NATIONAL ENERGY TECHNOLOGY LABORATORY

Cost and Performance Baseline for Fossil Energy Plants
Volume 1: Bituminous Coal and Natural Gas to Electricity

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

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NETL Viewpoint

Background

The goal of Fossil Energy Research, Development, and Demonstration (RD&D) is to ensure the availability of ultra-clean ("zero" emissions), abundant, low-cost, domestic electricity and energy (including hydrogen) to fuel economic prosperity and strengthen energy security. A broad portfolio of technologies is being developed within the Clean Coal Program to accomplish this objective. Ever increasing technological enhancements are in various stages of the research "pipeline," and multiple paths are being pursued to create a portfolio of promising technologies for development, demonstration, and eventual deployment. The technological progress of recent years has created a remarkable new opportunity for coal. Advances in technology are making it possible to generate power from fossil fuels with great improvements in the efficiency of energy use while at the same time significantly reducing the impact on the environment, including the long-term impact of fossil energy use on the Earth's climate. The objective of the Clean Coal RD&D Program is to build on these advances and bring these building blocks together into a new, revolutionary concept for future coal-based power and energy production.

Objective

To establish baseline performance and cost estimates for today's fossil energy plants, it is necessary to look at the current state of technology. Such a baseline can be used to benchmark the progress of the Fossil Energy RD&D portfolio. This study provides an accurate, independent assessment of the cost and performance for Pulverized Coal (PC) Combustion, Integrated Gasification Combined Cycles (IGCC), and Natural Gas Combined Cycles (NGCC), all with and without carbon dioxide (CO_2) capture and sequestration assuming that the plants use technology available today.

Approach

The power plant configurations analyzed in this study were modeled using the ASPEN Plus® (Aspen) modeling program. Performance and process limits were based upon published reports, information obtained from vendors and users of the technology, cost and performance data from design/build utility projects, and/or best engineering judgment. Capital and operating costs were estimated by WorleyParsons based on simulation results and through a combination of existing vendor quotes, scaled estimates from previous design/build projects, or a combination of the two. Operation and maintenance (O&M) costs and the cost for transporting, storing, and monitoring (TS&M) carbon dioxide (CO_2) in the cases with carbon capture were also estimated based on reference data and scaled estimates. The cost of electricity (COE) was determined for all plants assuming investor-owned utility (IOU) financing. The initial results of this analysis were subjected to a significant peer review by industry experts, academia and government research and regulatory agencies. Based on the feedback from these experts, the report was updated both in terms of technical content and revised costs.

Results

This independent analysis of fossil energy plant cost and performance is considered to be the most comprehensive set of publicly available data to date. While input was sought from technology vendors, the final assessment of performance and cost was determined independently, and may not represent the views of the technology vendors. The extent of collaboration with technology vendors varied from case to case, with minimal or no input from some vendors. Selection of system components and plant configurations from potential options and the rapid escalation in labor and material costs made it a challenge to develop state-of-the-art configurations and cost estimates. The rigorous expert technical review and systematic use of existing vendor quotes and project design/build data to develop the cost estimates in this report are believed to provide the most up-to-date performance and costs available in the public literature. The main purpose of publishing Revision 2 is to update performance and economic results. New data from technology vendors was incorporated into the modeling approach, owner's costs were added to the financial model, and supplemental chapters were added that extend beyond the original report scope. The following are highlights of the study:

- Coal-based plants using today's technology are capable of producing electricity at relatively high efficiencies of about 39 percent, higher heating value ([HHV], without CO_2 capture) on bituminous coal while meeting or exceeding current environmental requirements for criteria pollutants.
- Total overnight cost (TOC) for the non-capture plants are as follows: NGCC, $718/kW; PC, $2,010/kW (average); IGCC, $2,505/kW (average). With CO_2 capture, capital costs are: NGCC, $1,497/kW; PC, $3,590/kW (average); IGCC, $3,568/kW (average).
- At fuel costs of $1.64/MMBtu of coal and $6.55/MMBtu of natural gas, the COE for the non-capture plants is: 59 mills/kWh for NGCC, 59 mills/kWh for PC (average), and 77 mills/kWh (average) for IGCC.
- When today's technology for CO_2 capture and sequestration (CCS) is integrated into these new power plants, the resultant COE, including the cost of CO_2 TS&M, is: 86 mills/kWh for NGCC; 108 mills/kWh (average) for PC; and 112 mills/kWh (average) for IGCC. The cost of transporting CO_2 50 miles for storage in a geologic formation with over 30 years of monitoring is estimated to add about 3 to 6 mills/kWh. This represents less than 5.5 percent of the COE for each CO_2 capture case.
- A sensitivity study on natural gas price shows that at a coal price of $1.64/MMBtu, the average COE for IGCC with capture equals that of NGCC with CO_2 capture at a gas price of $9.80/MMBtu. The average COE for PC with capture equals that of NGCC with capture at a gas price of $9.25/MMBtu. In terms of capacity factor (CF), when non-capture NGCC drops to 40 percent, such as in a peaking application, the COE is comparable to non-capture IGCC operating at base load (80 percent CF).

Fossil Energy RD&D aims at improving the performance and cost of clean coal power systems including the development of new approaches to capture and sequester greenhouse gases (GHGs). Improved efficiencies and reduced costs are required to improve the competitiveness of these systems in today's market and regulatory environment as well as in a carbon constrained scenario. The results of this analysis provide a starting point from which to measure the progress of RD&D achievements.

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Acknowledgments

LIST OF ACRONYMS AND ABBREVIATIONS

AACE   Association for the Advancement of Cost Engineering
ADIP   Aqueous di-isoproponal
AEO   Annual Energy Outlook
AGR   Acid gas removal
ANSI   American National Standards Institute
Aspen   Aspen Plus®
ASU   Air separation unit
BACT   Best available control technology
BEC   Bare erected cost
BFD   Block flow diagram
BFW   Boiler feedwater
Btu   British thermal unit
Btu/hr   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
m^3/d   Cubic meters per day
CAMR   Clean Air Mercury Rule
CCF   Capital Charge Factor
CCS   Carbon capture and sequestration
CDR   Carbon Dioxide Recovery
CF   Capacity factor
CGE   Cold gas efficiency
CL   Closed-loop
cm   Centimeter
CMU   Carnegie Mellon University
CO   Carbon monoxide
CO_2 Carbon dioxide
COE   Cost of electricity
CoP   ConocoPhillips
COS   Carbonyl sulfide
CRT   Cathode ray tube
CS   Carbon steel
CT   Combustion turbine
CTG   Combustion Turbine-Generator
CWP   Circulating water pump
CWS   Circulating water system
DCS   Distributed control system
DI   De-ionized
DIPA   Diisopropanolamine
DLN   Dry low NOx
DOE   Department of Energy

EAF	Equivalent availability factor
E-Gas™	ConocoPhillips gasifier technology
EIA	Energy Information Administration
EM	Electromagnetic
EMF	Emission modification factors
EPA	Environmental Protection Agency
EPC	Engineer/Procure/Construct
EPRI	Electric Power Research Institute
EPCM	Engineering/Procurement/Construction Management
EU	European Union
ESP	Electrostatic precipitator
FD	Forced draft
FERC	Federal Energy Regulatory Commission
FG	Flue gas
FGD	Flue gas desulfurization
FOAK	First-of-a-kind
FRP	Fiberglass-reinforced plastic
ft	Foot, feet
FW	Feedwater
ft, w.g.	Feet of water gauge
GADS	Generating Availability Data System
gal	Gallon
gal/MWh	Gallon per megawatt hour
GCV	Gross calorific value
GDP	Gross domestic product
GEE	General Electric Energy
GHG	Greenhouse gas
gpd	Gallons per day
gpm	Gallons per minute
gr/100 scf	grains per one hundred standard cubic feet
GSU	Generator step-up transformers
GT	Gas turbine
GWh	Gigawatt-hour
h	Hour
H_2	Hydrogen
H_2S	Hydrogen sulfide
H_2SO_4	Sulfuric acid
Hg	Mercury
HDPE	High-density polyethylene
HHV	Higher heating value
hp	Horsepower
HP	High-pressure
HRSG	Heat recovery steam generator

HSS	Heat stable salts
HVAC	Heating, ventilating, and air conditioning
ICR	Information Collection Request
ID	Induced draft
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
IGVs	Inlet guide vanes
In. H$_2$O	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/hr	Kilogram per hour
kJ	Kilojoules
kJ/hr	Kilojoules per hour
kJ/kg	Kilojoules per kilogram
km	Kilometer
KO	Knockout
kPa	Kilopascal absolute
kV	Kilovolt
kW	Kilowatt
kWe	Kilowatt-electric
kWh	Kilowatt-hour
LAER	Lowest Achievable Emission Rate
LF	Levelization factor
lb	Pound
lb/gal	Pound per gallon
lb/hr	Pounds per hour
lb/ft^2	Pounds per square foot
lb/MMBtu	Pounds per million British thermal units
lb/MWh	Pounds per megawatt-hour
lb/TBtu	Pounds per trillion British thermal units
LCOE	Levelized cost of electricity
LGTI	Louisiana Gasification Technology, Inc.
LHV	Lower heating value
LMP	Locational Marginal Price
LNB	Low NOx burner
LNG	Liquified natural gas
LP	Low-pressure

lpm   Liters per minute
LSE   Load-serving entities
m   Meters
m/min   Meters per minute
m^3/min Cubic meter per minute
MAC   Main Air Compressor
MAF   Moisture/Ash-Free
MCR   Maximum continuous rating
md   Millidarcy
MDEA   Methyldiethanolamine
MEA   Monoethanolamine
MHz   Megahertz
Mills/kWh Tenths of a cent per kilowatt hour
MJ/Nm^3 Megajoule per normal cubic meter
MMBtu   Million British thermal units (also shown as 10^6 Btu)
MMBtu/hr Million British thermal units (also shown as 10^6 Btu) per hour
MMkJ   Million kilojoules (also shown as 10^6 kJ)
MMkJ/hr   Million kilojoules (also shown as 10^6 kJ) per hour
MNQC   Multi Nozzle Quiet Combustor
mol%   Mole percent
MPa   Megapascals
MVA   Mega volt-amps
MW   Megawatt
MWe   Megawatts electric
MWh   Megawatt-hour
N$_2$ Nitrogen
N/A   Not applicable
NaOH   Sodium hydroxide
NEMA   National Electrical Manufacturers Association
NERC   North American Electric Reliability Council
NETL   National Energy Technology Laboratory
NGCC   Natural gas combined cycle
NH$_3$ Ammonia
Nm^3 Normal cubic meter
Nm^3/hr Normal cubic meter per hour
NMP   N-methyl-2-pyrrolidone
NOAK   Nth-of-a-kind
NOx   Oxides of nitrogen
NSPS   New Source Performance Standards
NSR   New Source Review
O&GJ   Oil & Gas Journal
O$_2$ Oxygen
O&M   Operation and maintenance

OC$_{Fn}$	Category n fixed operating cost for the initial year of operation
OD	Outside diameter
OEM	Original equipment manufacturers
OFA	Overfire air
OP/VWO	Over pressure/valves wide open
PA	Primary air
PC	Pulverized coal
PECO	Philadelphia Electric Company
PJM	Pennsylvania-New Jersey-Maryland Interconnection
PM	Particulate matter
PO	Purchase order
POTW	Publicly Owned Treatment Works
PP&L	Pennsylvania Power & Light Company
ppm	Parts per million
ppmv	Parts per million volume
ppmvd	Parts per million volume, dry
PPS	Polyphenylensulfide
PRB	Powder River Basin coal region
PSD	Prevention of Significant Deterioration
PSE&G	Public Service Electric & Gas Company
psi	Pounds per square inch
psia	Pounds per square inch absolute
psig	Pounds per square inch gage
PTFE	Teflon (Polytetrafluoroethylene)
PSFM	Power systems financial model
RD&D	Research, Development, and Demonstration
RDS	Research and Development Solutions, LLC
RH	Reheater
RTO	Regional transmission organization
SC	Supercritical
scf	Standard cubic feet
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
SC PC	Supercritical Pulverized Coal
SCR	Selective catalytic reduction
SEP	Samenwerkende Electriciteits-Productiebedrijven NV
SG	Specific gravity
SFC	Synthetic Fuels Corporation
SGC	Synthesis gas cooler
SGS	Sour gas shift

Shell	Shell Global Solutions
SNCR	Selective non-catalytic reduction
SNG	Synthetic natural gas
SO_2	Sulfur dioxide
SOx	Oxides of sulfur
SRU	Sulfur recovery unit
SS	Stainless steel
SS Amine	SS Specialty Amine
STG	Steam turbine generator
Syngas	Synthetic gas
TASC	Total as-spent cost
TOC	Total overnight cost
TPC	Total plant cost
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
U.S.	United States
vol%	Volume percent
WB	Wet bulb
WGS	Water-gas shift
wg	Water gauge
WTI	West Texas Intermediate
wt%	Weight percent
yr	Year
$/kW	Dollars per kilowatt
$/MMBtu	Dollars per million British thermal units
$/MMkJ	Dollars per million kilojoule
$/MW	Dollars per megawatt
$/MWh	Dollars per megawatt-hour
°C	Degrees Celsius
°F	Degrees Fahrenheit
5-10s	Fifty hour work weeks

EXECUTIVE SUMMARY

The objective of this report is to present an accurate, independent assessment of the cost and performance of fossil energy power systems, specifically integrated gasification combined cycle (IGCC), pulverized coal (PC), and natural gas combined cycle (NGCC) plants, using a consistent technical and economic approach that accurately reflects current market conditions. This is Volume 1 of a four volume report. The four volume series consists of the following:

- Volume 1: Bituminous Coal and Natural Gas to Electricity

- Volume 2: Coal to Synthetic Natural Gas and Ammonia (Various Coal Ranks)

- Volume 3: Low Rank Coal and Natural Gas to Electricity

- Volume 4: Bituminous Coal to Liquid Fuels with Carbon Capture

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) Clean Coal Programs

Twelve power plant configurations were analyzed as listed in Exhibit ES-1. The list includes six IGCC cases utilizing General Electric Energy (GEE), ConocoPhillips (CoP), and Shell Global Solutions (Shell) gasifiers each with and without carbon dioxide (CO_2) capture; four PC cases, two subcritical and two supercritical (SC), each with and without CO_2 capture; and two NGCC plants with and without CO_2 capture. Two additional cases were originally included in this study and involve production of synthetic natural gas (SNG) and the repowering of an existing NGCC facility using SNG. The two SNG cases were subsequently moved to Volume 2 of this report resulting in the discontinuity of case numbers (1-6 and 9-14).

While input was sought from various technology vendors, the final assessment of performance and cost was determined independently and has not been reviewed by individual vendors. Thus, portions of this report may not represent the views of the technology vendors. The extent of collaboration with technology vendors varied from case to case, with minimal or no collaboration obtained from some vendors.

The methodology included performing steady-state simulations of the various technologies using the ASPEN Plus® (Aspen) modeling program. The resulting mass and energy balance data from

the Aspen model were used to size major pieces of equipment. These equipment sizes formed the basis for cost estimating. Performance and process limits were based upon published reports, information obtained from vendors and users of the technology, performance data from design/build utility projects, and/or best engineering judgment. Capital and operating costs were estimated by WorleyParsons based on simulation results and through a combination of vendor quotes, scaled estimates from previous design/build projects, or a combination of the two. Baseline fuel costs for this analysis were determined using data from the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2008. The first year of capital expenditure (2007) costs used are \$1.55/MMkJ (\$1.64/MMBtu) for coal (Illinois No. 6) and \$6.21/MMkJ (\$6.55 /MMBtu) for natural gas, both on a HHV basis and in 2007 United States (U.S.) dollars.

Exhibit ES-1 Case Descriptions

Case	Unit Cycle	Steam Cycle, psig/°F/°F	Combustion Turbine	Gasifier/Boiler Technology	Oxidant	H_2S Separation/ Removal	Sulfur Removal/ Recovery	CO_2 Separa- tion
1	IGCC	1800/1050/1050	2 x Advanced F Class	GEE Radiant Only	95 mol% O_2	Selexol	Claus Plant	
2	IGCC	1800/1000/1000	2 x Advanced F Class	GEE Radiant Only	95 mol% O_2	Selexol	Claus Plant	Selexol 2nd stage
3	IGCC	1800/1050/1050	2 x Advanced F Class	CoP E-Gas™	95 mol% O_2	Refrigerated MDEA	Claus Plant	
4	IGCC	1800/1000/1000	2 x Advanced F Class	CoP E-Gas™	95 mol% O_2	Selexol	Claus Plant	Selexol 2nd stage
5	IGCC	1800/1050/1050	2 x Advanced F Class	Shell	95 mol% O_2	Sulfinol-M	Claus Plant	
6	IGCC	1800/1000/1000	2 x Advanced F Class	Shell	95 mol% O_2	Selexol	Claus Plant	Selexol 2nd stage
--	--	--	--	--	--	--	--	--
--	--	--	--	--	--	--	--	--
9	PC	2400/1050/1050		Subcritical PC	Air		Wet Flue gas desulfuri- zation (FGD)/ Gypsum	
10	PC	2400/1050/1050		Subcritical PC	Air		Wet FGD/ Gypsum	Amine Absorber
11	PC	3500/1100/1100		Supercritical PC	Air		Wet FGD/ Gypsum	
12	PC	3500/1100/1100		Supercritical PC	Air		Wet FGD/ Gypsum	Amine Absorber
13	NGCC	2400/1050/1050	2 x Advanced F Class	HRSG	Air			
14	NGCC	2400/1050/1050	2 x Advanced F Class	HRSG	Air			Amine Absorber

All plant configurations are evaluated based on installation at a greenfield site. Since these are state-of-the-art plants, they will have higher efficiencies than the average power plant population. Consequently, these plants would be expected to be near the top of the dispatch list and the study

capacity factor (CF) is chosen to reflect the maximum availability demonstrated for the specific plant type, i.e., 80 percent for IGCC and 85 percent for PC and NGCC configurations. Since variations in fuel costs and other factors can influence dispatch order and CF, sensitivity of the cost of electricity (COE) to CF is evaluated and presented later in this Executive Summary (Exhibit ES-10) and in the body of the report.

The nominal net plant output for this study is set at 550 megawatt (MW). The actual net output varies between technologies because the combustion turbines (CTs) in the IGCC and NGCC cases are manufactured in discrete sizes, but the boilers and steam turbines in the PC cases are readily available in a wide range of capacities. The result is that all of the PC cases have a net output of 550 MW, but the IGCC cases have net outputs ranging from 497 (Case 6) to 629 MW (Case 5). The range in IGCC net output is caused by 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 (WGS) reactions, which reduces steam turbine output. Higher auxiliary load and extraction steam requirements can be accommodated in the PC cases (larger boiler and steam turbine) but not in the IGCC cases where it is impossible to maintain a constant net output from the steam cycle given the fixed input (CT). Likewise, the two NGCC cases have a net output of 555 and 474 MW because of the CT constraint.

Exhibit ES-2 shows the cost, performance, and environmental profile summary for all cases. The results are discussed below in the following order:

- Performance (efficiency and raw water consumption)

- Cost (plant capital costs and COE)

- Environmental profile

PERFORMANCE

Energy Efficiency

The net plant efficiency (HHV basis) for all twelve cases is shown in Exhibit ES-3. The primary conclusions that can be drawn are:

- The NGCC with no CO_2 capture has the highest net efficiency of the technologies modeled in this study with an efficiency of 50.2 percent.

- The NGCC case with CO_2 capture results in the highest efficiency (42.8 percent) among all of the capture technologies.

- The NGCC with CO_2 capture results in a relative efficiency penalty of 14.7 percent (7.4 absolute percent), compared to the non-capture case. The NGCC penalty is less than for the PC cases because natural gas is less carbon intensive than coal, and there is less CO_2 to capture and to compress for equal net power outputs.

- The energy efficiency of the IGCC non-capture cases is as follows: the dry-fed Shell gasifier (42.1 percent), the slurry-fed, two-stage CoP gasifier (39.7 percent) and the slurry-fed, single-stage GEE gasifier (39.0 percent).

- When CO_2 capture is added to the IGCC cases, the energy efficiency of all three cases is more nearly equal than the non-capture cases, ranging from 31.0 percent for CoP to 32.6 percent for GEE, with Shell intermediate at 31.2 percent.

- The relative efficiency penalty for adding CO_2 capture to the IGCC cases is 21.4 percent on average. The relative penalty for subcritical and SC PC is 28.9 and 27.6 percent, respectively. The relative penalty for NGCC is 14.7 percent.

- SC PC without CO_2 capture has an efficiency of 39.3 percent. Subcritical PC has an efficiency of 36.8 percent, which is the lowest of all the non-capture cases in the study.

- The addition of CO_2 capture to the PC cases via the Fluor Econamine FG Plus[SM] (Econamine) process has the highest relative efficiency penalties out of all the cases studied. This is primarily because the low partial pressure of CO_2 in the flue gas (FG) from a PC plant requires a chemical absorption process rather than physical absorption. For chemical absorption processes, the regeneration requirements are more energy intensive. The relative efficiency impact on NGCC is less because of the lower carbon intensity of natural gas relative to coal as mentioned above.

Exhibit ES-2 Cost and Performance Summary and Environmental Profile for All Cases

	Integrated Gasification Combined Cycle						Pulverized Coal Boiler				NGCC	
	GEE R+Q		CoP E-Gas FSQ		Shell		PC Subcritical		PC Supercritical		Advanced F Class	
PERFORMANCE	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 9	Case 10	Case 11	Case 12	Case 13	Case 14
CO2 Capture	0%	90%	0%	90%	0%	90%	0%	90%	0%	90%	0%	90%
Gross Power Output (kWe)	747,800	734,000	738,200	703,700	737,000	673,400	582,600	672,700	580,400	662,800	564,700	511,000
Auxiliary Power Requirement (kWe)	125,750	190,750	113,140	190,090	108,020	176,540	32,580	122,740	30,410	112,830	9,620	37,430
Net Power Output (kWe)	622,050	543,250	625,060	513,610	628,980	496,860	550,020	549,960	549,990	549,970	555,080	473,570
Coal Flowrate (lb/hr)	466,901	487,011	459,958	484,212	436,646	465,264	437,378	614,994	409,528	565,820	N/A	N/A
Natural Gas Flowrate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	167,333	167,333
HHV Thermal Input (kWth)	1,596,320	1,665,074	1,572,582	1,655,503	1,492,878	1,590,722	1,495,379	2,102,643	1,400,162	1,934,519	1,105,812	1,105,812
Net Plant HHV Efficiency (%)	39.0%	32.6%	39.7%	31.0%	42.1%	31.2%	36.8%	26.2%	39.3%	28.4%	50.2%	42.8%
Net Plant HHV Heat Rate (Btu/kWh)	8,756	10,458	8,585	10,998	8,099	10,924	9,277	13,046	8,687	12,002	6,798	7,968
Raw Water Withdrawal (gpm/MW$_{net}$)	7.6	10.7	7.0	11.1	6.6	11.3	10.7	20.4	9.7	18.3	4.3	8.4
Process Water Discharge (gpm/MW$_{net}$)	1.6	2.0	1.4	2.1	1.2	2.0	2.2	4.7	2.0	4.3	1.0	2.1
Raw Water Consumption (gpm/MW$_{net}$)	6.0	8.7	5.5	9.0	5.3	9.3	8.5	15.7	7.7	14.1	3.3	6.3
CO$_2$ Emissions (lb/MMBtu)	197	20	199	20	197	20	204	20	204	20	118	12
CO$_2$ Emissions (lb/MWh$_{gross}$)	1,434	152	1,448	158	1,361	161	1,783	217	1,675	203	790	87
CO$_2$ Emissions (lb/MWh$_{net}$)	1,723	206	1,710	217	1,595	218	1,888	266	1,768	244	804	94
SO$_2$ Emissions (lb/MMBtu)	0.0012	0.0022	0.0117	0.0022	0.0042	0.0021	0.0858	0.0017	0.0858	0.0016	Negligible	Negligible
SO$_2$ Emissions (lb/MWh$_{gross}$)	0.0090	0.0166	0.0852	0.0173	0.0290	0.0171	0.7515	0.0176	0.7063	0.0162	Negligible	Negligible
NOx Emissions (lb/MMBtu)	0.059	0.049	0.060	0.049	0.059	0.049	0.070	0.070	0.070	0.070	0.009	0.008
NOx Emissions (lb/MWh$_{gross}$)	0.430	0.376	0.434	0.396	0.409	0.396	0.613	0.747	0.576	0.697	0.060	0.061
PM Emissions (lb/MMBtu)	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071	0.0130	0.0130	0.0130	0.0130	Negligible	Negligible
PM Emissions (lb/MWh$_{gross}$)	0.052	0.055	0.052	0.057	0.049	0.057	0.114	0.139	0.107	0.129	Negligible	Negligible
Hg Emissions (lb/TBtu)	0.571	0.571	0.571	0.571	0.571	0.571	1.143	1.143	1.143	1.143	Negligible	Negligible
Hg Emissions (lb/MWh$_{gross}$)	4.16E-06	4.42E-06	4.15E-06	4.59E-06	3.95E-06	4.61E-06	1.00E-05	1.22E-05	9.41E-06	1.14E-05	Negligible	Negligible
COST												
Total Plant Cost (2007$/kW)	1,987	2,711	1,913	2,817	2,217	3,181	1,622	2,942	1,647	2,913	584	1,226
Total Overnight Cost (2007$/kW)	2,447	3,334	2,351	3,466	2,716	3,904	1,996	3,610	2,024	3,570	718	1,497
Bare Erected Cost	1,528	2,032	1,470	2,113	1,695	2,385	1,317	2,255	1,345	2,239	482	926
Home Office Expenses	144	191	138	199	156	221	124	213	127	211	40	78
Project Contingency	265	369	256	385	302	444	182	369	176	362	62	162
Process Contingency	50	119	50	120	63	131	0	105	0	100	0	60
Owner's Costs	460	623	438	649	500	723	374	667	377	657	133	271
Total Overnight Cost (2007$ x 1,000)	1,521,880	1,811,411	1,469,577	1,780,290	1,708,524	1,939,878	1,098,124	1,985,432	1,113,445	1,963,644	398,290	709,039
Total As Spent Capital (2007$/kW)	2,789	3,801	2,680	3,952	3,097	4,451	2,264	4,115	2,296	4,070	771	1,614
COE (mills/kWh, 2007$)[1,2]	76.3	105.6	74.0	110.3	81.3	119.4	59.4	109.6	58.9	106.5	58.9	85.9
CO2 TS&M Costs	0.0	5.2	0.0	5.5	0.0	5.6	0.0	5.8	0.0	5.6	0.0	3.2
Fuel Costs	14.3	17.1	14.0	18.0	13.3	17.9	15.2	21.3	14.2	19.6	44.5	52.2
Variable Costs	7.3	9.3	7.2	9.8	7.8	9.9	5.1	9.2	5.0	8.7	1.3	2.6
Fixed Costs	11.3	14.8	11.1	15.5	12.1	16.7	7.8	13.1	8.0	13.0	3.0	5.7
Capital Costs	43.4	59.1	41.7	61.5	48.2	69.2	31.2	60.2	31.7	59.6	10.1	22.3
LCOE (mills/kWh, 2007$)[1,2]	96.7	133.9	93.8	139.9	103.1	151.4	75.3	139.0	74.7	135.2	74.7	108.9

[1] CF is 80% for IGCC cases and 85% for PC and NGCC cases

[2] COE and Levelized COE are defined in Section 2.7.

Exhibit ES-3 Net Plant Efficiency (HHV Basis)
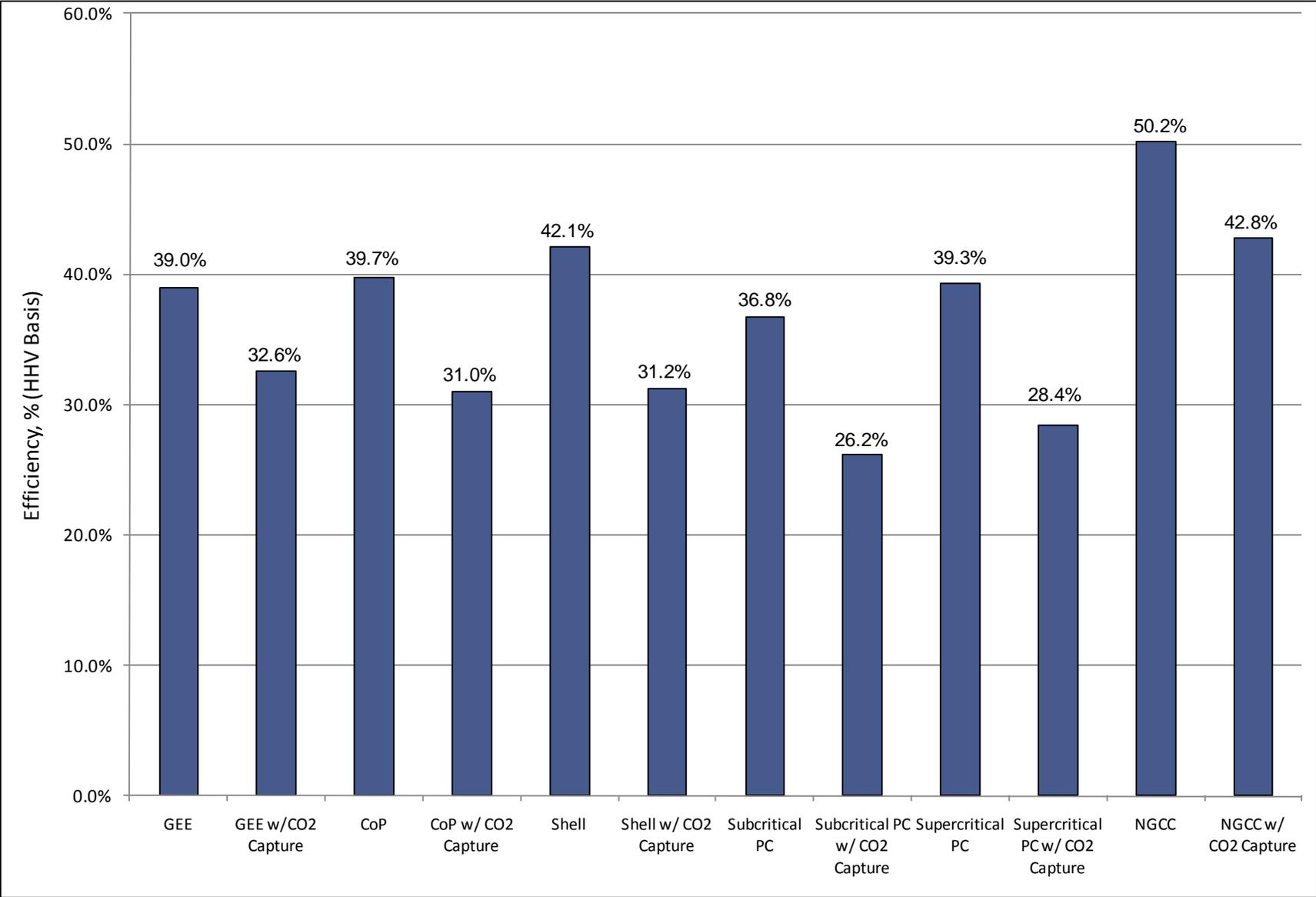
Water Use

Three water values are presented for each technology in Exhibit ES-4: raw water withdrawal, process discharge, and raw water consumption. Each value is normalized by net output. Raw water withdrawal is the difference between demand and internal recycle. Demand is the amount of water required to satisfy a particular process (slurry, quench, flue gas desulfurization [FGD] makeup, etc.) and internal recycle is water available within the process (boiler feedwater [BFW] blowdown, condensate, etc.). Raw water withdrawal is the water removed from the ground or diverted from a surface-water source for use in the plant. Raw water consumption is the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source it was withdrawn from. Raw water consumption is the difference between withdrawal and process discharge, and it represents the overall impact of the process on the water source, which in this study is considered to be 50 percent from groundwater (wells) and 50 percent from a municipal source. All plants are equipped with evaporative cooling towers, and all process blowdown streams are assumed to be treated and recycled to the cooling tower. The primary conclusions that can be drawn are:

- In all cases the primary water consumer is cooling tower makeup, which ranges from 73 to 99 percent of the total raw water consumption.

- Among non-capture cases, NGCC requires the least amount of raw water withdrawal, followed by IGCC and PC. If an average raw water consumption for the three IGCC cases and two PC cases is used, the relative normalized raw water consumption for the technologies is 2.5:1.7:1.0 (PC:IGCC:NGCC). The relative results are as expected given the much higher steam turbine output in the PC cases, which results in higher condenser duties, higher cooling water flows, and ultimately higher cooling water makeup. The IGCC cases and the NGCC case have comparable steam turbine outputs, but IGCC requires additional water for coal slurry (GEE and CoP), syngas quench (GEE), humidification (CoP and Shell), gasifier steam (Shell), and slag handling (all cases), which increases the IGCC water withdrawal over NGCC.

- Among capture cases, raw water withdrawal requirements increase (relative to non-capture cases) more dramatically for the PC and NGCC cases than for IGCC cases because of the large cooling water demand of the Econamine process, which results in greater cooling water makeup requirements. If average water consumption values are used for IGCC and PC cases, the relative normalized raw water consumption for the technologies in CO_2 capture cases is 2.4:1.4:1.0 (PC:IGCC:NGCC). The NGCC CO_2 capture case still has the lowest water consumption.

- CO_2 capture increases the average raw water consumption for all three technologies evaluated, but the increase is lowest for the IGCC cases. The average normalized raw water consumption for the three IGCC cases increases by about 58 percent due primarily to the need for additional water in the syngas to accomplish the WGS reaction. With the addition of CO_2 capture, PC normalized raw water consumption increases by 83 percent and NGCC by 91 percent. The large cooling water demand of the Econamine process drives this substantial increase for PC and NGCC.

Exhibit ES-4 Raw Water Withdrawal and Consumption
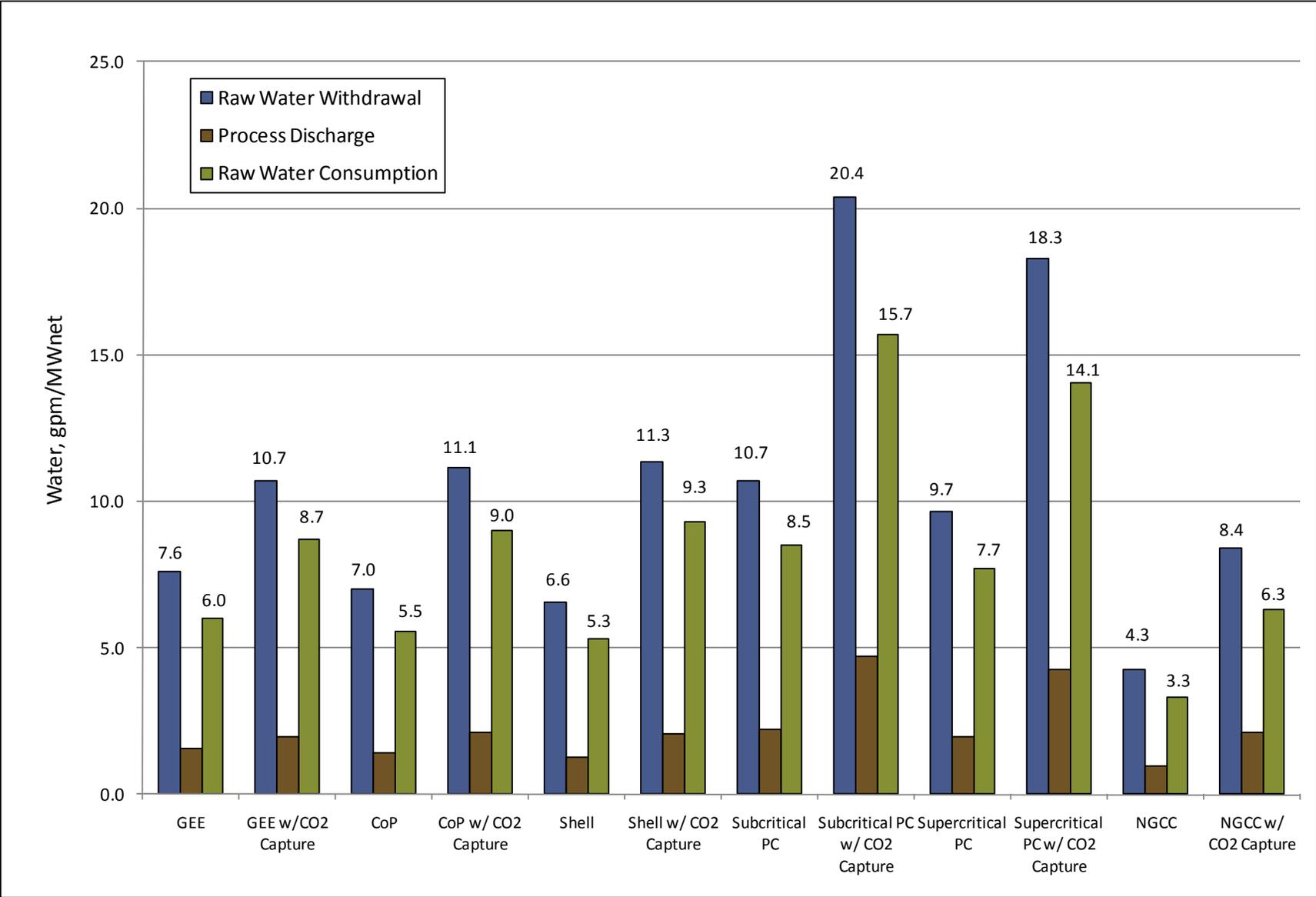
COST RESULTS

Total Overnight Cost

The Total Overnight Cost (TOC) for each plant was calculated by adding owner's costs to the Total Plant Cost (TPC). The TPC for each technology was determined through a combination of vendor quotes, scaled estimates from previous design/build projects, or a combination of the two. TPC includes all equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Escalation and interest on debt during the capital expenditure period were estimated and added to the TOC to provide the Total As-Spent Cost (TASC).

The cost estimates carry an accuracy of -15%/+30%, consistent with a "feasibility 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 (FOAK) or posed significant risk due to lack of operating experience. The cost accounts that received a process contingency include:

- Slurry Prep and Feed – 5 percent on GE IGCC cases - systems are operating at approximately 800 psia as compared to 600 psia for the other IGCC cases.

- 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/NGCC capture cases - post-combustion process unproven at commercial scale for power plant applications.

- Combustion Turbine-Generator (CTG) – 5 percent on all IGCC non-capture cases – syngas firing and air separation unit (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 and NGCC capture cases – integration issues.

The normalized components of TOC and overall TASC are shown for each technology in Exhibit ES-5. The following conclusions can be drawn:
- Among the non-capture cases, NGCC has the lowest TOC at $718 kW followed by PC with an average cost of $2,010/kW and IGCC with an average cost of $2,505/kW.

Exhibit ES-5 Plant Capital Costs
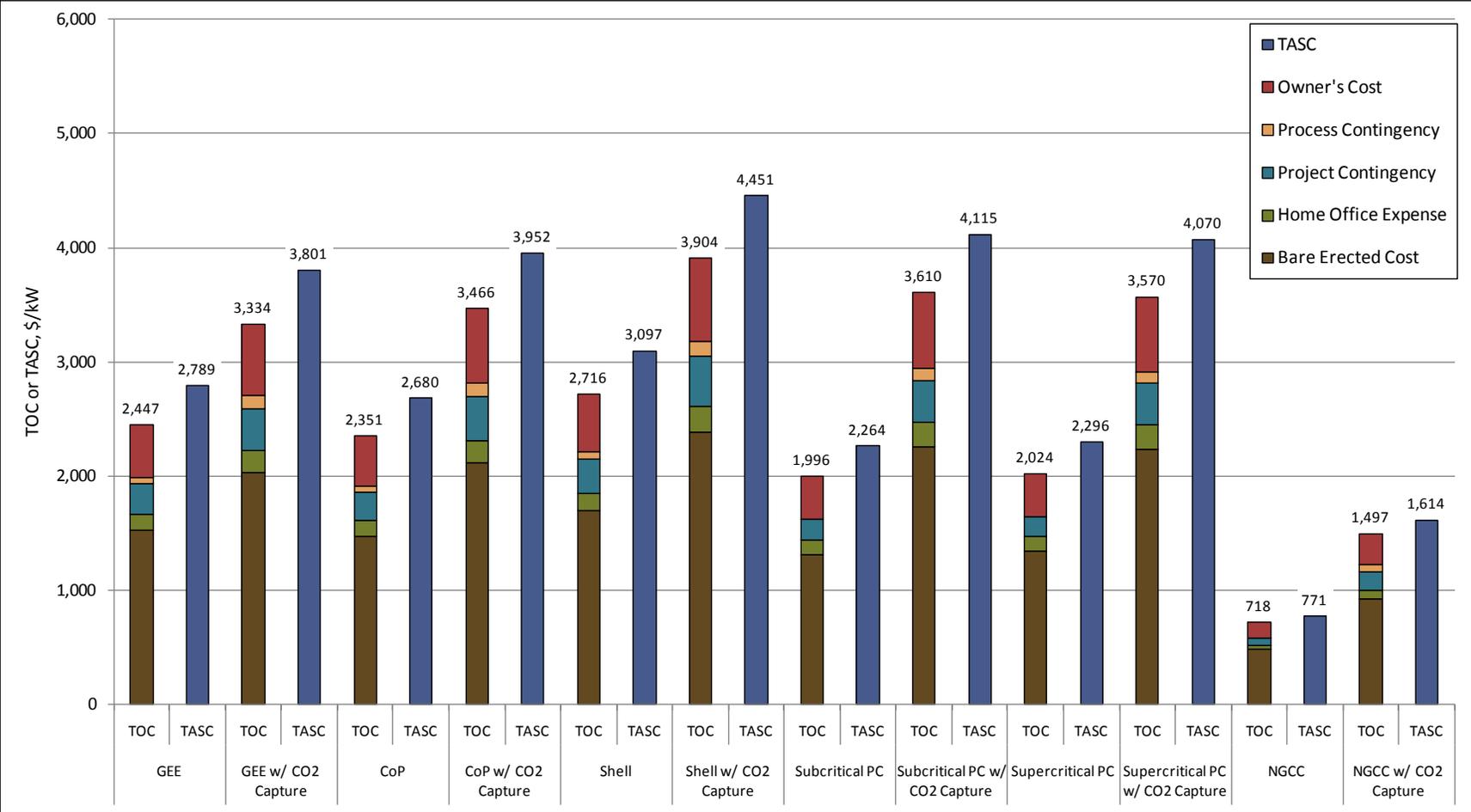
Note: TOC expressed in 2007 dollars. TASC expressed in mixed-year 2007 to 2011 year dollars for coal plants and 2007 to 2009 mixed-year dollars for NGCC.

The average IGCC cost is 25 percent greater than the average PC cost. The process contingency for the IGCC cases ranges from $50-63/kW while there is zero process contingency for the PC and NGCC non-capture cases. The differential between IGCC and PC is reduced to 22 percent when process contingency is eliminated.

- The three IGCC non-capture cases have a TOC ranging from $2,351/kW (CoP) to $2,716/kW (Shell) with GEE intermediate at $2,447/kW.

- Among the capture cases, NGCC has the lowest TOC, despite the fact that the TOC of the NGCC capture case is more than double the cost of the non-capture case at $1,497kW.

- Among the capture cases, the PC cases have the highest TOC at an average of $3,590/kW. The average TOC for IGCC CO_2 capture cases is $3,568/kW, which is less than one percent lower than the average of the PC cases. The process contingency for the IGCC capture cases ranges from $119-131/kW, for the PC cases from $100-105/kW and $60/kW for the NGCC case.

Cost of Electricity

The cost metric used in this study is the COE, which is the revenue received by the generator per net megawatt-hour during the power plant's first year of operation, *assuming that the COE escalates thereafter at a nominal annual rate equal to the general inflation rate, i.e., that it remains constant in real terms over the operational period of the power plant*. To calculate the COE, the Power Systems Financial Model (PSFM) [2] was used to determine a "base-year" (2007) COE that, when escalated at an assumed nominal annual general inflation rate of 3 percent[1], provided the stipulated internal rate of return on equity over the entire economic analysis period (capital expenditure period plus thirty years of operation). The first year capital charge factor (CCF) shown in Exhibit ES-6, which was derived using the PSFM, can also be used to calculate COE using a simplified equation as detailed in Section 2.7.4.

The project financial structure varies depending on the type of project (high risk or low risk) and the length of the capital expenditure period (3 year or 5 year). All cases were assumed to be undertaken at investor owned utilities (IOUs). 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 and NGCC cases with CO_2 capture were considered to be high risk. The non-capture PC and NGCC cases were considered to be low risk. Coal based cases were assumed to have a 5 year capital expenditure period and natural gas cases a 3 year period. The current-dollar, 30-year levelized cost of electricity (LCOE) was also calculated and is shown in Exhibit 2-23, but the primary metric used in the balance of this study is COE. A more detailed discussion of the two metrics is provided in Section 2.7 of the report.

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[1] This nominal escalation rate is equal to the average annual inflation rate between 1947 and 2008 for the U.S. Department of Labor's Producer Price Index for Finished Goods. This index was used instead of the Producer Price Index for the Electric Power Generation Industry because the Electric Power Index only dates back to December 2003 and the Producer Price Index is considered the "headline" index for all of the various Producer Price Indices.

Exhibit ES-6 Economic Parameters Used to Calculate COE

	High Risk (5 year capital expenditure period)	Low Risk (5 year capital expenditure period)	High Risk (3 year capital expenditure period)	Low Risk (3 year capital expenditure period)
First Year Capital Charge Factor	0.1243	0.1165	0.1111	0.1048

Commodity prices fluctuate over time based on overall economic activity and general supply and demand curves. While the cost basis for this study is June 2007, many price indices had similar values in January 2010 compared to June 2007. For example, the Chemical Engineering Plant Cost Index was 532.7 in June 2007 and 532.9 in January 2010, and the Gross Domestic Product Chain-type Price Index was 106.7 on July 1, 2007 and 110.0 on January 1, 2010. Hence the June 2007 dollar cost base used in this study is expected to be representative of January 2010 costs.

The COE results are shown in Exhibit ES-7 with the capital cost, fixed operating cost, variable operating cost, and fuel cost shown separately. In the capture cases, the CO_2 transport, storage, and monitoring (TS&M) costs are also shown as a separate bar segment. The following conclusions can be drawn:

- In non-capture cases, NGCC plants have the lowest COE (58.9 mills/kWh), followed by PC (average 59.2 mills/kWh) and IGCC (average 77.2 mills/kWh).

- In capture cases, NGCC plants have the lowest COE (85.9 mills/kWh), followed by PC (average 108.2 mills/kWh) and IGCC (average 111.8 mills/kWh).

- The COE for the three IGCC non-capture cases ranges from 74.0 mills/kWh (CoP) to 81.3 mills/kWh (Shell) with GEE intermediate at 76.3 mills/kWh. The study level of accuracy is insufficient to definitively quantify the differences in COE of the three IGCC technologies.

- Non-capture SC PC has a COE of 58.9 mills/kWh and subcritical PC is 59.4 mills/kWh, an insignificant difference given the level of accuracy of the study estimate.

- IGCC is the most expensive technology with CO_2 capture, 3 percent higher than PC and 30 percent higher than NGCC.

- The capital cost component of COE is between 56 and 59 percent in all IGCC and PC cases. It represents only 17 percent of COE in the NGCC non-capture case and 26 percent in the CO_2 capture case.

- The fuel component of COE ranges from 15-19 percent for the IGCC cases and the PC CO_2 capture cases. For the PC non-capture cases the fuel component varies from 24-26 percent. The fuel component is 76 percent of the total in the NGCC non-capture case and 61 percent in the CO_2 capture case.

- CO_2 TS&M is estimated to add 3 to 6 mills/kWh to the COE, which is less than 5.5 percent of the total for all capture cases.

Exhibit ES-7 COE by Cost Component
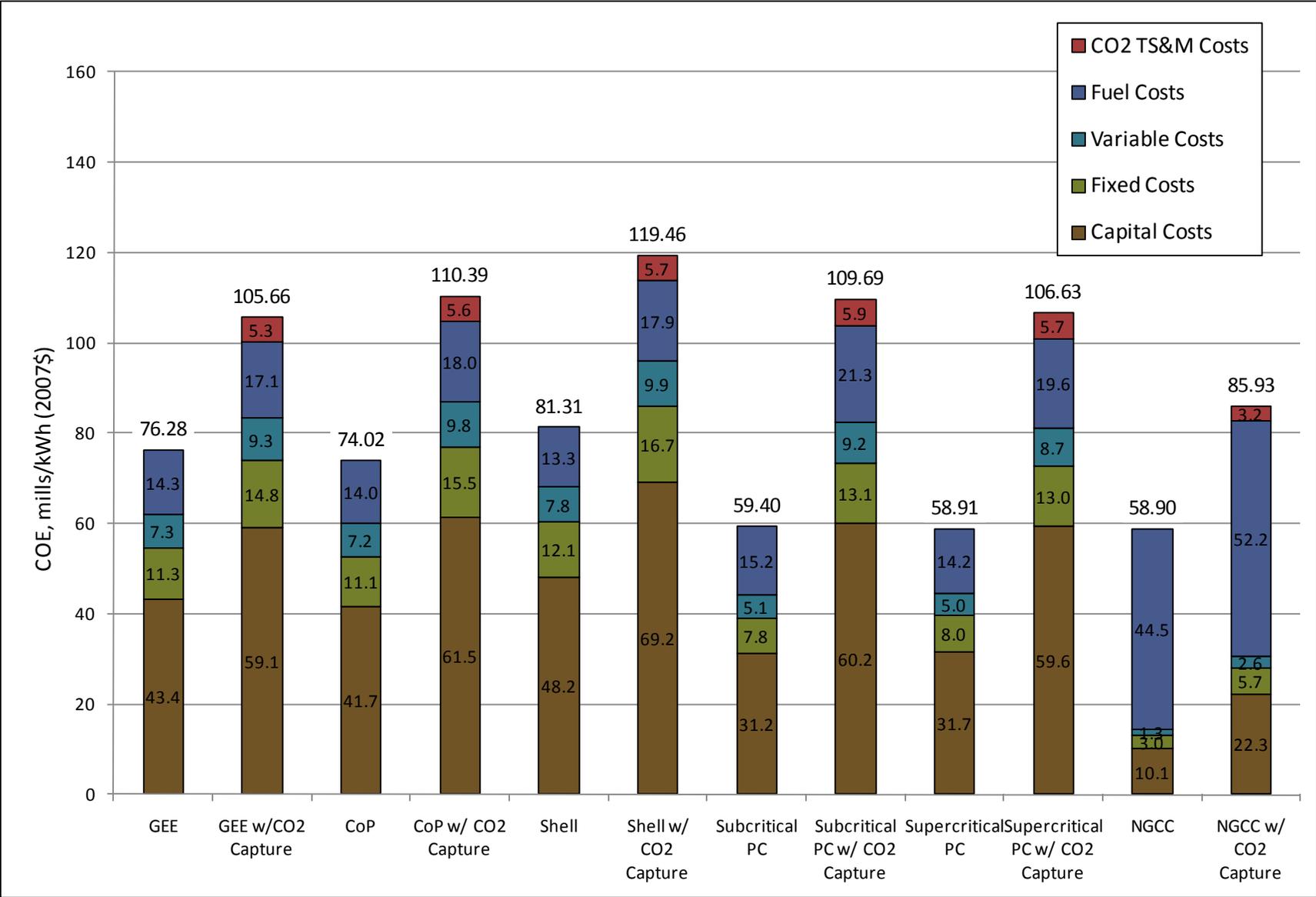
Exhibit ES-8 shows the COE sensitivity to fuel costs for the non-capture cases. The solid line is the COE of NGCC as a function of natural gas cost. The points on the line represent the natural gas cost that would be required to make the COE of NGCC equal to PC or IGCC at a given coal cost. The coal prices shown ($1.23, $1.64, and $2.05/MMBtu) represent the baseline cost and a range of ±25 percent around the baseline. As an example, at a coal cost of $1.64/MMBtu, the COE of PC equals NGCC at a natural gas price of $6.59/MMBtu.

Another observation from Exhibit ES-8 is that the COE of IGCC at a coal price of $1.23/MMBtu is greater than PC at a coal price of $2.05/MMBtu, due to the higher capital cost of IGCC and its relative insensitivity to fuel price. For example, a decrease in coal cost of 40 percent (from $2.05 to $1.23/MMBtu) results in an IGCC COE decrease of only nine percent (80.7 to 73.7 mills/kWh).

Fuel cost sensitivity is presented for the CO_2 capture cases in Exhibit ES-9. Even at the lowest coal cost shown, the COE of NGCC is less than IGCC and PC at the baseline natural gas price of $6.55/MMBtu. For the coal-based technologies at the baseline coal cost of $1.64/MMBtu to be equal to NGCC, the cost of natural gas would have to be $9.34/MMBtu (PC) or $9.80/MMBtu (IGCC). Alternatively, for the COE of coal-based technologies to be equal to NGCC at the high end coal cost of $2.05/MMBtu, natural gas prices would have to be $9.98/MMBtu for PC and $10.35/MMBtu for IGCC.

Exhibit ES-8 COE Sensitivity to Fuel Costs in Non-Capture Cases
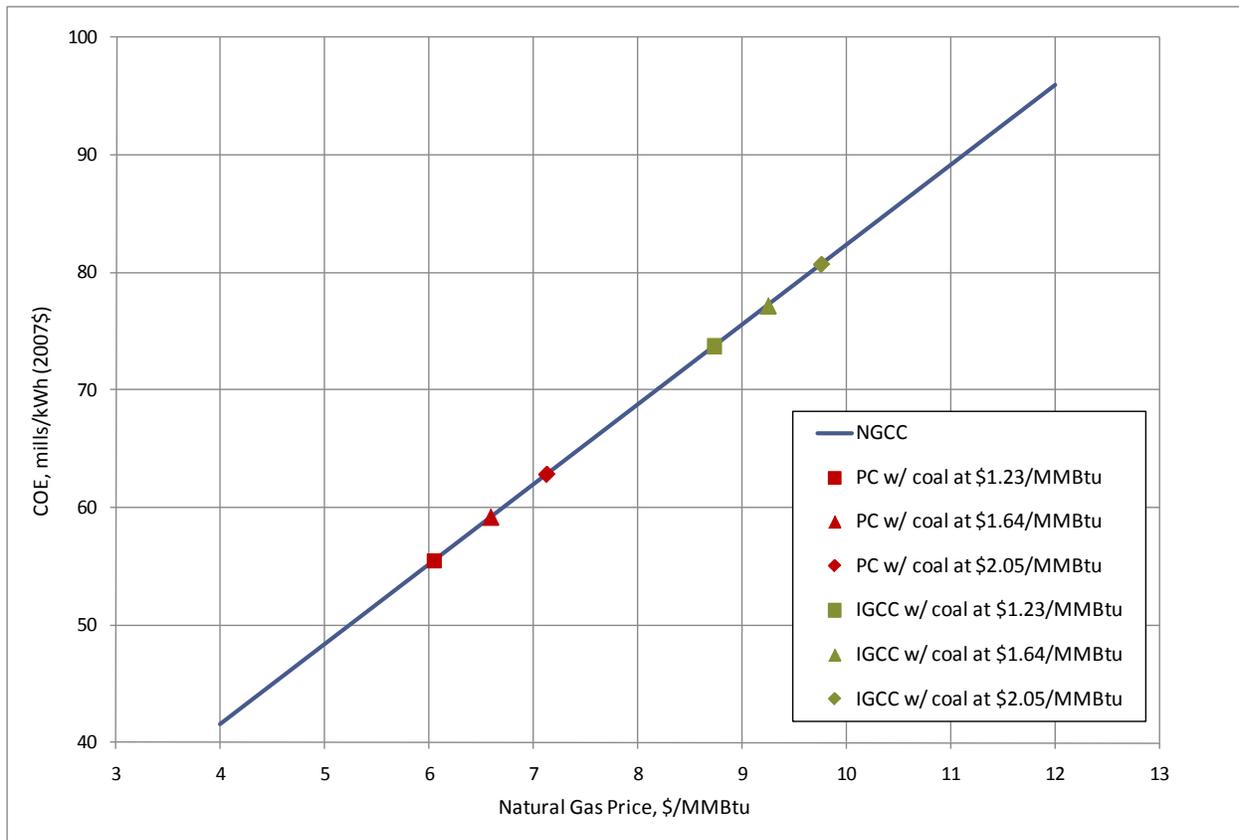
Exhibit ES-9 COE Sensitivity to Fuel Costs in CO_2 Capture Cases
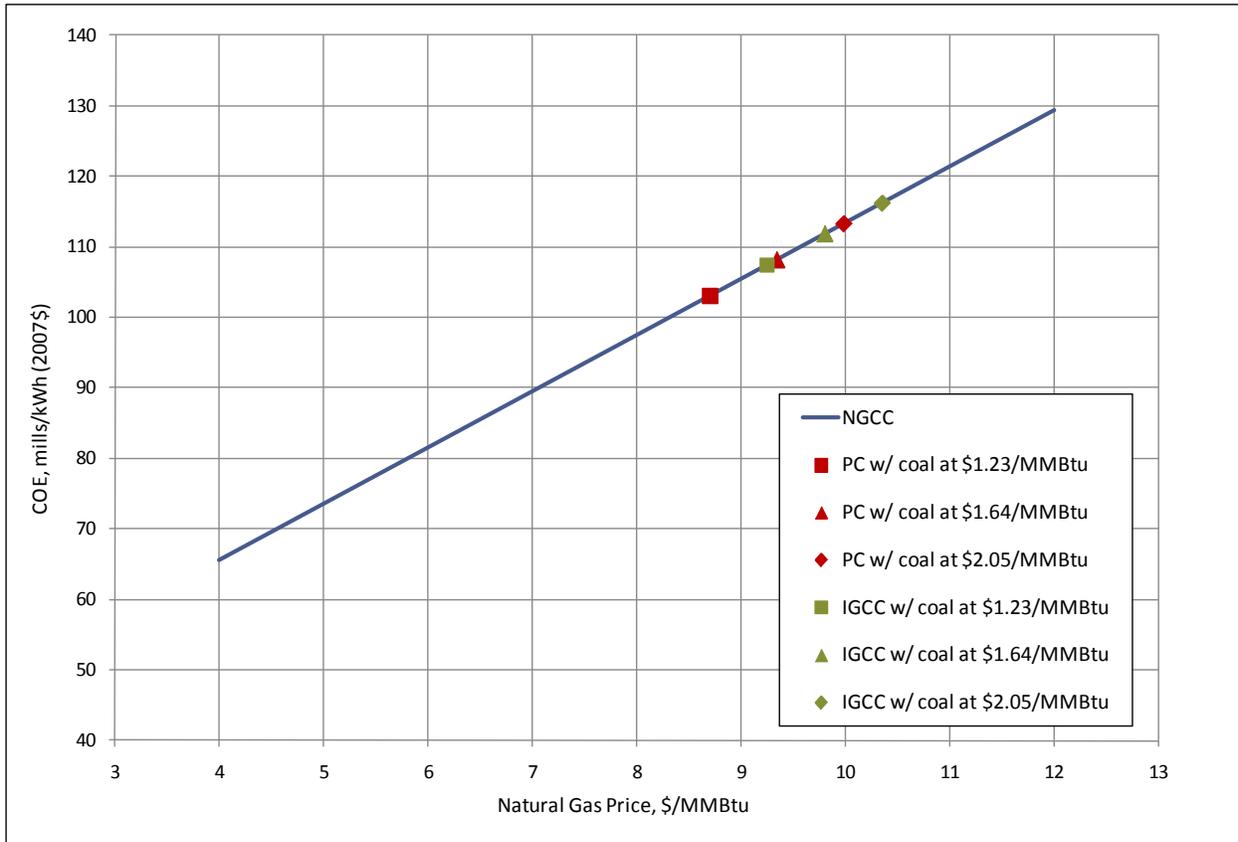
The sensitivity of COE to CF is shown for all technologies in Exhibit ES-10. The subcritical and SC PC cases with no CO_2 capture are nearly identical so that the two curves appear as a single curve on the graph. The CF is plotted from 30 to 90 percent. The baseline CF is 80 percent for IGCC cases with no spare gasifier and is 85 percent for PC and NGCC cases. The curves plotted in Exhibit ES-10 for the IGCC cases assume that the CF could be extended to 90 percent with no spare gasifier. Similarly, the PC and NGCC curves assume that the CF could reach 90 percent with no additional capital equipment.

Technologies with high capital cost (PC and IGCC with CO_2 capture) show a greater increase in COE with decreased CF. Conversely, NGCC with no CO_2 capture is relatively flat because the COE is dominated by fuel charges, which decrease as the CF decreases. Conclusions that can be drawn from Exhibit ES-10 include:

- At a CF at or below 85 percent, NGCC has the lowest COE out of the non-capture cases.

- The COE of NGCC with CO_2 capture is the lowest of the capture technologies in the baseline study, and the advantage increases as CF decreases. The relatively low capital cost component of NGCC accounts for the increased cost differential with decreased CF.

- In non-capture cases, NGCC at 40 percent CF has approximately the same COE as the average of the three IGCC cases at base load (80 percent CF) further illustrating the relatively small impact of CF on NGCC COE.

Exhibit ES-10 COE Sensitivity to Capacity Factor
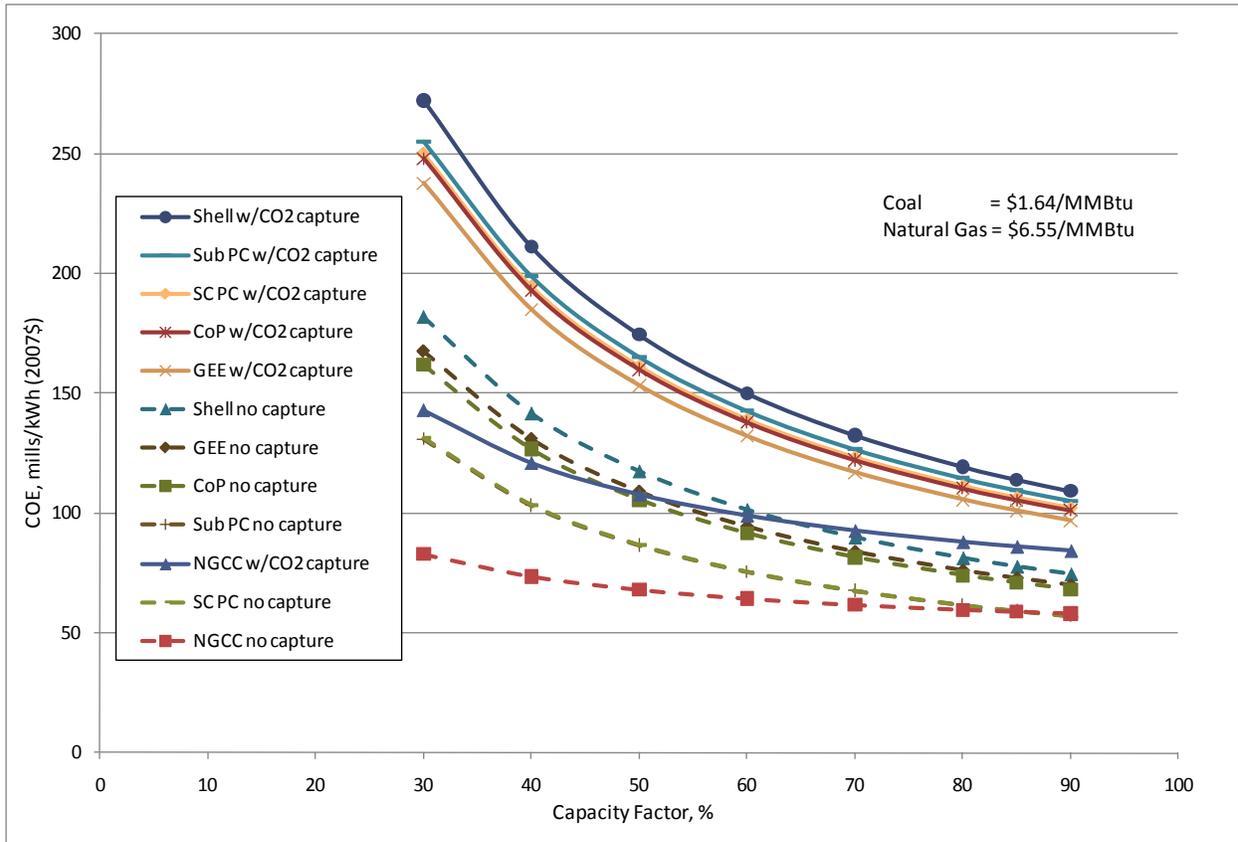
CO₂ Emission Price Impact

In the event that future legislation assigns a cost to carbon emissions, all of the technologies examined in this study will become more expensive. The technologies without carbon capture will be impacted to a larger extent than those with carbon capture, and coal-based technologies will be impacted more than natural gas-based technologies. The most economically favored option for each technology is shown in Exhibit ES-11. Hence the IGCC non-capture case is based on the CoP gasifier, the IGCC capture case is based on the GEE technology, and the PC technology is based on supercritical steam conditions.

The curves represent the study design conditions (capacity factor) and fuel prices used for each technology; namely 80 percent capacity factor for IGCC plants and 85 percent for PC and NGCC plants, and $1.64/MMBtu for coal and $6.55/MMBtu for natural gas. Natural gas fuel prices are more volatile than coal and tend to fluctuate over a fairly large range. The two black lines shown in Exhibit ES-11 represent NGCC at a fuel price of $9.50/MMBtu and are shown for reference. The dispatch-based capacity factor for NGCC plants, addressed in Section 6.4 of this report, is significantly less than 85 percent and would result in a higher COE as shown in Exhibit ES-10.

Exhibit ES-11 Impact of Carbon Emissions Price on Study Technologies
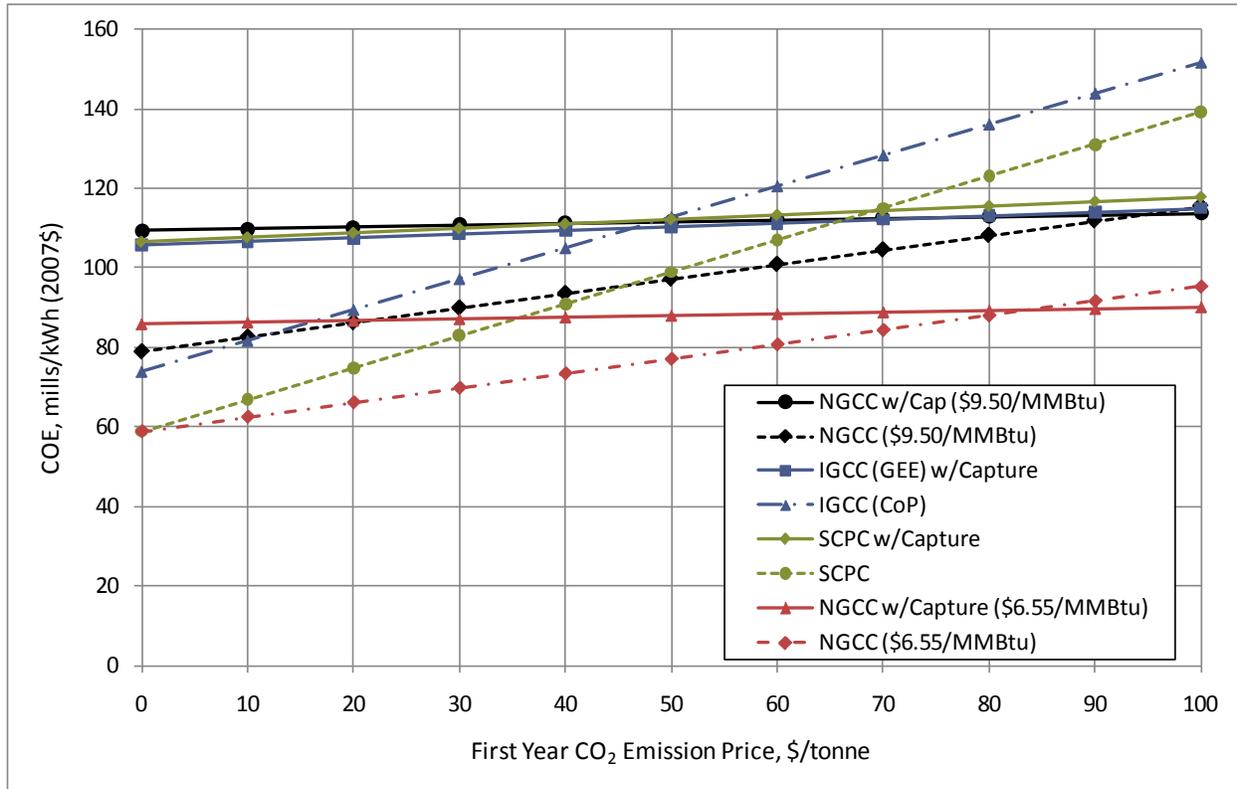
The intersection of the capture and non-capture curves for a given technology gives the cost of CO_2 avoided for that technology, except for the IGCC cases which use different gasifier technologies for the capture and non-capture cases. For example, the cost of CO_2 avoided is $69/tonne ($63/ton) for SC PC and $84/tonne ($76/ton) for NGCC. These values can be compared to those shown in Exhibit ES-13.

The following conclusions can be drawn from the carbon emissions price graph:

- At the baseline study conditions any cost applied to carbon emissions favors NGCC technology. While PC and NGCC with no capture start at essentially equivalent COEs, they diverge rapidly as the CO_2 emission cost increases. The lower carbon intensity of natural gas relative to coal and the greater efficiency of the NGCC technology account for this effect.

- Capture for NGCC systems is only justified economically at CO_2 emissions prices greater than $83/tonne ($75/ton) at the baseline natural gas price of $6.55/MMBtu and $95/tonne ($86/ton) at the higher natural gas price of $9.50/MMBtu.

- The SC PC and IGCC non-capture curves are nearly parallel indicating that the CO_2 emission price impacts the two technologies nearly equally. The two lines gradually converge due to the slightly lower efficiency of SC PC relative to the CoP IGCC technology (39.3 versus 39.7 percent net efficiency). The SC PC and GEE IGCC cases with CO_2 capture start at nearly equivalent COE values and slowly diverge. The COE of the SC PC case increases slightly faster than the GEE IGCC case

because of the lower efficiency (28.4 versus 32.6 percent net efficiency) and slightly lower capture efficiency (90.2 versus 90.3 percent).

- Comparing only the coal-based technologies, IGCC or PC with capture become the favored technology compared to SC PC with no capture at an emission price of $67/tonne ($61/ton).

- At a natural gas price of $9.50/MMBtu, NGCC with capture has nearly the same COE as IGCC and SC PC with capture at a CO_2 emission price of $30/tonne ($27/ton).

- At a natural gas price of $9.50/MMBtu, SC PC without capture has a lower COE than NGCC without capture until the CO_2 emissions price exceeds $46/tonne ($42/ton).

The relationship between technologies and CO_2 emission pricing can also be considered in a "phase diagram" type plot as shown in Exhibit ES-12. The lines in the plot represent cost parity between different pairs of technologies.

Exhibit ES-12 Lowest Cost Power Generation Options Comparing NGCC and Coal
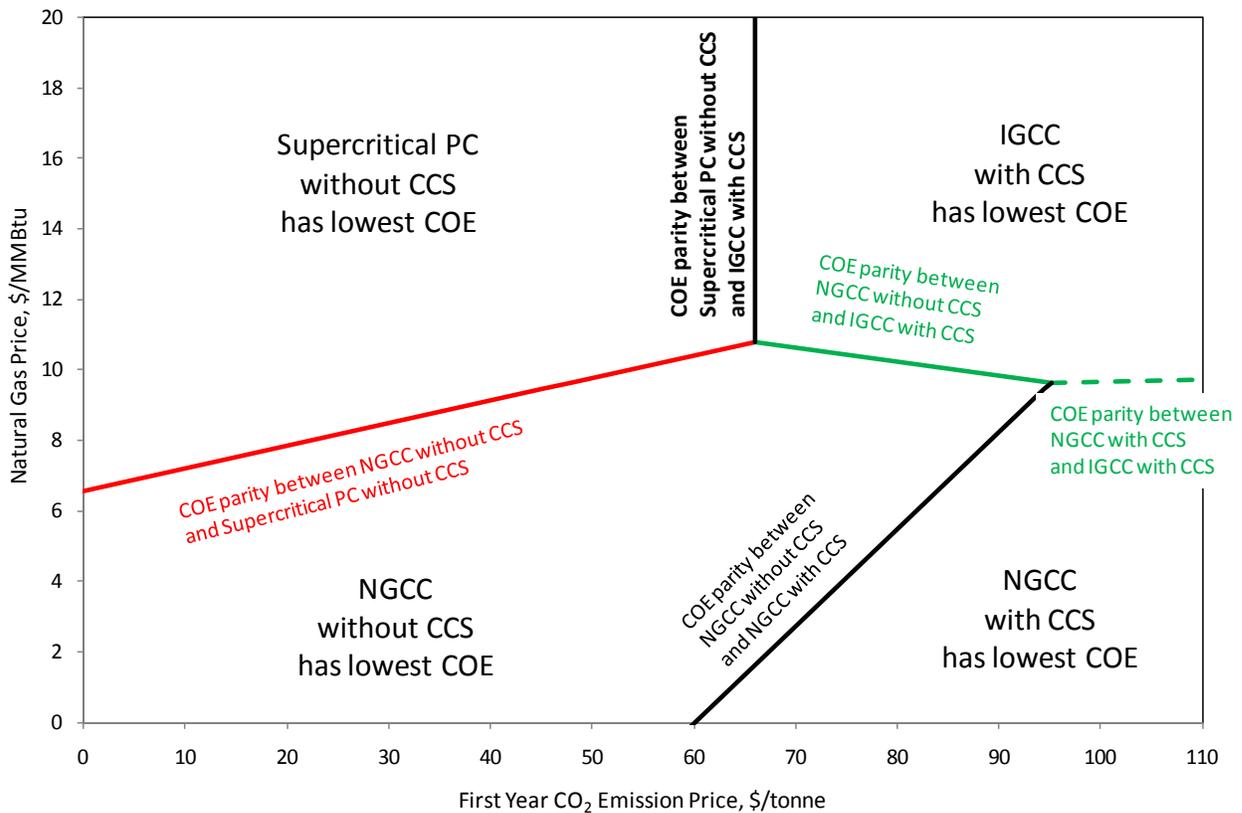
The plot demonstrates the following points:

- Non-capture plants are the low cost option below a first year CO_2 price of $60/tonne ($54/ton).

- At natural gas prices below \$6.50/MMBtu (and a capacity factor of 85 percent) NGCC is always preferred.

- At natural gas prices above \$11/MMBtu coal plants are always preferred.

Cost of CO_2 Avoided

The first year cost of CO_2 avoided was calculated as illustrated in Equation ES-1:

$$Avoided\ Cost = \frac{\{COE_{with\ removal} - COE_{reference}\}\ \$/MWh}{\{CO_2\ Emissions_{reference} - CO_2\ Emissions_{with\ removal}\}\ tons/MWh} \quad \text{(ES-1)}$$

The COE with CO_2 removal includes the costs of capture and compression as well as TS&M costs. The resulting avoided costs are shown in Exhibit ES-13 for each of the six technologies modeled. The avoided costs for each capture case are calculated using the analogous non-capture plant as the reference and again with SC PC without CO_2 capture as the reference. The following conclusions can be drawn:

- The total first year cost of CO_2 avoided is \$52.9/tonne (\$48/ton) (average IGCC), \$68.3/tonne (\$62/ton) (average PC), and \$83.8/tonne (\$76/ton) (NGCC) using analogous non-capture plants as the reference and \$75/tonne (\$68/ton) (average IGCC), \$71.6/tonne (\$65/ton) (average PC), and \$35.3/tonne (\$32/ton) (NGCC) using SC PC without capture as the reference.

- CO_2 avoided costs for IGCC plants using analogous non-capture plants as reference are substantially less than for PC and NGCC because the IGCC CO_2 removal is accomplished prior to combustion and at elevated pressure using physical absorption.

- CO_2 avoided costs for IGCC plants using analogous non-capture as reference are less than NGCC plants because the baseline CO_2 emissions for NGCC plants are 44 percent less than for IGCC plants. Consequently, the normalized removal cost for NGCC plants is divided by a smaller amount of CO_2.

- CO_2 avoided costs for the GEE IGCC plant are less than for the CoP and Shell IGCC plants. This is consistent with the efficiency changes observed when going from a non-capture to capture configuration for the GEE IGCC plant. The GEE plant started with the lowest efficiency of the IGCC plants but realized the smallest reduction in efficiency between the non-capture and capture configurations.

- CO_2 avoided costs for NGCC using SC PC as the reference are 53 percent lower than IGCC and 50 percent lower than PC because of the relatively low COE of the NGCC capture plant compared to IGCC and PC.

Exhibit ES-13 First Year CO$_2$ Avoided Costs
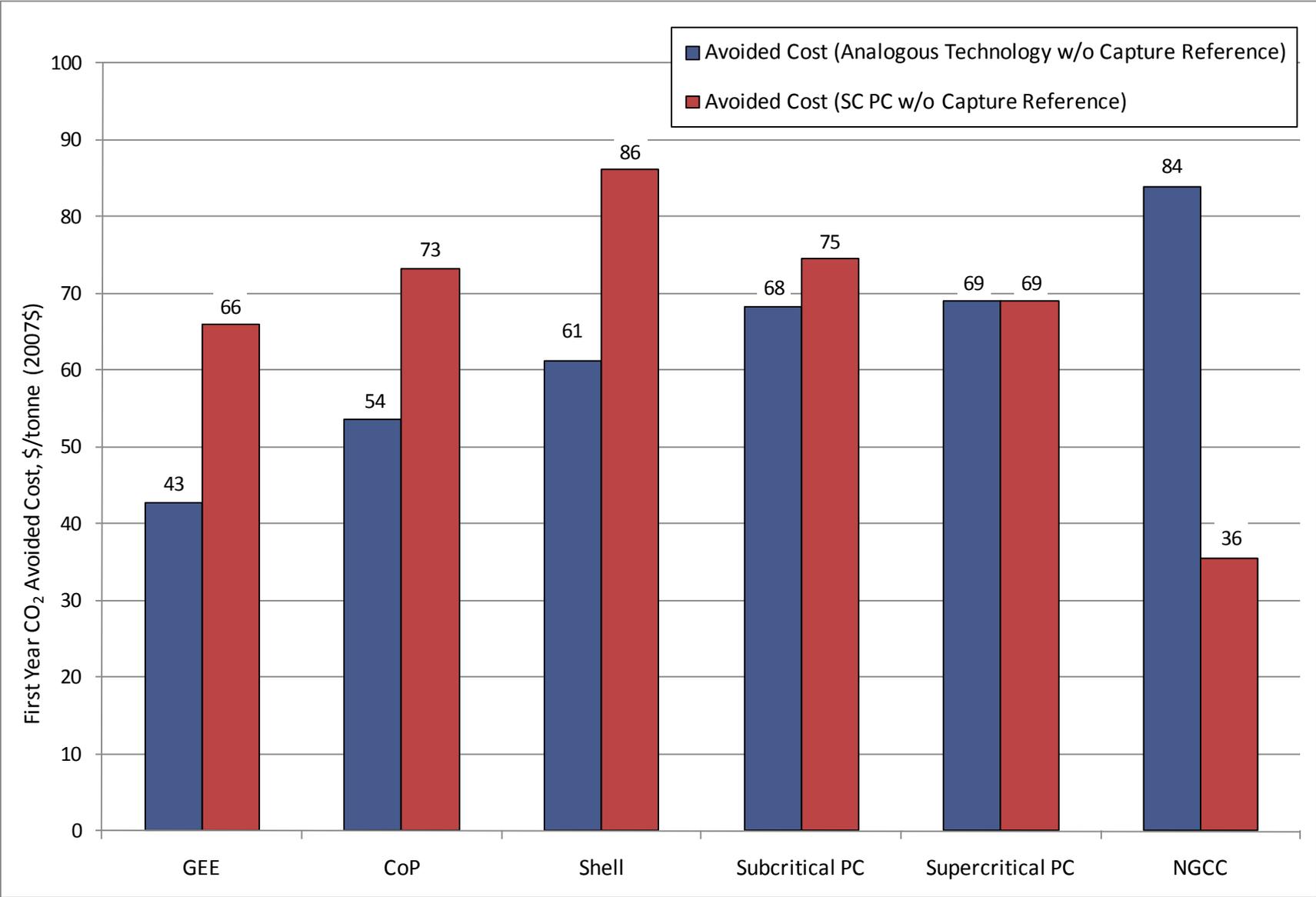
ENVIRONMENTAL PERFORMANCE

The environmental targets for each technology are summarized in Exhibit ES-14. Emission rates of sulfur dioxide (SO_2), nitrogen oxide (NOx), and particulate matter (PM) are shown graphically in Exhibit ES-15, and emission rates of mercury (Hg) are shown separately in Exhibit ES-16 because of the orders of magnitude difference in emission rate values.

Exhibit ES-14 Study Environmental Targets

Pollutant	Technology		
	IGCC	PC	NGCC
SO_2	0.0128 lb/MMBtu	0.085 lb/MMBtu	Negligible
NOx	15 ppmv (dry) @ 15% O_2	0.070 lb/MMBtu	2.5 ppmv (dry) @ 15% O_2
PM (Filterable)	0.0071 lb/MMBtu	0.013 lb/MMBtu	Negligible
Hg	>90% capture	1.14 lb/TBtu	N/A

Environmental targets were established for each of the technologies 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, EPRI, Palo Alto, CA, 2009.*

- PC and NGCC cases are based on best available control technology (BACT)

The primary conclusions that can be drawn are:

- The NGCC baseline plant generates the lowest emissions, followed by IGCC and then PC.

- In NGCC cases, study assumptions result in zero emissions of SO_2, PM, and Hg. If the pipeline natural gas contained the maximum amount of sulfur allowed by Environmental Protection Agency (EPA) definition (0.6 gr/100 scf), SO_2 emissions would be 0.000839 kg/GJ (0.00195 lb/MMBtu).

- Based on vendor data it was assumed that dry low NOx (DLN) burners could achieve 25 ppmv (dry) at 15 percent O_2 and, coupled with a selective catalytic reduction (SCR) unit that achieves 90 percent NOx reduction efficiency, would result in the environmental target of 2.5 ppmv (dry) at 15 percent O_2 for both NGCC cases.

- Based on vendor data it was assumed that Selexol, Sulfinol-M, and refrigerated methyldiethanolamine (MDEA) could all meet the sulfur environmental target, hence emissions of approximately 0.0128 lb/MMBtu in each of the IGCC non-capture cases. In the CO_2 capture cases, to achieve 95 percent CO_2 capture from the syngas, the sulfur

removal is greater than in the non-capture cases resulting in emissions of approximately 0.0009 kg/GJ (0.0022 lb/MMBtu).

- It was a study assumption that each IGCC technology could meet the filterable particulate emission limit with the combination of technologies employed. In the case of Shell and CoP, this consists of cyclones, candle filters, and the syngas scrubber. In the case of GEE particulate control consists of a water quench and syngas scrubber.

- Based on vendor data it was assumed that a combination of low NOx burners (LNBs) and nitrogen (N_2) dilution could limit IGCC NOx emissions to the environmental target of 15 ppmvd at 15 percent O_2. The small variations in NOx emissions are due to small variations in CT gas volumes.

- Based on vendor data it was assumed that 95 percent Hg removal could be achieved using carbon beds thus meeting the environmental target. The Hg emissions are reported in Exhibit ES-16 as lb per trillion Btu to make the values the same order of magnitude as the other reported values.

- It was a study assumption that the PC FGD unit would remove 98 percent of the inlet SO_2, resulting in the environmental target of 0.037 kg/GJ (0.085 lb/MMBtu). In the CO_2 capture cases, the Econamine system employs a polishing scrubber to reduce emissions to 10 ppmv entering the CO_2 absorber. Nearly all of the remaining SO_2 is absorbed by the Econamine solvent resulting in negligible emissions of SO_2 in those cases.

- In PC cases, it was a study assumption that a fabric filter would remove 99.8 percent of the entering particulate and that there is an 80/20 split between fly ash and bottom ash. The result is the environmental target of 0.006 kg/GJ (0.013 lb/MMBtu) of filterable particulate.

- In PC cases, it was a study assumption that NOx emissions exiting the boiler equipped with LNBs and overfire air (OFA) would be 0.22 kg/GJ (0.50 lb/MMBtu) and that an SCR unit would further reduce the NOx by 86 percent, resulting in the environmental target of 0.030 kg/GJ (0.070 lb/MMBtu).

- In PC cases, it was a study assumption that the environmental target of 90 percent of the incoming Hg would be removed by the combination of SCR, fabric filter and wet FGD thus eliminating the need for activated carbon injection. The resulting Hg emissions for each of the PC cases are 4.92 x 10^{-7} kg/GJ (1.14 lb/TBtu).

CO_2 emissions are not currently regulated. However, since there is increasing momentum for establishing carbon limits, it was an objective of this study to examine the relative amounts of CO_2 capture achievable among the six technologies. CO_2 emissions are presented in Exhibit ES-17 for each case, normalized by net output. In the body of the report CO_2 emissions are presented on both a net and gross MWh basis. New Source Performance Standards (NSPS) contain emission limits for SO_2 and NOx on a lb/(gross) MWh basis. However, since CO_2 emissions are not currently regulated, the potential future emission limit basis is not known and CO_2 emissions are presented in both ways. The following conclusions can be drawn:

Exhibit ES-15 SO$_2$, NOx, and Particulate Emission Rates
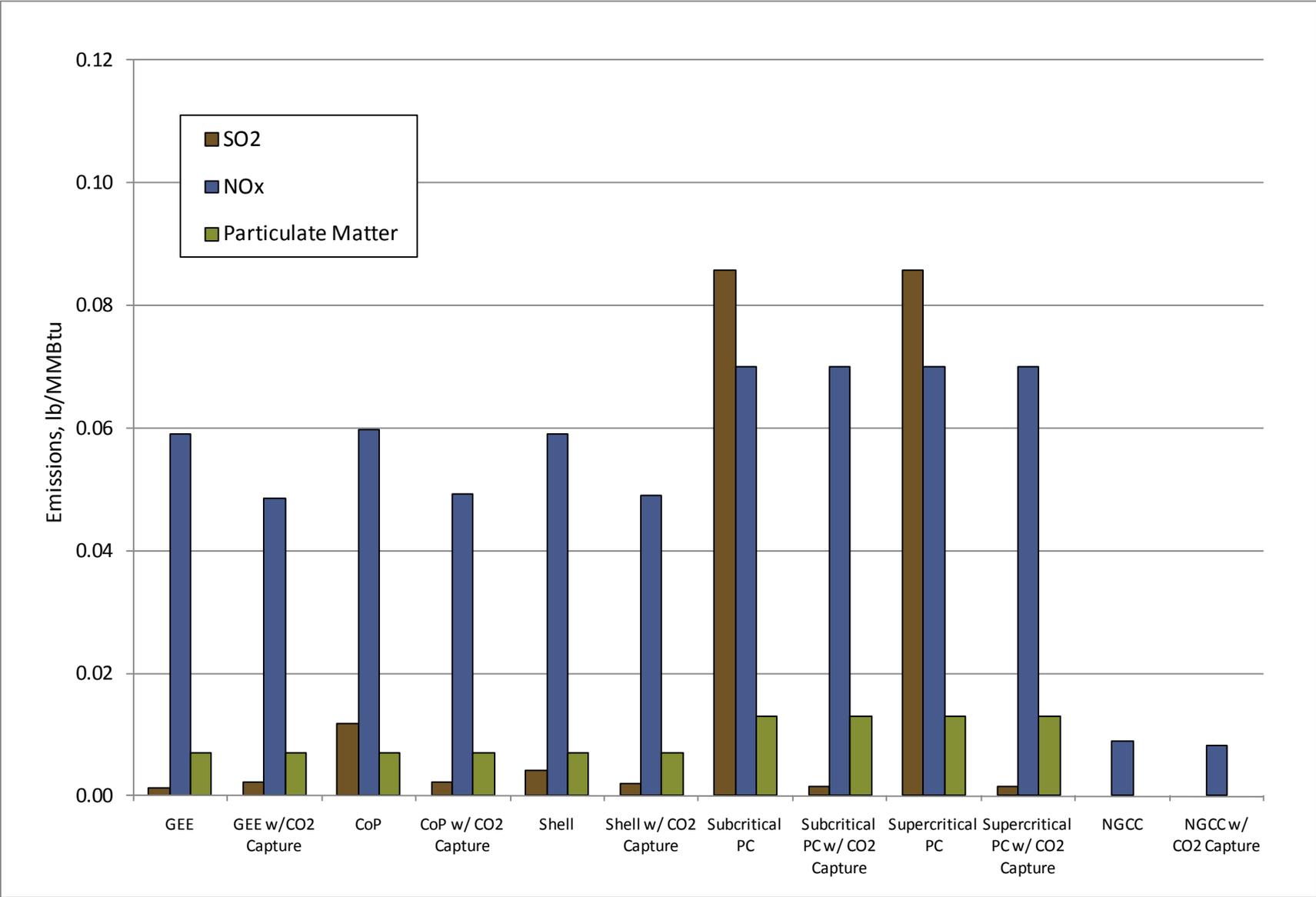
Exhibit ES-16 Mercury Emission Rates
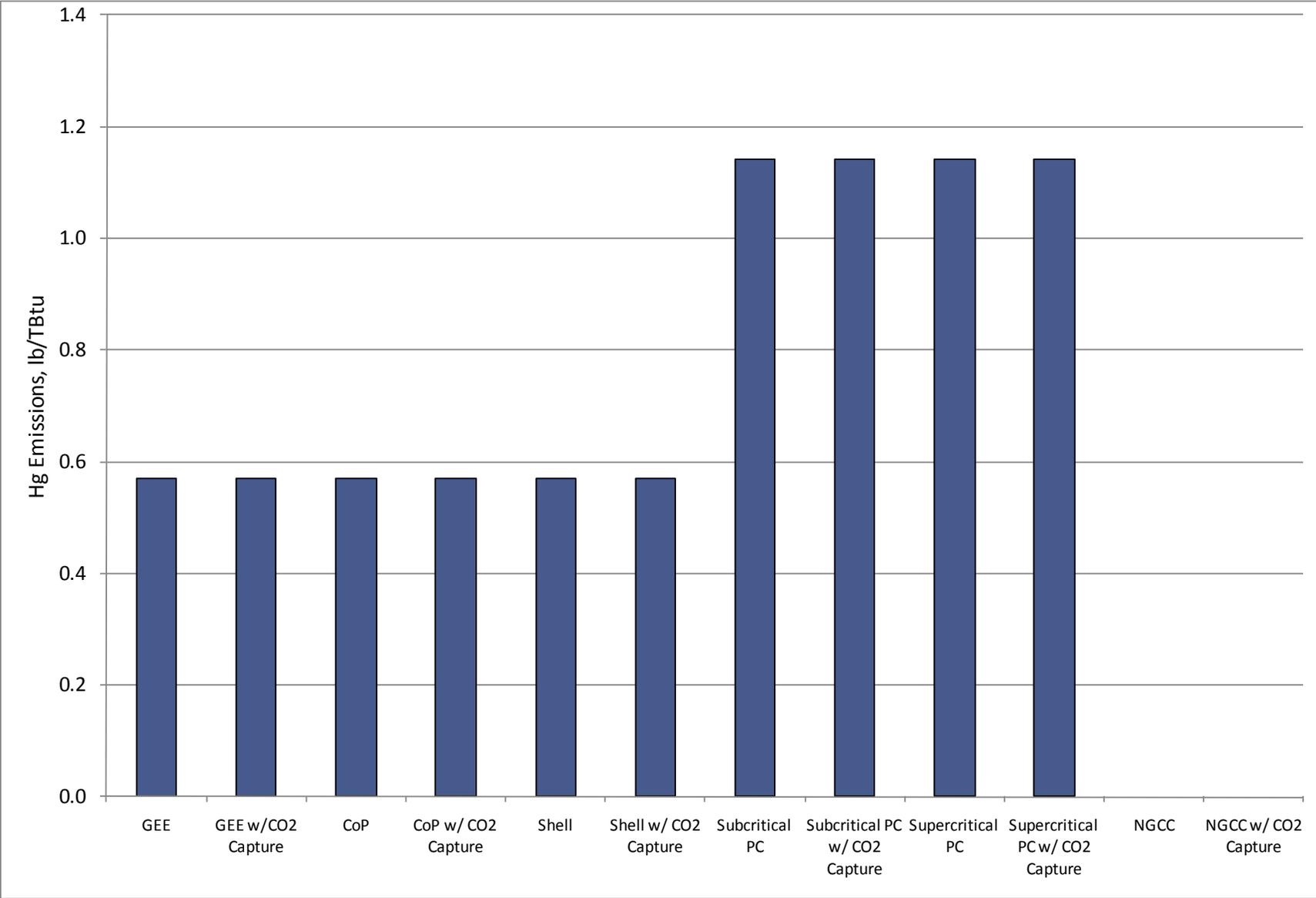
- In cases with no CO_2 capture, NGCC emits 56 percent less CO_2 than PC and 52 percent less CO_2 than IGCC per unit of net output. The lower NGCC CO_2 emissions reflect the lower carbon intensity of natural gas relative to coal and the higher cycle efficiency of NGCC relative to IGCC and PC. Based on the fuel compositions used in this study, natural gas contains 41 lb carbon/MMBtu of heat input and coal contains 55 lb/MMBtu.

- The CO_2 reduction goal in this study was a nominal 90 percent in all cases. The result is that the controlled CO_2 emissions follow the same trend as the uncontrolled, i.e., the NGCC case emits less CO_2 than the IGCC cases, which emit less than the PC cases.

- In the IGCC cases the nominal 90 percent CO_2 reduction was accomplished by using two sour gas shift (SGS) reactors to convert carbon monoxide (CO) to CO_2. A two-stage Selexol process with a second stage CO_2 removal efficiency of 92 percent, a number that was supported by vendor quotes, was used in the GEE and Shell cases. The GEE CO_2 capture case resulted in 90.3 percent reduction of CO_2 in the syngas. The Shell capture case resulted in 90.1 percent reduction of CO_2 in the syngas. In the CoP case, in order for the capture target of 90 percent to be achieved, the Selexol efficiency was increased to 95 percent. This was done because of the high syngas methane content (1.5 vol% compared to 0.10 vol% in the GEE gasifier and 0.06 vol% in the Shell gasifier). The CoP capture case resulted in 90.4 percent reduction of CO_2 in the syngas.

- Among the three non-capture IGCC cases the Shell process has slightly lower emissions primarily because it is the most efficient. The emissions in the CO_2 capture cases are nearly identical for each case.

- The PC and NGCC cases both assume that all of the carbon in the fuel is converted to CO_2 in the FG and that 90 percent is subsequently removed in the Econamine process, which was also supported by a vendor quote.

Exhibit ES-17 CO$_2$ Emissions Normalized By Net Output
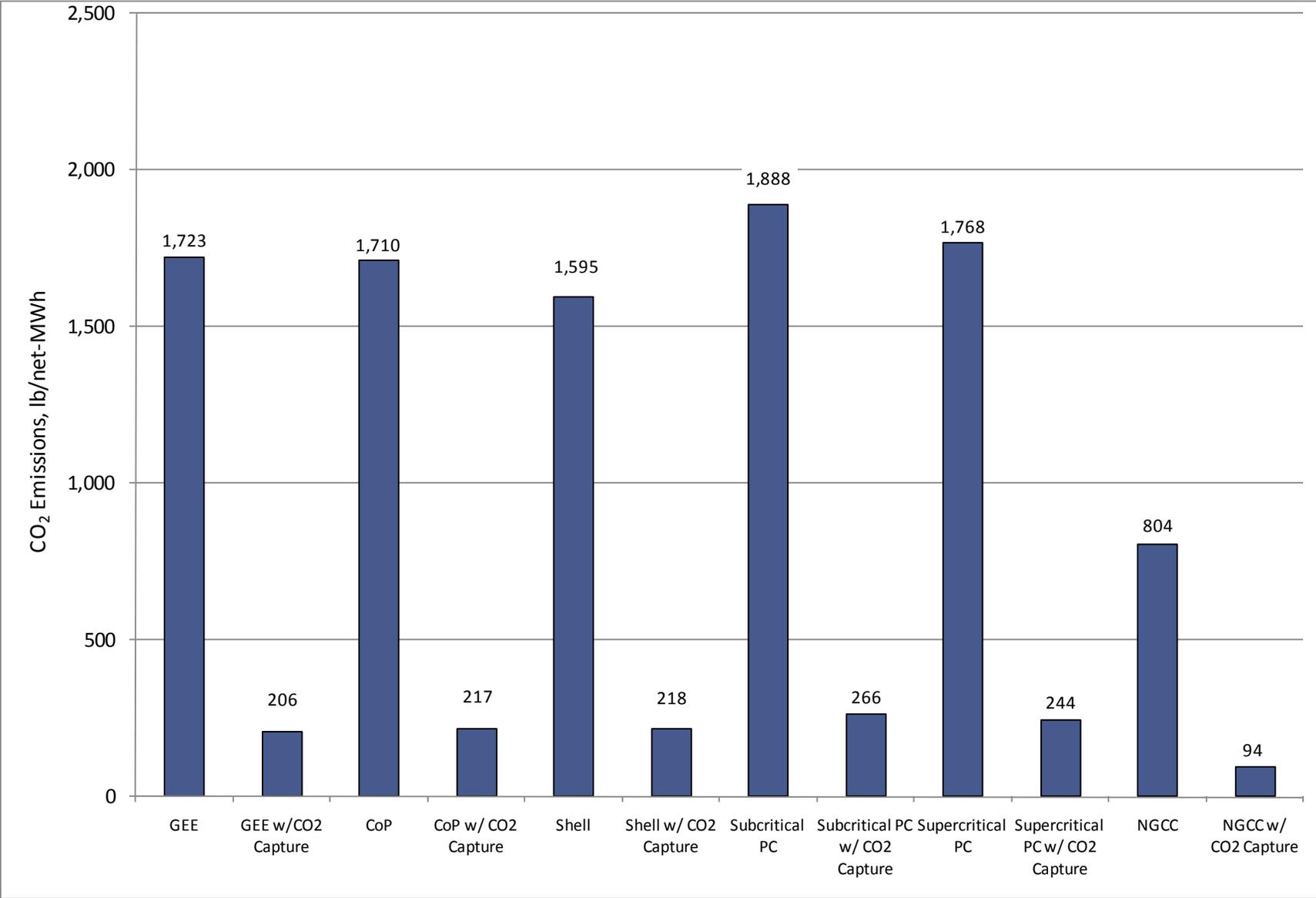
1.   <u>INTRODUCTION</u>

The objective of this report is to present an accurate, independent assessment of the cost and performance of fossil energy power systems, specifically IGCC, PC, and NGCC plants, in a consistent technical and economic manner that accurately reflects current market conditions. This is Volume 1 of a four volume report. The four volume series consists of the following:

- Volume 1: Bituminous Coal and Natural Gas to Electricity

- Volume 2: Coal to Synthetic Natural Gas and Ammonia (Various Coal Ranks)

- Volume 3: Low Rank Coal and Natural Gas to Electricity

- Volume 4: Bituminous Coal to Liquid Fuels with Carbon Capture

The cost and performance of the various fossil fuel-based technologies will largely determine which 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 DOE's Clean Coal Programs

Twelve different power plant design configurations were analyzed. The configurations are listed in Exhibit 1-1. The list includes six IGCC cases utilizing the GEE, CoP, and Shell gasifiers each with and without CO_2 capture, and six cases representing conventional technologies: PC-subcritical, PC-SC, and NGCC plants, with and without CO_2 capture. While input was sought from various technology vendors, the final assessment of performance and cost was determined independently, and may not represent the views of the technology vendors. Individual vendors have not reviewed this report and the extent of collaboration with technology vendors varied from case to case, with minimal or no collaboration obtained from some vendors.

Cases 7 and 8 were originally included in this study and involve production of SNG and the repowering of an existing NGCC facility using SNG. The two SNG cases were subsequently moved to Volume 2 of this report resulting in the discontinuity of case numbers (1-6 and 9-14).

GENERATING UNIT CONFIGURATIONS

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

The IGCC cases have different gross and net power outputs because of the gas turbine (GT) size constraint. The advanced F-class turbine used to model the IGCC cases comes in a standard size of 232 MW when operated on syngas at International Standards Organization (ISO) conditions. Each case uses two CTs for a combined gross output of 464 MW. In the combined cycle a heat recovery steam generator (HRSG) extracts heat from the CT exhaust to power a steam turbine. However, the CO_2 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. While the two CTs provide 464 MW gross output in all six cases, the overall combined cycle gross output ranges from 673 to 748 MW, which results in a range of net output from 497 (case 6) to 629 MW (case 5). The coal feed rate required to achieve the gross power output is also different between the six cases, ranging from 198,220 to 220,899 kg/hr (437,000 to 487,000 lb/hr).

Similar to the IGCC cases, the NGCC cases do not have a common net power output. The NGCC system is again constrained by the available CT size, which is 181 MW at ISO conditions for both cases (based on the same advanced F class turbine used in the IGCC cases). Since the CO_2 capture case requires both a higher auxiliary power load and a significant amount of extraction steam, which significantly reduces the steam turbine output, the net output in the NGCC case is also reduced.

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

The balance of this report is organized as follows:

- Chapter 2 provides the basis for technical, environmental, and cost evaluations.

- Chapter 3 describes the IGCC technologies modeled and presents the results for the six IGCC cases.

- Chapter 4 describes the PC technologies modeled and presents the results for the four PC cases.

- Chapter 5 describes the NGCC technologies modeled and presents the results for the two NGCC cases.

- Chapter 6 is a supplemental chapter examining the impact of dry and parallel cooling systems.

- Chapter 7 is a supplemental chapter examining the cost and performance of a GEE gasifier in a quench-only configuration with CO_2 capture.

- Chapter 8 is a supplemental chapter examining the COE sensitivity to monoethanolamine (MEA) system performance and cost.

- Chapter 9 includes a record of report revisions.

- Chapter 10 contains the reference list.

Exhibit 1-1 Case Descriptions

Case	Unit Cycle	Steam Cycle, psig/°F/°F	Combustion Turbine	Gasifier/Boiler Technology	Oxidant	H2S Separation/ Removal	Sulfur Removal/ Recovery	PM Control	NOx Control	CO2 Separation	CO2 Capture	CO2 Sequestration
1	IGCC	1800/1050/1050	2 x Advanced F Class	GEE Radiant Only	95 mol% O_2	Single-Stage Selexol	Claus Plant	Quench, scrubber and AGR adsorber	N_2 dilution			
2	IGCC	1800/1000/1000	2 x Advanced F Class	GEE Radiant Only	95 mol% O_2	Two-Stage Selexol	Claus Plant	Quench, scrubber and AGR adsorber	N_2 dilution	Selexol 2nd stage	90%[1]	Off-Site
3	IGCC	1800/1050/1050	2 x Advanced F Class	CoP E-Gas™	95 mol% O_2	Refrigerated MDEA	Claus Plant	Cyclone, barrier filter and scrubber	N_2 dilution			
4	IGCC	1800/1000/1000	2 x Advanced F Class	CoP E-Gas™	95 mol% O_2	Selexol	Claus Plant	Cyclone, barrier filter and scrubber	N_2 dilution	Selexol 2nd stage	90%[1]	Off-Site
5	IGCC	1800/1050/1050	2 x Advanced F Class	Shell	95 mol% O_2	Sulfinol-M	Claus Plant	Cyclone, barrier filter and scrubber	N_2 dilution			
6	IGCC	1800/1000/1000	2 x Advanced F Class	Shell	95 mol% O_2	Selexol	Claus Plant	Cyclone, barrier filter and scrubber	N_2 dilution	Selexol 2nd stage	90%[1]	Off-Site
9	PC	2400/1050/1050		Subcritical PC	Air		Wet FGD/ Gypsum	Baghouse	LNB w/OFA and SCR			
10	PC	2400/1050/1050		Subcritical PC	Air		Wet FGD/ Gypsum	Baghouse	LNB w/OFA and SCR	Amine Absorber	90%	Off-Site
11	PC	3500/1100/1100		Supercritical PC	Air		Wet FGD/ Gypsum	Baghouse	LNB w/OFA and SCR			
12	PC	3500/1100/1100		Supercritical PC	Air		Wet FGD/ Gypsum	Baghouse	LNB w/OFA and SCR	Amine Absorber	90%	Off-Site
13	NGCC	2400/1050/1050	2 x Advanced F Class	HRSG	Air				LNB and SCR			
14	NGCC	2400/1050/1050	2 x Advanced F Class	HRSG	Air				LNB and SCR	Amine Absorber	90%	Off-Site

[1] Defined as the percentage of carbon in the syngas that is captured; differences are explained in Chapter 3.

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2. GENERAL EVALUATION BASIS

For each of the plant configurations in this study an Aspen 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 generating the capital and operating cost estimates. Performance and process limits were based upon published reports, information obtained from vendors and users of the technology, performance data from design/build utility projects, and/or best engineering judgment. Capital and operating costs were estimated by WorleyParsons based on simulation results and through a combination of vendor quotes, scaled estimates from previous design/build projects, or a combination of the two. Ultimately a COE was calculated for each of the cases and is reported as the revenue requirement figure-of-merit.

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

2.1 SITE CHARACTERISTICS

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

Exhibit 2-1 Site Ambient Conditions

Elevation, (ft)	0
Barometric Pressure, MPa (psia)	0.10 (14.696)
Design Ambient Temperature, Dry Bulb, °C (°F)	15 (59)
Design Ambient Temperature, Wet Bulb,°C, (°F)	11 (51.5)
Design Ambient Relative Humidity, %	60

Exhibit 2-2 Site Characteristics

Location	Greenfield, Midwestern USA
Topography	Level
Size, acres	300 (PC/IGCC), 100 (NGCC)
Transportation	Rail
Ash/Slag Disposal	Off Site
Water	Municipal (50%) / Groundwater (50%)
Access	Land locked, having access by rail and highway
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 m (4,055 ft)

The land area for PC and IGCC cases assumes 30 acres are required for the plant proper and the balance provides a buffer of approximately 0.25 miles to the fence line. The extra land could also provide for a rail loop if required. In the NGCC cases it was assumed the plant proper occupies about 10 acres leaving a buffer of 0.15 miles to the plant fence line.

In all cases it was assumed that the steam turbine is enclosed in a turbine building and in the PC cases the boiler is also enclosed. The gasifier in the IGCC cases and the CTs in the IGCC and NGCC cases are 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

- Local code height requirements

- Noise regulations – Impact on site and surrounding area

2.2   COAL CHARACTERISTICS

The design coal is Illinois No. 6 with characteristics presented in Exhibit 2-3. The coal properties are from NETL's Coal Quality Guidelines [1].

The Power Systems Financial Model (PSFM) was used to derive the capital charge factors (CCF) and levelization factors (LF) for this study [2]. The PSFM requires that all cost inputs have a consistent cost year basis. Because the capital and operating cost estimates are in June 2007 dollars, the fuel costs must also be in June 2007 dollars.

The coal cost used in this study is $1.55/GJ ($1.64/MMBtu) (2007 cost of coal in June 2007 dollars). This cost was determined using the following information from the EIA 2008 AEO:

- The 2007 minemouth cost of Illinois No. 6 in 2006 dollars, $32.66/tonne ($29.63/ton), was obtained from Supplemental Table 112 of the EIA's 2008 AEO for eastern interior high-sulfur bituminous coal.

- The cost of Illinois No. 6 coal was escalated to 2007 dollars using the gross domestic product (GDP) chain-type price index from AEO 2008, resulting in a price of $33.67/tonne ($30.55/ton) [3].

- Transportation costs for Illinois No. 6 were estimated to be 25 percent of the minemouth cost based on the average transportation rate of the respective coals to the surrounding regions [4]. The final delivered costs for Illinois No. 6 coal used in the calculations is $42.09/tonne ($38.18/ton) or $1.55/GJ ($1.64/MMBtu). (Note: The Illinois No. 6 coal cost of $1.6366/MMBtu was used in calculations, but only two decimal places are shown in the report.)

Exhibit 2-3 Design Coal

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

Notes: A. The proximate analysis assumes sulfur as volatile matter
B. By difference

2.3 NATURAL GAS CHARACTERISTICS

Natural gas is utilized as the main fuel in Cases 13 and 14 (NGCC with and without CO_2 capture), and its composition is presented in Exhibit 2-4 [5].

Exhibit 2-4 Natural Gas Composition

Component		Volume Percentage	
Methane	CH_4	93.1	
Ethane	C_2H_6	3.2	
Propane	C_3H_8	0.7	
n-Butane	C_4H_{10}	0.4	
Carbon Dioxide	CO_2	1.0	
Nitrogen	N_2	1.6	
	Total	100.0	
		LHV	**HHV**
kJ/kg		47,454	52,581
MJ/scm		34.71	38.46
Btu/lb		20,410	22,600
Btu/scf		932	1,032

Note: Fuel composition is normalized and heating values are calculated

The first year cost of natural gas used in this study is \$6.21/MMkJ (\$6.55/MMBtu) (2007 cost of natural gas in 2007 dollars). The cost was determined using the following information from the EIA's 2008 AEO:

- The 2007 East North Central region delivered cost of natural gas to electric utilities in 2006 dollars, \$231.47/1000 m^3 (\$6.55/1000 ft^3), was obtained from the AEO 2008 reference case Table 108 and converted to an energy basis, \$6.02/MMkJ (\$6.35/MMBtu).

- The 2007 cost was escalated to 2007 dollars using the GDP chain-type price index from AEO 2008, resulting in a delivered 2007 price in 2007 dollars of \$6.21/MMkJ (\$6.55/MMBtu) [3]. (Note: The natural gas cost of \$6.5478/MMBtu was used in calculations, but only two decimal places are shown in the report.)

2.4 ENVIRONMENTAL TARGETS

The environmental targets for the study were considered on a technology- and fuel-specific basis. In setting the environmental targets a number of factors were considered, including current emission regulations, regulation trends, results from recent permitting activities and the status of current BACT.

The current federal regulation governing new fossil-fuel fired electric utility steam generating units is the 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 [6]. Stationary CT emission limits are further defined in 40 CFR Part 60, Subpart KKKK.

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
SO₂	1.4 lb/MWh	95	0.15	95	0.15	90
NOx	1.0 lb/MWh	N/A	0.11	N/A	0.15	N/A

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 CTs 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 BACT determinations for new sources being located in areas meeting ambient air quality standards (attainment areas), or Lowest Achievable Emission Rate (LAER) technology for sources being located in areas not meeting ambient air quality standards (non-attainment areas). Environmental area designation varies by county and can be established only for a specific site location. Based on the EPA Green Book Non-attainment Area Map relatively few areas in the Midwestern U.S. are classified as "non-attainment" so the plant site for this study was assumed to be in an attainment area [7].

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.

As of October 2009, no active legislation establishes acceptable mercury emission levels. The levels previously established by the Clean Air Mercury Rule (CAMR) have been vacated through the D.C Circuit Court. Until new limits are established, the previously established CAMR levels are used in this report. The CAMR established NSPS limits for Hg emissions from new PC-fired boilers based on coal type as well as for IGCC units independent of coal type. The NSPS limits, based on gross output, are shown in Exhibit 2-6 [8]. The applicable limit in this study is 20 x 10⁻⁶ lb/MWh for both bituminous coal-fired PC boilers and for IGCC units.

Exhibit 2-6 NSPS Mercury Emission Limits

Coal Type / Technology	Hg Emission Limit
Bituminous	**20 x 10⁻⁶ lb/MWh**
Subbituminous (wet units)	66 x 10⁻⁶ lb/MWh
Subbituminous (dry units)	97 x 10⁻⁶ lb/MWh
Lignite	175 x 10⁻⁶ lb/MWh
Coal refuse	16 x 10⁻⁶ lb/MWh
IGCC	**20 x 10⁻⁶ lb/MWh**

The mercury content of 34 samples of Illinois No. 6 coal has an arithmetic mean value of 0.09 ppm (dry basis) with standard deviation of 0.06 based on coal samples shipped by Illinois mines [9]. Hence, as illustrated in Exhibit 2-7, there is a 50 percent probability that the mercury content in the Illinois No. 6 coal would not exceed 0.09 ppm (dry basis). The coal mercury content for this study was assumed to be 0.15 ppm (dry) for all IGCC and PC cases, which corresponds to the mean plus one standard deviation and encompasses about 84 percent of the samples. It was further assumed that all of the coal Hg enters the gas phase and none leaves with the bottom ash or slag.

The current NSPS emission limits are provided below for each technology along with the environmental targets for this study and the control technologies employed to meet the targets. In some cases, application of the control technology results in emissions that are less than the target, but in no case are the emissions greater than the target.

Exhibit 2-7 Probability Distribution of Mercury Concentration in the Illinois No. 6 Coal
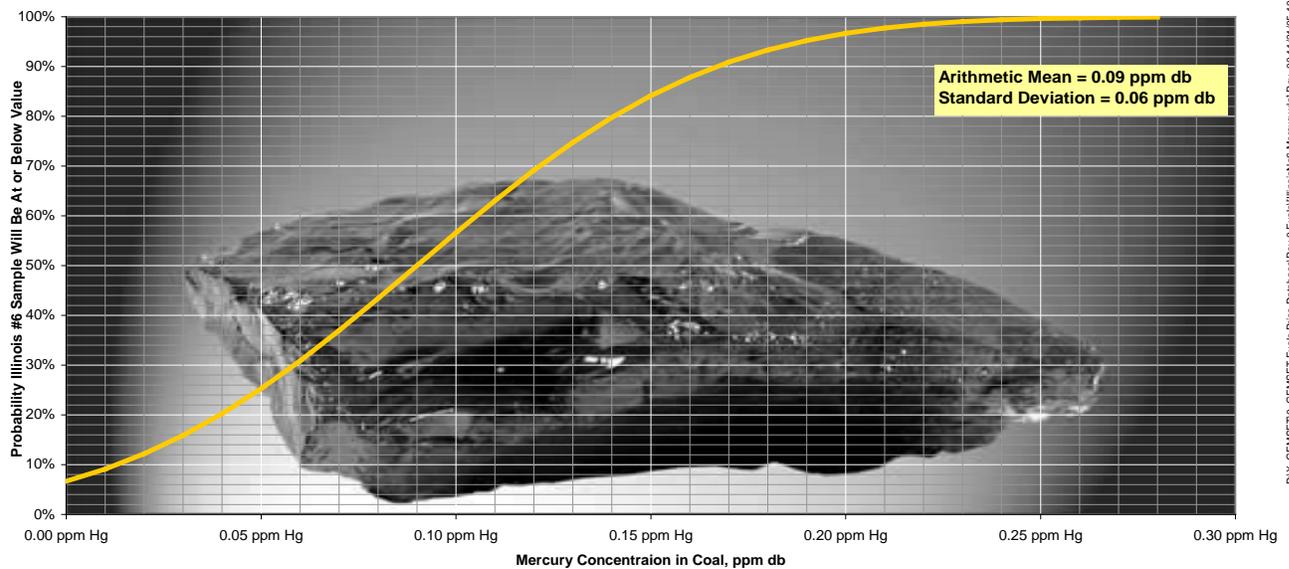
2.4.1   IGCC

The IGCC environmental targets were chosen to match the EPRI's design basis for their CoalFleet for Tomorrow Initiative and are shown in Exhibit 2-8 [10]. EPRI notes that these are design targets and are not to be used for permitting values.

Exhibit 2-8 Environmental Targets for IGCC Cases

Pollutant	Environmental Target	NSPS Limit[1]	Control Technology
NOx	15 ppmv (dry) @ 15% O_2	1.0 lb/MWh (0.091 lb/MMBtu)	Low NOx burners and syngas nitrogen dilution
SO_2	0.0128 lb/MMBtu	1.4 lb/MWh (0.127 lb/MMBtu)	Selexol, MDEA or Sulfinol (depending on gasifier technology)
Particulate Matter (Filterable)	0.0071 lb/MMBtu	0.015 lb/MMBtu	Quench, water scrubber, and/or cyclones and candle filters (depending on gasifier technology)
Mercury	> 90% capture	20×10^{-6} lb/MWh (1.8 lb/TBtu)	Carbon bed

[1] The value in parentheses is calculated based on the highest IGCC heat rate in this study of 10,998 Btu/kWh, CoP E-Gas with CO_2 capture.

Based on published vendor literature, it was assumed that LNBs and nitrogen dilution can achieve 15 ppmvd at 15 percent O_2, and that value was used for all IGCC cases [11,12].

To achieve an environmental target of 0.0128 lb/MMBtu of SO_2 requires approximately 28 ppmv sulfur in the sweet syngas. The acid gas removal (AGR) process must have a sulfur capture efficiency of about 99.7 percent to reach the environmental target. Vendor data on each of the three AGR processes used in the non-capture cases indicate that this level of sulfur removal is possible. In the CO_2 capture cases, the two-stage Selexol process was designed for 95 percent CO_2 removal, which results in a sulfur capture of greater than 99.7 percent, hence the lower sulfur emissions in the CO_2 capture cases.

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 (CoP and Shell). The environmental target of 0.0071 lb/MMBtu filterable particulates can be achieved with each combination of particulate control devices so that in each IGCC case it was assumed the environmental target was met exactly.

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 [13]. 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.

2.4.2   PC

BACT was applied to each of the PC cases and the resulting emissions 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 as shown in Exhibit 2-9. 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.

It was assumed that LNBs and staged OFA would limit NOx emissions to 0.5 lb/MMBtu and that SCR technology would be 86 percent efficient, resulting in emissions of 0.07 lb/MMBtu for all cases.

The wet limestone scrubber was assumed to be 98 percent efficient, which results in SO_2 emissions of 0.085 lb/MMBtu. Current technology allows FGD removal efficiencies in excess of 99 percent, but based on NSPS requirements and recent permit averages, such high removal efficiency is not necessary.

The fabric filter used for particulate control was assumed to be 99.8 percent efficient. The result is particulate emissions of 0.013 lb/MMBtu in all cases, which also exceeds NSPS and recent permit average requirements.

Exhibit 2-9 Environmental Targets for PC Cases

Pollutant	Environmental Target	NSPS Limit	Average of Recent Permits	Control Technology
NOx	0.07 lb/MMBtu	1.0 lb/MWh (0.111 lb/MMBtu)	0.08 lb/MMBtu	Low NOx burners, overfire air and SCR
SO_2	0.085 lb/MMBtu	1.4 lb/MWh (0.156 lb/MMBtu)	0.16 lb/MMBtu	Wet limestone scrubber
Particulate Matter (Filterable)	0.013 lb/MMBtu	0.015 lb/MMBtu	0.017 lb/MMBtu	Fabric filter
Mercury	1.14 lb/TBtu	20×10^{-6} lb/MWh (2.2 lb/TBtu)	2.49 lb/TBtu	Co-benefit capture

Mercury control for PC cases was assumed to occur through 90 percent co-benefit capture in the fabric filter and the wet FGD scrubber. EPA used a statistical method to calculate the Hg co-benefit capture from units using a "best demonstrated technology" approach, which for bituminous coals was considered to be a combination of a fabric filter and an FGD system. The statistical analysis resulted in a co-benefit capture estimate of 86.7 percent with an efficiency range of 83.8 to 98.8 percent [14]. EPA's documentation for their Integrated Planning Model (IPM) provides mercury emission modification factors (EMF) based on 190 combinations of boiler types and control technologies. The EMF is simply one minus the removal efficiency. For PC boilers (as opposed to cyclones, stokers, fluidized beds, and 'others') with a fabric filter, SCR and wet FGD, the EMF is 0.1, which corresponds to a removal efficiency of 90 percent [15]. The average reduction in total Hg emissions developed from EPA's Information Collection Request (ICR) data on U.S. coal-fired boilers using bituminous coal, fabric filters, and wet FGD is 98 percent [16]. The referenced sources bound the co-benefit Hg capture for bituminous coal units employing SCR, a fabric filter and a wet FGD system between 83.8 and 98 percent. Ninety percent was chosen as near the mid-point of this range and it also matches the value used by EPA in their IPM.

Since co-benefit capture alone exceeds the requirements of NSPS and recent permit averages, no activated carbon injection is included in this study.

2.4.3 NGCC

BACT was applied to the NGCC cases and the resulting emissions compared to NSPS limits. The NGCC environmental targets were chosen based on reasonably obtainable limits given the control technologies employed and are presented in Exhibit 2-10.

Exhibit 2-10 Environmental Targets for NGCC Cases

Pollutant	Environmental Target	40 CFR Part 60, Subpart KKKK Limits	Control Technology
NOx	2.5 ppmv @ 15% O_2	15 ppmv @ 15% O_2	Low NOx burners and SCR
SO_2	Negligible	0.9 lb/MWh (0.134 lb/MMBtu)[1]	Low sulfur content fuel
Particulate Matter (Filterable)	N/A	N/A	N/A
Mercury	N/A	N/A	N/A

[1] Assumes a heat rate of 6,719 Btu/kWh from the NGCC non-capture case.

Published vendor literature indicates that 25 ppmv NOx at 15 percent O_2 is achievable using natural gas and DLN technology [17,18]. The application of SCR with 90 percent efficiency further reduces NOx emissions to 2.5 ppmv, which was selected as the environmental target.

For the purpose of this study, natural gas was assumed to contain a negligible amount of sulfur compounds, and therefore generate negligible sulfur emissions. The EPA defines pipeline natural gas as containing >70 percent methane by volume or having a gross calorific value (GCV) of between 35.4 and 40.9 MJ/Nm^3 (950 and 1,100 Btu/scf) and having a total sulfur content of less than 13.7 mg/Nm^3 (0.6 gr/100 scf) [19]. Assuming a sulfur content equal to the EPA limit for pipeline natural gas, resulting SO_2 emissions for the two NGCC cases in this study would be approximately 21 tonnes/yr (23.2 tons/yr) at 85 percent CF or 0.00084 kg/GJ (0.00195 lb/MMBtu). Thus, for the purpose of this study, SO_2 emissions were considered negligible.

The pipeline natural gas was assumed to contain no particulate matter (PM) and no mercury resulting in no emissions of either.

2.4.4   **Carbon Dioxide**

CO_2 is not currently regulated nationally. However, the possibility exists that federal carbon limits will be imposed in the future and this study examines cases that include a reduction in CO_2 emissions. Because the form of emission limits, should they be imposed, is not known, CO_2 emissions are reported on both a lb/(gross) MWh and lb/(net) MWh basis in each capture case emissions table.

For the IGCC cases that have CO_2 capture, the basis is a nominal 90 percent removal based on carbon input from the coal and excluding carbon that exits the gasifier with the slag. In the GEE and Shell cases, this was accomplished by using two SGS reactors, to convert CO to CO_2, and a two-stage Selexol process with a second stage CO_2 removal efficiency of 92 percent, a number that was supported by vendor quotes. The GEE CO_2 capture case resulted in 90.3 percent reduction of CO_2 in the syngas. The Shell capture case resulted in 90.1 percent reduction of CO_2 in the syngas. In the CoP case, in order for the capture target of 90 percent to be achieved, a third SGS reactor was added and the Selexol efficiency was increased to 95 percent (the maximum removal efficiency supported by vendor quotes). This was done because of the high syngas methane content (1.5 vol% compared to 0.10 vol% in the GEE gasifier and 0.06 vol% in the Shell gasifier). The CoP capture case resulted in 90.4 percent reduction of CO_2 in the syngas.

For PC and NGCC cases that have CO_2 capture, it is assumed that all of the fuel carbon is converted to CO_2 in the FG. CO_2 is also generated from limestone in the FGD system, and 90 percent of the CO_2 exiting the FGD absorber is subsequently captured using the Econamine technology.

The cost of CO_2 capture was calculated as an avoided cost as illustrated in the equation below. Analogous non-capture technologies and SC non-capture PC were chosen as separate reference cases. The COE in the CO_2 capture cases includes TS&M as well as capture and compression.

$$Avoided\ Cost = \frac{\{COE_{with\ removal} - COE_{reference}\}\ \$/MWh}{\{CO_2\ Emissions_{reference} - CO_2\ Emissions_{with\ removal}\}\ tons/MWh}$$

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, CF and availability are equal. The availability for PC and NGCC cases was determined using the Generating Availability Data System (GADS) from the North American Electric Reliability Council (NERC) [20]. Since there are only two operating IGCC plants in North America, the same database was not useful for determining IGCC availability. Rather, input from EPRI and their work on the CoalFleet for Tomorrow Initiative was used.

NERC defines an equivalent availability factor (EAF), which is essentially a measure of the plant CF assuming there is always a demand for the output. The EAF accounts for planned and scheduled derated hours as well as seasonal derated hours. As such, the EAF matches this study's definition of CF.

The average EAF for 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 of the plants in this size range are older, the EAF was rounded up to 85 percent and that value was used as the PC plant CF.

The average EAF for NGCC plants in the 400-599 MW size range was 84.7 percent in 2004 and averaged 82.7 percent from 2000-2004. Using the same rationale as for PC plants, the EAF was rounded up to 85 percent and that value was also used as the NGCC plant CF.

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 [21]. 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 CF, 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 [22]. The CF 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 CF 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 CF. This assumption was made to enable a comparison based on the impact of capital and variable operating costs only. Any reduction in assumed CF would further increase the COE 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 and internal recycle water available from various sources like BFW blowdown and condensate from syngas or FG (in CO_2 capture cases) was applied to offset the water demand. The difference between demand and recycle is raw

water withdrawal. Raw water withdrawal is the water removed from the ground or diverted from a surface-water source for use in the plant. Raw water consumption is also accounted for as the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source it was withdrawn from.

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

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

The largest consumer of raw water in all cases is cooling tower makeup. It was assumed that all cases utilized a mechanical draft, evaporative cooling tower, and all process blowdown streams were assumed to be treated and recycled to the cooling tower. The design ambient wet bulb temperature of 11°C (51.5°F) (Exhibit 2-1) was used to achieve a cooling water temperature of 16°C (60°F) using an approach of 5°C (8.5°F). The cooling water range was assumed to be 11°C (20°F). The cooling tower makeup rate was determined using the following:[23]

- 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:

  o Blowdown Losses = Evaporative Losses / (Cycles of Concentration - 1)

    Where cycles of concentration is 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, the amount of raw water withdrawal by difference, the amount of process water returned to the source and the raw water consumption, again by difference.

2.7 COST ESTIMATING METHODOLOGY

The estimating methodology for capital costs, operations and maintenance costs, and CO_2 TS&M costs are described below. The finance structure, basis for the discounted cash flow analysis, and first-year COE cost calculations are also described.

2.7.1 Capital Costs

As illustrated in Exhibit 2-11, this study reports capital cost at four levels: Bare Erected Cost (BEC), Total Plant Cost (TPC), Total Overnight Cost (TOC) and Total As-spent Capital (TASC). BEC, TPC and TOC are "overnight" costs and are expressed in "base-year" dollars. The base year is the first year of capital expenditure, which for this study is assumed to be 2007. TASC is

expressed in mixed-year, current-year dollars over the entire capital expenditure period, which is assumed to last five years coal plants (2007 to 2012) and three years for natural gas plants (2007 to 2010).

Exhibit 2-11 Capital Cost Levels and their Elements
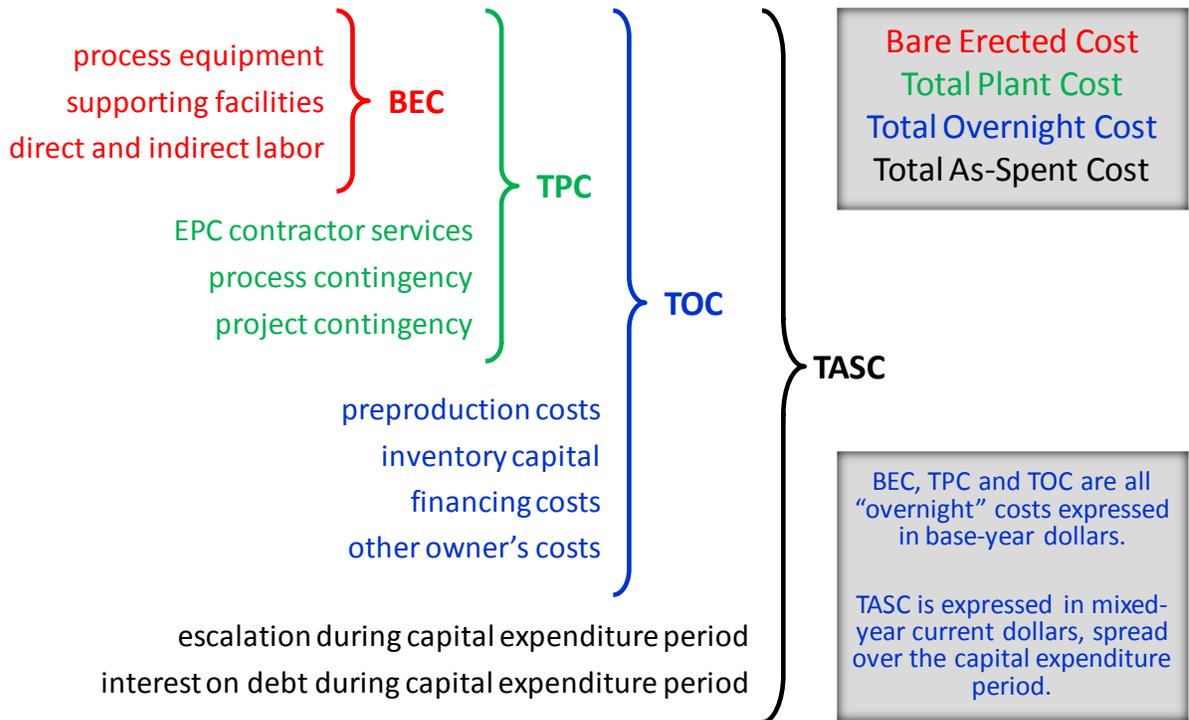
The <u>BEC</u> comprises the cost of process equipment, on-site facilities and infrastructure that support the plant (e.g., shops, offices, labs, road), and the direct and indirect labor required for its construction and/or installation. The cost of EPC services and contingencies is not included in BEC. BEC is an overnight cost expressed in base-year (2007) dollars.

The <u>TPC</u> comprises the BEC plus the cost of services provided by the engineering, procurement and construction (EPC) contractor and project and process contingencies. EPC services include: detailed design, contractor permitting (i.e., those permits that individual contractors must obtain to perform their scopes of work, as opposed to project permitting, which is not included here), and project/construction management costs. TPC is an overnight cost expressed in base-year (2007) dollars.

The <u>TOC</u> comprises the TPC plus owner's costs. TOC is an "overnight" cost, expressed in base-year (2007) dollars and as such does not include escalation during construction or interest during construction. TOC is an overnight cost expressed in base-year (2007) dollars.

The <u>TASC</u> is the sum of all capital expenditures as they are incurred during the capital expenditure period including their escalation. TASC also includes interest during construction.

Accordingly, TASC is expressed in mixed, current-year dollars over the capital expenditure period.

Cost Estimate Basis and Classification

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

Recommended Practice 18R-97 of the Association for the Advancement of Cost Engineering International (AACE) describes a Cost Estimate Classification System as applied in Engineering, Procurement and Construction for the process industries [24].

Most techno-economic studies completed by NETL feature cost estimates intended for the purpose of a "Feasibility Study" (AACE Class 4). Exhibit 2-12 describes the characteristics of an AACE Class 4 Cost Estimate. Cost estimates in this study have an expected accuracy range of -15%/+30%.

Exhibit 2-12 Features of an AACE Class 4 Cost Estimate

Project Definition	Typical Engineering Completed	Expected Accuracy
1 to 15%	plant capacity, block schematics, indicated layout, process flow diagrams for main process systems, and preliminary engineered process and utility equipment lists	-15% to -30% on the low side, and -20% to +50% on the high side

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).

Plant Maturity

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

Cost estimates in this report reflect the cost of the next commercial offering for plants that include technologies that are not yet fully mature and/or which have not yet been serially deployed in a commercial context, e.g., IGCC plants and any plant with CO_2 capture. These cost estimates for next commercial offerings do not include the unique cost premiums associated with first-of-a-kind (FOAK) plants that must demonstrate emerging technologies and resolve the cost and performance challenges associated with initial iterations. However, these estimates do

utilize currently available cost bases for emerging technologies with associated process contingencies applied at the appropriate subsystem levels.

Cost estimates for all of the plants, regardless of technology maturity, are based on many design assumptions that affect costs, including the use of a favorable site with no unusual characteristics that make construction more costly. The primary value of this report lies not in the absolute accuracy of cost estimates for the individual cases (estimated to be -15%/+30%), but in the fact that all cases were evaluated using a common methodology with an internally consistent set of technical and economic assumptions. This consistency of approach allows meaningful comparisons of relative costs among the cases evaluated.

Contracting Strategy

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

Capital Cost Assumptions

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

Other key estimate considerations include the following:

- Labor costs are based on Midwest, Merit Shop. The estimating models are based on U.S. Gulf Coast and the labor has been factored to Midwest. The basis for the factors is the PAS, Inc. (PAS) "Merit Shop Wage & Benefit Survey," which is published annually. Based on the data provided in PAS, WorleyParsons used the weighted average payroll plus fringe rate for a standard craft distribution as developed for the estimating models.

PAS presents information for eight separate regions. For this study, Region 5 (IL, IN, MI, MN, OH, and WI) was selected.

- The estimates are based on a competitive bidding environment, with adequate skilled craft labor available locally.

- Labor is based on a 50-hour work-week (5-10s). No additional incentives such as per-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.

- 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, which are treated as an addition to COE.

- Engineering and Construction Management are estimated at 8-10 percent of BEC. These costs consist of all home office engineering and procurement services as well as field construction management costs. Site staffing generally includes a construction manager, resident engineer, scheduler, and personnel for project controls, document control, materials management, site safety, and field inspection.

Price Fluctuations

During the course of this study, the prices of equipment and bulk materials fluctuated quite substantially. Some reference quotes pre-dated the 2007 year cost basis while others were received post-2007. All vendor quotes used to develop these estimates were adjusted to June 2007 dollars accounting for the price fluctuations. Adjustments of costs pre-dating 2007 benefitted from a vendor survey of actual and projected pricing increases from 2004 through mid-2007 that WorleyParsons conducted for another project. The results of that survey were used to validate/recalibrate the corresponding escalation factors used in the conceptual estimating models. The more recent economic down turn has resulted in a reduction of commodity prices such that many price indices have similar values in January 2010 compared to June 2007. For example, the Chemical Engineering Plant Cost Index was 532.7 in June 2007 and 532.9 in January 2010, and the Gross Domestic Product Chain-type Price Index was 106.7 on July 1, 2007 and 110.0 on January 1, 2010. While these overall indices are nearly constant, it should be noted that the cost of individual equipment types may still deviate from the June 2007 reference point.

Cross-comparisons

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

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

- The CT account in the GEE IGCC cases includes a syngas expander, which is not required for the CoP or Shell cases.

- The CTs 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 excluded from the capital costs:

- All taxes, with the exception of payroll and property taxes (property taxes are included with the fixed O&M costs)

- Site specific considerations – including, but not limited to, seismic zone, accessibility, local regulatory requirements, excessive rock, piles, laydown space, etc.

- Labor incentives in excess of 5-10s

- Additional premiums associated with an EPC contracting approach

Contingency

Process and project contingencies are included in estimates to account for unknown costs that are omitted or unforeseen due to a lack of complete project definition and engineering. Contingencies are added because experience has shown that such costs are likely, and expected, to be incurred even though they cannot be explicitly determined at the time the estimate is prepared.

Capital cost contingencies do not cover uncertainties or risks associated with

- scope changes
- changes in labor availability or productivity
- delays in equipment deliveries
- changes in regulatory requirements
- unexpected cost escalation
- performance of the plant after startup (e.g., availability, efficiency)

Process Contingency

Process contingency is intended to compensate for uncertainty in cost estimates caused by performance uncertainties associated with the development status of a technology. Process contingencies are applied to each plant section based on its current technology status.

As shown in Exhibit 2-13, AACE International Recommended Practice 16R-90 provides guidelines for estimating process contingency based on EPRI philosophy [25].

Process contingencies have been applied to the estimates in this study as follows:

- Slurry Prep and Feed – 5 percent on GE IGCC cases - systems are operating at approximately 800 psia as compared to 600 psia for the other IGCC cases

- 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 - unproven technology 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/NGCC capture cases - post-combustion process unproven at commercial scale for power plant applications

- CTG – 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 and NGCC capture cases – integration issues

Exhibit 2-13 AACE Guidelines for Process Contingency

Technology Status	Process Contingency (% of Associated Process Capital)
New concept with limited data	40+
Concept with bench-scale data	30-70
Small pilot plant data	20-35
Full-sized modules have been operated	5-20
Process is used commercially	0-10

Process contingency is typically not applied to costs that are set equal to a research goal or programmatic target since these values presume to reflect the total cost.

Project Contingency

AACE 16R-90 states that project contingency for a "budget-type" estimate (AACE Class 4 or 5) should be 15 to 30 percent of the sum of BEC, EPC fees and process contingency. This was used as a general guideline, but some project contingency values outside of this range occur based on WorleyParsons' in-house experience.

Owner's Costs

Exhibit 2-15 explains the estimation method for owner's costs. With some exceptions, the estimation method follows guidelines in Sections 12.4.7 to 12.4.12 of AACE International Recommended Practice No. 16R-90 [25]. The Electric Power Research Institute's "Technical Assessment Guide (TAG®) – Power Generation and Storage Technology Options" also has guidelines for estimating owner's costs. The EPRI and AACE guidelines are very similar. In instances where they differ, this study has sometimes adopted the EPRI approach.

Interest during construction and escalation during construction are not included as owner's costs but are factored into the COE and are included in TASC. These costs vary based on the capital expenditure period and the financing scenario. Ratios of TASC/TOC determined from the PSFM are used to account for escalation and interest during construction. Given TOC, TASC can be determined from the ratios given in Exhibit 2-14.

Exhibit 2-14 TASC/TOC Factors

Finance Structure	High Risk IOU		Low Risk IOU	
Capital Expenditure Period	Three Years	Five Years	Three Years	Five Years
TASC/TOC	1.078	1.140	1.075	1.134

Exhibit 2-15 Owner's Costs Included in TOC

Owner's Cost	Estimate Basis
Prepaid Royalties	Any technology royalties are assumed to be included in the associated equipment cost, and thus are not included as an owner's cost.
Preproduction (Start-Up) Costs	6 months operating labor 1 month maintenance materials at full capacity 1 month non-fuel consumables at full capacity 1 month waste disposal 25% of one month's fuel cost at full capacity 2% of TPC Compared to AACE 16R-90, this includes additional costs for operating labor (6 months versus 1 month) to cover the cost of training the plant operators, including their participation in startup, and involving them occasionally during the design and construction. AACE 16R-90 and EPRI TAG® differ on the amount of fuel cost to include; this estimate follows EPRI.
Working Capital	Although inventory capital (see below) is accounted for, no additional costs are included for working capital.
Inventory Capital	0.5% of TPC for spare parts 60 day supply (at full capacity) of fuel. Not applicable for natural gas. 60 day supply (at full capacity) of non-fuel consumables (e.g., chemicals and catalysts) that are stored on site. Does not include catalysts and adsorbents that are batch replacements such as WGS, COS, and SCR catalysts and activated carbon. AACE 16R-90 does not include an inventory cost for fuel, but EPRI TAG® does.
Land	$3,000/acre (300 acres for IGCC and PC, 100 acres for NGCC)
Financing Cost	2.7% of TPC This financing cost (not included by AACE 16R-90) covers the cost of securing financing, including fees and closing costs but not including interest during construction (or AFUDC). The "rule of thumb" estimate (2.7% of TPC) is based on a 2008 private communication with a capital services firm.

Owner's Cost	Estimate Basis
Other Owner's Costs	• 15% of TPC This additional lumped cost is not included by AACE 16R-90 or EPRI TAG®. The "rule of thumb" estimate (15% of TPC) is based on a 2009 private communication with WorleyParsons. Significant deviation from this value is possible as it is very site and owner specific. The lumped cost includes: – 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. Owner's contingency is NOT a part of project contingency.) This lumped cost does NOT include: – EPC Risk Premiums (Costs estimates are based on an Engineering Procurement Construction Management approach utilizing multiple subcontracts, in which the owner assumes project risks for performance, schedule and cost) – 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.

2.7.2   Operations and Maintenance Costs

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

- Operating labor

- Maintenance – material and labor

- Administrative and support labor

- Consumables

- Fuel

- Waste disposal

- Co-product or by-product credit (that is, a negative cost for any by-products sold)

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

Operating Labor

Operating labor cost was determined based on of the number of operators required for each specific case. The average base labor rate used to determine annual cost is $34.65/hour. The associated labor burden is estimated at 30 percent of the base labor rate. Taxes and insurance are included as fixed O&M costs totaling 2 percent of the TPC.

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.

Administrative and Support Labor

Labor administration and overhead charges are assessed at rate of 25 percent of the burdened O&M 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 and sorbent were taken from technology-specific heat and mass balance diagrams developed for each plant application. Other consumables were evaluated on the basis of the quantity required using reference data.

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

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

Waste Disposal

Waste quantities and disposal costs were determined/evaluated similarly to the consumables. In this study both slag from the IGCC cases and fly ash and bottom ash from the PC cases are considered a waste with a disposal cost of $17.89/tonne ($16.23/ton). The carbon used for mercury control in the IGCC cases is considered a hazardous waste with disposal cost of $926/tonne ($840/ton).

Co-Products and By-Products

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

It should be noted that by-product credits and/or disposal costs could potentially be an additional determining factor in the choice of technology for some companies and in selecting some sites. A high local value of the product can establish whether or not added capital should be included in the plant costs to produce a particular co-product. Ash and slag are both potential by-products in certain markets, and in the absence of activated carbon injection in the PC cases, the fly ash would remain uncontaminated and have potential marketability. However, as stated above, the ash and slag are considered wastes in this study with a concomitant disposal cost.

2.7.3 CO_2 Transport, Storage and Monitoring

For those cases that feature carbon sequestration, the capital and operating costs for CO_2 TS&M were independently estimated by NETL. Those costs were converted to a TS&M COE increment that was added to the plant COE.

