Plus system, including amine solvent, sodium hydroxide, sulfuric acid, activated carbon and corrosion inhibitor at the same unit costs as used in the SC PC cases
- Incremental soda ash required after the FGD upgrade at a cost of $80/ton (obtained from the BART analysis)
- Incremental FGD waste disposal at a cost of $24.33/ton (obtained from the BART analysis)

The addition of CO_2 capture to an existing plant results in a de-rating of the plant output because of extraction steam required to regenerate the solvent and because of the additional auxiliary load from the CO_2 capture and compression process. In this analysis it was assumed that the plant would simply operate with a reduced net output. Alternatively, the plant could purchase power to compensate for the de-rated capacity. However, that option was not investigated in this study.

The IGCC plants also experience a decrease in net power output with CO_2 capture because of the fixed combustion turbine output constraint. However, the greenfield IGCC plants could add an additional train of gasification and a third combustion turbine if additional output is required with minimal impact to the cost of electricity. Thus makeup electricity cost was also not considered for the IGCC plant cases.

3. IGCC POWER PLANTS

Three IGCC power plant configurations were evaluated and the results are presented in this section. Each design is based on a market-ready technology that is assumed to be commercially available to support startup in 2015.

The three cases are based on the Shell gasifier using Montana Rosebud PRB coal, with and without CO_2 capture. As discussed in Section 1, the net output for the three cases varies because of the constraint imposed by the fixed gas turbine output, the site elevation, and the high auxiliary loads imparted by the CO_2 capture process.

The combustion turbine is based on an advanced F-class design. The HRSG/steam turbine cycle is 12.4 MPa/564°C/564°C (1800 psig/1048°F/1048°F) for the non-CO_2 capture case; 12.4 MPa/549°C/549°C (1800 psig/1020°F/1020°F) for the partial CO_2 capture case; and 12.4 MPa/536°C/536°C (1800 psig/996°F/996°F) for the 90 percent CO_2 capture case. The capture cases have a lower main and reheat steam temperature primarily because the turbine inlet temperature is reduced to allow for a parts life equivalent to NGCC operation with a high-hydrogen content fuel, which results in a lower turbine exhaust temperature. The effect is more pronounced in the 90 percent capture case than the 1,100 lb CO_2/net-MWh capture case. The combustion turbine output is also de-rated from ISO conditions because of operating at altitude at the location used in this study.

The evaluation scope included developing heat and mass balances and estimating plant performance. Equipment lists were developed for each design to support plant capital and operating cost estimates. The evaluation basis details, including site ambient conditions, fuel composition and environmental targets, were provided in Section 2. Section 3.1 covers general information that is common to all IGCC cases, and case specific information is subsequently presented in Section 4.

3.1 COMMON PROCESS AREAS

The three Shell IGCC cases have process areas which are common to each plant configuration such as coal receiving and storage, coal drying, oxygen supply, gas cleanup, and power generation. As detailed descriptions of these process areas for each case would be burdensome and repetitious, they are presented in this section for general background information. Where there is case-specific performance information, the performance features are presented in the relevant case sections.

3.1.1 Coal Receiving and Storage

The function of the Coal Receiving and Storage system is to convey, prepare, and store the coal delivered to the plant. The scope of the system is from the minemouth up to and including the slide gate valves at the outlet of the coal storage silos. Coal receiving and storage is identical for all three IGCC cases.

Operation Description – Coal is delivered to the site by conveyors from the nearby minemouth. 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.

The reclaimer loads the coal into two vibratory feeders located in the reclaim hopper under the pile. The feeders transfer the coal onto a belt conveyor that transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 3 cm x 0 (1¼" x 0) by the crusher. A conveyor then transfers the coal to a transfer tower. In the transfer tower the coal is routed to the tripper, which loads the coal into one of three silos. Two sampling systems are supplied: the as-received sampling system and the as-fired sampling system. Data from the analyses are used to support the reliable and efficient operation of the plant.

3.1.2 Coal Drying

Reduction in coal moisture content improves the efficiency of dry-feed gasifiers, but is also required for materials handling reasons. Coal moisture consists of two components, surface moisture and inherent moisture. Low rank coals have higher inherent moisture content and total moisture content than bituminous and other high rank coals. It is necessary to reduce most, if not all, of the surface moisture for coal transport properties to be acceptable.

In a recent GTC paper, Shell examined the WTA process for drying low rank coals and considered two cases [35]:

1) Case 1: Lignite coal dried from 53 to 12 percent
2) Case 2: Subbituminous coal dried from 30 to 6 percent

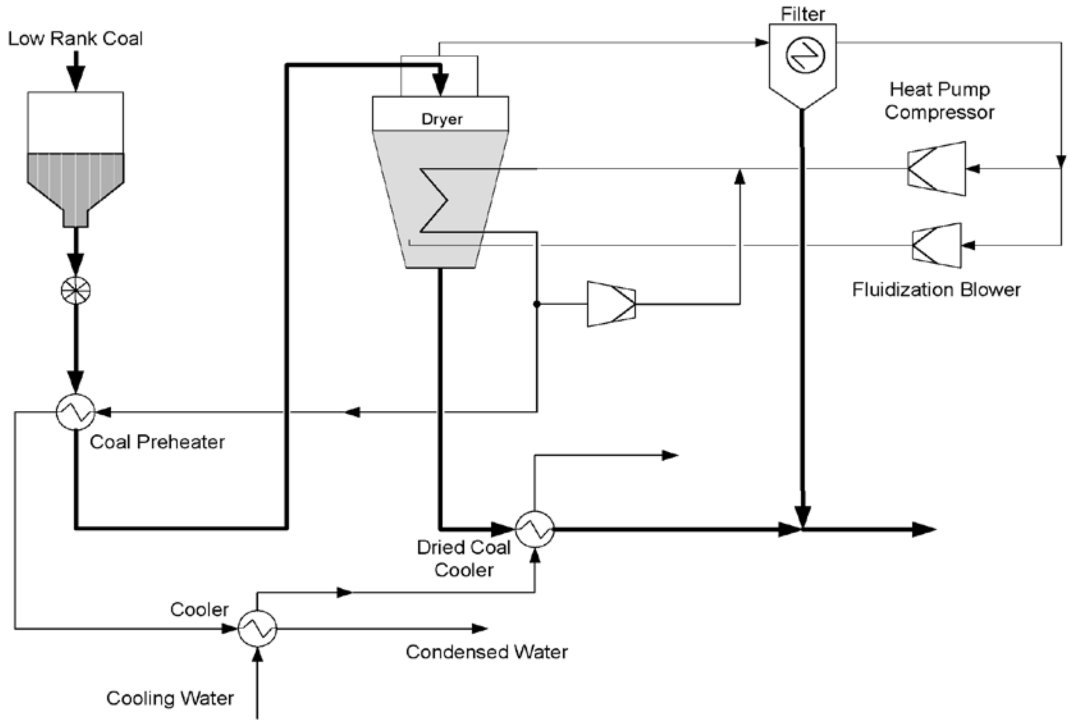
In personal correspondence with Shell, they indicated the moisture content of the coal after drying should be 3-14 percent depending on coal type [36]. EPRI and IEA recently performed studies that included the Shell gasifier using lignite coal that used a design moisture content of 5 percent entering the gasifier [37, 38].

For the Shell IGCC cases it is assumed that the subbituminous coal is dried to 6 percent moisture. This is consistent with the Shell GTC presentation and in the range suggested by the personal correspondence with Shell.

The WTA coal drying system was used in this study because of its ability to recover the water from the coal in liquid state for use in the process and the fact that syngas is not used to provide heat for drying. In conventional dryers, the water is mixed with the heating gas and discharged to atmosphere as vapor. Recovery of the coal moisture in a liquid state results in a sizable electric auxiliary load.

The ‘closed’ WTA process has been demonstrated at pilot scale. Plans for a commercial demonstration of an ‘open’ version of the process have been delayed. In spite of the uncertainty of the commercial demonstration, the potential benefit of the technology was viewed to be significant enough to use the ‘closed version’ of the process in this study. A process schematic is shown in Exhibit 3-1.

Exhibit 3-1 WTA Process Schematic



3.1.3 Air Separation Unit Choice and Integration

In order to economically and efficiently support IGCC projects, air separation equipment has been modified and improved in response to production requirements and the consistent need to increase single train output. "Elevated pressure" air separation designs have been implemented that result in distillation column operating pressures that are about twice as high as traditional plants. In this study, the main air compressor discharge pressure was set at 1.3 MPa (190 psia) compared to a traditional ASU plant operating pressure of about 0.7 MPa (105 psia) [39]. For IGCC designs, the elevated pressure ASU process minimizes power consumption and decreases the size of some of the equipment items. When the air supply to the ASU is integrated with the gas turbine, the ASU operates at or near the supply pressure from the gas turbine's air compressor.

Residual Nitrogen Injection

The residual nitrogen that is available after gasifier oxygen and nitrogen requirements have been met is often compressed and sent to the gas turbine. Since all product streams are being compressed, the ASU air feed pressure is optimized to reduce the total power consumption and to provide a good match with available compressor frame sizes.

Increasing the diluent flow to the gas turbine by injecting residual nitrogen from the ASU can have a number of benefits, depending on the design of the gas turbine:

- Increased diluent increases mass flow through the turbine, thus increasing the power output of the gas turbine while maintaining optimum firing temperatures for syngas operation. This is particularly beneficial for locations where the ambient temperature and/or elevation are high and the gas turbine would normally operate at reduced output.
- By mixing with the syngas or by being injected directly into the combustor, the diluent nitrogen lowers the firing temperature (relative to natural gas) and reduces the formation of NOx.
- In this study, the ASU nitrogen product was used as the primary diluent with a design target of reducing the syngas lower heating value (LHV) to 4.3-4.8 MJ/Nm^3 (115-129 Btu/scf). If the amount of available nitrogen was not sufficient to meet this target, additional dilution was provided through syngas humidification, and if still more dilution was required, the third option was steam injection. For the three Shell IGCC cases, nitrogen dilution was sufficient in the capture cases and humidification was required for the non-capture case.

Air Integration

Integration between the ASU and the combustion turbine can be practiced by extracting some, or all, of the ASU's air requirement from the gas turbine. Medium Btu syngas streams result in a higher mass flow than natural gas to provide the same heat content to the gas turbine. Some gas turbine designs may need to extract air to maintain stable compressor or turbine operation in response to increased fuel flow rates. Other gas turbines may balance air extraction against injection of all of the available nitrogen from the ASU. The amount of air extracted can also be varied as the ambient temperature changes at a given site to optimize year-round performance.

An important aspect of air-integrated designs is the need to efficiently recover the heat of compression contained in the air extracted from the gas turbine. Extraction air temperature is normally in the range 399 - 454°C (750 - 850°F), and must be cooled to the last stage main air compressor discharge temperature prior to admission to the ASU. High-level recovery from the extracted air occurs by transferring heat to the nitrogen stream to be injected into the gas turbine with a gas-to-gas heat exchanger.

Elevated Pressure ASU Experience in Gasification

The Buggenum, Netherlands unit built for Demkolec was the first elevated-pressure, fully integrated ASU to be constructed. It was designed to produce up to 1,796 tonnes/day (1,980 TPD) of 95 percent purity oxygen for a Shell coal-based gasification unit that fuels a Siemens V94.2 gas turbine. In normal operation at the Buggenum plant the ASU receives all of its air supply from and sends all residual nitrogen to the gas turbine.

The Polk County, Florida ASU for the Tampa Electric IGCC is also an elevated-pressure, 95 percent purity oxygen design that provides 1,832 tonnes/day (2,020 TPD) of oxygen to a GEE coal-based gasification unit, which fuels a General Electric 7FA gas turbine. All of the nitrogen produced in the ASU is used in the gas turbine. The original design did not allow for air extraction from the combustion turbine. After a combustion turbine air compressor failure in January, 2005, a modification was made to allow air extraction which in turn eliminated a bottleneck in ASU capacity and increased overall power output [40].

ASU Basis

For this study, air integration is used for the non-carbon capture case only. In the carbon capture cases, once the syngas is diluted to the target heating value, all of the available combustion air is required to maintain mass flow through the turbine and hence maintain power output.

The amount of air extracted from the gas turbine in the non-capture case is determined through a process that includes the following constraints:

- The combustion turbine must be fully loaded; i.e., sufficient gas mass flow is supplied to maximize the turbine power output at the given elevation.
- The diluted syngas must meet heating value requirements specified by a combustion turbine vendor, which ranged from 4.3-4.8 MJ/Nm^3 (115-129 Btu/scf) (LHV).

The air extraction for the non-CO_2 capture case is shown in Exhibit 3-2. It was not a goal of this project to optimize the integration of the combustion turbine and the ASU, although several recent papers have shown that providing 25-30 percent of the ASU air from the turbine compressor provides the best balance between maximizing plant output and efficiency without compromising plant availability or reliability [41, 42].

Exhibit 3-2 Air Extracted from the Combustion Turbine and Supplied to the ASU in Non-Carbon Capture Cases

	Case 1
Air Extracted from Gas Turbine, %	5.7
Air Provided to ASU, % of ASU Total	22.5

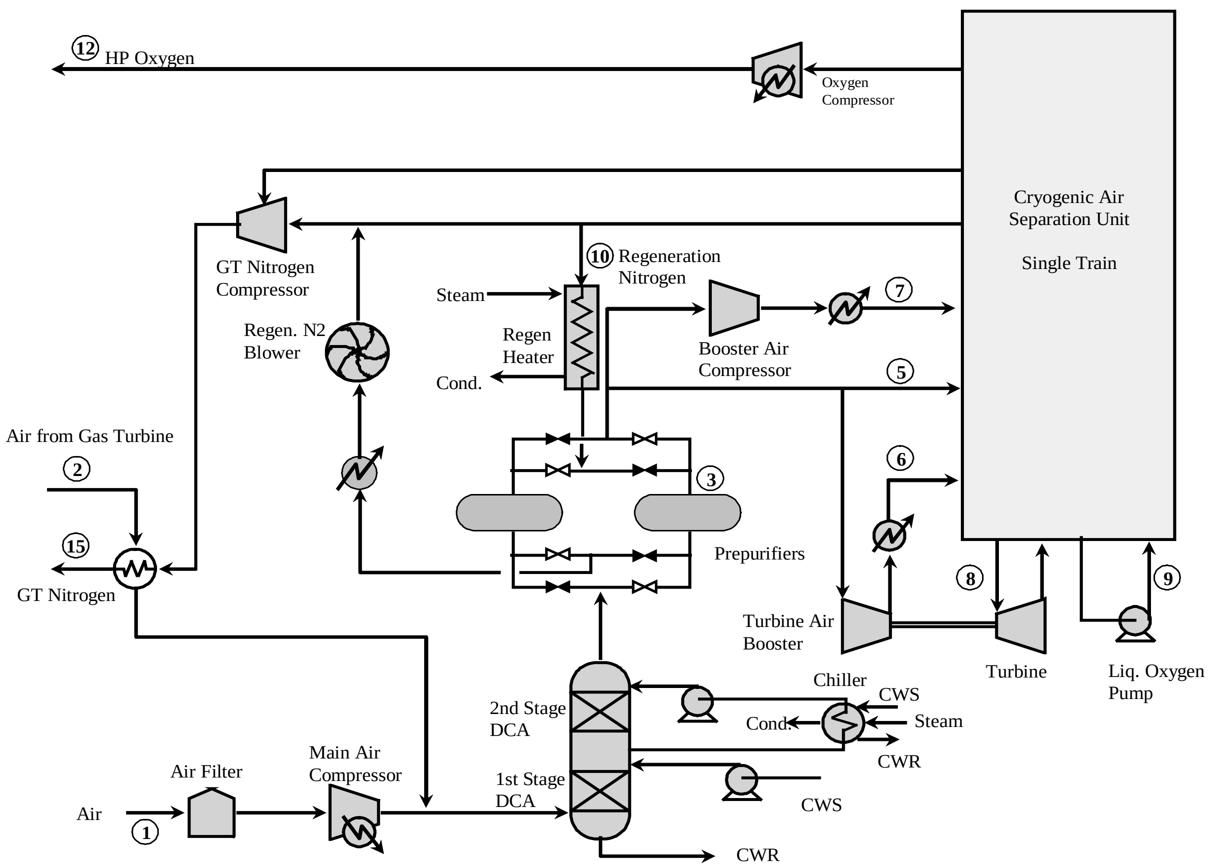
Air Separation Plant Process Description [43]

The air separation plant is designed to produce 95 mole percent O_2 for use in the gasifier. The plant is designed with two production trains, one for each gasifier. The air compressor is powered by an electric motor. Nitrogen is also recovered, compressed, and used as dilution in the gas turbine combustor. A process schematic of a typical ASU is shown in Exhibit 3-3.

The air feed to the ASU is supplied from two sources. A portion of the air is extracted from the compressor of the gas turbine (non-CO_2 capture cases only). The remaining air is supplied from a stand-alone compressor. Air to the stand-alone compressor is first filtered in a suction filter upstream of the compressor. This air filter removes particulate, which may tend to cause compressor wheel erosion and foul intercoolers. The filtered air is then compressed in the centrifugal compressor, with intercooling between each stage.

Air from the stand-alone compressor is combined with the extraction air, and the combined stream is cooled and fed to an adsorbent-based pre-purifier system. The adsorbent removes water, carbon dioxide, and C_4+ saturated hydrocarbons in the air. After passing through the adsorption beds, the air is filtered with a dust filter to remove any adsorbent fines that may be present. Downstream of the dust filter a small stream of air is withdrawn to supply the instrument air requirements of the ASU.

Exhibit 3-3 Typical ASU Process Schematic



Regeneration of the adsorbent in the pre-purifiers is accomplished by passing a hot nitrogen stream through the off-stream bed(s) in a direction countercurrent to the normal airflow. The nitrogen is heated against extraction steam (1.7 MPa [250 psia]) in a shell and tube heat exchanger. The regeneration nitrogen drives off the adsorbed contaminants. Following regeneration, the heated bed is cooled to near normal operating temperature by passing a cool nitrogen stream through the adsorbent beds. The bed is re-pressurized with air and placed on stream so that the current on-stream bed(s) can be regenerated.

The air from the pre-purifier is then split into three streams. About 70 percent of the air is fed directly to the cold box. About 25 percent of the air is compressed in an air booster compressor. This boosted air is then cooled in an aftercooler against cooling water in the first stage and against chilled water in the second stage before it is fed to the cold box. The chiller utilizes low pressure process steam at 0.45 MPa (65 psia). The remaining 5 percent of the air is fed to a turbine-driven, single-stage, centrifugal booster compressor. This stream is cooled in a shell and tube aftercooler against cooling water before it is fed to the cold box.

All three air feeds are cooled in the cold box to cryogenic temperatures against returning product oxygen and nitrogen streams in plate-and-fin heat exchangers. The large air stream is fed directly to the first distillation column to begin the separation process. The second largest air stream is liquefied against boiling liquid oxygen before it is fed to the distillation columns. The third, smallest air stream is fed to the cryogenic expander to produce refrigeration to sustain the cryogenic separation process.

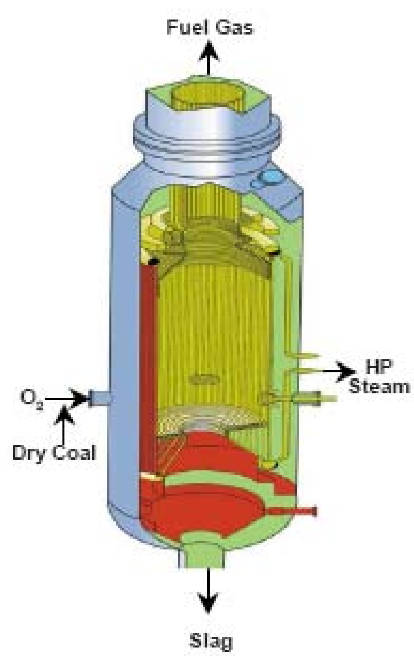
Inside the cold box the air is separated into oxygen and nitrogen products. The oxygen product is withdrawn from the distillation columns as a liquid and is pressurized by a cryogenic pump. The pressurized liquid oxygen is then vaporized against the high-pressure air feed before being warmed to ambient temperature. The gaseous oxygen exits the cold box and is fed to the centrifugal compressor with intercooling between each stage of compression. The compressed oxygen is then fed to the gasification unit.

Nitrogen is produced from the cold box at two pressure levels. Each stream is compressed to 2.63 MPa (381 psia) for use as combustion turbine diluent nitrogen. Some of the nitrogen stream is compressed further for use as transport gas in the lockhoppers.

3.1.4 Gasifier

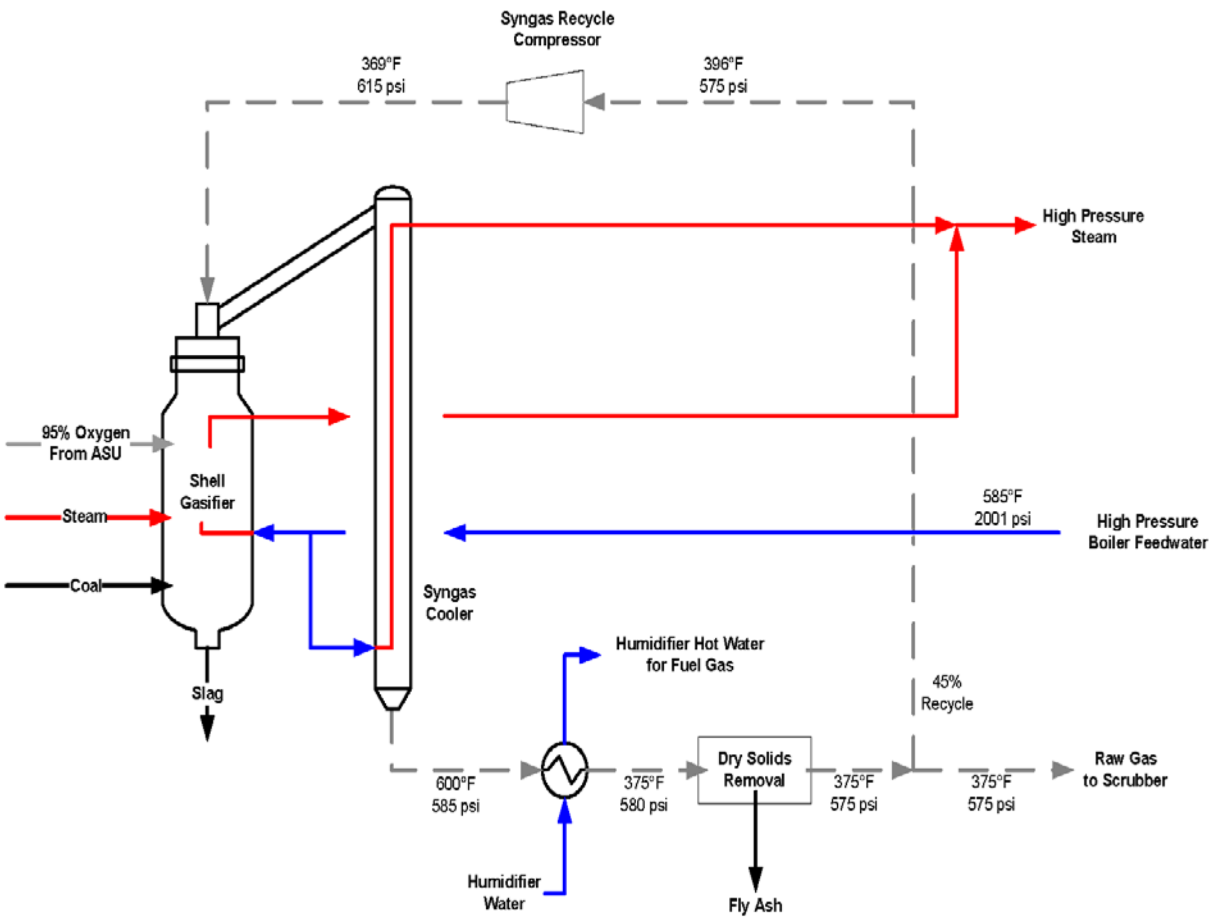
The Shell gasifier, which is a single-stage, entrained-flow, dry-feed gasifier, is modeled as an equilibrium reactor. A schematic of the Shell gasifier as a stand-alone unit is shown in Exhibit 3-4. Many literature references support this modeling strategy [37,44,45]. Steam injection is based on published data and the oxygen injection is controlled to maintain published heat losses for the gasifier. The predicted raw gas composition for the PRB coal is reasonable relative to published data.

Exhibit 3-4 Shell Gasifier



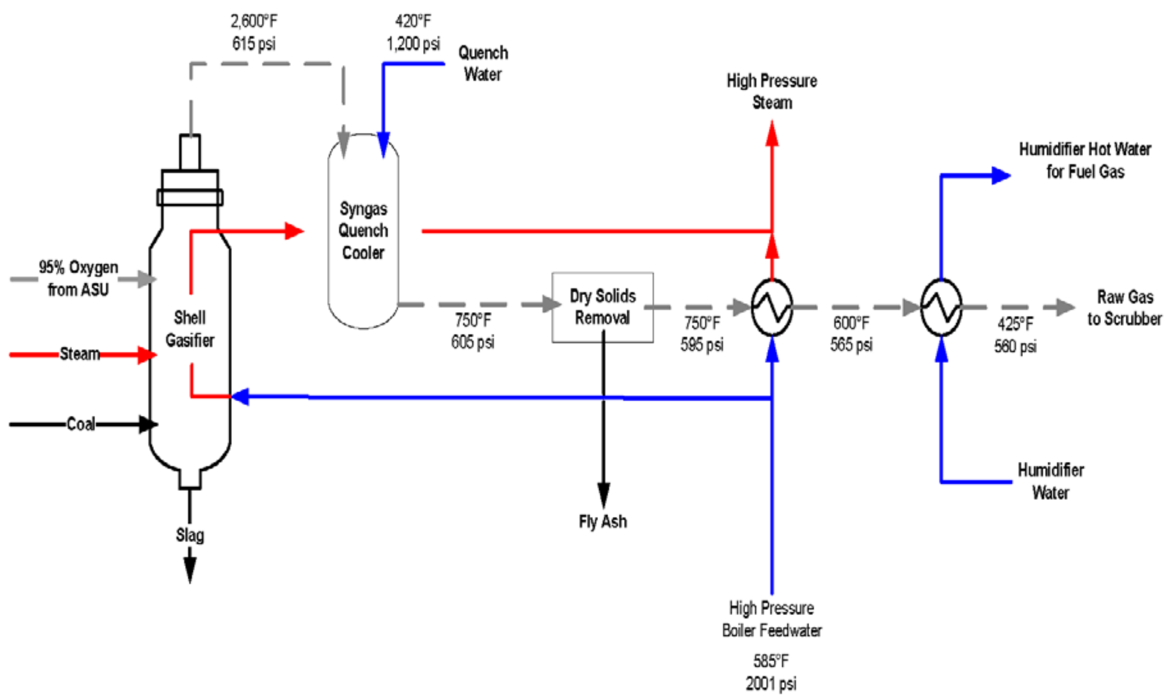
Two different raw gas cooling configurations were used in this study with the Shell gasifier. One configuration is a gasifier with a syngas cooler and the other is a gasifier with full quench. For the non-capture case (Case 1), a syngas cooler was implemented. The syngas cooler cools the raw gas from the gasifier to 600°F by creating high pressure steam. This configuration was utilized in the non-capture case for the ability of the syngas cooler to produce high pressure steam that supplements the steam produced in the heat recovery steam generator and subsequently is used for power generation in the steam cycle. A process schematic of the gasifier and syngas cooler is shown in Exhibit 3-5.

Exhibit 3-5 Shell Gasifier with Syngas Cooler



For the capture cases (Cases 2 and 3), a full quench design was implemented. This configuration is implemented because it reduces the amount of steam extracted from the steam cycle, which would be used for power generation, necessary for the Water Gas Shift (WGS) reactors to achieve the required levels of carbon capture. This is accomplished by using water to quench the raw gas from the gasifier to 750°F. The quench water is subsequently used in the WGS reactors to create the desired amount of shift of carbon monoxide (CO) to carbon dioxide (CO_2), which is later separated and captured to the specified levels of 1,100 lb CO_2/net-MWh or 90 percent capture. The full quench gasifier configuration is shown in Exhibit 3-6.

Exhibit 3-6 Shell Gasifier with Full Quench



With the syngas quench cooler configuration high pressure steam is still produced, but at a reduced quantity because the temperature available for steam production is now at 750°F instead of 2,600°F, as in the syngas cooler configuration. This causes a decrease in overall plant efficiency, but the quench design is still utilized to enhance the shift reaction necessary for carbon capture. For comparison, if full quench is implemented on the non-capture case, the net efficiency is reduced from 41.8 percent to 37.9 percent, a decrease of 3.9 percent.

3.1.5 Water Gas Shift Reactors

Selection of Technology - In the cases with CO_2 separation and capture, the gasifier product must be converted to hydrogen-rich syngas. The first step is to convert most of the syngas carbon monoxide (CO) to CO_2 by reacting the CO with water over a bed of catalyst. The H_2O:dry gas molar ratio at the exit of the final shift reactor is adjusted to a minimum of 0.3:1 by the addition of steam to the syngas stream thus promoting a high conversion of CO. The H_2O:dry gas molar ratio is adjusted as necessary (but maintaining a minimum 0.3:1) to achieve 90 percent overall CO_2 removal. In the cases without CO_2 separation and capture, CO shift convertors are not required.

Water Gas Shift: $CO + H_2O \leftrightarrow CO_2 + H_2$

The CO shift converter can be located either upstream of the acid gas removal step (sour gas shift) or immediately downstream (sweet gas shift). If the CO converter is located downstream of the acid gas removal, then the metallurgy of the unit is less stringent but additional equipment must be added to the process. Products from the gasifier are quenched with water and contain a portion of the water vapor necessary to meet the water-to-dry gas criterion at the reactor outlet. If the CO converter is located downstream of the acid gas removal, then the gasifier product would first have to be cooled and the free water separated and treated. Then additional steam would have to be generated and re-injected into the CO converter feed to meet the required water-to-dry gas ratio. If the CO converter is located upstream of the acid gas removal step, no additional equipment is required. This is because the CO converter promotes carbonyl sulfide (COS) hydrolysis without a separate catalyst bed. Therefore, for this study the CO converter was located upstream of the acid gas removal unit and is referred to as sour gas shift (SGS). In the 1,100 lb CO_2/net-MWh capture case, the partial bypass around the SGS reactor in each train causes an elevation in the sulfur content of the CO_2 product because not all of the COS gets converted to H_2S and consequently is removed to a much lesser extent in the AGR process.

Process Description - The SGS consists of two paths of parallel fixed-bed reactors arranged in series. Two reactors in series are used in each parallel path to achieve sufficient conversion to meet the 90 percent CO_2 capture target. Only one reactor in each train is necessary to achieve the emission limit of 1,100 lb CO_2/net-MWh. In addition for the 1,100 lb CO_2/net-MWh case, a bypass stream around the SGS is implemented to further reduce the conversion of CO to CO_2 to reach the required emissions limit.

In the 1,100 lb CO_2/net-MWh capture case, the 2 gasifier trains each have 1 SGS reactor with a bypass to achieve the emission limit, which resulted in 46 percent carbon capture. Since less than 50 percent carbon capture is required, 2 or 3 stages of SGS could be used in one train and none in the second train. This configuration would require a separate one-stage Selexol unit and a two-stage Selexol unit, which was deemed to not offer any particular advantage.

Cooling is provided between the series of reactors in the 90 percent case to control the exothermic temperature rise. The parallel set of reactors is required due to the high gas mass flow rate. In the 90 percent CO_2 capture case the heat exchanger after the first SGS reactor is used to superheat steam that is then used to adjust the syngas H_2O:dry gas ratio to greater than 0.3:1 on a molar basis. The heat exchanger after the second SGS reactor is a gas-gas exchanger used to preheat the syngas prior to the first SGS reactor to raise the syngas temperature above the dew point.

3.1.6 Mercury Removal

An IGCC power plant has the potential of removing mercury in a more simple and cost-effective manner than conventional PC plants. This is because mercury can be removed from the syngas at elevated pressure and prior to combustion so that syngas volumes are much smaller than flue gas volumes in comparable PC cases. A conceptual design for a carbon bed adsorption system was developed for mercury control in the IGCC plants being studied. Data on the performance of carbon bed systems were obtained from the Eastman Chemical Company, which uses carbon beds at its syngas facility in Kingsport, Tennessee [16]. The coal mercury content (0.081 ppm dry for PRB) and carbon bed removal efficiency (95 percent) were discussed previously in Section 2.3. IGCC-specific design considerations are discussed below.

Carbon Bed Location – The packed carbon bed vessels are located upstream of the acid gas removal (AGR) process and syngas enters at a temperature near 38°C (100°F). Consideration was given to locating the beds further upstream before the COS hydrolysis unit (in non-CO_2 capture cases) at a temperature near 204°C (400°F). However, while the mercury removal efficiency of carbon has been found to be relatively insensitive to pressure variations, temperature adversely affects the removal efficiency [46]. Eastman Chemical also operates their beds ahead of their sulfur recovery unit at a temperature of 30°C (86°F) [16].

Consideration was also given to locating the beds downstream of the AGR. However, it was felt that removing the mercury and other contaminants before the AGR unit would enhance the performance of both the AGR and sulfur recover unit (SRU) and increase the life of the various solvents.

Process Parameters – An empty vessel basis gas residence time of approximately 20 seconds was used based on Eastman Chemical's experience [16]. Allowable gas velocities are limited by considerations of particle entrainment, bed agitation, and pressure drop. One-foot-per-second superficial velocity is in the middle of the range normally encountered [46] and was selected for this application.

The bed density of 30 lb/ft^3 was based on the Calgon Carbon Corporation HGR-P sulfur-impregnated pelletized activated carbon [47]. These parameters determined the size of the vessels and the amount of carbon required. Each gasifier train has one mercury removal bed and there are two gasifier trains in each IGCC case, resulting in two carbon beds per case.

Carbon Replacement Time – Eastman Chemicals replaces its bed every 18 to 24 months [16]. However, bed replacement is not because of mercury loading, but for other reasons including:

- A buildup in pressure drop
- A buildup of water in the bed
- A buildup of other contaminants

For this study a 24 month carbon replacement cycle was assumed. Under these assumptions, the mercury loading in the bed would build up to 0.64 weight percent (wt%). Mercury capacity of sulfur-impregnated carbon can be as high as 20 wt% [48]. The mercury laden carbon is considered to be a hazardous waste, and the disposal cost estimate reflects this categorization.

3.1.7 Acid Gas Removal (AGR) Process Selection

Gasification of coal to generate power produces a syngas that must be treated prior to further utilization. A portion of the treatment consists of acid gas removal (AGR) and sulfur recovery. The environmental target for these IGCC cases, 0.0128 lb SO_2/MMBtu, is based on the EPRI CoalFleet values for bituminous coal [13] and requires that the total sulfur content of the syngas be reduced to less than 30 ppmv. This includes all sulfur species, but in particular the total of COS and H_2S, thereby resulting in stack gas emissions of less than 4 ppmv SO_2. Because the low rank western coals have substantially less sulfur than eastern bituminous coal, the resulting sulfur emissions are significantly below the environmental target.

COS Hydrolysis

The use of COS hydrolysis pretreatment in the feed to the acid gas removal process provides a means to reduce the COS concentration. This method was first commercially proven at the Buggenum plant, and was also used at both the Tampa Electric and Wabash River IGCC projects. Several catalyst manufacturers including Haldor Topsoe and Porocel offer a catalyst that promotes the COS hydrolysis reaction. The non-carbon capture COS hydrolysis reactor designs are based on information from Porocel. In cases with carbon capture, the SGS reactors reduce COS to H_2S as discussed in Section 3.1.4.

The COS hydrolysis reaction is equimolar with a slightly exothermic heat of reaction. The reaction is represented as follows.

$$COS + H_2O \leftrightarrow CO_2 + H_2S$$

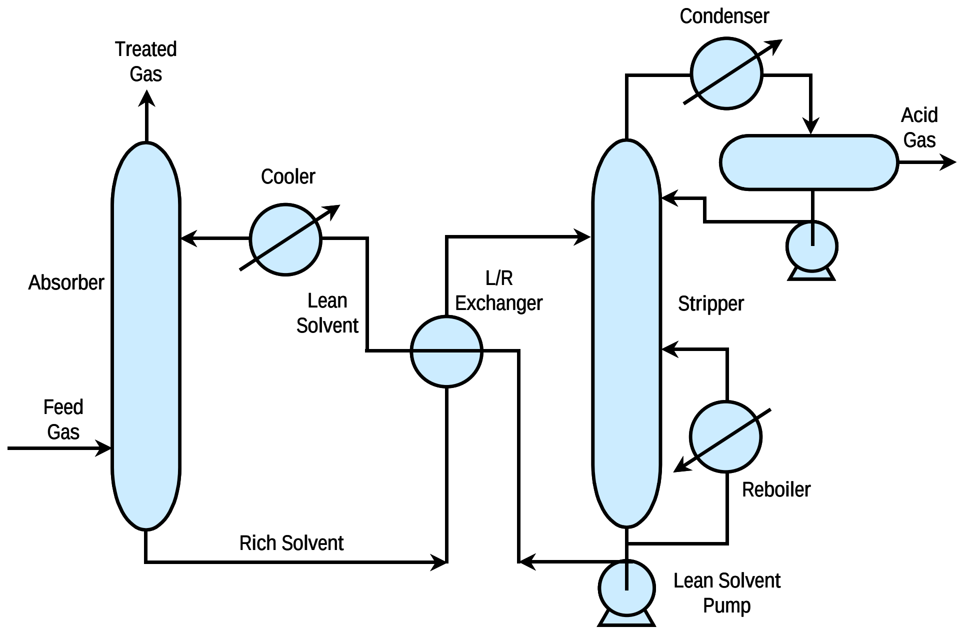
Since the reaction is exothermic, higher conversion is achieved at lower temperatures. However, at lower temperatures the reaction kinetics are slower. Since the exit gas COS concentration is critical to the amount of H_2S that must be removed with the AGR process, a retention time of 50-75 seconds was used to achieve 99.5 percent conversion of the COS. The Porocel activated alumina-based catalyst, designated as Hydrocel 640 catalyst, promotes the COS hydrolysis reaction without promoting reaction of H_2S and CO to form COS and H_2.

Although the reaction is exothermic, the heat of reaction is dissipated among the large amount of non-reacting components. Therefore, the reaction is essentially isothermal. The product gas, now containing less than 4 ppmv of COS, is cooled prior to entering the mercury removal process and the AGR.

Sulfur Removal

Hydrogen sulfide removal generally consists of absorption by a regenerable solvent. The most commonly used technique is based on countercurrent contact with the solvent. Acid-gas-rich solution from the absorber is stripped of its acid gas in a regenerator, usually by application of heat. The regenerated lean solution is then cooled and recirculated to the top of the absorber, completing the cycle. Exhibit 3-7 is a simplified diagram of the AGR process [49].

Exhibit 3-7 Flow Diagram for a Conventional AGR Unit



There are well over 30 AGR processes in common commercial use throughout the oil, chemical, and natural gas industries. However, in a 2002 report by SFA Pacific a list of 42 operating and planned gasifiers shows that only six AGR processes are represented: Rectisol, Sulfinol, methyldiethanolamine (MDEA), Selexol, aqueous di-isoproponal (ADIP) amine and FLEXSORB [50]. These processes can be separated into three general types: chemical reagents, physical solvents, and hybrid solvents. A summary of these common AGR processes is shown in Exhibit 3-8. The optimum technology choice for a particular IGCC plant depends on many factors such as gasifier operating pressure, availability of low/medium pressure steam, acid gas removal requirements, and capital cost.

Chemical Solvents

Frequently used for acid gas removal, chemical solvents are more suitable than physical or hybrid solvents for applications at lower operating pressures. The chemical nature of acid gas absorption makes solution loading and circulation less dependent on the acid gas partial pressure. Because the solution is aqueous, co-absorption of hydrocarbons is minimal.

In a conventional amine unit, the chemical solvent reacts exothermically with the acid gas constituents. They form a weak chemical bond that can be broken, releasing the acid gas and regenerating the solvent for reuse.

In recent years MDEA, a tertiary amine, has acquired a much larger share of the gas-treating market. Compared with primary and secondary amines, MDEA has superior capabilities for selectively removing H_2S in the presence of CO_2, is resistant to degradation by organic sulfur compounds, has a low tendency for corrosion, has a relatively low circulation rate, and consumes less energy. Commercially available are several MDEA-based solvents that are formulated for high H_2S selectivity.

Exhibit 3-8 Summary of Common AGR Processes

Solvent Type	Process	H_2S Selectivity	Solvent Circulation	Heat Input	Capital Cost	Pressure Sensitive	High Removal
Physical	Rectisol, Selexol	Good	High, decreases with increased pressure	Low	High	Yes	Yes, at high acid gas partial pressures
Mixed	Sulfinol, FLEXSORB	Good but more complicated to achieve	Intermediate	Intermediate	Intermediate	Yes, but to a lesser extent than physical solvents only	Yes, at optimum operating conditions
Chemical	Amines (MEA, DEA, MDEA)	Varies depending on amine selected, highest for MDEA	Low	High	Low	No	Yes, but with refrigeration

Chemical reagents are used to remove the acid gases by a reversible chemical reaction of the acid gases with an aqueous solution of various alkanolamines or alkaline salts in water. Exhibit 3-9 lists commonly used chemical reagents along with principal licensors that use them in their processes. The process consists of an absorber and regenerator, which are connected by a circulation of the chemical reagent aqueous solution. The absorber contacts the lean solution with the main gas stream (at pressure) to remove the acid gases by absorption/ reaction with the chemical solution. The acid-gas-rich solution is reduced to low pressure and heated in the stripper to reverse the reactions and strip the acid gas. The acid-gas-lean solution leaves the bottom of the regenerator stripper and is cooled, pumped to the required pressure and recirculated back to the absorber. For some amines, a filter and a separate reclaiming section (not shown) are needed to remove undesirable reaction byproducts.

Exhibit 3-9 Common Chemical Reagents Used in AGR Processes

Chemical Reagent	Designation	Process Licensors Using the Reagent
Monoethanolamine	MEA	Dow, Exxon, Lurgi, Union Carbide
Diethanolamine	DEA	Elf, Lurgi
Diglycolamine	DGA	Texaco, Fluor
Triethanolamine	TEA	AMOCO
Diisopropanolamine	DIPA	Shell
Methyldiethanolamine	MDEA	BASF, Dow, Elf, Snamprogetti, Shell, Union Carbide, Coastal Chemical
Hindered amine		Exxon
Potassium carbonate	“hot pot”	Eickmeyer, Exxon, Lurgi, Union Carbide

Typically, the absorber temperature is 27 to 49°C (80 to 120°F) for amine processes, and the regeneration temperature is the boiling point of the solutions, generally 104 to 127°C (220 to 260°F). The liquid circulation rates can vary widely, depending on the amount of acid gas being captured. However, the most suitable processes are those that will dissolve 2 to 10 scf acid gas per gallon of solution circulated. Steam consumption can vary widely also: 0.7 to 1.5 pounds per gallon of liquid is typical, with 0.8 to 0.9 being a typical “good” value.

The major advantage of these systems is the ability to remove acid gas to low levels at low to moderate H_2S partial pressures.

Physical Solvents

Physical solvents involve absorption of acid gases into certain organic solvents that have a high solubility for acid gases. As the name implies, physical solvents involve only the physical solution of acid gas – the acid gas loading in the solvent is proportional to the acid gas partial pressure (Henry’s Law). Physical solvent absorbers are usually operated at lower temperatures than is the case for chemical solvents. The solution step occurs at high pressure and at or below ambient temperature while the regeneration step (dissolution) occurs by pressure letdown and indirect stripping with low-pressure 0.45 MPa (65 psia) steam. It is generally accepted that physical solvents become increasingly economical, and eventually superior to amine capture, as the partial pressure of acid gas in the syngas increases.

The physical solvents are regenerated by multistage flashing to low pressures. Because the solubility of acid gases increases as the temperature decreases, absorption is generally carried out at lower temperatures, and refrigeration is often required.

Most physical solvents are capable of removing organic sulfur compounds. Exhibiting higher solubility of H_2S than CO_2, they can be designed for selective H_2S or total acid gas removal. In applications where CO_2 capture is desired the CO_2 is flashed off at various pressures, which reduces the compression work and parasitic power load associated with sequestration.

Physical solvents co-absorb heavy hydrocarbons from the feed stream. Since heavy hydrocarbons cannot be recovered by flash regeneration, they are stripped along with the acid gas during heated regeneration. These hydrocarbon losses result in a loss of valuable product and may lead to CO_2 contamination.

Several physical solvents that use anhydrous organic solvents have been commercialized. They include the Selexol process, which uses dimethyl ether of polyethylene glycol as a solvent; Rectisol, with methanol as the solvent; Purisol, which uses N-methyl-2-pyrrolidone (NMP) as a solvent; and the propylene-carbonate process.

Exhibit 3-10 is a simplified flow diagram for a physical reagent type acid gas removal process [49]. Common physical solvent processes, along with their licensors, are listed in Exhibit 3-11.

Exhibit 3-10 Physical Solvent AGR Process Simplified Flow Diagram

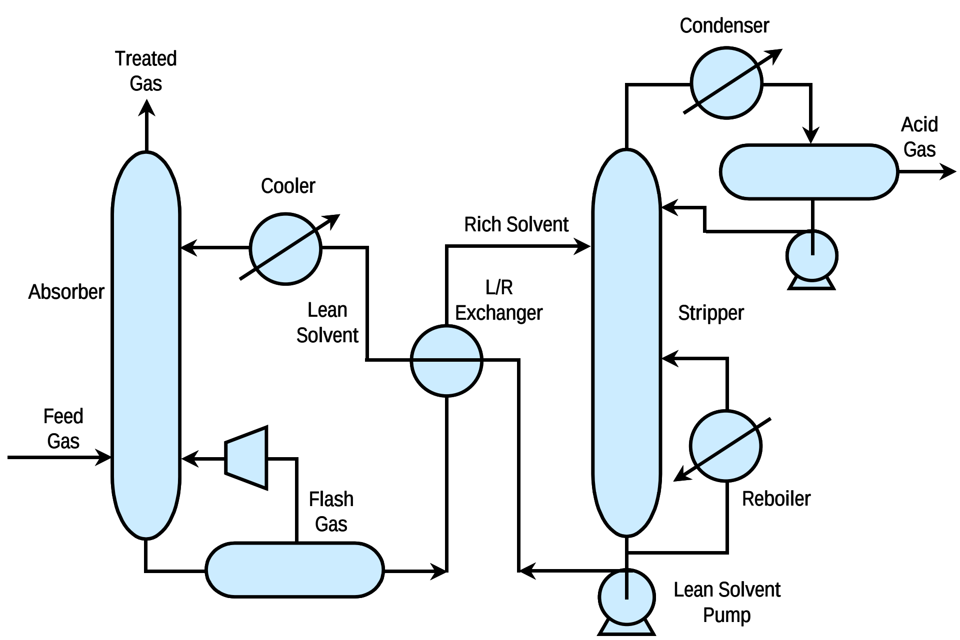


Exhibit 3-11 Common Physical Solvents Used in AGR Processes

Solvent	Solvent/Process Trade Name	Process Licensors
Dimethyl ether of poly-ethylene glycol	Selexol	UOP
Methanol	Rectisol	Linde AG and Lurgi
Methanol and toluene	Rectisol II	Linde AG
N—methyl pyrrolidone	Purisol	Lurgi
Polyethylene glycol and dialkyl ethers	Sepasolv MPE	BASF
Propylene carbonate	Fluor Solvent	Fluor
Tetrahydrothiophenedioxide	Sulfolane	Shell
Tributyl phosphate	Estasolvan	Uhde and IFP

Hybrid Solvents

Hybrid solvents combine the high treated-gas purity offered by chemical solvents with the flash regeneration and lower energy requirements of physical solvents. Some examples of hybrid solvents are Sulfinol, Flexsorb PS, and Ucarsol LE.

Sulfinol is a mixture of sulfolane (a physical solvent), diisopropanolamine (DIPA) or MDEA (chemical solvent), and water. DIPA is used when total acid gas removal is specified, while MDEA provides for selective removal of H_2S.

Flexsorb PS is a mixture of a hindered amine and an organic solvent. Physically similar to Sulfinol, Flexsorb PS is very stable and resistant to chemical degradation. High treated-gas purity, with less than 50 ppmv of CO_2 and 4 ppmv of H_2S, can be achieved. Both Ucarsol LE-701, for selective removal, and LE-702, for total acid gas removal, are formulated to remove mercaptans from feed gas.

Mixed chemical and physical solvents combine the features of both systems. The mixed solvent allows the solution to absorb an appreciable amount of gas at high pressure. The amine portion is effective as a reagent to remove the acid gas to low levels when high purity is desired.

Mixed solvent processes generally operate at absorber temperatures similar to those of the amine-type chemical solvents and do not require refrigeration. They also retain some advantages of the lower steam requirements typical of the physical solvents. Common mixed chemical and physical solvent processes, along with their licensors, are listed in Exhibit 3-12. The key advantage of mixed solvent processes is their apparent ability to remove H_2S and, in some cases, COS to meet very stringent purified gas specifications.

Exhibit 3-12 Common Mixed Solvents Used in AGR Processes

Solvent/Chemical Reagent	Solvent/Process Trade Name	Process Licensors
Methanol/MDEA or diethylamine	Amisol	Lurgi
Sulfolane/MDEA or DIPA	Sulfinol	Shell
Methanol and toluene	Selefining	Snamprogetti
(Unspecified) /MDEA	FLEXSORB PS	Exxon

Exhibit 3-13 shows reported equilibrium solubility data for H_2S and CO_2 in various representative solvents [49]. The solubility is expressed as standard cubic feet of gas per gallon liquid per atmosphere gas partial pressure.

The figure illustrates the relative solubilities of CO_2 and H_2S in different solvents and the effects of temperature. More importantly, it shows an order of magnitude higher solubility of H_2S over CO_2 at a given temperature, which gives rise to the selective absorption of H_2S in physical solvents. It also illustrates that the acid gas solubility in physical solvents increases with lower solvent temperatures.

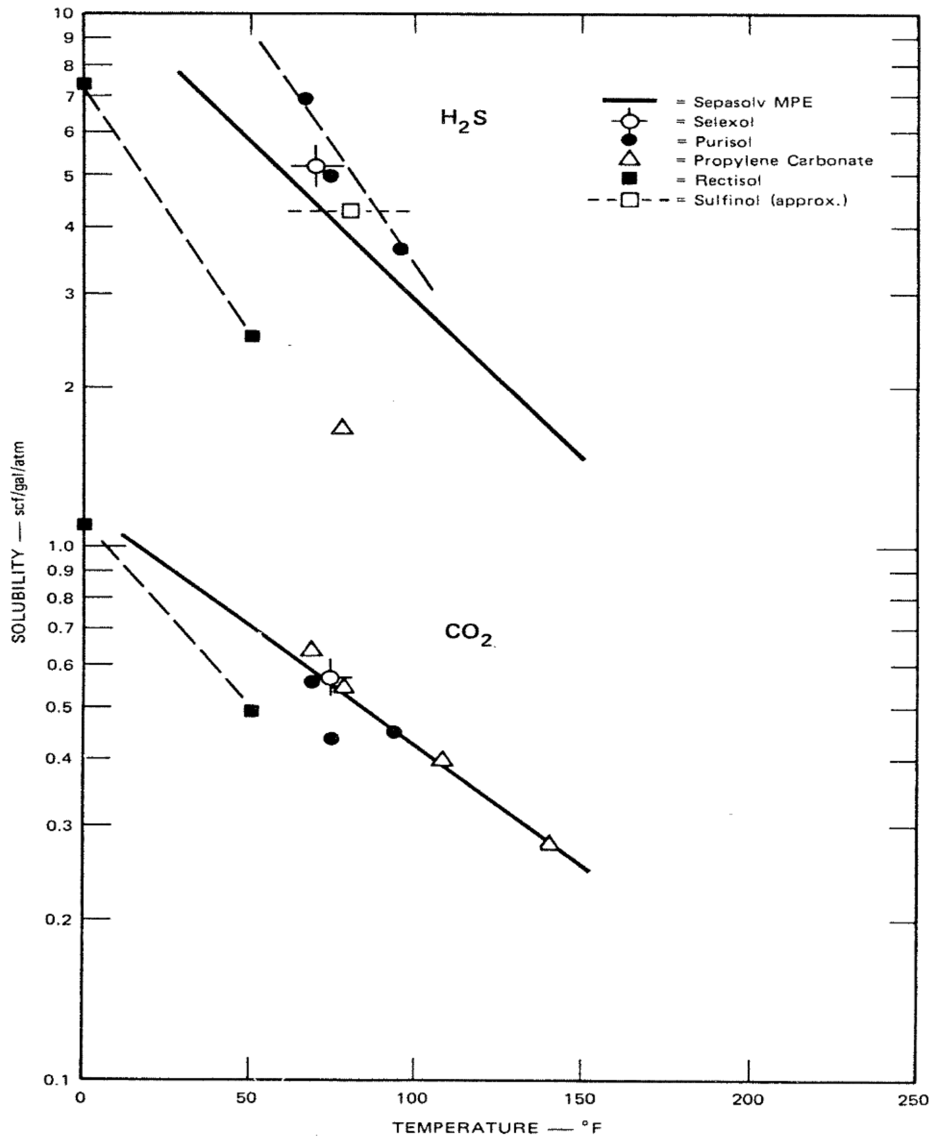
The ability of a process to selectively absorb H_2S may be further enhanced by the relative absorption rates of H_2S and CO_2. Thus, some processes, besides using equilibrium solubility differences, will use absorption rate differences between the two acid gases to achieve selectivity. This is particularly true of the amine processes where the CO_2 and H_2S absorption rates are very different.

CO_2 Capture

A two-stage Selexol process is used for both IGCC CO_2 capture cases in this report. A brief process description follows.

Untreated syngas enters the first of two absorbers where H_2S is preferentially removed using loaded solvent from the CO_2 absorber. The gas exiting the H_2S absorber passes through the second absorber where CO_2 is removed using first flash regenerated, chilled solvent followed by thermally regenerated solvent added near the top of the column. The treated gas exits the absorber and is sent either directly to the combustion turbine or is partially humidified prior to entering the combustion turbine.

Exhibit 3-13 Equilibrium Solubility Data on H_2S and CO_2 in Various Solvents



The amount of hydrogen remaining in the syngas stream is dependent on the Selexol process design conditions. In this study, hydrogen recovery is 99.4 percent. The minimal hydrogen slip to the CO_2 sequestration stream maximizes the overall plant efficiency. The Selexol plant cost estimates are based on a plant designed to recover this high percentage of hydrogen. The balance of the hydrogen is either co-sequestered with the CO_2, destroyed in the Claus plant burner, or recycled to the gasifier.

The CO_2 loaded solvent exits the CO_2 absorber and a portion is sent to the H_2S absorber, a portion is sent to a reabsorber and the remainder is sent to a series of flash drums for regeneration. The CO_2 product stream is obtained from the three flash drums, and after flash regeneration the solvent is chilled and returned to the CO_2 absorber.

The rich solvent exiting the H_2S absorber is combined with the rich solvent from the reabsorber and the combined stream is heated using the lean solvent from the stripper. The hot, rich solvent enters the H_2S concentrator and partially flashes. The remaining liquid contacts nitrogen from the ASU and a portion of the CO_2 along with lesser amounts of H_2S and COS are stripped from the rich solvent. The stripped gases from the H_2S concentrator are sent to the reabsorber where the H_2S and COS that were co-stripped in the concentrator are transferred to a stream of loaded solvent from the CO_2 absorber. The clean gas from the reabsorber is combined with the clean gas from the H_2S absorber and sent to the combustion turbine.

The solvent exiting the H_2S concentrator is sent to the stripper where the absorbed gases are liberated by hot gases flowing up the column from the steam heated reboiler. Water in the overhead vapor from the stripper is condensed and returned as reflux to the stripper or exported as necessary to maintain the proper water content of the lean solvent. The acid gas from the stripper is sent to the Claus plant for further processing. The lean solvent exiting the stripper is first cooled by providing heat to the rich solvent, then further cooled by exchange with the product gas and finally chilled in the lean chiller before returning to the top of the CO_2 absorber.

AGR/Gasifier Pairings

There are numerous commercial AGR processes that could meet the sulfur environmental target of this study. The most frequently used AGR systems (Selexol, Sulfinol, MDEA, and Rectisol) have all been used with the Shell gasifier in various applications. Since there is no compelling reason to select one AGR process over another, the Sulfinol-M process was chosen to be consistent with the Shell cases in previous studies. Previous vendor performance estimates for Sulfinol systems showed high removals for H_2S (99.77 percent) and CO_2 (97.5 percent). With the higher CO_2 and lower H_2S concentrations in the raw gas for the lower rank coals, it is necessary for the AGR to slip a significant amount of CO_2. The high slip is necessary to reduce the volume and increase the H_2S concentration of the acid gas stream to the Claus plant for adequate performance and minimum capital cost.

The literature indicates that Sulfinol systems with CO_2 slips of 60% have been designed. The Shell non-capture cases assume a 60 percent CO_2 slip.

The two-stage Selexol process is used in both cases that require carbon capture. According to the previously referenced SFA Pacific report, "For future IGCC with CO_2 removal for sequestration, a two-stage Selexol process presently appears to be the preferred AGR process – as indicated by ongoing engineering studies at EPRI and various engineering firms with IGCC interests." [50]

3.1.8 Sulfur Recovery/Tail Gas Cleanup Process Selection

Currently, most of the world's sulfur is produced from the acid gases coming from gas treating. The Claus process remains the mainstay for sulfur recovery. Conventional three-stage Claus plants, with indirect reheat and feeds with a high H_2S content, can approach 98 percent sulfur recovery efficiency. However, since environmental regulations have become more stringent, sulfur recovery plants are required to recover sulfur with over 99.8 percent efficiency. To meet these stricter regulations, the Claus process underwent various modifications and add-ons.

The Claus Process

The Claus process converts H_2S to elemental sulfur via the following reactions:

$$H_2S + 3/2\ O_2 \leftrightarrow H_2O + SO_2$$

$$2H_2S + SO_2 \leftrightarrow 2H_2O + 3S$$

The second reaction, the Claus reaction, is equilibrium limited. The overall reaction is:

$$3H_2S + 3/2\ O_2 \leftrightarrow 3H_2O + 3S$$

The sulfur in the vapor phase exists as S_2, S_6, and S_8 molecular species, with the S_2 predominant at higher temperatures, and S_8 predominant at lower temperatures.

A simplified process flow diagram of a typical three-stage Claus plant is shown in Exhibit 3-14 [50]. One-third of the H_2S is burned in the furnace with oxygen from the air to give sufficient SO_2 to react with the remaining H_2S. Since these reactions are highly exothermic, a waste heat boiler that recovers this heat to generate high-pressure steam usually follows the furnace. Sulfur is condensed in a condenser that follows the high-pressure steam recovery section. Low-pressure steam is raised in the condenser. The tail gas from the first condenser then goes to several catalytic conversion stages, usually 2 to 3, where the remaining sulfur is recovered via the Claus reaction. Each catalytic stage consists of gas preheat, a catalytic reactor, and a sulfur condenser. The liquid sulfur goes to the sulfur pit, while the tail gas proceeds to the incinerator or for further processing in a TGTU.

Claus Plant Sulfur Recovery Efficiency

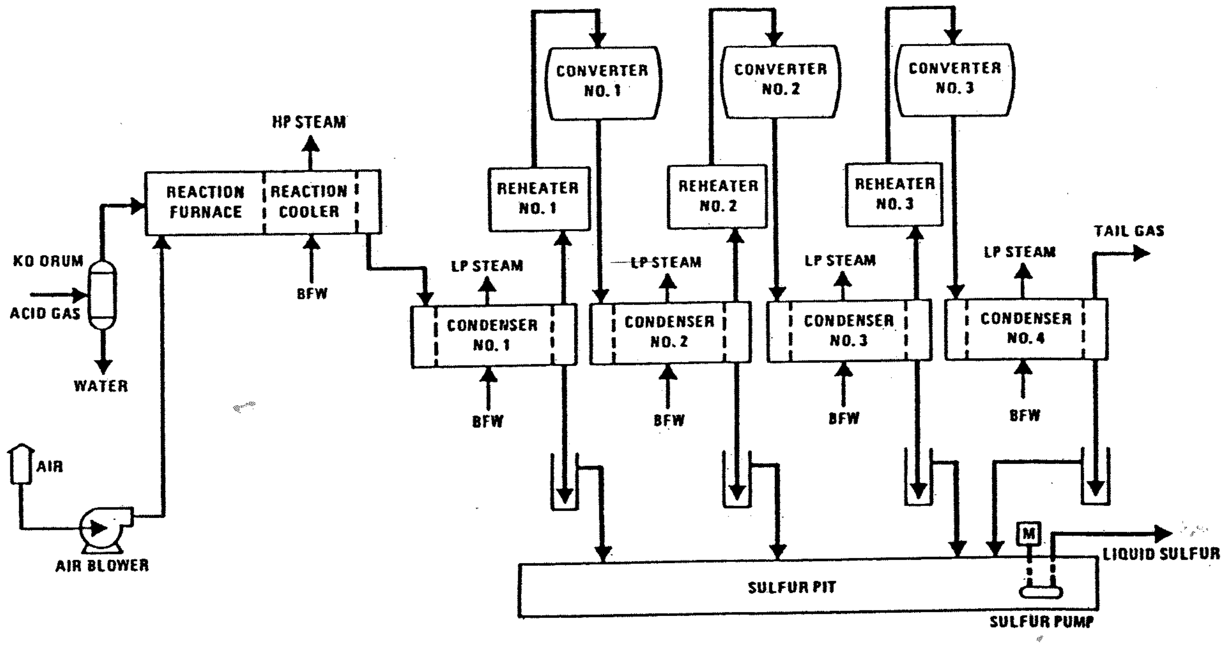
The Claus reaction is equilibrium limited, and sulfur conversion is sensitive to the reaction temperature. The highest sulfur conversion in the thermal zone is limited to about 75 percent. Typical furnace temperatures are in the range from 1093 to 1427°C (2000 to 2600°F), and as the temperature decreases, conversion increases dramatically.

Claus plant sulfur recovery efficiency depends on many factors:

- H_2S concentration of the feed gas
- Number of catalytic stages
- Gas reheat method

In order to keep Claus plant recovery efficiencies approaching 94 to 96 percent for feed gases that contain about 20 to 50 percent H_2S, a split-flow design is often used. In this version of the Claus plant, part of the feed gas is bypassed around the furnace to the first catalytic stage, while the rest of the gas is oxidized in the furnace to mostly SO_2. This results in a more stable temperature in the furnace.

Exhibit 3-14 Typical Three-Stage Claus Sulfur Plant



Oxygen-Blown Claus

Large diluent streams in the feed to the Claus plant, such as N_2 from combustion air, or a high CO_2 content in the feed gas, lead to higher cost Claus processes and any add-on or tail gas units. One way to reduce diluent flows through the Claus plant and to obtain stable temperatures in the furnace for dilute H_2S streams is the oxygen-blown Claus process.

The oxygen-blown Claus process was originally developed to increase capacity at existing conventional Claus plants and to increase flame temperatures of low H_2S content gases. The process has also been used to provide the capacity and operating flexibility for sulfur plants where the feed gas is variable in flow and composition such as often found in refineries. The application of the process has now been extended to grass roots installations, even for rich H_2S feed streams, to provide operating flexibility at lower costs than would be the case for conventional Claus units. At least four of the recently built gasification plants in Europe use oxygen enriched Claus units.

Oxygen enrichment results in higher temperatures in the front-end furnace, potentially reaching temperatures as high as 1593 to 1649°C (2900 to 3000°F) as the enrichment moves beyond 40 to 70 volume percent O_2 in the oxidant feed stream. Although oxygen enrichment has many benefits, its primary benefit for lean H_2S feeds is a stable furnace temperature. Sulfur recovery is not significantly enhanced by oxygen enrichment. Because the IGCC process already requires an ASU, the oxygen-blown Claus plant was chosen for all cases.

Tail Gas Treating

In many refinery and other conventional Claus applications, tail gas treating involves the removal of the remaining sulfur compounds from gases exiting the sulfur recovery unit. Tail gas from a typical Claus process, whether a conventional Claus or one of the extended versions of the process, usually contains small but varying quantities of COS, CS_2, H_2S, SO_2, and elemental sulfur vapors. In addition, there may be H_2, CO, and CO_2 in the tail gas. In order to remove the rest of the sulfur compounds from the tail gas, all of the sulfur-bearing species must first be converted to H_2S. Then, the resulting H_2S is absorbed into a solvent and the clean gas vented or recycled for further processing. The clean gas resulting from the hydrolysis step can undergo further cleanup in a dedicated absorption unit or be integrated with an upstream AGR unit. The latter option is particularly suitable with physical absorption solvents. The approach of treating the tail gas in a dedicated amine absorption unit and recycling the resulting acid gas to the Claus plant is the one used by the Shell Claus Off-gas Treating (SCOT) process. With tail gas treatment, Claus plants can achieve overall removal efficiencies in excess of 99.9 percent.

In the case of IGCC applications, the tail gas from the Claus plant can be catalytically hydrogenated and then recycled back into the system with the choice of location being technology dependent, or it can be treated with a SCOT-type process. The Shell cases in this report all use a catalytic hydrogenation step with tail gas recycle to the gasifier. The Shell Puertollano plant treats the tail gas in a similar manner, but the recycle endpoint is not specified [51].

Flare Stack

A self-supporting, refractory-lined, carbon steel flare stack is typically provided to combust and dispose of unreacted gas during startup, shutdown, and upset conditions. However, in the three IGCC cases a flare stack was provided for syngas dumping during startup and shutdown. This flare stack eliminates the need for a separate Claus plant flare.

3.1.9 Slag Handling

The slag handling system conveys, stores, and disposes of slag removed from the gasification process. Spent material drains from the gasifier bed into a water bath in the bottom of the gasifier vessel. A slag crusher receives slag from the water bath and grinds the material into pea-sized fragments. A slag/water slurry that is between 5 and 10 percent solids leaves the gasifier pressure boundary through the use of lockhoppers to a series of dewatering bins.

The slag is dewatered, the water is clarified and recycled and the dried slag is transferred to a storage area for disposal. The specifics of slag handling vary among different gasification technologies regarding how the water is separated and the end uses of the water recycle streams.

In this study the slag bins were sized for a nominal holdup capacity of 72 hours of full-load operation. At periodic intervals, a convoy of slag-hauling trucks will transit the unloading station underneath the hopper and remove a quantity of slag for disposal. While the slag is suitable for use as a component of road paving mixtures, it was assumed in this study that the slag would be landfilled at a specified cost.

3.1.10 Power Island

Combustion Turbine

The gas turbine generator selected for this application is representative of the advanced F Class turbines. This machine is an axial flow, single spool, and constant speed unit, with variable inlet guide vanes. The turbine includes advanced bucket cooling techniques, compressor aerodynamic design and advanced alloys, enabling a higher firing temperature than the previous generation machines. The standard production version of this machine is fired with natural gas and is also commercially offered for use with IGCC derived syngas, although only earlier versions of the turbine are currently operating on syngas. For the purposes of this study, it was assumed that the advanced F Class turbine will be commercially available to support a 2015 startup date on both conventional and high hydrogen content syngas representative of the cases with CO_2 capture. High H_2 fuel combustion issues like flame stability, flashback and NOx formation were assumed to be solved in the time frame needed to support deployment. However, because these are first-of-a-kind applications, process contingencies were included in the cost estimates as described in Section 2.7. Performance typical of an advanced F class turbine on natural gas at ISO conditions is presented in Exhibit 3-15.

Exhibit 3-15 Advanced F Class Combustion Turbine Performance Characteristics Using Natural Gas

	Advanced F Class
Firing Temperature Class, °C (°F)	1371+ (2500+)
Airflow, kg/s (lb/s)	431 (950)
Pressure Ratio	18.5
NOx Emissions, ppmv	25
Simple Cycle Output, MW	185
Combined cycle performance	
Net Output, MW	280
Net Efficiency (LHV), %	57.5
Net Heat Rate (LHV), kJ/kWh (Btu/kWh)	6,256 (5,934)

In this service, with syngas from an IGCC plant, the machine requires some modifications to the burner and turbine nozzles in order to properly combust the low-Btu gas and expand the combustion products in the turbine section of the machine.

The modifications to the machine include some redesign of the original can-annular combustors. A second modification involves increasing the nozzle areas of the turbine to accommodate the mass and volume flow of low-Btu fuel gas combustion products, which are increased relative to those produced when firing natural gas. Other modifications include rearranging the various auxiliary skids that support the machine to accommodate the spatial requirements of the plant general arrangement. The generator is a standard hydrogen-cooled machine with static exciter.

Combustion Turbine Package Scope of Supply

The combustion turbine (CT) is typically supplied in several fully shop-fabricated modules, complete with all mechanical, electrical and control systems as required for CT operation. Site CT installation involves module inter-connection, and linking CT modules to the plant systems. The CT package scope of supply for combined cycle application, while project specific, does not vary much from project-to-project. The typical scope of supply is presented in Exhibit 3-16.

Exhibit 3-16 Combustion Turbine Typical Scope of Supply

	System	System Scope
1.0	**ENGINE ASSEMBLY**	Coupling to Generator, Dry Chemical Exhaust Bearing Fire Protection System, Insulation Blankets, Platforms, Stairs and Ladders
1.1	Engine Assembly with Bedplate	Variable Inlet Guide, Vane System Compressor, Bleed System, Purge Air System, Bearing Seal Sir System, Combustors, Dual Fuel Nozzles Turbine Rotor Air Cooler
1.2	Walk-in acoustical enclosure	HVAC, Lighting, and Low Pressure CO_2 Fire Protection System
2.0	**MECHANICAL PACKAGE**	HVAC and Lighting, Air Compressor for Pneumatic System, Low Pressure CO_2 Fire Protection System
2.1 2.2	Lubricating Oil System and Control Oil System	Lube Oil Reservoir, Accumulators, 2x100% AC Driven Oil Pumps DC Emergency Oil Pump with Starter, 2x100% Oil Coolers, Duplex Oil Filter, Oil Temperature and Pressure Control Valves, Oil Vapor Exhaust Fans and Demister Oil Heaters Oil Interconnect Piping (SS and CS) Oil System Instrumentation Oil for Flushing and First Filling
3.0	**ELECTRICAL PACKAGE**	HVAC and 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, Low Pressure CO_2 Fire Protection System, Cable Tray and Conduit Provisions for Performance Testing including Test Ports, Thermowells, Instrumentation and DCS interface cards

	System	System Scope
4.0	**INLET AND EXHAUST SYSTEMS**	Inlet Duct Trash Screens, Inlet Duct and Silencers, Self Cleaning Filters, Hoist System For Filter Maintenance, Evaporative Cooler System, Exhaust Duct Expansion Joint, Exhaust Silencers Inlet and Exhaust Flow, Pressure and Temperature Ports and Instrumentation
5.0	**FUEL SYSTEMS**	
5.1	Fuel Syngas System	Gas Valves Including Vent, Throttle and Trip Valves Gas Filter/Separator Gas Supply Instruments and Instrument Panel
5.2	Backup Fuel System	Specific to backup fuel type
6.0	**STARTING SYSTEM**	Enclosure, Starting Motor or Static Start System, Turning Gear and Clutch Assembly, Starting Clutch Torque Converter
7.0	**GENERATOR**	Static or Rotating Exciter (Excitation transformer to be included for a static system), Line Termination Enclosure with CTs, VTs, Surge Arrestors, and Surge Capacitors, Neutral Cubicle with CT, Neutral Tie Bus, Grounding Transformer, and Secondary Resistor, Generator Gas Dryer, Seal Oil System (including Defoaming Tank, Reservoir, Seal Oil Pump, Emergency Seal Oil Pump, Vapor Extractor, and Oil Mist Eliminator), Generator Auxiliaries Control Enclosure, Generator Breaker, Iso-Phase bus connecting generator and breaker, Grounding System Connectors
7.1	Generator Cooling	TEWAC System (including circulation system, interconnecting piping and controls), or Hydrogen Cooling System (including H_2 to Glycol and Glycol to Air heat exchangers, liquid level detector circulation system, interconnecting piping and controls)
8.0	**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

CT Firing Temperature Control Issue for Low Calorific Value Fuel

A gas turbine when fired on low calorific value syngas has the potential to increase power output due to the increase in flow rate through the turbine. The higher turbine flow and moisture content of the combustion products can contribute to overheating of turbine components, affect rating criteria for the parts lives, and require a reduction in syngas firing temperatures (compared to the natural gas firing) to maintain design metal temperature [52]. Uncontrolled syngas firing temperature could result in more than 50 percent life cycle reduction of stage 1 buckets. Control systems for syngas applications include provisions to compensate for these effects by maintaining virtually constant generation output for the range of the specified ambient conditions. Inlet guide vanes (IGV) and firing temperature are used to maintain the turbine output at the maximum torque rating, producing a flat rating up to the IGV full open position. Beyond the IGV full open position, flat output may be extended to higher ambient air temperatures by steam/nitrogen injection.

In the three Shell IGCC cases, the turbine inlet temperature ranged from 1,348°C (2,459°F) in the non-capture case to 1,322°C (2,412°F) in the 90 percent capture case. The outlet temperature was 592°C (1,098°F) in the non-capture case, 563°C (1,046°F) in the 90 percent capture case and 577°C (1,070°F) for the 1,100 lb CO_2/net-MWh case. The H_2O content of the combustion products is low, 5.2 volume percent (vol%), in the non-capture cases and increases up to 12 vol% in the 90 percent capture case.

Combustion Turbine Syngas Fuel Requirements

Typical fuel specifications and contaminant levels for successful combustion turbine operation are provided in reference [53] and presented for F Class machines in Exhibit 3-17 and Exhibit 3-18. The vast majority of published CT performance information is specific to natural gas operation. Turbine performance using syngas requires vendor input as was obtained for these cases.

Normal Operation

Inlet air is compressed in a single spool compressor to a pressure ratio of approximately 16:1. This pressure ratio was vendor specified and less than the 18.5:1 ratio used in natural gas applications. The majority of compressor discharge air remains on-board the machine and passes to the burner section to support combustion of the syngas. Compressed air is also used in burner, transition, and film cooling services. About 5.7 percent of the compressor air is extracted and integrated with the air supply of the ASU in non-carbon capture cases. It may be technically possible to integrate the CT and ASU in CO_2 capture cases as well; however, in this study integration was not recommended by the CT vendor and is considered only for non-carbon capture cases.

Pressurized syngas is combusted in several (14) parallel diffusion combustors and syngas dilution is used to limit NOx formation. As described in Section 3.1.2 nitrogen from the ASU is used as the primary diluent followed by syngas humidification and finally by steam dilution, if necessary, to achieve an LHV of 4.3-4.8 MJ/Nm^3 (115-129 Btu/scf). In the three IGCC cases discussed in this report, nitrogen dilution alone was sufficient for the capture cases, but humidification was necessary for the non-capture case. The advantages of using nitrogen as the primary diluent include:

- Nitrogen from the ASU is already partially compressed and using it for dilution eliminates wasting the compression energy.
- Limiting the water content reduces the need to de-rate firing temperature, particularly in the high-hydrogen (CO_2 capture) cases.

Exhibit 3-17 Typical Fuel Specification for F-Class Machines

	Max	Min
LHV, kJ/m^3 (Btu/scf)	None	3.0 (100)
Gas Fuel Pressure, MPa (psia)	3.1 (450)	
Gas Fuel Temperature, °C (°F)	(1)	Varies with gas pressure (2)
Flammability Limit Ratio, Rich-to-Lean, Volume Basis	(3)	2:2.1
Sulfur	(4)	

Notes:

1. The maximum fuel temperature is defined in reference [54]
2. To ensure that the fuel gas supply to the gas turbine is 100 percent free of liquids the minimum fuel gas temperature must meet the required superheat over the respective dew point. This requirement is independent of the hydrocarbon and moisture concentration. Superheat calculation shall be performed as described in GEI-4140G [53].
3. Maximum flammability ratio limit is not defined. Fuel with flammability ratio significantly larger than those of natural gas may require start-up fuel
4. The quantity of sulfur in syngas is not limited by specification. Experience has shown that fuel sulfur levels up to 1 percent by volume do not significantly affect oxidation/corrosion rates.

There are some disadvantages to using nitrogen as the primary diluent, and these include:

- There is a significant auxiliary power requirement to further compress the large nitrogen flow from the ASU pressure to two pressure levels at the CT (2.7 and 3.2 MPa [384 and 469 psia]).
- The low quality heat used in the syngas humidification process does not provide significant benefit to the process in other applications.
- Nitrogen is not as efficient as water in limiting NOx emissions

It is not clear that one dilution method provides a significant advantage over the other. However, in this study nitrogen was chosen as the primary diluent based on suggestions by turbine industry experts.

Hot combustion products are expanded in the three-stage turbine-expander. Given the assumed ambient conditions, back-end loss, and HRSG pressure drop, the CT exhaust temperature for the capture cases is nominally 563°C (1,046°F) for Case 3 and 577°C (1,070°F) for Case 2 and 592°C (1,098°F) for the non-capture Case 1.

Gross turbine power, as measured prior to the generator terminals, is 232 MW at ISO conditions. Turbine output was reduced for all cases due to the site elevation. The CT generator is a standard hydrogen-cooled machine with static exciter.

Exhibit 3-18 Allowable Gas Fuel Contaminant Level for F-Class Machines

	Turbine Inlet Limit, ppbw	Fuel Limit, ppmw		
		Turbine Inlet Flow/Fuel Flow		
		50	*12*	*4*
Lead	20	1.0	0.240	.080
Vanadium	10	0.5	0.120	0.040
Calcium	40	2.0	0.480	0.160
Magnesium	40	2.0	0.480	0.160
Sodium + Potassium				
Na/K = 28 (1)	20	1.0	0.240	0.080
Na/K = 3	10	0.5	0.120	0.40
Na/K ≤ 1	6	0.3	0.072	0.024
Particulates Total (2)	600	30	7.2	2.4
Above 10 microns	6	0.3	0.072	0.024

Notes:
1. Na/K=28 is nominal sea salt ratio
2. The fuel gas delivery system shall be designed to prevent generation or admittance of solid particulate to the gas turbine gas fuel system

The power output of the combustion turbine increases slightly with increased carbon capture primarily because of the increased hydrogen content of the syngas. The higher hydrogen concentration results in a higher water concentration after the combustor, which increases the specific heat of the flue gas stream. The higher specific heat more than offsets the small decrease in mass flow rate that occurs in the carbon capture cases and the net result is a 1.2 percent power output increase in the 1,100 lb CO_2/net-MWh emission rate case and a 2.2 percent increase in the 90 percent capture case relative to the non-capture case.

3.1.11 Steam Generation Island

Heat Recovery Steam Generator

The heat recovery steam generator (HRSG) is a horizontal gas flow, drum-type, multi-pressure design that is matched to the characteristics of the gas turbine exhaust when firing medium-Btu gas. High-temperature flue gas exiting the CT is conveyed through the HRSG to recover the large quantity of thermal energy that remains. Flue gas travels through the HRSG gas path and exits at 132°C (270°F) in all three Shell IGCC cases.

The high pressure (HP) drum produces steam at main steam pressure, while the intermediate pressure (IP) drum produces process steam and turbine dilution steam, if required. The HRSG drum pressures are nominally 12.4/2.9 MPa (1800/420 psia) for the HP/IP turbine sections, respectively. In addition to generating and superheating steam, the HRSG performs reheat duty for the cold/hot reheat steam for the steam turbine, provides condensate and feedwater heating, and also provides deaeration of the condensate.

Natural circulation of steam is accomplished in the HRSG by utilizing differences in densities due to temperature differences of the steam. The natural circulation HRSG provides the most cost-effective and reliable design.

The HRSG drums include moisture separators, internal baffles, and piping for feedwater/steam. All tubes, including economizers, superheaters, and headers and drums, are equipped with drains.

Safety relief valves are furnished in order to comply with appropriate codes and ensure a safe work place.

Superheater, boiler, and economizer sections are supported by shop-assembled structural steel. Inlet and outlet duct is provided to route the gases from the gas turbine outlet to the HRSG inlet and the HRSG outlet to the stack. A diverter valve is included in the inlet duct to bypass the gas when appropriate. Suitable expansion joints are also included.

Steam Turbine Generator and Auxiliaries

The steam turbine consists of an HP section, an IP section, and one double-flow low pressure (LP) section, all connected to the generator by a common shaft. The HP and IP sections are contained in a single-span, opposed-flow casing, with the double-flow LP section in a separate casing. The LP turbine has a last stage bucket length of 76 cm (30 in).

Main steam from the HRSG and gasifier island is combined in a header, and then passes through the stop valves and control valves and enters the turbine at either 12.4 MPa/566°C (1800 psig/1050°F) for the non-carbon capture cases, or 12.4 MPa/538°C (1800 psig/1000°F) for the carbon capture cases. The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the HRSG for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 3.2 MPa/566°C (467 psia/1050°F) for the non-carbon capture cases or 3.2 MPa/538°C (467 psia/1000°F) for the carbon capture cases. After passing through the IP section, the steam enters a crossover pipe, which transports the steam to the LP section. The steam divides into two paths and flows through the LP sections, exhausting downward into the condenser.

Turbine bearings are lubricated by a closed-loop, water-cooled, pressurized oil system. The oil is contained in a reservoir located below the turbine floor. During startup or unit trip an emergency oil pump mounted on the reservoir pumps the oil. When the turbine reaches 95 percent of synchronous speed, the main pump mounted on the turbine shaft pumps oil. The oil flows through water-cooled heat exchangers prior to entering the bearings. The oil then flows through the bearings and returns by gravity to the lube oil reservoir.

Turbine shafts are sealed against air in-leakage or steam blowout using a modern positive pressure variable clearance shaft sealing design arrangement connected to a low-pressure steam seal system. During startup, seal steam is provided from the main steam line. As the unit increases load, HP turbine gland leakage provides the seal steam. Pressure-regulating valves control the gland header pressure and dump any excess steam to the condenser. A steam packing exhauster maintains a vacuum at the outer gland seals to prevent leakage of steam into the turbine room. Any steam collected is condensed in the packing exhauster and returned to the condensate system.

The generator is a hydrogen-cooled synchronous type, generating power at 24 kV. A static, transformer type exciter is provided. The generator is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Gas is prevented from escaping at the rotor shafts by a closed-loop oil seal system. The oil seal system consists of storage tank, pumps, filters, and pressure controls, all skid-mounted.

The steam turbine generator 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 CRT operator interfacing, and datalink interfaces to the balance-of-plant DCS, and incorporates on-line repair capability.

Condensate System

The condensate system transfers condensate from the condenser hotwell to the deaerator, through the gland steam condenser, gasifier, and the low-temperature economizer section in the HRSG. The system consists of one main condenser; two 50 percent capacity, motor-driven, vertical condensate pumps; one gland steam condenser; and a low-temperature tube bundle in the HRSG. Condensate is delivered to a common discharge header through separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

Feedwater System

The function of the feedwater system is to pump the various feedwater streams from the deaerator storage tank in the HRSG to the respective steam drums. Two 50 percent capacity boiler feed pumps are provided for each of three pressure levels, HP, IP, and LP. Each pump is provided with inlet and outlet isolation valves, and outlet check valve. Minimum flow recirculation to prevent overheating and cavitation of the pumps during startup and low loads is provided by an automatic recirculation valve and associated piping that discharges back to the deaerator storage tank. Pneumatic flow control valves control the recirculation flow.

The feedwater pumps are supplied with instrumentation to monitor and alarm on low oil pressure, or high bearing temperature. Feedwater pump suction pressure and temperature are also monitored. In addition, the suction of each boiler feed pump is equipped with a startup strainer.

Main and Reheat Steam Systems

The function of the main steam system is to convey main steam generated in the synthesis gas cooler (SGC) and HRSG from the HRSG superheater outlet to the HP turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the HRSG reheater, and to the turbine reheat stop valves.

Main steam at approximately 12.4 MPa/566°C (1800 psig/1050°F) (non-carbon capture cases) or 12.4 MPa/538°C (1800 psig/1000°F) (carbon capture cases) exits the HRSG superheater through a motor-operated stop/check valve and a motor-operated gate valve, and is routed to the HP turbine. Cold reheat steam at approximately 3.45 MPa/352-376°C (500 psia/666-708°F) exits the HP turbine, flows through a motor-operated isolation gate valve, to the HRSG reheater. Hot reheat steam at approximately 3.2 MPa/566°C (467 psia/1050°F) for non-carbon capture cases and 3.2 MPa/538°C (467 psia/1000°F) for carbon capture cases exits the HRSG reheater through a motor-operated gate valve and is routed to the IP turbines.

Steam piping is sloped from the HRSG to the drip pots located near the steam turbine for removal of condensate from the steam lines. Condensate collected in the drip pots and in low-point drains is discharged to the condenser through the drain system.

Steam flow is measured by means of flow nozzles in the steam piping. The flow nozzles are located upstream of any branch connections on the main headers.

Safety valves are installed to comply with appropriate codes and to ensure the safety of personnel and equipment.

Circulating Water System

Exhaust steam from the steam turbine is split 50/50 to a surface condenser cooled with cooling water and to an air-cooled condenser used ambient air and forced convection. A decision to use a parallel wet/dry cooling system was based primarily on the plans for the Xcel Energy Comanche 3 PC plant currently under construction, and the desire to reduce the plant water requirement. Parallel cooling has less of a performance impact on combined cycle systems than on PC systems; and with the relatively low ambient temperature, the performance impact from the parallel cooling, as compared to wet cooling, is minor.

The major impact of parallel cooling is a significant reduction in water requirement when compared to a wet cooling system. This impact is included in the water balance presented later in this report.

With this cooling system and the specific ambient temperature, a condenser pressure of 0.005 MPa (0.698 psia) (condensing temperature of 32°C [90°F]) is used in the model.

The circulating water system is a closed-cycle cooling water system that supplies cooling water to the surface condenser to condense one-half of the main turbine exhaust steam. The system also supplies cooling water to the AGR plant as required, and to the auxiliary cooling system. The auxiliary cooling system is a closed-loop 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 heat exchangers. The heat transferred to the circulating water in the surface condenser and other applications is removed by a mechanical draft cooling tower.

The system consists of two 50 percent capacity vertical circulating water pumps, a mechanical draft evaporative cooling tower, and carbon steel 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. The cooling tower is a multi-cell, counterflow mechanical draft cooling tower.

The 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 air-cooled condenser utilizes ambient air and forced convection across tube bundles to condense the balance of the turbine exhaust steam.

Both condensers are 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.

Raw Water, Fire Protection, and Cycle Makeup Water Systems

The raw water system supplies cooling tower makeup, cycle makeup, service water and potable water requirements. The water source is 50 percent from municipal sources and 50 percent from groundwater. Booster pumps within the plant boundary provide the necessary pressure.

The fire protection system provides water under pressure to the fire hydrants, hose stations, and fixed water suppression system within the buildings and structures. The system consists of pumps, underground and aboveground supply piping, distribution piping, hydrants, hose stations, spray systems, and deluge spray systems. One motor-operated booster pump is supplied on the intake structure of the cooling tower with a diesel engine backup pump installed on the water inlet line.

The cycle makeup water system provides high quality demineralized water for makeup to the HRSG cycle, for steam injection ahead of the water gas shift reactors in CO_2 capture cases, and for injection steam to the auxiliary boiler for control of NOx emissions, if required.

The cycle makeup system consists of two 100 percent trains, each with a full-capacity activated carbon filter, primary cation exchanger, primary anion exchanger, mixed bed exchanger, recycle pump, and regeneration equipment. The equipment is skid-mounted and includes a control panel and associated piping, valves, and instrumentation.

3.1.12 Accessory Electric Plant

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

3.1.13 Instrumentation and Control

An integrated plant-wide distributed control system (DCS) is provided. The DCS is a redundant microprocessor-based, functionally distributed control system. The control room houses an array of multiple video monitor (CRT) and keyboard units. The CRT/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 be operational and accessible 99.5 percent of the time it is required (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 manually implemented, with operator selection of modular automation routines available. The exception to this, and an important facet of the control system for gasification, is the critical controller system, which is a part of the license package from the gasifier supplier and is a dedicated and distinct hardware segment of the DCS.

This critical controller system is used to control the gasification process. The partial oxidation of the fuel feed and oxygen feed streams to form a syngas product is a stoichiometric, temperature- and pressure-dependent reaction. The critical controller utilizes a redundant microprocessor executing calculations and dynamic controls at 100- to 200-millisecond intervals. The enhanced execution speeds as well as evolved predictive controls allow the critical controller to mitigate process upsets and maintain the reactor operation within a stable set of operating parameters.

4. GREENFIELD IGCC CASES (CASES 1-3)

Revision 2 Updates

The modeling updates made to the IGCC cases consisted of the following:

- *Eliminated the ambient heat loss from the gasifier (previously was 2.7 percent of the heat input to the gasifier)*
- *Added syngas recycle to the CO_2 capture cases*
- *Added heat recovery to simulate the jacketed transfer duct between the gasifier and quench vessel (capture cases) or between the gasifier and the syngas cooler (non-capture case)*
- *Relocated the sulfur plant tail gas recycle stream to upstream of the AGR instead of to the gasifier*
- *Updated the combustion turbine model to be more predictive over the range of performance estimates*
- *Updated process heat integration to take advantage of the transfer duct heat recovery and account for the syngas recycle stream in the capture cases*

This section contains an evaluation of plant designs for Cases 1 through 3, which are based on the Shell Global Solutions (Shell) gasifier. These three cases are very similar in terms of process, equipment, scope and arrangement, except that Case 1 employs a syngas cooler as opposed to the full water quench in Cases 2 and 3. There are no provisions for CO_2 removal in Case 1.

Section 4.1 covers Case 1 (non-capture case) using Montana Rosebud PRB coal and Cases 2 and 3 (CO_2-capture cases) also using Montana Rosebud PRB coal. The cases are organized analogously as follows:

- Process and System Description provides an overview of the technology operation as applied to Cases 1 - 3.
- Key Assumptions is a summary of study and modeling assumptions relevant to Cases 1 - 3.
- Sparing Philosophy is provided for Cases 1 - 3.
- Performance Results provide the main modeling results from Cases 1 - 3, including the performance summary, environmental performance, carbon balance, sulfur balance, water balance, mass and energy balance diagrams and mass and energy balance tables.

- Equipment List provides an itemized list of major equipment for Cases 1 - 3 with account codes that correspond to the cost accounts in the Cost Estimates section.
- Cost Estimates provide a summary of capital and operating costs for Cases 1 - 3.

4.1 SHELL IGCC NON-CAPTURE CASE 1 AND CAPTURE CASES 2 AND 3

4.1.1 Process Description for Non-Capture Case 1

In this section the overall Shell gasification process for Case 1 is described. The system description follows the BFD in Exhibit 4-1 and stream numbers reference the same Exhibit. The stream tables provide process data in Exhibit 4-2 for the numbered streams in the BFD.

Coal Preparation and Feed Systems

Coal receiving and handling is common to all cases and was covered in Section 3.1.1. The receiving and handling subsystem ends at the coal silo. The Shell process uses a dry feed system, which is sensitive to the coal moisture content. Coal moisture consists of two parts, surface moisture and inherent moisture. For coal to flow smoothly through the lock hoppers, the surface moisture must be removed. The PRB coal used in this study contains 25.77 percent total moisture on an as-received basis (stream 9). It was assumed that the PRB coal must be dried to 6 percent moisture to allow for smooth flow through the dry feed system (stream 11).

The raw coal is crushed in the coal mill then delivered to a surge hopper with an approximate 2-hour capacity, which in turn delivers the coal to the coal pre-heater (stream 9). The WTA coal drying process includes a water-heated-, horizontal-, rotary-kiln coal pre-heater, a fluidized bed coal dryer and a water-cooled-, horizontal-, rotary-kiln coal cooler. The moisture driven from the coal in the fluid bed dryer passes through a baghouse for particulate removal and then is split into two streams. The smaller of the two streams is compressed and used as the fluidizing medium in the coal dryer. The bulk of the removed moisture is compressed to 0.66 MPa (96 psia) and the temperature is raised to about 413°C (776°F) in the process. The high temperature vapor passes through internal coils in the dryer to provide the heat to drive off the coal moisture and then exits the dryer as liquid water. The warm water is used in the coal pre-heater before being used as cooling tower makeup water (stream 10). The vapor compressor consumes the vast majority of the WTA process auxiliary load.

The coal is drawn from the surge hoppers and fed through a pressurization lock hopper system to a dense phase pneumatic conveyor, which uses nitrogen from the ASU (stream 6) to convey the coal to the gasifiers.

Gasifier

There are two Shell dry feed, pressurized, upflow, entrained, slagging gasifiers, operating at 4.2 MPa (615 psia) and processing a total of 5,211 tonnes/day (5,744 TPD) of as-received coal. Coal reacts with oxygen (stream 7) and steam (stream 8) at a temperature of 1,454°C (2,650°F) to produce principally hydrogen and carbon monoxide with little carbon dioxide formed (stream 13).

The gasifier includes a refractory-lined water wall that is also protected by molten slag that solidifies on the cooled walls.

Raw Gas Cooling/Particulate Removal

High-temperature heat recovery in each gasifier train is accomplished in three steps, including the gasifier jacket, which cools the syngas by maintaining the reaction temperature at 1454°C (2650°F). The product gas from the gasifier (stream 13) is cooled to 1,093°C (2,000°F) by adding cooled recycled fuel gas (stream 14) and then further cooled in a jacketed duct cooler to 899°C (1,650°F) to lower the temperature below the ash melting point. Syngas then goes through a raw gas cooler, which lowers the gas temperature from 899°C (1,650°F) to 335°C (635°F), and produces high-pressure steam for use in the steam cycle. The syngas is further cooled to 191°C (375°F) by vaporizing high-pressure water and subsequently low-pressure water.

After passing through the raw gas coolers, the syngas passes through a cyclone and a raw gas candle filter where a majority of the fine particles are removed and returned to the gasifier with the coal fuel. The filter consists of an array of ceramic candle elements in a pressure vessel. Fines produced by the gasification system are recirculated to extinction. The ash that is not carried out with the gas forms slag and runs down the interior walls, exiting the gasifier in liquid form. The slag is solidified in a quench tank for disposal (stream 12). Lockhoppers are used to reduce the pressure of the solids from 4.2 MPa (615 psia) to ambient. The syngas scrubber removes additional particulate matter further downstream.

Quench Gas Compressor

About 30 percent of the raw gas from the filter is recycled back to the gasifier as quench gas. A single-stage compressor is utilized to boost the pressure of a cooled fuel gas stream from 4.0 MPa (575 psia) to 4.2 MPa (615 psia) (stream 14) to provide quench gas to cool the gas stream from the gasifier.

Syngas Scrubber/Sour Water Stripper

The raw synthesis gas exiting the ceramic particulate filter at 191°C (375°F) (stream 15) then enters the scrubber for removal of chlorides and remaining particulate. The quench scrubber washes the syngas in a counter-current flow in two packed beds. The syngas leaves the scrubber saturated at a temperature of 98°C (208°F). The quench scrubber removes essentially all traces of entrained particles, principally unconverted carbon, slag, and metals. The bottoms from the scrubber are sent to the slag removal and handling system for processing.

The sour water stripper removes NH_3, SO_2, and other impurities from the waste stream of the scrubber. The sour gas stripper consists of a sour drum that accumulates sour water from the gas scrubber and condensate from synthesis gas coolers. Sour water from the drum flows to the sour stripper, which consists of a packed column with a steam-heated reboiler. Sour gas is stripped from the liquid and sent to the sulfur recovery unit. Remaining water is sent to wastewater treatment.

COS Hydrolysis, Mercury Removal and Acid Gas Removal

H_2S and COS are at significant concentrations, requiring removal for the power plant to achieve the low design level of SO_2 emissions. H_2S is removed in an acid gas removal process; however, because COS is not readily removed, it is first catalytically converted to H_2S in a COS hydrolysis unit.

Following the water scrubber, the gas is reheated to 177°C (350°F) and fed to the COS hydrolysis reactor. The COS in the sour gas is hydrolyzed with steam over a catalyst bed to H_2S, which is more easily removed by the AGR solvent. Before the raw fuel gas can be treated in the AGR process (stream 18), it must be cooled to about 35°C (95°F). During this cooling through a series of heat exchangers, part of the water vapor condenses. This water, which contains some NH_3, is sent to the sour water stripper. The cooled syngas (stream 17) then passes through a carbon bed to remove 95 percent of the Hg (Section 3.1.6).

The Sulfinol process, developed by Shell in the early 1960s, is a combination process that uses a mixture of amines and a physical solvent. The solvent consists of an aqueous amine and sulfolane. Sulfinol-D uses diisopropanolamine (DIPA), while Sulfinol-M uses MDEA. The mixed solvents allow for better solvent loadings at high acid gas partial pressures and higher solubility of COS and organic sulfur compounds than straight aqueous amines. Sulfinol-M was selected for the non-CO_2 capture applications.

The sour syngas is fed directly into an HP contactor. The HP contactor is an absorption column in which the H_2S, COS, CO_2, and small amounts of H_2 and CO are removed from the gas by the Sulfinol solvent. The overhead gas stream from the HP contactor is then washed with water in the sweet gas scrubber before leaving the unit as the feed gas to the sulfur polishing unit.

The rich solvent from the bottom of the HP contactor flows through a hydraulic turbine and is flashed in the rich solvent flash vessel. The flashed gas is then scrubbed in the LP contactor with lean solvent to remove H_2S and COS. The overhead from the LP contactor is flashed in the LP KO drum. This gas can be used as a utility fuel gas, consisting primarily of H_2 and CO, at 0.8 MPa (118 psia) and 38°C (101°F). The solvent from the bottom of the LP contactor is returned to the rich solvent flash vessel.

Hot, lean solvent in the lean/rich solvent exchanger then heats the flashed rich solvent before entering the stripper. The stripper strips the H_2S, COS, and CO_2 from the solvent at low pressure with heat supplied through the stripper reboiler. The acid gas stream to sulfur recovery/tail gas cleanup is recovered as the flash gas from the stripper accumulator. The lean solvent from the bottom of the stripper is cooled in the lean/rich solvent exchanger and the lean solvent cooler. Most of the lean solvent is pumped to the HP contactor. A small amount goes to the LP contactor.

The Sulfinol process removes about 40 percent of the CO_2 along with the H_2S and COS. The acid gas fed to the SRU contains 28 vol% H_2S and 41 vol% CO_2. The CO_2 passes through the SRU, the hydrogenation reactor and is recycled to the gasifier. Since the amount of CO_2 in the syngas is small initially, this does not have a significant effect on the mass flow reaching the gas turbine. However, the costs of the sulfur recovery/tail gas treatment are higher than for a sulfur removal process producing an acid gas stream with a higher sulfur concentration.

Claus Unit

The sulfur recovery unit is a Claus bypass type sulfur recovery unit utilizing oxygen (stream 4) instead of air. The Claus plant produces molten sulfur (stream 20) by reacting approximately one third of the H_2S in the feed to SO_2, then reacting the H_2S and SO_2 to sulfur and water. The combination of Claus technology and tail gas recycle to the gasifier results in an overall sulfur recovery exceeding 99 percent.

Utilizing oxygen instead of air in the Claus plant reduces the overall cost of the sulfur recovery plant. The sulfur plant produces approximately 38 tonnes/day (42 TPD) of elemental sulfur. Feed for each case consists of acid gas from both the acid gas cleanup unit (stream 22) and a vent stream from the sour water stripper in the gasifier section.

In the furnace waste heat boiler steam is generated. This steam is used to satisfy all Claus process preheating and reheating requirements as well as to provide some steam to the medium-pressure steam header. The sulfur condensers produce 0.34 MPa (50 psig) steam for the low-pressure steam header.

Power Block

Clean syngas exiting the Sulfinol absorber (stream 23) is humidified and reheated (stream 24), diluted with nitrogen from the ASU (stream 5), and enters the advanced F Class combustion turbine (CT) burner. The CT compressor provides combustion air to the burner and also 14 percent of the air requirements in the ASU (stream 2). The exhaust gas exits the CT at 591°C (1,095°F) (stream 26) and enters the HRSG where additional heat is recovered until the flue gas exits the HRSG at 132°C (270°F) (stream 27) and is discharged through the plant stack. The steam raised in the HRSG is used to power an advanced, commercially available steam turbine using a nominal 12.4 MPa/566°C/566°C (1800 psig/1050°F/1050°F) steam cycle.

Air Separation Unit (ASU)

The ASU is designed to produce a nominal output of 3,201 tonnes/day (3,529 TPD) of 95 mole percent O_2 for use in the gasifier (stream 7) and sulfur recovery unit (stream 4). The plant is designed with two production trains. The air compressor is powered by an electric motor. Approximately 10,220 tonnes/day (11,265 TPD) of nitrogen are also recovered, compressed, and used as dilution in the gas turbine combustor or as transport nitrogen. Approximately 3.25 percent of the gas turbine air is used to supply approximately 14 percent of the ASU air requirements.

Exhibit 4-1 Case 1: IGCC without CO_2 Capture - Block Flow Diagram

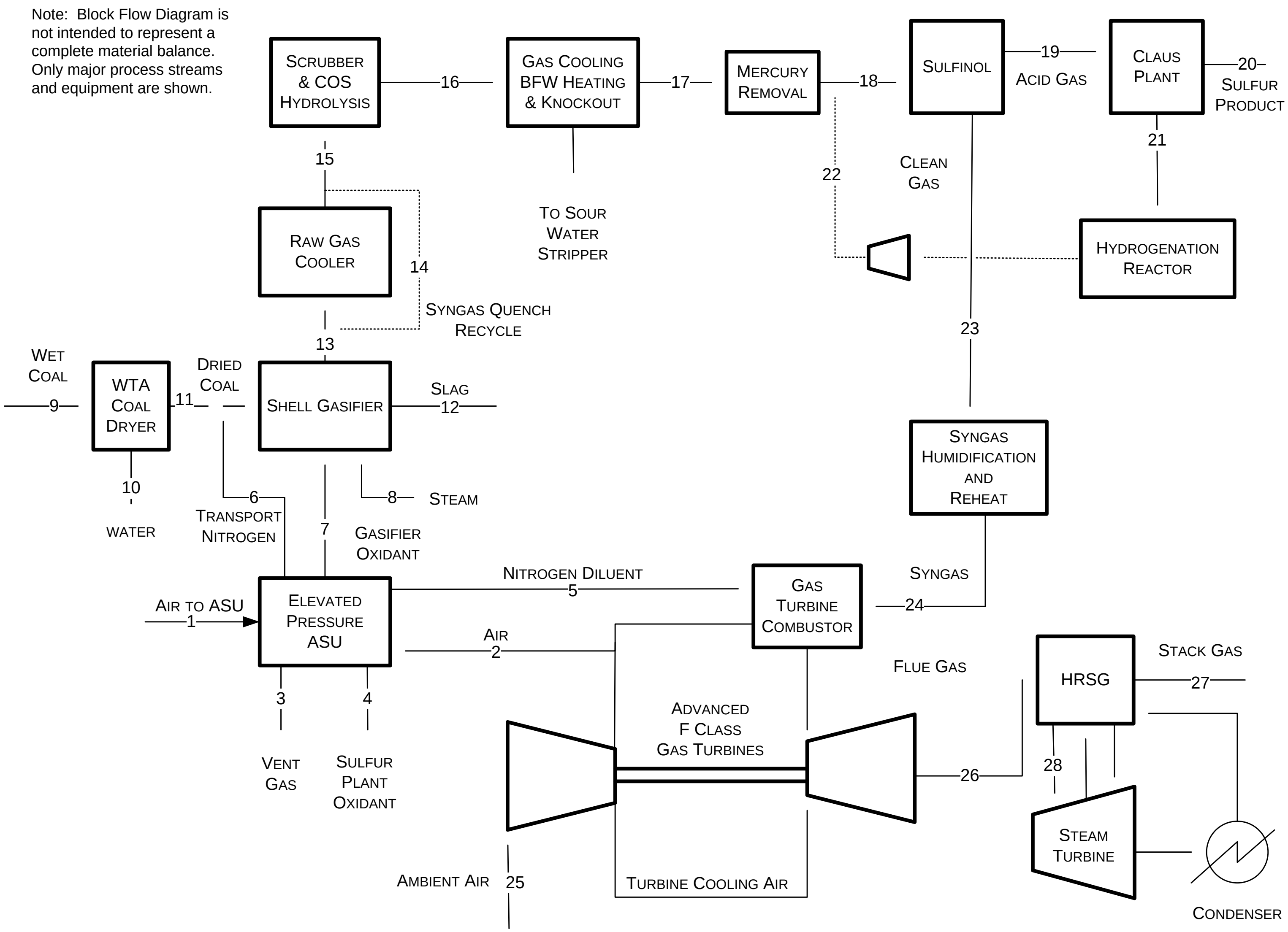


Exhibit 4-2 Case 1: IGCC without CO_2 Capture - Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
V-L Mole Fraction														
Ar	0.0093	0.0093	0.0240	0.0318	0.0023	0.0000	0.0318	0.0000	0.0000	0.0000	0.0000	0.0000	0.0104	0.0104
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	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.6018	0.6018
CO_2	0.0003	0.0003	0.0083	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0312	0.0312
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0005	0.0005
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2613	0.2613
H_2O	0.0071	0.0071	0.1723	0.0000	0.0003	0.0000	0.0000	0.0000	0.0000	1.0000	0.0000	0.0000	0.0289	0.0289
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0030	0.0030
N_2	0.7753	0.7753	0.5912	0.0178	0.9920	1.0000	0.0178	0.0000	0.0000	0.0000	0.0000	0.0000	0.0607	0.0607
NH_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	0.0022	0.0022
O_2	0.2080	0.2080	0.2042	0.9504	0.0054	0.0000	0.9504	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	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	0.0000	0.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	17,257	2,860	796	46	14,411	765	4,099	0	0	2,535	0	0	14,216	6,237
V-L Flowrate (kg/hr)	498,497	82,611	21,912	1,466	404,377	21,433	131,921	0	0	45,667	0	0	306,499	134,463
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	217,133	0	171,466	18,322	0	0
Temperature (°C)	6	411	20	32	196	293	32	---	6	37	71	1,454	1,454	202
Pressure (MPa, abs)	0.08	1.25	0.11	0.86	2.65	5.62	0.86	---	0.08	0.49	0.08	4.24	4.24	4.24
Enthalpy (kJ/kg)^A	16.42	435.50	38.23	26.67	202.67	306.58	26.67	---	---	53.85	---	---	2,291.03	336.24
Density (kg/m^3)	1.0	6.3	1.5	11.0	18.9	32.8	11.0	---	---	981.9	---	---	6.3	22.8
V-L Molecular Weight	28.887	28.887	27.524	32.181	28.061	28.013	32.181	---	---	18.015	---	---	21.561	21.560
V-L Flowrate (lb_{mol}/hr)	38,045	6,305	1,755	100	31,771	1,687	9,038	0	0	5,589	0	0	31,340	13,749
V-L Flowrate (lb/hr)	1,098,999	182,127	48,308	3,232	891,498	47,252	290,836	0	0	100,679	0	0	675,714	296,440
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	478,697	0	378,018	40,392	0	0
Temperature (°F)	42	771	68	90	385	560	90	---	42	98	160	2,650	2,650	396
Pressure (psia)	11.4	181.8	16.4	125.0	385.0	815.0	125.0	---	11.4	71.1	11.1	614.7	614.7	615.0
Enthalpy (Btu/lb)^A	7.1	187.2	16.4	11.5	87.1	131.8	11.5	---	---	23.2	---	---	985.0	144.6
Density (lb/ft^3)	0.061	0.396	0.095	0.687	1.183	2.045	0.687	---	---	61.300	---	---	0.395	1.425

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 4-2 Case 1: IGCC without CO_2 Capture - Stream Table (continued)

	15	16	17	18	19	20	21	22	23	24	25	26	27	28
V-L Mole Fraction														
Ar	0.0104	0.0104	0.0107	0.0107	0.0008	0.0000	0.0074	0.0118	0.0108	0.0099	0.0093	0.0090	0.0090	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	0.0000	0.0000
CO	0.6018	0.6041	0.6199	0.6131	0.0311	0.0000	0.0337	0.0011	0.6208	0.5658	0.0000	0.0000	0.0000	0.0000
CO_2	0.0312	0.0318	0.0326	0.0380	0.4087	0.0000	0.2984	0.5259	0.0331	0.0302	0.0003	0.0832	0.0832	0.0000
COS	0.0005	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.2613	0.2623	0.2692	0.2669	0.0148	0.0000	0.0161	0.0576	0.2702	0.2462	0.0000	0.0000	0.0000	0.0000
H_2O	0.0289	0.0252	0.0016	0.0016	0.0122	0.0000	0.3918	0.0027	0.0014	0.0899	0.0071	0.0524	0.0524	1.0000
H_2S	0.0030	0.0035	0.0036	0.0036	0.2788	0.0000	0.0018	0.0101	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0607	0.0609	0.0625	0.0660	0.2536	0.0000	0.2464	0.3909	0.0636	0.0579	0.7753	0.7480	0.7480	0.0000
NH_3	0.0022	0.0017	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	0.2080	0.1073	0.1073	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0042	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	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	14,216	14,161	13,801	13,953	182	0	241	152	13,771	15,110	87,994	108,520	108,520	32,498
V-L Flowrate (kg/hr)	306,499	305,520	299,060	304,386	6,494	0	6,910	5,326	297,892	322,015	2,541,887	3,185,667	3,185,667	585,466
Solids Flowrate (kg/hr)	0	0	0	0	0	1,577	0	0	0	0	0	0	0	0
Temperature (°C)	191	177	35	34	51	173	232	38	34	196	6	591	132	563
Pressure (MPa, abs)	3.96	3.79	3.69	3.62	0.41	0.4	0.335	5.106	3.618	3.216	0.079	0.082	0.079	12.512
Enthalpy (kJ/kg)[A]	319.72	292.77	42.48	41.43	60.82	---	893.748	7.747	41.723	461.248	16.424	720.811	216.287	3,507.354
Density (kg/m^3)	21.9	21.6	31.2	30.9	5.6	5,289.3	2.3	77.5	30.6	17.5	1.0	0.3	0.7	35.0
V-L Molecular Weight	21.561	21.575	21.669	21.815	35.747	---	28.713	35.104	21.631	21.311	28.887	29.356	29.356	18.015
V-L Flowrate (lb_{mol}/hr)	31,340	31,220	30,426	30,761	400	0	531	334	30,360	33,312	193,993	239,245	239,245	71,647
V-L Flowrate (lb/hr)	675,714	673,557	659,314	671,055	14,317	0	15,234	11,742	656,739	709,921	5,603,902	7,023,194	7,023,194	1,290,732
Solids Flowrate (lb/hr)	0	0	0	0	0	3,477	0	0	0	0	0	0	0	0
Temperature (°F)	375	351	95	94	124	344	450	100	94	385	42	1,095	270	1,045
Pressure (psia)	574.7	549.7	534.7	524.7	60.0	53.6	48.6	740.5	524.7	466.4	11.4	11.9	11.4	1,814.7
Enthalpy (Btu/lb)[A]	137.5	125.9	18.3	17.8	26.1	---	384.2	3.3	17.9	198.3	7.1	309.9	93.0	1,507.9
Density (lb/ft^3)	1.367	1.348	1.945	1.926	0.347	330	0.143	4.838	1.908	1.090	0.061	0.021	0.043	2.187

4.1.2 Process Description for Capture Cases 2 and 3

Cases 2 and 3 are configured to produce electric power with CO_2 capture. The plant configurations are similar to Case 1 with the major difference being the use of a two-stage Selexol AGR plant instead of Sulfinol and subsequent compression of the captured CO_2 stream. The gross power output is constrained by the capacity of the two combustion turbines, and since the CO_2 capture and compression processes increase the auxiliary load on the plant, the net output is significantly reduced relative to Case 1.

The process description for Case 2 and Case 3 is similar to Case 1 with several notable exceptions to accommodate CO_2 capture. A BFD for the 1,100 lb/net-MWh CO_2 capture Case 2 is shown in Exhibit 4-3 and stream tables for Case 2 are shown in Exhibit 4-4. The BFD for Case 3 is shown in Exhibit 4-5 and the associated stream tables are in Exhibit 4-6. Instead of repeating the entire process description, only differences from Case 1 are reported here.

Gasification

The gasification process is the same as Case 1 with the following exceptions:

- The syngas exiting the duct cooler is quenched to 399°C (750°F) with water rather than a syngas cooler to provide a portion of the water required for water gas shift
- Total coal feed (as-received) to the two gasifiers is 5,393 tonnes/day (5,944 TPD) in Case 2 and 5,632 tonnes/day (6,208 TPD) in Case 3 (stream 8)
- The ASU provides 3,283 tonnes/day (3,619 TPD) of 95 mole percent oxygen to the gasifier and Claus plant in the Case 2 and 3,444 tonnes/day (3,796 TPD) in the Case 3 (streams 6 and 3, respectively)

Raw Gas Cooling/Particulate Removal

Following the water quench and particulate removal the syngas is cooled to 260°C (500°F) prior to the syngas scrubber (stream 13) by vaporizing HP BFW and pre-heating IP BFW.

Syngas Scrubber/Sour Water Stripper

Syngas exits the scrubber at 189°C (373°F).

Sour Gas Shift (SGS)

The SGS process was described in Section 3.1.4. In Cases 2 and 3 the syngas after the scrubber is reheated to 232°C (450°F) and then steam (stream 16) is added to adjust the steam:dry gas molar ratio to a minimum of 0.3:1 at the exit of the shift reactor in Case 2 and to 0.47:1 in Case 3. The higher ratio is required in Case 3 to achieve sufficient CO conversion to achieve an overall capture of 90 percent. The hot syngas exiting the first stage of SGS is used to superheat the steam that is added in stream 16. One more stage of SGS (for a total of two) results in 97.4 percent overall conversion of the CO to CO_2 in Case 3. Case 2 uses a single SGS reactor with a bypass stream (stream 32) to achieve a conversion of 49.7 percent CO to CO_2 to reach the 1,100 lb CO_2/net-MWh emission limit. The warm syngas from the second stage of SGS is cooled to 275°C (527°F) by preheating the syngas prior to the first stage of SGS in Case 3. The SGS catalyst also serves to hydrolyze COS thus eliminating the need for a separate COS hydrolysis reactor. The bypass utilized in Case 2 prevents all COS from being hydrolyzed. Therefore, the CO_2 product contains more sulfur than in Case 3. Following the second stage (or first and only in Case 2) of SGS, the syngas is further cooled to 35°C (95°F) prior to the mercury removal beds.

Mercury Removal and Acid Gas Removal

Mercury removal is the same as in Case 1.

The AGR process in Cases 2 and 3 is a two-stage Selexol process where H_2S is removed in the first stage and CO_2 in the second stage of absorption. The process results in three product streams, the clean syngas, a CO_2-rich stream and an acid gas feed to the Claus plant. The feed to the Claus plant in Case 3 contains 16 percent H_2S, 66 percent CO_2, 13 percent H_2, and the balance primarily H_2O. In Case 2 the acid gas contains about 22 percent H_2S, 49 percent CO_2, 12 percent H_2, 11 percent CO, and the balance primarily H_2O. The higher concentration of CO in Case 2 relative to Case 3 is due to the bypass stream around the SGS reactor in each train. The CO_2-rich stream is discussed further in the CO_2 compression section.

CO_2 Compression and Dehydration

CO_2 from the AGR process is generated at two pressure levels. The LP stream is compressed from 0.12 MPa (17 psia) to 1.0 MPa (150 psia) and then combined with the HP stream. The combined stream is further compressed to a supercritical condition at 15.3 MPa (2215 psia) using a multiple-stage, intercooled compressor. During compression, the CO_2 stream is dehydrated to a dewpoint of -40ºC (-40°F). The raw CO_2 stream from the Selexol process contains at least 97.9 percent CO_2. The dehydrated CO_2 (stream 26 in Case 2 and stream 25 in Case 3) is transported to the plant fence line and is sequestration ready. CO_2 TS&M costs were estimated using the methodology described in Section 2.7.

Claus Unit

The Claus plant is the same as Case 1 with the following exception:

- 38 tonnes/day (42 TPD) of sulfur are produced in Case 2 and 41 tonnes/day (45 TPD) in Case 3.

Power Block

Clean syngas from the AGR plant (stream 27 in Case 2 and stream 26 in Case 3) is reheated to 196°C (385°F) using HP boiler feedwater, diluted with nitrogen (stream 4), and then enters the CT burner. The exhaust gas (stream 30 in Case 2 and stream 29 in Case 3) exits the CT at 577°C (1,071°F) in Case 2 and 563°C (1,046°F) in Case 3 and enters the HRSG where additional heat is recovered. The flue gas exits the HRSG at 132°C (270°F) (stream 31 in Case 2 and stream 30 in Case 3) and is discharged through the plant stack. The steam raised in the HRSG is used to power an advanced commercially available steam turbine using a nominal 12.4 MPa/538°C/538°C (1800 psig/1000°F/1000°F) steam cycle. There is no integration between the CT and the ASU in either capture case.

Air Separation Unit

The same elevated pressure ASU is used as in Case 1 except the output is 3,283 tonnes/day (3,619 TPD) of 95 mole percent oxygen and 10,291 tonnes/day (11,344 TPD) of nitrogen in Case 2 and 3,444 tonne/day (3,796 tpd) of 95 mole percent oxygen and 11,068 tonne/day (12,201 tpd) of nitrogen in Case 3.

Exhibit 4-3 Case 2: IGCC with CO_2 Capture to an Emission Limit of 1,100 lb CO_2/net-MWh - Block Flow Diagram

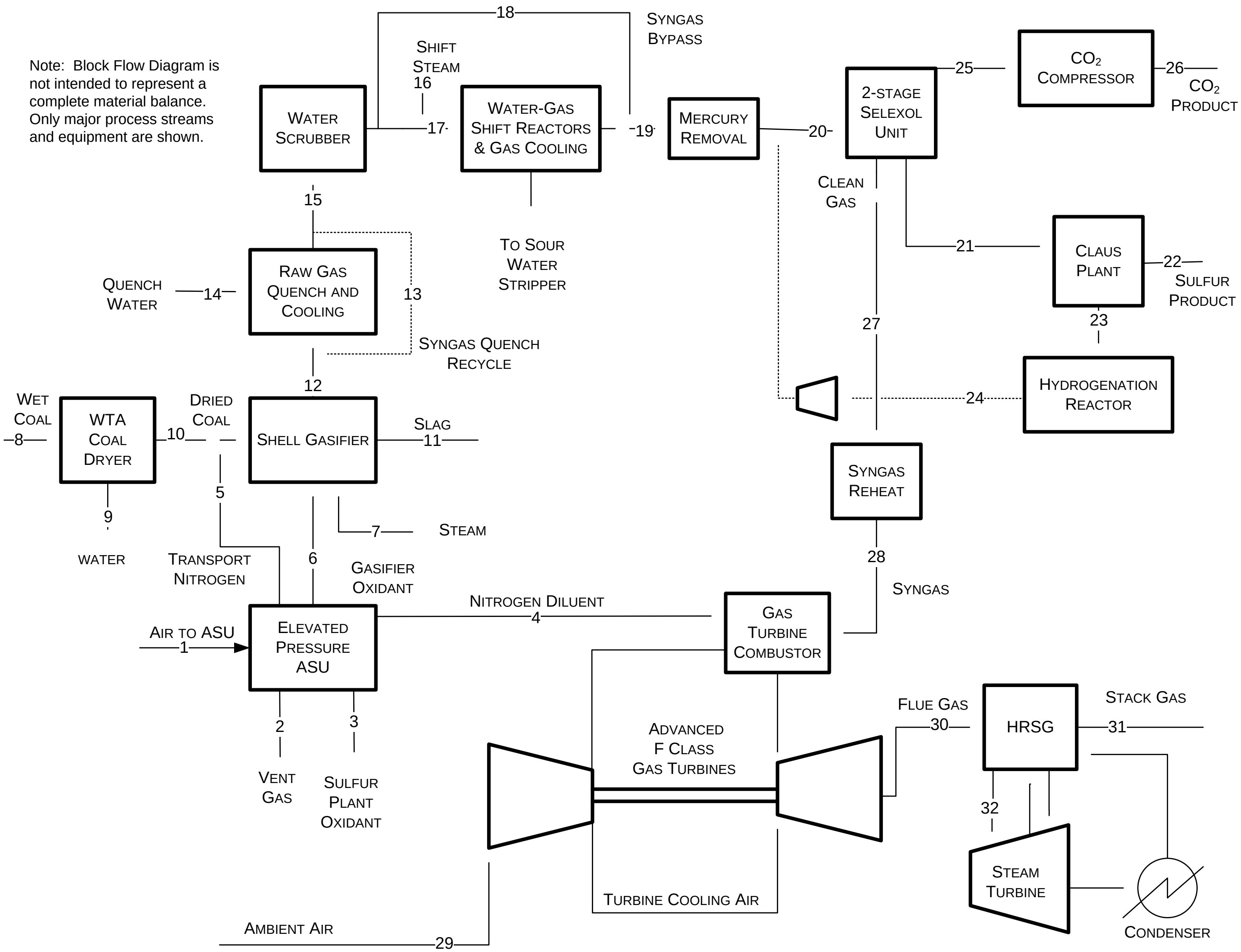


Exhibit 4-4 Case 2: IGCC with CO_2 Capture to an Emission Limit of 1,100 lb CO_2/net-MWh - Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
V-L Mole Fraction																
Ar	0.0093	0.0185	0.0318	0.0023	0.0000	0.0318	0.0000	0.0000	0.0000	0.0000	0.0000	0.0103	0.0066	0.0000	0.0066	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	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.6040	0.3872	0.0000	0.3872	0.0000
CO_2	0.0003	0.0061	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0295	0.0189	0.0000	0.0189	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0005	0.0003	0.0000	0.0003	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	0.2634	0.1689	0.0000	0.1689	0.0000
H_2O	0.0071	0.1296	0.0000	0.0003	0.0000	0.0000	0.0000	0.0000	1.0000	0.0000	0.0000	0.0260	0.3755	1.0000	0.3755	1.0000
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0030	0.0019	0.0000	0.0019	0.0000
N_2	0.7753	0.6930	0.0178	0.9920	1.0000	0.0178	0.0000	0.0000	0.0000	0.0000	0.0000	0.0603	0.0387	0.0000	0.0387	0.0000
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0029	0.0019	0.0000	0.0019	0.0000
O_2	0.2080	0.1528	0.9504	0.0054	0.0000	0.9504	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	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	20,634	1,102	45	14,490	792	4,206	0	0	2,623	0	0	14,699	5,913	8,226	22,925	3,570
V-L Flowrate (kg/hr)	596,059	30,474	1,451	406,596	22,179	135,358	0	0	47,257	0	0	316,011	119,741	148,194	464,205	64,317
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	224,690	0	177,433	18,959	0	0	0	0	0
Temperature (°C)	6	19	32	196	293	32	---	6	33	71	1,427	1,427	274	216	260	288
Pressure (MPa, abs)	0.08	0.11	0.86	2.65	5.62	0.86	---	0.08	0.46	0.08	4.24	4.24	4.24	8.27	3.93	4.14
Enthalpy (kJ/kg)[A]	16.42	36.76	26.67	202.68	306.58	26.67	---	---	37.62	---	---	2,241.81	1,243.02	904.03	1,220.77	2,956.19
Density (kg/m^3)	1.0	1.5	11.0	18.9	32.8	11.0	---	---	985.4	---	---	6.4	19.1	782	18.2	18.2
V-L Molecular Weight	28.887	27.646	32.181	28.060	28.013	32.181	---	---	18.015	---	---	21.499	20.249	18.015	20.249	18.015
V-L Flowrate (lb_{mol}/hr)	45,490	2,430	99	31,945	1,745	9,273	0	0	5,783	0	0	32,405	13,037	18,135	50,540	7,871
V-L Flowrate (lb/hr)	1,314,085	67,183	3,200	896,392	48,897	298,414	0	0	104,183	0	0	696,686	263,983	326,712	1,023,397	141,795
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	495,356	0	391,173	41,798	0	0	0	0	0
Temperature (°F)	42	65	90	385	560	90	---	42	92	160	2,600	2,600	525	420	500	550
Pressure (psia)	11.4	16.4	125.0	384.0	815.0	125.0	---	11.4	66.8	11.1	614.7	614.7	615.0	1,200.0	569.7	600.0
Enthalpy (Btu/lb)[A]	7.1	15.8	11.5	87.1	131.8	11.5	---	---	16.2	---	---	963.8	534.4	388.7	524.8	1,270.9
Density (lb/ft^3)	0.061	0.091	0.687	1.180	2.045	0.687	---	---	61.518	---	---	0.400	1.193	48.817	1.136	1.135

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 4-4 Case 2: IGCC with CO_2 Capture to an Emission Limit of 1,100 lb CO_2/net-MWh - Stream Table (Continued)

	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
V-L Mole Fraction																
Ar	0.0055	0.0069	0.0082	0.0082	0.0031	0.0000	0.0077	0.0093	0.0003	0.0003	0.0107	0.0107	0.0093	0.0091	0.0091	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	0.0000	0.0000	0.0000	0.0000
CO	0.3213	0.4050	0.2538	0.2509	0.1079	0.0000	0.1456	0.0075	0.0097	0.0097	0.3280	0.3280	0.0000	0.0000	0.0000	0.0000
CO_2	0.0157	0.0198	0.2500	0.2540	0.4912	0.0000	0.2864	0.5166	0.9790	0.9834	0.0256	0.0256	0.0003	0.0455	0.0455	0.0000
COS	0.0003	0.0003	0.0002	0.0002	0.0058	0.0000	0.0004	0.0000	0.0004	0.0004	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.1401	0.1767	0.4357	0.4340	0.1188	0.0000	0.0657	0.2486	0.0057	0.0058	0.5716	0.5716	0.0000	0.0000	0.0000	0.0000
H_2O	0.4819	0.3469	0.0016	0.0016	0.0444	0.0000	0.4287	0.1380	0.0045	0.0000	0.0001	0.0001	0.0071	0.0789	0.0789	1.0000
H_2S	0.0016	0.0020	0.0026	0.0026	0.2200	0.0000	0.0012	0.0021	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0321	0.0405	0.0480	0.0485	0.0087	0.0000	0.0642	0.0778	0.0004	0.0004	0.0640	0.0640	0.7753	0.7574	0.7574	0.0000
NH_3	0.0015	0.0019	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
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	0.2080	0.1091	0.1091	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	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	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)	17,269	8,219	18,491	18,709	218	0	305	252	4,376	4,357	14,114	14,114	87,994	110,250	110,250	23,153
V-L Flowrate (kg/hr)	343,112	167,277	384,368	390,946	7,385	0	8,160	7,198	190,359	190,008	193,201	193,201	2,541,887	3,141,685	3,141,685	417,101
Solids Flowrate (kg/hr)	0	0	0	0	0	1,571	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	242	232	35	35	48	178	232	49	16	54	31	196	6	577	132	549
Pressure (MPa, abs)	3.79	3.79	3.48	3.41	0.16	0.1	0.1	0.073	1.032	15.270	3.238	3.203	0.079	0.082	0.079	12.512
Enthalpy (kJ/kg)[A]	1,453.12	1,106.37	43.59	43.04	106.80	---	1,024.4	275.092	6.977	-146.702	60.738	421.700	16.424	759.629	263.644	3,471.595
Density (kg/m^3)	18.1	18.6	28.6	28.2	2.1	5,280	0.5	0.8	20.0	592.7	17.4	11.1	1.0	0.3	0.7	35.8
V-L Molecular Weight	19.869	20.352	20.787	20.897	33.896	---	27	28.558	43.498	43.612	13.688	13.688	28.887	28.496	28.496	18.015
V-L Flowrate (lb_{mol}/hr)	38,072	18,121	40,766	41,245	480	0	673	556	9,648	9,605	31,117	31,117	193,993	243,059	243,059	51,043
V-L Flowrate (lb/hr)	756,433	368,783	847,387	861,888	16,281	0	17,991	15,869	419,671	418,895	425,936	425,936	5,603,902	6,926,230	6,926,230	919,549
Solids Flowrate (lb/hr)	0	0	0	0	0	3,464	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	467	450	95	94	119	352	450	120	60	130	87	385	42	1,071	270	1,021
Pressure (psia)	549.7	549.7	504.7	494.7	23.7	17.3	12.3	10.6	149.7	2,214.7	469.6	464.6	11.4	11.9	11.4	1,814.7
Enthalpy (Btu/lb)[A]	624.7	475.7	18.7	18.5	45.9	---	440.4	118.3	3.0	-63.1	26.1	181.3	7.1	326.6	113.3	1,492.5
Density (lb/ft^3)	1.133	1.163	1.783	1.760	0.130	330	0	0.049	1.246	37.001	1.085	0.693	0.061	0.021	0.041	2.236

Exhibit 4-5 Case 3: IGCC with 90% CO_2 Capture - Block Flow Diagram

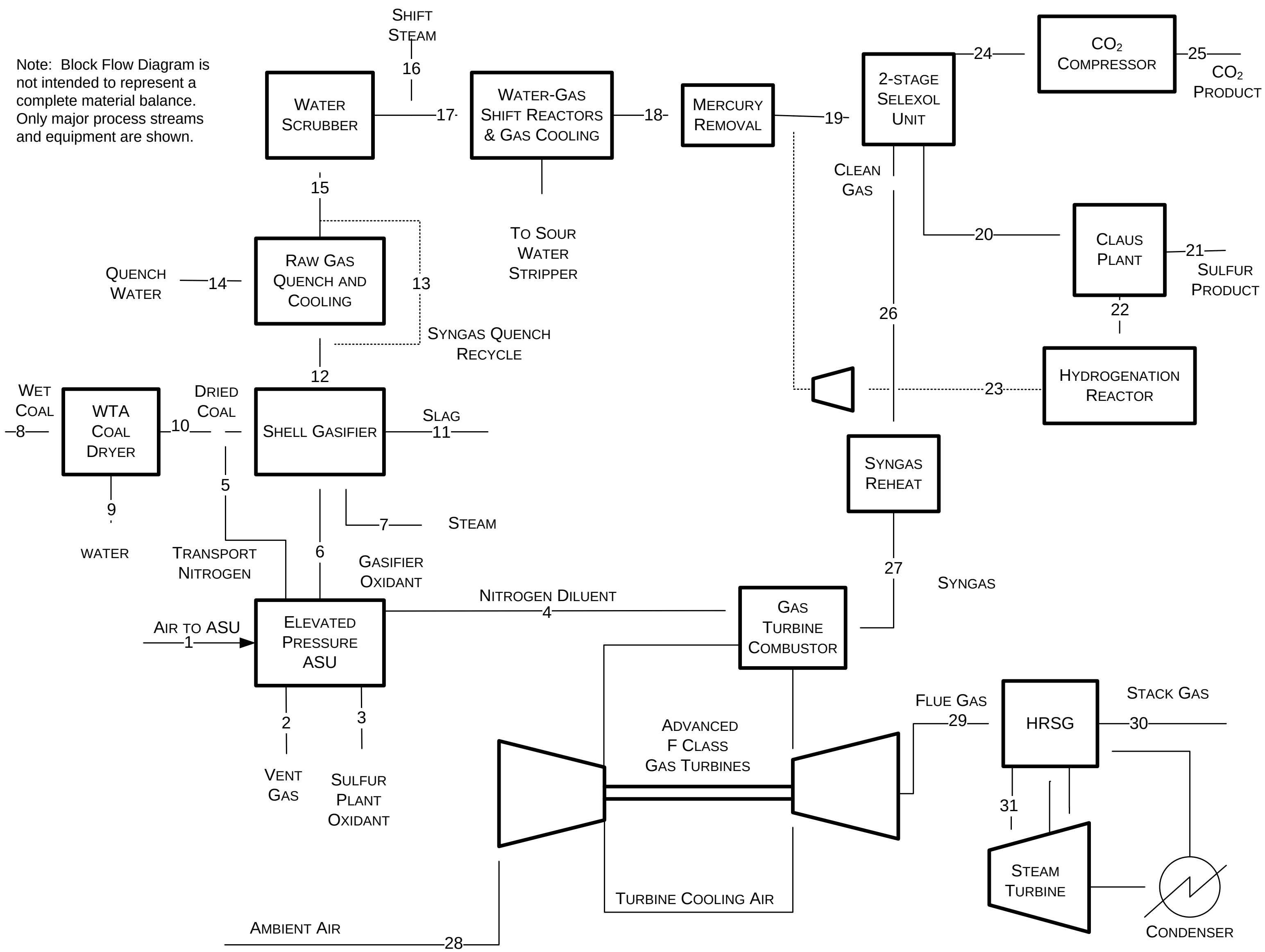


Exhibit 4-6 Case 3: IGCC with 90% CO_2 Capture - Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
V-L Mole Fraction																
Ar	0.0093	0.0272	0.0318	0.0023	0.0000	0.0318	0.0000	0.0000	0.0000	0.0000	0.0000	0.0103	0.0066	0.0000	0.0066	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	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.6026	0.3860	0.0000	0.3860	0.0000
CO_2	0.0003	0.0095	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0308	0.0197	0.0000	0.0197	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0005	0.0003	0.0000	0.0003	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	0.2624	0.1681	0.0000	0.1681	0.0000
H_2O	0.0071	0.2005	0.0000	0.0003	0.0000	0.0000	0.0000	0.0000	1.0000	0.0000	0.0000	0.0271	0.3768	1.0000	0.3768	1.0000
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0030	0.0019	0.0000	0.0019	0.0000
N_2	0.7753	0.5294	0.0178	0.9920	1.0000	0.0178	0.0000	0.0000	0.0000	0.0000	0.0000	0.0604	0.0387	0.0000	0.0387	0.0000
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0029	0.0019	0.0000	0.0019	0.0000
O_2	0.2080	0.2334	0.9504	0.0054	0.0000	0.9504	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	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	21,640	746	47	15,610	827	4,412	0	0	2,740	0	0	15,353	6,133	8,614	23,967	12,382
V-L Flowrate (kg/hr)	625,129	20,460	1,497	438,022	23,164	141,985	0	0	49,355	0	0	330,662	124,331	155,192	485,853	223,066
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	234,669	0	185,314	19,801	0	0	0	0	0
Temperature (°C)	6	21	32	196	293	32	---	6	33	71	1,427	1,427	274	216	260	288
Pressure (MPa, abs)	0.08	0.11	0.86	2.65	5.62	0.86	---	0.08	0.46	0.08	4.24	4.24	4.24	8.27	3.93	4.14
Enthalpy (kJ/kg)[A]	16.42	38.94	26.67	202.68	306.58	26.67	---	---	37.62	---	---	2,242.42	1,244.56	904.03	1,222.34	2,956.19
Density (kg/m^3)	1.0	1.6	11.0	18.9	32.8	11.0	---	---	985.4	---	---	6.4	19.1	782.0	18.2	18.2
V-L Molecular Weight	28.887	27.415	32.181	28.061	28.013	32.181	---	---	18.015	---	---	21.538	20.272	18.015	20.272	18.015
V-L Flowrate (lb_{mol}/hr)	47,709	1,645	103	34,414	1,823	9,727	0	0	6,040	0	0	33,847	13,522	18,992	52,839	27,298
V-L Flowrate (lb/hr)	1,378,173	45,107	3,300	965,674	51,068	313,023	0	0	108,810	0	0	728,984	274,103	342,139	1,071,123	491,776
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	517,357	0	408,547	43,654	0	0	0	0	0
Temperature (°F)	42	69	90	385	560	90	---	42	92	160	2,600	2,600	525	420	500	550
Pressure (psia)	11.4	16.4	125.0	384.0	815.0	125.0	---	11.4	66.8	11.1	614.7	614.7	615.0	1,200.0	569.7	600.0
Enthalpy (Btu/lb)[A]	7.1	16.7	11.5	87.1	131.8	11.5	---	---	16.2	---	---	964.1	535.1	388.7	525.5	1,270.9
Density (lb/ft^3)	0.061	0.097	0.687	1.180	2.045	0.687	---	---	61.518	---	---	0.401	1.195	48.817	1.138	1.135

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 4-6 Case 3: IGCC with 90% CO_2 Capture - Stream Table (continued)

	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
V-L Mole Fraction															
Ar	0.0045	0.0066	0.0066	0.0022	0.0000	0.0057	0.0069	0.0002	0.0002	0.0105	0.0105	0.0093	0.0090	0.0090	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	0.0000	0.0000	0.0000
CO	0.2622	0.0099	0.0098	0.0036	0.0000	0.0847	0.0060	0.0002	0.0002	0.0156	0.0156	0.0000	0.0000	0.0000	0.0000
CO_2	0.0134	0.3964	0.4004	0.6618	0.0000	0.4271	0.6199	0.9919	0.9948	0.0489	0.0489	0.0003	0.0090	0.0090	0.0000
COS	0.0002	0.0000	0.0000	0.0001	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.1141	0.5445	0.5401	0.1264	0.0000	0.0595	0.1695	0.0046	0.0046	0.8623	0.8623	0.0000	0.0000	0.0000	0.0000
H_2O	0.5768	0.0017	0.0017	0.0388	0.0000	0.3743	0.1381	0.0029	0.0000	0.0001	0.0001	0.0071	0.1218	0.1218	1.0000
H_2S	0.0013	0.0022	0.0022	0.1610	0.0000	0.0009	0.0016	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0263	0.0387	0.0390	0.0060	0.0000	0.0474	0.0580	0.0002	0.0002	0.0625	0.0625	0.7753	0.7553	0.7553	0.0000
NH_3	0.0012	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2080	0.1049	0.1049	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	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	0.0000	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)	35,289	23,954	24,258	331	0	430	352	8,829	8,803	15,098	15,098	87,994	112,074	112,074	23,733
V-L Flowrate (kg/hr)	689,820	485,653	496,128	11,876	0	12,750	11,342	386,104	385,637	98,149	98,149	2,541,887	3,078,059	3,078,059	427,554
Solids Flowrate (kg/hr)	0	0	0	0	1,703	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	249	35	35	48	175	232	49	16	51	31	196	6	563	132	535
Pressure (MPa, abs)	3.79	3.43	3.36	0.16	0.12	0.1	0.073	1.032	15.270	3.238	3.203	0.079	0.082	0.079	12.512
Enthalpy (kJ/kg)[A]	1,705.35	43.90	42.97	94.95	---	851.3	245.007	5.268	-162.321	135.691	896.467	16.424	835.278	343.152	3,435.794
Density (kg/m^3)	17.8	27.7	27.5	2.2	5,284.8	0.6	0.9	20.1	642.0	8.2	5.3	1.0	0.3	0.6	36.7
V-L Molecular Weight	19.548	20.275	20.453	35.932	---	30	32.234	43.733	43.809	6.501	6.501	28.887	27.464	27.464	18.015
V-L Flowrate (lb_{mol}/hr)	77,799	52,809	53,479	729	0	948	776	19,464	19,407	33,286	33,286	193,993	247,081	247,081	52,322
V-L Flowrate (lb/hr)	1,520,792	1,070,681	1,093,776	26,181	0	28,108	25,004	851,213	850,185	216,381	216,381	5,603,902	6,785,957	6,785,957	942,596
Solids Flowrate (lb/hr)	0	0	0	0	3,754	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	480	95	94	119	348	450	120	60	124	87	385	42	1,046	270	996
Pressure (psia)	549.7	497.6	487.6	23.7	17.3	12.3	10.6	149.7	2,214.7	469.6	464.6	11.4	11.9	11.4	1,814.7
Enthalpy (Btu/lb)[A]	733.2	18.9	18.5	40.8	---	366.0	105.3	2.3	-69.8	58.3	385.4	7.1	359.1	147.5	1,477.1
Density (lb/ft^3)	1.114	1.731	1.714	0.138	329.917	0	0.055	1.254	40.076	0.514	0.329	0.061	0.020	0.040	2.289

4.1.3 Key System Assumptions

System assumptions for Cases 1 through 3, Shell IGCC using Montana Rosebud PRB coal with and without CO_2 capture, are compiled in Exhibit 4-7.

Exhibit 4-7 Cases 1 - 3 IGCC Plant System Assumptions/ Configuration Matrix

	Case 1	Cases 2 and 3
Gasifier Pressure, MPa (psia)	4.2 (615)	4.2 (615)
O_2:Coal Ratio, kg O_2/kg dried coal	0.77	0.76
Carbon Conversion, %	99.5	99.5
Syngas HHV at Gasifier Outlet, kJ/Nm^3 (Btu/scf)	10,470 (281)	10,546 (283)
Nominal Steam Cycle, MPa/°C/°C (psig/°F/°F)	12.4/566/566 (1800/1050/1050)	12.4/538/538 (1800/1000/1000)
Condenser Pressure, mm Hg (in Hg)	36 (1.4)	36 (1.4)
Combustion Turbine	2x Advanced F Class (Nominal 232 MW output each, reduced by elevation considerations)	2x Advanced F Class (Nominal 232 MW output each, reduced by elevation considerations)
Gasifier Technology	Shell	Shell
Oxidant	95 vol% Oxygen	95 vol% Oxygen
Coal	Montana Rosebud PRB	Montana Rosebud PRB
Coal Feed Moisture Content, %	6	6
COS Hydrolysis	Yes	Yes (Part of WGS)
Water Gas Shift	No	Yes
H_2S Separation	Sulfinol-M	Selexol (1st Stage)
Sulfur Removal, %	99.9	96-99.8
CO_2 Separation	None	Selexol (2nd Stage)
CO_2 Removal	N/A	1,100 lb/net MWh / 90%
Sulfur Recovery	Claus Plant with Tail Gas Treatment / Elemental Sulfur	Claus Plant with Tail Gas Treatment / Elemental Sulfur
Particulate Control	Cyclone, Candle Filter, Scrubber, and AGR Absorber	Cyclone, Candle Filter, Scrubber, and AGR Absorber
Mercury Control	Carbon Bed	Carbon Bed
NOx Control	MNQC (LNB) and N_2 Dilution	MNQC (LNB) and N_2 Dilution

Balance of Plant – All Cases

The balance of plant assumptions are common to all cases and are presented in Exhibit 4-8. Items were also covered in Sections 3.1.10, 3.1.11, 3.1.12 and 3.1.13.

Exhibit 4-8 Balance of Plant Assumptions

Cooling water system	Recirculating Wet Cooling Tower
Fuel and Other storage Coal	30 days
Slag	30 days
Sulfur	30 days
Sorbent	30 days
Plant Distribution Voltage Motors below 1 hp	110/220 volt
Motors between 1 hp and 250 hp	480 volt
Motors between 250 hp and 5,000 hp	4,160 volt
Motors above 5,000 hp	13,800 volt
Steam and Gas Turbine Generators	24,000 volt
Grid Interconnection Voltage	345 kV
Water and Waste Water Makeup Water	The water supply is 50 percent from a local Publicly Owned Treatment Works and 50 percent from groundwater, and is assumed to be in sufficient quantities to meet plant makeup requirements. Makeup for potable, process, and de-ionized (DI) water is drawn from municipal sources
Process Wastewater	Water associated with gasification activity and 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 was sized for 5.68 cubic meters per day (1,500 gallons per day)
Water Discharge	Most of the process wastewater is recycled to the cooling tower basin. Blowdown is treated for chloride and metals, and discharged.

4.1.4 Sparing Philosophy

The sparing philosophy for Cases 1 through 3 is provided below. Single trains are utilized throughout 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:

- Two air separation units (2 x 50%).
- Two trains of coal drying and dry feed systems (2 x 50%).
- Two trains of gasification, including gasifier, synthesis gas cooler, cyclone, and barrier filter (2 x 50%).
- Two trains of syngas clean-up process (2 x 50%).
- Two trains of Sulfinol-M acid gas removal in non-capture cases and two trains to two-stage Selexol in CO_2 capture cases (2 x 50%).
- One train of Claus-based sulfur recovery (1 x 100%).
- Two combustion turbine/HRSG tandems (2 x 50%).
- One steam turbine (1 x 100%).

4.1.5 Cases 1 - 3 Performance Results

The non-capture Shell IGCC plant using PRB coal produces a net output of 502 MWe at a net plant efficiency of 41.8 percent (HHV basis). The net output in the 1,100 lb CO_2/net-MWh case is 443 MWe at a net efficiency of 35.6 percent and 401 MWe at a net efficiency of 30.9 percent in the 90 percent capture case.

Overall performance for the three plants is summarized in Exhibit 4-9 which includes auxiliary power requirements. The ASU accounts for approximately 74 percent, 64 percent, and 57 percent of the total auxiliary load in Case 1, Case 2, and Case 3, respectively. The ASU auxiliary load is distributed between the main air compressor, the oxygen compressor, the nitrogen compressor, and ASU auxiliaries. The coal drying process accounts for 7.6 percent of the auxiliary load in the non-capture case and 5 to 6 percent in the capture cases. The cooling water system, including the circulating water pumps and cooling tower fan, and the air-cooled condenser account for about 3 to 5 percent of the auxiliary load in all three cases, and the BFW pumps account for an additional 3 percent in the non-capture case and less than 2 percent in the two capture cases. All other individual auxiliary loads are less than 3 percent of the total.

Exhibit 4-9 Cases 1 - 3 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	Case 1	Case 2	Case 3
Gas Turbine Power	372,500	377,000	380,600
Steam Turbine Power	240,400	208,000	192,900
TOTAL POWER, kWe	**612,900**	**585,000**	**573,500**
AUXILIARY LOAD SUMMARY, kWe			
Coal Handling	460	470	480
Coal Milling	2,230	2,310	2,410
Slag Handling	480	490	520
WTA Coal Dryer Compressor	7,860	7,910	8,260
WTA Coal Dryer Auxiliaries	510	520	540
Air Separation Unit Auxiliaries	1,000	1,000	1,000
Air Separation Unit Main Air Compressor	46,830	56,000	58,730
Oxygen Compressor	7,220	7,410	7,770
Nitrogen Compressor	26,250	26,420	30,660
CO_2 Compressor	0	13,130	25,960
Boiler Feedwater Pumps	3,650	2,800	3,040
Condensate Pump	180	210	250
Quench Water Pump	0	490	510
Syngas Recycle Compressor	650	780	810
Circulating Water Pumps	1,660	2,150	2,470
Ground Water Pumps	150	220	280
Cooling Tower Fans	1,080	1,400	1,610
Air-Cooled Condenser Fans	2,670	2,740	2,540
Scrubber Pumps	500	310	330
Acid Gas Removal Auxiliaries	220	7,940	16,240
Gas Turbine Auxiliaries	1,000	1,000	1,000
Steam Turbine Auxiliaries	100	100	100
Claus Plant/TGTU Auxiliaries	250	250	250
Claus Plant Tail Gas Recycle Compressor	410	1,020	1,380
Miscellaneous Balance of Plant (Note 1)	3,000	3,000	3,000
Transformer Loss	2,160	2,170	2,220
TOTAL AUXILIARIES, kWe	**110,520**	**142,240**	**172,360**
NET POWER, kWe	**502,380**	**442,760**	**401,140**
Net Plant Efficiency, % (HHV)	41.8%	35.6%	30.9%
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,610 (8,160)	10,109 (9,581)	11,653 (11,045)
CONDENSER COOLING DUTY GJ/h (10^6 Btu/h)	**1,192 (1,130)**	**1,213 (1,150)**	**1,129 (1,070)**
CONSUMABLES			
As-Received Coal Feed, kg/h (lb/h)	217,133 (478,697)	224,690 (495,356)	234,669 (517,357)
Thermal Input, kWt	1,201,463	1,243,274	1,298,493
Raw Water Withdrawal, m^3/min (gpm)	6.1 (1,616)	9.1 (2,412)	11.8 (3,124)
Raw Water Consumption, m^3/min (gpm)	4.7 (1,232)	7.2 (1,910)	9.6 (2,544)

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2 and particulate matter were presented in Section 2.3. A summary of the plant air emissions for Cases 1 - 3 is presented in Exhibit 4-10.