CO_2 TS&M was modeled based on the following assumptions:

- CO_2 is supplied to the pipeline at the plant fence line at a pressure of 15.3 MPa (2,215 psia). The CO_2 product gas composition varies in the cases presented, but is expected to meet the specification described in Exhibit 2-16 [26]. A glycol dryer located near the mid-point of the compression train is used to meet the moisture specification.

Exhibit 2-16 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)	35 (95)
N_2 Concentration	ppmv	< 300
O_2 Concentration	ppmv	< 40
Ar Concentration	ppmv	< 10
H_2O Concentration	ppmv	< 150

- The CO_2 is transported 80 km (50 miles) via pipeline to a geologic sequestration field for injection into a saline formation.

- The CO_2 is transported and injected as a SC fluid in order to avoid two-phase flow and achieve maximum efficiency [27]. The pipeline is assumed to have an outlet pressure (above the SC pressure) of 8.3 MPa (1,200 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 6.9 MPa (1,000 psi) over an 80 km (50 mile) pipeline length [28]. (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, with hydrostatic head making up the difference between the injection and reservoir pressure.

- The saline formation is at a depth of 1,236 m (4,055 ft) and has a permeability of 22 millidarcy (md) (22 μm^2) and formation pressure of 8.4 MPa (1,220 psig) [29]. This is considered an average storage site and requires roughly one injection well for each 9,360 tonnes (10,320 short tons) of CO_2 injected per day [29]. The assumed aquifer characteristics are tabulated in Exhibit 2-17.

The cost metrics utilized in this study provide a best estimate of TS&M costs for a "favorable" sequestration project, and may vary significantly based on variables such as terrain to be crossed by the pipeline, reservoir characteristics, and number of land owners from which sub-surface rights must be acquired. Raw capital and operating costs are derived from detailed cost metrics found in the literature, escalated to June 2007-year dollars using appropriate price indices. These costs were then verified against values quoted by industrial sources where possible. Where regulatory uncertainty exists or costs are undefined, such as liability costs and the acquisition of underground pore volume, analogous existing policies were used for representative cost scenarios.

Exhibit 2-17 Deep, Saline Aquifer Specification

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
Pipeline Distance	km (miles)	80 (50)
Injection Rate per Well	tonne (ton) CO_2/day	9,360 (10,320)

The following sections describe the sources and methodology used for each metric.

TS&M Captial Costs

TS&M capital costs include both a 20 percent process contingency and 30 percent project contingency.

In several areas, such as Pore Volume Acquisition, Monitoring, and Liability, cost outlays occur over a longer time period, up to 100 years. In these cases a capital fund is established based on the net present value of the cost outlay, and this fund is then levelized similar to the other costs.

Transport Costs

CO_2 transport costs are broken down into three categories: pipeline costs, related capital expenditures, and O&M costs.

Pipeline costs are derived from data published in the Oil and Gas Journal's (O&GJ) annual Pipeline Economics Report for existing natural gas, oil, and petroleum pipeline project costs from 1991 to 2003. These costs are expected to be analogous to the cost of building a CO_2 pipeline, as noted in various studies [27, 29, 30]. The University of California performed a regression analysis to generate cost curves from the O&GJ data: (1) Pipeline Materials, (2) Direct Labor, (3) Indirect Costs, and (4) Right-of-way acquisition, with each represented as a function of pipeline length and diameter [30]. These cost curves were escalated to the June 2007 year dollars used in this study.

Related capital expenditures were based on the findings of a previous study funded by DOE/NETL, Carbon Dioxide Sequestration in Saline Formations – Engineering and Economic Assessment [29]. This study utilized a similar basis for pipeline costs (O&GJ Pipeline cost data up to the year 2000) but added a CO_2 surge tank and pipeline control system to the project.

Transport O&M costs were assessed using metrics published in a second DOE/NETL sponsored report entitled Economic Evaluation of CO_2 Storage and Sink Enhancement Options [27]. This study was chosen due to the reporting of O&M costs in terms of pipeline length, whereas the other studies mentioned above either (a) do not report operating costs, or (b) report them in absolute terms for one pipeline, as opposed to as a length- or diameter-based metric.

Storage Costs

Storage costs were divided into five categories: (1) Site Screening and Evaluation, (2) Injection Wells, (3) Injection Equipment, (4) O&M Costs, and (5) Pore Volume Acquisition. With the exception of Pore Volume Acquisition, all of the costs were obtained from Economic Evaluation of CO_2 Storage and Sink Enhancement Options [27]. These costs include all of the costs associated with determining, developing, and maintaining a CO_2 storage location, including site evaluation, well drilling, and the capital equipment required for distributing and injecting CO_2.

Pore Volume Acquisition costs are the costs associated with acquiring rights to use the sub-surface volume where the CO_2 will be stored, i.e., the pore space in the geologic formation. These costs were based on recent research by Carnegie Mellon University, which examined existing sub-surface rights acquisition as it pertains to natural gas storage [31]. The regulatory uncertainty in this area combined with unknowns regarding the number and type (private or government) of property owners, require a number of "best engineering judgment" decisions to be made. In this study it was assumed that long-term lease rights were acquired from the property owners in the projected CO_2 plume growth region for a nominal fee, and that an annual "rent" was paid when the plume reached each individual acre of their property for a period of up

to 100 years from the injection start date. The present value of the life cycle pore volume costs are assessed at a 10 percent discount rate and a capital fund is set up to pay for these costs over the 100 year rent scenario.

Liability Protection

Liability Protection addresses the fact that if damages are caused by injection and long-term storage of CO_2, the injecting party may bear financial liability. Several types of liability protection schemes have been suggested for CO_2 storage, including Bonding, Insurance, and Federal Compensation Systems combined with either tort law (as with the Trans-Alaska Pipeline Fund), or with damage caps and preemption, as is used for nuclear energy under the Price Anderson Act [32]. However, at present, a specific liability regime has yet to be dictated either at a Federal or (to our knowledge) State level. However, certain state governments have enacted legislation, which assigns liability to the injecting party, either in perpetuity (Wyoming) or until ten years after the cessation of injection operations, pending reservoir integrity certification, at which time liability is turned over to the state (North Dakota and Louisiana) [33,34,35]. In the case of Louisiana, a trust fund totaling five million dollars is established over the first ten years (120 months) of injection operations for each injector. This fund is then used by the state for CO_2 monitoring and, in the event of an at-fault incident, damage payments.

Liability costs assume that a bond must be purchased before injection operations are permitted in order to establish the ability and good will of an injector to address damages where they are deemed liable. A figure of five million dollars was used for the bond based on the Louisiana fund level. This bond level may be conservatively high, in that the Louisiana fund covers both liability and monitoring, but that fund also pertains to a certified reservoir where injection operations have ceased, having a reduced risk compared to active operations. The bond cost was not escalated.

Monitoring Costs

Monitoring costs were evaluated based on the methodology set forth in the International Energy Agency (IEA) Greenhouse Gas (GHG) R&D Programme's Overview of Monitoring Projects for Geologic Storage Projects report [36]. In this scenario, operational monitoring of the CO_2 plume occurs over 30 years (during plant operation) and closure monitoring occurs for the following fifty years (for a total of eighty years). Monitoring is via electromagnetic (EM) survey, gravity survey, and periodic seismic survey; EM and gravity surveys are ongoing while seismic survey occurs in years 1, 2, 5, 10, 15, 20, 25, and 30 during the operational period, then in years 40, 50, 60, 70, and 80 after injection ceases.

2.7.4   Finance Structure, Discounted Cash Flow Analysis, and COE

The global economic assumptions are listed in Exhibit 2-18.

Finance structures were chosen based on the assumed type of developer/owner (investor-owned utility (IOU) or independent power producer) and the assumed risk profile of the plant being assessed (low-risk or high-risk). For this study the owner/developer was assumed to be an IOU. All IGCC cases as well as PC and NGCC cases with CO_2 capture were considered high risk. The non-capture PC and NGCC cases were considered low risk. Exhibit 2-19 describes the low-risk IOU and high-risk IOU finance structures that were assumed for this study. These finance

structures were recommended in a 2008 NETL report based on interviews with project developers/owners, financial organizations and law firms [37].

Exhibit 2-18 Global Economic Assumptions

Parameter	Value
TAXES	
Income Tax Rate	38% (Effective 34% Federal, 6% State)
Capital Depreciation	20 years, 150% declining balance
Investment Tax Credit	0%
Tax Holiday	0 years
CONTRACTING AND FINANCING TERMS	
Contracting Strategy	Engineering Procurement Construction Management (owner assumes project risks for performance, schedule and cost)
Type of Debt Financing	Non-Recourse (collateral that secures debt is limited to the real assets of the project)
Repayment Term of Debt	15 years
Grace Period on Debt Repayment	0 years
Debt Reserve Fund	None
ANALYSIS TIME PERIODS	
Capital Expenditure Period	Natural Gas Plants: 3 Years Coal Plants: 5 Years
Operational Period	30 years
Economic Analysis Period (used for IRROE)	33 or 35 Years (capital expenditure period plus operational period)
TREATMENT OF CAPITAL COSTS	
Capital Cost Escalation During Capital Expenditure Period (nominal annual rate)	3.6% [2]
Distribution of Total Overnight Capital over the Capital Expenditure Period (before escalation)	3-Year Period: 10%, 60%, 30% 5-Year Period: 10%, 30%, 25%, 20%, 15%
Working Capital	zero for all parameters
% of Total Overnight Capital that is Depreciated	100% *(this assumption introduces a very small error even if a substantial amount of TOC is actually non-depreciable)*
ESCALATION OF OPERATING REVENUES AND COSTS	
Escalation of COE (revenue), O&M Costs, and Fuel Costs (nominal annual rate)	3.0% [3]

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[2] 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.

[3] An average annual inflation rate of 3.0 percent is assumed. This rate is equivalent to the average annual escalation rate between 1947 and 2008 for the U.S. Department of Labor's Producer Price Index for Finished Goods, the so-called "headline" index of the various Producer Price Indices. (The Producer Price Index for the Electric Power Generation Industry may be more applicable, but that data does not provide a long-term historical perspective since it only dates back to December 2003.)

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%

DCF Analysis and Cost of Electricity

The NETL Power Systems Financial Model (PSFM) is a nominal-dollar[4] (current dollar) discounted cash flow (DCF) analysis tool. As explained below, the PSFM was used to calculate COE[5] in two ways: a COE and a levelized COE (LCOE). To illustrate how the two are related, COE solutions are shown in Exhibit 2-20 for a generic pulverized coal (PC) power plant and a generic natural gas combined cycle (NGCC) power plant, each with carbon capture and sequestration installed.

- The **COE** is the revenue received by the generator per net megawatt-hour during the power plant's first year of operation, *assuming that the COE escalates thereafter at a nominal annual rate equal to the general inflation rate, i.e., that it remains constant in real terms over the operational period of the power plant*. To calculate the COE, the PSFM was used to determine a "base-year" (2007) COE that, when escalated at an assumed nominal annual general inflation rate of 3 percent[6], provided the stipulated internal rate of return on equity over the entire economic analysis period (capital expenditure period plus thirty years of operation). The COE solutions are shown as curved lines in the upper portion of Exhibit 2-20 for a PC power plant and a NGCC power plant. Since this analysis assumes that COE increases over the economic analysis period at the nominal annual general inflation rate, it remains constant in real terms and the first-year COE is equivalent to the base-year COE when expressed in base-year (2007) dollars.

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[4] Since the analysis takes into account taxes and depreciation, a nominal dollar basis is preferred to properly reflect the interplay between depreciation and inflation.

[5] For this calculation, "cost of electricity" is somewhat of a misnomer because from the power plant's perspective it is actually the "price" received for the electricity generated to achieve the stated IRROE. However, since the price paid for generation is ultimately charged to the end user, from the customer's perspective it is part of the cost of electricity.

[6] This nominal escalation rate is equal to the average annual inflation rate between 1947 and 2008 for the U.S. Department of Labor's Producer Price Index for Finished Goods. This index was used instead of the Producer Price Index for the Electric Power Generation Industry because the Electric Power Index only dates back to December 2003 and the Producer Price Index is considered the "headline" index for all of the various Producer Price Indices.

- The **LEVELIZED COE** is the revenue received by the generator per net megawatt-hour during the power plant's first year of operation, *assuming that the COE escalates thereafter at a nominal annual rate of 0 percent, i.e., that it remains constant in nominal terms over the operational period of the power plant.* This study reports LCOE on a current-dollar basis over thirty years. "Current dollar" refers to the fact that levelization is done on a nominal, rather than a real, basis[7]. "Thirty-years" refers to the length of the operational period assumed for the economic analysis. To calculate the LCOE, the PSFM was used to calculate a base-year COE that, when escalated at a nominal annual rate of 0 percent, provided the stipulated return on equity over the entire economic analysis period. For the example PC and NGCC power plant cases, the LCOE solutions are shown as horizontal lines in the upper portion of Exhibit 2-20.

Exhibit 2-20 also illustrates the relationship between COE and the assumed developmental and operational timelines for the power plants. As shown in the lower portion of Exhibit 2-20, the capital expenditure period is assumed to start in 2007 for all cases in this report. All capital costs included in this analysis, including project development and construction costs, are assumed to be incurred during the capital expenditure period. Coal-fueled plants are assumed to have a capital expenditure period of five years and natural gas-fueled plants are assumed to have a capital expenditure period of three years. Since both types of plants begin expending capital in the base year (2007), this means that the analysis assumes that they begin operating in different years: 2012 for coal plants and 2010 for natural gas plants in this study. Note that, according to the *Chemical Engineering* Plant Cost Index, June-2007 dollars are nearly equivalent to January-2010 dollars.

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[7] For this current-dollar analysis, the LCOE is uniform in current dollars over the analysis period. In contrast, a constant-dollar analysis would yield an LCOE that is uniform in constant dollars over the analysis period.

Exhibit 2-20 Illustration of COE Solutions using DCF Analysis
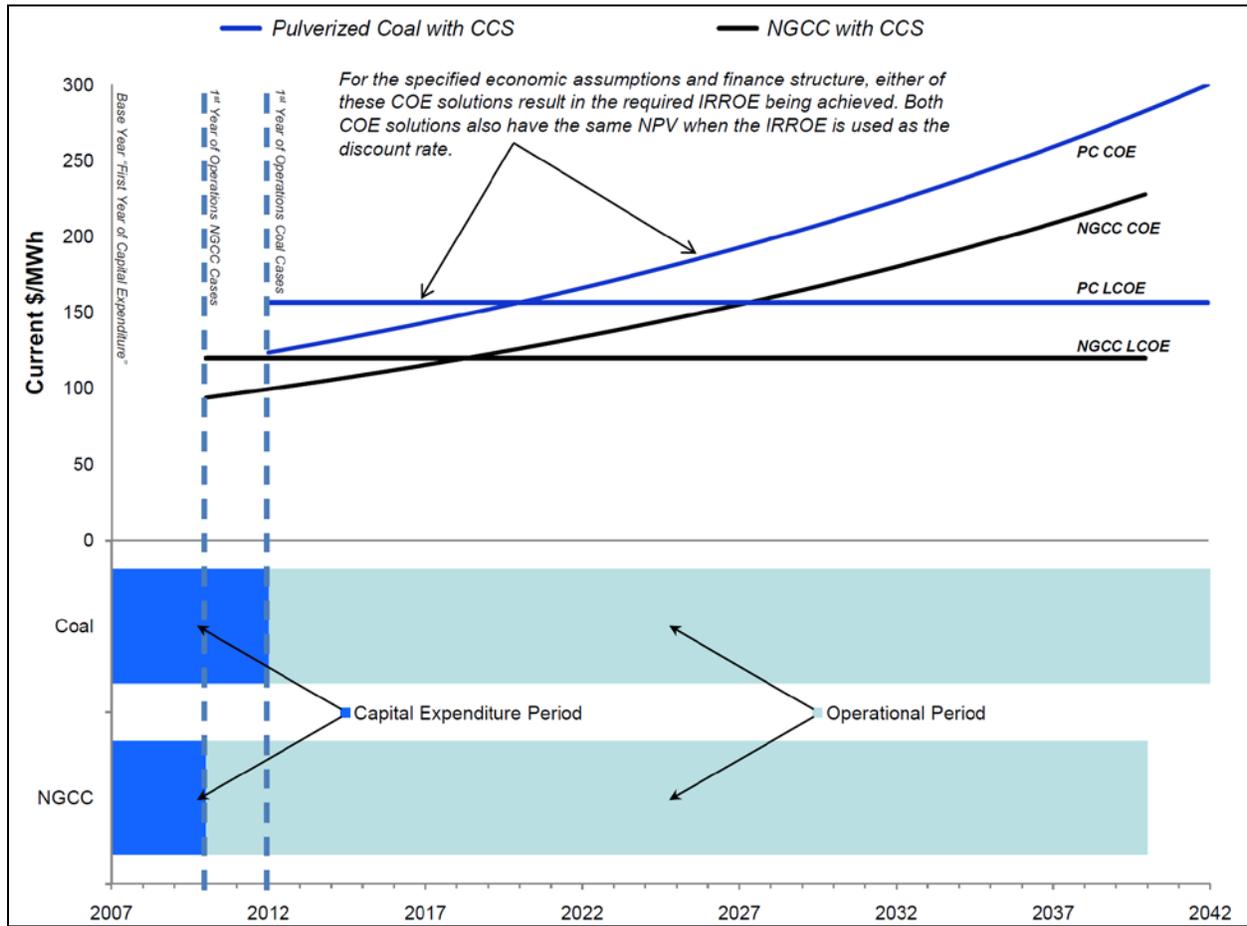
In addition to the capital expenditure period, the economic analysis considers thirty years of operation for both coal and natural gas plants.

Since 2007 is the first year of the capital expenditure period, it is also the base year for the economic analysis. Accordingly, it is convenient to report the results of the economic analysis in base-year (June 2007) dollars, except for TASC, which is expressed in mixed-year, current dollars over the capital expenditure period.

Consistent with our nominal-dollar discounted cash flow methodology, the COEs shown on Exhibit 2-20 are expressed in current dollars. However, they can also be expressed in constant, base year dollars (June 2007) as shown in Exhibit 2-21 by adjusting them with the assumed nominal annual general inflation rate (3 percent).

Exhibit 2-21 illustrates the same information as in Exhibit 2-20 for a PC plant with CCS only on a constant 2007 dollar basis. With an assumed nominal COE escalation rate equal to the rate of inflation, the COE line now becomes horizontal and the LCOE decreases at a rate of 3 percent per year.

Exhibit 2-21 PC with CCS in Current 2007 Dollars
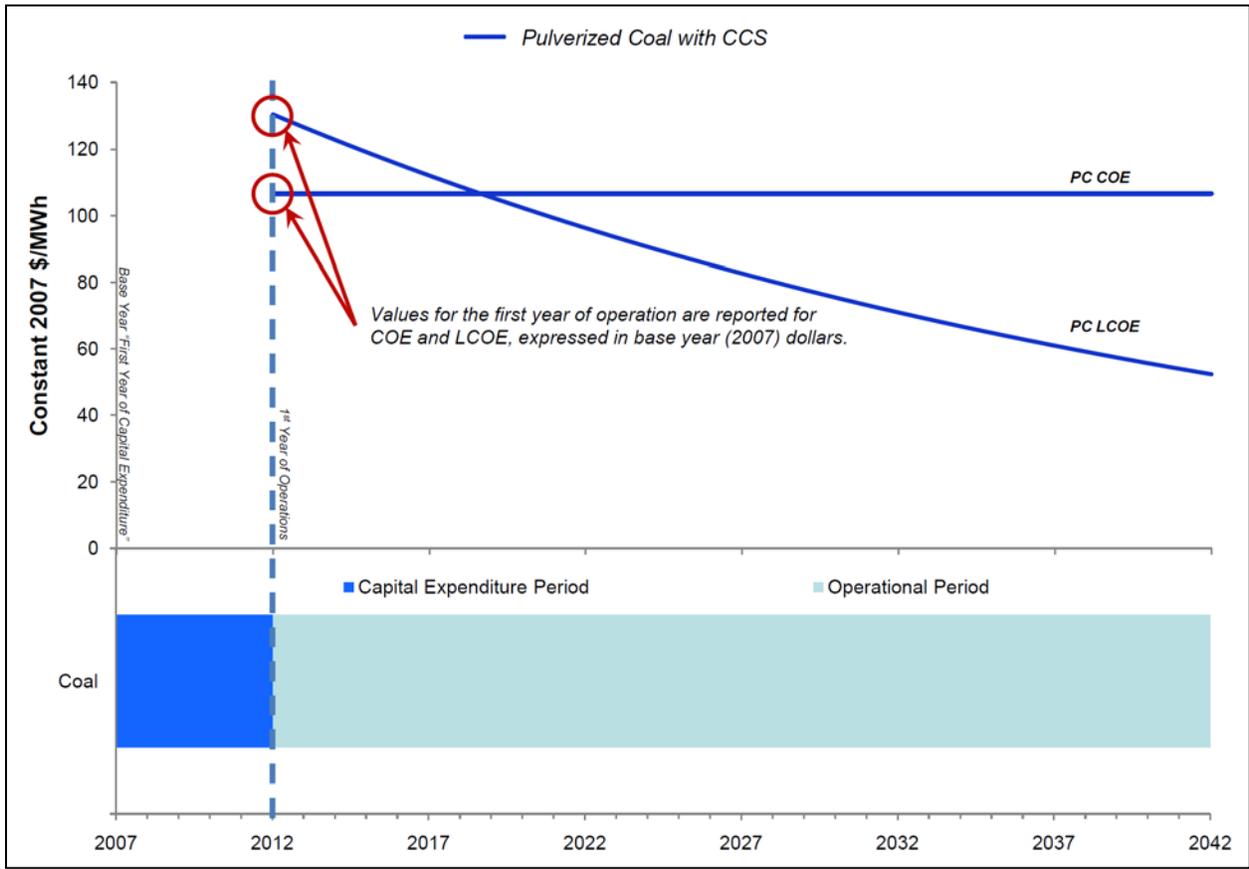
Estimating COE with Capital Charge Factors

For scenarios that adhere to the global economic assumptions listed in Exhibit 2-18 and utilize one of the finance structures listed in Exhibit 2-19, the following simplified equation can be used to estimate COE as a function of TOC[8], fixed O&M, variable O&M (including fuel), capacity factor and net output. The equation requires the application of one of the capital charge factors (CCF) listed in Exhibit 2-22. These CCFs are valid only for the global economic assumptions listed in Exhibit 2-18, the stated finance structure, and the stated capital expenditure period.

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[8] Although TOC is used in the simplified COE equation, the CCF that multiplies it accounts for escalation during construction and interest during construction (along with other factors related to the recovery of capital costs).

Exhibit 2-22 Capital Charge Factors for COE Equation

Finance Structure	High Risk IOU		Low Risk IOU	
Capital Expenditure Period	Three Years	Five Years	Three Years	Five Years
Capital Charge Factor (CCF)	0.111	0.124	0.105	0.116

All factors in the COE equation are expressed in base-year dollars. The base year is the first year of capital expenditure, which for this study is assumed to be 2007. As shown in Exhibit 2-18, all factors (COE, O&M and fuel) are assumed to escalate at a nominal annual general inflation rate of 3.0 percent. Accordingly, all first-year costs (COE and O&M) are equivalent to base-year costs when expressed in base-year (2007) dollars.

$$COE = \frac{\begin{array}{c}first\ year\\capital\ charge\end{array} + \begin{array}{c}first\ year\\fixed\ operating\\costs\end{array} + \begin{array}{c}first\ year\\variable\ operating\\costs\end{array}}{\begin{array}{c}annual\ net\ megawatt\ hours\\of\ power\ generated\end{array}}$$

$$COE = \frac{(CCF)(TOC) + OC_{FIX} + (CF)(OC_{VAR})}{(CF)(MWH)}$$

where:

COE =   revenue received by the generator ($/MWh, equivalent to mills/kWh) during the power plant's first year of operation (*but expressed in base-year dollars*), assuming that the COE escalates thereafter at a nominal annual rate equal to the general inflation rate, i.e., that it remains constant in real terms over the operational period of the power plant.

CCF =   capital charge factor taken from Exhibit 2-22 that matches the applicable finance structure and capital expenditure period

TOC =   total overnight capital, expressed in *base-year dollars*

OC_{FIX} =   the sum of all fixed annual operating costs, *expressed in base-year dollars*

OC_{VAR} =   the sum of all variable annual operating costs, including fuel at 100 percent capacity factor, *expressed in base-year dollars*

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

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

The primary cost metric in this study is the COE, which is the base-year cost presented in base-year dollars. Exhibit 2-23 presents this cost metric along with the COE escalated to the first year of operation (2010 for NGCC cases and 2012 for coal cases) using the average annual inflation rate of 3 percent. Similarly, the LCOE is presented in both base-year dollars and first year of operation dollars. Using a similar methodology, the reader may generate either metric in the desired cost year basis.

Exhibit 2-23 COE and LCOE Summary

Case	COE			LCOE		
	Base-Year	**First Operational Year**		**Base-Year**	**First Operational Year**	
	2007$ (all cases)	**2010$ (NGCC cases)**	**2012$ (coal cases)**	**2007$ (all cases)**	**2010$ (NGCC cases)**	**2012$ (coal cases)**
1	76.28	N/A	88.43	96.70	N/A	112.10
2	105.66	N/A	122.49	133.94	N/A	155.27
3	74.02	N/A	85.81	93.83	N/A	108.77
4	110.39	N/A	127.97	139.93	N/A	162.22
5	81.31	N/A	94.26	103.07	N/A	119.48
6	119.46	N/A	138.49	151.43	N/A	175.55
9	59.40	N/A	68.86	75.29	N/A	87.29
10	109.69	N/A	127.16	139.05	N/A	161.20
11	58.91	N/A	68.29	74.67	N/A	86.56
12	106.63	N/A	123.61	135.16	N/A	156.69
13	58.90	64.36	N/A	74.65	81.58	N/A
14	85.93	93.89	N/A	108.93	119.03	N/A

2.8   IGCC STUDY COST ESTIMATES COMPARED TO INDUSTRY ESTIMATES

The estimated TOC for IGCC cases in this study ranges from $2,351 to $2,716/kW for non- CO_2 capture cases and $3,334/kW to $3,904/kW for capture cases. Plant size ranges from 622 - 629 MW (net) for non-capture cases and 497 - 543 MW (net) for capture cases.

Within the power industry there are several power producers interested in pursuing construction of an IGCC plant. While these projects are still in the relatively early stages of development, some cost estimates have been published. Published estimates tend to be limited in detail, leaving it to the reader to speculate as to what is contained within the estimate. In November 2007, the Indiana Utility Regulatory Commission approved Duke Energy's proposal to build an IGCC plant in Edwardsport, Indiana. The estimated cost to build the 630 MW plant is $4,472/kW in June 2007 dollars. Duke expects the plant to begin operation in 2012. Other published estimates for similar proposed non-CO_2 capture gasification plants range from $2,483/kW to $3,122/kW in June 2007 dollars. Corresponding plant sizes range form 770 - 600

MW, respectively. Published estimates from similar CO_2 capture facilities range from $4,581/kW to $5,408/kW, in June 2007 dollars, with sizes ranging from 400 to 580 MW [38,39,40,41].[9]

Differences in Cost Estimates

Project Scope

For this report, the scope of work is generally limited to work inside the project "fence line". For outgoing power, the scope stops at the high side terminals of the Generator Step-up Transformers (GSUs).

Some typical examples of items outside the fenceline include:

- New access roads and railroad tracks
- Upgrades to existing roads to accommodate increased traffic
- Makeup water pipe outside the fenceline
- Landfill for on-site waste (slag) disposal
- Natural gas line for backup fuel provisions
- Plant switchyard
- Electrical transmission lines & substation

Estimates in this report are based on a generic mid-western greenfield site having "normal" characteristics. Accordingly, the estimates do not address items such as:

- Piles or caissons
- Rock removal
- Excessive dewatering
- Expansive soil considerations
- Excessive seismic considerations
- Extreme temperature considerations
- Hazardous or contaminated soils
- Demolition or relocation of existing structures
- Leasing of offsite land for parking or laydown
- Busing of craft to site
- Costs of offsite storage

This report is based on a reasonably "standard" plant. No unusual or extraordinary process equipment is included such as:

- Excessive water treatment equipment
- Air-cooled condenser
- Automated coal reclaim
- Zero Liquid Discharge equipment
- SCR catalyst (IGCC cases only)

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[9] Costs were adjusted to June 2007 using the Chemical Engineering Plant Cost Index

For non-capture cases, which are likely the most appropriate comparison against industry published estimates, this report is based on plant equipment sized for non-capture only. None of the equipment is sized to accommodate a future conversion to CO_2 capture.

Labor

This report is based on Merit Shop (non-union) labor. If a project is to use Union labor, there is a strong likelihood that overall labor costs will be greater than those estimated in this report.

This report is based on a 50 hour work week, with an adequate local supply of skilled craft labor. No additional incentives such as per-diems or bonuses have been included to attract and retain skilled craft labor.

Contracting Methodology

The estimates in this report are based on a competitively bid, multiple subcontract approach, often referred to as EPCM. Accordingly, the estimates do not include premiums associated with an EPC approach. It is believed that, given current market conditions, the premium charged by an EPC contractor could be as much as 30 percent or more over an EPCM approach.

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3. IGCC POWER PLANTS

Six 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.

The six cases are based on the GEE gasifier, the CoP E-Gas™ gasifier and the Shell gasifier, each with and without CO_2 capture. As discussed in Section 1, the net output for the six cases varies because of the constraint imposed by the fixed GT output and the high auxiliary loads imparted by the CO_2 capture process.

The CT is based on an advanced F-class design. The HRSG/steam turbine cycle varies based on the CT exhaust conditions. Steam conditions range from 12.4 MPa/559°C/559°C (1800 psig/1038°F/1038°F) to 12.4 MPa/562°C/562°C (1800 psig/1043°F/1043°F) for all of the non-CO_2 capture cases and 12.4 MPa/534°C/534°C (1800 psig/993°F/993°F) to 12.4 MPa/534°C/534°C (1800 psig/994°F/994°F) for all of the CO_2 capture cases. The capture cases have a lower main and reheat steam temperature primarily because the turbine firing 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 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 Sections 3.2, 3.3 and 3.4.

3.1 IGCC COMMON PROCESS AREAS

The IGCC cases have process areas, which are common to each plant configuration such as coal receiving and storage, oxygen supply, gas cleanup, power generation, etc. 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 unload, convey, prepare, and store the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to and including the slide gate valves at the outlet of the coal storage silos. Coal receiving and storage is identical for all six IGCC cases; however, coal preparation and feed are gasifier-specific.

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

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   Air Separation Unit (ASU) 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) [42]. 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 GT, the ASU operates at or near the supply pressure from the GT'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 GT. 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 GT by injecting residual nitrogen from the ASU can have a number of benefits, depending on the design of the GT:

- Increased diluent increases mass flow through the turbine, thus increasing the power output of the GT 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 GT 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 thermal 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 4.4-4.7 MJ/Nm^3 (119-125 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.

Air Integration

Integration between the ASU and the CT can be practiced by extracting some, or all, of the ASU's air requirement from the GT. Medium British thermal unit (Btu) syngas streams result in a higher mass flow than natural gas to provide the same heat content to the GT. Some GT designs may need to extract air to maintain stable compressor or turbine operation in response to increased fuel flow rates. Other GTs 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 GT. 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 GT with a gas-to-gas heat exchanger.

<u>Elevated Pressure ASU Experience in Gasification</u>

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 tons per day [TPD]) of 95 percent purity oxygen for a Shell coal-based gasification unit that fuels a Siemens V94.2 GT. In normal operation at the Buggenum plant the ASU receives all of its air supply from and sends all residual nitrogen to the GT.

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 GT. All of the nitrogen produced in the ASU is used in the GT. The original design did not allow for air extraction from the CT. After a CT 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 [43].

<u>ASU Basis</u>

For this study, air integration is used for the non-carbon capture cases only. In the CO_2 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 GT in the non-capture cases is determined through a process that includes the following constraints:

- The CT output must be maintained at 232 MW.

- The diluted syngas must meet heating value requirements specified by a CT vendor, which ranged from 4.4-4.7 MJ/Nm^3 (119-125 Btu/scf).

Meeting the above constraints resulted in different levels of air extraction in the three non-carbon capture cases as shown in Exhibit 3-1. It was not a goal of this project to optimize the integration of the CT 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 [44,45].

Exhibit 3-1 Air Extracted from the Combustion Turbine and Supplied to the ASU in Non-Carbon Capture Cases

Case No.	1	3	5
Gasifier	GEE	CoP	Shell
Air Extracted from Gas Turbine, %	4.0	4.0	4.0
Air Provided to ASU, % of ASU Total	16.8	18.9	19.4

Air Separation Plant Process Description [46]

The air separation plant is designed to produce 95 mole percent (mol%) 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 GT combustor. A process schematic of a typical ASU is shown in Exhibit 3-2.

The air feed to the ASU is supplied from two sources. A portion of the air is extracted from the compressor of the GT (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, CO_2, 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.

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 (LP) process steam at 0.3 MPa (50 psia) to drive the absorption refrigeration cycle. The remaining five 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 (HP) 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. LP nitrogen is split into two streams. The majority of the LP nitrogen is compressed and fed to the GT as diluent nitrogen. A small portion of the nitrogen is used as the regeneration gas for the pre-purifiers and recombined with the diluent nitrogen. A HP nitrogen stream is also produced from the cold box and is further compressed before it is also supplied to the GT.

Exhibit 3-2 Typical ASU Process Schematic
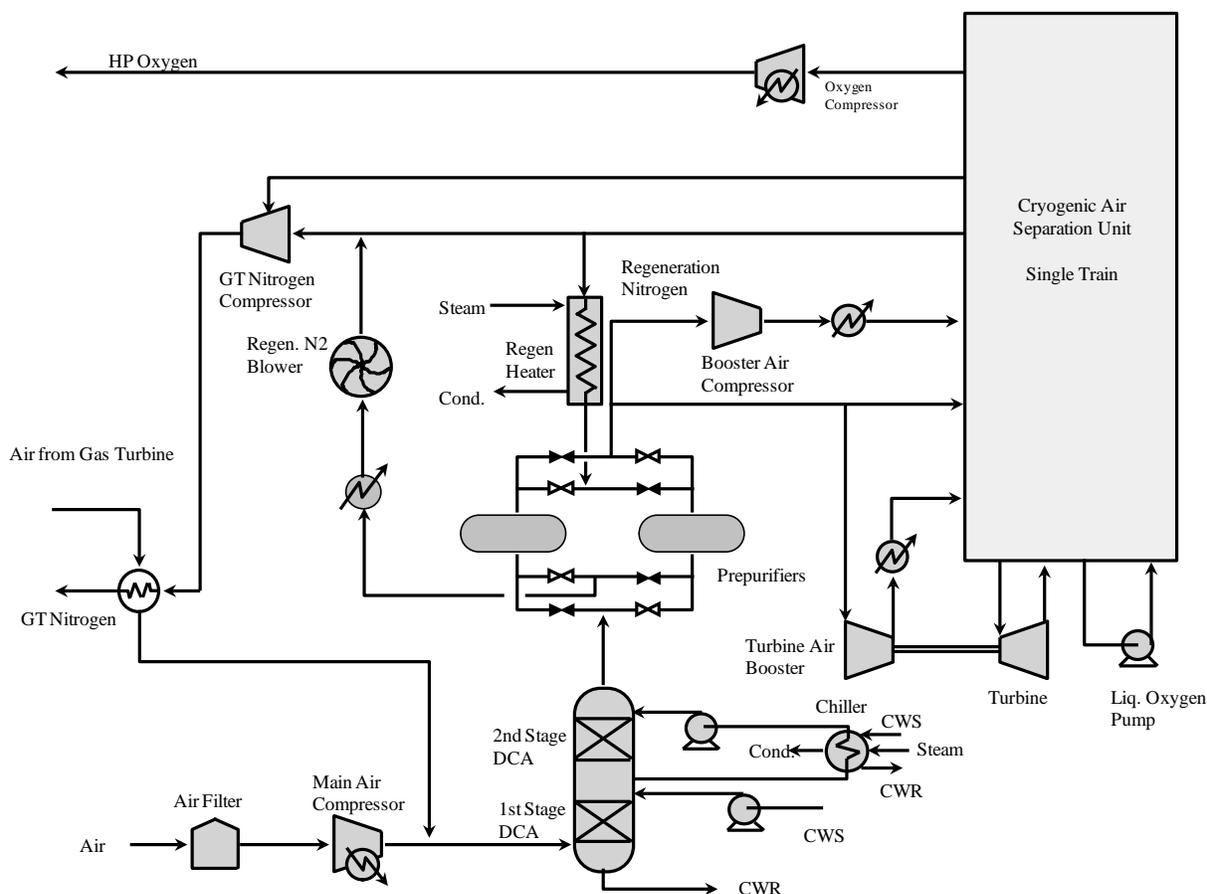
3.1.3   Water Gas Shift Reactors

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 CO to hydrogen (H_2) and CO_2 by reacting the CO with water over a bed of catalyst. The H_2O:CO molar ratio in the shift reaction, shown below, is adjusted to approximately 2: 1 by the addition of steam to the syngas stream thus promoting a high conversion of CO. 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 AGR step (SGS) or immediately downstream (sweet gas shift). If the CO converter is located downstream of the AGR, then the metallurgy of the unit is less stringent but additional equipment must be added to the process. Products from the gasifier are humidified with steam or water and contain a portion of the water vapor necessary to meet the water-to-gas criteria at the reactor inlet. If the CO converter is located downstream of the AGR, 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-gas ratio. If the CO converter is located upstream of the AGR 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 AGR unit and is referred to as SGS.

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. In the CoP case, a third shift reactor is added to each path to increase the CO conversion because of the relatively high amount of CH_4 present in the syngas. With the third reactor added, CO_2 capture is 90.4 percent in the CoP case.

Cooling is provided between the series of reactors to control the exothermic temperature rise. The parallel set of reactors is required due to the high gas mass flow rate. In all three CO_2 capture cases the heat exchanger after the first SGS reactor is used to vaporize water that is then used to adjust the syngas H_2O:CO ratio to 2:1 on a molar basis. The heat exchanger after the second SGS reactor is used to raise intermediate pressure (IP) steam, which then passes through the reheater (RH) section of the HRSG in the GEE and CoP cases, and is used to preheat the syngas prior to the first SGS reactor in the Shell case. Approximately 97 percent conversion of the CO is achieved in the GEE and Shell cases, and about 98 percent conversion is achieved in the CoP case.

3.1.4   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 FG volumes in comparable PC cases. A conceptual design for an activated, sulfur-impregnated, 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 [13].

The coal mercury content (0.15 ppm dry) and carbon bed removal efficiency (95 percent) were discussed previously in Section 2.4. IGCC-specific design considerations are discussed below.

Carbon Bed Location – The packed carbon bed vessels are located upstream of the sulfur recovery unit (SRU) 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 [47]. Eastman Chemical also operates their beds ahead of their SRU at a temperature of 30°C (86°F) [13].

Consideration was also given to locating the beds downstream of the SRU. However, it was felt that removing the mercury and other contaminants before the SRU would enhance the performance of the 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 [13]. 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 [47] 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 [48]. 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 [13]. 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 0.6 - 1.1 weight percent (wt%). Mercury capacity of sulfur-impregnated carbon can be as high as 20 wt% [49]. The mercury laden carbon is considered to be a hazardous waste, and the disposal cost estimate reflects this categorization.

3.1.5 <u>Acid Gas Removal (AGR) Process Selection</u>

Gasification of coal to generate power produces a syngas that must be treated prior to further utilization. A portion of the treatment consists of AGR and sulfur recovery. The environmental target for these IGCC cases is 0.0128 lb SO_2/MMBtu, which 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.

<u>COS Hydrolysis</u>

The use of COS hydrolysis pretreatment in the feed to the AGR 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 CO_2 capture, the SGS reactors reduce COS to H_2S as discussed in Section 3.1.3.

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

$$COS + H_2O \leftrightarrow CO_2 + H_2S$$
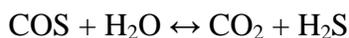
Since the reaction is exothermic, higher conversion is achieved at lower temperatures. However, at lower temperatures the reaction kinetics are slower. Based on the feed gas for this evaluation, Porocel recommended a temperature of 177 to 204°C (350 to 400°F). Since the exit gas COS concentration is 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

H_2S 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 3-3 is a simplified diagram of the AGR process [50].

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, MDEA, Selexol, aqueous di-isoproponal (ADIP) amine, and FLEXSORB [52]. These processes can be separated into three general types: chemical reagents, physical solvents, and hybrid solvents.

Exhibit 3-3 Flow Diagram for a Conventional AGR Unit
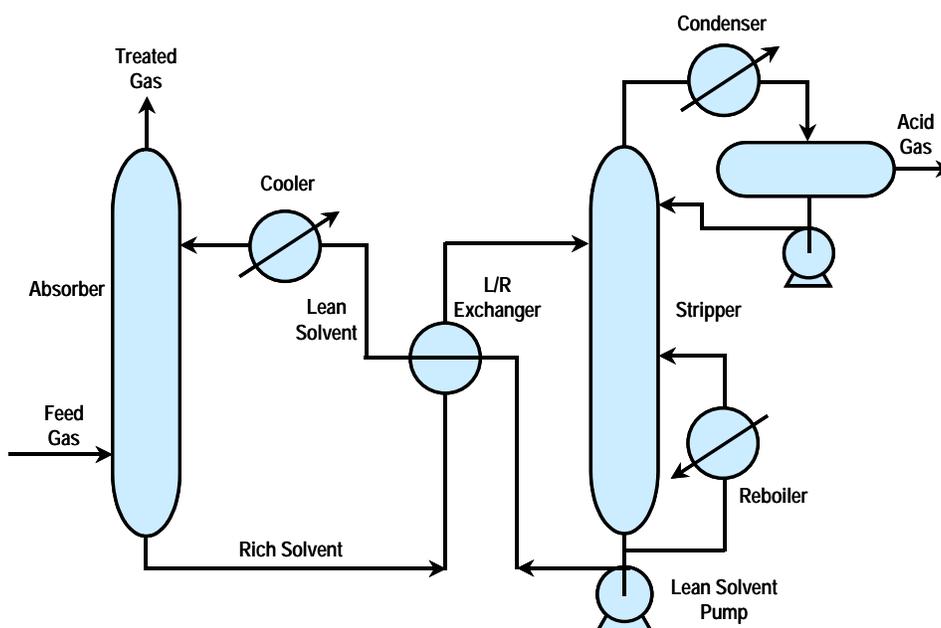
Chemical Solvents

Frequently used for AGR, 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.

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 3-4 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 LP 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 3-4 Common Chemical Reagents Used in AGR Processes

Chemical Reagent	Acronym	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 standard cubic feet (scf) acid gas per gallon of solution circulated. Steam consumption can vary widely also: 0.7 to 1.5 pounds per gallon (lb/gal) of liquid is typical, with 0.8 to 0.9 being a typical "good" value. CoP non-capture, which utilizes the chemical solvent MDEA, uses 0.88 pounds of steam per gallon of liquid. The steam conditions are 0.45 MPa (65 psia) and 151°C (304°F).

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

<u>Physical Solvents</u>

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 HP and at or below ambient temperature while the regeneration step (dissolution) occurs by pressure letdown and indirect stripping with LP 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 LPs. 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 AGR. 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 3-5 is a simplified flow diagram for a physical reagent type AGR process [50]. Common physical solvent processes, along with their licensors, are listed in Exhibit 3-6.

Exhibit 3-5 Physical Solvent AGR Process Simplified Flow Diagram
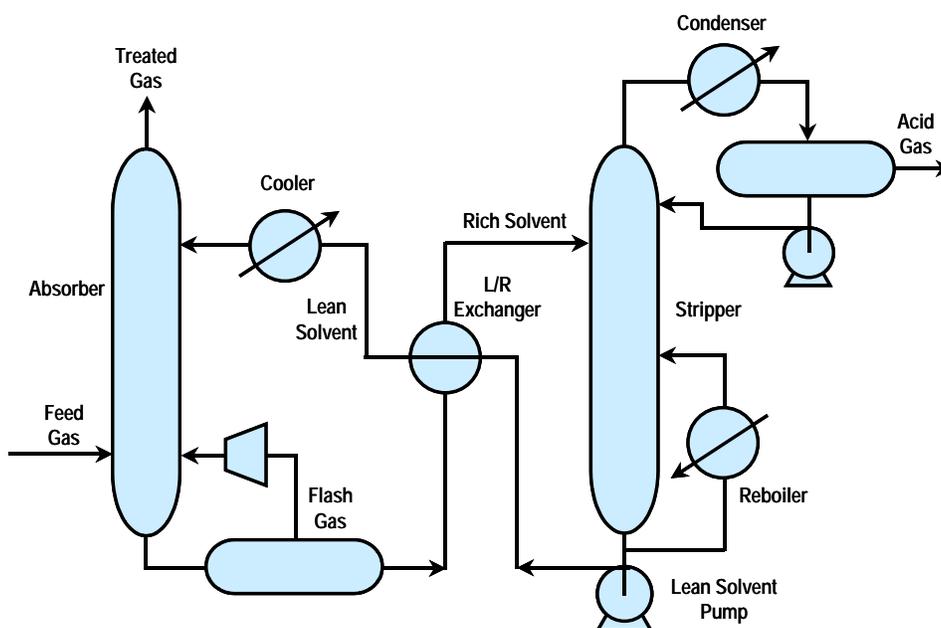
Hybrid Solvents

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 AGR is specified, while MDEA provides for selective removal of H_2S.

Exhibit 3-6 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

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 AGR, 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 HP. 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 3-7. 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 3-8 shows reported equilibrium solubility data for H_2S and CO_2 in various representative solvents [50]. The solubility is expressed as scf 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.

Exhibit 3-7 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 3-8 Equilibrium Solubility Data on H_2S and CO_2 in Various Solvents
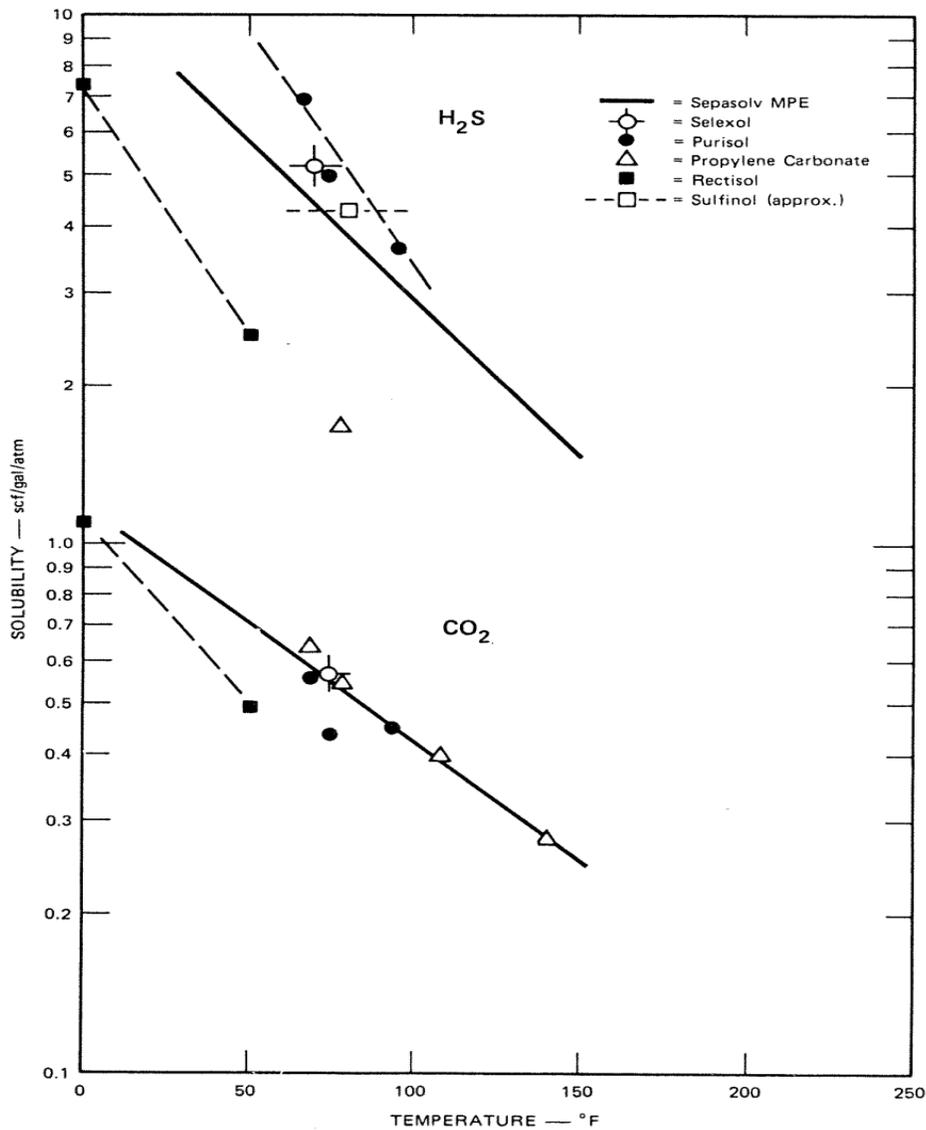
The ability of a process to selectively absorb H_2S may be further enhanced by the relative absorption rates of H_2S and CO_2. Thus, some processes, besides using equilibrium solubility differences, will use absorption rate differences between the two acid gases to achieve selectivity. This is particularly true of the amine processes where the CO_2 and H_2S absorption rates are very different.

AGR used in CO_2 Capture Cases

A two-stage Selexol process is used for all IGCC CO_2 capture cases in this study. 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 CT or is partially humidified prior to entering the CT. A portion of the gas can also be used for coal drying, when required.

The amount of hydrogen recovered from 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 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 CT.

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 and GEE gasifiers in various applications. Both existing E-Gas gasifiers use MDEA, but could in theory use any of the existing AGR technologies [50]. The following selections were made for the AGR process in non-CO_2 capture cases:

- GEE gasifier: Selexol was chosen based on the GE gasifier operating at the highest pressure (815 psia versus 615 psia for CoP and Shell), which favors the physical solvent used in the Selexol process.

- CoP gasifier: Refrigerated MDEA was chosen because the two operating E-Gas gasifiers use MDEA and because CoP lists MDEA as the selected AGR process on their website [51]. Refrigerated MDEA was chosen over conventional MDEA because the sulfur emissions environmental target chosen is just outside of the range of conventional (higher temperature) MDEA.

- Shell gasifier: The Sulfinol process was chosen for this case because it is a Shell owned technology. While the Shell gasifier can and has been used with other AGR processes, it was concluded the most likely pairing would be with the Sulfinol process.

The two-stage Selexol process is used in all three cases that require CO_2 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."[52]

3.1.6 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 add-on modification to the Claus plant selected for this study can be considered a separate option from the Claus process. In this context, it is often called a tail gas treating unit (TGTU) process.

The Claus Process

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

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

$$2H_2S + SO_2 \leftrightarrow 2H_2O + 3S$$
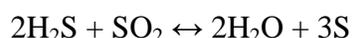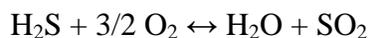
The second reaction, the Claus reaction, is equilibrium limited. The overall reaction is:

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

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 3-9 [52]. 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 HP steam usually follows the furnace. Sulfur is condensed in a condenser that follows the HP steam recovery section. LP 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.

Exhibit 3-9 Typical Three-Stage Claus Sulfur Plant
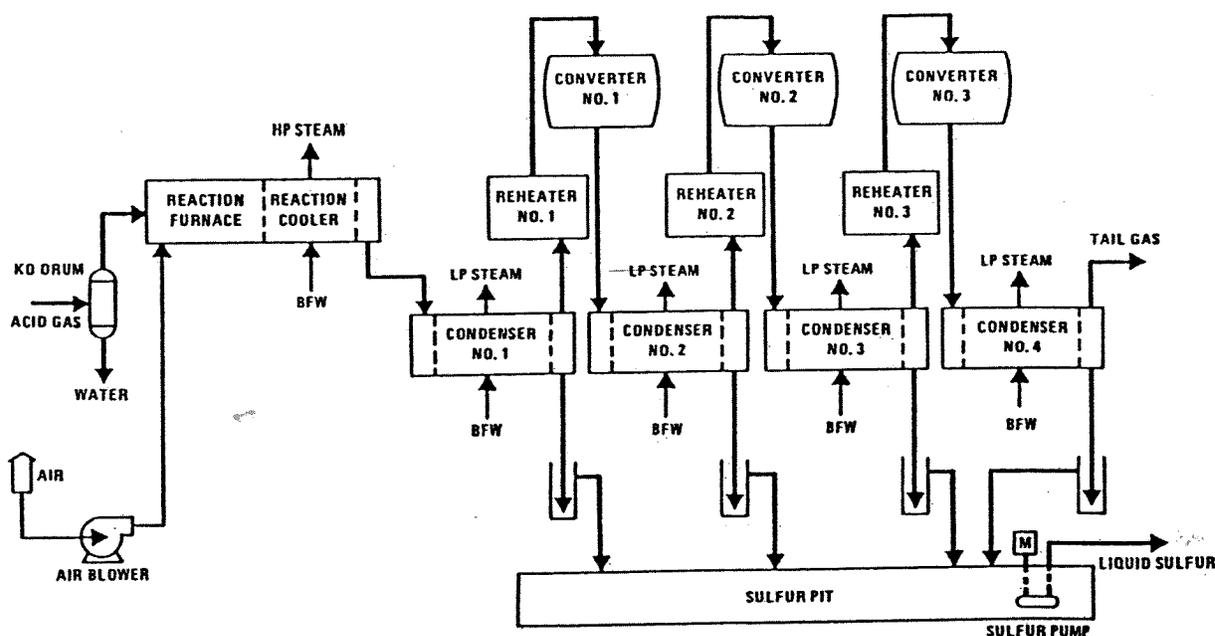
Claus plant sulfur recovery efficiency depends on many factors:

- 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.

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 vol% 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 SRU. 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. In the each of the six IGCC cases the Claus plant tail gas is hydrogenated, water is separated, the tail gas is compressed and then returned to the AGR process for further treatment.

Flare Stack

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

3.1.7   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 either a proprietary pressure letdown device (CoP) or through the use of lockhoppers (GEE and Shell) to a series of dewatering bins.

The general aspects of slag handling are the same for all three technologies. 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 the 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. Approximately ten truckloads per day are required to remove the total quantity of slag produced by the plant operating at nominal rated power. 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 just as the ash from the PC boiler cases is assumed to be landfilled at the same per ton cost.

3.1.8   Power Island

Combustion Turbine

The GT 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 vane (IGV). 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 for use 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 FOAK 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 3-10.

**Exhibit 3-10 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 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.

CT Firing Temperature Control Issue for Low Calorific Value Fuel

A GT when fired on LCV 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 [53]. 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. IGVs 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 this study the firing temperature (defined as inlet rotor temperature) using natural gas in NGCC applications is 1371°C (2500°F) while the firing temperature in the non-capture IGCC cases is 1333-1343°C (2432-2449°F) and in the CO_2 capture cases is 1317-1322°C (2402-2412°F). The further reduction in firing temperature in the CO_2 capture cases is done to maintain parts life as the H_2O content of the combustion products increases from 6-9 vol% in the non-capture cases to 12-14 vol% in the capture cases. The decrease in temperature also results in the lower temperature steam cycle in the CO_2 capture cases, ranging from 12.4 MPa/534°C/534°C (1800 psig/993°F/993°F) to 12.4 MPa/534°C/534°C (1800 psig/994°F/994°F) for all of the CO_2 capture cases versus 12.4 MPa/559°C/559°C (1800 psig/1038°F/1038°F) to 12.4 MPa/562°C/562°C (1800 psig/1043°F/1043°F) for all of the non-CO_2 capture cases.

Combustion Turbine Syngas Fuel Requirements

Typical fuel specifications and contaminant levels for successful CT operation are provided in reference [54] and presented for F Class machines in Exhibit 3-11 and Exhibit 3-12. 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 this study.

Exhibit 3-11 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 [55]
2. To ensure that the fuel gas supply to the GT 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 [54].
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 one percent by volume do not significantly affect oxidation/corrosion rates.

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 4-7 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 considered only for non-carbon capture cases.

Exhibit 3-12 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 GT gas fuel system

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 4.4-4.7 MJ/Nm^3 (119-125 Btu/scf). 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.

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 pressures of 0.4 and 1.3 MPa (56 and 182 psia) to the CT pressure of 3.2 MPa (465 psia).

- Low quality heat not otherwise useful for other applications can be used to preheat water for the syngas humidification process.

- 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 during peer review of the report.

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 is nominally 588°C (1090°F) for non-CO_2 capture cases and 562°C (1044°F) for capture cases.

Gross turbine power, as measured prior to the generator terminals, is 232 MW. The CT generator is a standard hydrogen-cooled machine with static exciter.

3.1.9   Steam Generation Island

Heat Recovery Steam Generator

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

The HP drum produces steam at main steam pressure, while the IP drum produces process steam and turbine dilution steam, if required. The HRSG drum pressures are nominally 12.4/3.1 MPa (1800/443 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 (FW) 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 FW/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 GT 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.

<u>Steam Turbine Generator and Auxiliaries</u>

The steam turbine consists of an HP section, an IP section, and one double-flow LP section, all connected to the generator by a common shaft. The HP and IP sections are contained in a single-span, opposed-flow casing, with the double-flow LP section in a separate casing. 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/559°C to 562°C (1800 psig/1038°F to 1043°F) for the non-carbon capture cases, or 12.4 MPa/534°C (1800 psig/993°F to 994°F) for the carbon capture cases. The steam initially enters the turbine near the middle of the HP 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 3.1 MPa/558°C to 561°C (443 psig/1036°F to 1041°F) for the non-carbon capture cases or 3.1 MPa/532°C to 533°C (443 psig/990°F to 992°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 (CL), 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 LP 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 CL oil seal system. The oil seal system consists of storage tank, pumps, filters, and pressure controls, all skid-mounted.

The STG is controlled by a triple-redundant, microprocessor-based electro-hydraulic control system. The system provides digital control of the unit in accordance with programmed control

algorithms, color cathode ray tube (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 FW system is to pump the various FW 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 FW pumps are supplied with instrumentation to monitor and alarm on low oil pressure, or high bearing temperature. FW 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 RH, and to the turbine reheat stop valves.

Main steam at approximately 12.4 MPa/559°C to 562°C (1800 psig/1038°F to 1043°F) (non-CO_2 capture cases) or 12.4 MPa/534°C (1800 psig/993°F to 994°F) (CO_2 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 3.5 MPa/349°C to 372°C (501 psia/661°F to 702°F) exits the HP turbine, flows through a motor-operated isolation gate valve, to the HRSG reheater. Hot reheat steam at approximately 3.1 MPa/558 to 561°C (443 psig/1036°F to 1041°F) for the non-carbon capture cases and 3.1 MPa/532°C to 533°C (443 psig/990°F to 992°F) for the CO_2 capture cases exits the HRSG RH 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

The circulating water system (CWS) is a closed-cycle cooling water system that supplies cooling water to the condenser to condense 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 CL process that utilizes a higher quality water to remove heat from compressor intercoolers, oil coolers and other ancillary equipment and transfers that heat to the main circulating cooling water system in plate and frame heat exchangers. The heat transferred to the circulating water in the condenser and other applications is removed by a mechanical draft cooling tower.

The system consists of two 50 percent capacity vertical CWPs, a mechanical draft evaporative cooling tower, and CS cement-lined interconnecting piping. The pumps are single-stage vertical pumps. The piping system is equipped with butterfly isolation valves and all required expansion joints. The cooling tower is a multi-cell wood frame counterflow mechanical draft cooling tower.

The condenser is a single-pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One-half of the condenser can be removed from service for cleaning or for plugging tubes. This can be done during normal operation at reduced load.

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

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 a POTW 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 WGS 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.

3.1.10 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, all required foundations, and standby equipment.

3.1.11 Instrumentation and Control

An integrated plant-wide distributed control system (DCS) is provided. The DCS is a redundant microprocessor-based, functionally DCS. 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.

3.2   GENERAL ELECTRIC ENERGY IGCC CASES

This section contains an evaluation of plant designs for Cases 1 and 2, which are based on the GEE gasifier in the "radiant only" configuration. GEE offers three design configurations:[56]

- Quench: In this configuration, the hot syngas exiting the gasifier passes through a pool of water to quench the temperature to 289°C (550°F) before entering the syngas scrubber. It is the simplest and lowest capital cost design, but also the least efficient. This configuration is examined in Section 8.

- Radiant Only: In this configuration, the hot syngas exiting the gasifier passes through a radiant syngas cooler where it is cooled from about 1316°C (2400°F) to 677°C (1250°F), then through a water quench where the syngas is further cooled to about 232°C (450°F) prior to entering the syngas scrubber. Relative to the quench configuration, the radiant only design offers increased output, higher efficiency, improved reliability/availability, and results in the lowest COE. This configuration was chosen by GEE and Bechtel for the design of their reference plant.

- Radiant-Convective: In this configuration, the hot syngas exiting the gasifier passes through a radiant syngas cooler where it is cooled from about 1316°C (2400°F) to 760°C (1400°F), then passes over a pool of water where particulate is removed but the syngas is not quenched, then through a convective syngas cooler where the syngas is further cooled to about 371°C (700°F) prior to entering additional heat exchangers or the scrubber. This configuration has the highest overall efficiency, but at the expense of highest capital cost and the lowest availability. This is the configuration used at Tampa Electric's Polk Power Station.

Note that the radiant only configuration includes a water quench and, based on functionality, would be more appropriately named radiant-quench. The term radiant only is used to distinguish it from the radiant-convective configuration. Since radiant only is the terminology used by GEE, it will be used throughout this report.

The balance of Section 3.2 is organized as follows:

- Gasifier Background provides information on the development and status of the GEE gasification technology.

- Process and System Description provides an overview of the technology operation as applied to Case 1. The systems that are common to all gasifiers were covered in Section 3.1 and only features that are unique to Case 1 are discussed further in this section.

- Key Assumptions is a summary of study and modeling assumptions relevant to Cases 1 and 2.

- Sparing Philosophy is provided for both Cases 1 and 2.

- Performance Results provides the main modeling results from Case 1, 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 Case 1 with account codes that correspond to the cost accounts in the Cost Estimates section.

- Cost Estimates provides a summary of capital and operating costs for Case 1.

- Process and System Description, Performance Results, Equipment List and Cost Estimates are repeated for Case 2.

3.2.1   Gasifier Background

Development and Current Status [57] – Initial development of the GEE gasification technology (formerly licensed by Texaco and then ChevronTexaco) was conducted in the 1940s at Texaco's Montebello, California laboratories. From 1946 to 1954 the Montebello pilot plant produced syngas (hydrogen and carbon monoxide) by partial oxidation of a variety of feedstocks, including natural gas, oil, asphalt, coal tar, and coal. From 1956 to 1958, coal was gasified in a 91 tonne/day (100 TPD) Texaco coal gasifier at the Olin Mathieson Chemical Plant in Morgantown, West Virginia, for the production of ammonia.

The oil price increases and supply disruptions of the 1970s renewed interest in the Texaco partial-oxidation process for gasification of coal or other solid opportunity fuels. Three 14 tonne/day (15 TPD) pilot plants at the Montebello laboratories have been used to test numerous coals. Two larger pilot plants were also built. The first gasified 150 tonne/day (165 TPD) of coal and was built to test syngas generation by Rührchemie and Rührkohle at Oberhausen, Germany, and included a SGC. The second gasified 172 tonne/day (190 TPD) of coal using a quench-only gasifier cooler and was built to make hydrogen at an existing TVA ammonia plant at Muscle Shoals, Alabama. These two large-scale pilot plants successfully operated for several years during the 1980s and tested a number of process variables and numerous coals.

The first commercial Texaco coal gasification plant was built for Tennessee Eastman at Kingsport, Tennessee, and started up in 1983. To date, 24 gasifiers have been built in 12 plants for coal and petroleum coke. Several of the plants require a hydrogen-rich gas and therefore directly water quench the raw gas to add the water for shifting the CO to H_2, and have no SGCs.

The Cool Water plant was the first commercial-scale Texaco coal gasification project for the electric utility industry. This facility gasified 907 tonne/day (1,000 TPD) (dry basis) of bituminous coal and generated 120 MW of electricity by IGCC operation. In addition, the plant was the first commercial-sized Texaco gasifier used with a SGC. The Cool Water plant operated from 1984 to 1989 and was a success in terms of operability, availability, and environmental performance.

The Tampa Electric IGCC Clean Coal Technology Demonstration Project built on the Cool Water experience to demonstrate the use of the Texaco coal gasification process in an IGCC plant. The plant utilizes approximately 2,268 tonne/day (2,500 TPD) of coal in a single Texaco gasifier to generate a net of approximately 250 megawatts electric (MW_e). The syngas is cooled in a high-temperature radiant heat exchanger, generating HP steam, and further cooled in convective heat exchangers (the radiant-convective configuration). The particles in the cooled gas are removed in a water-based scrubber. The cleaned gas then enters a hydrolysis reactor where COS is converted to H_2S. After additional cooling, the syngas is sent to a conventional AGR unit, where H_2S is absorbed by reaction with an amine solvent. H_2S is removed from the amine by steam stripping and sent to a sulfuric acid (H_2SO_4) plant. The cleaned gas is sent to a General Electric MS 7001FA CT.

The Delaware Clean Energy Project is a coke gasification and CT repowering of an existing 130 MW coke-fired boiler cogeneration power plant at the Motiva oil refinery in Delaware City, Delaware. The Texaco coal gasification process was modified to gasify 1,814 tonne/day (2,000 TPD) of this low-quality petroleum coke. The plant is designed to use all the fluid petroleum coke generated at Motiva's Delaware City Plant and produce a nominal 238,136 kg/hr (525,000 lb/hr) of 8.6 MPa (1250 psig) steam, and 120,656 kg/hr (266,000 lb/hr) of 1.2 MPa (175 psig) steam for export to the refinery and the use/sale of 120 MW of electrical power. Environmentally, these new facilities help satisfy tighter NOx and SO_2 emission limitations at the Delaware City Plant.

Gasifier Capacity – The largest GEE gasifier is the unit at Tampa Electric, which consists of the radiant-convective configuration. The daily coal-handling capacity of this unit is 2,268 tonnes (2,500 tons) of bituminous coal. The dry gas production rate is 0.19 million Nm^3/hr (6.7 million scfh) with an energy content of about 1,897 million kJ/hr (HHV) (1,800 million Btu/hr). This size matches the F Class CTs that are used at Tampa.

Distinguishing Characteristics – A key advantage of the GEE coal gasification technology is the extensive operating experience at full commercial scale. Furthermore, Tampa Electric is an IGCC power generation facility, operated by conventional electric utility staff, and is environmentally one of the cleanest coal-fired power plants in the world. The GEE gasifier also operates at the highest pressure of the three gasifiers in this study, 5.6 MPa (815 psia) compared to 4.2 MPa (615 psia) for CoP and Shell.

Entrained-flow gasifiers have fundamental environmental advantages over fluidized-bed and moving-bed gasifiers. They produce no hydrocarbon liquids, and the only solid waste is an inert slag. The relatively high H_2/CO ratio and CO_2 content of GEE gasification fuel gas helps achieve low NOx and CO emissions in even the higher-temperature advanced CTs.

The key disadvantages of the GEE coal gasification technology are the limited refractory life, the relatively high oxygen requirements and high waste heat recovery duty (SGC design). As with the other entrained-flow slagging gasifiers, the GEE process has this disadvantage due to its high operating temperature. The disadvantage is magnified in the single-stage, slurry feed design. The quench design significantly reduces the capital cost of syngas cooling, while innovative heat integration maintains good overall thermal efficiency although lower than the SGC design. Another disadvantage of the GEE process is the limited ability to economically handle low-rank coals relative to moving-bed and fluidized-bed gasifiers or to entrained-flow gasifiers with dry feed. For slurry fed entrained gasifiers using low-rank coals, developers of two-stage slurry fed gasifiers claim advantages over single-stage slurry fed.

Important Coal Characteristics – The slurry feeding system and the recycle of process condensate water as the principal slurrying liquid make low levels of ash and soluble salts desirable coal characteristics for use in the GEE coal gasification process. High ash levels increase the ratio of water-to-carbon in the feed slurry, thereby increasing the oxygen requirements. The slurry feeding also favors the use of high-rank coals, such as bituminous coal, since their low inherent moisture content increases the moisture-free solids content of the slurry and thereby reduces oxygen requirements.

3.2.2 Process Description

In this section the overall GEE gasification process is described. The system description follows the block flow diagram (BFD) in Exhibit 3-13 and stream numbers reference the same exhibit. The tables in Exhibit 3-14 provide stream compositions, temperature, pressure, enthalpy, and flow rates for the numbered streams in the BFD.

Coal Grinding and Slurry Preparation

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. Coal is then fed onto a conveyor by vibratory feeders located below each silo. The conveyor feeds the coal to an inclined conveyor that delivers the coal to the rod mill feed hopper. The feed hopper provides a surge capacity of about two hours and contains two hopper outlets. Each hopper outlet discharges onto a weigh feeder, which in turn feeds a rod mill. Each rod mill is sized to process 55 percent of the coal feed requirements of the gasifier. The rod mill grinds the coal and wets it with treated slurry water transferred from the slurry water tank by the slurry water pumps. The coal slurry is discharged through a trommel screen into the rod mill discharge tank, and then the slurry is pumped to the slurry storage tanks. The dry solids concentration of the final slurry is 63 percent. The Polk Power Station operates at a slurry concentration of 62-68 percent using bituminous coal and CoP presented a paper showing the slurry concentration of Illinois No. 6 coal as 63 percent [58].

The coal grinding system is equipped with a dust suppression system consisting of water sprays aided by a wetting agent. The degree of dust suppression required depends on local environmental regulations. All of the tanks are equipped with vertical agitators to keep the coal slurry solids suspended.

The equipment in the coal grinding and slurry preparation system is fabricated of materials appropriate for the abrasive environment present in the system. The tanks and agitators are rubber lined. The pumps are either rubber-lined or hardened metal to minimize erosion. Piping is fabricated of high-density polyethylene (HDPE).

Gasification

This plant utilizes two gasification trains to process a total of 5,083 tonnes/day (5,603 TPD) of Illinois No. 6 coal. Each of the 2 x 50 percent gasifiers operates at maximum capacity. The largest operating GEE gasifier is the 2,268 tonne/day (2,500 TPD) unit at Polk Power Station. However, that unit operates at about 2.8 MPa (400 psia). The gasifier in this study, which operates at 5.6 MPa (815 psia), will be able to process more coal and maintain the same gas residence time.

The slurry feed pump takes suction from the slurry run tank, and the discharge is sent to the feed injector of the GEE gasifier (stream 6). Oxygen from the ASU is vented during preparation for startup and is sent to the feed injector during normal operation. The air separation plant supplies 4,171 tonnes/day (4,597 TPD) of 95 mol% oxygen to the gasifiers (stream 5) and the Claus plant (stream 3). Carbon conversion in the gasifier is assumed to be 98 percent including a fines recycle stream.

The gasifier vessel is a refractory-lined, HP combustion chamber. The coal slurry feedstock and oxygen are fed through a fuel injector at the top of the gasifier vessel. The coal slurry and the oxygen react in the gasifier at 5.6 MPa (815 psia) and 1,316°C (2,400°F) to produce syngas.

The syngas consists primarily of hydrogen and carbon monoxide, with lesser amounts of water vapor and carbon dioxide, and small amounts of hydrogen sulfide, COS, methane, argon, and nitrogen. The heat in the gasifier liquefies coal ash. Hot syngas and molten solids from the reactor flow downward into a radiant heat exchanger where the syngas is cooled.

Raw Gas Cooling/Particulate Removal

Syngas is cooled from 1,316°C (2,400°F) to 677°C (1,250°F) in the radiant SGC (stream 9) and the molten slag solidifies in the process. The solids collect in the water sump at the bottom of the gasifier and are removed periodically using a lock hopper system (stream 8). The waste heat from this cooling is used to generate HP steam. BFW in the tubes is saturated, and then steam and water are separated in a steam drum. Approximately 412,096 kg/hr (908,500 lb/hr) of saturated steam at 13.8 MPa (2,000 psia) is produced. This steam then forms part of the general heat recovery system that provides steam to the steam turbine.

The syngas exiting the radiant cooler is directed downwards by a dip tube into a water sump. Most of the entrained solids are separated from the syngas at the bottom of the dip tube as the syngas goes upwards through the water. The syngas exits the quench chamber saturated at a temperature of 232°C (450°F).

The slag handling system removes solids from the gasification process equipment. These solids consist of a small amount of unconverted carbon and essentially all of the ash contained in the feed coal. These solids are in the form of glass, which fully encapsulates any metals. Solids collected in the water sump below the radiant SGC are removed by gravity and forced circulation of water from the lock hopper circulating pump. The fine solids not removed from the bottom of the quench water sump remain entrained in the water circulating through the quench chamber. In order to limit the amount of solids recycled to the quench chamber, a continuous blowdown stream is removed from the bottom of the syngas quench. The blowdown is sent to the vacuum flash drum in the black water flash section. The circulating quench water is pumped by circulating pumps to the quench gasifier.

Syngas Scrubber/Sour Water Stripper

Syngas exiting the water quench passes to a syngas scrubber where a water wash is used to remove remaining chlorides, NH_3, SO_2, and PM. The syngas exits the scrubber still saturated at 206°C (403°F) before it is preheated to 223°C (433°F) (stream 10) prior to entering the COS hydrolysis reactor.

The sour water stripper removes NH_3, SO_2, and other impurities from the scrubber and other waste streams. The stripper consists of a sour drum that accumulates sour water from the gas scrubber and condensate from SGCs. 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 SRU. Remaining water is sent to wastewater treatment.

Exhibit 3-13 Case 1 Block Flow Diagram, GEE IGCC without CO₂ Capture

Exhibit 3-14 Case 1 Stream Table, GEE IGCC without CO₂ Capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0233	0.0318	0.0023	0.0318	0.0000	0.0000	0.0000	0.0086	0.0068	0.0068	0.0099
CH₄	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0012	0.0009	0.0009	0.0013
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3579	0.2825	0.2825	0.4151
CO₂	0.0003	0.0081	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1366	0.1078	0.1079	0.1586
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	0.0001	0.0000	0.0000
H₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3416	0.2696	0.2696	0.3961
H₂O	0.0099	0.2081	0.0000	0.0003	0.0000	0.0000	0.9994	0.0000	0.1358	0.3181	0.3180	0.0012
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0008	0.0002	0.0002	0.0000
H₂S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0073	0.0057	0.0059	0.0085
N₂	0.7732	0.5621	0.0178	0.9919	0.0178	0.0000	0.0000	0.0000	0.0080	0.0063	0.0063	0.0092
NH₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0006	0.0000	0.0021	0.0020	0.0020	0.0000
O₂	0.2074	0.1985	0.9504	0.0054	0.9504	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO₂	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	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg$_{mol}$/hr)	21,872	1,067	102	19,380	5,298	0	4,829	0	22,212	28,142	28,142	19,153
V-L Flowrate (kg/hr)	631,164	28,941	3,290	543,810	170,485	0	87,000	0	446,032	552,597	552,597	390,595
Solids Flowrate (kg/hr)	0	0	0	0	0	211,783	0	23,236	0	0	0	0
Temperature (°C)	15	20	32	93	32	15	146	1,316	677	223	223	35
Pressure (MPa, abs)	0.10	0.11	0.86	2.65	0.86	0.10	5.79	5.62	5.55	5.48	5.41	5.24
Enthalpy (kJ/kg)^A	30.23	36.80	26.67	92.52	26.67	---	558.58	---	1,424.13	1,066.74	1,066.63	40.35
Density (kg/m³)	1.2	1.6	11.0	24.4	11.0	---	866.9	---	13.9	26.7	26.3	41.9
V-L Molecular Weight	28.857	27.132	32.181	28.060	32.181	---	18.015	---	20.081	19.636	19.636	20.393
V-L Flowrate (lb$_{mol}$/hr)	48,220	2,352	225	42,726	11,680	0	10,647	0	48,969	62,043	62,043	42,226
V-L Flowrate (lb/hr)	1,391,479	63,803	7,253	1,198,895	375,855	0	191,803	0	983,333	1,218,267	1,218,267	861,115
Solids Flowrate (lb/hr)	0	0	0	0	0	466,901	0	51,227	0	0	0	0
Temperature (°F)	59	68	90	199	90	59	295	2,400	1,250	433	433	95
Pressure (psia)	14.7	16.4	125.0	384.0	125.0	14.7	840.0	815.0	805.0	795.0	785.0	760.0
Enthalpy (Btu/lb)^A	13.0	15.8	11.5	39.8	11.5	---	240.1	---	612.3	458.6	458.6	17.3
Density (lb/ft³)	0.076	0.098	0.687	1.521	0.687	---	54.120	---	0.870	1.665	1.643	2.617

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-14 Case 1 Stream Table, GEE IGCC without CO₂ Capture (Continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0097	0.0000	0.0000	0.0040	0.0100	0.0100	0.0100	0.0092	0.0092	0.0089	0.0089	0.0000
CH₄	0.0013	0.0000	0.0000	0.0000	0.0013	0.0013	0.0013	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.3977	0.0002	0.0000	0.0021	0.4089	0.4089	0.4089	0.0000	0.0000	0.0000	0.0000	0.0000
CO₂	0.1811	0.6124	0.0000	0.6947	0.1562	0.1562	0.1562	0.0003	0.0003	0.0807	0.0807	0.0000
COS	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H₂	0.3812	0.0000	0.0000	0.0415	0.3920	0.3920	0.3920	0.0000	0.0000	0.0000	0.0000	0.0000
H₂O	0.0012	0.0128	0.0000	0.0018	0.0006	0.0006	0.0006	0.0099	0.0099	0.0638	0.0638	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H₂S	0.0086	0.1817	0.0000	0.0111	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N₂	0.0191	0.1905	0.0000	0.2448	0.0309	0.0309	0.0309	0.7732	0.7732	0.7427	0.7427	0.0000
NH₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O₂	0.0000	0.0023	0.0000	0.0000	0.0000	0.0000	0.0000	0.2074	0.2074	0.1039	0.1039	0.0000
SO₂	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	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg$_{mol}$/hr)	19,992	951	0	839	19,445	19,445	19,445	110,253	4,410	136,882	136,882	35,596
V-L Flowrate (kg/hr)	422,592	36,883	0	31,997	397,047	397,047	397,047	3,181,557	127,262	3,995,152	3,995,152	641,276
Solids Flowrate (kg/hr)	0	0	5,307	0	0	0	0	0	0	0	0	0
Temperature (°C)	35	45	174	38	45	241	196	15	432	589	132	561
Pressure (MPa, abs)	5.21	5.2	0.409	5.512	5.171	5.136	3.172	0.101	1.619	0.105	0.105	12.512
Enthalpy (kJ/kg)^A	36.92	-1.2	---	-5.039	54.553	365.190	296.114	30.227	463.785	741.466	235.132	3,502.816
Density (kg/m³)	43.4	95.0	5,288.2	97.7	40.0	24.1	16.4	1.2	7.9	0.4	0.9	35.1
V-L Molecular Weight	21.138	39	---	38.145	20.419	20.419	20.419	28.857	28.857	29.187	29.187	18.015
V-L Flowrate (lb$_{mol}$/hr)	44,075	2,096	0	1,849	42,870	42,870	42,870	243,066	9,723	301,773	301,773	78,476
V-L Flowrate (lb/hr)	931,655	81,313	0	70,540	875,339	875,339	875,339	7,014,133	280,565	8,807,803	8,807,803	1,413,772
Solids Flowrate (lb/hr)	0	0	11,699	0	0	0	0	0	0	0	0	0
Temperature (°F)	94	112	345	100	112	465	386	59	810	1,093	270	1,043
Pressure (psia)	755.0	750.0	59.3	799.5	750.0	745.0	460.0	14.7	234.9	15.2	15.2	1,814.7
Enthalpy (Btu/lb)^A	15.9	-0.5	---	-2.2	23.5	157.0	127.3	13.0	199.4	318.8	101.1	1,505.9
Density (lb/ft³)	2.712	6	330.129	6.098	2.499	1.508	1.026	0.076	0.495	0.027	0.057	2.191

COS Hydrolysis, Mercury Removal and Acid Gas Removal

Syngas exiting the scrubber (stream 10) passes through a COS hydrolysis reactor where about 99.5 percent of the COS is converted to CO_2 and H_2S (Section 3.1.5). The gas exiting the COS reactor (stream 11) passes through a series of heat exchangers and knockout (KO) drums to lower the syngas temperature to 35°C (95°F) and to separate entrained water. The cooled syngas (stream 12) then passes through a carbon bed to remove 95 percent of the Hg (Section 3.1.4).

Cool, particulate-free syngas (stream 13) enters the Selexol absorber unit at approximately 5.2 MPa (755 psia) and 34°C (94°F). In this absorber, H_2S is preferentially removed from the fuel gas stream along with smaller amounts of CO_2, COS and other gases such as hydrogen. The rich solution leaving the bottom of the absorber is heated against the lean solvent returning from the regenerator before entering the H_2S concentrator. A portion of the non-sulfur bearing absorbed gases is driven from the solvent in the H_2S concentrator using N_2 from the ASU as the stripping medium. The temperature of the H_2S concentrator overhead stream is reduced prior to entering the reabsorber where a second stage of H_2S absorption occurs. The rich solvent from the reabsorber is combined with the rich solvent from the absorber and sent to the stripper where it is regenerated through the indirect application of thermal energy via condensation of LP steam in a reboiler. The stripper acid gas stream (stream 14), consisting of 18 percent H_2S and 61 percent CO_2 (with the balance mostly N_2), is then sent to the Claus unit.

Claus Unit

Acid gas from the first-stage stripper of the Selexol unit is routed to the Claus plant. The Claus plant partially oxidizes the H_2S in the acid gas to elemental sulfur. About 5,307 kg/hr (11,699 lb/hr) of elemental sulfur (stream 15) are recovered from the fuel gas stream. This value represents an overall sulfur recovery efficiency of 99.6 percent.

Acid gas from the Selexol unit is preheated to 232°C (450°F). A portion of the acid gas along with all of the sour gas from the stripper and oxygen from the ASU are fed to the Claus furnace. In the furnace, H_2S is catalytically oxidized to SO_2 at a furnace temperature greater than 1,343°C (2,450°F), which must be maintained in order to thermally decompose all of the NH_3 present in the sour gas stream.

Following the thermal stage and condensation of sulfur, two reheater and two sulfur converters are used to obtain a per-pass H_2S conversion of approximately 99.9 percent. The Claus Plant tail gas is hydrogenated and recycled back to the Selexol process (stream 16). In the furnace waste heat boiler, 12,432 kg/hr (27,408 lb/hr) of 4.2 MPa (605 psia) steam are generated. This steam is used to satisfy all Claus process preheating and reheating requirements as well as to produce some steam for the medium-pressure steam header. The sulfur condensers produce 0.34 MPa (50 psig) and steam for the LP steam header and 2.9 MPa (415 psig) for IP steam.

Power Block

Clean syngas exiting the Selexol absorber is re-heated (stream 18) using HP BFW and then expanded to 3.2 MPa (460 psia) using an expansion turbine (stream 19). The syngas stream is diluted with nitrogen from the ASU (stream 4) and enters the advanced F Class CT burner. The CT compressor provides combustion air to the burner and also 17 percent of the air requirements in the ASU (stream 21). The exhaust gas exits the CT at 589°C (1,093°F) (stream 22) and enters the HRSG where additional heat is recovered until the FG exits the HRSG at 132°C (270°F) (stream 23) 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 12.4 MPa/562°C/562°C (1800 psig/1043°F/1043°F) steam cycle.

Air Separation Unit

The elevated pressure ASU was described in Section 3.1.2. In Case 1 the ASU is designed to produce a nominal output of 4,171 tonnes/day (4,597 TPD) of 95 mol% O_2 for use in the gasifier (stream 5) and Claus plant (stream 3). The plant is designed with two production trains. The air compressor is powered by an electric motor. Approximately 13,051 tonnes/day (14,387 TPD) of nitrogen are also recovered, compressed, and used for dilution in the GT combustor (stream 4). About 4 percent of the GT air is used to supply approximately 17 percent of the ASU air requirements (stream 21).

Balance of Plant

Balance of plant items were covered in Sections 3.1.9, 3.1.10, and 3.1.11.

3.2.3 Key System Assumptions

System assumptions for Cases 1 and 2, GEE IGCC with and without CO_2 capture, are presented in Exhibit 3-15.

Exhibit 3-15 GEE IGCC Plant Study Configuration Matrix

Case	1	2
Gasifier Pressure, MPa (psia)	5.6 (815)	5.6 (815)
O_2:Coal Ratio, kg O_2/kg dry coal	0.91	0.91
Carbon Conversion, %	98	98
Syngas HHV at Gasifier Outlet, kJ/Nm^3 (Btu/scf)	8,663 (233)	8,644 (232)
Steam Cycle, MPa/°C/°C (psig/°F/°F)	12.4/562/562 (1800/1043/1043)	12.4/534/534 (1800/994/994)
Condenser Pressure, mm Hg (in Hg)	51 (2.0)	51 (2.0)
Combustion Turbine	2x Advanced F Class (232 MW output each)	2x Advanced F Class (232 MW output each)
Gasifier Technology	GEE Radiant Only	GEE Radiant Only
Oxidant	95 vol% Oxygen	95 vol% Oxygen
Coal	Illinois No. 6	Illinois No. 6
Coal Slurry Solids Content, %	63	63
COS Hydrolysis	Yes	Occurs in SGS
Sour Gas Shift	No	Yes
H_2S Separation	Selexol	Selexol 1st Stage
Sulfur Removal, %	99.7	99.9
Sulfur Recovery	Claus Plant with Tail Gas Recycle to Selexol/ Elemental Sulfur	Claus Plant with Tail Gas Recycle to Selexol/ Elemental Sulfur
Particulate Control	Water Quench, Scrubber, and AGR Absorber	Water Quench, Scrubber, and AGR Absorber
Mercury Control	Carbon Bed	Carbon Bed
NOx Control	Multi Nozzle Quiet Combustor (MNQC) (LNB) and N_2 Dilution	MNQC (LNB) and N_2 Dilution
CO_2 Separation	N/A	Selexol 2nd Stage
Overall CO_2 Capture	N/A	90.3%
CO_2 Sequestration	N/A	Off-site Saline Formation

Balance of Plant – Cases 1 and 2

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

Exhibit 3-16 Balance of Plant Assumptions

Cooling 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 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	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.

3.2.4   Sparing Philosophy

The sparing philosophy for Cases 1 and 2 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 ASUs (2 x 50%)

- Two trains of slurry preparation and slurry pumps (2 x 50%)

- Two trains of gasification, including gasifier, SGC, quench and scrubber (2 x 50%).

- Two trains of syngas clean-up process (2 x 50%).

- Two trains of Selexol AGR, single-stage in Case 1 and two-stage in Case 2, (2 x 50%) and one Claus-based SRU (1 x 100%).

- Two CT/HRSG tandems (2 x 50%).

- One steam turbine (1 x 100%).

3.2.5   Case 1 Performance Results

The plant produces a net output of 622 MWe at a net plant efficiency of 39.0 percent (HHV basis). GEE has reported a net plant efficiency of 38.5 percent for their reference plant, and they also presented a range of efficiencies of 38.5-40 percent depending on fuel type [59,60]. Typically the higher efficiencies result from fuel blends that include petroleum coke.

Overall performance for the plant is summarized in Exhibit 3-17, which includes auxiliary power requirements. The ASU accounts for approximately 78 percent of the auxiliary load between the main air compressor, the nitrogen compressor, the oxygen compressor and ASU auxiliaries. The cooling water system, including the CWPs and the cooling tower fan, account for approximately 5 percent of the auxiliary load, and the BFW pumps account for an additional 3 percent. All other individual auxiliary loads are less than 3 percent of the total.

Exhibit 3-17 Case 1 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	464,000
Sweet Gas Expander Power	7,500
Steam Turbine Power	276,300
TOTAL POWER, kWe	**747,800**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	460
Coal Milling	2,180
Sour Water Recycle Slurry Pump	180
Slag Handling	1,120
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	53,820
Oxygen Compressor	10,260
Nitrogen Compressors	33,340
Boiler Feedwater Pumps	3,980
Condensate Pump	230
Quench Water Pump	520
Circulating Water Pump	4,200
Ground Water Pumps	430
Cooling Tower Fans	2,170
Scrubber Pumps	220
Acid Gas Removal	2,590
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	250
Claus Plant TG Recycle Compressor	2,090
Miscellaneous Balance of Plant[2]	3,000
Transformer Losses	2,610
TOTAL AUXILIARIES, kWe	**125,750**
NET POWER, kWe	**622,050**
Net Plant Efficiency, % (HHV)	39.0
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,238 (8,756)
CONDENSER COOLING DUTY 10^6 kJ/hr (10^6 Btu/hr)	**1,540 (1,460)**
CONSUMABLES	
As-Received Coal Feed, kg/hr (lb/hr)	211,783 (466,901)
Thermal Input[1], kWt	1,596,320
Raw Water Withdrawal, m^3/min (gpm)	17.9 (4,735)
Raw Water Consumption, m^3/min (gpm)	14.2 (3,755)

1 - HHV of As-Received Illinois No. 6 coal is 27,135 kJ/kg (11,666 Btu/lb)

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 PM were presented in Section 2.4. A summary of the plant air emissions for Case 1 is presented in Exhibit 3-18.

Exhibit 3-18 Case 1 Emissions

	kg/GJ (lb/10^6 Btu)	Tonne/year (ton/year) @ 80% capacity factor	kg/MWh (lb/MWh)
SO$_2$	0.001 (0.001)	21 (24)	0.004 (.01)
NOx	0.025 (0.059)	1,023 (1,128)	0.195 (.430)
Particulates	0.003 (0.0071)	123 (136)	0.023 (.052)
Hg	2.46E-7 (5.71E-7)	0.010 (0.011)	1.89E-6 (4.16E-6)
CO$_2$	84.6 (196.8)	3,407,901 (3,756,568)	650 (1,434)
CO$_2$[1]			782 (1,723)

[1] CO_2 emissions based on net power instead of gross power

The low level of SO_2 emissions is achieved by capture of the sulfur in the gas by the Selexol AGR process. The AGR process removes over 99 percent of the sulfur compounds in the fuel gas down to a level of less than 30 ppmv. This results in a concentration in the FG of less than 4 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 to convert all sulfur species to H_2S and then recycled back to the Selexol process, thereby eliminating the need for a tail gas treatment unit.

NOx emissions are limited by nitrogen dilution of the syngas 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 ultimately destroyed in the Claus plant burner. This helps lower NOx levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of the syngas quench 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 the plant is shown in Exhibit 3-19. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag and as CO_2 in the stack gas and ASU vent gas.

Exhibit 3-19 Case 1 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	135,000 (297,625)	Slag	2,700 (5,952)
Air (CO_2)	519 (1,143)	Stack Gas	132,716 (292,588)
		ASU Vent	103 (227)
		CO_2 Product	0 (0)
Total	135,519 (298,768)	Total	135,519 (298,768)

Exhibit 3-20 shows the sulfur balances for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant and sulfur emitted in the stack gas. Sulfur in the slag is considered to be negligible.

Exhibit 3-20 Case 1 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	5,308 (11,702)	Elemental Sulfur	5,307 (11,699)
		Stack Gas	2 (3)
		CO_2 Product	0 (0)
Total	5,308 (11,702)	Total	5,308 (11,702)

Exhibit 3-21 shows the overall water balance for the plant. Water demand represents the total amount of water required for a particular process. Some water is recovered within the process, primarily as syngas condensate, and is re-used as internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a surface-water source for use in the plant and was assumed to be provided 50 percent by a POTW and 50 percent from groundwater. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for any and all purposes, such as cooling tower makeup, BFW makeup, quench system makeup, and slag handling makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source balance.

Exhibit 3-21 Case 1 Water Balance

Water Use	Water Demand, m³/min (gpm)	Internal Recycle, m³/min (gpm)	Raw Water Withdrawal, m³/min (gpm)	Process Water Discharge, m³/min (gpm)	Raw Water Consumption, m³/min (gpm)
Slag Handling	0.50 (133)	0.50 (133)	0.0 (0)	0.0 (0)	0.0 (0)
Slurry Water	1.45 (384)	1.45 (384)	0.0 (0)	0.0 (0)	0.0 (0)
Quench/Wash	2.7 (726)	0.90 (237)	1.9 (489)	0.0 (0)	1.9 (489)
Humidifier	0.0 (0)	0.0 (0)	0.0 (0)	0.0 (0)	0.0 (0)
SWS Blowdown	0.0 (0)	0.0 (0)	0.0 (0)	0.03 (8)	-0.03 (-8)
Condenser Makeup *Gasifier Steam* *Shift Steam* *GT Steam Dilution* *BFW Makeup*	**0.2 (54)** *0.20 (54)*	**0.0 (0)**	**0.2 (54)** *0.20 (54)*	**0.0 (0)**	**0.2 (54)**
Cooling Tower *BFW Blowdown* *SWS Blowdown* *SWS Excess Water* *Humidifier Tower* *Blowdown*	**16.4 (4,321)**	**0.49 (129)** *0.20 (54)* *0.29 (75)*	**15.9 (4,192)** *-0.20 (-54)* *-0.29 (-75)*	**3.7 (972)**	**12.2 (3,220)**
Total	**21.3 (5,618)**	**3.34 (883)**	**17.9 (4,735)**	**3.7 (979)**	**14.2 (3,755)**

<u>Heat and Mass Balance Diagrams</u>

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-22 through Exhibit 3-24:

- Coal gasification and ASU
- Syngas cleanup, sulfur recovery and tail gas recycle
- Combined cycle power generation, steam, and FW

An overall plant energy balance is provided in tabular form in Exhibit 3-25. The power out is the combined CT, steam turbine and expander power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-17) is calculated by multiplying the power out by a combined generator efficiency of 98.2 percent.

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Exhibit 3-22 Case 1 Coal Gasification and Air Separation Units Heat and Mass Balance Schematic
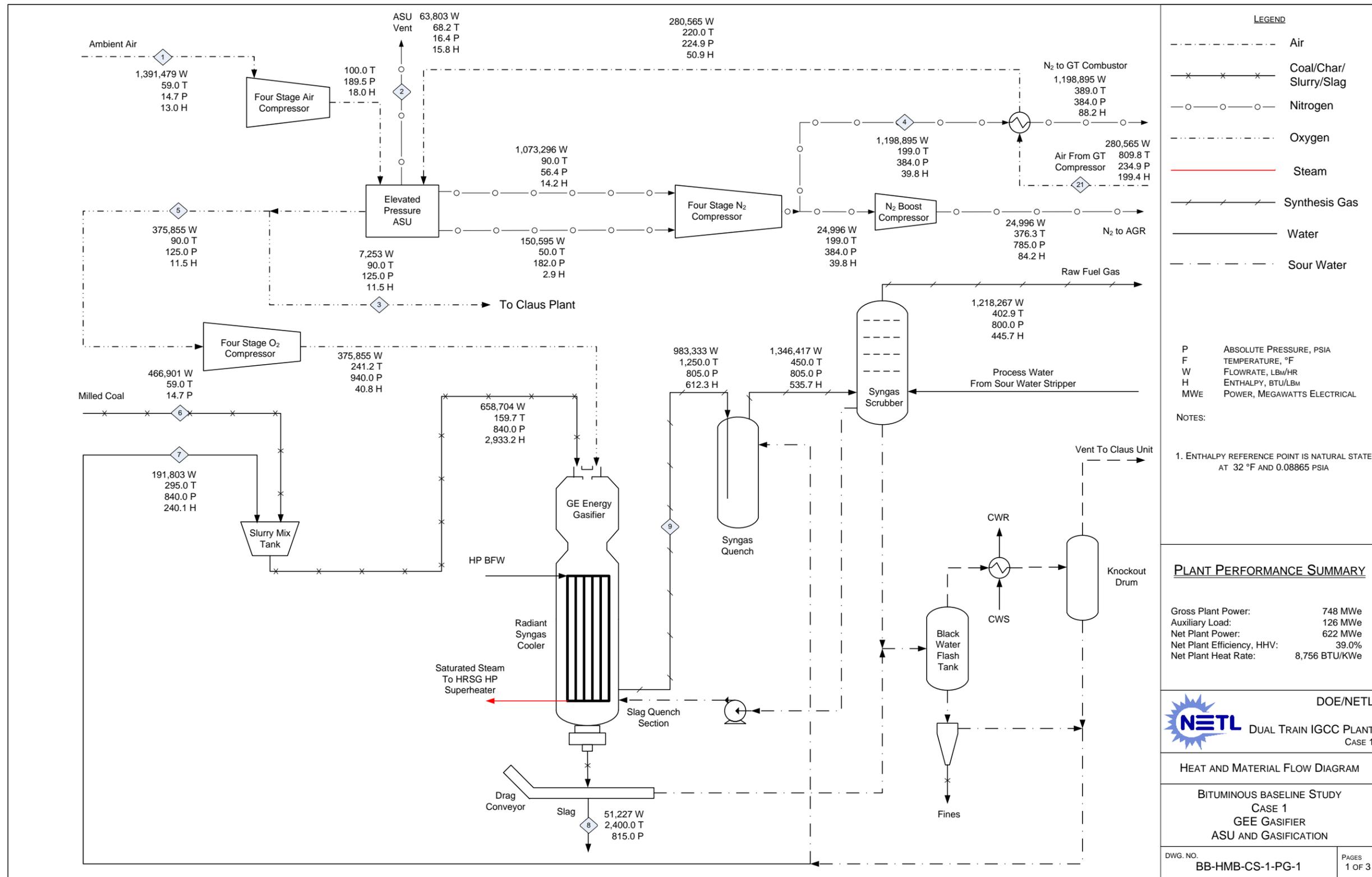
Exhibit 3-23 Case 1 Syngas Cleanup Heat and Mass Balance Schematic

Exhibit 3-24 Case 1 Combined-Cycle Power Generation Heat and Mass Balance Schematic

LEGEND

- Air
- Coal/Char/Slurry/Slag
- Nitrogen
- Oxygen
- Sour Gas
- Sour Water
- Steam
- Synthesis Gas
- Water
- Flue Gas

P — ABSOLUTE PRESSURE, PSIA
F — TEMPERATURE, °F
W — FLOWRATE, LBM/HR
H — ENTHALPY, BTU/LBM
MWe — POWER, MEGAWATTS ELECTRICAL

NOTES:

1. ENTHALPY REFERENCE POINT IS NATURAL STATE AT 32 °F AND 0.08865 PSIA

HP BFW to Radiant Syngas Cooler

HP Saturated Steam to HRSG Superheater

LP Process Header

HRSG

8,807,803 W
269.7 T
15.2 P
101.1 H

Stack

23

22

8,807,803 W
1,092.7 T
15.2 P
318.8 H

LP Flash Tops

MP Flash Bottoms

9,644 W
298.0 T
65.0 P
1,179.0 H

From Gasifier Island Preheating

1,581,185 W
235.0 T
105.0 P
203.7 H

Nitrogen Diluent
1,198,895 W
385.0 T
389.0 P
87.2 H

24

1,413,772 W
1,042.7 T
1,814.7 P
1,505.9 H

Deaerator

1,440,764 W
278.8 T
2,250.7 P
252.3 H

LP BFW

Fuel Gas
875,339 W
385.6 T
460.0 P
127.3 H

19

Blowdown Flash

26,992 W
585.0 T
2,000.7 P
593.3 H

To WWT

HP Pump

LP Pump

To Claus

Air Extraction
280,565 W
809.8 T
234.9 P
199.4 H

21

IP Pump

IP BFW

Compressor Expander

Generator

Advanced F-Class Gas Turbine

1,542,260 W
512.1 T
65.0 P
1,288.0 H

HP Turbine IP Turbine

Steam Turbine

LP Turbine

Generator

Intake

Ip Extraction Steam To 250 PSIA Header

780 W
1,042.7 T
1,814.7 P
1,505.9 H

8,822 W
701.7 T
501.4 P
1,358.0 H

1,312 W
540.7 T
65.0 P
1,302.1 H

35,544 W
897.8 T
280.0 P
1,472.7 H

9,515 W
661.9 T
65.0 P
1,361.9 H

Make-up

27,011 W
59.0 T
14.7 P
27.1 H

1,400 W
212.0 T
14.7 P
179.9 H

CONDENSER

HOT WELL

Steam Seal Regulator

1,400 W
661.9 T
65.0 P
1,361.9 H

1,581,185 W
101.1 T
1.0 P
69.1 H

Condensate Pump

Ambient Air
7,014,133 W
59.0 T
14.7 P
13.0 H

20

Gland Steam Condenser

1,581,185 W
103.2 T
120.0 P
71.4 H

Condensate to Gasification Island

PLANT PERFORMANCE SUMMARY

Gross Plant Power:	748 MWe
Auxiliary Load:	126 MWe
Net Plant Power:	622 MWe
Net Plant Efficiency, HHV:	39.0%
Net Plant Heat Rate:	8,756 BTU/KWe

NETL

DOE/NETL

DUAL TRAIN IGCC PLANT
CASE 1

HEAT AND MATERIAL FLOW DIAGRAM

BITUMINOUS BASELINE STUDY
CASE 1
GEE GASIFIER
POWER BLOCK SYSTEM

DWG. NO.
BB-HMB-CS-1-PG-3

PAGES
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Exhibit 3-25 Case 1 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	5,747 (5,447)	4.8 (4.6)		5,752 (5,451)
ASU Air		19.1 (18.1)		19 (18)
CT Air		96.2 (91.2)		96 (91)
Water		67.4 (63.9)		67 (64)
Auxiliary Power			453 (429)	453 (429)
TOTAL	**5,747 (5,447)**	**187.4 (177.7)**	**453 (429)**	**6,387 (6,054)**
Heat Out GJ/hr (MMBtu/hr)				
ASU Vent		1.1 (1.0)		1 (1)
Slag	89 (84)	36.3 (34.4)		125 (118)
Sulfur	49 (47)	0.6 (0.6)		50 (47)
CO_2				
Cooling Tower Blowdown		27.3 (25.9)		27 (26)
HRSG Flue Gas		939 (890)		939 (890)
Condenser		1,536 (1,456)		1,536 (1,456)
Non-Condenser Cooling Tower Loads*		422 (400)		422 (400)
Process Losses**		594 (563)		594 (563)
Power			2,692 (2,552)	2,692 (2,552)
TOTAL	**138 (131)**	**3,557 (3,372)**	**2,692 (2,552)**	**6,387 (6,054)**

* Includes ASU compressor intercoolers, CO_2 compressor intercoolers, sour water stripper condenser, syngas cooler (low level heat rejection) and extraction air cooler.

** Calculated by difference to close the energy balance.

3.2.6   Case 1 - Major Equipment List

Major equipment items for the GEE gasifier with no CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 3.2.7. 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	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	45 tonne (50 ton)	2	1
9	Feeder	Vibratory	172 tonne/hr (190 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	354 tonne/hr (390 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	172 tonne (190 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	354 tonne/hr (390 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	354 tonne/hr (390 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	816 tonne (900 ton)	3	0

ACCOUNT 2   COAL PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Vibratory	82 tonne/h (90 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	236 tonne/h (260 tph)	1	0
3	Rod Mill Feed Hopper	Dual Outlet	463 tonne (510 ton)	1	0
4	Weigh Feeder	Belt	118 tonne/h (130 tph)	2	0
5	Rod Mill	Rotary	118 tonne/h (130 tph)	2	0
6	Slurry Water Storage Tank with Agitator	Field erected	287,504 liters (75,950 gal)	2	0
7	Slurry Water Pumps	Centrifugal	795 lpm (210 gpm)	2	1
8	Trommel Screen	Coarse	163 tonne/h (180 tph)	2	0
9	Rod Mill Discharge Tank with Agitator	Field erected	376,122 liters (99,360 gal)	2	0
10	Rod Mill Product Pumps	Centrifugal	3,028 lpm (800 gpm)	2	2
11	Slurry Storage Tank with Agitator	Field erected	1,128,440 liters (298,100 gal)	2	0
12	Slurry Recycle Pumps	Centrifugal	6,435 lpm (1,700 gpm)	2	2
13	Slurry Product Pumps	Positive displacement	3,028 lpm (800 gpm)	2	2

ACCOUNT 3   FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,082,628 liters (286,000 gal)	2	0
2	Condensate Pumps	Vertical canned	6,624 lpm @ 91 m H2O (1,750 gpm @ 300 ft H2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	493,508 kg/hr (1,088,000 lb/hr)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	8,366 lpm @ 27 m H2O (2,210 gpm @ 90 ft H2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 6,246 lpm @ 1,859 m H2O (1,650 gpm @ 6,100 ft H2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,060 lpm @ 223 m H2O (280 gpm @ 730 ft H2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
10	Closed Cylce Cooling Heat Exchangers	Plate and frame	247 GJ/hr (234 MMBtu/hr) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	88,579 lpm @ 21 m H2O (23,400 gpm @ 70 ft H2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H2O (1,000 gpm @ 350 ft H2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H2O (700 gpm @ 250 ft H2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	4,618 lpm @ 18 m H2O (1,220 gpm @ 60 ft H2O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	3,066 lpm @ 268 m H2O (810 gpm @ 880 ft H2O)	3	1
16	Filtered Water Pumps	Stainless steel, single suction	2,082 lpm @ 49 m H2O (550 gpm @ 160 ft H2O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	1,003,134 liter (265,000 gal)	2	0
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	303 lpm (80 gpm)	2	0
19	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

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

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized slurry-feed, entrained bed	2,812 tonne/day, 5.6 MPa (3,100 tpd, 815 psia)	2	0
2	Synthesis Gas Cooler	Vertical downflow radiant heat exchanger with outlet quench chamber	245,393 kg/hr (541,000 lb/hr)	2	0
3	Syngas Scrubber Including Sour Water Stripper	Vertical upflow	336,112 kg/hr (741,000 lb/hr)	2	0
4	Raw Gas Coolers	Shell and tube with condensate drain	215,910 kg/hr (476,000 lb/hr)	8	0
5	Raw Gas Knockout Drum	Vertical with mist eliminator	215,456 kg/hr, 35°C, 5.3 MPa (475,000 lb/hr, 95°F, 765 psia)	2	0
6	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	336,112 kg/hr (741,000 lb/hr) syngas	2	0
7	ASU Main Air Compressor	Centrifugal, multi-stage	4,757 m3/min @ 1.3 MPa (168,000 scfm @ 190 psia)	2	0
8	Cold Box	Vendor design	2,268 tonne/day (2,500 tpd) of 95% purity oxygen	2	0
9	Oxygen Compressor	Centrifugal, multi-stage	1,161 m3/min (41,000 scfm) Suction - 0.9 MPa (130 psia) Discharge - 6.5 MPa (940 psia)	2	0
10	Primary Nitrogen Compressor	Centrifugal, multi-stage	3,766 m3/min (133,000 scfm) Suction - 0.4 MPa (60 psia) Discharge - 2.7 MPa (390 psia)	2	0
11	Secondary Nitrogen Compressor	Centrifugal, single-stage	538 m3/min (19,000 scfm) Suction - 1.2 MPa (180 psia) Discharge - 2.7 MPa (390 psia)	2	0
12	Syngas Dilution Nitrogen Boost Compressor	Centrifugal, single-stage	0 m3/min (0 scfm) Suction - 2.6 MPa (380 psia) Discharge - 3.2 MPa (470 psia)	2	0
13	AGR Nitrogen Boost Compressor	Centrifugal, single-stage	85 m3/min (3,000 scfm) Suction - 2.6 MPa (380 psia) Discharge - 5.4 MPa (790 psia)	2	0
14	Extraction Air Heat Exchanger	Gas-to-gas, vendor design	69,853 kg/hr, 432°C, 1.6 MPa (154,000 lb/hr, 810°F, 235 psia)	2	0

ACCOUNT 5A   SYNGAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber	Sulfated carbon bed	215,003 kg/hr (474,000 lb/hr) 35°C (95°F) 5.2 MPa (760 psia)	2	0
2	Sulfur Plant	Claus type	140 tonne/day (154 tpd)	1	0
3	COS Hydrolysis Reactor	Fixed bed, catalytic	303,907 kg/hr (670,000 lb/hr) 221°C (430°F) 5.4 MPa (790 psia)	2	0
4	Acid Gas Removal Plant	Selexol	232,239 kg/hr (512,000 lb/hr) 35°C (94°F) 5.2 MPa (755 psia)	2	0
5	Hydrogenation Reactor	Fixed bed, catalytic	36,161 kg/hr (79,721 lb/hr) 232°C (450°F) 0.4 MPa (58.9 psia)	1	0
6	Tail Gas Recycle Compressor	Centrifugal	31,997 kg/hr (70,540 lb/hr) each	1	0

ACCOUNT 6   COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class	230 MW	2	0
2	Gas Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0
3	Syngas Expansion Turbine/Generator	Turbo Expander	218,359 kg/h (481,400 lb/h) 5.1 MPa (745 psia) Inlet 3.2 MPa (460 psia) Outlet	2	0

ACCOUNT 7   HRSG, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.4 m (27 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 352,702 kg/hr, 12.4 MPa/561°C (777,575 lb/hr, 1,800 psig/1,043°F) Reheat steam - 345,710 kg/hr, 3.1 MPa/561°C (762,160 lb/hr, 452 psig/1,043°F)	2	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	291 MW 12.4 MPa/561°C/561°C (1,800 psig/ 1043°F/1043°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitiation	320 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,688 GJ/hr (1,600 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	420,181 lpm @ 30 m (111,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 2,353 GJ/hr (2,230 MMBtu/hr) heat duty	1	0

ACCOUNT 10   SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	242,266 liters (64,000 gal)	2	0
2	Slag Crusher	Roll	13 tonne/hr (14 tph)	2	0
3	Slag Depressurizer	Lock Hopper	13 tonne/hr (14 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	147,631 liters (39,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	64,352 liters (17,000 gal)	2	
6	Slag Conveyor	Drag chain	13 tonne/hr (14 tph)	2	0
7	Slag Separation Screen	Vibrating	13 tonne/hr (14 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	13 tonne/hr (14 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	208,198 liters (55,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	38 lpm @ 14 m H2O (10 gpm @ 46 ft H2O)	2	2
11	Grey Water Storage Tank	Field erected	68,137 liters (18,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	227 lpm @ 564 m H2O (60 gpm @ 1,850 ft H2O)	2	2
13	Slag Storage Bin	Vertical, field erected	907 tonne (1,000 tons)	2	0
14	Unloading Equipment	Telescoping chute	109 tonne/hr (120 tph)	1	0

ACCOUNT 11   ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Step-up Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Step-up Transformer	Oil-filled	24 kV/345 kV, 320 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 54 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 29 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 4 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12   INSTRUMENTATION AND CONTROLS

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

3.2.7 Case 1 - Cost Estimating

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-26 shows the total plant capital cost summary organized by cost account and Exhibit 3-27 shows a more detailed breakdown of the capital costs, along with owner's costs, TOC, and TASC. Exhibit 3-28 shows the initial and annual O&M costs.

The estimated TOC of the GEE gasifier with no CO_2 capture is $2,447/kW. Process contingency represents 2.0 percent of the TOC and project contingency represents 10.8 percent. The COE is 76.3 mills/kWh.

Exhibit 3-26 Case 1 Total Plant Cost Summary

Client:		USDOE/NETL								Report Date:	2009-Oct-08	
Project:		Bituminous Baseline Study										
		TOTAL PLANT COST SUMMARY										
Case:		Case 1 - GEE Radiant 640MW IGCC w/o CO2										
Plant Size:		622.1	MW,net	Estimate Type:		Conceptual			Cost Base (Jun)		2007	($x1000)

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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$13,912	$2,585	$10,788	$0	$0	**$27,285**	$2,477	$0	$5,952	**$35,714**	$57
2	COAL & SORBENT PREP & FEED	$23,713	$4,326	$14,245	$0	$0	**$42,284**	$3,844	$1,535	$9,533	**$57,195**	$92
3	FEEDWATER & MISC. BOP SYSTEMS	$9,622	$7,783	$9,458	$0	$0	**$26,863**	$2,531	$0	$6,737	**$36,131**	$58
4	GASIFIER & ACCESSORIES											
4.1	Syngas Cooler Gasifier System	$111,116	$0	$60,871	$0	$0	**$171,987**	$15,755	$23,878	$32,445	**$244,065**	$392
4.2	Syngas Cooler (w/ Gasifier - $)	w/4.1	$0	w/4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$160,703	$0	w/equip.	$0	$0	**$160,703**	$15,577	$0	$17,628	**$193,908**	$312
4.4-4.9	Other Gasification Equipment	$7,664	$11,266	$12,070	$0	$0	**$31,001**	$3,020	$0	$7,624	**$41,645**	$67
	SUBTOTAL 4	**$279,483**	**$11,266**	**$72,942**	**$0**	**$0**	**$363,691**	**$34,352**	**$23,878**	**$57,697**	**$479,618**	**$771**
5A	GAS CLEANUP & PIPING	$57,957	$3,800	$55,494	$0	$0	**$117,251**	$11,380	$93	$25,944	**$154,668**	$249
5B	CO2 REMOVAL & COMPRESSION	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$85,752	$0	$6,269	$0	$0	**$92,021**	$8,724	$4,601	$10,535	**$115,881**	$186
6.2-6.9	Combustion Turbine Other	$5,928	$887	$1,801	$0	$0	**$8,615**	$816	$0	$1,721	**$11,152**	$18
	SUBTOTAL 6	**$91,679**	**$887**	**$8,070**	**$0**	**$0**	**$100,636**	**$9,540**	**$4,601**	**$12,256**	**$127,033**	**$204**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$35,357	$0	$5,027	$0	$0	**$40,384**	$3,840	$0	$4,422	**$48,646**	$78
7.2-7.9	SCR System, Ductwork and Stack	$3,329	$2,373	$3,108	$0	$0	**$8,810**	$817	$0	$1,566	**$11,193**	$18
	SUBTOTAL 7	**$38,685**	**$2,373**	**$8,136**	**$0**	**$0**	**$49,194**	**$4,657**	**$0**	**$5,989**	**$59,839**	**$96**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$29,111	$0	$4,994	$0	$0	**$34,104**	$3,272	$0	$3,738	**$41,114**	$66
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$10,373	$1,001	$7,239	$0	$0	**$18,613**	$1,694	$0	$4,041	**$24,348**	$39
	SUBTOTAL 8	**$39,483**	**$1,001**	**$12,233**	**$0**	**$0**	**$52,718**	**$4,967**	**$0**	**$7,778**	**$65,462**	**$105**
9	COOLING WATER SYSTEM	$9,649	$9,237	$7,877	$0	$0	**$26,763**	$2,486	$0	$5,971	**$35,220**	$57
10	ASH/SPENT SORBENT HANDLING SYS	$14,359	$8,029	$14,555	$0	$0	**$36,943**	$3,559	$0	$4,363	**$44,864**	$72
11	ACCESSORY ELECTRIC PLANT	$28,222	$10,643	$21,238	$0	$0	**$60,103**	$5,165	$0	$12,277	**$77,546**	$125
12	INSTRUMENTATION & CONTROL	$10,249	$1,885	$6,603	$0	$0	**$18,737**	$1,698	$937	$3,561	**$24,933**	$40
13	IMPROVEMENTS TO SITE	$3,349	$1,974	$8,263	$0	$0	**$13,586**	$1,341	$0	$4,478	**$19,405**	$31
14	BUILDINGS & STRUCTURES	$0	$6,725	$7,701	$0	$0	**$14,427**	$1,314	$0	$2,573	**$18,313**	$29
	TOTAL COST	**$620,363**	**$72,516**	**$257,603**	**$0**	**$0**	**$950,481**	**$89,310**	**$31,044**	**$165,109**	**$1,235,944**	**$1,987**

Exhibit 3-27 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,653	$0	$1,785	$0	$0	$5,439	$487	$0	$1,185	$7,111	$11
1.2	Coal Stackout & Reclaim	$4,721	$0	$1,144	$0	$0	$5,865	$514	$0	$1,276	$7,655	$12
1.3	Coal Conveyors & Yd Crush	$4,389	$0	$1,132	$0	$0	$5,522	$485	$0	$1,201	$7,207	$12
1.4	Other Coal Handling	$1,148	$0	$262	$0	$0	$1,410	$123	$0	$307	$1,840	$3
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	$2,585	$6,464	$0	$0	$9,049	$867	$0	$1,983	$11,900	$19
	SUBTOTAL 1.	$13,912	$2,585	$10,788	$0	$0	$27,285	$2,477	$0	$5,952	$35,714	$57
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	w/ 2.3	$0	w/ 2.3	$0	$0	$0	$0	$0	$0	$0	$0
2.2	Prepared Coal Storage & Feed	$1,558	$373	$244	$0	$0	$2,175	$186	$0	$472	$2,833	$5
2.3	Slurry Prep & Feed	$21,299	$0	$9,398	$0	$0	$30,697	$2,789	$1,535	$7,004	$42,025	$68
2.4	Misc.Coal Prep & Feed	$857	$623	$1,869	$0	$0	$3,349	$308	$0	$731	$4,388	$7
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	$3,330	$2,734	$0	$0	$6,063	$562	$0	$1,325	$7,950	$13
	SUBTOTAL 2.	$23,713	$4,326	$14,245	$0	$0	$42,284	$3,844	$1,535	$9,533	$57,195	$92
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	Feedwater System	$2,896	$4,974	$2,626	$0	$0	$10,496	$972	$0	$2,294	$13,762	$22
3.2	Water Makeup & Pretreating	$620	$65	$347	$0	$0	$1,031	$98	$0	$339	$1,469	$2
3.3	Other Feedwater Subsystems	$1,585	$536	$482	$0	$0	$2,602	$234	$0	$567	$3,403	$5
3.4	Service Water Systems	$355	$731	$2,536	$0	$0	$3,621	$353	$0	$1,192	$5,167	$8
3.5	Other Boiler Plant Systems	$1,904	$738	$1,829	$0	$0	$4,471	$424	$0	$979	$5,874	$9
3.6	FO Supply Sys & Nat Gas	$315	$596	$556	$0	$0	$1,467	$141	$0	$322	$1,930	$3
3.7	Waste Treatment Equipment	$867	$0	$529	$0	$0	$1,395	$136	$0	$459	$1,991	$3
3.8	Misc. Power Plant Equipment	$1,080	$145	$554	$0	$0	$1,779	$172	$0	$585	$2,536	$4
	SUBTOTAL 3.	$9,622	$7,783	$9,458	$0	$0	$26,863	$2,531	$0	$6,737	$36,131	$58
4	GASIFIER & ACCESSORIES											
4.1	Syngas Cooler Gasifier System	$111,116	$0	$60,871	$0	$0	$171,987	$15,755	$23,878	$32,445	$244,065	$392
4.2	Syngas Cooler (w/ Gasifier - $)	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$160,703	$0	w/equip.	$0	$0	$160,703	$15,577	$0	$17,628	$193,908	$312
4.4	Scrubber & Low Temperature Cooling	$5,873	$4,781	$4,975	$0	$0	$15,629	$1,501	$0	$3,426	$20,556	$33
4.5	Black Water & Sour Gas Section	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Other Gasification Equipment	$1,791	$0	$1,681	$0	$0	$3,472	$417	$0	$948	$4,837	$8
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	$6,486	$5,414	$0	$0	$11,900	$1,103	$0	$3,251	$16,253	$26
	SUBTOTAL 4.	$279,483	$11,266	$72,942	$0	$0	$363,691	$34,352	$23,878	$57,697	$479,618	$771

Exhibit 3-27 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	Single Stage Selexol	$41,961	$0	$35,605	$0	$0	$77,565	$7,501	$0	$17,013	$102,080	$164
5A.2	Elemental Sulfur Plant	$10,055	$2,004	$12,972	$0	$0	$25,031	$2,431	$0	$5,493	$32,955	$53
5A.3	Mercury Removal	$1,057	$0	$804	$0	$0	$1,862	$180	$93	$427	$2,561	$4
5A.4	COS Hydrolysis	$3,575	$0	$4,668	$0	$0	$8,243	$801	$0	$1,809	$10,853	$17
5A.5	Particulate Removal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Blowback Gas Systems	$1,310	$0	$248	$0	$0	$1,558	$190	$0	$350	$2,098	$3
5A.7	Fuel Gas Piping	$0	$688	$482	$0	$0	$1,170	$108	$0	$256	$1,534	$2
5A.9	HGCU Foundations	$0	$1,108	$714	$0	$0	$1,822	$167	$0	$597	$2,586	$4
	SUBTOTAL 5A.	$57,957	$3,800	$55,494	$0	$0	$117,251	$11,380	$93	$25,944	$154,668	$249
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	$85,752	$0	$6,269	$0	$0	$92,021	$8,724	$4,601	$10,535	$115,881	$186
6.2	Syngas Expander	$5,928	$0	$819	$0	$0	$6,747	$641	$0	$1,108	$8,496	$14
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$887	$982	$0	$0	$1,868	$175	$0	$613	$2,656	$4
	SUBTOTAL 6.	$91,679	$887	$8,070	$0	$0	$100,636	$9,540	$4,601	$12,256	$127,033	$204
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$35,357	$0	$5,027	$0	$0	$40,384	$3,840	$0	$4,422	$48,646	$78
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,706	$1,217	$0	$0	$2,923	$256	$0	$636	$3,816	$6
7.4	Stack	$3,329	$0	$1,250	$0	$0	$4,579	$439	$0	$502	$5,519	$9
7.9	HRSG,Duct & Stack Foundations	$0	$667	$640	$0	$0	$1,307	$122	$0	$429	$1,858	$3
	SUBTOTAL 7.	$38,685	$2,373	$8,136	$0	$0	$49,194	$4,657	$0	$5,989	$59,839	$96
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$29,111	$0	$4,994	$0	$0	$34,104	$3,272	$0	$3,738	$41,114	$66
8.2	Turbine Plant Auxiliaries	$202	$0	$463	$0	$0	$665	$65	$0	$73	$803	$1
8.3	Condenser & Auxiliaries	$5,053	$0	$1,484	$0	$0	$6,537	$625	$0	$716	$7,878	$13
8.4	Steam Piping	$5,117	$0	$3,600	$0	$0	$8,717	$749	$0	$2,367	$11,833	$19
8.9	TG Foundations	$0	$1,001	$1,693	$0	$0	$2,694	$255	$0	$885	$3,835	$6
	SUBTOTAL 8.	$39,483	$1,001	$12,233	$0	$0	$52,718	$4,967	$0	$7,778	$65,462	$105

Exhibit 3-27 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$6,699	$0	$1,219	$0	$0	$7,918	$754	$0	$1,301	$9,973	$16
9.2	Circulating Water Pumps	$1,737	$0	$122	$0	$0	$1,859	$157	$0	$302	$2,318	$4
9.3	Circ.Water System Auxiliaries	$147	$0	$21	$0	$0	$168	$16	$0	$28	$211	$0
9.4	Circ.Water Piping	$0	$6,124	$1,588	$0	$0	$7,712	$697	$0	$1,682	$10,090	$16
9.5	Make-up Water System	$343	$0	$490	$0	$0	$833	$80	$0	$183	$1,096	$2
9.6	Component Cooling Water Sys	$723	$865	$615	$0	$0	$2,203	$206	$0	$482	$2,891	$5
9.9	Circ.Water System Foundations	$0	$2,248	$3,822	$0	$0	$6,071	$576	$0	$1,994	$8,640	$14
	SUBTOTAL 9.	**$9,649**	**$9,237**	**$7,877**	**$0**	**$0**	**$26,763**	**$2,486**	**$0**	**$5,971**	**$35,220**	**$57**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$11,822	$6,519	$13,243	$0	$0	$31,584	$3,048	$0	$3,463	$38,095	$61
10.2	Gasifier Ash Depressurization	w/10.1	w/10.1	w/10.1	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	w/10.1	w/10.1	w/10.1	$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 Recovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$575	$0	$626	$0	$0	$1,201	$116	$0	$198	$1,515	$2
10.7	Ash Transport & Feed Equipment	$771	$0	$186	$0	$0	$957	$89	$0	$157	$1,204	$2
10.8	Misc. Ash Handling Equipment	$1,191	$1,460	$436	$0	$0	$3,087	$294	$0	$507	$3,888	$6
10.9	Ash/Spent Sorbent Foundation	$0	$51	$64	$0	$0	$115	$11	$0	$38	$163	$0
	SUBTOTAL 10.	**$14,359**	**$8,029**	**$14,555**	**$0**	**$0**	**$36,943**	**$3,559**	**$0**	**$4,363**	**$44,864**	**$72**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$958	$0	$947	$0	$0	$1,905	$182	$0	$209	$2,296	$4
11.2	Station Service Equipment	$3,920	$0	$353	$0	$0	$4,273	$394	$0	$467	$5,134	$8
11.3	Switchgear & Motor Control	$7,247	$0	$1,318	$0	$0	$8,565	$794	$0	$1,404	$10,763	$17
11.4	Conduit & Cable Tray	$0	$3,366	$11,106	$0	$0	$14,472	$1,400	$0	$3,968	$19,840	$32
11.5	Wire & Cable	$0	$6,432	$4,226	$0	$0	$10,658	$774	$0	$2,858	$14,291	$23
11.6	Protective Equipment	$0	$686	$2,496	$0	$0	$3,182	$311	$0	$524	$4,017	$6
11.7	Standby Equipment	$236	$0	$230	$0	$0	$466	$44	$0	$77	$587	$1
11.8	Main Power Transformers	$15,862	$0	$146	$0	$0	$16,008	$1,211	$0	$2,583	$19,801	$32
11.9	Electrical Foundations	$0	$158	$416	$0	$0	$574	$55	$0	$189	$818	$1
	SUBTOTAL 11.	**$28,222**	**$10,643**	**$21,238**	**$0**	**$0**	**$60,103**	**$5,165**	**$0**	**$12,277**	**$77,546**	**$125**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	w/6.1	$0	w/6.1	$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	$1,012	$0	$676	$0	$0	$1,687	$160	$84	$290	$2,221	$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	$233	$0	$149	$0	$0	$382	$36	$19	$87	$524	$1
12.7	Computer & Accessories	$5,397	$0	$173	$0	$0	$5,570	$511	$278	$636	$6,995	$11
12.8	Instrument Wiring & Tubing	$0	$1,885	$3,854	$0	$0	$5,739	$487	$287	$1,628	$8,141	$13
12.9	Other I & C Equipment	$3,608	$0	$1,752	$0	$0	$5,359	$504	$268	$920	$7,051	$11
	SUBTOTAL 12.	**$10,249**	**$1,885**	**$6,603**	**$0**	**$0**	**$18,737**	**$1,698**	**$937**	**$3,561**	**$24,933**	**$40**

Exhibit 3-27 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$105	$2,246	$0	$0	$2,351	$233	$0	$775	$3,360	$5
13.2	Site Improvements	$0	$1,869	$2,483	$0	$0	$4,352	$429	$0	$1,435	$6,216	$10
13.3	Site Facilities	$3,349	$0	$3,534	$0	$0	$6,883	$679	$0	$2,268	$9,830	$16
	SUBTOTAL 13.	$3,349	$1,974	$8,263	$0	$0	$13,586	$1,341	$0	$4,478	$19,405	$31
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	$2,446	$3,484	$0	$0	$5,930	$546	$0	$971	$7,447	$12
14.3	Administration Building	$0	$845	$613	$0	$0	$1,459	$130	$0	$238	$1,827	$3
14.4	Circulation Water Pumphouse	$0	$167	$88	$0	$0	$255	$22	$0	$42	$319	$1
14.5	Water Treatment Buildings	$0	$518	$506	$0	$0	$1,024	$93	$0	$167	$1,284	$2
14.6	Machine Shop	$0	$433	$296	$0	$0	$729	$65	$0	$119	$912	$1
14.7	Warehouse	$0	$699	$451	$0	$0	$1,149	$102	$0	$188	$1,439	$2
14.8	Other Buildings & Structures	$0	$418	$326	$0	$0	$744	$66	$0	$162	$973	$2
14.9	Waste Treating Building & Str.	$0	$935	$1,787	$0	$0	$2,723	$254	$0	$595	$3,572	$6
	SUBTOTAL 14.	$0	$6,725	$7,701	$0	$0	$14,427	$1,314	$0	$2,573	$18,313	$29
	TOTAL COST	$620,363	$72,516	$257,603	$0	$0	$950,481	$89,310	$31,044	$165,109	$1,235,944	$1,987

Owner's Costs				
Preproduction Costs				
6 Months All Labor			$12,214	$20
1 Month Maintenance Materials			$2,742	$4
1 Month Non-fuel Consumables			$269	$0
1 Month Waste Disposal			$304	$0
25% of 1 Months Fuel Cost at 100% CF			$1,627	$3
2% of TPC			$24,719	$40
Total			**$41,874**	**$67**
Inventory Capital				
60 day supply of fuel and consumables at 100% CF			$13,328	$21
0.5% of TPC (spare parts)			$6,180	$10
Total			**$19,507**	**$31**
Initial Cost for Catalyst and Chemicals			$4,892	$8
Land			$900	$1
Other Owner's Costs			$185,392	$298
Financing Costs			$33,370	$54
Total Overnight Costs (TOC)			**$1,521,880**	**$2,447**
TASC Multiplier	(IOU, high-risk, 35 year)		1.140	
Total As-Spent Cost (TASC)			**$1,734,944**	**$2,789**

Exhibit 3-28 Case 1 Initial and Annual O&M Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun):	2007
Case 1 - GEE Radiant 640MW IGCC w/o CO2					Heat Rate-net (Btu/kWh):	8,756
					MWe-net:	622
					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			
Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.		Plant			
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		$5,918,913	$9.515
Maintenance Labor Cost		$13,622,877	$21.900
Administrative & Support Labor		$4,885,447	$7.854
Property Taxes and Insurance		$24,718,883	$39.738
TOTAL FIXED OPERATING COSTS		**$49,146,120**	**$79.007**

VARIABLE OPERATING COSTS						$/kWh-net
Maintenance Material Cost					**$26,322,759**	**$0.00604**

Consumables	Consumption Initial Fill	/Day	Unit Cost	Initial Fill Cost		
Water (/1000 gallons)	0	3,409	1.08	$0	$1,076,793	$0.00025
Chemicals						
MU & WT Chem. (lbs)	0	20,311	0.17	$0	$1,026,436	$0.00024
Carbon (Mercury Removal) (lb)	54,833	75	1.05	$57,584	$23,034	$0.00001
COS Catalyst (m3)	422	0.29	2,397.36	$1,011,578	$202,316	$0.00005
Water Gas Shift Catalyst (ft3)	0	0	498.83	$0	$0	$0.00000
Selexol Solution (gal)	285,358	45	13.40	$3,823,295	$175,961	$0.00004
SCR Catalyst (m3)	0	0	0.00	$0	$0	$0.00000
Ammonia (19% NH3) (ton)	0	0	0.00	$0	$0	$0.00000
Claus Catalyst (ft3)	w/equip.	1.94	131.27	$0	$74,422	$0.00002
Subtotal Chemicals				**$4,892,457**	**$1,502,168**	**$0.00034**
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	75	0.42	$0	$9,148	$0.00000
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Slag (ton)	0	615	16.23	$0	$2,912,403	$0.00067
Subtotal-Waste Disposal				**$0**	**$2,921,551**	**$0.00067**
By-products & Emissions						
Sulfur (tons)	0	140	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$4,892,457**	**$31,823,271**	**$0.00730**
Fuel (ton)	0	5,603	38.18	$0	$62,470,676	$0.01433

3.2.8   Case 2 - GEE IGCC with CO$_2$ Capture

Case 2 is configured to produce electric power with CO$_2$ capture. The plant configuration is the same as Case 1, namely two gasifier trains, two advanced F Class turbines, two HRSGs, and one steam turbine. The gross power output from the plant is constrained by the capacity of the two CTs, and since the CO$_2$ capture process increases the auxiliary load on the plant, the net output is significantly reduced relative to Case 1.

The process description for Case 2 is similar to Case 1 with several notable exceptions to accommodate CO$_2$ capture. A BFD and stream tables for Case 2 are shown in Exhibit 3-29 and Exhibit 3-30, respectively. 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 exception that total coal feed to the two gasifiers is 5,302 tonnes/day (5,844 TPD) (stream 6) and the ASU provides 4,342 tonnes/day (4,786 TPD) of 95 percent oxygen to the gasifier and Claus plant (streams 3 and 5).

Raw Gas Cooling/Particulate Removal

Raw gas cooling and particulate removal are the same as Case 1 with the exception that approximately 443,118 kg/hr (976,891 lb/hr) of saturated steam at 13.8 MPa (2,000 psia) is generated in the radiant SGCs.

Syngas Scrubber/Sour Water Stripper

No differences from Case 1.

SGS

The SGS process was described in Section 3.1.3. In Case 2 steam (stream 11) is added to the syngas exiting the scrubber to adjust the H$_2$O:CO molar ratio to 2:1 prior to the first SGS reactor. The hot syngas exiting the first stage of SGS is used to generate the steam that is added in stream 11. A second stage of SGS results in 97 percent overall conversion of the CO to CO$_2$. The warm syngas from the second stage of SGS (stream 12) is cooled to 236°C (456°F) by preheating the unshifted syngas prior to the SGS. The SGS catalyst also serves to hydrolyze COS thus eliminating the need for a separate COS hydrolysis reactor. Following the second SGS cooler the syngas is further cooled to 35°C (95°F) prior to the mercury removal beds.

Mercury Removal and AGR

Mercury removal is the same as in Case 1.

The AGR process in Case 2 is a two stage Selexol process where H$_2$S is removed in the first stage and CO$_2$ in the second stage of absorption as previously described in Section 3.1.5. 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 acid gas (stream 18) contains 35 percent H$_2$S and 52 percent CO$_2$ with the balance primarily N$_2$. The CO$_2$-rich stream is discussed further in the CO$_2$ compression section.

Exhibit 3-29 Case 2 Block Flow Diagram, GEE IGCC with CO$_2$ Capture

Exhibit 3-30 Case 2 Stream Table, GEE IGCC with CO₂ Capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0166	0.0318	0.0023	0.0318	0.0000	0.0000	0.0000	0.0086	0.0068	0.0000	0.0054
CH₄	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0011	0.0009	0.0000	0.0007
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3576	0.2823	0.0000	0.0060
CO₂	0.0003	0.0054	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1380	0.1089	0.0000	0.3082
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	0.0001	0.0000	0.0000
H₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3406	0.2689	0.0000	0.4366
H₂O	0.0099	0.1363	0.0000	0.0003	0.0000	0.0000	0.9995	0.0000	0.1369	0.3190	1.0000	0.2325
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0008	0.0002	0.0000	0.0001
H₂S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0073	0.0057	0.0000	0.0047
N₂	0.7732	0.7061	0.0178	0.9920	0.0178	0.0000	0.0000	0.0000	0.0070	0.0055	0.0000	0.0044
NH₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0005	0.0000	0.0019	0.0016	0.0000	0.0013
O₂	0.2074	0.1356	0.9504	0.0054	0.9504	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO₂	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	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg$_{mol}$/hr)	27,361	1,650	96	20,051	5,526	0	5,037	0	23,122	29,284	7,193	36,478
V-L Flowrate (kg/hr)	789,560	45,332	3,080	562,615	177,828	0	90,748	0	465,243	575,983	129,587	705,570
Solids Flowrate (kg/hr)	0	0	0	0	0	220,904	0	24,237	0	0	0	0
Temperature (°C)	15	18	32	93	32	15	142	1,316	677	206	288	240
Pressure (MPa, abs)	0.10	0.11	0.86	2.65	0.86	0.10	5.79	5.62	5.55	5.52	5.52	5.41
Enthalpy (kJ/kg)^A	30.23	35.64	26.67	92.50	26.67	---	537.77	---	1,424.65	1,065.71	2,918.18	942.21
Density (kg/m³)	1.2	1.5	11.0	24.4	11.0	---	872.0	---	14.0	27.2	25.6	24.8
V-L Molecular Weight	28.857	27.476	32.181	28.060	32.181	---	18.015	---	20.121	19.669	18.015	19.343
V-L Flowrate (lb$_{mol}$/hr)	60,321	3,637	211	44,204	12,183	0	11,106	0	50,976	64,561	15,858	80,419
V-L Flowrate (lb/hr)	1,740,683	99,940	6,791	1,240,354	392,044	0	200,064	0	1,025,685	1,269,825	285,691	1,555,516
Solids Flowrate (lb/hr)	0	0	0	0	0	487,011	0	53,433	0	0	0	0
Temperature (°F)	59	65	90	199	90	59	287	2,400	1,250	403	550	463
Pressure (psia)	14.7	16.4	125.0	384.0	125.0	14.7	840.0	815.0	805.0	800.0	800.0	785.0
Enthalpy (Btu/lb)^A	13.0	15.3	11.5	39.8	11.5	---	231.2	---	612.5	458.2	1,254.6	405.1
Density (lb/ft³)	0.076	0.091	0.687	1.521	0.687	---	54.440	---	0.871	1.699	1.597	1.550

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-30 Case 2 Stream Table, GEE IGCC with CO$_2$ Capture (Continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0071	0.0071	0.0115	0.0115	0.0002	0.0018	0.0000	0.0103	0.0092	0.0091	0.0091	0.0000
CH$_4$	0.0009	0.0009	0.0015	0.0015	0.0000	0.0004	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0078	0.0077	0.0124	0.0124	0.0002	0.0022	0.0000	0.0064	0.0000	0.0000	0.0000	0.0000
CO$_2$	0.4019	0.4055	0.0502	0.0502	0.9948	0.5214	0.0000	0.6664	0.0003	0.0083	0.0083	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H$_2$	0.5692	0.5649	0.9139	0.9139	0.0048	0.1028	0.0000	0.2561	0.0000	0.0000	0.0000	0.0000
H$_2$O	0.0012	0.0013	0.0001	0.0001	0.0000	0.0226	0.0000	0.0017	0.0099	0.1222	0.1222	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H$_2$S	0.0061	0.0061	0.0000	0.0000	0.0000	0.3477	0.0000	0.0050	0.0000	0.0000	0.0000	0.0000
N$_2$	0.0058	0.0064	0.0105	0.0105	0.0000	0.0008	0.0000	0.0542	0.7732	0.7541	0.7541	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	0.0000
O$_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2074	0.1064	0.1064	0.0000
SO$_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg$_{mol}$/hr)	27,978	28,368	17,423	17,423	10,425	497	0	390	110,253	139,657	139,657	34,500
V-L Flowrate (kg/hr)	552,391	564,920	90,179	90,179	456,650	17,684	0	12,529	3,181,557	3,834,352	3,834,352	621,521
Solids Flowrate (kg/hr)	0	0	0	0	0	0	5,524	0	0	0	0	0
Temperature (°C)	35	35	35	196	51	48	178	38	15	562	132	534
Pressure (MPa, abs)	5.14	5.1	5.102	3.172	15.270	0.163	0.119	5.512	0.101	0.105	0.105	12.512
Enthalpy (kJ/kg)^A	37.11	36.4	195.532	1,124.237	-162.306	74.865	---	5.295	30.227	834.762	343.819	3,432.885
Density (kg/m^3)	40.7	40.9	10.1	4.2	641.8	2.2	5,280.5	77.9	1.2	0.4	0.9	36.7
V-L Molecular Weight	19.744	20	5.176	5.176	43.805	35.588	---	32.153	28.857	27.455	27.455	18.015
V-L Flowrate (lb$_{mol}$/hr)	61,681	62,540	38,412	38,412	22,983	1,095	0	859	243,066	307,891	307,891	76,059
V-L Flowrate (lb/hr)	1,217,813	1,245,436	198,810	198,810	1,006,740	38,986	0	27,622	7,014,133	8,453,299	8,453,299	1,370,220
Solids Flowrate (lb/hr)	0	0	0	0	0	0	12,178	0	0	0	0	0
Temperature (°F)	95	95	95	384	124	119	352	100	59	1,044	270	994
Pressure (psia)	745.0	740.0	740.0	460.0	2,214.7	23.7	17.3	799.5	14.7	15.2	15.2	1,814.7
Enthalpy (Btu/lb)^A	16.0	15.7	84.1	483.3	-69.8	32.2	---	2.3	13.0	358.9	147.8	1,475.9
Density (lb/ft^3)	2.544	3	0.630	0.260	40.068	0.137	329.649	4.864	0.076	0.026	0.053	2.293

CO$_2$ Compression and Dehydration

CO$_2$ from the AGR process is flashed at three pressure levels to separate CO$_2$ and decrease H$_2$ losses to the CO$_2$ product pipeline. The HP CO$_2$ stream is flashed at 2.0 MPa (289.7 psia), compressed, and recycled back to the CO$_2$ absorber. The MP CO$_2$ stream is flashed at 1.0 MPa (149.7 psia). The LP CO$_2$ stream is flashed at 0.1 MPa (16.7 psia), compressed to 1.0 MPa (149.5 psia), and combined with the MP CO$_2$ stream. The combined stream is compressed from 2.1 MPa (149.5 psia) to a SC condition at 15.3 MPa (2,215 psia) using a multiple-stage, intercooled compressor. During compression, the CO$_2$ stream is dehydrated to a dewpoint of -40ºC (-40°F) with triethylene glycol. The raw CO$_2$ stream from the Selexol process contains over 99 percent CO$_2$. The CO$_2$ (stream 17) 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 exceptions:

- 5,528 kg/hr (12,178 lb/hr) of sulfur (stream 19) are produced

- The waste heat boiler generates 13,555 kg/hr (29,884 lb/hr) of 4.0 MPa (575 psia) steam of which 12,679 kg/hr (27,953 lb/hr) is available to the medium pressure steam header.

Power Block

Clean syngas from the AGR plant is heated to 241°C (465°F) using HP BFW before passing through an expansion turbine. The clean syngas (stream 16) is diluted with nitrogen (stream 4) and then enters the CT burner. There is no integration between the CT and the ASU in this case. The exhaust gas (stream 22) exits the CT at 562°C (1044°F) and enters the HRSG where additional heat is recovered. The FG exits the HRSG at 132°C (270°F) (stream 23) 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 12.4 MPa/534°C/534°C (1800 psig/994°F/994°F) steam cycle.

Air Separation Unit (ASU)

The same elevated pressure ASU is used in Case 2 and produces 4,342 tonnes/day (4,786 TPD) of 95 mole% oxygen and 14,591 tonnes/day (16,084 TPD) of nitrogen. There is no integration between the ASU and the CT.