Exhibit 4-10 Cases 1 - 3 Air Emissions

	Case 1	Case 2	Case 3
kg/GJ (lb/10^6 Btu)			
SO_2	0.001 (0.002)	0.0003 (0.0008)	0.0004 (0.0008)
NO_X	0.026 (0.062)	0.024 (0.056)	0.022 (0.051)
Particulates	0.003 (0.0071)	0.003 (0.0071)	0.003 (0.0071)
Hg	1.51E-7 (3.51E-7)	1.51E-7 (3.51E-7)	1.51E-7 (3.51E-7)
CO_2	92 (214)	49 (115)	9.4 (22)
Tonne/year (tons/year) 80% capacity			
SO_2	30 (33)	11 (12)	12 (13)
NO_X	802 (884)	749 (826)	718 (792)
Particulates	93 (102)	96 (106)	100 (110)
Hg	0.005 (0.005)	0.005 (0.005)	0.005 (0.005)
CO_2	2,786,239 (3,071,303)	1,548,138 (1,706,530)	309,368 (341,020)
kg/MWh (lb/gross-MWh)			
SO_2	0.007 (0.015)	0.003 (0.006)	0.003 (0.007)
NO_X	0.187 (.411)	0.183 (0.403)	0.179 (0.394)
Particulates	0.022 (.047)	0.023 (0.051)	0.025 (0.055)
Hg	1.07E-6 (2.35E-6)	1.15E-6 (2.55E-6)	1.23E-6 (2.71E-6)
CO_2	649 (1,430)	378 (833)	77 (170)
kg/MWh (lb/net-MWh)			
CO_2	791 (1,745)	499 (1,100)	110 (243)

The low level of SO_2 emissions is achieved by capture of the sulfur in the syngas by the Sulfinol-M AGR process in the non-capture case and a two-stage Selexol process in the capture cases. The AGR process removes over 99 percent of the sulfur compounds in the fuel gas down to a level of less than 3 ppmv in all three cases. This results in a concentration in the flue gas of less than 1 ppmv. The H_2S-rich regeneration gas from the AGR system is fed to a Claus plant, producing elemental sulfur. The Claus plant tail gas is hydrogenated and recycled to the inlet of the AGR process to capture most of the remaining sulfur. Because the environmental target was set based on higher sulfur bituminous coal, the resulting SO_2 emissions with lower sulfur western coals are substantially less than the environmental target.

NO_X emissions are limited by the use of nitrogen dilution to 15 ppmvd (as NO_2 @ 15 percent O_2). Ammonia in the syngas is removed with process condensate prior to the low-temperature AGR process and destroyed in the Claus plant burner. This helps lower NO_X levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of a cyclone and a barrier filter in addition to the syngas scrubber and the gas washing effect of the AGR absorber. The particulate emissions represent filterable particulate only.

Ninety five percent of the mercury is captured from the syngas by an activated carbon bed. CO_2 emissions represent the uncontrolled discharge from the process.

The carbon balance for all three IGCC cases is shown in Exhibit 4-11. The carbon input to the plant consists of carbon in the coal plus carbon in the air. Carbon leaves the plant as unburned carbon in the slag, CO_2 in the stack gas, CO_2 in the ASU vent, and CO_2 in the product gas in capture cases. Slag contains 2.97 percent carbon. The percent of total carbon sequestered for the capture cases is defined as the amount of carbon product produced (as sequestration-ready CO_2) divided by the carbon in the coal feedstock, less carbon contained in solid byproducts (slag).

Exhibit 4-11 Cases 1 - 3 Carbon Balance

	Case 1	**Case 2**	**Case 3**
Carbon In, kg/hr (lb/hr)			
Coal	108,715 (239,675)	112,498 (248,015)	117,494 (259,031)
Air (CO_2)	414 (913)	428 (942)	431 (951)
Total In	**109,129 (240,588)**	**112,925 (248,958)**	**117,926 (259,982)**
Carbon Out, kg/hr (lb/hr)			
Slag	544 (1,198)	562 (1,240)	587 (1,295)
Stack Gas	108,506 (239,215)	60,290 (132,917)	12,048 (26,561)
ASU Vent	79 (175)	81 (179)	85 (188)
CO_2 Product	0 (0)	51,992 (114,622)[1]	105,205 (231,938)[2]
Total Out	**109,129 (240,588)**	**112,925 (248,958)**	**117,926 (259,982)**

[1] Carbon capture is 46.4 percent to achieve an emission rate of 1,100 lb CO_2/net-MWh
[2] Carbon capture is 90 percent

Exhibit 4-12 shows the sulfur balance for all three IGCC cases. Sulfur input is the sulfur in the coal. Sulfur output is the sulfur recovered in the Claus plant, sulfur emitted in the stack gas, and sulfur sequestered with the CO_2 product in the capture cases. Sulfur in the slag and sulfur stripped from the wastewater streams are considered negligible.

Note that a significant amount of unconverted COS in Case 2 (because of the bypass around the SGS reactor) ends up as sulfur in the CO_2 product, thus reducing the capture fraction without increasing sulfur emissions.

Exhibit 4-12 Cases 1 – 3 Sulfur Balance

	Case 1	Case 2	Case 3
Sulfur In, kg/h (lb/hour)			
Coal	1,580 (3,482)	1,635 (3,603)	1,707 (3,764)
Total In	**1,580 (3,482)**	**1,635 (3,603)**	**1,707 (3,764)**
Sulfur Out, kg/h (lb/hour)			
Elemental Sulfur	1,577 (3,477)[1]	1,571 (3,464)[2]	1,703 (3,754)[3]
Stack Gas	2 (5)	1 (2)	1 (2)
CO_2 Product	0 (0)	62 (137)	3 (7)
Total Out	**1,580 (3,482)**	**1,635 (3,603)**	**1,707 (3,764)**

[1] Sulfur capture is 99.9 percent
[2] Sulfur capture is 96.1 percent
[3] Sulfur capture is 99.8 percent

Some water is returned to the source, namely cooling tower blowdown and sour water stripper blowdown. The difference between raw water withdrawal and water returned to the source (process discharge) is raw water consumption, which represents the net impact on the water source. Exhibit 4-13 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). Water demand represents the total amount of water required for a particular process. Some water is recovered within the process, primarily as coal moisture from the drying process and syngas condensate, and that water is re-used as internal recycle. Raw water withdrawal is the difference between water demand and internal recycle. Some water is returned to the source, namely cooling tower blowdown and sour water stripper blowdown. The difference between raw water withdrawal and water returned to the source (process discharge) is raw water consumption, which represents the net impact on the water source.

Exhibit 4-13 Cases 1 – 3 Water Balance

	Case 1	Case 2	Case 3
Water Demand, m^3/min (gpm)			
Slag Handling	**0.40 (105)**	**0.41 (109)**	**0.43 (113)**
Quench/Wash	**0.00 (0)**	**2.5 (653)**	**2.6 (684)**
Humidification	**0.42 (110)**	**0.00 (0)**	**0.00 (0)**
Condenser Makeup	**0.14 (36)**	**1.2 (316)**	**3.9 (1,020)**
Shift Steam	0.00 (0)	1.1 (284)	3.7 (984)
BFW Makeup	0.14 (36)	0.12 (33)	0.14 (37)
Cooling Tower	**6.5 (1,705)**	**8.4 (2,207)**	**9.6 (2,541)**
Total	**7.4 (1,956)**	**12.4 (3,285)**	**16.5 (4,358)**
Internal Recycle, m^3/min (gpm)			
Slag Handling	**0.35 (93)**	**0.41 (109)**	**0.43 (113)**
Quench/Wash	**0.0 (0)**	**1.8 (466)**	**2.6 (684)**
Humidification	**0.0 (0)**	**0.00 (0)**	**0.00 (0)**
Condenser Makeup	**0.0 (0)**	**0.00 (0)**	**0.00 (0)**
Cooling Tower	**0.93 (247)**	**1.1 (299)**	**1.7 (436)**
Water from Coal Drying	0.76 (201)	0.79 (208)	0.82 (218)
BFW Blowdown	0.14 (36)	0.12 (33)	0.14 (37)
SWS Blowdown	0.04 (9)	0.22 (57)	0.34 (89)
SWS Excess	0.00 (0)	0.00 (0)	0.35 (93)
Total	**1.3 (340)**	**3.3 (874)**	**4.7 (1,234)**
Raw Water Withdrawal, m^3/min (gpm)			
Slag Handling	**0.05 (12)**	**0.00 (0)**	**0.00 (0)**
Quench/Wash	**0.00 (0)**	**0.71 (187)**	**0.00 (0)**
Humidification	**0.42 (110)**	**0.00 (0)**	**0.00 (0)**
Condenser Makeup	**0.14 (36)**	**1.2 (316)**	**3.9 (1,020)**
Shift Steam	0.00 (0)	1.1 (283)	3.7 (983)
BFW Makeup	0.14 (36)	0.12 (33)	0.14 (37)
Cooling Tower	**5.5 (1,458)**	**7.2 (1,908)**	**8.0 (2,104)**
Total	**6.1 (1,616)**	**9.1 (2,412)**	**11.8 (3,124)**
Process Water Discharge, m^3/min (gpm)			
SWS Blowdown	**0.00 (0.9)**	**0.02 (6)**	**0.03 (9)**
Cooling Tower Blowdown	**1.5 (383)**	**1.9 (496)**	**2.2 (571)**
Total	**1.5 (384)**	**1.9 (502)**	**2.2 (580)**

Raw Water Consumption, m^3/min (gpm)			
Slag Handling	**0.05 (12)**	**0.00 (0)**	**0.00 (0)**
Quench/Wash	**0.00 (0)**	**0.71 (187)**	**0.00 (0)**
Humidification	**0.42 (110)**	**0.00 (0)**	**0.00 (0)**
SWS Blowdown	**-0.00 (-0.9)**	**-0.02 (-6)**	**-0.03 (-9)**
Condenser Makeup	**0.14 (36)**	**1.2 (316)**	**3.9 (1,020)**
Cooling Tower	**4.1 (1,074)**	**5.3 (1,412)**	**5.8 (1,533)**
Total	**4.7 (1,232)**	**7.2 (1,910)**	**9.6 (2,544)**
Total, gpm/MWnet	**2.5**	**4.3**	**6.3**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for all three IGCC cases for the following subsystems in Exhibit 4-14 through Exhibit 4-22.

- ASU and Gasifier Units
- Gas Cleanup System
- Power block

An overall plant energy balance is provided in tabular form in Exhibit 4-23 for the three cases.

Exhibit 4-14 Case 1: IGCC without CO_2 Capture - ASU and Gasification Heat and Mass Balance Schematic

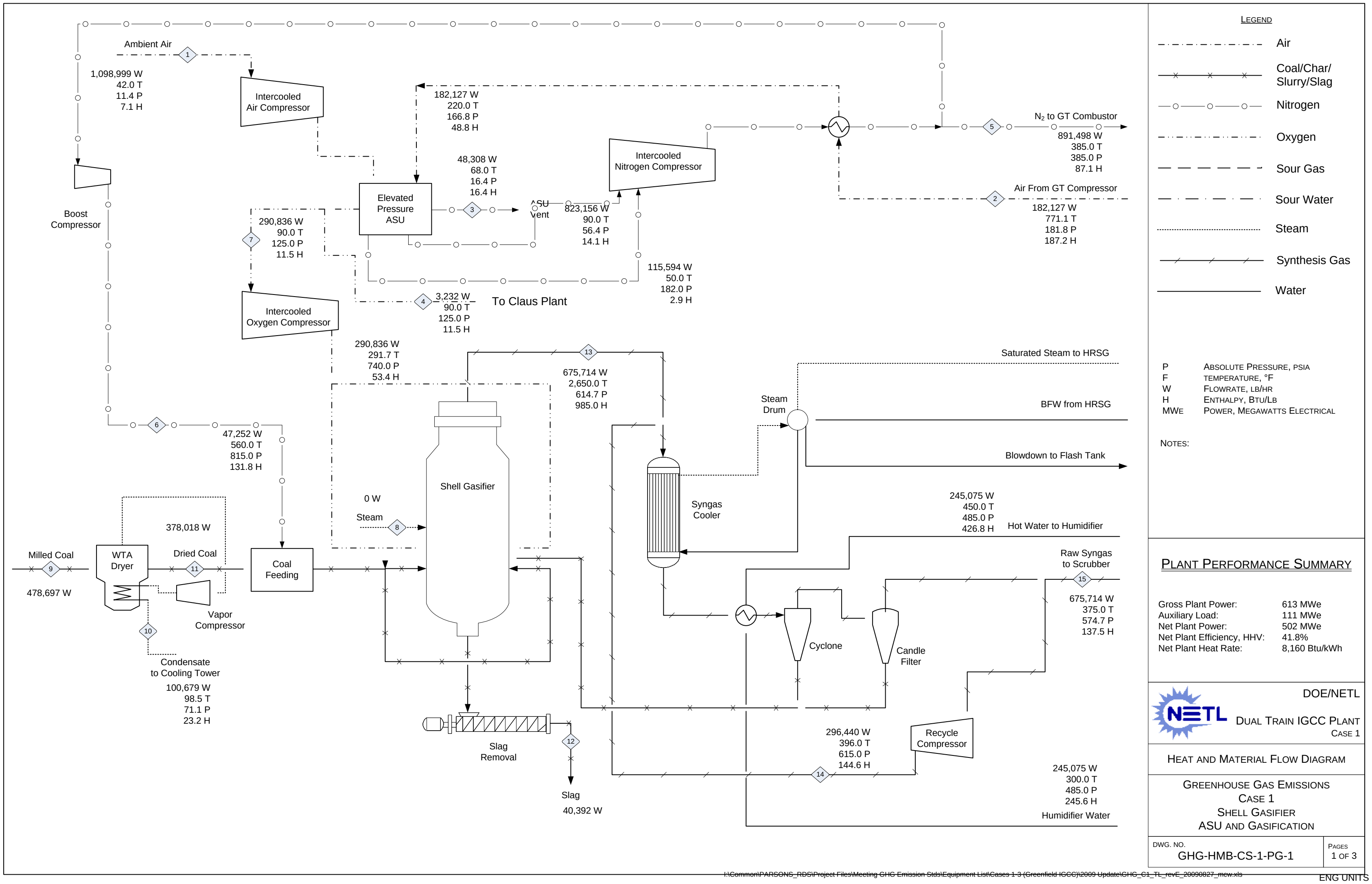


Exhibit 4-15 Case 1: IGCC without CO_2 Capture - Gas Cleanup System Heat and Mass Balance Schematic

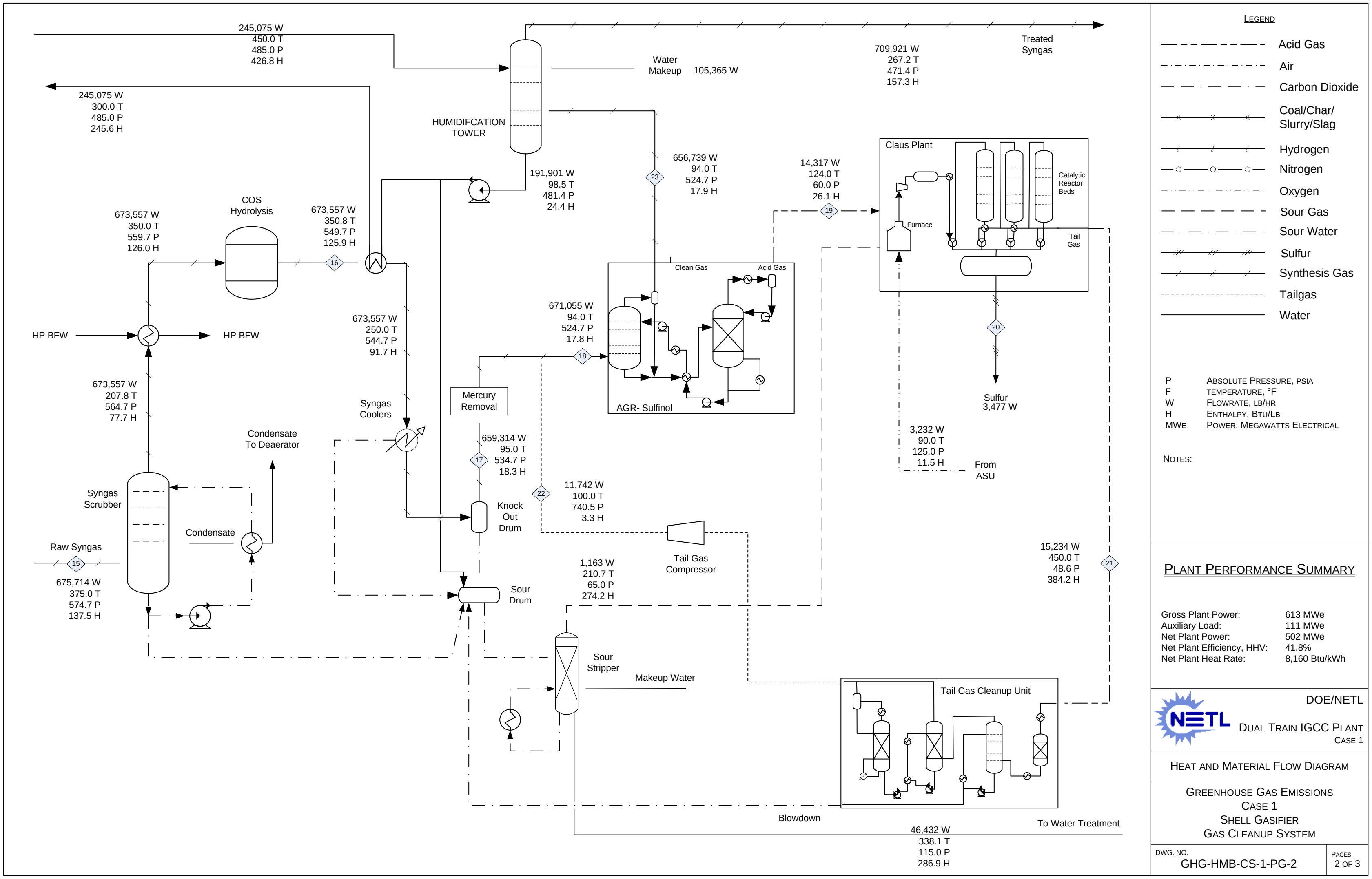


Exhibit 4-16 Case 1: IGCC without CO_2 Capture - Power Block System Heat and Mass Balance Schematic

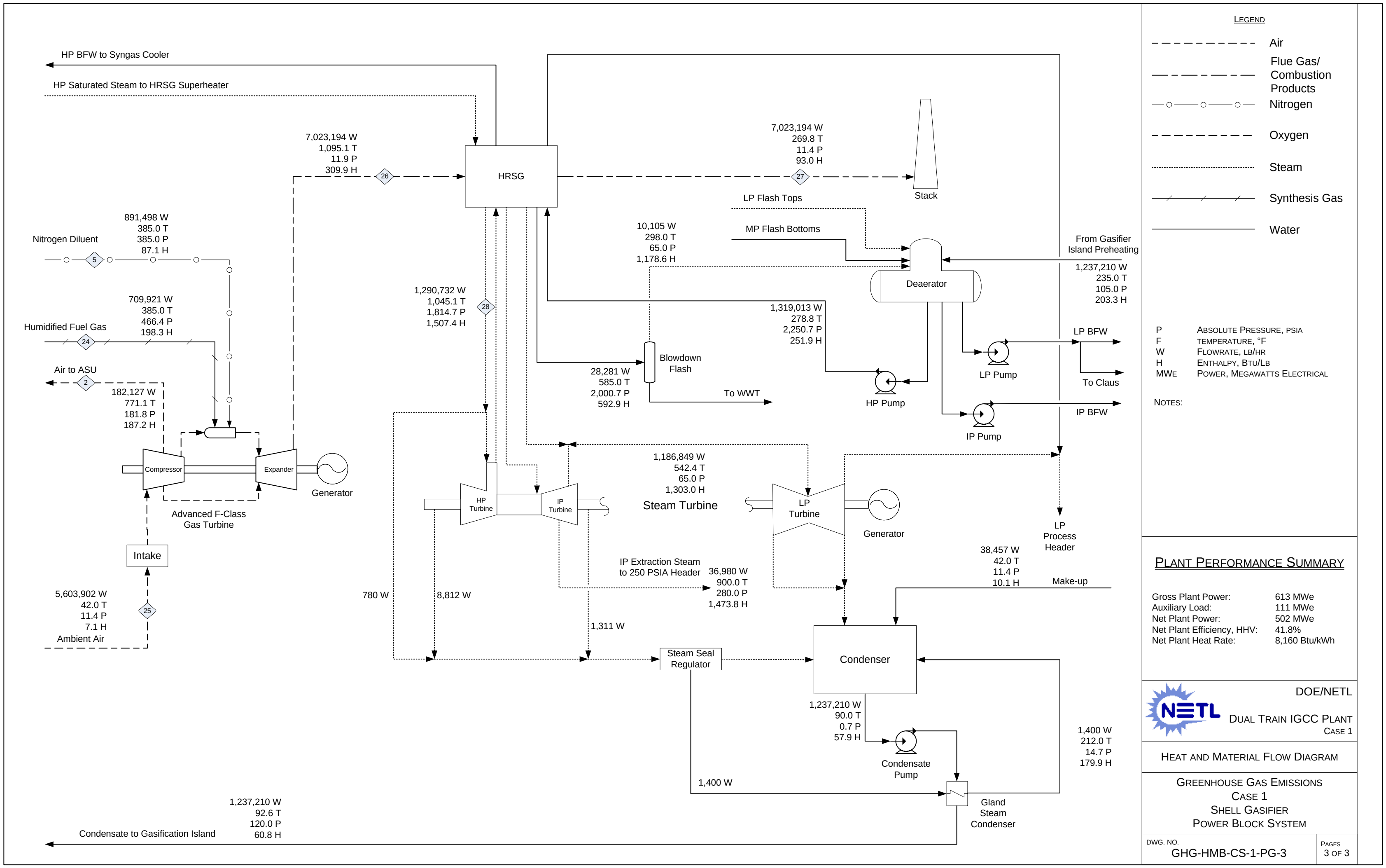
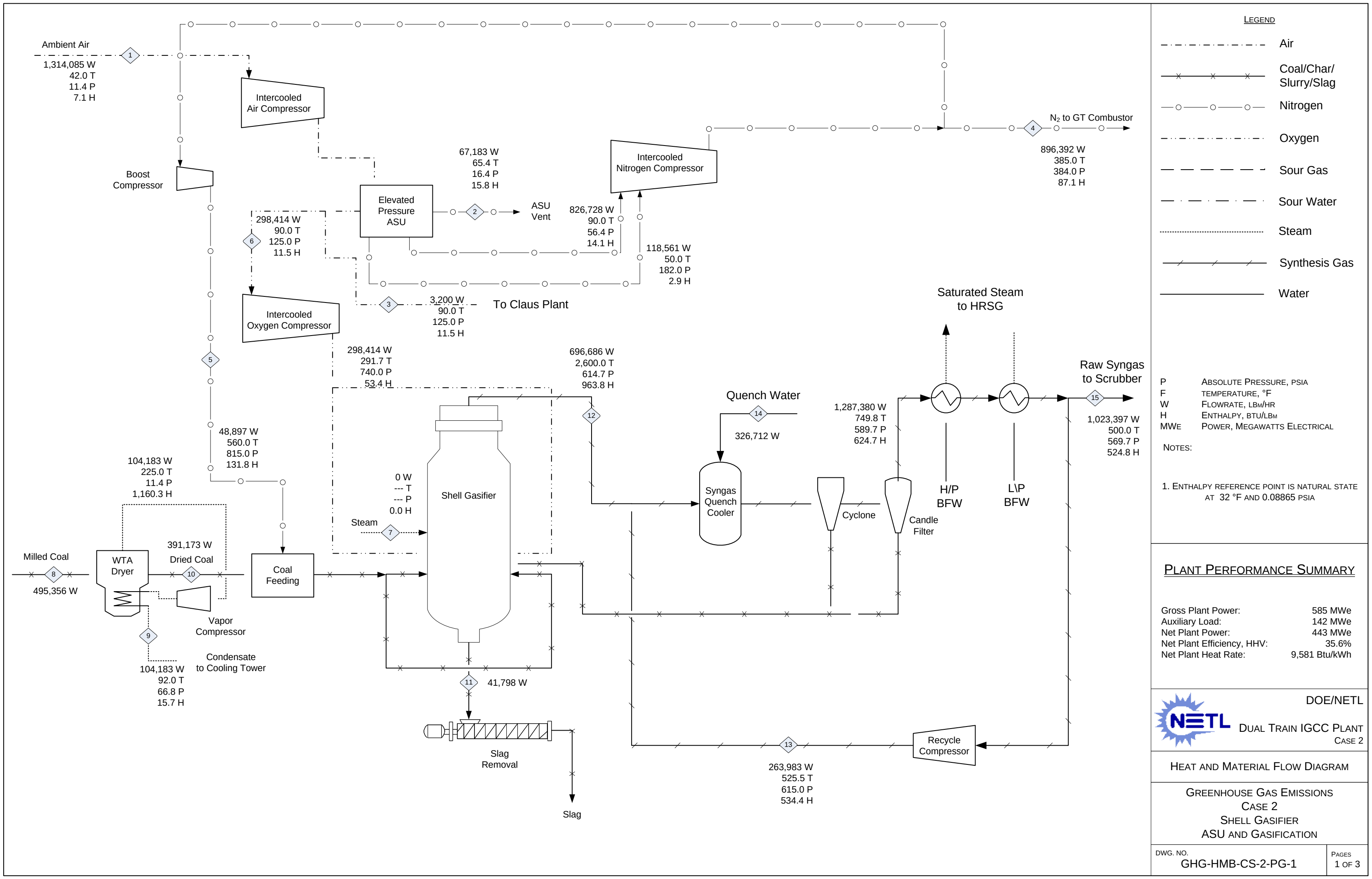


Exhibit 4-17 Case 2: IGCC with CO_2 Capture to an Emission Limit of 1,100 lb/net-MWh - ASU and Gasification Heat and Mass Balance Schematic



ENG UNITS

Exhibit 4-18 Case 2: IGCC with CO_2 Capture to an Emission Limit of 1,100 lb/net-MWh - Gas Cleanup Heat and Mass Balance Schematic

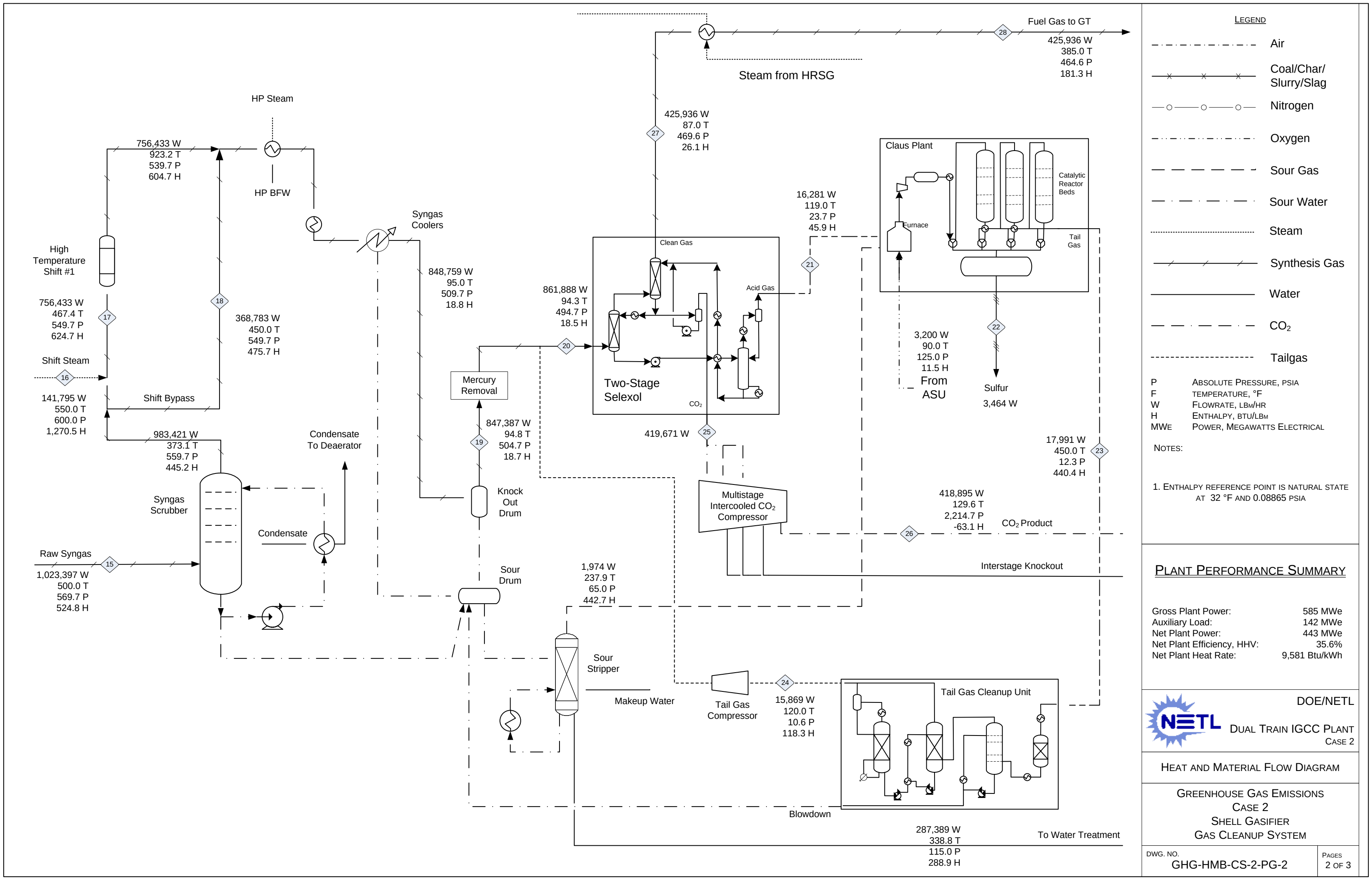


Exhibit 4-19 Case 2: IGCC with CO_2 Capture to an Emission Limit of 1,100 lb/net-MWh - Power Block System Heat and Mass Balance Schematic

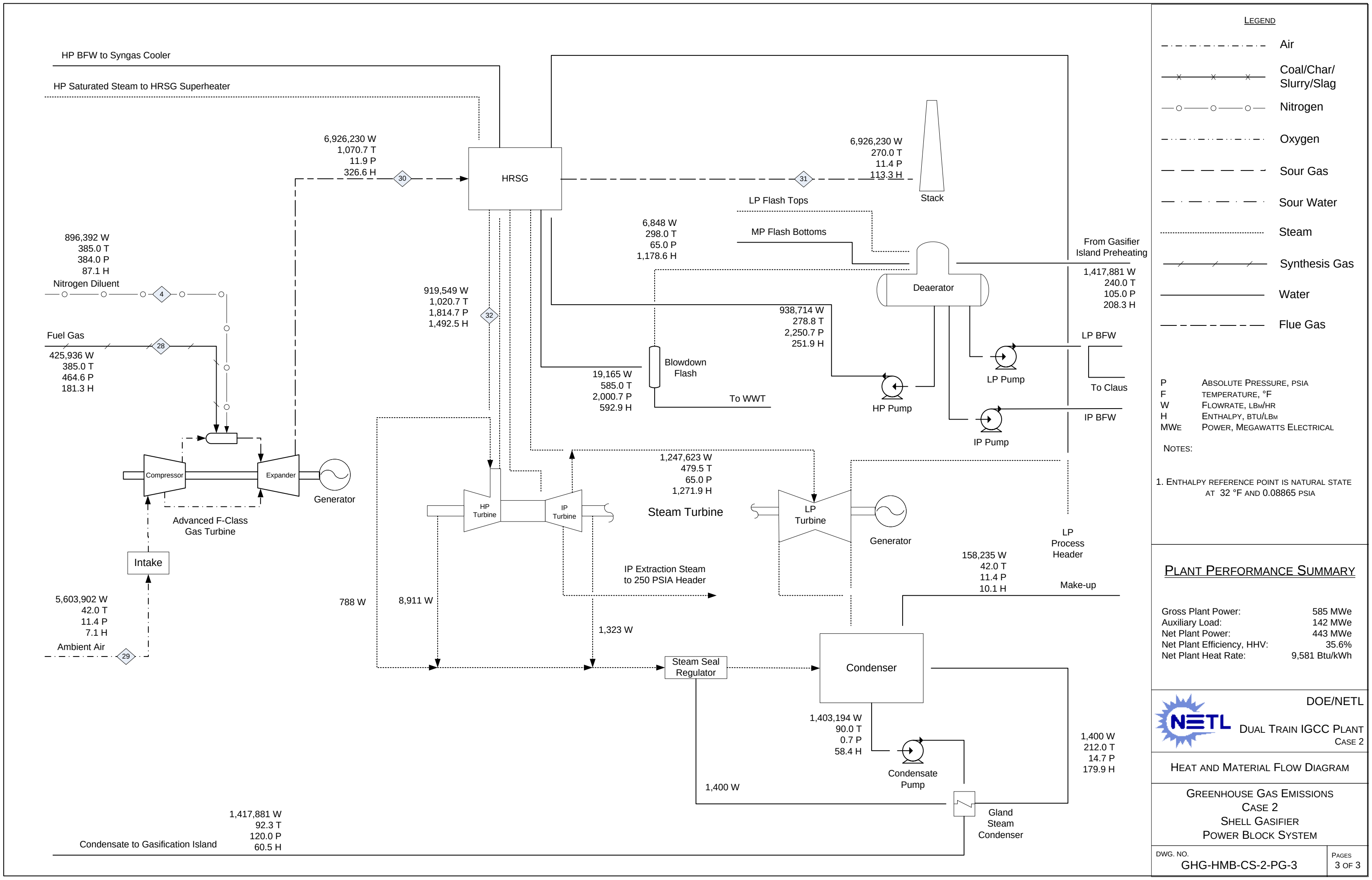
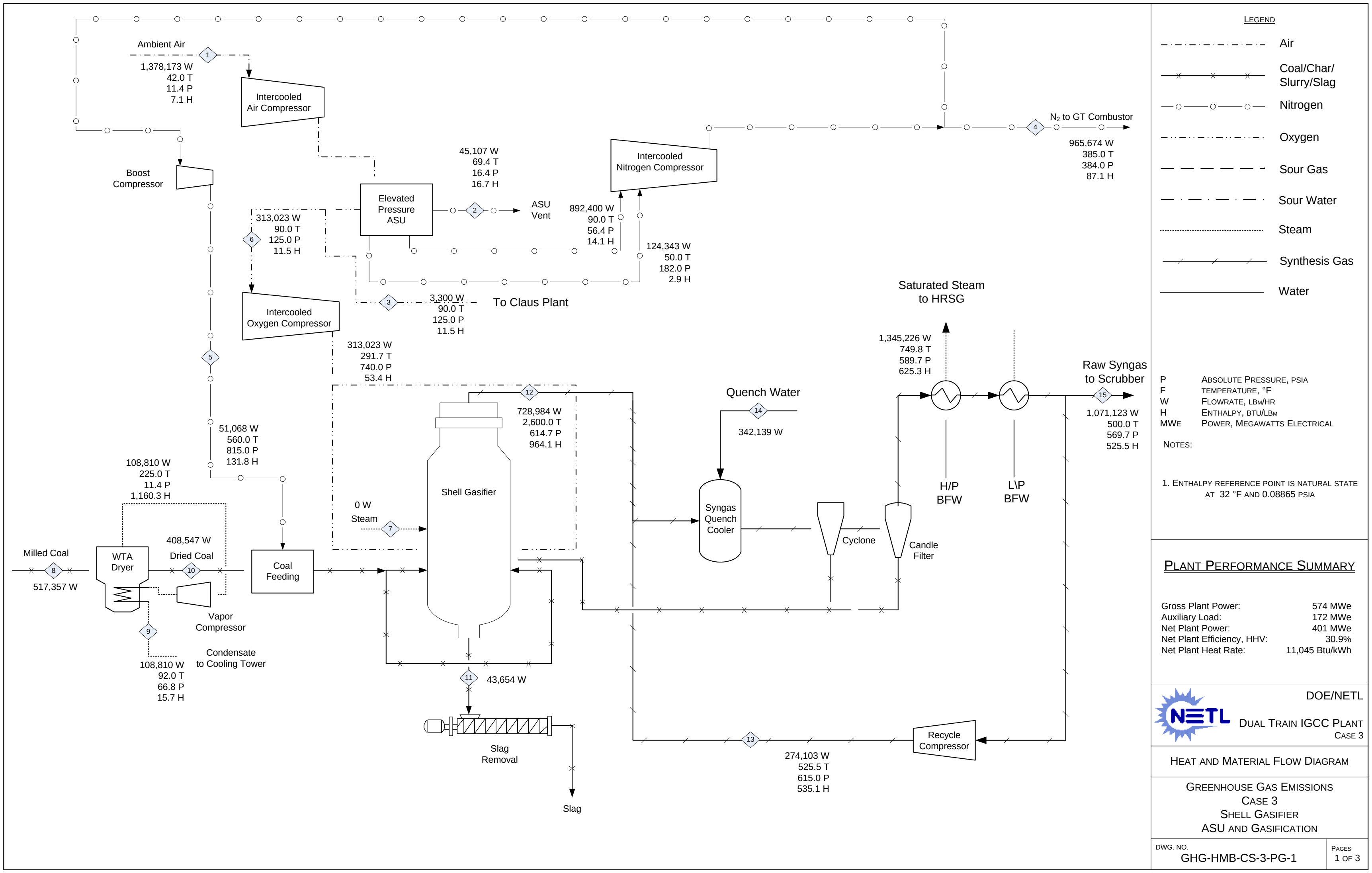


Exhibit 4-20 Case 3: IGCC with 90% CO_2 Capture - ASU and Gasification Heat and Mass Balance Schematic



ENG UNITS

Exhibit 4-21 Case 3: IGCC with 90% CO_2 Capture - Gas Cleanup System Heat and Mass Balance Schematic

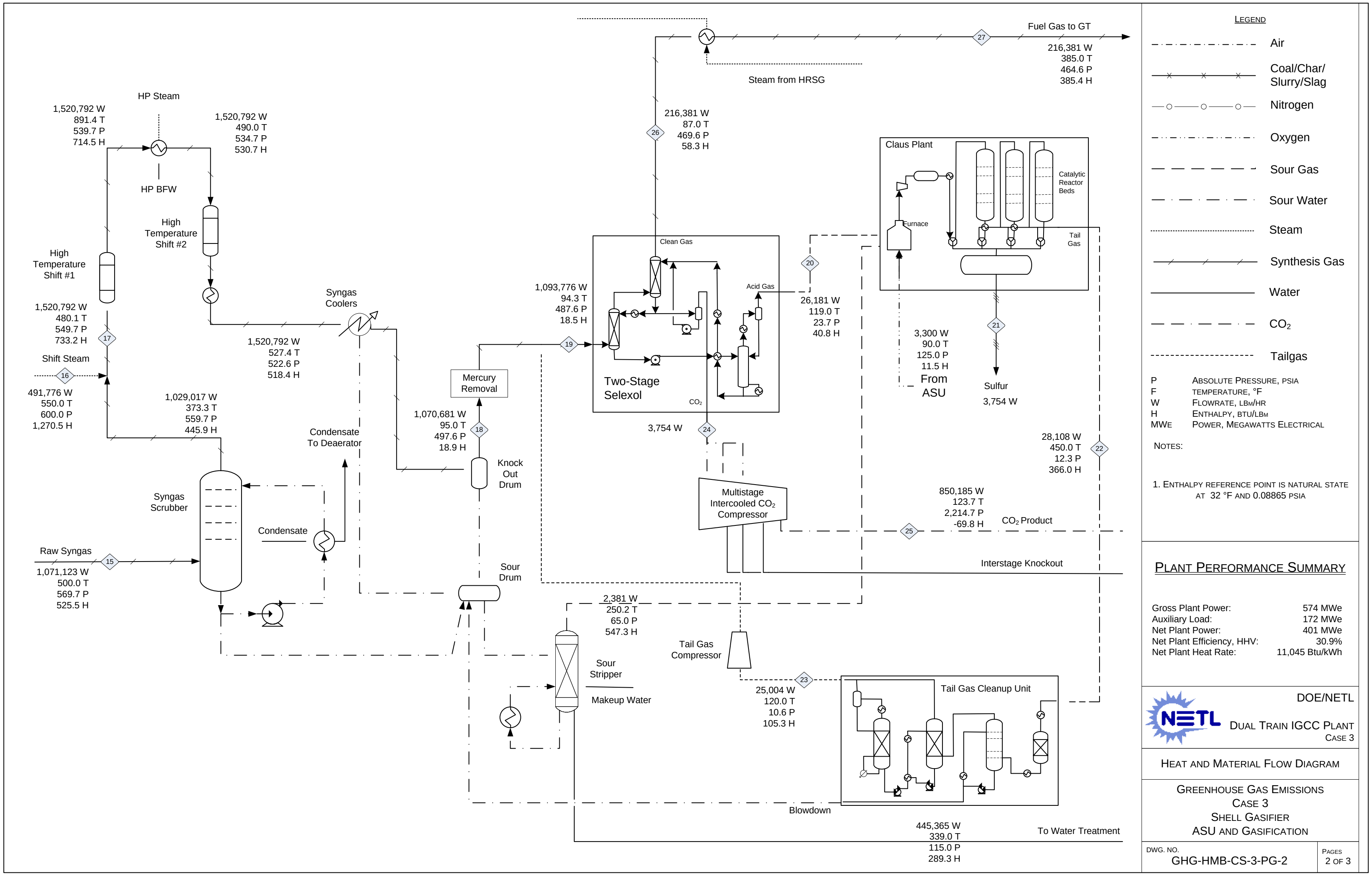


Exhibit 4-22 Case 3: IGCC with 90% CO_2 Capture - Power Block System Heat and Mass Balance Schematic

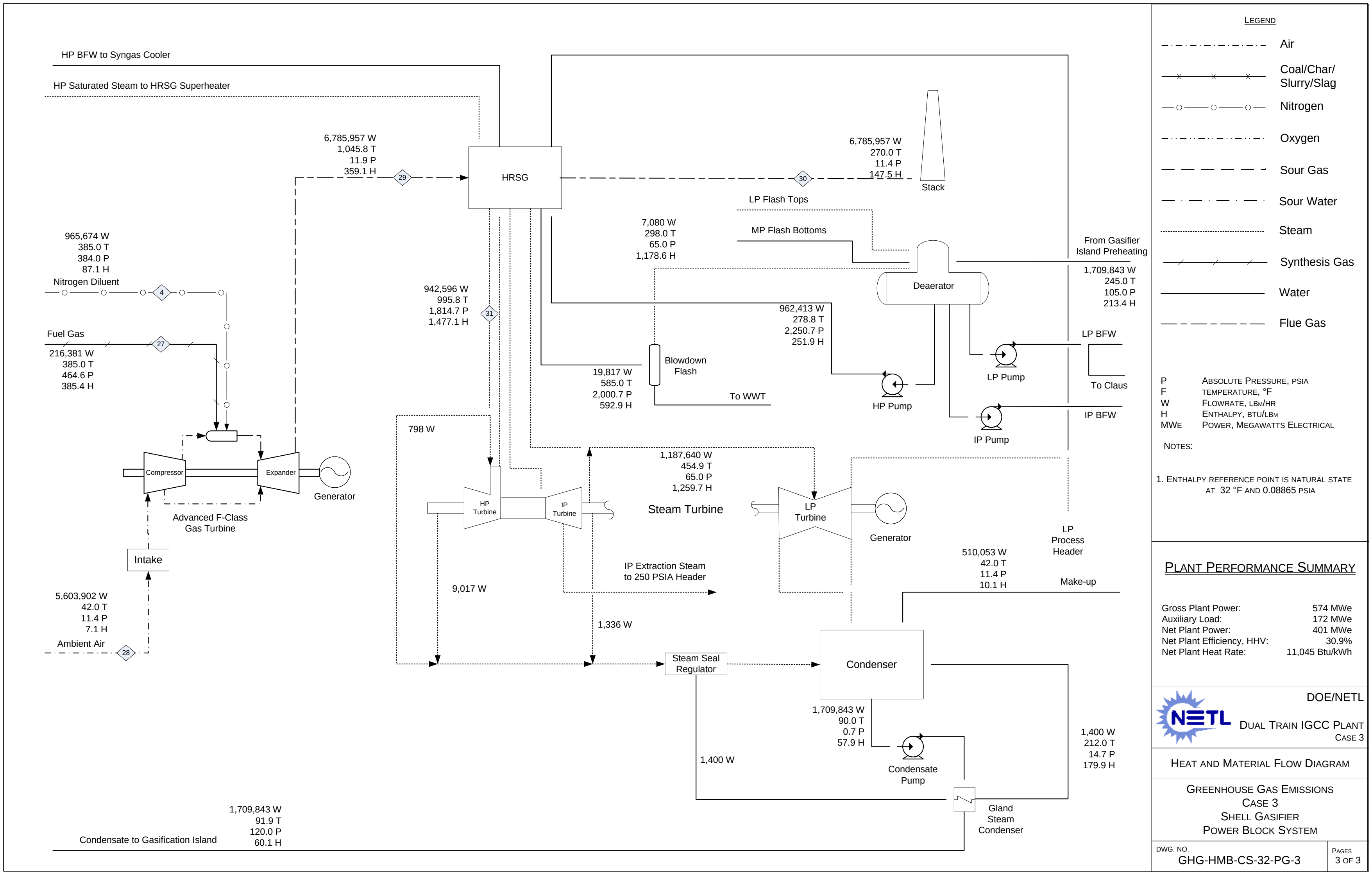


Exhibit 4-23 Cases 1 - 3 Energy Balance

	Case 1	Case 2	Case 3
Energy In, GJ/hr (MMBtu/hr)[1]			
Coal, HHV	**4,325 (4,100)**	**4,476 (4,242)**	**4,675 (4,431)**
Sensible + Latent			
Coal,	2.2 (2.1)	2.3 (2.2)	2.4 (2.3)
ASU Air	8.2 (7.8)	9.8 (9.3)	10.3 (9.7)
GT Air	41.7 (39.6)	41.7 (39.6)	41.7 (39.6)
Raw Water Makeup	8.5 (8.1)	12.7 (12.0)	16.5 (15.6)
Auxiliary Power	**398 (377)**	**512 (485)**	**620 (588)**
Total In	**4,784 (4,534)**	**5,054 (4,791)**	**5,366 (5,086)**
Energy Out, GJ/hr (MMBtu/hr)[1]			
Slag, HHV	**18 (17)**	**18 (17)**	**19 (18)**
Sulfur, HHV	**15 (14)**	**15 (14)**	**16 (15)**
Sensible + Latent			
ASU Intercoolers	169 (160)	190 (180)	201 (191)
ASU Vent	0.8 (0.8)	1.1 (1.1)	0.8 (0.8)
Slag	31.7 (30.1)	32.0 (30.3)	33.4 (31.7)
Sulfur	0.2 (0.2)	0.2 (0.2)	0.2 (0.2)
CO_2	0.0 (0.0)	-27.9 (-26.4)	-62.6 (-59.3)
CO_2 Compressor Intercoolers	0.0 (0.0)	73.4 (69.6)	152.6 (144.7)
Cooling Tower Blowdown	8.1 (7.7)	10.5 (9.9)	12.1 (11.4)
Gasifier Heat Loss	0.0 (0.0)	0.0 (0.0)	0.0 (0.0)
Combustion Turbine Heat Loss	63.3 (60.0)	63.3 (60.0)	63.3 (60.0)
HRSG Flue Gas	689 (653)	828 (785)	1,056 (1,001)
Condenser	1,188 (1,126)	1,218 (1,154)	1,132 (1,073)
Auxliary Cooling Load[2]	22 (21)	119 (113)	160 (152)
Process Losses[3]	*373 (353)*	*407 (386)*	*516 (489)*
Power	**2,206 (2,091)**	**2,106 (1,996)**	**2,065 (1,957)**
Total Out	**4,784 (4,534)**	**5,054 (4,791)**	**5,366 (5,086)**

[1] Enthalpy reference conditions are 0°C (32°F) and 614 Pa (0.089 psia)
[2]Auxiliary cooling load includes the sour water stripper condenser, syngas cooler (low level heat rejection) and the extraction air cooler (in extraction cases)
[3] Process losses are calculated by difference to close the energy balance

4.1.6 Cases 1 - 3 Equipment Lists

Major equipment items for all three IGCC cases 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 4.1.7. 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.

ACCOUNT 1 COAL HANDLING

Equipment No.	Description	Type	Operating Qty.	Spares	Case 1 Design Condition	Case 2 Design Condition	Case 3 Design Condition
1	Feeder	Belt	2	0	572 tonne/hr (630 tph)	572 tonne/hr (630 tph)	572 tonne/hr (630 tph)
2	Conveyor No. 1	Belt	1	0	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)
3	Transfer Tower No. 1	Enclosed	1	0	N/A	N/A	N/A
4	Conveyor No. 2	Belt	1	0	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)
5	As-Received Coal Sampling System	Two-stage	1	0	N/A	N/A	N/A
6	Stacker/Reclaimer	Traveling, linear	1	0	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)
7	Reclaim Hopper	N/A	2	1	45 tonne (50 ton)	45 tonne (50 ton)	45 tonne (50 ton)
8	Feeder	Vibratory	2	1	181 tonne/hr (200 tph)	181 tonne/hr (200 tph)	191 tonne/hr (210 tph)
9	Conveyor No. 3	Belt w/ tripper	1	0	354 tonne/hr (390 tph)	372 tonne/hr (410 tph)	390 tonne/hr (430 tph)
10	Crusher Tower	N/A	1	0	N/A	N/A	N/A
11	Coal Surge Bin w/ Vent Filter	Dual outlet	2	0	181 tonne (200 ton)	181 tonne (200 ton)	191 tonne (210 ton)
12	Crusher	Impactor reduction	2	0	8 cm x 0-3 cm x 0 (3" x 0-1-1/4" x 0)	8 cm x 0-3 cm x 0 (3" x 0-1-1/4" x 0)	8 cm x 0-3 cm x 0 (3" x 0-1-1/4" x 0)
13	As-Fired Coal Sampling System	Swing hammer	1	1	N/A	N/A	N/A
14	Conveyor No. 4	Belt w/tripper	1	0	354 tonne/hr (390 tph)	372 tonne/hr (410 tph)	390 tonne/hr (430 tph)
15	Transfer Tower No. 2	Enclosed	1	0	N/A	N/A	N/A
16	Conveyor No. 5	Belt w/ tripper	1	0	354 tonne/hr (390 tph)	372 tonne/hr (410 tph)	390 tonne/hr (430 tph)
17	Coal Silo w/ Vent Filter and Slide Gates	Field erected	3	0	816 tonne (900 ton)	816 tonne (900 ton)	816 tonne (900 ton)

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	Operating Qty.	Spares	Case 1 Design Condition	Case 2 Design Condition	Case 3 Design Condition
1	Feeder	Vibratory	3	0	82 tonne/hr (90 tph)	82 tonne/hr (90 tph)	82 tonne/hr (90 tph)
2	Conveyor No. 6	Belt w/tripper	1	0	236 tonne/hr (260 tph)	245 tonne/hr (270 tph)	254 tonne/hr (280 tph)
3	Roller Mill Feed Hopper	Dual Outlet	1	0	481 tonne (530 ton)	499 tonne (550 ton)	517 tonne (570 ton)
4	Weigh Feeder	Belt	2	0	118 tonne/hr (130 tph)	127 tonne/hr (140 tph)	127 tonne/hr (140 tph)
5	Pulverizer	Rotary	2	0	118 tonne/hr (130 tph)	127 tonne/hr (140 tph)	127 tonne/hr (140 tph)
6	Coal Dryer Feed Hopper	Vertical Hopper	2	0	236 tonne (260 ton)	245 tonne (270 ton)	254 tonne (280 ton)
7	Coal Preheater	Water Heated Horizontal Rotary Kiln	1	0	Coal feed: 236 tonne/hr (260 tph) Heat duty: 22.3 GJ/hr (21.2 MMBtu/hr)	Coal feed: 245 tonne/hr (270 tph) Heat duty: 23.1 GJ/hr (21.9 MMBtu/hr)	Coal feed: 254 tonne/hr (280 tph) Heat duty: 24.1 GJ/hr (22.9 MMBtu/hr)
8	Coal Dryer	Fluidized Bed with Internal Coils	2	0	Coal feed: 118 tonne/hr (130 tph) Heat duty: 69.2 GJ/hr (65.6 MMBtu/hr) Bed diameter: 11.3 m (37 ft)	Coal feed: 127 tonne/hr (140 tph) Heat duty: 71.6 GJ/hr (67.9 MMBtu/hr) Bed diameter: 11.3 m (37 ft)	Coal feed: 127 tonne/hr (140 tph) Heat duty: 74.8 GJ/hr (70.9 MMBtu/hr) Bed diameter: 11.6 m (38 ft)
9	Steam Compressor	Reciprocating, Multi-Stage	2	0	500 m^3/min (17,670 scfm) Suction - 0.08 MPa (11.4 psia) Discharge - 0.66 MPa (96 psia)	518 m^3/min (18,300 scfm) Suction - 0.08 MPa (11.4 psia) Discharge - 0.63 MPa (92 psia)	541 m^3/min (19,100 scfm) Suction - 0.08 MPa (11.4 psia) Discharge - 0.63 MPa (92 psia)
10	Dryer Exhaust Filter	Hot Baghouse	2	0	Steam - 25,129 kg/hr (55,400 lb/hr) Temperature - 107°C (225°F)	Steam - 25,991 kg/hr (57,300 lb/hr) Temperature - 107°C (225°F)	Steam - 27,125 kg/hr (59,800 lb/hr) Temperature - 107°C (225°F)
11	Dry Coal Cooler	Water Cooled Horizontal Rotary Kiln	1	0	189 tonne/hr (208 tph) Heat duty - 11 GJ/hr (10 MMBtu/hr)	195 tonne/hr (215 tph) Heat duty - 11 GJ/hr (11 MMBtu/hr)	204 tonne/hr (225 tph) Heat duty - 12 GJ/hr (11 MMBtu/hr)

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Operating Qty.	Spares	Case 1 Design Condition	Case 2 Design Condition	Case 3 Design Condition
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	2	0	526,172 liters (139,000 gal)	480,747 liters (127,000 gal)	537,528 liters (142,000 gal)
2	Condensate Pumps	Vertical canned	2	1	5,186 lpm @ 91 m H_2O (1,370 gpm @ 300 ft H_2O)	5,943 lpm @ 91 m H_2O (1,570 gpm @ 300 ft H_2O)	7,154 lpm @ 91 m H_2O (1,890 gpm @ 300 ft H_2O)
3	Deaerator (integral w/ HRSG)	Horizontal spray type	2	0	342,916 kg/hr (756,000 lb/hr)	409,140 kg/hr (902,000 lb/hr)	506,663 kg/hr (1,117,000 lb/hr)
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	2	1	227 lpm @ 27 m H_2O (60 gpm @ 90 ft H_2O)	1,779 lpm @ 27 m H_2O (470 gpm @ 90 ft H_2O)	2,385 lpm @ 27 m H_2O (630 gpm @ 90 ft H_2O)
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	2	1	HP water: 5,716 lpm @ 1,890 m H_2O (1,510 gpm @ 6,200 ft H_2O)	HP water: 4,050 lpm @ 1,890 m H_2O (1,070 gpm @ 6,200 ft H_2O)	HP water: 4,164 lpm @ 1,890 m H_2O (1,100 gpm @ 6,200 ft H_2O)
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	2	1	IP water: 1,703 lpm @ 223 m H_2O (450 gpm @ 730 ft H_2O)	IP water: 1,098 lpm @ 223 m H_2O (290 gpm @ 730 ft H_2O)	IP water: 1,173 lpm @ 223 m H_2O (310 gpm @ 730 ft H_2O)
7	Auxiliary Boiler	Shop fabricated, water tube	1	0	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)
8	Service Air Compressors	Flooded Screw	2	1	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)
9	Instrument Air Dryers	Duplex, regenerative	2	1	28 m^3/min (1,000 scfm)	28 m^3/min (1,000 scfm)	28 m^3/min (1,000 scfm)
10	Closed Cycle Cooling Heat Exchangers	Plate and frame	2	0	120 GJ/hr (113 MMBtu/hr) each	225 GJ/hr (213 MMBtu/hr) each	297 GJ/hr (282 MMBtu/hr) each

Equipment No.	Description	Type	Operating Qty.	Spares	Case 1 Design Condition	Case 2 Design Condition	Case 3 Design Condition
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	2	1	42,775 lpm @ 21 m H_2O (11,300 gpm @ 70 ft H_2O)	80,629 lpm @ 21 m H_2O (21,300 gpm @ 70 ft H_2O)	106,749 lpm @ 21 m H_2O (28,200 gpm @ 70 ft H_2O)
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	1	1	3,785 lpm @ 107 m H_2O (1,000 gpm @ 350 ft H_2O)	3,785 lpm @ 107 m H_2O (1,000 gpm @ 350 ft H_2O)	3,785 lpm @ 107 m H_2O (1,000 gpm @ 350 ft H_2O)
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	1	1	2,650 lpm @ 76 m H_2O (700 gpm @ 250 ft H_2O)	2,650 lpm @ 76 m H_2O (700 gpm @ 250 ft H_2O)	2,650 lpm @ 76 m H_2O (700 gpm @ 250 ft H_2O)
14	Raw Water Pumps	Stainless steel, single suction	2	1	1,741 lpm @ 18 m H_2O (460 gpm @ 60 ft H_2O)	2,574 lpm @ 18 m H_2O (680 gpm @ 60 ft H_2O)	3,293 lpm @ 18 m H_2O (870 gpm @ 60 ft H_2O)
15	Ground Water Pumps	Stainless steel, single suction	1	1	3,445 lpm @ 268 m H_2O (910 gpm @ 880 ft H_2O)	2,574 lpm @ 268 m H_2O (680 gpm @ 880 ft H_2O)	3,293 lpm @ 268 m H_2O (870 gpm @ 880 ft H_2O)
16	Filtered Water Pumps	Stainless steel, single suction	2	1	606 lpm @ 49 m H_2O (160 gpm @ 160 ft H_2O)	2,347 lpm @ 49 m H_2O (620 gpm @ 160 ft H_2O)	3,861 lpm @ 49 m H_2O (1,020 gpm @ 160 ft H_2O)
17	Filtered Water Tank	Vertical, cylindrical	2	0	295,262 liter (78,000 gal)	1,124,267 liter (297,000 gal)	1,858,637 liter (491,000 gal)
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	2	0	151 lpm (40 gpm)	757 lpm (200 gpm)	2,196 lpm (580 gpm)
19	Liquid Waste Treatment System		1	0	10 years, 24-hour storm	10 years, 24-hour storm	10 years, 24-hour storm

ACCOUNT 4 GASIFIER, ASU AND ACCESSORIES INCLUDING LOW TEMPERATURE HEAT RECOVERY

Equipment No.	Description	Type	Operating Qty.	Spares	Case 1 Design Condition	Case 2 Design Condition	Case 3 Design Condition
1	Gasifier	Pressurized dry-feed, entrained bed	2	0	2,903 tonne/day, 4.2 MPa (3,200 tpd, 614.696 psia)	2,994 tonne/day, 4.2 MPa (3,300 tpd, 614.696 psia)	3,084 tonne/day, 4.2 MPa (3,400 tpd, 614.696 psia)
2	Synthesis Gas Cooler	Convective spiral-wound tube boiler	2	0	242,672 kg/hr (535,000 lb/hr)	321,143 kg/hr (708,000 lb/hr)	335,658 kg/hr (740,000 lb/hr)
3	Synthesis Gas Cyclone	High efficiency	2	0	242,672 kg/hr (535,000 lb/hr) Design efficiency 90%	321,143 kg/hr (708,000 lb/hr) Design efficiency 90%	335,658 kg/hr (740,000 lb/hr) Design efficiency 90%
4	Candle Filter	Pressurized filter with pulse-jet cleaning	2	0	metallic filters	metallic filters	metallic filters
5	Syngas Scrubber Including Sour Water Stripper	Vertical upflow	2	0	168,736 kg/hr (372,000 lb/hr)	255,373 kg/hr (563,000 lb/hr)	267,166 kg/hr (589,000 lb/hr)
6	Raw Gas Coolers	Shell and tube with condensate drain	6	0	164,654 kg/hr (363,000 lb/hr)	240,858 kg/hr (531,000 lb/hr)	305,721 kg/hr (674,000 lb/hr)
7	Raw Gas Knockout Drum	Vertical with mist eliminator	2	0	164,654 kg/hr, 35°C, 3.6 MPa (363,000 lb/hr, 95°F, 525 psia)	211,828 kg/hr, 35°C, 3.5 MPa (467,000 lb/hr, 95°F, 510 psia)	267,619 kg/hr, 35°C, 3.5 MPa (590,000 lb/hr, 95°F, 503 psia)
8	Saturation Water Economizers	Shell and tube	2	0	164,654 kg/hr (363,000 lb/hr)	N/A	N/A
9	Fuel Gas Saturator	Vertical tray tower	2	0	176,901 kg/hr, 131°C, 3.3 MPa (390,000 lb/hr, 267°F, 480 psia)	N/A	N/A
10	Saturator Water Pump	Centrifugal	2	2	757 lpm @ 12 m H_2O (200 gpm @ 40 ft H_2O)	N/A	N/A

Equipment No.	Description	Type	Operating Qty.	Spares	Case 1 Design Condition	Case 2 Design Condition	Case 3 Design Condition
11	Synthesis Gas Reheater	Shell and tube	2	0	176,901 kg/hr (390,000 lb/hr)	106,141 kg/hr (234,000 lb/hr)	53,977 kg/hr (119,000 lb/hr)
12	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	2	0	168,736 kg/hr (372,000 lb/hr) syngas	255,373 kg/hr (563,000 lb/hr) syngas	267,166 kg/hr (589,000 lb/hr) syngas
13	ASU Main Air Compressor	Centrifugal, multi-stage	2	0	3,738 m^3/min @ 1.3 MPa (132,000 scfm @ 190 psia)	4,474 m^3/min @ 1.3 MPa (158,000 scfm @ 190 psia)	4,701 m^3/min @ 1.3 MPa (166,000 scfm @ 190 psia)
14	Cold Box	Vendor design	2	0	1,724 tonne/day (1,900 tpd) of 95% purity oxygen	1,814 tonne/day (2,000 tpd) of 95% purity oxygen	1,905 tonne/day (2,100 tpd) of 95% purity oxygen
15	Oxygen Compressor	Centrifugal, multi-stage	2	0	878 m^3/min (31,000 scfm) Suction - 0.9 MPa (130 psia) Discharge - 5.1 MPa (740 psia)	906 m^3/min (32,000 scfm) Suction - 0.9 MPa (130 psia) Discharge - 5.1 MPa (740 psia)	963 m^3/min (34,000 scfm) Suction - 0.9 MPa (130 psia) Discharge - 5.1 MPa (740 psia)
16	Primary Nitrogen Compressor	Centrifugal, multi-stage	2	0	2,888 m^3/min (102,000 scfm) Suction - 0.4 MPa (60 psia) Discharge - 2.7 MPa (390 psia)	2,888 m^3/min (102,000 scfm) Suction - 0.4 MPa (60 psia) Discharge - 2.7 MPa (390 psia)	3,143 m^3/min (111,000 scfm) Suction - 0.4 MPa (60 psia) Discharge - 2.7 MPa (390 psia)
17	Secondary Nitrogen Compressor	Centrifugal, single-stage	2	0	396 m^3/min (14,000 scfm) Suction - 2.7 MPa (390 psia) Discharge - 5.7 MPa (820 psia)	425 m^3/min (15,000 scfm) Suction - 2.6 MPa (380 psia) Discharge - 5.7 MPa (820 psia)	425 m^3/min (15,000 scfm) Suction - 2.6 MPa (380 psia) Discharge - 5.7 MPa (820 psia)

Equipment No.	Description	Type	Operating Qty.	Spares	Case 1 Design Condition	Case 2 Design Condition	Case 3 Design Condition
18	Extraction Air Heat Exchanger	Gas-to-gas, vendor design	2	0	45,359 kg/hr, 411°C, 1.3 MPa (100,000 lb/hr, 771°F, 182 psia)	N/A	N/A
19	Transport Nitrogen Boost Compressor	Centrifugal, single-stage	2	0	167 m^3/min (5,900 scfm) Suction - 2.7 MPa (389 psia) Discharge - 5.6 MPa (815 psia)	173 m^3/min (6,100 scfm) Suction - 2.6 MPa (384 psia) Discharge - 5.6 MPa (815 psia)	178 m^3/min (6,300 scfm) Suction - 2.6 MPa (384 psia) Discharge - 5.6 MPa (815 psia)
20	Syngas Dilution Nitrogen Boost Compressor	Centrifugal, single-stage	2	0	N/A	N/A	1,478 m^3/min (52,200 scfm) Suction - 2.6 MPa (384 psia) Discharge - 3.2 MPa (469 psia)

ACCOUNT 5 SYNGAS CLEANUP

Equipment No.	Description	Type	Operating Qty.	Spares	Case 1 Design Condition	Case 2 Design Condition	Case 3 Design Condition
1	Mercury Adsorber	Sulfated carbon bed	2	0	164,654 kg/hr (363,000 lb/hr) 35°C (95°F) 3.7 MPa (535 psia)	211,374 kg/hr (466,000 lb/hr) 35°C (95°F) 3.5 MPa (505 psia)	267,166 kg/hr (589,000 lb/hr) 35°C (95°F) 3.4 MPa (498 psia)
2	Sulfur Plant	Claus type	1	0	42 tonne/day (46 tpd)	41 tonne/day (46 tpd)	45 tonne/day (50 tpd)
3	COS/WGS Reactor(s)	Fixed bed, catalytic	Case 1 - 2 Case 2 - 2 Case 3 - 4	0	167,829 kg/hr (370,000 lb/hr) 177°C (350°F) 3.9 MPa (560 psia)	188,694 kg/hr (416,000 lb/hr) 243°C (470°F) 3.8 MPa (550 psia)	379,203 kg/hr (836,000 lb/hr) 249°C (480°F) 3.8 MPa (550 psia)

Equipment No.	Description	Type	Operating Qty.	Spares	Case 1 Design Condition	Case 2 Design Condition	Case 3 Design Condition
4	WGS Heat Exchangers	Shell and tube	Case 1 – 0 Case 2 – 2 Case 3 - 4	0	N/A	Exchanger 1: 73 GJ/hr (69 MMBtu/hr) Exchanger 2: -17 GJ/hr (-16 MMBtu/hr)	Exchanger 1: 162 GJ/hr (154 MMBtu/hr) Exchanger 2: 8 GJ/hr (8 MMBtu/hr)
5	Acid Gas Removal Plant	Sulfinol/ Selexol/ Selexol	2	0	167,376 kg/hr (369,000 lb/hr) 34°C (94°F) 3.6 MPa (525 psia)	215,003 kg/hr (474,000 lb/hr) 35°C (94°F) 3.4 MPa (495 psia)	273,063 kg/hr (602,000 lb/hr) 35°C (94°F) 3.4 MPa (488 psia)
6	Hydrogenation Reactor	Fixed bed, catalytic	1	0	6,910 kg/hr (15,234 lb/hr) 232°C (450°F) 0.3 MPa (48.6 psia)	8,976 kg/hr (19,790 lb/hr) 232°C (450°F) 0.1 MPa (12.3 psia)	14,025 kg/hr (30,919 lb/hr) 232°C (450°F) 0.1 MPa (12.3 psia)
7	Tail Gas Recycle Compressor	Centrifugal	1	0	5,326 kg/hr (11,742 lb/hr)	7,243 kg/hr (15,969 lb/hr)	11,534 kg/hr (25,428 lb/hr)

ACCOUNT 5B CO_2 COMPRESSION

Equipment No.	Description	Type	Operating Qty.	Spares	Case 1 Design Condition	Case 2 Design Condition	Case 3 Design Condition
	CO_2 Compressor	Integrally geared, multi-stage centrifugal	4	0	N/A	473 m^3/min @ 15.3 MPa (16,700 scfm @ 2,215 psia)	957 m^3/min @ 15.3 MPa (33,800 scfm @ 2,215 psia)

ACCOUNT 5C CO_2 TRANSPORT, STORAGE, AND MONITORING (not shown in Total Plant Cost Details)

Equipment No.	Description	Type	Case 1 Design Condition	Case 2 Design Condition	Case 3 Design Condition
1	CO_2 Pipeline	Carbon Steel	N/A	50 miles @ 12 in diameter w/ inlet pressure of 2,200 psi and outlet pressure of 1,500 psi	50 miles @ 14 in diameter w/ inlet pressure of 2,200 psi and outlet pressure of 1,500 psi

Equipment No.	Description	Type	Case 1 Design Condition	Case 2 Design Condition	Case 3 Design Condition
2	CO_2 Sequestration Source	Saline Formation	N/A	1 well with bottom hole pressure @ 1,220 psi, 530 ft thickness, 4,055 ft depth, 22 Md permeability	2 wells with bottom hole pressure @ 1,220 psi, 530 ft thickness, 4,055 ft depth, 22 Md permeability
3	CO_2 Monitoring	N/A	N/A	20 year monitoring during plant life / 80 years following / Total of 100 years	20 year monitoring during plant life / 80 years following / Total of 100 years

ACCOUNT 6 COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Operating Qty.	Spares	Case 1 Design Condition	Case 2 Design Condition	Case 3 Design Condition
1	Gas Turbine	Advanced F class	2	0	185 MW	190 MW	190 MW
2	Gas Turbine Generator	TEWAC	2	0	210 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	210 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	210 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase

ACCOUNT 7 HRSG, DUCTING AND STACK

Equipment No.	Description	Type	Operating Qty.	Spares	Case 1 Design Condition	Case 2 Design Condition	Case 3 Design Condition
1	Stack	CS plate, type 409SS liner	1	0	76 m (250 ft) high x 8.6 m (28 ft) diameter	76 m (250 ft) high x 8.7 m (28 ft) diameter	76 m (250 ft) high x 8.8 m (29 ft) diameter

Equipment No.	Description	Type	Operating Qty.	Spares	Case 1 Design Condition	Case 2 Design Condition	Case 3 Design Condition
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	2	0	Main steam - 322,006 kg/hr, 12.4 MPa/563°C (709,902 lb/hr, 1,800 psig/1,045°F) Reheat steam - 310,531 kg/hr, 3.1 MPa/563°C (684,604 lb/hr, 452 psig/1,045°F)	Main steam - 229,405 kg/hr, 12.4 MPa/549°C (505,752 lb/hr, 1,800 psig/1,021°F) Reheat steam - 254,747 kg/hr, 3.1 MPa/549°C (561,621 lb/hr, 452 psig/1,021°F)	Main steam - 235,155 kg/hr, 12.4 MPa/535°C (518,428 lb/hr, 1,800 psig/996°F) Reheat steam - 228,561 kg/hr, 3.1 MPa/535°C (503,891 lb/hr, 452 psig/996°F)

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Operating Qty.	Spares	Case 1 Design Condition	Case 2 Design Condition	Case 3 Design Condition
1	Steam Turbine	Commercially available	1	0	253 MW 12.4 MPa/563°C/563°C (1800 psig/ 1,045°F/1,045°F)	219 MW 12.4 MPa/549°C/549°C (1800 psig/ 1,021°F/1,021°F)	203 MW 12.4 MPa/535°C/535°C (1800 psig/ 996°F/996°F)
2	Steam Turbine Generator	Hydrogen cooled, static excitation	1	0	280 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	240 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	230 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1	0	654 GJ/hr (620 MMBtu/hr), Condensing temperature 32°C (90°F), Inlet water temperature 9°C (48°F), Water temperature rise 11°C (20°F)	665 GJ/hr (630 MMBtu/hr), Condensing temperature 32°C (90°F), Inlet water temperature 9°C (48°F), Water temperature rise 11°C (20°F)	622 GJ/hr (590 MMBtu/hr), Condensing temperature 32°C (90°F), Inlet water temperature 9°C (48°F), Water temperature rise 11°C (20°F)

Equipment No.	Description	Type	Operating Qty.	Spares	Case 1 Design Condition	Case 2 Design Condition	Case 3 Design Condition
4	Air-cooled Condenser	---	1	0	654 GJ/hr (620 MMBtu/hr), Condensing temperature 32°C (90°F), Ambient temperature 6°C (42°F)	665 GJ/hr (630 MMBtu/hr), Condensing temperature 32°C (90°F), Ambient temperature 6°C (42°F)	622 GJ/hr (590 MMBtu/hr), Condensing temperature 32°C (90°F), Ambient temperature 6°C (42°F)

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Operating Qty.	Spares	Case 1 Design Condition	Case 2 Design Condition	Case 3 Design Condition
1	Circulating Water Pumps	Vertical, wet pit	2	1	166,558 lpm @ 30 m (44,000 gpm @ 100 ft)	215,768 lpm @ 30 m (57,000 gpm @ 100 ft)	246,052 lpm @ 30 m (65,000 gpm @ 100 ft)
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	1	0	3°C (37°F) wet bulb / 9°C (48°F) CWT / 20°C (68°F) HWT / 928 GJ/hr (880 MMBtu/hr) heat duty	3°C (37°F) wet bulb / 9°C (48°F) CWT / 20°C (68°F) HWT / 1,203 GJ/hr (1140 MMBtu/hr) heat duty	3°C (37°F) wet bulb / 9°C (48°F) CWT / 20°C (68°F) HWT / 1382 GJ/hr (1,310 MMBtu/hr) heat duty

ACCOUNT 10 SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Operating Qty.	Spares	Case 1 Design Condition	Case 2 Design Condition	Case 3 Design Condition
1	Slag Quench Tank	Water bath	2	0	193,056 liters (51,000 gal)	200,627 liters (53,000 gal)	208,198 liters (55,000 gal)
2	Slag Crusher	Roll	2	0	10 tonne/hr (11 tph)	11 tonne/hr (12 tph)	11 tonne/hr (12 tph)
3	Slag Depressurizer	Lock Hopper	2	0	10 tonne/hr (11 tph)	11 tonne/hr (12 tph)	11 tonne/hr (12 tph)
4	Slag Receiving Tank	Horizontal, weir	2	0	117,348 liters (31,000 gal)	121,133 liters (32,000 gal)	124,919 liters (33,000 gal)
5	Black Water Overflow Tank	Shop fabricated	2		52,996 liters (14,000 gal)	52,996 liters (14,000 gal)	56,781 liters (15,000 gal)

Equipment No.	Description	Type	Operating Qty.	Spares	Case 1 Design Condition	Case 2 Design Condition	Case 3 Design Condition
6	Slag Conveyor	Drag chain	2	0	10 tonne/hr (11 tph)	11 tonne/hr (12 tph)	11 tonne/hr (12 tph)
7	Slag Separation Screen	Vibrating	2	0	10 tonne/hr (11 tph)	11 tonne/hr (12 tph)	11 tonne/hr (12 tph)
8	Coarse Slag Conveyor	Belt/bucket	2	0	10 tonne/hr (11 tph)	11 tonne/hr (12 tph)	11 tonne/hr (12 tph)
9	Fine Ash Settling Tank	Vertical, gravity	2	0	162,773 liters (43,000 gal)	170,344 liters (45,000 gal)	177,914 liters (47,000 gal)
10	Fine Ash Recycle Pumps	Horizontal centrifugal	2	2	38 lpm @ 14 m H_2O (10 gpm @ 46 ft H_2O)	38 lpm @ 14 m H_2O (10 gpm @ 46 ft H_2O)	38 lpm @ 14 m H_2O (10 gpm @ 46 ft H_2O)
11	Grey Water Storage Tank	Field erected	2	0	52,996 liters (14,000 gal)	52,996 liters (14,000 gal)	56,781 liters (15,000 gal)
12	Grey Water Pumps	Centrifugal	2	2	189 lpm @ 433 m H_2O (50 gpm @ 1,420 ft H_2O)	189 lpm @ 433 m H_2O (50 gpm @ 1,420 ft H_2O)	189 lpm @ 433 m H_2O (50 gpm @ 1,420 ft H_2O)
13	Slag Storage Bin	Vertical, field erected	2	0	726 tonne (800 tons)	726 tonne (800 tons)	816 tonne (900 tons)
14	Unloading Equipment	Telescoping chute	1	0	82 tonne/hr (90 tph)	91 tonne/hr (100 tph)	91 tonne/hr (100 tph)

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Operating Qty.	Spares	Case 1 Design Condition	Case 2 Design Condition	Case 3 Design Condition
1	CTG Step-up Transformer	Oil-filled	2	0	24 kV/345 kV, 210 MVA, 3-ph, 60 Hz	24 kV/345 kV, 210 MVA, 3-ph, 60 Hz	24 kV/345 kV, 210 MVA, 3-ph, 60 Hz
2	STG Step-up Transformer	Oil-filled	1	0	24 kV/345 kV, 280 MVA, 3-ph, 60 Hz	24 kV/345 kV, 240 MVA, 3-ph, 60 Hz	24 kV/345 kV, 230 MVA, 3-ph, 60 Hz
3	High Voltage Auxiliary Transformer	Oil-filled	2	0	345 kV/13.8 kV, 49 MVA, 3-ph, 60 Hz	345 kV/13.8 kV, 62 MVA, 3-ph, 60 Hz	345 kV/13.8 kV, 73 MVA, 3-ph, 60 Hz
4	Medium Voltage Auxiliary Transformer	Oil-filled	1	1	24 kV/4.16 kV, 22 MVA, 3-ph, 60 Hz	24 kV/4.16 kV, 32 MVA, 3-ph, 60 Hz	24 kV/4.16 kV, 43 MVA, 3-ph, 60 Hz
5	Low Voltage Transformer	Dry ventilated	1	1	4.16 kV/480 V, 3 MVA, 3-ph, 60 Hz	4.16 kV/480 V, 5 MVA, 3-ph, 60 Hz	4.16 kV/480 V, 6 MVA, 3-ph, 60 Hz
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	2	0	24 kV, 3-ph, 60 Hz	24 kV, 3-ph, 60 Hz	24 kV, 3-ph, 60 Hz
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	1	0	24 kV, 3-ph, 60 Hz	24 kV, 3-ph, 60 Hz	24 kV, 3-ph, 60 Hz
8	Medium Voltage Switchgear	Metal clad	1	1	4.16 kV, 3-ph, 60 Hz	4.16 kV, 3-ph, 60 Hz	4.16 kV, 3-ph, 60 Hz

Equipment No.	Description	Type	Operating Qty.	Spares	Case 1 Design Condition	Case 2 Design Condition	Case 3 Design Condition
9	Low Voltage Switchgear	Metal enclosed	1	1	480 V, 3-ph, 60 Hz	480 V, 3-ph, 60 Hz	480 V, 3-ph, 60 Hz
10	Emergency Diesel Generator	Sized for emergency shutdown	1	0	750 kW, 480 V, 3-ph, 60 Hz	750 kW, 480 V, 3-ph, 60 Hz	750 kW, 480 V, 3-ph, 60 Hz

ACCOUNT 12 INSTRUMENTATION AND CONTROLS

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

4.1.7 Case 1 – Cost Estimating

The cost estimating methodology was described previously in Section 2.6. Exhibit 4-24 shows the TPC cost details organized by cost account as well as TOC and TASC. Exhibit 4-25 shows the initial and annual O&M costs.