3.2.9   **Case 2 Performance Results**

The Case 2 modeling assumptions were presented previously in Section 3.2.3.

The plant produces a net output of 543 MW at a net plant efficiency of 32.6 percent (HHV basis). Overall performance for the entire plant is summarized in Exhibit 3-31, which includes auxiliary power requirements. The ASU accounts for nearly 60 percent of the auxiliary load between the main air compressor, the nitrogen compressor, the oxygen compressor, and ASU auxiliaries. The two-stage Selexol process and CO$_2$ compression account for an additional 26 percent of the auxiliary power load. The BFW pumps and cooling water system (CWPs and cooling tower fan) comprise over 6 percent of the load, leaving 8 percent of the auxiliary load for all other systems.

Exhibit 3-31 Case 2 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	464,000
Sweet Gas Expander Power	6,500
Steam Turbine Power	263,500
TOTAL POWER, kWe	**734,000**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	470
Coal Milling	2,270
Sour Water Recycle Slurry Pump	190
Slag Handling	1,160
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	67,330
Oxygen Compressor	10,640
Nitrogen Compressors	35,640
CO_2 Compressor	31,160
Boiler Feedwater Pumps	4,180
Condensate Pump	280
Quench Water Pump	540
Circulating Water Pump	4,620
Ground Water Pumps	530
Cooling Tower Fans	2,390
Scrubber Pumps	230
Acid Gas Removal	19,230
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	250
Claus Plant TG Recycle Compressor	1,780
Miscellaneous Balance of Plant[2]	3,000
Transformer Losses	2,760
TOTAL AUXILIARIES, kWe	**190,750**
NET POWER, kWe	**543,250**
Net Plant Efficiency, % (HHV)	32.6
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,034 (10,458)
CONDENSER COOLING DUTY 10^6 kJ/hr (10^6 Btu/hr)	**1,509 (1,430)**
CONSUMABLES	
As-Received Coal Feed, kg/hr (lb/hr)	220,904 (487,011)
Thermal Input[1], kWt	1,665,074
Raw Water Withdrawal, m^3/min (gpm)	22.0 (5,815)
Raw Water Consumption, m^3/min (gpm)	17.9 (4,739)

1 - HHV of As-Received Illinois No. 6 coal is 27,135 kJ/kg (11,666 Btu/lb)

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 PM were presented in Section 2.4. A summary of the plant air emissions for Case 2 is presented in Exhibit 3-32.

Exhibit 3-32 Case 2 Air Emissions

	kg/GJ (lb/10^6 Btu)	Tonne/year (tons/year) @ 80% capacity factor	kg/MWh (lb/MWh)
SO_2	0.001 (0.002)	39 (43)	0.008 (.02)
NOx	0.021 (0.049)	878 (967)	0.171 (.376)
Particulates	0.003 (0.0071)	128 (141)	0.025 (.055)
Hg	2.46E-7 (5.71E-7)	0.010 (0.011)	2.01E-6 (4.42E-6)
CO_2	8.5 (19.7)	355,438 (391,804)	69 (152)
CO_2[1]			93 (206)

[1] CO_2 emissions based on net power instead of gross power

The low level of SO_2 emissions is achieved by capture of the sulfur in the gas by the two-stage Selexol AGR process. As a result of achieving the 90 percent CO_2 removal target, the sulfur compounds are removed to an extent that exceeds the environmental target in Section 2.4. The clean syngas exiting the AGR process has a sulfur concentration of approximately 5 ppmv. This results in a concentration in the FG 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 to convert all sulfur species to H_2S and then recycled back to the Selexol process, thereby eliminating the need for a tail gas treatment unit.

NOx emissions are limited by 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. This helps lower NOx levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of the syngas quench 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 mercury is captured from the syngas by an activated carbon bed.

Ninety-two percent of the CO_2 from the syngas is captured in the AGR system and compressed for sequestration.

The carbon balance for the plant is shown in Exhibit 3-33. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag, as CO_2 in the stack gas, ASU vent gas, and the captured CO_2 product. The carbon capture efficiency is defined as the amount of carbon in the CO_2 product stream relative to the amount of carbon in the coal less carbon contained in the slag, represented by the following fraction:

(Carbon in CO_2 Product)/[(Carbon in the Coal)-(Carbon in Slag)] or
274,672/(310,444-6,209) *100 or
90.3 percent

Exhibit 3-33 Case 2 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	140,815 (310,444)	Slag	2,816 (6,209)
Air (CO_2)	540 (1,191)	Stack Gas	13,842 (30,516)
		ASU Vent	107 (237)
		CO_2 Product	124,589 (274,672)
Total	141,355 (311,634)	Total	141,355 (311,634)

Exhibit 3-34 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant and sulfur emitted in the stack gas. Sulfur in the slag is considered to be negligible.

Exhibit 3-34 Case 2 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	5,537 (12,207)	Elemental Sulfur	5,524 (12,178)
		Stack Gas	3 (6)
		CO_2 Product	10 (23)
Total	5,537 (12,207)	Total	5,537 (12,207)

Exhibit 3-35 shows the overall water balance for the plant. The exhibit is presented in an identical manner for Case 1.

Exhibit 3-35 Case 2 Water Balance

Water Use	Water Demand, m³/min (gpm)	Internal Recycle, m³/min (gpm)	Raw Water Withdrawal, m³/min (gpm)	Process Water Discharge, m³/min (gpm)	Raw Water Consumption, m³/min (gpm)
Slag Handling	0.53 (139)	0.53 (139)	0.0 (0)	0.0 (0)	0.0 (0)
Slurry Water	1.51 (400)	1.51 (400)	0.0 (0)	0.0 (0)	0.0 (0)
Quench/Wash	2.9 (757)	0.72 (191)	2.1 (566)	0.0 (0)	2.1 (566)
Humidifier	0.0 (0)	0.0 (0)	0.0 (0)	0.0 (0)	0.0 (0)
SWS Blowdown	0.0 (0)	0.0 (0)	0.0 (0)	0.03 (7)	-0.03 (-7)
Condenser Makeup *Gasifier Steam* *Shift Steam* *GT Steam Dilution* *BFW Makeup*	**2.4 (627)** *2.2 (571)* *0.21 (56)*	**0.0 (0)**	**2.4 (627)** *2.2 (571)* *0.21 (56)*	**0.0 (0)**	**2.4 (627)**
Cooling Tower *BFW Blowdown* *SWS Blowdown* *SWS Excess Water* *Humidifier Tower* *Blowdown*	**18.0 (4,750)**	**0.49 (129)** *0.21 (56)* *0.28 (73)*	**17.5 (4,622)** *-0.21 (-56)* *-0.28 (-73)*	**4.0 (1,068)**	**13.5 (3,553)**
Total	**25.3 (6,673)**	**3.25 (858)**	**22.0 (5,815)**	**4.1 (1,076)**	**17.9 (4,739)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-36 through Exhibit 3-38:

- Coal gasification and ASU

- Syngas cleanup, sulfur recovery, and tail gas recycle

- Combined cycle power generation, steam, and FW

An overall plant energy balance is presented in tabular form in Exhibit 3-39. The power out is the combined CT, steam turbine and expander power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-31) is calculated by multiplying the power out by a combined generator efficiency of 98.3 percent.

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Exhibit 3-36 Case 2 Coal Gasification and Air Separation Units Heat and Mass Balance Schematic
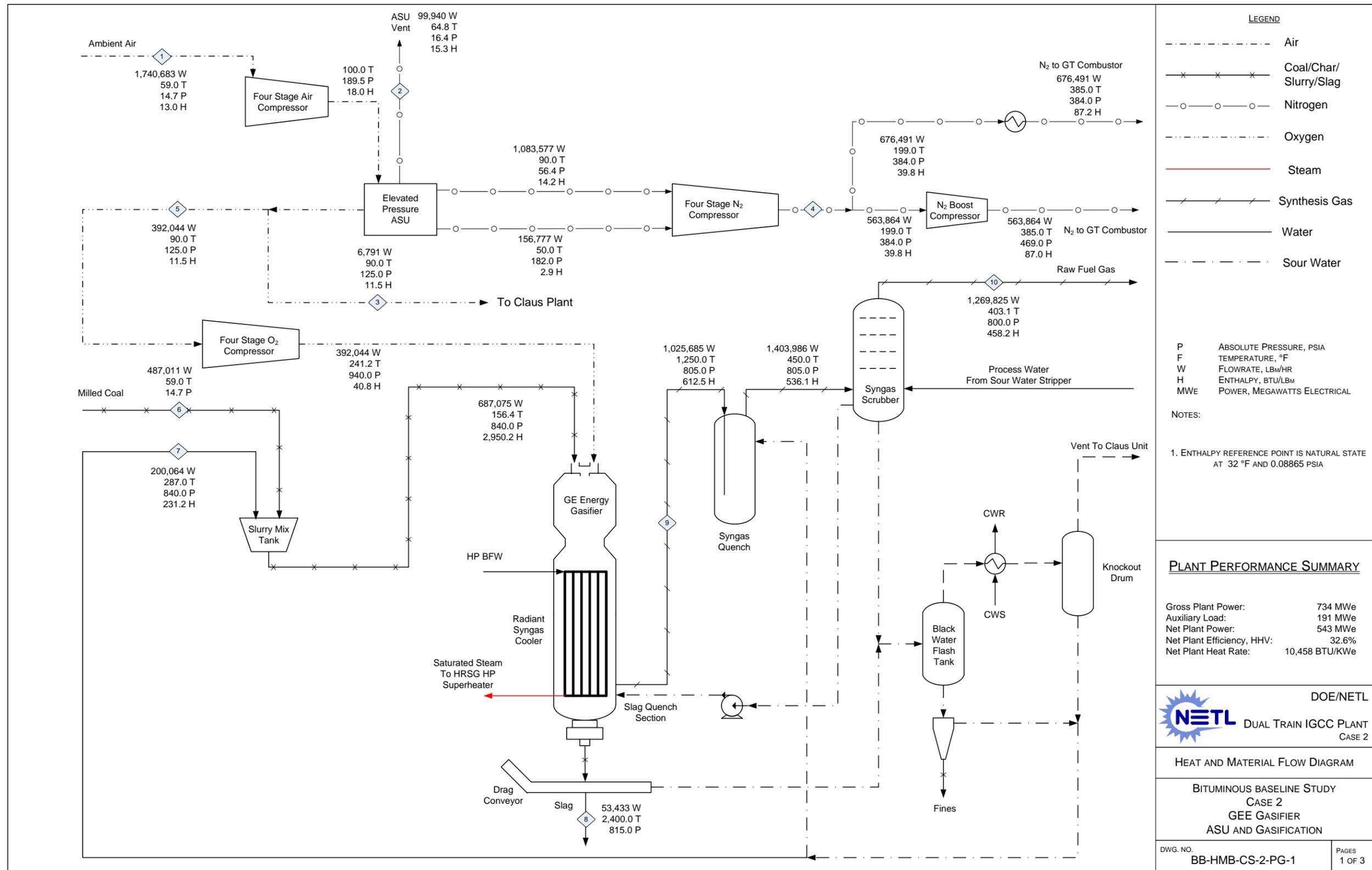
Exhibit 3-37 Case 2 Syngas Cleanup Heat and Mass Balance Schematic
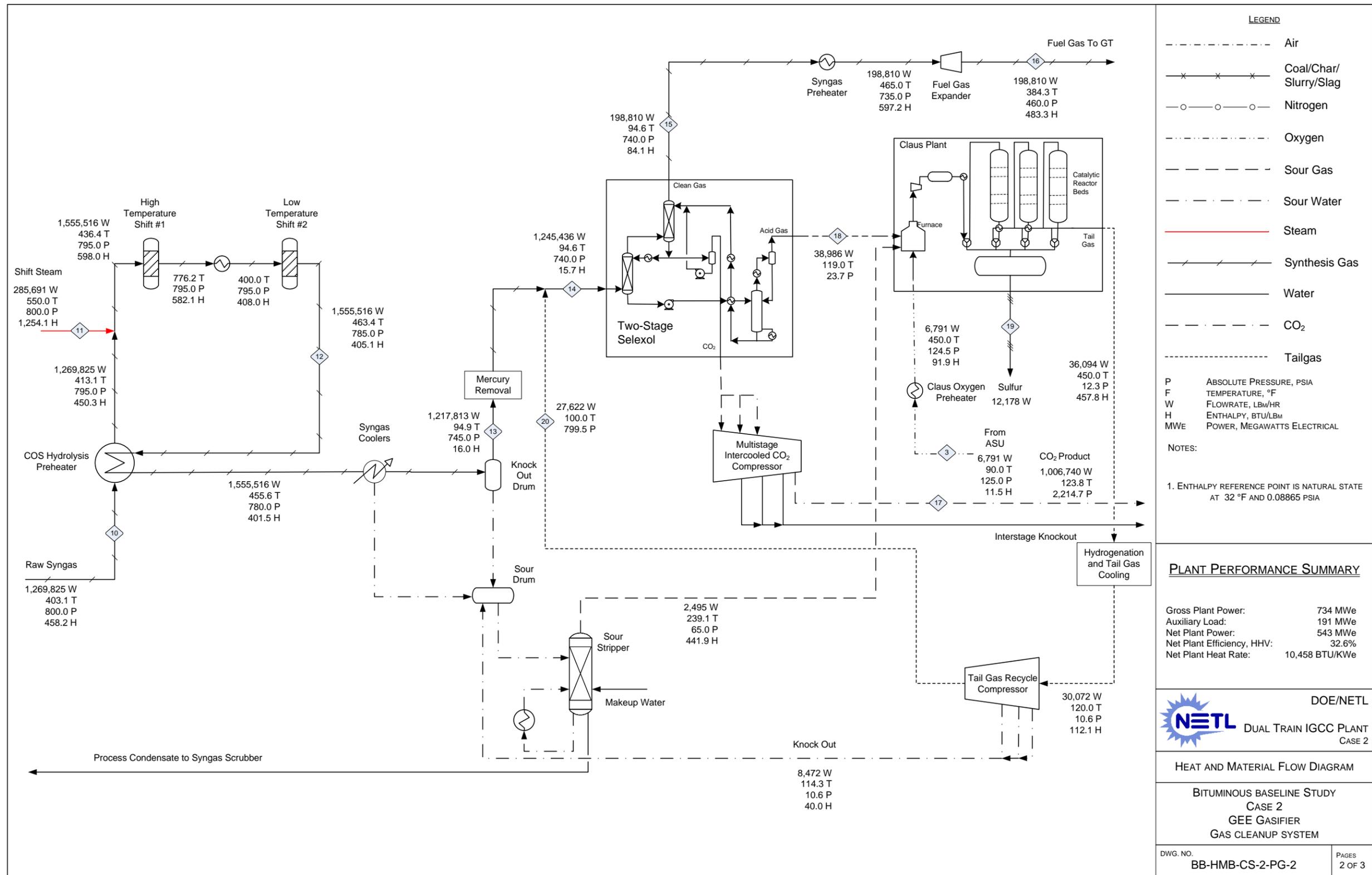
Exhibit 3-38 Case 2 Combined-Cycle Power Generation Heat and Mass Balance Schematic

LEGEND

- – · – · – Air
- —×—×—×— Coal/Char/Slurry/Slag
- —○—○—○— Nitrogen
- ———— Oxygen
- – – – – Sour Gas
- ——— Sour Water
- ——— Steam
- —/—/— Synthesis Gas
- ——— Water
- – – – Flue Gas

P   ABSOLUTE PRESSURE, PSIA
F   TEMPERATURE, °F
W   FLOWRATE, LBM/HR
H   ENTHALPY, BTU/LBM
MWE   POWER, MEGAWATTS ELECTRICAL

NOTES:

1. ENTHALPY REFERENCE POINT IS NATURAL STATE AT 32 °F AND 0.08865 PSIA

PLANT PERFORMANCE SUMMARY

Gross Plant Power:	734 MWe
Auxiliary Load:	191 MWe
Net Plant Power:	543 MWe
Net Plant Efficiency, HHV:	32.6%
Net Plant Heat Rate:	10,458 BTU/KWe

DOE/NETL

NETL

DUAL TRAIN IGCC PLANT
CASE 2

HEAT AND MATERIAL FLOW DIAGRAM

BITUMINOUS BASELINE STUDY
CASE 2
GEE GASIFIER
POWER BLOCK SYSTEM

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Exhibit 3-39 Case 2 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	5,994 (5,681)	5.0 (4.7)		5,999 (5,686)
ASU Air		24 (23)		24 (23)
GT Air		96 (91)		96 (91)
Water		83 (78)		83 (78)
Auxiliary Power			687 (651)	687 (651)
TOTAL	**5,994 (5,681)**	**208 (197)**	**687 (651)**	**6,889 (6,529)**
Heat Out GJ/hr (MMBtu/hr)				
ASU Vent		2 (2)		2 (2)
Slag	92 (88)	38 (36)		130 (123)
Sulfur	51 (49)	1 (1)		52 (49)
CO_2		-74 (-70)		-74 (-70)
Cooling Tower Blowdown		30 (28)		30 (28)
HRSG Flue Gas		1,318 (1,250)		1,318 (1,250)
Condenser		1,513 (1,434)		1,513 (1,434)
Non-Condenser Cooling Tower Loads*		632 (599)		632 (599)
Process Losses**		643 (610)		643 (610)
Power			2,642 (2,505)	2,642 (2,505)
TOTAL	**144 (136)**	**4,103 (3,889)**	**2,642 (2,505)**	**6,889 (6,529)**

* Includes ASU compressor intercoolers, CO_2 compressor intercoolers, sour water stripper condenser, and syngas cooler (low level heat rejection).

** Calculated by difference to close the energy balance.

3.2.10 Case 2 - Major Equipment List

Major equipment items for the GEE gasifier with CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 3.2.11. 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	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	45 tonne (50 ton)	2	1
9	Feeder	Vibratory	181 tonne/hr (200 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	363 tonne/hr (400 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	181 tonne (200 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	363 tonne/hr (400 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	363 tonne/hr (400 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	816 tonne (900 ton)	3	0

ACCOUNT 2   COAL PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Vibratory	82 tonne/h (90 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	245 tonne/h (270 tph)	1	0
3	Rod Mill Feed Hopper	Dual Outlet	490 tonne (540 ton)	1	0
4	Weigh Feeder	Belt	118 tonne/h (130 tph)	2	0
5	Rod Mill	Rotary	118 tonne/h (130 tph)	2	0
6	Slurry Water Storage Tank with Agitator	Field erected	299,921 liters (79,230 gal)	2	0
7	Slurry Water Pumps	Centrifugal	833 lpm (220 gpm)	2	1
8	Trommel Screen	Coarse	172 tonne/h (190 tph)	2	0
9	Rod Mill Discharge Tank with Agitator	Field erected	392,323 liters (103,640 gal)	2	0
10	Rod Mill Product Pumps	Centrifugal	3,407 lpm (900 gpm)	2	2
11	Slurry Storage Tank with Agitator	Field erected	1,176,894 liters (310,900 gal)	2	0
12	Slurry Recycle Pumps	Centrifugal	6,435 lpm (1,700 gpm)	2	2
13	Slurry Product Pumps	Positive displacement	3,407 lpm (900 gpm)	2	2

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,093,984 liters (289,000 gal)	2	0
2	Condensate Pumps	Vertical canned	7,836 lpm @ 91 m H2O (2,070 gpm @ 300 ft H2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	546,579 kg/hr (1,205,000 lb/hr)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	8,025 lpm @ 27 m H2O (2,120 gpm @ 90 ft H2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 6,057 lpm @ 1,859 m H2O (1,600 gpm @ 6,100 ft H2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,703 lpm @ 223 m H2O (450 gpm @ 730 ft H2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
10	Closed Cylce Cooling Heat Exchangers	Plate and frame	362 GJ/hr (343 MMBtu/hr) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	129,840 lpm @ 21 m H2O (34,300 gpm @ 70 ft H2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H2O (1,000 gpm @ 350 ft H2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H2O (700 gpm @ 250 ft H2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	5,716 lpm @ 18 m H2O (1,510 gpm @ 60 ft H2O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	2,839 lpm @ 268 m H2O (750 gpm @ 880 ft H2O)	4	1
16	Filtered Water Pumps	Stainless steel, single suction	3,369 lpm @ 49 m H2O (890 gpm @ 160 ft H2O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	1,608,800 liter (425,000 gal)	2	0
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	1,476 lpm (390 gpm)	2	0
19	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

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

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized slurry-feed, entrained bed	2,903 tonne/day, 5.6 MPa (3,200 tpd, 814.96 psia)	2	0
2	Synthesis Gas Cooler	Vertical downflow radiant heat exchanger with outlet quench chamber	255,826 kg/hr (564,000 lb/hr)	2	0
3	Syngas Scrubber Including Sour Water Stripper	Vertical upflow	350,173 kg/hr (772,000 lb/hr)	2	0
4	Raw Gas Coolers	Shell and tube with condensate drain	388,275 kg/hr (856,000 lb/hr)	8	0
5	Raw Gas Knockout Drum	Vertical with mist eliminator	304,360 kg/hr, 35°C, 5.2 MPa (671,000 lb/hr, 95°F, 750 psia)	2	0
6	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	350,173 kg/hr (772,000 lb/hr) syngas	2	0
7	ASU Main Air Compressor	Centrifugal, multi-stage	5,947 m3/min @ 1.3 MPa (210,000 scfm @ 190 psia)	2	0
8	Cold Box	Vendor design	2,359 tonne/day (2,600 tpd) of 95% purity oxygen	2	0
9	Oxygen Compressor	Centrifugal, multi-stage	1,189 m3/min (42,000 scfm) Suction - 0.9 MPa (130 psia) Discharge - 6.5 MPa (940 psia)	2	0
10	Primary Nitrogen Compressor	Centrifugal, multi-stage	3,794 m3/min (134,000 scfm) Suction - 0.4 MPa (60 psia) Discharge - 2.7 MPa (390 psia)	2	0
11	Secondary Nitrogen Compressor	Centrifugal, single-stage	538 m3/min (19,000 scfm) Suction - 1.2 MPa (180 psia) Discharge - 2.7 MPa (390 psia)	2	0
12	Syngas Dilution Nitrogen Boost Compressor	Centrifugal, single-stage	1,982 m3/min (70,000 scfm) Suction - 2.6 MPa (380 psia) Discharge - 3.2 MPa (470 psia)	2	0

ACCOUNT 5A   SOUR GAS SHIFT AND SYNGAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber	Sulfated carbon bed	303,907 kg/hr (670,000 lb/hr) 35°C (95°F) 5.1 MPa (745 psia)	2	0
2	Sulfur Plant	Claus type	146 tonne/day (161 tpd)	1	0
3	Water Gas Shift Reactors	Fixed bed, catalytic	388,275 kg/hr (856,000 lb/hr) 227°C (440°F) 5.4 MPa (790 psia)	4	0
4	Shift Reactor Heat Recovery Exchangers	Shell and Tube	Exchanger 1: 157 GJ/hr (149 MMBtu/hr) Exchanger 2: 3 GJ/hr (3 MMBtu/hr)	4	0
5	Acid Gas Removal Plant	Two-stage Selexol	310,711 kg/hr (685,000 lb/hr) 35°C (95°F) 5.1 MPa (740 psia)	2	0
6	Hydrogenation Reactor	Fixed bed, catalytic	18,009 kg/hr (39,704 lb/hr) 232°C (450°F) 0.1 MPa (12.3 psia)	1	0
7	Tail Gas Recycle Compressor	Centrifugal	13,782 kg/hr (30,385 lb/hr)	1	0

ACCOUNT 5B CO_2 COMPRESSION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CO2 Compressor	Integrally geared, multi-stage centrifugal	1,133 m3/min @ 15.3 MPa (40,000 scfm @ 2,215 psia)	4	0

ACCOUNT 6   COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class	232 MW	2	0
2	Gas Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0
3	Syngas Expansion Turbine/Generator	Turbo Expander	49,578 kg/h (109,300 lb/h) 5.1 MPa (735 psia) Inlet 3.2 MPa (460 psia) Outlet	2	0

ACCOUNT 7   HRSG, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.5 m (28 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 341,837 kg/hr, 12.4 MPa/534°C (753,621 lb/hr, 1,800 psig/994°F) Reheat steam - 336,628 kg/hr, 3.1 MPa/534°C (742,137 lb/hr, 452 psig/994°F)	2	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	277 MW 12.4 MPa/534°C/534°C (1,800 psig/ 994°F/994°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitiation	310 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,667 GJ/hr (1,580 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	461,820 lpm @ 30 m (122,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 2,585 GJ/hr (2,450 MMBtu/hr) heat duty	1	0

ACCOUNT 10   SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	253,623 liters (67,000 gal)	2	0
2	Slag Crusher	Roll	14 tonne/hr (15 tph)	2	0
3	Slag Depressurizer	Lock Hopper	14 tonne/hr (15 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	151,416 liters (40,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	68,137 liters (18,000 gal)	2	
6	Slag Conveyor	Drag chain	14 tonne/hr (15 tph)	2	0
7	Slag Separation Screen	Vibrating	14 tonne/hr (15 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	14 tonne/hr (15 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	215,768 liters (57,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	38 lpm @ 14 m H2O (10 gpm @ 46 ft H2O)	2	2
11	Grey Water Storage Tank	Field erected	68,137 liters (18,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	227 lpm @ 564 m H2O (60 gpm @ 1,850 ft H2O)	2	2
13	Slag Storage Bin	Vertical, field erected	998 tonne (1,100 tons)	2	0
14	Unloading Equipment	Telescoping chute	109 tonne/hr (120 tph)	1	0

ACCOUNT 11   ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Step-up Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Step-up Transformer	Oil-filled	24 kV/345 kV, 310 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 80 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 48 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 7 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12   INSTRUMENTATION AND CONTROL

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

3.2.11 Case 2 - Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 3-40 shows the TPC summary organized by cost account and Exhibit 3-41 shows a more detailed breakdown of the capital costs along with owner's costs, TOC, and TASC. Exhibit 3-42 shows the initial and annual O&M costs.

The estimated TOC of the GEE gasifier with CO_2 capture is $3,334/kW. Process contingency represents 3.6 percent of the TPC and project contingency represents 11.1 percent. The COE, including CO_2 TS&M costs of 5.3 mills/kWh is 105.7 mills/kWh.

Exhibit 3-40 Case 2 Total Plant Cost Summary

	Client:	USDOE/NETL						Report Date:	2010-Jan-14	
	Project:	Bituminous Baseline Study								
	TOTAL PLANT COST SUMMARY									
	Case:	Case 2 - GEE Radiant 550MW IGCC w/ CO2								
	Plant Size:	543.3 MW,net	Estimate Type:	Conceptual			Cost Base (Jun)	2007	($x1000)	

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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$14,280	$2,654	$11,074	$0	$0	**$28,008**	$2,542	$0	$6,110	**$36,660**	$67
2	COAL & SORBENT PREP & FEED	$24,391	$4,448	$14,651	$0	$0	**$43,489**	$3,954	$1,579	$9,804	**$58,826**	$108
3	FEEDWATER & MISC. BOP SYSTEMS	$10,158	$7,914	$10,237	$0	$0	**$28,309**	$2,671	$0	$7,166	**$38,146**	$70
4	GASIFIER & ACCESSORIES											
4.1	Syngas Cooler Gasifier System	$113,863	$0	$62,389	$0	$0	**$176,251**	$16,146	$24,460	$33,252	**$250,109**	$460
4.2	Syngas Cooler (w/ Gasifier - $)	w/4.1	$0	w/ 4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$193,046	$0	w/equip.	$0	$0	**$193,046**	$18,712	$0	$21,176	**$232,934**	$429
4.4-4.9	Other Gasification Equipment	$7,894	$12,285	$12,270	$0	$0	**$32,449**	$3,078	$0	$7,755	**$43,282**	$80
	SUBTOTAL 4	**$314,803**	**$12,285**	**$74,659**	**$0**	**$0**	**$401,747**	**$37,935**	**$24,460**	**$62,183**	**$526,325**	**$969**
5A	GAS CLEANUP & PIPING	$96,775	$3,334	$82,247	$0	$0	**$182,357**	$17,666	$27,526	$45,625	**$273,174**	$503
5B	CO2 COMPRESSION	$18,256	$0	$11,190	$0	$0	**$29,446**	$2,836	$0	$6,456	**$38,739**	$71
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$92,026	$0	$6,583	$0	$0	**$98,609**	$9,348	$9,861	$11,782	**$129,600**	$239
6.2-6.9	Combustion Turbine Other	$5,550	$887	$1,748	$0	$0	**$8,185**	$775	$0	$1,650	**$10,610**	$20
	SUBTOTAL 6	**$97,576**	**$887**	**$8,331**	**$0**	**$0**	**$106,794**	**$10,123**	**$9,861**	**$13,432**	**$140,210**	**$258**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$33,620	$0	$4,780	$0	$0	**$38,401**	$3,651	$0	$4,205	**$46,257**	$85
7.2-7.9	SCR System, Ductwork and Stack	$3,376	$2,407	$3,153	$0	$0	**$8,936**	$828	$0	$1,589	**$11,353**	$21
	SUBTOTAL 7	**$36,996**	**$2,407**	**$7,933**	**$0**	**$0**	**$47,336**	**$4,480**	**$0**	**$5,794**	**$57,610**	**$106**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$28,123	$0	$4,808	$0	$0	**$32,931**	$3,160	$0	$3,609	**$39,699**	$73
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$10,211	$967	$7,075	$0	$0	**$18,253**	$1,662	$0	$3,950	**$23,865**	$44
	SUBTOTAL 8	**$38,333**	**$967**	**$11,883**	**$0**	**$0**	**$51,183**	**$4,821**	**$0**	**$7,559**	**$63,564**	**$117**
9	COOLING WATER SYSTEM	$10,319	$9,775	$8,388	$0	$0	**$28,483**	$2,646	$0	$6,348	**$37,477**	$69
10	ASH/SPENT SORBENT HANDLING SYS	$14,734	$8,239	$14,938	$0	$0	**$37,910**	$3,652	$0	$4,476	**$46,038**	$85
11	ACCESSORY ELECTRIC PLANT	$32,062	$12,584	$24,591	$0	$0	**$69,237**	$5,953	$0	$14,261	**$89,451**	$165
12	INSTRUMENTATION & CONTROL	$11,404	$2,098	$7,347	$0	$0	**$20,849**	$1,889	$1,042	$3,962	**$27,743**	$51
13	IMPROVEMENTS TO SITE	$3,485	$2,054	$8,600	$0	$0	**$14,140**	$1,396	$0	$4,661	**$20,196**	$37
14	BUILDINGS & STRUCTURES	$0	$6,882	$7,834	$0	$0	**$14,716**	$1,340	$0	$2,628	**$18,684**	$34
	TOTAL COST	**$723,574**	**$76,529**	**$303,902**	**$0**	**$0**	**$1,104,005**	**$103,905**	**$64,468**	**$200,468**	**$1,472,845**	**$2,711**

Exhibit 3-41 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,750	$0	$1,833	$0	$0	$5,583	$500	$0	$1,217	$7,299	$13
1.2	Coal Stackout & Reclaim	$4,846	$0	$1,175	$0	$0	$6,021	$528	$0	$1,310	$7,858	$14
1.3	Coal Conveyors & Yd Crush	$4,505	$0	$1,162	$0	$0	$5,668	$498	$0	$1,233	$7,398	$14
1.4	Other Coal Handling	$1,179	$0	$269	$0	$0	$1,448	$127	$0	$315	$1,889	$3
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	$2,654	$6,635	$0	$0	$9,289	$890	$0	$2,036	$12,215	$22
	SUBTOTAL 1.	$14,280	$2,654	$11,074	$0	$0	$28,008	$2,542	$0	$6,110	$36,660	$67
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	w/2.3	$0	w/2.3	$0	$0	$0	$0	$0	$0	$0	$0
2.2	Prepared Coal Storage & Feed	$1,602	$383	$251	$0	$0	$2,236	$191	$0	$485	$2,913	$5
2.3	Slurry Prep & Feed	$21,908	$0	$9,667	$0	$0	$31,575	$2,869	$1,579	$7,205	$43,227	$80
2.4	Misc.Coal Prep & Feed	$881	$641	$1,922	$0	$0	$3,443	$316	$0	$752	$4,512	$8
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	$3,424	$2,811	$0	$0	$6,234	$577	$0	$1,362	$8,174	$15
	SUBTOTAL 2.	$24,391	$4,448	$14,651	$0	$0	$43,489	$3,954	$1,579	$9,804	$58,826	$108
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	Feedwater System	$2,836	$4,870	$2,571	$0	$0	$10,276	$952	$0	$2,246	$13,474	$25
3.2	Water Makeup & Pretreating	$717	$75	$401	$0	$0	$1,193	$114	$0	$392	$1,699	$3
3.3	Other Feedwater Subsystems	$1,552	$524	$472	$0	$0	$2,548	$229	$0	$555	$3,332	$6
3.4	Service Water Systems	$411	$845	$2,934	$0	$0	$4,190	$409	$0	$1,380	$5,979	$11
3.5	Other Boiler Plant Systems	$2,203	$854	$2,116	$0	$0	$5,173	$491	$0	$1,133	$6,796	$13
3.6	FO Supply Sys & Nat Gas	$315	$596	$556	$0	$0	$1,467	$141	$0	$322	$1,930	$4
3.7	Waste Treatment Equipment	$1,003	$0	$612	$0	$0	$1,615	$157	$0	$532	$2,303	$4
3.8	Misc. Power Plant Equipment	$1,121	$150	$576	$0	$0	$1,847	$178	$0	$608	$2,634	$5
	SUBTOTAL 3.	$10,158	$7,914	$10,237	$0	$0	$28,309	$2,671	$0	$7,166	$38,146	$70
4	GASIFIER & ACCESSORIES											
4.1	Syngas Cooler Gasifier System	$113,863	$0	$62,389	$0	$0	$176,251	$16,146	$24,460	$33,252	$250,109	$460
4.2	Syngas Cooler (w/ Gasifier - $)	w/4.1	$0	w/ 4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$193,046	$0	w/equip.	$0	$0	$193,046	$18,712	$0	$21,176	$232,934	$429
4.4	Scrubber & Low Temperature Cooling	$6,049	$4,924	$5,125	$0	$0	$16,097	$1,546	$0	$3,529	$21,172	$39
4.5	Black Water & Sour Gas Section	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Soot Recovery & SARU	$1,845	$876	$1,731	$0	$0	$4,452	$429	$0	$976	$5,857	$11
4.8	Major Component Rigging	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Gasification Foundations	$0	$6,486	$5,414	$0	$0	$11,900	$1,103	$0	$3,251	$16,253	$30
	SUBTOTAL 4.	$314,803	$12,285	$74,659	$0	$0	$401,747	$37,935	$24,460	$62,183	$526,325	$969

Exhibit 3-41 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	Double Stage Selexol	$74,127	$0	$62,899	$0	$0	$137,025	$13,252	$27,405	$35,536	$213,219	$392
5A.2	Elemental Sulfur Plant	$10,329	$2,059	$13,326	$0	$0	$25,713	$2,498	$0	$5,642	$33,853	$62
5A.3	Mercury Removal	$1,376	$0	$1,047	$0	$0	$2,423	$234	$121	$556	$3,334	$6
5A.4	Shift Reactors	$9,594	$0	$3,862	$0	$0	$13,456	$1,290	$0	$2,949	$17,696	$33
5A.5	Particulate Removal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Blowback Gas Systems	$1,349	$0	$256	$0	$0	$1,605	$196	$0	$360	$2,161	$4
5A.7	Fuel Gas Piping	$0	$634	$444	$0	$0	$1,078	$100	$0	$236	$1,413	$3
5A.9	HGCU Foundations	$0	$642	$414	$0	$0	$1,056	$97	$0	$346	$1,498	$3
	SUBTOTAL 5A.	$96,775	$3,334	$82,247	$0	$0	$182,357	$17,666	$27,526	$45,625	$273,174	$503
5B	CO2 COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$18,256	$0	$11,190	$0	$0	$29,446	$2,836	$0	$6,456	$38,739	$71
	SUBTOTAL 5B.	$18,256	$0	$11,190	$0	$0	$29,446	$2,836	$0	$6,456	$38,739	$71
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$92,026	$0	$6,583	$0	$0	$98,609	$9,348	$9,861	$11,782	$129,600	$239
6.2	Syngas Expander	$5,550	$0	$767	$0	$0	$6,316	$600	$0	$1,038	$7,954	$15
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$887	$982	$0	$0	$1,868	$175	$0	$613	$2,656	$5
	SUBTOTAL 6.	$97,576	$887	$8,331	$0	$0	$106,794	$10,123	$9,861	$13,432	$140,210	$258
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$33,620	$0	$4,780	$0	$0	$38,401	$3,651	$0	$4,205	$46,257	$85
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,731	$1,235	$0	$0	$2,965	$260	$0	$645	$3,870	$7
7.4	Stack	$3,376	$0	$1,268	$0	$0	$4,644	$445	$0	$509	$5,598	$10
7.9	HRSG, Duct & Stack Foundations	$0	$676	$650	$0	$0	$1,326	$123	$0	$435	$1,884	$3
	SUBTOTAL 7.	$36,996	$2,407	$7,933	$0	$0	$47,336	$4,480	$0	$5,794	$57,610	$106
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$28,123	$0	$4,808	$0	$0	$32,931	$3,160	$0	$3,609	$39,699	$73
8.2	Turbine Plant Auxiliaries	$195	$0	$447	$0	$0	$642	$63	$0	$70	$775	$1
8.3	Condenser & Auxiliaries	$5,009	$0	$1,471	$0	$0	$6,480	$619	$0	$710	$7,809	$14
8.4	Steam Piping	$5,006	$0	$3,522	$0	$0	$8,528	$733	$0	$2,315	$11,576	$21
8.9	TG Foundations	$0	$967	$1,635	$0	$0	$2,603	$247	$0	$855	$3,704	$7
	SUBTOTAL 8.	$38,333	$967	$11,883	$0	$0	$51,183	$4,821	$0	$7,559	$63,564	$117

Exhibit 3-41 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$7,155	$0	$1,302	$0	$0	$8,457	$805	$0	$1,389	$10,652	$20
9.2	Circulating Water Pumps	$1,856	$0	$134	$0	$0	$1,990	$168	$0	$324	$2,481	$5
9.3	Circ.Water System Auxiliaries	$155	$0	$22	$0	$0	$177	$17	$0	$29	$224	$0
9.4	Circ.Water Piping	$0	$6,481	$1,680	$0	$0	$8,161	$738	$0	$1,780	$10,679	$20
9.5	Make-up Water System	$388	$0	$555	$0	$0	$943	$90	$0	$207	$1,240	$2
9.6	Component Cooling Water Sys	$765	$915	$651	$0	$0	$2,331	$218	$0	$510	$3,060	$6
9.9	Circ.Water System Foundations	$0	$2,379	$4,044	$0	$0	$6,423	$609	$0	$2,110	$9,142	$17
	SUBTOTAL 9.	$10,319	$9,775	$8,388	$0	$0	$28,483	$2,646	$0	$6,348	$37,477	$69
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$12,136	$6,692	$13,595	$0	$0	$32,424	$3,129	$0	$3,555	$39,109	$72
10.2	Gasifier Ash Depressurization	w/10.1	w/10.1	w/10.1	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	w/10.1	w/10.1	w/10.1	$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 Recovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$589	$0	$641	$0	$0	$1,229	$119	$0	$202	$1,551	$3
10.7	Ash Transport & Feed Equipment	$790	$0	$190	$0	$0	$980	$91	$0	$161	$1,232	$2
10.8	Misc. Ash Handling Equipment	$1,219	$1,494	$446	$0	$0	$3,160	$301	$0	$519	$3,980	$7
10.9	Ash/Spent Sorbent Foundation	$0	$52	$65	$0	$0	$117	$11	$0	$39	$167	$0
	SUBTOTAL 10.	$14,734	$8,239	$14,938	$0	$0	$37,910	$3,652	$0	$4,476	$46,038	$85
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$947	$0	$937	$0	$0	$1,885	$180	$0	$206	$2,271	$4
11.2	Station Service Equipment	$4,697	$0	$423	$0	$0	$5,121	$472	$0	$559	$6,152	$11
11.3	Switchgear & Motor Control	$8,684	$0	$1,579	$0	$0	$10,264	$952	$0	$1,682	$12,898	$24
11.4	Conduit & Cable Tray	$0	$4,034	$13,308	$0	$0	$17,342	$1,677	$0	$4,755	$23,775	$44
11.5	Wire & Cable	$0	$7,708	$5,064	$0	$0	$12,772	$928	$0	$3,425	$17,125	$32
11.6	Protective Equipment	$0	$686	$2,496	$0	$0	$3,182	$311	$0	$524	$4,016	$7
11.7	Standby Equipment	$234	$0	$228	$0	$0	$462	$44	$0	$76	$581	$1
11.8	Main Power Transformers	$17,500	$0	$144	$0	$0	$17,644	$1,334	$0	$2,847	$21,825	$40
11.9	Electrical Foundations	$0	$156	$410	$0	$0	$567	$54	$0	$186	$807	$1
	SUBTOTAL 11.	$32,062	$12,584	$24,591	$0	$0	$69,237	$5,953	$0	$14,261	$89,451	$165
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	w/6.1	$0	w/6.1	$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	$1,126	$0	$752	$0	$0	$1,877	$178	$94	$322	$2,471	$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	$259	$0	$166	$0	$0	$425	$40	$21	$97	$583	$1
12.7	Computer & Accessories	$6,005	$0	$192	$0	$0	$6,197	$569	$310	$708	$7,784	$14
12.8	Instrument Wiring & Tubing	$0	$2,098	$4,288	$0	$0	$6,386	$542	$319	$1,812	$9,059	$17
12.9	Other I & C Equipment	$4,014	$0	$1,949	$0	$0	$5,963	$561	$298	$1,023	$7,846	$14
	SUBTOTAL 12.	$11,404	$2,098	$7,347	$0	$0	$20,849	$1,889	$1,042	$3,962	$27,743	$51

Exhibit 3-41 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$109	$2,337	$0	$0	$2,447	$243	$0	$807	$3,496	$6
13.2	Site Improvements	$0	$1,945	$2,585	$0	$0	$4,530	$447	$0	$1,493	$6,470	$12
13.3	Site Facilities	$3,485	$0	$3,678	$0	$0	$7,163	$706	$0	$2,361	$10,230	$19
	SUBTOTAL 13.	$3,485	$2,054	$8,600	$0	$0	$14,140	$1,396	$0	$4,661	$20,196	$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	$2,377	$3,387	$0	$0	$5,764	$530	$0	$944	$7,238	$13
14.3	Administration Building	$0	$882	$640	$0	$0	$1,522	$136	$0	$249	$1,906	$4
14.4	Circulation Water Pumphouse	$0	$166	$88	$0	$0	$253	$22	$0	$41	$317	$1
14.5	Water Treatment Buildings	$0	$600	$585	$0	$0	$1,185	$107	$0	$194	$1,486	$3
14.6	Machine Shop	$0	$452	$309	$0	$0	$761	$68	$0	$124	$952	$2
14.7	Warehouse	$0	$729	$471	$0	$0	$1,200	$106	$0	$196	$1,502	$3
14.8	Other Buildings & Structures	$0	$437	$340	$0	$0	$777	$69	$0	$169	$1,015	$2
14.9	Waste Treating Building & Str.	$0	$976	$1,865	$0	$0	$2,841	$265	$0	$621	$3,728	$7
	SUBTOTAL 14.	$0	$6,882	$7,834	$0	$0	$14,716	$1,340	$0	$2,628	$18,684	$34
	TOTAL COST	$723,574	$76,529	$303,902	$0	$0	$1,104,005	$103,905	$64,468	$200,468	$1,472,845	$2,711

Owner's Costs	$	$/kW
Preproduction Costs		
6 Months All Labor	$13,488	$25
1 Month Maintenance Materials	$2,998	$6
1 Month Non-fuel Consumables	$384	$1
1 Month Waste Disposal	$318	$1
25% of 1 Months Fuel Cost at 100% CF	$1,697	$3
2% of TPC	$29,457	$54
Total	$48,341	$89
Inventory Capital		
60 day supply of fuel and consumables at 100% CF	$14,068	$26
0.5% of TPC (spare parts)	$7,364	$14
Total	$21,432	$39
Initial Cost for Catalyst and Chemicals	$7,199	$13
Land	$900	$2
Other Owner's Costs	$220,927	$407
Financing Costs	$39,767	$73
Total Overnight Costs (TOC)	$1,811,411	$3,334
TASC Multiplier (IOU, high-risk, 35 year)	1.140	
Total As-Spent Cost (TASC)	$2,065,009	$3,801

Exhibit 3-42 Case 2 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun):	2007	
Case 2 - GEE Radiant 550MW IGCC w/ CO2					Heat Rate-net (Btu/kWh):	10,458	
					MWe-net:	543	
					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				

Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.	Total Plant	
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	$6,313,507	$11.622
Maintenance Labor Cost	$15,266,708	$28.103
Administrative & Support Labor	$5,395,054	$9.931
Property Taxes and Insurance	$29,456,896	$54.223
TOTAL FIXED OPERATING COSTS	**$56,432,165**	**$103.879**

VARIABLE OPERATING COSTS							$/kWh-net
Maintenance Material Cost						**$28,779,845**	**$0.00756**

Consumables	Consumption Initial Fill	/Day	Unit Cost	Initial Fill Cost			
Water (/1000 gallons)	0	4,187	1.08	$0	$1,322,398		$0.00035
Chemicals							
MU & WT Chem. (lbs)	0	24,944	0.17	$0	$1,260,554		$0.00033
Carbon (Mercury Removal) (lb)	79,786	109	1.05	$83,789	$33,516		$0.00001
COS Catalyst (m3)	0	0	2,397.36	$0	$0		$0.00000
Water Gas Shift Catalyst (ft3)	6,246	4.28	498.83	$3,115,855	$623,171		$0.00016
Selexol Solution (gal)	298,502	95	13.40	$3,999,401	$371,618		$0.00010
SCR Catalyst (m3)	0	0	0.00	$0	$0		$0.00000
Ammonia (19% NH3) (ton)	0	0	0.00	$0	$0		$0.00000
Claus Catalyst (ft3)	w/equip	2.01	131.27	$0	$77,209		$0.00002
Subtotal-Chemicals				$7,199,046	$2,366,068		$0.00062
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	109	0.42	$0	$13,311		$0.00000
Flyash (ton)	0	0	0.00	$0	$0		$0.00000
Slag (ton)	0	641	16.23	$0	$3,037,841		$0.00080
Subtotal Waste Disposal				$0	$3,051,152		$0.00080
By-products & Emissions	0	0	0.00		$0		$0.00000
Sulfur (ton)	0	146	0.00	$0	$0		$0.00000
Subtotal By-products				$0	$0		$0.00000
TOTAL VARIABLE OPERATING COSTS				$7,199,046	$35,519,462		$0.00933
Fuel (ton)	0	5,844	38.18	$0	$65,161,317		$0.01712

3.3   CONOCOPHILLIPS E-GAS^{TM} IGCC CASES

This section contains an evaluation of plant designs for Cases 3 and 4, which are based on the CoP E-Gas™ gasifier. Cases 3 and 4 are very similar in terms of process, equipment, scope and arrangement, except that Case 4 includes SGS reactors, CO_2 absorption/regeneration and compression/transport systems. There are no provisions for CO_2 removal in Case 3.

The balance of this section is organized in an analogous manner to Section 3.2:

- Gasifier Background

- Process System Description for Case 3

- Key Assumptions for Cases 3 and 4

- Sparing Philosophy for Cases 3 and 4

- Performance Results for Case 3

- Equipment List for Case 3

- Cost Estimates for Case 3

- Process and System Description, Performance Results, Equipment List, and Cost Estimate for Case 4

3.3.1   <u>Gasifier Background</u>

Dow Chemical (the former principal stockholder of Destec Energy, which was bought by Global Energy, Inc., the gasifier business that was later purchased by CoP is a major producer of chemicals. They began coal gasification development work in 1976 with bench-scale (2 kg/hr [4 lb/hr]) reactor testing. Important fundamental data were obtained for conversion and yields with various coals and operating conditions. This work led to the construction of a pilot plant at Dow's large chemical complex in Plaquemine, Louisiana. The pilot plant was designed for a capacity of 11 tonnes/day (12 TPD) (dry lignite basis) and was principally operated with air as the oxidant. The plant also operated with oxygen at an increased capacity of 33 tonnes/day (36 TPD) (dry lignite basis). This pilot plant operated from 1978 through 1983.

Following successful operation of the pilot plant, Dow built a larger 499 tonnes/day (550 TPD) (dry lignite basis) gasifier at Plaquemine. In 1984, Dow Chemical and the U.S. Synthetic Fuels Corporation (SFC) announced a price guarantee contract, which allowed the building of the first commercial-scale Dow coal gasification unit. The Louisiana Gasification Technology, Inc. (LGTI) plant, sometimes called the Dow Syngas Project, was also located in the Dow Plaquemine chemical complex. The plant gasified about 1,451 tonnes/day (1,600 TPD) (dry basis) of subbituminous coal to generate 184 MW (gross) of combined-cycle electricity. To ensure continuous power output to the petrochemical complex, a minimum of 20 percent of natural gas was co-fired with the syngas. LGTI was operated from 1987 through 1995.

In September 1991, DOE selected the Wabash River coal gasification repowering project, which used the Destec Energy process, for funding under the Clean Coal Technology Demonstration Program. The project was a joint venture of Destec and Public Service of Indiana (PSI Energy, Inc.). Its purpose was to repower a unit at PSI's Wabash River station in West Terre Haute, Indiana to produce 265 MW of net power from local high-sulfur bituminous coal. The design of

the project gasifier was based on the Destec LGTI gasifier. Experience gained in that project provided significant input to the design of the Wabash River coal gasification facility and eliminated much of the risk associated with scale-up and process variables.

Gasifier Capacity – The gasifier originally developed by Dow is now known as the CoP E-Gas™ gasifier. The daily coal-handling capacity of the E-Gas gasifier operating at Plaquemine was in the range of 1,270 tonnes (1,400 tons) (moisture/ash-free [MAF] basis) for bituminous coal to 1,497 tonnes (1,650 tons) for lignite. The dry gas production rate was 141,600 Nm^3/hr (5 million scf/hr) with an energy content of about 1,370 MMkJ/hr (1,300 MMBtu/hr) (HHV). The daily coal-handling capacity of the gasifier at Wabash River is about 1,678 tonnes (1,850 tons) (MAF basis) for high-sulfur bituminous coal. The dry gas production rate is about 189,724 Nm^3/hr (6.7 million scf/hr) with an energy content of about 1,950 MMkJ/hr (1,850 MMBtu/hr) (HHV). This size matches the CT, which is a GE 7FA.

With increased power and fuel GT demand, the gasifier coal feed increases proportionately. CoP has indicated that the gasifier can readily handle the increased demand.

Distinguishing Characteristics - A key advantage of the CoP coal gasification technology is the current operating experience with subbituminous coal at full commercial scale at the Plaquemine plant and bituminous coal at the Wabash plant. The two-stage operation improves the efficiency, reduces oxygen requirements, and enables more effective operation on slurry feeds relative to a single stage gasifier. The fire-tube SGC used by E-Gas has a lower capital cost than a water-tube design, an added advantage for the CoP technology at this time. However, this experience may spur other developers to try fire-tube designs.

Entrained-flow gasifiers have fundamental environmental advantages over fluidized-bed and moving-bed gasifiers. They produce no hydrocarbon liquids, and the only solid waste is an inert slag.

The key disadvantages of the CoP coal gasification technology are the relatively short refractory life and the high waste heat recovery (SGC) duty. As with the other entrained-flow slagging gasifiers, these disadvantages result from high operating temperature. However, the two-stage operation results in a quenched syngas that is higher in CH_4 content than other gasifiers. This becomes a disadvantage in CO_2 capture cases since the CH_4 passes through the SGS reactors without change, and is also not separated by the AGR thus limiting the amount of carbon that can be captured.

Important Coal Characteristics - The slurry feeding system and the recycle of process condensate water as the principal slurrying liquid make low levels of ash and soluble salts desirable coal characteristics for use in the E-Gas™ coal gasification process. High ash levels increase the ratio of water to carbon in the coal in the feed slurry, thereby increasing the oxygen requirements. Soluble salts affect the processing cost and amount of water blowdown required to avoid problems associated with excessive buildup of salts in the slurry water recycle loop.

Bituminous coals with lower inherent moisture improve the slurry concentration and reduce oxygen requirements. The two-stage operation reduces the negative impact of low-rank coal use in slurry feed, entrained-flow gasification. Low to moderate ash fusion-temperature coals are preferred for slagging gasifiers. Coals with high ash fusion temperatures may require flux addition for optimal gasification operation.

3.3.2   Process Description

In this section the overall CoP gasification process is described. The system description follows the BFD in Exhibit 3-43 and stream numbers reference the same exhibit. The tables in Exhibit 3-44 provide process data for the numbered streams in the BFD.

Coal Grinding and Slurry Preparation

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. Coal grinding and slurry preparation is similar to the GEE cases but repeated here for completeness.

Coal from the coal silo is fed onto a conveyor by vibratory feeders located below each silo. The conveyor feeds the coal to an inclined conveyor that delivers the coal to the rod mill feed hopper. The feed hopper provides a surge capacity of about two hours and contains two hopper outlets. Each hopper outlet discharges onto a weigh feeder, which in turn feeds a rod mill. Each rod mill is sized to process 55 percent of the coal feed requirements of the gasifier. The rod mill grinds the coal and wets it with treated slurry water transferred from the slurry water tank by the slurry water pumps. The coal slurry is discharged through a trommel screen into the rod mill discharge tank, and then the slurry is pumped to the slurry storage tanks. The dry solids concentration of the final slurry is 63 percent. The Polk Power Station operates at a slurry concentration of 62-68 percent using bituminous coal and CoP presented a paper showing the slurry concentration of Illinois No. 6 coal as 63 percent [58].

The coal grinding system is equipped with a dust suppression system consisting of water sprays aided by a wetting agent. The degree of dust suppression required depends on local environmental regulations. All of the tanks are equipped with vertical agitators to keep the coal slurry solids suspended.

The equipment in the coal grinding and slurry preparation system is fabricated of materials appropriate for the abrasive environment present in the system. The tanks and agitators are rubber lined. The pumps are either rubber-lined or hardened metal to minimize erosion. Piping is fabricated of HDPE.

Gasification

This plant utilizes two gasification trains to process a total of 5,007 tonnes/day (5,519 TPD) of Illinois No. 6 coal. Each of the 2 x 50 percent gasifiers operate at maximum capacity. The E-Gas™ two-stage coal gasification technology features an oxygen-blown, entrained-flow, refractory-lined gasifier with continuous slag removal. About 78 percent of the total slurry feed is fed to the first (or bottom) stage of the gasifier. The air separation plant supplies 3,711 tonnes/day (4,090 TPD) of 95 percent oxygen to the gasifiers (stream 5) and the Claus plant (stream 3). All oxygen for gasification is fed to this stage of the gasifier at a pressure of 4.2 MPa (615 psia). This stage is best described as a horizontal cylinder with two horizontally opposed burners. The highly exothermic gasification/oxidation reactions take place rapidly at temperatures of 1,316 to 1,427°C (2,400 to 2,600°F). The hot raw gas from the first stage enters the second (top) stage, which is a vertical cylinder perpendicular to the first stage. The remaining 22 percent of coal slurry is injected into this hot raw gas. The endothermic gasification/devolatilization reaction in this stage reduces the final gas temperature to about 1,038°C (1,900°F). Total slurry to both stages is shown as stream 7 in Exhibit 3-43.

Exhibit 3-43 Case 3 Block Flow Diagram, E-Gas™ IGCC without CO₂ Capture

Exhibit 3-44 Case 3 Stream Table, E-Gas™ IGCC without CO$_2$ Capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0241	0.0318	0.0023	0.0318	0.0000	0.0000	0.0000	0.0000	0.0078	0.0078	0.0096
CH$_4$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0465	0.0465	0.0575
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3011	0.3011	0.3727
CO$_2$	0.0003	0.0083	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1556	0.1559	0.1929
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0003	0.0000	0.0000
H$_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2724	0.2724	0.3372
H$_2$O	0.0099	0.2163	0.0000	0.0003	0.0000	1.0000	0.0000	0.9968	0.0000	0.1889	0.1885	0.0015
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	0.0002	0.0000
H$_2$S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0072	0.0075	0.0092
N$_2$	0.7732	0.5460	0.0178	0.9919	0.0178	0.0000	0.0000	0.0000	0.0000	0.0157	0.0157	0.0194
NH$_3$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0032	0.0000	0.0045	0.0045	0.0000
O$_2$	0.2074	0.2054	0.9504	0.0054	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
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg$_{mol}$/hr)	18,976	916	111	17,427	4,694	3,766	0	4,758	0	21,817	21,817	17,626
V-L Flowrate (kg/hr)	547,576	24,820	3,567	489,004	151,056	67,848	0	85,707	0	459,732	459,732	384,240
Solids Flowrate (kg/hr)	0	0	0	0	0	0	208,634	0	21,295	0	0	0
Temperature (°C)	15	20	32	93	32	343	15	149	1,038	186	186	35
Pressure (MPa, abs)	0.10	0.11	0.86	2.65	0.86	5.10	0.10	5.79	4.24	4.07	4.00	3.83
Enthalpy (kJ/kg)^A	30.23	36.92	26.67	92.52	26.67	0.00	---	567.36	---	673.10	672.88	39.55
Density (kg/m^3)	1.2	1.6	11.0	24.4	11.0	20.1	---	862.4	---	22.7	22.3	33.0
V-L Molecular Weight	28.857	27.090	32.181	28.060	32.181	18.015	---	18.012	---	21.073	21.073	21.799
V-L Flowrate (lb$_{mol}$/hr)	41,834	2,020	244	38,420	10,348	8,303	0	10,490	0	48,098	48,098	38,859
V-L Flowrate (lb/hr)	1,207,199	54,719	7,864	1,078,070	333,021	149,578	0	188,951	0	1,013,536	1,013,536	847,104
Solids Flowrate (lb/hr)	0	0	0	0	0	0	459,958	0	46,947	0	0	0
Temperature (°F)	59	69	90	199	90	650	59	300	1,900	367	367	95
Pressure (psia)	14.7	16.4	125.0	384.0	125.0	740.0	14.7	840.0	615.0	590.0	580.0	555.0
Enthalpy (Btu/lb)^A	13.0	15.9	11.5	39.8	11.5		---	243.9	---	289.4	289.3	17.0
Density (lb/ft^3)	0.076	0.098	0.687	1.521	0.687	1.257	---	53.837	---	1.416	1.391	2.061
A - Reference conditions are 32.02 F & 0.089 PSIA												

Exhibit 3-44 Case 3 Stream Table (Continued)

	13	14	15	16	17	18	19	20	21	22	23	24	25
V-L Mole Fraction													
Ar	0.0095	0.0098	0.0085	0.0085	0.0000	0.0000	0.0041	0.0055	0.0092	0.0092	0.0087	0.0087	0.0000
CH$_4$	0.0555	0.0576	0.0500	0.0500	0.0002	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.3597	0.3734	0.3241	0.3241	0.0010	0.0000	0.0848	0.0061	0.0000	0.0000	0.0000	0.0000	0.0000
CO$_2$	0.2137	0.1931	0.1676	0.1676	0.7537	0.0000	0.4983	0.7790	0.0003	0.0003	0.0803	0.0803	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0003	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H$_2$	0.3299	0.3425	0.2973	0.2973	0.0009	0.0000	0.0209	0.1311	0.0000	0.0000	0.0000	0.0000	0.0000
H$_2$O	0.0015	0.0015	0.1333	0.1333	0.0000	0.0000	0.3350	0.0018	0.0099	0.0099	0.0860	0.0860	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H$_2$S	0.0090	0.0000	0.0000	0.0000	0.2443	0.0000	0.0014	0.0043	0.0000	0.0000	0.0000	0.0000	0.0000
N$_2$	0.0213	0.0221	0.0192	0.0192	0.0000	0.0000	0.0537	0.0723	0.7732	0.7732	0.7250	0.7250	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	0.0000	0.0000
O$_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2074	0.2074	0.1000	0.1000	0.0000
SO$_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0013	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
V-L Flowrate (kg$_{mol}$/hr)	18,275	17,601	20,276	20,276	674	0	873	649	110,253	4,410	137,246	137,246	40,181
V-L Flowrate (kg/hr)	408,330	380,350	428,548	428,548	27,980	0	28,108	24,090	3,181,557	127,262	3,971,848	3,971,848	723,874
Solids Flowrate (kg/hr)	0	0	0	0	0	5,215	0	0	0	0	0	0	0
Temperature (°C)	34	45	143	193	45	175	232	38	15	432	588	132	561
Pressure (MPa, abs)	3.79	3.76	3.21	3.2	3.757	0.409	0.406	5.512	0.101	1.619	0.105	0.105	12.512
Enthalpy (kJ/kg)^A	36.82	55.08	489.40	569.9	-0.670	---	731.470	-6.625	30.227	463.785	783.868	272.294	3,500.624
Density (kg/m^3)	33.7	31.0	19.7	17.3	73.5	5,285.4	3.1	96.3	1.2	7.9	0.4	0.9	35.2
V-L Molecular Weight	22.344	21.610	21.135	21	41.529	---	32.209	37.141	28.857	28.857	28.940	28.940	18.015
V-L Flowrate (lb$_{mol}$/hr)	40,289	38,804	44,702	44,702	1,485	0	1,924	1,430	243,066	9,723	302,576	302,576	88,584
V-L Flowrate (lb/hr)	900,213	838,528	944,788	944,788	61,685	0	61,967	53,110	7,014,133	280,565	8,756,427	8,756,427	1,595,870
Solids Flowrate (lb/hr)	0	0	0	0	0	11,497	0	0	0	0	0	0	0
Temperature (°F)	94	112	290	380	112	347	450	100	59	810	1,091	270	1,041
Pressure (psia)	550.0	545.0	465.0	460.0	545.0	59.3	58.9	799.5	14.7	234.9	15.2	15.2	1,814.7
Enthalpy (Btu/lb)^A	15.8	23.7	210.4	245.0	-0.3	---	314.5	-2.8	13.0	199.4	337.0	117.1	1,505.0
Density (lb/ft^3)	2.105	1.938	1.230	1	4.586	329.954	0.195	6.012	0.076	0.495	0.026	0.056	2.194

The syngas produced by the CoP gasifier is higher in methane content than either the GEE or Shell gasifier. The two stage design allows for improved cold gas efficiency (CGE) and lower oxygen consumption, but the quenched second stage allows some CH_4 to remain. The syngas CH_4 concentration exiting the gasifier in Case 3 is 4.3 vol% (compared to 0.10 vol% in Case 1 [GEE] and 0.001 vol% in Case 5 [Shell]). The relatively high CH_4 concentration impacts CO_2 capture efficiency as discussed further in Section 3.3.8.

Raw Gas Cooling/Particulate Removal

The raw syngas, less than 1,038°C (1,900°F), from the second stage of the gasifier is cooled to 316°C (600°F) in the waste heat recovery (SGC) unit, which consists of a fire-tube boiler and convective superheating and economizing sections. 554,830 kg/hr (1,223,171 lb/hr) of HP saturated steam is raised as a result of the raw gas cooling. Fire-tube boilers cost markedly less than comparable duty water-tube boilers. This is because of the large savings in high-grade steel associated with containing the hot HP syngas in relatively small tubes.

The coal ash is converted to molten slag, which flows down through a tap hole. The molten slag is quenched in water and removed through a proprietary continuous-pressure letdown/dewatering system (stream 9). Char is produced in the second gasifier stage and is captured and recycled to the hotter first stage to be gasified.

The cooled gas from the SGC is cleaned of remaining particulate via a cyclone collector followed by a ceramic candle filter. Recycled syngas is used as the pulse gas to clean the candle filters. The recovered fines are pneumatically returned to the first stage of the gasifier. The combination of recycled char and recycled particulate results in high overall carbon conversion (99.2 percent used in this study).

Following particulate removal, additional heat is removed from the syngas to raise saturated IP steam at 0.4 MPa (65 psia). In this manner the syngas is cooled to 232°C (450°F) prior to the syngas scrubber.

Syngas Scrubber/Sour Water Stripper

Syngas exiting the second of the two low temperature heat exchangers passes to a syngas scrubber where a water wash is used to remove chlorides, SO_2, NH_3, and particulate. The syngas exits the scrubber saturated at 169°C (337°F).

The sour water stripper removes NH_3, SO_2, and other impurities from the scrubber and other waste streams. The stripper consists of a sour drum that accumulates sour water from the gas scrubber and condensate from SGCs. 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 SRU. Remaining water is sent to wastewater treatment.

COS Hydrolysis, Mercury Removal and Acid Gas Removal

Syngas exiting the scrubber is reheated to 186°C (367°F) by using HP steam from the HRSG evaporator prior to entering a COS hydrolysis reactor (stream 10). About 99.5 percent of the COS is converted to CO_2 and H_2O (Section 3.1.5). The gas exiting the COS reactor (stream 11) passes through a series of heat exchangers and KO drums to lower the syngas temperature to 35°C (95°F) and to separate entrained water. The cooled syngas (stream 12) then passes through a carbon bed to remove 95 percent of the Hg (Section 3.1.4).

Cool, particulate-free syngas (stream 13) enters the absorber unit at approximately 3.8 MPa (550 psia) and 34°C (94°F). In the absorber, H_2S is preferentially removed from the fuel gas stream by contact with MDEA. The absorber column is operated at 44°C (112°F) by refrigerating the lean MDEA solvent. The lower temperature is required to achieve an outlet H_2S concentration of less than 30 ppmv in the sweet syngas. The stripper acid gas stream (stream 17), consisting of 24 percent H_2S and 75 percent CO_2, is sent to the Claus unit. The acid gas is combined with the sour water stripper off gas and introduced into the Claus plant burner section.

Claus Unit

Acid gas from the MDEA unit is preheated to 232°C (450°F). A portion of the acid gas along with all of the sour gas from the stripper and oxygen from the ASU are fed to the Claus furnace. In the furnace, H_2S is catalytically oxidized to SO_2 at a furnace temperature of 1,316°C (2,400°F), which must be maintained in order to thermally decompose all of the NH_3 present in the sour gas stream.

Following the thermal stage and condensation of sulfur, two reheaters and two sulfur converters are used to obtain a per-pass H_2S conversion of approximately 99.5 percent. The Claus Plant tail gas is hydrogenated and recycled back to the gasifier (stream 20). In the furnace waste heat boiler, 13,866 kg/hr (30,568 lb/hr) of 3.0 MPa (430 psia) 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 LP steam header and IP steam at 2.9 MPa (415 psig).

A flow rate of 5,215 kg/hr (11,497 lb/hr) of elemental sulfur (stream 18) is recovered from the fuel gas stream. This value represents an overall sulfur recovery efficiency of 99.7 percent.

Power Block

Clean syngas exiting the MDEA absorber (stream 14) is partially humidified (stream 15) because there is not sufficient nitrogen from the ASU to provide the level of dilution required to reach the target syngas heating value. The moisturized syngas stream is reheated (stream 16), further diluted with nitrogen from the ASU (stream 4) and enters the advanced F Class CT burner. The CT compressor provides combustion air to the burner and also 19 percent of the total ASU air requirement (stream 22). The exhaust gas exits the CT at 588°C (1,091°F) (stream 23) and enters the HRSG where additional heat is recovered until the FG exits the HRSG at 132°C (270°F) (stream 24) 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 12.4 MPa/561°C/561°C (1800 psig/1041°F/1041°F) steam cycle.

Air Separation Unit

The elevated pressure ASU was described in Section 3.1.2. In Case 3, the ASU is designed to produce a nominal output of 3,711 tonnes/day (4,091 TPD) of 95 mol% O_2 for use in the gasifier (stream 5) and Claus plant (stream 3). The plant is designed with two production trains. The air compressor is powered by an electric motor. Approximately 11,736 tonnes/day (12,937 TPD) of nitrogen are also recovered, compressed, and used as dilution in the GT combustor (stream 4). About 4 percent of the GT air is used to supply approximately 19 percent of the ASU air requirements (stream 22).

Balance of Plant

Balance of plant items were covered in Sections 3.1.9, 3.1.10, and 3.1.11.

3.3.3 Key System Assumptions

System assumptions for Cases 3 and 4, CoP IGCC with and without CO_2 capture, are compiled in Exhibit 3-45.

Balance of Plant – Cases 3 and 4

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

3.3.4 Sparing Philosophy

The sparing philosophy for Cases 3 and 4 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 ASUs (2 x 50%)

- Two trains of slurry preparation and slurry pumps (2 x 50%)

- Two trains of gasification, including gasifier, SGC, cyclone, and candle filter (2 x 50%).

- Two trains of syngas clean-up process (2 x 50%).

- Two trains of refrigerated MDEA AGR in Case 3 and two-stage Selexol in Case 4 (2 x 50%),

- One train of Claus-based sulfur recovery (1 x 100%).

- Two CT/HRSG tandems (2 x 50%).

- One steam turbine (1 x 100%).

Exhibit 3-45 CoP IGCC Plant Study Configuration Matrix

Case	3	4
Gasifier Pressure, MPa (psia)	4.2 (615)	4.2 (615)
O_2:Coal Ratio, kg O_2/kg dry coal	0.81	0.88
Carbon Conversion, %	99.2	99.2
Syngas HHV at Gasifier Outlet, kJ/Nm^3 (Btu/scf)	8,319 (223)	7,021 (189)
Steam Cycle, MPa/°C/°C (psig/°F/°F)	12.4/561/561 (1800/1041/1041)	12.4/534/534 (1800/994/994)
Condenser Pressure, mm Hg (in Hg)	51 (2.0)	51 (2.0)
CT	2x Advanced F Class (232 MW output each)	2x Advanced F Class (232 MW output each)
Gasifier Technology	CoP E-Gas™	CoP E-Gas™
Oxidant	95 vol% Oxygen	95 vol% Oxygen
Coal	Illinois No. 6	Illinois No. 6
Coal Slurry Solids Content, %	63	63
COS Hydrolysis	Yes	Occurs in SGS
SGS	No	Yes
H_2S Separation	Refrigerated MDEA	Selexol 1st Stage
Sulfur Removal, %	99.7	99.9
Sulfur Recovery	Claus Plant with Tail Gas Recycle to Gasifier/ Elemental Sulfur	Claus Plant with Tail Gas Recycle to Gasifier/ 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), N_2 Dilution and Humidification	MNQC (LNB), N_2 Dilution and Humidification
CO_2 Separation	N/A	Selexol 2nd Stage
Overall CO_2 Capture	N/A	90.4%
CO_2 Sequestration	N/A	Off-site Saline Formation

3.3.5 Case 3 Performance Results

The plant produces a net output of 625 MWe at a net plant efficiency of 39.7 percent (HHV basis).

Overall performance for the entire plant is summarized in Exhibit 3-46, which includes auxiliary power requirements. The ASU accounts for approximately 76 percent of the total auxiliary load distributed between the main air compressor, the oxygen compressor, the nitrogen compressor, and ASU auxiliaries. The cooling water system, including the CWPs and cooling tower fan, accounts for approximately 5 percent of the auxiliary load, and the BFW pumps account for an additional 3.9 percent. All other individual auxiliary loads are less than 3.5 percent of the total.

Exhibit 3-46 Case 3 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	464,000
Sweet Gas Expander Power	0
Steam Turbine Power	274,200
TOTAL POWER, kWe	**738,200**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	460
Coal Milling	2,150
Sour Water Recycle Slurry Pump	180
Slag Handling	1,100
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	46,700
Oxygen Compressor	7,920
Nitrogen Compressors	29,910
Boiler Feedwater Pumps	4,410
Condensate Pump	240
Syngas Recycle Compressor	810
Circulating Water Pump	3,880
Ground Water Pumps	400
Cooling Tower Fans	2,010
Scrubber Pumps	320
Acid Gas Removal	3,150
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	250
Claus Plant TG Recycle Compressor	1,610
Miscellaneous Balance of Plant[2]	3,000
Transformer Losses	2,540
TOTAL AUXILIARIES, kWe	**113,140**
NET POWER, kWe	**625,060**
Net Plant Efficiency, % (HHV)	39.7
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,057 (8,585)
CONDENSER COOLING DUTY 10^6 kJ/hr (10^6 Btu/hr)	**1,414 (1,340)**
CONSUMABLES	
As-Received Coal Feed, kg/hr (lb/hr)	208,634 (459,958)
Thermal Input[1], kWt	1,572,582
Raw Water Withdrawal, m^3/min (gpm)	16.5 (4,367)
Raw Water Consumption, m^3/min (gpm)	13.1 (3,465)

1 - HHV of As-Received Illinois No. 6 coal is 27,135 kJ/kg (11,666 Btu/lb)

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 PM were presented in Section 2.4. A summary of the plant air emissions for Case 3 is presented in Exhibit 3-47.

Exhibit 3-47 Case 3 Air Emissions

	kg/GJ (lb/10[6] Btu)	Tonne/year (ton/year) 80% capacity factor	kg/MWh (lb/MWh)
SO_2	0.005 (0.012)	200 (220)	0.039 (.09)
NOx	0.026 (0.060)	1,017 (1,122)	0.197 (.434)
Particulates	0.003 (0.0071)	121 (133)	0.023 (.052)
Hg	2.46E-7 (5.71E-7)	0.010 (0.011)	1.88E-6 (4.15E-6)
CO_2	85.7 (199.2)	3,398,362 (3,746,053)	657 (1,448)
CO_2[1]			776 (1,710)

[1] CO_2 emissions based on net power instead of gross power

The low level of SO_2 in the plant emissions is achieved by capture of the sulfur in the gas by the refrigerated Coastal SS Specialty Amine (SS Amine) AGR process. The AGR process removes 99.7 percent of the sulfur compounds in the fuel gas down to a level of less than 30 ppmv. This results in a concentration in the FG of less than 4 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 to convert all sulfur species to H_2S and then recycled back to the gasifier, thereby eliminating the need for a tail gas treatment unit.

NOx emissions are limited by the use of nitrogen dilution (primarily) and humidification (to a lesser extent) 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 NOx 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 the plant is shown in Exhibit 3-48. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag and CO_2 in the stack gas and ASU vent gas.

Exhibit 3-48 Case 3 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	132,993 (293,199)	Slag	1,064 (2,346)
Air (CO_2)	507 (1,118)	Stack Gas	132,344 (291,769)
		ASU Vent	92 (202)
		CO_2 Product	0 (0)
Total	133,500 (294,317)	Total	133,500 (294,317)

Exhibit 3-49 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant and sulfur emitted in the stack gas. Sulfur in the slag is considered to be negligible.

Exhibit 3-49 Case 3 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	5,229 (11,528)	Elemental Sulfur	5,215 (11,497)
		Stack Gas	14 (31)
		CO_2 Product	0 (0)
Total	5,229 (11,528)	Total	5,229 (11,528)

Exhibit 3-50 shows the overall water balance for the plant. The water balance was explained in Case 1 [GEE], but is also presented here for completeness.

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

Exhibit 3-50 Case 3 Water Balance

Water Use	Water Demand, m³/min (gpm)	Internal Recycle, m³/min (gpm)	Raw Water Withdrawal, m³/min (gpm)	Process Water Discharge, m³/min (gpm)	Raw Water Consumption, m³/min (gpm)
Slag Handling	0.46 (122)	0.46 (122)	0.0 (0)	0.0 (0)	0.0 (0)
Slurry Water	1.43 (378)	0.99 (263)	0.4 (115)	0.0 (0)	0.4 (115)
Quench/Wash	0.0 (0)	0.0 (0)	0.0 (0)	0.0 (0)	0.0 (0)
Humidifier	0.8 (222)	0.8 (222)	0.0 (0)	0.0 (0)	0.0 (0)
SWS Blowdown	0.0 (0)	0.0 (0)	0.0 (0)	0.01 (4)	-0.01 (-4)
Condenser Makeup *Gasifier Steam* *Shift Steam* *GT Steam Dilution* *BFW Makeup*	**1.3 (354)** *1.1 (299)* *0.21 (55)*	**0.0 (0)**	**1.3 (354)** *1.1 (299)* *0.21 (55)*	**0.0 (0)**	**1.3 (354)**
Cooling Tower *BFW Blowdown* *SWS Blowdown* *SWS Excess Water* *Humidifier Tower Blowdown*	**15.1 (3,991)** *0.21 (55)* *0.15 (38)*	**0.35 (93)** *0.21 (55)* *0.15 (38)*	**14.8 (3,898)** *-0.21 (-55)* *-0.15 (-38)*	**3.4 (897)**	**11.4 (3,000)**
Total	**19.2 (5,067)**	**2.65 (700)**	**16.5 (4,367)**	**3.4 (901)**	**13.1 (3,465)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-51 through Exhibit 3-53:

- Coal gasification and ASU

- Syngas cleanup, sulfur recovery, and tail gas recycle

- Combined cycle power generation, steam, and FW

An overall plant energy balance is provided in tabular form in Exhibit 3-54. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-46) is calculated by multiplying the power out by a combined generator efficiency of 98.3 percent.

Exhibit 3-51 Case 3 Coal Gasification and Air Separation Unit Heat and Mass Balance Schematic
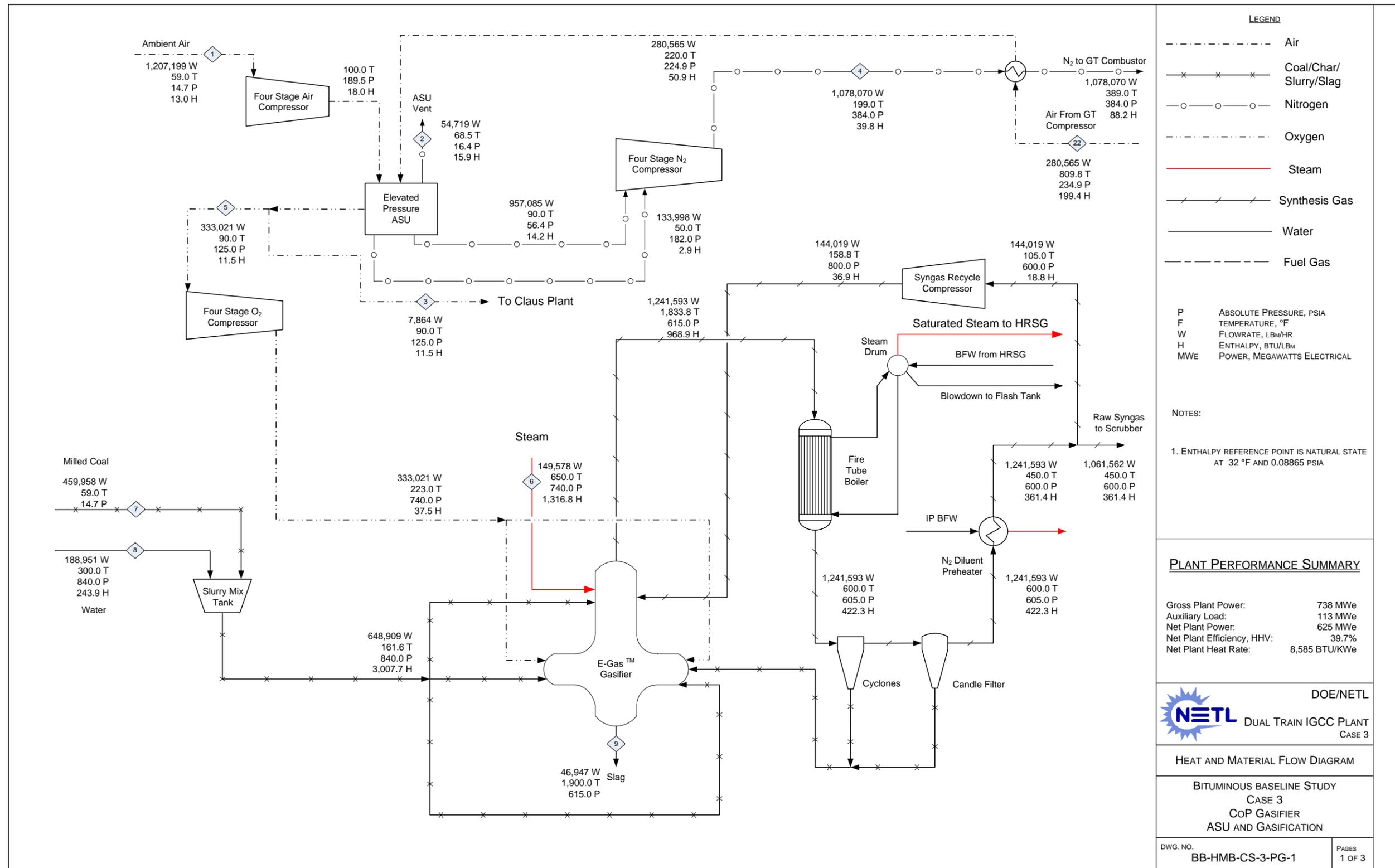
Exhibit 3-52 Case 3 Syngas Cleanup Heat and Mass Balance Schematic
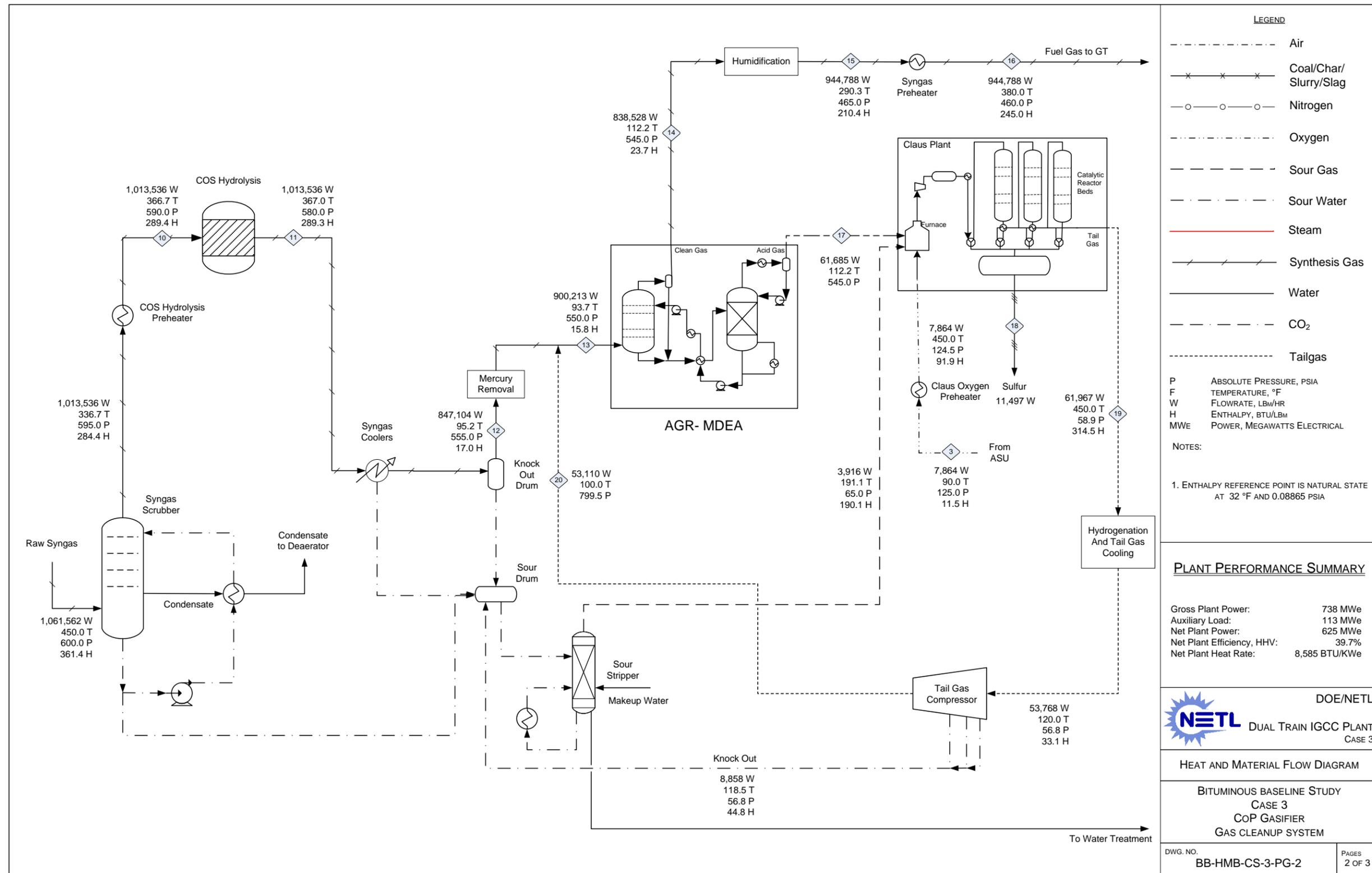
Exhibit 3-53 Case 3 Combined Cycle Power Generation Heat and Mass Balance Schematic
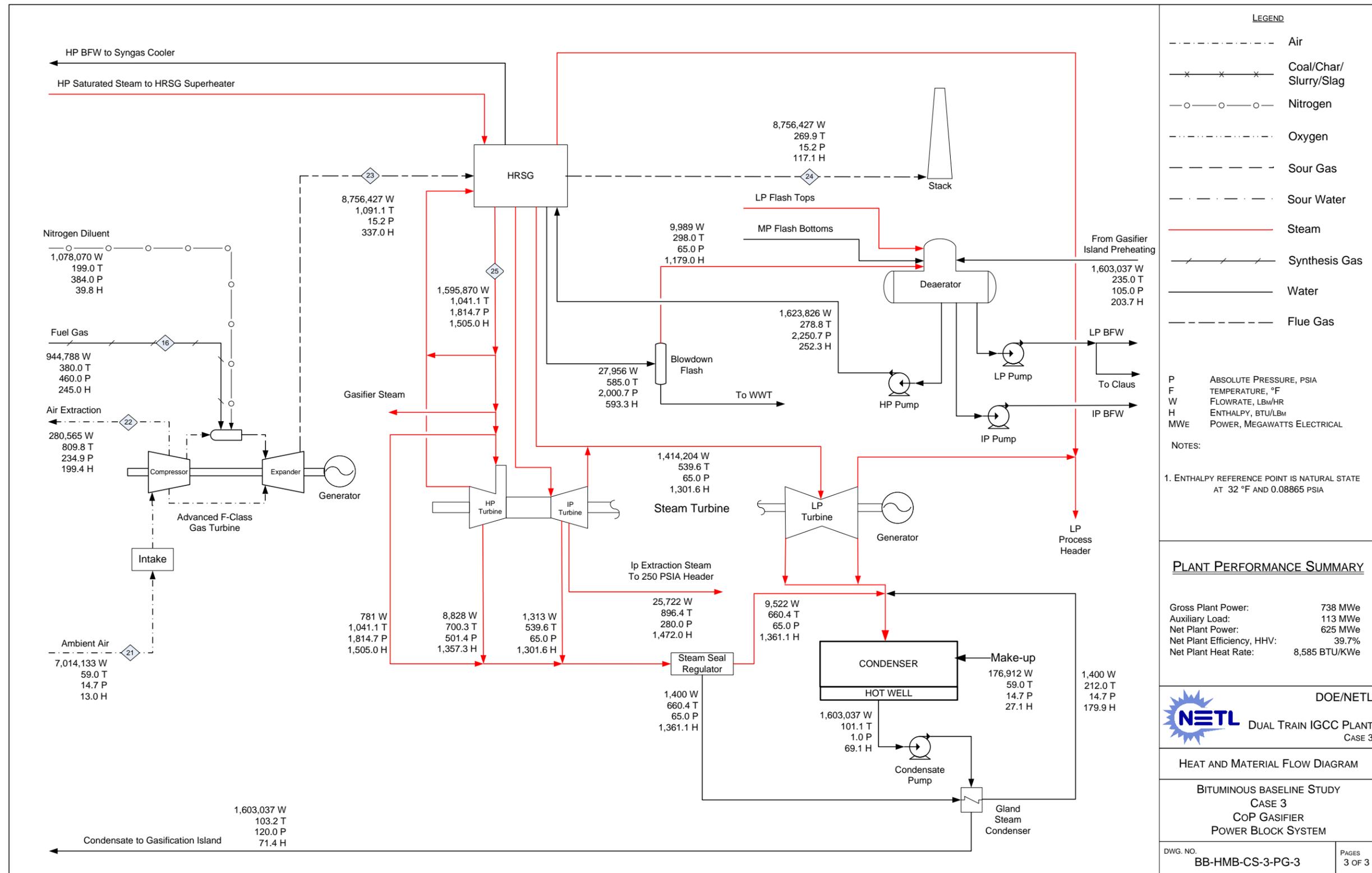
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Exhibit 3-54 Case 3 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	5,661 (5,366)	4.7 (4.5)		5,666 (5,370)
ASU Air		16.6 (15.7)		17 (16)
GT Air		96.2 (91.2)		96 (91)
Water		62.2 (58.9)		62 (59)
Auxiliary Power			407 (386)	407 (386)
TOTAL	**5,661 (5,366)**	**179.6 (170.2)**	**407 (386)**	**6,248 (5,922)**
Heat Out GJ/hr (MMBtu/hr)				
ASU Vent		0.9 (0.9)		1 (1)
Slag	35 (33)	23.9 (22.7)		59 (56)
Sulfur	48 (46)	0.6 (0.6)		49 (46)
CO_2				
Cooling Tower Blowdown		25.2 (23.9)		25 (24)
HRSG Flue Gas		1,082 (1,025)		1,082 (1,025)
Condenser		1,415 (1,342)		1,415 (1,342)
Non-Condenser Cooling Tower Loads*		411 (389)		411 (389)
Process Losses**		549 (521)		549 (521)
Power			2,658 (2,519)	2,658 (2,519)
TOTAL	**83 (79)**	**3,507 (3,324)**	**2,658 (2,519)**	**6,248 (5,922)**

* Includes ASU compressor intercoolers, CO_2 compressor intercoolers, sour water stripper condenser, syngas cooler (low level heat rejection) and extraction air cooler.

** Calculated by difference to close the energy balance.

3.3.6 Case 3 - Major Equipment List

Major equipment items for the CoP gasifier with no CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 3.3.7. 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	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	45 tonne (50 ton)	2	1
9	Feeder	Vibratory	172 tonne/hr (190 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	345 tonne/hr (380 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	172 tonne (190 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	345 tonne/hr (380 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	345 tonne/hr (380 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	726 tonne (800 ton)	3	0

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Vibratory	73 tonne/h (80 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	227 tonne/h (250 tph)	1	0
3	Rod Mill Feed Hopper	Dual Outlet	463 tonne (510 ton)	1	0
4	Weigh Feeder	Belt	118 tonne/h (130 tph)	2	0
5	Rod Mill	Rotary	118 tonne/h (130 tph)	2	0
6	Slurry Water Storage Tank with Agitator	Field erected	283,227 liters (74,820 gal)	2	0
7	Slurry Water Pumps	Centrifugal	795 lpm (210 gpm)	2	1
8	Trommel Screen	Coarse	163 tonne/h (180 tph)	2	0
9	Rod Mill Discharge Tank with Agitator	Field erected	370,519 liters (97,880 gal)	2	0
10	Rod Mill Product Pumps	Centrifugal	3,028 lpm (800 gpm)	2	2
11	Slurry Storage Tank with Agitator	Field erected	1,111,406 liters (293,600 gal)	2	0
12	Slurry Recycle Pumps	Centrifugal	6,057 lpm (1,600 gpm)	2	2
13	Slurry Product Pumps	Positive displacement	3,028 lpm (800 gpm)	2	2

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,082,628 liters (286,000 gal)	2	0
2	Condensate Pumps	Vertical canned	6,700 lpm @ 91 m H2O (1,770 gpm @ 300 ft H2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	478,994 kg/hr (1,056,000 lb/hr)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	8,101 lpm @ 27 m H2O (2,140 gpm @ 90 ft H2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 7,041 lpm @ 1,859 m H2O (1,860 gpm @ 6,100 ft H2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 492 lpm @ 223 m H2O (130 gpm @ 730 ft H2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
10	Closed Cylce Cooling Heat Exchangers	Plate and frame	240 GJ/hr (228 MMBtu/hr) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	86,307 lpm @ 21 m H2O (22,800 gpm @ 70 ft H2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H2O (1,000 gpm @ 350 ft H2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H2O (700 gpm @ 250 ft H2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	4,240 lpm @ 18 m H2O (1,120 gpm @ 60 ft H2O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	2,801 lpm @ 268 m H2O (740 gpm @ 880 ft H2O)	3	1
16	Filtered Water Pumps	Stainless steel, single suction	1,628 lpm @ 49 m H2O (430 gpm @ 160 ft H2O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	787,366 liter (208,000 gal)	2	0
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	303 lpm (80 gpm)	2	0
19	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

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

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized two-stage, slurry-feed entrained bed	2,722 tonne/day, 4.2 MPa (3,000 tpd, 615 psia)	2	0
2	Synthesis Gas Cooler	Fire-tube boiler	309,804 kg/hr (683,000 lb/hr)	2	0
3	Synthesis Gas Cyclone	High efficiency	309,804 kg/hr (683,000 lb/hr) Design efficiency 90%	2	0
4	Candle Filter	Pressurized filter with pulse-jet cleaning	metallic filters	2	0
5	Syngas Scrubber Including Sour Water Stripper	Vertical upflow	264,898 kg/hr (584,000 lb/hr)	2	0
6	Raw Gas Coolers	Shell and tube with condensate drain	212,735 kg/hr (469,000 lb/hr)	8	0
7	Raw Gas Knockout Drum	Vertical with mist eliminator	212,281 kg/hr, 35°C, 3.9 MPa (468,000 lb/hr, 95°F, 560 psia)	2	0
8	Saturation Water Economizers	Shell and tube	91 GJ/hr (86 MMBtu/hr)	2	0
9	Fuel Gas Saturator	Vertical tray tower	235,868 kg/hr, 143°C, 3.3 MPa (520,000 lb/hr, 290°F, 480 psia)	2	0
10	Saturator Water Pump	Centrifugal	2,271 lpm @ 12 m H2O (600 gpm @ 40 ft H2O)	2	2
11	Synthesis Gas Reheater	Shell and tube	209,106 kg/hr (461,000 lb/hr)	2	0
12	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	264,898 kg/hr (584,000 lb/hr) syngas	2	0
13	ASU Main Air Compressor	Centrifugal, multi-stage	4,134 m3/min @ 1.3 MPa (146,000 scfm @ 190 psia)	2	0
14	Cold Box	Vendor design	1,996 tonne/day (2,200 tpd) of 95% purity oxygen	2	0
15	Oxygen Compressor	Centrifugal, multi-stage	1,019 m3/min (36,000 scfm) Suction - 0.9 MPa (130 psia) Discharge - 5.1 MPa (740 psia)	2	0
16	Primary Nitrogen Compressor	Centrifugal, multi-stage	3,370 m3/min (119,000 scfm) Suction - 0.4 MPa (60 psia) Discharge - 2.7 MPa (390 psia)	2	0
17	Secondary Nitrogen Compressor	Centrifugal, single-stage	481 m3/min (17,000 scfm) Suction - 1.2 MPa (180 psia) Discharge - 2.7 MPa (390 psia)	2	0
18	Transport Nitrogen Boost Compressor	Centrifugal, single-stage	57 m3/min (2,000 scfm) Suction - 2.6 MPa (380 psia) Discharge - 5.4 MPa (790 psia)	2	0
19	Extraction Air Heat Exchanger	Gas-to-gas, vendor design	69,853 kg/hr, 432°C, 1.6 MPa (154,000 lb/hr, 810°F, 235 psia)	2	0

ACCOUNT 5   SYNGAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber	Sulfated carbon bed	211,374 kg/hr (466,000 lb/hr) 35°C (95°F) 3.8 MPa (555 psia)	2	0
2	Sulfur Plant	Claus type	138 tonne/day (152 tpd)	1	0
3	COS Hydrolysis Reactor	Fixed bed, catalytic	252,651 kg/hr (557,000 lb/hr) 188°C (370°F) 4.1 MPa (590 psia)	2	0
4	Acid Gas Removal Plant	MDEA	224,528 kg/hr (495,000 lb/hr) 34°C (94°F) 3.8 MPa (550 psia)	2	0
5	Hydrogenation Reactor	Fixed bed, catalytic	28,108 kg/hr (61,967 lb/hr) 232°C (450°F) 0.4 MPa (58.9 psia)	1	0
6	Tail Gas Recycle Compressor	Centrifugal	24,090 kg/hr (53,110 lb/hr) each	1	0

ACCOUNT 6   COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class	232 MW	2	0
2	Gas Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

ACCOUNT 7   HRSG, STACK, AND DUCTING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.4 m (28 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 398,131 kg/hr, 12.4 MPa/561°C (877,728 lb/hr, 1,800 psig/1,041°F) Reheat steam - 358,685 kg/hr, 3.1 MPa/561°C (790,766 lb/hr, 452 psig/1,041°F)	2	0

ACCOUNT 8   STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	289 MW 12.4 MPa/561°C/561°C (1,800 psig/ 1041°F/1041°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitiation	320 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,561 GJ/hr (1,480 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9   COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	389,897 lpm @ 30 m (103,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 2,173 GJ/hr (2,060 MMBtu/hr) heat duty	1	0

ACCOUNT 10   SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	223,339 liters (59,000 gal)	2	0
2	Slag Crusher	Roll	12 tonne/hr (13 tph)	2	0
3	Slag Depressurizer	Proprietary	12 tonne/hr (13 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	136,275 liters (36,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	60,567 liters (16,000 gal)	2	
6	Slag Conveyor	Drag chain	12 tonne/hr (13 tph)	2	0
7	Slag Separation Screen	Vibrating	12 tonne/hr (13 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	12 tonne/hr (13 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	189,271 liters (50,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	38 lpm @ 14 m H2O (10 gpm @ 46 ft H2O)	2	2
11	Grey Water Storage Tank	Field erected	60,567 liters (16,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	227 lpm @ 433 m H2O (60 gpm @ 1,420 ft H2O)	2	2
13	Slag Storage Bin	Vertical, field erected	816 tonne (900 tons)	2	0
14	Unloading Equipment	Telescoping chute	100 tonne/hr (110 tph)	1	0

ACCOUNT 11   ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Step-up Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Step-up Transformer	Oil-filled	24 kV/345 kV, 320 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 47 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 29 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 4 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12   INSTRUMENTATION AND CONTROLS

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

3.3.7 Case 3 - Costs Estimating Results

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-55 shows the total plant capital cost summary organized by cost account and Exhibit 3-56 shows a more detailed breakdown of the capital costs along with owner's costs, TOC and TASC. Exhibit 3-57 shows the initial and annual O&M costs.

The estimated TOC of the CoP gasifier with no CO_2 capture is $2,351/kW. Process contingency represents 2.1 percent of the TOC and project contingency is 10.9 percent. The COE is 74.0 mills/kWh.

Exhibit 3-55 Case 3 Total Plant Cost Summary

	Client:	USDOE/NETL							Report Date:	2010-Jan-14	
	Project:	Bituminous Baseline Study									
		TOTAL PLANT COST SUMMARY									
	Case:	Case 3 - ConocoPhillips 625MW IGCC w/o CO2									
	Plant Size:	625.1 MW,net	**Estimate Type:**	Conceptual			**Cost Base (Jun)**	2007	($x1000)		

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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$13,783	$2,561	$10,689	$0	$0	**$27,033**	$2,454	$0	$5,897	**$35,384**	$57
2	COAL & SORBENT PREP & FEED	$23,433	$4,283	$14,157	$0	$0	**$41,873**	$3,759	$0	$9,126	**$54,759**	$88
3	FEEDWATER & MISC. BOP SYSTEMS	$9,806	$8,188	$9,436	$0	$0	**$27,429**	$2,581	$0	$6,822	**$36,832**	$59
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (E-GAS)	$117,991	$0	$65,449	$0	$0	**$183,440**	$16,853	$25,442	$34,617	**$260,352**	$417
4.2	Syngas Cooling	w/4.1	$0	w/ 4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$145,765	$0	w/equip.	$0	$0	**$145,765**	$14,129	$0	$15,989	**$175,883**	$281
4.4-4.9	Other Gasification Equipment	$17,104	$9,335	$11,583	$0	$0	**$38,023**	$3,633	$0	$9,003	**$50,658**	$81
	SUBTOTAL 4	**$280,861**	**$9,335**	**$77,032**	**$0**	**$0**	**$367,228**	**$34,614**	**$25,442**	**$59,609**	**$486,893**	**$779**
5A	GAS CLEANUP & PIPING	$47,943	$3,806	$47,221	$0	$0	**$98,970**	$9,573	$85	$21,865	**$130,493**	$209
5B	CO2 COMPRESSION	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$85,751	$0	$6,269	$0	$0	**$92,021**	$8,724	$4,601	$10,535	**$115,881**	$185
6.2-6.9	Combustion Turbine Other	$0	$806	$892	$0	$0	**$1,699**	$159	$0	$557	**$2,415**	$4
	SUBTOTAL 6	**$85,751**	**$806**	**$7,162**	**$0**	**$0**	**$93,719**	**$8,883**	**$4,601**	**$11,092**	**$118,295**	**$189**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$35,467	$0	$5,043	$0	$0	**$40,510**	$3,852	$0	$4,436	**$48,798**	$78
7.2-7.9	SCR System, Ductwork and Stack	$3,335	$2,378	$3,114	$0	$0	**$8,827**	$818	$0	$1,570	**$11,215**	$18
	SUBTOTAL 7	**$38,802**	**$2,378**	**$8,157**	**$0**	**$0**	**$49,337**	**$4,670**	**$0**	**$6,006**	**$60,013**	**$96**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$28,970	$0	$4,963	$0	$0	**$33,934**	$3,256	$0	$3,719	**$40,909**	$65
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$10,556	$996	$7,591	$0	$0	**$19,143**	$1,738	$0	$4,220	**$25,101**	$40
	SUBTOTAL 8	**$39,526**	**$996**	**$12,554**	**$0**	**$0**	**$53,076**	**$4,994**	**$0**	**$7,939**	**$66,009**	**$106**
9	COOLING WATER SYSTEM	$9,144	$8,826	$7,504	$0	$0	**$25,474**	$2,366	$0	$5,687	**$33,527**	$54
10	ASH/SPENT SORBENT HANDLING SYS	$19,026	$1,439	$9,440	$0	$0	**$29,905**	$2,869	$0	$3,575	**$36,349**	$58
11	ACCESSORY ELECTRIC PLANT	$27,425	$10,189	$20,427	$0	$0	**$58,041**	$4,986	$0	$11,827	**$74,854**	$120
12	INSTRUMENTATION & CONTROL	$10,234	$1,883	$6,594	$0	$0	**$18,710**	$1,696	$936	$3,556	**$24,897**	$40
13	IMPROVEMENTS TO SITE	$3,328	$1,962	$8,212	$0	$0	**$13,503**	$1,333	$0	$4,451	**$19,287**	$31
14	BUILDINGS & STRUCTURES	$0	$6,670	$7,642	$0	$0	**$14,313**	$1,303	$0	$2,553	**$18,169**	$29
	TOTAL COST	**$609,063**	**$63,322**	**$246,227**	**$0**	**$0**	**$918,612**	**$86,080**	**$31,064**	**$160,007**	**$1,195,762**	**$1,913**

Exhibit 3-56 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,619	$0	$1,769	$0	$0	$5,388	$483	$0	$1,174	$7,045	$11
1.2	Coal Stackout & Reclaim	$4,677	$0	$1,134	$0	$0	$5,811	$509	$0	$1,264	$7,584	$12
1.3	Coal Conveyors & Yd Crush	$4,349	$0	$1,122	$0	$0	$5,470	$480	$0	$1,190	$7,141	$11
1.4	Other Coal Handling	$1,138	$0	$260	$0	$0	$1,397	$122	$0	$304	$1,823	$3
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	$2,561	$6,404	$0	$0	$8,966	$859	$0	$1,965	$11,790	$19
	SUBTOTAL 1.	$13,783	$2,561	$10,689	$0	$0	$27,033	$2,454	$0	$5,897	$35,384	$57
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying (incl. w/2.3)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.2	Prepared Coal Storage & Feed	$1,542	$369	$242	$0	$0	$2,153	$184	$0	$467	$2,805	$4
2.3	Slurry Prep & Feed	$21,042	$0	$9,358	$0	$0	$30,400	$2,714	$0	$6,623	$39,737	$64
2.4	Misc.Coal Prep & Feed	$848	$617	$1,851	$0	$0	$3,316	$305	$0	$724	$4,345	$7
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	$3,297	$2,707	$0	$0	$6,004	$556	$0	$1,312	$7,871	$13
	SUBTOTAL 2.	$23,433	$4,283	$14,157	$0	$0	$41,873	$3,759	$0	$9,126	$54,759	$88
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	Feedwater System	$3,157	$5,422	$2,862	$0	$0	$11,440	$1,060	$0	$2,500	$15,000	$24
3.2	Water Makeup & Pretreating	$585	$61	$327	$0	$0	$974	$93	$0	$320	$1,387	$2
3.3	Other Feedwater Subsystems	$1,727	$584	$525	$0	$0	$2,836	$255	$0	$618	$3,709	$6
3.4	Service Water Systems	$335	$690	$2,394	$0	$0	$3,419	$334	$0	$1,126	$4,879	$8
3.5	Other Boiler Plant Systems	$1,798	$697	$1,727	$0	$0	$4,221	$400	$0	$924	$5,546	$9
3.6	FO Supply Sys & Nat Gas	$313	$591	$551	$0	$0	$1,456	$140	$0	$319	$1,915	$3
3.7	Waste Treatment Equipment	$818	$0	$499	$0	$0	$1,318	$128	$0	$434	$1,880	$3
3.8	Misc. Power Plant Equipment	$1,072	$143	$550	$0	$0	$1,765	$170	$0	$581	$2,517	$4
	SUBTOTAL 3.	$9,806	$8,188	$9,436	$0	$0	$27,429	$2,581	$0	$6,822	$36,832	$59
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (E-GAS)	$117,991	$0	$65,449	$0	$0	$183,440	$16,853	$25,442	$34,617	$260,352	$417
4.2	Syngas Cooling	w/4.1	$0	w/ 4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$145,765	$0	w/equip.	$0	$0	$145,765	$14,129	$0	$15,989	$175,883	$281
4.4	LT Heat Recovery & FG Saturation	$17,104	$0	$6,502	$0	$0	$23,606	$2,304	$0	$5,182	$31,092	$50
4.5	Misc. Gasification Equipment	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Flare Stack System	$0	$1,503	$612	$0	$0	$2,114	$203	$0	$463	$2,780	$4
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	$7,833	$4,469	$0	$0	$12,302	$1,126	$0	$3,357	$16,785	$27
	SUBTOTAL 4.	$280,861	$9,335	$77,032	$0	$0	$367,228	$34,614	$25,442	$59,609	$486,893	$779

Exhibit 3-56 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	MDEA-LT AGR	$33,341	$0	$28,290	$0	$0	$61,631	$5,960	$0	$13,518	$81,110	$130
5A.2	Elemental Sulfur Plant	$9,938	$1,981	$12,822	$0	$0	$24,741	$2,403	$0	$5,429	$32,573	$52
5A.3	Mercury Removal	$970	$0	$738	$0	$0	$1,708	$165	$85	$392	$2,350	$4
5A.4	COS Hydrolysis	$3,196	$0	$4,173	$0	$0	$7,369	$717	$0	$1,617	$9,703	$16
5A.5	Particulate Removal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Blowback Gas Systems	$499	$280	$157	$0	$0	$936	$89	$0	$205	$1,230	$2
5A.7	Fuel Gas Piping	$0	$768	$538	$0	$0	$1,306	$121	$0	$285	$1,712	$3
5A.9	HGCU Foundations	$0	$778	$501	$0	$0	$1,279	$118	$0	$419	$1,816	$3
	SUBTOTAL 5A.	$47,943	$3,806	$47,221	$0	$0	$98,970	$9,573	$85	$21,865	$130,493	$209
5B	CO2 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	$85,751	$0	$6,269	$0	$0	$92,021	$8,724	$4,601	$10,535	$115,881	$185
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	$4
	SUBTOTAL 6.	$85,751	$806	$7,162	$0	$0	$93,719	$8,883	$4,601	$11,092	$118,295	$189
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$35,467	$0	$5,043	$0	$0	$40,510	$3,852	$0	$4,436	$48,798	$78
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,710	$1,220	$0	$0	$2,929	$257	$0	$637	$3,823	$6
7.4	Stack	$3,335	$0	$1,253	$0	$0	$4,588	$440	$0	$503	$5,530	$9
7.9	HRSG, Duct & Stack Foundations	$0	$668	$642	$0	$0	$1,310	$122	$0	$430	$1,861	$3
	SUBTOTAL 7.	$38,802	$2,378	$8,157	$0	$0	$49,337	$4,670	$0	$6,006	$60,013	$96
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$28,970	$0	$4,963	$0	$0	$33,934	$3,256	$0	$3,719	$40,909	$65
8.2	Turbine Plant Auxiliaries	$201	$0	$460	$0	$0	$661	$65	$0	$73	$798	$1
8.3	Condenser & Auxiliaries	$4,785	$0	$1,529	$0	$0	$6,314	$604	$0	$692	$7,609	$12
8.4	Steam Piping	$5,570	$0	$3,918	$0	$0	$9,489	$815	$0	$2,576	$12,880	$21
8.9	TG Foundations	$0	$996	$1,683	$0	$0	$2,679	$254	$0	$880	$3,813	$6
	SUBTOTAL 8.	$39,526	$996	$12,554	$0	$0	$53,076	$4,994	$0	$7,939	$66,009	$106

Exhibit 3-56 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$6,338	$0	$1,153	$0	$0	$7,491	$713	$0	$1,231	$9,434	$15
9.2	Circulating Water Pumps	$1,648	$0	$113	$0	$0	$1,761	$149	$0	$287	$2,197	$4
9.3	Circ.Water System Auxiliaries	$140	$0	$20	$0	$0	$160	$15	$0	$26	$202	$0
9.4	Circ.Water Piping	$0	$5,855	$1,518	$0	$0	$7,373	$666	$0	$1,608	$9,647	$15
9.5	Make-up Water System	$327	$0	$467	$0	$0	$794	$76	$0	$174	$1,044	$2
9.6	Component Cooling Water Sys	$691	$827	$588	$0	$0	$2,106	$197	$0	$461	$2,764	$4
9.9	Circ.Water System Foundations	$0	$2,144	$3,645	$0	$0	$5,789	$549	$0	$1,901	$8,239	$13
	SUBTOTAL 9.	$9,144	$8,826	$7,504	$0	$0	$25,474	$2,366	$0	$5,687	$33,527	$54
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$16,609	$0	$8,191	$0	$0	$24,799	$2,383	$0	$2,718	$29,900	$48
10.2	Gasifier Ash Depressurization	w/10.1	w/10.1	w/10.1	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	w/10.1	w/10.1	w/10.1	$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 Recovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$548	$0	$596	$0	$0	$1,144	$111	$0	$188	$1,443	$2
10.7	Ash Transport & Feed Equipment	$735	$0	$177	$0	$0	$912	$85	$0	$150	$1,147	$2
10.8	Misc. Ash Handling Equipment	$1,135	$1,391	$415	$0	$0	$2,941	$280	$0	$483	$3,704	$6
10.9	Ash/Spent Sorbent Foundation	$0	$48	$61	$0	$0	$109	$10	$0	$36	$155	$0
	SUBTOTAL 10.	$19,026	$1,439	$9,440	$0	$0	$29,905	$2,869	$0	$3,575	$36,349	$58
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$951	$0	$940	$0	$0	$1,891	$181	$0	$207	$2,279	$4
11.2	Station Service Equipment	$3,741	$0	$337	$0	$0	$4,078	$376	$0	$445	$4,900	$8
11.3	Switchgear & Motor Control	$6,917	$0	$1,258	$0	$0	$8,174	$758	$0	$1,340	$10,272	$16
11.4	Conduit & Cable Tray	$0	$3,213	$10,599	$0	$0	$13,812	$1,336	$0	$3,787	$18,935	$30
11.5	Wire & Cable	$0	$6,139	$4,034	$0	$0	$10,172	$739	$0	$2,728	$13,639	$22
11.6	Protective Equipment	$0	$680	$2,474	$0	$0	$3,153	$308	$0	$519	$3,980	$6
11.7	Standby Equipment	$234	$0	$229	$0	$0	$463	$44	$0	$76	$583	$1
11.8	Main Power Transformers	$15,583	$0	$145	$0	$0	$15,727	$1,190	$0	$2,538	$19,454	$31
11.9	Electrical Foundations	$0	$157	$412	$0	$0	$569	$54	$0	$187	$810	$1
	SUBTOTAL 11.	$27,425	$10,189	$20,427	$0	$0	$58,041	$4,986	$0	$11,827	$74,854	$120
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	w/6.1	$0	w/6.1	$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	$1,010	$0	$675	$0	$0	$1,685	$159	$84	$289	$2,218	$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	$232	$0	$149	$0	$0	$381	$36	$19	$87	$523	$1
12.7	Computer & Accessories	$5,389	$0	$173	$0	$0	$5,562	$510	$278	$635	$6,985	$11
12.8	Instrument Wiring & Tubing	$0	$1,883	$3,849	$0	$0	$5,731	$486	$287	$1,626	$8,130	$13
12.9	Other I & C Equipment	$3,602	$0	$1,749	$0	$0	$5,352	$504	$268	$918	$7,041	$11
	SUBTOTAL 12.	$10,234	$1,883	$6,594	$0	$0	$18,710	$1,696	$936	$3,556	$24,897	$40

Exhibit 3-56 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$104	$2,232	$0	$0	$2,336	$232	$0	$771	$3,339	$5
13.2	Site Improvements	$0	$1,857	$2,468	$0	$0	$4,326	$427	$0	$1,426	$6,178	$10
13.3	Site Facilities	$3,328	$0	$3,512	$0	$0	$6,841	$674	$0	$2,255	$9,770	$16
	SUBTOTAL 13.	$3,328	$1,962	$8,212	$0	$0	$13,503	$1,333	$0	$4,451	$19,287	$31
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	$2,435	$3,468	$0	$0	$5,903	$543	$0	$967	$7,413	$12
14.3	Administration Building	$0	$842	$611	$0	$0	$1,452	$129	$0	$237	$1,819	$3
14.4	Circulation Water Pumphouse	$0	$166	$88	$0	$0	$254	$22	$0	$41	$317	$1
14.5	Water Treatment Buildings	$0	$489	$477	$0	$0	$967	$87	$0	$158	$1,212	$2
14.6	Machine Shop	$0	$431	$295	$0	$0	$726	$64	$0	$119	$909	$1
14.7	Warehouse	$0	$696	$449	$0	$0	$1,145	$101	$0	$187	$1,433	$2
14.8	Other Buildings & Structures	$0	$417	$324	$0	$0	$741	$66	$0	$161	$969	$2
14.9	Waste Treating Building & Str.	$0	$931	$1,780	$0	$0	$2,711	$253	$0	$593	$3,557	$6
	SUBTOTAL 14.	$0	$6,670	$7,642	$0	$0	$14,313	$1,303	$0	$2,553	$18,169	$29
	TOTAL COST	$609,063	$63,322	$246,227	$0	$0	$918,612	$86,080	$31,064	$160,007	$1,195,762	$1,913

Owner's Costs

Preproduction Costs

6 Months All Labor	$12,309	$20
1 Month Maintenance Materials	$2,766	$4
1 Month Non-fuel Consumables	$239	$0
1 Month Waste Disposal	$279	$0
25% of 1 Months Fuel Cost at 100% CF	$1,603	$3
2% of TPC	$23,915	$38
Total	$41,111	$66

Inventory Capital

60 day supply of fuel and consumables at 100% CF	$13,092	$21
0.5% of TPC (spare parts)	$5,979	$10
Total	$19,071	$31

Initial Cost for Catalyst and Chemicals	$1,084	$2
Land	$900	$1
Other Owner's Costs	$179,364	$287
Financing Costs	$32,286	$52
Total Overnight Costs (TOC)	$1,469,577	$2,351
TASC Multiplier (IOU, high-risk, 35 year)	1.140	
Total As-Spent Cost (TASC)	$1,675,318	$2,680

Exhibit 3-57 Case 3 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun):		2007
Case 3 - ConocoPhillips 625MW IGCC w/o CO2					Heat Rate-net(Btu/kWh):		8,585
					MWe-net:		625
					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		

Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.	Total Plant
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	$5,918,913	$9.469
Maintenance Labor Cost	$13,775,415	$22.039
Administrative & Support Labor	$4,923,582	$7.877
Property Taxes and Insurance	$23,935,631	$38.293
TOTAL FIXED OPERATING COSTS	**$48,553,541**	**$77.678**

VARIABLE OPERATING COSTS

							$/kWh-net
Maintenance Material Cost						$26,551,568	$0.00606

Consumables	Consumption Initial Fill	/Day	Unit Cost	Initial Fill Cost			
Water (/1000 gallons)	0	3,144.24	1.08	$0	$993,106		$0.00023
Chemicals							
MU & WT Chem. (lbs)	0	18,732	0.17	$0	$946,662		$0.00022
Carbon (Mercury Removal) (lb)	68,511	94	1.05	$71,948	$28,779		$0.00001
COS Catalyst (m3)	327	0.22	2,397.36	$784,204	$156,841		$0.00004
Water Gas Shift Catalyst (ft3)	0	0	498.83	$0	$0		$0.00000
MDEA Solution (gal)	26,146	37	8.70	$227,412	$93,463		$0.00002
SCR Catalyst (m3)	0	0	0.00	$0	$0		$0.00000
Ammonia (19% NH3) (ton)	0	0	0.00	$0	$0		$0.00000
Claus Catalyst (ft3)	w/equip.	1.91	131.27	$0	$73,243		$0.00002
Subtotal Chemicals				$1,083,564	$1,298,988		$0.00030
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	94	0.42	$0	$11,430		$0.00000
Flyash (ton)	0	0	0.00	$0	$0		$0.00000
Slag (ton)	0	563	16.23	$0	$2,669,064		$0.00061
Subtotal-Waste Disposal				$0	$2,680,493		$0.00061
By-products & Emissions							
Sulfur (ton)	0	138	0.00	$0	$0		$0.00000
Subtotal By-Products				$0	$0		$0.00000
TOTAL VARIABLE OPERATING COSTS				$1,083,564	$31,524,155		$0.00720
Fuel (ton)	0	5,519	38.18	$0	$61,541,712		$0.01405

3.3.8   Case 4 - E-Gas™ IGCC Power Plant with CO_2 Capture

This case is configured to produce electric power with CO_2 capture. The plant configuration is the same as Case 3, namely two gasifier trains, two advanced F class turbines, two HRSGs, and one steam turbine. The gross power output from the plant is constrained by the capacity of the two CTs, and since the CO_2 capture and compression process increases the auxiliary load on the plant, the net output is significantly reduced relative to Case 3.

The process description for Case 4 is similar to Case 3 with several notable exceptions to accommodate CO_2 capture. A BFD and stream tables for Case 4 are shown in Exhibit 3-58 and Exhibit 3-59, respectively. Instead of repeating the entire process description, only differences from Case 3 are reported here.

Coal Preparation and Feed Systems

No differences from Case 3.

Gasification

The gasification process is the same as Case 3 with the exception that total coal feed to the two gasifiers is 5,271 tonnes/day (5,811 TPD) (stream 8) and the ASU provides 4,234 tonnes/day (4,668 TPD) of 95 mol% oxygen to the gasifier and Claus plant (streams 5 and 3).

Raw Gas Cooling/Particulate Removal

Raw gas cooling and particulate removal are the same as Case 3 with the exception that approximately 418,710 kg/hr (923,082 lb/hr) of saturated steam at 13.8 MPa (2,000 psia) is generated in the SGC.

Syngas Scrubber/Sour Water Stripper

No differences from Case 3.

Sour Gas Shift (SGS)

The SGS process was described in Section 3.1.3. In Case 4 steam (stream 11) is added to the syngas exiting the scrubber to adjust the H_2O:CO molar ratio to approximately 2.25:1 prior to the first WGS reactor. The hot syngas exiting the first stage of SGS is used to preheat a portion of the water used to humidify the clean syngas leaving the AGR. The final stage of SGS brings the overall conversion of the CO to CO_2 to 98.5 percent. The syngas exiting the final stage of SGS still contains 1.2 vol% CH_4, which is subsequently oxidized to CO_2 in the CT and results in a carbon capture of 90.4 percent. The warm syngas exiting the second stage of the SGS at 204°C (400°F) (stream 12) is cooled to 201°C (393°F) by preheating the syngas entering the first SGS reactor. The SGS catalyst also serves to hydrolyze COS thus eliminating the need for a separate COS hydrolysis reactor. The syngas is further dehydrated and cooled to 35°C (95°F) in syngas coolers prior to the mercury removal beds.

Mercury Removal and Acid Gas Removal

Mercury removal is the same as in Case 3.

Exhibit 3-58 Case 4 Block Flow Diagram, E-Gas™ IGCC with CO_2 Capture
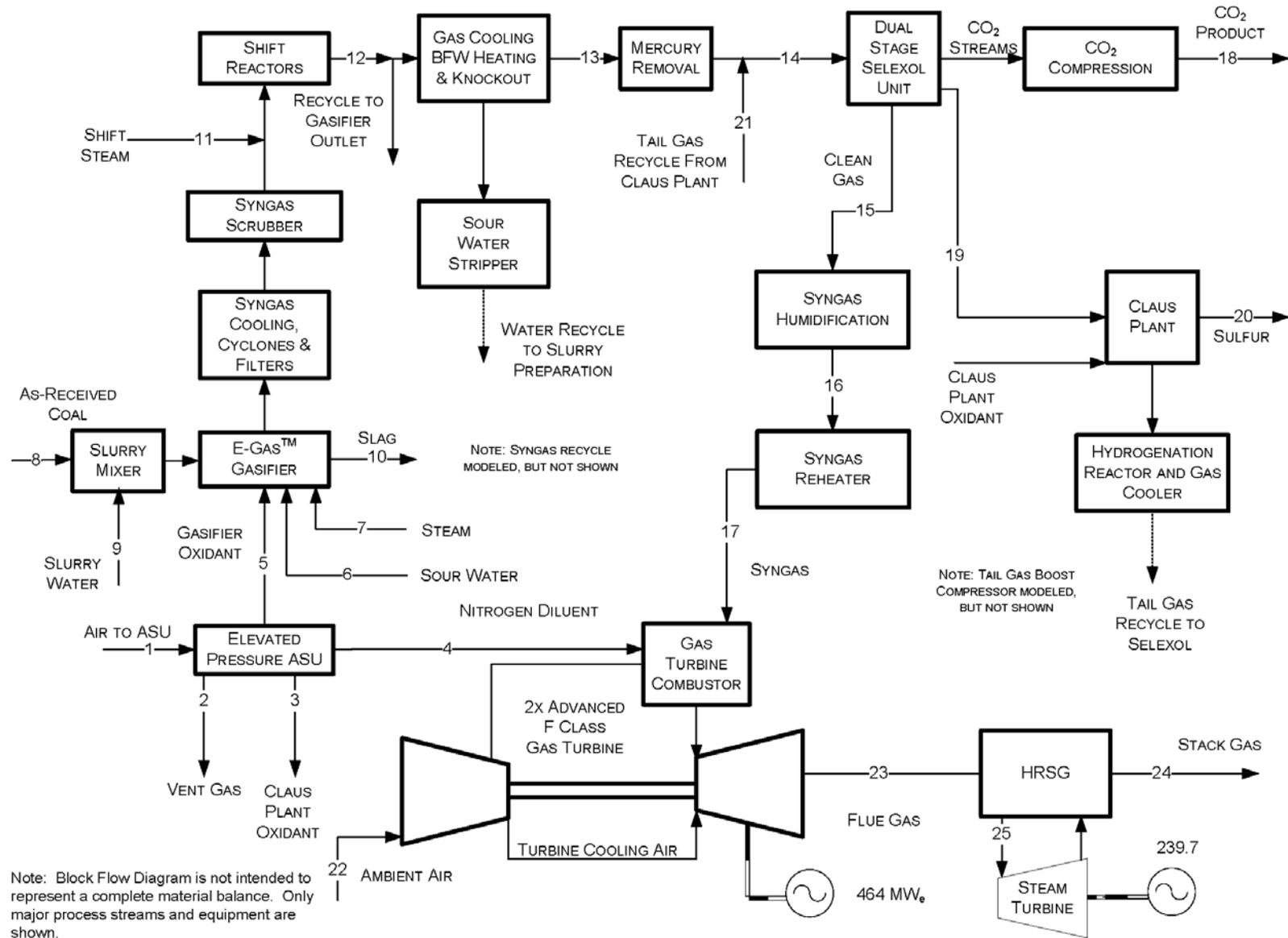
Exhibit 3-59 Case 4 Stream Table, E-Gas™ IGCC with CO₂ Capture

	1	2	3	4	5	6	7	8	9	10	11	12	13
V-L Mole Fraction													
Ar	0.0092	0.0209	0.0318	0.0023	0.0318	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0054	0.0071
CH₄	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0125	0.0164
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0028	0.0037
CO₂	0.0003	0.0071	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3103	0.4090
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	0.0000
H₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.4128	0.5441
H₂O	0.0099	0.1780	0.0000	0.0003	0.0000	1.0000	1.0000	0.0000	0.9963	0.0000	1.0000	0.2376	0.0015
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000
H₂S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0048	0.0063
N₂	0.7732	0.6187	0.0178	0.9919	0.0178	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0090	0.0119
NH₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0037	0.0000	0.0000	0.0046	0.0000
O₂	0.2074	0.1754	0.9504	0.0054	0.9504	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO₂	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	1.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_mol/hr)	26,685	1,231	145	19,704	5,338	1,287	4,969	0	5,009	0	9,357	37,866	26,948
V-L Flowrate (kg/hr)	770,042	33,603	4,654	552,893	171,782	23,193	89,523	0	90,226	0	168,566	748,369	547,649
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	219,635	0	22,418	0	0	0
Temperature (°C)	15	19	32	93	32	154	343	15	171	1,038	288	204	35
Pressure (MPa, abs)	0.10	0.11	0.86	2.65	0.86	5.79	5.10	0.10	5.79	4.24	5.52	4.07	3.79
Enthalpy (kJ/kg)^A	30.23	36.49	26.67	92.50	26.67	599.34	3,063.97	---	673.50	---	2,918.18	873.73	40.91
Density (kg/m³)	1.2	1.5	11.0	24.4	11.0	857.7	20.1	---	836.0	---	25.6	20.6	30.9
V-L Molecular Weight	28.857	27.295	32.181	28.060	32.181	18.015	18.015	---	18.012	---	18.015	19.764	20.322
V-L Flowrate (lb_mol/hr)	58,830	2,714	319	43,440	11,768	2,838	10,955	0	11,044	0	20,628	83,479	59,411
V-L Flowrate (lb/hr)	1,697,652	74,082	10,260	1,218,920	378,715	51,133	197,365	0	198,914	0	371,625	1,649,872	1,207,359
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	484,212	0	49,422	0	0	0
Temperature (°F)	59	67	90	199	90	310	650	59	340	1,900	550	400	95
Pressure (psia)	14.7	16.4	125.0	384.0	125.0	840.0	740.0	14.7	840.0	615.0	800.0	590.0	550.0
Enthalpy (Btu/lb)^A	13.0	15.7	11.5	39.8	11.5	257.7	1,317.3	---	289.6	---	1,254.6	375.6	17.6
Density (lb/ft³)	0.076	0.095	0.687	1.521	0.687	53.543	1.257	---	52.192	---	1.597	1.285	1.928

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-59 Case 4 Stream Table, E-Gas™ IGCC with CO$_2$ Capture (Continued)

	14	15	16	17	18	19	20	21	22	23	24	25
V-L Mole Fraction												
Ar	0.0071	0.0119	0.0114	0.0114	0.0002	0.0011	0.0000	0.0068	0.0092	0.0090	0.0090	0.0000
CH$_4$	0.0159	0.0262	0.0251	0.0251	0.0008	0.0045	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0038	0.0063	0.0060	0.0060	0.0001	0.0007	0.0000	0.0076	0.0000	0.0000	0.0000	0.0000
CO$_2$	0.4172	0.0352	0.0338	0.0338	0.9945	0.7021	0.0000	0.6907	0.0003	0.0082	0.0082	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H$_2$	0.5341	0.8964	0.8588	0.8588	0.0044	0.0591	0.0000	0.2007	0.0000	0.0000	0.0000	0.0000
H$_2$O	0.0015	0.0001	0.0421	0.0421	0.0000	0.0162	0.0000	0.0017	0.0099	0.1246	0.1246	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H$_2$S	0.0062	0.0000	0.0000	0.0000	0.0000	0.2153	0.0000	0.0026	0.0000	0.0000	0.0000	0.0000
N$_2$	0.0142	0.0239	0.0229	0.0229	0.0001	0.0010	0.0000	0.0901	0.7732	0.7529	0.7529	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	0.0000
O$_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2074	0.1052	0.1052	0.0000
SO$_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg$_{mol}$/hr)	27,761	16,435	17,155	17,155	10,499	800	0	812	110,253	139,694	139,694	34,515
V-L Flowrate (kg/hr)	575,208	83,813	96,780	96,780	459,855	31,069	0	27,560	3,181,557	3,831,230	3,831,230	621,792
Solids Flowrate (kg/hr)	0	0	0	0	0	0	5,494	0	0	0	0	0
Temperature (°C)	34	34	108	193	51	48	176	38	15	562	132	534
Pressure (MPa, abs)	3.8	3.757	3.206	3.172	15.270	0.163	0.119	5.512	0.101	0.105	0.105	12.512
Enthalpy (kJ/kg)^A	39.0	196.106	903.063	1,360.503	-162.349	62.132	---	1.774	30.227	839.766	348.188	3,432.696
Density (kg/m^3)	31.3	7.4	5.6	4.6	641.8	2.4	5,283.7	83.6	1.2	0.4	0.9	36.7
V-L Molecular Weight	21	5.100	5.642	5.642	43.800	38.814	---	33.925	28.857	27.426	27.426	18.015
V-L Flowrate (lb$_{mol}$/hr)	61,202	36,233	37,820	37,820	23,146	1,765	0	1,791	243,066	307,972	307,972	76,092
V-L Flowrate (lb/hr)	1,268,117	184,776	213,363	213,363	1,013,807	68,496	0	60,759	7,014,133	8,446,417	8,446,417	1,370,817
Solids Flowrate (lb/hr)	0	0	0	0	0	0	12,112	0	0	0	0	0
Temperature (°F)	94	94	227	380	124	119	349	100	59	1,044	270	994
Pressure (psia)	545.0	545.0	465.0	460.0	2,214.7	23.7	17.3	799.5	14.7	15.2	15.2	1,814.7
Enthalpy (Btu/lb)^A	16.8	84.3	388.2	584.9	-69.8	26.7	---	0.8	13.0	361.0	149.7	1,475.8
Density (lb/ft^3)	2	0.461	0.352	0.285	40.067	0.149	329.851	5.220	0.076	0.026	0.053	2.293

The AGR process in Case 4 is a two stage Selexol process where H_2S is removed in the first stage and CO_2 in the second stage of absorption as previously described in Section 3.1.5. 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 acid gas (stream 19) contains 21.5 percent H_2S and 70 percent CO_2 with the balance primarily H_2. 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 flashed at three pressure levels to separate CO_2 and decrease H_2 losses to the CO_2 product pipeline. The HP CO_2 stream is flashed at 2.0 MPa (289.7 psia), compressed, and recycled back to the CO_2 absorber. The MP CO_2 stream is flashed at 1.0 MPa (149.7 psia). The LP CO_2 stream is flashed at 0.1 MPa (16.7 psia), compressed to 1.0 MPa (149.5 psia), and combined with the MP CO_2 stream. The combined stream is compressed from 1.0 MPa (149.5 psia) to a SC 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) with triethylene glycol. The raw CO_2 stream from the Selexol process contains over 99 percent CO_2. The CO_2 (stream 18) 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 3 with the following exceptions:

- 5,494 kg/hr (12,112 lb/hr) of sulfur (stream 20) are produced

- The waste heat boiler generates 12,679 kg/hr (27,953 lb/hr) of 3.0 MPa (430 psia) steam, which provides all of the Claus plant process needs and provides some additional steam to the medium pressure steam header.

Power Block

Clean syngas from the AGR plant is partially humidified to 4 percent because the nitrogen available from the ASU is insufficient to provide adequate dilution. The moisturized syngas is reheated (stream 17) to 193°C (380°F) using HP BFW, diluted with nitrogen (stream 4), and then enters the CT burner. There is no integration between the CT and the ASU in this case. The exhaust gas (stream 23) exits the CT at 562°C (1044°F) and enters the HRSG where additional heat is recovered. The FG exits the HRSG at 132°C (270°F) (stream 24) 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 12.4 MPa/534°C/534°C (1800 psig/994°F/994°F) steam cycle.

Air Separation Unit (ASU)

The elevated pressure ASU is the same as in other cases and produces 4,234 tonnes/day (4,668 TPD) of 95 mol% oxygen and 14,230 tonnes/day (15,686 TPD) of nitrogen. There is no integration between the ASU and the CT.

3.3.9   Case 4 Performance Results

The Case 4 modeling assumptions were presented previously in Section 3.3.3.

The plant produces a net output of 514 MWe at a net plant efficiency of 31.0 percent (HHV basis). Overall performance for the entire plant is summarized in Exhibit 3-60, which includes auxiliary power requirements. The ASU accounts for nearly 58 percent of the auxiliary load between the main air compressor, the nitrogen compressor, the oxygen compressor, and ASU auxiliaries. The two-stage Selexol process and CO_2 compression account for an additional 27 percent of the auxiliary power load. The BFW pumps and cooling water system (CWPs and cooling tower fan) comprise nearly 6 percent of the load, leaving 9 percent of the auxiliary load for all other systems.

Exhibit 3-60 Case 4 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	464,000
Sweet Gas Expander Power	0
Steam Turbine Power	239,700
TOTAL POWER, kWe	**703,700**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	470
Coal Milling	2,260
Sour Water Recycle Slurry Pump	200
Slag Handling	1,160
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	65,670
Oxygen Compressor	9,010
Nitrogen Compressors	35,340
CO_2 Compressor	31,380
Boiler Feedwater Pumps	4,160
Condensate Pump	310
Syngas Recycle Compressor	520
Circulating Water Pump	4,670
Ground Water Pumps	520
Cooling Tower Fans	2,410
Scrubber Pumps	400
Acid Gas Removal	19,900
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	250
Claus Plant TG Recycle Compressor	3,700
Miscellaneous Balance of Plant[2]	3,000
Transformer Losses	2,660
TOTAL AUXILIARIES, kWe	**190,090**
NET POWER, kWe	**513,610**
Net Plant Efficiency, % (HHV)	31.0
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,604 (10,998)
CONDENSER COOLING DUTY 10^6 kJ/hr (10^6 Btu/hr)	**1,403 (1,330)**
CONSUMABLES	
As-Received Coal Feed, kg/hr (lb/hr)	219,635 (484,212)
Thermal Input[1], kWt	1,655,503
Raw Water Withdrawal, m^3/min (gpm)	21.6 (5,717)
Raw Water Consumption, m^3/min (gpm)	17.5 (4,631)

1 - HHV of As-Received Illinois No. 6 coal is 27,135 kJ/kg (11,666 Btu/lb)

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

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, CO_2, and PM were presented in Section 2.4. A summary of the plant air emissions for Case 4 is presented in Exhibit 3-61.

Exhibit 3-61 Case 4 Air Emissions

	kg/GJ (lb/10^6 Btu)	Tonne/year (tons/year) 80% CF	kg/MWh (lb/MWh)
SO_2	0.001 (0.002)	39 (43)	0.008 (.02)
NOx	0.021 (0.049)	885 (976)	0.180 (.396)
Particulates	0.003 (0.0071)	127 (141)	0.026 (.057)
Hg	2.46E-7 (5.71E-7)	0.010 (0.011)	2.08E-6 (4.59E-6)
CO_2	8.5 (19.7)	354,267 (390,512)	72 (158)
CO_2[1]			98 (217)

[1] CO_2 emissions based on net power instead of gross power

The low level of SO_2 emissions is achieved by capture of the sulfur in the gas by the two-stage Selexol AGR process. The CO_2 capture target results in the sulfur compounds being removed to a greater extent than required in the environmental targets of Section 2.4. The clean syngas exiting the AGR process has a sulfur concentration of approximately 5 ppmv. This results in a concentration in the FG 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 to convert all sulfur species to H_2S, and then recycled back to the Selexol, thereby eliminating the need for a tail gas treatment unit.

NOx emissions are limited by the use of humidification and nitrogen dilution to 15 ppmvd (NO_2 @ 15 percent O_2). Ammonia in the syngas is removed with process condensate prior to the low-temperature AGR process and ultimately destroyed in the Claus plant burner. This helps lower NOx 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 mercury is captured from the syngas by an activated carbon bed.

Ninety five percent of the CO_2 from the syngas is captured in the AGR system and compressed for sequestration. The overall carbon removal is 90.4 percent.

The carbon balance for the plant is shown in Exhibit 3-62. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not neglected in the carbon balance below since the Aspen model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag, CO_2 in the stack gas, ASU vent gas and the captured CO_2 product. The carbon capture efficiency is defined as the amount of carbon in the

CO_2 product stream relative to the amount of carbon in the coal less carbon contained in the slag, represented by the following fraction:

(Carbon in Product for Sequestration)/[(Carbon in the Coal)-(Carbon in Slag)] or
276,728/(308,659-2,469) *100 or
90.4 percent

In revision 1 of this report, the reported CO_2 capture efficiency was 88.4 percent. The high methane content of the syngas, relative to the GEE and Shell cases, prevented reaching the nominal 90 percent CO_2 capture. In order to achieve 90 percent capture, the two-stage Selexol CO_2 removal efficiency was increased from 92 to 95 percent.

Exhibit 3-62 Case 4 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	140,006 (308,659)	Slag	1,120 (2,469)
Air (CO_2)	537 (1,185)	Stack Gas	13,796 (30,416)
		ASU Vent	105 (231)
		CO_2 Product	125,522 (276,728)
Total	140,543 (309,844)	Total	140,543 (309,844)

Exhibit 3-63 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant, sulfur emitted in the stack gas, and sulfur in the CO_2 product. Sulfur in the slag is considered to be negligible.

Exhibit 3-63 Case 4 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	5,505 (12,136)	Elemental Sulfur	5,494 (12,112)
		Stack Gas	3 (6)
		CO_2 Product	8 (18)
Total	5,505 (12,136)	Total	5,505 (12,136)

Exhibit 3-64 shows the overall water balance for the plant. The exhibit is presented in an identical manner for Cases 1 through 3.

Exhibit 3-64 Case 4 Water Balance

Water Use	Water Demand, m³/min (gpm)	Internal Recycle, m³/min (gpm)	Raw Water Withdrawal, m³/min (gpm)	Process Water Discharge, m³/min (gpm)	Raw Water Consumption, m³/min (gpm)
Slag Handling	0.49 (128)	0.49 (128)	0.0 (0)	0.0 (0)	0.0 (0)
Slurry Water	1.51 (398)	1.51 (398)	0.0 (0)	0.0 (0)	0.0 (0)
Quench/Wash	0.0 (0)	0.0 (0)	0.0 (0)	0.0 (0)	0.0 (0)
Humidifier	0.2 (61)	0.2 (61)	0.0 (0)	0.0 (0)	0.0 (0)
SWS Blowdown	0.0 (0)	0.0 (0)	0.0 (0)	0.03 (7)	-0.03 (-7)
Condenser Makeup *Gasifier Steam* *Shift Steam* *GT Steam* *Dilution* *BFW Makeup*	**4.5 (1,193)** *1.5 (395)* *2.8 (743)* *0.21 (55)*	**0.0 (0)**	**4.5 (1,193)** *1.5 (395)* *2.8 (743)* *0.21 (55)*	**0.0 (0)**	**4.5 (1,193)**
Cooling Tower *BFW Blowdown* *SWS Blowdown* *SWS Excess Water* *Humidifier Tower Blowdown*	**18.2 (4,798)**	**1.0 (274)** *0.21 (55)* *0.26 (68)* *0.6 (152)*	**17.1 (4,524)** *-0.21 (-55)* *-0.26 (-68)* *-0.6 (-152)*	**4.1 (1,079)**	**13.0 (3,445)**
Total	**24.9 (6,578)**	**3.3 (861)**	**21.6 (5,717)**	**4.1 (1,086)**	**17.5 (4,631)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-65 through Exhibit 3-67:

- Coal gasification and ASU

- Syngas cleanup including sulfur recovery and tail gas recycle

- Combined cycle power generation, steam, and FW

An overall plant energy balance is provided in tabular form in Exhibit 3-68. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-60) is calculated by multiplying the power out by a combined generator efficiency of 98.4 percent.