The estimated TOC of the IGCC case with no CO_2 capture is $3,128/kW. Owner's costs represent 18 percent of the TOC. The current dollar, 30-year LCOE is $117.84/MWh.

Exhibit 4-24 Case 1 Total Plant Cost Details

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 1 TOTAL PLANT COST $	Case 1 TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,710	$0	$1,813	$0	$0	$5,523	$495	$0	$1,204	$7,222	$14
1.2	Coal Stackout & Reclaim	$4,794	$0	$1,162	$0	$0	$5,957	$522	$0	$1,296	$7,775	$15
1.3	Coal Conveyors	$4,458	$0	$1,150	$0	$0	$5,608	$492	$0	$1,220	$7,320	$15
1.4	Other Coal Handling	$1,166	$0	$266	$0	$0	$1,432	$125	$0	$312	$1,869	$4
1.5	Sorbent Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.6	Sorbent Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.7	Sorbent Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.8	Other Sorbent Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Coal & Sorbent Hnd.Foundations	$0	$2,625	$6,565	$0	$0	$9,190	$881	$0	$2,014	$12,086	$24
	SUBTOTAL 1.	**$14,128**	**$2,625**	**$10,957**	**$0**	**$0**	**$27,710**	**$2,515**	**$0**	**$6,045**	**$36,271**	**$72**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$42,557	$2,557	$6,201	$0	$0	$51,315	$4,428	$0	$11,149	$66,892	$133
2.2	Prepared Coal Storage & Feed	$2,016	$482	$316	$0	$0	$2,814	$241	$0	$611	$3,666	$7
2.3	Dry Coal Injection System	$66,338	$770	$6,161	$0	$0	$73,269	$6,311	$0	$15,916	$95,495	$190
2.4	Misc.Coal Prep & Feed	$1,108	$807	$2,418	$0	$0	$4,334	$398	$0	$946	$5,678	$11
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$4,309	$3,537	$0	$0	$7,846	$727	$0	$1,714	$10,287	$20
	SUBTOTAL 2.	**$112,019**	**$8,924**	**$18,634**	**$0**	**$0**	**$139,577**	**$12,104**	**$0**	**$30,336**	**$182,017**	**$362**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$2,718	$4,668	$2,464	$0	$0	$9,850	$913	$0	$2,153	$12,915	$26
3.2	Water Makeup & Pretreating	$289	$30	$162	$0	$0	$481	$46	$0	$158	$685	$1
3.3	Other Feedwater Subsystems	$1,487	$503	$452	$0	$0	$2,442	$219	$0	$532	$3,194	$6
3.4	Service Water Systems	$165	$341	$1,182	$0	$0	$1,688	$165	$0	$556	$2,409	$5
3.5	Other Boiler Plant Systems	$888	$344	$852	$0	$0	$2,084	$198	$0	$456	$2,738	$5
3.6	FO Supply Sys & Nat Gas	$292	$551	$514	$0	$0	$1,357	$131	$0	$298	$1,786	$4
3.7	Waste Treatment Equipment	$404	$0	$246	$0	$0	$650	$63	$0	$214	$928	$2
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$999	$134	$513	$0	$0	$1,646	$159	$0	$541	$2,346	$5
	SUBTOTAL 3.	**$7,242**	**$6,570**	**$6,386**	**$0**	**$0**	**$20,198**	**$1,893**	**$0**	**$4,908**	**$27,000**	**$54**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$137,274	$0	$59,482	$0	$0	$196,756	$17,552	$27,621	$36,980	$278,909	$555
4.2	Syngas Cooling (w/4.1)	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$142,499	$0	w/equip.	$0	$0	$142,499	$13,812	$0	$15,631	$171,943	$342
4.4	LT Heat Recovery & FG Saturation	$16,347	$0	$6,214	$0	$0	$22,561	$2,202	$0	$4,953	$29,716	$59
4.5	Misc. Gasification Equipment w/4.1 & 4.2	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Other Gasification Equipment	$0	$819	$333	$0	$0	$1,152	$110	$0	$253	$1,515	$3
4.8	Major Component Rigging	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Gasification Foundations	$0	$8,073	$4,606	$0	$0	$12,679	$1,161	$0	$3,460	$17,299	$34
	SUBTOTAL 4.	**$296,120**	**$8,892**	**$70,636**	**$0**	**$0**	**$375,648**	**$34,837**	**$27,621**	**$61,276**	**$499,383**	**$994**

Exhibit 4-24 Case 1 Total Plant Cost Details **(Continued)**

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 1 TOTAL PLANT COST $	Case 1 TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	Sulfinol/Selexol System	$33,314	$0	$15,556	$0	$0	$48,870	$4,693	$0	$10,713	$64,275	$128
5A.2	Elemental Sulfur Plant	$4,460	$889	$5,754	$0	$0	$11,103	$1,078	$0	$2,436	$14,617	$29
5A.3	Mercury Removal	$833	$0	$634	$0	$0	$1,466	$142	$73	$336	$2,018	$4
5A.4	COS Hydrolysis/WGS Reactors	$2,459	$0	$3,211	$0	$0	$5,671	$551	$0	$1,244	$7,466	$15
5A.5	Particulate Removal	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
5A.5	Blowback Gas Systems	$1,273	$214	$121	$0	$0	$1,608	$153	$0	$352	$2,113	$4
5A.6	Fuel Gas Piping	$0	$694	$486	$0	$0	$1,179	$109	$0	$258	$1,546	$3
5A.9	HGCU Foundations	$0	$635	$410	$0	$0	$1,045	$96	$0	$342	$1,483	$3
	SUBTOTAL 5A.	**$42,339**	**$2,432**	**$26,171**	**$0**	**$0**	**$70,942**	**$6,822**	**$73**	**$15,681**	**$93,518**	**$186**
5B	CO2 REMOVAL & COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5B.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$87,466	$0	$6,269	$0	$0	$93,736	$8,886	$4,687	$10,731	$118,040	$235
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$806	$892	$0	$0	$1,699	$159	$0	$557	$2,415	$5
	SUBTOTAL 6.	**$87,466**	**$806**	**$7,162**	**$0**	**$0**	**$95,434**	**$9,045**	**$4,687**	**$11,288**	**$120,454**	**$240**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$30,167	$0	$4,289	$0	$0	$34,457	$3,276	$0	$3,773	$41,506	$83
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,774	$1,298	$0	$0	$3,071	$270	$0	$668	$4,009	$8
7.4	Stack	$3,460	$0	$1,300	$0	$0	$4,760	$456	$0	$522	$5,738	$11
7.9	HRSG,Duct & Stack Foundations	$0	$693	$666	$0	$0	$1,359	$127	$0	$446	$1,931	$4
	SUBTOTAL 7.	**$33,628**	**$2,467**	**$7,553**	**$0**	**$0**	**$43,648**	**$4,128**	**$0**	**$5,409**	**$53,185**	**$106**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$26,335	$0	$4,527	$0	$0	$30,862	$2,961	$0	$3,382	$37,206	$74
8.2	Turbine Plant Auxiliaries	$182	$0	$418	$0	$0	$600	$59	$0	$66	$724	$1
8.3a	Condenser & Auxiliaries	$2,602	$0	$831	$0	$0	$3,433	$328	$0	$376	$4,137	$8
8.3b	Air Cooled Condenser	$23,849	$0	$4,781	$0	$0	$28,631	$2,863	$0	$6,299	$37,792	$75
8.4	Steam Piping	$4,958	$0	$3,488	$0	$0	$8,446	$726	$0	$2,293	$11,465	$23
8.9	TG Foundations	$0	$903	$1,527	$0	$0	$2,430	$230	$0	$798	$3,459	$7
	SUBTOTAL 8.	**$57,926**	**$903**	**$15,572**	**$0**	**$0**	**$74,402**	**$7,167**	**$0**	**$13,214**	**$94,783**	**$189**

Exhibit 4-24 Case 1 Total Plant Cost Details **(Continued)**

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 1 TOTAL PLANT COST $	Case 1 TOTAL PLANT COST $/kW
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$3,494	$0	$636	$0	$0	$4,130	$393	$0	$678	$5,202	$10
9.2	Circulating Water Pumps	$909	$0	$74	$0	$0	$983	$83	$0	$160	$1,227	$2
9.3	Circ.Water System Auxiliaries	$84	$0	$12	$0	$0	$96	$9	$0	$16	$121	$0
9.4	Circ.Water Piping	$0	$3,551	$921	$0	$0	$4,472	$404	$0	$975	$5,851	$12
9.5	Make-up Water System	$187	$0	$268	$0	$0	$455	$44	$0	$100	$599	$1
9.6	Component Cooling Water Sys	$418	$500	$356	$0	$0	$1,274	$119	$0	$279	$1,672	$3
9.9	Circ.Water System Foundations& Structures	$0	$1,349	$2,293	$0	$0	$3,642	$345	$0	$1,196	$5,184	$10
	SUBTOTAL 9.	**$5,093**	**$5,400**	**$4,559**	**$0**	**$0**	**$15,053**	**$1,398**	**$0**	**$3,404**	**$19,855**	**$40**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$14,744	$0	$7,271	$0	$0	$22,014	$2,115	$0	$2,413	$26,542	$53
10.2	Gasifier Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Rrecovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$503	$0	$548	$0	$0	$1,051	$102	$0	$173	$1,326	$3
10.7	Ash Transport & Feed Equipment	$675	$0	$163	$0	$0	$838	$78	$0	$137	$1,054	$2
10.8	Misc. Ash Handling Equipment	$1,043	$1,278	$382	$0	$0	$2,702	$257	$0	$444	$3,403	$7
10.9	Ash/Spent Sorbent Foundation	$0	$45	$56	$0	$0	$100	$9	$0	$33	$143	$0
	SUBTOTAL 10.	**$16,965**	**$1,322**	**$8,419**	**$0**	**$0**	**$26,706**	**$2,562**	**$0**	**$3,200**	**$32,468**	**$65**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$853	$0	$843	$0	$0	$1,696	$162	$0	$186	$2,044	$4
11.2	Station Service Equipment	$3,688	$0	$332	$0	$0	$4,020	$371	$0	$439	$4,830	$10
11.3	Switchgear & Motor Control	$6,817	$0	$1,240	$0	$0	$8,057	$747	$0	$1,321	$10,125	$20
11.4	Conduit & Cable Tray	$0	$3,167	$10,448	$0	$0	$13,615	$1,317	$0	$3,733	$18,664	$37
11.5	Wire & Cable	$0	$6,051	$3,976	$0	$0	$10,027	$728	$0	$2,689	$13,444	$27
11.6	Protective Equipment	$0	$655	$2,385	$0	$0	$3,041	$297	$0	$501	$3,838	$8
11.7	Standby Equipment	$214	$0	$209	$0	$0	$424	$40	$0	$70	$534	$1
11.8	Main Power Transformers	$13,713	$0	$127	$0	$0	$13,840	$1,047	$0	$2,233	$17,120	$34
11.9	Electrical Foundations	$0	$138	$362	$0	$0	$500	$48	$0	$164	$712	$1
	SUBTOTAL 11.	**$25,285**	**$10,011**	**$19,922**	**$0**	**$0**	**$55,218**	**$4,757**	**$0**	**$11,335**	**$71,310**	**$142**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$978	$0	$653	$0	$0	$1,632	$154	$82	$280	$2,148	$4
12.5	Signal Processing Equipment	W/12.7	$0	W/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$225	$0	$144	$0	$0	$369	$35	$18	$84	$507	$1
12.7	Computer & Accessories	$5,220	$0	$167	$0	$0	$5,387	$494	$269	$615	$6,765	$13
12.8	Instrument Wiring & Tubing	$0	$1,823	$3,728	$0	$0	$5,551	$471	$278	$1,575	$7,874	$16
12.9	Other I & C Equipment	$3,489	$0	$1,694	$0	$0	$5,183	$488	$259	$890	$6,820	$14
	SUBTOTAL 12.	**$9,912**	**$1,823**	**$6,386**	**$0**	**$0**	**$18,122**	**$1,642**	**$906**	**$3,444**	**$24,114**	**$48**

Exhibit 4-24 Case 1 Total Plant Cost Details (Continued)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 1 TOTAL PLANT COST $	Case 1 TOTAL PLANT COST $/kW
13	Improvements to Site											
13.1	Site Preparation	$0	$101	$2,164	$0	$0	$2,265	$225	$0	$747	$3,237	$6
13.2	Site Improvements	$0	$1,801	$2,393	$0	$0	$4,194	$414	$0	$1,382	$5,990	$12
13.3	Site Facilities	$3,227	$0	$3,405	$0	$0	$6,632	$654	$0	$2,186	$9,472	$19
	SUBTOTAL 13.	**$3,227**	**$1,902**	**$7,962**	**$0**	**$0**	**$13,092**	**$1,293**	**$0**	**$4,315**	**$18,699**	**$37**
14	Buildings & Structures											
14.1	Combustion Turbine Area	$0	$265	$150	$0	$0	$414	$36	$0	$90	$541	$1
14.2	Steam Turbine Building	$0	$2,429	$3,460	$0	$0	$5,889	$542	$0	$965	$7,395	$15
14.3	Administration Building	$0	$825	$598	$0	$0	$1,423	$127	$0	$232	$1,782	$4
14.4	Circulation Water Pumphouse	$0	$153	$81	$0	$0	$234	$21	$0	$38	$293	$1
14.5	Water Treatment Buildings	$0	$258	$252	$0	$0	$510	$46	$0	$83	$639	$1
14.6	Machine Shop	$0	$425	$291	$0	$0	$716	$64	$0	$117	$896	$2
14.7	Warehouse	$0	$686	$443	$0	$0	$1,129	$100	$0	$184	$1,413	$3
14.8	Other Buildings & Structures	$0	$409	$318	$0	$0	$727	$65	$0	$158	$951	$2
14.9	Waste Treating Building & Str.	$0	$903	$1,725	$0	$0	$2,627	$245	$0	$574	$3,447	$7
	SUBTOTAL 14.	**$0**	**$6,351**	**$7,318**	**$0**	**$0**	**$13,669**	**$1,245**	**$0**	**$2,443**	**$17,357**	**$35**
	TOTAL COST	**$711,351**	**$60,430**	**$217,637**	**$0**	**$0**	**$989,418**	**$91,410**	**$33,287**	**$176,300**	**$1,290,415**	**$2,569**
	Owner's Costs											
	Preproduction Costs											
	6 Months All Labor										$11,703	$23
	1 Month Maintenance Materials										$2,567	$5
	1 Month Non-fuel Consumables										$92	$0
	1 Month Waste Disposal										$240	$0
	25% of 1 Months Fuel Cost at 100% CF										$453	$1
	2% of TPC										$25,808	$51
	Total										**$40,863**	**$81**
	Inventory Capital											
	60 day supply of fuel and consumables at 100% CF										$3,808	$8
	0.5% of TPC (spare parts)										$6,452	$13
	Total										**$10,260**	**$20**
	Initial Cost for Catalyst and Chemicals										$568	$1
	Land										$900	$2
	Other Owner's Costs										$193,562	$385
	Financing Costs										$34,841	$69
	Total Overnight Costs (TOC)										**$1,571,409**	**$3,128**
	TASC Multiplier								(IOU, high-risk, 35 year)		1.140	
	Total As-Spent Cost (TASC)										**$1,791,407**	**$3,566**

Exhibit 4-25 Case 1 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (June)	2007
Case 1 - Shell IGCC w/o CO2					Heat Rate-net(Btu/kWh):	8,160
					MWe-net:	502
					Capacity Factor: (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	34.65	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Skilled Operator	2.0		2.0			
Operator	9.0		9.0			
Foreman	1.0		1.0			
Lab Tech's, etc.	3.0		3.0			
TOTAL-O.J.'s	15.0		15.0			
					Annual Cost	Annual Unit Cost
					$	$/kW-net
Annual Operating Labor Cost	Maintenance labor cost		% of BEC	1.2942	$5,918,913	$11.782
Maintenance Labor Cost	(Case S1A is reference)		BEC	$989,418	$12,805,347	$25.490
Administrative & Support Labor					$4,681,065	$9.318
Property Taxes & Insurance					$25,808,296	$51.373
TOTAL FIXED OPERATING COSTS					**$49,213,621.24**	**$97.963**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost			% of BEC	2.4905	**$24,641,658**	**$0.00700**
Consumables	Consumption		Unit	Initial Fill		
	Initial Fill	/Day	Cost	Cost		
Water(/1000 gallons)	0	1,164	1.08	**$0**	**$367,497**	**$0.00010**
Chemicals		5.959				
MU & WT Chem.(lb)	0	6,934	0.17	$0	$350,395	$0.00010
Carbon (Mercury Removal) (lb)	56,520	77	1.05	$59,356	$23,742	$0.00001
COS Catalyst (m3)	212	0.15	2,397.36	$509,009	$101,732	$0.00003
Water Gas Shift Catalyst(ft3)	0	0	498.83	$0	$0	$0.00000
Selexol Solution (gal.)	0	0	13.40	$0	$0	$0.00000
MDEA Solution (gal)	0	0	8.70	$0	$0	$0.00000
Sulfinol Solution (gal)	w/equip.	7	10.05	$0	$19,366	$0.00001
SCR Catalyst (m3)	0	0	0.00	$0	$0	$0.00000
Aqueous Ammonia (ton)	0	0	0.00	$0	$0	$0.00000
Claus Catalyst(ft3)	w/equip.	0.63	131.27	$0	$24,232	$0.00001
Subtotal Chemicals				**$568,365**	**$519,468**	**$0.00015**
Other						
Supplemental Fuel(MBtu)	0	0	0.00	$0	$0	$0.00000
Gases,N2 etc.(/100scf)	0	0	0.00	$0	$0	$0.00000
L.P. Steam(/1000 pounds)	0	0	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$0**	**$0.00000**
Waste Disposal						
Spent Mercury Catalyst (lb)	0	77	0.42	$0	$9,429	$0.00000
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Slag (ton)	0	485	16.23	$0	$2,296,856	$0.00065
Subtotal-Waste Disposal				**$0**	**$2,306,285**	**$0.00066**
By-products & Emissions						
Sulfur(tons)	0	42	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$568,365**	**$27,834,907.70**	**$0.00791**
Fuel(ton)	0	5,744	10.367	**$0**	**$17,389,132**	**$0.00494**

4.1.8 Case 2 – Cost Estimating

Exhibit 4-26 shows the TPC cost details organized by cost account as well as TOC and TASC. Exhibit 4-27 shows the initial and annual O&M costs.

The estimated TOC of the IGCC case with an emission rate of 1,100 lb CO_2/net-MWh is $3,938/kW. Owner's costs represent 18 percent of the TOC. The current dollar, 30-year LCOE, including TS&M, is $149.33/MWh.

Exhibit 4-26 Case 2 Total Plant Cost Details

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 2 TOTAL PLANT COST $	Case 2 TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,790	$0	$1,852	$0	$0	$5,642	$505	$0	$1,229	$7,377	$17
1.2	Coal Stackout & Reclaim	$4,897	$0	$1,187	$0	$0	$6,084	$533	$0	$1,324	$7,941	$18
1.3	Coal Conveyors	$4,553	$0	$1,175	$0	$0	$5,728	$503	$0	$1,246	$7,477	$17
1.4	Other Coal Handling	$1,191	$0	$272	$0	$0	$1,463	$128	$0	$318	$1,909	$4
1.5	Sorbent Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.6	Sorbent Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.7	Sorbent Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.8	Other Sorbent Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Coal & Sorbent Hnd.Foundations	$0	$2,682	$6,706	$0	$0	$9,387	$900	$0	$2,057	$12,345	$28
	SUBTOTAL 1.	**$14,431**	**$2,682**	**$11,191**	**$0**	**$0**	**$28,304**	**$2,569**	**$0**	**$6,175**	**$37,048**	**$84**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$43,529	$2,615	$6,343	$0	$0	$52,487	$4,529	$0	$11,403	$68,419	$155
2.2	Prepared Coal Storage & Feed	$2,062	$493	$323	$0	$0	$2,878	$246	$0	$625	$3,749	$8
2.3	Dry Coal Injection System	$67,853	$788	$6,301	$0	$0	$74,942	$6,455	$0	$16,279	$97,676	$221
2.4	Misc.Coal Prep & Feed	$1,134	$825	$2,474	$0	$0	$4,433	$407	$0	$968	$5,808	$13
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$4,407	$3,618	$0	$0	$8,025	$743	$0	$1,754	$10,522	$24
	SUBTOTAL 2.	**$114,577**	**$9,128**	**$19,059**	**$0**	**$0**	**$142,764**	**$12,381**	**$0**	**$31,029**	**$186,174**	**$420**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$2,128	$3,654	$1,929	$0	$0	$7,711	$714	$0	$1,685	$10,111	$23
3.2	Water Makeup & Pretreating	$384	$40	$215	$0	$0	$639	$61	$0	$210	$910	$2
3.3	Other Feedwater Subsystems	$1,164	$393	$354	$0	$0	$1,912	$172	$0	$417	$2,500	$6
3.4	Service Water Systems	$220	$453	$1,571	$0	$0	$2,243	$219	$0	$739	$3,201	$7
3.5	Other Boiler Plant Systems	$1,180	$457	$1,133	$0	$0	$2,769	$263	$0	$606	$3,638	$8
3.6	FO Supply Sys & Nat Gas	$289	$546	$509	$0	$0	$1,344	$129	$0	$295	$1,768	$4
3.7	Waste Treatment Equipment	$537	$0	$328	$0	$0	$864	$84	$0	$285	$1,233	$3
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$993	$133	$510	$0	$0	$1,636	$158	$0	$538	$2,332	$5
	SUBTOTAL 3.	**$6,894**	**$5,676**	**$6,548**	**$0**	**$0**	**$19,118**	**$1,800**	**$0**	**$4,774**	**$25,692**	**$58**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$116,362	$0	$49,863	$0	$0	$166,225	$14,844	$22,983	$31,320	$235,372	$532
4.2	Syngas Cooling (w/4.1)	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$160,585	$0	w/equip.	$0	$0	$160,585	$15,565	$0	$17,615	$193,765	$438
4.4	LT Heat Recovery & FG Saturation	$26,641	$0	$10,128	$0	$0	$36,768	$3,588	$0	$8,071	$48,428	$109
4.5	Misc. Gasification Equipment w/4.1 & 4.2	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Other Gasification Equipment	$0	$1,646	$670	$0	$0	$2,316	$222	$0	$508	$3,046	$7
4.8	Major Component Rigging	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Gasification Foundations	$0	$8,212	$4,686	$0	$0	$12,898	$1,181	$0	$3,520	$17,598	$40
	SUBTOTAL 4.	**$303,588**	**$9,858**	**$65,346**	**$0**	**$0**	**$378,792**	**$35,401**	**$22,983**	**$61,033**	**$498,209**	**$1,125**

Exhibit 4-26 Case 2 Total Plant Cost Details (Continued)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 2 TOTAL PLANT COST $	Case 2 TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	Sulfinol/Selexol System	$56,111	$0	$48,095	$0	$0	$104,206	$10,079	$20,841	$27,025	$162,152	$366
5A.2	Elemental Sulfur Plant	$4,449	$887	$5,740	$0	$0	$11,075	$1,076	$0	$2,430	$14,581	$33
5A.3	Mercury Removal	$1,416	$0	$1,078	$0	$0	$2,494	$241	$125	$572	$3,432	$8
5A.4	COS Hydrolysis/WGS Reactors	$5,066	$0	$2,039	$0	$0	$7,105	$681	$0	$1,557	$9,343	$21
5A.5	Particulate Removal	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
5A.5	Blowback Gas Systems	$1,850	$311	$175	$0	$0	$2,337	$222	$0	$512	$3,070	$7
5A.6	Fuel Gas Piping	$0	$699	$490	$0	$0	$1,189	$110	$0	$260	$1,559	$4
5A.9	HGCU Foundations	$0	$687	$443	$0	$0	$1,131	$104	$0	$370	$1,605	$4
	SUBTOTAL 5A.	**$68,893**	**$2,585**	**$58,059**	**$0**	**$0**	**$129,537**	**$12,513**	**$20,966**	**$32,727**	**$195,742**	**$442**
5B	CO2 REMOVAL & COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$8,653	$0	$5,015	$0	$0	$13,668	$1,316	$0	$2,997	$17,980	$41
	SUBTOTAL 5B.	**$8,653**	**$0**	**$5,015**	**$0**	**$0**	**$13,668**	**$1,316**	**$0**	**$2,997**	**$17,980**	**$41**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$93,866	$0	$6,583	$0	$0	$100,449	$9,522	$10,045	$12,002	$132,017	$298
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$806	$892	$0	$0	$1,699	$159	$0	$557	$2,415	$5
	SUBTOTAL 6.	**$93,866**	**$806**	**$7,475**	**$0**	**$0**	**$102,147**	**$9,681**	**$10,045**	**$12,559**	**$134,432**	**$304**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$29,527	$0	$4,198	$0	$0	$33,725	$3,207	$0	$3,693	$40,625	$92
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,794	$1,312	$0	$0	$3,106	$273	$0	$676	$4,055	$9
7.4	Stack	$3,499	$0	$1,315	$0	$0	$4,814	$461	$0	$528	$5,803	$13
7.9	HRSG,Duct & Stack Foundations	$0	$701	$673	$0	$0	$1,374	$128	$0	$451	$1,953	$4
	SUBTOTAL 7.	**$33,026**	**$2,495**	**$7,499**	**$0**	**$0**	**$43,020**	**$4,069**	**$0**	**$5,347**	**$52,435**	**$118**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$23,844	$0	$3,994	$0	$0	$27,838	$2,671	$0	$3,051	$33,560	$76
8.2	Turbine Plant Auxiliaries	$164	$0	$376	$0	$0	$540	$53	$0	$59	$652	$1
8.3a	Condenser & Auxiliaries	$2,631	$0	$840	$0	$0	$3,471	$332	$0	$380	$4,184	$9
8.3b	Air Cooled Condenser	$24,118	$0	$4,835	$0	$0	$28,953	$2,895	$0	$6,370	$38,218	$86
8.4	Steam Piping	$3,908	$0	$2,749	$0	$0	$6,658	$572	$0	$1,807	$9,037	$20
8.9	TG Foundations	$0	$813	$1,374	$0	$0	$2,187	$207	$0	$718	$3,113	$7
	SUBTOTAL 8.	**$54,665**	**$813**	**$14,169**	**$0**	**$0**	**$69,647**	**$6,730**	**$0**	**$12,386**	**$88,763**	**$200**

Exhibit 4-26 Case 2 Total Plant Cost Details (Continued)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 2 TOTAL PLANT COST $	Case 2 TOTAL PLANT COST $/kW
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$4,188	$0	$762	$0	$0	$4,950	$471	$0	$813	$6,235	$14
9.2	Circulating Water Pumps	$1,097	$0	$73	$0	$0	$1,170	$99	$0	$190	$1,459	$3
9.3	Circ.Water System Auxiliaries	$98	$0	$14	$0	$0	$112	$11	$0	$18	$141	$0
9.4	Circ.Water Piping	$0	$4,155	$1,077	$0	$0	$5,232	$473	$0	$1,141	$6,846	$15
9.5	Make-up Water System	$238	$0	$341	$0	$0	$579	$56	$0	$127	$762	$2
9.6	Component Cooling Water Sys	$488	$584	$415	$0	$0	$1,487	$139	$0	$325	$1,951	$4
9.9	Circ.Water System Foundations& Structures	$0	$1,578	$2,682	$0	$0	$4,260	$404	$0	$1,399	$6,063	$14
	SUBTOTAL 9.	**$6,110**	**$6,316**	**$5,364**	**$0**	**$0**	**$17,790**	**$1,652**	**$0**	**$4,014**	**$23,457**	**$53**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$15,071	$0	$7,432	$0	$0	$22,503	$2,162	$0	$2,466	$27,131	$61
10.2	Gasifier Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Rrecovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$513	$0	$558	$0	$0	$1,071	$104	$0	$176	$1,352	$3
10.7	Ash Transport & Feed Equipment	$688	$0	$166	$0	$0	$854	$80	$0	$140	$1,074	$2
10.8	Misc. Ash Handling Equipment	$1,063	$1,302	$389	$0	$0	$2,754	$262	$0	$452	$3,469	$8
10.9	Ash/Spent Sorbent Foundation	$0	$45	$57	$0	$0	$102	$10	$0	$34	$146	$0
	SUBTOTAL 10.	**$17,335**	**$1,348**	**$8,602**	**$0**	**$0**	**$27,285**	**$2,617**	**$0**	**$3,269**	**$33,171**	**$75**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$830	$0	$821	$0	$0	$1,650	$158	$0	$181	$1,989	$4
11.2	Station Service Equipment	$4,109	$0	$370	$0	$0	$4,479	$413	$0	$489	$5,381	$12
11.3	Switchgear & Motor Control	$7,596	$0	$1,382	$0	$0	$8,978	$833	$0	$1,472	$11,282	$25
11.4	Conduit & Cable Tray	$0	$3,529	$11,641	$0	$0	$15,170	$1,467	$0	$4,159	$20,797	$47
11.5	Wire & Cable	$0	$6,742	$4,430	$0	$0	$11,172	$812	$0	$2,996	$14,980	$34
11.6	Protective Equipment	$0	$655	$2,385	$0	$0	$3,041	$297	$0	$501	$3,838	$9
11.7	Standby Equipment	$210	$0	$205	$0	$0	$414	$40	$0	$68	$522	$1
11.8	Main Power Transformers	$15,376	$0	$124	$0	$0	$15,500	$1,172	$0	$2,501	$19,173	$43
11.9	Electrical Foundations	$0	$133	$350	$0	$0	$483	$46	$0	$159	$689	$2
	SUBTOTAL 11.	**$28,121**	**$11,060**	**$21,708**	**$0**	**$0**	**$60,889**	**$5,237**	**$0**	**$12,526**	**$78,652**	**$178**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$1,013	$0	$677	$0	$0	$1,690	$160	$84	$290	$2,225	$5
12.5	Signal Processing Equipment	W/12.7	$0	W/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$233	$0	$149	$0	$0	$382	$36	$19	$87	$525	$1
12.7	Computer & Accessories	$5,405	$0	$173	$0	$0	$5,578	$512	$279	$637	$7,006	$16
12.8	Instrument Wiring & Tubing	$0	$1,888	$3,860	$0	$0	$5,749	$488	$287	$1,631	$8,154	$18
12.9	Other I & C Equipment	$3,613	$0	$1,755	$0	$0	$5,368	$505	$268	$921	$7,062	$16
	SUBTOTAL 12.	**$10,265**	**$1,888**	**$6,614**	**$0**	**$0**	**$18,767**	**$1,701**	**$938**	**$3,567**	**$24,973**	**$56**

Exhibit 4-26 Case 2 Total Plant Cost Details (Continued)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 2 TOTAL PLANT COST $	Case 2 TOTAL PLANT COST $/kW
13	Improvements to Site											
13.1	Site Preparation	$0	$102	$2,179	$0	$0	$2,281	$226	$0	$752	$3,259	$7
13.2	Site Improvements	$0	$1,813	$2,409	$0	$0	$4,223	$417	$0	$1,392	$6,031	$14
13.3	Site Facilities	$3,249	$0	$3,429	$0	$0	$6,678	$658	$0	$2,201	$9,537	$22
	SUBTOTAL 13.	**$3,249**	**$1,915**	**$8,017**	**$0**	**$0**	**$13,181**	**$1,301**	**$0**	**$4,345**	**$18,827**	**$43**
14	Buildings & Structures											
14.1	Combustion Turbine Area	$0	$265	$150	$0	$0	$414	$36	$0	$90	$541	$1
14.2	Steam Turbine Building	$0	$2,062	$2,938	$0	$0	$5,000	$460	$0	$819	$6,279	$14
14.3	Administration Building	$0	$833	$605	$0	$0	$1,438	$128	$0	$235	$1,801	$4
14.4	Circulation Water Pumphouse	$0	$140	$74	$0	$0	$215	$19	$0	$35	$269	$1
14.5	Water Treatment Buildings	$0	$343	$335	$0	$0	$678	$61	$0	$111	$850	$2
14.6	Machine Shop	$0	$431	$295	$0	$0	$726	$64	$0	$119	$909	$2
14.7	Warehouse	$0	$696	$449	$0	$0	$1,145	$101	$0	$187	$1,434	$3
14.8	Other Buildings & Structures	$0	$418	$325	$0	$0	$743	$66	$0	$162	$971	$2
14.9	Waste Treating Building & Str.	$0	$903	$1,725	$0	$0	$2,628	$245	$0	$575	$3,448	$8
	SUBTOTAL 14.	**$0**	**$6,091**	**$6,896**	**$0**	**$0**	**$12,987**	**$1,182**	**$0**	**$2,332**	**$16,501**	**$37**
	TOTAL COST	**$763,672**	**$62,661**	**$251,562**	**$0**	**$0**	**$1,077,896**	**$100,149**	**$54,932**	**$199,078**	**$1,432,055**	**$3,234**
	Owner's Costs											
	Preproduction Costs											
	6 Months All Labor										$12,092	$27
	1 Month Maintenance Materials										$2,573	$6
	1 Month Non-fuel Consumables										$164	$0
	1 Month Waste Disposal										$249	$1
	25% of 1 Months Fuel Cost at 100% CF										$469	$1
	2% of TPC										$28,641	$65
	Total										**$44,188**	**$100**
	Inventory Capital											
	60 day supply of fuel and consumables at 100% CF										$4,077	$9
	0.5% of TPC (spare parts)										$7,160	$16
	Total										**$11,238**	**$25**
	Initial Cost for Catalyst and Chemicals										$1,558	$4
	Land										$900	$2
	Other Owner's Costs										$214,808	$485
	Financing Costs										$38,665	$87
	Total Overnight Costs (TOC)										**$1,743,413**	**$3,937.6**
	TASC Multiplier								(IOU, high-risk, 35 year)		1.140	
	Total As-Spent Cost (TASC)										**$1,987,490**	**$4,489**

Exhibit 4-27 Case 2 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (June)	2007
Case 2 - Shell IGCC w/ CO2 capture (1,100 lb/net MWh)					Heat Rate-net(Btu/kWh):	9,581
					MWe-net:	443
					Capacity Factor: (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	34.65	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Skilled Operator	2.0		2.0			
Operator	10.0		10.0			
Foreman	1.0		1.0			
Lab Tech's, etc.	3.0		3.0			
TOTAL-O.J.'s	16.0		16.0			
					Annual Cost	Annual Unit Cost
					$	$/kW-net
Annual Operating Labor Cost	Maintenance labor cost		% of BEC	1.2092	$6,313,507	$14.259
Maintenance Labor Cost	(Case S1B is reference)		BEC	$1,077,896	$13,033,374	$29.437
Administrative & Support Labor					$4,836,720	$10.924
Property Taxes & Insurance					$28,641,102	$64.688
TOTAL FIXED OPERATING COSTS					**$52,824,703.55**	**$119.308**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost			% of BEC	2.2918	**$24,702,887**	**$0.00796**
Consumables	Consumption		Unit	Initial Fill		
	Initial Fill	/Day	Cost	Cost		
Water(/1000 gallons)	0	1,737	1.08	**$0**	**$548,516**	**$0.00018**
Chemicals		5.959				
MU & WT Chem.(lb)	0	10,349	0.17	$0	$522,991	$0.00017
Carbon (Mercury Removal) (lb)	79,200	108	1.05	$83,174	$33,269	$0.00001
COS Catalyst (m3)	0	0.00	2,397.36	$0	$0	$0.00000
Water Gas Shift Catalyst(ft3)	2,957	2.0	498.83	$1,475,043	$294,807	$0.00010
Selexol Solution (gal.)	w/equip.	39	13.40	$0	$153,362	$0.00005
MDEA Solution (gal)	0	0	8.70	$0	$0	$0.00000
Sulfinol Solution (gal)	0	0	10.05	$0	$0	$0.00000
SCR Catalyst (m3)	0	0	0.00	$0	$0	$0.00000
Aqueous Ammonia (ton)	0	0	0.00	$0	$0	$0.00000
Claus Catalyst(ft3)	w/equip.	0.63	131.27	$0	$24,142	$0.00001
Subtotal Chemicals				**$1,558,217**	**$1,028,570**	**$0.00033**
Other						
Supplemental Fuel(MBtu)	0	0	0.00	$0	$0	$0.00000
Gases,N2 etc.(/100scf)	0	0	0.00	$0	$0	$0.00000
L.P. Steam(/1000 pounds)	0	0	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$0**	**$0.00000**
Waste Disposal						
Spent Mercury Catalyst (lb)	0	108	0.42	$0	$13,213	$0.00000
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Slag (ton)	0	502	16.23	$0	$2,376,450	$0.00077
Subtotal-Waste Disposal				**$0**	**$2,389,663**	**$0.00077**
By-products & Emissions						
Sulfur(tons)	0	42	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$1,558,217**	**$28,669,636.71**	**$0.00924**
Fuel(ton)	0	5,944	10.37	**$0**	**$17,994,286**	**$0.00580**

4.1.9 Case 3 – Cost Estimating

Exhibit 4-28 shows the TPC cost details organized by cost account as well as TOC and TASC. Exhibit 4-29 shows the initial and annual O&M costs.

The estimated TOC of the IGCC case with 90 percent carbon capture is $4,595/kW. Owner's costs represent 18 percent of the TOC. The current dollar, 30-year LCOE, including TS&M, is $174.86/MWh.

Exhibit 4-28 Case 3 Total Plant Cost Details

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 3 TOTAL PLANT COST $	Case 3 TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,893	$0	$1,903	$0	$0	$5,796	$519	$0	$1,263	$7,578	$19
1.2	Coal Stackout & Reclaim	$5,031	$0	$1,220	$0	$0	$6,251	$548	$0	$1,360	$8,158	$20
1.3	Coal Conveyors	$4,677	$0	$1,207	$0	$0	$5,884	$517	$0	$1,280	$7,681	$19
1.4	Other Coal Handling	$1,224	$0	$279	$0	$0	$1,503	$132	$0	$327	$1,961	$5
1.5	Sorbent Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.6	Sorbent Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.7	Sorbent Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.8	Other Sorbent Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Coal & Sorbent Hnd.Foundations	$0	$2,755	$6,889	$0	$0	$9,644	$924	$0	$2,114	$12,682	$32
	SUBTOTAL 1.	**$14,825**	**$2,755**	**$11,497**	**$0**	**$0**	**$29,077**	**$2,639**	**$0**	**$6,343**	**$38,060**	**$95**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$44,796	$2,691	$6,527	$0	$0	$54,014	$4,661	$0	$11,735	$70,410	$176
2.2	Prepared Coal Storage & Feed	$2,122	$508	$333	$0	$0	$2,962	$253	$0	$643	$3,859	$10
2.3	Dry Coal Injection System	$69,827	$810	$6,485	$0	$0	$77,122	$6,642	$0	$16,753	$100,518	$251
2.4	Misc.Coal Prep & Feed	$1,167	$849	$2,546	$0	$0	$4,561	$419	$0	$996	$5,977	$15
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$4,535	$3,723	$0	$0	$8,258	$765	$0	$1,805	$10,828	$27
	SUBTOTAL 2.	**$117,911**	**$9,393**	**$19,614**	**$0**	**$0**	**$146,918**	**$12,741**	**$0**	**$31,932**	**$191,591**	**$478**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$2,165	$3,719	$1,963	$0	$0	$7,847	$727	$0	$1,715	$10,289	$26
3.2	Water Makeup & Pretreating	$462	$48	$258	$0	$0	$768	$73	$0	$252	$1,093	$3
3.3	Other Feedwater Subsystems	$1,185	$400	$360	$0	$0	$1,945	$175	$0	$424	$2,544	$6
3.4	Service Water Systems	$264	$544	$1,888	$0	$0	$2,695	$263	$0	$888	$3,846	$10
3.5	Other Boiler Plant Systems	$1,417	$549	$1,361	$0	$0	$3,328	$316	$0	$729	$4,372	$11
3.6	FO Supply Sys & Nat Gas	$292	$551	$514	$0	$0	$1,357	$131	$0	$298	$1,785	$4
3.7	Waste Treatment Equipment	$645	$0	$394	$0	$0	$1,039	$101	$0	$342	$1,482	$4
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$1,003	$134	$515	$0	$0	$1,652	$160	$0	$543	$2,355	$6
	SUBTOTAL 3.	**$7,433**	**$5,946**	**$7,252**	**$0**	**$0**	**$20,631**	**$1,945**	**$0**	**$5,190**	**$27,766**	**$69**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$117,054	$0	$50,159	$0	$0	$167,213	$14,932	$23,119	$31,506	$236,770	$590
4.2	Syngas Cooling (w/4.1)	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$166,026	$0	w/equip.	$0	$0	$166,026	$16,093	$0	$18,212	$200,331	$499
4.4	LT Heat Recovery & FG Saturation	$26,799	$0	$10,188	$0	$0	$36,987	$3,610	$0	$8,119	$48,716	$121
4.5	Misc. Gasification Equipment w/4.1 & 4.2	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Other Gasification Equipment	$0	$1,029	$419	$0	$0	$1,447	$139	$0	$317	$1,903	$5
4.8	Major Component Rigging	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Gasification Foundations	$0	$8,392	$4,789	$0	$0	$13,181	$1,207	$0	$3,597	$17,984	$45
	SUBTOTAL 4.	**$309,879**	**$9,421**	**$65,554**	**$0**	**$0**	**$384,854**	**$35,980**	**$23,119**	**$61,751**	**$505,705**	**$1,261**

Exhibit 4-28 Case 3 Total Plant Cost Details (Continued)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 3 TOTAL PLANT COST $	Case 3 TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	Sulfinol/Selexol System	$69,149	$0	$59,269	$0	$0	$128,418	$12,421	$25,684	$33,304	$199,826	$498
5A.2	Elemental Sulfur Plant	$4,695	$936	$6,057	$0	$0	$11,688	$1,135	$0	$2,565	$15,388	$38
5A.3	Mercury Removal	$2,145	$0	$1,633	$0	$0	$3,778	$365	$189	$866	$5,198	$13
5A.4	COS Hydrolysis/WGS Reactors	$7,705	$0	$3,101	$0	$0	$10,806	$1,036	$0	$2,368	$14,210	$35
5A.5	Particulate Removal	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
5A.5	Blowback Gas Systems	$1,874	$315	$178	$0	$0	$2,367	$225	$0	$518	$3,110	$8
5A.6	Fuel Gas Piping	$0	$735	$515	$0	$0	$1,249	$116	$0	$273	$1,638	$4
5A.9	HGCU Foundations	$0	$732	$472	$0	$0	$1,205	$111	$0	$395	$1,710	$4
	SUBTOTAL 5A.	**$85,568**	**$2,718**	**$71,224**	**$0**	**$0**	**$159,511**	**$15,408**	**$25,872**	**$40,290**	**$241,081**	**$601**
5B	CO2 REMOVAL & COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$16,187	$0	$9,381	$0	$0	$25,568	$2,461	$0	$5,606	$33,635	$84
	SUBTOTAL 5B.	**$16,187**	**$0**	**$9,381**	**$0**	**$0**	**$25,568**	**$2,461**	**$0**	**$5,606**	**$33,635**	**$84**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$93,866	$0	$6,583	$0	$0	$100,449	$9,522	$10,045	$12,002	$132,017	$329
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$806	$892	$0	$0	$1,699	$159	$0	$557	$2,415	$6
	SUBTOTAL 6.	**$93,866**	**$806**	**$7,475**	**$0**	**$0**	**$102,147**	**$9,681**	**$10,045**	**$12,559**	**$134,432**	**$335**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$28,950	$0	$4,116	$0	$0	$33,067	$3,144	$0	$3,621	$39,832	$99
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,814	$1,327	$0	$0	$3,142	$276	$0	$684	$4,101	$10
7.4	Stack	$3,540	$0	$1,330	$0	$0	$4,869	$467	$0	$534	$5,869	$15
7.9	HRSG,Duct & Stack Foundations	$0	$709	$681	$0	$0	$1,390	$129	$0	$456	$1,976	$5
	SUBTOTAL 7.	**$32,490**	**$2,524**	**$7,455**	**$0**	**$0**	**$42,468**	**$4,016**	**$0**	**$5,294**	**$51,778**	**$129**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$22,586	$0	$3,783	$0	$0	$26,369	$2,530	$0	$2,890	$31,789	$79
8.2	Turbine Plant Auxiliaries	$155	$0	$355	$0	$0	$511	$50	$0	$56	$617	$2
8.3a	Condenser & Auxiliaries	$2,513	$0	$803	$0	$0	$3,315	$317	$0	$363	$3,996	$10
8.3b	Air Cooled Condenser	$23,035	$0	$4,618	$0	$0	$27,654	$2,765	$0	$6,084	$36,503	$91
8.4	Steam Piping	$3,975	$0	$2,796	$0	$0	$6,772	$582	$0	$1,838	$9,192	$23
8.9	TG Foundations	$0	$769	$1,300	$0	$0	$2,069	$196	$0	$680	$2,945	$7
	SUBTOTAL 8.	**$52,264**	**$769**	**$13,656**	**$0**	**$0**	**$66,690**	**$6,440**	**$0**	**$11,911**	**$85,041**	**$212**

Exhibit 4-28 Case 3 Total Plant Cost Details (Continued)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 3 TOTAL PLANT COST $	Case 3 TOTAL PLANT COST $/kW
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$4,616	$0	$840	$0	$0	$5,456	$520	$0	$896	$6,872	$17
9.2	Circulating Water Pumps	$1,206	$0	$80	$0	$0	$1,286	$108	$0	$209	$1,603	$4
9.3	Circ.Water System Auxiliaries	$107	$0	$15	$0	$0	$123	$12	$0	$20	$154	$0
9.4	Circ.Water Piping	$0	$4,527	$1,174	$0	$0	$5,701	$515	$0	$1,243	$7,459	$19
9.5	Make-up Water System	$278	$0	$398	$0	$0	$676	$65	$0	$148	$890	$2
9.6	Component Cooling Water Sys	$534	$639	$455	$0	$0	$1,628	$152	$0	$356	$2,137	$5
9.9	Circ.Water System Foundations& Structures	$0	$1,714	$2,913	$0	$0	$4,627	$439	$0	$1,520	$6,586	$16
	SUBTOTAL 9.	**$6,743**	**$6,880**	**$5,875**	**$0**	**$0**	**$19,497**	**$1,811**	**$0**	**$4,393**	**$25,701**	**$64**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$15,485	$0	$7,636	$0	$0	$23,122	$2,222	$0	$2,534	$27,877	$69
10.2	Gasifier Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Rrecovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$525	$0	$572	$0	$0	$1,097	$106	$0	$180	$1,384	$3
10.7	Ash Transport & Feed Equipment	$705	$0	$170	$0	$0	$875	$82	$0	$143	$1,099	$3
10.8	Misc. Ash Handling Equipment	$1,088	$1,333	$398	$0	$0	$2,820	$268	$0	$463	$3,551	$9
10.9	Ash/Spent Sorbent Foundation	$0	$46	$58	$0	$0	$105	$10	$0	$34	$149	$0
	SUBTOTAL 10.	**$17,803**	**$1,380**	**$8,835**	**$0**	**$0**	**$28,017**	**$2,688**	**$0**	**$3,356**	**$34,061**	**$85**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$820	$0	$811	$0	$0	$1,631	$156	$0	$179	$1,966	$5
11.2	Station Service Equipment	$4,462	$0	$402	$0	$0	$4,864	$448	$0	$531	$5,844	$15
11.3	Switchgear & Motor Control	$8,249	$0	$1,500	$0	$0	$9,749	$904	$0	$1,598	$12,251	$31
11.4	Conduit & Cable Tray	$0	$3,832	$12,641	$0	$0	$16,473	$1,593	$0	$4,517	$22,583	$56
11.5	Wire & Cable	$0	$7,321	$4,811	$0	$0	$12,132	$881	$0	$3,253	$16,267	$41
11.6	Protective Equipment	$0	$655	$2,385	$0	$0	$3,041	$297	$0	$501	$3,838	$10
11.7	Standby Equipment	$208	$0	$203	$0	$0	$410	$39	$0	$67	$517	$1
11.8	Main Power Transformers	$15,134	$0	$122	$0	$0	$15,256	$1,154	$0	$2,461	$18,871	$47
11.9	Electrical Foundations	$0	$132	$345	$0	$0	$477	$46	$0	$157	$679	$2
	SUBTOTAL 11.	**$28,872**	**$11,940**	**$23,220**	**$0**	**$0**	**$64,033**	**$5,518**	**$0**	**$13,264**	**$82,816**	**$206**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$1,039	$0	$694	$0	$0	$1,733	$164	$87	$297	$2,281	$6
12.5	Signal Processing Equipment	W/12.7	$0	W/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$239	$0	$153	$0	$0	$392	$37	$20	$90	$538	$1
12.7	Computer & Accessories	$5,542	$0	$177	$0	$0	$5,719	$525	$286	$653	$7,183	$18
12.8	Instrument Wiring & Tubing	$0	$1,936	$3,958	$0	$0	$5,894	$500	$295	$1,672	$8,361	$21
12.9	Other I & C Equipment	$3,705	$0	$1,799	$0	$0	$5,503	$518	$275	$944	$7,241	$18
	SUBTOTAL 12.	**$10,524**	**$1,936**	**$6,781**	**$0**	**$0**	**$19,241**	**$1,744**	**$962**	**$3,657**	**$25,604**	**$64**

Exhibit 4-28 Case 3 Total Plant Cost Details (Continued)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 3 TOTAL PLANT COST $	Case 3 TOTAL PLANT COST $/kW
13	Improvements to Site											
13.1	Site Preparation	$0	$102	$2,188	$0	$0	$2,290	$227	$0	$755	$3,273	$8
13.2	Site Improvements	$0	$1,821	$2,419	$0	$0	$4,240	$418	$0	$1,397	$6,056	$15
13.3	Site Facilities	$3,262	$0	$3,442	$0	$0	$6,705	$661	$0	$2,210	$9,576	$24
	SUBTOTAL 13.	**$3,262**	**$1,923**	**$8,049**	**$0**	**$0**	**$13,235**	**$1,307**	**$0**	**$4,362**	**$18,904**	**$47**
14	Buildings & Structures											
14.1	Combustion Turbine Area	$0	$265	$150	$0	$0	$414	$36	$0	$90	$541	$1
14.2	Steam Turbine Building	$0	$2,081	$2,964	$0	$0	$5,045	$464	$0	$826	$6,335	$16
14.3	Administration Building	$0	$838	$608	$0	$0	$1,446	$129	$0	$236	$1,811	$5
14.4	Circulation Water Pumphouse	$0	$149	$79	$0	$0	$228	$20	$0	$37	$285	$1
14.5	Water Treatment Buildings	$0	$412	$402	$0	$0	$814	$74	$0	$133	$1,021	$3
14.6	Machine Shop	$0	$432	$295	$0	$0	$727	$65	$0	$119	$910	$2
14.7	Warehouse	$0	$697	$450	$0	$0	$1,147	$102	$0	$187	$1,435	$4
14.8	Other Buildings & Structures	$0	$418	$326	$0	$0	$744	$66	$0	$162	$972	$2
14.9	Waste Treating Building & Str.	$0	$924	$1,766	$0	$0	$2,690	$251	$0	$588	$3,529	$9
	SUBTOTAL 14.	**$0**	**$6,215**	**$7,039**	**$0**	**$0**	**$13,254**	**$1,206**	**$0**	**$2,379**	**$16,839**	**$42**
	TOTAL COST	**$797,628**	**$64,606**	**$272,908**	**$0**	**$0**	**$1,135,142**	**$105,586**	**$59,999**	**$212,287**	**$1,513,013**	**$3,772**
	Owner's Costs											
	Preproduction Costs											
	6 Months All Labor										$12,524	$31
	1 Month Maintenance Materials										$2,710	$7
	1 Month Non-fuel Consumables										$247	$1
	1 Month Waste Disposal										$260	$1
	25% of 1 Months Fuel Cost at 100% CF										$489	$1
	2% of TPC										$30,260	$75
	Total										**$46,491**	**$116**
	Inventory Capital											
	60 day supply of fuel and consumables at 100% CF										$4,410	$11
	0.5% of TPC (spare parts)										$7,565	$19
	Total										**$11,975**	**$30**
	Initial Cost for Catalyst and Chemicals										$3,123	$8
	Land										$900	$2
	Other Owner's Costs										$226,952	$566
	Financing Costs										$40,851	$102
	Total Overnight Costs (TOC)										**$1,843,305**	**$4,595**
	TASC Multiplier								(IOU, high-risk, 35 year)		1.140	
	Total As-Spent Cost (TASC)										**$2,101,368**	**$5,238**

Exhibit 4-29 Case 3 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES						Cost Base (June)	2007
Case 3 - Shell IGCC w/ 90% CO2 capture						Heat Rate-net(Btu/kWh):	11,045
						MWe-net:	401
						Capacity Factor: (%):	80
OPERATING & MAINTENANCE LABOR							
Operating Labor							
Operating Labor Rate(base):		34.65	$/hour				
Operating Labor Burden:		30.00	% of base				
Labor O-H Charge Rate:		25.00	% of labor				
				Total			
Skilled Operator		2.0		2.0			
Operator		10.0		10.0			
Foreman		1.0		1.0			
Lab Tech's, etc.		3.0		3.0			
TOTAL-O.J.'s		16.0		16.0			
						Annual Cost	Annual Unit Cost
						$	$/kW-net
Annual Operating Labor Cost		Maintenance labor cost		% of BEC	1.2092	$6,313,507	$15.739
Maintenance Labor Cost		(Case S1B is reference)		BEC	$1,135,142	$13,725,566	$34.216
Administrative & Support Labor						$5,009,768	$12.489
Property Taxes & Insurance						$30,260,266	$68.345
TOTAL FIXED OPERATING COSTS						**$55,309,108.00**	**$130.789**
VARIABLE OPERATING COSTS							
							$/kWh-net
Maintenance Material Cost				% of BEC	2.2918	**$26,014,838**	**$0.00925**
Consumables		Consumption		Unit	Initial Fill		
		Initial Fill	/Day	Cost	Cost		
Water(/1000 gallons)		0	2,249	1.08	**$0**	**$710,433**	**$0.00025**
Chemicals			5.959				
MU & WT Chem.(lb)		0	13,404	0.17	$0	$677,373	$0.00024
Carbon (Mercury Removal) (lb)		103,110	141	1.05	$108,283	$43,313	$0.00002
COS Catalyst (m3)		0	0.00	2,397.36	$0	$0	$0.00000
Water Gas Shift Catalyst(ft3)		6,043.0	4.1	498.83	$3,014,436	$602,474	$0.00021
Selexol Solution (gal.)		w/equip.	80	13.40	$0	$313,765	$0.00011
MDEA Solution (gal)		0	0	8.70	$0	$0	$0.00000
Sulfinol Solution (gal)		0	0	10.05	$0	$0	$0.00000
SCR Catalyst (m3)		0	0	0.00	$0	$0	$0.00000
Aqueous Ammonia (ton)		0	0	0.00	$0	$0	$0.00000
Claus Catalyst(ft3)		w/equip.	0.68	131.27	$0	$26,163	$0.00001
Subtotal Chemicals					**$3,122,719**	**$1,663,089**	**$0.00059**
Other							
Supplemental Fuel(MBtu)		0	0	0.00	$0	$0	$0.00000
Gases,N2 etc.(/100scf)		0	0	0.00	$0	$0	$0.00000
L.P. Steam(/1000 pounds)		0	0	0.00	$0	$0	$0.00000
Subtotal Other					**$0**	**$0**	**$0.00000**
Waste Disposal							
Spent Mercury Catalyst (lb)		0	141	0.42	$0	$17,202	$0.00001
Flyash (ton)		0	0	0.00	$0	$0	$0.00000
Slag (ton)		0	523	16.23	$0	$2,478,785	$0.00088
Subtotal-Waste Disposal					**$0**	**$2,495,987**	**$0.00089**
By-products & Emissions							
Sulfur(tons)		0	45	0.00	$0	$0	$0.00000
Subtotal By-Products					**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS					**$3,122,719**	**$30,884,347.39**	**$0.01099**
Fuel(ton)		0	6,208	10.37	**$0**	**$18,793,494**	**$0.00669**

5. PULVERIZED COAL RANKINE CYCLE PLANTS

Six pulverized coal-fired Rankine cycle power plant configurations were evaluated and the results are presented in Sections 6 and 7 of this report. Cases 4 through 6 are based on greeenfield sites, and assume supercritical steam conditions. Case 7 is based on an existing subcritical PC unit, and Cases 8 and 9 are a retrofit of the existing subcritical PC plant.

The greenfield supercritical PC Cases 4 through 6 are evaluated with and without carbon capture on a common 550 MWe net basis. The designs that include carbon capture have a larger gross unit size to compensate for the higher auxiliary loads. The constant net output sizing basis is selected because it provides for a meaningful side-by-side comparison of the results. The boiler and steam turbine industry ability to match unit size to a custom specification has been commercially demonstrated enabling common net output comparison of the greenfield PC cases in this study. As discussed in Section 3, this was not possible in the IGCC cases because of the fixed output from the combustion turbine.

The subcritical PC retrofit Cases 7 through 9 are evaluated with and without carbon capture. Current performance parameters were taken from two sources, the NETL Coal Plant Database and a recent study performed by CH2MHill [8,55]. The initial Aspen model used the coal composition currently burned at Unit 4. Once performance parameters like coal feed rate, net plant heat rate, net stack output, and stack exit temperature were matched as closely as possible, the coal composition was changed to Montana Rosebud PRB coal and the results represent the baseline performance without CO_2 capture. This established a common 250,000 kg/hr (650,360 lb/hr) basis for coal feed rate for Cases 7 through 9.

Steam conditions for the Rankine cycle Cases 4 through 6 were selected to be consistent with supercritical steam conditions used in previous systems analysis studies [56]. For Cases 7 through 9 the steam cycle conditions were matched according to typical subcritical steam plant operation:

- For supercritical cases (4 - 6) – 24.1 MPa/593°C/593°C (3500 psig/1100°F/1100°F)
- For subcritical cycle cases (7 - 9) – 16.5 MPa/538°C/538°C (2400 psig/1000°F/1000°F)

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

5.1 PC COMMON PROCESS AREAS

The PC cases have process areas which are common to each plant configuration such as coal receiving and storage, emissions control technologies and power generation. 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.

5.1.1 Coal and Sorbent Receiving and Storage

The function of the coal portion of the Coal and Sorbent Receiving and Storage system for PC plants is identical to the IGCC facilities. It is to provide the equipment required for conveying, preparing, and storing the fuel delivered to the plant. The scope of the system is from the minemouth up to the coal storage silos. The system is designed to support short-term operation at the 5 percent over pressure/valves wide open (OP/VWO) condition (16 hours) and long-term operation of 90 days or more at the maximum continuous rating (MCR).

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

Operation Description - The coal is delivered to the site in the same manner as the IGCC cases. The 8 cm x 0 (3" x 0) coal from the minemouth is discharged onto a belt conveyor. Two conveyors with an intermediate transfer tower are assumed to convey the coal to the coal stacker, which transfer the coal to either the long-term storage pile or to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron and then to the reclaim pile.

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

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

5.1.2 Steam Generator and Ancillaries

The steam generator for the subcritical PC plants is a tangentially fired, totally enclosed dry bottom furnace, with superheater, reheater, economizer and air-heater.

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

It is assumed for the purposes of this study that the greenfield power plants are designed to be operated as a base-loaded unit but with some consideration for daily or weekly cycling, as can be cost effectively included in the base design.

The combustion systems for both subcritical and supercritical steam conditions are equipped with LNBs and OFA. In the subcritical CO_2 capture cases, the existing subcritical PC LNBs are replaced with state-of-the-art LNBs to reduce NOx emissions below the current performance. It is assumed for the purposes of this study that the power plant is designed for operation as a base-load unit.

Scope

The steam generator comprises the following for both subcritical and supercritical PCs (this is standard equipment and assumed applicable to the existing subcritical PC plant.):

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

The steam generator description for the subcritical case is for a generic unit, but it is assumed that the description would apply to the existing subcritical PC plant. The supercritical PC description is also for a generic greenfield application.

Feedwater and Steam

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

The steam then exits the steam generator en route to the 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 supercritical PC cases, feedwater 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.

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 pulverized coal to the burners is supplied by the PA fans. This air is heated in the Ljungstrom type air preheaters to permit drying of the pulverized coal, 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 pulverized coal and air mixture flows to the coal nozzles at various elevations of the furnace. The hot combustion products rise to the top of the boiler and pass through the superheater and reheater sections. The gases then pass through the economizer and air preheater. The gases exit the steam generator at this point and flow to the SCR reactor (SC PC cases only), fabric filter (or ESP in the existing subcritical PC plant cases), ID fan, FGD system, and stack.

Fuel Feed

The crushed Montana Rosebud PRB coal is fed through feeders to each of the mills (pulverizers), where its size is reduced to approximately 72% passing 200 mesh and less than 0.5% remaining on 50 mesh [57]. The pulverized coal 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.

Ash Removal

The furnace bottom comprises several hoppers, with a clinker grinder under each hopper. The hoppers are of welded steel construction, lined with refractory. The hopper design incorporates a water filled seal trough around the upper periphery for cooling and sealing. Water and ash discharged from the hopper pass through the clinker grinder to an ash sluice system for conveyance to hydrobins, where the ash is dewatered before it is transferred to trucks for offsite disposal. The description of the balance of the bottom ash handling system is presented in Section 5.1.9. The steam generator incorporates fly ash hoppers under the economizer outlet and air heater outlet.

Burners

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

The existing subcritical PC plant is a tangentially fired unit with older-vintage LNBs.

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

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.

Soot Blowers

The soot-blowing system utilizes an array of 50 to 150 retractable nozzles and lances that clean the furnace walls and convection surfaces with jets of high-pressure 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.

5.1.3 NO_x Control System

NOx Operation Performance (Greenfield SC PC)

The plant is designed to achieve the environmental target of 0.07 lb NOx/MMBtu. Two measures are taken to reduce the NOx. The first is a combination of low-NOx burners and the introduction of staged overfire air in the boiler. The low-NOx burners and overfire air reduce the emissions to about 0.2 lb/MMBtu.

The second measure taken to reduce the NOx emissions is the installation of an SCR system prior to the air heater. SCR uses ammonia and a catalyst to reduce NOx to N_2 and H_2O. The SCR system consists of three subsystems: reactor vessel, ammonia storage and injection, and gas flow control. The SCR system is designed for 65 percent reduction with 2 ppmv ammonia slip at the end of the catalyst life. This, along with the low-NOx burners, achieves the emission limit of 0.07 lb/MMBtu.

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

SCR Operation Description

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

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

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

NOx Operation Performance (Existing Subcritical PC)

The existing subcritical PC plant uses overfire air with a non-optimal configuration of low NOx burners for NOx control with emissions of 0.45 lb/MMBtu. This is the assumed performance for Case 7. Because the Econamine process requires low concentrations of NO_2 as well as SO_2, Cases 8 and 9 include new, reconfigured low NOx burners in addition to the overfire air to reduce NOx emissions to 0.24 lb/MMBtu.

In the event that NSR standards become applicable, an economic sensitivity case was performed with SCR retrofitted downstream of the LNBs in Cases 8 and 9. The projected NOx emissions with SCR are 0.07 lb/MMBtu.

5.1.4 Particulate Control

Greenfield SC PC

The fabric filter (or baghouse), for supercritical Cases 4 through 6, consists of two separate single-stage, in-line, multi-compartment units. Each unit is of high (0.9-1.5 m/min [3-5 ft/min]) air-to-cloth ratio design with a pulse-jet on-line cleaning system. The ash is collected on the outside of the bags, which are supported by steel cages. The dust cake is removed by a pulse of compressed air. The bag material is polyphenylensulfide (PPS) with intrinsic Teflon (PTFE) coating [58]. The bags are rated for a continuous temperature of 180°C (356°F) and a peak temperature of 210°C (410°F). Each compartment contains a number of gas passages with filter bags, and heated ash hoppers supported by a rigid steel casing. The fabric filter is provided with necessary control devices, inlet gas distribution devices, insulators, inlet and outlet nozzles, expansion joints, and other items as required.

Existing Subcritical PC Plant

The electrostatic precipitator (ESP), for subcritical Cases 7 through 9, consists of a hopper-bottomed, fully enclosed casing containing rows of vertical plates forming passages through which the flue gas flows horizontally. Centrally located in each passage are emitting electrodes energized with high-voltage, negative-polarity direct current. The applied voltage is of sufficient strength to ionize gas molecules close to the electrodes, resulting in a visible corona. When passing the flue gas, the charged ions collide with, and attach themselves to, fly ash particles suspended in the gas. The electric field forces the charged particles out of the gas stream toward the grounded plates, and here they collect and layer. The plates are periodically cleaned by a rapping system to release the layer into ash hoppers as an agglomerated mass. The ESP is located after the air heater and is referred to as a cold-side ESP.

5.1.5 Mercury Removal

Mercury removal is based on a coal Hg content of 0.081 ppmd. The basis for the coal Hg concentration was discussed in Section 2.2. The combination of pollution control technologies used in the PC plants, SCR, fabric filters, ESP, and FGD result in some co-benefit capture of mercury. The SCR promotes the oxidation of elemental mercury, which in turn enhances the mercury removal capability of the fabric filter and FGD unit. The mercury co-benefit capture for SC PC Cases 4 through 6 is assumed to be 15 percent for this combination of control technologies. Activated carbon injection is used to remove an additional 90 percent of the Hg at a carbon injection rate of 1 lb/MMscf. For Cases 7 through 9 mercury co-benefit capture is assumed to be 16 percent with wet FGD and a cold-side ESP.

5.1.6 Flue Gas Desulfurization

Greenfield SC PC

The FGD process uses a lime-based spray dryer system. 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 prior to entering the Carbon Dioxide Removal (CDR) facility. Sulfur removal efficiency is 93 percent in the FGD unit for all cases. The CDR unit includes a polishing scrubber to reduce the flue gas SO_2 concentration from about 55 ppmv at the FGD exit to the required 10 ppmv prior to the CDR absorber. The scope of the FGD system is from the outlet of the combustion air preheater to the ID fan.

A lime-based spray dryer absorber is a dry scrubbing process that is generally used for low-sulfur coal [59]. Flue gas is treated in an absorber by mixing the gas stream concurrently with atomized lime slurry droplets. The lime slurry is atomized through rotary cup spray atomizers or through dual fluid nozzles. Water in the spray droplets evaporates, cooling the gas from the inlet temperature of 300°F or higher to 160°F to 180°F. The final temperature is maintained at approximately 30ºF above the flue gas saturation temperature by regulating the quantity of the slurry water. The droplets absorb SO_2 from the gas and react the SO_2 with the lime in the slurry. The desulfurized flue gas, along with reaction products, unreacted lime, and the fly ash pass out of the dry scrubber to the baghouse. Sorbent utilization is increased by about 40 percent by slurrying and recycling a portion of the solid effluent collected in the baghouse into the absorber with the fresh lime slurry.

The system description is divided into three sections:

- Lime Handling and Reagent Preparation
- SO_2 Removal
- Baghouse

Reagent Handling and Preparation

Lime is received by truck and conveyed to storage. Lime is stored in a 14-day capacity bulk storage lime silo. The lime is pneumatically conveyed to a 16-hour capacity day bin. The lime day bin and a gravimetric feeder supply the lime to a 150 percent slaking system. This will allow two shift operations for the unit operating continuously at 100 percent load. A conventional lime slaker with high-efficiency grit removal and lime recovery system is used. Two 100 percent capacity slurry transfer pumps are used to provide high reliability to transfer the slurry to the slurry tank. The process makeup water is added to the slaker to produce 20 percent solids slurry. The slurry is diluted on line, if required, prior to injection into an absorber. The slurry is fed to the absorber by a dedicated reagent feed pump (100 percent spare capacity provided).

SO_2 Removal

Two absorbers, each treating 50 percent of the flue gas, are provided to achieve 93 percent SO_2 removal efficiency in the absorber and baghouse. The absorber is a vertical, open chamber with concurrent contact between the flue gas and lime slurry. The slurry is injected into the tower at the top using a rotary atomizer. The hopper in the bottom of the carbon steel absorber also removes large particles that may drop in the absorber. The absorber will be operated at 30°F adiabatic approach to saturation temperature. In the past, a lower approach had been proposed. However, over the years, operational problems associated with the lower adiabatic approach to saturation temperature, due to wetting of the walls and large deposits in the absorber, were alleviated by designs with 30°F adiabatic approach to saturation temperature.

Existing Subcritical PC Plant

The current FGD system configuration is a wet sodium carbonate-based forced oxidation positive pressure absorber with a bypass used to reheat the flue gas. The retrofit cases (Cases 8 and 9) will have no bypass and a modification to the stack to handle wet operation. The function of the FGD system is to scrub the boiler exhaust gases to remove the SO_2 prior to release to the environment, or entering into the Carbon Dioxide Removal (CDR) facility. SO_2 removal efficiency is 85 percent in the existing plant (Case 7) and 93 percent for the retrofit cases with a modifidied wet FGD (Cases 8 and 9). For Cases 8 and 9 with CO_2 capture, the SO_2 content of the scrubbed gases must be further reduced to approximately 10 ppmv to minimize formation of amine heat stable salts during the CO_2 absorption process. The CDR unit includes a polishing scrubber to reduce the flue gas SO_2 concentration from about 38 ppmv at the FGD exit to the required 10 ppmv prior to the CDR absorber. The scope of the FGD system is from the outlet of the ID fans to the stack inlet (Case 7) or to the CDR process inlet (Cases 8 and 9).