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Exhibit 3-65 Case 4 Coal Gasification and Air Separation Unit Heat and Mass Balance Schematic
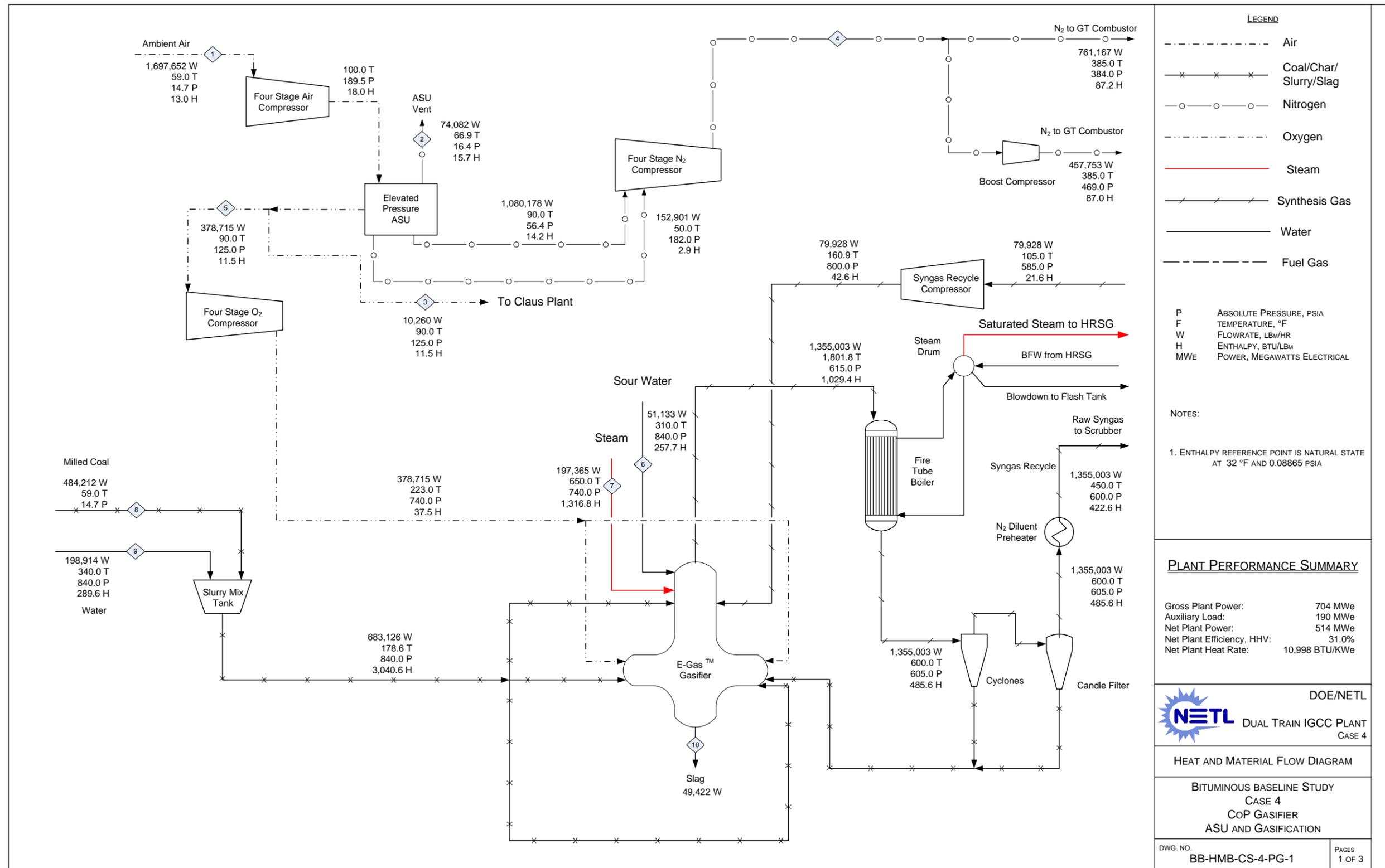
Exhibit 3-66 Case 4 Syngas Cleanup Heat and Mass Balance Schematic
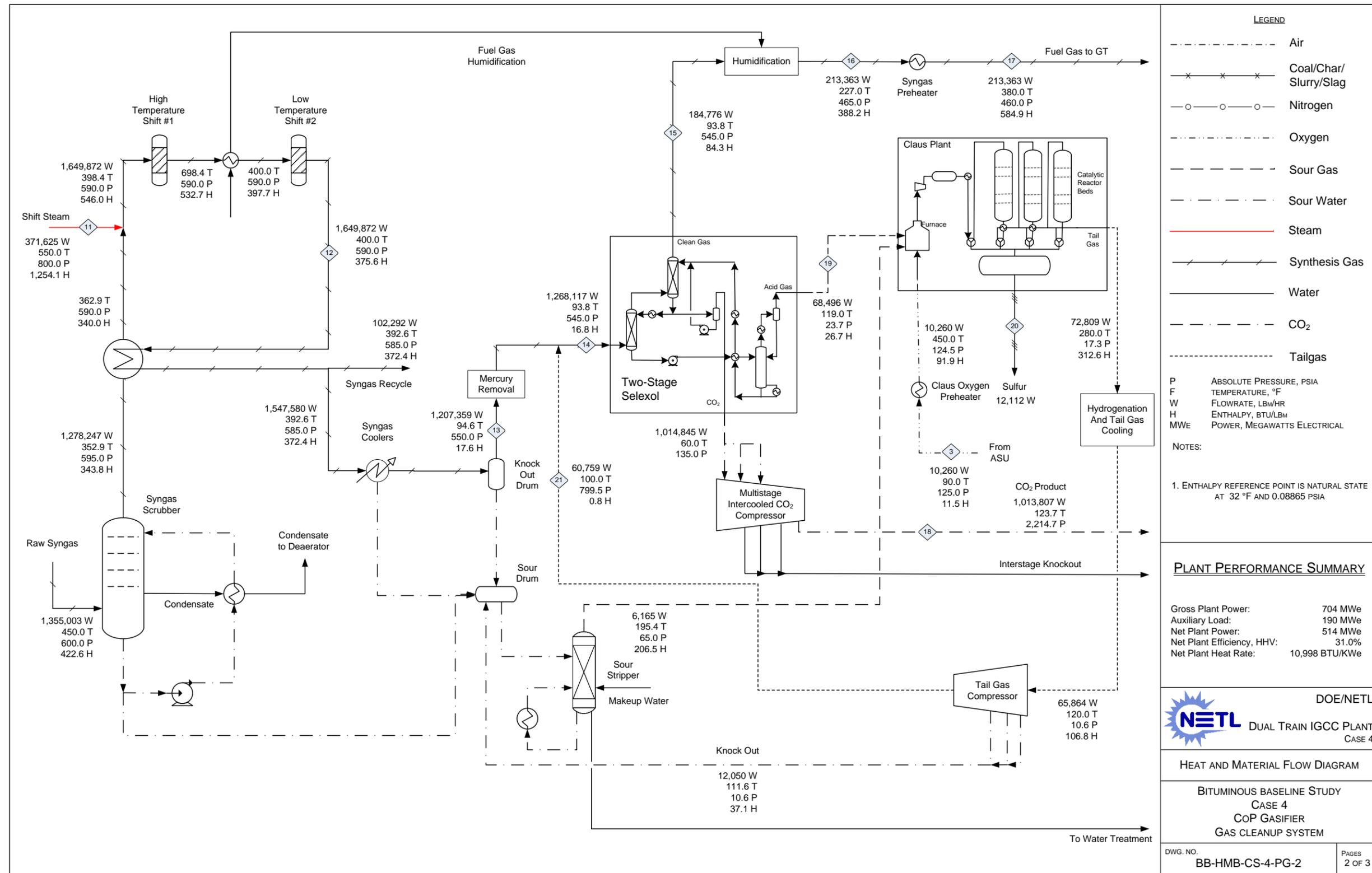
Exhibit 3-67 Case 4 Combined Cycle Power Generation Heat and Mass Balance Schematic
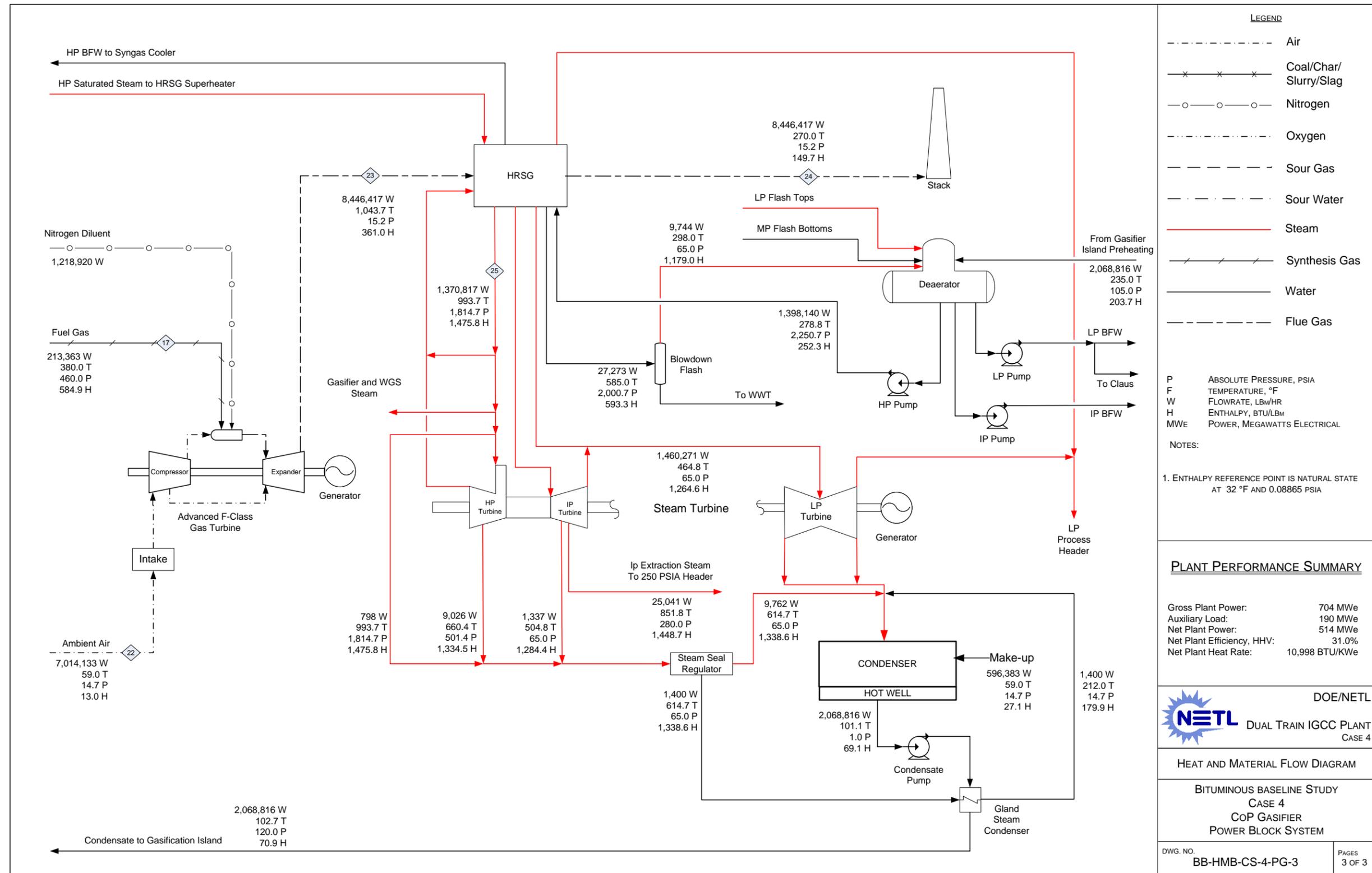
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Exhibit 3-68 Case 4 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	5,960 (5,649)	5.0 (4.7)		5,965 (5,654)
ASU Air		23.3 (22.1)		23 (22)
GT Air		96.2 (91.2)		96 (91)
Water		81.4 (77.1)		81 (77)
Auxiliary Power			684 (649)	684 (649)
TOTAL	**5,960 (5,649)**	**205.8 (195.1)**	**684 (649)**	**6,850 (6,492)**
Heat Out GJ/hr (MMBtu/hr)				
ASU Vent		1.2 (1.2)		1 (1)
Slag	37 (35)	25.2 (23.9)		62 (59)
Sulfur	51 (48)	0.6 (0.6)		52 (49)
CO_2		-74.7 (-70.8)		-75 (-71)
Cooling Tower Blowdown		30.3 (28.8)		30 (29)
HRSG Flue Gas		1,334 (1,264)		1,334 (1,264)
Condenser		1,408 (1,334)		1,408 (1,334)
Non-Condenser Cooling Tower Loads*		755 (716)		755 (716)
Process Losses**		749 (710)		749 (710)
Power			2,533 (2,401)	2,533 (2,401)
TOTAL	**88 (83)**	**4,229 (4,008)**	**2,533 (2,401)**	**6,850 (6,492)**

* Includes ASU compressor intercoolers, CO_2 compressor intercoolers, sour water stripper condenser, syngas cooler (low level heat rejection) and extraction air cooler.

** Calculated by difference to close the energy balance

3.3.10 Case 4 - Major Equipment List

Major equipment items for the CoP gasifier with CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 3.3.11. 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	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	45 tonne (50 ton)	2	1
9	Feeder	Vibratory	181 tonne/hr (200 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	363 tonne/hr (400 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	181 tonne (200 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	363 tonne/hr (400 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	363 tonne/hr (400 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	363 tonne (400 ton)	6	0

ACCOUNT 2   COAL PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Vibratory	82 tonne/h (90 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	245 tonne/h (270 tph)	1	0
3	Rod Mill Feed Hopper	Dual Outlet	481 tonne (530 ton)	1	0
4	Weigh Feeder	Belt	118 tonne/h (130 tph)	2	0
5	Rod Mill	Rotary	118 tonne/h (130 tph)	2	0
6	Slurry Water Storage Tank with Agitator	Field erected	298,179 liters (78,770 gal)	2	0
7	Slurry Water Pumps	Centrifugal	833 lpm (220 gpm)	2	1
8	Trommel Screen	Coarse	172 tonne/h (190 tph)	2	0
9	Rod Mill Discharge Tank with Agitator	Field erected	390,052 liters (103,040 gal)	2	0
10	Rod Mill Product Pumps	Centrifugal	3,407 lpm (900 gpm)	2	2
11	Slurry Storage Tank with Agitator	Field erected	1,170,080 liters (309,100 gal)	2	0
12	Slurry Recycle Pumps	Centrifugal	6,435 lpm (1,700 gpm)	2	2
13	Slurry Product Pumps	Positive displacement	3,407 lpm (900 gpm)	2	2

ACCOUNT 3   FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,101,555 liters (291,000 gal)	2	0
2	Condensate Pumps	Vertical canned	8,669 lpm @ 91 m H2O (2,290 gpm @ 300 ft H2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	606,907 kg/hr (1,338,000 lb/hr)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	8,555 lpm @ 27 m H2O (2,260 gpm @ 90 ft H2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 6,057 lpm @ 1,859 m H2O (1,600 gpm @ 6,100 ft H2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,287 lpm @ 223 m H2O (340 gpm @ 730 ft H2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
10	Closed Cylce Cooling Heat Exchangers	Plate and frame	430 GJ/hr (407 MMBtu/hr) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	154,066 lpm @ 21 m H2O (40,700 gpm @ 70 ft H2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H2O (1,000 gpm @ 350 ft H2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H2O (700 gpm @ 250 ft H2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	5,602 lpm @ 18 m H2O (1,480 gpm @ 60 ft H2O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	2,801 lpm @ 268 m H2O (740 gpm @ 880 ft H2O)	4	1
16	Filtered Water Pumps	Stainless steel, single suction	3,066 lpm @ 49 m H2O (810 gpm @ 160 ft H2O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	1,472,525 liter (389,000 gal)	2	0
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	1,855 lpm (490 gpm)	2	0
19	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

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

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized two-stage, slurry-feed entrained bed	2,903 tonne/day, 4.2 MPa (3,200 tpd, 614.96 psia)	2	0
2	Synthesis Gas Cooler	Fire-tube boiler	337,926 kg/hr (745,000 lb/hr)	2	0
3	Synthesis Gas Cyclone	High efficiency	337,926 kg/hr (745,000 lb/hr) Design efficiency 90%	2	0
4	Candle Filter	Pressurized filter with pulse-jet cleaning	metallic filters	2	0
5	Syngas Scrubber Including Sour Water Stripper	Vertical upflow	337,926 kg/hr (745,000 lb/hr)	2	0
6	Raw Gas Coolers	Shell and tube with condensate drain	386,007 kg/hr (851,000 lb/hr)	8	0
7	Raw Gas Knockout Drum	Vertical with mist eliminator	303,000 kg/hr, 35°C, 3.8 MPa (668,000 lb/hr, 95°F, 555 psia)	2	0
8	Saturation Water Economizers	Shell and tube	36 GJ/hr (34 MMBtu/hr)	2	0
9	Fuel Gas Saturator	Vertical tray tower	53,070 kg/hr, 108°C, 3.8 MPa (117,000 lb/hr, 227°F, 545 psia)	2	0
10	Saturator Water Pump	Centrifugal	757 lpm @ 12 m H2O (200 gpm @ 40 ft H2O)	2	2
11	Synthesis Gas Reheater	Shell and tube	53,070 kg/hr (117,000 lb/hr)	2	0
12	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	337,926 kg/hr (745,000 lb/hr) syngas	2	0
13	ASU Main Air Compressor	Centrifugal, multi-stage	5,805 m3/min @ 1.3 MPa (205,000 scfm @ 190 psia)	2	0
14	Cold Box	Vendor design	2,359 tonne/day (2,600 tpd) of 95% purity oxygen	2	0
15	Oxygen Compressor	Centrifugal, multi-stage	1,161 m3/min (41,000 scfm) Suction - 0.9 MPa (130 psia) Discharge - 5.1 MPa (740 psia)	2	0
16	Primary Nitrogen Compressor	Centrifugal, multi-stage	3,794 m3/min (134,000 scfm) Suction - 0.4 MPa (60 psia) Discharge - 2.7 MPa (390 psia)	2	0
17	Secondary Nitrogen Compressor	Centrifugal, single-stage	538 m3/min (19,000 scfm) Suction - 1.2 MPa (180 psia) Discharge - 2.7 MPa (390 psia)	2	0
18	Gasifier Purge Nitrogen Boost Compressor	Centrifugal, single-stage	1,614 m3/min (57,000 scfm) Suction - 2.6 MPa (380 psia) Discharge - 3.2 MPa (470 psia)	2	0

ACCOUNT 5A   SOUR GAS SHIFT AND SYNGAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber	Sulfated carbon bed	301,185 kg/hr (664,000 lb/hr) 35°C (95°F) 3.8 MPa (550 psia)	2	0
2	Sulfur Plant	Claus type	145 tonne/day (160 tpd)	1	0
3	Water Gas Shift Reactors	Fixed bed, catalytic	411,408 kg/hr (907,000 lb/hr) 204°C (400°F) 4.1 MPa (590 psia)	4	0
4	Shift Reactor Heat Recovery Exchangers	Shell and Tube	Exchanger 1: 94 GJ/hr (89 MMBtu/hr) Exchanger 2: 3 GJ/hr (3 MMBtu/hr)	4	0
5	Acid Gas Removal Plant	Two-stage Selexol	316,154 kg/hr (697,000 lb/hr) 34°C (94°F) 3.8 MPa (545 psia)	2	0
6	Hydrogenation Reactor	Fixed bed, catalytic	36,328 kg/hr (80,090 lb/hr) 232°C (450°F) 0.1 MPa (12.3 psia)	1	0
7	Tail Gas Recycle Compressor	Centrifugal	30,316 kg/hr (66,835 lb/hr)	1	0

ACCOUNT 5B CO_2 COMPRESSION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CO2 Compressor	Integrally geared, multi-stage centrifugal	1,141 m3/min @ 15.3 MPa (40,300 scfm @ 2,215 psia)	4	0

ACCOUNT 6   COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class	232 MW	2	0
2	Gas Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

ACCOUNT 7   HRSG, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.5 m (28 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 341,986 kg/hr, 12.4 MPa/534°C (753,949 lb/hr, 1,800 psig/994°F) Reheat steam - 298,222 kg/hr, 3.1 MPa/534°C (657,466 lb/hr, 452 psig/994°F)	2	0

ACCOUNT 8   STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	252 MW 12.4 MPa/534°C/534°C (1800 psig/ 994°F/994°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitiation	280 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,551 GJ/hr (1,470 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9   COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	469,391 lpm @ 30 m (124,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 2606 GJ/hr (2470 MMBtu/hr) heat duty	1	0

ACCOUNT 10   SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	234,696 liters (62,000 gal)	2	0
2	Slag Crusher	Roll	13 tonne/hr (14 tph)	2	0
3	Slag Depressurizer	Proprietary	13 tonne/hr (14 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	140,060 liters (37,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	64,352 liters (17,000 gal)	2	
6	Slag Conveyor	Drag chain	13 tonne/hr (14 tph)	2	0
7	Slag Separation Screen	Vibrating	13 tonne/hr (14 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	13 tonne/hr (14 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	200,627 liters (53,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	38 lpm @ 14 m H2O (10 gpm @ 46 ft H2O)	2	2
11	Grey Water Storage Tank	Field erected	64,352 liters (17,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	227 lpm @ 433 m H2O (60 gpm @ 1,420 ft H2O)	2	2
13	Slag Storage Bin	Vertical, field erected	907 tonne (1,000 tons)	2	0
14	Unloading Equipment	Telescoping chute	100 tonne/hr (110 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Step-up Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Step-up Transformer	Oil-filled	24 kV/345 kV, 280 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 79 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 51 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 8 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROLS

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

3.3.11 Case 4 - Cost Estimating Results

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-69 shows the total plant capital cost summary organized by cost account and Exhibit 3-70 shows a more detailed breakdown of the capital costs as well as TOC, TASC, and breakdown of owner's costs. Exhibit 3-71 shows the initial and annual O&M costs.

The estimated TOC of the CoP gasifier with CO_2 capture is \$3,466/kW. Process contingency represents 3.5 percent of the TOC and project contingency represents 11.1 percent. The COE, including CO_2 TS&M costs of 5.6 mills/kWh, is 110.4 mills/kWh.

Exhibit 3-69 Case 4 Total Plant Cost Summary

	Client:		USDOE/NETL						Report Date:	2010-Jan-14		
	Project:		Bituminous Baseline Study									
			TOTAL PLANT COST SUMMARY									
	Case:		Case 4 - ConocoPhillips 500MW IGCC w/ CO2									
	Plant Size:		513.6 MW,net	Estimate Type:		Conceptual			Cost Base (Jun)	2007	($x1000)	

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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$14,229	$2,644	$11,035	$0	$0	**$27,908**	$2,533	$0	$6,088	**$36,529**	$71
2	COAL & SORBENT PREP & FEED	$24,241	$4,431	$14,646	$0	$0	**$43,318**	$3,889	$0	$9,441	**$56,648**	$110
3	FEEDWATER & MISC. BOP SYSTEMS	$10,074	$7,882	$10,144	$0	$0	**$28,101**	$2,651	$0	$7,106	**$37,858**	$74
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (E-GAS)	$114,050	$0	$63,266	$0	$0	**$177,316**	$16,295	$24,521	$33,478	**$251,609**	$490
4.2	Syngas Cooling	w/4.1	$0	w/ 4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$186,025	$0	w/equip.	$0	$0	**$186,025**	$18,031	$0	$20,406	**$224,461**	$437
4.4-4.9	Other Gasification Equipment	$24,056	$10,168	$14,678	$0	$0	**$48,902**	$4,688	$0	$11,449	**$65,038**	$127
	SUBTOTAL 4	**$324,131**	**$10,168**	**$77,944**	**$0**	**$0**	**$412,242**	**$39,014**	**$24,521**	**$65,332**	**$541,109**	**$1,054**
5A	GAS CLEANUP & PIPING	$89,500	$3,812	$77,878	$0	$0	**$171,190**	$16,546	$26,077	$42,894	**$256,707**	$500
5B	CO2 COMPRESSION	$18,339	$0	$11,242	$0	$0	**$29,581**	$2,849	$0	$6,486	**$38,916**	$76
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$92,027	$0	$6,583	$0	$0	**$98,609**	$9,348	$9,861	$11,782	**$129,600**	$252
6.2-6.9	Combustion Turbine Other	$0	$806	$892	$0	$0	**$1,699**	$159	$0	$557	**$2,415**	$5
	SUBTOTAL 6	**$92,027**	**$806**	**$7,475**	**$0**	**$0**	**$100,308**	**$9,507**	**$9,861**	**$12,339**	**$132,015**	**$257**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$33,631	$0	$4,782	$0	$0	**$38,414**	$3,652	$0	$4,207	**$46,272**	$90
7.2-7.9	SCR System, Ductwork and Stack	$3,377	$2,407	$3,153	$0	$0	**$8,938**	$829	$0	$1,589	**$11,355**	$22
	SUBTOTAL 7	**$37,008**	**$2,407**	**$7,935**	**$0**	**$0**	**$47,351**	**$4,481**	**$0**	**$5,796**	**$57,628**	**$112**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$26,321	$0	$4,278	$0	$0	**$30,600**	$2,935	$0	$3,353	**$36,888**	$72
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$9,952	$903	$6,987	$0	$0	**$17,843**	$1,623	$0	$3,868	**$23,333**	$45
	SUBTOTAL 8	**$36,274**	**$903**	**$11,266**	**$0**	**$0**	**$48,442**	**$4,558**	**$0**	**$7,221**	**$60,222**	**$117**
9	COOLING WATER SYSTEM	$10,387	$9,859	$8,527	$0	$0	**$28,773**	$2,673	$0	$6,406	**$37,852**	$74
10	ASH/SPENT SORBENT HANDLING SYS	$19,651	$1,481	$9,750	$0	$0	**$30,882**	$2,963	$0	$3,691	**$37,536**	$73
11	ACCESSORY ELECTRIC PLANT	$31,778	$12,519	$24,431	$0	$0	**$68,728**	$5,909	$0	$14,164	**$88,801**	$173
12	INSTRUMENTATION & CONTROL	$11,157	$2,052	$7,188	$0	$0	**$20,397**	$1,849	$1,020	$3,877	**$27,142**	$53
13	IMPROVEMENTS TO SITE	$3,416	$2,014	$8,429	$0	$0	**$13,859**	$1,368	$0	$4,568	**$19,796**	$39
14	BUILDINGS & STRUCTURES	$0	$6,693	$7,589	$0	$0	**$14,282**	$1,300	$0	$2,555	**$18,136**	$35
	TOTAL COST	**$722,212**	**$67,672**	**$295,478**	**$0**	**$0**	**$1,085,363**	**$102,090**	**$61,479**	**$197,964**	**$1,446,895**	**$2,817**

Exhibit 3-70 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,737	$0	$1,826	$0	$0	$5,563	$498	$0	$1,212	$7,273	$14
1.2	Coal Stackout & Reclaim	$4,829	$0	$1,171	$0	$0	$5,999	$526	$0	$1,305	$7,830	$15
1.3	Coal Conveyors & Yd Crush	$4,489	$0	$1,158	$0	$0	$5,648	$496	$0	$1,229	$7,372	$14
1.4	Other Coal Handling	$1,175	$0	$268	$0	$0	$1,443	$126	$0	$314	$1,883	$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	$2,644	$6,612	$0	$0	$9,256	$887	$0	$2,029	$12,172	$24
	SUBTOTAL 1.	$14,229	$2,644	$11,035	$0	$0	$27,908	$2,533	$0	$6,088	$36,529	$71
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying (incl. w/2.3)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.2	Prepared Coal Storage & Feed	$1,596	$382	$250	$0	$0	$2,228	$190	$0	$484	$2,902	$6
2.3	Slurry Prep & Feed	$21,768	$0	$9,681	$0	$0	$31,449	$2,808	$0	$6,851	$41,108	$80
2.4	Misc.Coal Prep & Feed	$877	$639	$1,914	$0	$0	$3,430	$315	$0	$749	$4,495	$9
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	$3,411	$2,800	$0	$0	$6,211	$575	$0	$1,357	$8,143	$16
	SUBTOTAL 2.	$24,241	$4,431	$14,646	$0	$0	$43,318	$3,889	$0	$9,441	$56,648	$110
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	Feedwater System	$2,834	$4,868	$2,570	$0	$0	$10,272	$952	$0	$2,245	$13,468	$26
3.2	Water Makeup & Pretreating	$709	$74	$396	$0	$0	$1,179	$112	$0	$387	$1,679	$3
3.3	Other Feedwater Subsystems	$1,551	$524	$472	$0	$0	$2,546	$229	$0	$555	$3,330	$6
3.4	Service Water Systems	$406	$835	$2,899	$0	$0	$4,140	$404	$0	$1,363	$5,907	$12
3.5	Other Boiler Plant Systems	$2,177	$843	$2,090	$0	$0	$5,111	$485	$0	$1,119	$6,714	$13
3.6	FO Supply Sys & Nat Gas	$313	$591	$551	$0	$0	$1,456	$140	$0	$319	$1,915	$4
3.7	Waste Treatment Equipment	$991	$0	$604	$0	$0	$1,595	$155	$0	$525	$2,276	$4
3.8	Misc. Power Plant Equipment	$1,094	$146	$562	$0	$0	$1,802	$174	$0	$593	$2,569	$5
	SUBTOTAL 3.	$10,074	$7,882	$10,144	$0	$0	$28,101	$2,651	$0	$7,106	$37,858	$74
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (E-GAS)	$114,050	$0	$63,266	$0	$0	$177,316	$16,295	$24,521	$33,478	$251,609	$490
4.2	Syngas Cooling	w/4.1	$0	w/ 4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$186,025	$0	w/equip.	$0	$0	$186,025	$18,031	$0	$20,406	$224,461	$437
4.4	LT Heat Recovery & FG Saturation	$24,056	$0	$9,145	$0	$0	$33,201	$3,240	$0	$7,288	$43,730	$85
4.5	Misc. Gasification Equipment	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Flare Stack System	$0	$1,643	$669	$0	$0	$2,312	$222	$0	$507	$3,041	$6
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	$8,525	$4,864	$0	$0	$13,389	$1,226	$0	$3,654	$18,268	$36
	SUBTOTAL 4.	$324,131	$10,168	$77,944	$0	$0	$412,242	$39,014	$24,521	$65,332	$541,109	$1,054

Exhibit 3-70 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	Double Stage Selexol	$70,224	$0	$59,586	$0	$0	$129,810	$12,554	$25,962	$33,665	$201,991	$393
5A.2	Elemental Sulfur Plant	$10,291	$2,051	$13,278	$0	$0	$25,620	$2,489	$0	$5,622	$33,730	$66
5A.3	Mercury Removal	$1,302	$0	$991	$0	$0	$2,294	$222	$115	$526	$3,156	$6
5A.4	Shift Reactors	$7,138	$0	$2,873	$0	$0	$10,011	$960	$0	$2,194	$13,164	$26
5A.5	Particulate Removal	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Blowback Gas Systems	$545	$306	$172	$0	$0	$1,023	$98	$0	$224	$1,345	$3
5A.7	Fuel Gas Piping	$0	$723	$506	$0	$0	$1,229	$114	$0	$269	$1,612	$3
5A.9	HGCU Foundations	$0	$732	$472	$0	$0	$1,204	$111	$0	$394	$1,709	$3
	SUBTOTAL 5A.	$89,500	$3,812	$77,878	$0	$0	$171,190	$16,546	$26,077	$42,894	$256,707	$500
5B	CO2 COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$18,339	$0	$11,242	$0	$0	$29,581	$2,849	$0	$6,486	$38,916	$76
	SUBTOTAL 5B.	$18,339	$0	$11,242	$0	$0	$29,581	$2,849	$0	$6,486	$38,916	$76
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$92,027	$0	$6,583	$0	$0	$98,609	$9,348	$9,861	$11,782	$129,600	$252
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.	$92,027	$806	$7,475	$0	$0	$100,308	$9,507	$9,861	$12,339	$132,015	$257
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$33,631	$0	$4,782	$0	$0	$38,414	$3,652	$0	$4,207	$46,272	$90
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,731	$1,235	$0	$0	$2,966	$260	$0	$645	$3,871	$8
7.4	Stack	$3,377	$0	$1,269	$0	$0	$4,645	$445	$0	$509	$5,599	$11
7.9	HRSG,Duct & Stack Foundations	$0	$677	$650	$0	$0	$1,326	$123	$0	$435	$1,885	$4
	SUBTOTAL 7.	$37,008	$2,407	$7,935	$0	$0	$47,351	$4,481	$0	$5,796	$57,628	$112
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$26,321	$0	$4,278	$0	$0	$30,600	$2,935	$0	$3,353	$36,888	$72
8.2	Turbine Plant Auxiliaries	$182	$0	$417	$0	$0	$599	$59	$0	$66	$724	$1
8.3	Condenser & Auxiliaries	$4,762	$0	$1,521	$0	$0	$6,284	$601	$0	$688	$7,573	$15
8.4	Steam Piping	$5,008	$0	$3,523	$0	$0	$8,531	$733	$0	$2,316	$11,580	$23
8.9	TG Foundations	$0	$903	$1,526	$0	$0	$2,429	$230	$0	$798	$3,457	$7
	SUBTOTAL 8.	$36,274	$903	$11,266	$0	$0	$48,442	$4,558	$0	$7,221	$60,222	$117

Exhibit 3-70 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$7,196	$0	$1,401	$0	$0	$8,597	$819	$0	$1,412	$10,828	$21
9.2	Circulating Water Pumps	$1,877	$0	$136	$0	$0	$2,013	$170	$0	$327	$2,510	$5
9.3	Circ.Water System Auxiliaries	$157	$0	$22	$0	$0	$179	$17	$0	$29	$226	$0
9.4	Circ.Water Piping	$0	$6,545	$1,697	$0	$0	$8,241	$745	$0	$1,797	$10,783	$21
9.5	Make-up Water System	$384	$0	$549	$0	$0	$933	$90	$0	$205	$1,227	$2
9.6	Component Cooling Water Sys	$773	$924	$657	$0	$0	$2,354	$221	$0	$515	$3,090	$6
9.9	Circ.Water System Foundations	$0	$2,391	$4,064	$0	$0	$6,455	$612	$0	$2,120	$9,187	$18
	SUBTOTAL 9.	$10,387	$9,859	$8,527	$0	$0	$28,773	$2,673	$0	$6,406	$37,852	$74
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$17,164	$0	$8,464	$0	$0	$25,628	$2,462	$0	$2,809	$30,900	$60
10.2	Gasifier Ash Depressurization	w/10.1	w/10.1	w/10.1	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	w/10.1	w/10.1	w/10.1	$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 Recovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$564	$0	$613	$0	$0	$1,177	$114	$0	$194	$1,485	$3
10.7	Ash Transport & Feed Equipment	$756	$0	$182	$0	$0	$938	$88	$0	$154	$1,180	$2
10.8	Misc. Ash Handling Equipment	$1,168	$1,431	$427	$0	$0	$3,026	$288	$0	$497	$3,811	$7
10.9	Ash/Spent Sorbent Foundation	$0	$50	$63	$0	$0	$112	$11	$0	$37	$160	$0
	SUBTOTAL 10.	$19,651	$1,481	$9,750	$0	$0	$30,882	$2,963	$0	$3,691	$37,536	$73
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$924	$0	$914	$0	$0	$1,839	$176	$0	$201	$2,216	$4
11.2	Station Service Equipment	$4,676	$0	$421	$0	$0	$5,097	$470	$0	$557	$6,124	$12
11.3	Switchgear & Motor Control	$8,644	$0	$1,572	$0	$0	$10,216	$948	$0	$1,675	$12,838	$25
11.4	Conduit & Cable Tray	$0	$4,015	$13,247	$0	$0	$17,262	$1,670	$0	$4,733	$23,665	$46
11.5	Wire & Cable	$0	$7,672	$5,041	$0	$0	$12,713	$924	$0	$3,409	$17,046	$33
11.6	Protective Equipment	$0	$680	$2,474	$0	$0	$3,153	$308	$0	$519	$3,980	$8
11.7	Standby Equipment	$229	$0	$223	$0	$0	$452	$43	$0	$74	$570	$1
11.8	Main Power Transformers	$17,305	$0	$140	$0	$0	$17,445	$1,319	$0	$2,815	$21,579	$42
11.9	Electrical Foundations	$0	$152	$398	$0	$0	$550	$53	$0	$181	$784	$2
	SUBTOTAL 11.	$31,778	$12,519	$24,431	$0	$0	$68,728	$5,909	$0	$14,164	$88,801	$173
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	w/6.1	$0	w/6.1	$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	$1,101	$0	$735	$0	$0	$1,837	$174	$92	$315	$2,418	$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	$253	$0	$162	$0	$0	$415	$39	$21	$95	$571	$1
12.7	Computer & Accessories	$5,875	$0	$188	$0	$0	$6,063	$557	$303	$692	$7,615	$15
12.8	Instrument Wiring & Tubing	$0	$2,052	$4,196	$0	$0	$6,248	$530	$312	$1,773	$8,863	$17
12.9	Other I & C Equipment	$3,927	$0	$1,907	$0	$0	$5,834	$549	$292	$1,001	$7,676	$15
	SUBTOTAL 12.	$11,157	$2,052	$7,188	$0	$0	$20,397	$1,849	$1,020	$3,877	$27,142	$53

Exhibit 3-70 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$107	$2,291	$0	$0	$2,398	$238	$0	$791	$3,427	$7
13.2	Site Improvements	$0	$1,906	$2,533	$0	$0	$4,440	$438	$0	$1,463	$6,341	$12
13.3	Site Facilities	$3,416	$0	$3,605	$0	$0	$7,021	$692	$0	$2,314	$10,027	$20
	SUBTOTAL 13.	$3,416	$2,014	$8,429	$0	$0	$13,859	$1,368	$0	$4,568	$19,796	$39
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	$2,246	$3,200	$0	$0	$5,445	$501	$0	$892	$6,838	$13
14.3	Administration Building	$0	$870	$631	$0	$0	$1,501	$134	$0	$245	$1,880	$4
14.4	Circulation Water Pumphouse	$0	$163	$86	$0	$0	$250	$22	$0	$41	$312	$1
14.5	Water Treatment Buildings	$0	$592	$578	$0	$0	$1,171	$106	$0	$191	$1,468	$3
14.6	Machine Shop	$0	$445	$305	$0	$0	$750	$67	$0	$122	$939	$2
14.7	Warehouse	$0	$719	$464	$0	$0	$1,183	$105	$0	$193	$1,481	$3
14.8	Other Buildings & Structures	$0	$431	$335	$0	$0	$766	$68	$0	$167	$1,001	$2
14.9	Waste Treating Building & Str.	$0	$963	$1,840	$0	$0	$2,802	$261	$0	$613	$3,676	$7
	SUBTOTAL 14.	$0	$6,693	$7,589	$0	$0	$14,282	$1,300	$0	$2,555	$18,136	$35
	TOTAL COST	$722,212	$67,672	$295,478	$0	$0	$1,085,363	$102,090	$61,479	$197,964	$1,446,895	$2,817
	Owner's Costs											
	Preproduction Costs											
	6 Months All Labor										$13,491	$26
	1 Month Maintenance Materials										$2,999	$6
	1 Month Non-fuel Consumables										$385	$1
	1 Month Waste Disposal										$295	$1
	25% of 1 Months Fuel Cost at 100% CF										$1,687	$3
	2% of TPC										$28,938	$56
	Total										$47,793	$93
	Inventory Capital											
	60 day supply of fuel and consumables at 100% CF										$13,995	$27
	0.5% of TPC (spare parts)										$7,234	$14
	Total										$21,230	$41
	Initial Cost for Catalyst and Chemicals										$7,371	$14
	Land										$900	$2
	Other Owner's Costs										$217,034	$423
	Financing Costs										$39,066	$76
	Total Overnight Costs (TOC)										$1,780,290	$3,466
	TASC Multiplier							(IOU, high-risk, 35 year)			1.140	
	Total As-Spent Cost (TASC)										$2,029,531	$3,952

Exhibit 3-71 Case 4 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun):	2007
Case 4 - ConocoPhillips 500MW IGCC w/ CO2					Heat Rate-net (Btu/kWh):	10,998
					MWe-net:	514
					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
Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.	Plant

	1 unit/mod.	Total Plant
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	$6,313,507	$12.292
Maintenance Labor Cost	$15,271,560	$29.734
Administrative & Support Labor	$5,396,267	$10.507
Property Taxes and Insurance	$28,937,909	$56.342
TOTAL FIXED OPERATING COSTS	**$55,919,243**	**$108.875**

VARIABLE OPERATING COSTS

					Annual Cost	$/kWh-net
Maintenance Material Cost					**$28,787,121**	**$0.00800**

Consumables	Consumption Initial Fill	/Day	Unit Cost	Initial Fill Cost	Annual Cost	$/kWh-net
Water(/1000 gallons)	0	4,116	1.08	$0	$1,300,111	$0.00036
Chemicals						
MU & WT Chem. (lbs)	0	24,523	0.17	$0	$1,239,310	$0.00034
Carbon (Mercury Removal) (lb)	104,394	143	1.05	$109,631	$43,852	$0.00001
COS Catalyst (m3)	0	0	2,397.36	$0	$0	$0.00000
Water Gas Shift Catalyst (ft3)	6,484	4.44	498.83	$3,234,413	$646,883	$0.00018
Selexol Solution (gal)	300,533	98	13.40	$4,026,613	$384,543	$0.00011
SCR Catalyst (m3)	0	0	0.00	$0	$0	$0.00000
Ammonia (19% NH3) (ton)	0	0	0.00	$0	$0	$0.00000
Claus Catalyst (ft3)	w/equip.	2.00	131.27	$0	$76,827	$0.00002
Subtotal Chemicals				**$7,370,657**	**$2,391,415**	**$0.00066**
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	143	0.42	$0	$17,416	$0.00000
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Slag (ton)	0	593	16.23	$0	$2,809,802	$0.00078
Subtotal Waste Disposal				**$0**	**$2,827,218**	**$0.00079**
By-products & Emissions						
Sulfur (ton)	0	145	0.00	$0	$0	$0.00000
Subtotal By-products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$7,370,657**	**$35,305,866**	**$0.00981**
Fuel (ton)	0	5,811	38.18	$0	$64,786,772	$0.01800

3.4   SHELL GLOBAL SOLUTIONS IGCC CASES

This section contains an evaluation of plant designs for Cases 5 and 6, which are based on the Shell gasifier. Cases 5 and 6 are very similar in terms of process, equipment, scope and arrangement, except that Case 6 employs a syngas quench and includes SGS reactors, CO_2 absorption/regeneration, and compression/transport systems. There are no provisions for CO_2 removal in Case 5.

The balance of this section is organized in an analogous manner to Sections 3.2 and 3.3:

- Gasifier Background

- Process System Description for Case 5

- Key Assumptions for Cases 5 and 6

- Sparing Philosophy for Cases 5 and 6

- Performance Results for Case 5

- Equipment List for Case 5

- Cost Estimates For Case 5

- Process and System Description, Performance Results, Equipment List, and Cost Estimate for Case 6

3.4.1   <u>Gasifier Background</u>

Development and Current Status – Development of the Shell gasification process for partial oxidation of oil and gas began in the early 1950s. More than 75 commercial Shell partial-oxidation plants have been built worldwide to convert a variety of hydrocarbon liquids and gases to carbon monoxide and hydrogen.

Shell Internationale Petroleum Maatschappij B.V. began work on coal gasification in 1972. The coal gasifier is significantly different than the oil and gas gasifiers developed earlier. A pressurized, entrained-flow, slagging coal gasifier was built at Shell's Amsterdam laboratories. This 5 tonnes/day (6 TPD) process development unit has operated for approximately 12,000 hours since 1976. A larger 150 tonnes/day (165 TPD) pilot plant was built at Shell's Hamburg refinery in Hamburg, Germany. This larger unit operated for approximately 6,000 hours from 1978 to 1983, and successfully gasified over 27,216 tonnes (30,000 tons) of coal.

From 1974 until mid-1981, Heinrich Koppers GmbH (now Krupp Koppers) cooperated with Shell in the development work for the coal gasification technology at the 150 tonnes/day (165 TPD) pilot plant in Hamburg. Krupp Koppers is the licensor of the commercially proven Koppers-Totzek coal gasification technology, an entrained-flow slagging gasification system operated at atmospheric pressure.

In June 1981, the partnership between Shell and Krupp Koppers was terminated. Since that time, this gasification technology has been developed solely by Shell as the Shell Coal Gasification Process. Krupp Koppers continued its own development of a similar pressurized, dry feed, entrained-flow gasification technology called PRENFLO. Krupp Koppers has built and successfully operated a small 45 tonnes/day (50 TPD) PRENFLO pilot plant at Fuerstenhausen,

Germany. In 2000 Shell and Krupp Uhde agreed to join forces again in gasification and jointly offer the Shell coal gasification process.

Based on the experience it gained with the Hamburg unit, Shell built a demonstration unit at its oil refinery and chemical complex in Deer Park, Texas, near Houston. This new unit, commonly called SCGP-1 (for Shell Coal Gasification Plant-1), was designed to gasify bituminous coal at the rate of 227 tonnes/day (250 TPD) and to gasify high-moisture, high-ash lignite at the rate of 363 tonnes/day (400 TPD). The relatively small difference in size between the Hamburg and Deer Park units reflects design changes and improvements.

The Deer Park demonstration plant operated successfully after startup in July 1987. Before the end of the program in 1991, after 15,000 hours of operation, 18 different feedstocks were gasified at the plant, including domestic coals ranging from lignite to high-sulfur bituminous, three widely traded foreign coals, and petroleum coke. The Deer Park unit produced superheated HP steam in the waste heat recovery boiler. The plant also had facilities for extensive environmental monitoring and for sidestream testing of several AGR processes, including Sulfinol-D, Sulfinol-M, highly loaded MDEA, and various wastewater treatment schemes.

In spring 1989, Shell announced that its technology had been selected for the large commercial-scale Demkolec B.V. IGCC plant at Buggenum, near Roermond, in The Netherlands. This plant generates 250 MW of IGCC electricity with a single Shell gasifier consuming 1,814 tonnes/day (2,000 TPD) (dry basis) of coal. The plant was originally owned and operated by Samenwerkende Electriciteits-Productiebedrijven NV (SEP), a consortium of Dutch utilities, and began operation in 1994. In 2000 the plant was purchased by Nuon. Shell was extensively involved in the design, startup, and initial operation of this plant. A key feature of this design is the use of extraction air from the CT air compressor to feed the oxygen plant.

Gasifier Capacity – As of 2009, Shell reported ten gasifiers in operation producing 100,000-150,000 Nm^3/hr and three of the same size in construction. Another three ranging from 150,000-250,000 Nm^3/hr are also in construction [61]. The large gasifier operating in The Netherlands has a bituminous coal-handling capacity of 1,633 tonnes/day (1,800 TPD) and produces dry gas at a rate of 158,575 Nm^3/hr (5.6 million scf/hr) with an energy content of about 1,792 MMkJ/hr (1,700 MMBtu/hr) (HHV). This gasifier was sized to match the fuel gas requirements for the Siemens/Kraftwerk Union V-94.2 CT and could easily be scaled up to match advanced F Class turbine requirements.

Distinguishing Characteristics – The key advantage of the Shell coal gasification technology is its lack of feed coal limitations. One of the major achievements of the Shell development program has been the successful gasification of a wide variety of coals ranging from anthracite to brown coal. The dry pulverized feed system developed by Shell uses all coal types with essentially no operating and design modifications (provided the drying pulverizers are appropriately sized). The dry fed Shell gasifier also has the advantage of lower oxygen requirement than comparable slurry fed entrained flow gasifiers.

Entrained-flow slagging gasifiers have fundamental environmental advantages over fluidized-bed and moving-bed gasifiers. They produce no hydrocarbon liquids, and the only solid waste is an inert slag. The dry feed entrained-flow gasifiers also have minor environmental advantages over the slurry feed entrained-flow gasifiers. They produce a higher H_2S/CO_2 ratio acid gas, which improves sulfur recovery and lessens some of the gray water processing and the fixed-salts blowdown problems associated with slurry feeding.

A disadvantage of the Shell coal gasification technology is the high waste heat recovery (SGC) duty. As with the other slagging gasifiers, the Shell process has this disadvantage due to its high operating temperature. The ability to feed dry solids minimizes the oxygen requirement and makes the Shell gasifier somewhat more efficient than entrained flow gasifiers employing slurry feed systems. The penalty paid for this increase in efficiency is a coal feed system that is more costly and operationally more complex. Demonstration of the reliability and safety of the dry coal feeding system was essential for the successful development of the Shell technology. The high operating temperature required by all entrained-flow slagging processes can result in relatively high capital and maintenance costs. However, the Shell gasifier employs a cooled refractory, which requires fewer change outs than an uncooled refractory. Life of a water wall is determined by metallurgy and temperature and can provide a significant O&M cost benefit over refractory lined gasifiers.

Important Coal Characteristics – Characteristics desirable for coal considered for use in the Shell gasifier include moderate ash fusion temperature and relatively low ash content. The Shell gasifier is extremely flexible; it can handle a wide variety of different coals, including lignite. High-ash fusion-temperature coals may require flux addition for optimal gasifier operation. The ash content, fusion temperature, and composition affect the required gasifier operating temperature level, oxygen requirements, heat removal, slag management, and maintenance. However, dry feeding reduces the negative effects of high ash content relative to slurry feed gasifiers.

3.4.2   Process Description

In this section the overall Shell gasification process for Case 5 is described. The system description follows the BFD in Exhibit 3-72 and stream numbers reference the same Exhibit. The tables in Exhibit 3-73 provide process data 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 Illinois No. 6 coal used in this study contains 11.12 percent total moisture on an as-received basis (stream 9). It was assumed that the coal must be dried to 5 percent moisture to allow for smooth flow through the dry feed system (stream 10).

The coal is simultaneously crushed and dried in the coal mill then delivered to a surge hopper with an approximate 2-hour capacity. The drying medium is provided by combining the off-gas from the Claus plant TGTU and a slipstream of clean syngas (stream 8) and passing them through an incinerator. The incinerator FG, with an oxygen content of 6 vol%, is then used to dry the coal in the mill.

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 to convey the coal to the gasifiers.

Exhibit 3-72 Case 5 Block Flow Diagram, Shell IGCC without CO$_2$ Capture

Exhibit 3-73 Case 5 Stream Table, Shell IGCC without CO₂ Capture

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
V-L Mole Fraction														
Ar	0.0092	0.0262	0.0318	0.0023	0.0318	0.0000	0.0023	0.0100	0.0000	0.0000	0.0000	0.0095	0.0095	0.0096
CH₄	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0006	0.0000	0.0000	0.0000	0.0006	0.0006	0.0006
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.5980	0.0000	0.0000	0.0000	0.5797	0.5797	0.5833
CO₂	0.0003	0.0092	0.0000	0.0000	0.0000	0.0000	0.0000	0.0158	0.0000	0.0000	0.0000	0.0143	0.0143	0.0151
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0007	0.0007	0.0000
H₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3142	0.0000	0.8090	0.0000	0.3006	0.3006	0.3024
H₂O	0.0099	0.2378	0.0000	0.0003	0.0000	1.0000	0.0004	0.0013	0.0000	0.0935	0.0000	0.0252	0.0252	0.0194
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0030	0.0000	0.0009	0.0009	0.0001
H₂S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0081	0.0081	0.0089
N₂	0.7732	0.5018	0.0178	0.9919	0.0178	0.0000	0.9919	0.0601	0.0000	0.0163	0.0000	0.0567	0.0567	0.0570
NH₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0036	0.0036	0.0036
O₂	0.2074	0.2251	0.9504	0.0054	0.9504	0.0000	0.0054	0.0000	0.0000	0.0782	0.0000	0.0000	0.0000	0.0000
SO₂	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	1.0000	0.0000	1.0000	0.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg$_{mol}$/hr)	18,364	812	88	16,375	4,591	1,061	882	252	0	0	0	25,096	17,567	17,460
V-L Flowrate (kg/hr)	529,935	21,917	2,828	459,480	147,752	19,111	24,747	5,088	0	0	0	509,993	356,995	354,790
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	198,059	185,222	19,837	0	0	0
Temperature (°C)	15	21	32	93	32	343	32	45	15	16	1,427	1,079	191	177
Pressure (MPa, abs)	0.10	0.11	0.86	2.65	0.86	5.10	5.41	3.65	0.10	5.79	4.24	4.24	4.03	3.90
Enthalpy (kJ/kg)^A	30.23	37.32	26.67	92.52	26.67	3,063.97	21.22	60.75	---	0.00	0.00	0.00	325.96	297.28
Density (kg/m³)	1.2	1.6	11.0	24.4	11.0	20.1	60.5	27.8	---	16.5	---	7.6	21.0	20.9
V-L Molecular Weight	28.857	26.992	32.181	28.060	32.181	18.015	28.060	20.195	---	---	---	20.322	20.322	20.320
V-L Flowrate (lb$_{mol}$/hr)	40,486	1,790	194	36,101	10,122	2,339	1,944	555	0	0	0	55,328	38,729	38,493
V-L Flowrate (lb/hr)	1,168,307	48,319	6,236	1,012,980	325,738	42,132	54,557	11,218	0	0	0	1,124,342	787,039	782,178
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	436,646	408,345	43,732	0	0	0
Temperature (°F)	59	70	90	199	90	650	90	112	59	60	2,600	1,974	375	351
Pressure (psia)	14.7	16.4	125.0	384.0	125.0	740.0	785.0	530.0	14.7	840.0	615.0	615.0	585.0	565.0
Enthalpy (Btu/lb)^A	13.0	16.0	11.5	39.8	11.5	1,317.3	9.1	26.1	---				140.1	127.8
Density (lb/ft³)	0.076	0.101	0.687	1.521	0.687	1.257	3.774	1.734	---	1.029	---	0.475	1.310	1.303

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-73 Case 5 Stream Table, Shell IGCC without CO₂ Capture (Continued)

	15	16	17	18	19	20	21	22	23	24	25	26	27
V-L Mole Fraction													
Ar	0.0098	0.0098	0.0100	0.0079	0.0079	0.0004	0.0000	0.0058	0.0092	0.0092	0.0086	0.0086	0.0000
CH₄	0.0006	0.0006	0.0006	0.0005	0.0005	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.5962	0.5845	0.5980	0.4741	0.4741	0.0167	0.0000	0.1034	0.0000	0.0000	0.0000	0.0000	0.0000
CO₂	0.0155	0.0257	0.0158	0.0125	0.0125	0.4460	0.0000	0.2613	0.0003	0.0003	0.0752	0.0752	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0006	0.0000	0.0000	0.0000	0.0000	0.0000
H₂	0.3091	0.3072	0.3142	0.2491	0.2491	0.0096	0.0000	0.0429	0.0000	0.0000	0.0000	0.0000	0.0000
H₂O	0.0014	0.0015	0.0013	0.2083	0.2083	0.0063	0.0000	0.4259	0.0099	0.0099	0.0906	0.0906	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H₂S	0.0091	0.0089	0.0000	0.0000	0.0000	0.3872	0.0000	0.0016	0.0000	0.0000	0.0000	0.0000	0.0000
N₂	0.0583	0.0618	0.0601	0.0476	0.0476	0.1338	0.0000	0.1585	0.7732	0.7732	0.7210	0.7210	0.0000
NH₃	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
O₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2074	0.2074	0.1046	0.1046	0.0000
SO₂	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	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg$_{mol}$/hr)	17,081	17,426	16,771	21,155	21,155	402	0	510	110,253	4,410	137,428	137,428	39,521
V-L Flowrate (kg/hr)	347,994	358,740	338,688	417,666	417,666	14,964	0	13,723	3,181,557	127,262	3,962,154	3,962,154	711,987
Solids Flowrate (kg/hr)	0	0	0	0	0	0	4,959	0	0	0	0	0	0
Temperature (°C)	35	34	45	161	193	45	178	232	15	432	587	132	559
Pressure (MPa, abs)	3.72	3.69	3.65	3.21	3.2	3.654	0.409	0.406	0.101	1.619	0.105	0.105	12.512
Enthalpy (kJ/kg)^A	0.00	44.26	60.75	0.00	762.9	13.883	---	1,007.135	30.227	463.785	791.043	280.131	3,496.259
Density (kg/m³)	29.5	29.6	27.8	17.7	16.2	60.9	5,278.6	2.6	1.2	7.9	0.4	0.9	35.2
V-L Molecular Weight	20.373	20.587	20.195	19.743	20	37.190	---	26.923	28.857	28.857	28.831	28.831	18.015
V-L Flowrate (lb$_{mol}$/hr)	37,657	38,417	36,974	46,639	46,639	887	0	1,124	243,066	9,723	302,978	302,978	87,130
V-L Flowrate (lb/hr)	767,195	790,887	746,680	920,797	920,797	32,989	0	30,253	7,014,133	280,565	8,735,053	8,735,053	1,569,662
Solids Flowrate (lb/hr)	0	0	0	0	0	0	10,933	0	0	0	0	0	0
Temperature (°F)	94	94	112	321	380	112	353	450	59	810	1,088	270	1,038
Pressure (psia)	540.0	535.0	530.0	465.0	460.0	530.0	59.3	58.9	14.7	234.9	15.2	15.2	1,814.7
Enthalpy (Btu/lb)^A		19.0	26.1		328.0	6.0	---	433.0	13.0	199.4	340.1	120.4	1,503.1
Density (lb/ft³)	1.844	1.850	1.734	1.103	1	3.805	329.535	0.163	0.076	0.495	0.026	0.056	2.200

Gasifier

There are two Shell dry feed, pressurized, upflow, entrained, slagging gasifiers, operating at 4.2 MPa (615 psia) and processing a total of 4,753 tonnes/day (5,240 TPD) of as-received coal. The air separation plant supplies 3,614 tonnes/day (3,984 TPD) of 95 percent oxygen to the gasifiers (stream 5) and the Claus plant (stream 3). Coal reacts with oxygen and steam at a temperature of 1427°C (2600°F) in the gasifier to produce principally hydrogen and carbon monoxide with little carbon dioxide formed.

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 and solidifies slag touching the gasifier walls and maintains the syngas temperature at 1,427°C (2,600°F). The product gas from the gasifier is cooled to approximately 1,093°C (2,000°F) by adding cooled recycled fuel gas to lower the temperature below the ash melting point. Gas (stream 12) then goes through a duct cooler and syngas cooler, which lower the gas temperature from approximately 1,093°C (2,000°F) to 316°C (600°F), and produce HP steam for use in the steam cycle.

After passing through the duct cooler and syngas cooler, 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 11). Lockhoppers are used to reduce the pressure of the solids from 4.2 to 0.1 MPa (615 to 15 psia). The syngas scrubber removes additional PM further downstream.

After passing through the cyclone and ceramic candle filter array, the syngas is further cooled to 191°C (375°F) (stream 13) by raising IP steam.

Quench Gas Compressor

About 30 percent of the cooled syngas is recycled back to the gasifier exit as quench gas. A single-stage compressor is utilized to boost the pressure of the cooled fuel gas stream from 4.0 MPa (575 psia) to 4.0 MPa (585 psia) to provide quench gas to cool the gas stream from the gasifier.

Syngas Scrubber/Sour Water Stripper

The raw syngas exiting the final raw gas cooler at 191°C (375°F) (stream 13) then enters the scrubber for removal of chlorides, SO_2, NH_3 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 94°C (201°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 SGCs. 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 SRU. Remaining water is sent to wastewater treatment.

COS Hydrolysis, Mercury Removal and AGR

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 AGR process; however, because COS is not readily removable, 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 14), 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 15) then passes through a carbon bed to remove 95 percent of the Hg (Section 3.1.4).

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 this application.

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 LP 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 essentially all of the CO_2 along with the H_2S and COS. The acid gas fed to the SRU contains 39 vol% H_2S and 45 vol% CO_2. The CO_2 passes through the SRU, the TGTU and ultimately is vented through the coal dryer. 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 GT. However, the costs of the sulfur recovery/tail gas cleanup are higher than for a sulfur removal process producing an acid gas stream with a higher sulfur concentration.

Claus Unit

The SRU is a Claus bypass type SRU utilizing oxygen (stream 3) instead of air. The Claus plant produces molten sulfur (stream 21) 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 use of Claus technology 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 119 tonnes/day (131 TPD) of elemental sulfur. Feed for this case consists of acid gas from both the acid gas cleanup unit (stream 20) and a vent stream from the sour water stripper in the gasifier section. A slipstream of clean syngas (stream 8) is passed through an incinerator and combusted with air. The hot, nearly inert incinerator off gas is used to dry coal before being vented to the atmosphere.

In the furnace waste heat boiler, 11,991 kg/hr (26,435 lb/hr) of 3.0 MPa (430 psia) steam are 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 LP steam header.

Power Block

Clean syngas exiting the Sulfinol absorber (stream 17) is humidified because there is not sufficient nitrogen from the ASU to provide the level of dilution required. The moisturized syngas (stream 18) is reheated (stream 19), further diluted with nitrogen from the ASU (stream 4) and steam, and enters the advanced F Class CT burner. The CT compressor provides combustion air to the burner and also 19 percent of the air requirements in the ASU (stream 24). The exhaust gas exits the CT at 587°C (1,088°F) (stream 25) and enters the HRSG where additional heat is recovered until the FG exits the HRSG at 132°C (270°F) (stream 26) 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 12.4 MPa/559°C/559°C (1800 psig/1038°F/1038°F) steam cycle.

Air Separation Unit (ASU)

The ASU is designed to produce a nominal output of 3,614 tonnes/day (3,984 TPD) of 95 mol% O_2 for use in the gasifier (stream 5) and SRU (stream 3). The plant is designed with two production trains. The air compressor is powered by an electric motor. Approximately 11,028 tonnes/day (12,156 TPD) of nitrogen are also recovered, compressed, and used as dilution in the GT combustor. About 4 percent of the GT air is used to supply approximately 19 percent of the ASU air requirements.

Balance of Plant

Balance of plant items were covered in Sections 3.1.9, 3.1.10 and 3.1.11.

3.4.3 Key System Assumptions

System assumptions for Cases 5 and 6, Shell IGCC with and without CO_2 capture, are compiled in Exhibit 3-74.

Balance of Plant – Cases 5 and 6

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

Exhibit 3-74 Shell IGCC Plant Study Configuration Matrix

Case	5	6
Gasifier Pressure, MPa (psia)	4.2 (615)	4.2 (615)
O_2:Coal Ratio, kg O_2/kg dry coal	0.84	0.84
Carbon Conversion, %	99.5	99.5
Syngas HHV at Gasifier Outlet, kJ/Nm^3 (Btu/scf)	10,841 (291)	10,849 (291)
Steam Cycle, MPa/°C/°C (psig/°F/°F)	12.4/559/559 (1800/1038/1038)	12.4/534/534 (1800/993/993)
Condenser Pressure, mm Hg (in Hg)	51 (2.0)	51 (2.0)
CT	2x Advanced F Class (232 MW output each)	2x Advanced F Class (232 MW output each)
Gasifier Technology	Shell	Shell
Oxidant	95 vol% Oxygen	95 vol% Oxygen
Coal	Illinois No. 6	Illinois No. 6
Coal Feed Moisture Content, %	5	5
COS Hydrolysis	Yes	Occurs in SGS
SGS	No	Yes
H_2S Separation	Sulfinol-M	Selexol 1st Stage
Sulfur Removal, %	99.7	99.9
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), N_2 Dilution, Humidification and steam dilution	MNQC (LNB), N_2 Dilution and Humidification
CO_2 Separation	N/A	Selexol 2nd Stage
Overall CO_2 Capture	N/A	90.1%
CO_2 Sequestration	N/A	Off-site Saline Formation

3.4.4   <u>Sparing Philosophy</u>

The sparing philosophy for Cases 5 and 6 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 ASUs (2 x 50%)

- Two trains of coal drying and dry feed systems (2 x 50%)

- Two trains of gasification, including gasifier, SGC, 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 Case 5 and two-stage Selexol in Case 6 (2 x 50%),

- One train of Claus-based sulfur recovery (1 x 100%).

- Two CT/HRSG tandems (2 x 50%).

- One steam turbine (1 x 100%).

3.4.5   <u>Case 5 Performance Results</u>

The plant produces a net output of 629 MWe at a net plant efficiency of 42.1 percent (HHV basis). Shell has reported expected efficiencies using bituminous coal of around 44-45 percent (HHV basis), although this value excluded the net power impact of coal drying [62]. Accounting for coal drying would reduce the efficiency by only about 0.5-1 percentage points so the efficiency results for the Shell case are still lower in this study than reported by the vendor.

Overall performance for the entire plant is summarized in Exhibit 3-75, which includes auxiliary power requirements. The ASU accounts for approximately 79 percent of the total auxiliary load distributed between the main air compressor, the oxygen compressor, the nitrogen compressor, and ASU auxiliaries. The cooling water system, including the CWPs and cooling tower fan, accounts for approximately 5 percent of the auxiliary load, and the BFW pumps account for an additional 4 percent. All other individual auxiliary loads are 3 percent or less of the total.

Exhibit 3-75 Case 5 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	464,000
Sweet Gas Expander Power	0
Steam Turbine Power	273,000
TOTAL POWER, kWe	**737,000**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	440
Coal Milling	2,040
Slag Handling	520
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	45,190
Oxygen Compressor	8,890
Nitrogen Compressors	29,850
Boiler Feedwater Pumps	4,500
Condensate Pump	230
Syngas Recycle Compressor	680
Circulating Water Pump	3,400
Ground Water Pumps	370
Cooling Tower Fans	1,760
Scrubber Pumps	770
Acid Gas Removal	620
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	250
Claus Plant TG Recycle Compressor	890
Miscellaneous Balance of Plant[2]	3,000
Transformer Losses	2,520
TOTAL AUXILIARIES, kWe	**108,020**
NET POWER, kWe	**628,980**
Net Plant Efficiency, % (HHV)	42.1
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,545 (8,099)
CONDENSER COOLING DUTY 10^6 kJ/hr (10^6 Btu/hr)	**1,393 (1,320)**
CONSUMABLES	
As-Received Coal Feed, kg/hr (lb/hr)	198,059 (436,646)
Thermal Input[1], kWt	1,492,878
Raw Water Withdrawal, m^3/min (gpm)	15.7 (4,142)
Raw Water Consumption, m^3/min (gpm)	12.7 (3,356)

1 - HHV of As-Received Illinois No. 6 coal is 27,135 kJ/kg (11,666 Btu/lb)
2 - Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

<u>Environmental Performance</u>

The environmental targets for emissions of Hg, NOx, SO_2, and PM were presented in Section 2.4. A summary of the plant air emissions for Case 5 is presented in Exhibit 3-76.

Exhibit 3-76 Case 5 Air Emissions

	kg/GJ (lb/10^6 Btu)	Tonne/year (ton/year) 80% capacity factor	kg/MWh (lb/MWh)
SO_2	0.002 (0.004)	68 (75)	0.013 (.03)
NOx	0.025 (0.059)	957 (1,055)	0.185 (.409)
Particulates	0.003 (0.0071)	115 (127)	0.022 (.049)
Hg	2.46E-7 (5.71E-7)	0.009 (0.010)	1.79E-6 (3.95E-6)
CO_2	84.7 (196.9)	3,188,643 (3,514,877)	617 (1,361)
CO_2[1]			723 (1,595)

[1] CO_2 emissions based on net power instead of gross power

The low level of SO_2 emissions is achieved by capture of the sulfur in the gas by the Sulfinol-M AGR process. The AGR process removes over 99 percent of the sulfur compounds in the fuel gas down to a level of less than 6 ppmv. This results in a concentration in the HRSG FG of less than 2 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 compressed and recycled back to the AGR to capture most of the remaining sulfur. The SO_2 emissions in Exhibit 3-76 include both the stack emissions and the coal dryer emissions.

NOx emissions are limited by the use of nitrogen dilution, humidification and steam 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 NOx 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 the plant is shown in Exhibit 3-77. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag, as dissolved CO_2 in the wastewater blowdown stream, and as CO_2 in the stack gas, ASU vent gas and coal dryer vent gas. Carbon in the wastewater blowdown stream is calculated by difference to close the material balance.

Exhibit 3-77 Case 5 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	126,252 (278,339)	Slag	631 (1,392)
Air (CO$_2$)	508 (1,120)	Stack Gas	124,177 (273,764)
		ASU Vent	89 (197)
		CO$_2$ Product	0 (0)
		Dryer Stack Gas	1,863 (4,106)
Total	126,760 (279,459)	Total	126,760 (279,459)

Exhibit 3-78 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant, sulfur in the coal drying gas, and sulfur emitted in the stack gas. Sulfur in the slag is considered to be negligible.

Exhibit 3-78 Case 5 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	4,964 (10,944)	Elemental Sulfur	4,959 (10,933)
		Stack Gas	5 (11)
		CO$_2$ Product	0 (0)
Total	4,964 (10,944)	Total	4,964 (10,944)

Exhibit 3-79 shows the overall water balance for the plant. Explanation on the water balance has been given for Case 1 [GEE] and Case 3 [CoP] but is also presented here for completeness.

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

Exhibit 3-79 Case 5 Water Balance

Water Use	Water Demand, m³/min (gpm)	Internal Recycle, m³/min (gpm)	Raw Water Withdrawal, m³/min (gpm)	Process Water Discharge, m³/min (gpm)	Raw Water Consumption, m³/min (gpm)
Slag Handling	0.43 (114)	0.2 (45)	0.3 (69)	0.0 (0)	0.3 (69)
Quench/Wash	0.0 (0)	0.0 (0)	0.0 (0)	0.0 (0)	0.0 (0)
Humidifier	1.4 (365)	0.0 (0)	1.4 (365)	0.0 (0)	1.4 (365)
SWS Blowdown	0.0 (0)	0.0 (0)	0.0 (0)	0.0 (0)	0.0 (0)
Condenser Makeup *Gasifier Steam* *Shift Steam* *GT Steam Dilution* *BFW Makeup*	**1.1 (282)** *0.3 (84)* *0.5 (135)* *0.2 (62)*	**0.0 (0)**	**1.1 (282)** *0.3 (84)* *0.5 (135)* *0.2 (62)*	**0.0 (0)**	**1.1 (282)**
Cooling Tower *BFW Blowdown* *SWS Blowdown* *SWS Excess Water* *Humidifier Tower* *Blowdown*	**13.2 (3,494)** *0.23 (62)* *0.02 (4)* *0.0 (0)*	**0.25 (67)**	**13.0 (3,427)** *-0.23 (-62)* *-0.02 (-4)*	**3.0 (786)**	**10.0 (2,641)**
Total	**16.1 (4,254)**	**0.4 (112)**	**15.7 (4,142)**	**3.0 (786)**	**12.7 (3,356)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-80 through Exhibit 3-82:

- Coal gasification and ASU

- Syngas cleanup, sulfur recovery, and tail gas recycle

- Combined cycle power generation, steam, and FW

An overall plant energy balance is provided in tabular form in Exhibit 3-54. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-75) is calculated by multiplying the power out by a combined generator efficiency of 98.3 percent.

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Exhibit 3-80 Case 5 Coal Gasification and Air Separation Unit Heat and Mass Balance Schematic

LEGEND

––––	Air
×–×–×	Coal/Char/ Slurry/Slag
○–○–○	Nitrogen
––––	Oxygen
– – –	Sour Gas
–·–·–	Sour Water
(red line)	Steam
╱╱╱	Synthesis Gas
────	Water
–··–··–	Flue Gas/ Combustion Products

P ABSOLUTE PRESSURE, PSIA
F TEMPERATURE, °F
W FLOWRATE, LB/HR
H ENTHALPY, BTU/LB
MWE POWER, MEGAWATTS ELECTRICAL

NOTES:

1. ENTHALPY REFERENCE POINT IS NATURAL STATE AT 32 °F AND 0.08865 PSIA

PLANT PERFORMANCE SUMMARY

GROSS PLANT POWER:	737 MWE
AUXILIARY LOAD:	108 MWE
NET PLANT POWER:	629 MWE
NET PLANT EFFICIENCY, HHV:	42.1%
NET PLANT HEAT RATE:	8,099 BTU/KWE

DOE/NETL

DUAL TRAIN IGCC PLANT
CASE 5

HEAT AND MATERIAL FLOW DIAGRAM

BITUMINOUS BASELINE STUDY
CASE 5
SHELL GASIFIER
ASU, GASIFICATION, AND GAS COOLING

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Exhibit 3-81 Case 5 Syngas Cleanup Heat and Mass Balance Schematic
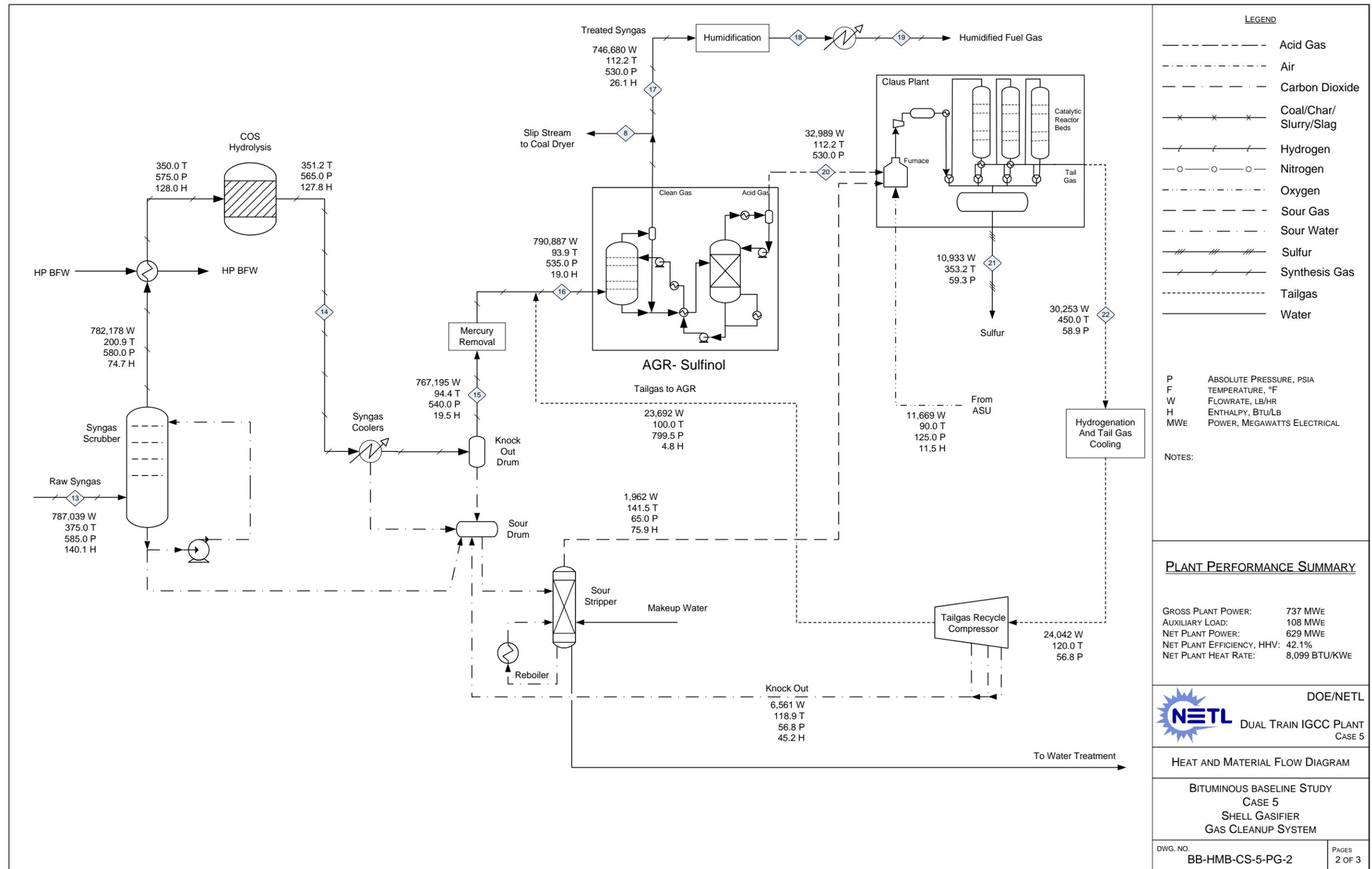
Exhibit 3-82 Case 5 Combined Cycle Power Generation Heat and Mass Balance Schematic
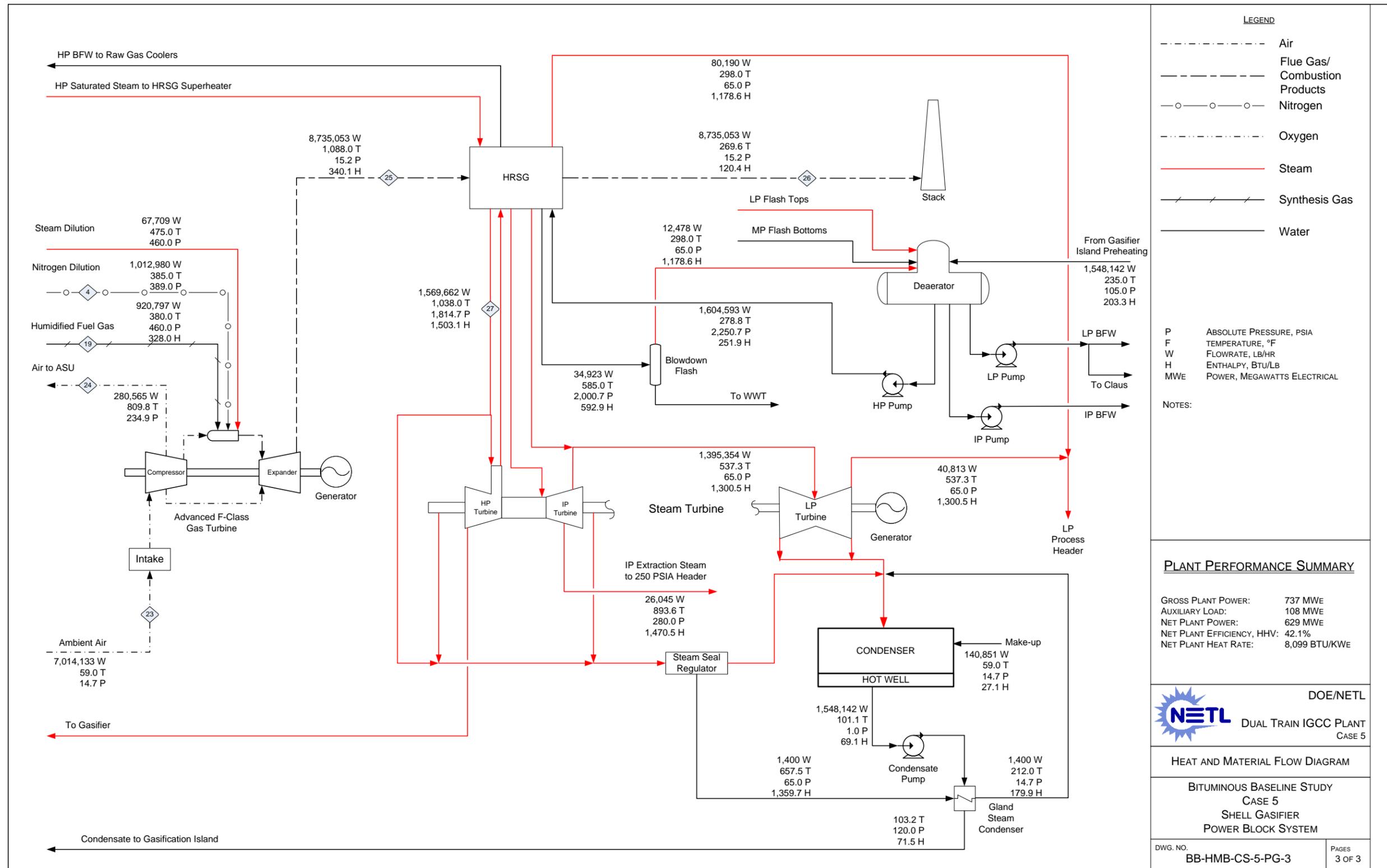
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Exhibit 3-83 Case 5 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	5,374 (5,094)	4.5 (4.3)		5,379 (5,098)
ASU Air		16.0 (15.2)		16 (15)
GT Air		96.2 (91.2)		96 (91)
Water		59.0 (55.9)		59 (56)
Auxiliary Power			389 (369)	389 (369)
TOTAL	**5,374 (5,094)**	**175.6 (166.5)**	**389 (369)**	**5,939 (5,629)**
Heat Out GJ/hr (MMBtu/hr)				
ASU Vent		0.8 (0.8)		1 (1)
Slag	21 (20)	33.5 (31.7)		54 (51)
Sulfur	46 (44)	0.6 (0.5)		47 (44)
CO₂				
Cooling Tower Blowdown		22.1 (20.9)		22 (21)
HRSG Flue Gas		1,110 (1,052)		1,110 (1,052)
Condenser		1,397 (1,324)		1,397 (1,324)
Non-Condenser Cooling Tower Loads*		215 (204)		215 (204)
Process Losses**		439 (417)		439 (417)
Power			2,653 (2,515)	2,653 (2,515)
TOTAL	**67 (63)**	**3,219 (3,051)**	**2,653 (2,515)**	**5,939 (5,629)**

* Includes ASU compressor intercoolers, CO₂ compressor intercoolers, sour water stripper condenser, syngas cooler (low level heat rejection) and extraction air cooler.

** Calculated by difference to close the energy balance.

3.4.6   Case 5 - Major Equipment List

Major equipment items for the Shell gasifier with no CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 3.4.7. 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	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	45 tonne (50 ton)	2	1
9	Feeder	Vibratory	163 tonne/hr (180 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	327 tonne/hr (360 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	163 tonne (180 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	327 tonne/hr (360 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	327 tonne/hr (360 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	726 tonne (800 ton)	3	0

ACCOUNT 2 COAL PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Vibratory	73 tonne/hr (80 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	218 tonne/hr (240 tph)	1	0
3	Roller Mill Feed Hopper	Dual Outlet	435 tonne (480 ton)	1	0
4	Weigh Feeder	Belt	109 tonne/hr (120 tph)	2	0
5	Coal Dryer and Pulverizer	Rotary	109 tonne/hr (120 tph)	2	0
6	Coal Dryer Feed Hopper	Vertical Hopper	218 tonne (240 ton)	2	0

ACCOUNT 3   FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,165,907 liters (308,000 gal)	2	0
2	Condensate Pumps	Vertical canned	6,473 lpm @ 91 m H2O (1,710 gpm @ 300 ft H2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	436,356 kg/hr (962,000 lb/hr)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	7,419 lpm @ 27 m H2O (1,960 gpm @ 90 ft H2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 6,927 lpm @ 1,859 m H2O (1,830 gpm @ 6,100 ft H2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 2,461 lpm @ 223 m H2O (650 gpm @ 730 ft H2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
10	Closed Cylce Cooling Heat Exchangers	Plate and frame	133 GJ/hr (126 MMBtu/hr) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	47,696 lpm @ 21 m H2O (12,600 gpm @ 70 ft H2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H2O (1,000 gpm @ 350 ft H2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H2O (700 gpm @ 250 ft H2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	4,391 lpm @ 18 m H2O (1,160 gpm @ 60 ft H2O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	2,915 lpm @ 268 m H2O (770 gpm @ 880 ft H2O)	3	1
16	Filtered Water Pumps	Stainless steel, single suction	1,779 lpm @ 49 m H2O (470 gpm @ 160 ft H2O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	851,718 liter (225,000 gal)	2	0
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	341 lpm (90 gpm)	2	0
19	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

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

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized dry-feed, entrained bed	2,631 tonne/day, 4.2 MPa (2,900 tpd, 615 psia)	2	0
2	Synthesis Gas Cooler	Convective spiral-wound tube boiler	280,320 kg/hr (618,000 lb/hr)	2	0
3	Synthesis Gas Cyclone	High efficiency	280,320 kg/hr (618,000 lb/hr) Design efficiency 90%	2	0
4	Candle Filter	Pressurized filter with pulse-jet cleaning	metallic filters	2	0
5	Syngas Scrubber Including Sour Water Stripper	Vertical upflow	196,405 kg/hr (433,000 lb/hr)	2	0
6	Raw Gas Coolers	Shell and tube with condensate drain	192,777 kg/hr (425,000 lb/hr)	8	0
7	Raw Gas Knockout Drum	Vertical with mist eliminator	191,870 kg/hr, 35°C, 3.8 MPa (423,000 lb/hr, 94°F, 545 psia)	2	0
8	Saturation Water Economizers	Shell and tube	131 GJ/hr (124 MMBtu/hr)	2	0
9	Fuel Gas Saturator	Vertical tray tower	229,518 kg/hr, 161°C, 3.3 MPa (506,000 lb/hr, 321°F, 480 psia)	2	0
10	Saturator Water Pump	Centrifugal	3,407 lpm @ 12 m H2O (900 gpm @ 40 ft H2O)	2	2
11	Synthesis Gas Reheater	Shell and tube	186,426 kg/hr (411,000 lb/hr)	2	0
12	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	196,405 kg/hr (433,000 lb/hr) syngas	2	0
13	ASU Main Air Compressor	Centrifugal, multi-stage	3,993 m3/min @ 1.3 MPa (141,000 scfm @ 190 psia)	2	0
14	Cold Box	Vendor design	1,996 tonne/day (2,200 tpd) of 95% purity oxygen	2	0
15	Oxygen Compressor	Centrifugal, multi-stage	991 m3/min (35,000 scfm) Suction - 0.9 MPa (130 psia) Discharge - 6.5 MPa (940 psia)	2	0
16	Primary Nitrogen Compressor	Centrifugal, multi-stage	3,285 m3/min (116,000 scfm) Suction - 0.4 MPa (60 psia) Discharge - 2.7 MPa (390 psia)	2	0
17	Secondary Nitrogen Compressor	Centrifugal, single-stage	453 m3/min (16,000 scfm) Suction - 1.2 MPa (180 psia) Discharge - 2.7 MPa (390 psia)	2	0
18	Transport Nitrogen Boost Compressor	Centrifugal, single-stage	198 m3/min (7,000 scfm) Suction - 2.6 MPa (380 psia) Discharge - 5.4 MPa (790 psia)	2	0
19	Extraction Air Heat Exchanger	Gas-to-gas, vendor design	69,853 kg/hr, 432°C, 1.6 MPa (154,000 lb/hr, 810°F, 235 psia)	2	0

ACCOUNT 5   SYNGAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber	Sulfated carbon bed	191,416 kg/hr (422,000 lb/hr) 35°C (94°F) 3.7 MPa (540 psia)	2	0
2	Sulfur Plant	Claus type	131 tonne/day (144 tpd)	1	0
3	COS Hydrolysis Reactor	Fixed bed, catalytic	195,045 kg/hr (430,000 lb/hr) 177°C (350°F) 4.0 MPa (580 psia)	2	0
4	Acid Gas Removal Plant	Sulfinol	197,313 kg/hr (435,000 lb/hr) 34°C (94°F) 3.7 MPa (535 psia)	2	0
5	Hydrogenation Reactor	Fixed bed, catalytic	13,723 kg/hr (30,253 lb/hr) 232°C (450°F) 0.4 MPa (58.9 psia)	1	0
6	Tail Gas Recycle Compressor	Centrifugal	10,747 kg/hr (23,692 lb/hr) each	1	0

ACCOUNT 6   COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class	232 MW	2	0
2	Gas Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

ACCOUNT 7   HRSG, DUCTING AND STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.4 m (28 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 393,555 kg/hr, 12.4 MPa/559°C (867,640 lb/hr, 1,800 psig/1,038°F) Reheat steam - 362,720 kg/hr, 3.1 MPa/559°C (799,662 lb/hr, 452 psig/1,038°F)	2	0

ACCOUNT 8   STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	289 MW 12.4 MPa/559°C/559°C (1,800 psig/ 1038°F/1038°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitiation	320 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,540 GJ/hr (1,460 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9   COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	340,687 lpm @ 30 m (90,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 1,899 GJ/hr (1,800 MMBtu/hr) heat duty	1	0

ACCOUNT 10   SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	208,198 liters (55,000 gal)	2	0
2	Slag Crusher	Roll	11 tonne/hr (12 tph)	2	0
3	Slag Depressurizer	Lock Hopper	11 tonne/hr (12 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	124,919 liters (33,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	56,781 liters (15,000 gal)	2	
6	Slag Conveyor	Drag chain	11 tonne/hr (12 tph)	2	0
7	Slag Separation Screen	Vibrating	11 tonne/hr (12 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	11 tonne/hr (12 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	177,914 liters (47,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	38 lpm @ 14 m H2O (10 gpm @ 46 ft H2O)	2	2
11	Grey Water Storage Tank	Field erected	56,781 liters (15,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	189 lpm @ 433 m H2O (50 gpm @ 1,420 ft H2O)	2	2
13	Slag Storage Bin	Vertical, field erected	816 tonne (900 tons)	2	0
14	Unloading Equipment	Telescoping chute	91 tonne/hr (100 tph)	1	0

ACCOUNT 11   ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Step-up Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Step-up Transformer	Oil-filled	24 kV/345 kV, 320 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 47 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 27 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 4 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12   INSTRUMENTATION AND CONTROLS

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

3.4.7   Case 5 - Cost Estimating

Costs Results

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-84 shows the total plant capital cost summary organized by cost account and Exhibit 3-85 shows a more detailed breakdown of the capital costs along with owner's costs, TOC and TASC. Exhibit 3-86 shows the initial and annual O&M costs.

The estimated TOC of the Shell gasifier with no CO_2 capture is $2,716/kW. Process contingency represents 2.3 percent of the TOC and project contingency represents 11.1 percent. The COE is 81.3 mills/kWh.

Exhibit 3-84 Case 5 Total Plant Cost Summary

Client:			USDOE/NETL							Report Date	2010-Jan-14	
Project:			Bituminous Baseline Study									
			TOTAL PLANT COST SUMMARY									
Case:			Case 5 - Shell 600MW IGCC w/o CO2									
Plant Size:			629.0 MW,net	Estimate Type:		Conceptual			Cost Base (Jun)	2007	($x1000)	

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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$13,346	$2,480	$10,349	$0	$0	**$26,175**	$2,376	$0	$5,710	**$34,261**	$54
2	COAL & SORBENT PREP & FEED	$105,424	$8,399	$17,537	$0	$0	**$131,359**	$11,391	$0	$28,550	**$171,300**	$272
3	FEEDWATER & MISC. BOP SYSTEMS	$9,632	$8,082	$9,224	$0	$0	**$26,938**	$2,534	$0	$6,691	**$36,163**	$57
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (Shell)	$171,446	$0	$73,699	$0	$0	**$245,145**	$21,883	$34,079	$46,149	**$347,255**	$552
4.2	Syngas Cooling	w/4.1	$0	w/ 4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$148,365	$0	w/equip.	$0	$0	**$148,365**	$14,381	$0	$16,275	**$179,021**	$285
4.4-4.9	Other Gasification Equipment	$15,541	$9,100	$10,950	$0	$0	**$35,592**	$3,394	$0	$8,498	**$47,483**	$75
	SUBTOTAL 4	**$335,353**	**$9,100**	**$84,649**	**$0**	**$0**	**$429,102**	**$39,657**	**$34,079**	**$70,922**	**$573,760**	**$912**
5A	GAS CLEANUP & PIPING	$50,101	$3,724	$47,806	$0	$0	**$101,630**	$9,827	$86	$22,447	**$133,990**	$213
5B	CO2 REMOVAL & COMPRESSION	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$85,752	$0	$6,269	$0	$0	**$92,021**	$8,724	$4,601	$10,535	**$115,881**	$184
6.2-6.9	Combustion Turbine Other	$0	$806	$892	$0	$0	**$1,699**	$159	$0	$557	**$2,415**	$4
	SUBTOTAL 6	**$85,752**	**$806**	**$7,162**	**$0**	**$0**	**$93,720**	**$8,883**	**$4,601**	**$11,092**	**$118,296**	**$188**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$35,374	$0	$5,030	$0	$0	**$40,404**	$3,842	$0	$4,425	**$48,670**	$77
7.2-7.9	Ductwork and Stack	$3,337	$2,379	$3,116	$0	$0	**$8,833**	$819	$0	$1,571	**$11,222**	$18
	SUBTOTAL 7	**$38,712**	**$2,379**	**$8,146**	**$0**	**$0**	**$49,237**	**$4,661**	**$0**	**$5,995**	**$59,893**	**$95**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$28,830	$0	$4,946	$0	$0	**$33,776**	$3,241	$0	$3,702	**$40,718**	$65
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$10,446	$993	$7,524	$0	$0	**$18,963**	$1,722	$0	$4,181	**$24,865**	$40
	SUBTOTAL 8	**$39,276**	**$993**	**$12,470**	**$0**	**$0**	**$52,739**	**$4,963**	**$0**	**$7,883**	**$65,584**	**$104**
9	COOLING WATER SYSTEM	$8,350	$8,140	$6,922	$0	$0	**$23,411**	$2,174	$0	$5,234	**$30,819**	$49
10	ASH/SPENT SORBENT HANDLING SYS	$17,858	$1,384	$8,862	$0	$0	**$28,104**	$2,696	$0	$3,366	**$34,166**	$54
11	ACCESSORY ELECTRIC PLANT	$26,986	$10,003	$20,101	$0	$0	**$57,090**	$4,905	$0	$11,625	**$73,620**	$117
12	INSTRUMENTATION & CONTROL	$10,318	$1,898	$6,648	$0	$0	**$18,864**	$1,710	$943	$3,585	**$25,102**	$40
13	IMPROVEMENTS TO SITE	$3,326	$1,960	$8,206	$0	$0	**$13,492**	$1,332	$0	$4,447	**$19,272**	$31
14	BUILDINGS & STRUCTURES	$0	$6,644	$7,614	$0	$0	**$14,258**	$1,298	$0	$2,544	**$18,100**	$29
	TOTAL COST	**$744,432**	**$65,991**	**$255,695**	**$0**	**$0**	**$1,066,118**	**$98,407**	**$39,709**	**$190,092**	**$1,394,325**	**$2,217**

Exhibit 3-85 Case 5 Total Plant Cost Details

Client:		USDOE/NETL						Report Date:	2010-Jan-14		
Project:		Bituminous Baseline Study									
		TOTAL PLANT COST SUMMARY									
Case:		Case 5 - Shell 600MW IGCC w/o CO2									
Plant Size:		629.0 MW,net	**Estimate Type:**	Conceptual				**Cost Base (Jun)**	2007	($x1000)	

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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,505	$0	$1,713	$0	$0	$5,217	$467	$0	$1,137	$6,822	$11
1.2	Coal Stackout & Reclaim	$4,529	$0	$1,098	$0	$0	$5,627	$493	$0	$1,224	$7,344	$12
1.3	Coal Conveyors & Yd Crush	$4,211	$0	$1,086	$0	$0	$5,297	$465	$0	$1,152	$6,914	$11
1.4	Other Coal Handling	$1,102	$0	$251	$0	$0	$1,353	$118	$0	$294	$1,766	$3
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	$2,480	$6,201	$0	$0	$8,681	$832	$0	$1,903	$11,416	$18
	SUBTOTAL 1.	$13,346	$2,480	$10,349	$0	$0	$26,175	$2,376	$0	$5,710	$34,261	$54
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$40,051	$2,406	$5,836	$0	$0	$48,294	$4,167	$0	$10,492	$62,953	$100
2.2	Prepared Coal Storage & Feed	$1,897	$454	$297	$0	$0	$2,648	$226	$0	$575	$3,450	$5
2.3	Dry Coal Injection System	$62,432	$725	$5,798	$0	$0	$68,955	$5,939	$0	$14,979	$89,872	$143
2.4	Misc.Coal Prep & Feed	$1,043	$759	$2,276	$0	$0	$4,078	$375	$0	$891	$5,344	$8
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	$4,055	$3,329	$0	$0	$7,384	$684	$0	$1,614	$9,681	$15
	SUBTOTAL 2.	$105,424	$8,399	$17,537	$0	$0	$131,359	$11,391	$0	$28,550	$171,300	$272
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	Feedwater System	$3,130	$5,375	$2,837	$0	$0	$11,343	$1,051	$0	$2,479	$14,872	$24
3.2	Water Makeup & Pretreating	$564	$59	$315	$0	$0	$938	$89	$0	$308	$1,335	$2
3.3	Other Feedwater Subsystems	$1,713	$579	$521	$0	$0	$2,812	$253	$0	$613	$3,678	$6
3.4	Service Water Systems	$323	$664	$2,306	$0	$0	$3,293	$321	$0	$1,084	$4,699	$7
3.5	Other Boiler Plant Systems	$1,732	$671	$1,663	$0	$0	$4,065	$386	$0	$890	$5,341	$8
3.6	FO Supply Sys & Nat Gas	$313	$591	$551	$0	$0	$1,454	$140	$0	$319	$1,913	$3
3.7	Waste Treatment Equipment	$788	$0	$481	$0	$0	$1,269	$124	$0	$418	$1,810	$3
3.8	Misc. Power Plant Equipment	$1,071	$143	$550	$0	$0	$1,764	$170	$0	$580	$2,514	$4
	SUBTOTAL 3.	$9,632	$8,082	$9,224	$0	$0	$26,938	$2,534	$0	$6,691	$36,163	$57
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (Shell)	$171,446	$0	$73,699	$0	$0	$245,145	$21,883	$34,079	$46,149	$347,255	$552
4.2	Syngas Cooling	w/4.1	$0	w/ 4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$148,365	$0	w/equip.	$0	$0	$148,365	$14,381	$0	$16,275	$179,021	$285
4.4	LT Heat Recovery & FG Saturation	$15,541	$0	$5,908	$0	$0	$21,449	$2,093	$0	$4,709	$28,251	$45
4.5	Misc. Gasification Equipment	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Flare Stack System	$0	$921	$375	$0	$0	$1,296	$124	$0	$284	$1,704	$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	$8,179	$4,667	$0	$0	$12,847	$1,176	$0	$3,506	$17,528	$28
	SUBTOTAL 4.	$335,353	$9,100	$84,649	$0	$0	$429,102	$39,657	$34,079	$70,922	$573,760	$912

Exhibit 3-85 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	Sulfinol System	$35,020	$0	$29,715	$0	$0	$64,735	$6,261	$0	$14,199	$85,194	$135
5A.2	Elemental Sulfur Plant	$9,609	$1,915	$12,397	$0	$0	$23,921	$2,324	$0	$5,249	$31,494	$50
5A.3	Mercury Removal	$976	$0	$743	$0	$0	$1,720	$166	$86	$394	$2,366	$4
5A.4	COS Hydrolysis	$2,882	$0	$3,764	$0	$0	$6,646	$646	$0	$1,459	$8,751	$14
5A.5	Particulate Removal	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Blowback Gas Systems	$1,613	$271	$153	$0	$0	$2,037	$193	$0	$446	$2,677	$4
5A.7	Fuel Gas Piping	$0	$764	$535	$0	$0	$1,298	$120	$0	$284	$1,703	$3
5A.9	HGCU Foundations	$0	$773	$499	$0	$0	$1,272	$117	$0	$417	$1,805	$3
	SUBTOTAL 5A.	$50,101	$3,724	$47,806	$0	$0	$101,630	$9,827	$86	$22,447	$133,990	$213
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	$85,752	$0	$6,269	$0	$0	$92,021	$8,724	$4,601	$10,535	$115,881	$184
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	$4
	SUBTOTAL 6.	$85,752	$806	$7,162	$0	$0	$93,720	$8,883	$4,601	$11,092	$118,296	$188
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$35,374	$0	$5,030	$0	$0	$40,404	$3,842	$0	$4,425	$48,670	$77
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,711	$1,220	$0	$0	$2,931	$257	$0	$638	$3,826	$6
7.4	Stack	$3,337	$0	$1,254	$0	$0	$4,591	$440	$0	$503	$5,534	$9
7.9	HRSG,Duct & Stack Foundations	$0	$669	$642	$0	$0	$1,311	$122	$0	$430	$1,863	$3
	SUBTOTAL 7.	$38,712	$2,379	$8,146	$0	$0	$49,237	$4,661	$0	$5,995	$59,893	$95
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$28,830	$0	$4,946	$0	$0	$33,776	$3,241	$0	$3,702	$40,718	$65
8.2	Turbine Plant Auxiliaries	$200	$0	$459	$0	$0	$659	$64	$0	$72	$796	$1
8.3	Condenser & Auxiliaries	$4,740	$0	$1,514	$0	$0	$6,254	$598	$0	$685	$7,537	$12
8.4	Steam Piping	$5,506	$0	$3,873	$0	$0	$9,379	$806	$0	$2,546	$12,731	$20
8.9	TG Foundations	$0	$993	$1,678	$0	$0	$2,671	$253	$0	$877	$3,801	$6
	SUBTOTAL 8.	$39,276	$993	$12,470	$0	$0	$52,739	$4,963	$0	$7,883	$65,584	$104
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$5,766	$0	$1,049	$0	$0	$6,815	$649	$0	$1,120	$8,584	$14
9.2	Circulating Water Pumps	$1,500	$0	$99	$0	$0	$1,599	$135	$0	$260	$1,993	$3
9.3	Circ.Water System Auxiliaries	$129	$0	$18	$0	$0	$148	$14	$0	$24	$186	$0
9.4	Circ.Water Piping	$0	$5,400	$1,400	$0	$0	$6,800	$615	$0	$1,483	$8,897	$14
9.5	Make-up Water System	$317	$0	$453	$0	$0	$769	$74	$0	$169	$1,012	$2
9.6	Component Cooling Water Sys	$637	$762	$542	$0	$0	$1,942	$182	$0	$425	$2,549	$4
9.9	Circ.Water System Foundations	$0	$1,977	$3,361	$0	$0	$5,339	$506	$0	$1,753	$7,598	$12
	SUBTOTAL 9.	$8,350	$8,140	$6,922	$0	$0	$23,411	$2,174	$0	$5,234	$30,819	$49

Exhibit 3-85 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$15,534	$0	$7,661	$0	$0	$23,194	$2,229	$0	$2,542	$27,965	$44
10.2	Gasifier Ash Depressurization	w/10.1	w/10.1	w/10.1	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	w/10.1	w/10.1	w/10.1	$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 Recovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$527	$0	$573	$0	$0	$1,100	$107	$0	$181	$1,387	$2
10.7	Ash Transport & Feed Equipment	$706	$0	$170	$0	$0	$877	$82	$0	$144	$1,102	$2
10.8	Misc. Ash Handling Equipment	$1,091	$1,337	$399	$0	$0	$2,827	$269	$0	$464	$3,561	$6
10.9	Ash/Spent Sorbent Foundation	$0	$47	$59	$0	$0	$105	$10	$0	$34	$149	$0
	SUBTOTAL 10.	$17,858	$1,384	$8,862	$0	$0	$28,104	$2,696	$0	$3,366	$34,166	$54
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$950	$0	$939	$0	$0	$1,889	$180	$0	$207	$2,276	$4
11.2	Station Service Equipment	$3,667	$0	$330	$0	$0	$3,998	$369	$0	$437	$4,803	$8
11.3	Switchgear & Motor Control	$6,780	$0	$1,233	$0	$0	$8,013	$743	$0	$1,313	$10,069	$16
11.4	Conduit & Cable Tray	$0	$3,149	$10,390	$0	$0	$13,539	$1,309	$0	$3,712	$18,561	$30
11.5	Wire & Cable	$0	$6,017	$3,954	$0	$0	$9,971	$724	$0	$2,674	$13,369	$21
11.6	Protective Equipment	$0	$679	$2,471	$0	$0	$3,150	$308	$0	$519	$3,976	$6
11.7	Standby Equipment	$234	$0	$228	$0	$0	$462	$44	$0	$76	$583	$1
11.8	Main Power Transformers	$15,356	$0	$144	$0	$0	$15,500	$1,173	$0	$2,501	$19,174	$30
11.9	Electrical Foundations	$0	$157	$411	$0	$0	$568	$54	$0	$187	$810	$1
	SUBTOTAL 11.	$26,986	$10,003	$20,101	$0	$0	$57,090	$4,905	$0	$11,625	$73,620	$117
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	w/6.1	$0	w/6.1	$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	$1,019	$0	$680	$0	$0	$1,699	$161	$85	$292	$2,236	$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	$234	$0	$150	$0	$0	$384	$36	$19	$88	$528	$1
12.7	Computer & Accessories	$5,433	$0	$174	$0	$0	$5,607	$515	$280	$640	$7,043	$11
12.8	Instrument Wiring & Tubing	$0	$1,898	$3,880	$0	$0	$5,778	$490	$289	$1,639	$8,197	$13
12.9	Other I & C Equipment	$3,632	$0	$1,764	$0	$0	$5,396	$508	$270	$926	$7,099	$11
	SUBTOTAL 12.	$10,318	$1,898	$6,648	$0	$0	$18,864	$1,710	$943	$3,585	$25,102	$40

Exhibit 3-85 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$104	$2,230	$0	$0	$2,335	$232	$0	$770	$3,336	$5
13.2	Site Improvements	$0	$1,856	$2,466	$0	$0	$4,322	$426	$0	$1,425	$6,173	$10
13.3	Site Facilities	$3,326	$0	$3,509	$0	$0	$6,835	$674	$0	$2,253	$9,762	$16
	SUBTOTAL 13.	$3,326	$1,960	$8,206	$0	$0	$13,492	$1,332	$0	$4,447	$19,272	$31
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	$2,428	$3,459	$0	$0	$5,887	$542	$0	$964	$7,394	$12
14.3	Administration Building	$0	$841	$610	$0	$0	$1,452	$129	$0	$237	$1,818	$3
14.4	Circulation Water Pumphouse	$0	$166	$88	$0	$0	$254	$22	$0	$41	$317	$1
14.5	Water Treatment Buildings	$0	$471	$460	$0	$0	$931	$84	$0	$152	$1,168	$2
14.6	Machine Shop	$0	$431	$295	$0	$0	$725	$64	$0	$118	$908	$1
14.7	Warehouse	$0	$695	$449	$0	$0	$1,144	$101	$0	$187	$1,432	$2
14.8	Other Buildings & Structures	$0	$416	$324	$0	$0	$741	$66	$0	$161	$968	$2
14.9	Waste Treating Building & Str.	$0	$931	$1,779	$0	$0	$2,710	$253	$0	$592	$3,555	$6
	SUBTOTAL 14.	$0	$6,644	$7,614	$0	$0	$14,258	$1,298	$0	$2,544	$18,100	$29
	TOTAL COST	$744,432	$65,991	$255,695	$0	$0	$1,066,118	$98,407	$39,709	$190,092	$1,394,325	$2,217

Owner's Costs			
Preproduction Costs			
6 Months All Labor		$12,811	$20
1 Month Maintenance Materials		$2,891	$5
1 Month Non-fuel Consumables		$407	$1
1 Month Waste Disposal		$260	$0
25% of 1 Months Fuel Cost at 100% CF		$1,521	$2
2% of TPC		$27,887	$44
Total		**$45,778**	**$73**
Inventory Capital			
60 day supply of fuel and consumables at 100% CF		$12,790	$20
0.5% of TPC (spare parts)		$6,972	$11
Total		**$19,762**	**$31**
Initial Cost for Catalyst and Chemicals		$963	$2
Land		$900	$1
Other Owner's Costs		$209,149	$333
Financing Costs		$37,647	$60
Total Overnight Costs (TOC)		**$1,708,524**	**$2,716**
TASC Multiplier	(IOU, high-risk, 35 year)	1.140	
Total As-Spent Cost (TASC)		**$1,947,717**	**$3,097**

Exhibit 3-86 Case 5 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun):	2007
Case 5 - Shell 600MW IGCC w/o CO2					Heat Rate-net (Btu/kWh):	8,099
					MWe-net:	629
					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	
Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.	Plant	
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	$5,918,913	$9.410
Maintenance Labor Cost	$14,578,930	$23.179
Administrative & Support Labor	$5,124,461	$8.147
Property Taxes and Insurance	$27,886,508	$44.336
TOTAL FIXED OPERATING COSTS	**$53,508,812**	**$85.072**

VARIABLE OPERATING COSTS

							$/kWh-net
Maintenance Material Cost						**$27,756,840**	**$0.00630**

Consumables	Consumption		Unit	Initial Fill			
	Initial Fill	/Day	Cost	Cost			
Water (/1000 gallons)	0	2,982	1.08	$0	$941,938		$0.00021
Chemicals							
MU & WT Chem. (lbs)	0	17,767	0.17	$0	$897,887		$0.00020
Carbon (Mercury Removal) (lb)	69,345	95	1.05	$72,824	$29,130		$0.00001
COS Catalyst (m3)	262	0.18	2,397.36	$627,613	$125,523		$0.00003
Water Gas Shift Catalyst (ft3)	0	0	498.83	$0	$0		$0.00000
Sulfinol Solution (gal)	26,146	629	10.05	$262,733	$1,846,503		$0.00042
SCR Catalyst (m3)	0	0	0.00	$0	$0		$0.00000
Ammonia (19% NH3) (ton)	0	0	0.00	$0	$0		$0.00000
Claus Catalyst (ft3)	w/equip.	1.82	131.27	$0	$69,945		$0.00002
Subtotal Chemicals				**$963,170**	**$2,968,988**		**$0.00067**
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	95	0.42	$0	$11,569		$0.00000
Flyash (ton)	0	0	0.00	$0	$0		$0.00000
Slag (ton)	0	525	16.23	$0	$2,486,313		$0.00056
Subtotal-Waste Disposal				**$0**	**$2,497,882**		**$0.00057**
By-products & Emissions							
Sulfur (ton)	0	131	0.00	$0	$0		$0.00000
Subtotal By-Products				**$0**	**$0**		**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$963,170**	**$34,165,649**		**$0.00775**
Fuel (ton)	0	5,240	38.18	$0	$58,422,569		$0.01325

3.4.8   Case 6 - Shell IGCC Power Plant with CO_2 Capture

This case is configured to produce electric power with CO_2 capture. The plant configuration is the same as Case 5, namely two Shell gasifier trains, two advanced F class turbines, two HRSGs and one steam turbine. The gross power output is constrained by the capacity of the two CTs, and since the CO_2 capture and compression process increases the auxiliary load on the plant, the net output is significantly reduced relative to Case 5 (497 MW versus 629 MW).

The process description for Case 6 is similar to Case 5 with several notable exceptions to accommodate CO_2 capture. A BFD and stream tables for Case 6 are shown in Exhibit 3-87 and Exhibit 3-88, respectively. Instead of repeating the entire process description, only differences from Case 5 are reported here.

Coal Preparation and Feed Systems

No differences from Case 5.

Gasification

The gasification process is the same as Case 5 with the following exceptions:

- Total coal feed (as-received) to the two gasifiers is 5,065 tonnes/day (5,583 TPD) (stream 9)

- The ASU provides 3,852 tonnes/day (4,246 TPD) of 95 mol% oxygen to the gasifier and Claus plant (streams 5 and 3)

Raw Gas Cooling/Particulate Removal

After the raw syngas is cooled to approximately 1,093°C (2,000°F) by the syngas quench recycle, syngas is further cooled to 899°C (1,650°F) by raising HP steam at 13.8 MPa (2,000 psia). A water quench follows to cool the raw syngas from 899°C (1,650°F) to 399°C (750°F) while providing a portion of the water required for WGS. The syngas is then cooled to 316°C (600°F) by raising steam, which is used in the SGS unit. After particulate filtration, the syngas is cooled to 232°C (450°F) by raising IP steam at 0.4 MPa (65 psia) before proceeding to the scrubber.

Syngas Scrubber/Sour Water Stripper

Syngas exits the scrubber at 191°C (376°F).

Sour Gas Shift (SGS)

The SGS process was described in Section 3.1.3. In Case 6 the syngas after the scrubber is reheated to 197°C (386°F) and then steam (stream 14) is added to adjust the H_2O:CO molar ratio to approximately 1.8:1 prior to the first SGS reactor. The hot syngas exiting the first stage of SGS is used to preheat water used to humidify clean syngas prior to entering the CT. One more stage of SGS (for a total of two) results in 97.8 percent overall conversion of the CO to CO_2. The warm syngas from the second stage of SGS is cooled to 248°C (478°F) by preheating the syngas prior to the first stage of SGS. The SGS catalyst also serves to hydrolyze COS thus eliminating the need for a separate COS hydrolysis reactor. Following the second stage of SGS, the syngas is further cooled to 35°C (95°F) prior to the mercury removal beds.

Mercury Removal and AGR

Mercury removal is the same as in Case 5.

The AGR process in Case 6 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 (stream 18), a CO_2-rich stream and an acid gas feed to the Claus plant (stream 22). The acid gas contains 34 percent H_2S and 51 percent CO_2 with the balance primarily H_2. 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 flashed at three pressure levels to separate CO_2 and decrease H_2 losses to the CO_2 product pipeline. The HP CO_2 stream is flashed at 2.0 MPa (289.7 psia), compressed, and recycled back to the CO_2 absorber. The MP CO_2 stream is flashed at 1.0 MPa (149.7 psia). The LP CO_2 stream is flashed at 0.1 MPa (16.7 psia), compressed to 1.0 MPa (149.5 psia), and combined with the MP CO_2 stream. The combined stream is compressed from 1.0 MPa (149.5 psia) to a SC 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) with triethylene glycol. The raw CO_2 stream from the Selexol process contains over 99 percent CO_2. The CO_2 (stream 21) 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 5 with the following exceptions:

- 5,277 kg/hr (11,634 lb/hr) of sulfur (stream 23) are produced

- The waste heat boiler generates 13,697 kg/hr (30,197 lb/hr) of 3.0 MPa (430 psia) steam, which provides all of the Claus plant process needs and provides some additional steam to the medium pressure steam header.

Power Block

Clean syngas from the AGR plant is combined with a small amount of clean gas from the CO_2 compression process (stream 18) and partially humidified because the nitrogen available from the ASU is insufficient to provide adequate dilution. The moisturized syngas is reheated to 193°C (380°F) using HP BFW, diluted with nitrogen (stream 4), and then enters the CT burner. The exhaust gas (stream 27) exits the CT at 562°C (1,043°F) and enters the HRSG where additional heat is recovered. The FG exits the HRSG at 132°C (270°F) (stream 28) 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 12.4 MPa/534°C/534°C (1800 psig/993°F/993°F) steam cycle. There is no integration between the CT and the ASU in this case.

Air Separation Unit (ASU)

The same elevated pressure ASU is used as in Case 5 and produces 3,852 tonnes/day (4,246 TPD) of 95 mol% oxygen and 12,290 tonnes/day (13,547 TPD) of nitrogen. There is no integration between the ASU and the CT.

<u>Balance of Plant</u>

Balance of plant items were covered in Sections 3.1.9, 3.1.10 and 3.1.11.

Exhibit 3-87 Case 6 Block Flow Diagram, Shell IGCC with CO$_2$ Capture
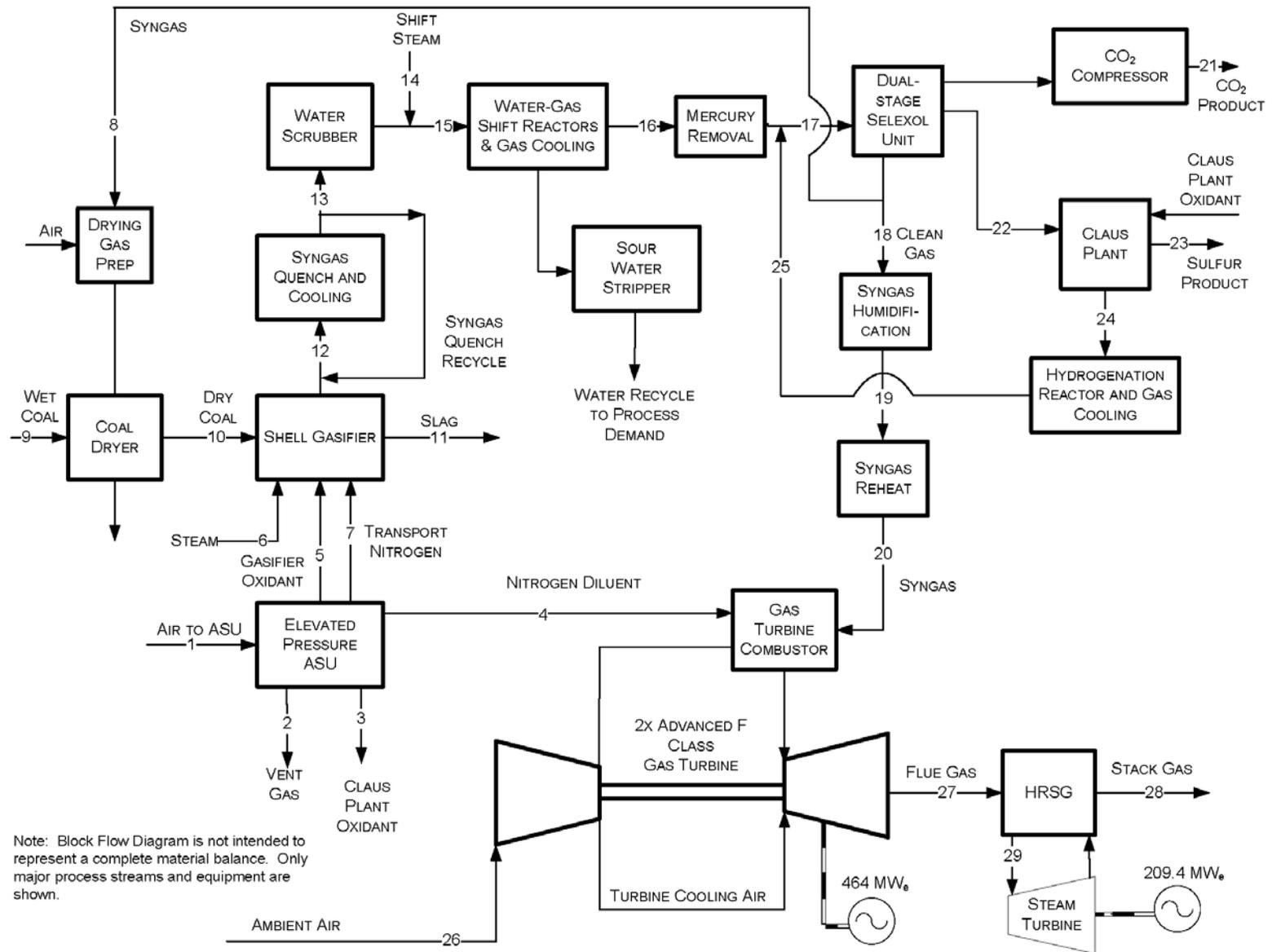
Exhibit 3-88 Case 6 Stream Table, Shell IGCC with CO_2 Capture

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
V-L Mole Fraction															
Ar	0.0092	0.0230	0.0318	0.0023	0.0318	0.0000	0.0023	0.0096	0.0000	0.0000	0.0000	0.0085	0.0061	0.0000	0.0047
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0006	0.0000	0.0000	0.0000	0.0005	0.0004	0.0000	0.0003
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0130	0.0000	0.0000	0.0000	0.5187	0.3712	0.0000	0.2873
CO_2	0.0003	0.0079	0.0000	0.0000	0.0000	0.0000	0.0000	0.0455	0.0000	0.0000	0.0000	0.0126	0.0090	0.0000	0.0070
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0006	0.0004	0.0000	0.0003
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.8727	0.0000	0.8090	0.0000	0.2691	0.1926	0.0000	0.1491
H_2O	0.0099	0.1984	0.0000	0.0003	0.0000	1.0000	0.0004	0.0001	0.0000	0.0935	0.0000	0.1278	0.3758	1.0000	0.5172
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0030	0.0000	0.0008	0.0006	0.0000	0.0001
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0073	0.0052	0.0000	0.0040
N_2	0.7732	0.5759	0.0178	0.9919	0.0178	0.0000	0.9919	0.0585	0.0000	0.0163	0.0000	0.0507	0.0363	0.0000	0.0281
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0033	0.0024	0.0000	0.0019
O_2	0.2074	0.1948	0.9504	0.0054	0.9504	0.0000	0.0054	0.0000	0.0000	0.0782	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
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	24,277	1,004	102	17,310	4,886	1,130	940	308	0	5,809	0	26,493	29,249	11,003	37,783
V-L Flowrate (kg/hr)	700,548	27,328	3,289	485,713	157,225	20,363	26,368	1,900	0	37,081	0	531,672	569,894	198,213	723,426
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	211,040	160,281	21,137	0	0	0	0
Temperature (°C)	15	20	32	93	32	343	32	35	15	16	1,427	1,082	232	288	217
Pressure (MPa, abs)	0.10	0.11	0.86	2.65	0.86	5.10	5.62	3.59	0.10	5.79	4.24	4.24	4.03	5.52	3.96
Enthalpy (kJ/kg)[A]	30.23	36.90	26.67	92.51	26.67	3,063.97	20.78	163.14	---	3,549.69	---	2,043.24	1,217.35	2,918.18	1,541.02
Density (kg/m³)	1.2	1.5	11.0	24.4	11.0	20.1	62.8	8.5	---	16.5	---	7.5	19.1	25.6	19.5
V-L Molecular Weight	28.857	27.206	32.181	28.060	32.181	18.015	28.060	6.159	---	6.383	---	20.069	19.484	18.015	19.147
V-L Flowrate (lb_{mol}/hr)	53,521	2,215	225	38,162	10,771	2,492	2,072	680	0	12,807	0	58,407	64,482	24,256	83,298
V-L Flowrate (lb/hr)	1,544,445	60,249	7,250	1,070,813	346,622	44,894	58,132	4,188	0	81,749	0	1,172,137	1,256,401	436,986	1,594,881
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	465,264	353,359	46,599	0	0	0	0
Temperature (°F)	59	68	90	199	90	650	90	94	59	60	2,600	1,980	450	550	422
Pressure (psia)	14.7	16.4	125.0	384.0	125.0	740.0	815.0	520.0	14.7	840.0	615.0	615.0	585.0	800.0	575.0
Enthalpy (Btu/lb)[A]	13.0	15.9	11.5	39.8	11.5	1,317.3	8.9	70.1	---	1,526.1	---	878.4	523.4	1,254.6	662.5
Density (lb/ft³)	0.076	0.097	0.687	1.521	0.687	1.257	3.918	0.531	---	1.029	---	0.468	1.190	1.597	1.218

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 3-88 Case 6 Stream Table (Continued)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29
V-L Mole Fraction														
Ar	0.0062	0.0062	0.0096	0.0086	0.0086	0.0002	0.0017	0.0000	0.0065	0.0102	0.0092	0.0088	0.0088	0.0000
CH_4	0.0004	0.0004	0.0006	0.0005	0.0005	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0084	0.0084	0.0130	0.0116	0.0116	0.0002	0.0025	0.0000	0.1143	0.0060	0.0000	0.0000	0.0000	0.0000
CO_2	0.3776	0.3810	0.0455	0.0407	0.0407	0.9944	0.5141	0.0000	0.2866	0.6257	0.0003	0.0080	0.0080	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0004	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.5633	0.5593	0.8727	0.7819	0.7819	0.0050	0.1068	0.0000	0.0659	0.2694	0.0000	0.0000	0.0000	0.0000
H_2O	0.0016	0.0016	0.0001	0.1041	0.1041	0.0000	0.0300	0.0000	0.4715	0.0017	0.0099	0.1374	0.1374	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2S	0.0057	0.0057	0.0000	0.0000	0.0000	0.0000	0.3398	0.0000	0.0014	0.0057	0.0000	0.0000	0.0000	0.0000
N_2	0.0368	0.0374	0.0585	0.0524	0.0524	0.0002	0.0047	0.0000	0.0516	0.0813	0.7732	0.7397	0.7397	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	0.0000	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	0.2074	0.1060	0.1060	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0018	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	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	28,837	29,237	18,312	20,438	20,438	10,099	488	0	630	400	110,253	139,892	139,892	28,855
V-L Flowrate (kg/hr)	562,223	574,690	112,786	151,092	151,092	442,270	17,202	0	16,585	12,466	3,181,557	3,818,362	3,818,362	519,836
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	5,277	0	0	0	0	0	0
Temperature (°C)	35	35	35	137	193	51	48	178	232	38	15	562	132	534
Pressure (MPa, abs)	3.62	3.6	3.585	3.206	3.172	15.270	0.163	0.119	0.085	5.51	0.101	0.105	0.105	12.512
Enthalpy (kJ/kg)[A]	45.33	44.5	163.144	1,181.236	1,416.715	-161.704	85.006	---	1,114.498	8.30	30.227	866.140	371.288	3,431.999
Density (kg/m³)	28.1	28.1	8.5	6.9	6.0	639.8	2.2	5,279.4	0.5	74.4	1.2	0.4	0.8	36.8
V-L Molecular Weight	19.496	20	6.159	7.393	7.393	43.792	35.245	---	26.336	31.160	28.857	27.295	27.295	18.015
V-L Flowrate (lb_{mol}/hr)	63,576	64,458	40,371	45,059	45,059	22,265	1,076	0	1,388	882	243,066	308,408	308,408	63,615
V-L Flowrate (lb/hr)	1,239,491	1,266,974	248,650	333,100	333,100	975,038	37,925	0	36,563	27,484	7,014,133	8,418,047	8,418,047	1,146,042
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	11,634	0	0	0	0	0	0
Temperature (°F)	95	94	94	278	380	124	119	352	450	100	59	1,043	270	993
Pressure (psia)	525.0	520.0	520.0	465.0	460.0	2,214.7	23.7	17.3	12.3	799.5	14.7	15.2	15.2	1,814.7
Enthalpy (Btu/lb)[A]	19.5	19.1	70.1	507.8	609.1	-69.5	36.5	---	479.1	3.6	13.0	372.4	159.6	1,475.5
Density (lb/ft³)	1.753	2	0.531	0.431	0.374	39.942	0.135	329.584	0.033	4.646	0.076	0.026	0.053	2.295

3.4.9 Case 6 Performance Results

The Case 6 modeling assumptions were presented previously in Section 3.4.3.

The plant produces a net output of 497 MWe at a net plant efficiency of 31.2 percent (HHV basis). Overall performance for the plant is summarized in Exhibit 3-89, which includes auxiliary power requirements. The ASU accounts for approximately 58 percent of the auxiliary load between the main air compressor, the nitrogen compressor, the oxygen compressor and ASU auxiliaries. The two-stage Selexol process and CO_2 compression account for an additional 28 percent of the auxiliary power load. The BFW and CWS (CWPs and cooling tower fan) comprise approximately 4 percent of the load, leaving 10 percent of the auxiliary load for all other systems.

Exhibit 3-89 Case 6 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	464,000
Sweet Gas Expander Power	0
Steam Turbine Power	209,400
TOTAL POWER, kWe	**673,400**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling	460
Coal Milling	2,170
Slag Handling	550
Air Separation Unit Auxiliaries	1,000
Air Separation Unit Main Air Compressor	59,740
Oxygen Compressor	9,460
Nitrogen Compressors	32,910
CO_2 Compressor	30,210
Boiler Feedwater Pumps	3,500
Condensate Pump	280
Quench Water Pump	610
Syngas Recycle Compressor	790
Circulating Water Pump	4,370
Ground Water Pumps	510
Cooling Tower Fans	2,260
Scrubber Pumps	360
Acid Gas Removal	18,650
Gas Turbine Auxiliaries	1,000
Steam Turbine Auxiliaries	100
Claus Plant/TGTU Auxiliaries	250
Claus Plant TG Recycle Compressor	1,830
Miscellaneous Balance of Plant[2]	3,000
Transformer Losses	2,530
TOTAL AUXILIARIES, kWe	**176,540**
NET POWER, kWe	**496,860**
Net Plant Efficiency, % (HHV)	31.2
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,526 (10,924)
CONDENSER COOLING DUTY 10^6 kJ/hr (10^6 Btu/hr)	**1,340 (1,270)**
CONSUMABLES	
As-Received Coal Feed, kg/hr (lb/hr)	211,040 (465,264)
Thermal Input[1], kWt	1,590,722
Raw Water Withdrawal, m³/min (gpm)	21.3 (5,633)
Raw Water Consumption, m³/min (gpm)	17.5 (4,616)

1 - HHV of As-Received Illinois No. 6 coal is 27,135 kJ/kg (11,666 Btu/lb)

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

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, CO_2, and PM were presented in Section 2.4. A summary of the plant air emissions for Case 6 is presented in Exhibit 3-90.

Exhibit 3-90 Case 6 Air Emissions

	kg/GJ (lb/10^6 Btu)	Tonne/year (ton/year) 80% CF	kg/MWh (lb/MWh)
SO_2	0.001 (0.002)	37 (40)	0.008 (.02)
NOx	0.021 (0.049)	847 (934)	0.180 (.396)
Particulates	0.003 (0.0071)	123 (135)	0.026 (.057)
Hg	2.46E-7 (5.71E-7)	0.010 (0.011)	2.09E-6 (4.61E-6)
CO_2	8.6 (20.0)	344,507 (379,754)	73 (161)
CO_2[1]			99 (218)

[1] CO_2 emissions based on net power instead of gross power

The low level of SO_2 emissions is achieved by capture of the sulfur in the gas by the two-stage Selexol AGR process. The CO_2 capture target results in the sulfur compounds being removed to a greater extent than required in the environmental targets of Section 2.4. The clean syngas exiting the AGR process has a sulfur concentration of approximately 4 ppmv. This results in a concentration in the HRSG FG 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 compressed and recycled back to the AGR where most of the remaining sulfur is removed.

NOx emissions are limited by the use of nitrogen dilution and humidification 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 subsequently destroyed in the Claus plant burner. This helps lower NOx 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 mercury is captured from the syngas by an activated carbon bed.

Ninety five percent of the CO_2 from the syngas is captured in the AGR system and compressed for sequestration. Because not all CO is converted to CO_2 in the shift reactors, the overall CO_2 removal is 90.1 percent.

The carbon balance for the plant is shown in Exhibit 3-91. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not used in the carbon capture equation below, but it is not neglected in the balance since the Aspen model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag, CO_2 in the stack gas, coal dryer vent gas, ASU vent gas and the captured CO_2 product. The carbon capture efficiency is defined as the amount of carbon in the CO_2 product stream relative to the amount of carbon in the coal less carbon contained in the slag, represented by the following fraction:

(Carbon in Product for Sequestration)/[(Carbon in the Coal)-(Carbon in Slag)] or
265,992/(296,581-1,483) * 100 or
90.1 percent

Exhibit 3-91 Case 6 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	134,527 (296,581)	Slag	673 (1,483)
Air (CO$_2$)	532 (1,173)	Stack Gas	13,416 (29,578)
		ASU Vent	95 (210)
		CO$_2$ Product	120,652 (265,992)
		Coal Dryer Stack Gas	223 (491)
Total	135,059 (297,754)	Total	135,059 (297,754)

Exhibit 3-92 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant, sulfur emitted in the stack gas and sulfur from the tail gas unit that is vented through the coal dryer. Sulfur in the slag is considered negligible.

Exhibit 3-92 Case 6 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	5,290 (11,661)	Elemental Sulfur	5,277 (11,634)
		Stack Gas	3 (6)
		CO$_2$ Product	10 (22)
Total	5,290 (11,661)	Total	5,290 (11,661)

Exhibit 3-93 shows the overall water balance for the plant. The exhibit is presented in an identical manner as for previous cases.

Exhibit 3-93 Case 6 Water Balance

Water Use	Water Demand, m³/min (gpm)	Internal Recycle, m³/min (gpm)	Raw Water Withdrawal, m³/min (gpm)	Process Water Discharge, m³/min (gpm)	Raw Water Consumption, m³/min (gpm)
Slag Handling	0.46 (121)	0.46 (121)	0.0 (0)	0.0 (0)	0.0 (0)
Quench/Wash	3.2 (836)	2.2 (587)	0.9 (250)	0.0 (0)	0.9 (250)
Humidifier	0.7 (177)	0.7 (177)	0.0 (0)	0.0 (0)	0.0 (0)
SWS Blowdown	0.0 (0)	0.0 (0)	0.0 (0)	0.03 (7)	-0.03 (-7)
Condenser Makeup *Gasifier Steam* *Shift Steam* *GT Steam Dilution* *BFW Makeup*	**3.8 (1,012)** *0.3 (90)* *3.3 (874)* *0.18 (48)*	**0.0 (0)**	**3.8 (1,012)** *0.3 (90)* *3.3 (874)* *0.18 (48)*	**0.0 (0)**	**3.8 (1,012)**
Cooling Tower *BFW Blowdown* *SWS Blowdown* *SWS Excess Water* *Humidifier Tower Blowdown*	**17.0 (4,490)** *0.18 (48)* *0.27 (71)*	**0.45 (119)** *0.18 (48)* *0.27 (71)*	**16.5 (4,371)** *-0.18 (-48)* *-0.27 (-71)*	**3.8 (1,010)**	**12.7 (3,361)**
Total	**25.1 (6,637)**	**3.8 (1,004)**	**21.3 (5,633)**	**3.8 (1,017)**	**17.5 (4,616)**

Heat and Mass Balance Diagrams

Heat and mass balance diagrams are shown for the following subsystems in Exhibit 3-94 through Exhibit 3-96:

- Coal gasification and ASU

- Syngas cleanup including sulfur recovery and tail gas recycle

- Combined cycle power generation, steam, and FW

An overall plant energy balance is provided in tabular form in Exhibit 3-97. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-89) is calculated by multiplying the power out by a combined generator efficiency of 98.4 percent.

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Exhibit 3-94 Case 6 Coal Gasification and Air Separation Unit Heat and Mass Balance Schematic
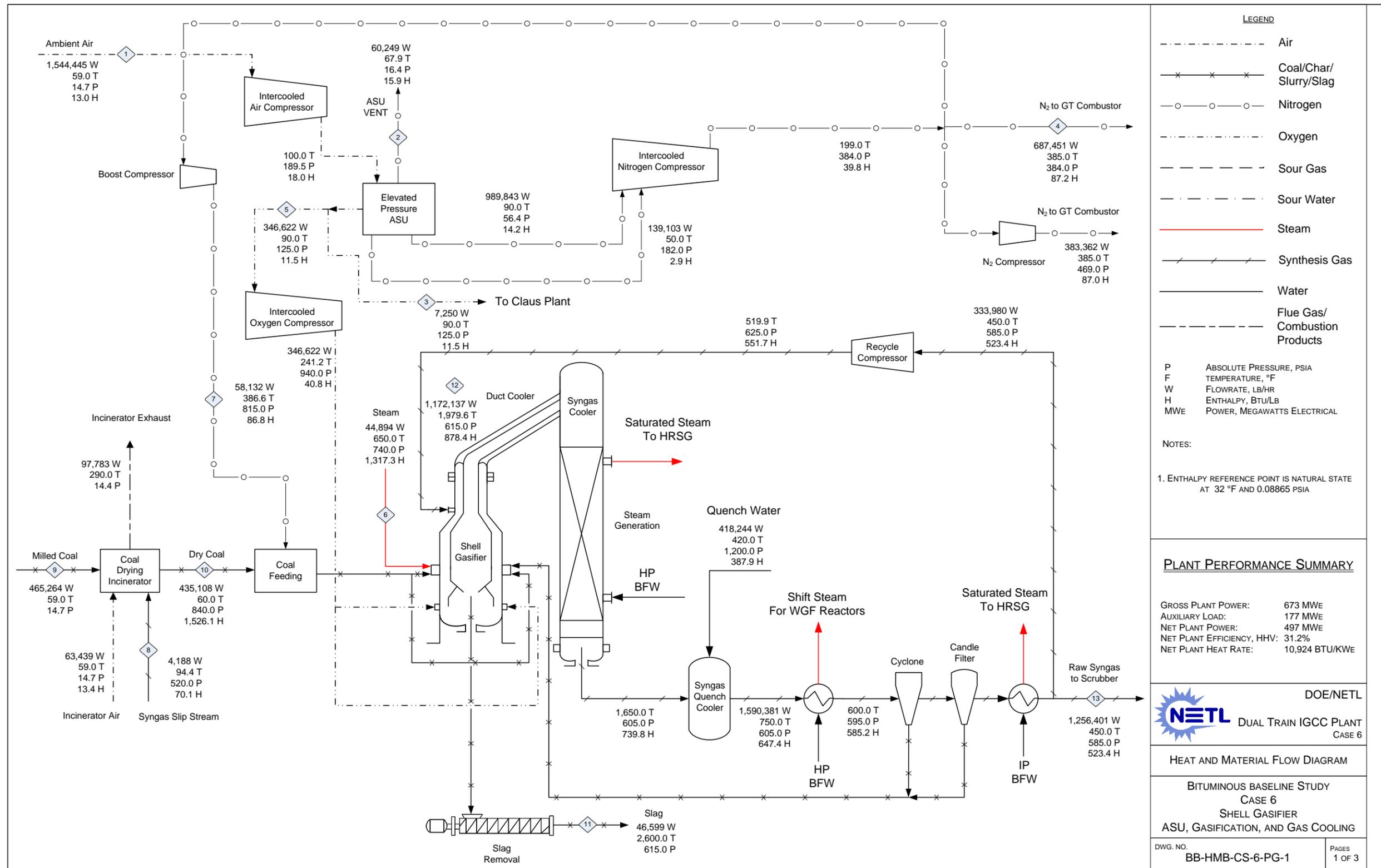
Exhibit 3-95 Case 6 Syngas Cleanup Heat and Mass Balance Schematic
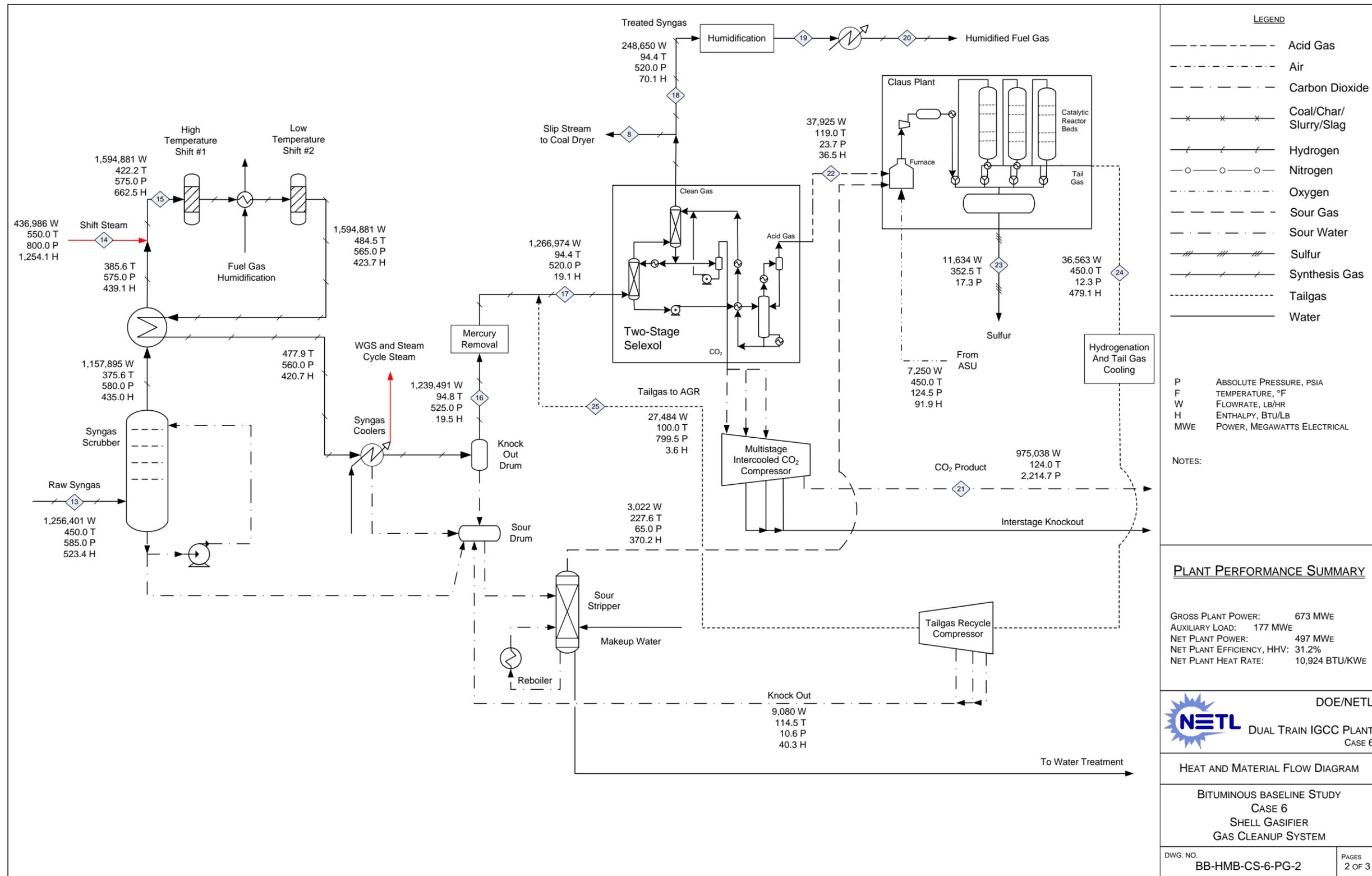
Exhibit 3-96 Case 6 Combined Cycle Power Generation Heat and Mass Balance Schematic
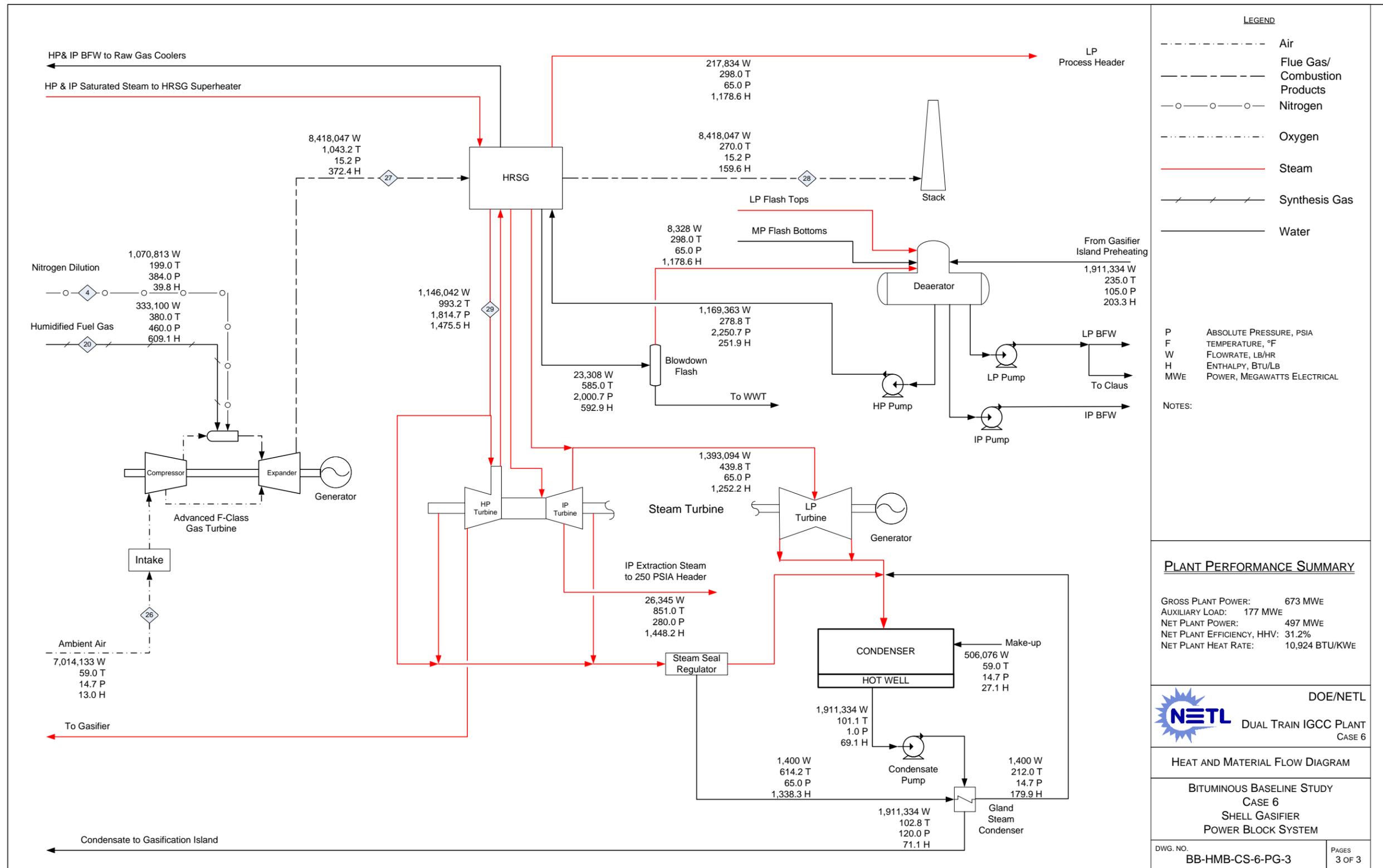
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Exhibit 3-97 Case 6 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	5,727 (5,428)	4.8 (4.5)		5,731 (5,432)
ASU Air		21.2 (20.1)		21 (20)
GT Air		96.2 (91.2)		96 (91)
Water		80.2 (76.0)		80 (76)
Auxiliary Power			636 (602)	636 (602)
TOTAL	**5,727 (5,428)**	**202.3 (191.7)**	**636 (602)**	**6,564 (6,222)**
Heat Out GJ/hr (MMBtu/hr)				
ASU Vent		1.0 (1.0)		1 (1)
Slag	22 (21)	35.7 (33.8)		58 (55)
Sulfur	49 (46)	0.6 (0.6)		50 (47)
CO_2		-71.5 (-67.8)		-72 (-68)
Cooling Tower Blowdown		28.4 (26.9)		28 (27)
HRSG Flue Gas		1,418 (1,344)		1,418 (1,344)
Condenser		1,335 (1,265)		1,335 (1,265)
Non-Condenser Cooling Tower Loads*		687 (651)		687 (651)
Process Losses**		635 (602)		635 (602)
Power			2,424 (2,298)	2,424 (2,298)
TOTAL	**71 (67)**	**4,069 (3,857)**	**2,424 (2,298)**	**6,564 (6,222)**

* Includes ASU compressor intercoolers, CO_2 compressor intercoolers, sour water stripper condenser, syngas cooler (low level heat rejection) and extraction air cooler.
** Calculated by difference to close the energy balance.

3.4.10 Case 6 - Major Equipment List

Major equipment items for the Shell gasifier with CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 3.4.11. 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	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	45 tonne (50 ton)	2	1
9	Feeder	Vibratory	172 tonne/hr (190 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	345 tonne/hr (380 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	172 tonne (190 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	345 tonne/hr (380 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	345 tonne/hr (380 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	816 tonne (900 ton)	3	0

ACCOUNT 2   COAL PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Vibratory	82 tonne/hr (90 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	236 tonne/hr (260 tph)	1	0
3	Roller Mill Feed Hopper	Dual Outlet	463 tonne (510 ton)	1	0
4	Weigh Feeder	Belt	118 tonne/hr (130 tph)	2	0
5	Coal Dryer and Pulverizer	Rotary	118 tonne/hr (130 tph)	2	0
6	Coal Dryer Feed Hopper	Vertical Hopper	236 tonne (260 ton)	2	0

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	987,992 liters (261,000 gal)	2	0
2	Condensate Pumps	Vertical canned	7,987 lpm @ 91 m H2O (2,110 gpm @ 300 ft H2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	551,115 kg/hr (1,215,000 lb/hr)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	7,987 lpm @ 27 m H2O (2,110 gpm @ 90 ft H2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 5,072 lpm @ 1,859 m H2O (1,340 gpm @ 6,100 ft H2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,211 lpm @ 223 m H2O (320 gpm @ 730 ft H2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
10	Closed Cylce Cooling Heat Exchangers	Plate and frame	393 GJ/hr (372 MMBtu/hr) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	140,817 lpm @ 21 m H2O (37,200 gpm @ 70 ft H2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H2O (1,000 gpm @ 350 ft H2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H2O (700 gpm @ 250 ft H2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	5,943 lpm @ 18 m H2O (1,570 gpm @ 60 ft H2O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	2,953 lpm @ 268 m H2O (780 gpm @ 880 ft H2O)	4	1
16	Filtered Water Pumps	Stainless steel, single suction	4,656 lpm @ 49 m H2O (1,230 gpm @ 160 ft H2O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	2,225,822 liter (588,000 gal)	2	0
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	2,082 lpm (550 gpm)	2	0
19	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

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

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized dry-feed, entrained bed	2,812 tonne/day, 4.2 MPa (3,100 tpd, 615 psia)	2	0
2	Synthesis Gas Cooler	Convective spiral-wound tube boiler	396,893 kg/hr (875,000 lb/hr)	2	0
3	Synthesis Gas Cyclone	High efficiency	313,432 kg/hr (691,000 lb/hr) Design efficiency 90%	2	0
4	Candle Filter	Pressurized filter with pulse-jet cleaning	metallic filters	2	0
5	Syngas Scrubber Including Sour Water Stripper	Vertical upflow	313,432 kg/hr (691,000 lb/hr)	2	0
6	Raw Gas Coolers	Shell and tube with condensate drain	397,801 kg/hr (877,000 lb/hr)	8	0
7	Raw Gas Knockout Drum	Vertical with mist eliminator	309,804 kg/hr, 35°C, 3.7 MPa (683,000 lb/hr, 95°F, 530 psia)	2	0
8	Saturation Water Economizers	Shell and tube	78 GJ/hr (74 MMBtu/hr)	2	0
9	Fuel Gas Saturator	Vertical tray tower	83,007 kg/hr, 137°C, 3.6 MPa (183,000 lb/hr, 278°F, 520 psia)	2	0
10	Saturator Water Pump	Centrifugal	1,893 lpm @ 12 m H2O (500 gpm @ 40 ft H2O)	2	2
11	Synthesis Gas Reheater	Shell and tube	83,007 kg/hr (183,000 lb/hr)	2	0
12	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	313,432 kg/hr (691,000 lb/hr) syngas	2	0
13	ASU Main Air Compressor	Centrifugal, multi-stage	5,267 m3/min @ 1.3 MPa (186,000 scfm @ 190 psia)	2	0
14	Cold Box	Vendor design	2,087 tonne/day (2,300 tpd) of 95% purity oxygen	2	0
15	Oxygen Compressor	Centrifugal, multi-stage	1,048 m3/min (37,000 scfm) Suction - 0.9 MPa (130 psia) Discharge - 6.5 MPa (940 psia)	2	0
16	Primary Nitrogen Compressor	Centrifugal, multi-stage	3,483 m3/min (123,000 scfm) Suction - 0.4 MPa (60 psia) Discharge - 2.7 MPa (390 psia)	2	0
17	Secondary Nitrogen Compressor	Centrifugal, single-stage	481 m3/min (17,000 scfm) Suction - 1.2 MPa (180 psia) Discharge - 2.7 MPa (390 psia)	2	0
18	Gasifier Purge Nitrogen Boost Compressor	Centrifugal, single-stage	1,359 m3/min (48,000 scfm) Suction - 2.6 MPa (380 psia) Discharge - 3.2 MPa (470 psia)	2	0

ACCOUNT 5   SYNGAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber	Sulfated carbon bed	309,350 kg/hr (682,000 lb/hr) 35°C (95°F) 3.6 MPa (525 psia)	2	0
2	Sulfur Plant	Claus type	139 tonne/day (154 tpd)	1	0
3	Water Gas Shift Reactors	Fixed bed, catalytic	397,801 kg/hr (877,000 lb/hr) 216°C (420°F) 4.0 MPa (580 psia)	4	0
4	Shift Reactor Heat Recovery Exchangers	Shell and Tube	Exchanger 1: 121 GJ/hr (114 MMBtu/hr) Exchanger 2: 3 GJ/hr (3 MMBtu/hr)	4	0
5	Acid Gas Removal Plant	Two-stage Selexol	316,154 kg/hr (697,000 lb/hr) 35°C (94°F) 3.6 MPa (520 psia)	2	0
6	Hydrogenation Reactor	Fixed bed, catalytic	18,243 kg/hr (40,220 lb/hr) 232°C (450°F) 0.1 MPa (12.3 psia)	1	0
7	Tail Gas Recycle Compressor	Centrifugal	13,713 kg/hr (30,232 lb/hr)	1	0

ACCOUNT 5B CO_2 COMPRESSION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CO2 Compressor	Integrally geared, multi-stage centrifugal	1,096 m3/min @ 15.3 MPa (38,700 scfm @ 2,215 psia)	4	0

ACCOUNT 6   COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class	232 MW	2	0
2	Gas Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

ACCOUNT 7 HRSG, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.5 m (28 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 285,910 kg/hr, 12.4 MPa/534°C (630,323 lb/hr, 1,800 psig/993°F) Reheat steam - 244,783 kg/hr, 3.1 MPa/534°C (539,654 lb/hr, 452 psig/993°F)	2	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	220 MW 12.4 MPa/534°C/534°C (1800 psig/ 993°F/993°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitiation	240 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,467 GJ/hr (1,390 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	439,108 lpm @ 30 m (116,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 2437 GJ/hr (2310 MMBtu/hr) heat duty	1	0

ACCOUNT 10 SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	223,339 liters (59,000 gal)	2	0
2	Slag Crusher	Roll	12 tonne/hr (13 tph)	2	0
3	Slag Depressurizer	Lock Hopper	12 tonne/hr (13 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	132,489 liters (35,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	60,567 liters (16,000 gal)	2	
6	Slag Conveyor	Drag chain	12 tonne/hr (13 tph)	2	0
7	Slag Separation Screen	Vibrating	12 tonne/hr (13 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	12 tonne/hr (13 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	189,271 liters (50,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	38 lpm @ 14 m H_2O (10 gpm @ 46 ft H_2O)	2	2
11	Grey Water Storage Tank	Field erected	60,567 liters (16,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	227 lpm @ 433 m H_2O (60 gpm @ 1,420 ft H_2O)	2	2
13	Slag Storage Bin	Vertical, field erected	816 tonne (900 tons)	2	0
14	Unloading Equipment	Telescoping chute	100 tonne/hr (110 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Step-up Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Step-up Transformer	Oil-filled	24 kV/345 kV, 240 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 74 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 46 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 7 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROLS

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

3.4.11 Case 6 - Cost Estimating

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-98 shows the total plant capital cost summary organized by cost account and Exhibit 3-99 shows a more detailed breakdown of the capital costs along with owner's costs, TOC and TASC. Exhibit 3-100 shows the initial and annual O&M costs.

The estimated TOC of the Shell gasifier with CO_2 capture is $3,904/kW. Process contingency represents 3.4 percent of the TOC and project contingency represents 11.4 percent. The COE, including CO_2 TS&M costs of 5.7 mills/kWh, is 119.5 mills/kWh.

Exhibit 3-98 Case 6 Total Plant Cost Summary

	Client:	USDOE/NETL							Report Date	2010-Jan-14		
	Project:	Bituminous Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case 6 - Shell 500MW IGCC w/ CO2										
	Plant Size:	496.9 MW,net	Estimate Type:		Conceptual			Cost Base (Jun)	2007	($x1000)		

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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$13,881	$2,580	$10,765	$0	$0	**$27,226**	$2,471	$0	$5,939	**$35,636**	**$72**
2	COAL & SORBENT PREP & FEED	$109,935	$8,758	$18,287	$0	$0	**$136,980**	$11,879	$0	$29,772	**$178,630**	**$360**
3	FEEDWATER & MISC. BOP SYSTEMS	$9,471	$7,207	$9,699	$0	$0	**$26,377**	$2,492	$0	$6,717	**$35,585**	**$72**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$144,815	$0	$61,614	$0	$0	**$206,430**	$18,447	$28,271	$38,955	**$292,103**	**$588**
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	$173,504	$0	w/equip.	$0	$0	**$173,504**	$16,818	$0	$19,032	**$209,354**	**$421**
4.4-4.9	Other Gasification Equipment	$25,591	$9,849	$15,118	$0	$0	**$50,557**	$4,851	$0	$11,805	**$67,213**	**$135**
	SUBTOTAL 4	**$343,911**	**$9,849**	**$76,732**	**$0**	**$0**	**$430,492**	**$40,115**	**$28,271**	**$69,793**	**$568,670**	**$1,145**
5A	Gas Cleanup & Piping	$91,097	$3,993	$77,814	$0	$0	**$172,904**	$16,706	$26,070	$43,284	**$258,964**	**$521**
5B	CO₂ REMOVAL & COMPRESSION	$17,811	$0	$10,524	$0	$0	**$28,335**	$2,728	$0	$6,213	**$37,276**	**$75**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$92,026	$0	$6,583	$0	$0	**$98,609**	$9,348	$9,861	$11,782	**$129,599**	**$261**
6.2-6.9	Combustion Turbine Other	$0	$806	$892	$0	$0	**$1,699**	$159	$0	$557	**$2,415**	**$5**
	SUBTOTAL 6	**$92,026**	**$806**	**$7,475**	**$0**	**$0**	**$100,307**	**$9,507**	**$9,861**	**$12,339**	**$132,014**	**$266**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$33,709	$0	$4,793	$0	$0	**$38,502**	$3,661	$0	$4,216	**$46,379**	**$93**
7.2-7.9	Ductwork and Stack	$3,380	$2,410	$3,156	$0	$0	**$8,946**	$829	$0	$1,591	**$11,367**	**$23**
	SUBTOTAL 7	**$37,089**	**$2,410**	**$7,949**	**$0**	**$0**	**$47,448**	**$4,490**	**$0**	**$5,807**	**$57,745**	**$116**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$23,934	$0	$4,000	$0	$0	**$27,935**	$2,680	$0	$3,061	**$33,676**	**$68**
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$9,162	$818	$6,331	$0	$0	**$16,312**	$1,486	$0	$3,487	**$21,285**	**$43**
	SUBTOTAL 8	**$33,096**	**$818**	**$10,332**	**$0**	**$0**	**$44,246**	**$4,166**	**$0**	**$6,549**	**$54,961**	**$111**
9	COOLING WATER SYSTEM	$9,932	$9,472	$8,108	$0	$0	**$27,512**	$2,555	$0	$6,134	**$36,202**	**$73**
10	ASH/SPENT SORBENT HANDLING SYS	$18,585	$1,433	$9,223	$0	$0	**$29,241**	$2,805	$0	$3,501	**$35,547**	**$72**
11	ACCESSORY ELECTRIC PLANT	$30,536	$12,099	$23,664	$0	$0	**$66,300**	$5,703	$0	$13,663	**$85,666**	**$172**
12	INSTRUMENTATION & CONTROL	$11,002	$2,024	$7,089	$0	$0	**$20,115**	$1,823	$1,006	$3,823	**$26,766**	**$54**
13	IMPROVEMENTS TO SITE	$3,346	$1,972	$8,255	$0	$0	**$13,572**	$1,340	$0	$4,474	**$19,386**	**$39**
14	BUILDINGS & STRUCTURES	$0	$6,461	$7,281	$0	$0	**$13,741**	$1,250	$0	$2,463	**$17,455**	**$35**
	TOTAL COST	**$821,717**	**$69,882**	**$293,196**	**$0**	**$0**	**$1,184,795**	**$110,031**	**$65,208**	**$220,470**	**$1,580,505**	**$3,181**

Exhibit 3-99 Case 6 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,645	$0	$1,781	$0	$0	$5,427	$486	$0	$1,183	$7,095	$14
1.2	Coal Stackout & Reclaim	$4,711	$0	$1,142	$0	$0	$5,853	$513	$0	$1,273	$7,639	$15
1.3	Coal Conveyors & Yd Crush	$4,380	$0	$1,130	$0	$0	$5,510	$484	$0	$1,199	$7,192	$14
1.4	Other Coal Handling	$1,146	$0	$261	$0	$0	$1,407	$123	$0	$306	$1,836	$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	$2,580	$6,450	$0	$0	$9,030	$865	$0	$1,979	$11,874	$24
	SUBTOTAL 1.	$13,881	$2,580	$10,765	$0	$0	$27,226	$2,471	$0	$5,939	$35,636	$72
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$41,765	$2,509	$6,086	$0	$0	$50,360	$4,346	$0	$10,941	$65,647	$132
2.2	Prepared Coal Storage & Feed	$1,978	$473	$310	$0	$0	$2,762	$236	$0	$600	$3,598	$7
2.3	Dry Coal Injection System	$65,103	$756	$6,046	$0	$0	$71,905	$6,193	$0	$15,620	$93,718	$189
2.4	Misc.Coal Prep & Feed	$1,088	$792	$2,373	$0	$0	$4,253	$391	$0	$929	$5,573	$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	$4,228	$3,471	$0	$0	$7,700	$713	$0	$1,683	$10,095	$20
	SUBTOTAL 2.	$109,935	$8,758	$18,287	$0	$0	$136,980	$11,879	$0	$29,772	$178,630	$360
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	Feedwater System	$2,492	$4,279	$2,259	$0	$0	$9,029	$836	$0	$1,973	$11,839	$24
3.2	Water Makeup & Pretreating	$701	$73	$392	$0	$0	$1,167	$111	$0	$383	$1,661	$3
3.3	Other Feedwater Subsystems	$1,363	$461	$415	$0	$0	$2,238	$201	$0	$488	$2,928	$6
3.4	Service Water Systems	$401	$827	$2,869	$0	$0	$4,097	$400	$0	$1,349	$5,845	$12
3.5	Other Boiler Plant Systems	$2,154	$835	$2,069	$0	$0	$5,057	$480	$0	$1,107	$6,644	$13
3.6	FO Supply Sys & Nat Gas	$313	$591	$551	$0	$0	$1,454	$140	$0	$319	$1,913	$4
3.7	Waste Treatment Equipment	$981	$0	$598	$0	$0	$1,579	$154	$0	$520	$2,252	$5
3.8	Misc. Power Plant Equipment	$1,066	$143	$547	$0	$0	$1,756	$170	$0	$578	$2,503	$5
	SUBTOTAL 3.	$9,471	$7,207	$9,699	$0	$0	$26,377	$2,492	$0	$6,717	$35,585	$72
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries (Shell)	$144,815	$0	$61,614	$0	$0	$206,430	$18,447	$28,271	$38,955	$292,103	$588
4.2	Syngas Cooling	w/4.1	$0	w/ 4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$173,504	$0	w/equip.	$0	$0	$173,504	$16,818	$0	$19,032	$209,354	$421
4.4	LT Heat Recovery & FG Saturation	$25,591	$0	$9,728	$0	$0	$35,319	$3,447	$0	$7,753	$46,519	$94
4.5	Misc. Gasification Equipment	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Flare Stack System	$0	$1,406	$572	$0	$0	$1,978	$190	$0	$433	$2,601	$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	$8,443	$4,818	$0	$0	$13,261	$1,214	$0	$3,619	$18,094	$36
	SUBTOTAL 4.	$343,911	$9,849	$76,732	$0	$0	$430,492	$40,115	$28,271	$69,793	$568,670	$1,145

Exhibit 3-99 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	Double Stage Selexol	$70,179	$0	$59,549	$0	$0	$129,728	$12,546	$25,946	$33,644	$201,864	$406
5A.2	Elemental Sulfur Plant	$10,017	$1,996	$12,924	$0	$0	$24,937	$2,422	$0	$5,472	$32,831	$66
5A.3	Mercury Removal	$1,410	$0	$1,073	$0	$0	$2,483	$240	$124	$569	$3,417	$7
5A.4	Shift Reactors	$7,366	$0	$2,965	$0	$0	$10,330	$990	$0	$2,264	$13,585	$27
5A.5	Particulate Removal	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
5A.5	Blowback Gas Systems	$2,125	$358	$201	$0	$0	$2,684	$255	$0	$588	$3,526	$7
5A.6	Fuel Gas Piping	$0	$814	$570	$0	$0	$1,384	$128	$0	$303	$1,815	$4
5A.9	HGCU Foundations	$0	$824	$532	$0	$0	$1,356	$125	$0	$444	$1,925	$4
	SUBTOTAL 5A.	$91,097	$3,993	$77,814	$0	$0	$172,904	$16,706	$26,070	$43,284	$258,964	$521
5B	CO2 COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$17,811	$0	$10,524	$0	$0	$28,335	$2,728	$0	$6,213	$37,276	$75
	SUBTOTAL 5B.	$17,811	$0	$10,524	$0	$0	$28,335	$2,728	$0	$6,213	$37,276	$75
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$92,026	$0	$6,583	$0	$0	$98,609	$9,348	$9,861	$11,782	$129,599	$261
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.	$92,026	$806	$7,475	$0	$0	$100,307	$9,507	$9,861	$12,339	$132,014	$266
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$33,709	$0	$4,793	$0	$0	$38,502	$3,661	$0	$4,216	$46,379	$93
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,733	$1,236	$0	$0	$2,969	$260	$0	$646	$3,875	$8
7.4	Stack	$3,380	$0	$1,270	$0	$0	$4,650	$445	$0	$510	$5,605	$11
7.9	HRSG,Duct & Stack Foundations	$0	$677	$650	$0	$0	$1,328	$124	$0	$435	$1,887	$4
	SUBTOTAL 7.	$37,089	$2,410	$7,949	$0	$0	$47,448	$4,490	$0	$5,807	$57,745	$116
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$23,934	$0	$4,000	$0	$0	$27,935	$2,680	$0	$3,061	$33,676	$68
8.2	Turbine Plant Auxiliaries	$165	$0	$378	$0	$0	$543	$53	$0	$60	$656	$1
8.3	Condenser & Auxiliaries	$4,579	$0	$1,463	$0	$0	$6,042	$578	$0	$662	$7,282	$15
8.4	Steam Piping	$4,418	$0	$3,108	$0	$0	$7,526	$647	$0	$2,043	$10,215	$21
8.9	TG Foundations	$0	$818	$1,383	$0	$0	$2,201	$209	$0	$723	$3,132	$6
	SUBTOTAL 8.	$33,096	$818	$10,332	$0	$0	$44,246	$4,166	$0	$6,549	$54,961	$111
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$6,867	$0	$1,249	$0	$0	$8,116	$773	$0	$1,333	$10,222	$21
9.2	Circulating Water Pumps	$1,791	$0	$127	$0	$0	$1,919	$162	$0	$312	$2,393	$5
9.3	Circ.Water System Auxiliaries	$151	$0	$21	$0	$0	$172	$16	$0	$28	$217	$0
9.4	Circ.Water Piping	$0	$6,288	$1,630	$0	$0	$7,918	$716	$0	$1,727	$10,360	$21
9.5	Make-up Water System	$381	$0	$544	$0	$0	$925	$89	$0	$203	$1,217	$2
9.6	Component Cooling Water Sys	$742	$888	$632	$0	$0	$2,262	$212	$0	$495	$2,968	$6
9.9	Circ.Water System Foundations	$0	$2,296	$3,904	$0	$0	$6,200	$588	$0	$2,037	$8,825	$18
	SUBTOTAL 9.	$9,932	$9,472	$8,108	$0	$0	$27,512	$2,555	$0	$6,134	$36,202	$73

Exhibit 3-99 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$16,178	$0	$7,978	$0	$0	$24,156	$2,321	$0	$2,648	$29,125	$59
10.2	Gasifier Ash Depressurization	w/10.1	w/10.1	w/10.1	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	w/10.1	w/10.1	w/10.1	$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 Recovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$546	$0	$594	$0	$0	$1,139	$111	$0	$187	$1,437	$3
10.7	Ash Transport & Feed Equipment	$732	$0	$177	$0	$0	$908	$85	$0	$149	$1,142	$2
10.8	Misc. Ash Handling Equipment	$1,130	$1,385	$414	$0	$0	$2,929	$279	$0	$481	$3,689	$7
10.9	Ash/Spent Sorbent Foundation	$0	$48	$61	$0	$0	$109	$10	$0	$36	$155	$0
	SUBTOTAL 10.	$18,585	$1,433	$9,223	$0	$0	$29,241	$2,805	$0	$3,501	$35,547	$72
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$901	$0	$891	$0	$0	$1,792	$171	$0	$196	$2,159	$4
11.2	Station Service Equipment	$4,510	$0	$406	$0	$0	$4,916	$453	$0	$537	$5,906	$12
11.3	Switchgear & Motor Control	$8,338	$0	$1,516	$0	$0	$9,854	$914	$0	$1,615	$12,383	$25
11.4	Conduit & Cable Tray	$0	$3,873	$12,777	$0	$0	$16,650	$1,610	$0	$4,565	$22,826	$46
11.5	Wire & Cable	$0	$7,400	$4,862	$0	$0	$12,262	$891	$0	$3,288	$16,442	$33
11.6	Protective Equipment	$0	$679	$2,471	$0	$0	$3,150	$308	$0	$519	$3,976	$8
11.7	Standby Equipment	$224	$0	$219	$0	$0	$443	$42	$0	$73	$558	$1
11.8	Main Power Transformers	$16,564	$0	$136	$0	$0	$16,699	$1,263	$0	$2,694	$20,656	$42
11.9	Electrical Foundations	$0	$147	$386	$0	$0	$534	$51	$0	$175	$760	$2
	SUBTOTAL 11.	$30,536	$12,099	$23,664	$0	$0	$66,300	$5,703	$0	$13,663	$85,666	$172
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	w/6.1	$0	w/6.1	$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	$1,086	$0	$725	$0	$0	$1,811	$171	$91	$311	$2,384	$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	$250	$0	$160	$0	$0	$410	$39	$20	$94	$563	$1
12.7	Computer & Accessories	$5,794	$0	$185	$0	$0	$5,979	$549	$299	$683	$7,510	$15
12.8	Instrument Wiring & Tubing	$0	$2,024	$4,137	$0	$0	$6,161	$523	$308	$1,748	$8,740	$18
12.9	Other I & C Equipment	$3,873	$0	$1,881	$0	$0	$5,753	$541	$288	$987	$7,570	$15
	SUBTOTAL 12.	$11,002	$2,024	$7,089	$0	$0	$20,115	$1,823	$1,006	$3,823	$26,766	$54

Exhibit 3-99 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$105	$2,244	$0	$0	$2,349	$233	$0	$775	$3,356	$7
13.2	Site Improvements	$0	$1,867	$2,481	$0	$0	$4,348	$429	$0	$1,433	$6,210	$12
13.3	Site Facilities	$3,346	$0	$3,530	$0	$0	$6,876	$678	$0	$2,266	$9,820	$20
	SUBTOTAL 13.	$3,346	$1,972	$8,255	$0	$0	$13,572	$1,340	$0	$4,474	$19,386	$39
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	$2,071	$2,950	$0	$0	$5,021	$462	$0	$822	$6,306	$13
14.3	Administration Building	$0	$857	$622	$0	$0	$1,479	$132	$0	$242	$1,853	$4
14.4	Circulation Water Pumphouse	$0	$161	$85	$0	$0	$246	$22	$0	$40	$308	$1
14.5	Water Treatment Buildings	$0	$586	$572	$0	$0	$1,158	$105	$0	$189	$1,452	$3
14.6	Machine Shop	$0	$439	$300	$0	$0	$739	$66	$0	$121	$926	$2
14.7	Warehouse	$0	$709	$457	$0	$0	$1,166	$103	$0	$190	$1,460	$3
14.8	Other Buildings & Structures	$0	$424	$330	$0	$0	$755	$67	$0	$164	$987	$2
14.9	Waste Treating Building & Str.	$0	$949	$1,813	$0	$0	$2,762	$257	$0	$604	$3,623	$7
	SUBTOTAL 14.	$0	$6,461	$7,281	$0	$0	$13,741	$1,250	$0	$2,463	$17,455	$35
	TOTAL COST	$821,717	$69,882	$293,196	$0	$0	$1,184,795	$110,031	$65,208	$220,470	$1,580,505	$3,181

	Owner's Costs											
	Preproduction Costs											
	6 Months All Labor										$13,300	$27
	1 Month Maintenance Materials										$2,951	$6
	1 Month Non-fuel Consumables										$378	$1
	1 Month Waste Disposal										$278	$1
	25% of 1 Months Fuel Cost at 100% CF										$1,621	$3
	2% of TPC										$31,610	$64
	Total										**$50,138**	**$101**
	Inventory Capital											
	60 day supply of fuel and consumables at 100% CF										$13,459	$27
	0.5% of TPC (spare parts)										$7,903	$16
	Total										**$21,361**	**$43**
	Initial Cost for Catalyst and Chemicals										$7,224	$15
	Land										$900	$2
	Other Owner's Costs										$237,076	$477
	Financing Costs										$42,674	$86
	Total Overnight Costs (TOC)										**$1,939,878**	**$3,904**
	TASC Multiplier							(IOU, high-risk, 35 year)			1.140	
	Total As-Spent Cost (TASC)										**$2,211,461**	**$4,451**

Exhibit 3-100 Case 6 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun):	2007
Case 6 - Shell 500MW IGCC w/ CO2					Heat Rate-net (Btu/kWh):	10,924
					MWe-net:	497
					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

Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.	Total Plant
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	$6,313,507	$12.707
Maintenance Labor Cost	$14,966,466	$30.122
Administrative & Support Labor	$5,319,993	$10.707
Property Taxes and Insurance	$31,610,092	$63.620
TOTAL FIXED OPERATING COSTS	**$58,210,058**	**$117.156**

VARIABLE OPERATING COSTS

						$/kWh-net
Maintenance Material Cost					**$28,329,484**	**$0.00814**

Consumables	Consumption Initial Fill	/Day	Unit Cost	Initial Fill Cost		
Water (/1000 gallons)	0	4,056	1.08	$0	$1,281,009	$0.00037
Chemicals						
MU & WT Chem. (lbs)	0	24,163	0.17	$0	$1,221,101	$0.00035
Carbon (Mercury Removal) (lb)	117,815	161	1.05	$123,726	$49,490	$0.00001
COS Catalyst (m3)	0	0	2,397.36	$0	$0	$0.00000
Water Gas Shift Catalyst (ft3)	6,470	4.43	498.83	$3,227,388	$645,478	$0.00019
Selexol Solution (gal)	289,068	92	13.40	$3,873,002	$360,241	$0.00010
SCR Catalyst (m3)	0	0	0.00	$0	$0	$0.00000
Ammonia (19% NH3) (ton)	0	0	0.00	$0	$0	$0.00000
Claus Catalyst (ft3)	w/equip.	1.93	131.27	$0	$74,040	$0.00002
Subtotal Chemicals				**$7,224,116**	**$2,350,349**	**$0.00068**
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	161	0.42	$0	$19,655	$0.00001
Flyash (ton)	0	0	0.00	$0	$0	$0.00000
Slag (ton)	0	559	16.23	$0	$2,649,268	$0.00076
Subtotal-Waste Disposal				**$0**	**$2,668,923**	**$0.00077**
By-products & Emissions						
Sulfur (ton)	0	140	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$7,224,116**	**$34,629,764**	**$0.00995**
Fuel (ton)	0	5,583	38.18	**$0**	**$62,251,620**	**$0.01788**

3.5 IGCC CASE SUMMARY

The performance results of the six IGCC plant configurations modeled in this study are summarized in Exhibit 3-101.

Exhibit 3-101 Estimated Performance and Cost Results for IGCC Cases

	Integrated Gasification Combined Cycle					
	GEE R+Q		CoP E-Gas FSQ		Shell	
PERFORMANCE	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
CO2 Capture	0%	90%	0%	90%	0%	90%
Gross Power Output (kWe)	747,800	734,000	738,200	703,700	737,000	673,400
Auxiliary Power Requirement (kWe)	125,750	190,750	113,140	190,090	108,020	176,540
Net Power Output (kWe)	622,050	543,250	625,060	513,610	628,980	496,860
Coal Flowrate (lb/hr)	466,901	487,011	459,958	484,212	436,646	465,264
Natural Gas Flowrate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A
HHV Thermal Input (kWth)	1,596,320	1,665,074	1,572,582	1,655,503	1,492,878	1,590,722
Net Plant HHV Efficiency (%)	39.0%	32.6%	39.7%	31.0%	42.1%	31.2%
Net Plant HHV Heat Rate (Btu/kWh)	8,756	10,458	8,585	10,998	8,099	10,924
Raw Water Withdrawal (gpm/MW$_{net}$)	7.6	10.7	7.0	11.1	6.6	11.3
Process Water Discharge (gpm/MW$_{net}$)	1.6	2.0	1.4	2.1	1.2	2.0
Raw Water Consumption (gpm/MW$_{net}$)	6.0	8.7	5.5	9.0	5.3	9.3
CO_2 Emissions (lb/MMBtu)	197	20	199	20	197	20
CO_2 Emissions (lb/MWh$_{gross}$)	1,434	152	1,448	158	1,361	161
CO_2 Emissions (lb/MWh$_{net}$)	1,723	206	1,710	217	1,595	218
SO_2 Emissions (lb/MMBtu)	0.0012	0.0022	0.0117	0.0022	0.0042	0.0021
SO_2 Emissions (lb/MWh$_{gross}$)	0.0090	0.0166	0.0852	0.0173	0.0290	0.0171
NOx Emissions (lb/MMBtu)	0.059	0.049	0.060	0.049	0.059	0.049
NOx Emissions (lb/MWh$_{gross}$)	0.430	0.376	0.434	0.396	0.409	0.396
PM Emissions (lb/MMBtu)	0.0071	0.0071	0.0071	0.0071	0.0071	0.0071
PM Emissions (lb/MWh$_{gross}$)	0.052	0.055	0.052	0.057	0.049	0.057
Hg Emissions (lb/TBtu)	0.571	0.571	0.571	0.571	0.571	0.571
Hg Emissions (lb/MWh$_{gross}$)	4.16E-06	4.42E-06	4.15E-06	4.59E-06	3.95E-06	4.61E-06
COST						
Total Plant Cost (2007$/kW)	1,987	2,711	1,913	2,817	2,217	3,181
Total Overnight Cost (2007$/kW)	2,447	3,334	2,351	3,466	2,716	3,904
Bare Erected Cost	1,528	2,032	1,470	2,113	1,695	2,385
Home Office Expenses	144	191	138	199	156	221
Project Contingency	265	369	256	385	302	444
Process Contingency	50	119	50	120	63	131
Owner's Costs	460	623	438	649	500	723
Total Overnight Cost (2007$ x 1,000)	1,521,880	1,811,411	1,469,577	1,780,290	1,708,524	1,939,878
Total As Spent Capital (2007$/kW)	2,789	3,801	2,680	3,952	3,097	4,451
COE (mills/kWh, 2007$)[1,2]	76.3	105.6	74.0	110.3	81.3	119.4
CO2 TS&M Costs	0.0	5.2	0.0	5.5	0.0	5.6
Fuel Costs	14.3	17.1	14.0	18.0	13.3	17.9
Variable Costs	7.3	9.3	7.2	9.8	7.8	9.9
Fixed Costs	11.3	14.8	11.1	15.5	12.1	16.7
Capital Costs	43.4	59.1	41.7	61.5	48.2	69.2
LCOE (mills/kWh, 2007$)[1,2]	96.7	133.9	93.8	139.9	103.1	151.4

[1] CF is 80% for all IGCC cases
[2] COE and LCOE are defined in Section 2.7.

The components of TOC and the overall TASC of the six IGCC cases are shown in Exhibit 3-102. The following TOC observations are made with the caveat that the differences between cases are less than the estimate accuracy (-15%/+30%). However, all cases are evaluated using a common set of technical and economic assumptions allowing meaningful comparisons among the cases:

- CoP has the lowest TOC cost among the non-capture cases. The E-Gas technology has several features that lend it to being lower cost, such as:

  o The firetube syngas cooler is much smaller and less expensive than a radiant section. E-Gas can use a firetube boiler because the two-stage design reduces the gas temperature (slurry quench) and drops the syngas temperature into a range where a radiant cooler is not needed.

  o The firetube syngas cooler sits next to the gasifier instead of above or below it, which reduces the height of the main gasifier structure. The E-Gas proprietary slag removal system, used instead of lock hoppers below the gasifier, also contributes to the lower structure height.

The TOC of the GEE gasifier is about 4 percent greater than CoP and Shell is about 16 percent higher.

Exhibit 3-102 Plant Capital Cost for IGCC Cases
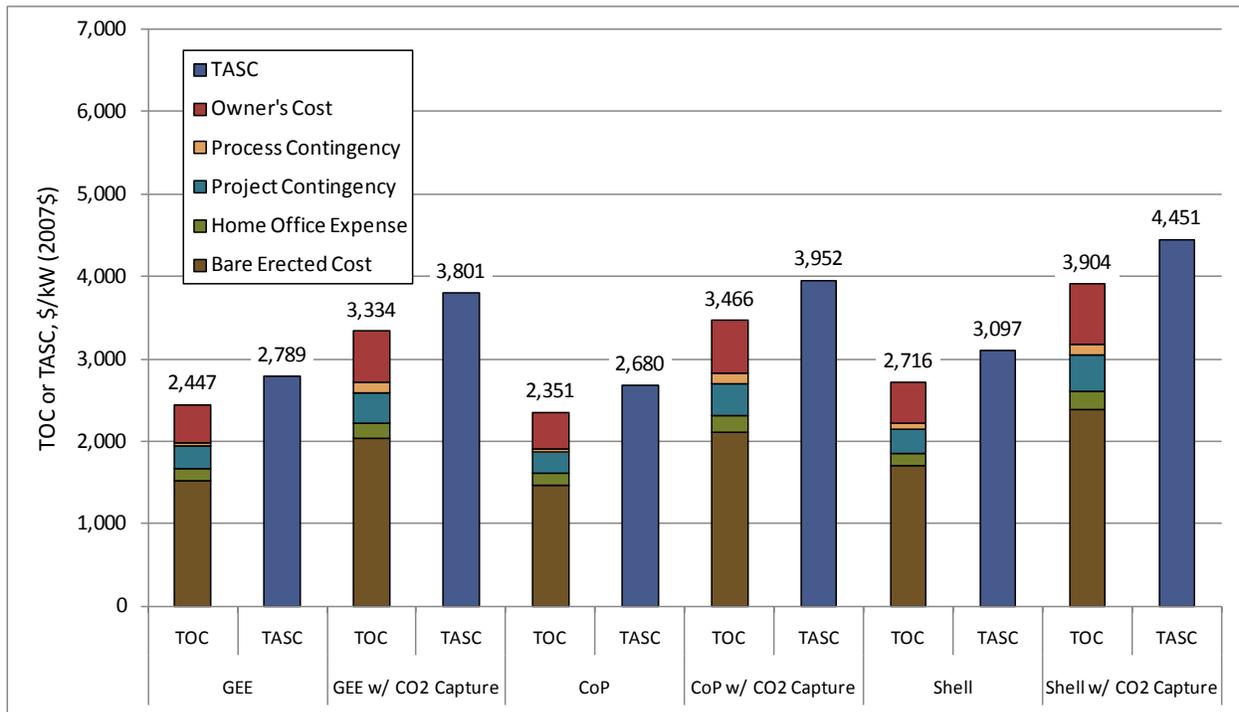
- The GEE gasifier is the low cost technology in the CO_2 capture cases, with CoP about 4 percent higher and Shell about 17 percent higher. The greatest uncertainty in all of the capital cost estimates is for the Shell capture case, which is based on a water quench process that has been proposed by Shell in a patent application [63]. However, to date there have been no commercial applications of this configuration.

- The ASU cost represents on average 12 percent of the TOC (range from 10.5-12.9 percent). The ASU cost includes oxygen and nitrogen compression, and in the non-capture cases, also includes the cost of the CT extraction air heat exchanger. With nitrogen dilution used to the maximum extent possible, nitrogen compression costs are significant.

- The TOC premium for adding CO_2 capture averages 42 percent ($3,568/kW versus $2,504/kW).

The COE is shown for the IGCC cases in Exhibit 3-103.

Exhibit 3-103 COE for IGCC Cases
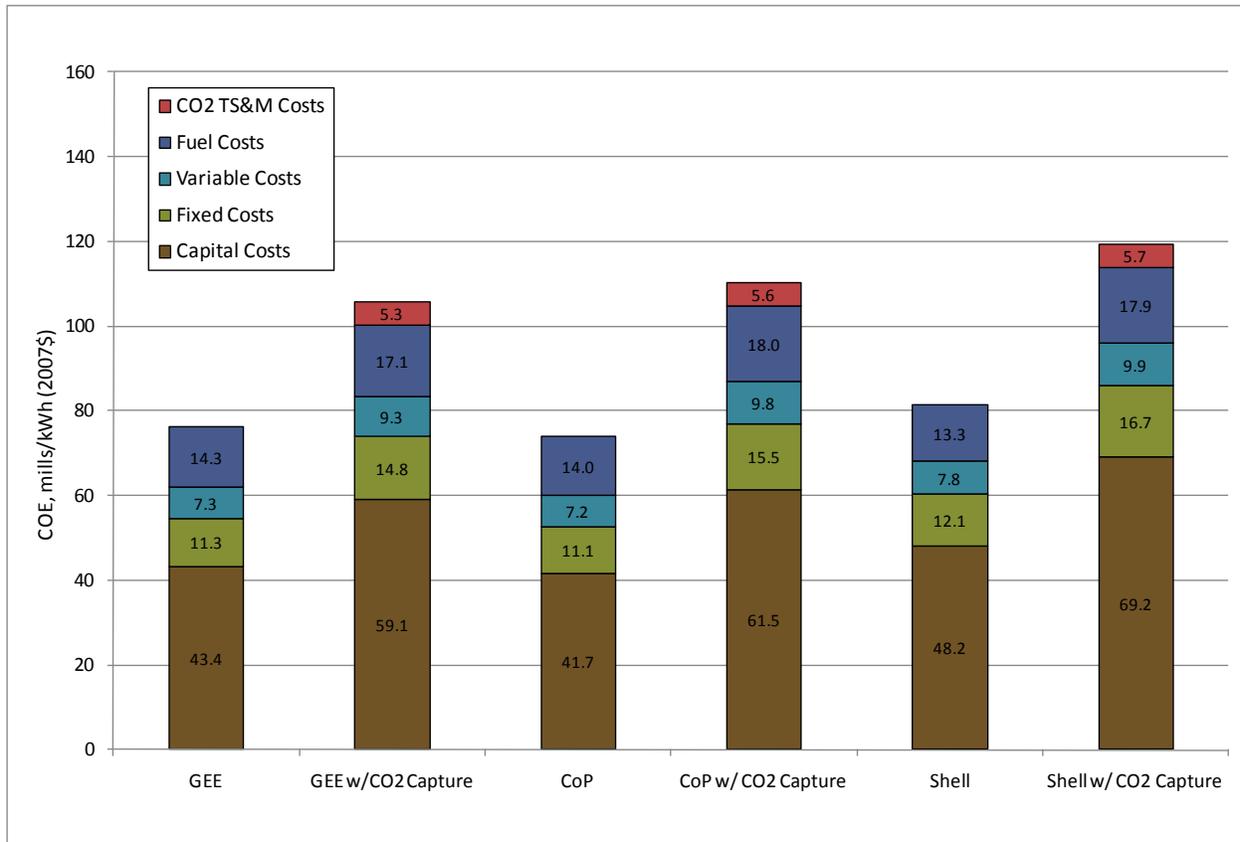
The following observations can be made:

- The COE is dominated by capital costs, at least 56 percent of the total in all cases.

- In the non-capture cases the CoP gasifier has the lowest COE, but the differential with Shell is reduced (compared to the TOC) primarily because of the higher efficiency of the Shell gasifier. The Shell COE is 10 percent higher than CoP (compared to 16 percent higher TOC). The GEE gasifier COE is about 3 percent higher than CoP.

- In the capture cases the variation in COE is small, however the order of the GEE and CoP gasifiers is reversed. The range is from 105.7 mills/kWh for GEE to 119.5 mills/kWh for Shell with CoP intermediate at 110.4 mills/kWh. The COE CO_2 capture premium for the IGCC cases averages 45 percent (range of 39 to 49 percent).

- The CO_2 TS&M COE component comprises less than 5.5 percent of the total COE in all capture cases.

The effect of CF and coal price on COE is shown in Exhibit 3-104 and Exhibit 3-105, respectively.

The assumption implicit in Exhibit 3-104 is that each gasifier technology can achieve a CF of up to 90 percent with no additional capital equipment. The cost differential between technologies decreases as CF increases. At low CF the capital cost differential is more magnified and the spread between technologies increases slightly.

Exhibit 3-104 Capacity Factor Sensitivity of IGCC Cases
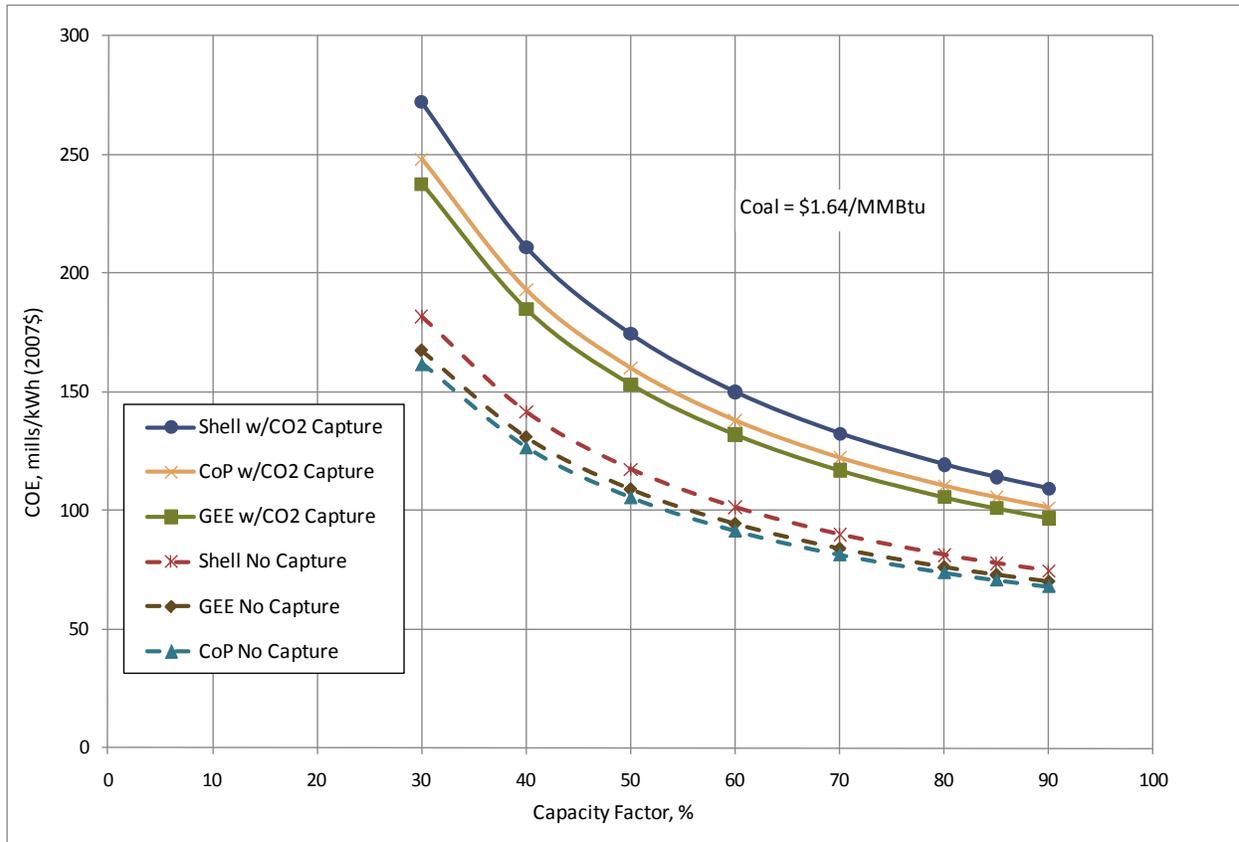
COE is relatively insensitive to fuel costs for the IGCC cases as shown in Exhibit 3-105. A tripling of coal price from 1 to $3/MMBtu results in an average COE increase of only about 19-25 percent for all cases.

As presented in Section 2.4 the cost of CO_2 capture was calculated as an avoided cost. The results for the IGCC CO_2 capture cases are shown in Exhibit 3-106. The first year cost of CO_2 avoided using each analogous IGCC non-capture technology as the reference averages $52.9/tonne ($48/ton) with a range of $43-$61.7/tonne ($39-$56/ton). The cost of CO_2 avoided is higher when using SC PC without CO_2 capture as the technology reference. Avoided costs average $75/tonne ($68/ton) with a range of $66.1-$86/tonne ($60-$78/ton). The avoided cost is elevated because SC PC without capture has a significantly lower COE than any IGCC technology.

Exhibit 3-105 Coal Price Sensitivity of IGCC Cases
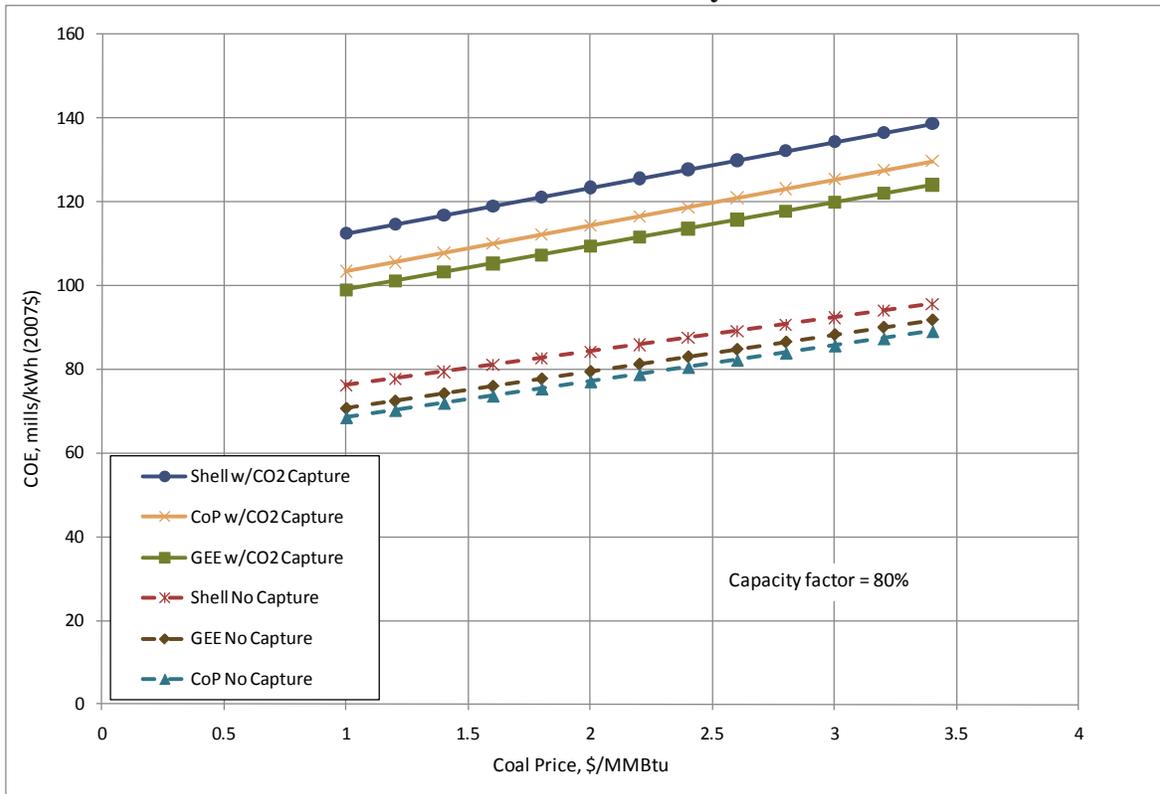
Exhibit 3-106 Cost of CO₂ Avoided in IGCC Cases
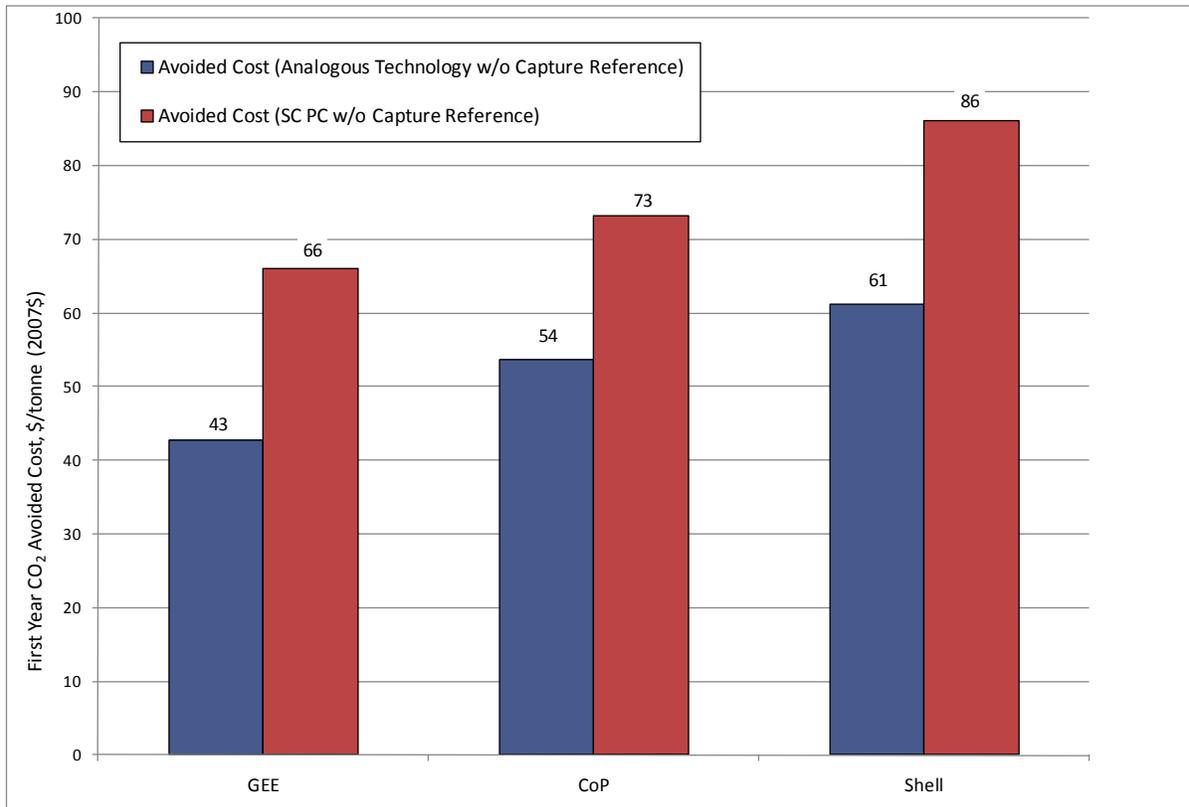
The following observations can be made regarding plant performance:

- In the non-carbon capture cases the dry fed Shell gasifier has the highest net plant efficiency (42.1 percent), followed by the two-stage CoP slurry fed gasifier (39.7 percent) and the single-stage GEE gasifier (39.0 percent). The absolute values of the GEE and CoP gasifiers are close to the reported values per the vendors [59, 60]. The Shell efficiency is slightly lower than reported by the vendor in other recent presentations [62].

- In the CO_2 capture cases the efficiency of the three gasifiers ranges from 31.0 to 32.6 percent.

- The dry fed Shell gasifier experiences the largest energy penalty (25.9 relative percent) primarily because addition of the steam required for the WGS reaction is provided as quench water to reduce the syngas temperature from 899°C (1,650°F) to 399°C (750°F). Quench to 399°C (750°F) reduces the amount of heat recovered in the syngas cooler relative to the non-capture case where syngas recycle reduces the temperature to only 1,093°C (2,000°F) prior to the cooler. The CO_2 capture scheme used in this study for the Shell process is similar to one described in a recent Shell patent application [63].

- The CoP process experiences the second largest energy penalty (21.9 relative percent) primarily because, like the Shell case, a significant amount of water must be added to the syngas for the SGS reactions.

- The energy penalty for the GEE gasifier with CO_2 capture is 16.3 relative percent. The smaller energy penalty results from the large amount of water already in the syngas from the quench step prior to SGS. While the quench limits the efficiency in the non-capture case, it is the primary reason that the net efficiency is slightly greater than CoP and Shell in the CO_2 capture case.

- The assumed carbon conversion efficiency in this study for the three gasifiers results in differing amount of carbon in the slag. Exhibit 3-107 shows carbon conversion and slag carbon content. CO_2 capture efficiency is reported based on the amount of carbon entering the system with the coal less the carbon exiting the gasifier with the slag.

Exhibit 3-107 Carbon Conversion Efficiency and Slag Carbon Content

Gasifier Vendor	Carbon Conversion, %	Slag Carbon Content, wt%
GEE	98.0	11.62
CoP	99.2	5.00
Shell	99.5	3.18

- Particulate emissions and Hg emissions are essentially the same for all six IGCC cases. The environmental target for particulate emissions is 0.0071 lb/MMBtu, and it was assumed that the combination of particulate control used by each technology could meet this limit. Similarly, the carbon beds used for mercury control were uniformly assumed to achieve 95 percent removal. The small variation in Hg emissions is due to a similar small variation in coal feed rate among the six cases. In all cases the Hg emissions are substantially below the NSPS requirement of 20 x 10^{-6} lb/MWh. Had 90 percent been

chosen for the Hg removal efficiency, all six cases would still have had emissions less than half of the NSPS limit.

- Based on vendor data, it was assumed that the advanced F class turbine would achieve 15 ppmv NOx emissions at 15 percent O_2 for both "standard" syngas in the non-capture cases and for high hydrogen syngas in the CO_2 capture cases. The NOx emissions are slightly lower in the three capture cases (compared to non-capture) because of the lower syngas volume generated in high hydrogen syngas cases.

- The environmental target for SO_2 emissions is 0.0128 lb/MMBtu. Vendor quotes confirmed that each of the AGR processes, Selexol, refrigerated MDEA and Sulfinol-M, could meet the limit. CoP E-Gas has the highest SO_2 emissions (0.005 kg/GJ (0.012 lb/MMBtu)) of the six IGCC cases because refrigerated MDEA has the lowest H_2S removal efficiency of the AGR technologies. The two-stage Selexol process used for each of the CO_2 capture cases resulted in lower SO_2 emissions because the unit was designed to meet the CO_2 removal requirement.

Water withdrawal, process discharge, and water consumption, all normalized by net output, are presented in Exhibit 3-108. The following observations can be made:

- Raw water usage for all cases is dominated by cooling tower makeup requirements, which accounts for 79-87 percent of raw water usage in non-capture cases and 73-75 percent in CO_2 capture cases.

- Normalized water withdrawal for the GEE non-capture case is 9 percent higher than the CoP non-capture case and 15 percent higher than the Shell non-capture case primarily because of the large quench water requirement. However, because much of the quench water is subsequently recovered as condensate as the syngas is cooled, the raw water consumption of the GEE process is only 9 percent higher than CoP and 13 percent higher than Shell.

- The Shell non-capture case has the lowest normalized water withdrawal, but is approximately equal to CoP in normalized raw water consumption because very little water is available to recover for internal recycle in the Shell system. The GEE normalized raw water consumption is slightly higher than CoP and Shell primarily because the larger steam turbine output leads to higher cooling tower makeup requirements.

- The normalized water withdrawal for the three CO_2 capture cases varies by only 6 percent from the highest to the lowest. The variation between cases is small because each technology requires approximately the same amount of water in the syngas prior to the shift reactors. The difference in technologies is where and how the water is introduced. Much of the water is introduced in the quench sections of the GEE and Shell cases while steam is added in the CoP case.

- The normalized raw water consumption in the CO_2 capture cases also shows little variation with GEE the lowest, CoP only 3.4 percent higher and Shell about 7 percent higher.

Exhibit 3-108 Raw Water Withdrawal and Consumption in IGCC Cases
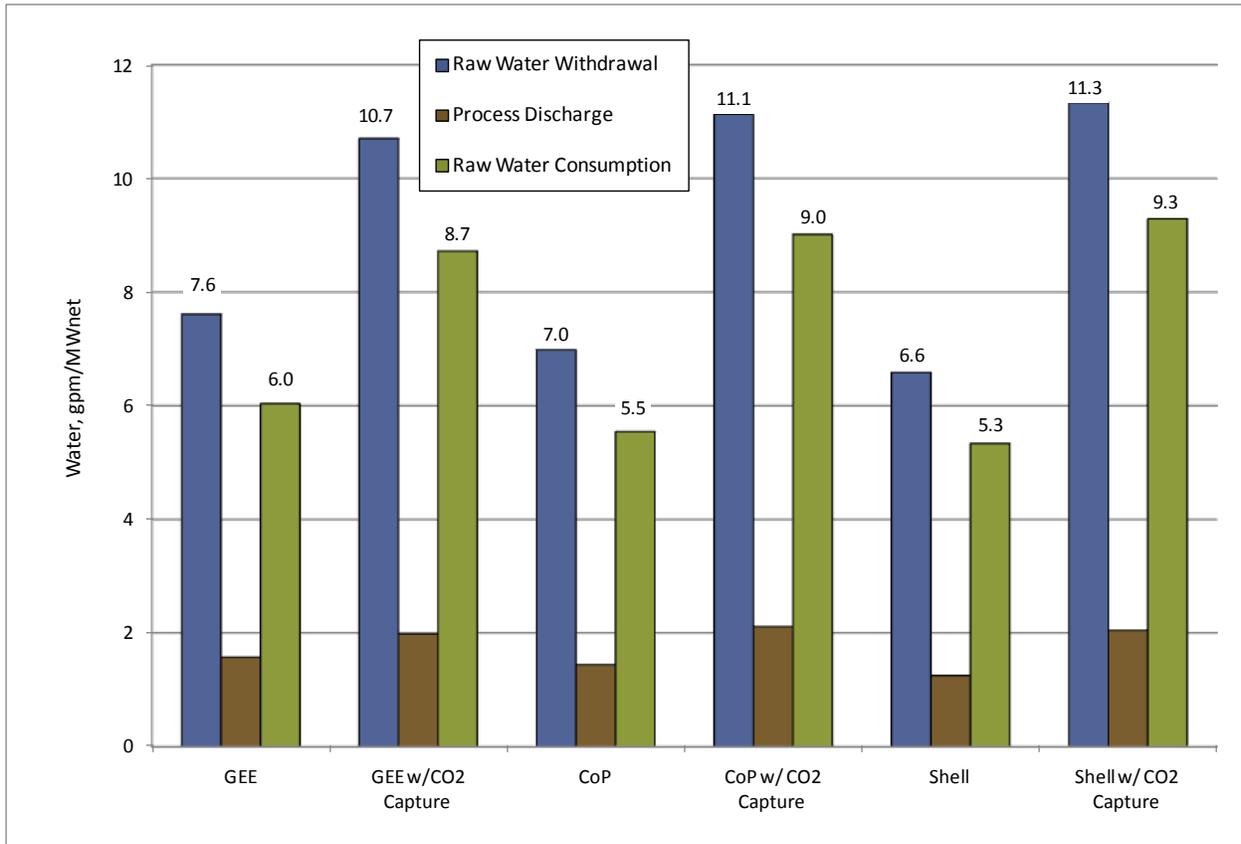
4.   PULVERIZED COAL RANKINE CYCLE PLANTS

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

The PC cases are evaluated with and without CO_2 capture on a common 550 MWe net basis. The designs that include CO_2 capture have a larger gross unit size to compensate for the higher auxiliary loads. The constant net output sizing basis is selected because it provides for a meaningful side-by-side comparison of the results. The boiler and steam turbine industry ability to match unit size to a custom specification has been commercially demonstrated enabling common net output comparison of the PC cases in this study. As discussed in Section 0, this was not possible in the IGCC cases because of the fixed output from the CT. However, the net output from the PC cases falls in the range of outputs from the IGCC cases, which average 518 MW for CO_2 capture cases and 625 MW for non-capture cases.

Steam conditions for the Rankine cycle cases were selected based on a survey of boiler and steam turbine original equipment manufacturers (OEM), who were asked for the most advanced steam conditions that they would guarantee for a commercial project in the US with subcritical and SC PC units rated at nominal 550 MWe net capacities and firing Illinois No. 6 coal [64]. Based on the OEM responses, the following single-reheat steam conditions were selected for the study:

  ➢ For subcritical cases (9 and 10) – 16.5 MPa/566°C/566°C (2,400 psig/1,050°F/1,050°F)

  ➢ For SC cases (11 and 12) – 24.1 MPa/593°C/593°C (3,500 psig/1,100°F/1,100°F)

While the current DOE program for the ultra SC cycle materials development targets 732°C/760°C (1,350ºF/1,400ºF) at 34.5 MPa (5,000 psi) cycle conditions to be available by 2015, and a similar Thermie program in the European Union (EU) has targeted 700°C/720°C (1,292ºF/1,328ºF) at about 29.0 MPa (4,200 psi) [65], steam temperature selection for boilers depends upon fuel corrosiveness. Most of the contacted OEMs were of the opinion that the steam conditions in this range would be limited to low sulfur coal applications (such as PRB). Their primary concern is that elevated temperature operation while firing high sulfur coal (such as Illinois No. 6) would result in an exponential increase of the material wastage rates of the highest temperature portions of the superheater and RH due to coal ash corrosion, requiring pressure parts replacement outages approximately every 10 or 15 years. This cost would offset the value of fuel savings and emissions reduction due to the higher efficiency. The availability/reliability of the more exotic materials required to support the elevated temperature environment for high sulfur/chlorine applications, while extensively demonstrated in the laboratory [66], has not been commercially demonstrated. In addition, the three most recently built SC units in North America have steam cycles similar to this study's design basis, namely Genesee Phase 3 in Canada, which started operations in 2004 (25.0 MPa/570°C/568°C [3,625 psia/1,058°F/1,054°F]), Council Bluffs 4 in the United States, which started operation in 2007 (25.4 MPa/566°C/593°C [3,690 psia/1,050°F/1,100°F]), and Oak Creek 1 and 2, which are currently under construction (24.1 MPa/566°C [3,500 psig/1,050°F]).

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

4.1 PC COMMON PROCESS AREAS

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

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

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

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

4.1.2   Steam Generator and Ancillaries

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

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

It is assumed for the purposes of this study that the power plant is designed to be operated as a base-loaded unit but with some consideration for daily or weekly cycling.

The combustion systems for both subcritical and SC steam conditions are equipped with LNBs and OFA. 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 includes the following for both subcritical and SC PCs:

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

The steam generator operates as follows:

Feedwater and Steam

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

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

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

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

Air and Combustion Products

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

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

Fuel Feed

The crushed Illinois No. 6 bituminous coal is fed through feeders to each of the mills (pulverizers), where its size is reduced to approximately 72 percent passing 200 mesh and less than 0.5 percent remaining on 50 mesh [67]. The PC exits each mill via the coal piping and is distributed to the coal nozzles in the furnace walls using air supplied by the PA fans.

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

Burners

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

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

<u>Air Preheaters</u>

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

<u>Soot Blowers</u>

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

4.1.3 NO$_x$ Control System

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 LNBs and the introduction of staged OFA in the boiler. The LNBs and OFA reduce the emissions to about 0.5 lb/MMBtu.

The second measure taken to reduce the NOx emissions is the installation of an SCR system prior to the air heater. SCR uses ammonia and a catalyst to reduce NOx to N_2 and H_2O. The SCR system consists of three subsystems: reactor vessel, ammonia storage and injection, and gas flow control. The SCR system is designed for 86 percent reduction with 2 ppmv ammonia slip at the end of the catalyst life. This, along with the LNBs, 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.

Selective non-catalytic reduction (SNCR) was considered for this application. However, with the installation of the LNBs and OFA system, the boiler exhaust gas contains relatively small amounts of NOx, which makes removal of the quantity of NOx with SNCR to reach the emissions limit of 0.07 lb/MMBtu difficult. SNCR works better in applications that contain medium to high quantities of NOx and require removal efficiencies in the range of 40 to 60 percent. SCR, because of the catalyst used in the reaction, can achieve higher efficiencies with lower concentrations of NOx.

<u>SCR Operation Description</u>

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 FG 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 FG 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.

4.1.4   Particulate Control

The fabric filter (or baghouse) consists of two separate single-stage, in-line, multi-compartment units. Each unit is of high (0.9-1.5 m/min [3-5 ft/min]) air-to-cloth ratio design with a pulse-jet on-line cleaning system. The ash is collected on the outside of the bags, which are supported by steel cages. The dust cake is removed by a pulse of compressed air. The bag material is polyphenylensulfide (PPS) with intrinsic Teflon Polytetrafluoroethylene (PTFE) coating [68]. 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.

4.1.5   Mercury Removal

Mercury removal is based on a coal Hg content of 0.15 ppmd. The basis for the coal Hg concentration was discussed in Section 2.4. The combination of pollution control technologies used in the PC plants, SCR, fabric filters and FGD, result in significant 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 is assumed to be 90 percent for this combination of control technologies as described in Section 2.4. Co-benefit capture alone is sufficient to meet current NSPS mercury limits so no activated carbon injection is included in the PC cases.

4.1.6   Flue Gas Desulfurization

The FGD system is a wet limestone forced oxidation positive pressure absorber non-reheat unit, with wet-stack, and gypsum production. The function of the FGD system is to scrub the boiler exhaust gases to remove the SO_2 prior to release to the environment, or entering into the Carbon Dioxide Removal (CDR) facility. Sulfur removal efficiency is 98 percent in the FGD unit for all cases. For Cases 10 and 12 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 (HSS) during the CO_2 absorption process. The CDR unit includes a polishing scrubber to reduce the FG SO_2 concentration from about 44 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 (Cases 9 and 11) or to the CDR process inlet (Cases 10 and 12). The system description is divided into three sections:

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

Reagent Preparation System

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

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

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

FGD Scrubber

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

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

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

This FGD system is designed for wet stack operation. Scrubber bypass or reheat, which may be utilized at some older facilities to ensure the exhaust gas temperature is above the saturation temperature, is not employed in this reference plant design because new scrubbers have improved mist eliminator efficiency, and detailed flow modeling of the flue interior enables the placement of gutters and drains to intercept moisture that may be present and convey it to a drain. Consequently, raising the exhaust gas temperature above the FGD discharge temperature of 57°C (135°F) (non-CO_2 capture cases) or 32°C (89°F) (CO_2 capture cases) is not necessary.

Byproduct Dewatering

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

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

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

Hydrocyclones

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

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

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

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

Horizontal Vacuum Belt Filters

The secondary dewatering system consists of horizontal vacuum belt filters. The pre-concentrated gypsum slurry (50 wt%) is pumped to an overflow pan through which the slurry flows onto the vacuum belt. As the vacuum is pulled, a layer of cake is formed. The cake is

dewatered to approximately 90 wt% solids as the belt travels to the discharge. At the discharge end of the filter, the filter cloth is turned over a roller where the solids are dislodged from the filter cloth. This cake falls through a chute onto the pile prior to the final byproduct uses. The required vacuum is provided by a vacuum pump. The filtrate is collected in a filtrate tank that provides surge volume for use of the filtrate in grinding the limestone. Filtrate that is not used for limestone slurry preparation is returned to the absorber.

4.1.7   Carbon Dioxide Recovery Facility

A Carbon Dioxide Recovery (CDR) facility is used in Cases 10 and 12 to remove 90 percent of the CO_2 in the flue gas exiting the FGD unit, purify it, and compress it to a SC condition. The flue gas exiting the FGD unit contains about 1 percent more CO_2 than the raw flue gas because of the CO_2 liberated from the limestone in the FGD absorber vessel. The CDR is comprised of the flue gas supply, 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 10 and 12 is based on the Fluor Econamine FG Plus[SM] technology [69, 70]. A typical flowsheet is shown in Exhibit 4-1. The Econamine FG Plus process uses a formulation of MEA and a proprietary corrosion inhibitor to recover CO_2 from the flue gas. This process is designed to recover high-purity CO_2 from LP streams that contain oxygen, such as flue gas from coal-fired power plants, GT exhaust gas, and other waste gases. The Econamine process used in this study differs from previous studies, including the 2003 IEA study, [71] 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 greatly reduced

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) [72].

Exhibit 4-1 Fluor Econamine FG Plus^{SM} Typical Flow Diagram
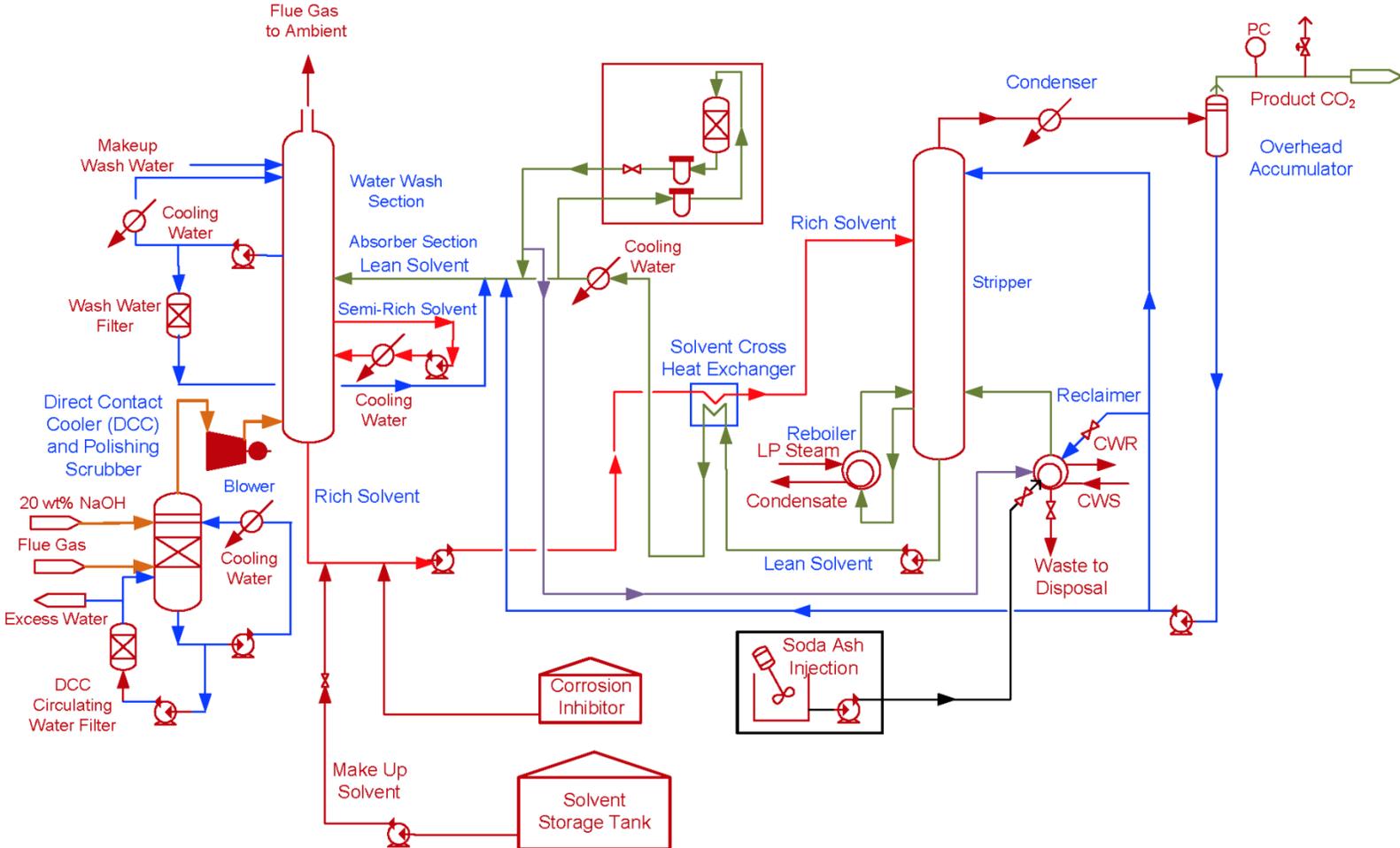
SO$_2$ Polishing and FG Cooling and Supply

To minimize the accumulation of HSS, 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 75 percent 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 flue gas temperature to below the adiabatic saturation temperature resulting in a reduction of the flue gas moisture content. Flue gas is cooled beyond the CO$_2$ absorption process requirements to 32°C (90°F) to account for the subsequent 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 FG 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 CWS 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 CDR facility in the two PC capture cases range from 1,173,350-1,286,900 lpm (310,000-340,000 gpm), which greatly exceeds the PC plant cooling water requirement of 643,450-757,000 lpm (170,000-200,000 gpm).

CO$_2$ Absorption Section

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. 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 section, absorbs the CO$_2$ from the FG and leaves the bottom of the absorber with the absorbed CO$_2$. The FG Plus process also includes solvent intercooling. The semi-rich solvent is extracted from the column, cooled using cooling water, and returned to the absorber section just below the extraction point. The CO$_2$ carrying capacity of the solvent is increased at lower temperature, which reduces the solvent circulation rate.

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, cooled by the Water Wash Cooler, and recirculated to the top of the CO_2 Absorber. The wash water level is maintained by wash water makeup.

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 Lean/Rich Cross 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 Lean Solvent Pump to the Lean Solvent Cooler. A slipstream of the lean solvent is then sent through the Amine Filter Package to prevent buildup of contaminants in the solution. The filtered lean solvent is mixed with the remaining lean solvent from the Lean Solvent Cooler and sent 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 Stripper and routed to the Reboiler where the rich solvent is heated by steam, stripping the CO_2 from the solution. Steam is provided from the crossover pipe between the IP and LP sections of the steam turbine and is 0.5 MPa (74 psia) and 152°C (306°F) for the two PC cases. The hot wet vapor from the top of the stripper containing CO_2, steam, and solvent vapor, is partially condensed in the Reflux Condenser by cross exchanging the hot wet vapor with cooling water. The partially condensed stream then flows to the Reflux Drum where the vapor and liquid are separated. The uncondensed CO_2-rich gas is then delivered to the CO_2 product compressor. The condensed liquid from the Reflux Drum is pumped via the Reflux Pump where a portion of condensed overhead liquid is combined with the lean solvent entering 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 Reclaimer

The low temperature reclaimer technology is a recent development for the FG Plus technology. A small slipstream of the lean solvent is fed to the Solvent Reclaimer for the removal of high-boiling nonvolatile impurities including HSS, volatile acids and iron products from the circulating solvent solution. Reclaiming occurs in two steps, the first is an ion-exchange process. There is a small amount of degradation products that cannot be removed via ion-exchange, and a second atmospheric pressure reclaiming process is used to remove the degradation products. 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 for disposal. The quantity of spent solvent is greatly reduced from the previously used thermal reclaimer systems.

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. Steam condensate from the Solvent Stripper Reboilers is also collected in the Solvent Reboiler

Condensate Drum and returned to the steam cycle between BFW heaters 4 and 5 via the Solvent Reboiler Condensate Pumps.

Corrosion Inhibitor System

A proprietary corrosion inhibitor is intermittently injected into the CO_2 Absorber rich solvent bottoms outlet line. This additive 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 4-2.

Exhibit 4-2 CO_2 Compressor Interstage Pressures

Stage	Outlet Pressure, MPa (psia)
1	0.36 (52)
2	0.78 (113)
3	1.71 (248)
4	3.76 (545)
5	8.27 (1,200)
6	15.3 (2,215)

Power consumption for this large compressor was estimated assuming a polytropic efficiency of 86 percent and a mechanical efficiency of 98 percent for all stages. 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 -40°C (-40°F) with triethylene glycol. The virtually moisture-free SC CO_2 stream is delivered to the plant battery limit as sequestration ready. CO_2 TS&M costs were estimated and included in LCOE and COE using the methodology described in Section 2.7.

Several alternatives to rejecting the heat of CO_2 compression to cooling water were investigated in a separate study [73]. The first alternative consisted of using a portion of the heat to pre-heat BFW while the remaining heat was still rejected to cooling water. This configuration resulted in an increase in efficiency of 0.3 percentage points (absolute). The second alternative modified the CO_2 compression intercooling configuration to enable integration into a LiBr-H_2O absorption refrigeration system, where water is the refrigerant. In the CO_2 compression section, the single intercooler between each compression stage was replaced with one kettle reboiler and two counter current shell and tube heat exchangers. The kettle reboiler acts as the generator that rejects heat from CO_2 compression to the LiBr-H_2O solution to enable the separation of the refrigerant from the brine solution. The second heat exchanger rejects heat to the cooling water. The evaporator heat exchanger acts as the refrigerator and cools the CO_2 compression stream by vaporizing the refrigerant. Only five stages of CO_2 compression were necessary for Approach 2. The compression ratios were increased from the reference cases to create a compressor outlet

temperature of at least 200°F to maintain a temperature gradient of 10°F in the kettle reboiler. This configuration resulted in an efficiency increase of 0.1 percentage points (absolute).

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

4.1.8   Power Generation

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

For the subcritical cases, the steam turbine is a tandem compound type, consisting of HP-IP-two LP (double flow) sections enclosed in three casings, designed for condensing single reheat operation, and equipped with non-automatic extractions and four-flow exhaust. The turbine drives a hydrogen-cooled generator. The turbine has DC motor-operated lube oil pumps, and main lube oil pumps, which are driven off the turbine shaft [74]. The exhaust pressure is 50.8 cm (2 in) Hg in the single pressure condenser. There are seven extraction points. The condenser is two-shell, transverse, single pressure with divided waterbox for each shell.

The steam-turbine generator systems for the SC plants are similar in design to the subcritical systems. The differences include steam cycle conditions and 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 LP steam seal system. The generator stator is cooled with a CL water system consisting of circulating pumps, shell and tube or plate and frame type heat exchangers, filters, and deionizers, all skid-mounted. The generator rotor is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft.

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

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

4.1.9   Balance of Plant

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

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

Feedwater

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

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

The deaerator is a horizontal, spray tray type with internal direct contact stainless steel (SS) vent condenser and storage tank. The boiler feed pump turbine is driven by main steam up to 60 percent plant load. Above 60 percent load, extraction from the IP turbine exhaust (1.05 MPa/395°C [153 psig/743°F]) 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 FW heater 7.

Extraction Steam

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

➤ 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

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

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

Circulating Water System

It is assumed that the plant is serviced by a public water facility and has access to groundwater for use as makeup cooling water with minimal pretreatment. All filtration and treatment of the circulating water are conducted on site. A mechanical draft, wood frame, counter-flow cooling tower is provided for the circulating water heat sink. Two 50 percent CWPs are provided. The CWS 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 CL system. Plate and frame heat exchangers with circulating water as the cooling medium are provided. This system provides cooling water to the lube oil coolers, turbine generator, boiler feed pumps, etc. All pumps, vacuum breakers, air release valves, instruments, controls, etc. are included for a complete operable system.

The CDR system in Cases 10 and 12 requires a substantial amount of cooling water that is provided by the PC plant CWS. The additional cooling load imposed by the CDR is reflected in the significantly larger CWPs 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, air heater and economizer hopper

collectors, and bottom ash hoppers to the hydrobins (for bottom ash) and truck filling stations (for fly ash). The system is designed to support short-term operation at the 5 percent OP/VWO condition (16 hours) and long-term operation at the 100 percent guarantee point (90 days or more).

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

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.

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

4.1.10 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.

4.1.11 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.

4.2 SUBCRITICAL PC CASES

This section contains an evaluation of plant designs for Cases 9 and 10, which are based on a subcritical PC plant with a nominal net output of 550 MWe. Both plants use a single reheat 16.5 MPa/566°C/566°C (2400 psig/1050°F/1050°F) cycle. The only difference between the two plants is that Case 10 includes CO_2 capture while Case 9 does not.

The balance of Section 4.2 is organized as follows:

- Process and System Description provides an overview of the technology operation as applied to Case 9. The systems that are common to all PC cases were covered in Section 4.1 and only features that are unique to Case 9 are discussed further in this section.

- Key Assumptions is a summary of study and modeling assumptions relevant to Cases 9 and 10.

- Sparing Philosophy is provided for both Cases 9 and 10.

- Performance Results provides the main modeling results from Case 9, including the performance summary, environmental performance, carbon/sulfur balances, water balance, mass and energy balance diagrams and energy balance table.

- Equipment List provides an itemized list of major equipment for Case 9 with account codes that correspond to the cost accounts in the Cost Estimates section.

- Cost Estimates provides a summary of capital and operating costs for Case 9.

- Process and System Description, Performance Results, Equipment List and Cost Estimates are discussed for Case 10.

4.2.1 Process Description

In this section the subcritical PC process without CO_2 capture is described. The system description follows the BFD in Exhibit 4-3 and stream numbers reference the same Exhibit. The tables in Exhibit 4-4 provide process data for the numbered streams in the BFD.

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

FG exits the boiler through the SCR reactor (stream 10) and is cooled to 169°C (337°F) in the combustion air preheater before passing through a fabric filter for particulate removal (stream 12). An ID fan increases the FG temperature to 181°C (357°F) and provides the motive force for the FG (stream 13) to pass through the FGD unit. FGD inputs and outputs include makeup water (stream 15), oxidation air (stream 16), limestone slurry (stream 14) and product gypsum (stream 17). The clean, saturated FG exiting the FGD unit (stream 18) passes to the plant stack and is discharged to atmosphere.

Exhibit 4-3 Case 9 Block Flow Diagram, Subcritical Unit without CO$_2$ Capture
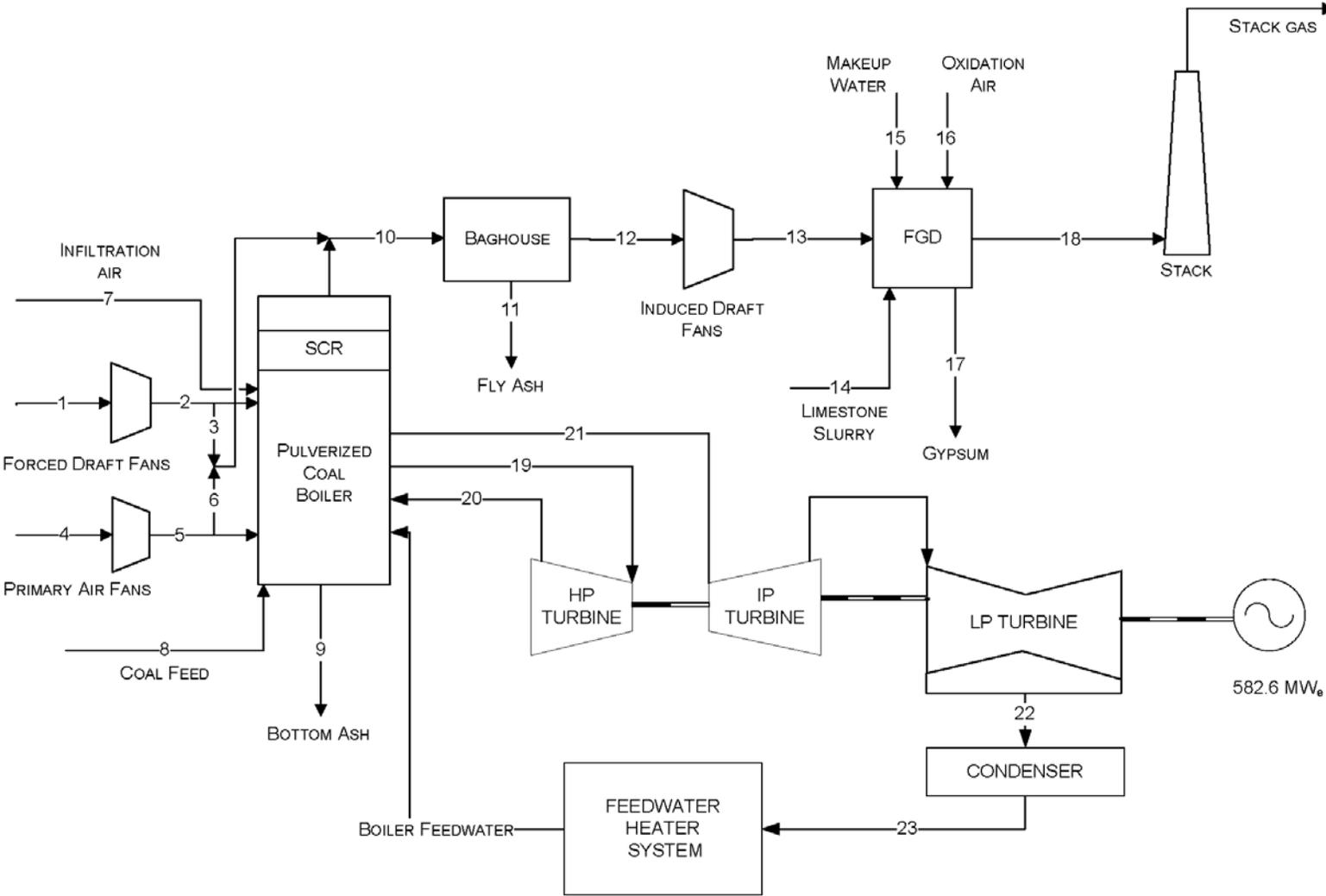
Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Exhibit 4-4 Case 9 Stream Table, Subcritical Unit without CO₂ Capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087	0.0000	0.0087
CO₂	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1447	0.0000	0.1447
H₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H₂O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0868	0.0000	0.0868
N₂	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7325	0.0000	0.7325
O₂	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0250	0.0000	0.0250
SO₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021
Total	1.0000	1.0000	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)	51,817	51,817	1,535	15,918	15,918	2,191	1,195	0	0	72,904	0	72,904
V-L Flowrate (kg/hr)	1,495,285	1,495,285	44,287	459,336	459,336	63,217	34,480	0	0	2,168,255	0	2,168,255
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	198,391	3,848	15,390	15,390	0
Temperature (°C)	15	19	19	15	25	25	15	15	15	169	15	169
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10
Enthalpy (kJ/kg)^A	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	327.06	---	308.70
Density (kg/m³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	0.8	---	0.8
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	29.741	---	29.741
V-L Flowrate (lb$_{mol}$/hr)	114,237	114,237	3,383	35,092	35,092	4,830	2,634	0	0	160,726	0	160,726
V-L Flowrate (lb/hr)	3,296,540	3,296,540	97,637	1,012,663	1,012,663	139,369	76,015	0	0	4,780,183	0	4,780,183
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	437,378	8,482	33,929	33,929	0
Temperature (°F)	59	66	66	59	78	78	59	59	59	337	59	337
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.7	14.4	14.7	14.2
Enthalpy (Btu/lb)^A	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	140.6	---	132.7
Density (lb/ft³)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	0.050	---	0.049
A - Reference conditions are 32.02 F & 0.089 PSIA												

Exhibit 4-4 Case 9 Stream Table, Subcritical Unit without CO₂ Capture (Continued)

	13	14	15	16	17	18	19	20	21	22	23
V-L Mole Fraction											
Ar	0.0087	0.0000	0.0000	0.0128	0.0000	0.0082	0.0000	0.0000	0.0000	0.0000	0.0000
CO₂	0.1447	0.0000	0.0000	0.0005	0.0004	0.1350	0.0000	0.0000	0.0000	0.0000	0.0000
H₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H₂O	0.0868	1.0000	1.0000	0.0062	0.9995	0.1517	1.0000	1.0000	1.0000	1.0000	1.0000
N₂	0.7325	0.0000	0.0000	0.7506	0.0000	0.6808	0.0000	0.0000	0.0000	0.0000	0.0000
O₂	0.0250	0.0000	0.0000	0.2300	0.0000	0.0243	0.0000	0.0000	0.0000	0.0000	0.0000
SO₂	0.0021	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_mol/hr)	72,904	2,530	10,275	775	188	79,300	93,366	85,851	85,851	76,805	77,739
V-L Flowrate (kg/hr)	2,168,255	45,571	185,106	22,509	3,383	2,287,903	1,682,017	1,546,628	1,546,628	1,383,663	1,400,483
Solids Flowrate (kg/hr)	0	19,690	0	0	30,645	0	0	0	0	0	0
Temperature (°C)	181	15	15	167	57	57	566	363	566	38	39
Pressure (MPa, abs)	0.11	0.10	0.10	0.31	0.10	0.10	16.65	4.28	3.90	0.01	1.69
Enthalpy (kJ/kg)^A	320.79	---	-46.80	177.65	---	297.69	3,472.33	3,120.82	3,594.06	2,016.19	165.31
Density (kg/m³)	0.8	---	1,003.1	2.5	---	1.1	47.7	15.7	10.3	0.1	993.3
V-L Molecular Weight	29.741	---	18.015	29.029	---	28.851	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_mol/hr)	160,726	5,577	22,652	1,709	414	174,826	205,837	189,269	189,269	169,326	171,384
V-L Flowrate (lb/hr)	4,780,183	100,467	408,090	49,625	7,459	5,043,963	3,708,212	3,409,730	3,409,730	3,050,454	3,087,536
Solids Flowrate (lb/hr)	0	43,410	0	0	67,561	0	0	0	0	0	0
Temperature (°F)	357	59	59	333	135	135	1,050	686	1,050	101	103
Pressure (psia)	15.3	15.0	14.7	45.0	14.8	14.8	2,415.0	620.5	565.5	1.0	245.0
Enthalpy (Btu/lb)^A	137.9	---	-20.1	76.4	---	128.0	1,492.8	1,341.7	1,545.2	866.8	71.1
Density (lb/ft³)	0.052	---	62.622	0.154	---	0.067	2.977	0.983	0.643	0.004	62.010

4.2.2 Key System Assumptions

System assumptions for Cases 9 and 10, subcritical PC with and without CO_2 capture, are compiled in Exhibit 4-5.

Exhibit 4-5 Subcritical PC Plant Study Configuration Matrix

	Case 9 w/o CO_2 Capture	Case 10 w/CO_2 Capture
Steam Cycle, MPa/°C/°C (psig/°F/°F)	16.5/566/566 (2400/1050/1050)	16.5/566/566 (2400/1050/1050)
Coal	Illinois No. 6	Illinois No. 6
Condenser pressure, mm Hg (in Hg)	50.8 (2)	50.8 (2)
Boiler Efficiency, %	88	88
Cooling water to condenser, °C (ºF)	16 (60)	16 (60)
Cooling water from condenser, °C (ºF)	27 (80)	27 (80)
Stack temperature, °C (°F)	57 (135)	32 (89)
SO_2 Control	Wet Limestone Forced Oxidation	Wet Limestone Forced Oxidation
FGD Efficiency, % (A)	98	98 (B, C)
NOx Control	LNB w/OFA and SCR	LNB w/OFA and SCR
SCR Efficiency, % (A)	86	86
Ammonia Slip (end of catalyst life), ppmv	2	2
Particulate Control	Fabric Filter	Fabric Filter
Fabric Filter efficiency, % (A)	99.8	99.8
Ash Distribution, Fly/Bottom	80% / 20%	80% / 20%
Mercury Control	Co-benefit Capture	Co-benefit Capture
Mercury removal efficiency, % (A)	90	90
CO_2 Control	N/A	Econamine
Overall CO_2 Capture (A)	N/A	90.2%
CO_2 Sequestration	N/A	Off-site Saline Formation

A. Removal efficiencies are based on the FG content
B. An SO_2 polishing step is included to meet more stringent SOx content limits in the FG (< 10 ppmv) to reduce formation of amine HSS during the CO_2 absorption process
C. SO_2 exiting the post-FGD polishing step is absorbed in the CO_2 capture process making stack emissions negligible

Balance of Plant – Cases 9 and 10

The balance of plant assumptions are common to all cases and are presented in Exhibit 4-6.

Exhibit 4-6 Balance of Plant Assumptions

Cooling system	Recirculating Wet Cooling Tower
Fuel and Other storage	
Coal	30 days
Ash	30 days
Gypsum	30 days
Limestone	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 GT generators	24,000 volt
Grid Interconnection voltage	345 kV
Water and Waste Water	
Makeup Water	The water supply is 50 percent from a local POTW and 50 percent from groundwater, and is assumed to be in sufficient quantities to meet plant makeup requirements. Makeup for potable, process, and DI water is drawn from municipal sources.
Process Wastewater	Storm water that contacts equipment surfaces is collected and treated for discharge through a permitted discharge.
Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant is sized for 5.68 cubic meters per day (1,500 gallons per day)
Water Discharge	Most of the process wastewater is recycled to the cooling tower basin. Blowdown will be treated for chloride and metals, and discharged.

4.2.3 Sparing Philosophy

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

- One dry-bottom, wall-fired PC subcritical boiler (1 x 100%)

- Two SCR reactors (2 x 50%)

- Two single-stage, in-line, multi-compartment fabric filters (2 x 50%)

- One wet limestone forced oxidation positive pressure absorber (1 x 100%)

- One steam turbine (1 x 100%)

- For Case 10 only, two parallel Econamine CO_2 absorption systems, with each system consisting of two absorbers, strippers and ancillary equipment (2 x 50%)

4.2.4 Case 9 Performance Results

The plant produces a net output of 550 MWe at a net plant efficiency of 36.8 percent (HHV basis). Overall performance for the plant is summarized in Exhibit 4-7, which includes auxiliary power requirements.

Exhibit 4-7 Case 9 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Steam Turbine Power	582,600
TOTAL (STEAM TURBINE) POWER, kWe	**582,600**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	450
Pulverizers	2,970
Sorbent Handling & Reagent Preparation	950
Ash Handling	570
Primary Air Fans	1,400
Forced Draft Fans	1,780
Induced Draft Fans	7,540
SCR	50
Baghouse	70
Wet FGD	3,180
Miscellaneous Balance of Plant[2,3]	2,000
Steam Turbine Auxiliaries	400
Condensate Pumps	890
Circulating Water Pump	5,250
Ground Water Pumps	530
Cooling Tower Fans	2,720
Transformer Losses	1,830
TOTAL AUXILIARIES, kWe	**32,580**
NET POWER, kWe	**550,020**
Net Plant Efficiency (HHV)	36.8%
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,788 (9,277)
CONDENSER COOLING DUTY 10^6 kJ/hr (10^6 Btu/hr)	2,566 (2,432)
CONSUMABLES	
As-Received Coal Feed, kg/hr (lb/hr)	198,391 (437,378)
Limestone Sorbent Feed, kg/hr (lb/hr)	19,691 (43,410)
Thermal Input, kWt[1]	1,495,379
Raw Water Withdrawal, m^3/min (gpm)	22.3 (5,896)
Raw Water Consumption, m^3/min (gpm)	17.7 (4,680)

1. HHV of As-Received Illinois No. 6 coal is 27,135 kJ/kg (11,666 Btu/lb)
2. Boiler feed pumps are turbine driven
3. Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, and PM were presented in Section 2.4. A summary of the plant air emissions for Case 9 is presented in Exhibit 4-8.

Exhibit 4-8 Case 9 Air Emissions

	kg/GJ (lb/10^6 Btu)	Tonne/year (ton/year) 85% CF	kg/MWh (lb/MWh)
SO_2	0.037 (0.086)	1,479 (1,630)	0.341 (.75)
NOx	0.030 (0.070)	1,206 (1,330)	0.278 (.613)
Particulates	0.006 (0.0130)	224 (247)	0.052 (.114)
Hg	4.91E-7 (1.14E-6)	0.020 (0.022)	4.54E-6 (1.00E-5)
CO_2	87.5 (203.5)	3,507,605 (3,866,472)	809 (1,783)
CO_2[1]			856 (1,888)

[1] CO_2 emissions based on net power instead of gross power

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

NOx emissions are controlled to about 0.5 lb/10^6 Btu through the use of LNBs and OFA. An SCR unit then further reduces the NOx concentration by 86 percent to 0.07 lb/10^6 Btu.

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.8 percent.

Co-benefit capture results in a 90 percent reduction of mercury emissions.

CO_2 emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 4-9. The carbon input to the plant consists of carbon in the coal, carbon in the air, and carbon in the limestone reagent used in the FGD. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant mostly as CO_2 through the stack but also leaves as gypsum.

Exhibit 4-9 Case 9 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	126,464 (278,805)	Stack Gas	128,563 (283,434)
Air (CO$_2$)	275 (607)	FGD Product	174 (383)
FGD Reagent	1,998 (4,405)		
Total	128,737 (283,817)	Total	128,737 (283,817)

Exhibit 4-10 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum and sulfur emitted in the stack gas.

Exhibit 4-10 Case 9 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	4,973 (10,963)	Stack Gas	99 (219)
		FGD Product	4,873 (10,743)
Total	4,973 (10,963)	Total	4,973 (10,963)

Exhibit 4-11 shows the water balance for Case 9. Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is re-used as internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a surface-water source for use in the plant and was assumed to be provided 50 percent by a POTW and 50 percent from groundwater. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for any and all purposes, such as FDG makeup, BFW makeup, and cooling tower makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source.

Exhibit 4-11 Case 9 Water Balance

Water Use	Water Demand, m³/min (gpm)	Internal Recycle, m³/min (gpm)	Raw Water Withdrawal, m³/min (gpm)	Process Water Discharge, m³/min (gpm)	Raw Water Consumption, m³/min (gpm)
FGD Makeup	3.9 (1,017)	0.0 (0)	3.9 (1,017)	0.0 (0)	3.9 (1,017)
BFW Makeup	0.3 (74)	0.0 (0)	0.3 (74)	0.0 (0)	0.3 (74)
Cooling Tower	20.5 (5,404)	2.3 (600)	18.2 (4,804)	4.6 (1,215)	13.6 (3,589)
Total	**24.6 (6,495)**	**2.3 (600)**	**22.3 (5,896)**	**4.6 (1,215)**	**17.7 (4,680)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the Case 9 PC boiler, the FGD unit, and steam cycle as shown in Exhibit 4-12 and Exhibit 4-13.

An overall plant energy balance is provided in tabular form in Exhibit 4-14. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-7) is calculated by multiplying the power out by a generator efficiency of 98.6 percent.

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Exhibit 4-12 Case 9 Heat and Mass Balance, Subcritical PC Boiler without CO₂ Capture

MAKE-UP WATER

408,090 W
59.0 T
14.7 P

15

OXIDATION AIR

49,625 W
332.9 T
45.0 P

16

Baghouse

12

4,780,183 W
337.0 T
14.2 P
132.7 H

ID FANS

13

357.4 T
15.3 P
137.9 H

FGD

ASH

11

33,929 W

143,877 W
59.0 T
15.0 P

14

75,020 W
135.0 T
14.8 P

17

5,043,963 W
135.0 T
14.8 P
128.0 H

18

LIMESTONE SLURRY   GYPSUM

4,814,113 W
337.0 T
14.4 P
140.6 H

10

19

Throttle Steam
To HP Turbine

3,708,212 W
1,050.0 T
2,415.0 P
1,492.8 H

21

Single Reheat
To IP Turbine

3,409,730 W
1,050.0 T
565.5 P
1,545.2 H

AMMONIA

SCR

INFILTRATION AIR

7

76,015 W
59.0 T
14.7 P
13.0 H

66.4 T
15.3 P
14.8 H

Pulverized Coal Boiler

20

3,409,730 W
686.0 T
620.5 P
1,341.7 H

AIR

1

3,296,540 W
59.0 T
14.7 P
13.0 H

FORCED DRAFT FANS

2

3

6

Single Reheat
Extraction from
HP Turbine

STACK

AIR

4

1,012,663 W
59.0 T
14.7 P
13.0 H

PRIMARY AIR FANS

5

77.8 T
16.1 P
17.5 H

9

437,378 W
COAL

8

ASH
8,482 W

From Feedwater
Heaters

3,708,212 W
484.4 T
3,100.5 P
469.5 H

PLANT PERFORMANCE SUMMARY

Gross Plant Power:	583 MWe
Auxiliary Load:	33 MWe
Net Plant Power:	550 MWe
Net Plant Efficiency, HHV:	36.8%
Net Plant Heat Rate:	9,277 BTU/KWe

NETL

DOE/NETL

SC PC PLANT
CASE 9

HEAT AND MATERIAL FLOW DIAGRAM

BITUMINOUS BASELINE STUDY
CASE 9
SUBCRITICAL PULVERIZED COAL
BOILER AND GAS CLEANUP SYSTEMS

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Exhibit 4-13 Case 9 Heat and Mass Balance, Subcritical Steam Cycle
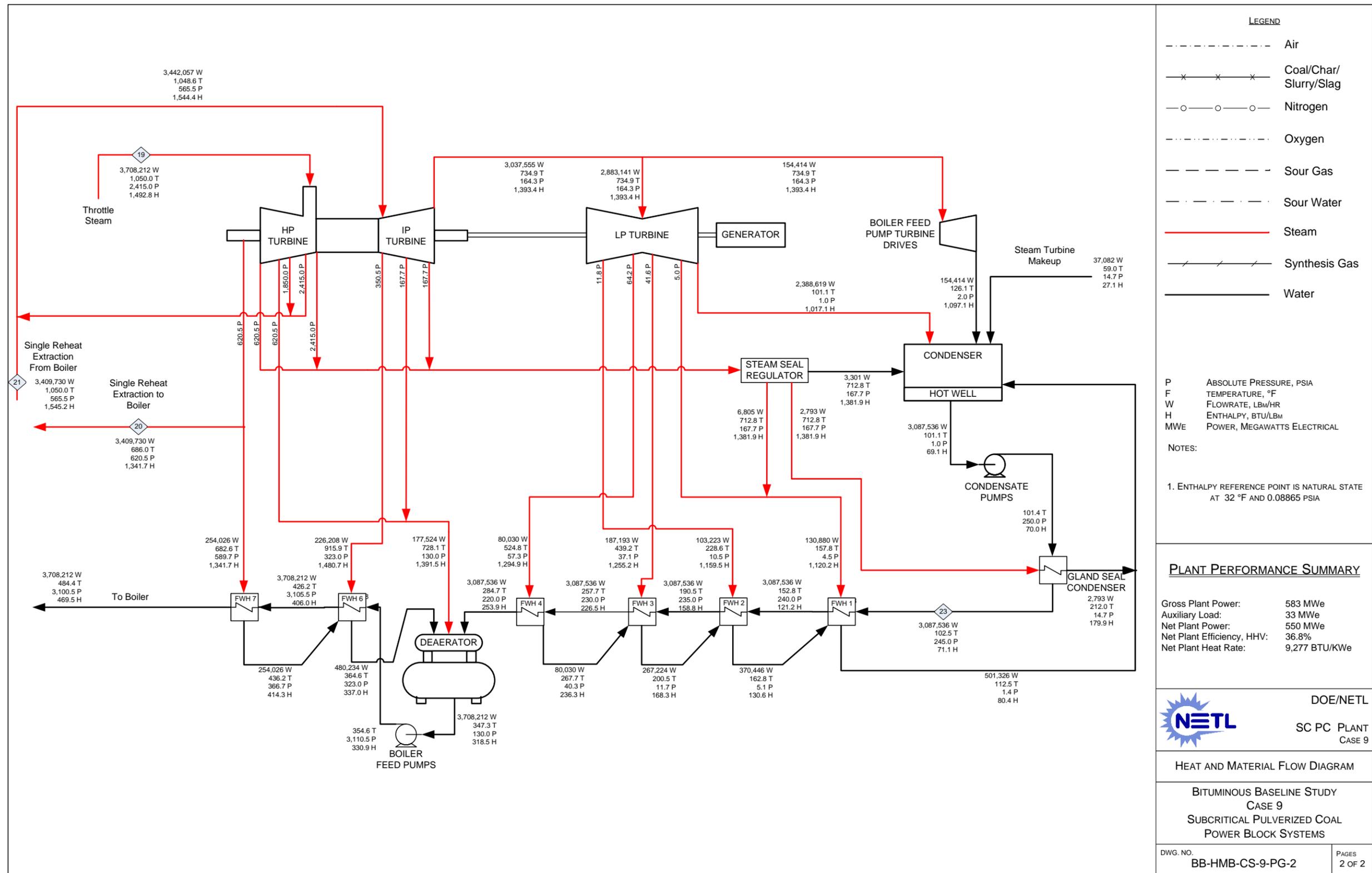
Exhibit 4-14 Case 9 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	5,383 (5,102)	4.5 (4.3)		5,388 (5,107)
Air		60.1 (57.0)		60.1 (57.0)
Raw Water Withdrawal		84.0 (79.6)		84.0 (79.6)
Limestone		0.22 (0.21)		0.22 (0.21)
Auxiliary Power			117 (111)	117 (111)
Totals	**5,383 (5,102)**	**148.8 (141.1)**	**117 (111)**	**5,649 (5,355)**
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash		0.5 (0.4)		0.5 (0.4)
Fly Ash + FGD Ash		1.9 (1.8)		1.9 (1.8)
Flue Gas		681 (646)		681 (646)
Condenser		2,566 (2,432)		2,566 (2,432)
Cooling Tower Blowdown		34.2 (32.4)		34.2 (32.4)
Process Losses*		*269 (255)*		*269 (255)*
Power			2,097 (1,988)	2,097 (1,988)
Totals	**0 (0)**	**3,552 (3,367)**	**2,097 (1,988)**	**5,649 (5,355)**

* Process losses are estimated to match the heat input to the plant. Process losses include losses from: turbines, gas cooling, etc.

4.2.5 Case 9 – Major Equipment List

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

ACCOUNT 1   COAL AND SORBENT HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	45 tonne (50 ton)	2	1
9	Feeder	Vibratory	163 tonne/hr (180 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	327 tonne/hr (360 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	163 tonne (180 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	327 tonne/hr (360 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	327 tonne/hr (360 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	726 tonne (800 ton)	3	0
19	Limestone Truck Unloading Hopper	N/A	36 tonne (40 ton)	1	0
20	Limestone Feeder	Belt	82 tonne/hr (90 tph)	1	0
21	Limestone Conveyor No. L1	Belt	82 tonne/hr (90 tph)	1	0
22	Limestone Reclaim Hopper	N/A	18 tonne (20 ton)	1	0
23	Limestone Reclaim Feeder	Belt	64 tonne/hr (70 tph)	1	0
24	Limestone Conveyor No. L2	Belt	64 tonne/hr (70 tph)	1	0
25	Limestone Day Bin	w/ actuator	263 tonne (290 ton)	2	0

ACCOUNT 2 COAL AND SORBENT PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	36 tonne/hr (40 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	36 tonne/hr (40 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	22 tonne/hr (24 tph)	1	1
4	Limestone Ball Mill	Rotary	22 tonne/hr (24 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	83,279 liters (22,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,401 lpm @ 12m H_2O (370 gpm @ 40 ft H_2O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5 cyclone bank	341 lpm (90 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	469,391 liters (124,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	984 lpm @ 9m H_2O (260 gpm @ 30 ft H_2O)	1	1

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,112,911 liters (294,000 gal)	2	0
2	Condensate Pumps	Vertical canned	25,741 lpm @ 213 m H2O (6,800 gpm @ 700 ft H2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	1,850,203 kg/hr (4,079,000 lb/hr), 5 min. tank	1	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	31,040 lpm @ 2,530 m H2O (8,200 gpm @ 8,300 ft H2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	9,085 lpm @ 2,530 m H2O (2,400 gpm @ 8,300 ft H2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	771,107 kg/hr (1,700,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	771,107 kg/hr (1,700,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	771,107 kg/hr (1,700,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	771,107 kg/hr (1,700,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	1,850,657 kg/hr (4,080,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	1,850,657 kg/hr (4,080,000 lb/hr)	1	0
12	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
13	Fuel Oil System	No. 2 fuel oil for light off	1,135,624 liter (300,000 gal)	1	0
14	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
15	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
16	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
17	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 30 m H2O (5,500 gpm @ 100 ft H2O)	2	1
18	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H2O (1,000 gpm @ 290 ft H2O)	1	1
19	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H2O (700 gpm @ 210 ft H2O)	1	1
20	Raw Water Pumps	Stainless steel, single suction	6,549 lpm @ 18 m H2O (1,730 gpm @ 60 ft H2O)	2	1
21	Ground Water Pumps	Stainless steel, single suction	2,612 lpm @ 268 m H2O (690 gpm @ 880 ft H2O)	5	1
22	Filtered Water Pumps	Stainless steel, single suction	2,006 lpm @ 49 m H2O (530 gpm @ 160 ft H2O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	1,919,204 liter (507,000 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	606 lpm (160 gpm)	1	1
25	Liquid Waste Treatment System	--	10 years, 24-hour storm	1	0

ACCOUNT 4 BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Subcritical, drum wall-fired, low NOx burners, overfire air	1,850,657 kg/hr steam @ 17.9 MPa/574°C/574°C (4,080,000 lb/hr steam @ 2,600 psig/1,065°F/1,065°F)	1	0
2	Primary Air Fan	Centrifugal	252,651 kg/hr, 3,446 m3/min @ 123 cm WG (557,000 lb/hr, 121,700 acfm @ 48 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	822,363 kg/hr, 11,222 m3/min @ 47 cm WG (1,813,000 lb/hr, 396,300 acfm @ 19 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,192,494 kg/hr, 25,114 m3/min @ 91 cm WG (2,629,000 lb/hr, 886,900 acfm @ 36 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	2,385,896 kg/hr (5,260,000 lb/hr)	2	0
6	SCR Catalyst	--	--	3	0
7	Dilution Air Blower	Centrifugal	142 m3/min @ 108 cm WG (5,000 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	155,202 liter (41,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	30 lpm @ 91 m H2O (8 gpm @ 300 ft H2O)	2	1

ACCOUNT 5   FLUE GAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,192,494 kg/hr (2,629,000 lb/hr) 99.8% efficiency	2	0
2	Absorber Module	Counter-current open spray	47,912 m3/min (1,692,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	166,558 lpm @ 64 m H2O (44,000 gpm @ 210 ft H2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	4,240 lpm (1,120 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	84 m3/min @ 0.3 MPa (2,960 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,060 lpm (280 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	34 tonne/hr (37 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	644 lpm @ 12 m H2O (170 gpm @ 40 ft H2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	416,395 lpm (110,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	3,407 lpm @ 21 m H2O (900 gpm @ 70 ft H2O)	1	1

ACCOUNT 6   COMBUSTION TURBINE/ACCESSORIES

N/A

ACCOUNT 7   HRSG, DUCTING & STACK

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

ACCOUNT 8   STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	613 MW 16.5 MPa/566°C/566°C (2400.3 psig/ 1050°F/1050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	680 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,828 GJ/hr (2,680 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9   COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	526,200 lpm @ 30 m (139,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 2944 GJ/hr (2790 MMBtu/hr) heat duty	1	0

ACCOUNT 10   ASH/SPENT SORBENT RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	--	--	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	--	--	2	0
3	Clinker Grinder	--	4.5 tonne/hr (5 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	--	--	6	0
5	Hydroejectors	--	--	12	
6	Economizer /Pyrites Transfer Tank	--	--	1	0
7	Ash Sluice Pumps	Vertical, wet pit	151 lpm @ 17 m H2O (40 gpm @ 56 ft H2O)	1	1
8	Ash Seal Water Pumps	Vertical, wet pit	7,571 lpm @ 9 m H2O (2000 gpm @ 28 ft H2O)	1	1
9	Hydrobins	--	151 lpm (40 gpm)	1	1
10	Baghouse Hopper (part of baghouse scope of supply)	--	--	24	0
11	Air Heater Hopper (part of boiler scope of supply)	--	--	10	0
12	Air Blower	--	16 m3/min @ 0.2 MPa (550 scfm @ 24 psi)	1	1
13	Fly Ash Silo	Reinforced concrete	998 tonne (1,100 ton)	2	0
14	Slide Gate Valves	--	--	2	0
15	Unloader	--	--	1	0
16	Telescoping Unloading Chute	--	91 tonne/hr (100 tph)	1	0

ACCOUNT 11   ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 650 MVA, 3-ph, 60 Hz	1	0
2	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 34 MVA, 3-ph, 60 Hz	1	1
3	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 5 MVA, 3-ph, 60 Hz	1	1
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
5	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
6	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
7	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12   INSTRUMENTATION AND CONTROL

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

4.2.6   Case 9 – Cost Estimating

The cost estimating methodology was described previously in Section 2.6. Exhibit 4-15 shows the total plant capital cost summary organized by cost account and Exhibit 4-16 shows a more detailed breakdown of the capital costs along with owner's costs, TOC and TASC. Exhibit 4-17 shows the initial and annual O&M costs.

The estimated TOC of the subcritical PC boiler with no CO_2 capture is \$1,996/kW. No process contingency is included in this case because all elements of the technology are commercially proven. The project contingency is 9.1 percent of the TOC. The COE is 59.4 mills/kWh.

Exhibit 4-15 Case 9 Total Plant Cost Summary

	Client:	USDOE/NETL							Report Date	2010-Jan-14		
	Project:	Bituminous Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case 9 - 1x550 MWnet SubCritical PC										
	Plant Size:	550 MW,net	Estimate Type:	Conceptual				Cost Base (Jun)	2007	($x1000)		

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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$17,068	$4,598	$10,229	$0	$0	$31,895	$2,862	$0	$5,214	$39,970	$73
2	COAL & SORBENT PREP & FEED	$11,494	$665	$2,916	$0	$0	$15,075	$1,321	$0	$2,459	$18,855	$34
3	FEEDWATER & MISC. BOP SYSTEMS	$39,707	$0	$19,059	$0	$0	$58,766	$5,391	$0	$10,518	$74,674	$136
4	PC BOILER											
4.1	PC Boiler & Accessories	$134,824	$0	$86,704	$0	$0	$221,527	$21,582	$0	$24,311	$267,420	$486
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
4.4-4.9	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4	$134,824	$0	$86,704	$0	$0	$221,527	$21,582	$0	$24,311	$267,420	$486
5	FLUE GAS CLEANUP	$83,799	$0	$28,488	$0	$0	$112,287	$10,747	$0	$12,303	$135,338	$246
5B	CO$_2$ REMOVAL & COMPRESSION	$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
6.2-6.9	Combustion Turbine Other	$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
7.2-7.9	HRSG Accessories, Ductwork and Stack	$18,242	$1,049	$12,388	$0	$0	$31,679	$2,908	$0	$4,516	$39,104	$71
	SUBTOTAL 7	$18,242	$1,049	$12,388	$0	$0	$31,679	$2,908	$0	$4,516	$39,104	$71
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$49,912	$0	$6,242	$0	$0	$56,154	$5,380	$0	$6,153	$67,688	$123
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$23,604	$1,092	$12,657	$0	$0	$37,354	$3,294	$0	$5,668	$46,316	$84
	SUBTOTAL 8	$73,516	$1,092	$18,900	$0	$0	$93,508	$8,674	$0	$11,822	$114,004	$207
9	COOLING WATER SYSTEM	$13,230	$6,710	$12,250	$0	$0	$32,189	$3,030	$0	$4,784	$40,003	$73
10	ASH/SPENT SORBENT HANDLING SYS	$4,573	$145	$6,114	$0	$0	$10,833	$1,042	$0	$1,222	$13,096	$24
11	ACCESSORY ELECTRIC PLANT	$17,808	$6,355	$18,529	$0	$0	$42,692	$3,765	$0	$5,747	$52,203	$95
12	INSTRUMENTATION & CONTROL	$8,665	$0	$8,786	$0	$0	$17,451	$1,582	$0	$2,338	$21,371	$39
13	IMPROVEMENTS TO SITE	$2,974	$1,710	$5,995	$0	$0	$10,679	$1,054	$0	$2,347	$14,079	$26
14	BUILDINGS & STRUCTURES	$0	$23,479	$22,248	$0	$0	$45,727	$4,125	$0	$12,463	$62,315	$113
	TOTAL COST	$425,899	$45,804	$252,606	$0	$0	$724,309	$68,082	$0	$100,043	$892,433	$1,622

Exhibit 4-16 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,508	$0	$1,602	$0	$0	$5,110	$457	$0	$835	$6,402	$12
1.2	Coal Stackout & Reclaim	$4,533	$0	$1,027	$0	$0	$5,561	$487	$0	$907	$6,954	$13
1.3	Coal Conveyors	$4,215	$0	$1,016	$0	$0	$5,231	$458	$0	$853	$6,543	$12
1.4	Other Coal Handling	$1,103	$0	$235	$0	$0	$1,338	$117	$0	$218	$1,673	$3
1.5	Sorbent Receive & Unload	$140	$0	$42	$0	$0	$183	$16	$0	$30	$229	$0
1.6	Sorbent Stackout & Reclaim	$2,269	$0	$416	$0	$0	$2,685	$234	$0	$438	$3,357	$6
1.7	Sorbent Conveyors	$810	$175	$199	$0	$0	$1,183	$102	$0	$193	$1,479	$3
1.8	Other Sorbent Handling	$489	$115	$257	$0	$0	$860	$76	$0	$140	$1,077	$2
1.9	Coal & Sorbent Hnd.Foundations	$0	$4,308	$5,435	$0	$0	$9,743	$915	$0	$1,599	$12,257	$22
	SUBTOTAL 1.	$17,068	$4,598	$10,229	$0	$0	$31,895	$2,862	$0	$5,214	$39,970	$73
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$2,014	$0	$393	$0	$0	$2,407	$210	$0	$393	$3,009	$5
2.2	Coal Conveyor to Storage	$5,158	$0	$1,126	$0	$0	$6,284	$549	$0	$1,025	$7,858	$14
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	$3,857	$166	$801	$0	$0	$4,824	$420	$0	$787	$6,031	$11
2.6	Sorbent Storage & Feed	$465	$0	$178	$0	$0	$643	$57	$0	$105	$805	$1
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	$499	$419	$0	$0	$917	$85	$0	$150	$1,153	$2
	SUBTOTAL 2.	$11,494	$665	$2,916	$0	$0	$15,075	$1,321	$0	$2,459	$18,855	$34
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	Feedwater System	$16,257	$0	$5,611	$0	$0	$21,868	$1,915	$0	$3,567	$27,351	$50
3.2	Water Makeup & Pretreating	$4,751	$0	$1,529	$0	$0	$6,280	$594	$0	$1,375	$8,248	$15
3.3	Other Feedwater Subsystems	$5,318	$0	$2,248	$0	$0	$7,566	$678	$0	$1,237	$9,480	$17
3.4	Service Water Systems	$931	$0	$507	$0	$0	$1,438	$135	$0	$315	$1,888	$3
3.5	Other Boiler Plant Systems	$6,259	$0	$6,179	$0	$0	$12,438	$1,181	$0	$2,043	$15,662	$28
3.6	FO Supply Sys & Nat Gas	$256	$0	$320	$0	$0	$575	$54	$0	$94	$724	$1
3.7	Waste Treatment Equipment	$3,221	$0	$1,836	$0	$0	$5,057	$492	$0	$1,110	$6,659	$12
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$2,715	$0	$829	$0	$0	$3,544	$341	$0	$777	$4,662	$8
	SUBTOTAL 3.	$39,707	$0	$19,059	$0	$0	$58,766	$5,391	$0	$10,518	$74,674	$136
4	PC BOILER & ACCESSORIES											
4.1	PC Boiler & Accessories	$134,824	$0	$86,704	$0	$0	$221,527	$21,582	$0	$24,311	$267,420	$486
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.	$134,824	$0	$86,704	$0	$0	$221,527	$21,582	$0	$24,311	$267,420	$486

Exhibit 4-16 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	$58,362	$0	$12,564	$0	$0	$70,926	$6,762	$0	$7,769	$85,456	$155
5.2	Other FGD	$3,046	$0	$3,451	$0	$0	$6,497	$631	$0	$713	$7,840	$14
5.3	Bag House & Accessories	$16,493	$0	$10,467	$0	$0	$26,959	$2,598	$0	$2,956	$32,513	$59
5.4	Other Particulate Removal Materials	$1,116	$0	$1,194	$0	$0	$2,310	$224	$0	$253	$2,788	$5
5.5	Gypsum Dewatering System	$4,783	$0	$812	$0	$0	$5,595	$533	$0	$613	$6,741	$12
5.6	Mercury Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.9	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	$83,799	$0	$28,488	$0	$0	$112,287	$10,747	$0	$12,303	$135,338	$246
5B	CO$_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
	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	$9,097	$0	$5,845	$0	$0	$14,942	$1,303	$0	$2,437	$18,682	$34
7.4	Stack	$9,145	$0	$5,351	$0	$0	$14,496	$1,396	$0	$1,589	$17,481	$32
7.9	Duct & Stack Foundations	$0	$1,049	$1,192	$0	$0	$2,241	$210	$0	$490	$2,941	$5
	SUBTOTAL 7.	$18,242	$1,049	$12,388	$0	$0	$31,679	$2,908	$0	$4,516	$39,104	$71
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$49,912	$0	$6,242	$0	$0	$56,154	$5,380	$0	$6,153	$67,688	$123
8.2	Turbine Plant Auxiliaries	$348	$0	$746	$0	$0	$1,094	$107	$0	$120	$1,321	$2
8.3	Condenser & Auxiliaries	$7,251	$0	$2,295	$0	$0	$9,545	$913	$0	$1,046	$11,504	$21
8.4	Steam Piping	$16,005	$0	$7,891	$0	$0	$23,896	$2,008	$0	$3,886	$29,790	$54
8.9	TG Foundations	$0	$1,092	$1,726	$0	$0	$2,818	$267	$0	$617	$3,701	$7
	SUBTOTAL 8.	$73,516	$1,092	$18,900	$0	$0	$93,508	$8,674	$0	$11,822	$114,004	$207

Exhibit 4-16 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$9,783	$0	$3,046	$0	$0	$12,829	$1,227	$0	$1,406	$15,461	$28
9.2	Circulating Water Pumps	$2,033	$0	$128	$0	$0	$2,161	$182	$0	$234	$2,578	$5
9.3	Circ.Water System Auxiliaries	$531	$0	$71	$0	$0	$602	$57	$0	$66	$725	$1
9.4	Circ.Water Piping	$0	$4,210	$4,080	$0	$0	$8,290	$776	$0	$1,360	$10,427	$19
9.5	Make-up Water System	$462	$0	$618	$0	$0	$1,080	$103	$0	$177	$1,361	$2
9.6	Component Cooling Water Sys	$421	$0	$335	$0	$0	$755	$72	$0	$124	$951	$2
9.9	Circ.Water System Foundations & Structures	$0	$2,500	$3,972	$0	$0	$6,471	$612	$0	$1,417	$8,500	$15
	SUBTOTAL 9.	$13,230	$6,710	$12,250	$0	$0	$32,189	$3,030	$0	$4,784	$40,003	$73
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	$612	$0	$1,885	$0	$0	$2,497	$245	$0	$274	$3,017	$5
10.7	Ash Transport & Feed Equipment	$3,961	$0	$4,058	$0	$0	$8,019	$767	$0	$879	$9,664	$18
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$145	$171	$0	$0	$317	$30	$0	$69	$416	$1
	SUBTOTAL 10.	$4,573	$145	$6,114	$0	$0	$10,833	$1,042	$0	$1,222	$13,096	$24
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$1,602	$0	$260	$0	$0	$1,862	$173	$0	$153	$2,187	$4
11.2	Station Service Equipment	$2,904	$0	$954	$0	$0	$3,858	$361	$0	$316	$4,535	$8
11.3	Switchgear & Motor Control	$3,339	$0	$567	$0	$0	$3,906	$362	$0	$427	$4,695	$9
11.4	Conduit & Cable Tray	$0	$2,093	$7,238	$0	$0	$9,331	$903	$0	$1,535	$11,769	$21
11.5	Wire & Cable	$0	$3,950	$7,625	$0	$0	$11,575	$975	$0	$1,882	$14,432	$26
11.6	Protective Equipment	$270	$0	$918	$0	$0	$1,188	$116	$0	$130	$1,434	$3
11.7	Standby Equipment	$1,279	$0	$29	$0	$0	$1,308	$120	$0	$143	$1,571	$3
11.8	Main Power Transformers	$8,414	$0	$172	$0	$0	$8,587	$652	$0	$924	$10,162	$18
11.9	Electrical Foundations	$0	$312	$765	$0	$0	$1,077	$103	$0	$236	$1,416	$3
	SUBTOTAL 11.	$17,808	$6,355	$18,529	$0	$0	$42,692	$3,765	$0	$5,747	$52,203	$95
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	$446	$0	$267	$0	$0	$713	$67	$0	$117	$898	$2
12.7	Distributed Control System Equipment	$4,504	$0	$787	$0	$0	$5,291	$491	$0	$578	$6,360	$12
12.8	Instrument Wiring & Tubing	$2,442	$0	$4,844	$0	$0	$7,285	$621	$0	$1,186	$9,092	$17
12.9	Other I & C Equipment	$1,273	$0	$2,888	$0	$0	$4,161	$403	$0	$456	$5,021	$9
	SUBTOTAL 12.	$8,665	$0	$8,786	$0	$0	$17,451	$1,582	$0	$2,338	$21,371	$39

Exhibit 4-16 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$50	$1,000	$0	$0	$1,050	$104	$0	$231	$1,385	$3
13.2	Site Improvements	$0	$1,660	$2,061	$0	$0	$3,721	$367	$0	$818	$4,906	$9
13.3	Site Facilities	$2,974	$0	$2,933	$0	$0	$5,908	$582	$0	$1,298	$7,788	$14
	SUBTOTAL 13.	$2,974	$1,710	$5,995	$0	$0	$10,679	$1,054	$0	$2,347	$14,079	$26
14	BUILDINGS & STRUCTURES											
14.1	Boiler Building	$0	$8,519	$7,491	$0	$0	$16,010	$1,439	$0	$4,362	$21,811	$40
14.2	Turbine Building	$0	$12,310	$11,473	$0	$0	$23,784	$2,144	$0	$6,482	$32,409	$59
14.3	Administration Building	$0	$587	$621	$0	$0	$1,208	$110	$0	$329	$1,647	$3
14.4	Circulation Water Pumphouse	$0	$168	$134	$0	$0	$302	$27	$0	$82	$411	$1
14.5	Water Treatment Buildings	$0	$603	$549	$0	$0	$1,152	$104	$0	$314	$1,570	$3
14.6	Machine Shop	$0	$393	$264	$0	$0	$657	$58	$0	$179	$893	$2
14.7	Warehouse	$0	$266	$267	$0	$0	$533	$48	$0	$145	$727	$1
14.8	Other Buildings & Structures	$0	$217	$185	$0	$0	$403	$36	$0	$110	$548	$1
14.9	Waste Treating Building & Str.	$0	$416	$1,263	$0	$0	$1,680	$159	$0	$460	$2,299	$4
	SUBTOTAL 14.	$0	$23,479	$22,248	$0	$0	$45,727	$4,125	$0	$12,463	$62,315	$113
	TOTAL COST	$425,899	$45,804	$252,606	$0	$0	$724,309	$68,082	$0	$100,043	$892,433	$1,622

	Owner's Costs											
	Preproduction Costs											
	6 Months All Labor										$7,104	$13
	1 Month Maintenance Materials										$859	$2
	1 Month Non-fuel Consumables										$956	$2
	1 Month Waste Disposal										$251	$0
	25% of 1 Months Fuel Cost at 100% CF										$1,524	$3
	2% of TPC										$17,849	$32
	Total										**$28,543**	**$52**
	Inventory Capital											
	60 day supply of fuel and consumables at 100% CF										$13,824	$25
	0.5% of TPC (spare parts)										$4,462	$8
	Total										**$18,287**	**$33**
	Initial Cost for Catalyst and Chemicals										$0	$0
	Land										$900	$2
	Other Owner's Costs										$133,865	$243
	Financing Costs										$24,096	$44
	Total Overnight Costs (TOC)										**$1,098,124**	**$1,996**
	TASC Multiplier							(IOU, low-risk, 35 year)			1.134	
	Total As-Spent Cost (TASC)										**$1,245,272**	**$2,264**

Exhibit 4-17 Case 9 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun):	2007	
Case 9 - 1x550 MWnet SubCritical PC					Heat Rate-net (Btu/kWh):	9,276	
					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

Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.	Total Plant
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	$5,524,319	$10.043
Maintenance Labor Cost	$5,842,145	$10.621
Administrative & Support Labor	$2,841,616	$5.166
Property Taxes and Insurance	$17,848,664	$32.449
TOTAL FIXED OPERATING COSTS	**$32,056,744**	**$58.280**

VARIABLE OPERATING COSTS

							$/kWh-net
Maintenance Material Cost						**$8,763,218**	**$0.00214**

Consumables	Consumption Initial Fill	/Day	Unit Cost	Initial Fill Cost			
Water (/1000 gallons)	0	4,245.12	1.08	$0	$1,424,619	$0.00035
Chemicals						
MU & WT Chem.(lbs)	0	20,549	0.17	$0	$1,103,371	$0.00027
Limestone (ton)	0	521	21.63	$0	$3,496,290	$0.00085
Carbon (Mercury Removal) (lb)	0	0	1.05	$0	$0	$0.00000
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 (19% NH3) ton	0	78	129.80	$0	$3,136,289	$0.00077
Subtotal Chemicals				$0	$7,735,950	$0.00189
Other						
Supplemental Fuel (MBtu)	0	0	0.00	$0	$0	$0.00000
SCR Catalyst (m3)	w/equip.	0.33	5,775.94	$0	$592,641	$0.00014
Emission Penalties	0	0	0.00	$0	$0	$0.00000
Subtotal Other				$0	$592,641	$0.00014
Waste Disposal						
Fly Ash (ton)	0	407	16.23	$0	$2,049,540	$0.00050
Bottom Ash (ton)	0	102	16.23	$0	$512,385	$0.00013
Subtotal-Waste Disposal				$0	$2,561,926	$0.00063
By-products & Emissions						
Gypsum (tons)	0	811	0.00	$0	$0	$0.00000
Subtotal By-Products				$0	$0	$0.00000
TOTAL VARIABLE OPERATING COSTS				$0	$21,078,354	$0.00515
Fuel (ton)	0	5,248	38.18	$0	$62,175,757	$0.01518

4.2.7   Case 10 – PC Subcritical Unit with CO$_2$ Capture

The plant configuration for Case 10, subcritical PC, is the same as Case 9 with the exception that the Econamine technology was added for CO$_2$ capture. The nominal net output was maintained at 550 MW by increasing the boiler size and turbine/generator size to account for the greater auxiliary load imposed by the CDR facility. Unlike the IGCC cases where gross output was fixed by the available size of the CTs, the PC cases utilize boilers and steam turbines that can be procured at nearly any desired output making it possible to maintain a constant net output.

The process description for Case 10 is essentially the same as Case 9 with one notable exception, the addition of CO$_2$ capture. A BFD and stream tables for Case 10 are shown in Exhibit 4-18 and Exhibit 4-19, respectively. Since the CDR facility process description was provided in Section 4.1.7, it is not repeated here.

4.2.8   Case 10 Performance Results

The Case 10 modeling assumptions were presented previously in Section 4.2.2.

The plant produces a net output of 550 MW at a net plant efficiency of 26.2 percent (HHV basis). Overall plant performance is summarized in Exhibit 4-20, which includes auxiliary power requirements. The CDR facility, including CO$_2$ compression, accounts for over half of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for over 14 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility.

Exhibit 4-18 Case 10 Block Flow Diagram, Subcritical Unit with CO_2 Capture

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

Exhibit 4-19 Case 10 Stream Table, Subcritical Unit with CO$_2$ Capture

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
V-L Mole Fraction														
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000
CO$_2$	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450	0.0000	0.1450	0.1450	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$_2$O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870	0.0000	0.0870	0.0870	1.0000
N$_2$	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324	0.0000	0.7324	0.7324	0.0000
O$_2$	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247	0.0000	0.0247	0.0247	0.0000
SO$_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021	0.0021	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	1.0000	1.0000	1.0000
V-L Flowrate (kg$_{mol}$/hr)	72,691	72,691	2,163	22,330	22,330	3,063	1,680	0	0	102,289	0	102,289	102,289	3,643
V-L Flowrate (kg/hr)	2,097,642	2,097,642	62,415	644,374	644,374	88,396	48,482	0	0	3,042,405	0	3,042,405	3,042,405	65,636
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	278,956	5,410	21,640	21,640	0	0	28,403
Temperature (°C)	15	19	19	15	25	25	15	15	15	169	15	169	182	15
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.10
Enthalpy (kJ/kg)^A	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	327.39	---	308.96	322.83	---
Density (kg/m^3)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	0.8	---	0.8	0.8	---
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	29.743	---	29.743	29.743	---
V-L Flowrate (lb$_{mol}$/hr)	160,256	160,256	4,768	49,229	49,229	6,753	3,704	0	0	225,509	0	225,509	225,509	8,032
V-L Flowrate (lb/hr)	4,624,510	4,624,510	137,601	1,420,601	1,420,601	194,880	106,884	0	0	6,707,354	0	6,707,354	6,707,354	144,703
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	614,994	11,927	47,708	47,708	0	0	62,618
Temperature (°F)	59	66	66	59	78	78	59	59	59	337	59	337	360	59
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.7	14.4	14.7	14.2	15.4	15.0
Enthalpy (Btu/lb)^A	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	140.8	---	132.8	138.8	---
Density (lb/ft^3)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	0.050	---	0.049	0.052	---

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 4-19 Case 10 Stream Table, Subcritical Unit with CO2 Capture (Continued)

	15	16	17	18	19	20	21	22	23	24	25	26	27	28
V-L Mole Fraction														
Ar	0.0000	0.0128	0.0000	0.0081	0.0108	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0005	0.0004	0.1350	0.0179	0.9961	0.9985	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
H_2O	1.0000	0.0062	0.9996	0.1537	0.0383	0.0039	0.0015	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.0000	0.7506	0.0000	0.6793	0.9013	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.2300	0.0000	0.0238	0.0316	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
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)	14,732	1,049	269	111,453	83,996	13,598	13,566	48,632	48,632	131,223	121,115	121,115	60,504	61,816
V-L Flowrate (kg/hr)	265,393	30,461	4,845	3,213,261	2,366,318	597,086	596,497	876,112	876,112	2,364,021	2,181,912	2,181,912	1,089,994	1,113,634
Solids Flowrate (kg/hr)	0	0	43,806	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	181	58	58	32	21	35	296	151	566	363	566	38	39
Pressure (MPa, abs)	0.10	0.31	0.10	0.10	0.10	0.16	15.27	0.51	0.90	16.65	4.28	3.90	0.01	1.69
Enthalpy (kJ/kg)[A]	-46.80	191.62	---	301.43	93.86	19.49	-211.71	3,054.75	636.27	3,472.33	3,120.82	3,594.06	2,028.64	165.87
Density (kg/m³)	1,003.1	2.4	---	1.1	1.1	2.9	795.9	2.0	916.0	47.7	15.7	10.3	0.1	993.3
V-L Molecular Weight	18.015	29.029	---	28.831	28.172	43.908	43.971	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	32,478	2,313	593	245,711	185,179	29,979	29,907	107,214	107,214	289,297	267,012	267,012	133,388	136,281
V-L Flowrate (lb/hr)	585,092	67,154	10,682	7,084,027	5,216,839	1,316,349	1,315,051	1,931,497	1,931,497	5,211,774	4,810,293	4,810,293	2,403,024	2,455,142
Solids Flowrate (lb/hr)	0	0	96,577	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	357	136	136	89	69	95	565	304	1,050	686	1,050	101	103
Pressure (psia)	14.7	45.0	14.9	14.9	14.7	23.5	2,214.5	73.5	130.0	2,415.0	620.5	565.5	1.0	245.0
Enthalpy (Btu/lb)[A]	-20.1	82.4	---	129.6	40.4	8.4	-91.0	1,313.3	273.5	1,492.8	1,341.7	1,545.2	872.2	71.3
Density (lb/ft³)	62.622	0.149	---	0.067	0.070	0.184	49.684	0.122	57.183	2.977	0.983	0.643	0.004	62.007

Exhibit 4-20 Case 10 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Steam Turbine Power	672,700
TOTAL (STEAM TURBINE) POWER, kWe	**672,700**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	540
Pulverizers	4,180
Sorbent Handling & Reagent Preparation	1,370
Ash Handling	800
Primary Air Fans	1,960
Forced Draft Fans	2,500
Induced Draft Fans	12,080
SCR	70
Baghouse	100
Wet FGD	4,470
Econamine FG Plus Auxiliaries	22,400
CO_2 Compression	48,790
Miscellaneous Balance of Plant[2,3]	2,000
Steam Turbine Auxiliaries	400
Condensate Pumps	700
Circulating Water Pumps	11,190
Ground Water Pumps	1,020
Cooling Tower Fans	5,820
Transformer Losses	2,350
TOTAL AUXILIARIES, kWe	**122,740**
NET POWER, kWe	**549,960**
Net Plant Efficiency (HHV)	26.2%
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	13,764 (13,046)
CONDENSER COOLING DUTY 10^6 kJ/hr (10^6 Btu/hr)	**2,034 (1,928)**
CONSUMABLES	
As-Received Coal Feed, kg/hr (lb/hr)	278,956 (614,994)
Limestone Sorbent Feed, kg/hr (lb/hr)	28,404 (62,618)
Thermal Input, kWt[1]	2,102,643
Raw Water Withdrawal, m³/min (gpm)	42.5 (11,224)
Raw Water Consumption, m³/min (gpm)	32.6 (8,620)

1. HHV of As-Received Illinois No. 6 coal is 27,135 kJ/kg (11,666 Btu/lb)
2. Boiler feed pumps are turbine driven
3. Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads.

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, and PM were presented in Section 2.4. A summary of the plant air emissions for Case 10 is presented in Exhibit 4-21.

Exhibit 4-21 Case 10 Air Emissions

	kg/GJ (lb/10^6 Btu)	Tonne/year (ton/year) 85% CF	kg/MWh (lb/MWh)
SO_2	0.001 (0.002)	40 (44)	0.008 (.02)
NOx	0.030 (0.070)	1,696 (1,870)	0.339 (.747)
Particulates	0.006 (0.0130)	315 (347)	0.063 (.139)
Hg	4.91E-7 (1.14E-6)	0.028 (0.031)	5.53E-6 (1.22E-5)
CO_2	8.8 (20.4)	493,198 (543,658)	98 (217)
CO_2^{1}			120 (266)

[1] CO_2 emissions based on net power instead of gross power

SO_2 emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The SO_2 emissions are further reduced to 10 ppmv using a NaOH based polishing scrubber in the CDR facility. The remaining low concentration of SO_2 is essentially completely removed in the CDR absorber vessel resulting in very low SO_2 emissions.

NOx emissions are controlled to about 0.5 lb/10^6 Btu through the use of LNBs and OFA. An SCR unit then further reduces the NOx concentration by 86 percent to 0.07 lb/10^6 Btu.

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.8 percent.

Co-benefit capture results in a 90 percent reduction of mercury emissions.

Ninety percent of the CO_2 in the FG is removed in CDR facility.