Sodium sulfate is produced by the injection of oxygen into the sodium carbonate in the absorber tower sump. The bleed from the absorber contains approximately 20 wt% sodium sulfate. 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 to 50 wt% solids. The second function of the primary hydrocyclone is to perform a $NaCO_3$ and $NaSO_4 \bullet 2H_2O$ separation. This process ensures a sodium carbonate stoichiometry in the absorber vessel of 1.10 and an overall limestone stoichiometry of 1.05. This system reduces the overall operating cost of the FGD system. The underflow from the hydrocyclone flows into the filter feed tank, from which it is pumped to a horizontal belt vacuum filter. Two 100 percent filter systems are provided for redundant capacity.

5.1.7 Carbon Dioxide Recovery Facility

A Carbon Dioxide Recovery (CDR) facility is used in Cases 5, 6, 8 and 9 to remove the specified amount of the CO_2 in the flue gas exiting the FGD unit, purify it, and compress it to a supercritical condition. In Cases 8 and 9 the flue gas exiting the FGD unit contains about 1 percent more CO_2 than the raw flue gas because of the CO_2 liberated by the sodium carbonate in the FGD absorber vessel. The CDR is comprised of the flue gas supply, a bypass system, SO_2 polishing, CO_2 absorption, solvent stripping and reclaiming, and CO_2 compression and drying.

The CO_2 absorption/stripping/solvent reclaim process for Cases 5, 6, 8 and 9 is based on the Fluor Econamine FG Plus technology [60]. A typical flowsheet is shown in Exhibit 5-1. The Econamine FG Plus process uses a formulation of monoethanolamine (MEA) and a proprietary inhibitor to recover CO_2 from the flue gas. This process is designed to recover high-purity CO_2 from low-pressure streams that contain oxygen, such as flue gas from coal-fired power plants, gas turbine exhaust gas, and other waste gases. The Econamine process used in this study differs from previous studies, including the 2004 IEA study [60], in the following ways:

- The complexity of the control and operation of the plant is significantly decreased
- Solvent consumption is decreased
- Hard to dispose waste from the plant is eliminated

The above are achieved at the expense of a slightly higher steam requirement in the stripper (3,556 kJ/kg [1,530 Btu/lb] versus 3,242 kJ/kg [1,395 Btu/lb] used in the IEA study) [61].

SO_2 Polishing and Flue Gas Cooling and Supply

To prevent the accumulation of heat stable salts, the incoming flue gas must have an SO_2 concentration of 10 ppmv or less. The gas exiting the FGD system passes through an SO_2 polishing step to achieve this objective. The polishing step consists of a non-plugging, low-differential-pressure, spray-baffle-type scrubber using a 20 wt% solution of sodium hydroxide (NaOH). A removal efficiency of about 82 percent (Cases 5 and 6) or 74 percent (Cases 8 and 9) is necessary to reduce SO_2 emissions from the FGD outlet to 10 ppmv as required by the Econamine process. The polishing scrubber proposed for this application has been demonstrated in numerous industrial applications throughout the world and can achieve removal efficiencies of over 95 percent if necessary.

The polishing scrubber also serves as the flue gas cooling system. Cooling water from the PC plant is used to reduce the temperature and hence moisture content of the saturated flue gas exiting the FGD system. Flue gas is cooled beyond the CO_2 absorption process requirements to 32°C (90°F) to account for the subsequent flue gas temperature increase of about 17°C (30°F) in the flue gas blower. Downstream from the Polishing Scrubber flue gas pressure is boosted in the Flue Gas Blowers by approximately 0.014 MPa (2 psi) to overcome pressure drop in the CO_2 absorber tower.

Circulating Water System

Cooling water is provided from the PC plant circulating water system and returned to the PC plant cooling tower. The CDR facility requires a significant amount of cooling water for flue gas cooling, water wash cooling, absorber intercooling, reflux condenser duty, reclaimer cooling, the lean solvent cooler, and CO_2 compression interstage cooling. The cooling water requirements for the plants with a CDR facility in the four PC capture cases range from 946,361-1,705,500 lpm (250,000-450,000 gpm), which exceeds the PC plant cooling water requirement of 340,690-681,380 lpm (90,000-180,000 gpm)

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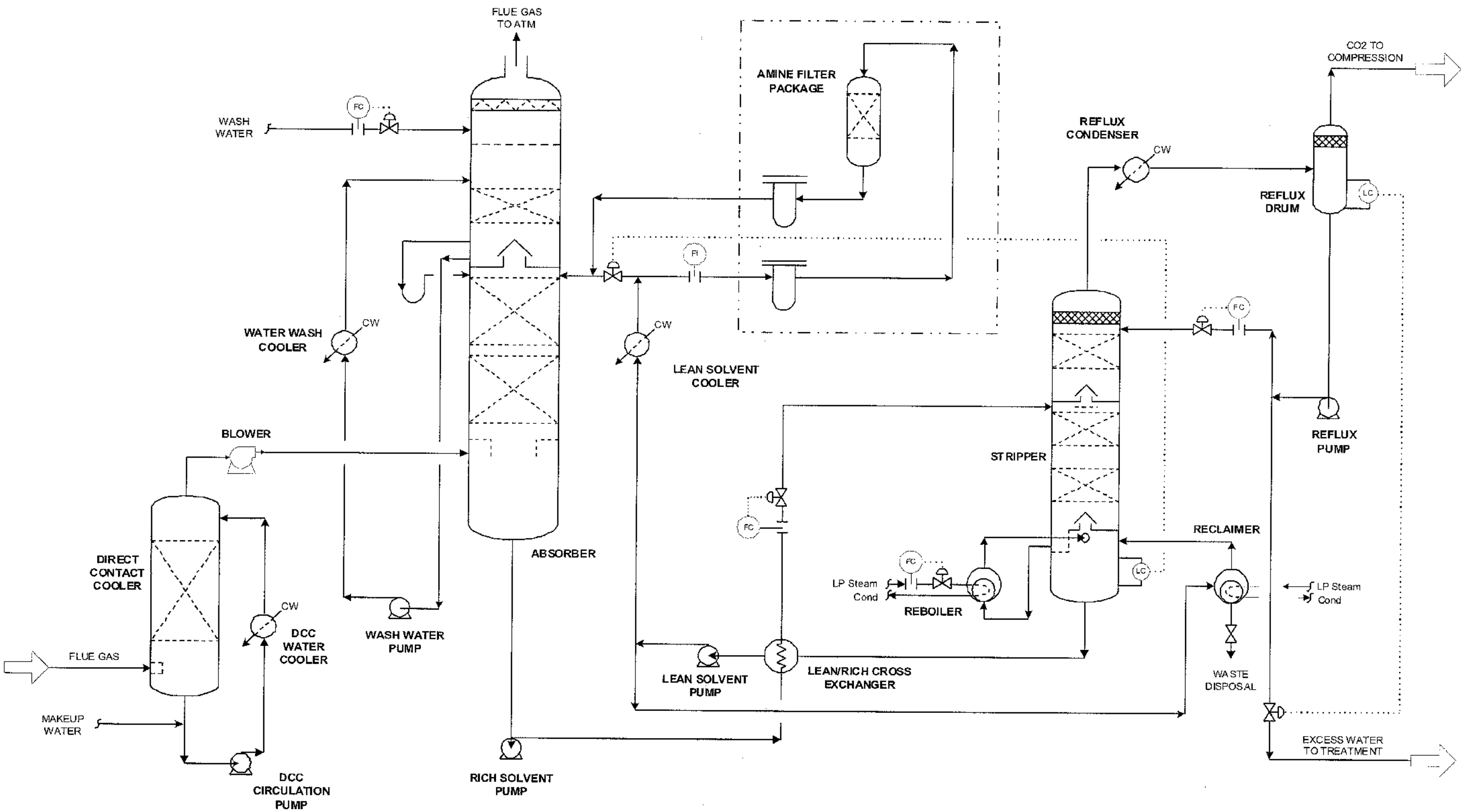
Exhibit 5-1 Fluor Econamine FG Plus Typical Flow Diagram



CO_2 Absorption

The cooled flue gas enters the bottom of the CO_2 Absorber and flows up through the tower countercurrent to a stream of lean MEA-based solvent (Econamine FG Plus). Approximately 90 percent of the CO_2 in the feed gas is absorbed into the lean solvent, and the rest leaves the top of the absorber section and flows into the water wash section of the tower. The lean solvent enters the top of the absorber, absorbs the CO_2 from the flue gases and leaves the bottom of the absorber with the absorbed CO_2.

Water Wash Section

The purpose of the Water Wash section is to minimize solvent losses due to mechanical entrainment and evaporation. The flue gas from the top of the CO_2 Absorption section is contacted with a re-circulating stream of water for the removal of most of the lean solvent. The scrubbed gases, along with unrecovered solvent, exit the top of the wash section for discharge to the atmosphere via the vent stack. The water stream from the bottom of the wash section is collected on a chimney tray. A portion of the water collected on the chimney tray spills over to the absorber section as water makeup for the amine with the remainder pumped via the Wash Water Pump and cooled by the Wash Water Cooler, and recirculated to the top of the CO_2 Absorber. The wash water level is maintained by water makeup from the Wash Water Makeup Pump.

Rich/Lean Amine Heat Exchange System

The rich solvent from the bottom of the CO_2 Absorber is preheated by the lean solvent from the Solvent Stripper in the Rich/Lean Solvent Exchanger. The heated rich solvent is routed to the Solvent Stripper for removal of the absorbed CO_2. The stripped solvent from the bottom of the Solvent Stripper is pumped via the Hot Lean Solvent Pumps through the Rich Lean Exchanger to the Solvent Surge Tank. Prior to entering the Solvent Surge Tank, a slipstream of the lean solvent is pumped via the Solvent Filter Feed Pump through the Solvent Filter Package to prevent buildup of contaminants in the solution. From the Solvent Surge Tank the lean solvent is pumped via the Warm Lean Solvent Pumps to the Lean Solvent Cooler for further cooling, after which the cooled lean solvent is returned to the CO_2 Absorber, completing the circulating solvent circuit.

Solvent Stripper

The purpose of the Solvent Stripper is to separate the CO_2 from the rich solvent feed exiting the bottom of the CO_2 Absorber. The rich solvent is collected on a chimney tray below the bottom packed section of the Solvent Stripper and routed to the Solvent Stripper Reboilers where the rich solvent is heated by steam, stripping the CO_2 from the solution. It was assumed that the steam turbine extraction point pressure could be selected to match the reboiler requirements in the greenfield cases, but would be fixed in the retrofit cases. The steam is extracted from the LP turbine at a pressure of 73 psia in the supercritical PC cases and requires only to be de-superheated prior to use in the stripper reboiler. The steam is extracted from the LP turbine at a pressure of 168 psia in the subcritical retrofit cases. The extracted steam in the subcritical PC cases is sent to a Let-Down Turbine to reduce the pressure to 71 psia and generate power from the extracted steam before being de-superheated. The hot wet vapor from the top of the stripper containing CO_2, steam, and solvent vapor, is partially condensed in the Solvent Stripper Condenser by cross exchanging the hot wet vapor with cooling water. The partially condensed stream then flows to the Solvent Stripper Reflux Drum where the vapor and liquid are separated. A portion of the condensate is combined with the vapor stream from the Let-Down Turbine to saturate the superheated vapor before entering the solvent stripper. The uncondensed CO_2-rich gas is then delivered to the CO_2 product compressor. The condensed liquid from the Solvent Stripper Reflux Drum is pumped via the Solvent Stripper Reflux Pumps where a portion of condensed overhead liquid is used as make-up water for the Water Wash section of the CO_2 Absorber. The rest of the pumped liquid is routed back to the Solvent Stripper as reflux, which aids in limiting the amount of solvent vapors entering the stripper overhead system.

Solvent Stripper Reclaimer

A small slipstream of the lean solvent from the Solvent Stripper bottoms is fed to the Solvent Stripper Reclaimer for the removal of high-boiling nonvolatile impurities (heat stable salts - HSS), volatile acids and iron products from the circulating solvent solution. The solvent bound in the HSS is recovered by reaction with caustic and heating with steam. The solvent reclaimer system reduces corrosion, foaming and fouling in the solvent system. The reclaimed solvent is returned to the Solvent Stripper and the spent solvent is pumped via the Solvent Reclaimer Drain Pump to the Solvent Reclaimer Drain Tank.

Steam Condensate

Steam condensate from the Solvent Stripper Reclaimer accumulates in the Solvent Reclaimer Condensate Drum and is level controlled to the Solvent Reboiler Condensate Drum. A portion of the condensate is vaporized to de-superheat the steam entering the stripping section. Steam condensate from the Solvent Stripper Reboilers is also collected in the Solvent Reboiler Condensate Drum and returned to the steam cycle between boiler feedwater heaters 4 and 5 via the Solvent Reboiler Condensate Pumps.

Corrosion Inhibitor System

A proprietary corrosion inhibitor is continuously injected into the CO_2 Absorber rich solvent bottoms outlet line, the Solvent Stripper bottoms outlet line and the Solvent Stripper top tray. This constant injection is to help control the rate of corrosion throughout the CO_2 recovery plant system.

Gas Compression and Drying System

In the compression section, the CO_2 is compressed to 15.3 MPa (2,215 psia) by a six-stage centrifugal compressor. The discharge pressures of the stages were balanced to give reasonable power distribution and discharge temperatures across the various stages as shown in Exhibit 5-2.

Power consumption for this large compressor was estimated assuming an isentropic efficiency of 84 percent. During compression to 15.3 MPa (2,215 psia) in the multiple-stage, intercooled compressor, the CO_2 stream is dehydrated to a dewpoint of -40ºC (-40°F) with triethylene glycol. The virtually moisture-free supercritical CO_2 stream is delivered to the plant battery limit as sequestration ready. CO_2 TS&M costs were estimated and included in LCOE using the methodology described in Section 2.7.

Exhibit 5-2 CO_2 Compressor Interstage Pressures

Stage	Outlet Pressure, MPa (psia)
1	0.35 (51)
2	0.77 (112)
3	1.69 (245)
4	3.71 (538)
5	8.16 (1,184)
6	15.3 (2,215)

Power consumption for this large compressor was estimated assuming an isentropic efficiency of 84 percent. During compression to 15.3 MPa (2,215 psia) in the multiple-stage, intercooled compressor, the CO_2 stream is dehydrated to a dewpoint of -40ºC (-40°F) with triethylene glycol. The virtually moisture-free supercritical CO_2 stream is delivered to the plant battery limit as sequestration ready. CO_2 TS&M costs were estimated and included in LCOE using the methodology described in Section 2.7.

5.1.8 <u>Power Generation</u>

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

For the subcritical cases, the steam turbine is assumed to be a tandem compound type, consisting of HP-IP-two LP (double flow) sections enclosed in three casings, designed for condensing single reheat operation, and equipped with non-automatic extractions and four-flow exhaust. The turbine drives a hydrogen cooled generator. The turbine has DC motor-operated lube oil pumps, and main lube oil pumps, which are driven off the turbine shaft [62]. The exhaust pressure is 50.8 cm (20 in) Hg in the single pressure condenser. There are seven extraction points. The condenser is two-shell, transverse, single pressure with divided waterbox for each shell.

The steam-turbine generator systems for the supercritical plants are similar in design to the subcritical systems. The differences include steam cycle conditions and eight extractions points versus seven for the subcritical design.

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 low-pressure steam seal system. The generator stator is cooled with a closed-loop water system consisting of circulating pumps, shell and tube or plate and frame type heat exchangers, filters, and deionizers, all skid-mounted. The generator rotor is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft.

Operation Description - The turbine stop valves, control valves, reheat stop valves, and intercept valves are controlled by an electro-hydraulic control system. Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 16.5 MPa/ 538°C (2400 psig/1000ºF) for the subcritical cases and 24.1MPa /593°C (3500 psig/1100°F) for the supercritical cases. The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the boiler for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 528°C (1000ºF) in the subcritical cases and 593°C (1100°F) in the supercritical cases. After passing through the IP section, the steam enters a crossover pipe, which transports the steam to the two LP sections. The steam divides into four paths and flows through the LP sections exhausting downward into the condenser.

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

5.1.9 Balance of Plant

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

Condensate

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser and the LP feedwater heaters. Each system consists of one main condenser; two variable speed electric motor-driven vertical condensate pumps each sized for 50 percent capacity; one gland steam condenser; four LP heaters; 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 feedwater heaters 1 through 4 are 50 percent capacity, parallel flow, and are located in the condenser neck. All remaining feedwater heaters are 100 percent capacity shell and U-tube heat exchangers. Each LP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. LP feedwater 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.

Feedwater

The function of the feedwater system is to pump the feedwater from the deaerator storage tank through the HP feedwater heaters to the economizer. One turbine-driven boiler feedwater pump sized at 100 percent capacity is provided to pump feedwater through the HP feedwater heaters. One 25 percent motor-driven boiler feedwater 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 feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. Feedwater 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 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 (1.16 MPa/367°C [168 psia/693°F] for subcritical PC and 0.50 MPa/292°C [73 psia/557°F] for SC PC) provides steam to the boiler feed pump steam turbine.

Main and Reheat Steam

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

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

Cold reheat steam exits the HP turbine, flows through a motor-operated isolation gate valve and a flow control valve, and enters the boiler reheater. Hot reheat steam exits the boiler reheater through a motor-operated gate valve and is routed to the IP turbine. A branch connection from the cold reheat piping supplies steam to feedwater heater 7.

Extraction Steam

The function of the extraction steam system is to convey steam from turbine extraction points to end use points as follows:

Greenfield SC PC Cases

- From HP turbine exhaust (cold reheat) to heater 7 and 8
- From IP turbine extraction to heater 6 and the deaerator (heater 5)
- From LP turbine extraction to heaters 1, 2, 3, and 4
- From the crossover pipe to the CDR facility via the Let-Down Turbine (capture cases only)

Existing Subcritical PC Plant Cases

- From HP turbine exhaust (cold reheat) to heater 7
- From IP turbine extraction to heater 6 and the deaerator (heater 5)
- From LP turbine extraction to heaters 1, 2, 3, and 4
- From the crossover pipe to the CDR facility via the Let-Down Turbine (capture cases only)

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 feedwater 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.

Circulating Water System

In the SC PC cases, it is assumed that the plant is serviced by a public water facility and has access to groundwater for use as makeup cooling water with minimal pretreatment. In the existing subcritical PC plant cases, makeup water comes from a nearby river. All filtration and treatment of the circulating water are conducted on site. A mechanical draft, counter-flow cooling tower is provided for the circulating water heat sink. Two 50 percent circulating water pumps are provided. The circulating water system provides cooling water to the condenser, the auxiliary cooling water system, and the CDR facility in capture cases.

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

The CDR system in Cases 5, 6, 8, and 9 requires a substantial amount of cooling water that is provided by the PC plant circulating water system. The additional cooling load imposed by the CDR is reflected in the significantly larger circulating water pumps and cooling tower in those cases.

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. The scope of the system is from the baghouse hoppers (SC PC cases) or the ESP hoppers (existing subcritical PC plant cases), air heater and economizer hopper collectors, and bottom ash hoppers to the hydrobins (for bottom ash) and truck filling stations (for fly ash). The system is designed to support short-term operation at the 5 percent OP/VWO condition (16 hours) and long-term operation at the 100 percent guarantee point (90 days or more).

The fly ash collected in the baghouse (Cases 4 – 6) or ESP (Cases 7 – 9) and the air heaters is conveyed to the fly ash storage silo. A pneumatic transport system using low-pressure 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.

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

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

Ducting and Stack

One stack is provided with a single fiberglass-reinforced plastic (FRP) liner. The stack is constructed of reinforced concrete. The stack is 152 m (500 ft) high for adequate particulate dispersion in all PC cases. The existing subcritical PC plant used for a baseline (Case 7) does not have an existing stack liner and a stack liner is added per the retrofit analysis for Cases 8 and 9.

Waste Treatment/Miscellaneous Systems

An onsite water treatment facility treats all runoff, cleaning wastes, blowdown, and backwash to within the U.S. EPA standards for suspended solids, oil and grease, pH, and miscellaneous metals. Waste treatment equipment is housed in a separate building. The waste treatment system consists of a water collection basin, three raw waste pumps, an acid neutralization system, an oxidation system, flocculation, clarification/thickening, and sludge dewatering. The water collection basin is a synthetic-membrane-lined earthen basin, which collects rainfall runoff, maintenance cleaning wastes, and backwash flows.

The raw waste is pumped to the treatment system at a controlled rate by the raw waste pumps. The neutralization system neutralizes the acidic wastewater with hydrated lime in a two-stage system, consisting of a lime storage silo/lime slurry makeup system, dry lime feeder, lime slurry tank, slurry tank mixer, and lime slurry feed pumps.

The oxidation system consists of an air compressor, which injects air through a sparger pipe into the second-stage neutralization tank. The flocculation tank is fiberglass with a variable speed agitator. A polymer dilution and feed system is also provided for flocculation. The clarifier is a plate-type, with the sludge pumped to the dewatering system. The sludge is dewatered in filter presses and disposed offsite. Trucking and disposal costs are included in the cost estimate. The filtrate from the sludge dewatering is returned to the raw waste sump.

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

Buildings and Structures

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

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

5.1.10 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.

5.1.11 Instrumentation and Control

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

6. GREENFIELD SUPERCRITICAL PC CASES (CASES 4 – 6)

Revision 2 Updates

- *Changed the IP turbine outlet pressure to match the requirements of the Econamine system and eliminated the let-down turbine from the system*
- *Changed the flue gas exit temperature from the combustion air preheater from 166°C (330°F) to 149°C (300°F) to take advantage of the lower sulfur content of the design coal*
- *Updated the steam turbine stage efficiencies and exhaust losses to more closely match existing supercritical steam turbine energy balances*
- *Changed the primary/secondary air split from 23.5 percent primary air to 40 percent primary air*
- *Incorporated air pre-heater leakage into the models*
- *Updated CO_2 compression stage efficiencies based on vendor input*

This section contains an evaluation of plant designs for Cases 4 through 6 which are based on a supercritical PC plant with a nominal net output of 550 MWe. The plants use a single reheat 24.1 MPa/593°C/593°C (3500 psig/1100°F/1100°F) steam cycle. The only difference between the plants is that Case 6 includes 90 percent CO_2 capture and Case 5 is based on an emission rate of 1,100 lb CO_2/net-MWh. Case 4 does not include CO_2 capture.

The balance of Section 6 is organized in an analogous manner to the IGCC section:

- Process and System Description for Cases 4 - 6
- Key Assumptions for Cases 4 - 6
- Sparing Philosophy for Cases 4 - 6
- Comparison of Performance Results for Cases 4 - 6
- Equipment List for Cases 4 -6
- Cost Estimates for Cases 4 – 6

6.1 SC PC NON-CAPTURE CASE 4 AND CAPTURE CASES 5 AND 6

6.1.1 Process Description for Non-Capture Case 4

In this section the supercritical PC process without CO_2 capture is described. The description follows the BFD in Exhibit 6-1 and stream numbers reference the same Exhibit. The tables in Exhibit 6-2 provide process data for the numbered streams in the BFD.

Coal (stream 8) and primary air (stream 5) are introduced into the boiler through the wall-fired burners. Additional combustion air, including the overfire air, is provided by the forced draft fans (stream 2). The boiler operates at a slight negative pressure so air leaks into the boiler, and the infiltration air is accounted for in stream 7. Air leakage also occurs in the combustion air preheater and is accounted for in streams 3 and 6.

Flue gas exits the boiler through the SCR reactor (stream 10) and is cooled to 149°C (300°F) in the combustion air preheater (not shown) before passing to the spray-dryer absorbers. The gases from the absorbers are sent to the baghouse to collect the waste products and the fly ash. Activated carbon is injected for additional mercury removal prior to the baghouse (stream 13). Flue gas exits the baghouse and enters the ID fan suction (stream 15). The clean flue gas passes to the plant stack and is discharged to the atmosphere.

Exhibit 6-1 Case 4: SC PC without CO_2 Capture - Block Flow Diagram

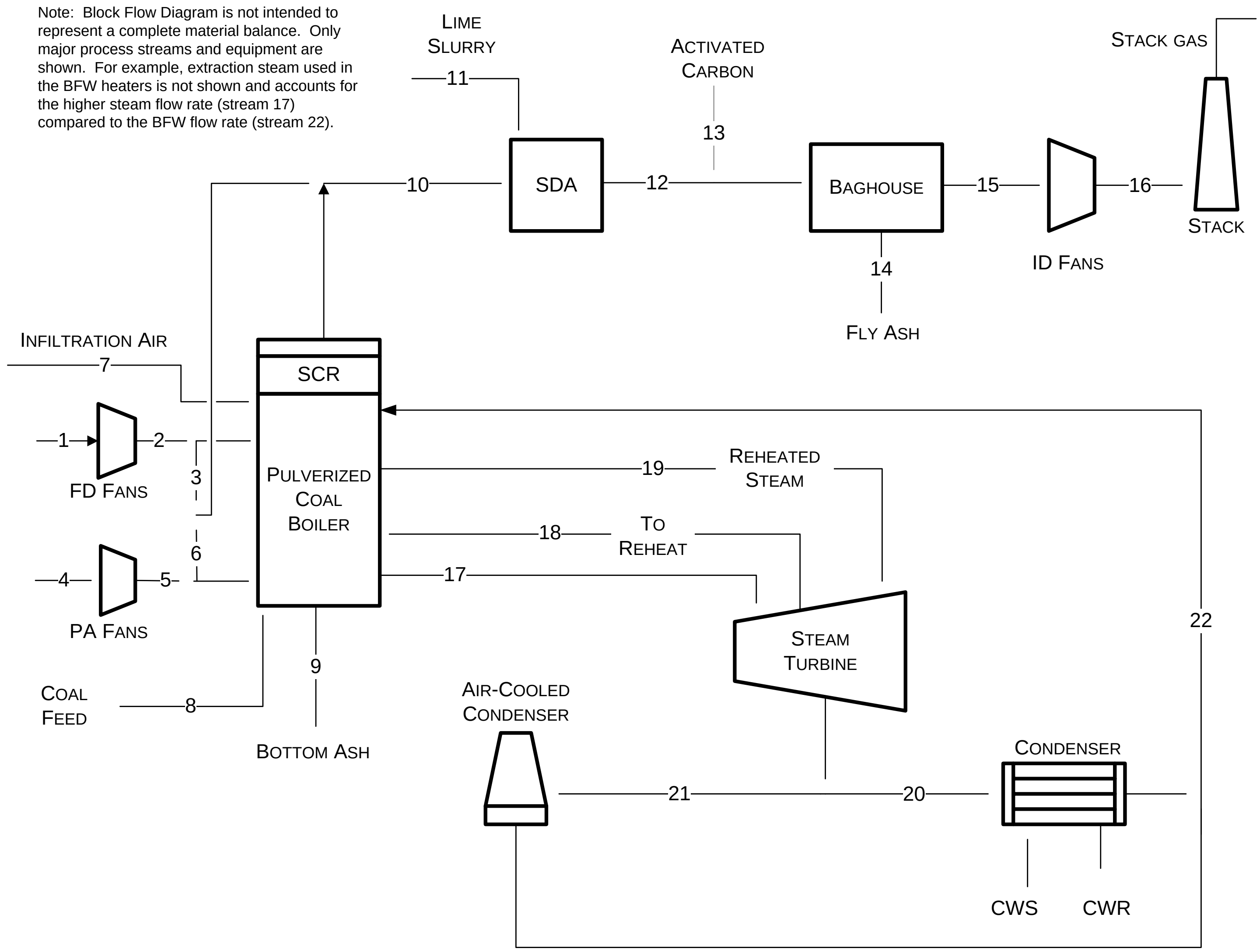


Exhibit 6-2 Case 4: SC PC without CO_2 Capture - Stream Table

	1	2	3	4	5	6	7	8	9	10	11
V-L Mole Fraction											
Ar	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0000	0.0000	0.0084	0.0000
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1470	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	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0000	0.0000	0.1159	1.0000
N_2	0.7753	0.7753	0.7753	0.7753	0.7753	0.7753	0.7753	0.0000	0.0000	0.7041	0.0000
O_2	0.2080	0.2080	0.2080	0.2080	0.2080	0.2080	0.2080	0.0000	0.0000	0.0239	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0008	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
V-L Flowrate (kg_{mol}/hr)	39,185	39,185	1,480	26,123	26,123	2,112	1,156	0	0	73,280	3,134
V-L Flowrate (kg/hr)	1,131,934	1,131,934	42,745	754,623	754,623	61,015	33,381	0	0	2,156,656	56,460
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	257,827	4,222	16,888	3,925
Temperature (°C)	6	11	11	6	19	19	6	6	143	143	6
Pressure (MPa, abs)	0.08	0.08	0.08	0.08	0.09	0.09	0.08	0.08	0.08	0.08	0.08
Enthalpy (kJ/kg)[A]	16.93	22.06	22.06	16.93	29.97	29.97	16.93	---	---	359.05	313.67
Density (kg/m^3)	1.0	1.0	1.0	1.0	1.1	1.1	1.0	---	---	0.7	1,012.1
V-L Molecular Weight	28.887	28.887	28.887	28.887	28.887	28.887	28.887	---	---	29.430	18.015
V-L Flowrate (lb_{mol}/hr)	86,387	86,387	3,262	57,592	57,592	4,657	2,548	0	0	161,555	6,909
V-L Flowrate (lb/hr)	2,495,488	2,495,488	94,237	1,663,659	1,663,659	134,516	73,593	0	0	4,754,612	124,473
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	568,411	9,308	37,231	8,653
Temperature (°F)	42	51	51	42	65	65	42	42	289	289	42
Pressure (psia)	11.4	12.0	12.0	11.4	12.8	12.8	11.4	11.4	11.1	11.1	11.4
Enthalpy (Btu/lb)[A]	7.3	9.5	9.5	7.3	12.9	12.9	7.3	---	---	154.4	134.9
Density (lb/ft^3)	0.061	0.063	0.063	0.061	0.066	0.066	0.061	---	---	0.041	63.182
	A - Reference conditions are 32.02 F & 0.089 PSIA										

Exhibit 6-2 Case 4: SC PC without CO_2 Capture - Stream Table (Continued)

	12	13	14	15	16	17	18	19	20	21	22
V-L Mole Fraction											
Ar	0.0081	0.0000	0.0000	0.0081	0.0081	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.1411	0.0000	0.0000	0.1411	0.1411	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	0.1519	0.0000	0.0000	0.1519	0.1519	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.6759	0.0000	0.0000	0.6759	0.6759	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0229	0.0000	0.0000	0.0229	0.0229	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0001	0.0000	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	0.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	76,332	0	0	76,332	76,332	91,664	75,983	75,983	34,671	34,671	69,342
V-L Flowrate (kg/hr)	2,209,141	0	0	2,209,141	2,209,141	1,651,346	1,368,854	1,368,854	624,605	624,605	1,249,210
Solids Flowrate (kg/hr)	24,788	49	24,837	0	0	0	0	0	0	0	0
Temperature (°C)	82	6	82	82	93	593	354	593	32	32	32
Pressure (MPa, abs)	0.07	0.10	0.07	0.07	0.08	24.23	4.90	4.52	0.00	0.00	1.72
Enthalpy (kJ/kg)[A]	333.49	---	---	335.14	347.33	3,476.62	3,082.92	3,652.22	1,932.01	1,932.01	136.94
Density (kg/m^3)	0.7	---	---	0.7	0.8	69.2	18.7	11.6	0.0	0.0	995.7
V-L Molecular Weight	28.941	---	---	28.941	28.941	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	168,284	0	0	168,284	168,284	202,084	167,514	167,514	76,436	76,436	152,872
V-L Flowrate (lb/hr)	4,870,322	0	0	4,870,322	4,870,322	3,640,595	3,017,806	3,017,806	1,377,018	1,377,018	2,754,037
Solids Flowrate (lb/hr)	54,648	108	54,756	0	0	0	0	0	0	0	0
Temperature (°F)	180	42	180	180	200	1,100	669	1,100	90	90	90
Pressure (psia)	10.7	14.4	10.5	10.5	11.5	3,514.7	710.8	655.8	0.7	0.7	250.0
Enthalpy (Btu/lb)[A]	143.4	---	---	144.1	149.3	1,494.7	1,325.4	1,570.2	830.6	830.6	58.9
Density (lb/ft^3)	0.045	---	---	0.044	0.047	4.319	1.164	0.722	0.003	0.003	62.162

6.1.2 Process Description for Capture Cases 5 and 6

Cases 5 and 6 are configured to produce electric power with CO_2 capture. Case 5 has an emission rate of 1,100 lb CO_2/net-MWh. This is achieved by bypassing a portion of the flue gas around the Econamine unit, leaving a portion untreated. Case 6 is designed to include a carbon capture rate of 90 percent. The plant configurations for Cases 5 and 6 are similar to Case 4, with the major difference being the use of an Econamine FG Plus system for CO_2 capture and subsequent compression of the captured CO_2 stream. Since the CO_2 capture and compression process increases the auxiliary load on the plant, the coal feed rate is increased and the overall efficiency is subsequently reduced relative to Case 4. Block flow diagrams for Cases 5 and 6 are shown in Exhibit 6-3 and in Exhibit 6-5, respectively. Stream tables for the BFD's are presented in Exhibit 6-4 (Case 5) and Exhibit 6-6 (Case 6). The CO_2 removal system was described previously in Section 5.1.7.

Exhibit 6-3 Case 5: SC PC with CO_2 Capture to an Emission Limit of 1,100 lb CO_2/net-MWh - Block Flow Diagram

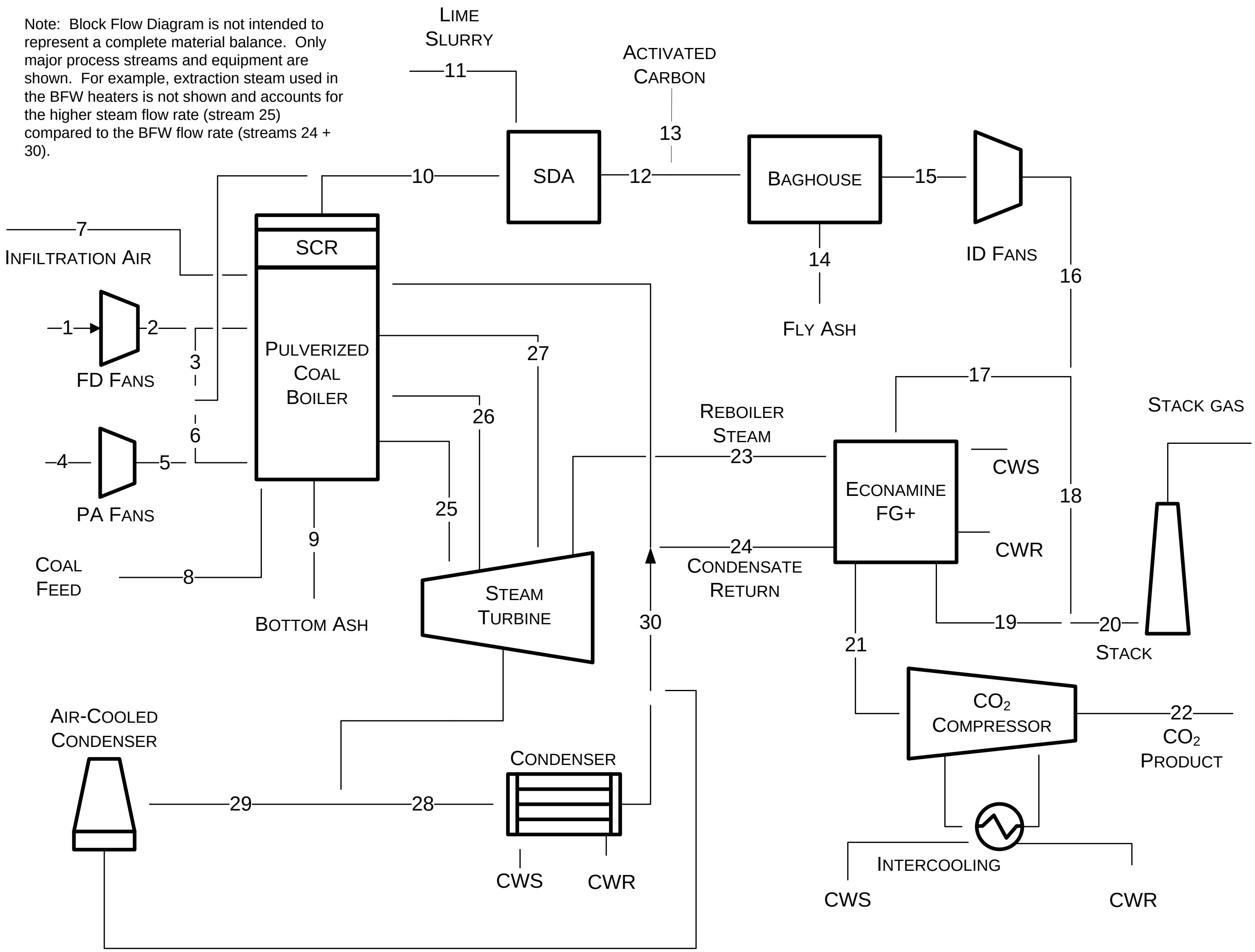


Exhibit 6-4 Case 5: SC PC with CO_2 Capture to an Emission Limit of 1,100 lb CO_2/net-MWh - Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0000	0.0000	0.0084	0.0000	0.0081	0.0000	0.0000	0.0081
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1468	0.0000	0.1410	0.0000	0.0000	0.1410
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0000	0.0000	0.1158	1.0000	0.1518	0.0000	0.0000	0.1518
N_2	0.7753	0.7753	0.7753	0.7753	0.7753	0.7753	0.7753	0.0000	0.0000	0.7041	0.0000	0.6760	0.0000	0.0000	0.6760
O_2	0.2080	0.2080	0.2080	0.2080	0.2080	0.2080	0.2080	0.0000	0.0000	0.0240	0.0000	0.0231	0.0000	0.0000	0.0231
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0008	0.0000	0.0001	0.0000	0.0000	0.0001
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	0.0000	0.0000	
V-L Flowrate (kg_{mol}/hr)	47,743	47,743	1,803	31,828	31,828	2,574	1,407	0	0	89,276	3,818	92,995	0	0	92,995
V-L Flowrate (kg/hr)	1,379,153	1,379,153	52,081	919,435	919,435	74,341	40,637	0	0	2,627,392	68,777	2,691,330	0	0	2,691,330
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	313,865	5,140	20,558	4,707	30,104	60	30,164	0
Temperature (°C)	6	11	11	6	19	19	6	6	143	143	6	82	6	82	82
Pressure (MPa, abs)	0.08	0.08	0.08	0.08	0.09	0.09	0.08	0.08	0.08	0.08	0.09	0.07	0.10	0.07	0.07
Enthalpy (kJ/kg)[A]	16.93	22.06	22.06	16.93	29.97	29.97	16.93	---	---	358.88	309.48	333.55	---	---	335.00
Density (kg/m^3)	1.0	1.0	1.0	1.0	1.1	1.1	1.0	---	---	0.7	1,012.1	0.7	---	---	0.7
V-L Molecular Weight	28.887	28.887	28.887	28.887	28.887	28.887	28.887	---	---	29.430	18.015	28.941	---	---	28.941
V-L Flowrate (lb_{mol}/hr)	105,255	105,255	3,975	70,170	70,170	5,674	3,101	0	0	196,821	8,417	205,018	0	0	205,018
V-L Flowrate (lb/hr)	3,040,511	3,040,511	114,819	2,027,007	2,027,007	163,895	89,589	0	0	5,792,408	151,627	5,933,367	0	0	5,933,367
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	691,955	11,331	45,323	10,377	66,369	131	66,500	0
Temperature (°F)	42	51	51	42	65	65	42	42	289	289	42	180	42	180	180
Pressure (psia)	11.4	12.0	12.0	11.4	12.8	12.8	11.4	11.4	11.1	11.1	13.0	10.7	14.4	10.5	10.5
Enthalpy (Btu/lb)[A]	7.3	9.5	9.5	7.3	12.9	12.9	7.3	---	---	154.3	133.1	143.4	---	---	144.0
Density (lb/ft^3)	0.061	0.063	0.063	0.061	0.066	0.066	0.061	---	---	0.041	63.182	0.045	---	---	0.044

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 6-4 Case 5: SC PC with CO_2 Capture to an Emission Limit of 1,100 lb CO_2/net-MWh - Stream Table (continued)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
V-L Mole Fraction															
Ar	0.0081	0.0081	0.0081	0.0107	0.0094	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.1410	0.1410	0.1410	0.0187	0.0783	0.9950	0.9998	0.0000	0.0000	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	0.0000	0.0000	0.0000	0.0000
H_2O	0.1518	0.1518	0.1518	0.0431	0.0961	0.0050	0.0002	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.6760	0.6760	0.6760	0.8969	0.7892	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0231	0.0231	0.0231	0.0306	0.0269	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0001	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000		1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	92,995	54,169	38,825	40,827	79,652	6,907	6,874	28,276	28,276	109,944	92,757	92,757	29,346	29,346	58,693
V-L Flowrate (kg/hr)	2,691,330	1,567,700	1,123,630	1,148,537	2,272,168	303,093	302,496	509,406	509,406	1,980,671	1,671,041	1,671,041	528,685	528,685	1,057,370
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	93	93	93	32	63	21	35	152	151	593	354	593	32	32	32
Pressure (MPa, abs)	0.08	0.08	0.08	0.09	0.08	0.16	15.27	0.51	0.49	24.23	4.90	4.52	0.00	0.00	1.72
Enthalpy (kJ/kg)[A]	347.20	347.20	347.20	104.77	224.65	20.81	-212.29	2,746.79	635.72	3,476.62	3,082.16	3,652.22	1,989.69	1,989.69	136.94
Density (kg/m^3)	0.8	0.8	0.8	1.0	0.8	2.9	794.5	2.7	915.8	69.2	18.7	11.6	0.0	0.0	995.7
V-L Molecular Weight	28.941	28.941	28.941	28.132	28.526	43.881	44.006	18.015	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	205,018	119,423	85,595	90,008	175,603	15,228	15,155	62,339	62,339	242,385	204,494	204,494	64,698	64,698	129,396
V-L Flowrate (lb/hr)	5,933,367	3,456,186	2,477,181	2,532,091	5,009,272	668,206	666,889	1,123,048	1,123,048	4,366,633	3,684,014	3,684,014	1,165,551	1,165,551	2,331,103
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	200	200	200	89	145	69	95	306	304	1,100	669	1,100	90	90	90
Pressure (psia)	11.5	11.5	11.5	13.1	11.5	23.2	2,215.0	73.5	71.0	3,514.7	710.8	655.8	0.7	0.7	250.0
Enthalpy (Btu/lb)[A]	149.3	149.3	149.3	45.0	96.6	8.9	-91.3	1,180.9	273.3	1,494.7	1,325.1	1,570.2	855.4	855.4	58.9
Density (lb/ft^3)	0.047	0.047	0.047	0.063	0.050	0.181	49.600	0.169	57.172	4.319	1.165	0.722	0.003	0.003	62.162

Exhibit 6-5 Case 6: SC PC with 90% CO_2 Capture - Block Flow Diagram

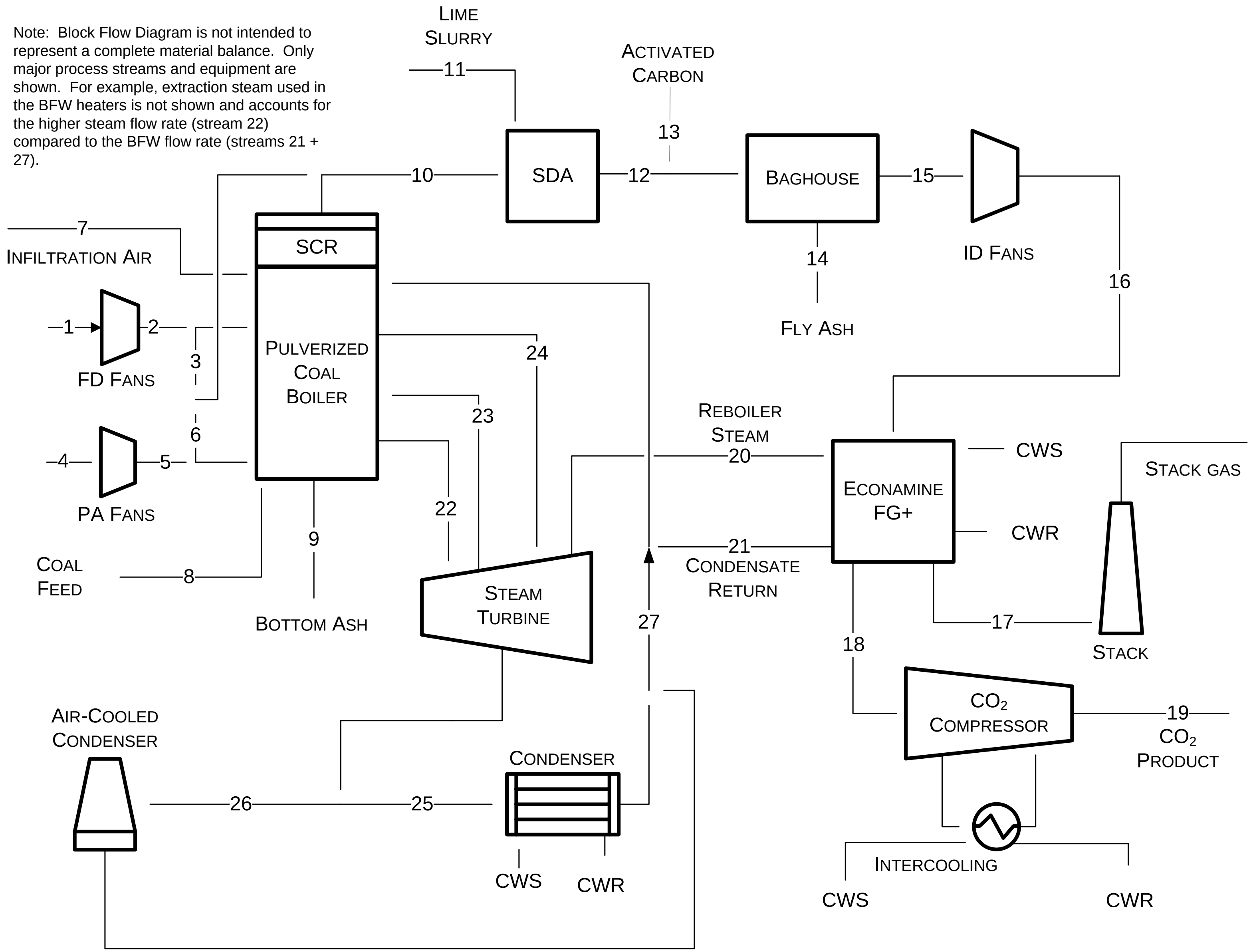


Exhibit 6-6 Case 6: SC PC with 90% CO_2 Capture - Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
V-L Mole Fraction														
Ar	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0093	0.0000	0.0000	0.0084	0.0000	0.0081	0.0000	0.0000
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1472	0.0000	0.1413	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	0.0000	0.0000
H_2O	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0000	0.0000	0.1160	1.0000	0.1521	0.0000	0.0000
N_2	0.7753	0.7753	0.7753	0.7753	0.7753	0.7753	0.7753	0.0000	0.0000	0.7040	0.0000	0.6758	0.0000	0.0000
O_2	0.2080	0.2080	0.2080	0.2080	0.2080	0.2080	0.2080	0.0000	0.0000	0.0236	0.0000	0.0227	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0008	0.0000	0.0001	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	0.0000	0.0000
V-L Flowrate (kg_{mol}/hr)	56,029	56,029	2,116	37,352	37,352	3,020	1,655	0	0	104,799	4,483	109,166	0	0
V-L Flowrate (kg/hr)	1,618,507	1,618,507	61,120	1,079,004	1,079,004	87,243	47,811	0	0	3,084,366	80,768	3,159,440	0	0
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	369,278	6,047	24,188	5,548	35,429	70	35,499
Temperature (°C)	6	11	11	6	19	19	6	6	143	143	6	82	6	82
Pressure (MPa, abs)	0.08	0.08	0.08	0.08	0.09	0.09	0.08	0.08	0.08	0.08	0.09	0.07	0.10	0.07
Enthalpy (kJ/kg)[A]	16.93	22.06	22.06	16.93	29.97	29.97	16.93	---	---	359.38	310.45	334.00	---	---
Density (kg/m^3)	1.0	1.0	1.0	1.0	1.1	1.1	1.0	---	---	0.7	1,012.1	0.7	---	---
V-L Molecular Weight	28.887	28.887	28.887	28.887	28.887	28.887	28.887	---	---	29.431	18.015	28.942	---	---
V-L Flowrate (lb_{mol}/hr)	123,522	123,522	4,665	82,348	82,348	6,658	3,649	0	0	231,043	9,884	240,669	0	0
V-L Flowrate (lb/hr)	3,568,197	3,568,197	134,746	2,378,798	2,378,798	192,339	105,406	0	0	6,799,862	178,062	6,965,373	0	0
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	814,119	13,331	53,325	12,231	78,107	154	78,262
Temperature (°F)	42	51	51	42	65	65	42	42	289	289	42	180	42	180
Pressure (psia)	11.4	12.0	12.0	11.4	12.8	12.8	11.4	11.4	11.1	11.1	13.0	10.7	14.4	10.5
Enthalpy (Btu/lb)[A]	7.3	9.5	9.5	7.3	12.9	12.9	7.3	---	---	154.5	133.5	143.6	---	---
Density (lb/ft^3)	0.061	0.063	0.063	0.061	0.066	0.066	0.061	---	---	0.041	63.182	0.045	---	---
	A - Referer	A - Reference conditions are 32.02 F & 0.089 PSIA												

Exhibit 6-6 Case 6: SC PC with 90% CO_2 Capture - Stream Table (continued)

	15	16	17	18	19	20	21	22	23	24	25	26	27
V-L Mole Fraction													
Ar	0.0081	0.0081	0.0107	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.1413	0.1413	0.0188	0.9951	0.9998	0.0000	0.0000	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	0.0000	0.0000
H_2O	0.1521	0.1521	0.0431	0.0049	0.0002	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.6758	0.6758	0.8974	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0227	0.0227	0.0301	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	109,166	109,166	82,216	13,951	13,884	57,113	57,113	129,323	109,243	109,243	24,397	24,397	48,793
V-L Flowrate (kg/hr)	3,159,440	3,159,440	2,312,797	612,190	610,986	1,028,906	1,028,906	2,329,782	1,968,043	1,968,043	439,510	439,510	879,020
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	82	93	32	21	35	152	151	593	354	593	32	32	32
Pressure (MPa, abs)	0.07	0.08	0.09	0.16	15.27	0.51	0.49	24.23	4.90	4.52	0.00	0.00	1.72
Enthalpy (kJ/kg)[A]	335.41	347.60	104.77	20.80	-212.29	2,861.67	635.72	3,476.62	3,081.64	3,652.22	2,002.88	2,002.88	136.94
Density (kg/m^3)	0.7	0.8	1.0	2.9	794.5	2.7	915.8	69.2	18.7	11.6	0.0	0.0	995.7
V-L Molecular Weight	28.942	28.942	28.131	43.881	44.006	18.015	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	240,669	240,669	181,254	30,757	30,609	125,913	125,913	285,107	240,840	240,840	53,785	53,785	107,570
V-L Flowrate (lb/hr)	6,965,373	6,965,373	5,098,844	1,349,648	1,346,995	2,268,350	2,268,350	5,136,290	4,338,793	4,338,793	968,953	968,953	1,937,907
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	180	200	89	69	95	306	304	1,100	668	1,100	90	90	90
Pressure (psia)	10.5	11.5	13.1	23.2	2,215.0	73.5	71.0	3,514.7	710.8	655.8	0.7	0.7	250.0
Enthalpy (Btu/lb)[A]	144.2	149.4	45.0	8.9	-91.3	1,230.3	273.3	1,494.7	1,324.9	1,570.2	861.1	861.1	58.9
Density (lb/ft^3)	0.044	0.047	0.063	0.181	49.600	0.169	57.172	4.319	1.166	0.722	0.003	0.003	62.162

6.1.3 Key System Assumptions

System assumptions for Cases 4 through 6, supercritical PC with and without CO_2 capture, are compiled in Exhibit 6-7.

Exhibit 6-7 Supercritical PC Plant Study Configuration Matrix

	Case 4 w/o CO_2 Capture	Case 5 w/CO_2 Capture	Case 6 w/CO_2 Capture
Steam Cycle, MPa/°C/°C (psig/°F/°F)	24.1/593/593 (3500/1100/1100)	24.1/593/593 (3500/1100/1100)	24.1/593/593 (3500/1100/1100)
Coal	Rosebud PRB	Rosebud PRB	Rosebud PRB
Condenser pressure, mm Hg (in Hg)	35.6 (1.4)	35.6 (1.4)	35.6 (1.4)
Boiler Efficiency, %	86	86	86
Cooling water to condenser, °C (ºF)	8.9 (48)	8.9 (48)	8.9 (48)
Cooling water from condenser, °C (ºF)	20 (68)	20 (68)	20 (68)
Stack temperature, °C (°F)	93 (200)	63 (145)	32 (89)
SO_2 Control	Dry Limestone FGD	Dry Limestone FGD (B)	Dry Limestone FGD (B)
FGD Efficiency, % (A)	93	93	93
NOx Control	LNB w/OFA and SCR	LNB w/OFA and SCR	LNB w/OFA and SCR
SCR Efficiency, % (A)	65	65	65
Ammonia Slip (end of catalyst life), ppmv	2	2	2
Particulate Control	Fabric Filter	Fabric Filter	Fabric Filter
Fabric Filter efficiency, % (A)	99.97	99.97	99.97
Ash Distribution, Fly/Bottom	80% / 20%	80% / 20%	80% / 20%
Mercury Control	Co-benefit Capture and Activated Carbon Injection	Co-benefit Capture and Activated Carbon Injection	Co-benefit Capture and Activated Carbon Injection
Mercury removal efficiency, % (A)	15% co-benefit capture and additional 90% with activated carbon injection	15% co-benefit capture and additional 90% with activated carbon injection	15% co-benefit capture and additional 90% with activated carbon injection
CO_2 Control	N/A	Econamine FG Plus	Econamine FG Plus
CO_2 Capture (A)	N/A	1,100 lb/net-MWh	90% (A)
CO_2 Sequestration	N/A	Off-site Saline Formation	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 (< 10 ppmv) to reduce formation of amine heat stable salts during the CO_2 absorption process

Balance of Plant – Cases 4 - 6

The balance of plant assumptions are common to all cases and are presented in Exhibit 6-8.

Exhibit 6-8 Balance of Plant Assumptions

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

6.1.4 Sparing Philosophy

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

- One dry-bottom, wall-fired PC supercritical boiler (1 x 100%)
- Two single-stage, in-line, multi-compartment fabric filters (2 x 50%)
- One lime-based spray dryer absorber (1 x 100%)
- One steam turbine (1 x 100%)
- For Case 6 only, two parallel Econamine FG Plus CO_2 absorption systems, with each system consisting of two absorbers, strippers and ancillary equipment (2 x 50%). Case 5 consists of a single train only.

6.1.5 Case 4 - 6 Performance Results

The plants produce a net output of 550 MWe at a net plant efficiency of 38.6, 31.7, and 26.9 percent (HHV basis) for Cases 4 through 6, respectively.

Overall performance for the plant is summarized in Exhibit 6-9, which includes auxiliary power requirements. The CDR facility, including CO_2 compression, accounts for over 45 and 57 percent of the auxiliary plant load for Cases 5 and 6, respectively. The CDR facility loads include a flue gas booster fan to overcome the absorber pressure drop and pumps to circulate the amine solvent. The circulating water system (circulating water pumps and cooling tower fan) accounts for over 11 percent the auxiliary load, largely due to the high cooling water demand of the CDR facility.

Exhibit 6-9 Cases 4 - 6 Plant Performance Summary

Power Output, kWe	Case 4	Case 5	Case 6
Steam Turbine Power	**585,300**	**629,800**	**675,500**
Gross Power	**585,300**	**629,800**	**675,500**
Auxiliary Load, kWe			
Coal Handling and Conveying	510	570	630
Pulverizers	3,870	4,710	5,540
Sorbent Handling & Reagent Preparation	170	210	250
Ash Handling	860	1,040	1,230
Primary Air Fans	2,830	3,450	4,050
Forced Draft Fans	1,670	2,040	2,390
Induced Draft Fans	7,750	9,450	11,030
SCR	10	20	20
Baghouse	120	150	170
Spray Dryer FGD	2,240	2,730	3,210
Econamine FG Plus Auxiliaries	N/A	11,400	22,900
CO_2 Compression	N/A	24,340	49,170
Miscellaneous Balance of Plant[1,2]	2,000	2,000	2,000
Steam Turbine Auxiliaries	400	400	400
Condensate Pumps	790	670	560
Circulating Water Pumps	2,410	5,160	9,190
Ground Water Pumps	250	460	800
Cooling Tower Fans	1,800	3,840	6,000
Air Cooled Condenser Fans	5,760	5,030	3,690
Transformer Losses	1,850	2,100	2,370
Total	35,290	79,770	125,600
Plant Performance			
Net Plant Power	550,010	550,030	549,900
Net Plant Efficiency (HHV)	38.6%	31.7%	26.9%
Net Plant Heat Rate (HHV)	9,338 (8,851)	11,367 (10,774)	13,377 (12,679)
Coal Feed Flowrate (kg/hr (lb/hr))	257,827 (568,411)	313,865 (691,955)	369,278 (814,119)
Thermal Input (kW_{th})	1,426,632	1,736,710	2,043,325
Condenser Duty (GJ/hr (MMBtu/hr))	2,245 (2,128)	1,961 (1,859)	1,642 (1,556)
Raw Water Withdrawal (m^3/min (gpm))	10.3 (2,733)	19.4 (5,117)	33.4 (8,820)
Raw Water Consumption (m^3/min (gpm))	8.2 (2,175)	14.9 (3,924)	25.3 (6,693)
Other Consumables			
Activated Carbon (kg/day (lb/day))	1,174 (2,588)	1,430 (3,153)	1,679 (3,701)
SCR Catalyst (m^3 (ft^3))	379 (13,390)	462 (16,313)	542 (19,150)
FGD Sorbent (tonne/day (ton/day))	3.93 (4.33)	4.71 (5.19)	5.55 (6.12)
Ammonia (19% Solution) (tonne/day (ton/day))	20.5 (22.6)	25.0 (27.6)	29.4 (32.4)
Econamine Consumables			
MEA (tonne/day (ton/day))	N/A	0.73 (0.80)	1.47 (1.62)
Activated Carbon (kg/day (lb/day))	N/A	435 (960)	880 (1,939)
Sodium Hydroxide (NaOH) (tonne/day (ton/day))	N/A	5.21 (5.74)	10.53 (11.61)
Sulfuric Acid (H_2SO_4) (tonne/day (ton/day))	N/A	3.47 (3.82)	7.00 (7.72)
Corrosion Inhibitor ($/yr)	N/A	3,733	7,541

1 - Boiler feed pumps are turbine driven

2 - Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2 and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Cases 4 through 6 is presented in Exhibit 6-10.

Exhibit 6-10 Cases 4 - 6 Air Emissions

	Case 4	Case 5	Case 6
kg/GJ (lb/10^6 Btu)			
SO_2	0.051 (0.119)	0.022 (0.051)	0.001 (0.002)
NO_X	0.030 (0.070)	0.030 (0.070)	0.030 (0.070)
Particulates	0.006 (0.013)	0.006 (0.013)	0.006 (0.013)
Hg	0.257E-6 (0.597E-6)	0.257E-6 (0.597E-6)	0.257E-6 (0.597E-6)
CO_2	92 (215)	44 (102)	9.2 (21)
Tonne/year (tons/year) 85% capacity			
SO_2	1,953 (2,153)	1,013 (1,116)	37 (40)
NO_X	1,151 (1,269)	1,401 (1,544)	1,648 (1,817)
Particulates	214 (236)	260 (287)	306 (337)
Hg	0.010 (0.011)	0.012 (0.013)	0.014 (0.015)
CO_2	3,529,083 (3,890,148)	2,043,885 (2,252,998)	505,458 (557,172)
kg/MWh (lb/gross-MWh)			
SO_2	0.448 (0.988)	0.216 (0.476)	0.007 (0.016)
NO_X	0.264 (0.582)	0.299 (0.659)	0.328 (0.722)
Particulates	0.049 (0.108)	0.055 (0.122)	0.061 (0.134)
Hg	2.25E-6 (4.96E-6)	2.55E-6 (5.62E-6)	2.79E-6 (6.16E-6)
CO_2	810 (1,785)	436 (961)	100 (222)
kg/MWh (lb/net-MWh)			
CO_2	862 (1,900)	499 (1,100)	123 (272)

SO_2 emissions are controlled using a lime-based spray dryer absorber that achieves a removal efficiency of 93 percent. The saturated flue gas exiting the scrubber is vented through the plant stack (Case 4) or sent to the Econamine unit (Cases 5 and 6).

NOx emissions are controlled to about 0.20 lb/10^6 Btu through the use of LNBs and OFA. An SCR unit then further reduces the NOx concentration by 65 percent to 0.07 lb/10^6 Btu.

Particulate emissions are controlled using a pulse jet fabric filter which operates at an efficiency of 99.97 percent.

Co-benefit capture results in a 15 percent reduction of mercury emissions. Activated carbon injection provides an additional 90 percent reduction of mercury emissions. CO_2 emissions represent the discharge from the respective processes.

Exhibit 6-11 shows the overall water balance for the plant. Raw water is obtained from groundwater (50 percent) and from municipal sources (50 percent). Water demand represents the total amount of water required for a particular process. Some water is recovered within the process, primarily as flue gas condensate in CO_2 capture cases, and that water is re-used as internal recycle. Raw water withdrawal is the difference between water demand and internal recycle. Some water is returned to the source, namely cooling tower blowdown. The difference between raw water withdrawal and water returned to the source (process discharge) is raw water consumption, which represents the net impact on the water source.

Exhibit 6-11 Cases 4 - 6 Water Balance

	Case 4	**Case 5**	**Case 6**
Water Demand, m^3/min (gpm)			
Econamine	N/A	0.07 (20)	0.15 (40)
FGD Makeup	0.94 (249)	1.1 (303)	1.3 (356)
Cooling Tower	9.4 (2,484)	20.1 (5,305)	35.8 (9,456)
Total	**10.3 (2,733)**	**21.3 (5,628)**	**37.3 (9,852)**
Internal Recycle, m^3/min (gpm)			
Econamine	N/A	0.0 (0)	0.0 (0)
FGD Makeup	0.00 (0)	0.0 (0)	0.0 (0)
Cooling Tower	0.00 (0)	1.9 (511)	3.9 (1,032)
Total	**0.00 (0)**	**1.9 (511)**	**3.9 (1,032)**
Raw Water Withdrawal, m^3/min (gpm)			
Econamine	N/A	0.07 (20)	0.15 (40)
FGD Makeup	0.94 (249)	1.1 (303)	1.3 (356)
Cooling Tower	9.4 (2,484)	18.1 (4,794)	31.9 (8,424)
Total	**10.3 (2,733)**	**19.4 (5,117)**	**33.4 (8,820)**
Process Water Discharge, m^3/min (gpm)			
Cooling Tower	2.1 (559)	4.5 (1,193)	8.0 (2,127)
Total	**2.1 (559)**	**4.5 (1,193)**	**8.0 (2,127)**
Raw Water Consumption, m^3/min (gpm)			
Econamine	N/A	0.07 (20)	0.15 (40)
FGD Makeup	0.94 (249)	1.1 (303)	1.3 (356)
Cooling Tower	7.3 (1,926)	13.6 (3,601)	23.8 (6,297)
Total	**8.2 (2,175)**	**14.9 (3,924)**	**25.3 (6,693)**
Total, gpm/MWnet	**4.0**	**7.1**	**12.2**

The carbon balance for the plant is shown in Exhibit 6-12. The carbon input to the plant consists of carbon in the coal and carbon in the air. Carbon leaves the plant as carbon in the CO_2 in the stack gas and CO_2 product. The percent of total carbon sequestered for the capture cases is defined as the amount of carbon product produced (as sequestration-ready CO_2) divided by the carbon in the coal feedstock, less carbon contained in solid byproducts (ash), expressed as a percentage.

Exhibit 6-12 Cases 4 – 6 Carbon Balance

	Case 4	Case 5	Case 6
Carbon In, kg/hr (lb/hr)			
Coal	129,089 (284,593)	157,147 (346,449)	184,891 (407,614)
Air (CO_2)	262 (577)	319 (703)	374 (825)
Activated Carbon	49 (108)	60 (131)	70 (154)
Total In	**129,400 (285,277)**	**157,525 (347,283)**	**185,335 (408,593)**
Carbon Out, kg/hr (lb/hr)			
Ash	49 (108)	60 (131)	70 (154)
Stack Gas	129,351 (285,169)	74,914 (165,157)	18,526 (40,844)
CO_2 Product	N/A	82,551 (181,994)[1]	166,738 (367,594)[2]
Total Out	**129,400 (285,277)**	**157,525 (347,283)**	**185,335 (408,593)**

[1] Carbon capture is 52.5 percent to achieve an emission rate of 1,100 lb CO_2/net-MWh
[2] Carbon capture is 90 percent

The sulfur balance for the plant is shown in Exhibit 6-13. Sulfur input is the sulfur in the coal. Sulfur output is the sulfur combined with lime in the ash and the sulfur emitted in the stack gas.

Exhibit 6-13 Cases 4 - 6 Sulfur Balance

	Case 4	Case 5	Case 6
Sulfur In, kg/h (lb/hour)			
Coal	1,876 (4,135)	2,283 (5,034)	2,686 (5,922)
Total In	**1,876 (4,135)**	**2,283 (5,034)**	**2,686 (5,922)**
Sulfur Out, kg/h (lb/hour)			
Ash	1,744 (3,845)[1]	2,123 (4,681)[1]	2,498 (5,508)[1]
Stack Gas	131 (289)	68 (150)	2 (5)
Polishing Scrubber	N/A	92 (202)	186 (409)
Total Out	**1,876 (4,135)**	**2,283 (5,034)**	**2,686 (5,922)**

[1] Sulfur capture is 93 percent

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for all three supercritical PC cases, including the boiler, gas cleanup, and the power block system in Exhibit 6-14 through Exhibit 6-19.

An overall plant energy balance is provided in tabular form in Exhibit 6-20. The power out is the steam turbine power prior to generator losses.