The carbon balance for the plant is shown in Exhibit 4-22. The carbon input to the plant consists of carbon in the coal in addition to carbon in the air and limestone for the FGD. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant as CO_2 in the stack gas, carbon in the FGD product, and the captured CO_2 product. The CO_2 capture efficiency is defined by the following fraction:

1-[(Stack Gas Carbon-Air Carbon)/(Total Carbon In-Air Carbon)] or
[1-(39,853-850)/(399,230-850) *100] or
90.2 percent

Exhibit 4-22 Case 10 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	177,820 (392,026)	Stack Gas	18,077 (39,853)
Air (CO$_2$)	386 (850)	FGD Product	317 (699)
FGD Reagent	2,882 (6,354)	CO$_2$ Product	162,694 (358,679)
Total	181,088 (399,230)	Total	181,088 (399,230)

Exhibit 4-23 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur emitted in the stack gas, and sulfur removed in the polishing scrubber.

Exhibit 4-23 Case 10 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	6,992 (15,414)	FGD Product	6,852 (15,106)
		Stack Gas	3 (6)
		Econamine Polishing Scrubber/HSS	137 (302)
Total	6,992 (15,414)	Total	6,992 (15,414)

Exhibit 4-24 shows the overall water balance for the plant. The exhibit is presented in an identical manner as was for Case 9.

Exhibit 4-24 Case 10 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Withdrawal, m^3/min (gpm)	Process Water Discharge, m^3/min (gpm)	Raw Water Consumption, m^3/min (gpm)
Econamine	0.2 (39)	0.0 (0)	0.2 (39)	0.0 (0)	0.2 (39)
FGD Makeup	5.5 (1,460)	0.0 (0)	5.5 (1,460)	0.0 (0)	5.5 (1,460)
BFW Makeup	0.4 (104)	0.0 (0)	0.4 (104)	0.0 (0)	0.4 (104)
Cooling Tower	43.8 (11,580)	7.4 (1,959)	36.4 (9,621)	9.9 (2,604)	26.6 (7,017)
Total	**49.9 (13,182)**	**7.4 (1,959)**	**42.5 (11,224)**	**9.9 (2,604)**	**32.6 (8,620)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the Case 10 PC boiler, the FGD unit, CDR system and steam cycle in Exhibit 4-25 and Exhibit 4-26. An overall plant energy balance is provided in tabular form in Exhibit 4-27.

The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-20) is calculated by multiplying the power out by a generator efficiency of 98.4 percent. The Econamine process heat out stream represents heat rejected to cooling water and ultimately to ambient via the cooling tower. The same is true of the condenser heat out stream. The CO_2 compressor intercooler load is included in the Econamine process heat out stream.

Exhibit 4-25 Case 10 Heat and Mass Balance, Subcritical PC Boiler with CO₂ Capture
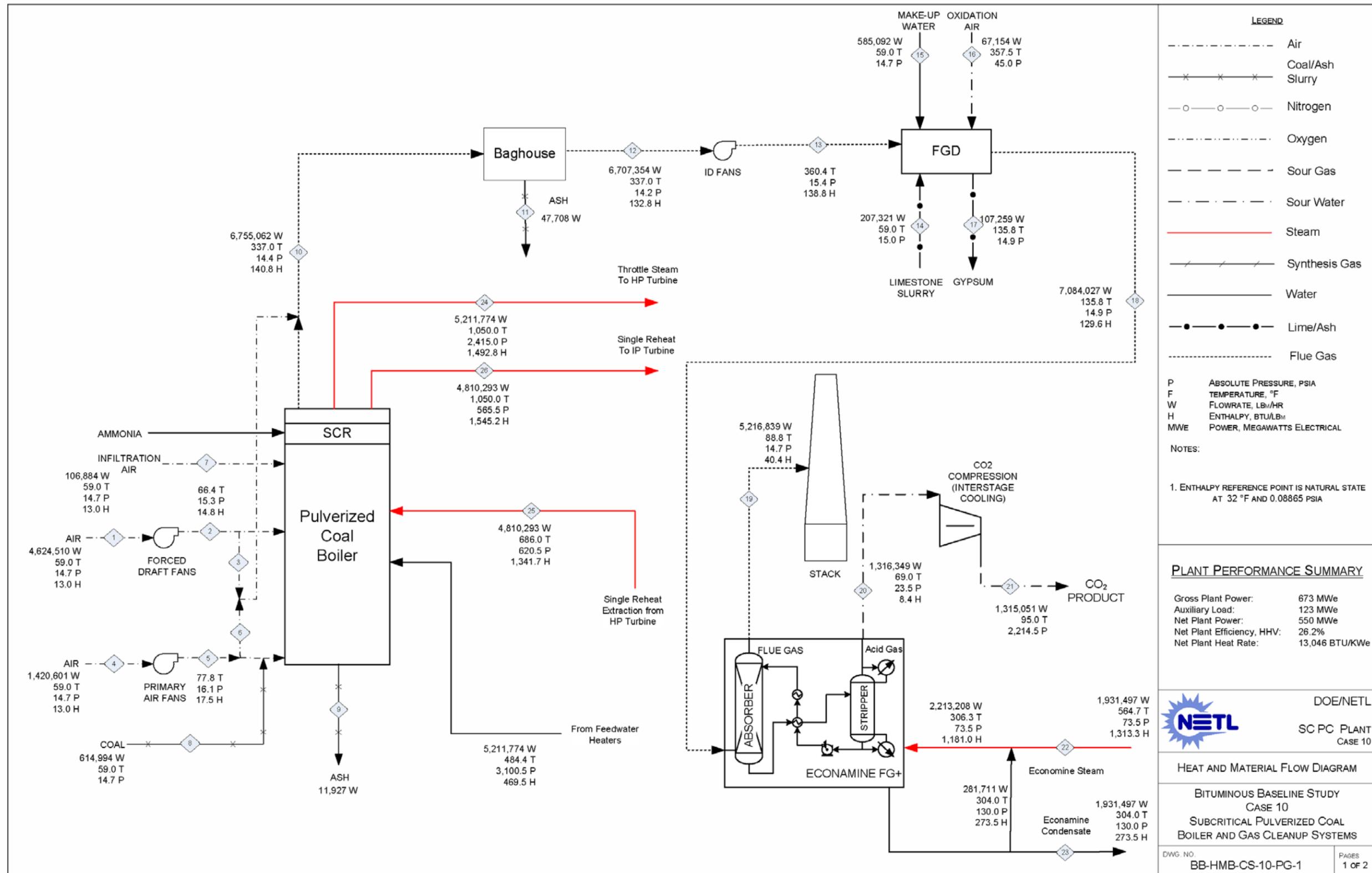
Exhibit 4-26 Case 10 Heat and Mass Balance, Subcritical Steam Cycle
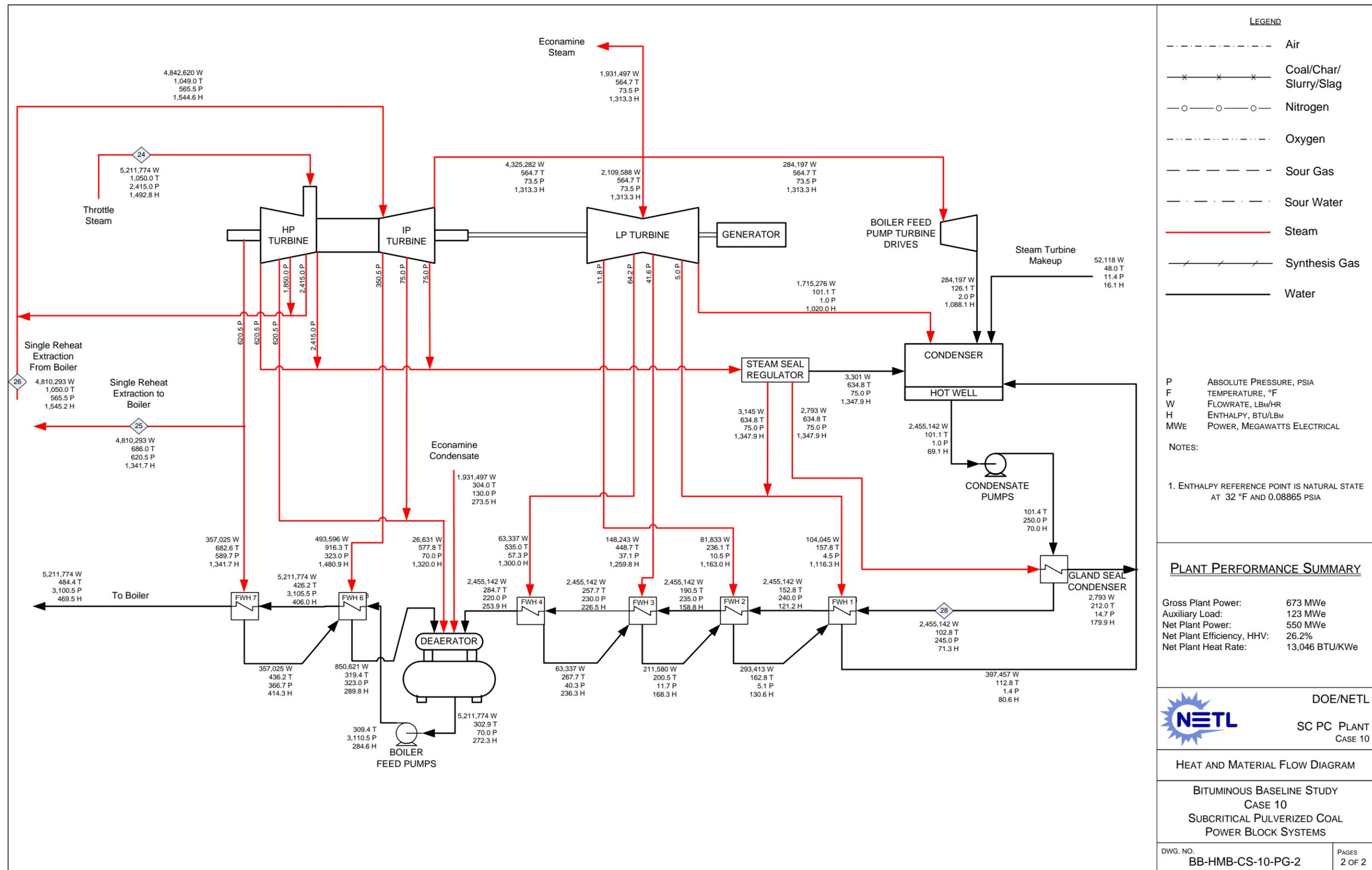
Exhibit 4-27 Case 10 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	7,570 (7,175)	6.3 (6.0)		7,576 (7,181)
Air		84.3 (79.9)		84.3 (79.9)
Raw Water Makeup		159.9 (151.5)		159.9 (151.5)
Limestone		0.32 (0.30)		0.32 (0.30)
Auxiliary Power			442 (419)	442 (419)
Totals	**7,570 (7,175)**	**250.9 (237.8)**	**442 (419)**	**8,262 (7,831)**
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash		0.7 (0.6)		0.7 (0.6)
Fly Ash + FGD Ash		2.6 (2.5)		2.6 (2.5)
Flue Gas		222 (211)		222 (211)
Condenser		2,034 (1,928)		2,034 (1,928)
CO_2		-126 (-120)		-126 (-120)
Cooling Tower Blowdown		73.2 (69.4)		73.2 (69.4)
Econamine Losses		3,585 (3,398)		3,585 (3,398)
Process Losses*		*49.6 (47.0)*		*49.6 (47.0)*
Power			2,422 (2,295)	2,422 (2,295)
Totals	**0 (0)**	**5,841 (5,536)**	**2,422 (2,295)**	**8,262 (7,831)**

* Process losses are estimated to match the heat input to the plant. Process losses include losses from: turbines, gas cooling, etc.

4.2.9   Case 10 – Major Equipment List

Major equipment items for the subcritical PC plant with CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.2.10. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1   FUEL AND SORBENT HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	54 tonne (60 ton)	2	1
9	Feeder	Vibratory	227 tonne/hr (250 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	463 tonne/hr (510 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	227 tonne (250 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	463 tonne/hr (510 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	463 tonne/hr (510 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	998 tonne (1,100 ton)	3	0
19	Limestone Truck Unloading Hopper	N/A	36 tonne (40 ton)	1	0
20	Limestone Feeder	Belt	118 tonne/hr (130 tph)	1	0
21	Limestone Conveyor No. L1	Belt	118 tonne/hr (130 tph)	1	0
22	Limestone Reclaim Hopper	N/A	27 tonne (30 ton)	1	0
23	Limestone Reclaim Feeder	Belt	91 tonne/hr (100 tph)	1	0
24	Limestone Conveyor No. L2	Belt	91 tonne/hr (100 tph)	1	0
25	Limestone Day Bin	w/ actuator	372 tonne (410 ton)	2	0

ACCOUNT 2   COAL AND SORBENT PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	54 tonne/hr (60 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	54 tonne/hr (60 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	31 tonne/hr (34 tph)	1	1
4	Limestone Ball Mill	Rotary	31 tonne/hr (34 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	121,133 liters (32,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	2,006 lpm @ 12m H2O (530 gpm @ 40 ft H2O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5 cyclone bank	492 lpm (130 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	673,803 liters (178,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,401 lpm @ 9m H2O (370 gpm @ 30 ft H2O)	1	1

ACCOUNT 3   FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,563,375 liters (413,000 gal)	2	0
2	Condensate Pumps	Vertical canned	20,441 lpm @ 213 m H2O (5,400 gpm @ 700 ft H2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	2,600,445 kg/hr (5,733,000 lb/hr), 5 min. tank	1	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	43,532 lpm @ 2,591 m H2O (11,500 gpm @ 8,500 ft H2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	12,870 lpm @ 2,591 m H2O (3,400 gpm @ 8,500 ft H2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	612,350 kg/hr (1,350,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	612,350 kg/hr (1,350,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	612,350 kg/hr (1,350,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	612,350 kg/hr (1,350,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	2,599,084 kg/hr (5,730,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	2,599,084 kg/hr (5,730,000 lb/hr)	1	0
12	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
13	Fuel Oil System	No. 2 fuel oil for light off	1,135,624 liter (300,000 gal)	1	0
14	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
15	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
16	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
17	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 30 m H2O (5,500 gpm @ 100 ft H2O)	2	1
18	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H2O (1,000 gpm @ 290 ft H2O)	1	1
19	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H2O (700 gpm @ 210 ft H2O)	1	1
20	Raw Water Pumps	Stainless steel, single suction	12,265 lpm @ 18 m H2O (3,240 gpm @ 60 ft H2O)	2	1
21	Ground Water Pumps	Stainless steel, single suction	4,921 lpm @ 268 m H2O (1,300 gpm @ 880 ft H2O)	5	1
22	Filtered Water Pumps	Stainless steel, single suction	2,953 lpm @ 49 m H2O (780 gpm @ 160 ft H2O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	2,839,059 liter (750,000 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	1,022 lpm (270 gpm)	1	1
25	Liquid Waste Treatment System	--	10 years, 24-hour storm	1	0

ACCOUNT 4   BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Subcritical, drum wall-fired, low NOx burners, overfire air	2,599,084 kg/hr steam @ 17.9 MPa/574°C/574°C (5,730,000 lb/hr steam @ 2,600 psig/1,065°F/1,065°F)	1	0
2	Primary Air Fan	Centrifugal	354,256 kg/hr, 4,837 m3/min @ 123 cm WG (781,000 lb/hr, 170,800 acfm @ 48 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	1,153,485 kg/hr, 15,744 m3/min @ 47 cm WG (2,543,000 lb/hr, 556,000 acfm @ 19 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,673,302 kg/hr, 35,314 m3/min @ 104 cm WG (3,689,000 lb/hr, 1,247,100 acfm @ 41 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	3,347,512 kg/hr (7,380,000 lb/hr)	2	0
6	SCR Catalyst	--	--	3	0
7	Dilution Air Blower	Centrifugal	198 m3/min @ 108 cm WG (7,000 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	219,554 liter (58,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	42 lpm @ 91 m H2O (11 gpm @ 300 ft H2O)	2	1

ACCOUNT 5   FLUE GAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,673,302 kg/hr (3,689,000 lb/hr) 99.8% efficiency	2	0
2	Absorber Module	Counter-current open spray	66,913 m3/min (2,363,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	230,910 lpm @ 64 m H2O (61,000 gpm @ 210 ft H2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	6,095 lpm (1,610 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	117 m3/min @ 0.3 MPa (4,130 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,514 lpm (400 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	48 tonne/hr (53 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	908 lpm @ 12 m H2O (240 gpm @ 40 ft H2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	605,666 lpm (160,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	4,883 lpm @ 21 m H2O (1,290 gpm @ 70 ft H2O)	1	1

ACCOUNT 5B   CARBON DIOXIDE RECOVERY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Econamine FG Plus	Amine-based CO2 capture technology	1,767,196 kg/h (3,896,000 lb/h) 20.6 wt % CO2 concentration	2	0
2	Econamine Condensate Pump	Centrifugal	18,435 lpm @ 52 m H2O (4,870 gpm @ 170 ft H2O)	1	1
3	CO2 Compressor	Integrally geared, multi-stage centrifugal	327,872 kg/h @ 15.3 MPa (722,834 lb/h @ 2,215 psia)	2	0

ACCOUNT 6   COMBUSTION TURBINE/ACCESSORIES

     N/A

ACCOUNT 7   HRSG, DUCTING & STACK

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

ACCOUNT 8   STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	708 MW 16.5 MPa/566°C/566°C (2400.3 psig/ 1050°F/1050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	790 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,237 GJ/hr (2,120 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9   COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	1,128,100 lpm @ 30 m (298,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 6299 GJ/hr (5970 MMBtu/hr) heat duty	1	0

ACCOUNT 10   ASH/SPENT SORBENT RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	--	--	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	--	--	2	0
3	Clinker Grinder	--	6.4 tonne/hr (7 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	--	--	6	0
5	Hydroejectors	--	--	12	
6	Economizer /Pyrites Transfer Tank	--	--	1	0
7	Ash Sluice Pumps	Vertical, wet pit	227 lpm @ 17 m H2O (60 gpm @ 56 ft H2O)	1	1
8	Ash Seal Water Pumps	Vertical, wet pit	7,571 lpm @ 9 m H2O (2000 gpm @ 28 ft H2O)	1	1
9	Hydrobins	--	227 lpm (60 gpm)	1	1
10	Baghouse Hopper (part of baghouse scope of supply)	--	--	24	0
11	Air Heater Hopper (part of boiler scope of supply)	--	--	10	0
12	Air Blower	--	22 m3/min @ 0.2 MPa (770 scfm @ 24 psi)	1	1
13	Fly Ash Silo	Reinforced concrete	1,451 tonne (1,600 ton)	2	0
14	Slide Gate Valves	--	--	2	0
15	Unloader	--	--	1	0
16	Telescoping Unloading Chute	--	136 tonne/hr (150 tph)	1	0

ACCOUNT 11   ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 650 MVA, 3-ph, 60 Hz	1	0
2	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 134 MVA, 3-ph, 60 Hz	1	1
3	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 20 MVA, 3-ph, 60 Hz	1	1
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
5	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
6	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
7	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12   INSTRUMENTATION AND CONTROL

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

4.2.10 <u>Case 10 – Cost Estimating</u>

The cost estimating methodology was described previously in Section 2.7. Exhibit 4-28 shows the total plant capital cost summary organized by cost account and Exhibit 4-29 shows a more detailed breakdown of the capital costs along with owner's costs, TOC, and TASC. Exhibit 4-30 shows the initial and annual O&M costs.

The estimated TOC of the subcritical PC boiler with CO_2 capture is \$3,610/kW. Process contingency represents 2.9 percent of the TOC and project contingency represents 10.2 percent. The COE, including CO_2 TS&M costs of 5.9 mills/kWh, is 109.7 mills/kWh.

Exhibit 4-28 Case 10 Total Plant Cost Summary

Client:			USDOE/NETL						Report Date	2010-Jan-14		
Project:			Bituminous Baseline Study									
			TOTAL PLANT COST SUMMARY									
Case:			Case 10 - 1x550 MWnet SubCritical PC w/ CO2 Capture									
Plant Size:			550.0 MW,net	**Estimate Type:**	Conceptual			**Cost Base (Jun)**	2007	($x1000)		

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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$21,191	$5,688	$12,662	$0	$0	**$39,542**	$3,548	$0	$6,463	**$49,553**	$90
2	COAL & SORBENT PREP & FEED	$14,465	$844	$3,675	$0	$0	**$18,984**	$1,664	$0	$3,097	**$23,744**	$43
3	FEEDWATER & MISC. BOP SYSTEMS	$52,748	$0	$25,315	$0	$0	**$78,063**	$7,174	$0	$14,102	**$99,339**	$181
4	PC BOILER											
4.1	PC Boiler & Accessories	$171,007	$0	$109,973	$0	$0	**$280,980**	$27,374	$0	$30,835	**$339,189**	$617
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
4.4-4.9	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$171,007**	**$0**	**$109,973**	**$0**	**$0**	**$280,980**	**$27,374**	**$0**	**$30,835**	**$339,189**	**$617**
5	FLUE GAS CLEANUP	$107,581	$0	$36,768	$0	$0	**$144,350**	$13,816	$0	$15,817	**$173,983**	$316
5B	CO₂ REMOVAL & COMPRESSION	$247,434	$0	$75,421	$0	$0	**$322,855**	$30,869	$56,959	$82,137	**$492,819**	$896
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6.2-6.9	Combustion Turbine Other	$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
7.2-7.9	HRSG Accessories, Ductwork and Stack	$19,509	$1,069	$13,214	$0	$0	**$33,792**	$3,095	$0	$4,848	**$41,735**	$76
	SUBTOTAL 7	**$19,509**	**$1,069**	**$13,214**	**$0**	**$0**	**$33,792**	**$3,095**	**$0**	**$4,848**	**$41,735**	**$76**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$55,209	$0	$6,905	$0	$0	**$62,114**	$5,951	$0	$6,806	**$74,871**	$136
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$26,840	$1,213	$15,303	$0	$0	**$43,356**	$3,796	$0	$6,701	**$53,853**	$98
	SUBTOTAL 8	**$82,049**	**$1,213**	**$22,207**	**$0**	**$0**	**$105,470**	**$9,747**	**$0**	**$13,507**	**$128,724**	**$234**
9	COOLING WATER SYSTEM	$22,313	$10,599	$19,714	$0	$0	**$52,626**	$4,953	$0	$7,745	**$65,324**	$119
10	ASH/SPENT SORBENT HANDLING SYS	$5,525	$176	$7,387	$0	$0	**$13,088**	$1,258	$0	$1,477	**$15,823**	$29
11	ACCESSORY ELECTRIC PLANT	$25,948	$11,057	$31,311	$0	$0	**$68,316**	$6,043	$0	$9,343	**$83,703**	$152
12	INSTRUMENTATION & CONTROL	$9,942	$0	$10,082	$0	$0	**$20,024**	$1,816	$1,001	$2,805	**$25,646**	$47
13	IMPROVEMENTS TO SITE	$3,344	$1,922	$6,739	$0	$0	**$12,006**	$1,184	$0	$2,638	**$15,828**	$29
14	BUILDINGS & STRUCTURES	$0	$25,775	$24,432	$0	$0	**$50,207**	$4,529	$0	$8,210	**$62,947**	$114
	TOTAL COST	**$783,055**	**$58,343**	**$398,903**	**$0**	**$0**	**$1,240,301**	**$117,071**	**$57,960**	**$203,025**	**$1,618,357**	**$2,942**

Exhibit 4-29 Case 10 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$4,333	$0	$1,979	$0	$0	$6,313	$564	$0	$1,031	$7,908	$14
1.2	Coal Stackout & Reclaim	$5,600	$0	$1,269	$0	$0	$6,869	$601	$0	$1,120	$8,590	$16
1.3	Coal Conveyors	$5,207	$0	$1,255	$0	$0	$6,462	$566	$0	$1,054	$8,083	$15
1.4	Other Coal Handling	$1,362	$0	$290	$0	$0	$1,653	$144	$0	$270	$2,067	$4
1.5	Sorbent Receive & Unload	$178	$0	$54	$0	$0	$231	$20	$0	$38	$289	$1
1.6	Sorbent Stackout & Reclaim	$2,869	$0	$526	$0	$0	$3,395	$296	$0	$554	$4,244	$8
1.7	Sorbent Conveyors	$1,024	$221	$251	$0	$0	$1,496	$129	$0	$244	$1,869	$3
1.8	Other Sorbent Handling	$618	$145	$324	$0	$0	$1,088	$96	$0	$178	$1,361	$2
1.9	Coal & Sorbent Hnd.Foundations	$0	$5,322	$6,714	$0	$0	$12,036	$1,130	$0	$1,975	$15,141	$28
	SUBTOTAL 1.	$21,191	$5,688	$12,662	$0	$0	$39,542	$3,548	$0	$6,463	$49,553	$90
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$2,523	$0	$492	$0	$0	$3,014	$263	$0	$492	$3,768	$7
2.2	Coal Conveyor to Storage	$6,459	$0	$1,410	$0	$0	$7,869	$688	$0	$1,283	$9,840	$18
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	$4,894	$211	$1,016	$0	$0	$6,121	$533	$0	$998	$7,652	$14
2.6	Sorbent Storage & Feed	$590	$0	$226	$0	$0	$815	$72	$0	$133	$1,021	$2
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	$633	$531	$0	$0	$1,164	$108	$0	$191	$1,463	$3
	SUBTOTAL 2.	$14,465	$844	$3,675	$0	$0	$18,984	$1,664	$0	$3,097	$23,744	$43
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	Feedwater System	$20,624	$0	$7,119	$0	$0	$27,743	$2,430	$0	$4,526	$34,699	$63
3.2	Water Makeup & Pretreating	$7,503	$0	$2,415	$0	$0	$9,919	$938	$0	$2,171	$13,028	$24
3.3	Other Feedwater Subsystems	$6,747	$0	$2,851	$0	$0	$9,599	$860	$0	$1,569	$12,027	$22
3.4	Service Water Systems	$1,471	$0	$800	$0	$0	$2,271	$214	$0	$497	$2,982	$5
3.5	Other Boiler Plant Systems	$8,081	$0	$7,979	$0	$0	$16,060	$1,526	$0	$2,638	$20,224	$37
3.6	FO Supply Sys & Nat Gas	$278	$0	$348	$0	$0	$626	$59	$0	$103	$788	$1
3.7	Waste Treatment Equipment	$5,087	$0	$2,900	$0	$0	$7,987	$777	$0	$1,753	$10,517	$19
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$2,955	$0	$903	$0	$0	$3,858	$371	$0	$846	$5,075	$9
	SUBTOTAL 3.	$52,748	$0	$25,315	$0	$0	$78,063	$7,174	$0	$14,102	$99,339	$181
4	PC BOILER											
4.1	PC Boiler & Accessories	$171,007	$0	$109,973	$0	$0	$280,980	$27,374	$0	$30,835	$339,189	$617
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.	$171,007	$0	$109,973	$0	$0	$280,980	$27,374	$0	$30,835	$339,189	$617

Exhibit 4-29 Case 10 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	$74,713	$0	$16,084	$0	$0	$90,797	$8,656	$0	$9,945	$109,399	$199
5.2	Other FGD	$3,899	$0	$4,418	$0	$0	$8,317	$807	$0	$912	$10,037	$18
5.3	Bag House & Accessories	$21,582	$0	$13,697	$0	$0	$35,279	$3,400	$0	$3,868	$42,546	$77
5.4	Other Particulate Removal Materials	$1,461	$0	$1,563	$0	$0	$3,023	$293	$0	$332	$3,648	$7
5.5	Gypsum Dewatering System	$5,926	$0	$1,007	$0	$0	$6,933	$660	$0	$759	$8,352	$15
5.6	Mercury Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.9	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	$107,581	$0	$36,768	$0	$0	$144,350	$13,816	$0	$15,817	$173,983	$316
5B	CO$_2$ REMOVAL & COMPRESSION											
5B.1	CO$_2$ Removal System	$218,463	$0	$66,332	$0	$0	$284,795	$27,229	$56,959	$73,796	$442,779	$805
5B.2	CO$_2$ Compression & Drying	$28,971	$0	$9,089	$0	$0	$38,060	$3,640	$0	$8,340	$50,040	$91
	SUBTOTAL 5B.	$247,434	$0	$75,421	$0	$0	$322,855	$30,869	$56,959	$82,137	$492,819	$896
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	$10,193	$0	$6,549	$0	$0	$16,743	$1,460	$0	$2,730	$20,933	$38
7.4	Stack	$9,316	$0	$5,451	$0	$0	$14,766	$1,422	$0	$1,619	$17,807	$32
7.9	Duct & Stack Foundations	$0	$1,069	$1,214	$0	$0	$2,283	$214	$0	$499	$2,996	$5
	SUBTOTAL 7.	$19,509	$1,069	$13,214	$0	$0	$33,792	$3,095	$0	$4,848	$41,735	$76
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$55,209	$0	$6,905	$0	$0	$62,114	$5,951	$0	$6,806	$74,871	$136
8.2	Turbine Plant Auxiliaries	$387	$0	$828	$0	$0	$1,215	$119	$0	$133	$1,467	$3
8.3	Condenser & Auxiliaries	$6,154	$0	$2,549	$0	$0	$8,702	$835	$0	$954	$10,490	$19
8.4	Steam Piping	$20,300	$0	$10,009	$0	$0	$30,310	$2,547	$0	$4,928	$37,784	$69
8.9	TG Foundations	$0	$1,213	$1,917	$0	$0	$3,130	$296	$0	$685	$4,111	$7
	SUBTOTAL 8.	$82,049	$1,213	$22,207	$0	$0	$105,470	$9,747	$0	$13,507	$128,724	$234
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$16,661	$0	$5,188	$0	$0	$21,850	$2,090	$0	$2,394	$26,333	$48
9.2	Circulating Water Pumps	$3,467	$0	$260	$0	$0	$3,727	$315	$0	$404	$4,446	$8
9.3	Circ.Water System Auxiliaries	$839	$0	$112	$0	$0	$951	$90	$0	$104	$1,146	$2
9.4	Circ.Water Piping	$0	$6,653	$6,448	$0	$0	$13,101	$1,226	$0	$2,149	$16,476	$30
9.5	Make-up Water System	$680	$0	$909	$0	$0	$1,589	$152	$0	$261	$2,002	$4
9.6	Component Cooling Water Sys	$665	$0	$529	$0	$0	$1,194	$113	$0	$196	$1,503	$3
9.9	Circ.Water System Foundations & Structures	$0	$3,946	$6,269	$0	$0	$10,214	$966	$0	$2,236	$13,417	$24
	SUBTOTAL 9.	$22,313	$10,599	$19,714	$0	$0	$52,626	$4,953	$0	$7,745	$65,324	$119

Exhibit 4-29 Case 10 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
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	$739	$0	$2,278	$0	$0	$3,017	$296	$0	$331	$3,645	$7
10.7	Ash Transport & Feed Equipment	$4,786	$0	$4,902	$0	$0	$9,688	$926	$0	$1,061	$11,676	$21
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$176	$207	$0	$0	$383	$36	$0	$84	$502	$1
	SUBTOTAL 10.	$5,525	$176	$7,387	$0	$0	$13,088	$1,258	$0	$1,477	$15,823	$29
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$1,742	$0	$283	$0	$0	$2,025	$188	$0	$166	$2,379	$4
11.2	Station Service Equipment	$5,148	$0	$1,691	$0	$0	$6,839	$639	$0	$561	$8,039	$15
11.3	Switchgear & Motor Control	$5,918	$0	$1,006	$0	$0	$6,924	$642	$0	$757	$8,322	$15
11.4	Conduit & Cable Tray	$0	$3,710	$12,830	$0	$0	$16,540	$1,601	$0	$2,721	$20,862	$38
11.5	Wire & Cable	$0	$7,001	$13,516	$0	$0	$20,517	$1,729	$0	$3,337	$25,582	$47
11.6	Protective Equipment	$270	$0	$918	$0	$0	$1,188	$116	$0	$130	$1,434	$3
11.7	Standby Equipment	$1,370	$0	$31	$0	$0	$1,401	$128	$0	$153	$1,682	$3
11.8	Main Power Transformers	$11,500	$0	$191	$0	$0	$11,691	$886	$0	$1,258	$13,835	$25
11.9	Electrical Foundations	$0	$345	$846	$0	$0	$1,191	$114	$0	$261	$1,566	$3
	SUBTOTAL 11.	$25,948	$11,057	$31,311	$0	$0	$68,316	$6,043	$0	$9,343	$83,703	$152
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	$512	$0	$307	$0	$0	$819	$77	$41	$141	$1,077	$2
12.7	Distributed Control System Equipment	$5,168	$0	$903	$0	$0	$6,071	$563	$304	$694	$7,632	$14
12.8	Instrument Wiring & Tubing	$2,802	$0	$5,558	$0	$0	$8,359	$712	$418	$1,423	$10,913	$20
12.9	Other I & C Equipment	$1,460	$0	$3,314	$0	$0	$4,774	$463	$239	$548	$6,024	$11
	SUBTOTAL 12.	$9,942	$0	$10,082	$0	$0	$20,024	$1,816	$1,001	$2,805	$25,646	$47

Exhibit 4-29 Case 10 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$56	$1,124	$0	$0	$1,180	$117	$0	$260	$1,557	$3
13.2	Site Improvements	$0	$1,866	$2,318	$0	$0	$4,184	$413	$0	$919	$5,516	$10
13.3	Site Facilities	$3,344	$0	$3,298	$0	$0	$6,642	$655	$0	$1,459	$8,756	$16
	SUBTOTAL 13.	$3,344	$1,922	$6,739	$0	$0	$12,006	$1,184	$0	$2,638	$15,828	$29
14	BUILDINGS & STRUCTURES											
14.1	Boiler Building	$0	$9,158	$8,054	$0	$0	$17,212	$1,547	$0	$2,814	$21,573	$39
14.2	Turbine Building	$0	$13,420	$12,507	$0	$0	$25,927	$2,337	$0	$4,240	$32,503	$59
14.3	Administration Building	$0	$646	$684	$0	$0	$1,330	$121	$0	$218	$1,668	$3
14.4	Circulation Water Pumphouse	$0	$176	$140	$0	$0	$317	$28	$0	$52	$397	$1
14.5	Water Treatment Buildings	$0	$952	$868	$0	$0	$1,819	$164	$0	$297	$2,281	$4
14.6	Machine Shop	$0	$432	$290	$0	$0	$723	$64	$0	$118	$905	$2
14.7	Warehouse	$0	$293	$294	$0	$0	$587	$53	$0	$96	$736	$1
14.8	Other Buildings & Structures	$0	$239	$204	$0	$0	$443	$40	$0	$72	$555	$1
14.9	Waste Treating Building & Str.	$0	$458	$1,391	$0	$0	$1,849	$176	$0	$304	$2,329	$4
	SUBTOTAL 14.	$0	$25,775	$24,432	$0	$0	$50,207	$4,529	$0	$8,210	$62,947	$114
	TOTAL COST	$783,055	$58,343	$398,903	$0	$0	$1,240,301	$117,071	$57,960	$203,025	$1,618,357	$2,942

Owner's Costs			
Preproduction Costs			
6 Months All Labor		$10,547	$19
1 Month Maintenance Materials		$1,534	$3
1 Month Non-fuel Consumables		$1,789	$3
1 Month Waste Disposal		$353	$1
25% of 1 Months Fuel Cost at 100% CF		$2,143	$4
2% of TPC		$32,367	$59
Total		**$48,733**	**$89**
Inventory Capital			
60 day supply of fuel and consumables at 100% CF		$20,189	$37
0.5% of TPC (spare parts)		$8,092	$15
Total		**$28,281**	**$51**
Initial Cost for Catalyst and Chemicals		$2,712	$5
Land		$900	$2
Other Owner's Costs		$242,754	$441
Financing Costs		$43,696	$79
Total Overnight Costs (TOC)		**$1,985,432**	**$3,610**
TASC Multiplier	(IOU, high-risk, 35 year)	1.140	
Total As-Spent Cost (TASC)		**$2,263,393**	**$4,115**

Exhibit 4-30 Case 10 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES				Cost Base (Jun):	2007
Case 10 - 1x550 MWnet SubCritical PC w/ CO2 Capture				Heat Rate-net (Btu/kWh):	13,044
				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

Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.	Total Plant
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	$6,444,907	$11.718
Maintenance Labor Cost	$10,429,543	$18.962
Administrative & Support Labor	$4,218,612	$7.670
Property Taxes and Insurance	$32,367,148	$58.848
TOTAL FIXED OPERATING COSTS	**$53,460,210**	**$97.199**

VARIABLE OPERATING COSTS						$/kWh-net
Maintenance Material Cost					**$15,644,314**	**$0.00382**

Consumables	Consumption Initial Fill	/Day	Unit Cost	Initial Fill Cost		
Water(/1000 gallons)	0	8,081	1.08	$0	$2,711,996	$0.00066
Chemicals						
MU & WT Chem.(lbs)	0	39,119	0.17	$0	$2,100,447	$0.00051
Limestone (ton)	0	751	21.63	$0	$5,043,346	$0.00123
Carbon (Mercury Removal) (lb)	0	0	1.05	$0	$0	$0.00000
MEA Solvent (ton)	1,117	1.58	2,249.89	$2,513,263	$1,105,563	$0.00027
NaOH (tons)	79	7.89	433.68	$34,221	$1,061,704	$0.00026
H2SO4 (tons)	75	7.53	138.78	$10,450	$324,217	$0.00008
Corrosion Inhibitor	0	0	0.00	$154,511	$7,358	$0.00000
Activated Carbon (lb)	0	1,892	1.05	$0	$616,433	$0.00015
Ammonia (19% NH3) ton	0	110	129.80	$0	$4,446,378	$0.00109
Subtotal Chemicals				**$2,712,445**	**$14,705,446**	**$0.00359**
Other						
Supplemental Fuel (MBtu)	0	0	0.00	$0	$0	$0.00000
SCR Catalyst (m3)	w/equip.	0.46	5,775.94	$0	$831,516	$0.00020
Emission Penalties	0	0	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$831,516**	**$0.00020**
Waste Disposal						
Fly Ash (ton)	0	572	16.23	$0	$2,881,846	$0.00070
Bottom Ash (ton)	0	143	16.23	$0	$720,462	$0.00018
Subtotal-Waste Disposal				**$0**	**$3,602,308**	**$0.00088**
By-products & Emissions						
Gypsum (tons)	0	1,159	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$2,712,445**	**$37,495,580**	**$0.00916**
Fuel(ton)	0	7,380	38.18	**$0**	**$87,425,787**	**$0.02135**

4.3   SUPERCRITICAL PC CASES

This section contains an evaluation of plant designs for Cases 11 and 12, which are based on a SC PC plant with a nominal net output of 550 MWe. Both plants use a single reheat 24.1 MPa/593°C/593°C (3,500 psig/1,100°F/1,100°F) cycle. The only difference between the two plants is that Case 12 includes CO_2 capture while Case 11 does not.

The balance of Section 4.3 is organized in an analogous manner to the subcritical PC section:

- Process and System Description for Case 11

- Key Assumptions for Cases 11 and 12

- Sparing Philosophy for Cases 11 and 12

- Performance Results for Case 11

- Equipment List for Case 11

- Cost Estimates for Case 11

- Process and System Description, Performance Results, Equipment List and Cost Estimates for Case 12

4.3.1   Process Description

In this section the SC PC process without CO_2 capture is described. The system description is nearly identical to the subcritical PC case without CO_2 capture but is repeated here for completeness. The description follows the BFD in Exhibit 4-31 and stream numbers reference the same Exhibit. The tables in Exhibit 4-32 provide process data for the numbered streams in the BFD.

Coal (stream 8) and PA (stream 4) are introduced into the boiler through the wall-fired burners. Additional combustion air, including the OFA, is provided by the FD fans (stream 1). The boiler operates at a slight negative pressure so air leakage is into the boiler, and the infiltration air is accounted for in stream 5. Streams 3 and 6 show Ljungstrom air preheater leakages from the FD and PA fan outlet streams to the boiler exhaust.

FG exits the boiler through the SCR reactor (stream 10) and is cooled to 169°C (337°F) in the combustion air preheater before passing through a fabric filter for particulate removal (stream 12). An ID fan increases the FG temperature to 181°C (357°F) and provides the motive force for the FG (stream 13) to pass through the FGD unit. FGD inputs and outputs include makeup water (stream 15), oxidation air (stream 16), limestone slurry (stream 14), and product gypsum (stream 17). The clean, saturated FG exiting the FGD unit (stream 18) passes to the plant stack and is discharged to the atmosphere.

Exhibit 4-31 Case 11 Block Flow Diagram, Supercritical Unit without CO₂ Capture
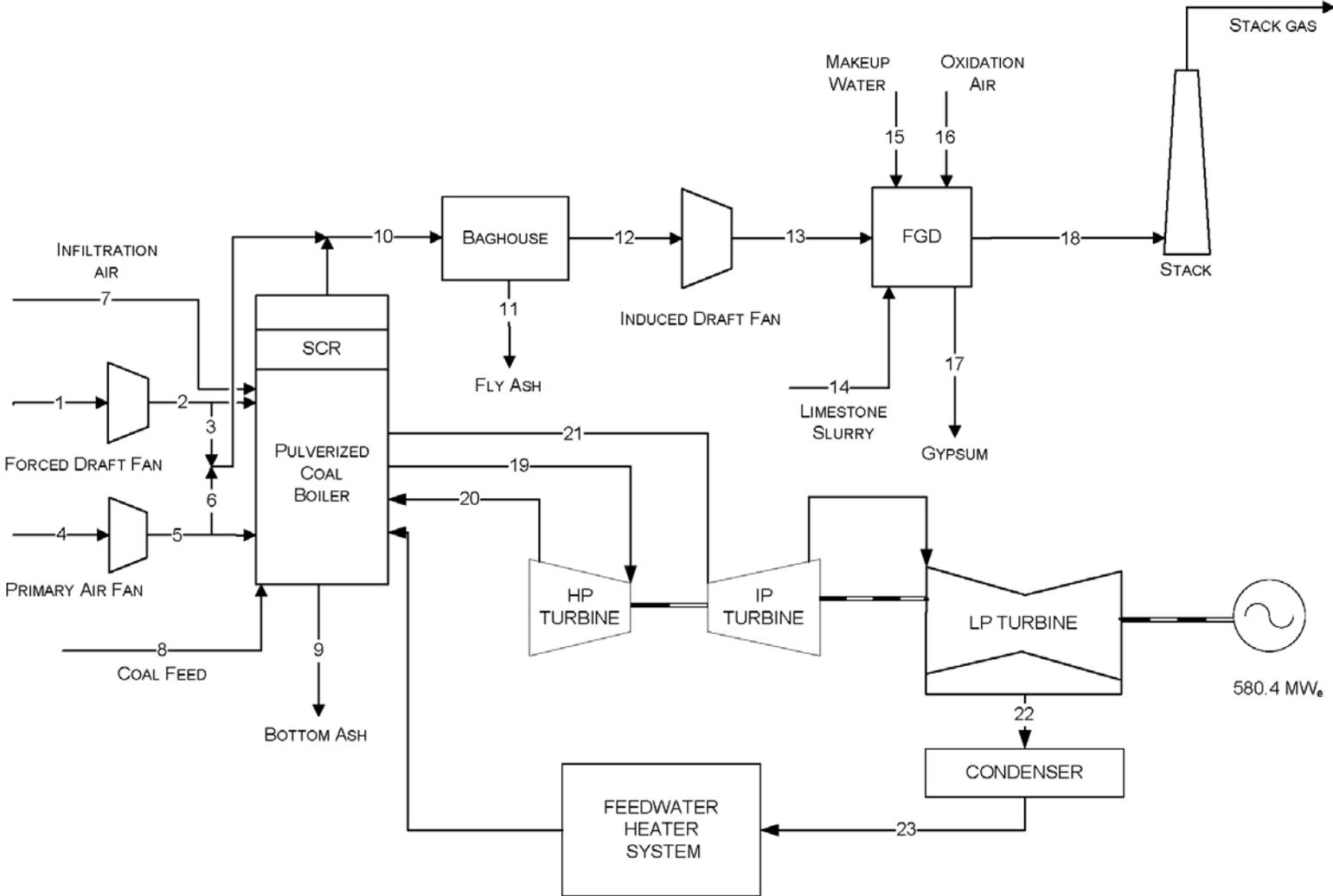
Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Exhibit 4-32 Case 11 Stream Table, Supercritical Unit without CO₂ Capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087	0.0000	0.0087
CO₂	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450	0.0000	0.1450
H₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H₂O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870	0.0000	0.0870
N₂	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324	0.0000	0.7324
O₂	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247	0.0000	0.0247
SO₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021
Total	1.0000	1.0000	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)	48,414	48,414	1,434	14,872	14,872	2,047	1,119	0	0	68,126	0	68,126
V-L Flowrate (kg/hr)	1,397,067	1,397,067	41,378	429,164	429,164	59,064	32,284	0	0	2,026,262	0	2,026,262
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	185,759	3,603	14,410	14,410	0
Temperature (°C)	15	19	19	15	25	25	15	15	15	169	15	169
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10
Enthalpy (kJ/kg)[A]	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	327.37	---	308.94
Density (kg/m³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	0.8	---	0.8
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	29.743	---	29.743
V-L Flowrate (lb_mol/hr)	106,734	106,734	3,161	32,787	32,787	4,512	2,466	0	0	150,191	0	150,191
V-L Flowrate (lb/hr)	3,080,006	3,080,006	91,224	946,145	946,145	130,215	71,175	0	0	4,467,142	0	4,467,142
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	409,528	7,942	31,769	31,769	0
Temperature (°F)	59	66	66	59	78	78	59	59	59	337	59	337
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.7	14.4	14.7	14.2
Enthalpy (Btu/lb)[A]	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	140.7	---	132.8
Density (lb/ft³)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	0.050	---	0.049
A - Reference conditions are 32.02 F & 0.089 PSIA												

Exhibit 4-32 Case 11 Stream Table, Supercritical Unit without CO$_2$ Capture (Continued)

	13	14	15	16	17	18	19	20	21	22	23
V-L Mole Fraction											
Ar	0.0087	0.0000	0.0000	0.0128	0.0000	0.0082	0.0000	0.0000	0.0000	0.0000	0.0000
CO$_2$	0.1450	0.0000	0.0000	0.0005	0.0004	0.1353	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$_2$O	0.0870	1.0000	1.0000	0.0062	0.9995	0.1517	1.0000	1.0000	1.0000	1.0000	1.0000
N$_2$	0.7324	0.0000	0.0000	0.7506	0.0000	0.6808	0.0000	0.0000	0.0000	0.0000	0.0000
O$_2$	0.0247	0.0000	0.0000	0.2300	0.0000	0.0240	0.0000	0.0000	0.0000	0.0000	0.0000
SO$_2$	0.0021	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg$_{mol}$/hr)	68,126	2,369	9,597	726	176	74,091	92,389	76,591	76,591	69,891	69,891
V-L Flowrate (kg/hr)	2,026,262	42,682	172,898	21,076	3,168	2,137,881	1,664,421	1,379,803	1,379,803	1,259,099	1,259,099
Solids Flowrate (kg/hr)	0	18,437	0	0	28,694	0	0	0	0	0	0
Temperature (°C)	181	15	15	167	57	57	593	354	593	38	39
Pressure (MPa, abs)	0.11	0.10	0.10	0.31	0.10	0.10	24.23	4.90	4.52	0.01	1.69
Enthalpy (kJ/kg)^A	321.02	---	-46.80	177.65	---	297.66	3,476.62	3,082.88	3,652.22	1,985.85	165.59
Density (kg/m^3)	0.8	---	1,003.1	2.5	---	1.1	69.2	18.7	11.6	0.1	993.3
V-L Molecular Weight	29.743	---	18.015	29.029	---	28.855	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb$_{mol}$/hr)	150,191	5,223	21,158	1,601	387	163,343	203,684	168,854	168,854	154,082	154,082
V-L Flowrate (lb/hr)	4,467,142	94,099	381,174	46,465	6,985	4,713,221	3,669,421	3,041,946	3,041,946	2,775,839	2,775,839
Solids Flowrate (lb/hr)	0	40,646	0	0	63,259	0	0	0	0	0	0
Temperature (°F)	357	59	59	333	135	135	1,100	669	1,100	101	103
Pressure (psia)	15.3	15.0	14.7	45.0	14.8	14.8	3,514.7	710.8	655.8	1.0	245.0
Enthalpy (Btu/lb)^A	138.0	---	-20.1	76.4	---	128.0	1,494.7	1,325.4	1,570.2	853.8	71.2
Density (lb/ft^3)	0.052	---	62.622	0.154	---	0.067	4.319	1.165	0.722	0.004	62.009

4.3.2 Key System Assumptions

System assumptions for Cases 11 and 12, SC PC with and without CO_2 capture, are compiled in Exhibit 4-33.

Exhibit 4-33 Supercritical PC Plant Study Configuration Matrix

	Case 11 w/o CO_2 Capture	Case 12 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)
Coal	Illinois No. 6	Illinois No. 6
Condenser pressure, mm Hg (in Hg)	50.8 (2)	50.8 (2)
Boiler Efficiency, %	88	88
Cooling water to condenser, °C (ºF)	16 (60)	16 (60)
Cooling water from condenser, °C (ºF)	27 (80)	27 (80)
Stack temperature, °C (°F)	57 (135)	32 (89)
SO_2 Control	Wet Limestone Forced Oxidation	Wet Limestone Forced Oxidation
FGD Efficiency, % (A)	98	98 (B, C)
NOx Control	LNB w/OFA and SCR	LNB w/OFA and SCR
SCR Efficiency, % (A)	86	86
Ammonia Slip (end of catalyst life), ppmv	2	2
Particulate Control	Fabric Filter	Fabric Filter
Fabric Filter efficiency, % (A)	99.8	99.8
Ash Distribution, Fly/Bottom	80% / 20%	80% / 20%
Mercury Control	Co-benefit Capture	Co-benefit Capture
Mercury removal efficiency, % (A)	90	90
CO_2 Control	N/A	Econamine
Overall CO_2 Capture (A)	N/A	90.2%
CO_2 Sequestration	N/A	Off-site Saline Formation

A. Removal efficiencies are based on the FG content
B. An SO_2 polishing step is included to meet more stringent SOx content limits in the FG (< 10 ppmv) to reduce formation of amine HSS during the CO_2 absorption process
C. SO_2 exiting the post-FGD polishing step is absorbed in the CO_2 capture process making stack emissions negligible

Balance of Plant – Cases 11 and 12

The balance of plant assumptions are common to all cases and were presented previously in Exhibit 4-6.

4.3.3   Sparing Philosophy

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

- One dry-bottom, wall-fired PC SC boiler (1 x 100%)

- Two SCR reactors (2 x 50%)

- Two single-stage, in-line, multi-compartment fabric filters (2 x 50%)

- One wet limestone forced oxidation positive pressure absorber (1 x 100%)

- One steam turbine (1 x 100%)

- For Case 12 only, two parallel Econamine CO_2 absorption systems, with each system consisting of two absorbers, strippers, and ancillary equipment (2 x 50%)

4.3.4   Case 11 Performance Results

The plant produces a net output of 550 MWe at a net plant efficiency of 39.3 percent (HHV basis).

Overall performance for the plant is summarized in Exhibit 4-34, which includes auxiliary power requirements.

Exhibit 4-34 Case 11 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Steam Turbine Power	580,400
TOTAL (STEAM TURBINE) POWER, kWe	**580,400**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	440
Pulverizers	2,780
Sorbent Handling & Reagent Preparation	890
Ash Handling	530
Primary Air Fans	1,300
Forced Draft Fans	1,660
Induced Draft Fans	7,050
SCR	50
Baghouse	70
Wet FGD	2,970
Miscellaneous Balance of Plant[2,3]	2,000
Steam Turbine Auxiliaries	400
Condensate Pumps	800
Circulating Water Pumps	4,730
Ground Water Pumps	480
Cooling Tower Fans	2,440
Transformer Losses	1,820
TOTAL AUXILIARIES, kWe	**30,410**
NET POWER, kWe	**549,990**
Net Plant Efficiency (HHV)	39.3%
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,165 (8,687)
CONDENSER COOLING DUTY, 10^6 kJ/hr (10^6 Btu/hr)	2,298 (2,178)
CONSUMABLES	
As-Received Coal Feed, kg/hr (lb/hr)	185,759 (409,528)
Limestone Sorbent Feed, kg/hr (lb/hr)	18,437 (40,646)
Thermal Input, kWt[1]	1,400,162
Raw Water Withdrawal, m^3/min (gpm)	20.1 (5,321)
Raw Water Consumption, m^3/min (gpm)	16.0 (4,227)

1. HHV of As-Received Illinois No. 6 coal is 27,135 kJ/kg (11,666 Btu/lb)
2. Boiler feed pumps are turbine driven
3. Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, and PM were presented in Section 2.4. A summary of the plant air emissions for Case 11 is presented in Exhibit 4-35.

Exhibit 4-35 Case 11 Air Emissions

	kg/GJ (lb/10⁶ Btu)	Tonne/year (ton/year) 85% CF	kg/MWh (lb/MWh)
SO₂	0.037 (0.086)	1,385 (1,526)	0.320 (.71)
NOx	0.030 (0.070)	1,130 (1,245)	0.261 (.576)
Particulates	0.006 (0.0130)	210 (231)	0.049 (.107)
Hg	4.91E-7 (1.14E-6)	0.018 (0.020)	4.27E-6 (9.41E-6)
CO₂	87.5 (203.5)	3,284,245 (3,620,261)	760 (1,675)
CO₂¹			802 (1,768)

¹ CO_2 emissions based on net power instead of gross power

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

NOx emissions are controlled to about 0.5 lb/10⁶ Btu through the use of LNBs and OFA. An SCR unit then further reduces the NOx concentration by 86 percent to 0.07 lb/10⁶ Btu.

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.8 percent.

Co-benefit capture results in a 90 percent reduction of mercury emissions.

CO_2 emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 4-36. The carbon input to the plant consists of carbon in the coal, carbon in the air, and carbon in the limestone reagent used in the FGD. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant mostly as CO_2 through the stack but also leaves as gypsum.

Exhibit 4-36 Case 11 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	118,411 (261,052)	**Stack Gas**	120,377 (265,385)
Air (CO₂)	257 (567)	**FGD Product**	163 (358)
FGD Reagent	1,871 (4,124)		
Total	120,539 (265,744)	**Total**	120,539 (265,744)

Exhibit 4-37 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes sulfur emitted in the stack gas and the sulfur recovered from the FGD as gypsum.

Exhibit 4-37 Case 11 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	4,656 (10,264)	Stack Gas	93 (205)
		FGD Product	4,563 (10,059)
Total	4,656 (10,264)	Total	4,656 (10,264)

Exhibit 4-38 shows the overall water balance for the plant. Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is re-used as internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a surface-water source for use in the plant and was assumed to be provided 50 percent by a POTW and 50 percent from groundwater. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for any and all purposes, such as FDG makeup, BFW makeup, and cooling tower makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source balance.

Exhibit 4-38 Case 11 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Withdrawal, m^3/min (gpm)	Process Water Discharge, m^3/min (gpm)	Raw Water Consumption, m^3/min (gpm)
FGD Makeup	3.6 (951)	0.0 (0)	3.6 (951)	0.0 (0)	3.6 (951)
BFW Makeup	0.0 (0)	0.0 (0)	0.0 (0)	0.0 (0)	0.0 (0)
Cooling Tower	18.4 (4,863)	1.9 (492)	16.5 (4,370)	4.1 (1,094)	12.4 (3,277)
Total	**22.0 (5,813)**	**1.9 (492)**	**20.1 (5,321)**	**4.1 (1,094)**	**16.0 (4,227)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the Case 11 PC boiler, the FGD unit and steam cycle in Exhibit 4-39 and Exhibit 4-40. An overall plant energy balance is provided in tabular form in Exhibit 4-41. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-34) is calculated by multiplying the power out by a generator efficiency of 98.4 percent.

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Exhibit 4-39 Case 11 Heat and Mass Balance, Supercritical PC Boiler without CO₂ Capture
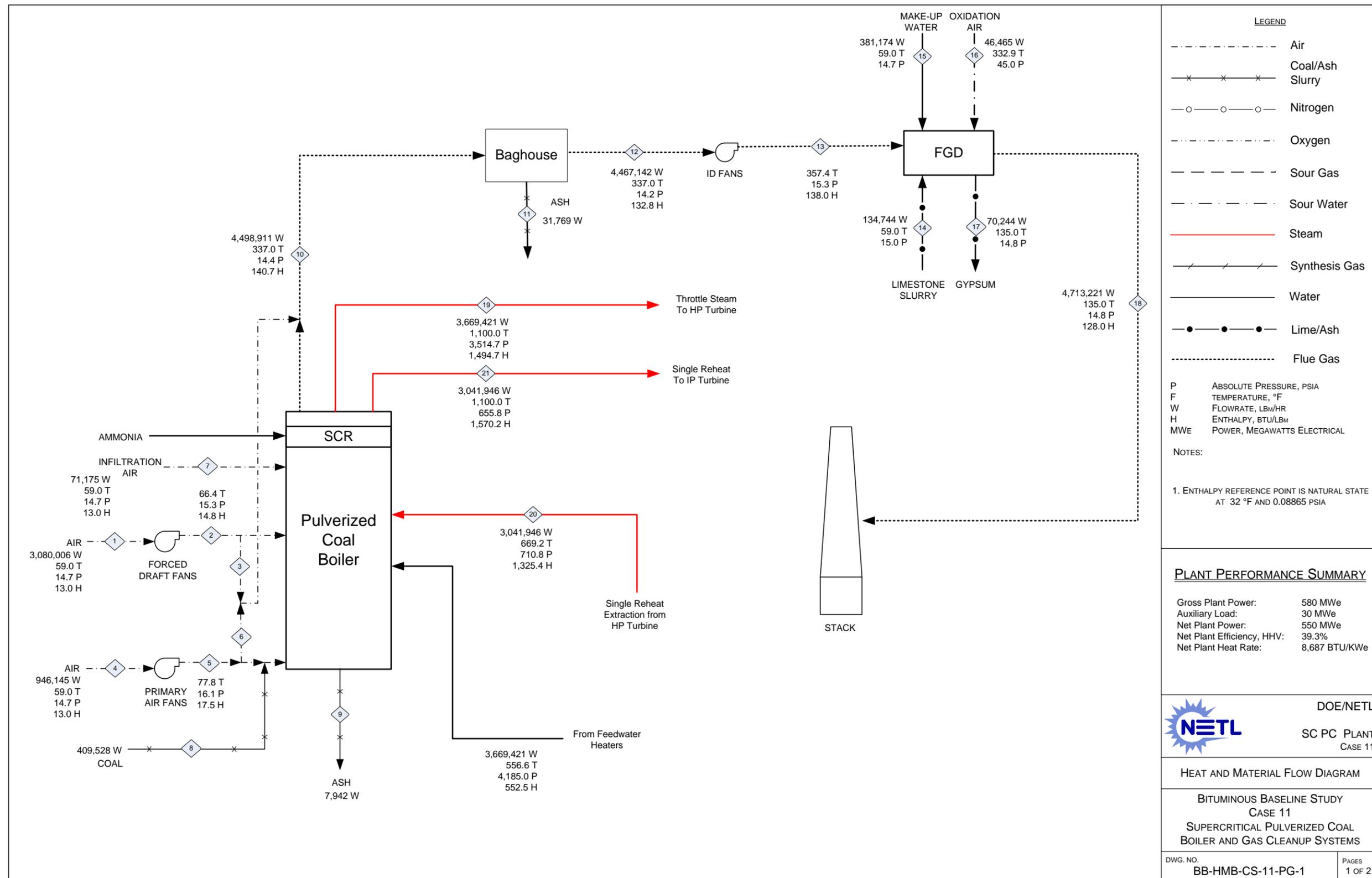
Exhibit 4-40 Case 11 Heat and Mass Balance, Supercritical Steam Cycle
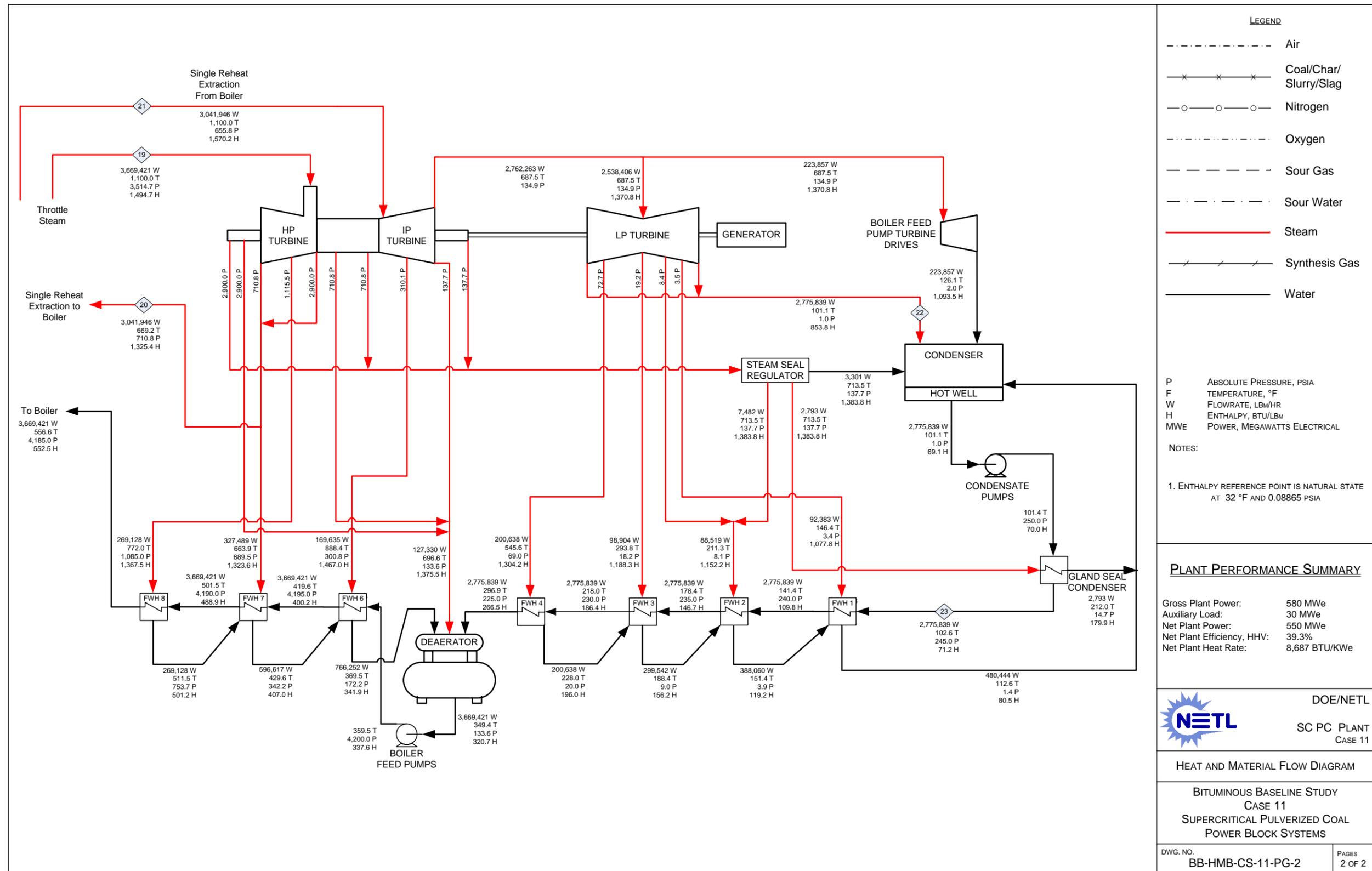
Exhibit 4-41 Case 11 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	5,041 (4,778)	4.2 (4.0)		5,045 (4,782)
Air		56.2 (53.2)		56.2 (53.2)
Raw Water Makeup		76.8 (72.8)		76.8 (72.8)
Limestone		0.21 (0.20)		0.21 (0.20)
Auxiliary Power			110 (104)	110 (104)
Totals	**5,041 (4,778)**	**137.4 (130.3)**	**110 (104)**	**5,288 (5,012)**
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash		0.4 (0.4)		0.4 (0.4)
Fly Ash + FGD Ash		1.7 (1.7)		1.7 (1.7)
Flue Gas		636 (603)		636 (603)
Condenser		2,298 (2,178)		2,298 (2,178)
Cooling Tower Blowdown		30.8 (29.2)		30.8 (29.2)
Process Losses*		*231 (219)*		*231 (219)*
Power			2,089 (1,980)	2,089 (1,980)
Totals	**0 (0)**	**3,198 (3,031)**	**2,089 (1,980)**	**5,288 (5,012)**

* Process losses are estimated to match the heat input to the plant. Process losses include losses from: turbines, gas cooling, etc.

4.3.5 Case 11 – Major Equipment List

Major equipment items for the SC PC plant with no CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.3.6. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1   FUEL AND SORBENT HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	36 tonne (40 ton)	2	1
9	Feeder	Vibratory	154 tonne/hr (170 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	308 tonne/hr (340 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	154 tonne (170 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	308 tonne/hr (340 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	308 tonne/hr (340 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	726 tonne (800 ton)	3	0
19	Limestone Truck Unloading Hopper	N/A	36 tonne (40 ton)	1	0
20	Limestone Feeder	Belt	82 tonne/hr (90 tph)	1	0
21	Limestone Conveyor No. L1	Belt	82 tonne/hr (90 tph)	1	0
22	Limestone Reclaim Hopper	N/A	18 tonne (20 ton)	1	0
23	Limestone Reclaim Feeder	Belt	64 tonne/hr (70 tph)	1	0
24	Limestone Conveyor No. L2	Belt	64 tonne/hr (70 tph)	1	0
25	Limestone Day Bin	w/ actuator	245 tonne (270 ton)	2	0

ACCOUNT 2   COAL AND SORBENT PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	36 tonne/hr (40 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	36 tonne/hr (40 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	20 tonne/hr (22 tph)	1	1
4	Limestone Ball Mill	Rotary	20 tonne/hr (22 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	75,708 liters (20,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,287 lpm @ 12m H2O (340 gpm @ 40 ft H2O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5 cyclone bank	341 lpm (90 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	439,108 liters (116,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	908 lpm @ 9m H2O (240 gpm @ 30 ft H2O)	1	1

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,101,555 liters (291,000 gal)	2	0
2	Condensate Pumps	Vertical canned	23,091 lpm @ 213 m H2O (6,100 gpm @ 700 ft H2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	1,830,699 kg/hr (4,036,000 lb/hr), 5 min. tank	1	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	30,662 lpm @ 3,444 m H2O (8,100 gpm @ 11,300 ft H2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	9,085 lpm @ 3,444 m H2O (2,400 gpm @ 11,300 ft H2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	693,996 kg/hr (1,530,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	693,996 kg/hr (1,530,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	693,996 kg/hr (1,530,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	693,996 kg/hr (1,530,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	1,832,513 kg/hr (4,040,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	1,832,513 kg/hr (4,040,000 lb/hr)	1	0
12	HP Feedwater heater 8	Horizontal U-tube	1,832,513 kg/hr (4,040,000 lb/hr)	1	0
13	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/hr, 2.8 MPa, 343℃ (40,000 lb/hr, 400 psig, 650°F)	1	0
14	Fuel Oil System	No. 2 fuel oil for light off	1,135,624 liter (300,000 gal)	1	0
15	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
16	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
17	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 30 m H2O (5,500 gpm @ 100 ft H2O)	2	1
19	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H2O (1,000 gpm @ 290 ft H2O)	1	1
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H2O (700 gpm @ 210 ft H2O)	1	1
21	Raw Water Pumps	Stainless steel, single suction	5,943 lpm @ 18 m H2O (1,570 gpm @ 60 ft H2O)	2	1
22	Ground Water Pumps	Stainless steel, single suction	2,385 lpm @ 268 m H2O (630 gpm @ 880 ft H2O)	5	1
23	Filtered Water Pumps	Stainless steel, single suction	1,893 lpm @ 49 m H2O (500 gpm @ 160 ft H2O)	2	1
24	Filtered Water Tank	Vertical, cylindrical	1,816,998 liter (480,000 gal)	1	0
25	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	606 lpm (160 gpm)	1	1
26	Liquid Waste Treatment System	--	10 years, 24-hour storm	1	0

ACCOUNT 4   **BOILER AND ACCESSORIES**

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, drum, wall-fired, low NOx burners, overfire air	1,832,513 kg/hr steam @ 25.5 MPa/602°C/602°C (4,040,000 lb/hr steam @ 3,700 psig/1,115°F/1,115°F)	1	0
2	Primary Air Fan	Centrifugal	235,868 kg/hr, 3,220 m3/min @ 123 cm WG (520,000 lb/hr, 113,700 acfm @ 48 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	768,385 kg/hr, 10,486 m3/min @ 47 cm WG (1,694,000 lb/hr, 370,300 acfm @ 19 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,114,476 kg/hr, 23,469 m3/min @ 91 cm WG (2,457,000 lb/hr, 828,800 acfm @ 36 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	2,227,139 kg/hr (4,910,000 lb/hr)	2	0
6	SCR Catalyst	--	--	3	0
7	Dilution Air Blower	Centrifugal	133 m3/min @ 108 cm WG (4,700 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	147,631 liter (39,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	28 lpm @ 91 m H2O (7 gpm @ 300 ft H2O)	2	1

ACCOUNT 5   FLUE GAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,114,476 kg/hr (2,457,000 lb/hr) 99.8% efficiency	2	0
2	Absorber Module	Counter-current open spray	44,769 m3/min (1,581,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	155,202 lpm @ 64 m H2O (41,000 gpm @ 210 ft H2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	3,975 lpm (1,050 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	78 m3/min @ 0.3 MPa (2,770 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	984 lpm (260 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	32 tonne/hr (35 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	606 lpm @ 12 m H2O (160 gpm @ 40 ft H2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	378,541 lpm (100,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	3,180 lpm @ 21 m H2O (840 gpm @ 70 ft H2O)	1	1

ACCOUNT 6   COMBUSTION TURBINE/ACCESSORIES

N/A

ACCOUNT 7   HRSG, DUCTING & STACK

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

ACCOUNT 8   STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	611 MW 24.1 MPa/593°C/593°C (3500 psig/ 1100°F/1100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	680 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	2,532 GJ/hr (2,400 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9   COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	473,200 lpm @ 30 m (125,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 2648 GJ/hr (2510 MMBtu/hr) heat duty	1	0

ACCOUNT 10   ASH/SPENT SORBENT RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	--	--	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	--	--	2	0
3	Clinker Grinder	--	3.6 tonne/hr (4 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	--	--	6	0
5	Hydroejectors	--	--	12	
6	Economizer /Pyrites Transfer Tank	--	--	1	0
7	Ash Sluice Pumps	Vertical, wet pit	151 lpm @ 17 m H2O (40 gpm @ 56 ft H2O)	1	1
8	Ash Seal Water Pumps	Vertical, wet pit	7,571 lpm @ 9 m H2O (2000 gpm @ 28 ft H2O)	1	1
9	Hydrobins	--	151 lpm (40 gpm)	1	1
10	Baghouse Hopper (part of baghouse scope of supply)	--	--	24	0
11	Air Heater Hopper (part of boiler scope of supply)	--	--	10	0
12	Air Blower	--	14 m3/min @ 0.2 MPa (510 scfm @ 24 psi)	1	1
13	Fly Ash Silo	Reinforced concrete	907 tonne (1,000 ton)	2	0
14	Slide Gate Valves	--	--	2	0
15	Unloader	--	--	1	0
16	Telescoping Unloading Chute	--	91 tonne/hr (100 tph)	1	0

ACCOUNT 11   ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 650 MVA, 3-ph, 60 Hz	1	0
2	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 32 MVA, 3-ph, 60 Hz	1	1
3	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 5 MVA, 3-ph, 60 Hz	1	1
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
5	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
6	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
7	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12   INSTRUMENTATION AND CONTROL

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

4.3.6   Case 11 – Costs Estimating Results

The cost estimating methodology was described previously in Section 2.7. Exhibit 4-42 shows the total plant capital cost summary organized by cost account and Exhibit 4-43 shows a more detailed breakdown of the capital costs as well as owner's costs, TOC, and TASC. Exhibit 4-44 shows the initial and annual O&M costs.

The estimated TOC of the SC PC boiler with no CO_2 capture is \$2,024/kW. No process contingency was included in this case because all elements of the technology are commercially proven. The project contingency is 8.7 percent of the TOC. The COE is 58.9 mills/kWh.

Exhibit 4-42 Case 11 Total Plant Cost Summary

Client:		USDOE/NETL						Report Date:	2010-Jan-14		
Project:		Bituminous Baseline Study									
		TOTAL PLANT COST SUMMARY									
Case:		Case 11 - 1x550 MWnet SuperCritical PC									
Plant Size:		550.0 MW,net	Estimate Type:	Conceptual			Cost Base (Jun)	2007	($x1000)		

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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$16,381	$4,414	$9,819	$0	$0	**$30,614**	$2,747	$0	$5,004	**$38,365**	$70
2	COAL & SORBENT PREP & FEED	$11,008	$637	$2,793	$0	$0	**$14,438**	$1,265	$0	$2,356	**$18,059**	$33
3	FEEDWATER & MISC. BOP SYSTEMS	$42,453	$0	$19,927	$0	$0	**$62,380**	$5,705	$0	$11,064	**$79,149**	$144
4	PC BOILER											
4.1	PC Boiler & Accessories	$157,253	$0	$88,235	$0	$0	**$245,488**	$23,891	$0	$26,938	**$296,317**	$539
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
4.4-4.9	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$157,253**	**$0**	**$88,235**	**$0**	**$0**	**$245,488**	**$23,891**	**$0**	**$26,938**	**$296,317**	**$539**
5	FLUE GAS CLEANUP	$79,643	$0	$27,049	$0	$0	**$106,692**	$10,211	$0	$11,690	**$128,593**	$234
5B	CO$_2$ REMOVAL & COMPRESSION	$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
6.2-6.9	Combustion Turbine Other	$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
7.2-7.9	HRSG Accessories, Ductwork and Stack	$17,397	$1,000	$11,814	$0	$0	**$30,211**	$2,773	$0	$4,307	**$37,291**	$68
	SUBTOTAL 7	**$17,397**	**$1,000**	**$11,814**	**$0**	**$0**	**$30,211**	**$2,773**	**$0**	**$4,307**	**$37,291**	**$68**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$51,625	$0	$6,866	$0	$0	**$58,491**	$5,606	$0	$6,410	**$70,507**	$128
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$22,954	$1,089	$12,590	$0	$0	**$36,633**	$3,228	$0	$5,580	**$45,441**	$83
	SUBTOTAL 8	**$74,579**	**$1,089**	**$19,456**	**$0**	**$0**	**$95,124**	**$8,833**	**$0**	**$11,990**	**$115,948**	**$211**
9	COOLING WATER SYSTEM	$12,303	$6,296	$11,466	$0	$0	**$30,066**	$2,830	$0	$4,475	**$37,370**	$68
10	ASH/SPENT SORBENT HANDLING SYS	$4,409	$140	$5,895	$0	$0	**$10,444**	$1,004	$0	$1,178	**$12,627**	$23
11	ACCESSORY ELECTRIC PLANT	$17,541	$6,187	$18,041	$0	$0	**$41,769**	$3,682	$0	$5,617	**$51,068**	$93
12	INSTRUMENTATION & CONTROL	$8,739	$0	$8,862	$0	$0	**$17,601**	$1,596	$0	$2,358	**$21,555**	$39
13	IMPROVEMENTS TO SITE	$2,969	$1,707	$5,984	$0	$0	**$10,660**	$1,052	$0	$2,342	**$14,054**	$26
14	BUILDINGS & STRUCTURES	$0	$22,720	$21,552	$0	$0	**$44,272**	$3,994	$0	$7,240	**$55,506**	$101
	TOTAL COST	**$444,675**	**$44,192**	**$250,892**	**$0**	**$0**	**$739,759**	**$69,584**	**$0**	**$96,558**	**$905,901**	**$1,647**

Exhibit 4-43 Case 11 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,368	$0	$1,538	$0	$0	$4,906	$438	$0	$802	$6,146	$11
1.2	Coal Stackout & Reclaim	$4,352	$0	$986	$0	$0	$5,338	$467	$0	$871	$6,676	$12
1.3	Coal Conveyors	$4,046	$0	$976	$0	$0	$5,022	$440	$0	$819	$6,282	$11
1.4	Other Coal Handling	$1,059	$0	$226	$0	$0	$1,284	$112	$0	$209	$1,606	$3
1.5	Sorbent Receive & Unload	$135	$0	$41	$0	$0	$175	$15	$0	$29	$219	$0
1.6	Sorbent Stackout & Reclaim	$2,176	$0	$399	$0	$0	$2,574	$224	$0	$420	$3,218	$6
1.7	Sorbent Conveyors	$776	$168	$190	$0	$0	$1,135	$98	$0	$185	$1,418	$3
1.8	Other Sorbent Handling	$469	$110	$246	$0	$0	$825	$73	$0	$135	$1,032	$2
1.9	Coal & Sorbent Hnd.Foundations	$0	$4,136	$5,218	$0	$0	$9,354	$879	$0	$1,535	$11,767	$21
	SUBTOTAL 1.	$16,381	$4,414	$9,819	$0	$0	$30,614	$2,747	$0	$5,004	$38,365	$70
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$1,929	$0	$376	$0	$0	$2,305	$201	$0	$376	$2,881	$5
2.2	Coal Conveyor to Storage	$4,939	$0	$1,078	$0	$0	$6,017	$526	$0	$981	$7,524	$14
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	$3,695	$159	$768	$0	$0	$4,622	$402	$0	$754	$5,778	$11
2.6	Sorbent Storage & Feed	$445	$0	$171	$0	$0	$616	$55	$0	$101	$771	$1
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	$478	$401	$0	$0	$879	$81	$0	$144	$1,105	$2
	SUBTOTAL 2.	$11,008	$637	$2,793	$0	$0	$14,438	$1,265	$0	$2,356	$18,059	$33
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$18,623	$0	$6,016	$0	$0	$24,638	$2,153	$0	$4,019	$30,810	$56
3.2	Water Makeup & Pretreating	$4,460	$0	$1,436	$0	$0	$5,895	$557	$0	$1,291	$7,743	$14
3.3	Other Feedwater Subsystems	$5,701	$0	$2,409	$0	$0	$8,111	$727	$0	$1,326	$10,163	$18
3.4	Service Water Systems	$874	$0	$476	$0	$0	$1,350	$127	$0	$295	$1,772	$3
3.5	Other Boiler Plant Systems	$6,807	$0	$6,721	$0	$0	$13,528	$1,285	$0	$2,222	$17,035	$31
3.6	FO Supply Sys & Nat Gas	$255	$0	$319	$0	$0	$574	$54	$0	$94	$723	$1
3.7	Waste Treatment Equipment	$3,024	$0	$1,724	$0	$0	$4,747	$462	$0	$1,042	$6,251	$11
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$2,709	$0	$828	$0	$0	$3,536	$340	$0	$775	$4,652	$8
	SUBTOTAL 3.	$42,453	$0	$19,927	$0	$0	$62,380	$5,705	$0	$11,064	$79,149	$144
4	PC BOILER											
4.1	PC Boiler & Accessories	$157,253	$0	$88,235	$0	$0	$245,488	$23,891	$0	$26,938	$296,317	$539
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.	$157,253	$0	$88,235	$0	$0	$245,488	$23,891	$0	$26,938	$296,317	$539

Exhibit 4-43 Case 11 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	$55,471	$0	$11,942	$0	$0	$67,413	$6,427	$0	$7,384	$81,224	$148
5.2	Other FGD	$2,895	$0	$3,280	$0	$0	$6,175	$599	$0	$677	$7,452	$14
5.3	Bag House & Accessories	$15,622	$0	$9,914	$0	$0	$25,536	$2,461	$0	$2,800	$30,797	$56
5.4	Other Particulate Removal Materials	$1,057	$0	$1,131	$0	$0	$2,189	$212	$0	$240	$2,641	$5
5.5	Gypsum Dewatering System	$4,598	$0	$781	$0	$0	$5,379	$512	$0	$589	$6,480	$12
5.6	Mercury Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.9	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	$79,643	$0	$27,049	$0	$0	$106,692	$10,211	$0	$11,690	$128,593	$234
5B	CO$_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
	SUBTOTAL 5.	$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	$8,675	$0	$5,574	$0	$0	$14,249	$1,242	$0	$2,324	$17,816	$32
7.4	Stack	$8,721	$0	$5,103	$0	$0	$13,824	$1,331	$0	$1,516	$16,671	$30
7.9	Duct & Stack Foundations	$0	$1,000	$1,137	$0	$0	$2,137	$200	$0	$467	$2,804	$5
	SUBTOTAL 7.	$17,397	$1,000	$11,814	$0	$0	$30,211	$2,773	$0	$4,307	$37,291	$68
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$51,625	$0	$6,866	$0	$0	$58,491	$5,606	$0	$6,410	$70,507	$128
8.2	Turbine Plant Auxiliaries	$347	$0	$744	$0	$0	$1,091	$107	$0	$120	$1,317	$2
8.3	Condenser & Auxiliaries	$6,712	$0	$2,288	$0	$0	$9,000	$861	$0	$986	$10,848	$20
8.4	Steam Piping	$15,895	$0	$7,837	$0	$0	$23,732	$1,994	$0	$3,859	$29,585	$54
8.9	TG Foundations	$0	$1,089	$1,721	$0	$0	$2,810	$266	$0	$615	$3,691	$7
	SUBTOTAL 8.	$74,579	$1,089	$19,456	$0	$0	$95,124	$8,833	$0	$11,990	$115,948	$211
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$9,084	$0	$2,829	$0	$0	$11,913	$1,139	$0	$1,305	$14,358	$26
9.2	Circulating Water Pumps	$1,887	$0	$116	$0	$0	$2,003	$169	$0	$217	$2,389	$4
9.3	Circ.Water System Auxiliaries	$498	$0	$66	$0	$0	$565	$54	$0	$62	$680	$1
9.4	Circ.Water Piping	$0	$3,950	$3,828	$0	$0	$7,779	$728	$0	$1,276	$9,783	$18
9.5	Make-up Water System	$438	$0	$585	$0	$0	$1,024	$98	$0	$168	$1,290	$2
9.6	Component Cooling Water Sys	$395	$0	$314	$0	$0	$709	$67	$0	$116	$892	$2
9.9	Circ.Water System Foundations& Structures	$0	$2,346	$3,727	$0	$0	$6,073	$575	$0	$1,330	$7,977	$15
	SUBTOTAL 9.	$12,303	$6,296	$11,466	$0	$0	$30,066	$2,830	$0	$4,475	$37,370	$68

Exhibit 4-43 Case 11 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
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	$590	$0	$1,818	$0	$0	$2,408	$236	$0	$264	$2,909	$5
10.7	Ash Transport & Feed Equipment	$3,819	$0	$3,912	$0	$0	$7,731	$739	$0	$847	$9,317	$17
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$140	$165	$0	$0	$305	$29	$0	$67	$401	$1
	SUBTOTAL 10.	$4,409	$140	$5,895	$0	$0	$10,444	$1,004	$0	$1,178	$12,627	$23
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$1,598	$0	$260	$0	$0	$1,858	$172	$0	$152	$2,182	$4
11.2	Station Service Equipment	$2,824	$0	$928	$0	$0	$3,752	$351	$0	$308	$4,410	$8
11.3	Switchgear & Motor Control	$3,247	$0	$552	$0	$0	$3,798	$352	$0	$415	$4,565	$8
11.4	Conduit & Cable Tray	$0	$2,035	$7,038	$0	$0	$9,073	$878	$0	$1,493	$11,445	$21
11.5	Wire & Cable	$0	$3,841	$7,414	$0	$0	$11,255	$948	$0	$1,830	$14,034	$26
11.6	Protective Equipment	$260	$0	$885	$0	$0	$1,146	$112	$0	$126	$1,383	$3
11.7	Standby Equipment	$1,277	$0	$29	$0	$0	$1,306	$120	$0	$143	$1,568	$3
11.8	Main Power Transformers	$8,335	$0	$172	$0	$0	$8,507	$646	$0	$915	$10,068	$18
11.9	Electrical Foundations	$0	$311	$763	$0	$0	$1,074	$103	$0	$235	$1,412	$3
	SUBTOTAL 11.	$17,541	$6,187	$18,041	$0	$0	$41,769	$3,682	$0	$5,617	$51,068	$93
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	$450	$0	$270	$0	$0	$720	$68	$0	$118	$906	$2
12.7	Distributed Control System Equipment	$4,543	$0	$794	$0	$0	$5,337	$495	$0	$583	$6,415	$12
12.8	Instrument Wiring & Tubing	$2,463	$0	$4,885	$0	$0	$7,348	$626	$0	$1,196	$9,170	$17
12.9	Other I & C Equipment	$1,284	$0	$2,913	$0	$0	$4,197	$407	$0	$460	$5,064	$9
	SUBTOTAL 12.	$8,739	$0	$8,862	$0	$0	$17,601	$1,596	$0	$2,358	$21,555	$39

Exhibit 4-43 Case 11 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$50	$998	$0	$0	$1,048	$104	$0	$230	$1,382	$3
13.2	Site Improvements	$0	$1,657	$2,058	$0	$0	$3,715	$366	$0	$816	$4,897	$9
13.3	Site Facilities	$2,969	$0	$2,928	$0	$0	$5,897	$581	$0	$1,296	$7,774	$14
	SUBTOTAL 13.	$2,969	$1,707	$5,984	$0	$0	$10,660	$1,052	$0	$2,342	$14,054	$26
14	BUILDINGS & STRUCTURES											
14.1	Boiler Building	$0	$8,281	$7,282	$0	$0	$15,564	$1,399	$0	$2,544	$19,507	$35
14.2	Turbine Building	$0	$11,828	$11,024	$0	$0	$22,851	$2,060	$0	$3,737	$28,648	$52
14.3	Administration Building	$0	$586	$620	$0	$0	$1,206	$109	$0	$197	$1,513	$3
14.4	Circulation Water Pumphouse	$0	$168	$134	$0	$0	$301	$27	$0	$49	$378	$1
14.5	Water Treatment Buildings	$0	$566	$516	$0	$0	$1,081	$97	$0	$177	$1,356	$2
14.6	Machine Shop	$0	$392	$264	$0	$0	$656	$58	$0	$107	$821	$1
14.7	Warehouse	$0	$266	$267	$0	$0	$532	$48	$0	$87	$668	$1
14.8	Other Buildings & Structures	$0	$217	$185	$0	$0	$402	$36	$0	$66	$504	$1
14.9	Waste Treating Building & Str.	$0	$416	$1,262	$0	$0	$1,678	$159	$0	$276	$2,112	$4
	SUBTOTAL 14.	$0	$22,720	$21,552	$0	$0	$44,272	$3,994	$0	$7,240	$55,506	$101
	TOTAL COST	$444,675	$44,192	$250,892	$0	$0	$739,759	$69,584	$0	$96,558	$905,901	$1,647

											TOTAL PLANT COST $	$/kW
	Owner's Costs											
	Preproduction Costs											
	6 Months All Labor										$7,258	$13
	1 Month Maintenance Materials										$895	$2
	1 Month Non-fuel Consumables										$892	$2
	1 Month Waste Disposal										$235	$0
	25% of 1 Months Fuel Cost at 100% CF										$1,427	$3
	2% of TPC										$18,118	$33
	Total										**$28,826**	**$52**
	Inventory Capital											
	60 day supply of fuel and consumables at 100% CF										$12,944	$24
	0.5% of TPC (spare parts)										$4,530	$8
	Total										**$17,474**	**$32**
	Initial Cost for Catalyst and Chemicals										$0	$0
	Land										$900	$2
	Other Owner's Costs										$135,885	$247
	Financing Costs										$24,459	$44
	Total Overnight Costs (TOC)										**$1,113,445**	**$2,024**
	TASC Multiplier						(IOU, low-risk, 35 year)				1.134	
	Total As-Spent Cost (TASC)										**$1,262,647**	**$2,296**

Exhibit 4-44 Case 11 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun):	2007
Case 11 - 1x550 MWnet SuperCritical PC					Heat Rate-net (Btu/kWh):	8,686
					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		

Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.	Total Plant
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	$5,524,319	$10.044
Maintenance Labor Cost	$6,088,905	$11.070
Administrative & Support Labor	$2,903,306	$5.279
Property Taxes and Insurance	$18,118,017	$32.941
TOTAL FIXED OPERATING COSTS	**$32,634,546**	**$59.333**

VARIABLE OPERATING COSTS						$/kWh-net
Maintenance Material Cost					**$9,133,357**	**$0.00223**

Consumables	Consumption Initial Fill	/Day	Unit Cost	Initial Fill Cost		
Water (/1000 gallons)	0	3,884	1.08	$0	$1,303,324	$0.00032
Chemicals						
MU & WT Chem.(lbs)	0	18,799	0.17	$0	$1,009,427	$0.00025
Limestone (ton)	0	488	21.63	$0	$3,273,667	$0.00080
Carbon (Mercury Removal) (lb)	0	0	1.05	$0	$0	$0.00000
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 (19% NH3) ton	0	74	129.80	$0	$2,960,869	$0.00072
Subtotal Chemicals				**$0**	**$7,243,963**	**$0.00177**
Other						
Supplemental Fuel (MBtu)	0	0	0.00	$0	$0	$0.00000
SCR Catalyst (m3)	w/equip.	0.31	5,775.94	$0	$553,798	$0.00014
Emission Penalties	0	0	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$553,798**	**$0.00014**
Waste Disposal						
Fly Ash (ton)	0	381	16.23	$0	$1,919,038	$0.00047
Bottom Ash (ton)	0	95	16.23	$0	$479,759	$0.00012
Subtotal-Waste Disposal				**$0**	**$2,398,797**	**$0.00059**
By-products & Emissions						
Gypsum (tons)	0	759	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$0**	**$20,633,239**	**$0.00504**
Fuel (ton)	0	4,914	38.18	$0	$58,217,892	$0.01422

4.3.7   <u>Case 12 – Supercritical PC with CO$_2$ Capture</u>

The plant configuration for Case 12, SC PC, is the same as Case 11 with the exception that the Econamine CDR technology was added for CO$_2$ capture. The nominal net output is maintained at 550 MW by increasing the boiler size and turbine/generator size to account for the greater auxiliary load imposed by the CDR facility. Unlike the IGCC cases where gross output was fixed by the available size of the CTs, the PC cases utilize boilers and steam turbines that can be procured at nearly any desired output making it possible to maintain a constant net output.

The process description for Case 12 is essentially the same as Case 11 with one notable exception, the addition of CO$_2$ capture. A BFD and stream tables for Case 12 are shown in Exhibit 4-45 and Exhibit 4-46, respectively. Since the CDR facility process description was provided in Section 4.1.7, it is not repeated here.

4.3.8   <u>Case 12 Performance Results</u>

The Case 12 modeling assumptions were presented previously in Section 4.3.2.

The plant produces a net output of 550 MW at a net plant efficiency of 28.4 percent (HHV basis). Overall plant performance is summarized in Exhibit 4-47, which includes auxiliary power requirements. The CDR facility, including CO$_2$ compression, accounts for approximately 58 percent of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for over 13 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility

Exhibit 4-45 Case 12 Block Flow Diagram, Supercritical Unit with CO$_2$ Capture

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

Exhibit 4-46 Case 12 Stream Table, Supercritical Unit with CO₂ Capture

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
V-L Mole Fraction														
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000
CO₂	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450	0.0000	0.1450	0.1450	0.0000
H₂	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
H₂O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870	0.0000	0.0870	0.0870	1.0000
N₂	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324	0.0000	0.7324	0.7324	0.0000
O₂	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247	0.0000	0.0247	0.0247	0.0000
SO₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021	0.0021	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	1.0000	1.0000	1.0000
V-L Flowrate (kg$_{mol}$/hr)	66,876	66,876	1,990	20,544	20,544	2,818	1,546	0	0	94,107	0	94,107	94,107	3,385
V-L Flowrate (kg/hr)	1,929,852	1,929,852	57,422	592,830	592,830	81,325	44,605	0	0	2,799,052	0	2,799,052	2,799,052	60,975
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	256,652	4,977	19,910	19,910	0	0	25,966
Temperature (°C)	15	19	19	15	25	25	15	15	15	169	15	169	182	15
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.10
Enthalpy (kJ/kg)^A	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	327.40	---	308.96	322.83	---
Density (kg/m³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	0.8	---	0.8	0.8	---
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	29.743	---	29.743	29.743	---
V-L Flowrate (lb$_{mol}$/hr)	147,437	147,437	4,387	45,291	45,291	6,213	3,408	0	0	207,471	0	207,471	207,471	7,462
V-L Flowrate (lb/hr)	4,254,595	4,254,595	126,595	1,306,967	1,306,967	179,291	98,338	0	0	6,170,854	0	6,170,854	6,170,854	134,426
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	565,820	10,973	43,893	43,893	0	0	57,245
Temperature (°F)	59	66	66	59	78	78	59	59	59	337	59	337	360	59
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.7	14.4	14.7	14.2	15.4	15.0
Enthalpy (Btu/lb)^A	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	140.8	---	132.8	138.8	---
Density (lb/ft³)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	0.050	---	0.049	0.052	---

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 4-46 Case 12 Stream Table, Supercritical Unit with CO_2 Capture (Continued)

	15	16	17	18	19	20	21	22	23	24	25	26	27	28
V-L Mole Fraction														
Ar	0.0000	0.0128	0.0000	0.0081	0.0108	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0005	0.0004	0.1350	0.0179	0.9961	0.9985	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
H_2O	1.0000	0.0062	0.9996	0.1537	0.0383	0.0039	0.0015	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.0000	0.7506	0.0000	0.6793	0.9013	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.2300	0.0000	0.0238	0.0316	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
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)	13,485	975	250	102,548	77,286	12,511	12,481	44,922	44,922	126,511	103,236	103,236	49,304	49,304
V-L Flowrate (kg/hr)	242,941	28,289	4,498	2,956,531	2,177,293	549,344	548,802	809,288	809,288	2,279,133	1,859,826	1,859,826	888,227	888,227
Solids Flowrate (kg/hr)	0	0	40,138	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	181	58	58	32	21	35	291	151	593	354	593	38	40
Pressure (MPa, abs)	0.10	0.31	0.10	0.10	0.10	0.16	15.27	0.51	0.92	24.23	4.90	4.52	0.01	1.69
Enthalpy (kJ/kg)^A	-46.80	191.58	---	301.43	93.86	19.49	-211.71	3,045.10	636.31	3,476.62	3,081.81	3,652.22	2,115.77	166.72
Density (kg/m^3)	1,003.1	2.4	---	1.1	1.1	2.9	795.9	2.0	916.0	69.2	18.7	11.6	0.1	993.2
V-L Molecular Weight	18.015	29.029	---	28.831	28.172	43.908	43.971	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb$_{mol}$/hr)	29,730	2,148	550	226,080	170,387	27,582	27,516	99,037	99,037	278,909	227,597	227,597	108,697	108,697
V-L Flowrate (lb/hr)	535,592	62,368	9,916	6,518,034	4,800,109	1,211,096	1,209,902	1,784,175	1,784,175	5,024,628	4,100,215	4,100,215	1,958,206	1,958,206
Solids Flowrate (lb/hr)	0	0	88,488	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	357	136	136	89	69	95	556	304	1,100	668	1,100	101	103
Pressure (psia)	14.7	45.0	14.9	14.9	14.7	23.5	2,214.5	73.5	133.6	3,514.7	710.8	655.8	1.0	245.0
Enthalpy (Btu/lb)^A	-20.1	82.4	---	129.6	40.4	8.4	-91.0	1,309.2	273.6	1,494.7	1,324.9	1,570.2	909.6	71.7
Density (lb/ft^3)	62.622	0.149	---	0.067	0.070	0.184	49.684	0.123	57.184	4.319	1.166	0.722	0.004	62.002

Exhibit 4-47 Case 12 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Steam Turbine Power	662,800
TOTAL (STEAM TURBINE) POWER, kWe	**662,800**
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling and Conveying	510
Pulverizers	3,850
Sorbent Handling & Reagent Preparation	1,250
Ash Handling	740
Primary Air Fans	1,800
Forced Draft Fans	2,300
Induced Draft Fans	11,120
SCR	70
Baghouse	100
Wet FGD	4,110
Econamine FG Plus Auxiliaries	20,600
CO_2 Compression	44,890
Miscellaneous Balance of Plant[2,3]	2,000
Steam Turbine Auxiliaries	400
Condensate Pumps	560
Circulating Water Pumps	10,100
Ground Water Pumps	910
Cooling Tower Fans	5,230
Transformer Losses	2,290
TOTAL AUXILIARIES, kWe	**112,830**
NET POWER, kWe	**549,970**
Net Plant Efficiency (HHV)	28.4%
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	12,663 (12,002)
CONDENSER COOLING DUTY, 10^6 kJ/hr (10^6 Btu/hr)	**1,737 (1,646)**
CONSUMABLES	
As-Received Coal Feed, kg/hr (lb/hr)	256,652 (565,820)
Limestone Sorbent Feed, kg/hr (lb/hr)	25,966 (57,245)
Thermal Input, kWt[1]	1,934,519
Raw Water Withdrawal, m³/min (gpm)	38.1 (10,071)
Raw Water Consumption, m³/min (gpm)	29.3 (7,733)

1. HHV of As-Received Illinois No. 6 coal is 27,135 kJ/kg (11,666 Btu/lb)
2. Boiler feed pumps are turbine driven
3. Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of Hg, NOx, SO_2, and PM were presented in Section 2.4. A summary of the plant air emissions for Case 12 is presented in Exhibit 4-48.

Exhibit 4-48 Case 12 Air Emissions

	kg/GJ (lb/10⁶ Btu)	Tonne/year (ton/year) 85% CF	kg/MWh (lb/MWh)
SO_2	0.001 (0.002)	36 (40)	0.007 (.02)
NOx	0.030 (0.070)	1,561 (1,720)	0.316 (.697)
Particulates	0.006 (0.0130)	290 (319)	0.059 (.129)
Hg	4.91E-7 (1.14E-6)	0.025 (0.028)	5.16E-6 (1.14E-5)
CO_2	8.8 (20.4)	453,763 (500,188)	92 (203)
$CO_2{}^1$			111 (244)

[1] CO_2 emissions based on net power instead of gross power

SO_2 emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The SO_2 emissions are further reduced to 10 ppmv using a NaOH based polishing scrubber in the CDR facility. The remaining low concentration of SO_2 is essentially completely removed in the CDR absorber vessel resulting in very low SO_2 emissions.

NOx emissions are controlled to about 0.5 lb/10⁶ Btu through the use of LNBs and OFA. An SCR unit then further reduces the NOx concentration by 86 percent to 0.07 lb/10⁶ Btu.

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.8 percent.

Co-benefit capture results in a 90 percent reduction of mercury emissions.

Ninety percent of the CO_2 in the FG is removed in CDR facility.

The carbon balance for the plant is shown in Exhibit 4-49. The carbon input to the plant consists of carbon in the coal in addition to carbon in the air and limestone for the FGD. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant as CO_2 in the stack gas, carbon in the FGD product, and the captured CO_2 product. The carbon capture efficiency is defined by the following fraction:

1-[(Stack Gas Carbon-Air Carbon)/(Total Carbon In-Air Carbon)] or
[1-(36,667-783)/(367,272-783) * 100] or
90.2 percent

Exhibit 4-49 Case 12 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	163,602 (360,680)	Stack Gas	16,632 (36,667)
Air (CO$_2$)	355 (783)	FGD Product	274 (605)
FGD Reagent	2,635 (5,809)	CO$_2$ Product	149,685 (329,999)
Total	166,592 (367,272)	Total	166,592 (367,272)

Exhibit 4-50 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur emitted in the stack gas, and sulfur removed in the polishing scrubber.

Exhibit 4-50 Case 12 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	6,433 (14,182)	FGD Product	6,304 (13,898)
		Stack Gas	2 (5)
		Econamine Polishing Scrubber/HSS	126 (278)
Total	6,433 (14,182)	Total	6,433 (14,182)

Exhibit 4-51 shows the overall water balance for the plant. The exhibit is presented in an identical manner as for Case 11.

Exhibit 4-51 Case 12 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Withdrawal, m^3/min (gpm)	Process Water Discharge, m^3/min (gpm)	Raw Water Consumption, m^3/min (gpm)
Econamine	0.1 (36)	0.0 (0)	0.1 (36)	0.00 (0)	0.1 (36)
FGD Makeup	5.1 (1,340)	0.0 (0)	5.1 (1,340)	0.00 (0)	5.1 (1,340)
BFW Makeup	0.0 (0)	0.0 (0)	0.0 (0)	0.00 (0)	0.0 (0)
Cooling Tower	39.4 (10,399)	6.5 (1,703)	32.9 (8,696)	8.9 (2,339)	24.1 (6,357)
Total	**44.6 (11,774)**	**6.5 (1,703)**	**38.1 (10,071)**	**8.9 (2,339)**	**29.3 (7,733)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the Case 12 PC boiler, the FGD unit, CDR system, and steam cycle in Exhibit 4-52 and Exhibit 4-53. An overall plant energy balance is provided in tabular form in Exhibit 4-54. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 4-47) is calculated by multiplying the power out by a generator efficiency of 98.5 percent. The Econamine process heat out stream represents heat rejected to cooling water and ultimately to ambient via the cooling tower. The same is true of the condenser heat out stream. The CO_2 compressor intercooler load is included in the Econamine process heat out stream.

Exhibit 4-52 Case 12 Heat and Mass Balance, Supercritical PC Boiler with CO₂ Capture
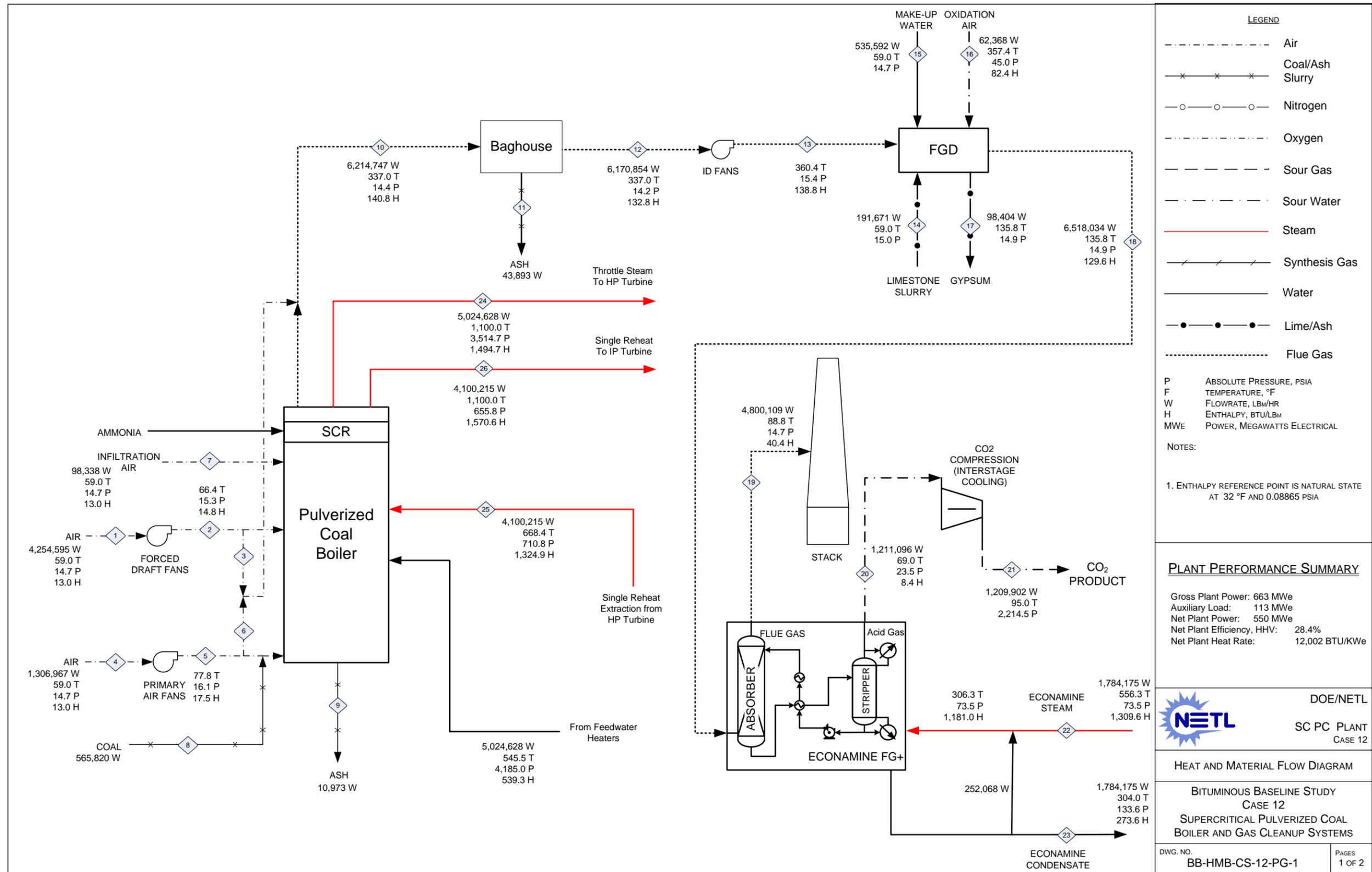
Exhibit 4-53 Case 12 Heat and Mass Balance, Supercritical Steam Cycle
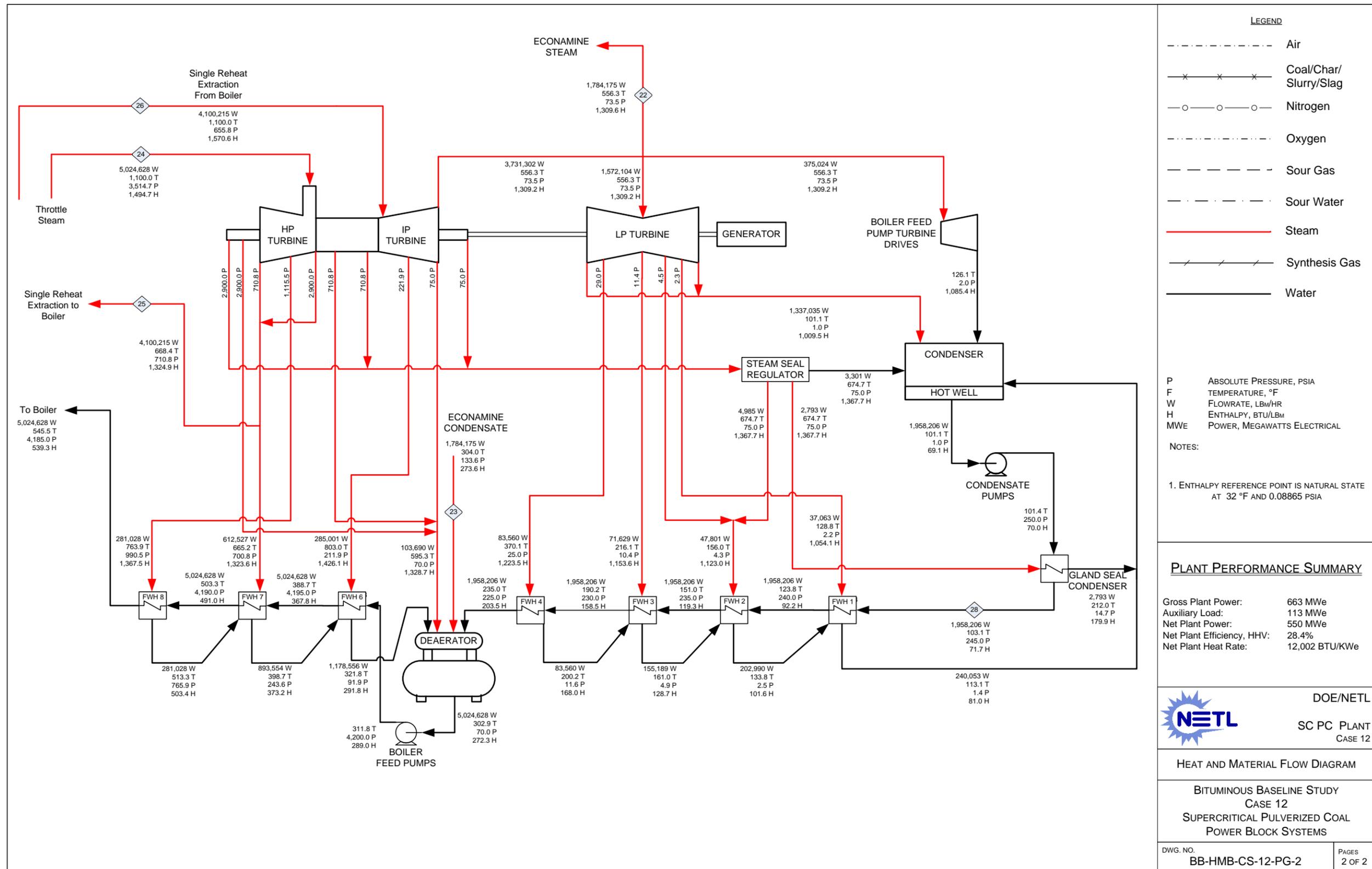
Exhibit 4-54 Case 12 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	6,964 (6,601)	5.8 (5.5)		6,970 (6,606)
Air		77.6 (73.6)		77.6 (73.6)
Raw Water Makeup		144.9 (137.3)		144.9 (137.3)
Limestone		0.29 (0.28)		0.29 (0.28)
Auxiliary Power			406 (385)	406 (385)
Totals	**6,964 (6,601)**	**228.6 (216.7)**	**406 (385)**	**7,599 (7,203)**
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash		0.6 (0.6)		0.6 (0.6)
Fly Ash + FGD Ash		2.4 (2.3)		2.4 (2.3)
Flue Gas		204 (194)		204 (194)
Condenser		1,737 (1,646)		1,737 (1,646)
CO_2		-116 (-110)		-116 (-110)
Cooling Tower Blowdown		65.8 (62.3)		65.8 (62.3)
Econamine Losses		3,298 (3,126)		3,298 (3,126)
Process Losses*		*21.3 (20.2)*		*21.3 (20.2)*
Power			2,386 (2,262)	2,386 (2,262)
Totals	**0 (0)**	**5,213 (4,941)**	**2,386 (2,262)**	**7,599 (7,203)**

* Process losses are estimated to match the heat input to the plant. Process losses include losses from: turbines, HRSGs, combustion reactions, gas cooling, etc.

4.3.9   Case 12 – Major Equipment List

Major equipment items for the SC PC plant with CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 4.3.10. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1   FUEL AND SORBENT HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	54 tonne (60 ton)	2	1
9	Feeder	Vibratory	209 tonne/hr (230 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	426 tonne/hr (470 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	209 tonne (230 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	426 tonne/hr (470 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	426 tonne/hr (470 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	907 tonne (1,000 ton)	3	0
19	Limestone Truck Unloading Hopper	N/A	36 tonne (40 ton)	1	0
20	Limestone Feeder	Belt	109 tonne/hr (120 tph)	1	0
21	Limestone Conveyor No. L1	Belt	109 tonne/hr (120 tph)	1	0
22	Limestone Reclaim Hopper	N/A	18 tonne (20 ton)	1	0
23	Limestone Reclaim Feeder	Belt	82 tonne/hr (90 tph)	1	0
24	Limestone Conveyor No. L2	Belt	82 tonne/hr (90 tph)	1	0
25	Limestone Day Bin	w/ actuator	345 tonne (380 ton)	2	0

ACCOUNT 2   COAL AND SORBENT PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	45 tonne/hr (50 tph)	6	0
2	Coal Pulverizer	Ball type or equivalent	45 tonne/hr (50 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	28 tonne/hr (31 tph)	1	1
4	Limestone Ball Mill	Rotary	28 tonne/hr (31 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	109,777 liters (29,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	1,855 lpm @ 12m H2O (490 gpm @ 40 ft H2O)	1	1
7	Hydroclone Classifier	4 active cyclones in a 5 cyclone bank	454 lpm (120 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	617,022 liters (163,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	1,287 lpm @ 9m H2O (340 gpm @ 30 ft H2O)	1	1

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	1,506,594 liters (398,000 gal)	2	0
2	Condensate Pumps	Vertical canned	16,277 lpm @ 213 m H2O (4,300 gpm @ 700 ft H2O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	2,507,005 kg/hr (5,527,000 lb/hr), 5 min. tank	1	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	42,018 lpm @ 3,505 m H2O (11,100 gpm @ 11,500 ft H2O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	12,492 lpm @ 3,505 m H2O (3,300 gpm @ 11,500 ft H2O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	489,880 kg/hr (1,080,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	489,880 kg/hr (1,080,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	489,880 kg/hr (1,080,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	489,880 kg/hr (1,080,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	2,508,366 kg/hr (5,530,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	2,508,366 kg/hr (5,530,000 lb/hr)	1	0
12	HP Feedwater heater 8	Horizontal U-tube	2,508,366 kg/hr (5,530,000 lb/hr)	1	0
13	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
14	Fuel Oil System	No. 2 fuel oil for light off	1,135,624 liter (300,000 gal)	1	0
15	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
16	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
17	Closed Cycle Cooling Heat Exchangers	Shell and tube	53 GJ/hr (50 MMBtu/hr) each	2	0
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	20,820 lpm @ 30 m H2O (5,500 gpm @ 100 ft H2O)	2	1
19	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H2O (1,000 gpm @ 290 ft H2O)	1	1
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H2O (700 gpm @ 210 ft H2O)	1	1
21	Raw Water Pumps	Stainless steel, single suction	11,016 lpm @ 18 m H2O (2,910 gpm @ 60 ft H2O)	2	1
22	Ground Water Pumps	Stainless steel, single suction	4,429 lpm @ 268 m H2O (1,170 gpm @ 880 ft H2O)	5	1
23	Filtered Water Pumps	Stainless steel, single suction	2,725 lpm @ 49 m H2O (720 gpm @ 160 ft H2O)	2	1
24	Filtered Water Tank	Vertical, cylindrical	2,619,505 liter (692,000 gal)	1	0
25	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	984 lpm (260 gpm)	1	1
26	Liquid Waste Treatment System	--	10 years, 24-hour storm	1	0

ACCOUNT 4   BOILER AND ACCESSORIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, drum, wall-fired, low NOx burners, overfire air	2,508,366 kg/hr steam @ 25.5 MPa/602°C/602°C (5,530,000 lb/hr steam @ 3,700 psig/1,115°F/1,115°F)	1	0
2	Primary Air Fan	Centrifugal	326,133 kg/hr, 4,449 m3/min @ 123 cm WG (719,000 lb/hr, 157,100 acfm @ 48 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	1,061,406 kg/hr, 14,484 m3/min @ 47 cm WG (2,340,000 lb/hr, 511,500 acfm @ 19 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	1,539,493 kg/hr, 32,491 m3/min @ 104 cm WG (3,394,000 lb/hr, 1,147,400 acfm @ 41 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	3,079,892 kg/hr (6,790,000 lb/hr)	2	0
6	SCR Catalyst	--	--	3	0
7	Dilution Air Blower	Centrifugal	184 m3/min @ 108 cm WG (6,500 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	200,627 liter (53,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	39 lpm @ 91 m H2O (10 gpm @ 300 ft H2O)	2	1

ACCOUNT 5   FLUE GAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	1,539,493 kg/hr (3,394,000 lb/hr) 99.8% efficiency	2	0
2	Absorber Module	Counter-current open spray	61,561 m3/min (2,174,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	215,768 lpm @ 64 m H2O (57,000 gpm @ 210 ft H2O)	5	1
4	Bleed Pumps	Horizontal centrifugal	5,565 lpm (1,470 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	109 m3/min @ 0.3 MPa (3,840 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	1,401 lpm (370 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	44 tonne/hr (49 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	833 lpm @ 12 m H2O (220 gpm @ 40 ft H2O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	567,812 lpm (150,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	4,467 lpm @ 21 m H2O (1,180 gpm @ 70 ft H2O)	1	1

ACCOUNT 5C   CARBON DIOXIDE RECOVERY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Econamine FG Plus	Amine-based CO2 capture technology	1,626,129 kg/h (3,585,000 lb/h) 20.6 wt % CO2 concentration	2	0
2	Econamine Condensate Pump	Centrifugal	16,959 lpm @ 52 m H2O (4,480 gpm @ 170 ft H2O)	1	1
3	CO2 Compressor	Integrally geared, multi-stage centrifugal	301,656 kg/h @ 15.3 MPa (665,037 lb/h @ 2,215 psia)	2	0

ACCOUNT 6   COMBUSTION TURBINE/ACCESSORIES

N/A

ACCOUNT 7   HRSG, DUCTING & STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	152 m (500 ft) high x 5.6 m (18 ft) diameter	1	0

ACCOUNT 8   STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	698 MW 24.1 MPa/593°C/593°C (3500 psig/ 1100°F/1100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	780 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,910 GJ/hr (1,810 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9   COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	1,014,500 lpm @ 30 m (268,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 5655 GJ/hr (5360 MMBtu/hr) heat duty	1	0

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	--	--	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	--	--	2	0
3	Clinker Grinder	--	5.4 tonne/hr (6 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	--	--	6	0
5	Hydroejectors	--	--	12	
6	Economizer /Pyrites Transfer Tank	--	--	1	0
7	Ash Sluice Pumps	Vertical, wet pit	227 lpm @ 17 m H2O (60 gpm @ 56 ft H2O)	1	1
8	Ash Seal Water Pumps	Vertical, wet pit	7,571 lpm @ 9 m H2O (2000 gpm @ 28 ft H2O)	1	1
9	Hydrobins	--	227 lpm (60 gpm)	1	1
10	Baghouse Hopper (part of baghouse scope of supply)	--	--	24	0
11	Air Heater Hopper (part of boiler scope of supply)	--	--	10	0
12	Air Blower	--	20 m3/min @ 0.2 MPa (710 scfm @ 24 psi)	1	1
13	Fly Ash Silo	Reinforced concrete	1,270 tonne (1,400 ton)	2	0
14	Slide Gate Valves	--	--	2	0
15	Unloader	--	--	1	0
16	Telescoping Unloading Chute	--	127 tonne/hr (140 tph)	1	0

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 650 MVA, 3-ph, 60 Hz	1	0
2	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 123 MVA, 3-ph, 60 Hz	1	1
3	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 18 MVA, 3-ph, 60 Hz	1	1
4	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
5	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
6	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
7	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROL

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

4.3.10 Case 12 – Cost Estimating Basis

The cost estimating methodology was described previously in Section 2.7. Exhibit 4-55 shows the total plant capital cost summary organized by cost account and Exhibit 4-56 shows a more detailed breakdown of the capital costs as well as owner's costs, TOC, and TASC. Exhibit 4-57 shows the initial and annual O&M costs.

The estimated TOC of the SC PC boiler with CO_2 capture is \$3,570/kW. Process contingency represents 2.8 percent of the TOC and project contingency represents 10.2 percent. The COE, including CO_2 TS&M costs of 5.7 mills/kWh, is 106.6 mills/kWh.

Exhibit 4-55 Case 12 Total Plant Cost Summary

Client:			USDOE/NETL							Report Date	2010-Jan-14	
Project:			Bituminous Baseline Study									
			TOTAL PLANT COST SUMMARY									
Case:			Case 12 - 1x550 MWnet Super-Critical PC w/ CO2 Capture									
Plant Size:			550.0 MW,net	**Estimate Type:**	Conceptual				**Cost Base (Jun)**	2007	($x1000)	

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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$20,098	$5,400	$12,019	$0	$0	**$37,517**	$3,366	$0	$6,132	**$47,015**	$85
2	COAL & SORBENT PREP & FEED	$13,673	$796	$3,473	$0	$0	**$17,942**	$1,572	$0	$2,927	**$22,442**	$41
3	FEEDWATER & MISC. BOP SYSTEMS	$54,851	$0	$25,849	$0	$0	**$80,700**	$7,397	$0	$14,455	**$102,552**	$186
4	PC BOILER											
4.1	PC Boiler & Accessories	$195,902	$0	$109,921	$0	$0	**$305,822**	$29,763	$0	$33,559	**$369,144**	$671
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
4.4-4.9	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$195,902**	**$0**	**$109,921**	**$0**	**$0**	**$305,822**	**$29,763**	**$0**	**$33,559**	**$369,144**	**$671**
5	FLUE GAS CLEANUP	$101,027	$0	$34,490	$0	$0	**$135,517**	$12,971	$0	$14,849	**$163,336**	$297
5B	CO2 REMOVAL & COMPRESSION	$235,366	$0	$71,742	$0	$0	**$307,108**	$29,363	$54,181	$78,130	**$468,782**	$852
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6.2-6.9	Combustion Turbine Other	$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
7.2-7.9	HRSG Accessories, Ductwork and Stack	$17,541	$961	$11,881	$0	$0	**$30,383**	$2,783	$0	$4,359	**$37,526**	$68
	SUBTOTAL 7	**$17,541**	**$961**	**$11,881**	**$0**	**$0**	**$30,383**	**$2,783**	**$0**	**$4,359**	**$37,526**	**$68**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$56,794	$0	$7,537	$0	$0	**$64,331**	$6,165	$0	$7,050	**$77,546**	$141
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$27,360	$1,200	$15,331	$0	$0	**$43,892**	$3,826	$0	$6,848	**$54,565**	$99
	SUBTOTAL 8	**$84,154**	**$1,200**	**$22,868**	**$0**	**$0**	**$108,222**	**$9,991**	**$0**	**$13,898**	**$132,111**	**$240**
9	COOLING WATER SYSTEM	$20,722	$9,941	$18,443	$0	$0	**$49,106**	$4,622	$0	$7,236	**$60,965**	$111
10	ASH/SPENT SORBENT HANDLING SYS	$5,276	$168	$7,053	$0	$0	**$12,497**	$1,202	$0	$1,410	**$15,108**	$27
11	ACCESSORY ELECTRIC PLANT	$25,213	$10,656	$30,191	$0	$0	**$66,060**	$5,843	$0	$9,029	**$80,931**	$147
12	INSTRUMENTATION & CONTROL	$10,017	$0	$10,157	$0	$0	**$20,174**	$1,829	$1,009	$2,826	**$25,838**	$47
13	IMPROVEMENTS TO SITE	$3,321	$1,909	$6,692	$0	$0	**$11,921**	$1,176	$0	$2,620	**$15,717**	$29
14	BUILDINGS & STRUCTURES	$0	$24,782	$23,519	$0	$0	**$48,301**	$4,357	$0	$7,899	**$60,557**	$110
	TOTAL COST	**$787,159**	**$55,813**	**$388,298**	**$0**	**$0**	**$1,231,270**	**$116,235**	**$55,190**	**$199,329**	**$1,602,023**	**$2,913**

Exhibit 4-56 Case 12 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$4,115	$0	$1,880	$0	$0	$5,995	$536	$0	$980	$7,510	$14
1.2	Coal Stackout & Reclaim	$5,318	$0	$1,205	$0	$0	$6,523	$571	$0	$1,064	$8,158	$15
1.3	Coal Conveyors	$4,944	$0	$1,192	$0	$0	$6,137	$538	$0	$1,001	$7,676	$14
1.4	Other Coal Handling	$1,294	$0	$276	$0	$0	$1,569	$137	$0	$256	$1,963	$4
1.5	Sorbent Receive & Unload	$168	$0	$51	$0	$0	$218	$19	$0	$36	$273	$0
1.6	Sorbent Stackout & Reclaim	$2,709	$0	$496	$0	$0	$3,205	$279	$0	$523	$4,007	$7
1.7	Sorbent Conveyors	$967	$209	$237	$0	$0	$1,413	$122	$0	$230	$1,765	$3
1.8	Other Sorbent Handling	$584	$137	$306	$0	$0	$1,027	$91	$0	$168	$1,285	$2
1.9	Coal & Sorbent Hnd.Foundations	$0	$5,054	$6,376	$0	$0	$11,430	$1,074	$0	$1,876	$14,379	$26
	SUBTOTAL 1.	$20,098	$5,400	$12,019	$0	$0	$37,517	$3,366	$0	$6,132	$47,015	$85
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$2,388	$0	$465	$0	$0	$2,853	$249	$0	$465	$3,567	$6
2.2	Coal Conveyor to Storage	$6,113	$0	$1,334	$0	$0	$7,447	$651	$0	$1,215	$9,313	$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	$4,617	$199	$959	$0	$0	$5,774	$503	$0	$942	$7,219	$13
2.6	Sorbent Storage & Feed	$556	$0	$213	$0	$0	$769	$68	$0	$126	$963	$2
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	$597	$501	$0	$0	$1,098	$102	$0	$180	$1,380	$3
	SUBTOTAL 2.	$13,673	$796	$3,473	$0	$0	$17,942	$1,572	$0	$2,927	$22,442	$41
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	Feedwater System	$22,860	$0	$7,384	$0	$0	$30,244	$2,643	$0	$4,933	$37,820	$69
3.2	Water Makeup & Pretreating	$6,997	$0	$2,252	$0	$0	$9,249	$875	$0	$2,025	$12,149	$22
3.3	Other Feedwater Subsystems	$6,998	$0	$2,958	$0	$0	$9,956	$892	$0	$1,627	$12,475	$23
3.4	Service Water Systems	$1,372	$0	$746	$0	$0	$2,118	$199	$0	$463	$2,780	$5
3.5	Other Boiler Plant Systems	$8,675	$0	$8,565	$0	$0	$17,240	$1,638	$0	$2,832	$21,709	$39
3.6	FO Supply Sys & Nat Gas	$276	$0	$345	$0	$0	$621	$59	$0	$102	$781	$1
3.7	Waste Treatment Equipment	$4,744	$0	$2,704	$0	$0	$7,448	$725	$0	$1,635	$9,808	$18
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$2,930	$0	$895	$0	$0	$3,825	$368	$0	$838	$5,031	$9
	SUBTOTAL 3.	$54,851	$0	$25,849	$0	$0	$80,700	$7,397	$0	$14,455	$102,552	$186
4	PC BOILER											
4.1	PC Boiler & Accessories	$195,902	$0	$109,921	$0	$0	$305,822	$29,763	$0	$33,559	$369,144	$671
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.	$195,902	$0	$109,921	$0	$0	$305,822	$29,763	$0	$33,559	$369,144	$671

Exhibit 4-56 Case 12 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	$70,185	$0	$15,109	$0	$0	$85,294	$8,132	$0	$9,343	$102,768	$187
5.2	Other FGD	$3,663	$0	$4,150	$0	$0	$7,813	$758	$0	$857	$9,428	$17
5.3	Bag House & Accessories	$20,190	$0	$12,813	$0	$0	$33,003	$3,180	$0	$3,618	$39,801	$72
5.4	Other Particulate Removal Materials	$1,366	$0	$1,462	$0	$0	$2,828	$274	$0	$310	$3,413	$6
5.5	Gypsum Dewatering System	$5,623	$0	$955	$0	$0	$6,579	$626	$0	$720	$7,925	$14
5.6	Mercury Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.9	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	$101,027	$0	$34,490	$0	$0	$135,517	$12,971	$0	$14,849	$163,336	$297
5B	CO2 REMOVAL & COMPRESSION											
5B.1	CO2 Removal System	$207,807	$0	$63,097	$0	$0	$270,904	$25,901	$54,181	$70,197	$421,183	$766
5B.2	CO2 Compression & Drying	$27,558	$0	$8,646	$0	$0	$36,204	$3,462	$0	$7,933	$47,599	$87
	SUBTOTAL 5.	$235,366	$0	$71,742	$0	$0	$307,108	$29,363	$54,181	$78,130	$468,782	$852
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	$9,165	$0	$5,889	$0	$0	$15,054	$1,313	$0	$2,455	$18,822	$34
7.4	Stack	$8,376	$0	$4,901	$0	$0	$13,277	$1,278	$0	$1,456	$16,011	$29
7.9	Duct & Stack Foundations	$0	$961	$1,092	$0	$0	$2,052	$192	$0	$449	$2,693	$5
	SUBTOTAL 7.	$17,541	$961	$11,881	$0	$0	$30,383	$2,783	$0	$4,359	$37,526	$68
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$56,794	$0	$7,537	$0	$0	$64,331	$6,165	$0	$7,050	$77,546	$141
8.2	Turbine Plant Auxiliaries	$382	$0	$819	$0	$0	$1,202	$118	$0	$132	$1,451	$3
8.3	Condenser & Auxiliaries	$5,509	$0	$2,030	$0	$0	$7,540	$722	$0	$826	$9,088	$17
8.4	Steam Piping	$21,469	$0	$10,585	$0	$0	$32,054	$2,693	$0	$5,212	$39,959	$73
8.9	TG Foundations	$0	$1,200	$1,896	$0	$0	$3,096	$293	$0	$678	$4,067	$7
	SUBTOTAL 8.	$84,154	$1,200	$22,868	$0	$0	$108,222	$9,991	$0	$13,898	$132,111	$240
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$15,451	$0	$4,811	$0	$0	$20,262	$1,938	$0	$2,220	$24,419	$44
9.2	Circulating Water Pumps	$3,219	$0	$248	$0	$0	$3,467	$293	$0	$376	$4,136	$8
9.3	Circ.Water System Auxiliaries	$787	$0	$105	$0	$0	$892	$85	$0	$98	$1,075	$2
9.4	Circ.Water Piping	$0	$6,243	$6,050	$0	$0	$12,293	$1,151	$0	$2,017	$15,460	$28
9.5	Make-up Water System	$641	$0	$857	$0	$0	$1,498	$144	$0	$246	$1,888	$3
9.6	Component Cooling Water Sys	$624	$0	$496	$0	$0	$1,120	$106	$0	$184	$1,410	$3
9.9	Circ.Water System Foundations & Structures	$0	$3,698	$5,876	$0	$0	$9,575	$906	$0	$2,096	$12,577	$23
	SUBTOTAL 9.	$20,722	$9,941	$18,443	$0	$0	$49,106	$4,622	$0	$7,236	$60,965	$111

Exhibit 4-56 Case 12 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
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	$706	$0	$2,175	$0	$0	$2,881	$283	$0	$316	$3,480	$6
10.7	Ash Transport & Feed Equipment	$4,570	$0	$4,681	$0	$0	$9,250	$885	$0	$1,014	$11,149	$20
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$168	$198	$0	$0	$365	$34	$0	$80	$479	$1
	SUBTOTAL 10.	**$5,276**	**$168**	**$7,053**	**$0**	**$0**	**$12,497**	**$1,202**	**$0**	**$1,410**	**$15,108**	**$27**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$1,727	$0	$280	$0	$0	$2,008	$186	$0	$165	$2,358	$4
11.2	Station Service Equipment	$4,957	$0	$1,629	$0	$0	$6,585	$616	$0	$540	$7,741	$14
11.3	Switchgear & Motor Control	$5,699	$0	$969	$0	$0	$6,667	$618	$0	$729	$8,014	$15
11.4	Conduit & Cable Tray	$0	$3,573	$12,354	$0	$0	$15,926	$1,542	$0	$2,620	$20,089	$37
11.5	Wire & Cable	$0	$6,742	$13,014	$0	$0	$19,756	$1,664	$0	$3,213	$24,633	$45
11.6	Protective Equipment	$261	$0	$888	$0	$0	$1,149	$112	$0	$126	$1,388	$3
11.7	Standby Equipment	$1,360	$0	$31	$0	$0	$1,391	$128	$0	$152	$1,670	$3
11.8	Main Power Transformers	$11,209	$0	$189	$0	$0	$11,398	$864	$0	$1,226	$13,488	$25
11.9	Electrical Foundations	$0	$342	$837	$0	$0	$1,179	$113	$0	$258	$1,550	$3
	SUBTOTAL 11.	**$25,213**	**$10,656**	**$30,191**	**$0**	**$0**	**$66,060**	**$5,843**	**$0**	**$9,029**	**$80,931**	**$147**
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	$1,085	$2
12.7	Distributed Control System Equipment	$5,207	$0	$910	$0	$0	$6,117	$567	$306	$699	$7,689	$14
12.8	Instrument Wiring & Tubing	$2,823	$0	$5,599	$0	$0	$8,422	$718	$421	$1,434	$10,995	$20
12.9	Other I & C Equipment	$1,471	$0	$3,339	$0	$0	$4,810	$466	$241	$552	$6,069	$11
	SUBTOTAL 12.	**$10,017**	**$0**	**$10,157**	**$0**	**$0**	**$20,174**	**$1,829**	**$1,009**	**$2,826**	**$25,838**	**$47**

Exhibit 4-56 Case 12 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$56	$1,116	$0	$0	$1,172	$116	$0	$258	$1,546	$3
13.2	Site Improvements	$0	$1,853	$2,301	$0	$0	$4,154	$410	$0	$913	$5,477	$10
13.3	Site Facilities	$3,321	$0	$3,275	$0	$0	$6,595	$650	$0	$1,449	$8,694	$16
	SUBTOTAL 13.	$3,321	$1,909	$6,692	$0	$0	$11,921	$1,176	$0	$2,620	$15,717	$29
14	BUILDINGS & STRUCTURES											
14.1	Boiler Building	$0	$8,851	$7,784	$0	$0	$16,635	$1,495	$0	$2,719	$20,849	$38
14.2	Turbine Building	$0	$12,808	$11,937	$0	$0	$24,746	$2,230	$0	$4,046	$31,023	$56
14.3	Administration Building	$0	$643	$680	$0	$0	$1,324	$120	$0	$217	$1,660	$3
14.4	Circulation Water Pumphouse	$0	$176	$139	$0	$0	$315	$28	$0	$51	$395	$1
14.5	Water Treatment Buildings	$0	$887	$809	$0	$0	$1,697	$153	$0	$277	$2,127	$4
14.6	Machine Shop	$0	$430	$289	$0	$0	$719	$64	$0	$117	$901	$2
14.7	Warehouse	$0	$292	$292	$0	$0	$584	$53	$0	$96	$732	$1
14.8	Other Buildings & Structures	$0	$238	$203	$0	$0	$441	$40	$0	$72	$553	$1
14.9	Waste Treating Building & Str.	$0	$456	$1,384	$0	$0	$1,840	$175	$0	$302	$2,317	$4
	SUBTOTAL 14.	$0	$24,782	$23,519	$0	$0	$48,301	$4,357	$0	$7,899	$60,557	$110
	TOTAL COST	$787,159	$55,813	$388,298	$0	$0	$1,231,270	$116,235	$55,190	$199,329	$1,602,023	$2,913
	Owner's Costs											
	Preproduction Costs											
	6 Months All Labor										$10,579	$19
	1 Month Maintenance Materials										$1,541	$3
	1 Month Non-fuel Consumables										$1,637	$3
	1 Month Waste Disposal										$325	$1
	25% of 1 Months Fuel Cost at 100% CF										$1,971	$4
	2% of TPC										$32,040	$58
	Total										**$48,094**	**$87**
	Inventory Capital											
	60 day supply of fuel and consumables at 100% CF										$18,563	$34
	0.5% of TPC (spare parts)										$8,010	$15
	Total										**$26,573**	**$48**
	Initial Cost for Catalyst and Chemicals										$2,496	$5
	Land										$900	$2
	Other Owner's Costs										$240,304	$437
	Financing Costs										$43,255	$79
	Total Overnight Costs (TOC)										**$1,963,644**	**$3,570**
	TASC Multiplier								(IOU, high-risk, 35 year)		1.140	
	Total As-Spent Cost (TASC)										**$2,238,554**	**$4,070**

Exhibit 4-57 Case 12 Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun):	2007	
Case 12 - 1x550 MWnet Super-Critical PC w/ CO2 Capture					Heat Rate-net (Btu/kWh):	12,002	
					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				
Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.		Plant				
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					$6,444,907	$11.719	
Maintenance Labor Cost					$10,481,104	$19.058	
Administrative & Support Labor					$4,231,503	$7.694	
Property Taxes and Insurance					$32,040,467	$58.260	
TOTAL FIXED OPERATING COSTS					**$53,197,981**	**$96.731**	
VARIABLE OPERATING COSTS							
						$/kWh-net	
Maintenance Material Cost					**$15,721,656**	**$0.00384**	

Consumables	Consumption		Unit	Initial Fill			
	Initial Fill	/Day	Cost	Cost			
Water(/1000 gallons)	0	7,324	1.08	**$0**	**$2,457,806**	**$0.00060**	
Chemicals							
MU & WT Chem.(lbs)	0	35,452	0.17	$0	$1,903,577	$0.00046	
Limestone (ton)	0	687	21.63	$0	$4,610,586	$0.00113	
Carbon (Mercury Removal) lb	0	0	1.05	$0	$0	$0.00000	
MEA Solvent (ton)	1,028	1.46	2,249.89	$2,312,307	$1,017,164	$0.00025	
NaOH (tons)	73	7.26	433.68	$31,484	$976,789	$0.00024	
H2SO4 (tons)	69	6.93	138.78	$9,615	$298,293	$0.00007	
Corrosion Inhibitor	0	0	0.00	$142,156	$6,769	$0.00000	
Activated Carbon (lb)	0	1,741	1.05	$0	$567,144	$0.00014	
Ammonia (19% NH3) ton	0	102	129.80	$0	$4,090,854	$0.00100	
Subtotal Chemicals				$2,495,562	$13,471,176	$0.00329	
Other							
Supplemental Fuel (MBtu)	0	0	0.00	$0	$0	$0.00000	
SCR Catalyst (m3)	w/equip.	0.43	5,775.94	$0	$765,005	$0.00019	
Emission Penalties	0	0	0.00	$0	$0	$0.00000	
Subtotal Other				$0	$765,005	$0.00019	
Waste Disposal							
Fly Ash (ton)	0	527	16.23	$0	$2,651,418	$0.00065	
Bottom Ash (ton)	0	132	16.23	$0	$662,855	$0.00016	
Subtotal-Waste Disposal				$0	$3,314,273	$0.00081	
By-products & Emissions							
Gypsum (tons)	0	1,062	0.00	$0	$0	$0.00000	
Subtotal By-Products				$0	$0	$0.00000	
TOTAL VARIABLE OPERATING COSTS				**$2,495,562**	**$35,729,917**	**$0.00873**	
Fuel (ton)	0	6,790	38.18	**$0**	**$80,434,598**	**$0.01964**	

4.4 PC CASE SUMMARY

The performance results of the four PC plant configurations are summarized in Exhibit 4-58.

Exhibit 4-58 Estimated Performance and Cost Results for Pulverized Coal Cases

	Pulverized Coal Boiler			
	PC Subcritical		PC Supercritical	
PERFORMANCE	Case 9	Case 10	Case 11	Case 12
CO2 Capture	0%	90%	0%	90%
Gross Power Output (kWe)	582,600	672,700	580,400	662,800
Auxiliary Power Requirement (kWe)	32,580	122,740	30,410	112,830
Net Power Output (kWe)	550,020	549,960	549,990	549,970
Coal Flowrate (lb/hr)	437,378	614,994	409,528	565,820
Natural Gas Flowrate (lb/hr)	N/A	N/A	N/A	N/A
HHV Thermal Input (kWth)	1,495,379	2,102,643	1,400,162	1,934,519
Net Plant HHV Efficiency (%)	36.8%	26.2%	39.3%	28.4%
Net Plant HHV Heat Rate (Btu/kWh)	9,277	13,046	8,687	12,002
Raw Water Withdrawal (gpm/MW$_{net}$)	10.7	20.4	9.7	18.3
Process Water Discharge (gpm/MW$_{net}$)	2.2	4.7	2.0	4.3
Raw Water Consumption (gpm/MW$_{net}$)	8.5	15.7	7.7	14.1
CO_2 Emissions (lb/MMBtu)	204	20	204	20
CO_2 Emissions (lb/MWh$_{gross}$)	1,783	217	1,675	203
CO_2 Emissions (lb/MWh$_{net}$)	1,888	266	1,768	244
SO_2 Emissions (lb/MMBtu)	0.0858	0.0017	0.0858	0.0016
SO_2 Emissions (lb/MWh$_{gross}$)	0.7515	0.0176	0.7063	0.0162
NOx Emissions (lb/MMBtu)	0.070	0.070	0.070	0.070
NOx Emissions (lb/MWh$_{gross}$)	0.613	0.747	0.576	0.697
PM Emissions (lb/MMBtu)	0.0130	0.0130	0.0130	0.0130
PM Emissions (lb/MWh$_{gross}$)	0.114	0.139	0.107	0.129
Hg Emissions (lb/TBtu)	1.143	1.143	1.143	1.143
Hg Emissions (lb/MWh$_{gross}$)	1.00E-05	1.22E-05	9.41E-06	1.14E-05
COST				
Total Plant Cost (2007$/kW)	1,622	2,942	1,647	2,913
Total Overnight Cost (2007$/kW)	1,996	3,610	2,024	3,570
Bare Erected Cost	1,317	2,255	1,345	2,239
Home Office Expenses	124	213	127	211
Project Contingency	182	369	176	362
Process Contingency	0	105	0	100
Owner's Costs	374	667	377	657
Total Overnight Cost (2007$ x 1,000)	1,098,124	1,985,432	1,113,445	1,963,644
Total As Spent Capital (2007$/kW)	2,264	4,115	2,296	4,070
COE (mills/kWh, 2007$)[1,2]	59.4	109.6	58.9	106.5
CO2 TS&M Costs	0.0	5.8	0.0	5.6
Fuel Costs	15.2	21.3	14.2	19.6
Variable Costs	5.1	9.2	5.0	8.7
Fixed Costs	7.8	13.1	8.0	13.0
Capital Costs	31.2	60.2	31.7	59.6
LCOE (mills/kWh, 2007$)[1,2]	75.3	139.0	74.7	135.2

[1] Capacity factor is 85% for all PC cases
[2] COE and LCOE are defined in Section 2.7.

The components of TOC and overall TASC are shown for each PC case in Exhibit 4-59.

The following observations about TOC can be made:

- The TOC of the non-capture SC PC case is only incrementally greater than non-capture subcritical PC (less than 2 percent). The TOC of subcritical PC with CO_2 capture is approximately 1 percent greater than SC PC with CO_2 capture.

- The TOC penalty for adding CO_2 capture in the subcritical case is 81 percent and is 76 percent in the SC case. The Econamine cost includes a process contingency of approximately $100/kW in both the subcritical and SC cases. Eliminating the process contingency results in a CO_2 capture cost penalty of 76 and 71 percent for the subcritical and SC PC cases, respectively. In addition to the high cost of the Econamine process, there is a significant increase in the cost of the cooling towers and CWPs in the CO_2 capture cases because of the larger cooling water demand discussed previously. In addition, the gross output of the two PC plants increases by 90 MW (subcritical) and 82 MW (SC) to maintain the net output at 550 MW. The increased gross output results in higher coal flow rate and consequent higher costs for all cost accounts in the estimate.