Exhibit 6-14 Case 4 SC PC without CO_2 Boiler and Gas Cleanup Systems Heat and Mass Balance Schematic

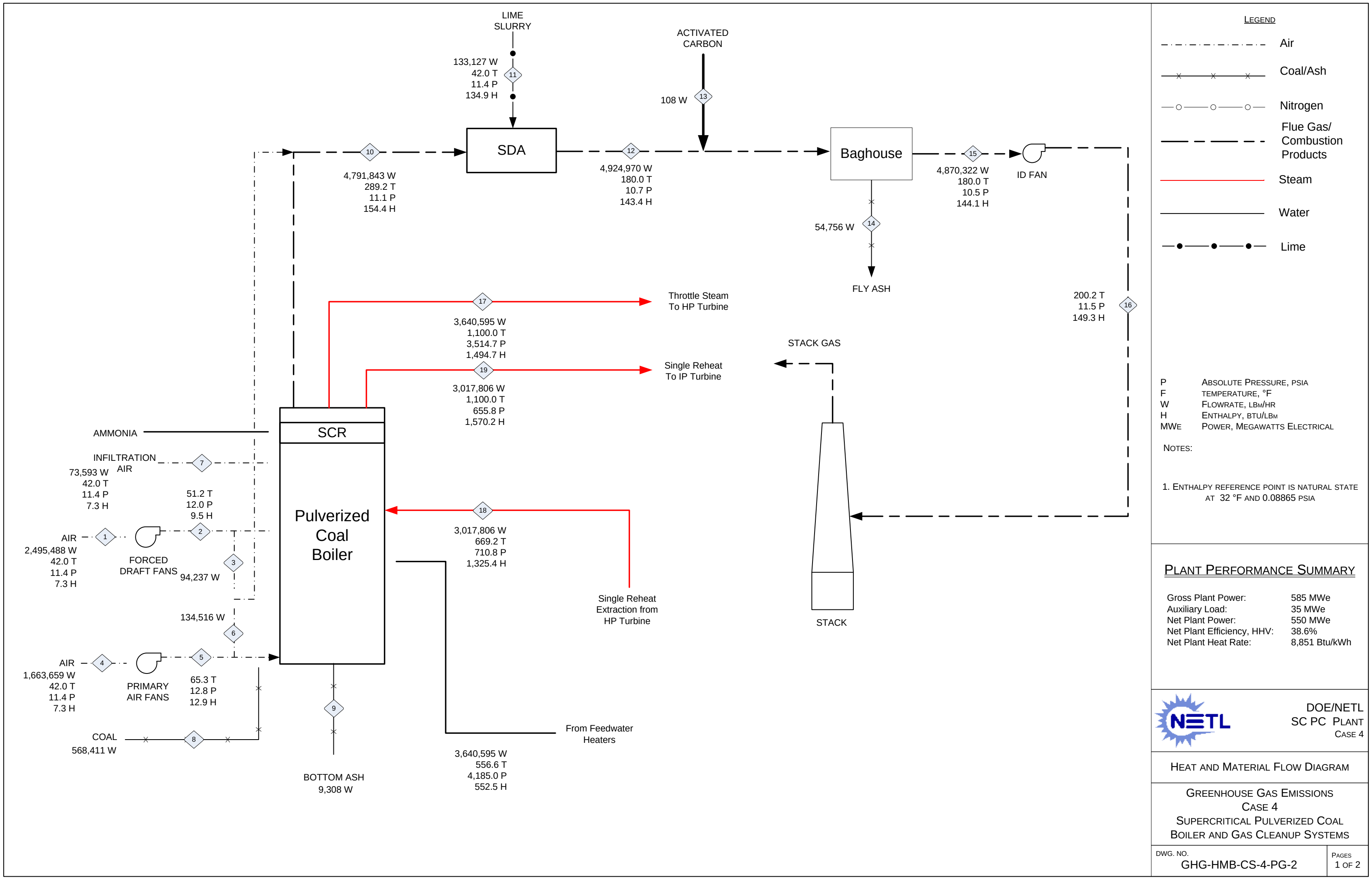


Exhibit 6-15 Case 4 SC PC without CO_2 Power Block Systems Heat and Mass Balance Schematic

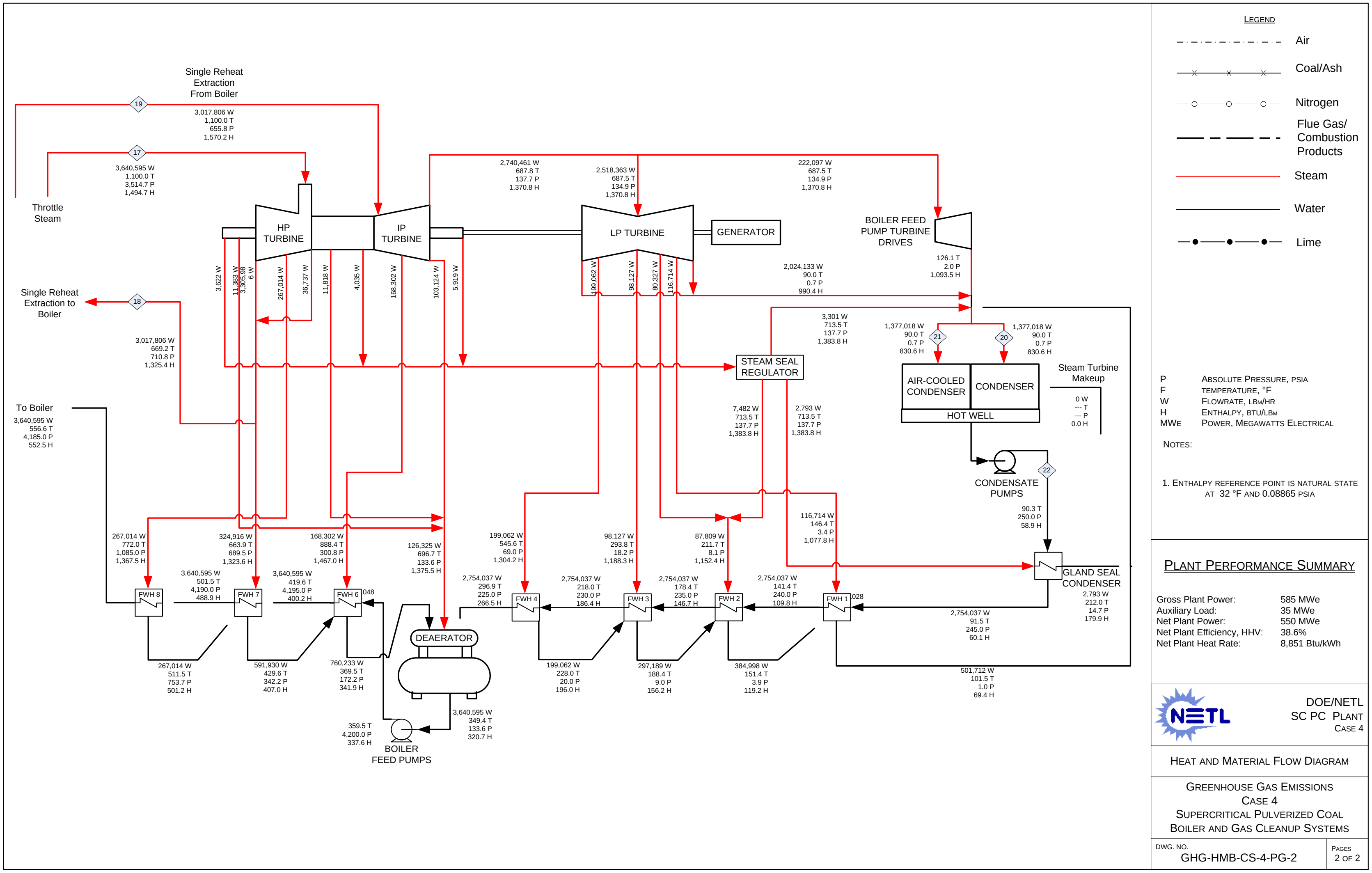


Exhibit 6-16 Case 5 SC PC with CO_2 Capture to an Emissions Limit of 1,100 lb/net-MWh Boiler and Gas Cleanup Heat and Mass Balance Schematic

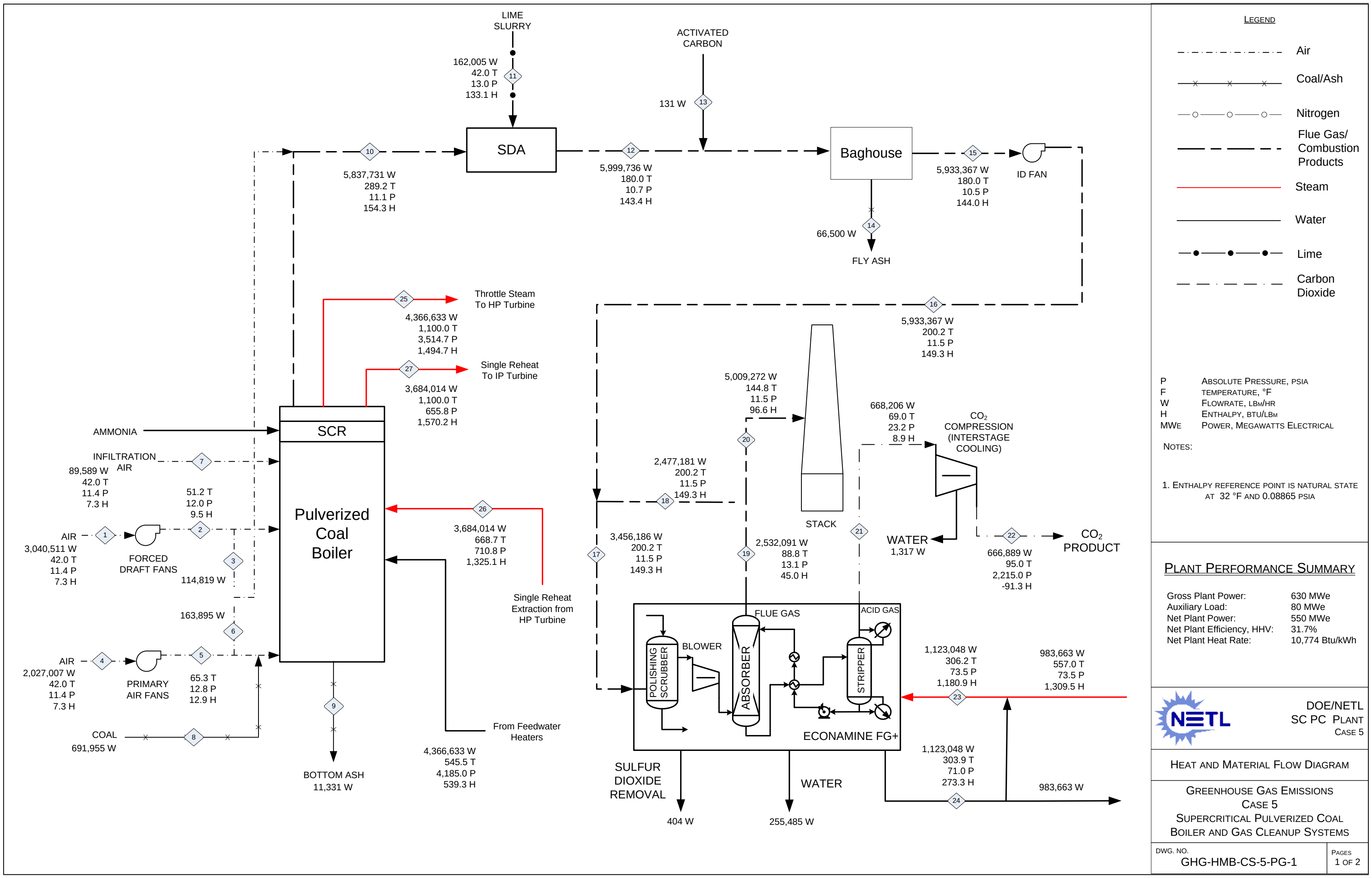


Exhibit 6-17 Case 5 SC PC with CO_2 Capture to an Emissions Limit of 1,100 lb/net-MWh Power Block Systems Heat and Mass Balance Schematic

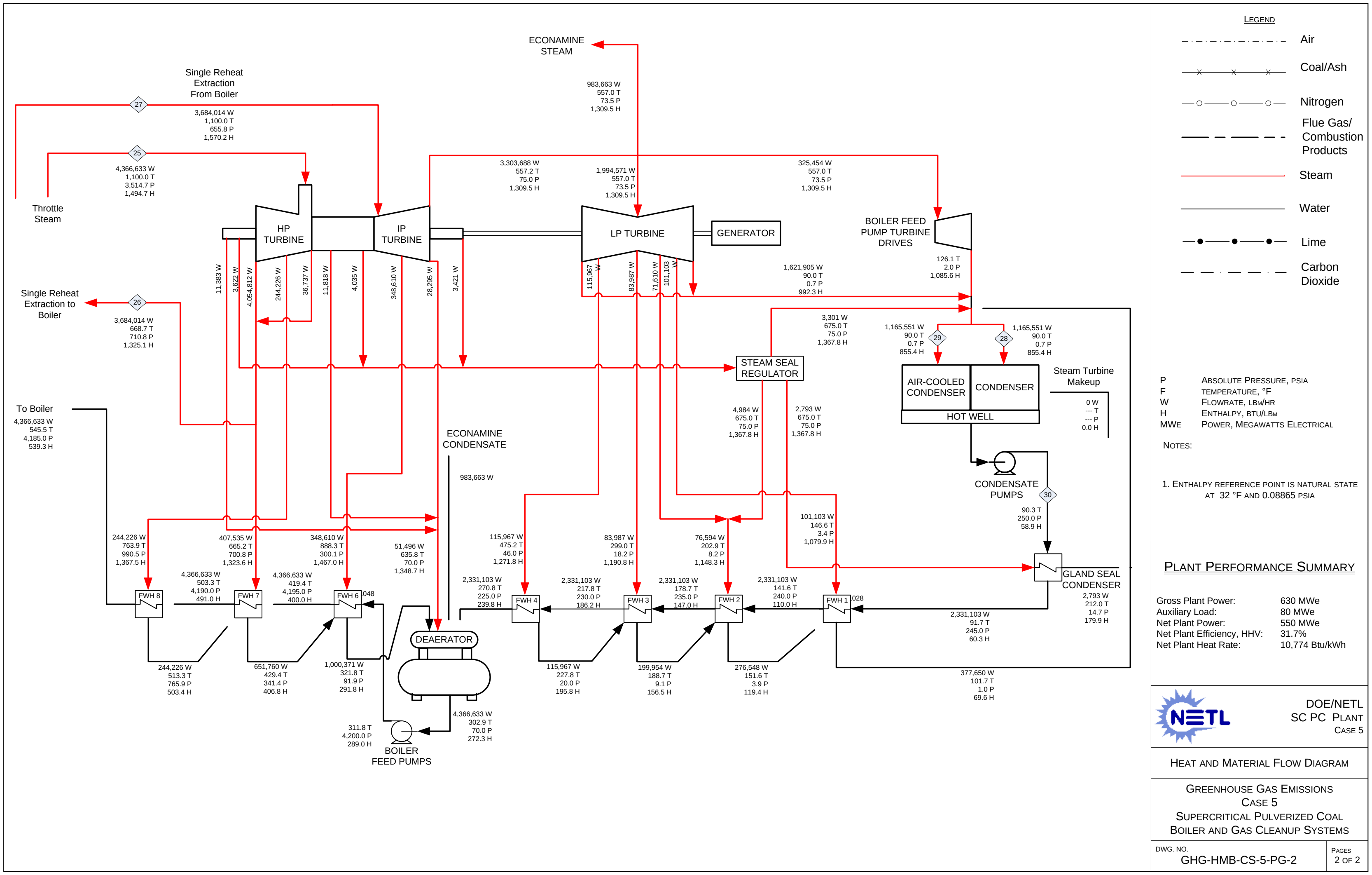


Exhibit 6-18 Case 6 SC PC with 90% CO_2 Capture Boiler and Gas Cleanup System Heat and Mass Balance Schematic

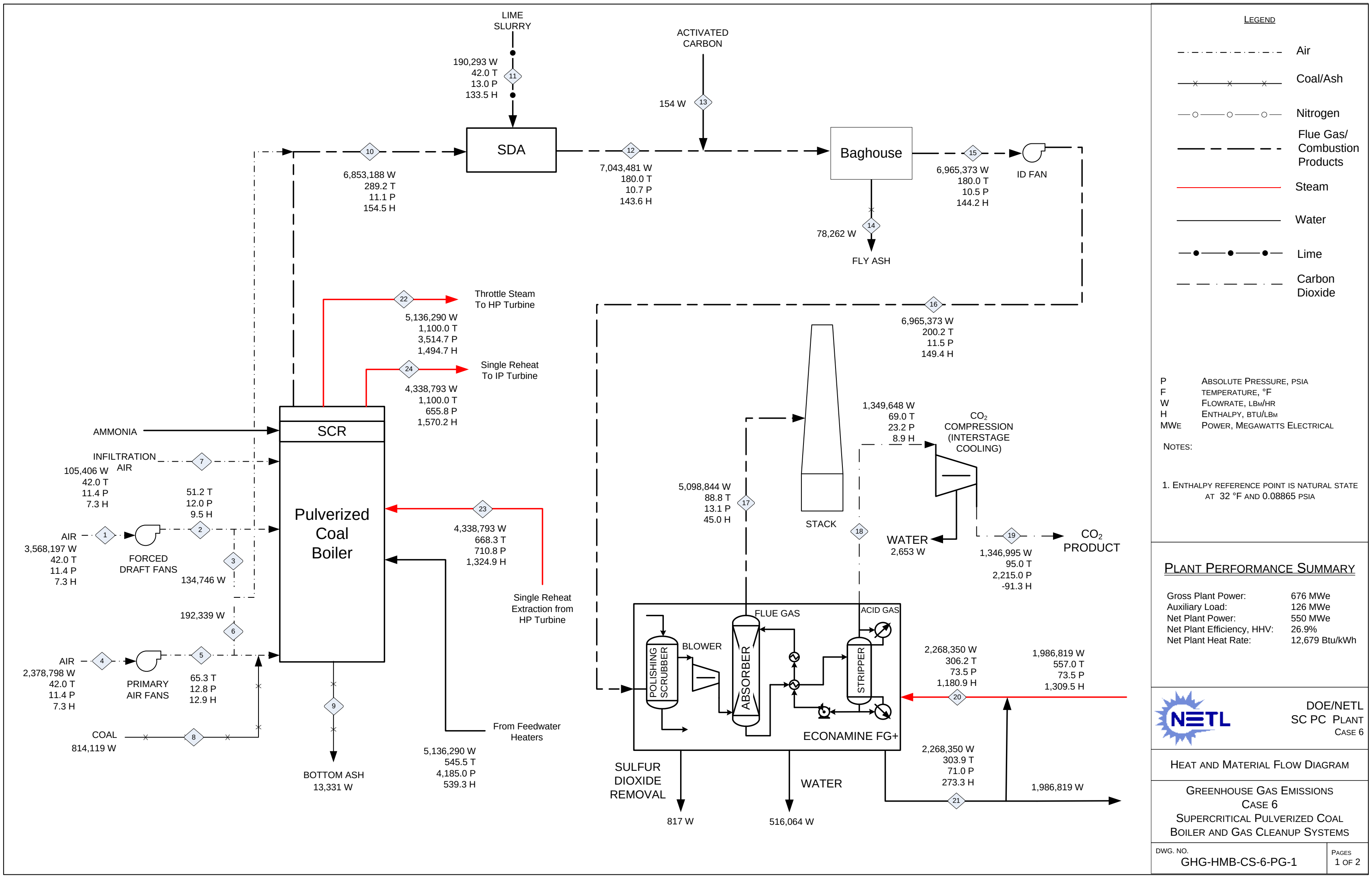


Exhibit 6-19 Case 6 SC PC with 90% CO_2 Capture Power Block System Heat and Mass Balance Schematic

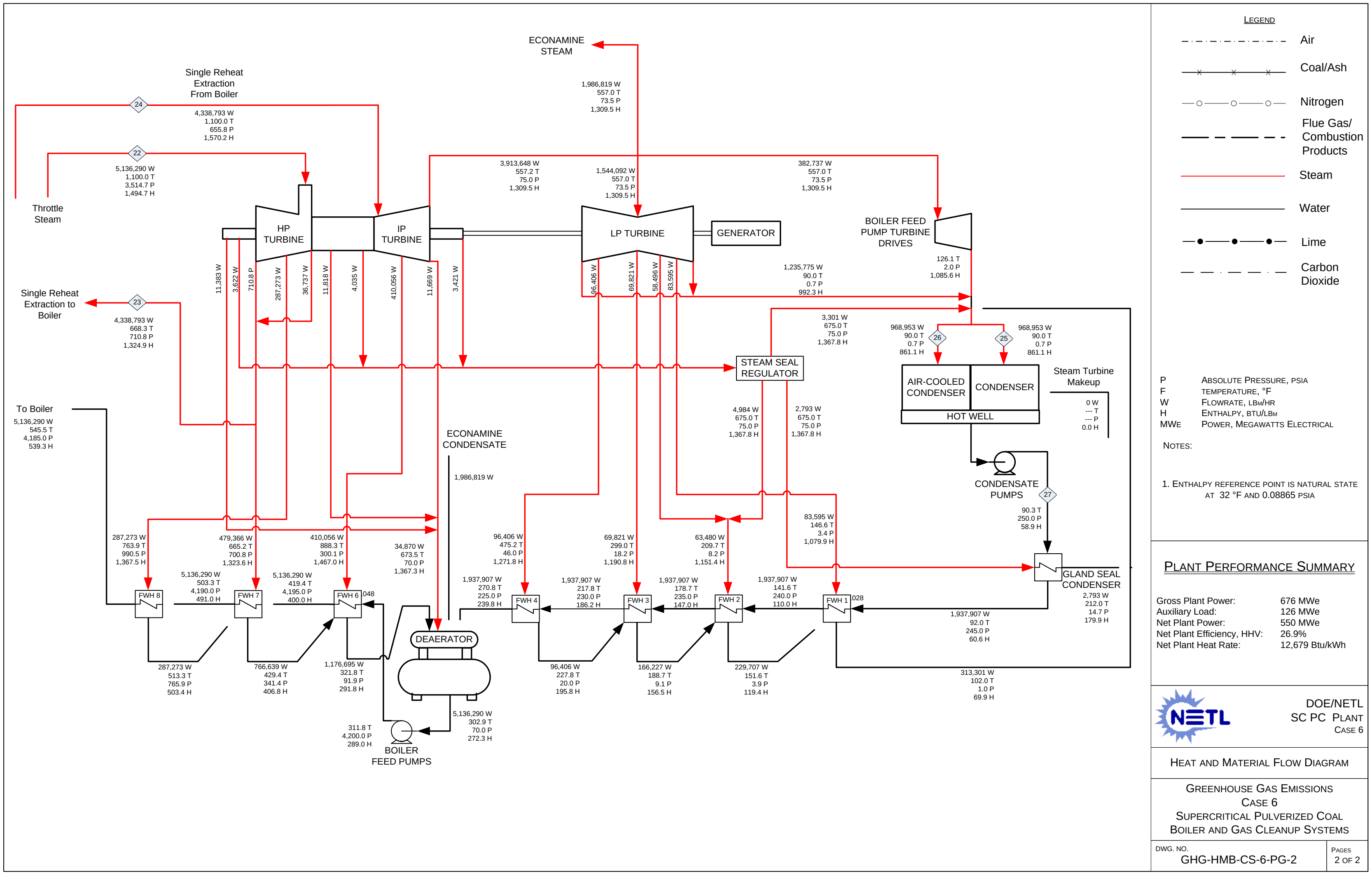


Exhibit 6-20 Cases 4 - 6 Overall Energy Balance

	Case 4	Case 5	Case 6
Energy In, GJ/hr (MMBtu/hr)[1]			
Coal, HHV	5,136 (4,868)	6,252 (5,926)	7,356 (6,972)
Sensible + Latent			
Coal	2.6 (2.5)	3.2 (3.0)	3.8 (3.6)
Air	32.5 (30.8)	39.6 (37.5)	46.5 (44.0)
Raw Water Makeup	14.4 (13.7)	27.0 (25.6)	46.5 (44.1)
Lime	0.02 (0.02)	0.02 (0.02)	0.02 (0.02)
Auxiliary Power	127 (120)	287 (272)	452 (429)
Total In	**5,312 (5,035)**	**6,609 (6,264)**	**7,905 (7,492)**
Energy Out, GJ/hr (MMBtu/hr)[1]			
Sensible + Latent			
Bottom Ash	0.5 (0.4)	0.6 (0.5)	0.7 (0.6)
Fly Ash + FGD Ash	1.6 (1.6)	2.0 (1.9)	2.4 (2.2)
Flue Gas	767 (727)	510 (484)	242 (230)
Condenser	2,245 (2,128)	1,961 (1,859)	1,642 (1,556)
CO_2	N/A	-64 (-61)	-130 (-123)
Cooling Tower Blowdown	11.8 (11.2)	25.2 (23.9)	44.9 (42.5)
Econamine Losses	N/A	1,536 (1,456)	3,298 (3,126)
Process Losses[2]	*179 (170)*	*370 (351)*	*373 (353)*
Power	2,107 (1,997)	2,267 (2,149)	2,432 (2,305)
Total Out	**5,312 (5,035)**	**6,609 (6,264)**	**7,905 (7,492)**

[1] Enthalpy reference conditions are 0°C (32°F) and 614 Pa (0.089 psia)
[2]Process losses are calculated by difference to close the energy balance

6.1.6 Case 4 - 6 – Major Equipment List

Major equipment items for the supercritical PC plant with and 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 6.1.7. 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.

ACCOUNT 1 COAL HANDLING

Equipment No.	Description	Type	Operating Qty.	Spares	Case 4 Design Condition	Case 5 Design Condition	Case 6 Design Condition
1	Feeder	Belt	2	0	572 tonne/hr (630 tph)	572 tonne/hr (630 tph)	572 tonne/hr (630 tph)
2	Conveyor No. 1	Belt	1	0	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)
3	Transfer Tower No. 1	Enclosed	1	0	N/A	N/A	N/A
4	Conveyor No. 2	Belt	1	0	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)
5	As-Received Coal Sampling System	Two-stage	1	0	N/A	N/A	N/A
6	Stacker/Reclaimer	Traveling, linear	1	0	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)	1,134 tonne/hr (1,250 tph)
7	Reclaim Hopper	N/A	2	1	54 tonne (60 ton)	64 tonne (70 ton)	73 tonne (80 ton)
8	Feeder	Vibratory	2	1	209 tonne/hr (230 tph)	263 tonne/hr (290 tph)	308 tonne/hr (340 tph)
9	Conveyor No. 3	Belt w/ tripper	1	0	426 tonne/hr (470 tph)	517 tonne/hr (570 tph)	608 tonne/hr (670 tph)
10	Crusher Tower	N/A	1	0	N/A	N/A	N/A
11	Coal Surge Bin w/ Vent Filter	Dual outlet	2	0	209 tonne (230 ton)	263 tonne (290 ton)	308 tonne (340 ton)
12	Crusher	Impactor reduction	2	0	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)

Equipment No.	Description	Type	Operating Qty.	Spares	Case 4 Design Condition	Case 5 Design Condition	Case 6 Design Condition
13	As-Fired Coal Sampling System	Swing hammer	1	1	N/A	N/A	N/A
14	Conveyor No. 4	Belt w/tripper	1	0	426 tonne/hr (470 tph)	517 tonne/hr (570 tph)	608 tonne/hr (670 tph)
15	Transfer Tower No. 2	Enclosed	1	0	N/A	N/A	N/A
16	Conveyor No. 5	Belt w/ tripper	1	0	426 tonne/hr (470 tph)	517 tonne/hr (570 tph)	608 tonne/hr (670 tph)
17	Coal Silo w/ Vent Filter and Slide Gates	Field erected	3	0	907 tonne (1,000 ton)	1,179 tonne (1,300 ton)	1,361 tonne (1,500 ton)
18	Lime Truck Unloading System	N/A	1	0	18 tonne/hr (20 tph)	18 tonne/hr (20 tph)	27 tonne/hr (30 tph)
19	Lime Bulk Storage Silo w/Vent Filter	Field erected	3	0	454 tonne (500 ton)	544 tonne (600 ton)	726 tonne (800 ton)
20	Lime Live Storage Transport	Pneumatic	1	0	6 tonne/hr (7 tph)	8 tonne/hr (9 tph)	9 tonne/hr (10 tph)
21	Lime Day Bin	w/ actuator	2	0	54 tonne (60 ton)	64 tonne (70 ton)	73 tonne (80 ton)
22	Activated Carbon Storage Silo and Feeder System with Vent Filter	Shop assembled	1	0	Silo - 36 tonne (40 ton) Feeder - 54 kg/hr (120 lb/hr)	Silo - 45 tonne (50 ton) Feeder - 64 kg/hr (140 lb/hr)	Silo - 54 tonne (60 ton) Feeder - 77 kg/hr (170 lb/hr)

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	Operating Qty.	Spares	Case 4 Design Condition	Case 5 Design Condition	Case 6 Design Condition
1	Coal Feeder	Gravimetric	6	0	45 tonne/hr (50 tph)	54 tonne/h (60 tph)	64 tonne/hr (70 tph)
2	Coal Pulverizer	Ball type or equivalent	6	0	45 tonne/hr (50 tph)	54 tonne/h (60 tph)	64 tonne/hr (70 tph)
3	Lime Slaker	N/A	1	1	5 tonne/hr (6 tph)	7 tonne/h (8 tph)	8 tonne/hr (9 tph)
4	Lime Slurry Tank	Field Erected	1	1	276,337 liters (73,000 gal)	333,119 liters (88,000 gal)	389,900 liters (103,000 gal)
5	Lime Slurry Feed Pumps	Horizontal centrifugal	1	1	303 lpm @ 9m H_2O (80 gpm @ 30 ft H_2O)	341 lpm @ 9m H_2O (90 gpm @ 30 ft H_2O)	416 lpm @ 9m H_2O (110 gpm @ 30 ft H_2O)

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Operating Qty.	Spares	Case 4 Design Condition	Case 5 Design Condition	Case 6 Design Condition
1	Condensate Pumps	Vertical canned	1	1	23,091 lpm @ 213 m H_2O (6,100 gpm @ 700 ft H_2O)	19,684 lpm @ 213 m H_2O (5,200 gpm @ 700 ft H_2O)	16,277 lpm @ 213 m H_2O (4,300 gpm @ 700 ft H_2O)
2	Deaerator and Storage Tank	Horizontal spray type	1	0	1,816,637 kg/hr (4,005,000 lb/hr), 5 min. tank	2,178,604 kg/hr (4,803,000 lb/hr), 5 min. tank	2,562,797 kg/hr (5,650,000 lb/hr), 5 min. tank
3	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	1	1	30,662 lpm @ 3,444 m H_2O (8,100 gpm @	36,718 lpm @ 3,505 m H_2O (9,700 gpm @	43,154 lpm @ 3,505 m H_2O (11,400 gpm @

Equipment No.	Description	Type	Operating Qty.	Spares	Case 4 Design Condition	Case 5 Design Condition	Case 6 Design Condition
					11,300 ft H_2O)	11,500 ft H_2O)	11,500 ft H_2O)
4	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	1	0	9,085 lpm @ 3,444 m H_2O (2,400 gpm @ 11,300 ft H_2O)	10,978 lpm @ 3,505 m H_2O (2,900 gpm @ 11,500 ft H_2O)	12,870 lpm @ 3,505 m H_2O (3,400 gpm @ 11,500 ft H_2O)
5	LP Feedwater Heater 1A/1B	Horizontal U-tube	2	0	684,924 kg/hr (1,510,000 lb/hr)	580,598 kg/hr (1,280,000 lb/hr)	485,344 kg/hr (1,070,000 lb/hr)
6	LP Feedwater Heater 2A/2B	Horizontal U-tube	2	0	684,924 kg/hr (1,510,000 lb/hr)	580,598 kg/hr (1,280,000 lb/hr)	485,344 kg/hr (1,070,000 lb/hr)
7	LP Feedwater Heater 3A/3B	Horizontal U-tube	2	0	684,924 kg/hr (1,510,000 lb/hr)	580,598 kg/hr (1,280,000 lb/hr)	485,344 kg/hr (1,070,000 lb/hr)
8	LP Feedwater Heater 4A/4B	Horizontal U-tube	2	0	684,924 kg/hr (1,510,000 lb/hr)	580,598 kg/hr (1,280,000 lb/hr)	485,344 kg/hr (1,070,000 lb/hr)
9	HP Feedwater Heater 6	Horizontal U-tube	1	0	1,814,369 kg/hr (4,000,000 lb/hr)	2,177,243 kg/hr (4,800,000 lb/hr)	2,562,797 kg/hr (5,650,000 lb/hr)
10	HP Feedwater Heater 7	Horizontal U-tube	1	0	1,814,369 kg/hr (4,000,000 lb/hr)	2,177,243 kg/hr (4,800,000 lb/hr)	2,562,797 kg/hr (5,650,000 lb/hr)
11	HP Feedwater heater 8	Horizontal U-tube	1	0	1,814,369 kg/hr (4,000,000 lb/hr)	2,177,243 kg/hr (4,800,000 lb/hr)	2,562,797 kg/hr (5,650,000 lb/hr)
12	Auxiliary Boiler	Shop fabricated, water tube	1	0	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)
13	Fuel Oil System	No. 2 fuel oil for light off	1	0	1,135,624 liter (300,000 gal)	1,135,624 liter (300,000 gal)	1,135,624 liter (300,000 gal)
14	Service Air Compressors	Flooded Screw	2	1	28 m^3/min @ 0.7 MPa (1,000 scfm	28 m^3/min @ 0.7 MPa (1,000 scfm	28 m^3/min @ 0.7 MPa (1,000 scfm

Equipment No.	Description	Type	Operating Qty.	Spares	Case 4 Design Condition	Case 5 Design Condition	Case 6 Design Condition
					@ 100 psig)	@ 100 psig)	@ 100 psig)
15	Instrument Air Dryers	Duplex, regenerative	2	1	28 m^3/min (1,000 scfm)	28 m^3/min (1,000 scfm)	28 m^3/min (1,000 scfm)
16	Closed Cycle Cooling Heat Exchangers	Shell and tube	2	0	53 GJ/hr (50 MMBtu/hr) each	53 GJ/hr (50 MMBtu/hr) each	53 GJ/hr (50 MMBtu/hr) each
17	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	2	1	20,820 lpm @ 30 m H_2O (5,500 gpm @ 100 ft H_2O)	20,820 lpm @ 30 m H_2O (5,500 gpm @ 100 ft H_2O)	20,820 lpm @ 30 m H_2O (5,500 gpm @ 100 ft H_2O)
18	Engine-Driven Fire Pump	Vertical turbine, diesel engine	1	1	3,785 lpm @ 88 m H_2O (1,000 gpm @ 290 ft H_2O)	3,785 lpm @ 88 m H_2O (1,000 gpm @ 290 ft H_2O)	3,785 lpm @ 88 m H_2O (1,000 gpm @ 290 ft H_2O)
19	Fire Service Booster Pump	Two-stage horizontal centrifugal	1	1	2,650 lpm @ 64 m H_2O (700 gpm @ 210 ft H_2O)	2,650 lpm @ 64 m H_2O (700 gpm @ 210 ft H_2O)	2,650 lpm @ 64 m H_2O (700 gpm @ 210 ft H_2O)
20	Raw Water Pumps	Stainless steel, single suction	2	1	2,688 lpm @ 43 m H_2O (710 gpm @ 140 ft H_2O)	5,565 lpm @ 43 m H_2O (1,470 gpm @ 140 ft H_2O)	8,896 lpm @ 43 m H_2O (2,350 gpm @ 140 ft H_2O)
21	Ground Water Pumps	Stainless steel, single suction	2	1	2,688 lpm @ 268 m H_2O (710 gpm @ 880 ft H_2O)	2,801 lpm @ 268 m H_2O (740 gpm @ 880 ft H_2O)	2,953 lpm @ 268 m H_2O (780 gpm @ 880 ft H_2O)
22	Filtered Water Pumps	Stainless steel, single suction	2	1	151 lpm @ 49 m H_2O (40 gpm @ 160 ft H_2O)	227 lpm @ 49 m H_2O (60 gpm @ 160 ft H_2O)	265 lpm @ 49 m H_2O (70 gpm @ 160 ft H_2O)
23	Filtered Water Tank	Vertical, cylindrical	1	0	158,987 liter (42,000 gal)	200,627 liter (53,000 gal)	238,481 liter (63,000 gal)

Equipment No.	Description	Type	Operating Qty.	Spares	Case 4 Design Condition	Case 5 Design Condition	Case 6 Design Condition
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrode ionization unit	1	1	341 lpm (90 gpm)	416 lpm (110 gpm)	492 lpm (130 gpm)
25	Liquid Waste Treatment System	--	1	0	10 years, 24-hour storm	10 years, 24-hour storm	10 years, 24-hour storm

ACCOUNT 4 BOILER AND ACCESSORIES

Equipment No.	Description	Type	Operating Qty.	Spares	Case 4 Design Condition	Case 5 Design Condition	Case 6 Design Condition
1	Boiler	Supercritical, drum, wall-fired, low NOx burners, overfire air	1	0	1,814,369 kg/hr steam @ 25.5 MPa/602°C/602°C (4,000,000 lb/hr steam @ 3,700 psig/1,115°F/1,115°F)	2,177,243 kg/hr steam @ 25.5 MPa/602°C/602°C (4,800,000 lb/hr steam @ 3,700 psig/1,115°F/1,115°F)	2,562,797 kg/hr steam @ 25.5 MPa/602°C/602°C (5,650,000 lb/hr steam @ 3,700 psig/1,115°F/1,115°F)
2	Primary Air Fan	Centrifugal	2	0	415,037 kg/hr, 7,054 m^3/min @ 123 cm WG (915,000 lb/hr, 249,100 acfm @ 48 in. WG)	505,755 kg/hr, 8,597 m^3/min @ 123 cm WG (1,115,000 lb/hr, 303,600 acfm @ 48 in. WG)	593,299 kg/hr, 10,086 m^3/min @ 123 cm WG (1,308,000 lb/hr, 356,200 acfm @ 48 in. WG)
3	Forced Draft Fan	Centrifugal	2	0	622,782 kg/hr, 10,582 m^3/min @ 47 cm WG (1,373,000 lb/hr, 373,700 acfm @ 19 in. WG)	758,406 kg/hr, 12,893 m^3/min @ 47 cm WG (1,672,000 lb/hr, 455,300 acfm @ 19 in. WG)	890,402 kg/hr, 15,133 m^3/min @ 47 cm WG (1,963,000 lb/hr, 534,400 acfm @ 19 in. WG)

Equipment No.	Description	Type	Operating Qty.	Spares	Case 4 Design Condition	Case 5 Design Condition	Case 6 Design Condition
4	Induced Draft Fan	Centrifugal 2		0	1,215,174 kg/hr, 28,524 m^3/min @ 82 cm WG (2,679,000 lb/hr, 1,007,300 acfm @ 32 in. WG)	1,480,072 kg/hr, 34,750 m^3/min @ 82 cm WG (3,263,000 lb/hr, 1,227,200 acfm @ 32 in. WG)	1,737,712 kg/hr, 40,793 m^3/min @ 82 cm WG (3,831,000 lb/hr, 1,440,600 acfm @ 32 in. WG)
5	SCR Reactor Vessel	Space for spare layer	2 0		2,431,255 kg/hr (5,360,000 lb/hr)	2,961,958 kg/hr (6,530,000 lb/hr)	3,474,518 kg/hr (7,660,000 lb/hr)
6 SCR	Catalyst	--	3	0	-- -- --		
7	Dilution Air Blower	Centrifugal 2		1	40 m^3/min @ 108 cm WG (1,400 acfm @ 42 in. WG)	51 m^3/min @ 108 cm WG (1,800 acfm @ 42 in. WG)	59 m^3/min @ 108 cm WG (2,100 acfm @ 42 in. WG)
8	Ammonia Storage	Horizontal tank	5 0		45,425 liter (12,000 gal)	52,996 liter (14,000 gal)	64,352 liter (17,000 gal)
9	Ammonia Feed Pump	Centrifugal 2		1	9 lpm @ 91 m H_2O 2 gpm @ 300 ft H_2O)	10 lpm @ 91 m H_2O (3 gpm @ 300 ft H_2O)	12 lpm @ 91 m H_2O (3 gpm @ 300 ft H_2O)

ACCOUNT 5 FLUE GAS CLEANUP

Equipment No.	**Description**	**Type**	**Operating Qty.**	**Spares**	**Case 4 Design Condition**	**Case 5 Design Condition**	**Case 6 Design Condition**
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system, air-to-cloth ratio - 3.5 ft/min	2 0		1,215,174 kg/hr (2,679,000 lb/hr) 99.9% efficiency	1,480,072 kg/hr (3,263,000 lb/hr) 99.9% efficiency	1,737,712 kg/hr (3,831,000 lb/hr) 99.9% efficiency
2	Spray Dryer	Co-current open spray	2	0	30,356 m^3/min (1,072,000 acfm)	36,982 m^3/min (1,306,000 acfm)	43,410 m^3/min (1,533,000 acfm)

Equipment No.	Description	Type	Operating Qty.	Spares	Case 4 Design Condition	Case 5 Design Condition	Case 6 Design Condition
3	Atomizer	Rotary	2	1	151 lpm @ 64 m H_2O (40 gpm @ 210 ft H_2O)	189 lpm @ 64 m H_2O (50 gpm @ 210 ft H_2O)	227 lpm @ 64 m H_2O (60 gpm @ 210 ft H_2O)
4	Spray Dryer Solids Conveying	---	2	0	---	---	---
5	Carbon Injectors	---	1	0	54 kg/hr (120 lb/hr)	64 kg/hr (140 lb/hr)	77 kg/hr (170 lb/hr)

ACCOUNT 5B CO$_2$ COMPRESSION

Equipment No.	Description	Type	Operating Qty.	Spares	Case 4 Design Condition	Case 5 Design Condition	Case 6 Design Condition
1	Econamine FG Plus	Amine-based CO_2 capture technology	2	0	N/A	862,279 kg/h (1,901,000 lb/h) 21.4 wt % CO_2 concentration	1,737,712 kg/h (3,831,000 lb/h) 21.5 wt % CO_2 concentration
2	Econamine Condensate Pump	Centrifugal	1	1	N/A	9,350 lpm @ 52 m H_2O (2,470 gpm @ 170 ft H_2O)	18,889 lpm @ 52 m H_2O (4,990 gpm @ 170 ft H_2O)
3	CO2 Compressor	Reciprocating	2	0	N/A	166,363 kg/h @ 15.3 MPa (366,767 lb/h @ 2,215 psia)	336,022 kg/h @ 15.3 MPa (740,801 lb/h @ 2,215 psia)

ACCOUNT 5C CO$_2$ TRANSPORT, STORAGE, AND MONITORING (not shown in Total Plant Cost Details)

Equipment No.	Description	Type	Case 4 Design Condition	Case 5 Design Condition	Case 6 Design Condition
1	CO_2 Pipeline	Carbon Steel	N/A	50 miles @ 14 in diameter w/ inlet pressure of 2,200 psi and outlet pressure of 1,500 psi	50 miles @ 18 in diameter w/ inlet pressure of 2,200 psi and outlet pressure of 1,500 psi
2	CO_2 Sequestration Source	Saline Formation	N/A	1 well with bottom hole pressure @ 1,220 psi, 530 ft thickness, 4,055 ft depth, 22 Md permeability	2 wells with bottom hole pressure @ 1,220 psi, 530 ft thickness, 4,055 ft depth, 22 Md permeability
3	CO_2 Monitoring	N/A	N/A	20 year monitoring life during plant life / 80 years following / Total of 100 years	20 year monitoring life during plant life / 80 years following / Total of 100 years

ACCOUNT 6 COMBUSTION TURBINE/ACCESSORIES

N/A

ACCOUNT 7 HRSG, DUCTING & STACK

Equipment No.	Description	Type	Operating Qty.	Spares	Case 4 Design Condition	Case 5 Design Condition	Case 6 Design Condition
1	Stack	Reinforced concrete with FRP liner	1	0	152 m (500 ft) high x 6.8 m (22 ft) diameter	152 m (500 ft) high x 6.7 m (22 ft) diameter	152 m (500 ft) high x 6.1 m (20 ft) diameter

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Operating Qty.	Spares	Case 4 Design Condition	Case 5 Design Condition	Case 6 Design Condition
1	Steam Turbine	Commercially available advanced steam turbine	1	0	616 MW 24.1 MPa/593°C/593°C (3500 psig/ 1100°F/1100°F)	663 MW 24.1 MPa/593°C/593°C (3500 psig/ 1100°F/1100°F)	711 MW 24.1 MPa/593°C/593°C (3500 psig/ 1100°F/1100°F)
2	Steam Turbine Generator	Hydrogen cooled, static excitation	1	0	680 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	740 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	790 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1	0	1,230 GJ/hr (1,170 MMBtu/hr), Condensing temperature 32°C (90°F), Inlet water temperature 9°C (48°F), Water temperature rise 11°C (20°F)	1,080 GJ/hr (1,020 MMBtu/hr), Condensing temperature 32°C (90°F), Inlet water temperature 9°C (48°F), Water temperature rise 11°C (20°F)	910 GJ/hr (860 MMBtu/hr), Condensing temperature 32°C (90°F), Inlet water temperature 9°C (48°F), Water temperature rise 11°C (20°F)
4	Air Cooled Condenser	Ambient air to steam	1	0	1,230 GJ/hr (1,170 MMBtu/hr), Condensing temperature 32°C (90°F), Ambient temperature 6°C (42°F)	1,080 GJ/hr (1,020 MMBtu/hr), Condensing temperature 32°C (90°F), Ambient temperature 6°C (42°F)	910 GJ/hr (860 MMBtu/hr), Condensing temperature 32°C (90°F), Ambient temperature 6°C (42°F)

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Operating Qty.	Spares	Case 4 Design Condition	Case 5 Design Condition	Case 6 Design Condition
1	Circulating Water Pumps	Vertical, wet pit	2	1	242,300 lpm @ 30 m (64,000 gpm @ 100 ft)	518,600 lpm @ 30 m (137,000 gpm @ 100 ft)	923,600 lpm @ 30 m (244,000 gpm @ 100 ft)
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	1	0	3°C (37°F) wet bulb / 9°C (48°F) CWT / 20°C (68°F) HWT / 1,350 GJ/hr (1,280 MMBtu/hr) heat duty	3°C (37°F) wet bulb / 9°C (48°F) CWT / 20°C (68°F) HWT / 2,880 GJ/hr (2,730 MMBtu/hr) heat duty	3°C (37°F) wet bulb / 9°C (48°F) CWT / 20°C (68°F) HWT / 5,138 GJ/hr (4,870 MMBtu/hr) heat duty

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Equipment No.	Description	Type	Operating Qty.	Spares	Case 4 Design Condition	Case 5 Design Condition	Case 6 Design Condition
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	--	1	1	4.5 tonne/hr (5 tph)	5.4 tonne/hr (6 tph)	6.4 tonne/hr (7 tph)
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	--	6	0	--	--	--
5	Hydroejectors	--	12		--	--	--

Equipment No.	Description	Type	Operating Qty.	Spares	Case 4 Design Condition	Case 5 Design Condition	Case 6 Design Condition
6	Economizer /Pyrites Transfer Tank	--	1	0	--	--	--
7	Ash Sluice Pumps	Vertical, wet pit	1	1	189 lpm @ 17 m H_2O (50 gpm @ 56 ft H_2O)	227 lpm @ 17 m H_2O (60 gpm @ 56 ft H_2O)	265 lpm @ 17 m H2O (70 gpm @ 56 ft H2O)
8	Ash Seal Water Pumps	Vertical, wet pit	1	1	7,571 lpm @ 9 m H_2O (2000 gpm @ 28 ft H_2O)	7,571 lpm @ 9 m H_2O (2000 gpm @ 28 ft H_2O)	7,571 lpm @ 9 m H_2O (2000 gpm @ 28 ft H_2O)
9	Hydrobins	--	1	1	189 lpm (50 gpm)	227 lpm (60 gpm)	265 lpm (70 gpm)
10	Baghouse Hopper (part of baghouse scope of supply)	--	24	0	--	--	--
11	Air Heater Hopper (part of boiler scope of supply)	--	10	0	--	--	--
12	Air Blower	--	1	1	25 m^3/min @ 0.2 MPa (880 scfm @ 24 psi)	30 m^3/min @ 0.2 MPa (1070 scfm @ 24 psi)	36 m^3/min @ 0.2 MPa (1260 scfm @ 24 psi)
13	Fly Ash Silo	Reinforced concrete	2	0	1,630 tonne (1,800 ton)	2,000 tonne (2,200 ton)	2,360 tonne (2,600 ton)
14	Slide Gate Valves	--	2	0	--	--	--
15	Unloader	--	1	0	--	--	--
16	Telescoping Unloading Chute	--	1	0	154 tonne/hr (170 tph)	181 tonne/hr (200 tph)	218 tonne/hr (240 tph)
17	Recycle Waste Storage Silo	Reinforced concrete	2	0	272 tonne (300 ton)	363 tonne (400 ton)	454 tonne (500 ton)
18	Recycle Waste Conveyor	--	1	0	36 tonne/hr (40 tph)	45 tonne/hr (50 tph)	54 tonne/hr (60 tph)

Equipment No.	Description	Type	Operating Qty.	Spares	Case 4 Design Condition	Case 5 Design Condition	Case 6 Design Condition
19	Recycle Slurry Mixer	--	1	1	984 lpm (260 gpm)	1,211 lpm (320 gpm)	1,438 lpm (380 gpm)
20	Recycle Waste Slurry Tank	--	1	0	60,570 liters (16,000 gal)	71,920 liters (19,000 gal)	87,060 liters (23,000 gal)
21	Recycle Waste Pump	--	1	1	984 lpm (260 gpm)	1,211 lpm (320 gpm)	1,438 lpm (380 gpm)

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Operating Qty.	Spares	Case 4 Design Condition	Case 5 Design Condition	Case 6 Design Condition
1	STG Transformer	Oil-filled	1	0	24 kV/345 kV, 650 MVA, 3-ph, 60 Hz	24 kV/345 kV, 650 MVA, 3-ph, 60 Hz	24 kV/345 kV, 650 MVA, 3-ph, 60 Hz
2	Auxiliary Transformer	Oil-filled	1	1	24 kV/4.16 kV, 37 MVA, 3-ph, 60 Hz	24 kV/4.16 kV, 86 MVA, 3-ph, 60 Hz	24 kV/4.16 kV, 137 MVA, 3-ph, 60 Hz
3	Low Voltage Transformer	Dry ventilated	1	1	4.16 kV/480 V, 6 MVA, 3-ph, 60 Hz	4.16 kV/480 V, 13 MVA, 3-ph, 60 Hz	4.16 kV/480 V, 21 MVA, 3-ph, 60 Hz
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	1	0	24 kV, 3-ph, 60 Hz	24 kV, 3-ph, 60 Hz	24 kV, 3-ph, 60 Hz
5	Medium Voltage Switchgear	Metal clad	1	1	4.16 kV, 3-ph, 60 Hz	4.16 kV, 3-ph, 60 Hz	4.16 kV, 3-ph, 60 Hz
6	Low Voltage Switchgear	Metal enclosed	1	1	480 V, 3-ph, 60 Hz	480 V, 3-ph, 60 Hz	480 V, 3-ph, 60 Hz
7	Emergency Diesel Generator	Sized for emergency shutdown	1	0	750 kW, 480 V, 3-ph, 60 Hz	750 kW, 480 V, 3-ph, 60 Hz	750 kW, 480 V, 3-ph, 60 Hz

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Operating Qty.	Spares	Case 4 Design Condition	Case 5 Design Condition	Case 6 Design Condition
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	1	0	Operator stations/printers and engineering stations/printers	Operator stations/printers and engineering stations/printers	Operator stations/printers and engineering stations/printers
2	DCS - Processor	Microprocessor with redundant input/output	1	0	N/A	N/A	N/A
3	DCS - Data Highway	Fiber optic	1	0	Fully redundant, 25% spare	Fully redundant, 25% spare	Fully redundant, 25% spare

6.1.7 Case 4 – Cost Estimating

The cost estimating methodology was described previously in Section 2.6. Exhibit 6-21 shows the total plant capital cost details organized by cost. Exhibit 6-22 shows the initial and annual O&M costs.

The estimated TOC of the supercritical PC case with no CO_2 capture is $2,296/kW. Owner's costs represent 18 percent of the TOC. The current dollar, 30-year LCOE is $79.86/MWh.

Exhibit 6-21 Case 4 Total Plant Cost Details

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 4 TOTAL PLANT COST $	Case 4 TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$4,127	$0	$1,885	$0	$0	$6,012	$537	$0	$982	$7,531	$14
1.2	Coal Stackout & Reclaim	$5,333	$0	$1,208	$0	$0	$6,542	$572	$0	$1,067	$8,181	$15
1.3	Coal Conveyors	$4,959	$0	$1,196	$0	$0	$6,154	$539	$0	$1,004	$7,698	$14
1.4	Other Coal Handling	$1,297	$0	$277	$0	$0	$1,574	$138	$0	$257	$1,968	$4
1.5	Sorbent Receive & Unload	$50	$0	$15	$0	$0	$65	$6	$0	$11	$82	$0
1.6	Sorbent Stackout & Reclaim	$811	$0	$149	$0	$0	$960	$84	$0	$157	$1,200	$2
1.7	Sorbent Conveyors	$290	$63	$71	$0	$0	$423	$37	$0	$69	$529	$1
1.8	Other Sorbent Handling	$175	$41	$92	$0	$0	$308	$27	$0	$50	$385	$1
1.9	Coal & Sorbent Hnd.Foundations	$0	$5,069	$6,394	$0	$0	$11,463	$1,077	$0	$1,881	$14,420	$26
	SUBTOTAL 1.	**$17,042**	**$5,172**	**$11,286**	**$0**	**$0**	**$33,501**	**$3,016**	**$0**	**$5,478**	**$41,994**	**$76**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$2,395	$0	$467	$0	$0	$2,862	$249	$0	$467	$3,578	$7
2.2	Coal Conveyor to Storage	$6,132	$0	$1,338	$0	$0	$7,470	$653	$0	$1,218	$9,342	$17
2.3	Coal Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.4	Misc.Coal Prep & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$685	$575	$0	$0	$1,260	$117	$0	$206	$1,583	$3
	SUBTOTAL 2.	**$8,527**	**$685**	**$2,380**	**$0**	**$0**	**$11,592**	**$1,019**	**$0**	**$1,892**	**$14,502**	**$26**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$18,522	$0	$5,983	$0	$0	$24,506	$2,141	$0	$3,997	$30,644	$56
3.2	Water Makeup & Pretreating	$2,296	$0	$739	$0	$0	$3,035	$287	$0	$665	$3,987	$7
3.3	Other Feedwater Subsystems	$5,671	$0	$2,396	$0	$0	$8,067	$723	$0	$1,318	$10,108	$18
3.4	Service Water Systems	$450	$0	$245	$0	$0	$695	$65	$0	$152	$913	$2
3.5	Other Boiler Plant Systems	$7,472	$0	$7,377	$0	$0	$14,848	$1,410	$0	$2,439	$18,697	$34
3.6	FO Supply Sys & Nat Gas	$256	$0	$320	$0	$0	$576	$54	$0	$95	$725	$1
3.7	Waste Treatment Equipment	$1,557	$0	$887	$0	$0	$2,444	$238	$0	$536	$3,219	$6
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$2,717	$0	$830	$0	$0	$3,547	$341	$0	$778	$4,666	$8
	SUBTOTAL 3.	**$38,941**	**$0**	**$18,778**	**$0**	**$0**	**$57,719**	**$5,260**	**$0**	**$9,980**	**$72,959**	**$133**
4	PC BOILER											
4.1	PC Boiler & Accessories	$186,248	$0	$91,031	$0	$0	$277,279	$26,958	$0	$30,424	$334,660	$608
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.3	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.4	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Primary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Secondary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Boiler Foundations	$0	w/14.1	w/14.1	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4.	**$186,248**	**$0**	**$91,031**	**$0**	**$0**	**$277,279**	**$26,958**	**$0**	**$30,424**	**$334,660**	**$608**

Exhibit 6-21 Case 4 Total Plant Cost Details (Continued)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 4 TOTAL PLANT COST $	Case 4 TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	$81,057	$0	$17,563	$0	$0	$98,620	$9,403	$0	$10,802	$118,825	$216
5.2	Other FGD	$947	$0	$488	$0	$0	$1,435	$138	$0	$157	$1,730	$3
5.3	Bag House & Accessories	w/5.1	$0	w/5.1	$0	$0	$0	$0	$0	$0	$0	$0
5.4	Other Particulate Removal Materials	$20,218	$0	$10,972	$0	$0	$31,190	$3,000	$0	$3,419	$37,609	$68
5.5	Gypsum Dewatering System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.6	Mercury Removal System	w/5.1	$0	w/5.1	$0	$0	$0	$0	$0	$0	$0	$0
5.9	Open											
	SUBTOTAL 5.	**$102,221**	**$0**	**$29,024**	**$0**	**$0**	**$131,245**	**$12,541**	**$0**	**$14,379**	**$158,164**	**$288**
5B	CO_2 REMOVAL & COMPRESSION											
5B.1	CO_2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO_2 Compression & Drying	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.3	CO_2 Removal System Let Down Turbine	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5B.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 6.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
7.2	HRSG Accessories	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$10,547	$0	$6,777	$0	$0	$17,324	$1,511	$0	$2,825	$21,660	$39
7.4	Stack	$11,542	$0	$6,753	$0	$0	$18,295	$1,761	$0	$2,006	$22,062	$40
7.9	Duct & Stack Foundations	$0	$1,348	$1,532	$0	$0	$2,880	$270	$0	$630	$3,779	$7
	SUBTOTAL 7.	**$22,089**	**$1,348**	**$15,062**	**$0**	**$0**	**$38,499**	**$3,541**	**$0**	**$5,461**	**$47,501**	**$86**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$52,000	$0	$6,918	$0	$0	$58,919	$5,647	$0	$6,457	$71,022	$129
8.2	Turbine Plant Auxiliaries	$349	$0	$748	$0	$0	$1,098	$107	$0	$121	$1,326	$2
8.3a	Condenser & Auxiliaries	$4,114	$0	$2,305	$0	$0	$6,418	$618	$0	$704	$7,740	$14
8.3b	Air Cooled Condenser	$37,199	$0	$7,458	$0	$0	$44,657	$4,466	$0	$9,824	$58,947	$107
8.4	Steam Piping	$20,436	$0	$10,076	$0	$0	$30,513	$2,564	$0	$4,961	$38,038	$69
8.9	TG Foundations	$0	$1,096	$1,732	$0	$0	$2,828	$268	$0	$619	$3,715	$7
	SUBTOTAL 8.	**$114,099**	**$1,096**	**$29,237**	**$0**	**$0**	**$144,432**	**$13,668**	**$0**	**$22,686**	**$180,786**	**$329**

Exhibit 6-21 Case 4 Total Plant Cost Details (Continued)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 4 TOTAL PLANT COST $	Case 4 TOTAL PLANT COST $/kW
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$5,750	$0	$1,791	$0	$0	$7,540	$721	$0	$826	$9,088	$17
9.2	Circulating Water Pumps	$1,190	$0	$116	$0	$0	$1,307	$111	$0	$142	$1,559	$3
9.3	Circ.Water System Auxiliaries	$363	$0	$48	$0	$0	$411	$39	$0	$45	$495	$1
9.4	Circ.Water Piping	$0	$2,877	$2,788	$0	$0	$5,665	$530	$0	$929	$7,125	$13
9.5	Make-up Water System	$278	$0	$371	$0	$0	$649	$62	$0	$107	$818	$1
9.6	Component Cooling Water Sys	$287	$0	$228	$0	$0	$516	$49	$0	$85	$649	$1
9.9	Circ.Water System Foundations& Structures	$0	$1,712	$2,721	$0	$0	$4,433	$419	$0	$971	$5,823	$11
	SUBTOTAL 9.	**$7,868**	**$4,590**	**$8,064**	**$0**	**$0**	**$20,522**	**$1,932**	**$0**	**$3,104**	**$25,558**	**$46**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Ash Coolers	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.2	Cyclone Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.3	HGCU Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Recovery Equipment	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$770	$0	$2,371	$0	$0	$3,141	$308	$0	$345	$3,794	$7
10.7	Ash Transport & Feed Equipment	$4,982	$0	$5,103	$0	$0	$10,085	$964	$0	$1,105	$12,154	$22
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$183	$215	$0	$0	$398	$37	$0	$87	$523	$1
	SUBTOTAL 10.	**$5,751**	**$183**	**$7,690**	**$0**	**$0**	**$13,624**	**$1,310**	**$0**	**$1,537**	**$16,471**	**$30**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$1,607	$0	$261	$0	$0	$1,867	$173	$0	$153	$2,194	$4
11.2	Station Service Equipment	$3,007	$0	$988	$0	$0	$3,995	$373	$0	$328	$4,696	$9
11.3	Switchgear & Motor Control	$3,457	$0	$588	$0	$0	$4,045	$375	$0	$442	$4,861	$9
11.4	Conduit & Cable Tray	$0	$2,167	$7,494	$0	$0	$9,662	$935	$0	$1,590	$12,187	$22
11.5	Wire & Cable	$0	$4,090	$7,895	$0	$0	$11,985	$1,010	$0	$1,949	$14,944	$27
11.6	Protective Equipment	$271	$0	$923	$0	$0	$1,195	$117	$0	$131	$1,443	$3
11.7	Standby Equipment	$1,282	$0	$29	$0	$0	$1,312	$120	$0	$143	$1,575	$3
11.8	Main Power Transformers	$6,183	$0	$175	$0	$0	$6,358	$484	$0	$684	$7,526	$14
11.9	Electrical Foundations	$0	$313	$768	$0	$0	$1,081	$103	$0	$237	$1,421	$3
	SUBTOTAL 11.	**$15,808**	**$6,570**	**$19,121**	**$0**	**$0**	**$41,499**	**$3,691**	**$0**	**$5,657**	**$50,846**	**$92**
12	INSTRUMENTATION & CONTROL											
12.1	PC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12.5	Signal Processing Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$454	$0	$272	$0	$0	$726	$69	$0	$119	$914	$2
12.7	Distributed Control System Equipment	$4,586	$0	$802	$0	$0	$5,388	$499	$0	$589	$6,476	$12
12.8	Instrument Wiring & Tubing	$2,486	$0	$4,932	$0	$0	$7,418	$632	$0	$1,208	$9,258	$17
12.9	Other I & C Equipment	$1,296	$0	$2,941	$0	$0	$4,237	$411	$0	$465	$5,112	$9
	SUBTOTAL 12.	**$8,823**	**$0**	**$8,946**	**$0**	**$0**	**$17,769**	**$1,611**	**$0**	**$2,380**	**$21,760**	**$40**

Exhibit 6-21 Case 4 Total Plant Cost Details (Continued)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 4 TOTAL PLANT COST $	Case 4 TOTAL PLANT COST $/kW
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$50	$1,004	$0	$0	$1,055	$105	$0	$232	$1,391	$3
13.2	Site Improvements	$0	$1,667	$2,071	$0	$0	$3,738	$369	$0	$821	$4,928	$9
13.3	Site Facilities	$2,988	$0	$2,947	$0	$0	$5,934	$585	$0	$1,304	$7,823	$14
	SUBTOTAL 13.	**$2,988**	**$1,718**	**$6,022**	**$0**	**$0**	**$10,727**	**$1,058**	**$0**	**$2,357**	**$14,143**	**$26**
14	BUILDINGS & STRUCTURES											
14.1	Boiler Building	$0	$9,149	$8,046	$0	$0	$17,196	$1,546	$0	$2,811	$21,552	$39
14.2	Turbine Building	$0	$11,890	$11,081	$0	$0	$22,971	$2,070	$0	$3,756	$28,797	$52
14.3	Administration Building	$0	$588	$622	$0	$0	$1,210	$110	$0	$198	$1,518	$3
14.4	Circulation Water Pumphouse	$0	$169	$134	$0	$0	$303	$27	$0	$49	$379	$1
14.5	Water Treatment Buildings	$0	$298	$246	$0	$0	$544	$49	$0	$89	$682	$1
14.6	Machine Shop	$0	$393	$264	$0	$0	$658	$58	$0	$107	$824	$1
14.7	Warehouse	$0	$267	$267	$0	$0	$534	$48	$0	$87	$670	$1
14.8	Other Buildings & Structures	$0	$218	$185	$0	$0	$403	$36	$0	$66	$505	$1
14.9	Waste Treating Building & Str.	$0	$408	$1,238	$0	$0	$1,646	$156	$0	$270	$2,073	$4
	SUBTOTAL 14.	**$0**	**$23,380**	**$22,084**	**$0**	**$0**	**$45,465**	**$4,101**	**$0**	**$7,435**	**$57,000**	**$104**
	TOTAL COST	**$530,405**	**$44,742**	**$268,724**	**$0**	**$0**	**$843,871**	**$79,706**	**$0**	**$112,767**	**$1,036,345**	**$1,884**
	Owner's Costs											
	Preproduction Costs											
	6 Months All Labor										$8,054	$15
	1 Month Maintenance Materials										$1,083	$2
	1 Month Non-fuel Consumables										$561	$1
	1 Month Waste Disposal										$379	$1
	25% of 1 Months Fuel Cost at 100% CF										$538	$1
	2% of TPC										$20,727	$38
	Total										**$31,341**	**$57**
	Inventory Capital											
	60 day supply of fuel and consumables at 100% CF										$5,424	$10
	0.5% of TPC (spare parts)										$5,182	$9
	Total										**$10,606**	**$19**
	Initial Cost for Catalyst and Chemicals										$0	$0
	Land										$900	$2
	Other Owner's Costs										$155,452	$283
	Financing Costs										$27,981	$51
	Total Overnight Costs (TOC)										**$1,262,625**	**$2,296**
	TASC Multiplier								(IOU, low risk, 35 year)		1.134	
	Total As-Spent Cost (TASC)										**$1,431,817**	**$2,603**

Exhibit 6-22 Case 4 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES						Cost Base (June)	2007
Case 4 - Supercritical PC w/o CO2						Heat Rate-net(Btu/kWh):	8,851
						MWe-net:	550
						Capacity Factor: (%):	85
	OPERATING & MAINTENANCE LABOR						
Operating Labor							
Operating Labor Rate(base):		34.65	$/hour				
Operating Labor Burden:		30.00	% of base				
Labor O-H Charge Rate:		25.00	% of labor				
				Total			
Skilled Operator		2.0		2.0			
Operator		9.0		9.0			
Foreman		1.0		1.0			
Lab Tech's, etc.		2.0		2.0			
TOTAL-O.J.'s		14.0		14.0			
						Annual Cost	Annual Unit Cost
						$	$/kW-net
Annual Operating Labor Cost		Maintenance labor cost		% of BEC	0.8723	$5,524,319	$10.044
Maintenance Labor Cost		(Case S12A is reference)		BEC	$843,871	$7,361,412	$13.384
Administrative & Support Labor						$3,221,433	$5.857
Property Taxes & Insurance						$20,726,893	$37.685
TOTAL FIXED OPERATING COSTS						**$36,834,056**	**$66.970**
VARIABLE OPERATING COSTS							
							$/kWh-net
Maintenance Material Cost				% of BEC	1.3085	**$11,042,118**	**$0.00270**
Consumables		Consumption		Unit	Initial Fill		
		Initial Fill	/Day	Cost	Cost		
Water(/1000 gallons)		0	1,566	1.08	**$0**	**$525,534**	**$0.00013**
Chemicals			4.841				
MU & WT Chem.(lb)		0	7,580	0.17	$0	$407,027	$0.00010
Lime (ton)		0	104	75.00	$0	$2,416,134	$0.00059
Carbon (Mercury Removal) (lb)		0	2,588	1.05	$0	$843,210	$0.00021
MEA Solvent (ton)		0	0	2,249.89	$0	$0	$0.00000
NaOH (tons)		0	0	433.68	$0	$0	$0.00000
H2SO4 (tons)		0	0	138.78	$0	$0	$0.00000
Corrosion Inhibitor		0	0	0.00	$0	$0	$0.00000
Activated Carbon(lb)		0	0	1.05	$0	$0	$0.00000
Ammonia (28% NH3) ton		0	23	129.80	$0	$912,133	$0.00022
Subtotal Chemicals					**$0**	**$4,578,504**	**$0.00112**
Other							
Supplemental Fuel(MBtu)		0	0	0.00	$0	$0	$0.00000
SCR Catalyst(m3)		w/equip.	0.346	5,775.94	$0	$620,518	$0.00015
Emission Penalties		0	0	0.00	$0	$0	$0.00000
Subtotal Other					**$0**	**$620,518**	**$0.00015**
Waste Disposal							
Flyash (ton)		0	657	16.23	$0	$3,307,580	$0.00081
Bottom Ash(ton)		0	112	16.23	$0	$562,230	$0.00014
Subtotal-Waste Disposal					**$0**	**$3,869,811**	**$0.00094**
By-products & Emissions							
Gypsum (tons)		0	0	0.00	$0	$0	$0.00000
Subtotal By-Products					**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS					**$0**	**$20,636,484**	**$0.00504**
Fuel(ton)		0	6,821	10.37	**$0**	**$21,938,585**	**$0.00536**

6.1.8 Case 5 – Cost Estimating

Exhibit 6-23 shows the total plant capital cost details organized by cost account. Exhibit 6-24 shows the initial and annual O&M costs.

The estimated TOC of the supercritical PC case with a CO_2 emission rate of 1,100 lb CO_2/net-MWh is $3,323/kW. Owner's costs represent 18 percent of the TOC. The current dollar, 30-year LCOE, including TS&M, is $120.01/MWh.

Exhibit 6-23 Case 5 Total Plant Cost Details

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 5 TOTAL PLANT COST $	Case 5 TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$4,662	$0	$2,130	$0	$0	$6,792	$607	$0	$1,110	$8,508	$15
1.2	Coal Stackout & Reclaim	$6,025	$0	$1,365	$0	$0	$7,390	$647	$0	$1,206	$9,243	$17
1.3	Coal Conveyors	$5,602	$0	$1,351	$0	$0	$6,953	$609	$0	$1,134	$8,696	$16
1.4	Other Coal Handling	$1,466	$0	$313	$0	$0	$1,778	$155	$0	$290	$2,224	$4
1.5	Sorbent Receive & Unload	$56	$0	$17	$0	$0	$73	$6	$0	$12	$92	$0
1.6	Sorbent Stackout & Reclaim	$910	$0	$167	$0	$0	$1,076	$94	$0	$176	$1,346	$2
1.7	Sorbent Conveyors	$325	$70	$80	$0	$0	$474	$41	$0	$77	$593	$1
1.8	Other Sorbent Handling	$196	$46	$103	$0	$0	$345	$30	$0	$56	$432	$1
1.9	Coal & Sorbent Hnd.Foundations	$0	$5,726	$7,223	$0	$0	$12,949	$1,216	$0	$2,125	$16,290	$30
	SUBTOTAL 1.	**$19,242**	**$5,842**	**$12,747**	**$0**	**$0**	**$37,831**	**$3,406**	**$0**	**$6,186**	**$47,422**	**$86**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$2,727	$0	$531	$0	$0	$3,258	$284	$0	$531	$4,074	$7
2.2	Coal Conveyor to Storage	$6,982	$0	$1,524	$0	$0	$8,506	$744	$0	$1,387	$10,637	$19
2.3	Coal Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.4	Misc.Coal Prep & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$780	$655	$0	$0	$1,434	$133	$0	$235	$1,802	$3
	SUBTOTAL 2.	**$9,709**	**$780**	**$2,710**	**$0**	**$0**	**$13,199**	**$1,161**	**$0**	**$2,154**	**$16,513**	**$30**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$20,866	$0	$6,740	$0	$0	$27,606	$2,412	$0	$4,503	$34,522	$63
3.2	Water Makeup & Pretreating	$3,672	$0	$1,182	$0	$0	$4,854	$459	$0	$1,063	$6,375	$12
3.3	Other Feedwater Subsystems	$6,388	$0	$2,700	$0	$0	$9,088	$814	$0	$1,485	$11,387	$21
3.4	Service Water Systems	$720	$0	$392	$0	$0	$1,111	$105	$0	$243	$1,459	$3
3.5	Other Boiler Plant Systems	$8,635	$0	$8,525	$0	$0	$17,160	$1,630	$0	$2,819	$21,609	$39
3.6	FO Supply Sys & Nat Gas	$268	$0	$335	$0	$0	$603	$57	$0	$99	$759	$1
3.7	Waste Treatment Equipment	$2,489	$0	$1,419	$0	$0	$3,909	$380	$0	$858	$5,147	$9
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$2,847	$0	$870	$0	$0	$3,716	$357	$0	$815	$4,889	$9
	SUBTOTAL 3.	**$45,885**	**$0**	**$22,163**	**$0**	**$0**	**$68,048**	**$6,215**	**$0**	**$11,884**	**$86,146**	**$157**
4	PC BOILER											
4.1	PC Boiler & Accessories	$213,607	$0	$104,237	$0	$0	$317,844	$30,901	$0	$34,874	$383,619	$697
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.3	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.4	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Primary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Secondary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Boiler Foundations	$0	w/14.1	w/14.1	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4.	**$213,607**	**$0**	**$104,237**	**$0**	**$0**	**$317,844**	**$30,901**	**$0**	**$34,874**	**$383,619**	**$697**

Exhibit 6-23 Case 5 Total Plant Cost Details (Continued)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 5 TOTAL PLANT COST $	Case 5 TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	$94,056	$0	$15,822	$0	$0	$109,878	$10,458	$0	$12,034	$132,369	$241
5.2	Other FGD	$1,120	$0	$448	$0	$0	$1,569	$150	$0	$172	$1,891	$3
5.3	Bag House & Accessories	w/5.1	$0	w/5.1	$0	$0	$0	$0	$0	$0	$0	$0
5.4	Other Particulate Removal Materials	$23,740	$0	$10,002	$0	$0	$33,742	$3,236	$0	$3,698	$40,676	$74
5.5	Gypsum Dewatering System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.6	Mercury Removal System	w/5.1	$0	w/5.1	$0	$0	$0	$0	$0	$0	$0	$0
5.9	Open											
	SUBTOTAL 5.	**$118,917**	**$0**	**$26,272**	**$0**	**$0**	**$145,188**	**$13,845**	**$0**	**$15,903**	**$174,936**	**$318**
5B	CO_2 REMOVAL & COMPRESSION											
5B.1	CO_2 Removal System	$141,982	$0	$43,078	$0	$0	$185,060	$17,693	$37,012	$47,953	$287,719	$523
5B.2	CO_2 Compression & Drying	$19,150	$0	$6,008	$0	$0	$25,157	$2,406	$0	$5,513	$33,076	$60
5B.3	CO_2 Removal System Let Down Turbine	$9,400	$0	$1,248	$0	$0	$10,648	$1,021	$0	$1,167	$12,836	$23
	SUBTOTAL 5B.	**$170,532**	**$0**	**$50,334**	**$0**	**$0**	**$220,866**	**$21,120**	**$37,012**	**$54,633**	**$333,631**	**$607**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 6.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
7.2	HRSG Accessories	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$10,553	$0	$6,780	$0	$0	$17,334	$1,511	$0	$2,827	$21,672	$39
7.4	Stack	$11,124	$0	$6,509	$0	$0	$17,633	$1,698	$0	$1,933	$21,264	$39
7.9	Duct & Stack Foundations	$0	$1,295	$1,471	$0	$0	$2,766	$259	$0	$605	$3,630	$7
	SUBTOTAL 7.	**$21,677**	**$1,295**	**$14,761**	**$0**	**$0**	**$37,733**	**$3,468**	**$0**	**$5,365**	**$46,566**	**$85**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$54,735	$0	$7,269	$0	$0	$62,004	$5,942	$0	$6,795	$74,741	$136
8.2	Turbine Plant Auxiliaries	$369	$0	$789	$0	$0	$1,158	$113	$0	$127	$1,398	$3
8.3a	Condenser & Auxiliaries	$3,734	$0	$2,253	$0	$0	$5,987	$577	$0	$656	$7,220	$13
8.3b	Air Cooled Condenser	$33,792	$0	$6,775	$0	$0	$40,567	$4,057	$0	$8,925	$53,548	$97
8.4	Steam Piping	$23,522	$0	$11,598	$0	$0	$35,120	$2,951	$0	$5,711	$43,781	$80
8.9	TG Foundations	$0	$1,158	$1,830	$0	$0	$2,988	$283	$0	$654	$3,925	$7
	SUBTOTAL 8.	**$116,152**	**$1,158**	**$30,514**	**$0**	**$0**	**$147,824**	**$13,922**	**$0**	**$22,868**	**$184,614**	**$336**

Exhibit 6-23 Case 5 Total Plant Cost Details (Continued)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 5 TOTAL PLANT COST $	Case 5 TOTAL PLANT COST $/kW
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$9,940	$0	$3,095	$0	$0	$13,035	$1,247	$0	$1,428	$15,710	$29
9.2	Circulating Water Pumps	$2,125	$0	$203	$0	$0	$2,328	$197	$0	$253	$2,778	$5
9.3	Circ.Water System Auxiliaries	$582	$0	$78	$0	$0	$660	$63	$0	$72	$795	$1
9.4	Circ.Water Piping	$0	$4,614	$4,472	$0	$0	$9,086	$851	$0	$1,490	$11,427	$21
9.5	Make-up Water System	$415	$0	$554	$0	$0	$969	$93	$0	$159	$1,221	$2
9.6	Component Cooling Water Sys	$461	$0	$366	$0	$0	$827	$79	$0	$136	$1,041	$2
9.9	Circ.Water System Foundations& Structures	$0	$2,739	$4,352	$0	$0	$7,091	$671	$0	$1,552	$9,314	$17
	SUBTOTAL 9.	**$13,523**	**$7,353**	**$13,120**	**$0**	**$0**	**$33,996**	**$3,199**	**$0**	**$5,091**	**$42,286**	**$77**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Ash Coolers	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.2	Cyclone Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.3	HGCU Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Recovery Equipment	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$857	$0	$2,642	$0	$0	$3,499	$343	$0	$384	$4,227	$8
10.7	Ash Transport & Feed Equipment	$5,550	$0	$5,685	$0	$0	$11,235	$1,074	$0	$1,231	$13,540	$25
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$204	$240	$0	$0	$444	$42	$0	$97	$582	$1
	SUBTOTAL 10.	**$6,407**	**$204**	**$8,566**	**$0**	**$0**	**$15,177**	**$1,459**	**$0**	**$1,712**	**$18,349**	**$33**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$1,674	$0	$272	$0	$0	$1,946	$180	$0	$159	$2,286	$4
11.2	Station Service Equipment	$4,277	$0	$1,405	$0	$0	$5,683	$531	$0	$466	$6,680	$12
11.3	Switchgear & Motor Control	$4,917	$0	$836	$0	$0	$5,753	$533	$0	$629	$6,915	$13
11.4	Conduit & Cable Tray	$0	$3,083	$10,660	$0	$0	$13,743	$1,331	$0	$2,261	$17,335	$32
11.5	Wire & Cable	$0	$5,817	$11,230	$0	$0	$17,048	$1,436	$0	$2,773	$21,256	$39
11.6	Protective Equipment	$270	$0	$920	$0	$0	$1,190	$116	$0	$131	$1,437	$3
11.7	Standby Equipment	$1,326	$0	$30	$0	$0	$1,356	$124	$0	$148	$1,629	$3
11.8	Main Power Transformers	$6,222	$0	$194	$0	$0	$6,416	$489	$0	$690	$7,595	$14
11.9	Electrical Foundations	$0	$329	$807	$0	$0	$1,136	$109	$0	$249	$1,493	$3
	SUBTOTAL 11.	**$18,688**	**$9,229**	**$26,354**	**$0**	**$0**	**$54,271**	**$4,849**	**$0**	**$7,506**	**$66,626**	**$121**
12	INSTRUMENTATION & CONTROL											
12.1	PC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12.5	Signal Processing Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$485	$0	$291	$0	$0	$776	$73	$39	$133	$1,021	$2
12.7	Distributed Control System Equipment	$4,898	$0	$856	$0	$0	$5,753	$533	$288	$657	$7,232	$13
12.8	Instrument Wiring & Tubing	$2,655	$0	$5,266	$0	$0	$7,921	$675	$396	$1,349	$10,341	$19
12.9	Other I & C Equipment	$1,384	$0	$3,141	$0	$0	$4,525	$439	$226	$519	$5,709	$10
	SUBTOTAL 12.	**$9,421**	**$0**	**$9,553**	**$0**	**$0**	**$18,975**	**$1,720**	**$949**	**$2,658**	**$24,302**	**$44**

Exhibit 6-23 Case 5 Total Plant Cost Details (Continued)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 5 TOTAL PLANT COST $	Case 5 TOTAL PLANT COST $/kW
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$54	$1,086	$0	$0	$1,141	$113	$0	$251	$1,505	$3
13.2	Site Improvements	$0	$1,803	$2,240	$0	$0	$4,043	$399	$0	$888	$5,330	$10
13.3	Site Facilities	$3,232	$0	$3,187	$0	$0	$6,419	$633	$0	$1,410	$8,462	$15
	SUBTOTAL 13.	**$3,232**	**$1,858**	**$6,513**	**$0**	**$0**	**$11,603**	**$1,145**	**$0**	**$2,549**	**$15,297**	**$28**
14	BUILDINGS & STRUCTURES											
14.1	Boiler Building	$0	$9,603	$8,445	$0	$0	$18,048	$1,622	$0	$2,951	$22,621	$41
14.2	Turbine Building	$0	$12,599	$11,742	$0	$0	$24,341	$2,194	$0	$3,980	$30,515	$55
14.3	Administration Building	$0	$637	$673	$0	$0	$1,310	$119	$0	$214	$1,644	$3
14.4	Circulation Water Pumphouse	$0	$233	$185	$0	$0	$418	$37	$0	$68	$523	$1
14.5	Water Treatment Buildings	$0	$481	$396	$0	$0	$877	$79	$0	$143	$1,099	$2
14.6	Machine Shop	$0	$426	$286	$0	$0	$712	$63	$0	$116	$892	$2
14.7	Warehouse	$0	$289	$290	$0	$0	$578	$52	$0	$95	$725	$1
14.8	Other Buildings & Structures	$0	$236	$201	$0	$0	$437	$39	$0	$71	$547	$1
14.9	Waste Treating Building & Str.	$0	$431	$1,307	$0	$0	$1,738	$165	$0	$285	$2,188	$4
	SUBTOTAL 14.	**$0**	**$24,934**	**$23,525**	**$0**	**$0**	**$48,459**	**$4,371**	**$0**	**$7,924**	**$60,754**	**$110**
	TOTAL COST	**$766,991**	**$52,653**	**$351,368**	**$0**	**$0**	**$1,171,013**	**$110,780**	**$37,961**	**$181,307**	**$1,501,061**	**$2,729**
	Owner's Costs											
	Preproduction Costs											
	6 Months All Labor										$10,480	$19
	1 Month Maintenance Materials										$1,518	$3
	1 Month Non-fuel Consumables										$911	$2
	1 Month Waste Disposal										$461	$1
	25% of 1 Months Fuel Cost at 100% CF										$655	$1
	2% of TPC										$30,021	$55
	Total										**$44,045**	**$80**
	Inventory Capital											
	60 day supply of fuel and consumables at 100% CF										$7,058	$13
	0.5% of TPC (spare parts)										$7,505	$14
	Total										**$14,563**	**$26**
	Initial Cost for Catalyst and Chemicals										$1,354	$2
	Land										$900	$2
	Other Owner's Costs										$225,159	$409
	Financing Costs										$40,529	$74
	Total Overnight Costs (TOC)										**$1,827,611**	**$3,323**
	TASC Multiplier								(IOU, high risk, 35 year)		1.140	
	Total As-Spent Cost (TASC)										**$2,083,477**	**$3,788**

Exhibit 6-24 Case 5 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES						Cost Base (June)	2007
Case 5 - Supercritical PC w/ CO2 capture (1,100 lb/net MWh)						Heat Rate-net(Btu/kWh):	10,774
						MWe-net:	550
						Capacity Factor: (%):	85
	OPERATING & MAINTENANCE LABOR						
Operating Labor							
Operating Labor Rate(base):		34.65	$/hour				
Operating Labor Burden:		30.00	% of base				
Labor O-H Charge Rate:		25.00	% of labor				
				Total			
Skilled Operator		2.0		2.0			
Operator		11.3		11.3			
Foreman		1.0		1.0			
Lab Tech's, etc.		2.0		2.0			
TOTAL-O.J.'s		16.3		16.3			
						Annual Cost	Annual Unit Cost
						$	$/kW-net
Annual Operating Labor Cost		Maintenance labor cost		% of BEC	0.8815	$6,444,907	$11.717
Maintenance Labor Cost		(Case S12B is reference)		BEC	$1,171,013	$10,322,636	$18.767
Administrative & Support Labor						$4,191,886	$7.621
Property Taxes & Insurance						$30,021,222	$54.583
TOTAL FIXED OPERATING COSTS						**$50,980,650**	**$92.689**
VARIABLE OPERATING COSTS							
							$/kWh-net
Maintenance Material Cost				% of BEC	1.3223	**$15,483,953**	**$0.00378**
Consumables		Consumption		Unit	Initial Fill		
		Initial Fill	/Day	Cost	Cost		
Water(/1000 gallons)		0	2,825	1.08	**$0**	**$948,135**	**$0.00023**
Chemicals			4.841				
MU & WT Chem.(lb)		0	13,676	0.17	$0	$734,333	$0.00018
Lime (ton)		0	125	75.00	$0	$2,897,518	$0.00071
Carbon (Mercury Removal) (lb)		0	3,153	1.05	$0	$1,027,296	$0.00025
MEA Solvent (ton)		567	0.80	2,249.89	$1,275,685	$560,934	$0.00014
NaOH (tons)		0	5.74	433.68	$0	$772,821	$0.00019
H2SO4 (tons)		0	3.82	138.78	$0	$164,508	$0.00004
Corrosion Inhibitor		0	0	0.00	$78,395	$3,733	$0.00000
Activated Carbon(lb)		0	960	1.05	$0	$312,780	$0.00008
Ammonia (28% NH3) ton		0	28	129.80	$0	$1,110,265	$0.00027
Subtotal Chemicals					**$1,354,079**	**$7,584,188**	**$0.00185**
Other							
Supplemental Fuel(MBtu)		0	0	0.00	$0	$0	$0.00000
SCR Catalyst(m3)		w/equip.	0.422	5,775.94	$0	$755,949	$0.00018
Emission Penalties		0	0	0.00	$0	$0	$0.00000
Subtotal Other					**$0**	**$755,949**	**$0.00018**
Waste Disposal							
Flyash (ton)		0	798	16.23	$0	$4,017,011	$0.00098
Bottom Ash(ton)		0	136	16.23	$0	$684,452	$0.00017
Subtotal-Waste Disposal					**$0**	**$4,701,463**	**$0.00115**
By-products & Emissions							
Gypsum (tons)		0	0	0.00	$0	$0	$0.00000
Subtotal By-Products					**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS					**$1,354,079**	**$29,473,688**	**$0.00720**
Fuel(ton)		0	8,303	10.37	**$0**	**$26,706,931**	**$0.00652**

6.1.9 Case 6 – Cost Estimating

Exhibit 6-25 shows the total plant capital cost details organized by cost account. Exhibit 6-26 shows the initial and annual O&M costs.

The estimated TOC of the supercritical PC case with 90 percent carbon capture is $3,969/kW. Owner's costs represent 18 percent of the TOC. The current dollar, 30-year LCOE, including TS&M costs, is $143.89/MWh.

Exhibit 6-25 Case 6 Total Plant Cost Details

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		Case 6 TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$5,157	$0	$2,355	$0	$0	$7,512	$671	$0	$1,228	$9,411	$17
1.2	Coal Stackout & Reclaim	$6,665	$0	$1,510	$0	$0	$8,175	$715	$0	$1,333	$10,223	$19
1.3	Coal Conveyors	$6,196	$0	$1,494	$0	$0	$7,690	$674	$0	$1,255	$9,619	$17
1.4	Other Coal Handling	$1,621	$0	$346	$0	$0	$1,967	$172	$0	$321	$2,459	$4
1.5	Sorbent Receive & Unload	$62	$0	$19	$0	$0	$81	$7	$0	$13	$102	$0
1.6	Sorbent Stackout & Reclaim	$1,009	$0	$185	$0	$0	$1,194	$104	$0	$195	$1,492	$3
1.7	Sorbent Conveyors	$360	$78	$88	$0	$0	$526	$45	$0	$86	$657	$1
1.8	Other Sorbent Handling	$217	$51	$114	$0	$0	$382	$34	$0	$62	$479	$1
1.9	Coal & Sorbent Hnd.Foundations	$0	$6,334	$7,990	$0	$0	$14,323	$1,345	$0	$2,350	$18,019	$33
	SUBTOTAL 1.	**$21,288**	**$6,462**	**$14,101**	**$0**	**$0**	**$41,851**	**$3,768**	**$0**	**$6,843**	**$52,462**	**$95**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$3,036	$0	$592	$0	$0	$3,628	$316	$0	$592	$4,535	$8
2.2	Coal Conveyor to Storage	$7,773	$0	$1,697	$0	$0	$9,470	$828	$0	$1,545	$11,842	$22
2.3	Coal Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.4	Misc.Coal Prep & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$868	$729	$0	$0	$1,597	$148	$0	$262	$2,007	$4
	SUBTOTAL 2.	**$10,809**	**$868**	**$3,017**	**$0**	**$0**	**$14,694**	**$1,292**	**$0**	**$2,398**	**$18,384**	**$33**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$23,208	$0	$7,497	$0	$0	$30,705	$2,683	$0	$5,008	$38,396	$70
3.2	Water Makeup & Pretreating	$5,615	$0	$1,807	$0	$0	$7,422	$702	$0	$1,625	$9,749	$18
3.3	Other Feedwater Subsystems	$7,105	$0	$3,003	$0	$0	$10,108	$905	$0	$1,652	$12,665	$23
3.4	Service Water Systems	$1,101	$0	$599	$0	$0	$1,700	$160	$0	$372	$2,231	$4
3.5	Other Boiler Plant Systems	$9,826	$0	$9,701	$0	$0	$19,527	$1,855	$0	$3,207	$24,589	$45
3.6	FO Supply Sys & Nat Gas	$279	$0	$348	$0	$0	$627	$59	$0	$103	$789	$1
3.7	Waste Treatment Equipment	$3,807	$0	$2,170	$0	$0	$5,977	$582	$0	$1,312	$7,870	$14
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$2,958	$0	$904	$0	$0	$3,862	$371	$0	$847	$5,080	$9
	SUBTOTAL 3.	**$53,898**	**$0**	**$26,029**	**$0**	**$0**	**$79,927**	**$7,317**	**$0**	**$14,125**	**$101,370**	**$184**
4	PC BOILER											
4.1	PC Boiler & Accessories	$239,129	$0	$116,692	$0	$0	$355,821	$34,593	$0	$39,041	$429,456	$781
4.2	SCR (w/4.1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.3	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.4	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Primary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Secondary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Boiler Foundations	$0	w/14.1	w/14.1	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4.	**$239,129**	**$0**	**$116,692**	**$0**	**$0**	**$355,821**	**$34,593**	**$0**	**$39,041**	**$429,456**	**$781**

Exhibit 6-25 Case 6 Total Plant Cost Details (Continued)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 6 TOTAL PLANT COST $	Case 6 TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	$102,672	$0	$17,271	$0	$0	$119,943	$11,416	$0	$13,136	$144,495	$263
5.2	Other FGD	$1,214	$0	$486	$0	$0	$1,700	$163	$0	$186	$2,049	$4
5.3	Bag House & Accessories	w/5.1	$0	w/5.1	$0	$0	$0	$0	$0	$0	$0	$0
5.4	Other Particulate Removal Materials	$25,300	$0	$10,659	$0	$0	$35,959	$3,449	$0	$3,941	$43,349	$79
5.5	Gypsum Dewatering System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.6	Mercury Removal System	w/5.1	$0	w/5.1	$0	$0	$0	$0	$0	$0	$0	$0
5.9	Open											
	SUBTOTAL 5.	**$129,186**	**$0**	**$28,416**	**$0**	**$0**	**$157,602**	**$15,028**	**$0**	**$17,263**	**$189,893**	**$345**
5B	CO_2 REMOVAL & COMPRESSION											
5B.1	CO_2 Removal System	$217,227	$0	$65,907	$0	$0	$283,134	$27,070	$56,627	$73,366	$440,197	$801
5B.2	CO_2 Compression & Drying	$29,198	$0	$9,160	$0	$0	$38,358	$3,669	$0	$8,405	$50,432	$92
5B.3	CO_2 Removal System Let Down Turbine	$10,400	$0	$1,381	$0	$0	$11,781	$1,129	$0	$1,291	$14,201	$26
	SUBTOTAL 5B.	**$256,825**	**$0**	**$76,448**	**$0**	**$0**	**$333,273**	**$31,867**	**$56,627**	**$83,063**	**$504,830**	**$918**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 6.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
7.2	HRSG Accessories	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$10,558	$0	$6,783	$0	$0	$17,342	$1,512	$0	$2,828	$21,682	$39
7.4	Stack	$9,475	$0	$5,544	$0	$0	$15,019	$1,446	$0	$1,646	$18,111	$33
7.9	Duct & Stack Foundations	$0	$1,087	$1,235	$0	$0	$2,323	$217	$0	$508	$3,048	$6
	SUBTOTAL 7.	**$20,033**	**$1,087**	**$13,563**	**$0**	**$0**	**$34,683**	**$3,175**	**$0**	**$4,983**	**$42,841**	**$78**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$57,457	$0	$7,631	$0	$0	$65,087	$6,238	$0	$7,133	$78,458	$143
8.2	Turbine Plant Auxiliaries	$388	$0	$830	$0	$0	$1,218	$119	$0	$134	$1,471	$3
8.3a	Condenser & Auxiliaries	$3,425	$0	$2,066	$0	$0	$5,491	$529	$0	$602	$6,622	$12
8.3b	Air Cooled Condenser	$29,987	$0	$6,012	$0	$0	$36,000	$3,600	$0	$7,920	$47,519	$86
8.4	Steam Piping	$26,668	$0	$13,149	$0	$0	$39,817	$3,345	$0	$6,474	$49,636	$90
8.9	TG Foundations	$0	$1,216	$1,922	$0	$0	$3,138	$297	$0	$687	$4,122	$7
	SUBTOTAL 8.	**$117,925**	**$1,216**	**$31,610**	**$0**	**$0**	**$150,751**	**$14,128**	**$0**	**$22,949**	**$187,828**	**$342**

Exhibit 6-25 Case 6 Total Plant Cost Details (Continued)

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		Case 6 TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/kW
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$15,102	$0	$4,703	$0	$0	$19,805	$1,894	$0	$2,170	$23,869	$43
9.2	Circulating Water Pumps	$3,149	$0	$300	$0	$0	$3,449	$292	$0	$374	$4,115	$7
9.3	Circ.Water System Auxiliaries	$834	$0	$111	$0	$0	$945	$90	$0	$104	$1,139	$2
9.4	Circ.Water Piping	$0	$6,612	$6,408	$0	$0	$13,021	$1,219	$0	$2,136	$16,375	$30
9.5	Make-up Water System	$596	$0	$796	$0	$0	$1,392	$133	$0	$229	$1,754	$3
9.6	Component Cooling Water Sys	$660	$0	$525	$0	$0	$1,184	$112	$0	$195	$1,492	$3
9.9	Circ.Water System Foundations& Structures	$0	$3,917	$6,224	$0	$0	$10,141	$959	$0	$2,220	$13,321	$24
	SUBTOTAL 9.	**$20,341**	**$10,530**	**$19,067**	**$0**	**$0**	**$49,938**	**$4,700**	**$0**	**$7,427**	**$62,065**	**$113**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Ash Coolers	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.2	Cyclone Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.3	HGCU Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Recovery Equipment	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$938	$0	$2,891	$0	$0	$3,829	$376	$0	$421	$4,626	$8
10.7	Ash Transport & Feed Equipment	$6,074	$0	$6,222	$0	$0	$12,295	$1,176	$0	$1,347	$14,818	$27
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$223	$263	$0	$0	$486	$46	$0	$106	$637	$1
	SUBTOTAL 10.	**$7,012**	**$223**	**$9,375**	**$0**	**$0**	**$16,610**	**$1,597**	**$0**	**$1,874**	**$20,081**	**$37**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$1,746	$0	$284	$0	$0	$2,030	$188	$0	$166	$2,384	$4
11.2	Station Service Equipment	$5,204	$0	$1,710	$0	$0	$6,914	$646	$0	$567	$8,127	$15
11.3	Switchgear & Motor Control	$5,983	$0	$1,017	$0	$0	$7,000	$649	$0	$765	$8,414	$15
11.4	Conduit & Cable Tray	$0	$3,751	$12,970	$0	$0	$16,721	$1,619	$0	$2,751	$21,091	$38
11.5	Wire & Cable	$0	$7,078	$13,664	$0	$0	$20,742	$1,747	$0	$3,373	$25,863	$47
11.6	Protective Equipment	$270	$0	$920	$0	$0	$1,190	$116	$0	$131	$1,437	$3
11.7	Standby Equipment	$1,372	$0	$31	$0	$0	$1,403	$129	$0	$153	$1,685	$3
11.8	Main Power Transformers	$6,266	$0	$195	$0	$0	$6,461	$492	$0	$695	$7,649	$14
11.9	Electrical Foundations	$0	$346	$848	$0	$0	$1,194	$114	$0	$262	$1,570	$3
	SUBTOTAL 11.	**$20,842**	**$11,175**	**$31,638**	**$0**	**$0**	**$63,656**	**$5,701**	**$0**	**$8,863**	**$78,220**	**$142**
12	INSTRUMENTATION & CONTROL											
12.1	PC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12.5	Signal Processing Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$516	$0	$309	$0	$0	$825	$78	$41	$142	$1,086	$2
12.7	Distributed Control System Equipment	$5,208	$0	$910	$0	$0	$6,118	$567	$306	$699	$7,691	$14
12.8	Instrument Wiring & Tubing	$2,823	$0	$5,601	$0	$0	$8,424	$718	$421	$1,434	$10,997	$20
12.9	Other I & C Equipment	$1,472	$0	$3,340	$0	$0	$4,811	$467	$241	$552	$6,070	$11
	SUBTOTAL 12.	**$10,019**	**$0**	**$10,159**	**$0**	**$0**	**$20,178**	**$1,830**	**$1,009**	**$2,827**	**$25,844**	**$47**

Exhibit 6-25 Case 6 Total Plant Cost Details (Continued)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 6 TOTAL PLANT COST $	Case 6 TOTAL PLANT COST $/kW
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$57	$1,130	$0	$0	$1,186	$118	$0	$261	$1,565	$3
13.2	Site Improvements	$0	$1,875	$2,329	$0	$0	$4,205	$415	$0	$924	$5,543	$10
13.3	Site Facilities	$3,361	$0	$3,314	$0	$0	$6,675	$658	$0	$1,467	$8,800	$16
	SUBTOTAL 13.	**$3,361**	**$1,932**	**$6,773**	**$0**	**$0**	**$12,066**	**$1,190**	**$0**	**$2,651**	**$15,908**	**$29**
14	BUILDINGS & STRUCTURES											
14.1	Boiler Building	$0	$9,838	$8,652	$0	$0	$18,490	$1,662	$0	$3,023	$23,174	$42
14.2	Turbine Building	$0	$12,968	$12,086	$0	$0	$25,055	$2,258	$0	$4,097	$31,410	$57
14.3	Administration Building	$0	$648	$685	$0	$0	$1,333	$121	$0	$218	$1,672	$3
14.4	Circulation Water Pumphouse	$0	$297	$236	$0	$0	$534	$48	$0	$87	$669	$1
14.5	Water Treatment Buildings	$0	$741	$611	$0	$0	$1,352	$121	$0	$221	$1,694	$3
14.6	Machine Shop	$0	$433	$291	$0	$0	$724	$64	$0	$118	$907	$2
14.7	Warehouse	$0	$294	$295	$0	$0	$588	$53	$0	$96	$738	$1
14.8	Other Buildings & Structures	$0	$240	$204	$0	$0	$444	$40	$0	$73	$557	$1
14.9	Waste Treating Building & Str.	$0	$452	$1,373	$0	$0	$1,825	$173	$0	$300	$2,298	$4
	SUBTOTAL 14.	**$0**	**$25,912**	**$24,433**	**$0**	**$0**	**$50,346**	**$4,541**	**$0**	**$8,233**	**$63,119**	**$115**
	TOTAL COST	**$910,668**	**$59,407**	**$411,322**	**$0**	**$0**	**$1,381,397**	**$130,728**	**$57,636**	**$222,541**	**$1,792,301**	**$3,259**
	Owner's Costs											
	Preproduction Costs											
	6 Months All Labor										$11,639	$21
	1 Month Maintenance Materials										$1,791	$3
	1 Month Non-fuel Consumables										$1,309	$2
	1 Month Waste Disposal										$461	$1
	25% of 1 Months Fuel Cost at 100% CF										$770	$1
	2% of TPC										$35,846	$65
	Total										**$51,816**	**$94**
	Inventory Capital											
	60 day supply of fuel and consumables at 100% CF										$8,779	$16
	0.5% of TPC (spare parts)										$8,962	$16
	Total										**$17,741**	**$32**
	Initial Cost for Catalyst and Chemicals										$2,734	$5
	Land										$900	$2
	Other Owner's Costs										$268,845	$489
	Financing Costs										$48,392	$88
	Total Overnight Costs (TOC)										**$2,182,729**	**$3,969**
	TASC Multiplier								(IOU, high risk, 35 year)		1.140	
	Total As-Spent Cost (TASC)										**$2,488,311**	**$4,525**

Exhibit 6-26 Case 6 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES						Cost Base (June)	2007
Case 6 - Supercritical PC w/ 90% CO2 capture						Heat Rate-net(Btu/kWh):	12,679
						MWe-net:	550
						Capacity Factor: (%):	85
	OPERATING & MAINTENANCE LABOR						
Operating Labor							
Operating Labor Rate(base):		34.65	$/hour				
Operating Labor Burden:		30.00	% of base				
Labor O-H Charge Rate:		25.00	% of labor				
				Total			
Skilled Operator		2.0		2.0			
Operator		11.3		11.3			
Foreman		1.0		1.0			
Lab Tech's, etc.		2.0		2.0			
TOTAL-O.J.'s		16.3		16.3			
						Annual Cost	Annual Unit Cost
						$	$/kW-net
Annual Operating Labor Cost		Maintenance labor cost		% of BEC	0.8815	$6,444,907	$11.720
Maintenance Labor Cost		(Case S12B is reference)		BEC	$1,381,397	$12,177,202	$22.144
Administrative & Support Labor						$4,655,527	$8.466
Property Taxes & Insurance						$35,846,019	$65.186
TOTAL FIXED OPERATING COSTS						**$59,123,655**	**$107.517**
VARIABLE OPERATING COSTS							
							$/kWh-net
Maintenance Material Cost				% of BEC	1.3223	**$18,265,802**	**$0.00446**
Consumables		Consumption		Unit	Initial		
		Initial	/Day	Cost	Cost		
Water(/1000 gallons)		0	4,819	1.08	**$0**	**$1,617,194**	**$0.00039**
Chemicals			4.841				
MU & WT Chem.(lb)		0	23,327	0.17	$0	$1,252,521	$0.00031
Lime (ton)		0	147	75.00	$0	$3,415,201	$0.00083
Carbon (Mercury Removal) (lb)		0	3,701	1.05	$0	$1,205,947	$0.00029
MEA Solvent (ton)		1,145	1.62	2,249.89	$2,576,119	$1,133,037	$0.00028
NaOH (tons)		0	11.61	433.68	$0	$1,561,782	$0.00038
H2SO4 (tons)		0	7.72	138.78	$0	$332,276	$0.00008
Corrosion Inhibitor		0	0	0.00	$158,350	$7,540	$0.00000
Activated Carbon(lb)		0	1,939	1.05	$0	$631,756	$0.00015
Ammonia (28% NH3) ton		0	32.4	129.80	$0	$1,306,344	$0.00032
Subtotal Chemicals					**$2,734,469**	**$10,846,404**	**$0.00265**
Other							
Supplemental Fuel(MBtu)		0	0	0.00	$0	$0	$0.00000
SCR Catalyst(m3)		w/equip.	0.495	5,775.94	$0	$887,391	$0.00022
Emission Penalties		0	0	0.00	$0	$0	$0.00000
Subtotal Other					**$0**	**$887,391**	**$0.00022**
Waste Disposal							
Flyash (ton)		0	939	16.23	$0	$4,727,488	$0.00115
Bottom Ash(ton)		0	160	16.23	$0	$805,315	$0.00020
Subtotal-Waste Disposal					**$0**	**$5,532,803**	**$0.00135**
By-products & Emissions							
Gypsum (tons)		0	0	0.00	$0	$0	$0.00000
Subtotal By-Products					**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS					**$2,734,469**	**$37,149,594**	**$0.00907**
Fuel(ton)		0	9,769	10.37	**$0**	**$31,422,015**	**$0.00767**

7. SUBCRITICAL PC CASES

This section contains an evaluation of plant designs for Cases 7 through 9 (which are based on typical subcritical PC plant operation), with a coal feed rate of 250,000 kg/hr (650,360 lb/hr), which is fixed due to the current size of the Unit 4 boiler. Once baseline performance parameters such as coal feed rate, net plant heat rate, net stack output and stack exit temperature were established, the coal composition was changed to Montana Rosebud PRB coal. All three cases use the same steam conditions, a single reheat 16.5 MPa/538°C/538°C (2400 psig/1,000°F/1,000°F) cycle. The more detailed modeling parameters are described in Section 7.1.3. Cases 7 through 9 are intended to represent a generic existing subcritical PC plant.

The balance of Section 7 is organized as follows:

- Process and System Description for Cases 7 - 9
- Key Assumptions for Cases 7 - 9
- Sparing Philosophy for Cases 7 - 9
- Comparison of Performance Results for Cases 7 - 9
- Equipment List for Cases 7 - 9
- Cost Estimates for Cases 7 – 9

7.1 SUBCRITICAL PC NON-CAPTURE CASE 7 AND CAPTURE CASES 8 AND 9

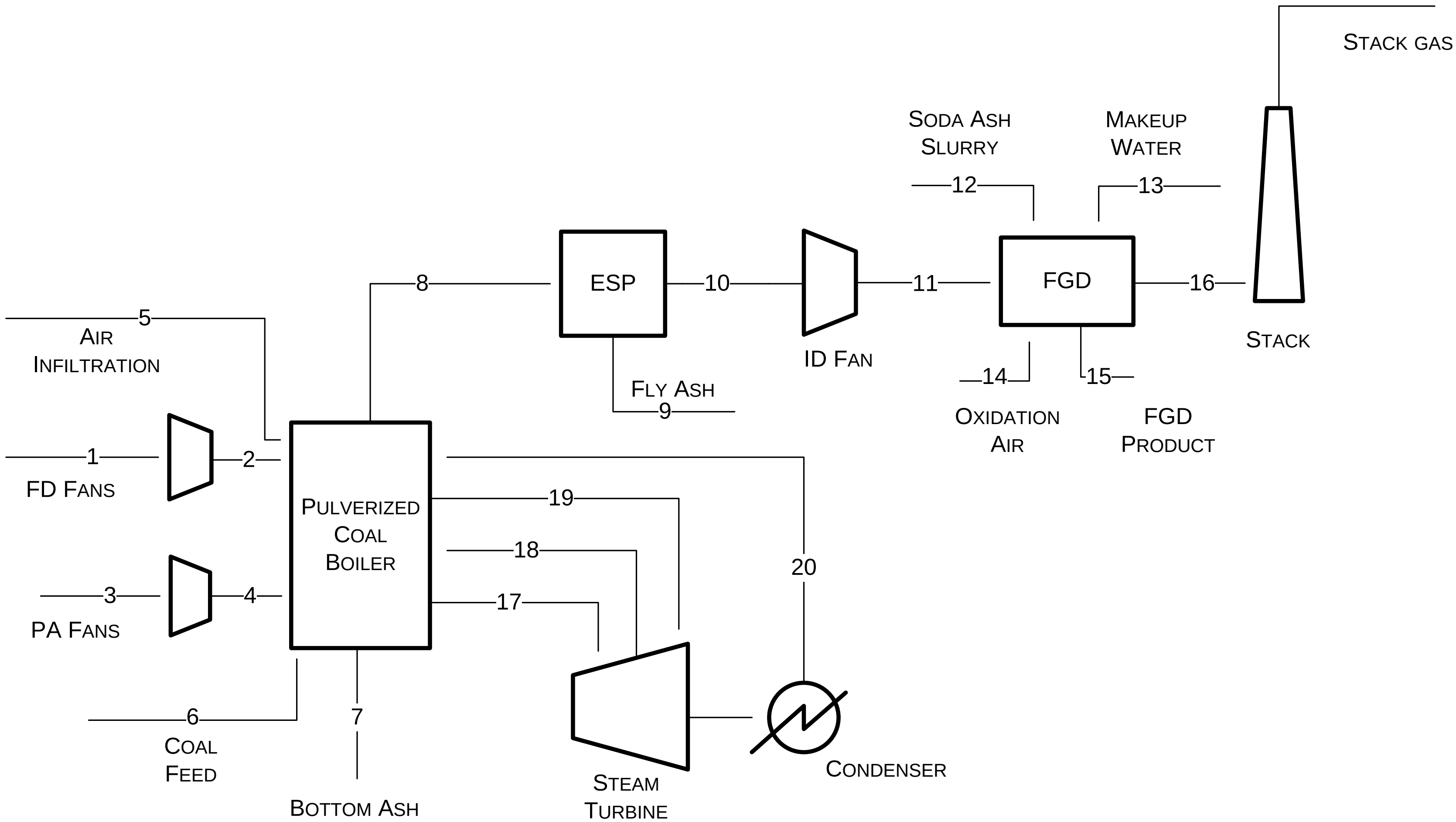
7.1.1 Case 7 Process Description

The system description is nearly identical to the supercritical PC case without CO_2 capture but is repeated here for completeness. The system description follows the block flow diagram (BFD) in Exhibit 7-1 and stream numbers reference the same Exhibit. The tables in Exhibit 7-2 provide process data for the numbered streams in the BFD.

Coal (stream 6) and primary air (stream 4) are introduced into the boiler through the tangentially fired burners. Additional combustion air, including the overfire air, is provided by the forced draft fans (stream 2). The boiler operates at a slight negative pressure so air leakage is into the boiler, and the infiltration air is accounted for in stream 5.

Flue gas exits the boiler (stream 8) and is cooled to 182°C (360°F) in the combustion air preheater (not shown) before passing through the ESP for particulate removal (stream 9). An ID fan increases the flue gas temperature to 199°C (390°F) and provides the motive force for the flue gas (stream 11) to pass through the FGD unit. FGD inputs and outputs include makeup water (stream 13), oxidation air (stream 14), soda ash slurry (stream 12) and FGD product (stream 15). The clean, saturated flue gas exiting the FGD unit (stream 16) passes to the plant stack and is discharged to atmosphere.

Exhibit 7-1 Case 7: Existing Subcritical PC - Block Flow Diagram



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

Exhibit 7-2 Case 7: Existing Subcritical PC - Stream Table

	1	2	3	4	5	6	7	8	9	10
V-L Mole Fraction										
Ar	0.0093	0.0093	0.0093	0.0093	0.0093	0.0000	0.0000	0.0084	0.0000	0.0084
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1434	0.0000	0.1434
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0071	0.0071	0.0071	0.0071	0.0071	0.0000	0.0000	0.1132	0.0000	0.1132
N_2	0.7753	0.7753	0.7753	0.7753	0.7753	0.0000	0.0000	0.7058	0.0000	0.7058
O_2	0.2080	0.2080	0.2080	0.2080	0.2080	0.0000	0.0000	0.0283	0.0000	0.0283
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0008	0.0000	0.0008
Total	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	58,751	58,751	18,048	18,048	1,322	0	0	85,921	0	85,921
V-L Flowrate (kg/hr)	1,697,155	1,697,155	521,348	521,348	38,194	0	0	2,527,543	0	2,527,543
Solids Flowrate (kg/hr)	0	0	0	0	0	294,998	4,831	19,323	19,323	0
Temperature (°C)	6	11	6	16	6	6	182	182	182	182
Pressure (MPa, abs)	0.08	0.08	0.08	0.09	0.08	0.08	0.08	0.08	0.08	0.08
Enthalpy (kJ/kg)	16.93	22.47	16.93	27.83	16.93	---	---	396.25	---	374.90
Density (kg/m^3)	1.0	1.0	1.0	1.0	1.0	---	---	0.6	---	0.6
V-L Molecular Weight	28.887	28.887	28.887	28.887	28.887	---	---	29.417	---	29.417
V-L Flowrate (lb_{mol}/hr)	129,524	129,524	39,788	39,788	2,915	0	0	189,422	0	189,422
V-L Flowrate (lb/hr)	3,741,587	3,741,587	1,149,376	1,149,376	84,204	0	0	5,572,278	0	5,572,278
Solids Flowrate (lb/hr)	0	0	0	0	0	650,360	10,650	42,599	42,599	0
Temperature (°F)	42	52	42	61	42	42	360	360	360	360
Pressure (psia)	11.4	12.0	11.4	12.6	11.4	11.4	11.2	11.2	11.0	11.0
Enthalpy (Btu/lb)	7.3	9.7	7.3	12.0	7.3	---	---	170.4	---	161.2
Density (lb/ft^3)	0.061	0.063	0.061	0.065	0.061	---	---	0.037	---	0.037
	A - Reference conditions are 32.02 F & 0.089 PSIA									

Exhibit 7-2 Case 7: Existing Subcritical PC - Stream Table (continued)

	11	12	13	14	15	16	17	18	19	20
V-L Mole Fraction										
Ar	0.0084	0.0000	0.0000	0.0093	0.0000	0.0077	0.0000	0.0000	0.0000	0.0000
CO_2	0.1434	0.0000	0.0000	0.0003	0.0000	0.1308	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.1132	1.0000	1.0000	0.0071	1.0000	0.1916	1.0000	1.0000	1.0000	1.0000
N_2	0.7058	0.0000	0.0000	0.7753	0.0000	0.6436	0.0000	0.0000	0.0000	0.0000
O_2	0.0283	0.0000	0.0000	0.2080	0.0000	0.0262	0.0000	0.0000	0.0000	0.0000
SO_2	0.0008	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	85,921	1,025	9,620	369	2,237	94,670	98,815	90,709	90,709	81,920
V-L Flowrate (kg/hr)	2,527,543	18,461	173,311	10,668	40,294	2,687,638	1,780,185	1,634,149	1,634,149	1,475,804
Solids Flowrate (kg/hr)	0	8,022	0	0	10,073	0	0	0	0	0
Temperature (°C)	199	6	6	6	58	58	538	340	538	47
Pressure (MPa, abs)	0.08	0.08	0.08	0.08	0.08	0.08	16.65	4.28	3.90	2.76
Enthalpy (kJ/kg)	392.99	1,520.57	25.25	16.93	1,371.69	380.66	3,395.97	3,062.35	3,530.88	197.81
Density (kg/m^3)	0.6	1,012.1	1,012.1	1.0	961.0	0.9	50.2	16.6	10.7	990.7
V-L Molecular Weight	29.417	18.015	18.015	28.887	18.015	28.390	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	189,422	2,259	21,209	814	4,931	208,711	217,850	199,979	199,979	180,602
V-L Flowrate (lb/hr)	5,572,278	40,699	382,086	23,518	88,832	5,925,226	3,924,635	3,602,682	3,602,682	3,253,590
Solids Flowrate (lb/hr)	0	17,686	0	0	22,208	0	0	0	0	0
Temperature (°F)	390	42	42	42	136	136	1,000	645	1,000	116
Pressure (psia)	12.2	11.4	12.0	11.4	12.0	12.0	2,415.0	620.5	565.5	400.0
Enthalpy (Btu/lb)	169.0	653.7	10.9	7.3	589.7	163.7	1,460.0	1,316.6	1,518.0	85.0
Density (lb/ft^3)	0.039	63.182	63.182	0.061	59.992	0.053	3.134	1.034	0.668	61.847

7.1.2 Cases 8 and 9 Process Description

Cases 8 and 9 are configured to produce electric power with CO_2 capture. Case 8 has an emission rate of 1,100 lb CO_2/net-MWh. This is achieved by bypassing a portion of the flue gas around the Econamine unit, therefore only treating a portion of the gas stream. Case 9 has a carbon capture rate of 90 percent. The plant configurations are similar to Case 7 with the major difference being the use of an Econamine FG Plus system for CO_2 capture and subsequent compression of the captured CO_2 stream. Low pressure steam (71 psi at approximately 305°F) is required for the Econamine system. For Case 8 (emission rate of 1,100 lb CO_2/net-MWh), approximately 35 percent of the total steam is extracted from the crossover pipe, sent to the let-down turbine and de-superheated before entering the Econamine system. For Case 9 (which includes 90 percent carbon capture), approximately 50 percent of the steam is extracted. For this analysis and based on results of the NETL/Alstom study, the existing steam turbine would be capable of turndown due to steam extraction. No other steam turbine retrofit is necessary other than the piping extraction from the IP/LP crossover [63]. Since the CO_2 capture and compression process increases the auxiliary load on the plant, the overall efficiency is significantly reduced relative to Case 7. A process block flow diagram for Cases 8 and 9 is shown in Exhibit 7-3 and Exhibit 7-5, respectively. Stream tables for Cases 8 and 9 are shown in Exhibit 7-4 and Exhibit 7-6, respectively. The CO_2 removal system is described in Section 5.1.7.

The boiler in the existing subcritical PC plant retrofit cases has a fixed heat duty and coal feed rate that is limited by its size and configuration. Therefore, the net power output decreases in the capture cases because of the extraction steam required in the CDR facility and the higher auxiliary loads.

Also, LNBs are upgraded for Cases 8 and 9 to reduce NOx emissions so that NO_2 is less than 20 ppmv as required by the Econamine process. The FGD system is upgraded to increase the efficiency from 85 to 92 percent to reduce the load on the polishing scrubber of the Econamine system. In the event that NSR would become relevant because of the CO_2 capture project, a cost sensitivity case was included with SCR retrofit to reduce NOx emissions to BACT limits.

Exhibit 7-3 Case 8: Subcritical PC Plant Retrofitted with Carbon Capture to an Emission Rate of 1,100 lb CO_2/net-MWh – Block Flow Diagram

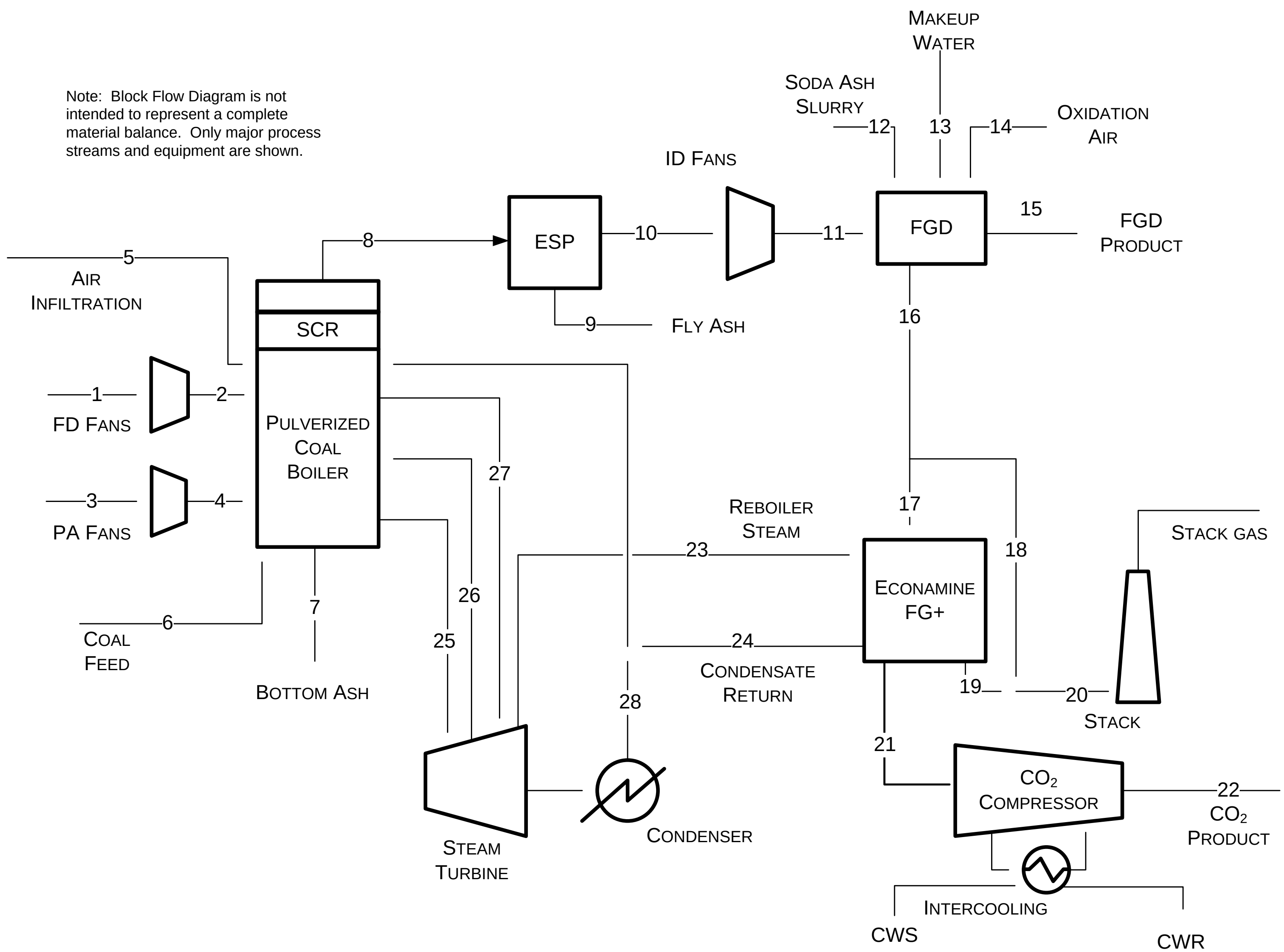


Exhibit 7-4 Case 8: Subcritical PC Plant Retrofitted with Carbon Capture to an Emission Rate of 1,100 lb CO_2/net-MWh - Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
V-L Mole Fraction														
Ar	0.0093	0.0093	0.0093	0.0093	0.0093	0.0000	0.0000	0.0084	0.0000	0.0084	0.0084	0.0000	0.0000	0.0093
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1432	0.0000	0.1432	0.1432	0.0000	0.0000	0.0003
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0071	0.0071	0.0071	0.0071	0.0071	0.0000	0.0000	0.1131	0.0000	0.1131	0.1131	1.0000	1.0000	0.0071
N_2	0.7753	0.7753	0.7753	0.7753	0.7753	0.0000	0.0000	0.7059	0.0000	0.7059	0.7059	0.0000	0.0000	0.7753
O_2	0.2080	0.2080	0.2080	0.2080	0.2080	0.0000	0.0000	0.0286	0.0000	0.0286	0.0286	0.0000	0.0000	0.2080
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0008	0.0000	0.0008	0.0008	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	58,852	58,852	18,079	18,079	1,322	0	0	86,052	0	86,052	86,052	1,113	9,692	374
V-L Flowrate (kg/hr)	1,700,066	1,700,066	522,242	522,242	38,194	0	0	2,531,345	0	2,531,345	2,531,345	20,057	174,600	10,818
Solids Flowrate (kg/hr)	0	0	0	0	0	294,996	4,831	19,322	19,322	0	0	8,436	0	0
Temperature (°C)	6	11	6	16	6	6	182	182	182	182	203	6	6	6
Pressure (MPa, abs)	0.08	0.08	0.08	0.09	0.08	0.08	0.08	0.08	0.07	0.07	0.08	0.08	0.08	0.08
Enthalpy (kJ/kg)	16.93	22.47	16.93	27.83	16.93	---	---	395.92	---	374.64	396.88	1,486.77	25.25	16.93
Density (kg/m^3)	1.0	1.0	1.0	1.0	1.0	---	---	0.6	---	0.6	0.6	1,012.1	1,012.1	1.0
V-L Molecular Weight	28.887	28.887	28.887	28.887	28.887	---	---	29.416	---	29.416	29.416	18.015	18.015	28.887
V-L Flowrate (lb_{mol}/hr)	129,746	129,746	39,857	39,857	2,915	0	0	189,713	0	189,713	189,713	2,455	21,367	826
V-L Flowrate (lb/hr)	3,748,004	3,748,004	1,151,348	1,151,348	84,203	0	0	5,580,661	0	5,580,661	5,580,661	44,219	384,927	23,850
Solids Flowrate (lb/hr)	0	0	0	0	0	650,355	10,650	42,599	42,599	0	0	18,599	0	0
Temperature (°F)	42	52	42	61	42	42	360	360	360	360	397	42	42	42
Pressure (psia)	11.4	12.0	11.4	12.6	11.4	11.4	10.9	10.9	10.7	10.7	12.2	11.4	12.0	11.4
Enthalpy (Btu/lb)	7.3	9.7	7.3	12.0	7.3	---	---	170.2	---	161.1	170.6	639.2	10.9	7.3
Density (lb/ft^3)	0.061	0.063	0.061	0.065	0.061	---	---	0.037	---	0.036	0.039	63.182	63.182	0.061

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 7-4 Case 8: Subcritical PC Plant Retrofitted with Carbon Capture to an Emission Rate of 1,100 lb CO_2/net-MWh - Stream Table (Continued)

	15	16	17	18	19	20	21	22	23	24	25	26	27	28
V-L Mole Fraction														
Ar	0.0000	0.0077	0.0077	0.0077	0.0106	0.0095	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.1306	0.1306	0.1306	0.0180	0.0609	0.9840	1.0000	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	0.0000	0.0000	0.0000
H_2O	1.0000	0.1916	0.1916	0.1916	0.0469	0.1020	0.0160	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.0000	0.6436	0.6436	0.6436	0.8879	0.7948	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0265	0.0265	0.0265	0.0365	0.0327	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0001	0.0001	0.0001	0.0001	0.0001	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)	2,366	94,835	65,569	29,266	47,527	76,794	7,832	7,706	31,690	31,690	98,801	90,696	90,696	53,946
V-L Flowrate (kg/hr)	42,626	2,691,975	1,861,232	830,744	1,335,889	2,166,632	341,414	339,150	570,895	570,895	1,779,931	1,633,913	1,633,913	971,852
Solids Flowrate (kg/hr)	10,656	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	58	58	58	58	32	45	21	35	152	151	538	340	538	47
Pressure (MPa, abs)	0.08	0.08	0.08	0.08	0.08	0.08	0.16	15.27	0.49	0.49	16.65	4.28	3.90	2.76
Enthalpy (kJ/kg)	1,375.35	380.70	380.70	380.70	111.30	214.60	28.91	-212.36	2,747.80	635.72	3,395.97	3,062.35	3,530.88	197.81
Density (kg/m^3)	958.8	0.9	0.9	0.9	0.9	0.9	2.9	794.4	2.6	915.8	50.2	16.6	10.7	990.7
V-L Molecular Weight	18.015	28.386	28.386	28.386	28.108	28.214	43.593	44.010	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	5,216	209,075	144,555	64,521	104,780	169,301	17,266	16,989	69,863	69,863	217,819	199,950	199,950	118,931
V-L Flowrate (lb/hr)	93,973	5,934,789	4,103,313	1,831,476	2,945,131	4,776,607	752,688	747,699	1,258,609	1,258,609	3,924,075	3,602,161	3,602,161	2,142,566
Solids Flowrate (lb/hr)	23,493	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	136	136	136	136	89	113	69	95	306	304	1,000	645	1,000	116
Pressure (psia)	12.0	12.0	12.0	12.0	12.0	12.0	23.5	2,215.0	71.0	71.0	2,415.0	620.5	565.5	400.0
Enthalpy (Btu/lb)	591.3	163.7	163.7	163.7	47.9	92.3	12.4	-91.3	1,181.3	273.3	1,460.0	1,316.6	1,518.0	85.0
Density (lb/ft^3)	59.857	0.053	0.053	0.053	0.057	0.055	0.183	49.590	0.163	57.172	3.134	1.034	0.668	61.847

Exhibit 7-5 Case 9: Existing Subcritical PC Retrofitted with 90% CO_2 Capture - Block Flow Diagram

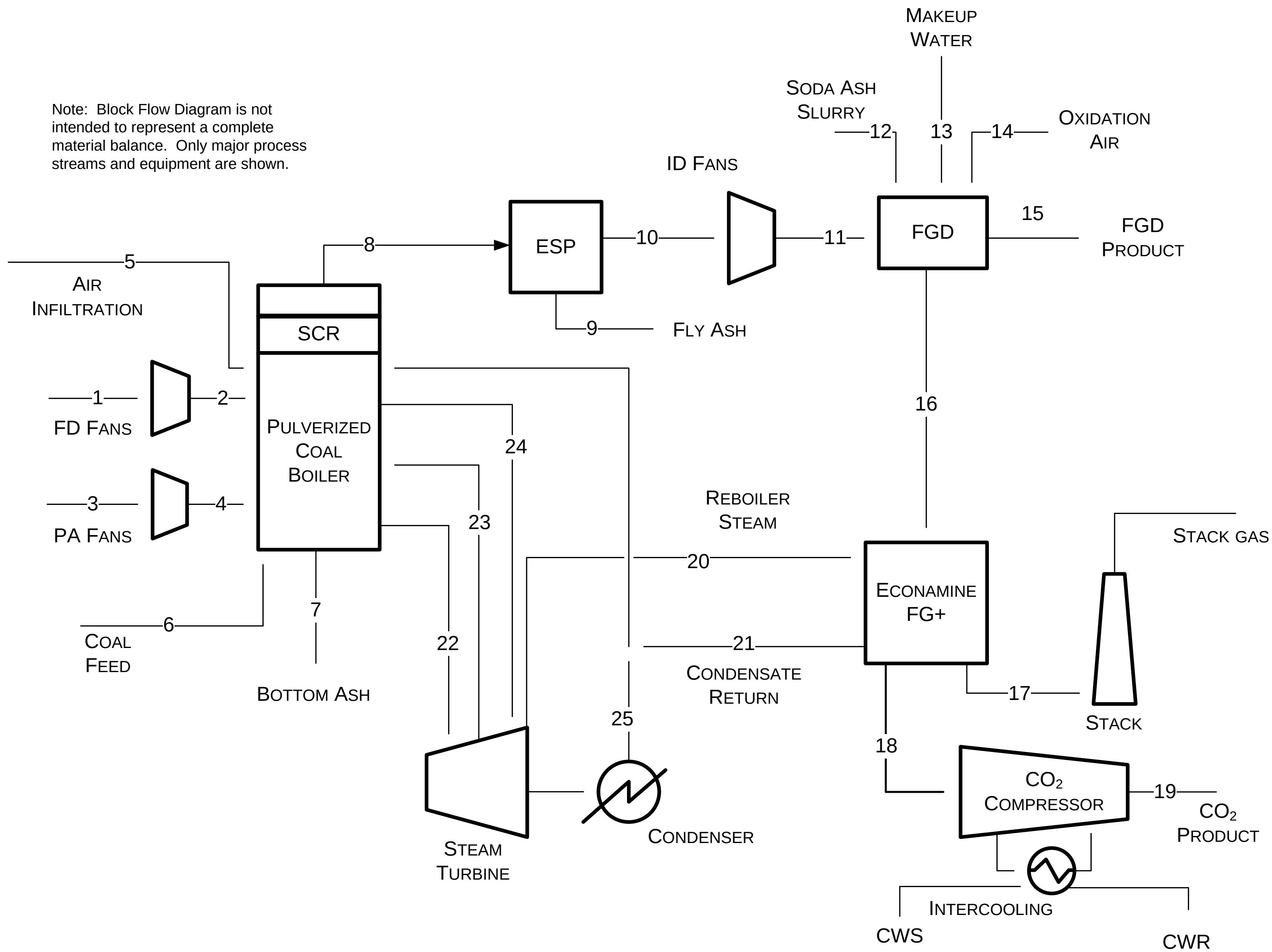


Exhibit 7-6 Case 9: Existing Subcritical PC Retrofitted with 90% CO_2 Capture - Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13
V-L Mole Fraction													
Ar	0.0093	0.0093	0.0093	0.0093	0.0093	0.0000	0.0000	0.0084	0.0000	0.0084	0.0084	0.0000	0.0000
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1437	0.0000	0.1437	0.1437	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	0.0000
H_2O	0.0071	0.0071	0.0071	0.0071	0.0071	0.0000	0.0000	0.1135	0.0000	0.1135	0.1135	1.0000	1.0000
N_2	0.7753	0.7753	0.7753	0.7753	0.7753	0.0000	0.0000	0.7057	0.0000	0.7057	0.7057	0.0000	0.0000
O_2	0.2080	0.2080	0.2080	0.2080	0.2080	0.0000	0.0000	0.0279	0.0000	0.0279	0.0279	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0008	0.0000	0.0008	0.0008	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	58,610	58,610	18,004	18,004	1,322	0	0	85,736	0	85,736	85,736	1,075	9,657
V-L Flowrate (kg/hr)	1,693,082	1,693,082	520,097	520,097	38,194	0	0	2,522,218	0	2,522,218	2,522,218	19,358	173,975
Solids Flowrate (kg/hr)	0	0	0	0	0	294,998	4,831	19,323	19,323	0	0	8,437	0
Temperature (°C)	6	11	6	16	6	6	182	182	182	182	203	6	6
Pressure (MPa, abs)	0.08	0.08	0.08	0.09	0.08	0.08	0.08	0.08	0.07	0.07	0.08	0.08	0.08
Enthalpy (kJ/kg)	16.93	22.47	16.93	27.83	16.93	---	---	396.72	---	375.28	397.52	1,523.61	25.25
Density (kg/m^3)	1.0	1.0	1.0	1.0	1.0	1,415.1	14.4	0.6	14.4	0.6	0.6	1,237.7	1,012.1
V-L Molecular Weight	28.887	28.887	28.887	28.887	28.887	---	---	29.418	---	29.418	29.418	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	129,213	129,213	39,693	39,693	2,915	0	0	189,016	0	189,016	189,016	2,369	21,290
V-L Flowrate (lb/hr)	3,732,607	3,732,607	1,146,618	1,146,618	84,204	0	0	5,560,540	0	5,560,540	5,560,540	42,677	383,549
Solids Flowrate (lb/hr)	0	0	0	0	0	650,360	10,650	42,599	42,599	0	0	18,600	0
Temperature (°F)	42	52	42	61	42	42	360	360	360	360	397	42	42
Pressure (psia)	11.4	12.0	11.4	12.6	11.4	11.4	10.9	10.9	10.7	10.7	12.2	11.4	12.0
Enthalpy (Btu/lb)	7.3	9.7	7.3	12.0	7.3	---	---	170.6	---	161.3	170.9	655.0	10.9
Density (lb/ft^3)	0.061	0.063	0.061	0.065	0.061	88.340	0.899	0.037	0.899	0.036	0.039	77.265	63.182

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 7-6 Case 9: Existing Subcritical PC Retrofitted with 90% CO_2 Capture - Stream Table (Continued)

	14	15	16	17	18	19	20	21	22	23	24	25
V-L Mole Fraction												
Ar	0.0093	0.0000	0.0077	0.0106	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0003	0.0000	0.1311	0.0181	0.9840	1.0000	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	0.0000
H_2O	0.0071	1.0000	0.1916	0.0469	0.0160	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.7753	0.0000	0.6437	0.8886	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2080	0.0000	0.0259	0.0357	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000			
V-L Flowrate (kg_{mol}/hr)	368	2,366	94,439	68,405	11,327	11,146	45,862	45,862	98,833	90,726	90,726	41,492
V-L Flowrate (kg/hr)	10,635	42,628	2,681,339	1,922,597	493,787	490,527	826,217	826,217	1,780,510	1,634,452	1,634,452	747,492
Solids Flowrate (kg/hr)	0	10,657	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	6	58	58	32	21	35	152	151	538	340	538	47
Pressure (MPa, abs)	0.08	0.08	0.08	0.08	0.16	15.27	0.49	0.49	16.65	4.28	3.90	2.76
Enthalpy (kJ/kg)	16.93	1,375.34	380.63	111.31	28.91	-212.36	2,746.50	635.72	3,395.97	3,062.35	3,530.88	197.81
Density (kg/m^3)	1.0	1,099.0	0.9	0.9	2.9	794.4	2.6	915.8	50.2	16.6	10.7	990.7
V-L Molecular Weight	28.887	18.016	28.392	28.106	43.595	44.010	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	812	5,217	208,203	150,807	24,971	24,572	101,108	101,108	217,890	200,016	200,016	91,474
V-L Flowrate (lb/hr)	23,447	93,978	5,911,340	4,238,600	1,088,614	1,081,427	1,821,496	1,821,496	3,925,353	3,603,349	3,603,349	1,647,938
Solids Flowrate (lb/hr)	0	23,494	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	42	136	136	89	69	95	305	304	1,000	645	1,000	116
Pressure (psia)	11.4	12.0	12.0	12.0	23.5	2,215.0	71.0	71.0	2,415.0	620.5	565.5	400.0
Enthalpy (Btu/lb)	7.3	591.3	163.6	47.9	12.4	-91.3	1,180.8	273.3	1,460.0	1,316.6	1,518.0	85.0
Density (lb/ft^3)	0.061	68.607	0.053	0.057	0.183	49.590	0.163	57.172	3.134	1.034	0.668	61.847

7.1.3 Key System Assumptions

System assumptions for Cases 7, 8 and 9, subcritical PC with and without CO_2 capture, are compiled in Exhibit 7-7.

Exhibit 7-7 Subcritical PC Plant Study Configuration Matrix

	Case 7 w/o CO_2 Capture	Case 8 w/CO_2 Capture	Case 9 w/CO_2 Capture
Steam Cycle, MPa/°C/°C (psig/°F/°F)	16.5/538/538 (2400/1000/1000)	16.5/538/538 (2400/1000/1000)	16.5/538/538 (2400/1000/1000)
Coal	Montana Rosebud PRB	Montana Rosebud PRB	Montana Rosebud PRB
Condenser pressure, mm Hg (in Hg)	35.6 (1.4)	35.6 (1.4)	35.6 (1.4)
Boiler Efficiency, %	83	83	83
Cooling water to condenser, °C (ºF)	8.9 (48)	8.9 (48)	8.9 (48)
Cooling water from condenser, °C (ºF)	20 (68)	20 (68)	20 (68)
Stack temperature, °C (°F)	58 (136)	45 (113)	32 (89)
SO_2 Control	Soda Ash-Based Wet Scrubber	Soda Ash-Based Wet Scrubber	Soda Ash-Based Wet Scrubber
FGD Efficiency, % (A)	85	92 (B)	92 (B)
NOx Control	LNB w/OFA	Advanced LNB w/OFA	Advanced LNB w/OFA
Particulate Control	ESP	ESP	ESP
ESP efficiency, % (A)	99.65	99.65	99.65
Ash Distribution, Fly/Bottom	80% / 20%	80% / 20%	80% / 20%
Mercury Control	Co-benefit Capture	Co-benefit Capture	Co-benefit Capture
Mercury removal efficiency, % (A)	16	16	16
CO_2 Control	N/A	Econamine FG Plus	Econamine FG Plus
CO_2 Capture (A)	N/A	1,100 lb/net-MWh	90%
CO_2 Sequestration	N/A	Off-site Saline Formation	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 (< 10 ppmv) to reduce formation of amine heat stable salts during the CO_2 absorption process

Balance of Plant – Cases 7 - 9

The balance of plant assumptions are common to all cases and are presented in Exhibit 7-8.

Exhibit 7-8 Balance of Plant Assumptions

Cooling system	Recirculating Wet Cooling Tower
Fuel and Other storage Coal	30 days
Ash	30 days
Soda Ash	30 days
Plant Distribution Voltage Motors below 1 hp	110/220 volt
Motors between 1 hp and 250 hp	480 volt
Motors between 250 hp and 5,000 hp	4,160 volt
Motors above 5,000 hp	13,800 volt
Steam and Gas Turbine generators	24,000 volt
Grid Interconnection voltage	345 kV
Water and Waste Water Makeup Water	The water supply 100 percent from the Green River. No municipal water sources are utilized.
Process Wastewater	Storm water that contacts equipment surfaces is collected and treated for discharge through a permitted discharge.
Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant is sized for 5.68 cubic meters per day (1,500 gallons per day)
Water Discharge	Most of the process wastewater is recycled to the cooling tower basin. Blowdown will be treated for chloride and metals, and discharged.

7.1.4 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, tangentially-fired PC subcritical boiler (1 x 100%)
- Two cold-side ESPs (2 x 50%)
- One soda ash-based wet forced oxidation positive pressure absorber (1 x 100%)
- One steam turbine (1 x 100%)
- For Case 9, two parallel Econamine FG Plus CO_2 absorption systems, with each system consisting of two absorbers, strippers and ancillary equipment (2 x 50%). Case 8 consists of a single train only.

7.1.5 Case 7 - 9 Performance Results

Cases 7 through 9 are based on a coal feed rate of 295,000 kg/hr (650,360 lb/hr). Overall performance for the plant is summarized in Exhibit 7-9 which includes auxiliary power requirements.

Exhibit 7-9 Cases 7 - 9 Plant Performance Summary

Power Output, kWe	Case 7	Case 8	Case 9
Steam Turbine Power	**577,800**	**476,800**	**432,000**
Econamine Let Down Turbine Power	**N/A**	**28,100**	**40,600**
Gross Power	**577,800**	**504,900**	**472,600**
Auxiliary Load, kWe			
Coal Handling and Conveying	550	550	550
Pulverizers	4,420	4,420	4,420
Sorbent Handling & Reagent Preparation	390	410	410
Ash Handling	710	710	710
Primary Air Fans	1,640	1,640	1,630
Forced Draft Fans	2,700	2,710	2,700
Induced Draft Fans	13,090	16,120	16,060
ESP	1,000	1,000	1,000
FGD Pumps and Agitators	1,370	1,370	1,370
Econamine FG Plus Auxiliaries	N/A	12,700	18,400
Econamine Condensate Return Pump	N/A	90	130
CO_2 Compression	N/A	28,200	40,780
Miscellaneous Balance of Plant[1,2]	6,500	6,500	6,500
Steam Turbine Auxiliaries	400	400	400
Condensate Pumps	1,470	990	760
Circulating Water Pumps	5,550	7,330	8,980
Cooling Tower Fans	4,130	5,460	6,690
Air Cooled Condenser Fans	0	0	0
Transformer Losses	1,850	1,760	1,720
Total	45,770	92,360	113,210
Plant Performance			
Net Plant Power	532,030	412,540	359,390
Net Plant Efficiency (HHV)	32.6%	25.3%	22.0%
Net Plant Heat Rate (HHV)	11,045 (10,469)	14,244 (13,501)	16,351 (15,498)
Coal Feed Flowrate (kg/hr (lb/hr))	294,998 (650,360)	294,996 (650,355)	294,998 (650,360)
Thermal Input (kW_{th})	1,632,313	1,632,299	1,632,314
Condenser Duty (GJ/hr (MMBtu/hr))	2,716 (2,574)	1,779 (1,686)	1,361 (1,290)
Raw Water Withdrawal (m^3/min (gpm))	24.8 (6,553)	30.5 (8,048)	33.9 (8,948)
Raw Water Consumption (m^3/min (gpm))	19.9 (5,270)	24.0 (6,352)	26.0 (6,869)
Other Consumables			
SCR Catalyst (m^3 (ft^3))	N/A	N/A	N/A
FGD Sorbent (tonne/day (ton/day))	8.02 (8.84)	8.44 (9.30)	8.44 (9.30)
Ammonia (19% Solution) (tonne/day (ton/day))	N/A	N/A	N/A
Econamine Consumables			
MEA (tonne/day (ton/day))	N/A	0.82 (0.90)	1.18 (1.30)
Activated Carbon (kg/day (lb/day))	N/A	488 (1,076)	706 (1,557)
Sodium Hydroxide (NaOH) (tonne/day (ton/day))	N/A	6.72 (7.41)	9.73 (10.72)
Sulfuric Acid (H2SO4) (tonne/day (ton/day))	N/A	3.89 (4.28)	5.62 (6.20)
Corrosion Inhibitor ($/yr)	N/A	4,186	6,054

1 - Boiler feed pumps are turbine driven

2 - Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads. Miscellaneous loads were estimated to match the reported efficiency for the existing subcritical PC plant.

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2 and particulate matter were presented in Section 2.4. A summary of the plant air emissions for Cases 7 through 9 is presented in Exhibit 7-10.

Exhibit 7-10 Cases 7 - 9 Air Emissions

	Case 7	Case 8	Case 9
kg/GJ (lb/10^6 Btu)			
SO_2	0.109 (0.255)	0.023 (0.054)	0.007 (0.017)
NO_X	0.193 (0.450)	0.103 (0.240)	0.103 (0.240)
Particulates	0.012 (0.0270)	0.012 (0.0270)	0.012 (0.027)
Hg	2.57E-6 (5.97E-6)	2.54E-6 (5.90E-6)	2.54E-6 (5.90E-6)
CO_2	93 (216)	35 (81)	9.3 (22)
Tonne/year (tons/year) 85% capacity			
SO_2	5,070 (5,589)	1,074 (1,184)	346 (381)
NO_X	8,963 (9,880)	4,780 (5,269)	4,780 (5,269)
Particulates	538 (593)	538 (593)	538 (593)
Hg	0.119 (0.131)	0.117 (0.129)	0.117 (0.129)
CO_2	4,295,414 (4,734,883)	1,623,154 (1,789,221)	429,701 (473,664)
kg/MWh (lb/gross-MWh)			
SO_2	1.11 (2.45)	0.270 (0.595)	0.093 (0.204)
NO_X	1.97 (4.34)	1.20 (2.65)	1.28 (2.83)
Particulates	0.118 (0.260)	0.135 (0.298)	0.144 (0.318)
Hg	2.61E-5 (5.75E-5)	2.95E-5 (6.51E-5)	3.15E-5 (6.95E-5)
CO_2	943 (2,079)	408 (899)	115 (254)
kg/MWh (lb/net-MWh)			
CO_2	1,024 (2,258)	499 (1,100)	152 (334)

SO_2 emissions are controlled using a wet soda ash-based forced oxidation scrubber that achieves a removal efficiency of 85, 92, and 92 percent for Cases 7 through 9, respectively. The byproduct sodium sulfate is dewatered and disposed of in a landfill. The flue gas exiting the scrubber is vented through the plant stack (Case 7) or sent to the Econamine unit (Cases 8 and 9).

NOx emissions are controlled to about 0.45 lb/10^6 Btu for Case 7 and 0.24 lb/10^6 Btu for Cases 8 and 9 through the use of LNBs and OFA. Particulate emissions are controlled using an electrostatic precipitator (ESP) which operates at an efficiency of 99.65 percent.

Co-benefit capture results in a 16 percent reduction of mercury emissions. CO_2 emissions represent the uncontrolled discharge from the process in Case 7. In Case 8 the CO_2 emission are limited to 1,100 lb/net-MWh, and in Case 9 there is a nominal 90 percent carbon capture.

Exhibit 7-11 shows the overall water balance for the plant. Raw water is obtained from the Green River.

Exhibit 7-11 Cases 7 - 9 Water Balance

	Case 7	Case 8	Case 9
Water Demand, m^3/min (gpm)			
Econamine	N/A	0.08 (22)	0.12 (32)
FGD Makeup	3.12 (846)	3.2 (858)	3.2 (852)
BFW Makeup	0.30 (78)	0.30 (78)	0.30 (79)
Cooling Tower	21.6 (5,708)	28.6 (7,543)	35.0 (9,246)
Total	**25.1 (6,632)**	**32.2 (8,502)**	**38.6 (10,209)**
Internal Recycle, m^3/min (gpm)			
Econamine	N/A	0.0 (0)	0.0 (0)
FGD Makeup	0.0 (0)	0.0 (0)	0.0 (0)
BFW Makeup	0.0 (0)	0.0 (0)	0.0 (0)
Cooling Tower	0.30 (78)	1.7 (454)	4.8 (1,260)
Total	**0.30 (78)**	**1.7 (454)**	**4.8 (1,260)**
Raw Water Withdrawal, m^3/min (gpm)			
Econamine	N/A	0.08 (22)	0.12 (32)
FGD Makeup	3.2 (846)	3.2 (858)	3.2 (852)
BFW Makeup	0.30 (78)	0.30 (78)	0.30 (79)
Cooling Tower	21.3 (5,629)	26.8 (7,089)	30.2 (7,985)
Total	**24.8 (6,553)**	**30.5 (8,048)**	**33.9 (8,948)**
Process Water Discharge, m^3/min (gpm)			
Cooling Tower	4.9 (1,284)	6.4 (1,696)	7.9 (2,079)
Total	**4.9 (1,284)**	**6.4 (1,696)**	**7.9 (2,079)**
Raw Water Consumption, m^3/min (gpm)			
Econamine	N/A	0.08 (22)	0.12 (32)
FGD Makeup	3.2 (846)	3.2 (858)	3.2 (852)
BFW Makeup	0.30 (78)	0.30 (78)	0.30 (79)
Cooling Tower	16.4 (4,346)	20.4 (5,393)	22.4 (5,906)
Total	**19.9 (5,270)**	**24.0 (6,352)**	**26.0 (6,869)**
Total, gpm/MWnet	**9.9**	**15.4**	**19.1**

Water demand represents the total amount of water required for a particular process. Some water is recovered within the process, primarily as flue gas condensate in CO_2 capture cases, and that water is re-used as internal recycle. Raw water withdrawal is the difference between water demand and internal recycle. Some water is returned to the source, namely cooling tower blowdown. The difference between raw water withdrawal and water returned to the source (process discharge) is raw water consumption, which represents the net impact on the water source.

The carbon balance for the plant is shown in Exhibit 7-12. The carbon input to the plant consists of carbon in the coal, carbon in the air, and carbon in the FGD reagent. Carbon leaves the plant as carbon in the FGD product, CO_2 in the stack gas, and CO_2 product. The percent of total carbon sequestered for the capture cases is defined as the amount of carbon product produced (as sequestration-ready CO_2) divided by the carbon in the coal feedstock, less carbon contained in solid byproducts (ash).

Exhibit 7-12
Cases 7 - 9 Carbon Balance

	Case 7	**Case 8**	**Case 9**
Carbon In, kg/hr (lb/hr)			
Coal	147,700 (325,623)	147,699 (325,620)	147,700 (325,623)
Air (CO_2)	309 (681)	309 (682)	308 (679)
FGD Reagent	818 (1,804)	860 (1,897)	860 (1,897)
Total In	**148,827 (328,108)**	**148,869 (328,200)**	**148,869 (328,200)**
Carbon Out, kg/hr (lb/hr)			
Ash	0 (0)	0 (0)	0 (0)
Stack Gas	148,692 (327,810)	56,188 (123,873)	14,875 (32,793)
FGD Product	135 (298)	121 (267)	121 (267)
CO_2 Product	N/A	92,560 (204,059)[1]	133,873 (295,139)[2]
Total Out	**148,827 (328,108)**	**148,869 (328,200)**	**148,869 (328,200)**

[1] Carbon capture is 62.3 percent to achieve an emission rate of 1,100 lb CO_2/net-MWh
[2] Carbon capture is 90 percent

Exhibit 7-13 shows the sulfur balance for the plant. Sulfur input is the sulfur in the coal. Sulfur output is the sulfur combined with lime in the ash, and the sulfur emitted in the stack gas.

Exhibit 7-13 Cases 4 - 6 Sulfur Balance

	Case 7	Case 8	Case 9
Sulfur In, kg/h (lb/hour)			
Coal	2,146 (4,731)	2,146 (4,731)	2,146 (4,731)
Total In	**2,146 (4,731)**	**2,146 (4,731)**	**2,146 (4,731)**
Sulfur Out, kg/h (lb/hour)			
FGD Product	1,824 (4,021)[1]	1,974 (4,353)[2]	1,974 (4,353)[2]
Stack Gas	322 (710)	172 (378)	172 (378)
CO_2 Product	N/A	0 (0)	0 (0)
Total Out	**2,146 (4,731)**	**2,146 (4,731)**	**2,146 (4,731)**

[1] Sulfur capture is 85 percent
[2] Sulfur capture is 92 percent

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown Exhibit 7-14 through Exhibit 7-19 for the three existing subcritical PC plant configurations

An overall plant energy balance is provided in tabular form in Exhibit 7-20.