Exhibit 4-59 Plant Capital Cost for PC Cases
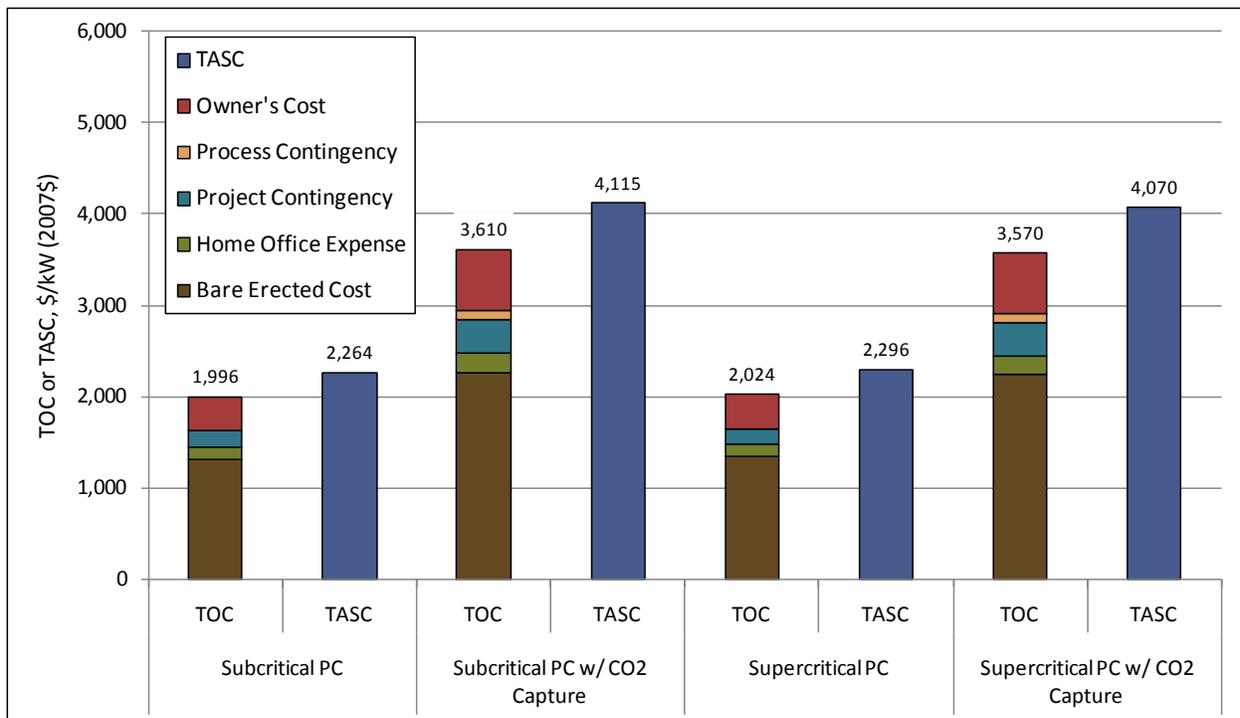
The COE is shown for the four PC cases in Exhibit 4-60. The following observations can be made:

- Capital costs represent the largest fraction of COE in all cases, but particularly so in the CO_2 capture cases. Fuel cost is the second largest component of COE, and capital charges and fuel costs combined represent 74 to 78 percent of the total in all cases.

- In the non-capture case the slight increase in capital cost in the SC case is more than offset by the efficiency gain so that the COE for SC PC is 1 percent less than subcritical despite having a nearly 2 percent higher TOC.

- In the CO_2 capture case, the cost differential between subcritical and SC PC is negligible (about 1 percent), but the SC PC has a 3 percent lower COE because of the higher efficiency.

Exhibit 4-60 COE for PC Cases
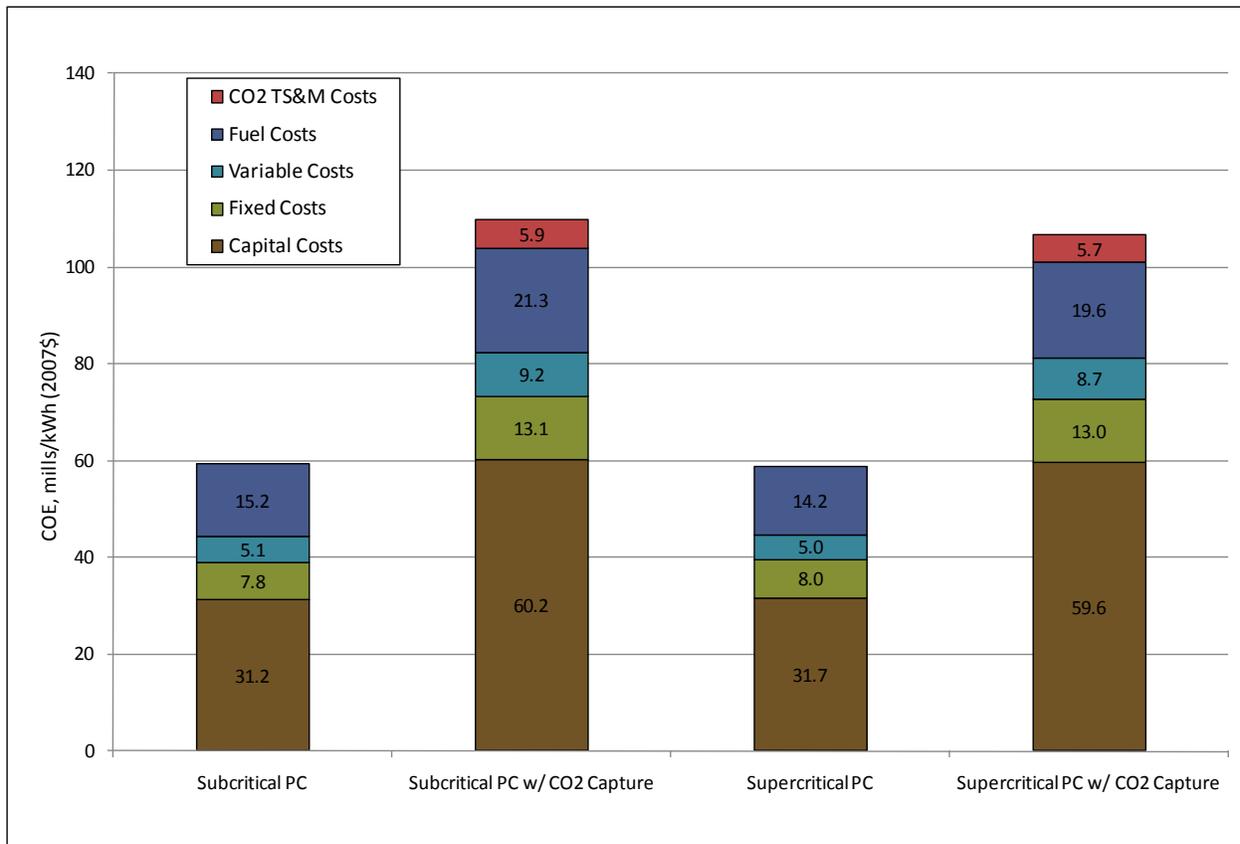
The sensitivity of COE to capacity factor is shown in Exhibit 4-61. Implicit in the curves is the assumption that a capacity factor of greater than 85 percent can be achieved without the expenditure of additional capital. The subcritical and SC cases with no CO_2 capture are nearly identical making it difficult to distinguish between the two lines. The COE increases more rapidly at low CF because the relatively high capital component is spread over fewer kilowatt-hours of generation.

The sensitivity of COE to coal price is shown in Exhibit 4-62. As in the IGCC cases, the COE in the PC cases is relatively insensitive to coal price.

As presented in Section 2.4 the first year cost of CO_2 avoided was calculated, and the results for the PC CO_2 capture cases are shown in Exhibit 4-63.

The cost of CO_2 avoided using the analogous non-capture technology as the reference is nearly identical for the subcritical and SC PC cases. Using SC PC as the non-capture reference case increases the avoided cost of subcritical PC with CO_2 capture because subcritical PC has the higher COE of the two capture technologies.

Exhibit 4-61 Sensitivity of COE to Capacity Factor for PC Cases
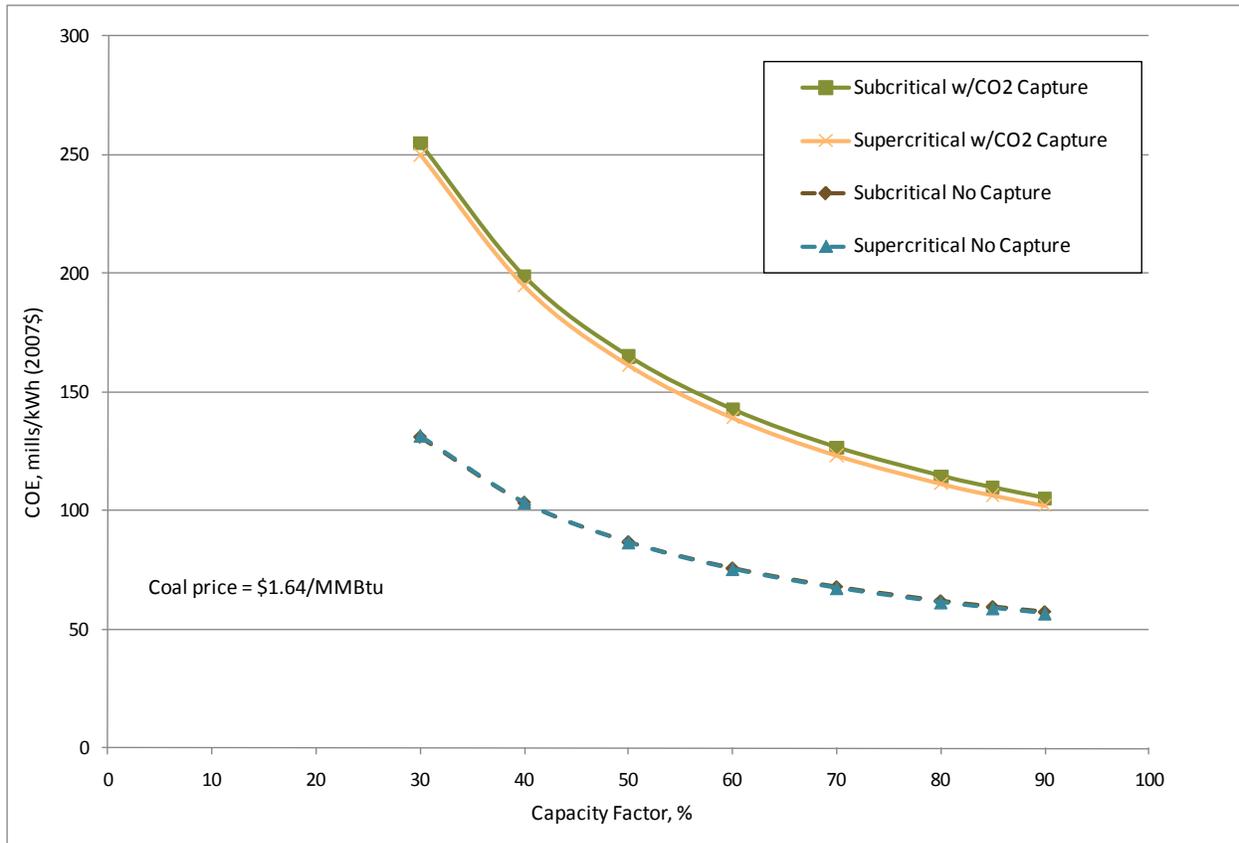
Exhibit 4-62 Sensitivity of COE to Coal Price for PC Cases

Capacity Factor = 85%

Legend:
- Subcritical w/CO2 Capture
- Supercritical w/CO2 Capture
- Subcritical No Capture
- Supercritical No Capture

Y-axis: COE, mills/kWh (2007$)
X-axis: Fuel Price, $/MMBtu
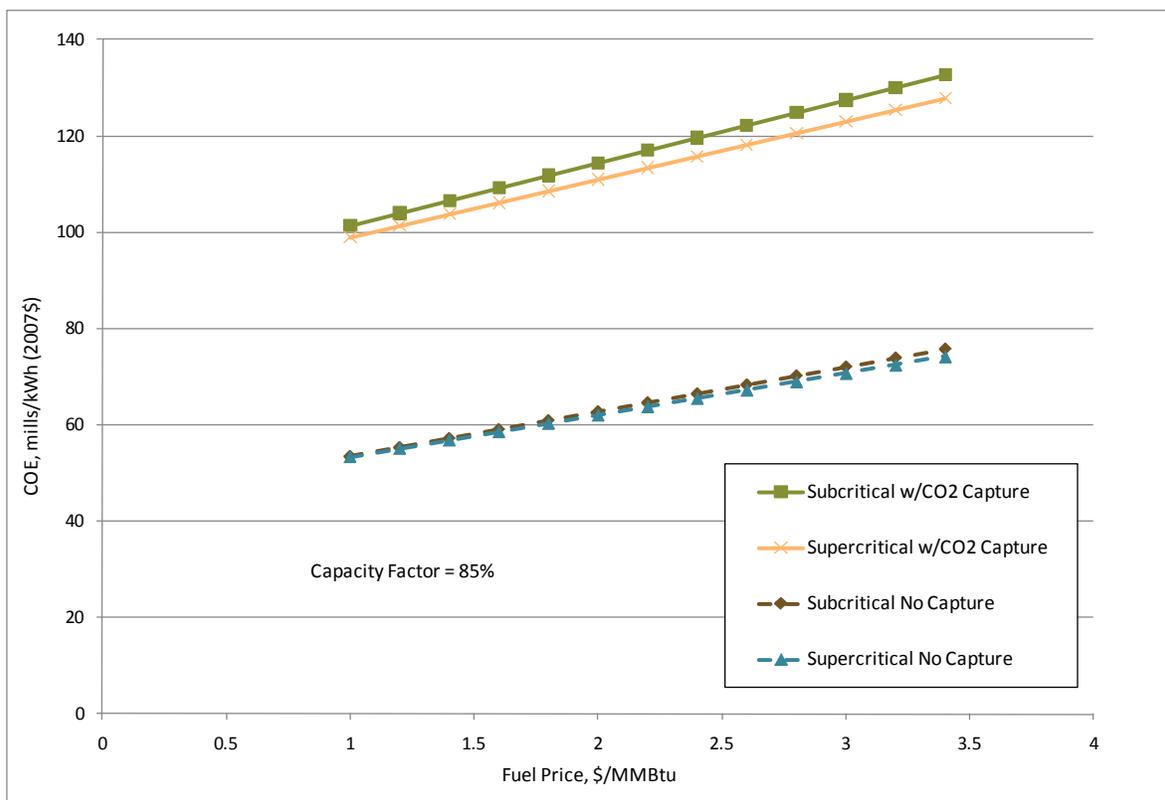
Exhibit 4-63 First Year Cost of CO₂ Avoided in PC Cases
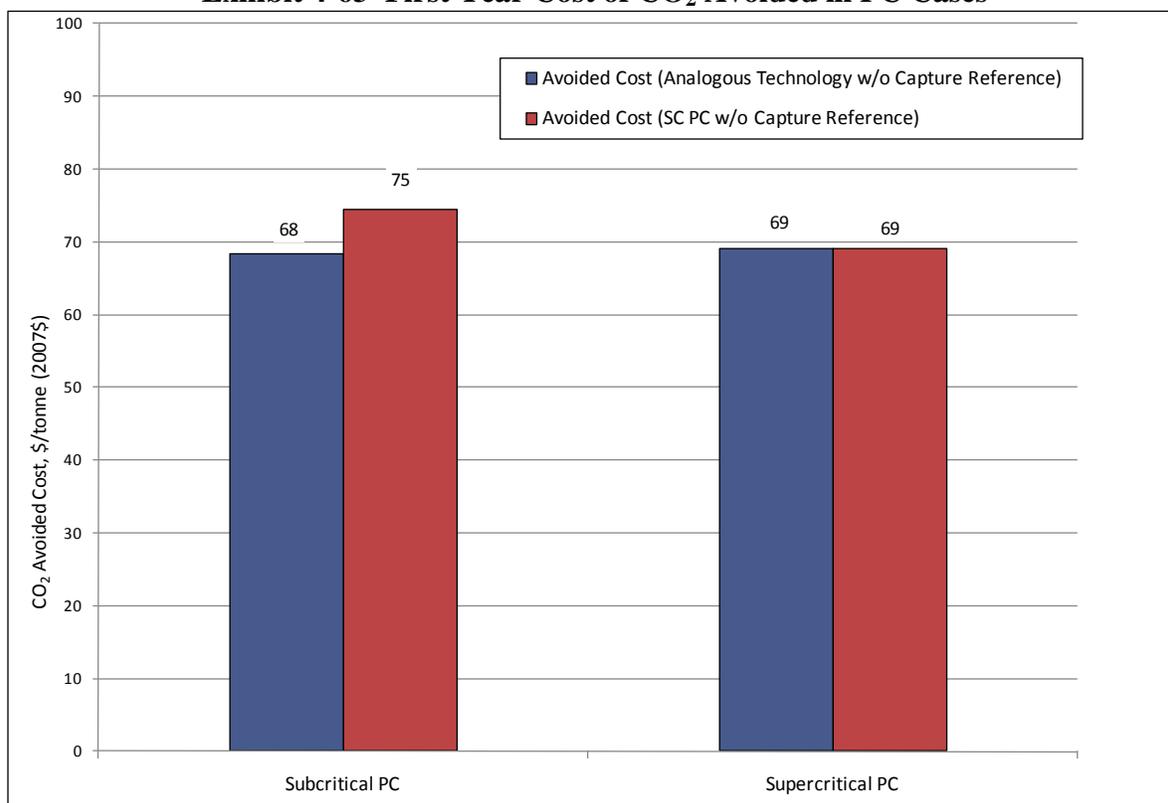
Legend:
- Avoided Cost (Analogous Technology w/o Capture Reference)
- Avoided Cost (SC PC w/o Capture Reference)

Subcritical PC: 68, 75
Supercritical PC: 69, 69

Y-axis: CO₂ Avoided Cost, $/tonne (2007$)

The following observations can be made regarding plant performance with reference to Exhibit 4-58:

- The efficiency of the non-capture, SC PC plant is 2.5 absolute percentage points higher than the equivalent subcritical PC plant (39.3 percent compared to 36.8 percent). The efficiencies are comparable to those reported in other studies once steam cycle conditions are considered. For example, in an EPA study [75] comparing PC and IGCC plant configurations the subcritical PC plant using bituminous coal had an efficiency of 35.9 percent with a steam cycle of 16.5 MPa/538°C/538°C (2,400 psig/1,000°F/1,000°F). The higher steam cycle temperature in this study 566°C/566°C (1,050°F/1,050°F) is one factor that results in a higher net efficiency. The same study reported a SC plant efficiency of 38.3 percent with a steam cycle of 24.1 MPa/566°C/566°C (3,500 psig/1,050°F/1,050°F). Again, the more aggressive steam conditions in this study, 593°C/593°C (1,100°F/1,100°F) are one factor resulting in a higher net efficiency.

  Similar results from an EPRI study using Illinois No. 6 coal were reported as follows:[76]

  - Subcritical PC efficiency of 35.7 percent with a steam cycle of 16.5 MPa/538°C/538°C (2,400 psig/1,000°F/1,000°F).
  - SC PC efficiency of 38.3 percent with a steam cycle of 24.8 MPa/593°C/593°C (3,600 psig/1,100°F/1,100°F).

- The addition of CO_2 capture to the two PC cases results in a relative efficiency penalty of 28.9 percent in the subcritical PC case and 27.6 percent in the SC PC case. The efficiency is negatively impacted by the large auxiliary loads of the Econamine process and CO_2 compression, as well as the large increase in cooling water requirement, which increases the CWP and cooling tower fan auxiliary loads. The auxiliary load increases by 90 MW in the subcritical PC case and by 82 MW in the SC PC case.

- NOx, PM, and Hg emissions are the same for all four PC cases on a heat input basis because of the environmental target assumptions of fixed removal efficiencies for each case (86 percent SCR efficiency, 99.8 percent baghouse efficiency and 90 percent co-benefit capture). The emissions on a mass basis or normalized by gross output are higher for subcritical cases than SC cases and are higher for CO_2 capture cases than non-capture cases because of the higher efficiencies of SC PC and non-capture PC cases.

- SO_2 emissions are likewise constant on a heat input basis for the non-capture cases, but the Econamine process polishing scrubber and absorber vessel result in negligible SO_2 emissions in CO_2 capture cases. The SO_2 emissions for subcritical PC are higher than SC on a mass basis and when normalized by gross output because of the lower efficiency.

- Uncontrolled CO_2 emissions on a mass basis are greater for subcritical PC compared to SC because of the lower efficiency. The capture cases result in a 90 percent reduction of CO_2 for both subcritical and SC PC.

- Raw water consumption for all cases is dominated by cooling tower makeup requirements, which accounts for about 77 percent of raw water in non-capture cases and 81 percent of raw water in CO_2 capture cases. The amount of raw water consumption in

the CO_2 capture cases is greatly increased by the cooling water requirements of the Econamine process. Cooling water is required to:

o Reduce the FG temperature from 57°C (135°F) (FGD exit temperature) to 32°C (89°F) (Econamine absorber operating temperature), which also requires condensing water from the FG that comes saturated from the FGD unit.

o Remove the heat input by the stripping steam to cool the solvent

o Remove the heat input from the auxiliary electric loads

o Remove heat in the CO_2 compressor intercoolers

The normalized water withdrawal, process discharge and raw water consumption are shown in Exhibit 4-64 for each of the PC cases. In the CO_2 capture cases, additional water is recovered from the FG as it is cooled to the absorber temperature of 32°C (89°F). The condensate is treated and also used as cooling tower makeup.

Exhibit 4-64 Raw Water Withdrawal and Consumption in PC Cases
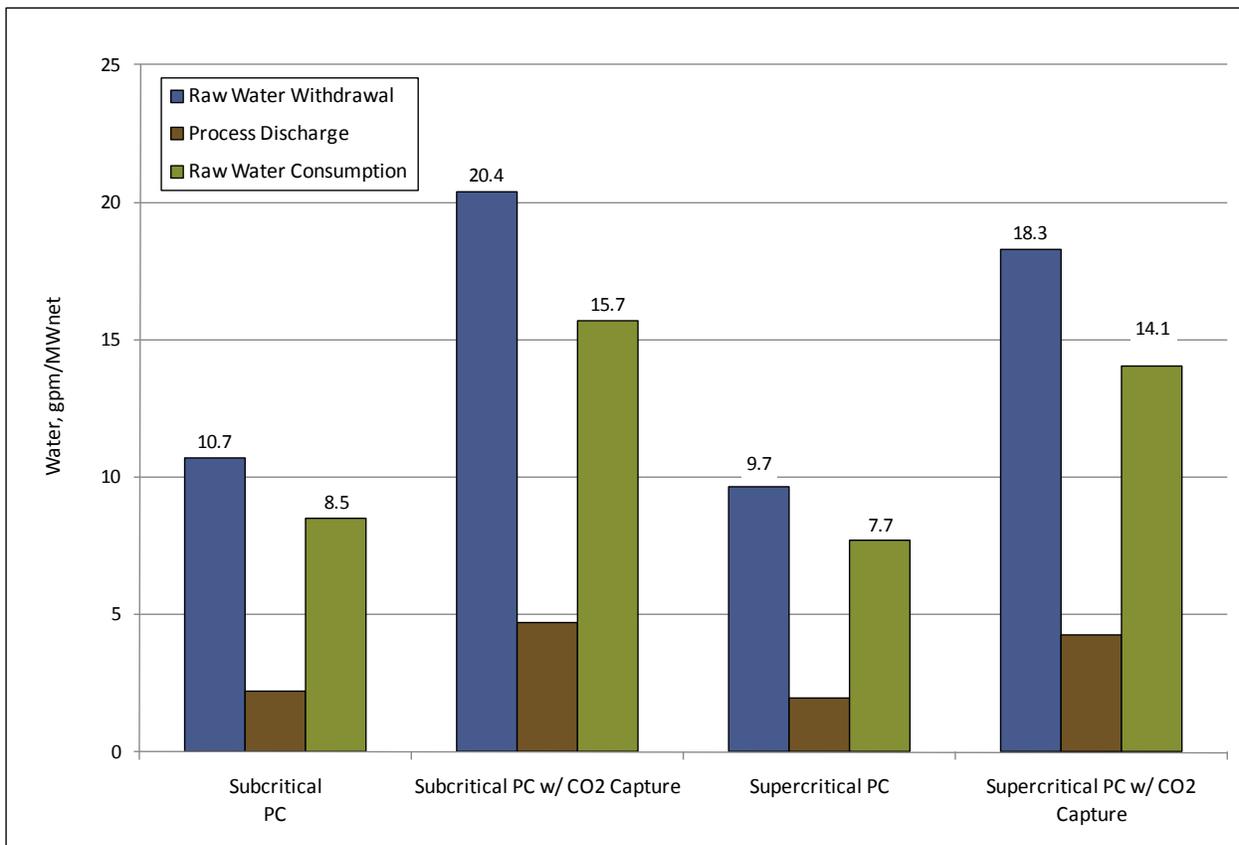
5. NATURAL GAS COMBINED CYCLE PLANTS

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

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

The Rankine cycle portion of both designs uses a single reheat 16.5 MPa/566°C/566°C (2400 psig/1050°F/1050°F) steam cycle. A more aggressive steam cycle was considered but not chosen because there are very few HRSGs in operation that would support such conditions [64].

5.1 NGCC COMMON PROCESS AREAS

The two NGCC cases are nearly identical in configuration with the exception that Case 14 includes CO_2 capture while Case 13 does not. The process areas that are common to the two plant configurations are presented in this section.

5.1.1 Natural Gas Supply System

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

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

5.1.2 Combustion Turbine

The combined cycle plant is based on two CTG's. The CTG is representative of the advanced F Class turbines with an ISO base rating of 184,400 kW when firing natural gas [77]. This machine is an axial flow, single spool, constant speed unit, with variable IGVs, and dry LNB combustion system.

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

The CTG is typically supplied in several fully shop-fabricated modules, complete with all mechanical, electrical, and control systems required for CTG operation. Site CTG installation involves module interconnection and linking CTG modules to the plant systems. The CTG package scope of supply for combined cycle application, while project specific, does not vary much from project-to-project. A typical scope of supply is presented in Exhibit 5-1.

Exhibit 5-1 Combustion Turbine Typical Scope of Supply

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

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

5.1.3   Heat Recovery Steam Generator

The HRSG is configured with HP, IP, and LP steam drums, and superheater, reheater, and economizer sections. The HP drum is supplied with FW by the HP boiler feed pump to generate HP steam, which passes to the superheater section for heating to 566°C (1050°F). The IP drum is supplied with FW by the IP boiler feed pump. The IP steam from the drum is superheated to 566°C (1050°F) and mixed with hot reheat steam from the reheat section at 566°C (1050ºF). The combined flows are admitted into the IP section of the steam turbine. The LP drum provides steam LP turbine.

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

5.1.4   NOx Control System

This reference plant is designed to achieve 2.5 ppmvd NOx emissions (expressed as NO_2 and referenced to 15 percent O_2). Two measures are taken to reduce the NOx. The first is a DLN burner in the CTG. The DLN burners are a low NOx design and reduce the emissions to about 25 ppmvd (referenced to 15 percent O_2) [78].

The second measure taken to reduce the NOx emissions was the installation of a SCR system. SCR uses ammonia and a catalyst to reduce NOx to N_2 and H_2O. The SCR system consists of reactor, and ammonia supply and storage system. The SCR system is designed for 90 percent reduction while firing natural gas. This along with the dry LNB achieves the emission limit of 2.5 ppmvd (referenced to 15 percent O_2).

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

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

5.1.5 Carbon Dioxide Recovery Facility

A CDR facility is used in Case 14 to remove 90 percent of the CO_2 in the FG exiting the HRSG, purify it, and compress it to a SC condition. It is assumed that all of the carbon in the natural gas is converted to CO_2. The CDR is comprised of FG supply, CO_2 absorption, solvent stripping and reclaiming, and CO_2 compression and drying.

The CO_2 absorption/stripping/solvent reclaim process for Case 14 is based on the Fluor Econamine FG Plus^{SM} technology as previously described in Section 4.1.7 with the exception that no SO_2 polishing step is required in the NGCC case. If the pipeline natural gas used in this study contained the maximum amount of sulfur allowed per EPA specifications (0.6 gr S/100 scf), the FG would contain 0.4 ppmv of SO_2, which is well below the limit where a polishing scrubber would be required (10 ppmv). A description of the basic process steps is repeated here for completeness with minor modifications to reflect application in an NGCC system as opposed to PC.

FG Cooling and Supply

The function of the FG cooling and supply system is to transport FG from the HRSG to the CO_2 absorption tower, and condition FG pressure, temperature and moisture content so it meets the requirements of the Econamine process. Temperature and hence moisture content of the FG exiting the HRSG is reduced in the Direct Contact FG Cooler, where FG is cooled using cooling water.

The water condensed from the FG is collected in the bottom of the Direct Contact FG Cooler section and re-circulated to the top of the Direct Contact FG Cooler section via the FG Circulation Water Cooler, which rejects heat to the plant CWS. Level in the Direct Contact FG Cooler is controlled by directing the excess water to the cooling water return line. In the Direct Contact FG Cooler, FG is cooled beyond the CO_2 absorption process requirements to 33°C (91°F) to account for the subsequent FG temperature increase of 14°C (25°F) in the FG blower. Downstream from the Direct Contact FG Cooler FG pressure is boosted in the FG blowers by approximately 0.01 MPa (2 psi) to overcome pressure drop in the CO_2 absorber tower.

Circulating Water System

Cooling water is provided from the NGCC plant CWS and returned to the NGCC plant cooling tower. The CDR facility requires a significant amount of cooling water for FG 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 CDR facility in the NGCC capture case is about 594,308 lpm (157,000 gpm), which greatly exceeds the NGCC plant cooling water requirement of about 200,626 lpm (53,000 gpm).

CO_2 Absorption

The cooled FG enters the bottom of the CO_2 Absorber and flows up through the tower countercurrent to a stream of lean MEA-based solvent called Econamine. 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 gas 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 FG 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. Steam is provided from the crossover pipe between the IP and LP sections of the steam turbine at about 0.51 MPa (73.5 psia) and 152°C (306°F). 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. 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 (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 level controlled to the Solvent Reboiler Condensate Drum. Steam condensate from the Solvent Stripper Reboilers is also collected in the Solvent Reboiler Condensate Drum and returned to the steam cycle just downstream of the deaerator 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 a polytropic efficiency of 86 percent and a mechanical efficiency of 98 percent for all stages. 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 SC CO_2 stream is delivered to the plant battery limit as sequestration ready. CO_2 TS&M costs were estimated and included in LCOE and COE using the methodology described in Section 2.7.

5.1.6 Steam Turbine

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

Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 16.5 MPa/566°C (2400 psig/1050°F). The steam initially enters the turbine near the middle of the HP 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 2.5 MPa/566°C (360 psia/1050°F). After passing through the IP section, the steam enters a cross-over pipe, which transports the steam to the LP section. A branch line equipped with combined stop/intercept valves conveys LP steam from the HRSG LP drum to a tie-in at the cross-over line. The steam divides into two paths and flows through the LP sections exhausting downward into the condenser.

Exhibit 5-2 CO$_2$ Compressor Interstage Pressures

Stage	Outlet Pressure, MPa (psia)
1	0.36 (52)
2	0.78 (113)
3	1.71 (248)
4	3.76 (545)
5	8.27 (1,200)
6	15.3 (2,215)

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

5.1.7   Water and Steam Systems

Condensate

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

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

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

Feedwater

The function of the FW system is to pump the various FW streams from the deaerator storage tank in the HRSG to the respective steam drums. One 100 percent capacity motor-driven feed pump is provided per each HRSG (total of two pumps for the plant). The FW pumps are equipped with an interstage takeoff to provide IP and LP FW. Each pump is provided with inlet and outlet isolation valves, outlet check valves, and individual minimum flow recirculation lines

discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

Steam System

The steam system is comprised of main, reheat, intermediate, and LP steam systems. The function of the main steam system is to convey main steam 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 from the HRSG reheater outlet to the turbine reheat stop valves.

Main steam 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 exits the HP turbine, and flows through a motor-operated isolation gate valve to the HRSG reheater. Hot reheat steam exits at the HRSG reheater through a motor-operated gate valve and is routed to the IP turbines.

Circulating Water System

The function of the CWS is to supply cooling water to condense the main turbine exhaust steam, for the auxiliary cooling system and for the CDR facility in Case 14. The system consists of two 50 percent capacity vertical CWPs (total of two pumps for the plant), a mechanical draft evaporative cooling tower, and interconnecting piping. The condenser is a single pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One-half of the condenser can be removed from service for cleaning or plugging tubes. This can be done during normal operation at reduced load.

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

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

The CDR system in Case 14 requires a substantial amount of cooling water that is provided by the NGCC plant CWS. The additional cooling load imposed by the CDR is reflected in the significantly larger CWPs and cooling tower in that case.

Buildings and Structures

Structures assumed for NGCC cases can be summarized as follows:

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

5.1.8 Accessory Electric Plant

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

5.1.9 Instrumentation and Control

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

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

5.2 NGCC CASES

This section contains an evaluation of plant designs for Cases 13 and 14. These two cases are similar in design and are based on an NGCC plant with a constant thermal input. Both plants use a single reheat 16.5 MPa/566°C/566°C (2400 psig/1050°F/1050°F) cycle. The only difference between the two plants is that Case 14 includes CO_2 capture while Case 13 does not.

The balance of Section 5.2 is organized as follows:

- Process and System Description provides an overview of the technology operation as applied to Case 13. The systems that are common to all NGCC cases were covered in Section 5.1 and only features that are unique to Case 13 are discussed further in this section.

- Key Assumptions is a summary of study and modeling assumptions relevant to Cases 13 and 14.

- Sparing Philosophy is provided for both Cases 13 and 14.

- Performance Results provides the main modeling results from Case 13, including the performance summary, environmental performance, carbon balance, water balance, mass and energy balance diagrams, and energy balance table.

- Equipment List provides an itemized list of major equipment for Case 13 with account codes that correspond to the cost accounts in the Cost Estimates section.

- Cost Estimates provides a summary of capital and operating costs for Case 13.

- Process and System Description, Performance Results, Equipment List and Cost Estimates are reported for Case 14.

5.2.1 Process Description

In this section the NGCC process without CO_2 capture is described. The system description follows the BFD in Exhibit 5-3 and stream numbers reference the same exhibit. The tables in Exhibit 5-4 provide process data for the numbered streams in the BFD. The BFD shows only one of the two CT/HRSG combinations, but the flow rates in the stream table are the total for two systems.

Ambient air (stream 1) and natural gas (stream 2) are combined in the dry LNB, which is operated to control the rotor inlet temperature at 1371°C (2500°F). The FG exits the turbine at 629°C (1163°F) (stream 3) and passes into the HRSG. The HRSG generates both the main steam and reheat steam for the steam turbine. FG exits the HRSG at 106°C (222°F) and passes to the plant stack

Exhibit 5-3 Case 13 Block Flow Diagram, NGCC without CO₂ Capture
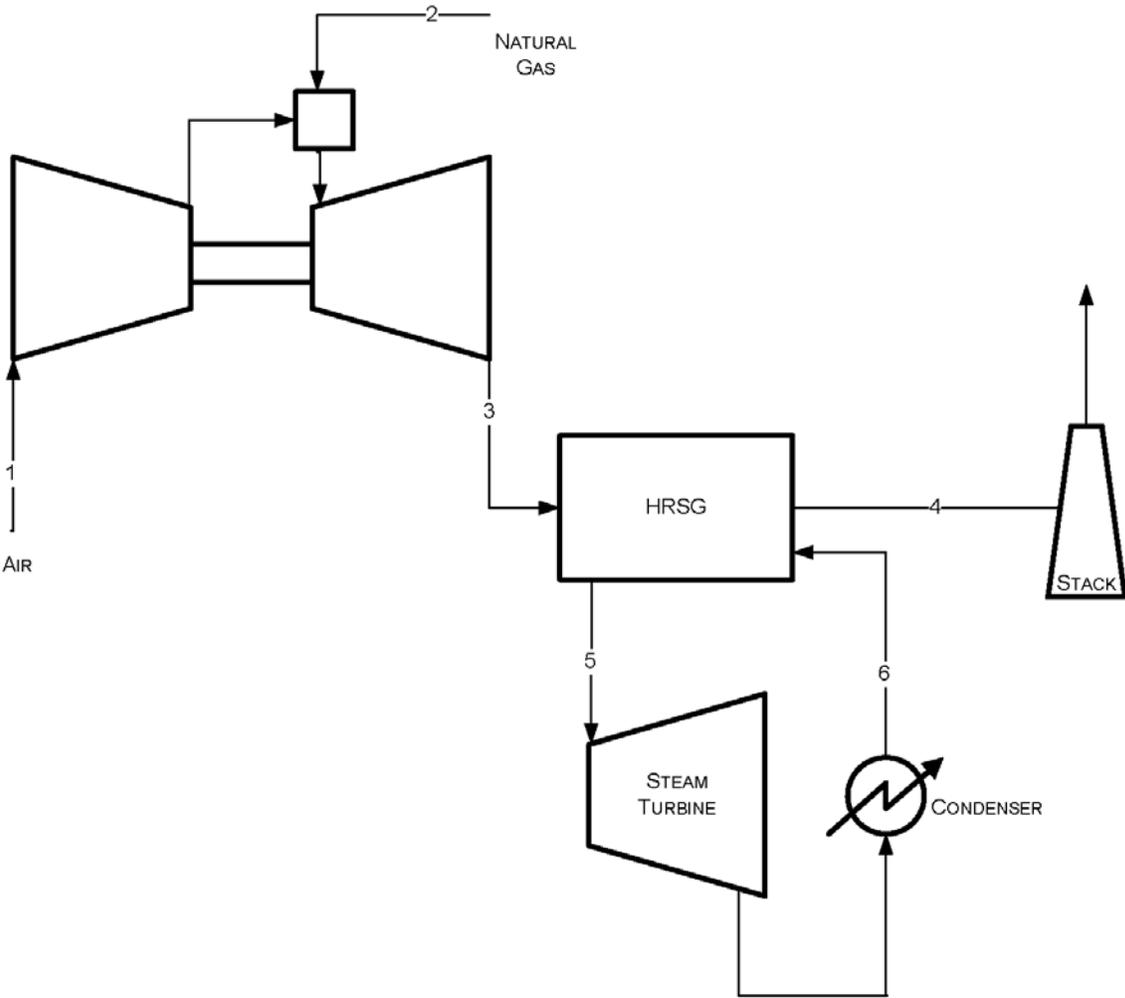
Exhibit 5-4 Case 13 Stream Table, NGCC without CO$_2$ Capture

	1	2	3	4	5	6
V-L Mole Fraction						
Ar	0.0092	0.0000	0.0089	0.0089	0.0000	0.0000
CH$_4$	0.0000	0.9310	0.0000	0.0000	0.0000	0.0000
C$_2$H$_6$	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000
C$_3$H$_8$	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000
C$_4$H$_{10}$	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO$_2$	0.0003	0.0100	0.0404	0.0404	0.0000	0.0000
H$_2$O	0.0099	0.0000	0.0867	0.0867	1.0000	1.0000
N$_2$	0.7732	0.0160	0.7432	0.7432	0.0000	0.0000
O$_2$	0.2074	0.0000	0.1209	0.1209	0.0000	0.0000
SO$_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg$_{mol}$/hr)	109,323	4,380	113,831	113,831	21,589	28,545
V-L Flowrate (kg/hr)	3,154,735	75,901	3,230,636	3,230,636	388,927	514,240
Solids Flowrate (kg/hr)	0	0	0	0	0	0
Temperature (°C)	15	38	629	106	566	38
Pressure (MPa, abs)	0.10	3.10	0.11	0.10	16.65	0.01
Enthalpy (kJ/kg)^A	30.23	46.30	835.81	248.81	3,472.36	160.61
Density (kg/m^3)	1.2	22.2	0.4	0.9	47.7	992.9
V-L Molecular Weight	28.857	17.328	28.381	28.381	18.015	18.015
V-L Flowrate (lb$_{mol}$/hr)	241,016	9,657	250,954	250,954	47,595	62,930
V-L Flowrate (lb/hr)	6,955,000	167,333	7,122,333	7,122,333	857,437	1,133,706
Solids Flowrate (lb/hr)	0	0	0	0	0	0
Temperature (°F)	59	100	1,163	222	1,050	101
Pressure (psia)	14.7	450.0	15.2	14.7	2,414.7	1.0
Enthalpy (Btu/lb)^A	13.0	19.9	359.3	107.0	1,492.8	69.1
Density (lb/ft^3)	0.076	1.384	0.025	0.057	2.977	61.982
A - Reference conditions are 32.02 F & 0.089 PSIA						

5.2.2 Key System Assumptions

System assumptions for Cases 13 and 14, NGCC with and without CO_2 capture, are compiled in Exhibit 5-5.

Exhibit 5-5 NGCC Plant Study Configuration Matrix

	Case 13 w/o CO_2 Capture	Case 14 w/CO_2 Capture
Steam Cycle, MPa/°C/°C (psig/°F/°F)	16.5/566/566 (2400/1050/1050)	16.5/566/566 (2400/1050/1050)
Fuel	Natural Gas	Natural Gas
Fuel Pressure at Plant Battery Limit MPa (psia)	3.1 (450)	3.1 (450)
Condenser Pressure, mm Hg (in Hg)	50.8 (2)	50.8 (2)
Cooling Water to Condenser, °C (°F)	16 (60)	16 (60)
Cooling Water from Condenser, °C (°F)	27 (80)	27 (80)
Stack Temperature, °C (°F)	106 (222)	29 (85)
SO_2 Control	Low Sulfur Fuel	Low Sulfur Fuel
NOx Control	LNB and SCR	LNB and SCR
SCR Efficiency, % (A)	90	90
Ammonia Slip (End of Catalyst Life), ppmv	10	10
Particulate Control	N/A	N/A
Mercury Control	N/A	N/A
CO_2 Control	N/A	Econamine
Overall CO_2 Capture (A)	N/A	90.7%
CO_2 Sequestration	N/A	Off-site Saline Formation

> A.   Removal efficiencies are based on the FG content

Balance of Plant – Cases 13 and 14

The balance of plant assumptions are common to both NGCC cases and are presented in Exhibit 5-6.

Exhibit 5-6 NGCC Balance of Plant Assumptions

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

5.2.3 Sparing Philosophy

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

- Two advanced F class CTGs (2 x 50%)

- Two 3-pressure reheat HRSGs with self supporting stacks and SCR systems (2 x 50%)

- One 3-pressure reheat, triple-admission STG (1 x 100%)

- Two trains of Econamine CO_2 capture (2 x 50%) (Case 14 only)

5.2.4   Case 13 Performance Results

The plant produces a net output of 555 MW at a net plant efficiency of 50.2 percent (HHV basis).

Overall plant performance is summarized in Exhibit 5-7, which includes auxiliary power requirements.

Exhibit 5-7 Case 13 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	362,200
Steam Turbine Power	202,500
TOTAL POWER, kWe	**564,700**
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	170
Boiler Feedwater Pumps	2,720
Circulating Water Pump	2,300
Ground Water Pumps	210
Cooling Tower Fans	1,190
SCR	10
Gas Turbine Auxiliaries	700
Steam Turbine Auxiliaries	100
Miscellaneous Balance of Plant[1]	500
Transformer Losses	1,720
TOTAL AUXILIARIES, kWe	**9,620**
NET POWER, kWe	**555,080**
Net Plant Efficiency (HHV)	50.2%
Net Plant Efficiency (LHV)	55.7%
Net Plant Heat Rate (HHV), kJ/kWh (Btu/kWh)	7,172 (6,798)
Net Plant Heat Rate (LHV), kJ/kWh (Btu/kWh)	6,466 (6,129)
CONDENSER COOLING DUTY, 10^6 kJ/hr (10^6 Btu/hr)	**1,139 (1,080)**
CONSUMABLES	
Natural Gas Feed Flow, kg/hr (lb/hr)	75,901 (167,333)
Thermal Input (HHV), kW$_{th}$	1,105,812
Thermal Input (LHV) , kW$_{th}$	997,032
Raw Water Withdrawal, m^3/min (gpm)	8.9 (2,362)
Raw Water Consumption, m^3/min (gpm)	6.9 (1,831)

1.   Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of NOx, SO_2, and PM were presented in Section 2.4. A summary of the plant air emissions for Case 13 is presented in Exhibit 5-8.

Exhibit 5-8 Case 13 Air Emissions

	kg/GJ (lb/10⁶ Btu)	Tonne/year (ton/year) 85% CF	kg/MWh (lb/MWh)
SO_2	Negligible	Negligible	Negligible
NOx	0.004 (0.009)	115 (127)	0.027 (0.060)
Particulates	Negligible	Negligible	Negligible
Hg	Negligible	Negligible	Negligible
CO_2	51 (118)	1,507,427 (1,661,654)	359 (790)
$CO_2{}^1$			365 (804)

[1] CO_2 emissions based on net power instead of gross power

The operation of the modern, state-of-the-art GT fueled by natural gas, coupled to a HRSG, results in very low levels of NOx emissions and negligible levels of SO_2, particulate and Hg emissions. As noted in Section 2.4, if the fuel contains the maximum amount of sulfur compounds allowed in pipeline natural gas, the NGCC SO_2 emissions would be 21 tonnes/yr (23 tons/yr) at 85 percent CF, or 0.00195 lb/MMBtu.

The low level of NOx production (2.5 ppmvd at 15 percent O_2) is achieved by utilizing a dry LNB coupled with an SCR system.

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

The carbon balance for the plant is shown in Exhibit 5-9. The carbon input to the plant consists of carbon in the natural gas and carbon as CO_2 in the CT air. Carbon leaves the plant as CO_2 through the stack.

Exhibit 5-9 Case 13 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Natural Gas	54,822 (120,863)	**Stack Gas**	55,251 (121,808)
Air (CO_2)	429 (946)		
Total	55,251 (121,808)	**Total**	55,251 (121,808)

A sulfur balance is not included for Case 13 because the sulfur concentration of the natural gas feed is negligible. Consequently, sulfur emissions are also negligible, as shown in Exhibit 5-8, despite the use of no sulfur control technology.

Exhibit 5-10 shows the water balance for Case 13. Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is re-used as internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a surface-water source for use in the plant and was assumed to be provided 50 percent by a POTW and 50 percent from groundwater. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for any and all purposes, such as condenser and cooling tower makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source balance.

Exhibit 5-10 Case 13 Water Balance

Water Use	Water Demand, m^3/min (gpm)	Internal Recycle, m^3/min (gpm)	Raw Water Withdrawal, m^3/min (gpm)	Process Water Discharge, m^3/min (gpm)	Raw Water Consumption, m^3/min (gpm)
Condenser Makeup *BFW Makeup*	**0.1 (23)** *0.1 (23)*	**0.0 (0)**	**0.1 (23)** *0.1 (23)*	**0.0 (0)**	**0.1 (23)**
Cooling Tower *BFW Blowdown*	**8.9 (2,362)** *0.0 (0)*	**0.1 (23)** *0.1 (23)*	**8.9 (2,339)** *-0.1 (-23)*	**2.0 (531)**	**6.8 (1,808)**
Total	**9.0 (2,385)**	**0.1 (23)**	**8.9 (2,362)**	**2.0 (531)**	**6.9 (1,831)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the NGCC in Exhibit 5-11. An overall plant energy balance is provided in tabular form in Exhibit 5-12. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 5-7) is calculated by multiplying the power out by a combined generator efficiency of 98.4 percent.

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Exhibit 5-11 Case 13 Heat and Mass Balance, NGCC without CO₂ Capture
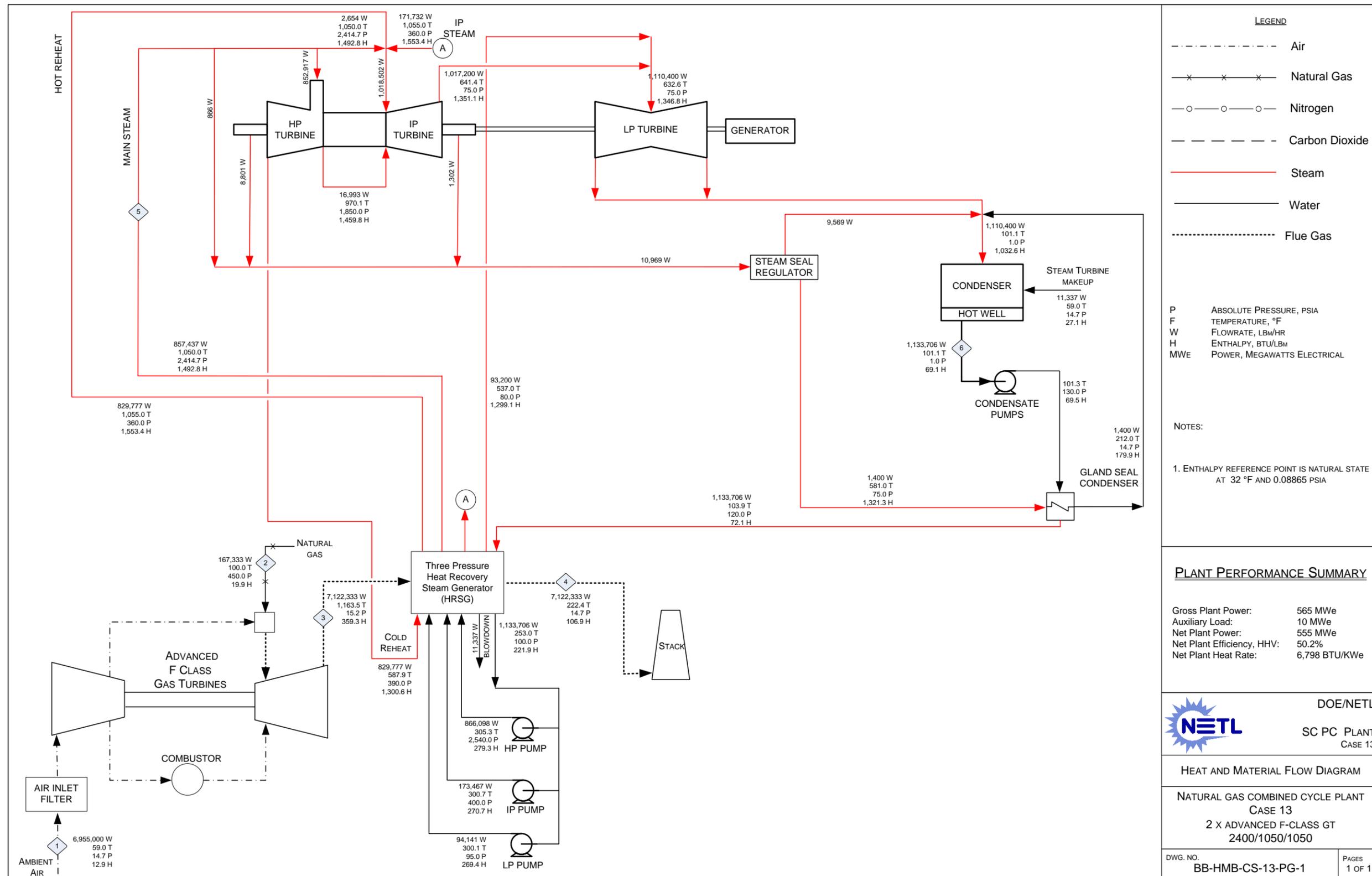
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Exhibit 5-12 Case 13 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Natural Gas	3,981 (3,773)	2.7 (2.5)		3,984 (3,776)
GT Air		95.4 (90.4)		95 (90)
Raw Water Withdrawal		33.6 (31.9)		34 (32)
Auxiliary Power			35 (33)	35 (33)
Totals	**3,981 (3,773)**	**131.6 (124.8)**	**35 (33)**	**4,147 (3,931)**
Heat Out GJ/hr (MMBtu/hr)				
Cooling Tower Blowdown		14.9 (14.2)		15 (14)
Stack Gas		804 (762)		804 (762)
Condenser		1,141 (1,082)		1,141 (1,082)
*Process Losses**		154 (146)		154 (146)
Power			2,033 (1,927)	2,033 (1,927)
Totals	**0 (0)**	**2,114 (2,004)**	**2,033 (1,927)**	**4,147 (3,931)**

* Process Losses are calculated by difference and reflect various turbine, and other heat and work losses.

5.2.5   Case 13 – Major Equipment List

Major equipment items for the NGCC plant with no CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 5.2.6. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1   COAL AND SORBENT HANDLING

N/A

ACCOUNT 2   FUEL AND SORBENT PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	63 m3/min @ 3.1 MPa (2,216 acfm @ 450 psia) 41 cm (16 in) standard wall pipe	16 km (10 mile)	0
2	Gas Metering Station	--	63 m3/min (2,216 acfm)	1	0

ACCOUNT 3   FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	678,767 liters (179,310 gal)	2	0
2	Condensate Pumps	Vertical canned	4,732 lpm @ 110 m H2O (1,250 gpm @ 360 ft H2O)	2	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP water: 3,634 lpm @ 2,103 m H2O (960 gpm @ 6,900 ft H2O)	2	1
			IP water: 719 lpm @ 283 m H2O (190 gpm @ 930 ft H2O)		
			LP water: 379 lpm @ 24.4 m H2O (100 gpm @ 80 ft H2O)		
4	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
5	Service Air Compressors	Flooded Screw	13 m3/min @ 0.7 MPa (450 scfm @ 100 psig)	2	1
6	Instrument Air Dryers	Duplex, regenerative	13 m3/min (450 scfm)	2	1
7	Closed Cycle Cooling Heat Exchangers	Plate and frame	13 MMkJ/hr (13 MMBtu/hr)	2	0
8	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	5,300 lpm @ 21 m H2O (1,400 gpm @ 70 ft H2O)	2	1
9	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H2O (1,000 gpm @ 350 ft H2O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H2O (700 gpm @ 250 ft H2O)	1	1
11	Raw Water Pumps	Stainless steel, single suction	4,921 lpm @ 18 m H2O (1,300 gpm @ 60 ft H2O)	2	1
12	Filtered Water Pumps	Stainless steel, single suction	151 lpm @ 49 m H2O (40 gpm @ 160 ft H2O)	2	1
13	Filtered Water Tank	Vertical, cylindrical	143,847 liter (38,000 gal)	1	0
14	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	341 lpm (90 gpm)	1	0
15	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

ACCOUNT 4   GASIFIER, BOILER AND ACCESSORIES

N/A

ACCOUNT 5   FLUE GAS CLEANUP

N/A

ACCOUNT 6   COMBUSTION TURBINE GENERATORS AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class w/ dry low-NOx burner	184 MW	2	0
2	Gas Turbine Generator	TEWAC	200 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

ACCOUNT 7   WASTE HEAT BOILER, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	46 m (150 ft) high x 7.5 m (25 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 213,910 kg/h, 16.5 MPa/566°C (471,590 lb/h, 2,400 psig/1,050°F) Reheat steam - 249,852 kg/h, 2.4 MPa/566°C (550,830 lb/h, 345 psig/1,050°F)	2	0
3	SCR Reactor	Space for spare layer	1,778,084 kg/h (3,920,000 lb/h)	2	0
4	SCR Catalyst	--	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	11 m3/min @ 107 cm WG (390 scfm @ 42 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	3.8 lpm @ 91 m H2O (1 gpm @ 300 ft H2O)	2	1
7	Ammonia Storage Tank	Horizontal tank	68,138 liter (18,000 gal)	1	0

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Tandem compound, HP, IP, and two-flow LP turbines	213 MW 16.5 MPa/566°C/566°C (2,400 psig/ 1050°F/1050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	240 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,254 MMkJ/hr, (1,190 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	230,912 lpm @ 30.5 m (61,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT 1,283 MMkJ/hr (1,217 MMBtu/hr) heat load	1	0

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

N/A

ACCOUNT 11   ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 200 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 230 MVA, 3-ph, 60 Hz	1	0
3	Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 09 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 1 MVA, 3-ph, 60 Hz	1	1
5	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
6	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
7	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
8	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
9	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12   INSTRUMENTATION AND CONTROL

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

5.2.6   Case 13 – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 5-13 shows the total plant capital cost summary organized by cost account and Exhibit 5-14 shows a more detailed breakdown of the capital costs. Exhibit 5-15 shows the initial and annual O&M costs.

The estimated TOC of the NGCC with no CO_2 capture is \$718/kW. No process contingency was included in this case because all elements of the technology are commercially proven. The project contingency is 8.6 percent of TOC. The COE is 58.9 mills/kWh.

Exhibit 5-13 Case 13 Total Plant Cost Summary

Client:			USDOE/NETL							Report Date:	2010-Jan-14	
Project:			Bituminous Baseline Study									
			TOTAL PLANT COST SUMMARY									
Case:			Case 13 - 1x555 MWnet 2x1 7FB NGCC									
Plant Size:			555.1 MW,net	**Estimate Type:**	Conceptual				**Cost Base (Jun)**	2007	($x1000)	

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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
2	COAL & SORBENT PREP & FEED	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
3	FEEDWATER & MISC. BOP SYSTEMS	$22,444	$4,461	$6,516	$0	$0	**$33,421**	$2,819	$0	$5,782	**$42,022**	$76
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.2	Syngas Cooling	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.4-4.9	Other gasification Equipment	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
5A	GAS CLEANUP & PIPING	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
5B	CO2 REMOVAL & COMPRESSION	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$75,294	$0	$4,804	$0	$0	**$80,098**	$6,800	$0	$8,690	**$95,589**	$172
6.2-6.9	Combustion Turbine Other	$0	$719	$744	$0	$0	**$1,462**	$122	$0	$317	**$1,901**	$3
	SUBTOTAL 6	**$75,294**	**$719**	**$5,548**	**$0**	**$0**	**$81,561**	**$6,922**	**$0**	**$9,007**	**$97,490**	**$176**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,958	$0	$4,279	$0	$0	**$37,237**	$3,170	$0	$4,041	**$44,448**	$80
7.2-7.9	SCR System, Ductwork and Stack	$1,243	$950	$1,118	$0	$0	**$3,311**	$282	$0	$583	**$4,176**	$8
	SUBTOTAL 7	**$34,200**	**$950**	**$5,397**	**$0**	**$0**	**$40,548**	**$3,453**	**$0**	**$4,624**	**$48,624**	**$88**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$23,774	$0	$3,855	$0	$0	**$27,630**	$2,374	$0	$3,000	**$33,005**	$59
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$8,304	$798	$5,509	$0	$0	**$14,611**	$1,190	$0	$2,164	**$17,965**	$32
	SUBTOTAL 8	**$32,078**	**$798**	**$9,365**	**$0**	**$0**	**$42,241**	**$3,565**	**$0**	**$5,164**	**$50,970**	**$92**
9	COOLING WATER SYSTEM	$5,524	$4,298	$3,854	$0	$0	**$13,677**	$1,137	$0	$2,106	**$16,920**	$30
10	ASH/SPENT SORBENT HANDLING SYS	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
11	ACCESSORY ELECTRIC PLANT	$16,639	$3,671	$8,860	$0	$0	**$29,170**	$2,237	$0	$3,330	**$34,737**	$63
12	INSTRUMENTATION & CONTROL	$5,778	$593	$4,801	$0	$0	**$11,173**	$930	$0	$1,387	**$13,490**	$24
13	IMPROVEMENTS TO SITE	$1,722	$935	$4,582	$0	$0	**$7,238**	$640	$0	$1,576	**$9,455**	$17
14	BUILDINGS & STRUCTURES	$0	$4,155	$4,417	$0	$0	**$8,571**	$697	$0	$1,390	**$10,658**	$19
	TOTAL COST	**$193,680**	**$20,581**	**$53,339**	**$0**	**$0**	**$267,599**	**$22,400**	**$0**	**$34,366**	**$324,365**	**$584**

Exhibit 5-14 Case 13 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	TOTAL PLANT COST $	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 & Yd Crush	$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	Prepared Coal Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.3	Slurry Prep & Feed	$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	Feedwater System	$2,426	$2,499	$2,055	$0	$0	$6,980	$576	$0	$1,133	$8,690	$16
3.2	Water Makeup & Pretreating	$1,466	$153	$766	$0	$0	$2,384	$203	$0	$517	$3,105	$6
3.3	Other Feedwater Subsystems	$1,106	$374	$314	$0	$0	$1,794	$144	$0	$291	$2,229	$4
3.4	Service Water Systems	$173	$357	$1,157	$0	$0	$1,687	$147	$0	$367	$2,201	$4
3.5	Other Boiler Plant Systems	$1,162	$450	$1,043	$0	$0	$2,655	$225	$0	$432	$3,313	$6
3.6	Natural Gas, incl. pipeline	$14,667	$505	$440	$0	$0	$15,612	$1,323	$0	$2,540	$19,476	$35
3.7	Waste Treatment Equipment	$529	$0	$302	$0	$0	$831	$72	$0	$181	$1,084	$2
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$915	$122	$439	$0	$0	$1,477	$128	$0	$321	$1,925	$3
	SUBTOTAL 3.	$22,444	$4,461	$6,516	$0	$0	$33,421	$2,819	$0	$5,782	$42,022	$76
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.2	Syngas Cooling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.4	LT Heat Recovery & FG Saturation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Misc. Gasification Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Other Gasification Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Gasification Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Exhibit 5-14 Case 13 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	MDEA-LT AGR	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.2	Elemental Sulfur Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.3	Mercury Removal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.4	COS Hydrolysis	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.5	Blowback Gas Systems	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Fuel Gas Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.9	HGCU Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
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 5.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$75,294	$0	$4,804	$0	$0	$80,098	$6,800	$0	$8,690	$95,589	$172
6.2	Combustion Turbine Accessories	$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	$719	$744	$0	$0	$1,462	$122	$0	$317	$1,901	$3
	SUBTOTAL 6.	$75,294	$719	$5,548	$0	$0	$81,561	$6,922	$0	$9,007	$97,490	$176
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,958	$0	$4,279	$0	$0	$37,237	$3,170	$0	$4,041	$44,448	$80
7.2	SCR System	$1,243	$522	$733	$0	$0	$2,498	$215	$0	$407	$3,120	$6
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	HRSG,Duct & Stack Foundations	$0	$428	$385	$0	$0	$813	$68	$0	$176	$1,057	$2
	SUBTOTAL 7.	$34,200	$950	$5,397	$0	$0	$40,548	$3,453	$0	$4,624	$48,624	$88
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$23,774	$0	$3,855	$0	$0	$27,630	$2,374	$0	$3,000	$33,005	$59
8.2	Turbine Plant Auxiliaries	$161	$0	$369	$0	$0	$530	$46	$0	$58	$634	$1
8.3	Condenser & Auxiliaries	$4,108	$0	$1,226	$0	$0	$5,334	$457	$0	$579	$6,370	$11
8.4	Steam Piping	$4,035	$0	$2,653	$0	$0	$6,688	$513	$0	$1,080	$8,281	$15
8.9	TG Foundations	$0	$798	$1,261	$0	$0	$2,059	$175	$0	$447	$2,680	$5
	SUBTOTAL 8.	$32,078	$798	$9,365	$0	$0	$42,241	$3,565	$0	$5,164	$50,970	$92
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$3,880	$0	$496	$0	$0	$4,377	$373	$0	$475	$5,224	$9
9.2	Circulating Water Pumps	$1,142	$0	$63	$0	$0	$1,205	$91	$0	$130	$1,425	$3
9.3	Circ.Water System Auxiliaries	$93	$0	$12	$0	$0	$105	$9	$0	$11	$126	$0
9.4	Circ.Water Piping	$0	$2,713	$657	$0	$0	$3,370	$272	$0	$546	$4,189	$8
9.5	Make-up Water System	$229	$0	$305	$0	$0	$534	$46	$0	$87	$667	$1
9.6	Component Cooling Water Sys	$180	$215	$143	$0	$0	$539	$45	$0	$88	$672	$1
9.9	Circ.Water System Foundations	$0	$1,370	$2,177	$0	$0	$3,547	$301	$0	$770	$4,618	$8
	SUBTOTAL 9.	$5,524	$4,298	$3,854	$0	$0	$13,677	$1,137	$0	$2,106	$16,920	$30

Exhibit 5-14 Case 13 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
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 Recovery Equipment	$0	$0	$0	$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	$4,068	$0	$2,444	$0	$0	$6,513	$552	$0	$530	$7,594	$14
11.2	Station Service Equipment	$1,208	$0	$102	$0	$0	$1,310	$108	$0	$106	$1,525	$3
11.3	Switchgear & Motor Control	$1,489	$0	$253	$0	$0	$1,742	$145	$0	$189	$2,076	$4
11.4	Conduit & Cable Tray	$0	$712	$2,194	$0	$0	$2,905	$251	$0	$474	$3,630	$7
11.5	Wire & Cable	$0	$2,266	$1,391	$0	$0	$3,657	$236	$0	$584	$4,477	$8
11.6	Protective Equipment	$0	$563	$1,916	$0	$0	$2,480	$217	$0	$270	$2,966	$5
11.7	Standby Equipment	$103	$0	$94	$0	$0	$197	$17	$0	$21	$235	$0
11.8	Main Power Transformers	$9,770	$0	$146	$0	$0	$9,916	$673	$0	$1,059	$11,648	$21
11.9	Electrical Foundations	$0	$130	$319	$0	$0	$449	$38	$0	$98	$585	$1
	SUBTOTAL 11.	$16,639	$3,671	$8,860	$0	$0	$29,170	$2,237	$0	$3,330	$34,737	$63
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	w/6.1	$0	w/6.1	$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	$735	$0	$458	$0	$0	$1,193	$101	$0	$194	$1,488	$3
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	$220	$0	$132	$0	$0	$351	$30	$0	$57	$438	$1
12.7	Computer & Accessories	$3,514	$0	$105	$0	$0	$3,619	$298	$0	$392	$4,308	$8
12.8	Instrument Wiring & Tubing	$0	$593	$1,134	$0	$0	$1,727	$130	$0	$279	$2,136	$4
12.9	Other I & C Equipment	$1,310	$0	$2,972	$0	$0	$4,282	$372	$0	$465	$5,120	$9
	SUBTOTAL 12.	$5,778	$593	$4,801	$0	$0	$11,173	$930	$0	$1,387	$13,490	$24

Exhibit 5-14 Case 13 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$92	$1,837	$0	$0	$1,929	$172	$0	$420	$2,520	$5
13.2	Site Improvements	$0	$843	$1,047	$0	$0	$1,890	$167	$0	$411	$2,469	$4
13.3	Site Facilities	$1,722	$0	$1,698	$0	$0	$3,419	$302	$0	$744	$4,465	$8
	SUBTOTAL 13.	$1,722	$935	$4,582	$0	$0	$7,238	$640	$0	$1,576	$9,455	$17
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area	$0	$236	$125	$0	$0	$361	$28	$0	$58	$447	$1
14.2	Steam Turbine Building	$0	$1,972	$2,626	$0	$0	$4,598	$378	$0	$746	$5,722	$10
14.3	Administration Building	$0	$455	$308	$0	$0	$763	$61	$0	$124	$947	$2
14.4	Circulation Water Pumphouse	$0	$152	$75	$0	$0	$227	$18	$0	$37	$281	$1
14.5	Water Treatment Buildings	$0	$316	$288	$0	$0	$605	$49	$0	$98	$752	$1
14.6	Machine Shop	$0	$394	$252	$0	$0	$647	$51	$0	$105	$803	$1
14.7	Warehouse	$0	$255	$154	$0	$0	$408	$32	$0	$66	$507	$1
14.8	Other Buildings & Structures	$0	$76	$56	$0	$0	$132	$11	$0	$21	$164	$0
14.9	Waste Treating Building & Str.	$0	$298	$533	$0	$0	$831	$69	$0	$135	$1,036	$2
	SUBTOTAL 14.	$0	$4,155	$4,417	$0	$0	$8,571	$697	$0	$1,390	$10,658	$19
	TOTAL COST	$193,680	$20,581	$53,339	$0	$0	$267,599	$22,400	$0	$34,366	$324,365	$584
	Owner's Costs											
	Preproduction Costs											
	6 Months All Labor										$2,880	$5
	1 Month Maintenance Materials										$388	$1
	1 Month Non-fuel Consumables										$146	$0
	1 Month Waste Disposal										$0	$0
	25% of 1 Months Fuel Cost at 100% CF										$4,509	$8
	2% of TPC										$6,487	$12
	Total										$14,410	$26
	Inventory Capital											
	60 day supply of consumables at 100% CF										$180	$0
	0.5% of TPC (spare parts)										$1,622	$3
	Total										$1,802	$3
	Initial Cost for Catalyst and Chemicals										$0	$0
	Land										$300	$1
	Other Owner's Costs										$48,655	$88
	Financing Costs										$8,758	$16
	Total Overnight Costs (TOC)										$398,290	$718
	TASC Multiplier							(IOU, low-risk, 33 year)			1.075	
	Total As-Spent Cost (TASC)										$428,162	$771

Exhibit 5-15 Case 13 Initial and Annual Operating and Maintenance Cost Summary

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun):		2007
Case 13 - 1x555 MWnet 2x1 7FB NGCC					Heat Rate-net (Btu/kWh):		6,798
					MWe-net:		555
					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				
Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.		Plant				
Skilled Operator	1.0		1.0				
Operator	2.0		2.0				
Foreman	1.0		1.0				
Lab Tech's, etc.	1.0		1.0				
TOTAL-O.J.'s	5.0		5.0				
						Annual Cost	Annual Unit Cost
						$	$/kW-net
Annual Operating Labor Cost						$1,972,971	$3.554
Maintenance Labor Cost						$2,635,374	$4.748
Administrative & Support Labor						$1,152,086	$2.076
Property Taxes and Insurance						$6,487,309	$11.687
TOTAL FIXED OPERATING COSTS						**$12,247,740**	**$22.065**

VARIABLE OPERATING COSTS							
							$/kWh-net
Maintenance Material Cost						**$3,953,061**	**$0.00096**
Consumables		Consumption		Unit	Initial Fill		
		Initial Fill	/Day	Cost	Cost		
Water (/1000 gallons)		0.00	1700.64	1.08	$0	$570,718	$0.00014
Chemicals							
MU & WT Chem. (lbs)		0.00	10131.92	0.17	$0	$544,027	$0.00013
MEA Solvent (ton)		0.00	0.00	2249.89	$0	$0	$0.00000
Activated Carbon (lb)		0.00	0.00	1.05	$0	$0	$0.00000
Corrosion Inhibitor		0.00	0.00	0.00	$0	$0	$0.00000
SCR Catalyst (m3)		w/equip.	0.07	5775.94	$0	$129,612	$0.00003
Ammonia (19% NH3) ton		0.00	6.06	129.80	$0	$244,142	$0.00006
Subtotal Chemicals					**$0**	**$917,781**	**$0.00022**
Other							
Supplemental Fuel (MBtu)		0.00	0.00	0.00	$0	$0	$0.00000
Gases, N2 etc.(/100scf)		0.00	0.00	0.00	$0	$0	$0.00000
L.P. Steam (/1000 pounds)		0.00	0.00	0.00	$0	$0	$0.00000
Subtotal Other					**$0**	**$0**	**$0.00000**
Waste Disposal							
Flyash (ton)		0.00	0.00	0.00	$0	$0	$0.00000
Bottom Ash (ton)		0.00	0.00	0.00	$0	$0	$0.00000
Subtotal Waste Disposal					**$0**	**$0**	**$0.00000**
By-products							
Sulfur (tons)		0.00	0.00	0.00	$0	$0	$0.00000
Subtotal By-products					**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS					**$0**	**$5,441,560**	**$0.00132**
Fuel (MMBtu)		0	90,562	6.55	**$0**	**$183,973,460**	**$0.04451**

5.2.7   Case 14 – NGCC with CO$_2$ Capture

The plant configuration for Case 14 is the same as Case 13 with the exception that the Econamine CDR technology was added for CO$_2$ capture. The nominal net output decreases to 474 MW because, like the IGCC cases, the CT fixes the output and the CDR facility significantly increases the auxiliary power load and reduces the steam turbine output.

The process description for Case 14 is essentially the same as Case 13 with one notable exception, the addition of CO$_2$ capture. A BFD and stream tables for Case 14 are shown in Exhibit 5-16 and Exhibit 5-17, respectively. Since the CDR facility process description was provided in Section 5.1.5, it is not repeated here.

5.2.8   Case 14 Performance Results

The Case 14 modeling assumptions were presented previously in Section 5.2.2.

The plant produces a net output of 474 MW at a net plant efficiency of 42.8 percent (HHV basis). Overall plant performance is summarized in Exhibit 5-18, which includes auxiliary power requirements. The CDR facility, including CO$_2$ compression, accounts for over 66 percent of the auxiliary plant load. The CWS (CWPs and cooling tower fan) accounts for nearly 18 percent of the auxiliary load, largely due to the high cooling water demand of the CDR facility.

Exhibit 5-16 Case 14 Block Flow Diagram, NGCC with CO₂ Capture

Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.
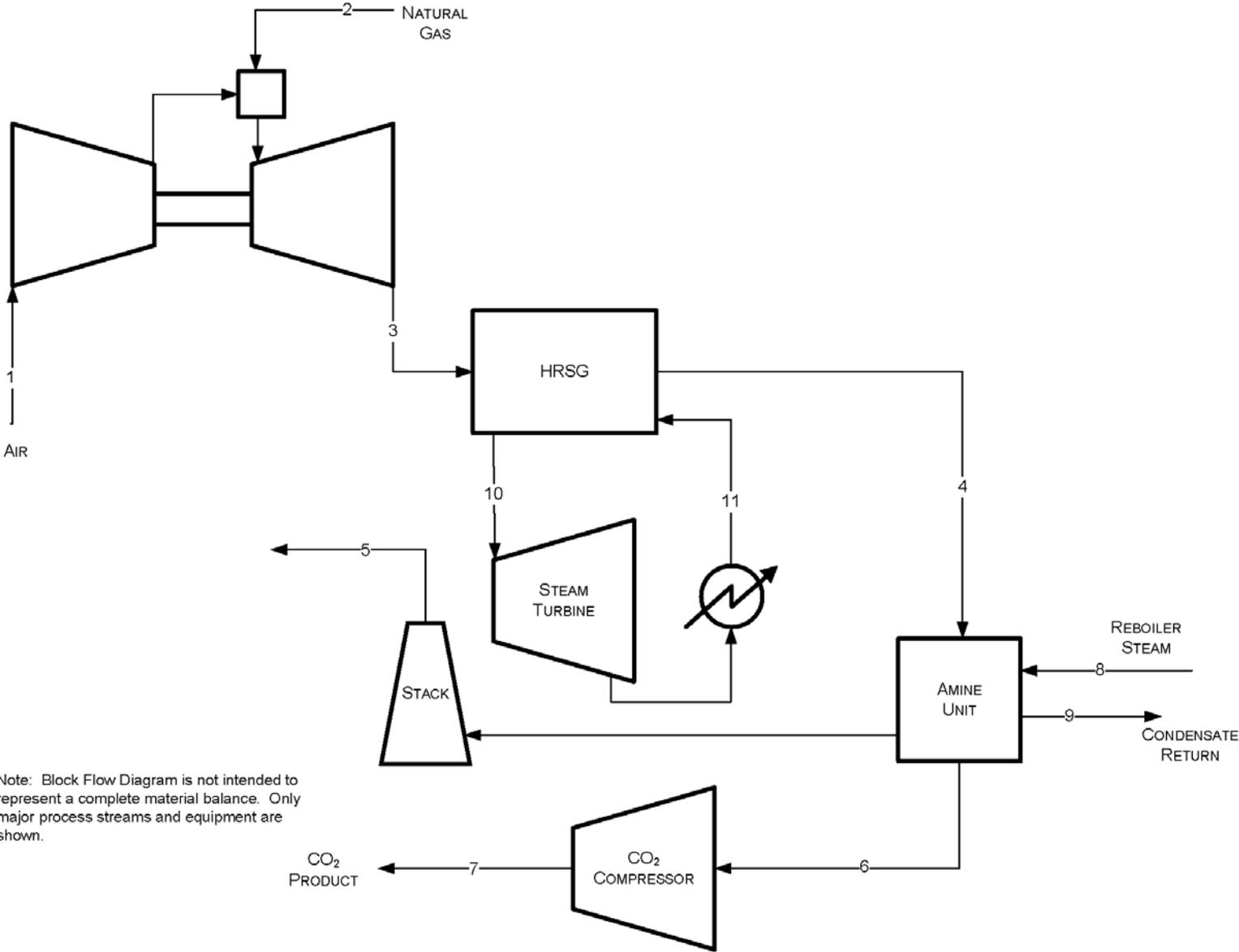
Exhibit 5-17 Case 14 Stream Table, NGCC with CO$_2$ Capture

	1	2	3	4	5	6	7	8	9	10	11
V-L Mole Fraction											
Ar	0.0092	0.0000	0.0089	0.0089	0.0098	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH$_4$	0.0000	0.9310	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C$_2$H$_6$	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C$_3$H$_8$	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C$_4$H$_{10}$	0.0000	0.0040	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
CO$_2$	0.0003	0.0100	0.0404	0.0404	0.0045	0.9893	1.0000	0.0000	0.0000	0.0000	0.0000
H$_2$O	0.0099	0.0000	0.0867	0.0867	0.0339	0.0107	0.0000	1.0000	1.0000	1.0000	1.0000
N$_2$	0.7732	0.0160	0.7432	0.7432	0.8187	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O$_2$	0.2074	0.0000	0.1209	0.1209	0.1332	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO$_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg$_{mol}$/hr)	109,323	4,380	113,831	113,831	103,333	4,185	4,140	17,887	17,887	21,589	13,482
V-L Flowrate (kg/hr)	3,154,735	75,901	3,230,636	3,230,636	2,933,892	183,013	182,203	322,243	322,243	388,927	242,889
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	38	629	143	30	21	51	152	151	566	38
Pressure (MPa, abs)	0.10	3.10	0.11	0.10	0.10	0.16	15.27	0.51	0.49	16.65	0.01
Enthalpy (kJ/kg)^A	30.23	46.30	835.81	288.61	83.96	26.65	-164.90	2,746.79	635.72	3,472.36	160.61
Density (kg/m^3)	1.2	22.2	0.4	0.8	1.1	2.9	653.5	2.7	915.8	47.7	992.9
V-L Molecular Weight	28.857	17.328	28.381	28.381	28.393	43.731	44.010	18.015	18.015	18.015	18.015
V-L Flowrate (lb$_{mol}$/hr)	241,016	9,657	250,954	250,954	227,809	9,226	9,127	39,435	39,435	47,595	29,724
V-L Flowrate (lb/hr)	6,955,000	167,333	7,122,333	7,122,333	6,468,125	403,474	401,689	710,425	710,425	857,437	535,480
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	100	1,163	290	85	69	124	306	304	1,050	101
Pressure (psia)	14.7	450.0	15.2	14.7	14.7	23.5	2,214.7	73.5	71.0	2,414.7	1.0
Enthalpy (Btu/lb)^A	13.0	19.9	359.3	124.1	36.1	11.5	-70.9	1,180.9	273.3	1,492.8	69.1
Density (lb/ft^3)	0.076	1.384	0.025	0.052	0.071	0.183	40.800	0.169	57.172	2.977	61.982

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 5-18 Case 14 Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	362,200
Steam Turbine Power	148,800
TOTAL POWER, kWe	**511,000**
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	80
Boiler Feedwater Pumps	2,710
Amine System Auxiliaries	9,600
CO_2 Compression	15,200
Circulating Water Pump	4,360
Ground Water Pumps	360
Cooling Tower Fans	2,250
SCR	10
Gas Turbine Auxiliaries	700
Steam Turbine Auxiliaries	100
Miscellaneous Balance of Plant[1]	500
Transformer Losses	1,560
TOTAL AUXILIARIES, kWe	**37,430**
NET POWER, kWe	**473,570**
Net Plant Efficiency (HHV)	42.8%
Net Plant Efficiency (LHV)	47.5%
Net Plant Heat Rate (HHV), kJ/kWh (Btu/kWh)	8,406 (7,968)
Net Plant Heat Rate (LHV), kJ/kWh (Btu/kWh)	7,579 (7,184)
CONDENSER COOLING DUTY, 10^6 kJ/hr (10^6 Btu/hr)	**528 (500)**
CONSUMABLES	
Natural Gas Feed Flow, kg/hr (lb/hr)	75,901 (167,333)
Thermal Input (HHV), kW$_{th}$	1,105,812
Thermal Input (LHV) , kW$_{th}$	997,032
Raw Water Withdrawal, m^3/min (gpm)	15.1 (3,980)
Raw Water Consumption, m^3/min (gpm)	11.3 (2,985)

1. Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

Environmental Performance

The environmental targets for emissions of NOx, SO$_2$, and PM were presented in Section 2.4. A summary of the plant air emissions for Case 14 is presented in Exhibit 5-19.

Exhibit 5-19 Case 14 Air Emissions

	kg/GJ (lb/10^6 Btu)	Tonne/year (ton/year) 85% CF	kg/MWh (lb/MWh)
SO$_2$	Negligible	Negligible	Negligible
NOx	0.004 (0.008)	105 (115)	0.027 (0.061)
Particulates	Negligible	Negligible	Negligible
Hg	Negligible	Negligible	Negligible
CO$_2$	5.1 (11.8)	150,743 (166,165)	40 (87)
CO$_2$[1]			43 (94)

[1] CO$_2$ emissions based on net power instead of gross power

The operation of the modern, state-of-the-art GT fueled by natural gas, coupled to a HRSG, results in very low levels of NOx emissions and negligible levels of SO$_2$, particulate, and Hg emissions. As noted in Section 2.4, if the fuel contains the maximum amount of sulfur compounds allowed in pipeline natural gas, the NGCC SO$_2$ emissions would be 21 tonnes/yr (23 tons/yr) at 85 percent CF, or 0.00195 lb/MMBtu.

The low level of NOx production (2.5 ppmvd at 15 percent O$_2$) is achieved by utilizing a dry LNB coupled with an SCR system.

Ninety percent of the CO$_2$ in the FG is removed in CDR facility.

The carbon balance for the plant is shown in Exhibit 5-20. The carbon input to the plant consists of carbon in the natural gas in addition to carbon in the CT air. Carbon leaves the plant as CO$_2$ in the stack gas and the captured CO$_2$ product. The CO$_2$ capture efficiency is defined by the following fraction:

$$\text{(CO}_2 \text{ Product Carbon)/(Natural Gas Carbon)*100 or}$$
$$(109,628)/(120,863) * 100 \text{ or}$$
$$90.7 \text{ percent}$$

Exhibit 5-20 Case 14 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Natural Gas	54,822 (120,863)	**Stack Gas**	5,525 (12,181)
Air (CO$_2$)	429 (946)	**CO$_2$ Product**	49,726 (109,628)
Total	55,251 (121,808)	**Total**	55,251 (121,808)

A sulfur balance is not included for Case 14 because the sulfur concentration of natural gas is negligible. Consequently, sulfur emissions are also negligible, as shown in Exhibit 5-19, despite the use of no sulfur control technology.

Exhibit 5-21 shows the overall water balance for the plant. The exhibit is presented in an identical manner as was for Case 13.

Exhibit 5-21 Case 14 Water Balance

Water Use	Water Demand, m³/min (gpm)	Internal Recycle, m³/min (gpm)	Raw Water Withdrawal, m³/min (gpm)	Process Water Discharge, m³/min (gpm)	Raw Water Consumption, m³/min (gpm)
Econamine	**0.04 (12)**	**0.0 (0)**	**0.04 (12)**	**0.0 (0)**	**0.04 (12)**
Condenser Makeup *BFW Makeup*	**0.1 (23)** *0.1 (23)*	**0.0 (0)**	**0.1 (23)** *0.1 (23)*	**0.0 (0)**	**0.1 (23)**
Cooling Tower *BFW Blowdown* *Flue Gas Condensate*	**17.0 (4,477)**	**2.0 (520)** *0.1 (23)* *1.9 (497)*	**15.0 (3,958)** *-0.1 (-23)* *-1.9 (-497)*	**3.8 (1,007)**	**11.2 (2,951)**
CO₂ Product Condensate		**0.03 (8)**	**-0.03 (-8)**		
Total	**17.1 (4,512)**	**2.0 (528)**	**15.1 (3,992)**	**3.8 (1,007)**	**11.3 (2,985)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the NGCC in Exhibit 5-22. An overall plant energy balance is provided in tabular form in Exhibit 5-23.

The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 5-18) is calculated by multiplying the power out by a combined generator efficiency of 98.3 percent. The Econamine process heat out stream represents heat rejected to cooling water and ultimately to ambient via the cooling tower. The same is true of the condenser heat out stream. The CO_2 compressor intercooler load is included in the Econamine process heat out stream.

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Exhibit 5-22 Case 14 Heat and Mass Balance, NGCC with CO₂ Capture
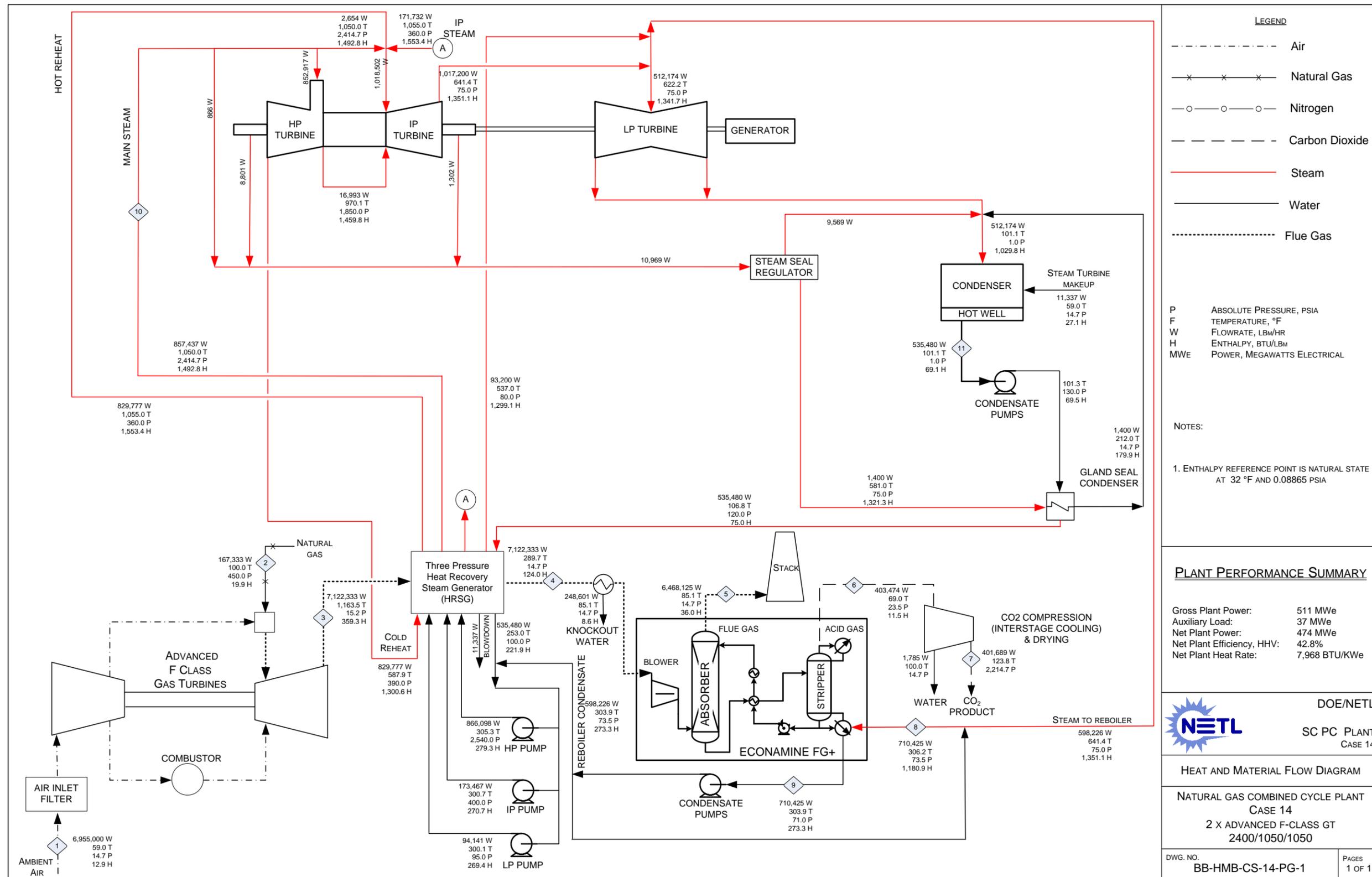
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Exhibit 5-23 Case 14 Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Natural Gas	3,981 (3,773)	2.7 (2.5)		3,984 (3,776)
GT Air		95.4 (90.4)		95 (90)
Raw Water Withdrawal		56.7 (53.7)		57 (54)
Auxiliary Power		0.0 (0.0)	135 (128)	135 (128)
Totals	**3,981 (3,773)**	**154.7 (146.6)**	**135 (128)**	**4,270 (4,048)**
Heat Out GJ/hr (MMBtu/hr)				
CO_2		-30.0 (-28.5)		-30 (-28)
Cooling Tower Blowdown		28.3 (26.8)		28 (27)
Econamine Losses		1,010 (957)		1,010 (957)
CO_2 Compression Intercooling		84.9 (80.5)		85 (81)
Stack Gas		246 (233)		246 (233)
Condenser		532 (504)		532 (504)
Process Losses*		560 (530)		560 (530)
Power			1,840 (1,744)	1,840 (1,744)
Totals	**0 (0)**	**2,431 (2,304)**	**1,840 (1,744)**	**4,270 (4,048)**

* Process Losses are calculated by difference and reflect various boiler, turbine, and other heat and work losses. Aspen flowsheet balance is within 0.5 percent.

5.2.9 Case 14 Major Equipment List

Major equipment items for the NGCC plant with CO_2 capture are shown in the following tables. The accounts used in the equipment list correspond to the account numbers used in the cost estimates in Section 5.2.10. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1   COAL AND SORBENT HANDLING

   N/A

ACCOUNT 2   FUEL AND SORBENT PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	63 m3/min @ 3.1 MPa (2,216 acfm @ 450 psia) 41 cm (16 in) standard wall pipe	16 km (10 mile)	0
2	Gas Metering Station	--	63 m3/min (2,216 acfm)	1	0

ACCOUNT 3   FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	677,594 liters (179,000 gal)	2	0
2	Condensate Pumps	Vertical canned	2,233 lpm @ 110 m H2O (590 gpm @ 360 ft H2O)	2	1
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP water: 3,634 lpm @ 2,103 m H2O (960 gpm @ 6,900 ft H2O) IP water: 719 lpm @ 283 m H2O (190 gpm @ 930 ft H2O) LP water: 379 lpm @ 24.4 m H2O (100 gpm @ 80 ft H2O)	2	1
4	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/h, 2.8 MPa, 343°C (40,000 lb/h, 400 psig, 650°F)	1	0
5	Service Air Compressors	Flooded Screw	13 m3/min @ 0.7 MPa (450 scfm @ 100 psig)	2	1
6	Instrument Air Dryers	Duplex, regenerative	13 m3/min (450 scfm)	2	1
7	Closed Cycle Cooling Heat Exchangers	Plate and frame	13 MMkJ/hr (13 MMBtu/hr)	2	0
8	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	5,300 lpm @ 21 m H2O (1,400 gpm @ 70 ft H2O)	2	1
9	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H2O (1,000 gpm @ 350 ft H2O)	1	1
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H2O (700 gpm @ 250 ft H2O)	1	1
11	Raw Water Pumps	Stainless steel, single suction	8,328 lpm @ 18 m H2O (2,200 gpm @ 60 ft H2O)	2	1
12	Filtered Water Pumps	Stainless steel, single suction	151 lpm @ 49 m H2O (40 gpm @ 160 ft H2O)	2	1
13	Filtered Water Tank	Vertical, cylindrical	143,847 liter (38,000 gal)	1	0
14	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly and electro-deionization unit	341 lpm (90 gpm)	1	0
15	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

ACCOUNT 4   GASIFIER, BOILER AND ACCESSORIES

N/A

ACCOUNT 5B   CARBON DIOXIDE RECOVERY

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Econamine FG Plus	Amine-based CO2 capture technology	1,776,723 kg/hr (3,917,000 lb/hr) 6.3 wt % CO2 concentration	2	0
2	CO2 Compressor	Integrally geared, mult	100,244 kg/hr @ 15.3 MPa (221,000 lb/hr @ 2,215 psia)	2	0

ACCOUNT 6   COMBUSTION TURBINE GENERATORS AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class w/ dry low-NOx burner	180 MW	2	0
2	Gas Turbine Generator	TEWAC	200 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0

ACCOUNT 7 WASTE HEAT BOILER, DUCTING, AND STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	46 m (150 ft) high x 6.4 m (21 ft) diameter	2	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 213,910 kg/h, 16.5 MPa/566°C (471,590 lb/h, 2,400 psig/1,050°F) Reheat steam - 249,852 kg/h, 2.4 MPa/566°C (550,830 lb/h, 345 psig/1,050°F)	2	0
3	SCR Reactor	Space for spare layer	1,614,791 kg/h (3,560,000 lb/h)	2	0
4	SCR Catalyst	--	Space available for an additional catalyst layer	1 layer	0
5	Dilution Air Blowers	Centrifugal	11 m3/min @ 107 cm WG (390 scfm @ 42 in WG)	2	1
6	Ammonia Feed Pump	Centrifugal	3.8 lpm @ 91 m H2O (1 gpm @ 300 ft H2O)	2	1
7	Ammonia Storage Tank	Horizontal tank	68,138 liter (18,000 gal)	1	0

ACCOUNT 8   STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Tandem compound, HP, IP, and two-flow LP turbines	157 MW 16.5 MPa/566°C/566°C (2,400 psig/ 1050°F/1050°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	170 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	580 MMkJ/hr, (550 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9   COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	435,326 lpm @ 30.5 m (115,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT 613 MMkJ/hr (582 MMBtu/hr) heat load	1	0

ACCOUNT 10   ASH/SPENT SORBENT RECOVERY AND HANDLING

N/A

ACCOUNT 11 ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Transformer	Oil-filled	24 kV/345 kV, 200 MVA, 3-ph, 60 Hz	2	0
2	STG Transformer	Oil-filled	24 kV/345 kV, 150 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 8 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 23 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 3 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12 INSTRUMENTATION AND CONTROL

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

5.2.10 Case 14 – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 5-24 shows the total plant capital cost summary organized by cost account and Exhibit 5-25 shows a more detailed breakdown of the capital costs. Exhibit 5-26 shows the initial and annual O&M costs.

The estimated TOC of the NGCC with CO_2 capture is \$1,497/kW. Process contingency represents 4.0 percent of the TOC and project contingency represents 10.8 percent. The COE, including CO_2 TS&M costs of 3.2 mills/kWh, is 85.9 mills/kWh.

Exhibit 5-24 Case 14 Total Plant Cost Summary

Client:		USDOE/NETL							Report Date:	2010-Jan-14		
Project:		Bituminous Baseline Study										
		TOTAL PLANT COST SUMMARY										
Case:		Case 14 - 1x475 MWnet 2x1 7FB NGCC w/ CO2 Capture										
Plant Size:		473.6 MW,net	Estimate Type:		Conceptual			Cost Base (Jun)	2007	($x1000)		

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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
2	COAL & SORBENT PREP & FEED	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
3	FEEDWATER & MISC. BOP SYSTEMS	$23,934	$4,864	$7,962	$0	$0	**$36,760**	$3,106	$0	$6,447	**$46,312**	$98
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.2	Syngas Cooling	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.4-4.9	Other gasification Equipment	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
5A	GAS CLEANUP & PIPING	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
5B	CO2 REMOVAL & COMPRESSION	$121,638	$0	$37,053	$0	$0	**$158,691**	$13,593	$27,994	$40,056	**$240,334**	$507
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$75,294	$0	$4,804	$0	$0	**$80,098**	$6,800	$0	$8,690	**$95,589**	$202
6.2-6.9	Combustion Turbine Other	$0	$719	$744	$0	$0	**$1,462**	$122	$0	$317	**$1,901**	$4
	SUBTOTAL 6	**$75,294**	**$719**	**$5,548**	**$0**	**$0**	**$81,561**	**$6,922**	**$0**	**$9,007**	**$97,490**	**$206**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,958	$0	$4,279	$0	$0	**$37,237**	$3,170	$0	$4,041	**$44,448**	$94
7.2-7.9	SCR System, Ductwork and Stack	$1,243	$950	$1,118	$0	$0	**$3,311**	$282	$0	$583	**$4,176**	$9
	SUBTOTAL 7	**$34,201**	**$950**	**$5,397**	**$0**	**$0**	**$40,548**	**$3,453**	**$0**	**$4,624**	**$48,624**	**$103**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$19,229	$0	$3,465	$0	$0	**$22,694**	$1,951	$0	$2,465	**$27,110**	$57
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$6,570	$637	$4,691	$0	$0	**$11,898**	$958	$0	$1,824	**$14,680**	$31
	SUBTOTAL 8	**$25,799**	**$637**	**$8,156**	**$0**	**$0**	**$34,592**	**$2,909**	**$0**	**$4,289**	**$41,791**	**$88**
9	COOLING WATER SYSTEM	$8,569	$6,296	$5,689	$0	$0	**$20,554**	$1,708	$0	$3,140	**$25,403**	$54
10	ASH/SPENT SORBENT HANDLING SYS	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
11	ACCESSORY ELECTRIC PLANT	$20,769	$5,564	$12,124	$0	$0	**$38,458**	$2,957	$0	$4,473	**$45,888**	$97
12	INSTRUMENTATION & CONTROL	$6,272	$644	$5,211	$0	$0	**$12,127**	$1,010	$606	$1,575	**$15,318**	$32
13	IMPROVEMENTS TO SITE	$1,724	$936	$4,588	$0	$0	**$7,248**	$641	$0	$1,578	**$9,467**	$20
14	BUILDINGS & STRUCTURES	$0	$3,982	$4,121	$0	$0	**$8,103**	$658	$0	$1,314	**$10,075**	$21
	TOTAL COST	**$318,200**	**$24,594**	**$95,849**	**$0**	**$0**	**$438,642**	**$36,957**	**$28,600**	**$76,502**	**$580,701**	**$1,226**

Exhibit 5-25 Case 14 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	TOTAL PLANT COST $	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 & Yd Crush	$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	Prepared Coal Storage & Feed	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.3	Slurry Prep & Feed	$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	Feedwater System	$2,426	$2,499	$2,055	$0	$0	$6,980	$576	$0	$1,133	$8,690	$18
3.2	Water Makeup & Pretreating	$2,123	$222	$1,109	$0	$0	$3,453	$294	$0	$750	$4,497	$9
3.3	Other Feedwater Subsystems	$1,106	$374	$314	$0	$0	$1,794	$144	$0	$291	$2,229	$5
3.4	Service Water Systems	$251	$517	$1,676	$0	$0	$2,444	$213	$0	$531	$3,188	$7
3.5	Other Boiler Plant Systems	$1,683	$652	$1,511	$0	$0	$3,846	$326	$0	$626	$4,798	$10
3.6	Natural Gas, incl. pipeline	$14,652	$476	$415	$0	$0	$15,543	$1,317	$0	$2,529	$19,389	$41
3.7	Waste Treatment Equipment	$766	$0	$437	$0	$0	$1,203	$105	$0	$262	$1,569	$3
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$927	$124	$445	$0	$0	$1,496	$129	$0	$325	$1,951	$4
	SUBTOTAL 3.	$23,934	$4,864	$7,962	$0	$0	$36,760	$3,106	$0	$6,447	$46,312	$98
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.2	Syngas Cooling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.4	LT Heat Recovery & FG Saturation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.5	Misc. Gasification Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Other Gasification Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.8	Major Component Rigging	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Gasification Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 4.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Exhibit 5-25 Case 14 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	MDEA-LT AGR	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.2	Elemental Sulfur Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.3	Mercury Removal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.4	COS Hydrolysis	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.5	Blowback Gas Systems	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Fuel Gas Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.9	HGCU Foundations	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B	CO2 REMOVAL & COMPRESSION											
5B.1	CO2 Removal System	$107,387	$0	$32,583	$0	$0	$139,970	$11,989	$27,994	$35,991	$215,943	$456
5B.2	CO2 Compression & Drying	$14,251	$0	$4,471	$0	$0	$18,721	$1,604	$0	$4,065	$24,390	$52
	SUBTOTAL 5.	$121,638	$0	$37,053	$0	$0	$158,691	$13,593	$27,994	$40,056	$240,334	$507
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$75,294	$0	$4,804	$0	$0	$80,098	$6,800	$0	$8,690	$95,589	$202
6.2	Combustion Turbine Accessories	$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	$719	$744	$0	$0	$1,462	$122	$0	$317	$1,901	$4
	SUBTOTAL 6.	$75,294	$719	$5,548	$0	$0	$81,561	$6,922	$0	$9,007	$97,490	$206
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,958	$0	$4,279	$0	$0	$37,237	$3,170	$0	$4,041	$44,448	$94
7.2	SCR System	$1,243	$522	$733	$0	$0	$2,498	$215	$0	$407	$3,120	$7
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	HRSG,Duct & Stack Foundations	$0	$428	$385	$0	$0	$813	$68	$0	$176	$1,057	$2
	SUBTOTAL 7.	$34,201	$950	$5,397	$0	$0	$40,548	$3,453	$0	$4,624	$48,624	$103
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$19,229	$0	$3,465	$0	$0	$22,694	$1,951	$0	$2,465	$27,110	$57
8.2	Turbine Plant Auxiliaries	$141	$0	$317	$0	$0	$458	$40	$0	$50	$548	$1
8.3	Condenser & Auxiliaries	$2,393	$0	$714	$0	$0	$3,107	$266	$0	$337	$3,711	$8
8.4	Steam Piping	$4,035	$0	$2,653	$0	$0	$6,688	$513	$0	$1,080	$8,281	$17
8.9	TG Foundations	$0	$637	$1,007	$0	$0	$1,644	$139	$0	$357	$2,140	$5
	SUBTOTAL 8.	$25,799	$637	$8,156	$0	$0	$34,592	$2,909	$0	$4,289	$41,791	$88
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$6,077	$0	$777	$0	$0	$6,854	$584	$0	$744	$8,182	$17
9.2	Circulating Water Pumps	$1,780	$0	$106	$0	$0	$1,887	$142	$0	$203	$2,232	$5
9.3	Circ.Water System Auxiliaries	$136	$0	$18	$0	$0	$154	$13	$0	$17	$184	$0
9.4	Circ.Water Piping	$0	$3,968	$962	$0	$0	$4,930	$399	$0	$799	$6,128	$13
9.5	Make-up Water System	$313	$0	$418	$0	$0	$730	$63	$0	$119	$912	$2
9.6	Component Cooling Water Sys	$264	$315	$210	$0	$0	$788	$66	$0	$128	$983	$2
9.9	Circ.Water System Foundations	$0	$2,013	$3,198	$0	$0	$5,211	$442	$0	$1,130	$6,783	$14
	SUBTOTAL 9.	$8,569	$6,296	$5,689	$0	$0	$20,554	$1,708	$0	$3,140	$25,403	$54

Exhibit 5-25 Case 14 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
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 Recovery Equipment	$0	$0	$0	$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	$5,372	$0	$3,228	$0	$0	$8,600	$728	$0	$700	$10,028	$21
11.2	Station Service Equipment	$1,980	$0	$167	$0	$0	$2,147	$177	$0	$174	$2,498	$5
11.3	Switchgear & Motor Control	$2,440	$0	$415	$0	$0	$2,855	$237	$0	$309	$3,402	$7
11.4	Conduit & Cable Tray	$0	$1,166	$3,595	$0	$0	$4,761	$412	$0	$776	$5,949	$13
11.5	Wire & Cable	$0	$3,713	$2,280	$0	$0	$5,993	$386	$0	$957	$7,337	$15
11.6	Protective Equipment	$0	$563	$1,916	$0	$0	$2,480	$217	$0	$270	$2,966	$6
11.7	Standby Equipment	$98	$0	$90	$0	$0	$188	$16	$0	$20	$224	$0
11.8	Main Power Transformers	$10,878	$0	$136	$0	$0	$11,014	$747	$0	$1,176	$12,937	$27
11.9	Electrical Foundations	$0	$121	$298	$0	$0	$419	$36	$0	$91	$546	$1
	SUBTOTAL 11.	$20,769	$5,564	$12,124	$0	$0	$38,458	$2,957	$0	$4,473	$45,888	$97
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	w/6.1	$0	w/6.1	$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	$797	$0	$498	$0	$0	$1,295	$110	$65	$220	$1,690	$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	$238	$0	$143	$0	$0	$381	$32	$19	$65	$497	$1
12.7	Computer & Accessories	$3,814	$0	$114	$0	$0	$3,928	$323	$196	$445	$4,892	$10
12.8	Instrument Wiring & Tubing	$0	$644	$1,230	$0	$0	$1,874	$141	$94	$316	$2,426	$5
12.9	Other I & C Equipment	$1,422	$0	$3,226	$0	$0	$4,648	$404	$232	$528	$5,813	$12
	SUBTOTAL 12.	$6,272	$644	$5,211	$0	$0	$12,127	$1,010	$606	$1,575	$15,318	$32

Exhibit 5-25 Case 14 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$92	$1,839	$0	$0	$1,931	$172	$0	$421	$2,524	$5
13.2	Site Improvements	$0	$844	$1,049	$0	$0	$1,893	$167	$0	$412	$2,472	$5
13.3	Site Facilities	$1,724	$0	$1,700	$0	$0	$3,424	$302	$0	$745	$4,471	$9
	SUBTOTAL 13.	$1,724	$936	$4,588	$0	$0	$7,248	$641	$0	$1,578	$9,467	$20
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area	$0	$236	$125	$0	$0	$361	$28	$0	$58	$447	$1
14.2	Steam Turbine Building	$0	$1,639	$2,183	$0	$0	$3,822	$314	$0	$620	$4,756	$10
14.3	Administration Building	$0	$462	$313	$0	$0	$775	$62	$0	$125	$962	$2
14.4	Circulation Water Pumphouse	$0	$147	$73	$0	$0	$220	$17	$0	$36	$272	$1
14.5	Water Treatment Buildings	$0	$458	$418	$0	$0	$876	$71	$0	$142	$1,089	$2
14.6	Machine Shop	$0	$401	$256	$0	$0	$657	$52	$0	$106	$815	$2
14.7	Warehouse	$0	$259	$156	$0	$0	$415	$33	$0	$67	$515	$1
14.8	Other Buildings & Structures	$0	$77	$56	$0	$0	$134	$11	$0	$22	$166	$0
14.9	Waste Treating Building & Str.	$0	$303	$541	$0	$0	$845	$70	$0	$137	$1,052	$2
	SUBTOTAL 14.	$0	$3,982	$4,121	$0	$0	$8,103	$658	$0	$1,314	$10,075	$21
	TOTAL COST	$318,200	$24,594	$95,849	$0	$0	$438,642	$36,957	$28,600	$76,502	$580,701	$1,226
	Owner's Costs											
	Preproduction Costs											
	6 Months All Labor										$4,163	$9
	1 Month Maintenance Materials										$612	$1
	1 Month Non-fuel Consumables										$273	$1
	1 Month Waste Disposal										$0	$0
	25% of 1 Months Fuel Cost at 100% CF										$4,509	$10
	2% of TPC										$11,614	$25
	Total										$21,170	$45
	Inventory Capital											
	60 day supply of consumables at 100% CF										$357	$1
	0.5% of TPC (spare parts)										$2,904	$6
	Total										$3,260	$7
	Initial Cost for Catalyst and Chemicals										$823	$2
	Land										$300	$1
	Other Owner's Costs										$87,105	$184
	Financing Costs										$15,679	$33
	Total Overnight Costs (TOC)										$709,039	$1,497
	TASC Multiplier							(IOU, high-risk, 33 year)			1.078	
	Total As-Spent Cost (TASC)										$764,344	$1,614

Exhibit 5-26 Case 14 Initial and Annual Operating and Maintenance Cost Summary

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun):	2007
Case 14 - 1x475 MWnet 2x1 7FB NGCC w/ CO2 Capture					Heat Rate-net (Btu/kWh):	7,968
					MWe-net:	474
					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	

Operating Labor Requirements(O.J.)per Shift:	1 unit/mod.	Total Plant		
Skilled Operator	1.0	1.0		
Operator	3.3	3.3		
Foreman	1.0	1.0		
Lab Tech's, etc.	1.0	1.0		
TOTAL-O.J.'s	6.3	6.3		

	Annual Cost $	Annual Unit Cost $/kW-net
Annual Operating Labor Cost	$2,497,781	$5.274
Maintenance Labor Cost	$4,162,295	$8.789
Administrative & Support Labor	$1,665,019	$3.516
Property Taxes and Insurance	$11,614,024	$24.524
TOTAL FIXED OPERATING COSTS	**$19,939,120**	**$42.104**

VARIABLE OPERATING COSTS

							$/kWh-net
Maintenance Material Cost						**$6,243,443**	**$0.00177**

Consumables	Consumption Initial Fill	/Day	Unit Cost	Initial Fill Cost			
Water (/1000 gallons)	0.00	2,865.60	1.08	**$0**	$961,666		$0.00027
Chemicals							
MU & WT Chem.(lbs)	0.00	17,072.41	0.17	$0	$916,693		$0.00026
MEA Solvent (ton)	344.71	0.48	2,249.89	$775,561	$337,908		$0.00010
Activated Carbon (lb)	0.00	578.27	1.05	$0	$188,408		$0.00005
Corrosion Inhibitor	0.00	0.00	0.00	$47,225	$2,249		$0.00000
SCR Catalyst (m3)	w/equip.	0.07	5,775.94	$0	$129,612		$0.00004
Ammonia (19% NH3) (ton)	0.00	6.06	129.80	$0	$244,142		$0.00007
Subtotal Chemicals				**$822,786**	**$1,819,011**		**$0.00052**
Other							
Supplemental Fuel (MBtu)	0.00	0.00	0.00	$0	$0		$0.00000
Gases,N2 etc. (/100scf)	0.00	0.00	0.00	$0	$0		$0.00000
L.P. Steam (/1000 pounds)	0.00	0.00	0.00	$0	$0		$0.00000
Subtotal Other				**$0**	**$0**		**$0.00000**
Waste Disposal							
Flyash (ton)	0.00	0.00	0.00	$0	$0		$0.00000
Bottom Ash (ton)	0.00	0.00	0.00	$0	$0		$0.00000
Subtotal Waste Disposal				**$0**	**$0**		**$0.00000**
By-products							
Sulfur (tons)	0.00	0.00	0.00	$0	$0		$0.00000
Subtotal By-products				**$0**	**$0**		**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$822,786**	**$9,024,121**		**$0.00256**
Fuel (MMBtu)	0	90,562	6.55	**$0**	**$183,972,091**		**$0.05217**

5.3 NGCC CASE SUMMARY

The performance results of the two NGCC plant configurations modeled in this study are summarized in Exhibit 5-27.

Exhibit 5-27 Estimated Performance and Cost Results for NGCC Cases

	NGCC	
	Advanced F Class	
PERFORMANCE	**Case 13**	**Case 14**
CO2 Capture	0%	90%
Gross Power Output (kWe)	564,700	511,000
Auxiliary Power Requirement (kWe)	9,620	37,430
Net Power Output (kWe)	555,080	473,570
Coal Flowrate (lb/hr)	N/A	N/A
Natural Gas Flowrate (lb/hr)	167,333	167,333
HHV Thermal Input (kWth)	1,105,812	1,105,812
Net Plant HHV Efficiency (%)	50.2%	42.8%
Net Plant HHV Heat Rate (Btu/kWh)	6,798	7,968
Raw Water Withdrawal (gpm/MW$_{net}$)	4.3	8.4
Process Water Discharge (gpm/MW$_{net}$)	1.0	2.1
Raw Water Consumption (gpm/MW$_{net}$)	3.3	6.3
CO_2 Emissions (lb/MMBtu)	118	12
CO_2 Emissions (lb/MWh$_{gross}$)	790	87
CO_2 Emissions (lb/MWh$_{net}$)	804	94
SO_2 Emissions (lb/MMBtu)	Negligible	Negligible
SO_2 Emissions (lb/MWh$_{gross}$)	Negligible	Negligible
NOx Emissions (lb/MMBtu)	0.009	0.008
NOx Emissions (lb/MWh$_{gross}$)	0.060	0.061
PM Emissions (lb/MMBtu)	Negligible	Negligible
PM Emissions (lb/MWh$_{gross}$)	Negligible	Negligible
Hg Emissions (lb/TBtu)	Negligible	Negligible
Hg Emissions (lb/MWh$_{gross}$)	Negligible	Negligible
COST		
Total Plant Cost (2007$/kW)	584	1,226
Total Overnight Cost (2007$/kW)	718	1,497
Bare Erected Cost	482	926
Home Office Expenses	40	78
Project Contingency	62	162
Process Contingency	0	60
Owner's Costs	133	271
Total Overnight Cost (2007$ x 1,000)	398,290	709,039
Total As Spent Capital (2007$/kW)	771	1,614
COE (mills/kWh, 2007$)[1,2]	58.9	85.9
CO2 TS&M Costs	0.0	3.2
Fuel Costs	44.5	52.2
Variable Costs	1.3	2.6
Fixed Costs	3.0	5.7
Capital Costs	10.1	22.3
LCOE (mills/kWh, 2007$)[1,2]	74.7	108.9

[1] Capacity factor is 85% for all NGCC cases
[2] COE and LCOE are defined in Section 2.7.

The components of TOC and overall TASC are shown for the two NGCC cases in Exhibit 5-28. The TOC of the non-capture case, \$718/kW, is the lowest of all technologies studied by at least 50 percent. Addition of CO_2 capture more than doubles the TOC cost, but NGCC with capture is still the least capital intensive of all the capture technologies by at least 55 percent. The process contingency included for the Econamine process totals \$59/kW, which represents approximately 4 percent of the TOC.

The COE for NGCC cases is heavily dependent on the price of natural gas as shown in Exhibit 5-29. The fuel component of COE represents 76 percent of the total in the non-capture case and 61 percent of the total in the CO_2 capture case. Because COE has a small capital component, it is less sensitive to CF than the more capital intensive PC and IGCC cases. The decrease in net kilowatt-hours (kWh) produced is nearly offset by a corresponding decrease in fuel cost. The CO_2 TS&M component of COE is only 4 percent of the total in the CO_2 capture case.

**Exhibit 5-28 Plant Capital Cost for NGCC Cases**
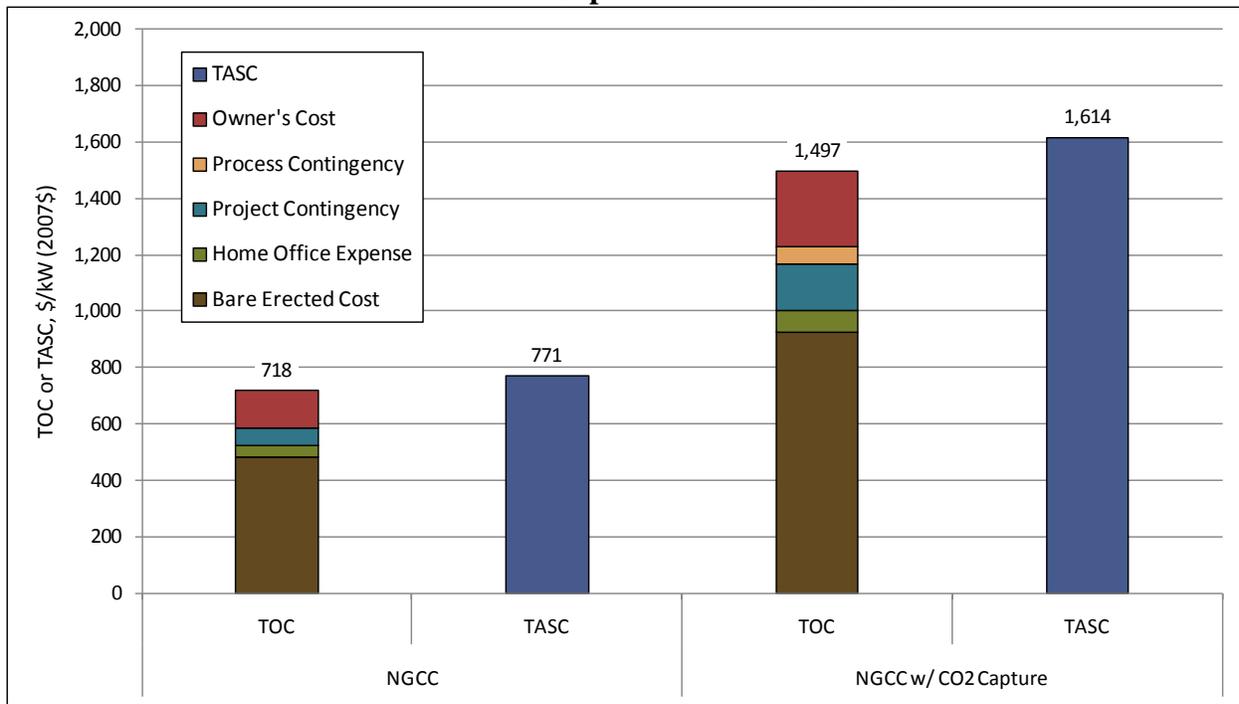
Exhibit 5-29 COE of NGCC Cases
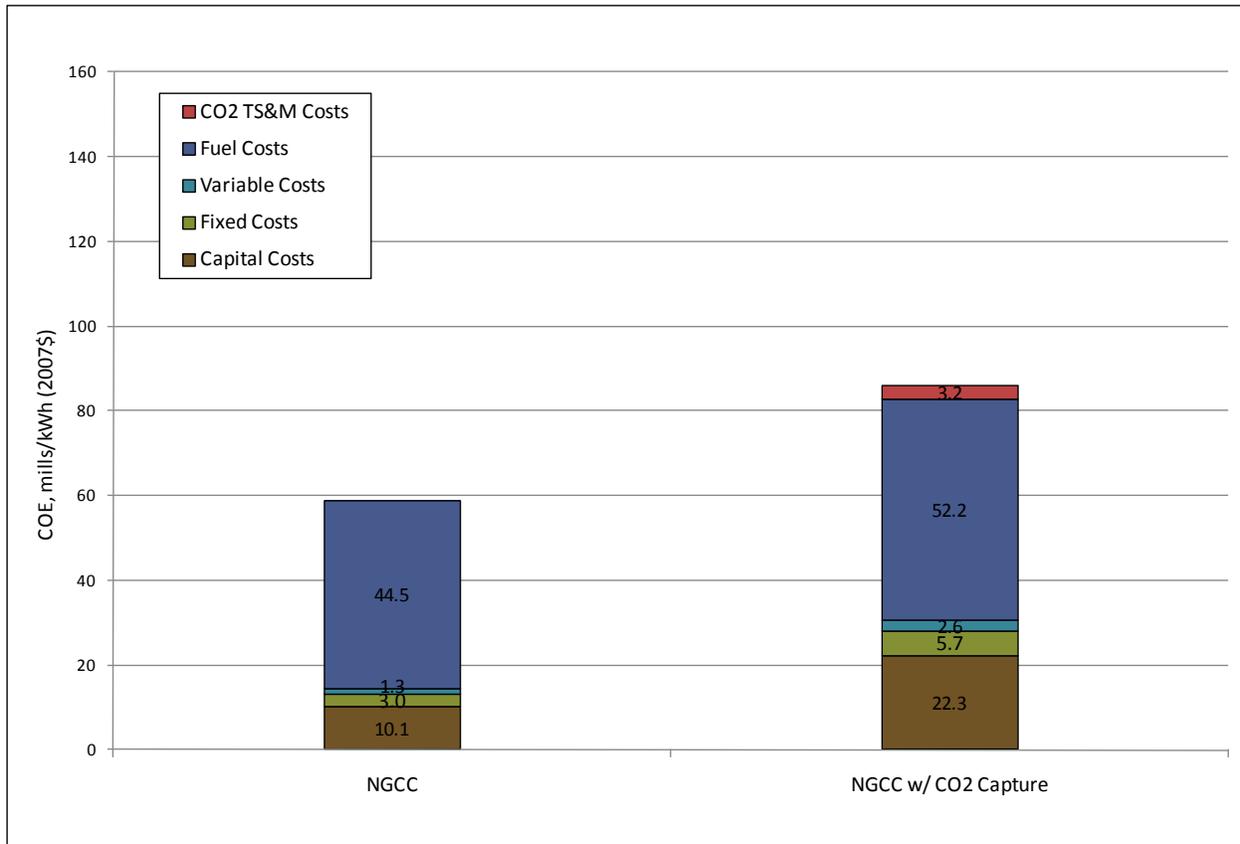
The sensitivity of NGCC to CF is shown in Exhibit 5-30. Unlike the PC and IGCC case, NGCC is relatively insensitive to CF but highly sensitive to fuel cost as shown in Exhibit 5-31. A 33 percent increase in natural gas price (from \$6 to \$8/MMBtu) results in a COE increase of 25 percent in the non-capture case and 20 percent in the CO_2 capture case. Because of the higher capital cost in the CO_2 capture case, the impact of fuel price changes is slightly diminished.

As presented in Section 2.4 the first year cost of CO_2 avoided cost was calculated. In the NGCC capture case the cost of CO_2 avoided using NGCC without CO_2 capture as the reference is \$69.5/tonne (\$63/ton). The high cost relative to PC and IGCC technologies is mainly due to the much smaller amount of CO_2 generated by NGCC and therefore captured in the Econamine process. The cost of CO_2 avoided is \$35.3/tonne (\$32/ton) when using SC PC without capture as the reference. This is due to the smaller difference in COE and larger difference in CO_2 emissions between the SC PC non-capture and NGCC capture cases.

## Exhibit 5-30 Sensitivity of COE to Capacity Factor in NGCC Cases
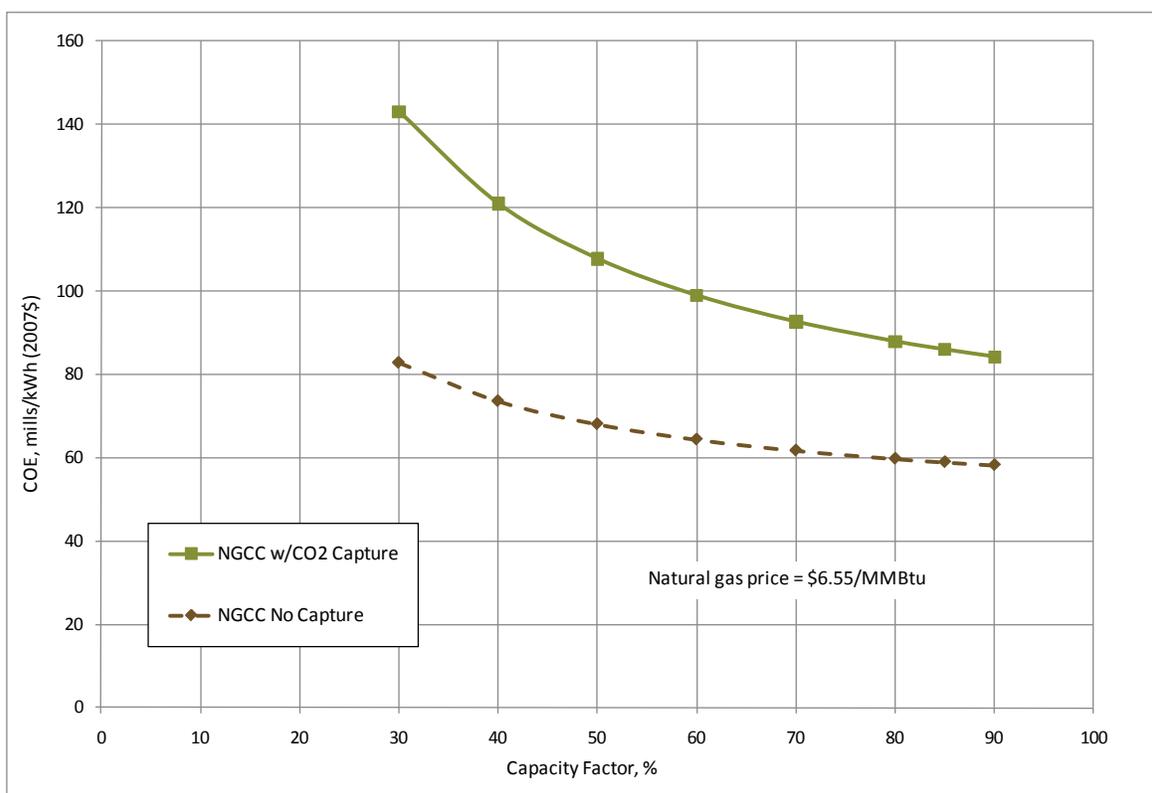
## Exhibit 5-31 Sensitivity of COE to Fuel Price in NGCC Cases
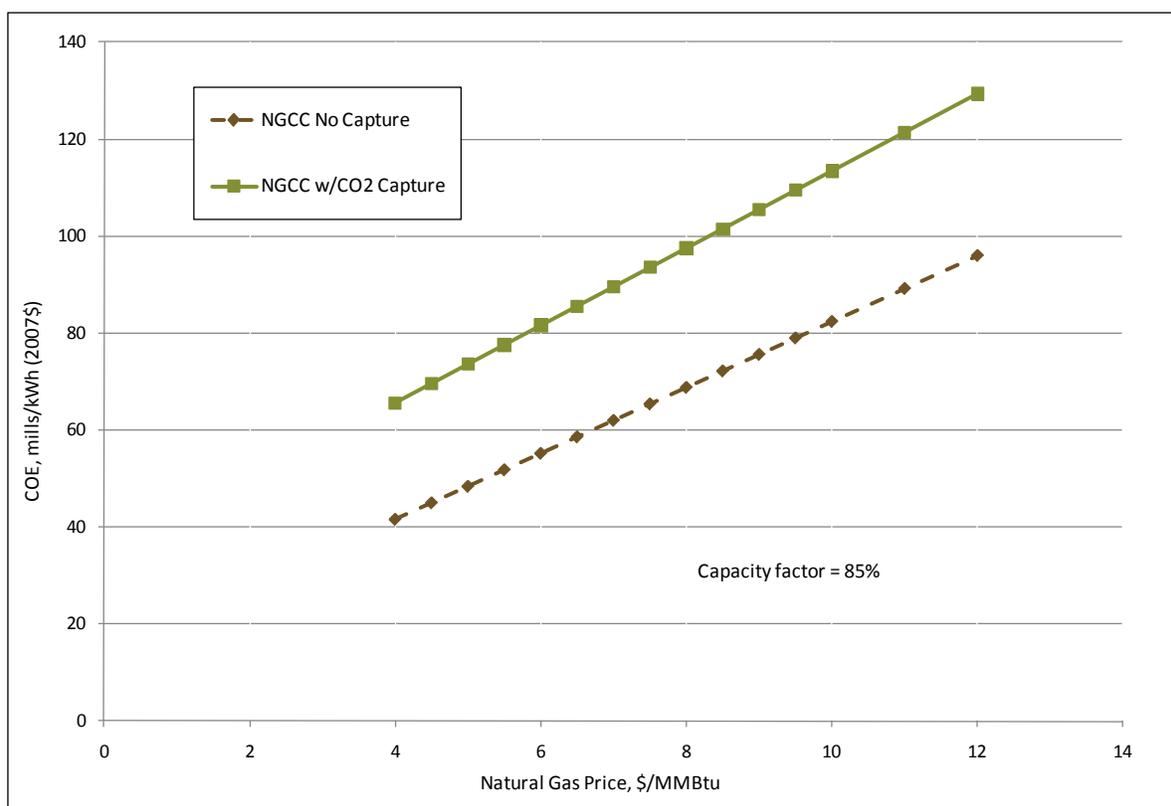
The following observations can be made regarding plant performance with reference to Exhibit 5-27:

- The efficiency of the NGCC case with no CO_2 capture is 50.2 percent (HHV basis). Gas Turbine World provides estimated performance for an advanced F class turbine operated on natural gas in a combined cycle mode, and the reported efficiency is 57.5 percent (LHV basis) [79]. Adjusting the result from this study to an LHV basis results in an efficiency of 55.7 percent.

- The efficiency penalty to add CO_2 capture in the NGCC case is 14.7 relative percent. The efficiency reduction is caused primarily by the auxiliary loads of the Econamine system and CO_2 compression as well as the significantly increased cooling water requirement, which increases the auxiliary load of the CWPs and the cooling tower fan. CO_2 capture results in a 28 MW increase in auxiliary load compared to the non-capture case.

- The energy penalty for NGCC is less than PC (14.7 relative percent for NGCC compared to 28.9 and 27.6 relative percent for subcritical and SC PC respectively) and IGCC (21.4 relative percent) mainly because natural gas has a lower carbon intensity than coal and NGCC has a higher efficiency than PC or IGCC. In the PC cases, about 589,670 kg/hr (1.3 million lb/hr) of CO_2 must be captured and compressed while in the NGCC case only about 181,437 kg/hr (400,000 lb/hr) is captured and compressed.

- A study assumption is that the natural gas contains no PM or Hg, resulting in negligible emissions of both.

- This study also assumes that the natural gas contains no sulfur compounds, resulting in negligible emissions of SO_2. As noted previously in the report, if the natural gas contained the maximum allowable amount of sulfur per EPA's pipeline natural gas specification, the resulting SO_2 emissions would be 21 tonnes/yr (23 tons/yr), or 0.00195 lb/MMBtu.

- NOx emissions are nearly identical for the two NGCC cases on a heat input and mass basis. This is a result of the fixed output from the GT (25 ppmv at 15 percent O_2) and the fixed efficiency of the SCR (90 percent).

The normalized water withdrawal, process discharge and raw water consumption are shown in Exhibit 5-32 for the NGCC cases. The following observations can be made:

- Normalized water withdrawal increases 95 percent and normalized raw water consumption 91 percent in the CO_2 capture case. The high cooling water demand of the Econamine process results in a large increase in cooling tower makeup requirements.

- Cooling tower makeup comprises approximately 99 percent of the raw water consumption in both NGCC cases. The only internal recycle stream in the non-capture case is the BFW blowdown, which is recycled to the cooling tower. In the CO_2 capture case condensate is recovered from the FG as it is cooled to the absorber temperature of 32°C (89°F) and is also recycled to the cooling tower.

Exhibit 5-32 Raw Water Withdrawal and Consumption in NGCC Cases
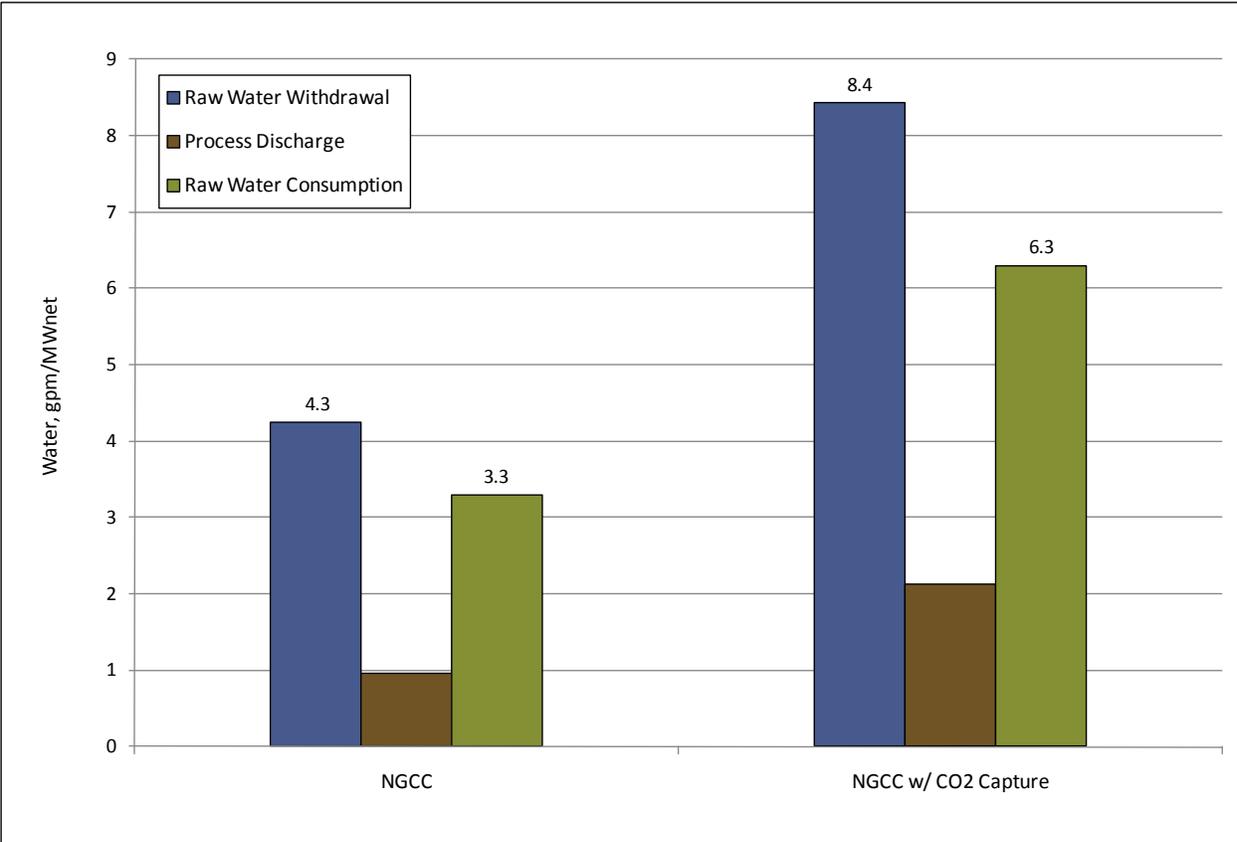
6. EFFECT OF HIGHER NATURAL GAS PRICES AND DISPATCH-BASED CAPACITY FACTORS

This supplementary chapter presents sensitivities of the economic performance to higher natural gas prices and dispatch-based CFs. Sections 6.1 through 6.3 discuss the sensitivity to higher natural gas prices (at a constant CF)[10] while Sections 6.4 through 6.8 examine dispatch-based CFs.

6.1 INCREASING NATURAL GAS PRICES

An investigation was conducted because of the potential for natural gas prices to increase over the long-term. Regulations limiting the emissions of CO_2 may cause natural gas to become an increasingly attractive fuel source for power generation. Natural gas is preferred in many cases because of its lower carbon intensity relative to coal: burning natural gas emits less CO_2 than an equivalent amount of coal. When compared to the average IGCC and PC non-capture cases in this study, NGCC emits 52 percent and 56 percent less CO_2 on a lb/net-MWh basis, respectively. As demand increases the natural gas supply has the potential to become constrained. Gas resources within the U.S. are mature and much of the low-cost gas has already been produced. Drilling and exploration will need to be done to find alternative sources of natural gas. Producers will have to drill higher cost wells with lower deliverability requiring high-cost technology to meet increased demand. Additional pipelines will have to be built as this gas will come from increasingly remote areas. The recently accessible Marcellus shale formation still must overcome environmental obstacles to be viable. The cost to produce the same volume of gas will increase causing the consumer to pay more for natural gas.

As domestic production costs increase, an alternative source for natural gas is imported liquefied natural gas (LNG). LNG is increasingly becoming a worldwide commodity as the supply and availability increase. As of 2009, there are only seven import terminals in the U.S. If imported LNG is to become a viable fuel source for the U.S., more terminal facilities will have to be built to keep up with the increasing demand. There is significant lag time between planning, permit acquisition, and construction of these large-scale facilities. This lag time, along with competition for LNG resources between other nations as the U.S. enters the market, will further limit the supply to the U.S.

6.2 PRICE METHODOLOGY

The baseline natural gas price used in this report is $6.55/MMBtu (June 2007 dollars). Two other natural gas prices are evaluated in this chapter to judge the sensitivity of the results to higher gas prices. The first is the EIA's AEO 2008 "High Price" projection for 2010. The "High Price" is $7.54/MMBtu in 2007 dollars[11].

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[10] It is acknowledged that changes in fuel pricing will likely have an impact on capacity factor. However for the purposes of this example, capacity factor is assumed to remain constant at a relatively high value of 85 percent in the face of changing fuel prices.

[11] The AEO 2008 "High Price" is reported as $7.31/MMBtu in 2006 dollars. This value was escalated to $7.54/MMBtu in 2007 dollars by using the GDP chain-type price index from AEO 2008.

The second natural gas cost is derived from applying the historical correlation between natural gas and West Texas Intermediate (WTI) crude oil [80].

$$\text{NG Price (\$/MMBtu)} = -0.4744 + 0.1543 \times (\text{Oil Price WTI (\$/bbl)})$$

The AEO "High Price" projection cost for imported crude oil in 2010 is \$71.33/bbl in 2007 dollars[12]. Using the "High Price" in the correlation equation results in a natural gas price of \$10.53/MMBtu. Using the Oil Correlation again, a \$51.94/bbl price would be needed to have a \$7.54/MMBtu price for natural gas.

6.3   COST OF ELECTRICITY

The COE results are shown in Exhibit 6-1 with the capital costs, fixed operating cost, variable operating cost, and fuel cost shown separately. In capture cases the CO_2 TS&M costs are also shown as a separate bar segment. Fuel cost is the dominant component of COE in all NGCC cases and therefore fuel price increases have a significant impact. The following conclusions can be drawn:

- In non-capture cases, the NGCC "High Price" case still has a lower COE (65.6 mills/kWh) than any of the IGCC cases (average 77.2 mills/kWh), but the NGCC Oil Correlation Price cost (86.0 mills/kWh) represents the highest COE of all the non-capture cases.
- In capture cases, the NGCC baseline cost (85.9 mills/kWh) is the lowest capture case cost in the initial study, and the NGCC "High Price" cost (93.8 mills/kWh) is still the lowest COE.
- When the natural gas price increases to \$10.53/MMBtu in the Oil Correlation case, NGCC becomes the most expensive technology with CO_2 capture. This differs from the baseline results where NGCC with capture was the lowest cost.
- For the three NGCC cases without CO_2 capture, the fuel component of COE ranges from 76 percent to 83 percent. For capture cases, the fuel component of COE ranges from 61 percent to 71 percent.
- For the NGCC non-capture cases, an increase in the natural gas price of 15.1 percent for "High Price" and 60.8 percent for the Oil Correlation price cause an increase of 11 percent and 46 percent in the COE, respectively. The COE in the NGCC CO_2 capture cases increases by 9 percent and 37 percent, respectively.

First year CO_2 avoided costs are shown in Exhibit 6-7 and are calculated using both analogous technologies and non-capture SC PC as references. The IGCC and PC cases were averaged to emphasize the NGCC cases at different natural gas prices. The following conclusions can be drawn:

- For NGCC cases, the first year CO_2 avoided costs increase with the price of natural gas. This is consistent with the COE trend as NGCC cases are predominately affected by fuel price.

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[12]   The AEO "High Price" is reported as \$69.19/bbl in 2006 dollars. This value was escalated to \$71.33 in 2007 dollars by using the GDP chain-type price index from AEO 2008.

- At the baseline natural gas price of \$6.55/MMBtu, the NGCC cases have a higher first year CO_2 avoided cost per ton than PC or IGCC when compared to the analogous non-capture technology. However, NGCC has the lowest first year avoided cost relative to a non-capture SC PC plant except at the highest natural gas price case.