Exhibit 7-14 Case 7: Existing Subcritical PC Boiler – Boiler and Gas Cleanup Systems Heat and Mass Balance Schematic

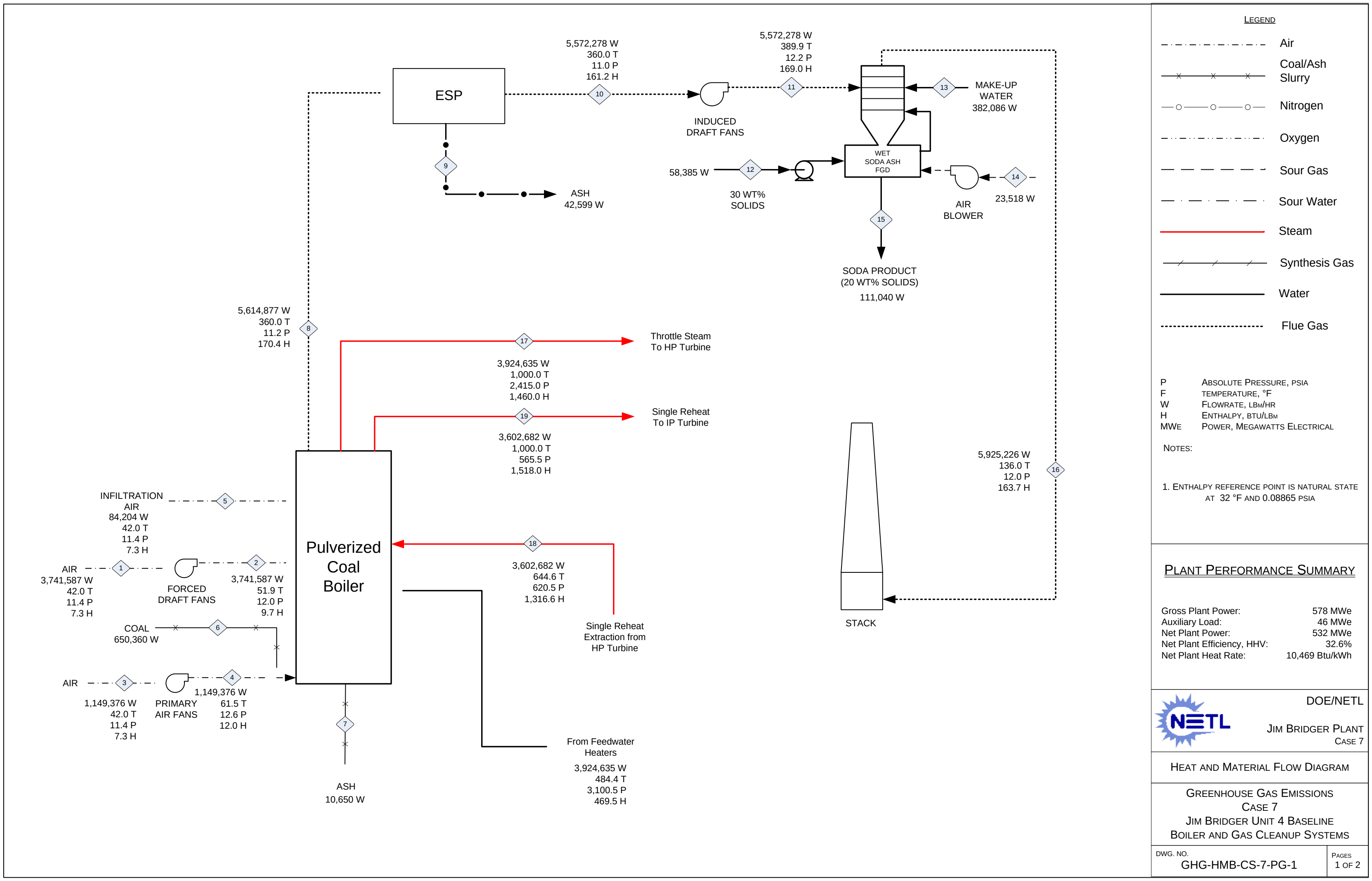


Exhibit 7-15 Case 7: Existing Subcritical PC - Power Block System Heat and Mass Balance Schematic

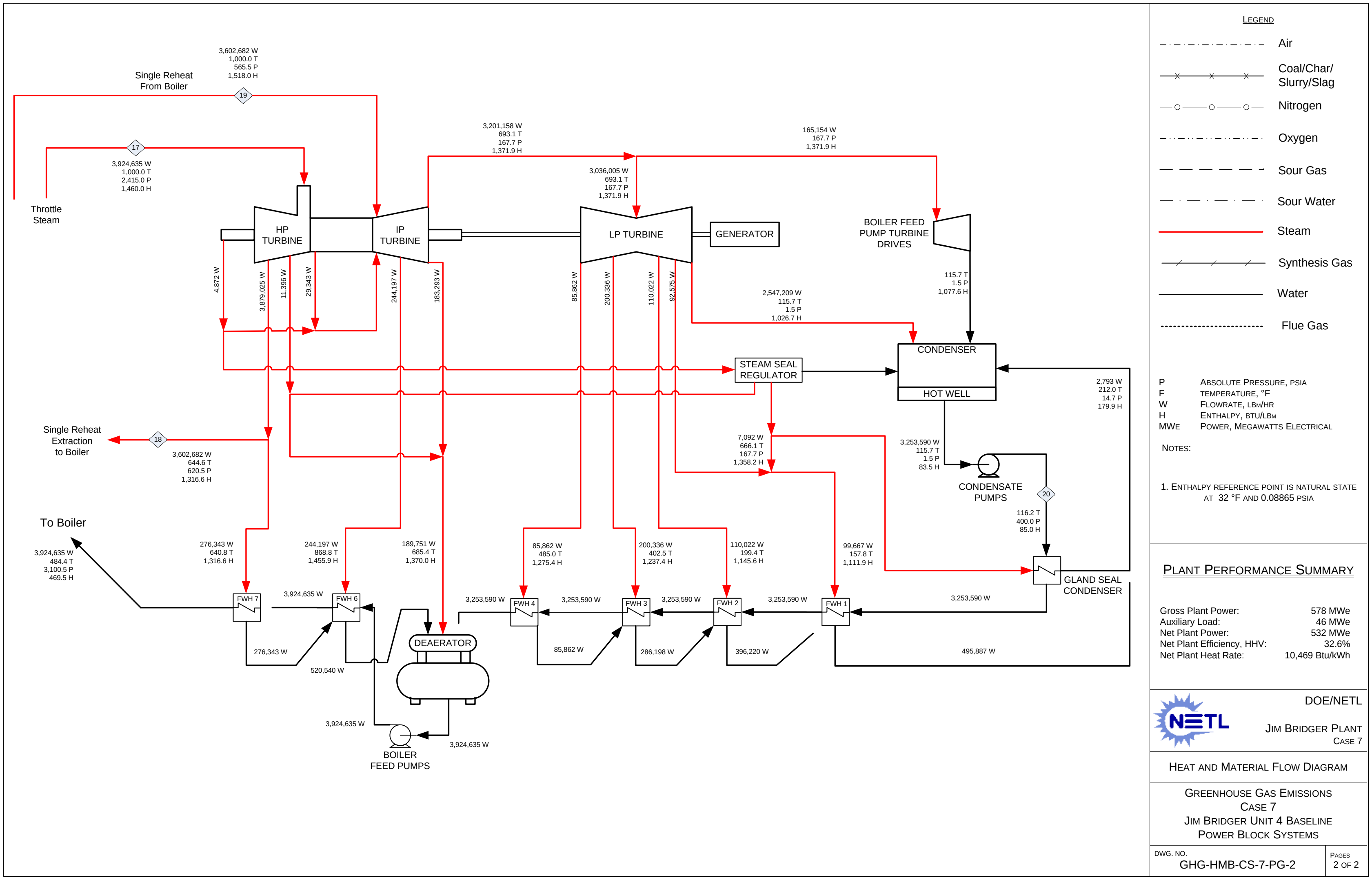


Exhibit 7-16 Case 8: Subcritical PC Plant Retrofitted with Carbon Capture to an Emission Rate of 1,100 lb CO_2/net-MWh - Boiler and Gas Cleanup Systems Heat and Mass Balance Schematic

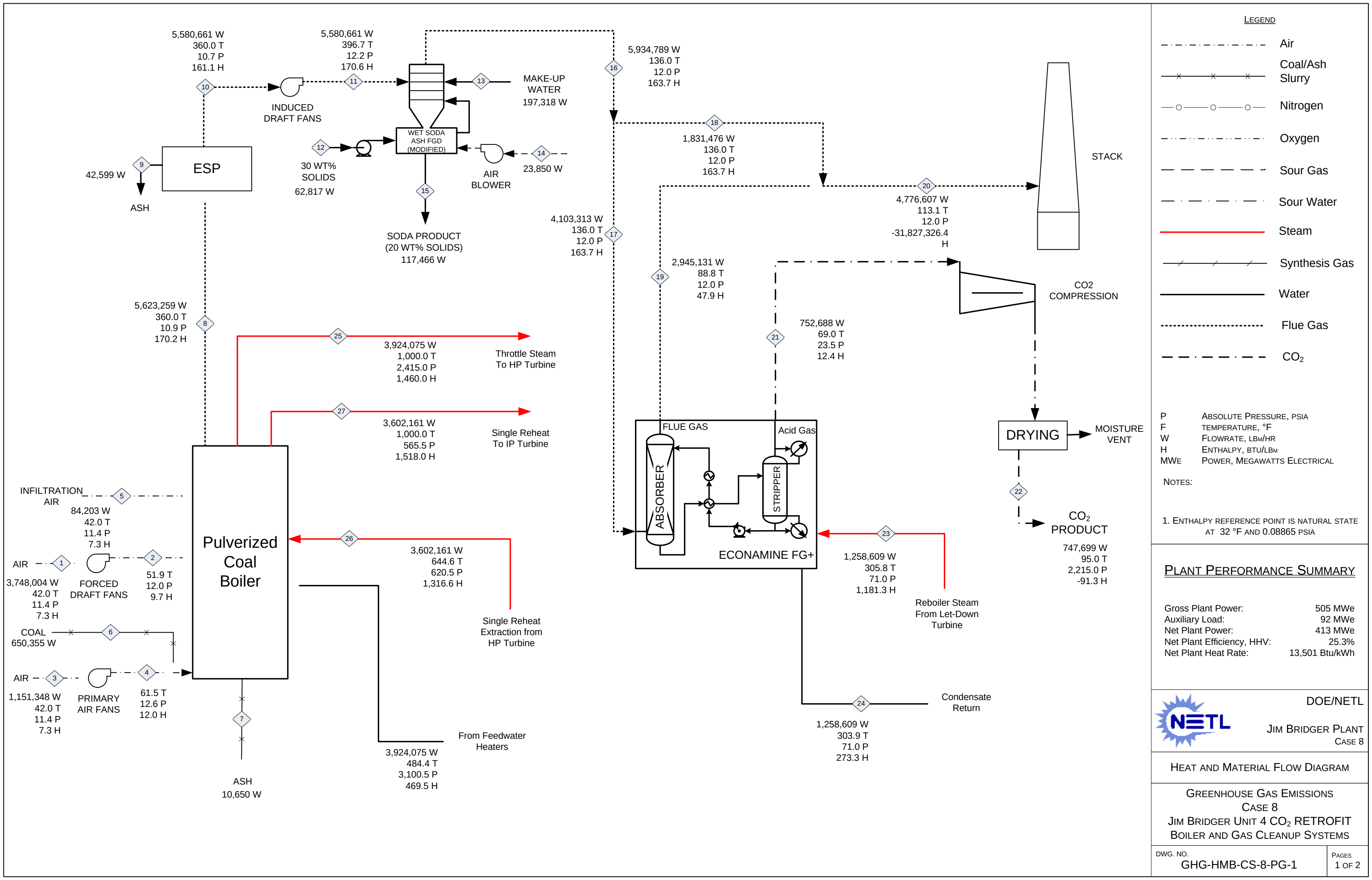


Exhibit 7-17 Case 8: Subcritical PC Plant Retrofitted with Carbon Capture to an Emission Rate of 1,100 lb CO_2/net-MWh - Power Block Systems Heat and Mass Balance Schematic

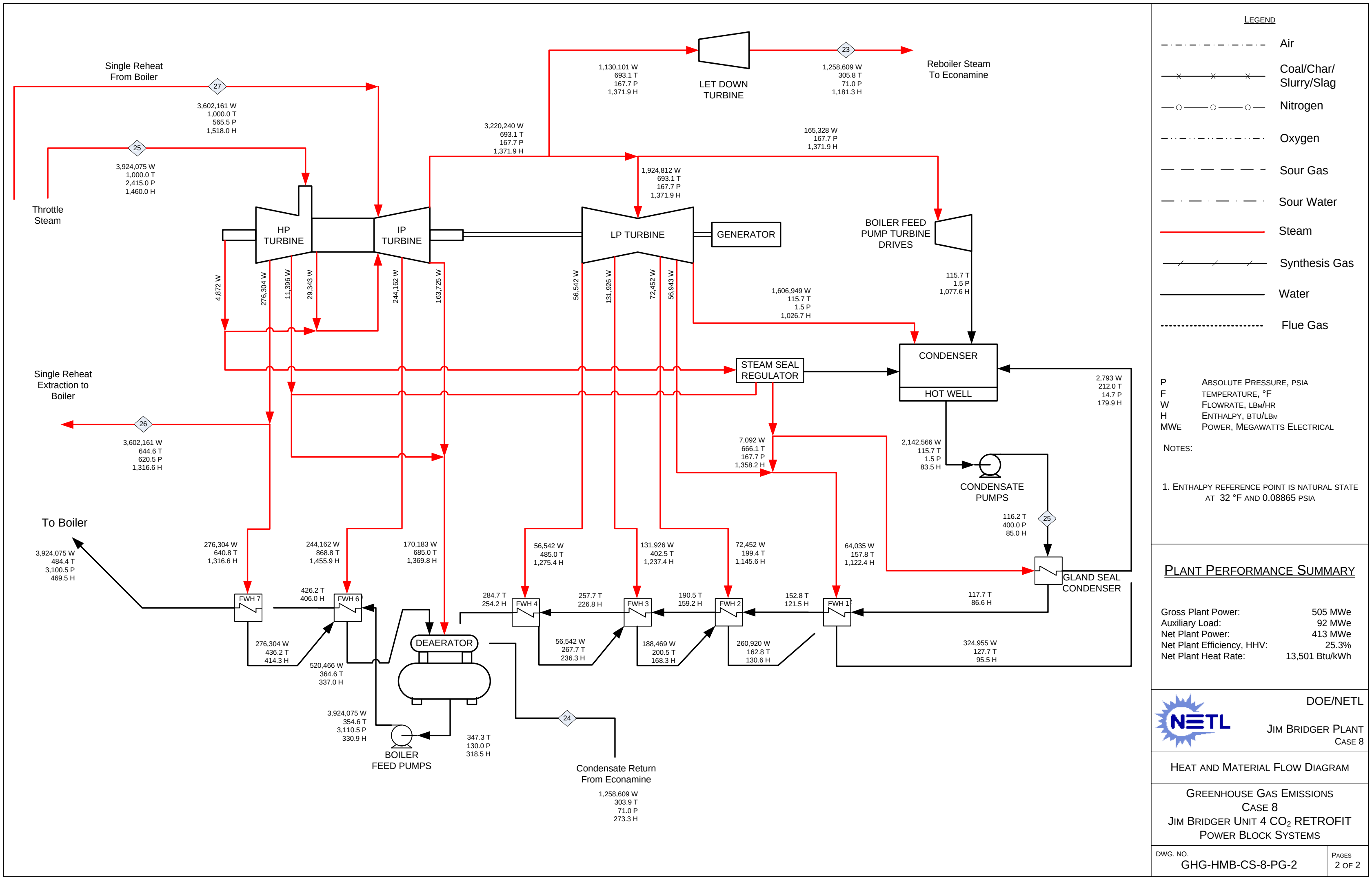


Exhibit 7-18 Case 9: Subcritical PC Plant Retrofitted with 90% CO_2 Capture - Boiler and Gas Cleanup Systems Heat and Mass Balance Schematic

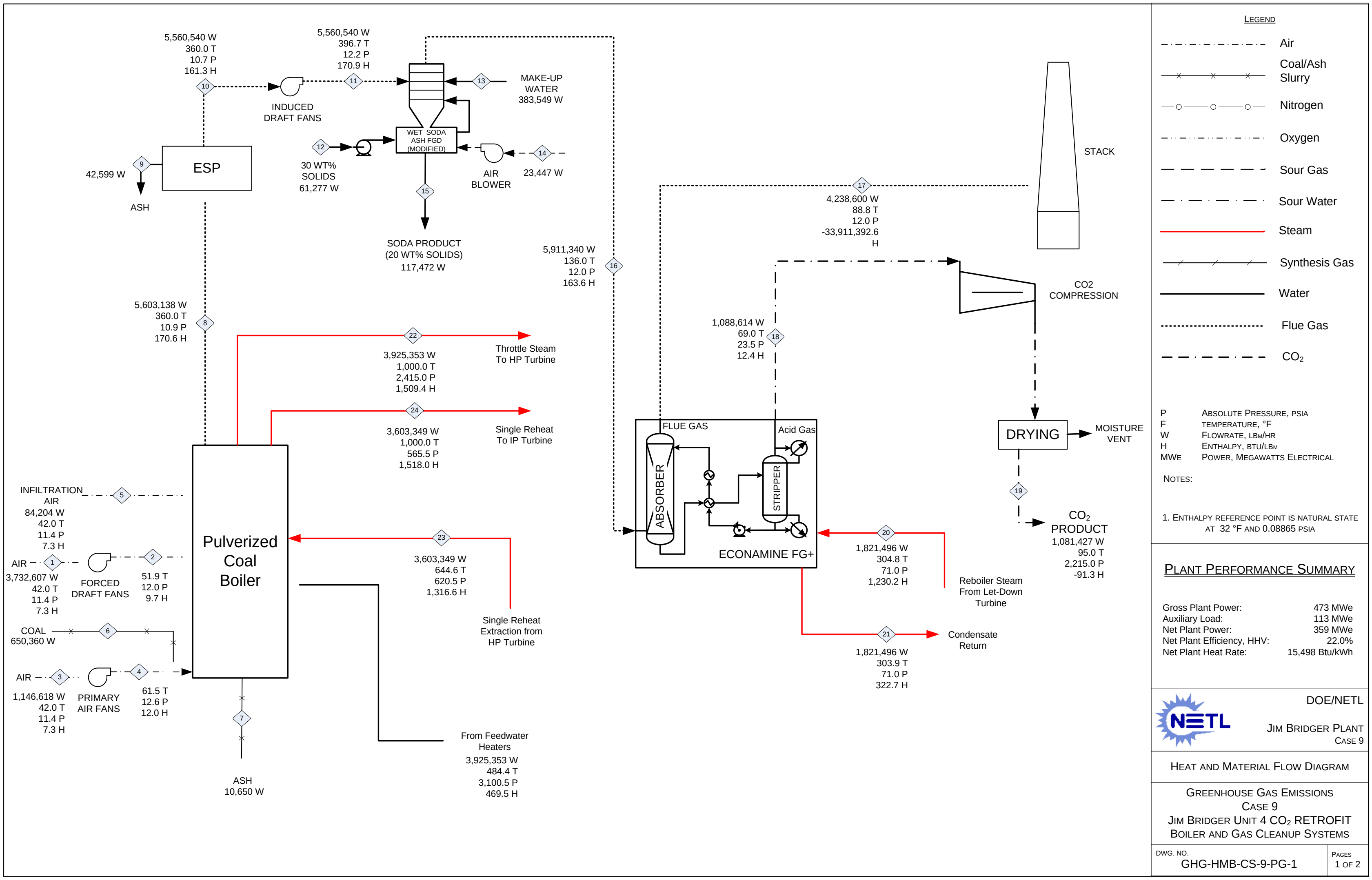


Exhibit 7-19 Case 9: Subcritical PC Plant Retrofitted with 90% CO_2 Capture - Power Block System Heat and Mass Balance Schematic

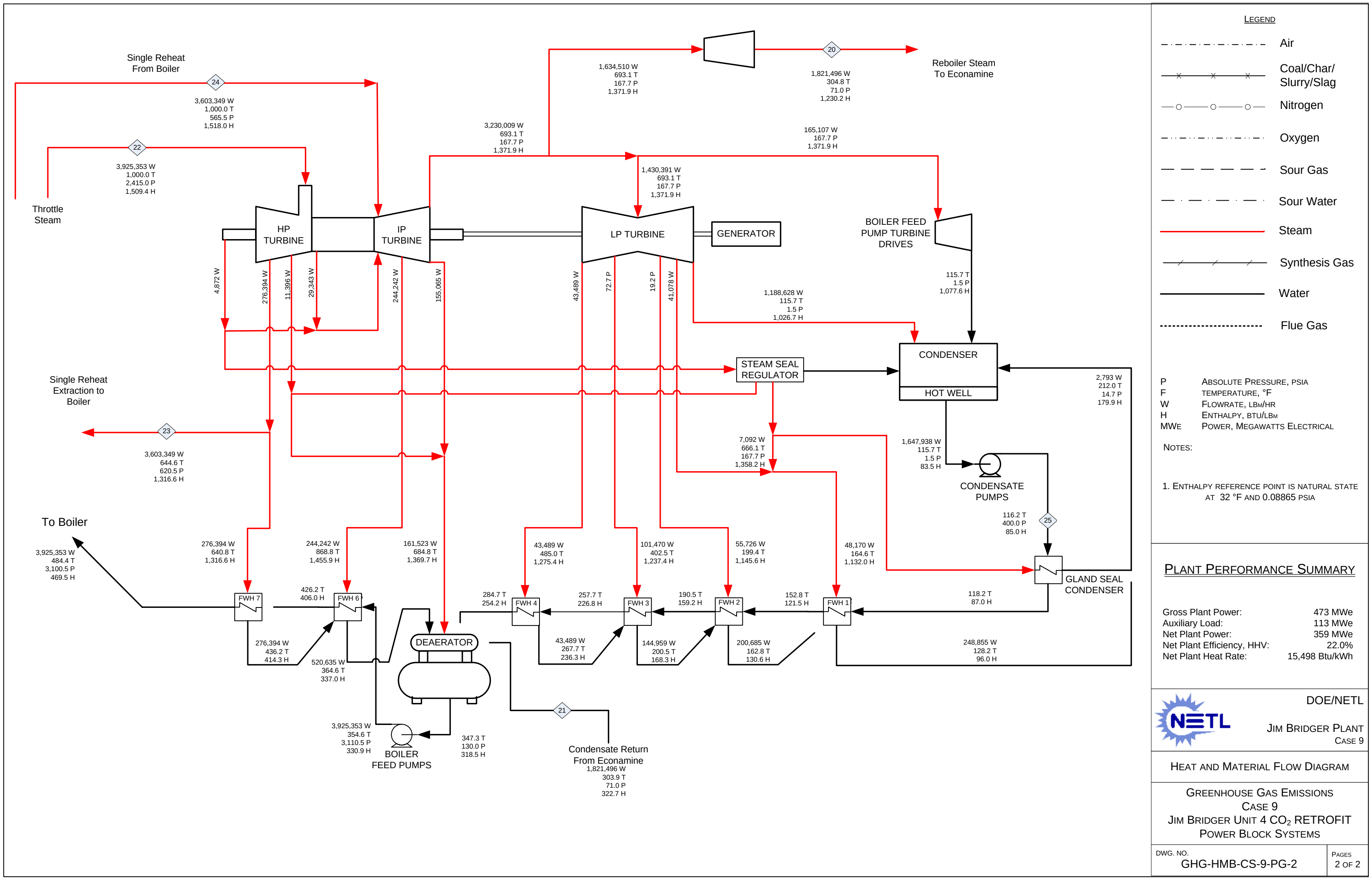


Exhibit 7-20 Cases 7 - 9 Overall Energy Balance

	Case 7	Case 8	Case 9
Energy In, GJ/hr (MMBtu/hr)[1]			
Coal, HHV	5,876 (5,570)	5,876 (5,570)	5,876 (5,570)
Sensible + Latent			
Coal	3.0 (2.9)	3.0 (2.9)	3.0 (2.9)
Air	38 (36)	38 (36)	38 (36)
Raw Water Makeup	35 (33)	42 (40)	47 (45)
Soda Ash	0.03 (0.03)	0.03 (0.03)	0.03 (0.03)
Auxiliary Power	165 (156)	332 (315)	408 (386)
Total In	**6,117 (5,798)**	**6,293 (5,964)**	**6,372 (6,040)**
Energy Out, GJ/hr (MMBtu/hr)[1]			
Sensible + Latent			
Bottom Ash	0.7 (0.7)	0.7 (0.7)	0.7 (0.7)
Fly Ash + FGD Ash	2.8 (2.6)	2.8 (2.6)	2.8 (2.6)
Flue Gas	1,023 (970)	465 (441)	214 (203)
Condenser	2,716 (2,574)	1,779 (1,686)	1,361 (1,290)
CO_2	N/A	-72 (-68)	-104 (-99)
Cooling Tower Blowdown	27 (26)	36 (34)	44 (42)
Econamine Losses	N/A	1,844 (1,748)	3,104 (2,942)
Process Losses[2]	*267 (253)*	*420 (398)*	*49 (46)*
Power	2,080 (1,972)	1,818 (1,723)	1,701 (1,613)
Total Out	**6,117 (5,798)**	**6,293 (5,964)**	**6,372 (6,040)**

[1] Enthalpy reference conditions are 0°C (32°F) and 614 Pa (0.089 psia)
[2]Process losses are calculated by difference to close the energy balance

7.1.6 Cases 7 - 9 Major Equipment List

Major equipment items for the existing subcritical PC plant with and without CO_2 capture are shown in the following tables. The Case 7 equipment list is an estimate of the existing subcritical PC plant using the same methodology as was used for the supercritical PC cases. Case 7 establishes a baseline equipment list that is used to determine the necessary plant equipment modifications. Cases 8 and 9 show the incremental increases due to the addition of equipment necessary for CO_2 capture. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 7.1.7. 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.

ACCOUNT 1 COAL AND SORBENT HANDLING

Equipment No.	Description	Type	Operating Qty.	Spares	Case 7 Design Condition	Case 8 Design Condition	Case 9 Design Condition
1	Feeder	Belt	2	0	572 tonne/h (630 tph)	No change	No change
2	Conveyor No. 1	Belt	1	0	1,134 tonne/h (1,250 tph)	No change	No change
3	Transfer Tower No. 1	Enclosed	1	0	N/A	N/A	N/A
4	Conveyor No. 2	Belt	1	0	1,134 tonne/h (1,250 tph)	No change	No change
5	As-Received Coal Sampling System	Two-stage	1	0	N/A	N/A	N/A
6	Stacker/Reclaimer	Traveling, linear	1	0	1,134 tonne/h (1,250 tph)	No change	No change
7	Reclaim Hopper	N/A	2	1	64 tonne (70 ton)	No change	No change
8	Feeder	Vibratory	2	1	245 tonne/h (270 tph)	No change	No change
9	Conveyor No. 3	Belt w/ tripper	1	0	490 tonne/h (540 tph)	No change	No change
10	Crusher Tower	N/A	1	0	N/A	N/A	N/A
11	Coal Surge Bin w/ Vent Filter	Dual outlet	2	0	245 tonne (270 ton)	No change	No change
12	Crusher	Impactor reduction	2	0	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	No change	No change
13	As-Fired Coal Sampling System	Swing hammer	1	1	N/A	N/A	N/A
14	Conveyor No. 4	Belt w/tripper	1	0	490 tonne/h (540 tph)	No change	No change
15	Transfer Tower No. 2	Enclosed	1	0	N/A	N/A	N/A

Equipment No.	**Description**	**Type**	**Operating Qty.**	**Spares**	**Case 7 Design Condition**	**Case 8 Design Condition**	**Case 9 Design Condition**
16	Conveyor No. 5	Belt w/ tripper	1	0	490 tonne/h (540 tph)	No change	No change
17	Coal Silo w/ Vent Filter and Slide Gates	Field erected	3	0	1,089 tonne (1,200 ton)	No change	No change
18	Soda Ash Truck Unloading Hopper	N/A	1	0	36 tonne (40 ton)	No change	No change
19	Soda Ash Feeder	Belt	3	0	36 tonne/h (40 tph)	No change	No change
20	Soda Conveyor No. L1	Belt	1	0	36 tonne/h (40 tph)	No change	No change
21	Soda Reclaim Hopper	N/A	2	0	9 tonne (10 ton)	No change	No change
22	Soda Reclaim Feeder	Belt	1	0	27 tonne/h (30 tph)	No change	No change
23	Soda Conveyor No. L2	Belt	1	0	27 tonne/h (30 tph)	No change	No change
24	Soda Day Bin	w/ actuator	2	0	109 tonne (120 ton)	No change	No change

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

Equipment No.	Description	Type	Operating Qty.	Spares	Case 7 Design Condition	Case 8 Design Condition	Case 9 Design Condition
1	Coal Feeder	Gravimetric	6	0	54 tonne/h (60 tph)	No change	No change
2	Coal Pulverizer	Ball type or equivalent	6	0	54 tonne/h (60 tph)	No change	No change
3	Soda Weigh Feeder	Gravimetric	1	1	9 tonne/h (10 tph)	No change	No change
4	Soda Ball Mill	Rotary	1	1	9 tonne/h (10 tph)	No change	No change
5	Soda Mill Slurry Tank with Agitator	N/A	1	1	37,854 liters (10,000 gal)	No change	No change

Equipment No.	Description	Type	Operating Qty.	Spares	Case 7 Design Condition	Case 8 Design Condition	Case 9 Design Condition
6	Soda Mill Recycle Pumps	Horizontal centrifugal	1	1	606 lpm @ 12m H_2O (160 gpm @ 40 ft H_2O)	No change	No change
7	Hydroclone Classifier	4 active cyclones in a 5 cyclone bank	1	1	151 lpm (40 gpm) per cyclone	No change	No change
8	Distribution Box	2-way	1	1	N/A	N/A	N/A
9	Soda Slurry Storage Tank with Agitator	Field erected	1	1	189,271 liters (50,000 gal)	No change	No change
10	Soda Slurry Feed Pumps	Horizontal centrifugal	1	1	416 lpm @ 9 m H_2O (110 gpm @ 30 ft H_2O)	No change	No change

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Operating Qty.	Spares	Case 7 Design Condition	Case 8 Design Condition	Case 9 Design Condition
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	2	0	1,177,263 liters (311,000 gal)	No change	No change
2	Condensate Pumps	Vertical canned	1	1	27,255 lpm @ 335 m H_2O (7,200 gpm @ 1,100 ft H_2O)	No change	No change
3	Deaerator and Storage Tank	Horizontal spray type	1	0	1,958,158 kg/h (4,317,000 lb/h), 5 min. tank	No change	No change

Equipment No.	Description	Type	Operating Qty.	Spares	Case 7 Design Condition	Case 8 Design Condition	Case 9 Design Condition
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	1	1	32,933 lpm @ 2,530 m H_2O (8,700 gpm @ 8,300 ft H_2O)	No change	No change
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	1	0	9,842 lpm @ 2,530 m H_2O (2,600 gpm @ 8,300 ft H_2O)	No change	No change
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	2	0	811,930 kg/h (1,790,000 lb/h)	No change	No change
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	2	0	811,930 kg/h (1,790,000 lb/h)	No change	No change
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	2	0	811,930 kg/h (1,790,000 lb/h)	No change	No change
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	2	0	811,930 kg/h (1,790,000 lb/h)	No change	No change
10	HP Feedwater Heater 6	Horizontal U-tube	1	0	1,959,519 kg/h (4,320,000 lb/h)	No change	No change
11	HP Feedwater Heater 7	Horizontal U-tube	1	0	1,959,519 kg/h (4,320,000 lb/h)	No change	No change
12	Auxiliary Boiler	Shop fabricated, water tube	1	0	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	No change	No change
13	Fuel Oil System	No. 2 fuel oil for light off	1	0	1,135,624 liter (300,000 gal)	No change	No change

Equipment No.	Description	Type	Operating Qty.	Spares	Case 7 Design Condition	Case 8 Design Condition	Case 9 Design Condition
14	Service Air Compressors	Flooded Screw	2	1	28 m^3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	No change	No change
15	Instrument Air Dryers	Duplex, regenerative	2	1	28 m^3/min (1,000 scfm)	No change	No change
16	Closed Cycle Cooling Heat Exchangers	Shell and tube	2	0	53 GJ/h (50 MMBtu/h) each	No change	No change
17	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	2	1	20,820 lpm @ 30 m H_2O (5,500 gpm @ 100 ft H_2O)	No change	No change
18	Engine-Driven Fire Pump	Vertical turbine, diesel engine	1	1	3,785 lpm @ 88 m H_2O (1,000 gpm @ 290 ft H_2O)	No change	No change
19	Fire Service Booster Pump	Two-stage horizontal centrifugal	1	1	2,650 lpm @ 64 m H_2O (700 gpm @ 210 ft H_2O)	No change	No change
20	Raw Water Pumps	Stainless steel, single suction	2	1	13,627 lpm @ 43 m H_2O (3,600 gpm @ 140 ft H_2O)	Δ3,634 lpm @ 43 m H_2O (Δ1,020 gpm @ 140 ft H_2O)	Δ7,344 lpm @ 43 m H_2O (Δ1,950 gpm @ 140 ft H_2O)
21	Filtered Water Pumps	Stainless steel, single suction	2	1	1,779 lpm @ 49 m H_2O (470 gpm @ 160 ft H_2O)	No change	No change
22	Filtered Water Tank	Vertical, cylindrical	1	0	1,688,294 liter (446,000 gal)	No change	No change

Equipment No.	Description	Type	Operating Qty.	Spares	Case 7 Design Condition	Case 8 Design Condition	Case 9 Design Condition
23	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	1	1	644 lpm (170 gpm)	Δ 113 lpm (Δ 30 gpm)	Δ 151 lpm (Δ 40 gpm)
24	Liquid Waste Treatment System	--	1	0	10 years, 24-hour storm	No change	No change

ACCOUNT 4 BOILER AND ACCESSORIES

Equipment No.	Description	Type	Operating Qty.	Spares	Case 7 Design Condition	Case 8 Design Condition	Case 9 Design Condition
1	Boiler	Subcritical, drum, wall-fired, low NOx burners, overfire air	1	0	1,959,519 kg/h steam @ 16.5 MPa/538°C/538°C (4,320,000 lb/h steam @ 2,400 psig /1,000°F /1,000°F)	No change	No change
2	Primary Air Fan	Centrifugal	2	0	286,670 kg/h, 4,873 m^3/min @ 102 cm WG (632,000 lb/h, 172,100 acfm @ 40 in. WG)	No change	No change
3	Forced Draft Fan	Centrifugal	2	0	933,493 kg/h, 15,866 m^3/min @ 51 cm WG (2,058,000 lb/h, 560,300 acfm @ 20 in. WG)	No change	No change

Equipment No.	Description	Type	Operating Qty.	Spares	Case 7 Design Condition	Case 8 Design Condition	Case 9 Design Condition
4	Induced Draft Fan	Centrifugal	2	0	1,390,261 kg/h, 39,312 m^3/min @ 128 cm WG (3,065,000 lb/h, 1,388,300 acfm @ 50 in. WG)	No change	No change
5	SCR Reactor Vessel	Space for spare layer	2	0	N/A	N/A	N/A
6	SCR Catalyst	--	3	0	--	N/A	N/A
7	Dilution Air Blower	Centrifugal	2	1	N/A	N/A	N/A
8	Ammonia Storage	Horizontal tank	5	0	N/A	N/A	N/A
9	Ammonia Feed Pump	Centrifugal	2	1	N/A	N/A	N/A

ACCOUNT 5 FLUE GAS CLEANUP

Equipment No.	Description	Type	Operating Qty.	Spares	Case 7 Design Condition	Case 8 Design Condition	Case 9 Design Condition
1	Electrostatic Precipitator	Cold-side	2	0	1,390,261 kg/h (3,065,000 lb/h) 99.65% efficiency	No change	No change
2	Absorber Module	Counter-current open spray	1	0	57,625 m^3/min (2,035,000 acfm)	Upgraded	Upgraded

Equipment No.	Description	Type	Operating Qty.	Spares	Case 7 Design Condition	Case 8 Design Condition	Case 9 Design Condition
3	Recirculation Pumps	Horizontal centrifugal	5	1	200,627 lpm @ 64 m H_2O (53,000 gpm @ 210 ft H_2O)	No change	No change
4	Bleed Pumps	Horizontal centrifugal	2	1	1,401 lpm (370 gpm) at 20 wt% solids	No change	No change
5	Oxidation Air Blowers	Centrifugal	2	1	100 m^3/min @ 0.3 MPa (3,520 acfm @ 42 psia)	No change	No change
6	Agitators	Side entering	5	1	50 hp	No change	No change
7	Dewatering Cyclones	Radial assembly, 5 units each	2	0	341 lpm (90 gpm) per cyclone	No change	No change
8	Vacuum Filter Belt	Horizontal belt	2	1	11 tonne/h (12 tph) of 50 wt % slurry	No change	No change
9	Filtrate Water Return Pumps	Horizontal centrifugal	1	1	227 lpm @ 12 m H_2O (60 gpm @ 40 ft H_2O)	No change	No change
10	Filtrate Water Return Storage Tank	Vertical, lined	1	0	151,416 lpm (40,000 gal)	No change	No change

Equipment No.	Description	Type	Operating Qty.	Spares	Case 7 Design Condition	Case 8 Design Condition	Case 9 Design Condition
11	Process Makeup Water Pumps	Horizontal centrifugal	1	1	341 lpm @ 21 m H_2O (90 gpm @ 70 ft H_2O)	No change	No change

ACCOUNT 5B CO$_2$ REMOVAL AND COMPRESSION

Equipment No.	Description	Type	Operating Qty.	Spares	Case 7 Design Condition	Case 8 Design Condition	Case 9 Design Condition
1	Econamine FG Plus	Amine-based CO_2 capture technology	2	0	N/A	1,023,758 kg/h (2,257,000 lb/h) 20.2 wt % CO_2 concentration	1,474,629 kg/h (3,251,000 lb/h) 20.3 wt % CO_2 concentration
2	Let-Down Turbine	Commercially available	1	0	N/A	30 MW 1.2 MPa/367°C (168 psig/ 693°F)	43 MW 1.2 MPa/367°C (168 psig/ 693°F)
3	Let-Down Turbine Generator		1	0	N/A	30 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	50 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase
4	Econamine Condensate Pump	Centrifugal	1	1	N/A	10,486 lpm @ 49 m H_2O (2,770 gpm @ 160 ft H_2O)	15,180 lpm @ 49 m H_2O (4,010 gpm @ 160 ft H_2O)
5	CO2 Compressor	Reciprocating	2	0	N/A	186,533 kg/h @ 15.3 MPa (411,234 lb/h @ 2,215 psia)	269,790 kg/h @ 15.3 MPa (594,785 lb/h @ 2,215 psia)

ACCOUNT 5C CO_2 TRANSPORT, STORAGE, AND MONITORING (not shown in Total Plant Cost Details)

Equipment No.	Description	Type	Case 7 Design Condition	Case 8 Design Condition	Case 9 Design Condition
1	CO_2 Pipeline	Carbon Steel	N/A	50 miles @ 12 in diameter w/ inlet pressure of 2,200 psi and outlet pressure of 1,200 psi	50 miles @ 14 in diameter w/ inlet pressure of 2,200 psi and outlet pressure of 1,200 psi
2	CO_2 Sequestration Source	Saline Formation	N/A	1 well with bottom hole pressure @ 1,220 psi, 530 ft thickness, 4,055 ft depth, 22 Md permeability	2 wells with bottom hole pressure @ 1,220 psi, 530 ft thickness, 4,055 ft depth, 22 Md permeability
3	CO_2 Monitoring	N/A	N/A	20 year monitoring life during plant life / 80 years following / Total of 100 years	20 year monitoring life during plant life / 80 years following / Total of 100 years

ACCOUNT 6 COMBUSTION TURBINE/ACCESSORIES

N/A

ACCOUNT 7 HRSG, DUCTING & STACK

Equipment No.	Description	Type	Operating Qty.	Spares	Case 7 Design Condition	Case 8 Design Condition	Case 9 Design Condition
1	Stack	Reinforced concrete	1	0	152 m (500 ft) high x 7.1 m (23 ft) diameter	New stack liner for wet operation	New stack liner for wet operation

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Operating Qty.	Spares	Case 7 Design Condition	Case 8 Design Condition	Case 9 Design Condition
1	Steam Turbine	Commercially available advanced steam turbine	1	0	608 MW 16.5 MPa/538°C/538°C (2400 psig/ 1000°F/1000°F)	No change	No change
2	Steam Turbine Generator	Hydrogen cooled, static excitiation	1	0	680 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	No change	No change
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1	0	2,986 GJ/h (2,830 MMBtu/h), Inlet water temperature 09°C (48°F), Water temperature rise 11°C (20°F)	No change	No change

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Operating Qty.	Spares	Case 7 Design Condition	Case 8 Design Condition	Case 9 Design Condition
1	Circulating Water Pumps	Vertical, wet pit	2	1	556,456 lpm @ 30 m (147,000 gpm @ 100 ft)	Δ355,828 lpm @ 30 m (Δ94,000 gpm @ 100 ft)	Δ688,944 lpm @ 30 m (Δ182,000gpm @ 100 ft)
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	1	0	3°C (37°F) wet bulb / 9°C (48°F) CWT / 20°C (68°F) HWT / 3102 GJ/h (2,940 MMBtu/h) heat duty	Δ1,002 GJ/h (Δ950 MMBtu/h) heat duty	Δ1,920 GJ/h (Δ1,820 MMBtu/h) heat duty

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Equipment No.	Description	Type	Operating Qty.	Spares	Case 7 Design Condition	Case 8 Design Condition	Case 9 Design Condition
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	--	1	1	5.4 tonne/h (6 tph)	No change	No change
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	--	6	0	--	--	--

Equipment No.	Description	Type	Operating Qty.	Spares	Case 7 Design Condition	Case 8 Design Condition	Case 9 Design Condition
5	Hydroejectors	--	12		--	--	--
6	Economizer /Pyrites Transfer Tank	--	1	0	--	--	--
7	Ash Sluice Pumps	Vertical, wet pit	1	1	227 lpm @ 17 m H_2O (60 gpm @ 56 ft H_2O)	No change	No change
8	Ash Seal Water Pumps	Vertical, wet pit	1	1	7,571 lpm @ 9 m H_2O (2,000 gpm @ 28 ft H_2O)	No change	No change
9	Hydrobins	--	1	1	227 lpm (60 gpm)	No change	No change
10	Baghouse Hopper (part of baghouse scope of supply)	--	24	0	--	--	--
11	Air Heater Hopper (part of boiler scope of supply)	--	10	0	--	--	--
12	Air Blower	--	1	1	20 m^3/min @ 0.2 MPa (690 scfm @ 24 psi)	No change	No change
13	Fly Ash Silo	Reinforced concrete	2	0	635 tonne (1,400 ton)	No change	No change
14	Slide Gate Valves	--	2	0	--	--	--
15	Unloader	--	1	0	--	--	--
16	Telescoping Unloading Chute	--	1	0	118 tonne/h (130 tph)	No change	No change

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Operating Qty.	Spares	Case 7 Design Condition	Case 8 Design Condition	Case 9 Design Condition
1	STG Transformer	Oil-filled	1	0	24 kV/345 kV, 620 MVA, 3-ph, 60 Hz	No change	No change
2	Auxiliary Transformer	Oil-filled	1	1	24 kV/4.16 kV, 49 MVA, 3-ph, 60 Hz	Δ52 MVA	Δ75 MVA
3	Low Voltage Transformer	Dry ventilated	1	1	4.16 kV/480 V, 7 MVA, 3-ph, 60 Hz	Δ8 MVA	Δ12 MVA
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	1	0	24 kV, 3-ph, 60 Hz	No change	No change
5	Medium Voltage Switchgear	Metal clad	1	1	4.16 kV, 3-ph, 60 Hz	As required	As required
6	Low Voltage Switchgear	Metal enclosed	1	1	480 V, 3-ph, 60 Hz	As required	As required
7	Emergency Diesel Generator	Sized for emergency shutdown	1	0	750 kW, 480 V, 3-ph, 60 Hz	No change	No change

ACCOUNT 12 INSTRUMENTATION AND CONTROL

Equipment No.	Description	Type	Operating Qty.	Spares	Case 7 Design Condition	Case 8 Design Condition	Case 9 Design Condition
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	1	0	Operator stations/printers and engineering stations/printers	As required	As required
2	DCS - Processor	Microprocessor with redundant input/output	1	0	N/A	As required	As required
3	DCS - Data Highway	Fiber optic	1	0	Fully redundant, 25% spare	As required	As required

7.1.7 Case 7 – Cost Estimating

Case 7 represents the existing subcritical PC plant. The Energy Velocity Database reports the current cost of electricity for a typical subcritical PC plant as $19.10/MWh [34]. An estimated value for insurances and taxes was added to the fixed costs from the Energy Velocity Database to obtain the total current COE. The original plant capital costs are assumed to be paid for in this report and the COE was multiplied by the appropriate levelization factor to obtain the LCOE. The estimated O&M costs for the subcritical PC plant were distributed as follows (as explained in Section 2.7) and then levelized:

- Variable operating costs: $1.48/MWh
- Fixed operating costs: $13.16/MWh (includes $7.19/MWh for taxes and insurance)
- Fuel operating costs: $19.14/MWh
- Total LCOE: $33.78/MWh

7.1.8 Case 8 – Cost Estimating

The cost estimating methodology was described previously in Section 2.6. Exhibit 7-21 shows the total plant capital cost details organized by cost account as well as TOC and TASC. The costs represent the TOC for retrofitting the Econamine process and ancillary equipment. Exhibit 7-22 shows the initial and annual O&M costs.

The estimated TOC for adding carbon capture and sequestration to the existing subcritical PC plant with a CO_2 emission rate of 1,100 lb/net-MWh is $1,348/kW. Owner's costs represent 18 percent of the TOC. In the event that NSR is triggered and the addition of an SCR unit is necessary to achieve the NOx emission rate of 0.07 lb/MMBtu, the TOC for Case 8 including carbon capture and sequestration as well as the SCR unit would be $1,717/kW, which represents an increase of 27.4 percent over the no SCR case ($369/kW increase). The estimated cost for the SCR retrofit is taken from the referenced BART analysis and appears high (approximately $127 million, or $308/kW) [8]. The current dollar, 30-year LCOE, without SCR but including CO_2 TS&M costs, is $84.81/MWh. The net plant output is decreased by 22 percent because of the carbon capture and compression equipment. The current dollar, 30-year LCOE including SCR and TS&M costs is $94.01/MWh.

Exhibit 7-21 Case 8 Total Plant Cost Details

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 8 TOTAL PLANT COST $	Case 8 TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.2	Coal Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.3	Coal Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.4	Other Coal Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.5	Sorbent Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.6	Sorbent Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.7	Sorbent Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.8	Other Sorbent Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Coal & Sorbent Hnd.Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 1.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.2	Coal Conveyor to Storage	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.3	Coal Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.4	Misc.Coal Prep & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 2.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3.2	Water Makeup & Pretreating	$1,793	$0	$577	$0	$0	$2,370	$224	$0	$519	$3,114	$8
3.3	Other Feedwater Subsystems	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3.4	Service Water Systems	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3.5	Other Boiler Plant Systems	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3.6	FO Supply Sys & Nat Gas	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3.7	Waste Treatment Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 3.	**$1,793**	**$0**	**$577**	**$0**	**$0**	**$2,370**	**$224**	**$0**	**$519**	**$3,114**	**$8**
4	PC BOILER											
4.1	PC Boiler & Accessories	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.2	LNB's and OFA	$2,982	$0	$2,544	$0	$0	$5,526	$0	$0	$382	$5,907	$14
4.3	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.4	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Primary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Secondary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Boiler Foundations	$0	w/14.1	w/14.1	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4.	**$2,982**	**$0**	**$2,544**	**$0**	**$0**	**$5,526**	**$0**	**$0**	**$382**	**$5,907**	**$14**

Exhibit 7-21 Case 8 Total Plant Cost Details (Continued)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 8 TOTAL PLANT COST $	Case 8 TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	$3,549	$0	$199	$0	$0	$3,748	$298	$0	$809	$4,855	$12
5.2	Other FGD	$100	$0	$0	$0	$0	$100	$0	$0	$0	$100	$0
5.3	Bag House & Accessories	w/5.1	$0	w/5.1	$0	$0	$0	$0	$0	$0	$0	$0
5.4	Other Particulate Removal Materials	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.5	Gypsum Dewatering System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.6	Mercury Removal System	w/5.1	$0	w/5.1	$0	$0	$0	$0	$0	$0	$0	$0
5.9	Open											
	SUBTOTAL 5.	**$3,649**	**$0**	**$199**	**$0**	**$0**	**$3,848**	**$298**	**$0**	**$809**	**$4,955**	**$12**
5B	CO_2 REMOVAL & COMPRESSION											
5B.1	CO_2 Removal System	$170,551	$0	$51,748	$0	$0	$222,299	$21,254	$44,460	$57,602	$345,614	$838
5B.2	CO_2 Compression & Drying	$20,574	$0	$6,454	$0	$0	$27,028	$2,585	$0	$5,923	$35,536	$86
5B.3	CO_2 Removal System Let Down Turbine	$9,900	$0	$1,315	$0	$0	$11,215	$1,075	$0	$1,229	$13,519	$33
	SUBTOTAL 5B.	**$201,025**	**$0**	**$59,517**	**$0**	**$0**	**$260,542**	**$24,913**	**$44,460**	**$64,754**	**$394,669**	**$957**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 6.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
7.2	HRSG Accessories	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.4	Stack	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.9	Duct & Stack Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 7.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8.2	Turbine Plant Auxiliaries	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8.3a	Condenser & Auxiliaries	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8.3b	Air Cooled Condenser	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8.4	Steam Piping	$2,353	$0	$1,160	$0	$0	$3,514	$295	$0	$571	$4,380	$11
8.9	TG Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 8.	**$2,353**	**$0**	**$1,160**	**$0**	**$0**	**$3,514**	**$295**	**$0**	**$571**	**$4,380**	**$11**

Exhibit 7-21 Case 8 Total Plant Cost Details (Continued)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 8 TOTAL PLANT COST $	Case 8 TOTAL PLANT COST $/kW
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$4,602	$0	$1,433	$0	$0	$6,035	$577	$0	$661	$7,273	$18
9.2	Circulating Water Pumps	$989	$0	$94	$0	$0	$1,083	$92	$0	$117	$1,292	$3
9.3	Circ.Water System Auxiliaries	$299	$0	$40	$0	$0	$339	$32	$0	$37	$408	$1
9.4	Circ.Water Piping	$0	$2,371	$2,298	$0	$0	$4,668	$437	$0	$766	$5,871	$14
9.5	Make-up Water System	$219	$0	$293	$0	$0	$512	$49	$0	$84	$645	$2
9.6	Component Cooling Water Sys	$237	$0	$188	$0	$0	$425	$40	$0	$70	$535	$1
9.9	Circ.Water System Foundations& Structures	$0	$1,413	$2,244	$0	$0	$3,657	$346	$0	$801	$4,803	$12
	SUBTOTAL 9.	**$6,345**	**$3,783**	**$6,590**	**$0**	**$0**	**$16,719**	**$1,574**	**$0**	**$2,536**	**$20,828**	**$50**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Ash Coolers	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.2	Cyclone Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.3	HGCU Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Recovery Equipment	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.7	Ash Transport & Feed Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 10.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11.2	Station Service Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11.3	Switchgear & Motor Control	$2,091	$0	$355	$0	$0	$2,446	$227	$0	$267	$2,940	$7
11.4	Conduit & Cable Tray	$0	$1,311	$4,532	$0	$0	$5,843	$566	$0	$961	$7,370	$18
11.5	Wire & Cable	$0	$2,473	$4,775	$0	$0	$7,248	$611	$0	$1,179	$9,038	$22
11.6	Protective Equipment	$7	$0	$22	$0	$0	$29	$3	$0	$3	$35	$0
11.7	Standby Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11.8	Main Power Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11.9	Electrical Foundations	$0	$24	$58	$0	$0	$81	$8	$0	$18	$107	$0
	SUBTOTAL 11.	**$2,097**	**$3,808**	**$9,743**	**$0**	**$0**	**$15,648**	**$1,414**	**$0**	**$2,428**	**$19,490**	**$47**
12	INSTRUMENTATION & CONTROL											
12.1	PC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12.5	Signal Processing Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$59	$0	$35	$0	$0	$95	$9	$5	$16	$125	$0
12.7	Distributed Control System Equipment	$598	$0	$104	$0	$0	$702	$65	$35	$80	$883	$2
12.8	Instrument Wiring & Tubing	$324	$0	$643	$0	$0	$967	$82	$48	$165	$1,262	$3
12.9	Other I & C Equipment	$169	$0	$383	$0	$0	$552	$54	$28	$63	$697	$2
	SUBTOTAL 12.	**$1,150**	**$0**	**$1,166**	**$0**	**$0**	**$2,316**	**$210**	**$116**	**$324**	**$2,966**	**$7**

Exhibit 7-21 Case 8 Total Plant Cost Details (Continued)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 8 TOTAL PLANT COST $	Case 8 TOTAL PLANT COST $/kW
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$40	$802	$0	$0	$843	$84	$0	$185	$1,112	$3
13.2	Site Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13.3	Site Facilities	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 13.	**$0**	**$40**	**$802**	**$0**	**$0**	**$843**	**$84**	**$0**	**$185**	**$1,112**	**$3**
14	BUILDINGS & STRUCTURES											
14.1	Boiler Building	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14.2	Turbine Building	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14.3	Administration Building	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14.4	Circulation Water Pumphouse	$0	$148	$118	$0	$0	$266	$24	$0	$43	$333	$1
14.5	Water Treatment Buildings	$0	$226	$186	$0	$0	$412	$37	$0	$67	$516	$1
14.6	Machine Shop	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14.7	Warehouse	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14.8	Other Buildings & Structures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14.9	Waste Treating Building & Str.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 14.	**$0**	**$374**	**$304**	**$0**	**$0**	**$678**	**$61**	**$0**	**$111**	**$849**	**$2**
	TOTAL COST	**$221,395**	**$8,005**	**$82,602**	**$0**	**$0**	**$312,002**	**$29,072**	**$44,576**	**$72,620**	**$458,271**	**$1,110.9**
	Owner's Costs											
	Preproduction Costs											
	6 Months All Labor										$2,285	$6
	1 Month Maintenance Materials										$401	$1
	1 Month Non-fuel Consumables										$367	$1
	1 Month Waste Disposal										$6	$0
	25% of 1 Months Fuel Cost at 100% CF										$0	$0
	2% of TPC										$9,165	$22
	Total										**$12,224**	**$30**
	Inventory Capital											
	60 day supply of consumables at 100% CF										$574	$1
	0.5% of TPC (spare parts)										$2,291	$6
	Total										**$2,865**	**$7**
	Initial Cost for Catalyst and Chemicals										$1,518	$4
	Land										$0	$0
	Other Owner's Costs										$68,741	$167
	Financing Costs										$12,373	$30
	Total Overnight Costs (TOC)										**$555,992**	**$1,348**
	TASC Multiplier								(IOU, high risk, 33 year)		1.078	
	Total As-Spent Cost (TASC)										**$599,360**	**$1,453**

Exhibit 7-22 Case 8 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES						Cost Base (June)	2007
Case 8 - Subcritical PC w/ CO2 capture (1,100 lb/net MWh) - Retrofit						Heat Rate-net(Btu/kWh):	13,495
						MWe-net:	413
						Capacity Factor: (%):	85
		OPERATING & MAINTENANCE LABOR					
Operating Labor							
Operating Labor Rate(base):		34.65	$/hour				
Operating Labor Burden:		30.00	% of base				
Labor O-H Charge Rate:		25.00	% of labor				
				Total			
Skilled Operator		1.0		1.0			
Operator		1.3		1.3			
Foreman		0.0		0.0			
Lab Tech's, etc.		0.0		0.0			
TOTAL-O.J.'s		2.3		2.3			
						Annual Cost	Annual Unit Cost
						$	$/kW-net
Annual Operating Labor Cost		Maintenance labor cost		% of BEC	0.8889	$907,567	$2.200
Maintenance Labor Cost		(Case S12B is reference)		BEC	$302,629	$2,749,062	$6.664
Administrative & Support Labor						$914,157	$2.216
Property Taxes & Insurance						$27,542,493	$66.763
TOTAL FIXED OPERATING COSTS						**$32,113,279**	**$77.843**
VARIABLE OPERATING COSTS							
							$/kWh-net
Maintenance Material Cost				% of BEC	1.3333	**$4,088,593**	**$0.00133**
Consumables		Consumption		Unit	Initial Fill		
		Initial Fill	/Day	Cost	Cost		
Water(/1000 gallons)		0	2,153	1.22	**$0**	**$814,846**	**$0.00027**
Chemicals			4.841				
MU & WT Chem.(lb)		0	10,421	0.17	$0	$559,545	$0.00018
Soda Ash (ton)		0	8	80.00	$0	$201,936	$0.00007
Carbon (Mercury Removal) (lb)		0	0	1.05	$0	$0	$0.00000
MEA Solvent (ton)		636	0.90	2,249.89	$1,430,574	$628,224	$0.00020
NaOH (tons)		0	7.41	433.68	$0	$997,006	$0.00032
H2SO4 (tons)		0	4.28	138.78	$0	$184,282	$0.00006
Corrosion Inhibitor		0	0	0.00	$87,799	$4,181	$0.00000
Activated Carbon(lb)		0	1,076	1.05	$0	$350,577	$0.00011
Ammonia (19% NH3) ton		0	0	129.80	$0	$0	$0.00000
Subtotal Chemicals					**$1,518,373**	**$2,925,751**	**$0.00095**
Other							
Supplemental Fuel(MBtu)		0	0	0.00	$0	$0	$0.00000
SCR Catalyst(m3)		w/equip.	0.000	5,775.94	$0	$0	$0.00000
Emission Penalties		0	0	0.00	$0	$0	$0.00000
Subtotal Other					**$0**	**$0**	**$0.00000**
Waste Disposal							
Flyash (ton)		0	8	24.33	$0	$61,414	$0.00002
Bottom Ash(ton)		0	0	16.23	$0	$0	$0.00000
Subtotal-Waste Disposal					**$0**	**$61,414**	**$0.00002**
By-products & Emissions							
Gypsum (tons)		0	0	0.00	$0	$0	$0.00000
Subtotal By-Products					**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS					**$1,518,373**	**$7,890,604**	**$0.00257**
Fuel(ton)		0	0	10.37	**$0**	**$0**	**$0.00000**

7.1.9 Case 9 – Cost Estimating

Exhibit 7-23 shows the TPC cost details organized by cost account along with TOC and TASC. Exhibit 7-24 shows the initial and annual O&M costs.

The estimated TOC for adding CC&S to the existing subcritical PC boiler with a CO_2 capture level of 90 percent is $1,999/kW. In the event that NSR is triggered and the addition of an SCR unit is necessary to achieve the NOx emission rate of 0.07 lb/MMBtu, the TOC for Case 9 increases to $2,430/kW, which represents an increase of 21.5 percent ($431/kW increase). Owner's costs represent 18 percent of the TOC. The current dollar 30-year LCOE, excluding SCR but including CO_2 TS&M, is $111.65/MWh. The net plant output is decreased by 32.4 percent in the 90 percent capture case. The current dollar, 30-year LCOE, including SCR and CO_2 TS&M, is $122.46/MWh.

Exhibit 7-23 Case 9 Total Plant Cost Details

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 9 TOTAL PLANT COST $	Case 9 TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.2	Coal Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.3	Coal Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.4	Other Coal Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.5	Sorbent Receive & Unload	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.6	Sorbent Stackout & Reclaim	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.7	Sorbent Conveyors	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.8	Other Sorbent Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1.9	Coal & Sorbent Hnd.Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 1.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.2	Coal Conveyor to Storage	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.3	Coal Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.4	Misc.Coal Prep & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.5	Sorbent Prep Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.6	Sorbent Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.7	Sorbent Injection System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Sorbent Feed Foundation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 2.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3.2	Water Makeup & Pretreating	$2,506	$0	$807	$0	$0	$3,312	$313	$0	$725	$4,351	$12
3.3	Other Feedwater Subsystems	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3.4	Service Water Systems	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3.5	Other Boiler Plant Systems	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3.6	FO Supply Sys & Nat Gas	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3.7	Waste Treatment Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 3.	**$2,506**	**$0**	**$807**	**$0**	**$0**	**$3,312**	**$313**	**$0**	**$725**	**$4,351**	**$12**
4	PC BOILER											
4.1	PC Boiler & Accessories	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.2	LNB's and OFA	$2,982	$0	$2,544	$0	$0	$5,526	$0	$0	$382	$5,907	$16
4.3	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.4	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Primary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Secondary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Boiler Foundations	$0	w/14.1	w/14.1	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4.	**$2,982**	**$0**	**$2,544**	**$0**	**$0**	**$5,526**	**$0**	**$0**	**$382**	**$5,907**	**$16**

Exhibit 7-23 Case 9 Total Plant Cost Details (Continued)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 9 TOTAL PLANT COST $	Case 9 TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	$3,549	$0	$199	$0	$0	$3,748	$298	$0	$809	$4,855	$14
5.2	Other FGD	$100	$0	$0	$0	$0	$100	$0	$0	$0	$100	$0
5.3	Bag House & Accessories	w/5.1	$0	w/5.1	$0	$0	$0	$0	$0	$0	$0	$0
5.4	Other Particulate Removal Materials	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.5	Gypsum Dewatering System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.6	Mercury Removal System	w/5.1	$0	w/5.1	$0	$0	$0	$0	$0	$0	$0	$0
5.9	Open											
	SUBTOTAL 5.	**$3,649**	**$0**	**$199**	**$0**	**$0**	**$3,848**	**$298**	**$0**	**$809**	**$4,955**	**$14**
5B	CO_2 REMOVAL & COMPRESSION											
5B.1	CO_2 Removal System	$223,265	$0	$67,742	$0	$0	$291,006	$27,823	$58,201	$75,406	$452,436	$1,259
5B.2	CO_2 Compression & Drying	$25,763	$0	$8,082	$0	$0	$33,845	$3,237	$0	$7,416	$44,498	$124
5B.3	CO_2 Removal System Let Down Turbine	$10,450	$0	$1,389	$0	$0	$11,839	$1,135	$0	$1,297	$14,270	$40
	SUBTOTAL 5B.	**$259,478**	**$0**	**$77,212**	**$0**	**$0**	**$336,690**	**$32,194**	**$58,201**	**$84,120**	**$511,205**	**$1,422**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 6.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
7.2	HRSG Accessories	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.4	Stack	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.9	Duct & Stack Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 7.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8.2	Turbine Plant Auxiliaries	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8.3a	Condenser & Auxiliaries	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8.3b	Air Cooled Condenser	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8.4	Steam Piping	$3,045	$0	$1,501	$0	$0	$4,546	$382	$0	$739	$5,667	$16
8.9	TG Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 8.	**$3,045**	**$0**	**$1,501**	**$0**	**$0**	**$4,546**	**$382**	**$0**	**$739**	**$5,667**	**$16**

Exhibit 7-23 Case 9 Total Plant Cost Details (Continued)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 9 TOTAL PLANT COST $	Case 9 TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	$3,549	$0	$199	$0	$0	$3,748	$298	$0	$809	$4,855	$14
5.2	Other FGD	$100	$0	$0	$0	$0	$100	$0	$0	$0	$100	$0
5.3	Bag House & Accessories	w/5.1	$0	w/5.1	$0	$0	$0	$0	$0	$0	$0	$0
5.4	Other Particulate Removal Materials	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.5	Gypsum Dewatering System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.6	Mercury Removal System	w/5.1	$0	w/5.1	$0	$0	$0	$0	$0	$0	$0	$0
5.9	Open											
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$7,254	$0	$2,259	$0	$0	$9,513	$910	$0	$1,042	$11,465	$32
9.2	Circulating Water Pumps	$1,545	$0	$147	$0	$0	$1,692	$143	$0	$184	$2,019	$6
9.3	Circ.Water System Auxiliaries	$444	$0	$59	$0	$0	$503	$48	$0	$55	$606	$2
9.4	Circ.Water Piping	$0	$3,521	$3,412	$0	$0	$6,933	$649	$0	$1,137	$8,720	$24
9.5	Make-up Water System	$291	$0	$388	$0	$0	$679	$65	$0	$112	$856	$2
9.6	Component Cooling Water Sys	$351	$0	$280	$0	$0	$631	$60	$0	$104	$795	$2
9.9	Circ.Water System Foundations& Structures	$0	$2,093	$3,326	$0	$0	$5,419	$513	$0	$1,186	$7,118	$20
	SUBTOTAL 9.	**$9,885**	**$5,614**	**$9,871**	**$0**	**$0**	**$25,371**	**$2,388**	**$0**	**$3,820**	**$31,579**	**$88**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Ash Coolers	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.2	Cyclone Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.3	HGCU Ash Letdown	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Recovery Equipment	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.7	Ash Transport & Feed Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 10.	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11.2	Station Service Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11.3	Switchgear & Motor Control	$2,453	$0	$417	$0	$0	$2,870	$266	$0	$314	$3,450	$10
11.4	Conduit & Cable Tray	$0	$1,538	$5,318	$0	$0	$6,856	$664	$0	$1,128	$8,647	$24
11.5	Wire & Cable	$0	$2,902	$5,602	$0	$0	$8,504	$716	$0	$1,383	$10,604	$30
11.6	Protective Equipment	$7	$0	$22	$0	$0	$29	$3	$0	$3	$35	$0
11.7	Standby Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11.8	Main Power Transformers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
11.9	Electrical Foundations	$0	$30	$74	$0	$0	$105	$10	$0	$23	$138	$0
	SUBTOTAL 11.	**$2,460**	**$4,470**	**$11,433**	**$0**	**$0**	**$18,363**	**$1,659**	**$0**	**$2,851**	**$22,873**	**$64**
12	INSTRUMENTATION & CONTROL											
12.1	PC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12.5	Signal Processing Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards,Panels & Racks	$62	$0	$37	$0	$0	$99	$9	$5	$17	$131	$0
12.7	Distributed Control System Equipment	$627	$0	$110	$0	$0	$736	$68	$37	$84	$925	$3
12.8	Instrument Wiring & Tubing	$340	$0	$674	$0	$0	$1,014	$86	$51	$173	$1,323	$4
12.9	Other I & C Equipment	$177	$0	$402	$0	$0	$579	$56	$29	$66	$731	$2
	SUBTOTAL 12.	**$1,206**	**$0**	**$1,223**	**$0**	**$0**	**$2,428**	**$220**	**$121**	**$340**	**$3,110**	**$9**

Exhibit 7-23 Case 9 Total Plant Cost Details (Continued)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	Case 9 TOTAL PLANT COST $	Case 9 TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	$3,549	$0	$199	$0	$0	$3,748	$298	$0	$809	$4,855	$14
5.2	Other FGD	$100	$0	$0	$0	$0	$100	$0	$0	$0	$100	$0
5.3	Bag House & Accessories	w/5.1	$0	w/5.1	$0	$0	$0	$0	$0	$0	$0	$0
5.4	Other Particulate Removal Materials	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.5	Gypsum Dewatering System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.6	Mercury Removal System	w/5.1	$0	w/5.1	$0	$0	$0	$0	$0	$0	$0	$0
5.9	Open											
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$43	$852	$0	$0	$894	$89	$0	$197	$1,179	$3
13.2	Site Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13.3	Site Facilities	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 13.	**$0**	**$43**	**$852**	**$0**	**$0**	**$894**	**$89**	**$0**	**$197**	**$1,179**	**$3**
14	BUILDINGS & STRUCTURES											
14.1	Boiler Building	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14.2	Turbine Building	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14.3	Administration Building	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14.4	Circulation Water Pumphouse	$0	$194	$154	$0	$0	$347	$31	$0	$57	$435	$1
14.5	Water Treatment Buildings	$0	$316	$260	$0	$0	$576	$52	$0	$94	$722	$2
14.6	Machine Shop	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14.7	Warehouse	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14.8	Other Buildings & Structures	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14.9	Waste Treating Building & Str.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 14.	**$0**	**$509**	**$414**	**$0**	**$0**	**$923**	**$83**	**$0**	**$151**	**$1,157**	**$3**
	TOTAL COST	**$285,210**	**$10,637**	**$106,055**	**$0**	**$0**	**$401,902**	**$37,626**	**$58,323**	**$94,133**	**$591,983**	**$1,647**
	Owner's Costs											
	Preproduction Costs											
	6 Months All Labor										$2,937	$8
	1 Month Maintenance Materials										$513	$1
	1 Month Non-fuel Consumables										$543	$2
	1 Month Waste Disposal										$6	$0
	25% of 1 Months Fuel Cost at 100% CF										$0	$0
	2% of TPC										$11,840	$33
	Total										**$15,838**	**$44**
	Inventory Capital											
	60 day supply of consumables at 100% CF										$829	$2
	0.5% of TPC (spare parts)										$2,960	$8
	Total										**$3,789**	**$11**
	Initial Cost for Catalyst and Chemicals										$2,196	$6
	Land										$0	$0
	Other Owner's Costs										$88,798	$247
	Financing Costs										$15,984	$44
	Total Overnight Costs (TOC)										**$718,587**	**$1,999**
	TASC Multiplier								(IOU, high risk, 33 year)		1.078	
	Total As-Spent Cost (TASC)										**$ 774,637**	**$2,155**

Exhibit 7-24 Case 9 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (June)	2007
Case 9 - Subcritical PC w/ 90% CO2 capture - Retrofit					Heat Rate-net(Btu/kWh):	15,496
					MWe-net:	359
					Capacity Factor: (%):	85
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	34.65	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Skilled Operator	1.0		1.0			
Operator	1.3		1.3			
Foreman	0.0		0.0			
Lab Tech's, etc.	0.0		0.0			
TOTAL-O.J.'s	2.3		2.3			
					Annual Cost	Annual Unit Cost
					$	$/kW-net
Annual Operating Labor Cost	Maintenance labor cost		% of BEC	0.8889	$907,567	$2.525
Maintenance Labor Cost	(Case S12B is reference)		BEC	$392,528	$3,791,163	$10.549
Administrative & Support Labor					$1,174,682	$3.269
Property Taxes & Insurance					$30,661,480	$85.315
TOTAL FIXED OPERATING COSTS					**$36,534,892**	**$101.658**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost			% of BEC	1.3333	**$5,233,695**	**$0.00196**
Consumables	Consumption		Unit	Initial		
	Initial	/Day	Cost	Cost		
Water(/1000 gallons)	0	3,449	1.22	**$0**	**$1,305,388**	**$0.00049**
Chemicals		4.841				
MU & WT Chem.(lb)	0	16,694	0.17	$0	$896,395	$0.00033
Soda Ash (ton)	0	8	80.00	$0	$201,936	$0.00008
Carbon (Mercury Removal) (lb)	0	0	1.05	$0	$0	$0.00000
MEA Solvent (ton)	920	1.30	2,249.89	$2,069,097	$907,435	$0.00034
NaOH (tons)	0	10.72	433.68	$0	$1,442,362	$0.00054
H2SO4 (tons)	0	6.20	138.78	$0	$266,950	$0.00010
Corrosion Inhibitor	0	0	0.00	$126,820	$6,039	$0.00000
Activated Carbon(lb)	0	1,557	1.05	$0	$507,295	$0.00019
Ammonia (19% NH3) ton	0	0	129.80	$0	$0	$0.00000
Subtotal Chemicals				**$2,195,917**	**$4,228,412**	**$0.00158**
Other						
Supplemental Fuel(MBtu)	0	0	0.00	$0	$0	$0.00000
SCR Catalyst(m3)	w/equip.	0.000	5,775.94	$0	$0	$0.00000
Emission Penalties	0	0	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$0**	**$0.00000**
Waste Disposal						
Flyash (ton)	0	8	24.33	$0	$61,414	$0.00002
Bottom Ash(ton)	0	0	16.23	$0	$0	$0.00000
Subtotal-Waste Disposal				**$0**	**$61,414**	**$0.00002**
By-products & Emissions						
Gypsum (tons)	0	0	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$2,195,917**	**$10,828,908**	**$0.00405**
Fuel(ton)	0	0	10.37	**$0**	**$0**	**$0.00000**

8. CONCLUSIONS

The objective of this report was to present the baseline cost and performance of greenfield integrated gasification combined cycle (IGCC) plants, greenfield supercritical (SC) pulverized coal (PC) plants, and retrofit subcritical PC plants that limit carbon dioxide (CO_2) emissions to various levels. For each plant type, three cases were modeled:

- Baseline performance with no CO_2 capture
- CO_2 emissions reduced to 1,100 lb/net-MWh
- CO_2 emissions reduced by 90 percent

The intermediate value of 1,100 lb/net-MWh was chosen to match the recent interim California standard established in January 2007. The results show that the cost and performance of the technologies analyzed at this emission limit fall approximately half way between the non-capture cases and the 90 percent capture cases. While the cost and performance penalties incurred at the 1,100 lb CO_2/net-MWh emission rate are less than for 90 percent capture, they are still substantial.

The performance and cost results of the nine cases modeled in this study are summarized in Exhibit 8-1. The primary conclusions that can be drawn are:

- The lowest LCOE for all cases is the subcritical PC and subcritical PC with retrofit, mainly due to the assumption that the original plant debt has been retired. The non-capture LCOE for the subcritical PC is 71 percent less than the non-capture IGCC case and 58 percent less than the non-capture SC PC case. The 90 percent CO_2 capture LCOE for the subcritical PC is 36 percent less than the corresponding IGCC case and 22 percent less than the SC PC case.
- The IGCC cases have the lowest percent change in LCOE from the non-capture case ($117.84/MWh) to the capture cases, with 27 percent for the 1,100 lb CO_2/net-MWh case and 48 percent for the 90 percent capture case. However, the absolute LCOE is highest for IGCC cases relative to the SC PC and subcritical PC cases.
- The existing subcritical PC plant with SCR has the highest percentage change in LCOE from the non-capture case ($33.78/MWh) to the capture cases with 178 percent and 263 percent for the 1,100 lb CO_2/net-MWh case and the 90 percent capture case, respectively. This is somewhat misleading because the LCOE of the existing non-capture subcritical PC plant does not have a capital cost component (plant is assumed to be paid for).
- For the 1,100 lb CO_2/net-MWh cases, the IGCC plant has the smallest energy penalty relative to the non-capture case at 6.2 absolute percentage points. SC PC is next with an energy penalty of 6.9 percentage points and the subcritical PC retrofit has the largest energy penalty at 7.3 percentage points.
- For the 90 percent capture cases, the subcritical PC retrofit plant has the smallest energy penalty relative to the non-capture case at 10.6 absolute percentage points. IGCC is next with an energy penalty of 10.9 percentage points and the SC PC plant has the largest energy penalty at 11.7 percentage points.

- The greenfield supercritical PC plant has the highest change in normalized TOC at 45 percent for the 1,100 lb/net-MWh case and 73 percent for the 90 percent capture case. While the net power for the SC PC capture and non-capture cases remained the same, the gross power output increased. This caused the increase in the capital costs to be greater than the greenfield IGCC cases and the existing subcritical PC retrofit, in which net power was derated to accommodate CO_2 capture.
- The costs of CO_2 captured and avoided were nearly identical for the SC PC and IGCC cases. The existing subcritical PC case has the lowest CO_2 removal costs at both CO_2 emissions levels and also the lowest CO_2 avoided cost at the 1,100 lb CO_2/net-MWh capture level. The CO_2 avoided cost at 90 percent capture level is slightly higher than the IGCC and SC PC cases.

Exhibit 8-1 Cost and Performance Summary of Cases 1 – 9

	Non-Capture	1,100 lb/net-MWh		90% Capture	
	Absolute	Absolute	% Change Relative to Non-Capture	Absolute	% Change Relative to Non-Capture
IGCC					
Net Plant Power (MWe)	502	443	-12%	401	-20%
Net Plant Efficiency, % (HHV)	41.8	35.6	-15%	30.9	-26%
TOC ($/kW)	3,128	3,938	26%	4,595	47%
LCOE ($/MWh)	117.84	149.38	27%	174.86	48%
CO_2 Removal Cost ($/tonne)	N/A	74	N/A	59	-20% (A)
CO_2 Avoided Cost ($/tonne)	N/A	108	N/A	84	-22% (A)
Supercritical PC					
Net Plant Power (MWe)	550	550	N/A	550	N/A
Net Plant Efficiency, % (HHV)	38.6	31.7	-18%	26.9	-30%
TOC ($/kW)	2,296	3,323	46%	3,969	73%
LCOE ($/MWh)	79.86	120.01	50%	143.89	80%
CO_2 Removal Cost ($/tonne)	N/A	73	N/A	58	-21% (A)
CO_2 Avoided Cost ($/tonne)	N/A	111	N/A	87	-22% (A)
Existing Subcritical PC Retrofit Plant					
Net Plant Power (MWe)	532	413	-22%	359	-33%
Net Plant Efficiency, % (HHV)	32.6	25.3	-22%	22.0	-33%
TOC ($/kW)	N/A	1,348	N/A	1,999	48% (A)
LCOE ($/MWh)	33.78	84.81	151%	111.64	230%
CO_2 Removal Cost ($/tonne)	N/A	62	N/A	57	-8% (A)
CO_2 Avoided Cost ($/tonne)	N/A	97	N/A	89	-8% (A)
Existing Subcritical PC Retrofit Plant w/ SCR					
Net Plant Power (MWe)	532	409	-23%	356	-33%
Net Plant Efficiency, % (HHV)	32.6	25.3	-22%	22.0	-33%
TOC ($/kW)	N/A	1,717	N/A	2,430	42% (A)
LCOE ($/MWh)	33.78	94.01	178%	122.46	263%
CO_2 Removal Cost ($/tonne)	N/A	73	N/A	64	-12% (A)
CO_2 Avoided Cost ($/tonne)	N/A	116	N/A	102	-12% (A)

(A) - Values relative to 1,100 lb/net-MWh case

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