Exhibit 6-1 COE By Cost Component
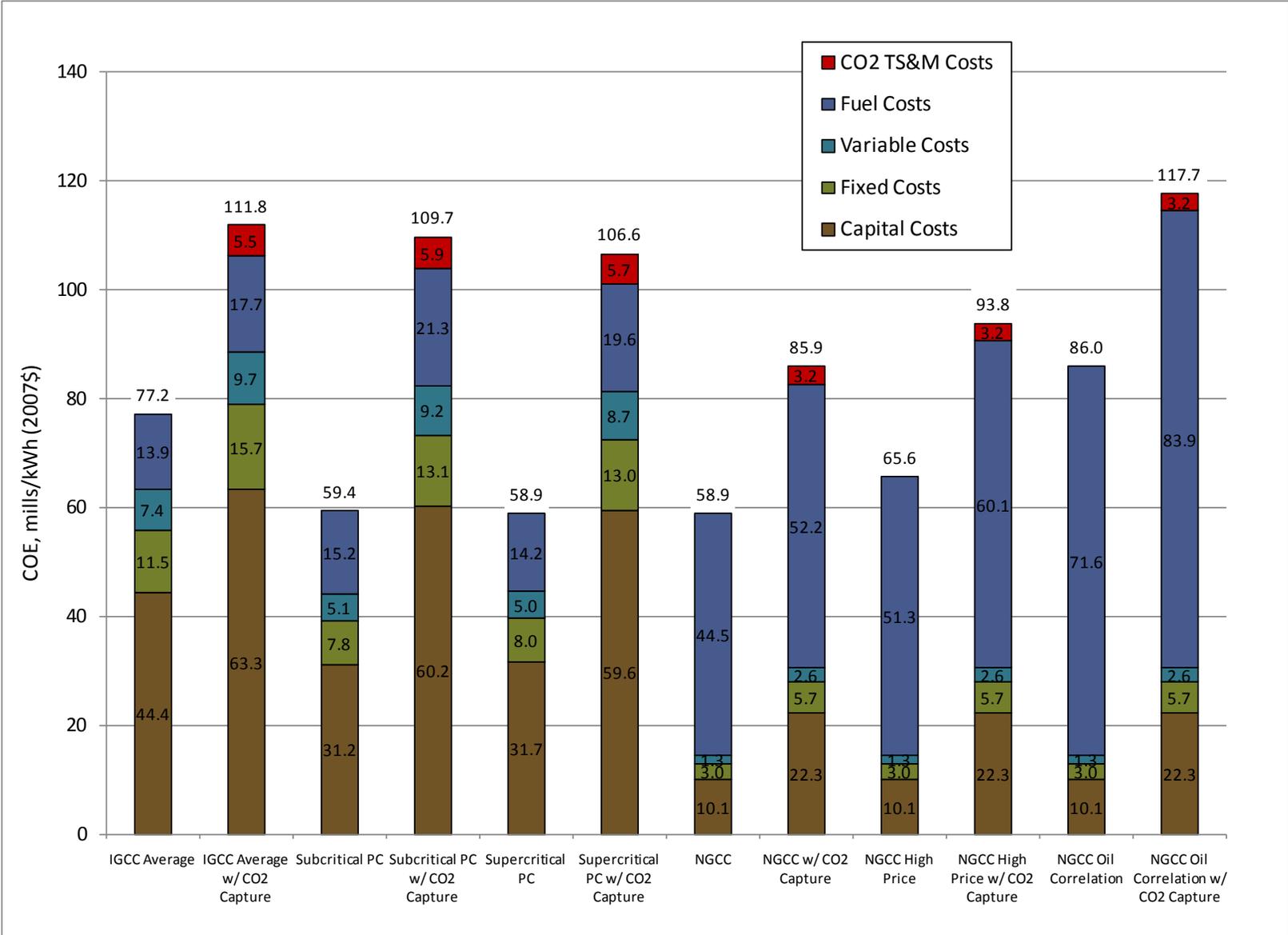
**Exhibit 6-2 First Year CO$_2$ Avoided Costs**
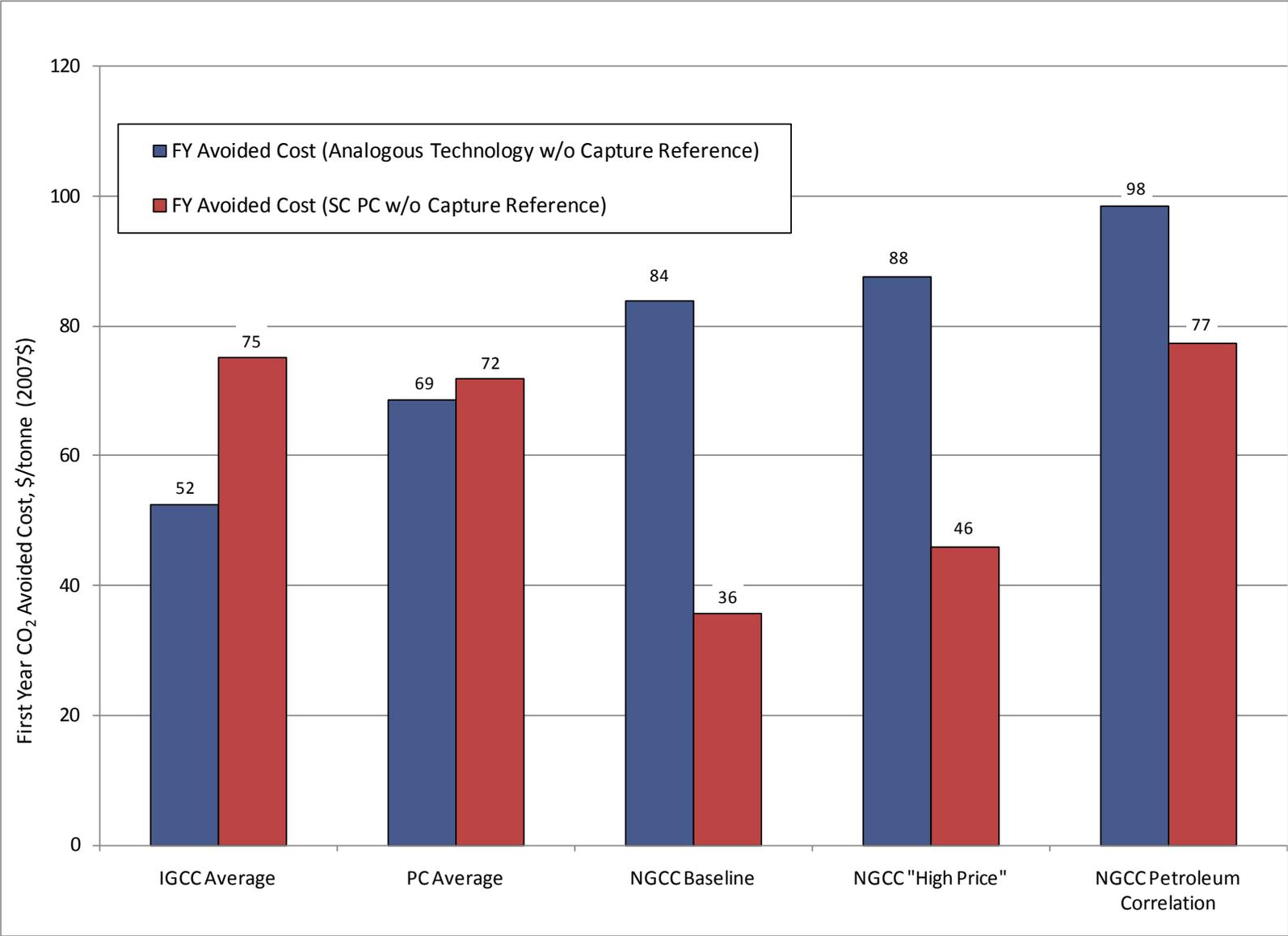
Exhibit 6-3 shows the COE sensitivity to fuel costs for the non-capture cases. The solid line is the COE of NGCC as a function of natural gas cost. The points on the line represent the natural gas costs that would be required to make the COE of NGCC equal to PC or IGCC at a given coal cost. The coal prices shown ($1.23, $1.64 and $2.05/MMBtu) represent the baseline cost and a range of ±25 percent around the baseline. The vertical lines represent the natural gas prices highlighted in this section.

At the AEO "High Price" of $7.54/MMBtu NGCC has a lower COE than all IGCC cases at any of the coal prices. At this natural gas price for non-capture cases PC is the most cost effective method for producing electricity. For IGCC cases to compete with NGCC cases at the highest studied coal price, the cost of natural gas would have to be $9.75/MMBtu.

Fuel cost sensitivity is presented for the CO_2 capture cases in Exhibit 6-4. Even at the lowest coal cost shown ($1.23/MMBtu), the COE of NGCC at the "High Price" is lower than both the IGCC cases and PC cases. At a natural gas price 52 percent higher than the baseline price of $6.55/MMBtu, the NGCC case is statistically equal to the PC cases at a coal cost of 25 percent more than the baseline price ($2.05/MMBtu).

Exhibit 6-3 COE Sensitivity to Fuel Costs in Non-Capture Cases
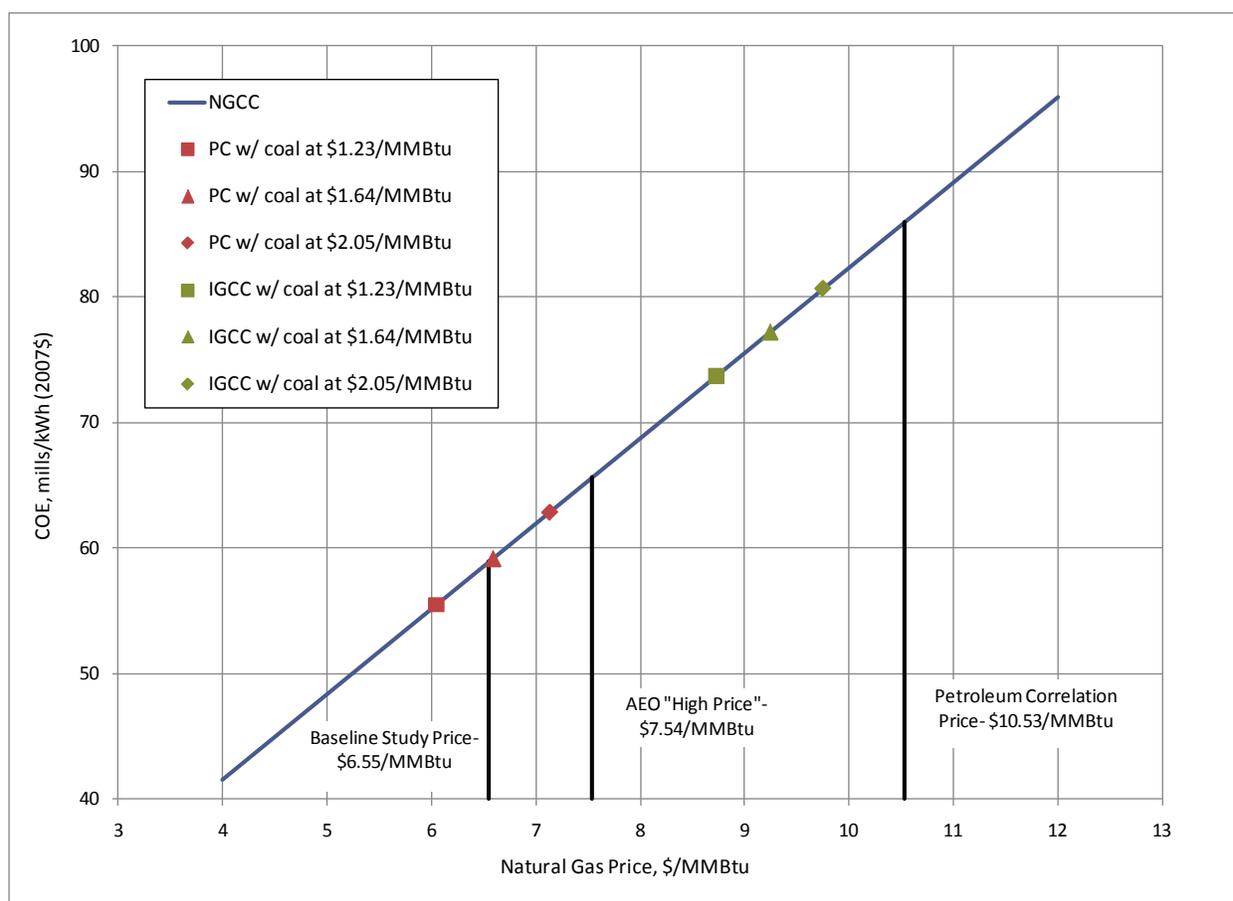
Exhibit 6-4 COE Sensitivity to Fuel Costs in CO$_2$ Capture Cases
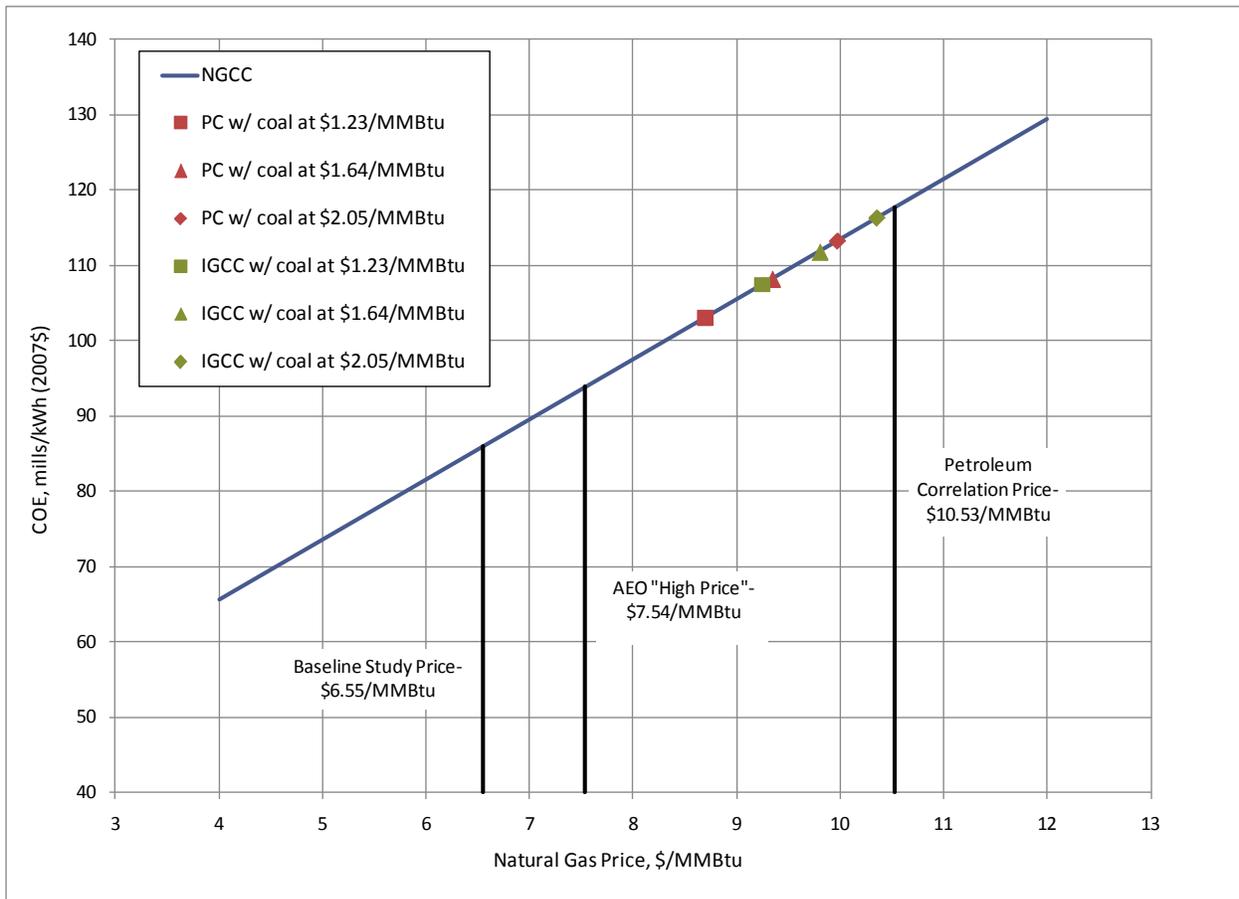
The sensitivity of COE to CF is shown for all non capture technologies in Exhibit 6-5 and for all capture technologies in Exhibit 6-6. The baseline PC and IGCC cases for non-capture and capture were averaged to highlight the comparison with the NGCC cases. The average PC plant with capture and the average IGCC plant with capture are nearly identical so that the two curves appear as a single curve on the graph. The CF is plotted from 30 to 90 percent. The baseline CF is 80 percent for IGCC cases with no spare gasifier and is 85 percent for PC and NGCC cases. The curves plotted in Exhibit 6-5 and Exhibit 6-6 for IGCC cases assume that the CF could be extended to 90 percent with no spare gasifier. Similarly, the PC and NGCC curves assume that the CF could reach 90 percent with no additional capital equipment.

Exhibit 6-5 COE Sensitivity to Capacity Factor in Non-Capture Cases
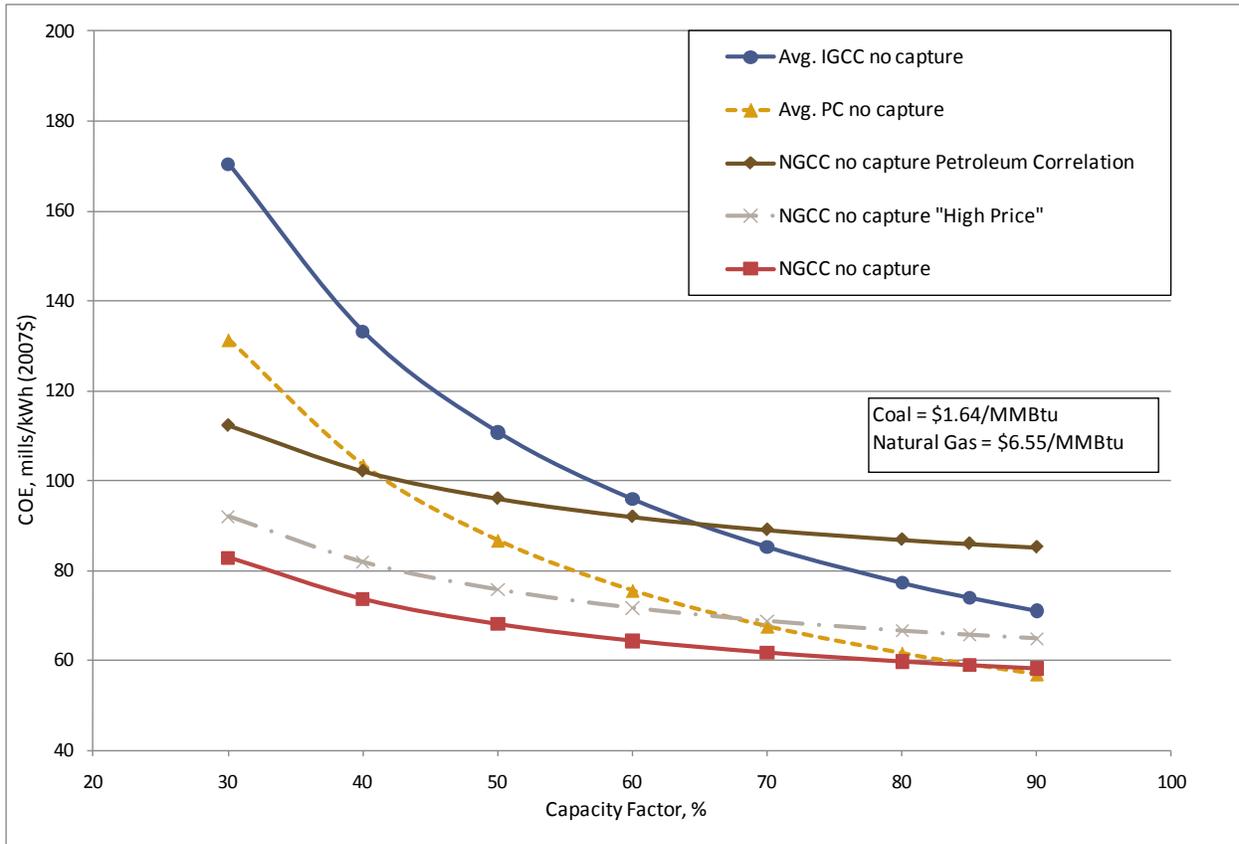
Exhibit 6-6 COE Sensitivity to Capacity Factor in Capture Cases
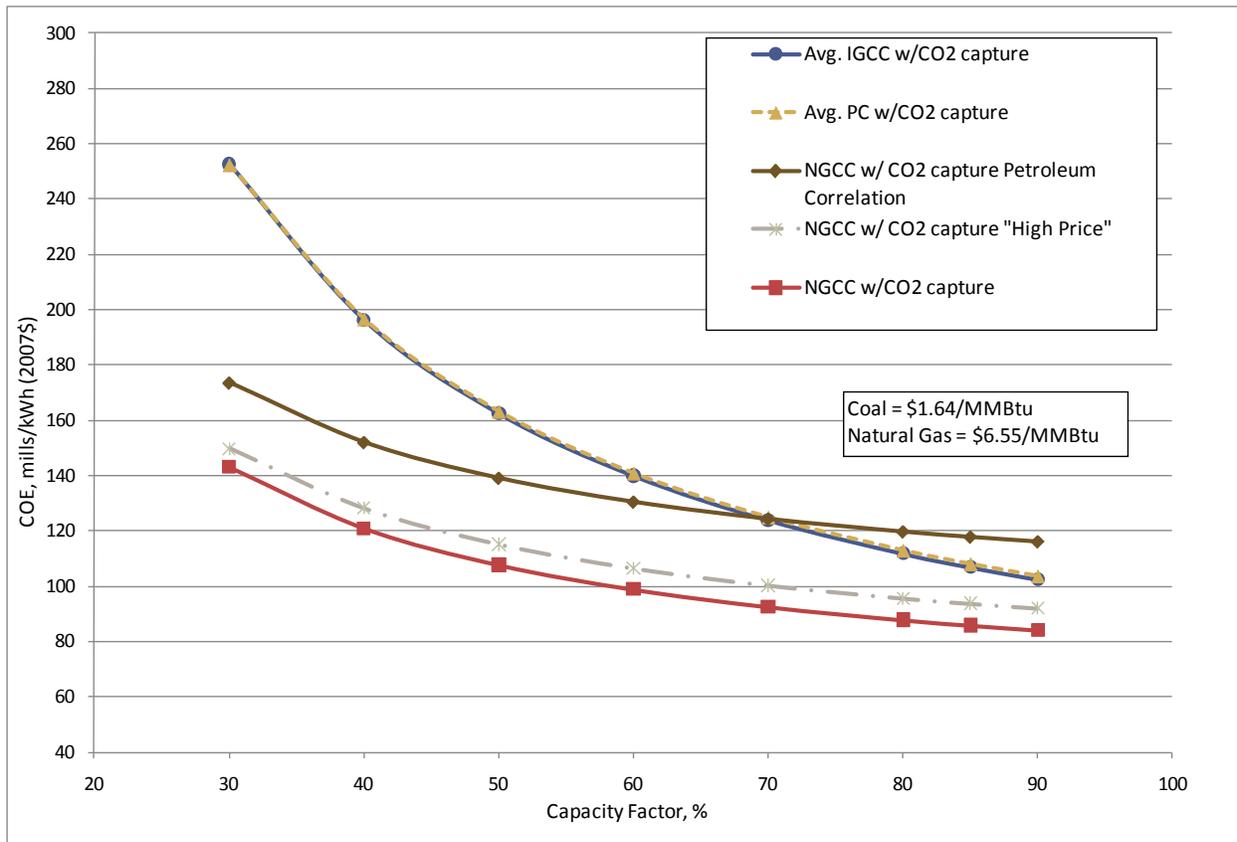
The NGCC curves are flatter than the coal curves because for NGCC the fuel cost, rather than the capital cost, is the dominant component of COE, even at baseline natural gas prices. Conclusions that can be drawn from Exhibit 6-5 and Exhibit 6-6 include:

- At high CFs, coal based technologies with and without CO_2 capture can be competitive with NGCC depending on the price of natural gas. As the CF falls among the non-capture technologies, IGCC becomes less competitive first, followed by PC. IGCC and PC with CO_2 capture become less competitive together as the CF decreases.
- At low CFs, the coal based IGCC and PC technologies are affected to a greater extent than NGCC. At a CF less than 45 percent, NGCC is the most economic option at each natural gas price examined.

6.4   DISPATCH-BASED CAPACITY FACTORS

The baseline assumption in this report was that all technologies would always be dispatched when available, making CF and availability factor equivalent. In reality the marginal production cost would determine dispatch order and hence CF. The balance of this chapter examines the determination and impact of a dispatch-based CF.

Estimates are provided for the plant dispatch expected in cases without CO_2 capture, if these units were to compete for electric sales with the other 1,706 generators that would provide the generation to supply the demand of the PJM Interconnection (PJM) control region in 2010. The

basis for projecting the expected CF of each of the units without CO_2 capture is provided, along with the financial implications of that dispatch.

The estimated year 2010 CFs earned in the PJM operating region for the units examined are listed in Exhibit 6-7. The bases for these estimates are discussed later in this chapter.

Exhibit 6-7 Dispatch Based Capacity Factors for Cases without CO_2 Capture

Case	Year 2010 Capacity Factor
Case 1 - GE IGCC	51.5%
Case 3 - CoP IGCC	54.1%
Case 5 - Shell IGCC	62.0%
Case 9 – Subcritical PC	73.4%
Case 11 - SC PC	85.0%
Case 13 – NGCC	16.5%

About Capacity Factor

The annual CF of an electric generating unit is the ratio of its actual generation (that is, the unit's annual kWh) to the kWh it would generate if, hypothetically, it could operate at full capacity for every hour of the year without interruption. The CF is a measure of how much the unit is used, and is an important measure for assessing the potential for profitable financial return from the investment in the purchase of the generating equipment.

No generating unit can run all of the time; thus, the CF of a unit is always less than 1.00. Reasons for the unit not running all of the time include:

- The unit is removed from service for planned maintenance.

- The unit is forced to temporarily decrease output due to a partial equipment failure that limits output, which requires unplanned maintenance that can be accomplished with the unit running at partial load.

- The unit is forced to be completely removed from service due to equipment failures and subsequent required unplanned maintenance.

- The unit runs only at part load because of grid variations in the demand for power. The ability of the unit to follow the demand makes this unit the most economical to turndown compared to the other units running at the same time.

- The unit costs more to operate than competing units, therefore it is displaced by units that are either more efficient or use less costly fuel. Since the unit's production costs are higher than competing units that could meet the system power demand at a given period

of time, the unit is dropped for periods of time from the dispatch order since it is not needed. Units that have lower production costs then meet the demand, and the unit remains idle until once again the system demand rises high enough so that the unit rejoins the dispatch order as the most cost effective unit available for service at that given level of demand.

A unit cannot have a CF greater than its equivalent availability (defined as the fraction of time that the unit is available accounting only for planned maintenance and forced outages). The equivalent availability thus forms the upper bound on the CF. Of course, the unit may have a lower CF when there are periods of time where competing units with lower production costs can win the competitive bidding to meet demand, forcing the less economical unit to be idle.

Financial Implications of Capacity Factor

For the most part, a generating unit can only provide a financial return to its investors when it is running. While a unit can earn revenue even if it is not providing output, selling ancillary services, such as providing reserve power and other standby services, overwhelmingly, the investment in the unit is made with anticipation of revenue from unit operations; the more hours the unit runs —that is, the higher its CF— the greater potential return from its operations.

An electric generating unit's CF has a dramatic impact on the annual fixed operating costs. These costs must be paid whether or not the unit is operating and earning revenue. These fixed costs include property tax, paying off the capital investment to the investment bankers, salaries for the operations staff who need to be there whether the plant is running or not, and others. The greater the CF (the number of hours that a unit operates, and thus earns revenue), the greater the period over which these fixed operating costs can be amortized, and the lower the percentage impact on the total annual costs of production for the unit.

Unit Dispatch in the PJM Control Region

PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. As an Independent System Operator, in 2006, PJM dispatched the generation of 1,706 sources for meeting demand. It is an excellent choice for modeling the dispatch prospects of the units modeled in this study, since:

- PJM is the largest control region in the world, eclipsing Japan, and of France, the next larger regions.

- PJM dispatches a diverse mix of generation.

- PJM is a model for competitive electric power dispatch operations; more than 70 nations have sent delegates to PJM to learn about its market model and its operation of the electric grid.

Method Used to Estimate Unit Dispatch in PJM in Year 2010

This analysis of unit dispatch within PJM for the cases in this study was performed with consideration for the following:

- Hour-by-hour forecast of expected electric demand within the control region in 2010.

- Forecast of fuel costs for the units competing for electric sales within the region in 2010.

- Assessment of the seasonal availability of the competing fleet of generating units.

- Estimates for each of the generating units competing for electric sales within the control region:

  - Variable operating costs for each.
  - Fuel and other production costs for each.

- Forecast the hour-by-hour unit dispatch that would result in the most competitive mix of units for each hour of operation throughout the target study year 2010.

Dispatch-Based Capacity Factor – What is Discussed

To update the examined cases, dispatched based CFs were determined for the six cases without CO_2 capture through modeling the dispatch of the units in the PJM ISO. The remainder of this chapter provides:

- The modeling results of the six non-capture cases within this region.

- A description of the PJM ISO.

- A review of the modeling method and assumptions that were used to develop these estimates.

- A listing of the case economics at the anticipated CF levels estimated in this chapter.

6.5   DISPATCH MODELING RESULTS WITHIN PJM

Year 2010 unit dispatch modeling in the PJM control region was performed under two scenarios:

- Natural gas price fixed at the EIA-predicted value for 2010 of $6.55/MMBtu.

- Varying the natural gas price over the range of $0 to $20/MMBtu.

The generating unit dispatch stack, including a list of generating units ordered by production costs, for the fixed natural gas price case is shown in Exhibit 6-8 and illustrates the increase in production cost with increased cumulative production from the system. Additionally, this plot shows the fuel type of the plants within the stack. As expected, the fuel price dominates the stacking order with the technologies using the lower cost (or no cost) fuels being dispatched first, then coal, then natural gas; those with the most expensive fuel, No. 2 oil, are dispatched last.

Exhibit 6-8 Estimated Stacking Order in PJM for Year 2010 Based on First Year Production Costs
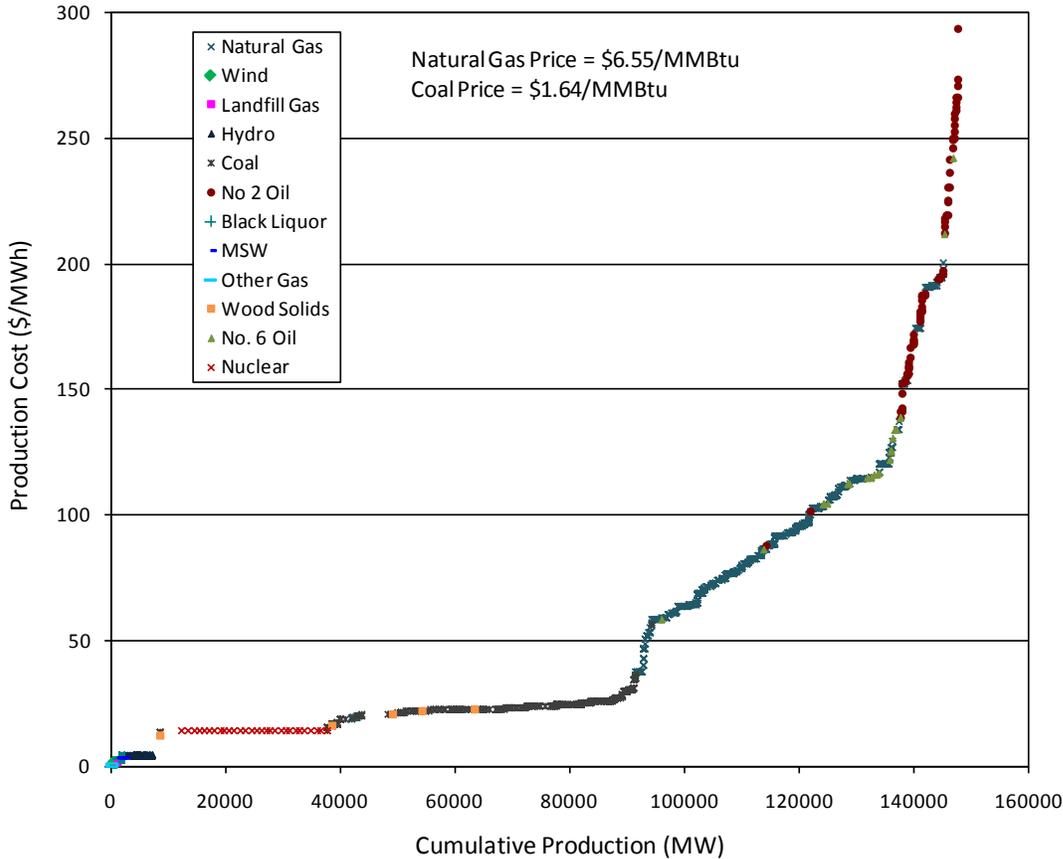
The stack curve in Exhibit 6-8 would change with variations in the natural gas price. For example, as the price of natural gas decreases, the production cost of the natural gas-fired units would decrease. This could eventually lead to a drop below the bituminous coal-fired unit's production costs. In this case, the natural gas units would shift to the left of the bituminous coal-fired units and be dispatched first.

Based on the uncertainty of natural gas prices in 2010, the initial dispatch modeling was performed as a scan of the natural gas price ranging from $0 to $20/MMBtu. At low natural gas prices, $2.50/MMBtu, the natural gas units in the PJM fleet are dispatched prior to the coal-fired units. The most efficient coal unit, SC PC, achieves the lowest production cost and therefore is the first to be dispatched with increasing natural gas prices. This results in the SC PC unit having the highest CF, as shown in Exhibit 6-9. Exhibit 6-9 further shows that the dispatch of the units is not significantly impacted by natural gas prices in the range of $6-$10/MMBtu. When the price of natural gas is above $12.50/MMBtu, the production cost of the NGCC unit is above that of the oil-fired units in the fleet, so the CF continues to drop.

Exhibit 6-9 Capacity Factors of Replacement Units Dispatched into PJM
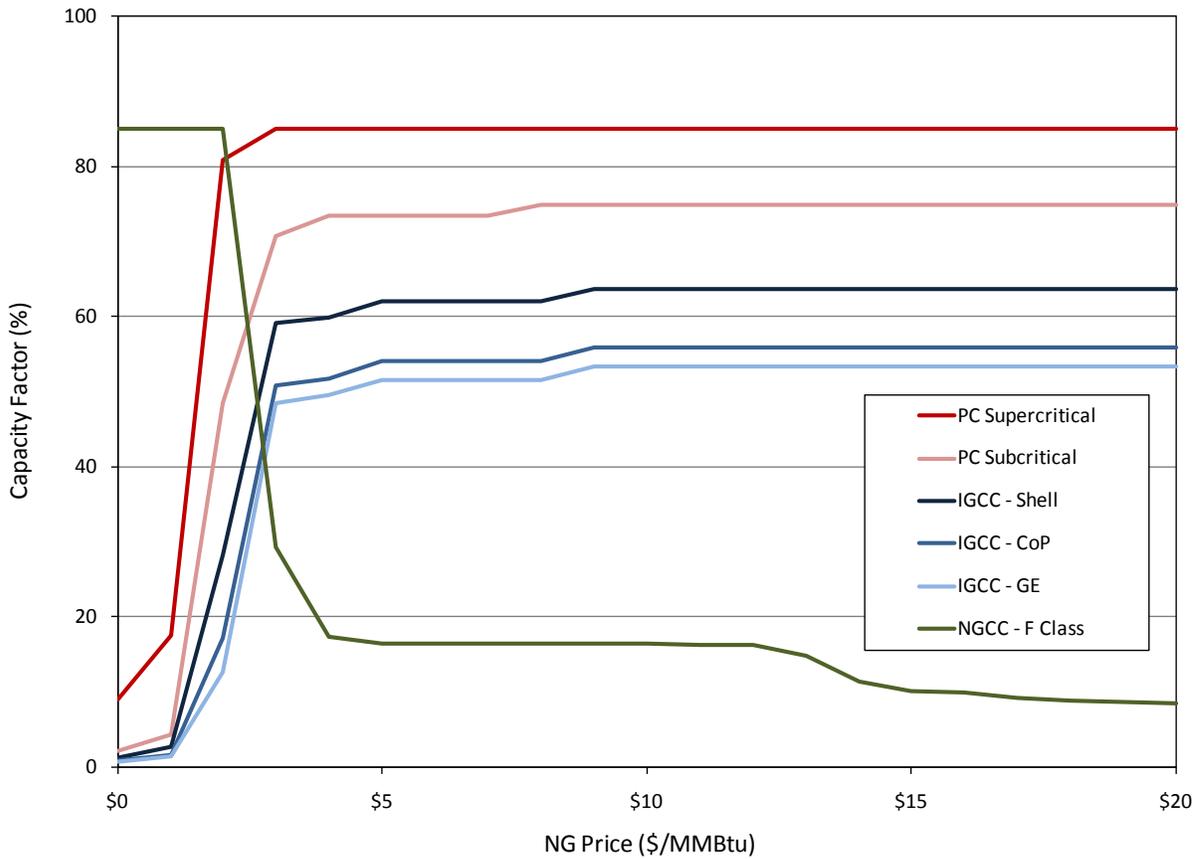
The fuel costs used in this study (coal at $1.64/MMBtu and natural gas at $6.55/MMBtu) lead to the CFs listed in Exhibit 6-10.

Exhibit 6-10 Dispatch Based Capacity Factors Assuming No CO_2 Capture

Case	CF
Case 1 - GE IGCC	51.5%
Case 3 - CoP IGCC	54.1%
Case 5 - Shell IGCC	62.0%
Case 9 – Subcritical PC	73.4%
Case 11 - SC PC	85.0%
Case 13 - NGCC	16.5%

Exhibit 6-11 illustrates the desired unit dispatch factor, which ignores availability and is therefore the percentage of time that a unit would be dispatched if it is 100 percent available, as a function of the production cost of the entire PJM fleet. For the coal-based cases, there is a high sensitivity of the dispatch factor on the production cost; that is if the production cost changes a

small amount the dispatch factor changes significantly. Additionally, the high efficiency of the SC PC leads to this unit being very competitive compared to the existing PJM portfolio.

Exhibit 6-11 Summary of Prospective Facility Parameters for Modeling
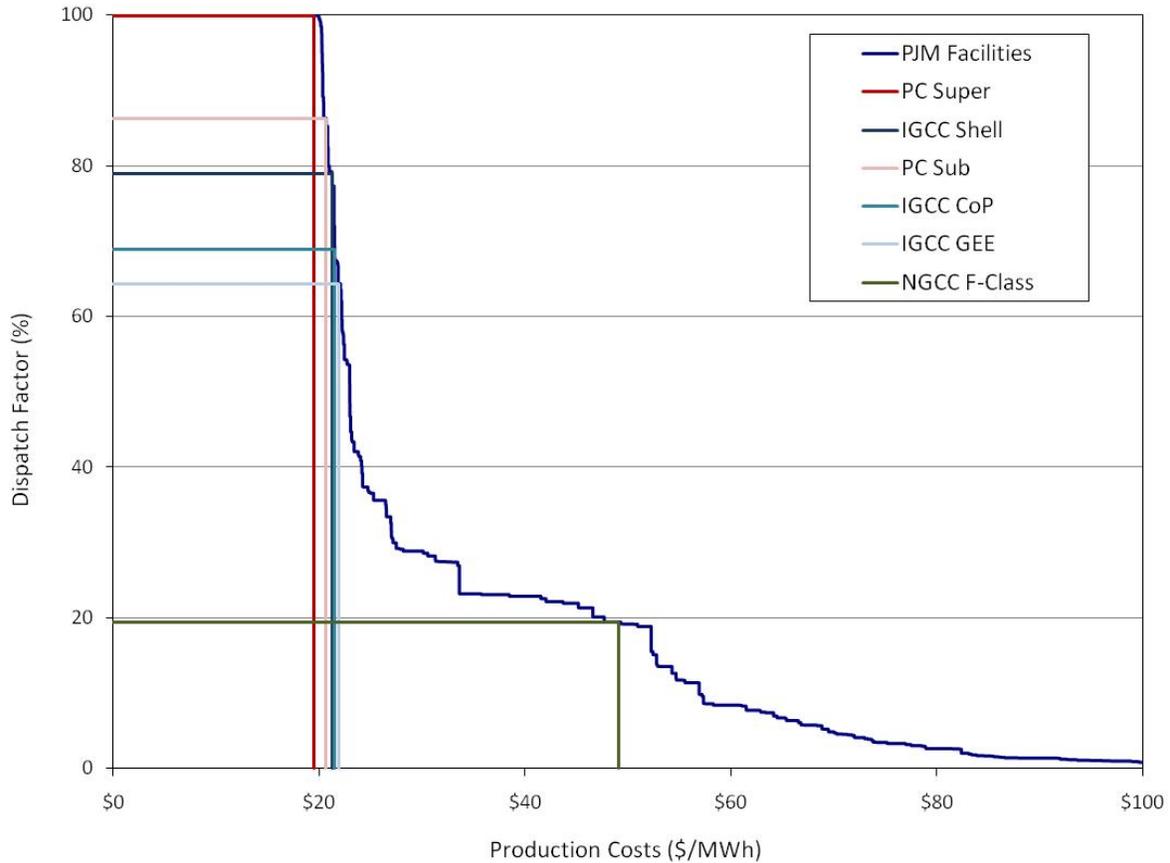
The dispatch based CFs were used to revise the economic analyses for the cases without CO_2 capture. The impact of dispatch based CFs on the LCOE are summarized in Exhibit 6-12 and Exhibit 6-13. These exhibits compare the "must run" LCOEs ("initial") determined with the CFs initially assumed in this report to the LCOEs determined with the dispatch-based CF ("calculated") for 2010 operations in PJM. In the comparison, it is important to note that variable costs (fuel and variable O&M) are the same while the fixed costs (capital charges and fixed O&M) vary.

Exhibit 6-12 Comparison of COE as a Function of Capacity Factor

			Breakdown of COE ($/MWh)				COE $/MWh
	CF		Capital Costs	Fixed O&M	Variable O&M	Fuel	
Case 1 GE IGCC	Initial	80.0%	$43.39	$11.28	$7.30	$14.36	$76.32
	Calculated	51.5%	$67.40	$17.52	$7.30	$14.36	$106.57
Case 3 CoP IGCC	Initial	80.0%	$41.68	$11.08	$7.20	$14.08	$74.05
	Calculated	54.1%	$61.64	$16.39	$7.20	$14.08	$99.31
Case 5 Shell IGCC	Initial	80.0%	$48.16	$12.16	$7.75	$13.28	$81.35
	Calculated	62.0%	$62.14	$15.69	$7.75	$13.28	$98.86
Case 9 Subcritical PC	Initial	85.0%	$33.31	$7.83	$5.15	$15.21	$61.50
	Calculated	73.4%	$38.57	$9.07	$5.15	$15.21	$68.00
Case 11 SC PC	Initial	85.0%	$33.78	$7.97	$5.04	$14.25	$61.03
	Calculated	85.0%	$33.78	$7.97	$5.04	$14.25	$61.03
Case 13 NGCC	Initial	85.0%	$10.11	$2.96	$1.32	$44.53	$58.92
	Calculated	16.5%	$52.08	$15.27	$1.32	$44.53	$113.20

Exhibit 6-13 Impact of Dispatched Based Capacity Factors on the Cost of Electricity
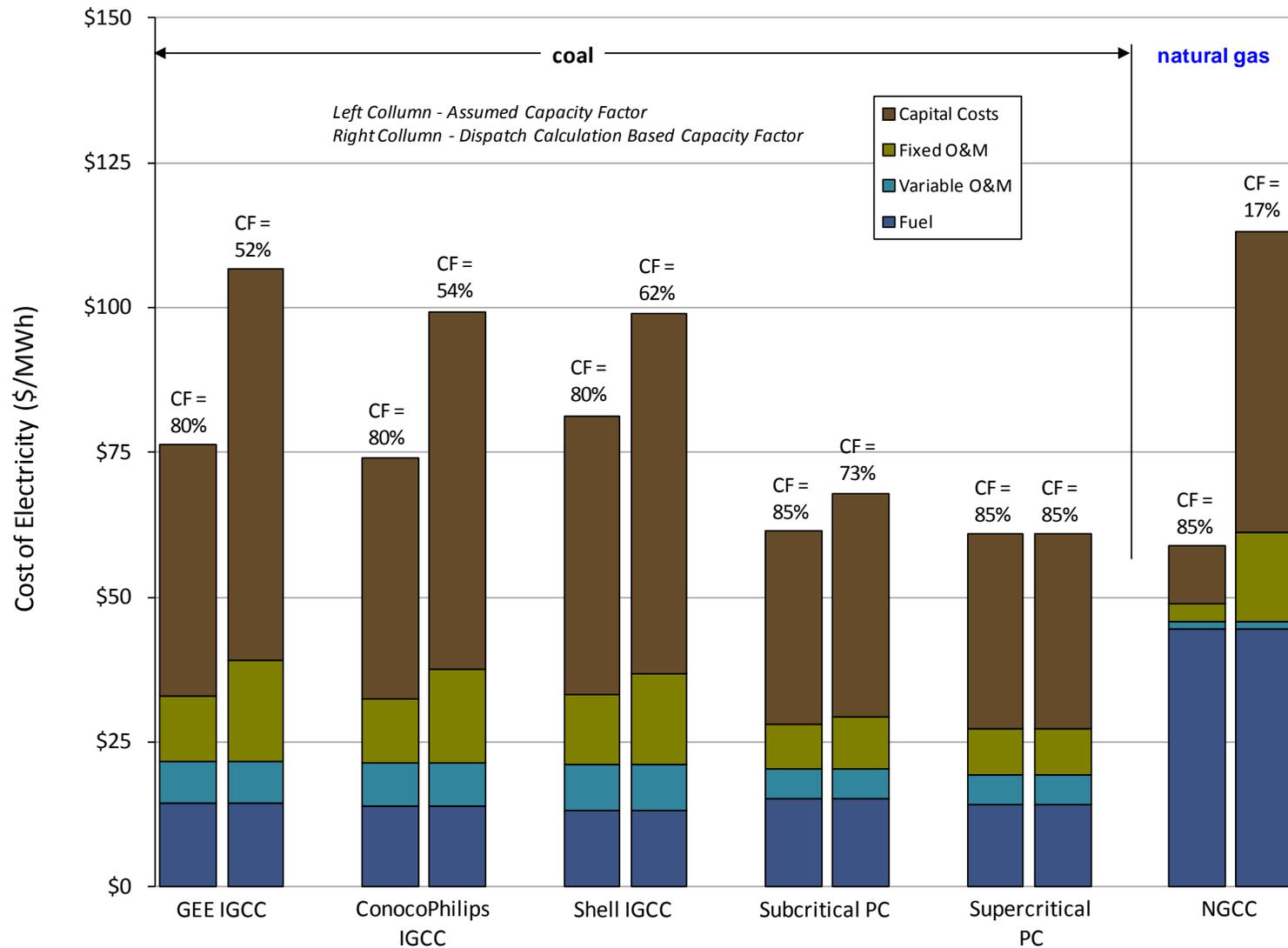
6.6   PJM INDEPENDENT SYSTEM OPERATOR

PJM was formed in 1927 in order to share the resources of three utilities, Philadelphia Electric Company (PECO), Pennsylvania Power & Light Company (PP&L), and Public Service Electric & Gas Company (PSE&G), thus allowing them to increase operational efficiencies. This became the world's first power pool. PJM became the first fully functioning Independent System Operator in 1998, responsible for both the safety and reliability of the transmission system and overseeing the administration of a competitive wholesale electric power market.

The scope of the PJM East and PJM West operations includes:

- 51 million people served

- 144,644 MW of peak load

- 164,905 MW of generation capacity

- 729,000 GWh (gigawatt-hour) of energy per year

- 1,706 generation sources of diverse types

- 56,250 miles of transmission lines

- 450+ members

- $71 billion in energy and energy service trades since 1997

PJM is a limited liability company that operates on a profit neutral basis. PJM's Operating Agreement and Tariff provide that it can recoup its operating expenses from its member companies. Debt service is included in the operating expenses that PJM bills to members on a monthly basis. It is a non-stock corporation owned by its members and governed by the Federal Energy Regulatory Commission (FERC) in cooperation with the state regulatory boards in which it operates. Other income comes from studies and interconnection fees, membership dues, and interest.

Today, PJM has evolved to become more of a process than a specific region, though its physical region is expanding rapidly, as well. The recent issues in wholesale trading and stalled unregulated retail initiatives have demonstrated the need to provide a uniform set of operating principles that allows the forces of supply and demand to work freely in a transparent manner while encouraging participation by new, non-utility participants. PJM has shown it has the technology (notably a suite of Internet scheduling and trading tools) and organizational structure to accomplish this while maintaining system reliability. PJM's operating territory as of February 2008 is shown in Exhibit 6-14 [81].

Exhibit 6-14 The PJM Operating Territory
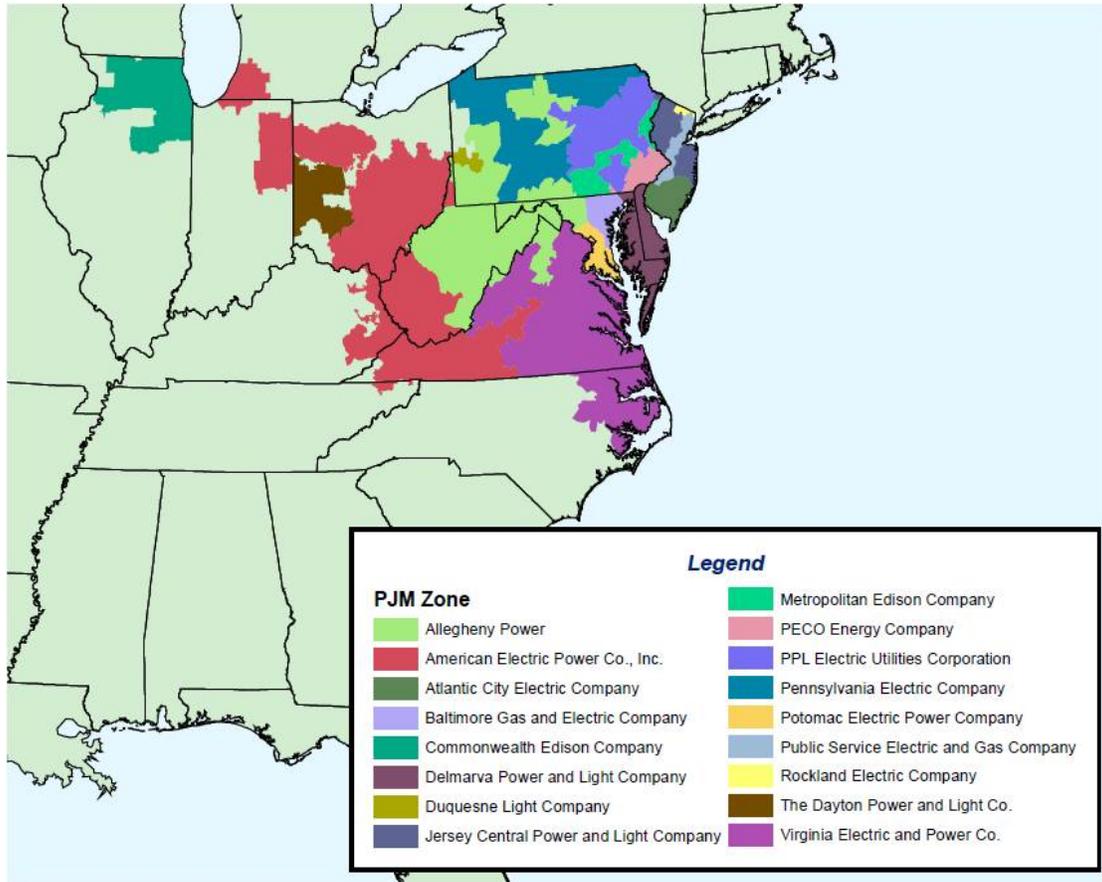
6.6.1   PJM Roles and Responsibilities

PJM is its region's RTO with responsibility to act in several roles, including:

- Control area operator

- Transmission provider

- Market administrator

- Regional transmission planner

- NERC security coordinator

PJM is responsible for the region's electric integrity, unit dispatch and reliability, and administering the pricing mechanisms for delivery of all power. With the implementation of the PJM Open Access Transmission Tariff in 1997, PJM began operating the nation's first regional bid-based energy market, and now operates six competitive markets selling energy, capacity and ancillary services. PJM enables participants to buy and sell energy, schedule bilateral electric sale transactions, and reserve transmission service. PJM provides the accounting and billing services for these transactions.

Each day, PJM forecasts how much electricity will be needed and receives offers to supply electricity from producers and other suppliers of electricity. PJM decides what offers to accept

by selecting which plants will make electricity over the next period. PJM bases its decisions on the overall least cost for the whole region, considering the pattern of demand and availability of supply. PJM directs the operation of the generation plants by agreements with their owners. The electricity actually flows through transmission lines (high tower, high voltage lines) to local utilities' distribution station and from there is sent on local electric lines to homes, factories and businesses. PJM also anticipates electricity needs years ahead and makes plans to ensure that enough electricity will be there as the region grows [82].

6.6.2   Generation Mix

Generation capacity in PJM is currently 187,172 MW based on the stacking order compiled in January 2008 for the year 2006. The mix of fuels in PJM as indicated in the stacking order is shown in Exhibit 6-15.

Exhibit 6-15   PJM Installed Capacity by Fuel Type
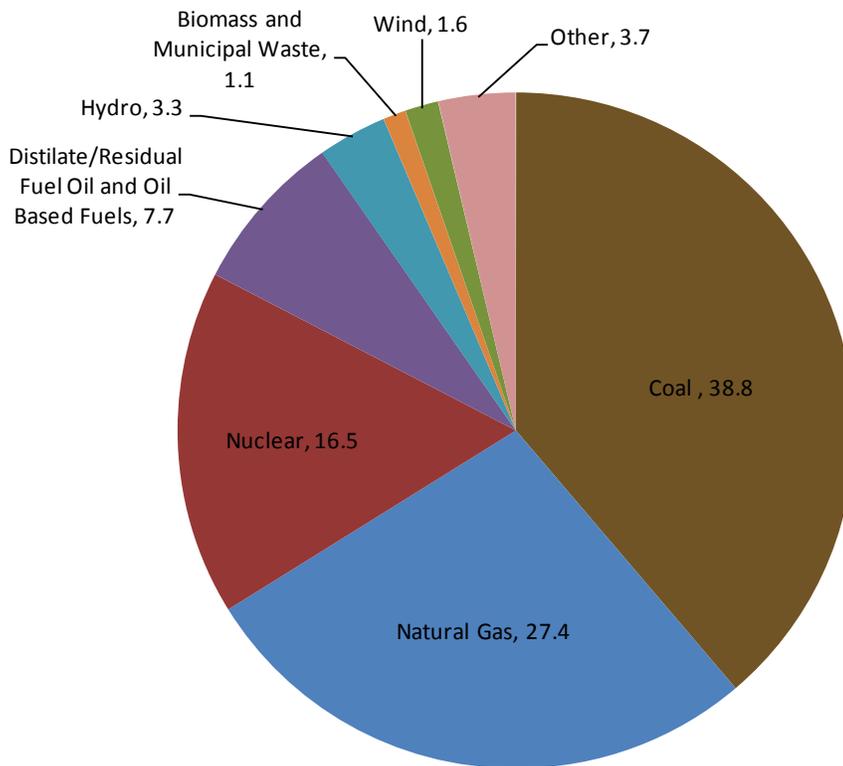
6.6.3   PJM Markets

PJM is dedicated to making all facets of electric generation service that are practicable available on a competitive market basis, thus providing accurate pricing signals and access to these products for all participants in a deregulated electricity environment. PJM's spot and ancillary markets offer market flexibility in that they support bilateral transactions by providing liquidity and risk management instruments, allowing self-scheduling of supply, and providing spot market access. Based on the short but significant history of this effort, it would appear that PJM has

succeeded in creating rational markets with the ability to adapt as market power or reliability issues arise. PJM currently operates six markets:

- Day-ahead energy market
- Real-time energy market
- Daily capacity market
- Monthly/multi-monthly (interval) capacity market
- Regulation market
- Monthly FTR auction market

6.6.4 PJM Energy Markets

Generation owners in PJM can sell the output from their units in three ways: bid into the PJM day-ahead market, self-schedule their output to serve their own load, or sell their output directly (bilaterally) to another party.

PJM was a net exporter of energy on a monthly basis for every month in 2006, and exported an average of 1.5 million MWh. Imports into the region and exports out of the region respond to market prices. As detailed in the PJM Interconnection State of the Market Report – 2006, this activity supports the view that the PJM energy market is liquid, and exists in the context of a much broader energy marketplace.

All anticipated generation and load in PJM must be scheduled through PJM at least the day before. Generators are contacted the day before and advised as to which (if any) of their bids were accepted, the hours they must run, and the amounts that they will be required to provide each hour. If a generator fails to supply the generation when required, it must replace that energy by purchasing it – either bilaterally or from the real-time energy market.

PJM runs two energy markets: the day-ahead market and the real-time market. All transactions made in the day-ahead market are financially binding, with adjustments for actual generation and usage made using the real-time market.

6.6.5 Day-Ahead Market

This study assumes that the units modeled in this study would be selling their output to the PJM day-ahead market. The day-ahead energy market is a financial market and is used to provide a hedge against price fluctuations (primarily congestion charges) in the real-time market. Based on load schedules submitted by all load-serving entities (LSEs) at least the day before the Operating Day, PJM calculates the expected energy needed at various locations (major busses) throughout the system, and accepts both sell and buy bids for the total amount needed each hour plus reserves. Then PJM stacks the sell bids in low-to-high price (or economic) order and assigns a price for electricity for each hour at each location for the following day in dollars per megawatt ($/MW). The price for one megawatt of power during each hour the next operating day in the day-ahead market will be the lowest price bid satisfying the anticipated load requirement for that hour, plus any congestion charges expected to occur at that location. This hourly price is known as the Locational Marginal Price, or LMP. All successful bidders for that hour receive the price accepted, regardless of the price they bid.

PJM defines LMP as the "cost of supplying the next MW of load at a specific location, considering generation marginal cost, cost of transmission congestion, and losses." LMP values

are the result of security-constrained economic dispatch operations, a method system operators have used to manage congestion for years. A least-cost security constrained dispatch algorithm determines the least expensive way to serve load while respecting transmission limits.

During periods of low demand, the LMP is generally the same at all locations. That is, none of the transmission capability is constrained. During periods of high demand, equipment problems, or system irregularities, the LMP can vary significantly from one location to another. This is especially so during peak system days.

Day-Ahead Energy Market Timeline

- Up to 12 noon – PJM receives bids and offers for energy for next Operating Day.
- 12 noon to 4 pm – Day-ahead market is closed for evaluation by PJM.
- 4 pm – PJM posts day-ahead and hourly schedules.
- 4 pm to 6 pm – Re-bidding period. Re-bidding period is for generation not selected for day-ahead market and lets them re-bid for regulation, operating, and spinning reserves. PJM desires to give preference to uncommitted capacity first.
- PJM continually re-evaluates and sends out individual generation schedule updates as required throughout the Operating Day.

The maximum and minimum day ahead electricity prices for the PJM ISO region for the year 2006 are shown in Exhibit 6-16.

Exhibit 6-16 PJM East Day-Ahead LMP for 2006
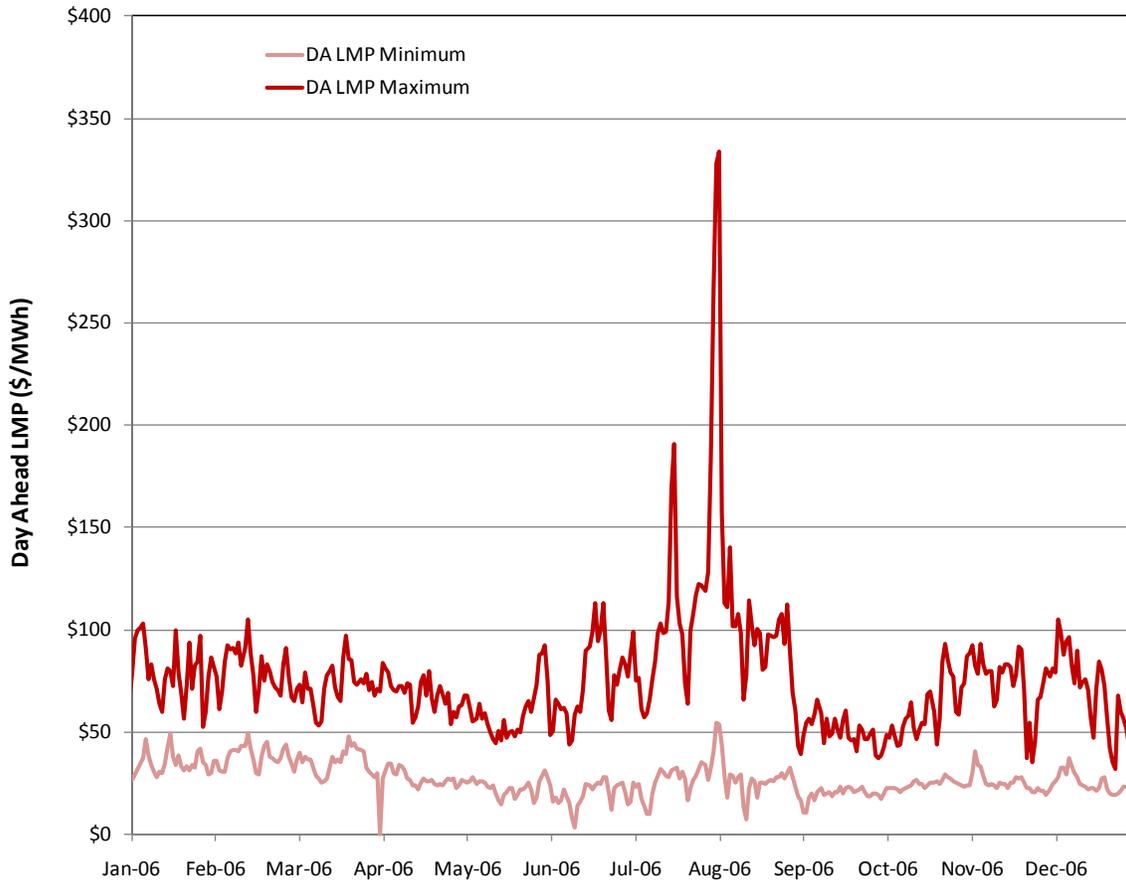
6.6.6 Prices and Demand

There is a strong correlation between price and demand in the PJM markets. Exhibit 6-17 illustrates day-ahead high and low prices, and daily high and low loads for the year 2006.

Exhibit 6-17 PJM Load and Day-Ahead LMP for 2006
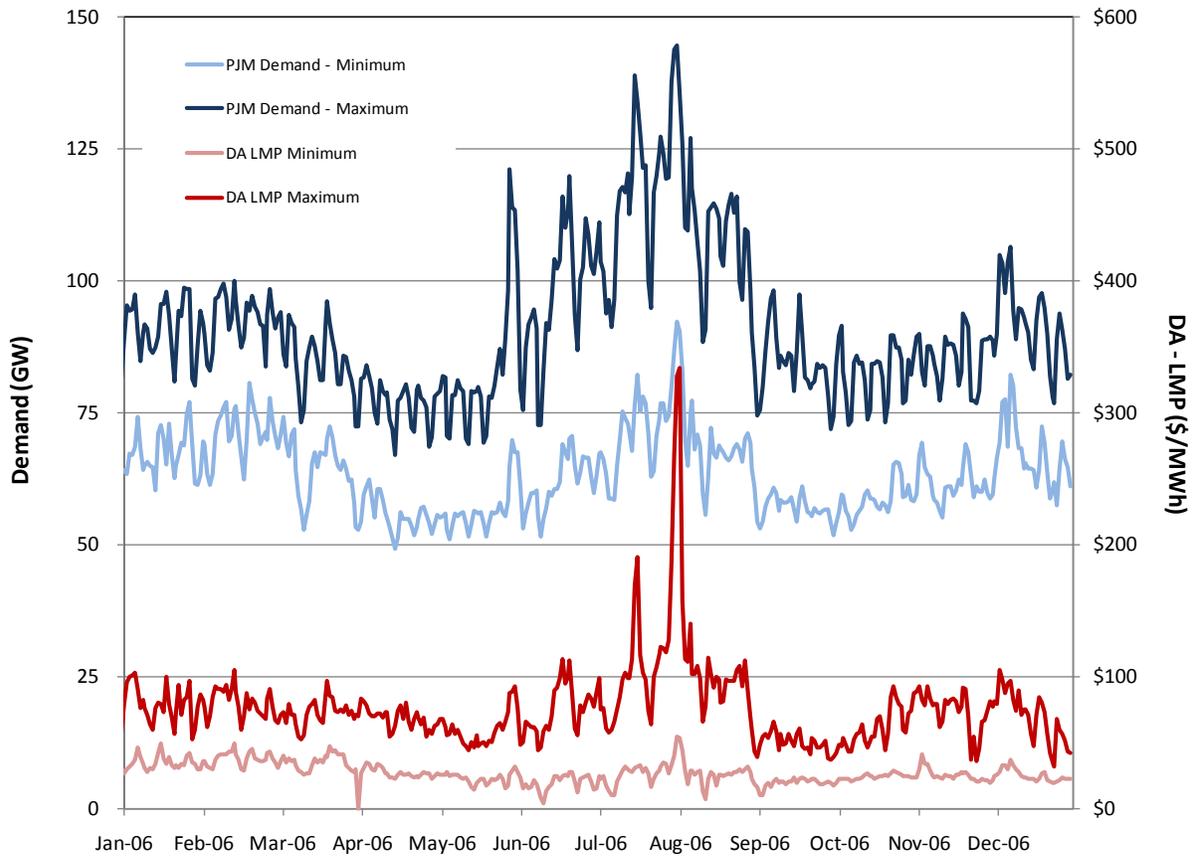
Exhibit 6-18 and Exhibit 6-19 show the correlation between price and demand over a one-year period. They also show a rational association between the two, supporting the viewpoint that PJM has been effective at creating competitive energy markets.

Exhibit 6-18 PJM Day-Ahead LMP vs. Demand for 2006
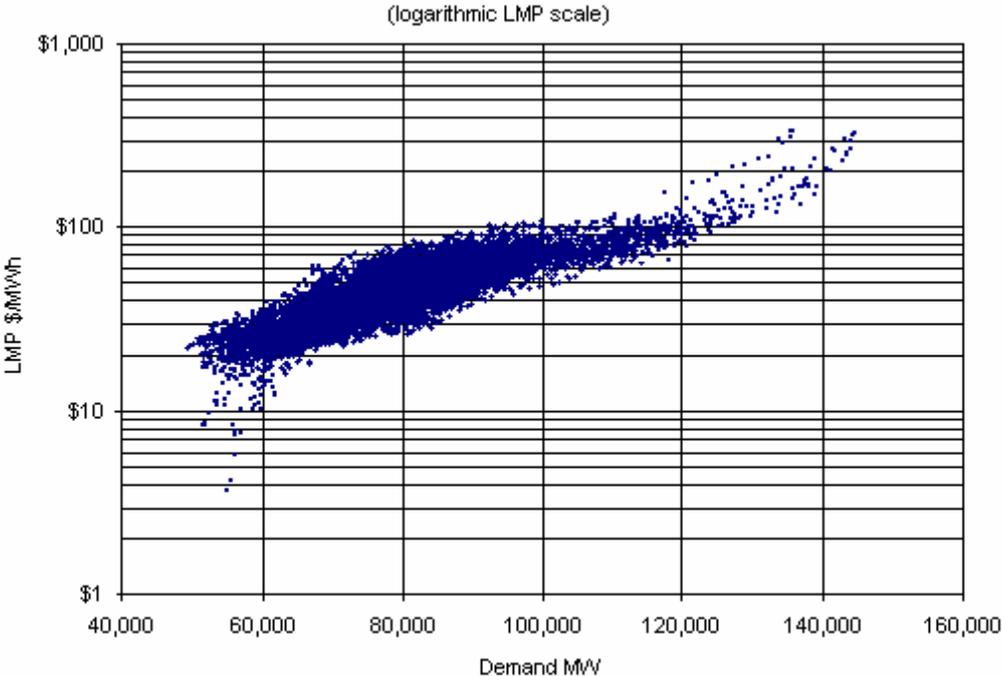
Exhibit 6-19 PJM Price/Load Distribution for 2006
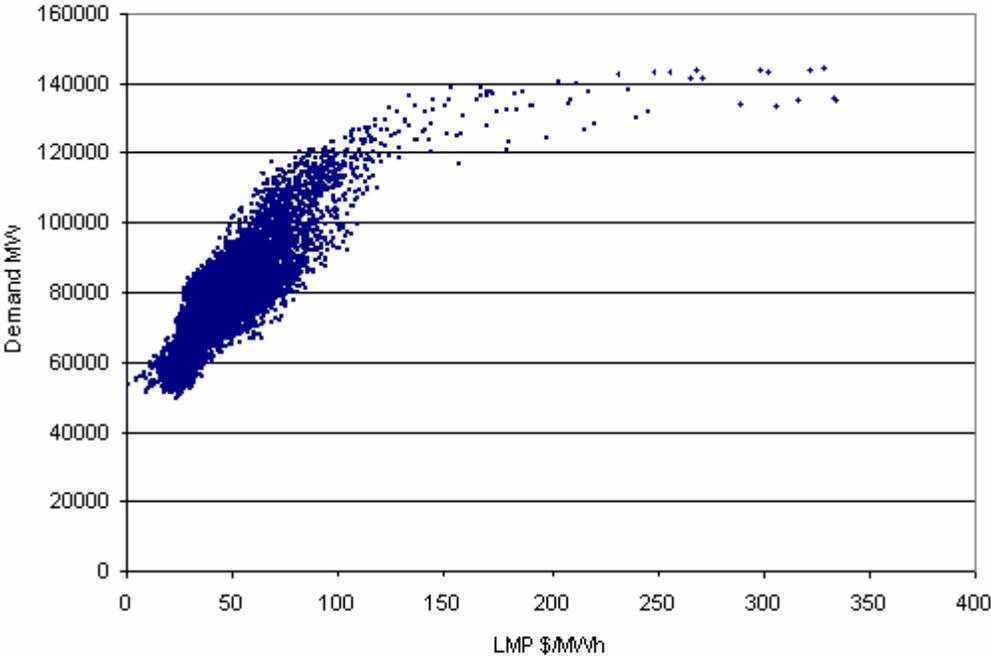
6.7   DESCRIPTION OF THE PJM REGIONAL MODELING

The analysis tools used to predict economic dispatch are a series of databases and calculations designed to model future dispatching of power generation facilities taking into account:

- Fuel Cost

- Additional new generation

- Changes in demand

- Changes in legislation

These procedures emulate the competitive dispatch of units. Outputs from the modeling include:

- CFs for competing units

- Individual and fleet wide emissions

The analysis method is based on modeling the current conditions in a power generation network and then projecting the operation of the system into the future. Modeling of a current generation system requires:

- The demand of the generation system on an hourly basis

- The selling price of electricity within the generation system on an hourly basis

- Identifying power generation units in the system with their operating parameters including:
    - Nameplate capacity
    - Fuel type
    - Heat rate
    - Emission intensities
    - Variable operating and maintenance costs
    - Delivered fuel costs

To project the existing system into the future, the existing conditions are modified by projections of future:

- Fuel Prices

- Demand

- Change in generation unit portfolio

- Changes in legislation

This data above is acquired through a variety of publicly available databases and internal modeling methods.

The dispatch of prospective units is determined through:

- Determining the dispatch order of the existing plants in a system based on the production costs of the individual units. These electricity production costs are determined from the fuel costs, plant efficiency, the variable operating and maintenance costs, and penalties that are related to the generation of electricity such as for CO_2 emissions. In the case of modeling the PJM region, 1,706 units are characterized. The list of plants and their

information, ordered by production cost, is referred to as the "stack". The units are then inserted into this mix of generating units, and ordered based upon their specific production costs.

- Identifying the marginal production cost of the last-dispatched unit for a given hour through comparing the hourly demand for the generation system to the cumulative generation in the stack. The last facility dispatched to meet the demand sets the production cost for that hour.

- Determining if a prospective unit is dispatched in an hour by comparing the plant production cost to the production cost of the last plant dispatched. If the prospective unit's production cost is less, then the unit is dispatched.

- Sum the hourly results for the prospective power plants to determine the CF for each unit during the year.

  o For the non-capture technologies, the CFs of the facilities, listed earlier in Exhibit 6-7, were determined through dispatch modeling of these units into the PJM ISO.

6.8   WPLANET MODEL INPUTS

The inputs for the model were obtained from standard databases containing generation information for the year 2006. Exhibit 6-20 provides a summary of the sources used to obtain the required information for 2006.

Exhibit 6-20 Data Sources for Electricity Generation in the PJM Region in Year 2006

Generation System Parameter for 2006	Data Source	Comments
Hourly System-Wide Demand	PJM website database	
Electricity Selling Price (DA-LMP[1])	PJM website database	Not required for current calculations
Contributing Power Generation Unit Names	PJM website database	
Generation Unit Parameters	2006 UDI Database[2]	
Fuel Type	2006 UDI Database	
Nameplate Capacity	2006 UDI Database	
Heat rate	2006 eGrid Database	
Emission Intensities	2006 eGrid Database	Not required for current calculations
Variable O&M Costs	Power plant operations models	
Delivered Fuel Costs	2006 FERC Form 423	

[1] DA-LMP is Day Ahead Locational Marginal Price
[2] UDI World Electric Power Plants Database 2006, available from www.platts.com

This data is cast into the future for projections of the fuel prices, generation demand, and additions to the generation facility portfolio. The assumptions for the projections and the data sources used are summarized in Exhibit 6-21.

Exhibit 6-21 Assumptions for Projecting PJM Year 2006 into 2010

Fuel Prices	Natural Gas	EAO 2007 - $6.55/MMBtu
	Bituminous Coal	EAO 2007 -$1.64/MMBtu
	Subbituminous Coal	Scaled Bituminous Coal Price
	Diesel Fuel Oil	2006 delivered fuel costs scaled to 2010 by futures market prices.
	Other Fuels	Fixed at previous study prices.
Demand Forecast	1.44 % increase per year based on 2006 EIA-411 projected demand growth for RFC Reliability Region.	
Changes in Generation Facility Portfolio	Data from future power generation studies on PJM website. Summarized in Exhibit 6-22	

The additional facilities that are planned or under construction and expected to be in service in 2010 amount to an additional 10,000 MW of generating capability. The breakdown of these technologies by fuel type is shown in Exhibit 6-22.

Exhibit 6-22 Breakdown of Additional Generation in the PJM ISO by Fuel Type
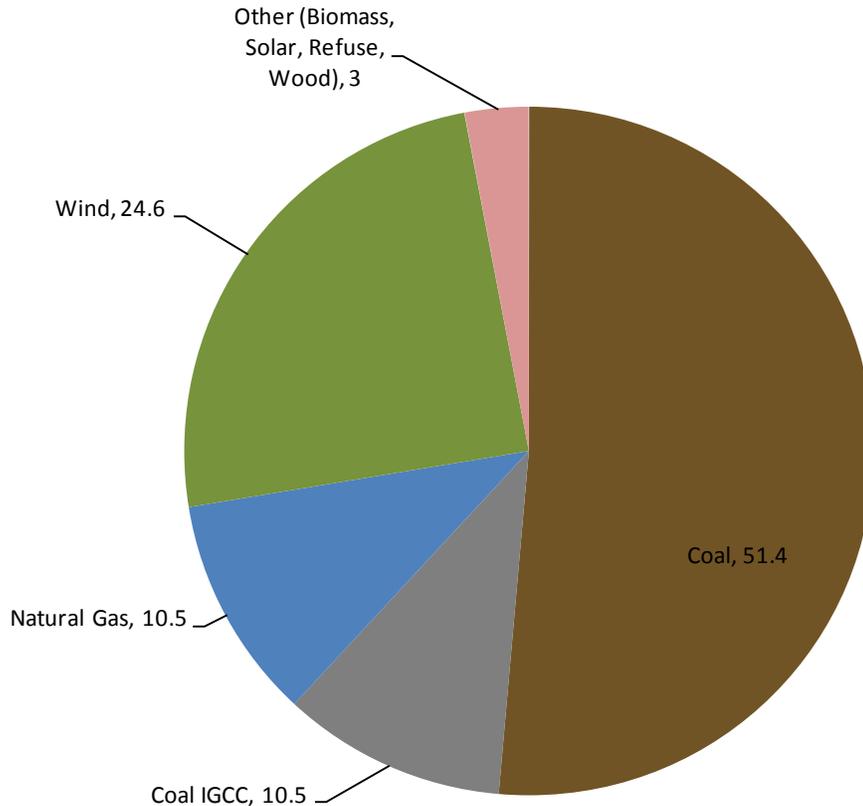
The characteristics of the non-carbon capture units are listed in Exhibit 6-23. These costs are based on the AEO 2008 projections of the 2007 natural gas and coal prices, $6.55/MMBtu and $1.64/MMBtu respectively. The SC PC facility has the lowest production costs (fuel and variable O&M costs) from the high efficiency and the low fuel cost. In spite of the greater efficiency and lower O&M cost of the natural gas-fired combined cycle system, the natural gas-fired unit has the greatest operating cost by a factor of two because of the greater fuel cost.

Exhibit 6-23 Summary of Prospective Facility Parameters

Bituminous Baseline Facility Types	Fuel Type	Fuel Cost ($/MMBtu)	O&M (mills/kWh)	Production Costs (mills/kWh)	Heat Rate (Btu/kWh)	Nameplate Capacity
Case 1 IGCC GEE	Bit Coal	$1.64	$7.30	$21.66	8,756	622
Case 3 IGCC CoP	Bit Coal	$1.64	$7.20	$21.28	8,585	625
Case 5 IGCC Shell	Bit Coal	$1.64	$7.75	$21.03	8,099	629
Case 9 PC Sub	Bit Coal	$1.64	$5.15	$20.36	9,276	550
Case 11 PC Super	Bit Coal	$1.64	$5.04	$19.28	8,686	550
Case 13 NGCC F-Class	NG	$6.55	$1.32	$45.84	6,798	555

7. DRY AND PARALLEL COOLING

This supplementary chapter examines the impact of dry and parallel cooling systems on the cost and performance of six plant configurations:

- IGCC (CoP) without CO_2 capture

- IGCC (CoP) with CO_2 capture

- SC PC without CO_2 capture

- SC PC with CO_2 capture

- NGCC without CO_2 capture

- NGCC with CO_2 capture

Parallel and dry cooling systems don't have universal definitions. In this study the systems are defined as follows:

Parallel Cooling: Steam exiting the LP turbine is divided equally between a conventional condenser using cooling water as the cooling medium and an air-cooled condenser using ambient air as the cooling medium. Additional cooling loads use cooling water, which rejects heat to an evaporative cooling tower.

Dry Cooling: Steam exiting the LP condenser is condensed entirely in an air-cooled condenser. Additional miscellaneous cooling loads use cooling water that rejects heat to an evaporative cooling tower.

The cooling system definition results in significant load on an evaporative cooling tower in PC and NGCC cases with CO_2 capture even in the dry cooling scenarios because of the large Econamine cooling water requirement. Since the cooling water temperature achieved in an air-cooled cooler would be significantly higher than in an evaporative cooling tower, the Econamine performance would also be affected. The quote basis for the Econamine process is for 16°C (60°F) cooling water and no data were available to estimate performance characteristics at higher temperatures. Hence the decision to maintain an evaporative cooling tower for non-condenser loads even in the dry cooling cases.

The study ambient design conditions are the same as ISO conditions and were presented previously in Exhibit 2-1. The ambient conditions and additional study assumptions result in the following design basis:

- Coal feed rate was maintained constant relative to the baseline case for both the parallel and dry cooling scenarios, which resulted in constant gross output but different net output for each case (different auxiliary loads for an air-cooled condenser).

- The condenser approach temperature in the baseline study was 12°C (21°F). The approach temperature for the air-cooled condenser was assumed to be 23°C (42°F) [83], which maintained a constant condenser temperature and pressure of 38°C (101°F) and 0.0068 MPa (0.9823 psia) for all cases.

- The power requirement for the air-cooled condenser fans is 3.5 times greater than for evaporative cooling tower fans when the air-cooled condenser and cooling tower have equivalent heat duty [84].

- The baseline study accounted for cooling loads that were modeled such as the steam turbine condenser; the CO_2 capture process; compressor intercoolers; low temperature syngas cooling and sour water stripper condenser (IGCC cases); and an allowance for miscellaneous loads. The miscellaneous loads assigned to each technology were 100 MMBtu/hr for PC and 25 MMBtu/hr for IGCC and NGCC. These loads were maintained at the same values for the parallel and dry cooling cases and were assigned to the evaporative cooling tower.

The cost accounts affected by the change in cooling system are shown in Exhibit 7-1 along with the process parameter used for cost scaling and the scaling exponent.

Exhibit 7-1 Cost Accounts Affected by Change in Cooling System

Cost Account	Scaling Parameter	Scaling Exponent
Account 3.2: Water Makeup and Pretreating	Raw water makeup	0.71
Account 3.4: Service Water Systems	Raw water makeup	0.71
Account 3.7: Waste Treatment Equipment	Raw water makeup	0.71
Account 8.3a: Condenser and Auxiliaries	Condenser duty	0.67
Account 8.3b: Air-Cooled Condenser	Air-cooled condenser duty	0.70
Account 9.1: Cooling Towers	Cooling tower duty	0.70
Account 9.2: CWPs	Circulating water flow rate	0.86
Account 9.3: CWS Auxiliaries	Circulating water flow rate	0.65
Account 9.4: Circulating Water Piping	Circulating water flow rate	0.65
Account 9.5: Makeup Water System	Raw water makeup	0.60
Account 9.6: Component Cooling Water System	Circulating water flow rate	0.65
Account 9.9: CWS Foundations and Structures	Circulating water flow rate	0.60
Account 14.4: Circulation Water Pumphouse	Circulating water flow rate	0.60
Account 14.5: Water Treatment Buildings	Raw water makeup	0.66
Account 14.9: Waste Treatment Building and Structures	Raw water makeup	0.07

7.1 STUDY RESULTS

Dry and parallel cooling systems result in decreased water consumption at the expense of increased cost and reduced efficiency. There is a net increase in capital cost because of the addition of the air-cooled condenser, which is greater than the reductions realized from the reduced cooling water flow rate and cooling tower duty. The O&M costs change minimally because an increase in fixed O&M costs (maintenance labor and materials) is approximately offset by a decrease in variable O&M costs (raw water and water treatment chemicals).

The normalized raw water withdrawal for the baseline, parallel, and dry cases is shown in Exhibit 7-2. In each case the raw water withdrawal (in gpm) is normalized by the net unit output (in MWs). In Exhibit 7-3 the absolute net reduction in raw water withdrawal (in gpm) for the parallel and dry cooling systems is shown. The raw water source continues to be 50 percent from groundwater and 50 percent from a municipal water supply. The following conclusions can be drawn:

- The greatest impact on raw water withdrawal is for PC and NGCC non-capture cases using dry cooling. The steam turbine condenser duty represents over 95 percent of the cooling duty in those cases, and the use of an air-cooled condenser leaves very little remaining load for the cooling tower. Water demand for FGD in the PC case and for BFW makeup in the PC and NGCC cases is relatively small, resulting in low normalized water withdrawal. The impact is not quite as dramatic in the IGCC non-capture case because there are additional cooling loads besides the steam turbine condenser, namely low temperature syngas cooling, the ASU Main Air Compressor (MAC) intercoolers, the AGR process, and the SWS condenser.

- The smallest impact of dry and parallel cooling on water withdrawal is for PC and NGCC CO_2 capture cases. The Econamine process requires significantly more cooling water than the two-stage Selexol process used in IGCC cases, and the capture process cooling load is assigned to an evaporative cooling tower. Therefore, the cases using the Econamine process continue to have significant evaporative and blowdown losses from the cooling tower, which diminishes the water savings of the parallel and dry systems.

- NGCC has the lowest normalized raw water withdrawal for CO_2 capture cases using conventional wet cooling. The same is true using a parallel cooling system. However, when using a dry cooling system, the IGCC capture plant has the lowest normalized raw water withdrawal primarily due to the higher steam turbine output of the IGCC plant (240 MW) compared to the NGCC plant (149 MW) and the associated cooling duty.

In all cases the use of parallel and dry cooling has a significant impact on water withdrawal. The absolute water savings ranges from 537 gpm for NGCC with CO_2 capture using parallel cooling to 4,649 gpm for SC PC without capture using dry cooling.

The reduction in water withdrawal comes with a performance and cost penalty. The net plant output decreases slightly because the increase in auxiliary load due to the air-cooled condenser fan is greater than the decrease due to a reduction in the cooling tower fan and CWP loads.

Exhibit 7-2 Normalized Raw Water Withdrawal for Baseline, Parallel and Dry Cooling Cases
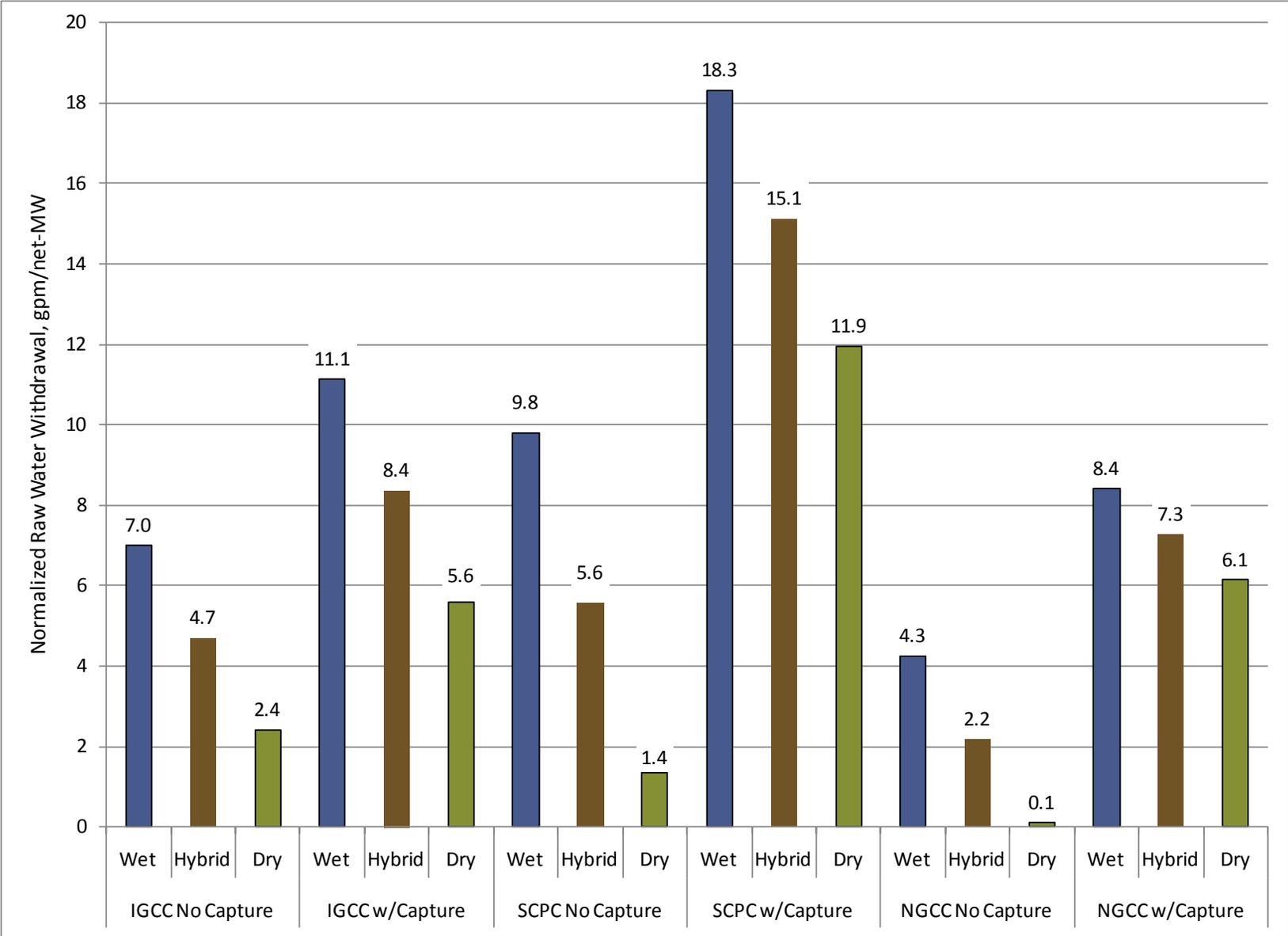
Exhibit 7-3 Absolute Decrease in Raw Water Withdrawal for Parallel and Dry Cooling Cases
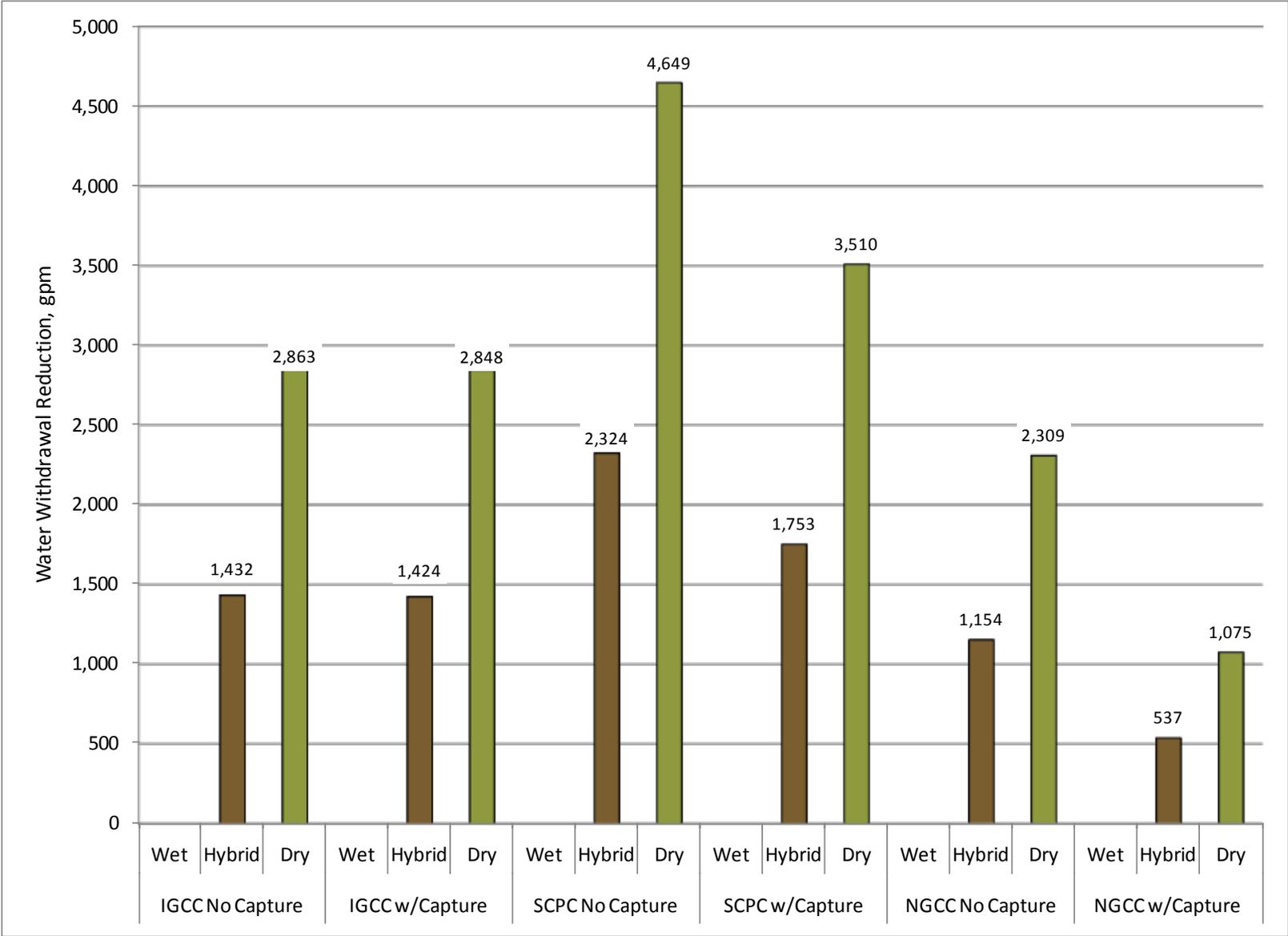
The impact on net plant output relative to the baseline (wet cooling) cases is shown in Exhibit 7-4. The plant de-rate is greatest for the dry cooling cases because the air-cooled condenser load increases faster than the cooling tower fan/CWP load decreases. The de-rate ranges from 100 kW for NGCC with CO_2 capture using parallel cooling to 1,059 kW for SC PC without CO_2 capture using dry cooling. The impact on net plant efficiency is relatively small with the largest decrease less than 0.3 percentage points when going from wet to dry cooling for the SC PC without CO_2 capture case.

Exhibit 7-4 Net Output Reduction Relative to the Baseline (Wet Cooling) Case

Technology/Cooling System	Net Output Reduction, kW (No CO_2 Capture)	Net Plant Efficiency, %	Net Output Reduction, kW (With CO_2 Capture)	Net Plant Efficiency, %
IGCC/Wet	**N/A**	**39.75**	**N/A**	**31.02**
IGCC/Parallel	-290	39.73	-280	31.01
IGCC/Dry	-690	39.70	-670	30.98
SC PC/Wet	**N/A**	**39.28**	**N/A**	**28.67**
SC PC/Parallel	-500	39.25	-300	28.40
SC PC/Dry	-1,059	39.21	-630	28.40
NGCC/Wet	**N/A**	**50.20**	**N/A**	**42.83**
NGCC/Parallel	-270	50.17	-100	42.82
NGCC/Dry	-497	50.15	-200	42.81

The cost impact is more significant than the performance impact. The capital cost of the air-cooled condenser is only partially offset by the reduction in cost of the cooling tower, CWS, and other water systems impacted by the reduction in water usage. Because there are always miscellaneous cooling loads assigned to the evaporative cooling tower, the cooling tower and CWSs are never eliminated, even in the dry cooling cases. The TOC for each case is shown in Exhibit 7-5.

The increase in TOC ranges from $46/kW for NGCC with CO_2 capture using parallel cooling to $109/kW for SC PC with CO_2 capture using dry cooling. The TOC delta between parallel and dry cooling cases is smallest for SC PC with no capture. The increase in cost of the air-cooled condenser is more nearly offset by reductions in other water related accounts because of the very large decrease in water withdrawal, which decreases from 3,080 gpm in the parallel cooling case to 770 gpm in the dry cooling case.

The O&M costs stay approximately constant for all cases as discussed at the beginning of Section 7.1. The TOC and O&M costs were used to calculate a COE for each of the cases. The impact on the COE is shown in Exhibit 7-6. The range of COE increase is from 0.83 mills/kWh (NGCC with capture using parallel cooling) to 2.16 mills/kWh (IGCC with CO_2 capture using dry cooling). The COE actually shows a slight decrease when going from parallel to dry cooling for the SC PC no capture case for several reasons:

- The TOC increase is small because of the large reduction in water requirements as discussed above.

- The decrease in variable operating cost is more significant because of the large decrease in water withdrawal.

Exhibit 7-5 Total Overnight Cost for Baseline, Parallel and Dry Cooling Cases
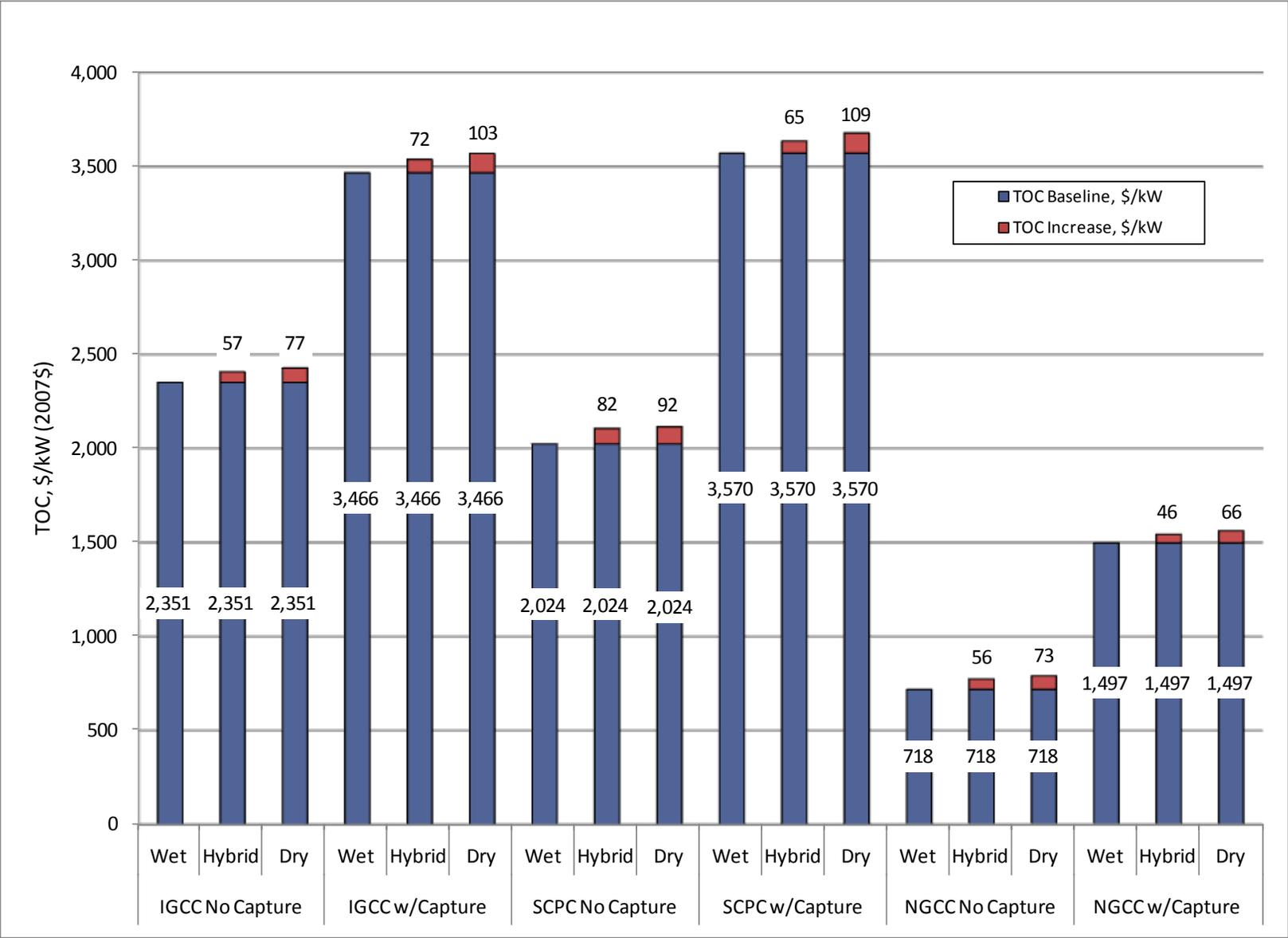
Exhibit 7-6 COE for Baseline, Parallel and Dry Cooling Systems
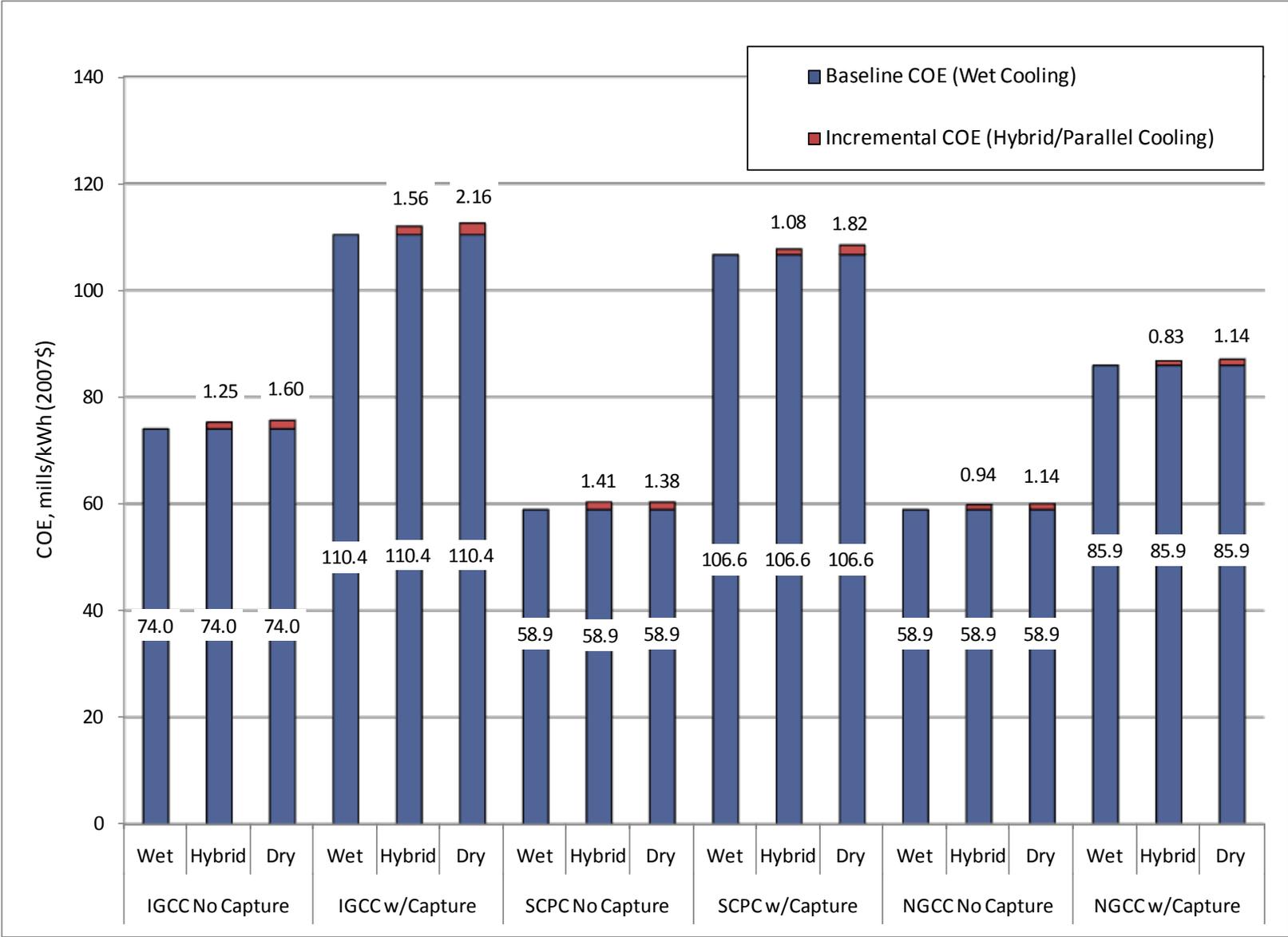
7.2 SENSITIVITY CASE

The assumptions made in this study resulted in a constant fuel feed rate and constant condenser operating condition for all cases. The constant condenser temperature and pressure are the result of assuming ISO ambient conditions. In reality fossil energy plants are designed for summer and winter temperature extremes. The SC PC case without CO_2 capture was used to examine the effect on a dry and wet cooling system of designing for a high ambient summer temperature.

The ambient design conditions used for the sensitivity study are shown in Exhibit 7-7 and are representative of summertime at Chicago's O'Hare Airport [85]. For the dry cooling case a 50°F approach to the dry bulb temperature was assumed [83], which results in a condenser temperature of 138°F. For the wet cooling case the following assumptions result in a condenser temperature of 118°F:

- Circulating water is cooled to within 5°F of the WB temperature

- The cooling water temperature range is 20°F

- The condenser temperature approach is 20°F

Exhibit 7-7 Design Ambient Conditions for SC PC Sensitivity Case

Elevation, m (ft)	0
Barometric Pressure, MPa (psia)	0.10 (14.696)
Design Ambient Temperature, Dry Bulb, °C (°F)	31 (88)
Design Ambient Temperature, WB, °C (°F)	23 (73)
Design Ambient Relative Humidity, %	47

In both cases the net output was maintained at approximately 550 MW, which required an increase in coal feed rate relative to the baseline SC PC cases. The results, presented below, show that the cost and performance penalties of a dry cooling system are greater than when using ISO design conditions.

The normalized water usage for the wet system at high ambient temperature design conditions is 10.3 gpm/MW(net) and for the dry system is 1.4 gpm/MW(net), or a reduction of 86 percent.

The performance penalty is 1.45 percentage points (38.23 to 36.78 percent). The dry cooling case requires an increase in coal feed rate of 3.9 percent to maintain the same net power output as the wet cooling case.

The cost penalty is also greater than in the ISO ambient condition case. The TOC increases by $145/kW in the dry cooling case compared to $92/kW for dry cooling at ISO conditions. The high ambient temperature case results in cost increases for all cost accounts (rather than just water based accounts) because of the increase in coal feed rate. The COE increases by 3.05 mills/kWh in the dry cooling case at high ambient temperature compared to only 1.38 mills/kWh at ISO conditions. The increase in COE represents a 5.1 percent increase over the wet cooling

case at high ambient temperature. The COE includes the increased fuel cost to maintain a nominal 550 MW net output.

7.3   CONCLUSIONS

Parallel and dry cooling have a significant impact on water consumption for all fossil energy technologies examined. The amount of water saved relative to a conventional wet cooling system ranges from 240 - 2,077 million gallons per year. The cost and performance penalty for dry and parallel cooling systems at ISO conditions is less than at a higher summer ambient design temperature that would represent a typical power plant design point. The performance penalty (net plant efficiency) at ISO conditions ranges from 0.006 to 0.270 percentage points and is 1.45 percentage points at the high temperature ambient condition. The cost penalty is primarily capital cost and ranges from 0.83 to 2.16 mills/kWh at ISO conditions and is 3.05 mills/kWh at high ambient temperature using SC PC with no capture and a dry cooling system.

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8. <u>GEE IGCC IN QUENCH-ONLY CONFIGURATION WITH CO$_2$ CAPTURE</u>

GEE offers three design configurations for their gasification system [86]:

- Quench: In this configuration, the hot syngas exiting the gasifier passes through a pool of water to quench the temperature to approximately 288°C (550°F) before entering the syngas scrubber. It is the simplest and lowest capital cost design, but also the least efficient.

- Radiant Only: In this configuration, the hot syngas exiting the gasifier passes through a radiant syngas cooler where it is cooled from about 1,316°C (2,400°F) to 677°C (1,250°F), then through a water quench where the syngas is further cooled to about 232°C (450°F) prior to entering the syngas scrubber. Relative to the quench configuration, the radiant only design offers increased net power output, higher efficiency, improved reliability/availability relative to the radiant-convective configuration described below, and results in the lowest COE. This configuration was chosen by GEE and Bechtel for the design of their reference plant.

- Radiant-Convective: In this configuration, the hot syngas exiting the gasifier passes through a radiant syngas cooler where it is cooled from about 1,316°C (2,400°F) to 677°C (1,250°F), then passes over a pool of water where particulate is removed but the syngas is not quenched, then through a convective syngas cooler where the syngas is further cooled to about 371°C (700°F) prior to entering additional heat exchangers or the scrubber. This configuration has the highest overall efficiency, but at the expense of highest capital cost and the lowest availability. This is the configuration used at Tampa Electric's Polk Power Station.

Section 3.2 of this report examined the radiant only version of the GEE gasifier in both non-capture and capture configurations (Cases 1 and 2). This supplementary chapter examines the performance of the GEE gasifier operated in the quench only mode with carbon capture (Case 2A).

The balance of this chapter is organized analogously to Section 3.2 of the original report (GEE IGCC Cases), and more specifically Section 3.2.8, which covers the GEE IGCC with CO$_2$ capture. However, only deviations from the original chapter are presented here to avoid needless repetition:

- Process and System Description provides an overview of the technology operation as applied to the GE IGCC operated in quench only mode. The systems that are common to all gasifiers were covered in Section 3.1 and features unchanged from the radiant only operation were covered in Section 3.2.8. Only features that are unique to quench only operation are discussed further in this section.

- Key Assumptions is a summary of study and modeling assumptions relevant to the GEE IGCC cases.

- Sparing Philosophy is unchanged from the radiant only cases and not repeated here.

- Performance Results provides the main modeling results from quench only configuration, 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 Case 2A.

8.1   CASE 2A – GEE IGCC IN QUENCH ONLY MODE WITH CO_2 CAPTURE

Case 2A is configured to produce electric power with CO_2 capture. The plant configuration is the same as the GEE IGCC Case 2 with the exception that the gasifier is operated in quench only mode. The gross power output from the plant is constrained by the capacity of the two CTs, and since the CO_2 capture process increases the auxiliary load on the plant, the net output is significantly reduced relative to Case 1.

The process description for Case 2A is similar to Case 2 with exception of the gasifier operating mode. A BFD and stream tables for Case 2A are shown in Exhibit 8-1 and Exhibit 8-2, respectively. Instead of repeating the entire process description, only differences from Case 2 are reported here.

Gasification

The gasification process is the same as Case 2 with the exception that the syngas exiting the gasifier passes through a water quench where the temperature is reduced from 1,316°C (2,400°F) to 288°C (550°F). The total coal feed to the two gasifiers is 5,301 tonnes/day (5,844 TPD) (stream 6) and the ASU provides 4,343 tonnes/day (4,787 TPD) of 95 percent oxygen to the gasifier and Claus plant (streams 3 and 5).

Raw Gas Cooling/Particulate Removal

Particulate is largely removed in the quench tank and no additional heat recovery occurs prior to the syngas scrubber.

Syngas Scrubber/Sour Water Stripper

The outlet temperature from the syngas scrubber is 227°C (440°F) (stream 10).

Sour Gas Shift (SGS)

The SGS process is the same as described for Case 2 with a 97 percent overall conversion of the CO to CO_2. The warm syngas from the second stage of SGS (stream 12) is cooled to 244°C (471°F) by heating the syngas entering the first shift reactor. The syngas is then cooled to 193°C (380°F) by producing IP steam that is sent to the RH in the HRSG. The SGS catalyst also serves to hydrolyze COS thus eliminating the need for a separate COS hydrolysis reactor. Following the second SGS cooler the syngas is further cooled to 35°C (95°F) prior to the mercury removal beds.

Exhibit 8-1 Case 2A Block Flow Diagram, GEE Quench Only IGCC with CO$_2$ Capture

Exhibit 8-2 Case 2A Stream Table, GEE Quench Only IGCC with CO_2 Capture

	1	2	3	4	5	6	7	8	9	10	11	12
V-L Mole Fraction												
Ar	0.0092	0.0165	0.0318	0.0023	0.0318	0.0000	0.0000	0.0000	0.0086	0.0053	0.0000	0.0053
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0011	0.0007	0.0000	0.0007
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3576	0.2197	0.0000	0.0061
CO_2	0.0003	0.0054	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.1380	0.0848	0.0000	0.2985
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	0.0001	0.0000	0.0000
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.3406	0.2093	0.0000	0.4229
H_2O	0.0099	0.1355	0.0000	0.0003	0.0000	0.0000	0.9997	0.0000	0.1369	0.4700	1.0000	0.2562
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0008	0.0001	0.0000	0.0001
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0073	0.0045	0.0000	0.0046
N_2	0.7732	0.7077	0.0178	0.9920	0.0178	0.0000	0.0000	0.0000	0.0070	0.0043	0.0000	0.0043
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0003	0.0000	0.0019	0.0013	0.0000	0.0013
O_2	0.2074	0.1349	0.9504	0.0054	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
Total	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	27,367	1,660	97	20,045	5,526	0	5,037	0	23,121	37,625	0	37,625
V-L Flowrate (kg/hr)	789,731	45,607	3,132	562,472	177,815	0	90,741	0	465,209	726,195	0	726,195
Solids Flowrate (kg/hr)	0	0	0	0	0	220,888	0	24,235	0	0	0	0
Temperature (°C)	15	18	32	93	32	15	146	1,316	1,316	227	288	250
Pressure (MPa, abs)	0.10	0.11	0.86	2.65	0.86	0.10	5.79	5.62	5.62	5.58	5.52	5.45
Enthalpy (kJ/kg)[A]	30.23	35.62	26.67	92.50	26.67	---	0.00	---	2,631.86	1,479.52	2,918.18	1,017.26
Density (kg/m^3)	1.2	1.5	11.0	24.4	11.0	---	867.1	---	8.5	25.9	25.6	24.5
V-L Molecular Weight	28.857	27.479	32.181	28.060	32.181	---	18.015	---	20.121	19.301	18.015	19.301
V-L Flowrate (lb_{mol}/hr)	60,334	3,659	215	44,193	12,182	0	11,105	0	50,972	82,948	0	82,948
V-L Flowrate (lb/hr)	1,741,060	100,545	6,906	1,240,039	392,015	0	200,050	0	1,025,611	1,600,986	0	1,600,986
Solids Flowrate (lb/hr)	0	0	0	0	0	486,976	0	53,430	0	0	0	0
Temperature (°F)	59	65	90	199	90	59	295	2,400	2,400	440	550	481
Pressure (psia)	14.7	16.4	125.0	384.0	125.0	14.7	840.0	815.0	815.0	810.0	800.0	790.0
Enthalpy (Btu/lb)[A]	13.0	15.3	11.5	39.8	11.5	---		---	1,131.5	636.1	1,254.6	437.3
Density (lb/ft^3)	0.076	0.091	0.687	1.521	0.687	---	54.131	---	0.530	1.619	1.597	1.529

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 8-2 Case 2A Stream Table, GEE Quench Only IGCC with CO_2 Capture (Continued)

	13	14	15	16	17	18	19	20	21	22	23	24
V-L Mole Fraction												
Ar	0.0071	0.0071	0.0115	0.0115	0.0002	0.0018	0.0000	0.0103	0.0092	0.0091	0.0091	0.0000
CH_4	0.0009	0.0009	0.0015	0.0015	0.0000	0.0004	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0082	0.0081	0.0130	0.0130	0.0002	0.0023	0.0000	0.0061	0.0000	0.0000	0.0000	0.0000
CO_2	0.4017	0.4053	0.0501	0.0501	0.9948	0.5218	0.0000	0.6606	0.0003	0.0083	0.0083	0.0000
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.5690	0.5647	0.9133	0.9133	0.0048	0.1029	0.0000	0.2596	0.0000	0.0000	0.0000	0.0000
H_2O	0.0012	0.0012	0.0001	0.0001	0.0000	0.0225	0.0000	0.0017	0.0099	0.1222	0.1222	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2S	0.0061	0.0061	0.0000	0.0000	0.0000	0.3472	0.0000	0.0043	0.0000	0.0000	0.0000	0.0000
N_2	0.0058	0.0065	0.0105	0.0105	0.0000	0.0008	0.0000	0.0574	0.7732	0.7541	0.7541	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	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2074	0.1064	0.1064	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	27,963	28,357	17,424	17,424	10,414	496	0	394	110,253	139,653	139,653	20,010
V-L Flowrate (kg/hr)	552,101	564,705	90,455	90,455	456,190	17,654	0	12,604	3,181,557	3,834,485	3,834,485	360,491
Solids Flowrate (kg/hr)	0	0	0	0	0	0	5,523	0	0	0	0	0
Temperature (°C)	35	35	35	195	51	48	178	38	15	562	132	534
Pressure (MPa, abs)	5.17	5.1	5.137	3.172	15.270	0.163	0.119	5.512	0.101	0.105	0.105	12.512
Enthalpy (kJ/kg)[A]	36.94	36.2	194.924	1,117.278	-162.292	74.702	---	5.842	30.227	834.643	343.500	3,432.968
Density (kg/m³)	41.0	41.2	10.2	4.2	641.8	2.2	5,280.6	77.3	1.2	0.4	0.9	36.7
V-L Molecular Weight	19.744	20	5.191	5.191	43.804	35.590	---	31.966	28.857	27.457	27.457	18.015
V-L Flowrate (lb_{mol}/hr)	61,647	62,516	38,414	38,414	22,960	1,094	0	869	243,066	307,881	307,881	44,115
V-L Flowrate (lb/hr)	1,217,174	1,244,961	199,419	199,419	1,005,728	38,921	0	27,786	7,014,133	8,453,593	8,453,593	794,747
Solids Flowrate (lb/hr)	0	0	0	0	0	0	12,177	0	0	0	0	0
Temperature (°F)	95	95	95	383	124	119	352	100	59	1,044	270	994
Pressure (psia)	750.0	745.0	745.0	460.0	2,214.7	23.7	17.3	799.5	14.7	15.2	15.2	1,814.7
Enthalpy (Btu/lb)[A]	15.9	15.6	83.8	480.3	-69.8	32.1	---	2.5	13.0	358.8	147.7	1,475.9
Density (lb/ft³)	2.562	3	0.636	0.261	40.065	0.137	329.655	4.823	0.076	0.026	0.053	2.293

Mercury Removal and Acid Gas Removal

Mercury removal and the AGR process are the same as in Case 2.

The AGR process in Case 2A is a two stage Selexol process where H_2S is removed in the first stage and CO_2 in the second stage of absorption as previously described in Section 3.1.5. 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 acid gas (stream 18) contains 35 percent H_2S and 52 percent CO_2 with the balance primarily H_2.

CO_2 Compression and Dehydration

The CO_2 compression and dehydration scheme is the same as for Case 2.

Claus Unit

The Claus plant is the same as Case 2 with the following exceptions:

- 5,523 kg/hr (12,177 lb/hr) of sulfur (stream 19) are produced

- The waste heat boiler generates 12,957 kg/hr (28,564 lb/hr) of 3.0 MPa (430 psia) steam.

Power Block

Clean syngas from the AGR plant is heated to 241°C (465°F) using first hot water from the syngas scrubber followed by HP BFW before passing through an expansion turbine. The clean syngas (stream 16) is diluted with nitrogen (stream 4) and then enters the CT burner. There is no integration between the CT and the ASU in this case. The exhaust gas (stream 22) exits the CT at 562°C (1,044°F) and enters the HRSG where additional heat is recovered. The FG exits the HRSG at 132°C (270°F) (stream 23) 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.

Air Separation Unit

The same elevated pressure ASU is used in Case 2A and produces 4,343 tonnes/day (4,787 TPD) of 95 mol% oxygen and 14,595 tonnes/day (16,087 TPD) of nitrogen. There is no integration between the ASU and the CT.

8.1.1   Key System Assumptions

System assumptions for Case 2A are shown in Exhibit 8-3.

Exhibit 8-3 GEE IGCC Plant Study Configuration Matrix

Case	2A
Gasifier Pressure, MPa (psia)	5.6 (815)
O_2:Coal Ratio, kg O_2/kg dry coal	0.91
Carbon Conversion, %	98
Syngas HHV at Gasifier Outlet, kJ/Nm^3 (Btu/scf)	8,655 (232)
Steam Cycle, MPa/°C/°C (psig/°F/°F)	12.4/534/534 (1800/994/994)
Condenser Pressure, mm Hg (in Hg)	51 (2.0)
CT	2x Advanced F Class (232 MW output each)
Gasifier Technology	GEE Quench Only
Oxidant	95 vol% Oxygen
Coal	Illinois No. 6
Coal Slurry Solids Content, %	63
COS Hydrolysis	Occurs in SGS
SGS	Yes
H_2S Separation	Selexol 1st Stage
Sulfur Removal, %	99.8
Sulfur Recovery	Claus Plant with Tail Gas Recycle to Selexol/ Elemental Sulfur
Particulate Control	Water Quench, Scrubber, and AGR Absorber
Mercury Control	Carbon Bed
NOx Control	MNQC (LNB) and N_2 Dilution
CO_2 Separation	Selexol 2nd Stage
CO_2 Capture	90.2%
CO_2 Sequestration	Off-site Saline Formation

8.1.2   Case 2A Performance Results

The plant produces a net output of 494 MW at a net plant efficiency of 29.7 percent (HHV basis). Overall performance for the entire plant is summarized in Exhibit 8-4, which includes auxiliary power requirements. The ASU accounts for 60 percent of the auxiliary load between the main air compressor, the nitrogen compressor, the oxygen compressor, and ASU auxiliaries. The two-stage Selexol process and CO_2 compression account for an additional 26 percent of the auxiliary power load. The BFW pumps and cooling water system (CWPs and cooling tower fan) comprise about 5 percent of the load, leaving 9 percent of the auxiliary load for all other systems.

Exhibit 8-4 Case 2A Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	Case 2	Case 2A
Gas Turbine Power	464,000	464,000
Sweet Gas Expander Power	6,500	6,600
Steam Turbine Power	263,500	213,600
TOTAL POWER, kWe	**734,000**	**684,200**
AUXILIARY LOAD SUMMARY, kWe		
Coal Handling	470	470
Coal Milling	2,270	2,270
Sour Water Recycle Slurry Pump	190	200
Slag Handling	1,160	1,160
Air Separation Unit Auxiliaries	1,000	1,000
Air Separation Unit Main Air Compressor	67,330	67,350
Oxygen Compressor	10,640	10,640
Nitrogen Compressors	35,640	35,630
CO_2 Compressor	31,160	31,130
Boiler Feedwater Pumps	4,180	2,620
Condensate Pump	280	230
Quench Water Pump	540	1,270
Circulating Water Pump	4,620	4,810
Ground Water Pumps	530	550
Cooling Tower Fans	2,390	2,490
Scrubber Pumps	230	480
Acid Gas Removal	19,230	19,210
Gas Turbine Auxiliaries	1,000	1,000
Steam Turbine Auxiliaries	100	100
Claus Plant/TGTU Auxiliaries	250	250
Claus Plant TG Recycle Compressor	1,780	1,800
Miscellaneous Balance of Plant[2]	3,000	3,000
Transformer Losses	2,760	2,600
TOTAL AUXILIARIES, kWe	**190,750**	**190,260**
NET POWER, kWe	**543,250**	**493,940**
Net Plant Efficiency, % (HHV)	32.6	29.7
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	11,034 (10,458)	12,135 (11,502)
CONDENSER COOLING DUTY 10^6 kJ/hr (10^6 Btu/hr)	**1,509 (1,430)**	**1,467 (1,390)**
CONSUMABLES		
As-Received Coal Feed, kg/hr (lb/hr)	220,904 (487,011)	220,888 (486,976)
Thermal Input, kWt[1]	1,665,074	1,664,954
Raw Water Withdrawal, m^3/min (gpm)	22.0 (5,815)	23.2 (6,117)
Raw Water Consumption, m^3/min (gpm)	17.9 (4,739)	18.9 (4,993)

1 - HHV of As-Received Illinois No. 6 coal is 27,135 kJ/kg (11,666 Btu/lb)

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 PM were presented in Section 2.4. A summary of the plant air emissions for Case 2A is presented in Exhibit 8-5.

Exhibit 8-5 Case 2A Air Emissions

	kg/GJ (lb/10^6 Btu)	Tonne/year (tons/year) @ 80% CF	kg/MWh (lb/MWh)
SO$_2$	0.001 (0.002)	39 (43)	0.008 (.018)
NOx	0.021 (0.049)	878 (968)	0.183 (.404)
Particulates	0.003 (0.0071)	128 (141)	0.027 (.059)
Hg	2.46E-7 (5.71E-7)	0.010 (0.011)	2.15E-6 (4.74E-6)
CO$_2$	8.5 (19.8)	358,390 (395,058)	75 (165)
CO$_2$^{1}			104 (228)

^{1} CO_2 emissions based on net power instead of gross power

The low level of SO_2 emissions is achieved by capture of the sulfur in the gas by the two-stage Selexol AGR process. As a result of achieving the 90 percent CO_2 removal target, the sulfur compounds are removed to an extent that exceeds the environmental target in Section 2.4. The clean syngas exiting the AGR process has a sulfur concentration of approximately 5 ppmv. This results in a concentration in the FG of less than 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 to convert all sulfur species to H_2S and then recycled back to the Selexol process, thereby eliminating the need for a tail gas treatment unit.

NOx emissions are limited by 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. This helps lower NOx levels as well.

Particulate discharge to the atmosphere is limited to extremely low values by the use of the syngas quench 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 mercury is captured from the syngas by an activated carbon bed.

Ninety percent of the CO_2 from the syngas is captured in the AGR system and compressed for sequestration.

The carbon balance for the plant is shown in Exhibit 8-6. The carbon input to the plant consists of carbon in the air in addition to carbon in the coal. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant as unburned carbon in the slag and as CO_2 in the stack gas, ASU vent gas, and the captured CO_2 product. The CO_2 capture efficiency is defined as the amount of carbon in the CO_2 product stream relative to the amount of carbon in the coal less carbon contained in the slag, represented by the following fraction:

(Carbon in CO_2 Product)/[(Carbon in the Coal)-(Carbon in Slag)] or
274,397/(310,421-6,208) * 100 or
90.2 percent

Exhibit 8-6 Case 2A Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	140,805 (310,421)	Slag	2,816 (6,208)
Air (CO_2)	540 (1,191)	Stack Gas	13,957 (30,770)
		ASU Vent	107 (237)
		CO_2 Product	124,464 (274,397)
Total	141,345 (311,612)	Total	141,345 (311,612)

Exhibit 8-7 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered in the Claus plant, sulfur co-sequestered with the CO_2 product, and sulfur emitted in the stack gas. Sulfur in the slag is considered to be negligible.

Exhibit 8-7 Case 2A Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	5,536 (12,206)	Elemental Sulfur	5,523 (12,177)
		Stack Gas	3 (6)
		CO_2 Product	10 (23)
Total	5,536 (12,206)	Total	5,536 (12,206)

Exhibit 8-8 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 syngas condensate, and that water is re-used as internal recycle. Raw water withdrawal is the difference between water demand and internal recycle. Some process water is returned to the source via cooling tower and sour water stripper blowdown. The difference between raw water withdrawal and process water discharge is raw water consumption, or the net impact on the water source.

Exhibit 8-8 Case 2A Water Balance

Water Use	Water Demand m³/min (gpm)	Internal Recycle m³/min (gpm)	Raw Water Withdrawal m³/min (gpm)	Process Water Discharge m³/min (gpm)	Raw Water Consumption m³/min (gpm)
Slag Handling	**0.53 (139)**	**0.53 (139)**	**0.0 (0)**	**0.0 (0)**	**0.0 (0)**
Slurry Water	**1.5 (400)**	**1.5 (400)**	**0.0 (0)**	**0.0 (0)**	**0.0 (0)**
Quench Water	**6.7 (1,759)**	**1.9 (493)**	**4.8 (1,267)**	**0.0 (0)**	**4.8 (1,267)**
SWS Blowdown	**0.0 (0)**	**0.0 (0)**	**0.0 (0)**	**0.04 (10)**	**-0.04 (-10)**
Condenser Makeup *Gasifier Steam* *Shift Steam* *BFW Makeup*	**0.15 (40)** *0.15 (40)*	**0.0 (0)**	**0.15 (40)** *0.15 (40)*	**0.0 (0)**	**0.15 (40)**
Cooling Tower Makeup *BFW* *Blowdown* *SWS Blowdown* *SWS Excess*	**18.8 (4,954)**	**0.54 (143)** *0.15 (40)* *0.39 (103)*	**18.2 (4,811)** *-0.15 (-40)* *-0.39 (-103)*	**4.2 (1,114)**	**14.0 (3,697)**
Total	**27.6 (7,292)**	**4.4 (1,174)**	**23.2 (6,117)**	**4.3 (1,124)**	**18.9 (4,993)**

Energy Balance

A plant heat and material balance is presented in Exhibit 8-9 through Exhibit 8-11 with an overall plant energy balance presented in tabular form in Exhibit 8-12.

Exhibit 8-9 Case 2A Coal Gasification and Air Separation Unit Heat and Mass Balance Schematic
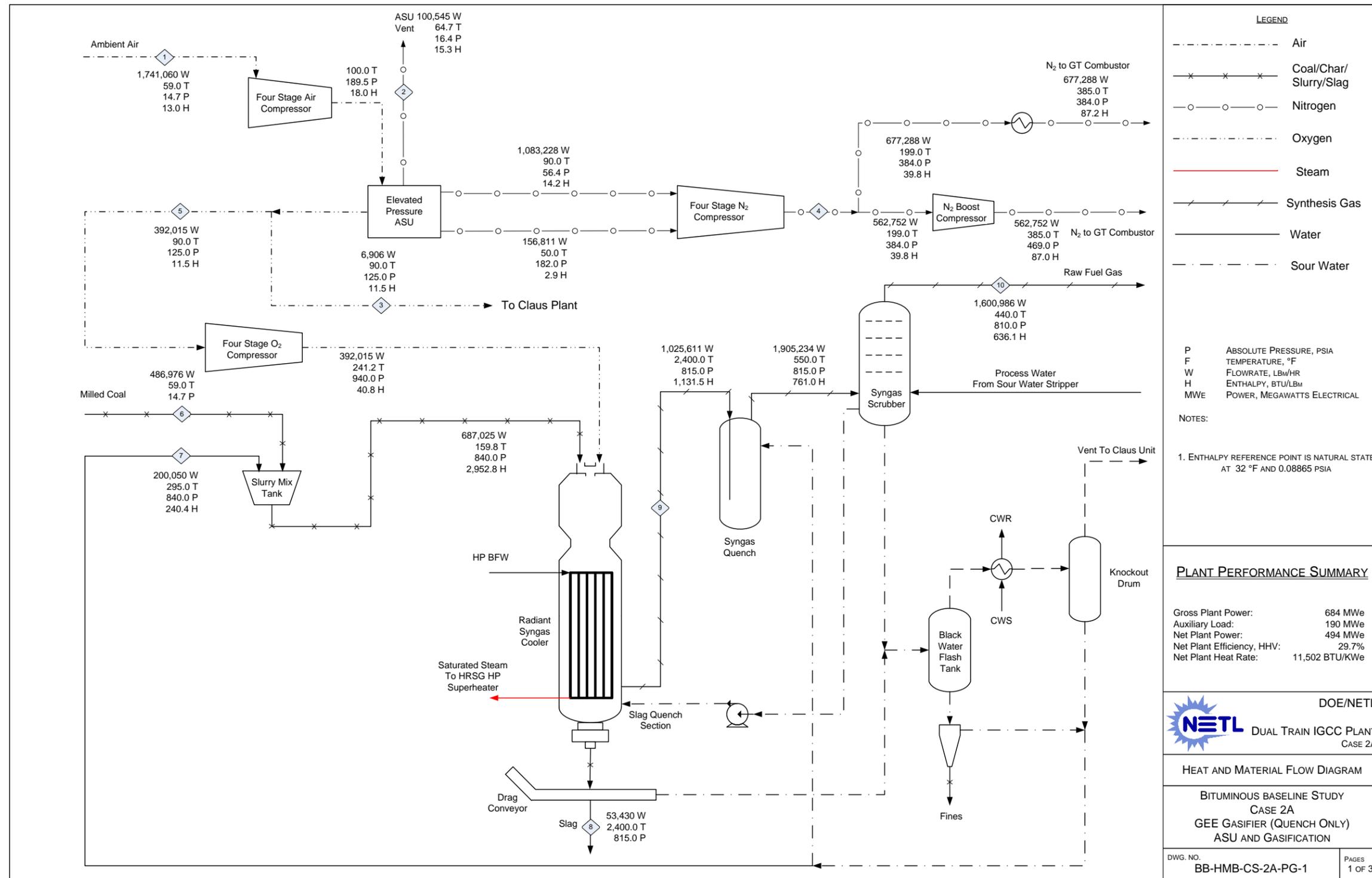
Exhibit 8-10 Case 2A Syngas Cleanup Heat and Mass Balance Schematic
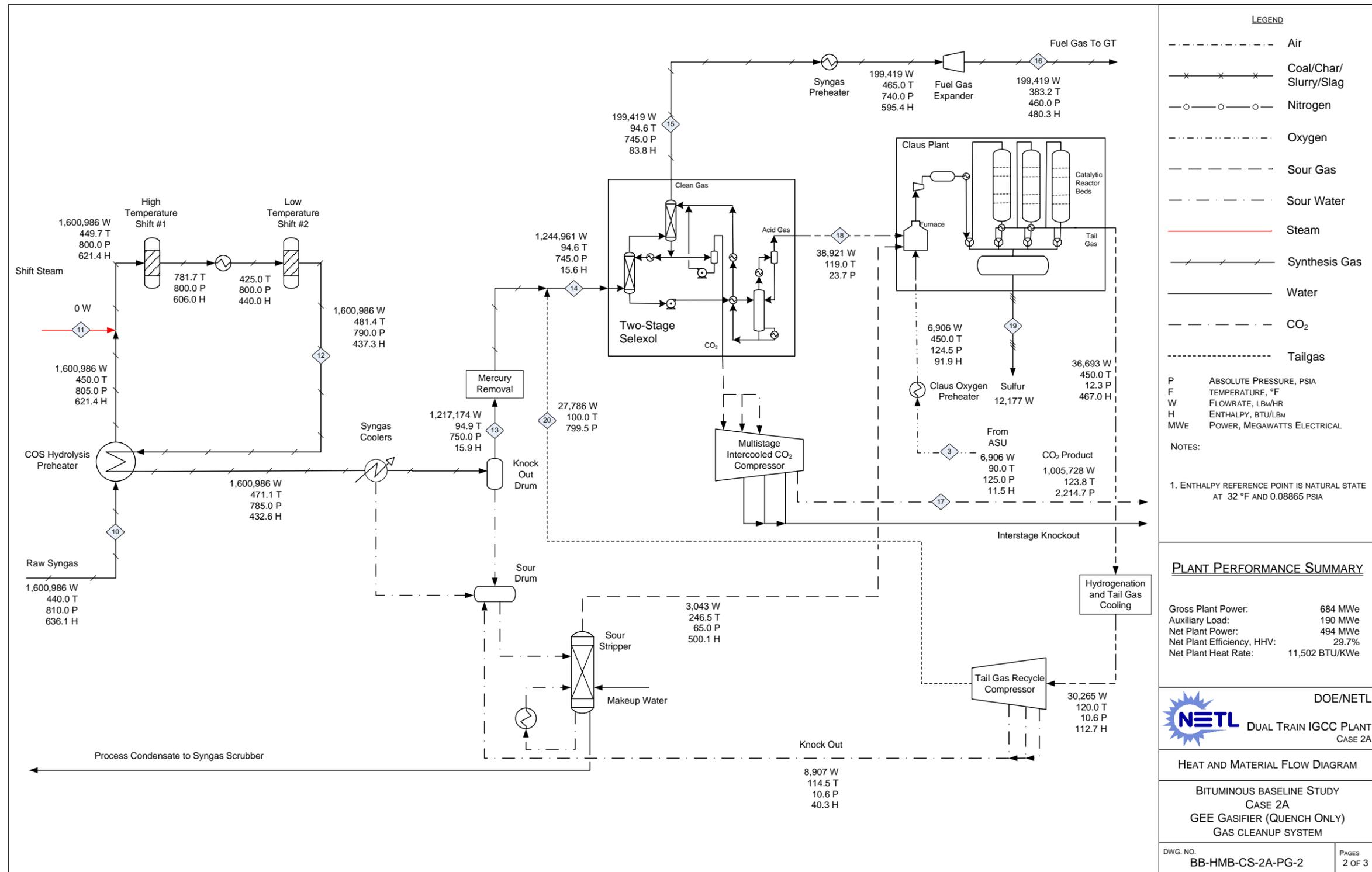
Exhibit 8-11 Case 2A Combined Cycle Power Generation Heat and Mass Balance Schematic
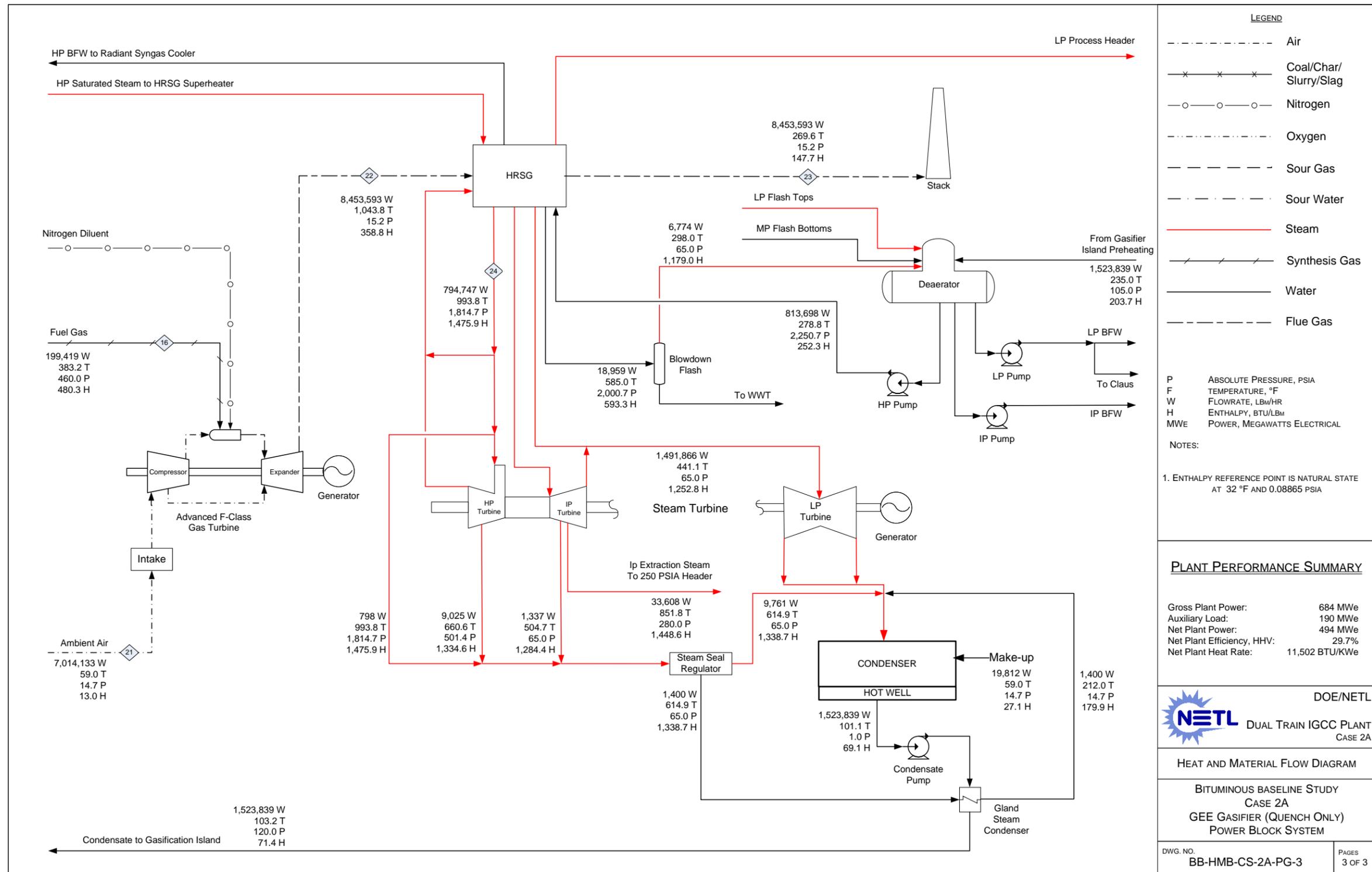
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Exhibit 8-12 Case 2A Overall Energy Balance

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	5,994 (5,681)	5.0 (4.7)		5,999 (5,686)
ASU Air		23.9 (22.6)		24 (23)
GT Air		96.2 (91.2)		96 (91)
Water		87.1 (82.5)		87 (83)
Auxiliary Power			685 (649)	685 (649)
TOTAL	**5,994 (5,681)**	**212.1 (201.1)**	**685 (649)**	**6,891 (6,531)**
Heat Out GJ/hr (MMBtu/hr)				
ASU Vent		1.6 (1.5)		2 (2)
Slag	92 (88)	37.8 (35.9)		130 (123)
Sulfur	51 (49)	0.6 (0.6)		52 (49)
CO_2		-74.0 (-70.2)		-74 (-70)
Cooling Tower Blowdown		31.3 (29.7)		31 (30)
HRSG Flue Gas		1,317 (1,248)		1,317 (1,248)
Condenser		1,452 (1,377)		1,452 (1,377)
Non-Condenser Cooling Tower Loads[1]		794 (753)		794 (753)
Process Losses[2]		723 (686)		723 (686)
Power			2,463 (2,335)	2,463 (2,335)
TOTAL	**144 (136)**	**4,284 (4,061)**	**2,463 (2,335)**	**6,891 (6,531)**

[1] Includes ASU compressor intercoolers, CO_2 compressor intercoolers, sour water stripper condenser, and syngas cooler (low level heat rejection)

[2] Calculated by difference to close the energy balance

8.1.3   Case 2A – Major Equipment List

Major equipment items for the GEE quench only gasifier with CO_2 capture are shown in the following tables. 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	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	181 tonne (200 ton)	2	0
2	Feeder	Belt	572 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,134 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,134 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,134 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	45 tonne (50 ton)	2	1
9	Feeder	Vibratory	181 tonne/hr (200 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	363 tonne/hr (400 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	181 tonne (200 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3" x 0 - 1-1/4" x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	363 tonne/hr (400 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Conveyor No. 5	Belt w/ tripper	363 tonne/hr (400 tph)	1	0
18	Coal Silo w/ Vent Filter and Slide Gates	Field erected	816 tonne (900 ton)	3	0

ACCOUNT 2   COAL PREPARATION AND FEED

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Feeder	Vibratory	82 tonne/h (90 tph)	3	0
2	Conveyor No. 6	Belt w/tripper	245 tonne/h (270 tph)	1	0
3	Rod Mill Feed Hopper	Dual Outlet	490 tonne (540 ton)	1	0
4	Weigh Feeder	Belt	118 tonne/h (130 tph)	2	0
5	Rod Mill	Rotary	118 tonne/h (130 tph)	2	0
6	Slurry Water Storage Tank with Agitator	Field erected	299,883 liters (79,220 gal)	2	0
7	Slurry Water Pumps	Centrifugal	833 lpm (220 gpm)	2	1
8	Trommel Screen	Coarse	172 tonne/h (190 tph)	2	0
9	Rod Mill Discharge Tank with Agitator	Field erected	392,285 liters (103,630 gal)	2	0
10	Rod Mill Product Pumps	Centrifugal	3,407 lpm (900 gpm)	2	2
11	Slurry Storage Tank with Agitator	Field erected	1,176,894 liters (310,900 gal)	2	0
12	Slurry Recycle Pumps	Centrifugal	6,435 lpm (1,700 gpm)	2	2
13	Slurry Product Pumps	Positive displacement	3,407 lpm (900 gpm)	2	2

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	810,078 liters (214,000 gal)	2	0
2	Condensate Pumps	Vertical canned	6,397 lpm @ 91 m H2O (1,690 gpm @ 300 ft H2O)	2	1
3	Deaerator (integral w/ HRSG)	Horizontal spray type	464,932 kg/hr (1,025,000 lb/hr)	2	0
4	Intermediate Pressure Feedwater Pump	Horizontal centrifugal, single stage	6,587 lpm @ 27 m H2O (1,740 gpm @ 90 ft H2O)	2	1
5	High Pressure Feedwater Pump No. 1	Barrel type, multi-stage, centrifugal	HP water: 3,520 lpm @ 1,859 m H2O (930 gpm @ 6,100 ft H2O)	2	1
6	High Pressure Feedwater Pump No. 2	Barrel type, multi-stage, centrifugal	IP water: 1,590 lpm @ 223 m H2O (420 gpm @ 730 ft H2O)	2	1
7	Auxiliary Boiler	Shop fabricated, water tube	18,144 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
8	Service Air Compressors	Flooded Screw	28 m3/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
9	Instrument Air Dryers	Duplex, regenerative	28 m3/min (1,000 scfm)	2	1
10	Closed Cylce Cooling Heat Exchangers	Plate and frame	451 GJ/hr (428 MMBtu/hr) each	2	0
11	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	162,016 lpm @ 21 m H2O (42,800 gpm @ 70 ft H2O)	2	1
12	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H2O (1,000 gpm @ 350 ft H2O)	1	1
13	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H2O (700 gpm @ 250 ft H2O)	1	1
14	Raw Water Pumps	Stainless steel, single suction	5,867 lpm @ 18 m H2O (1,550 gpm @ 60 ft H2O)	2	1
15	Ground Water Pumps	Stainless steel, single suction	2,915 lpm @ 268 m H2O (770 gpm @ 880 ft H2O)	4	1
16	Filtered Water Pumps	Stainless steel, single suction	3,899 lpm @ 49 m H2O (1,030 gpm @ 160 ft H2O)	2	1
17	Filtered Water Tank	Vertical, cylindrical	1,862,423 liter (492,000 gal)	2	0
18	Makeup Water Demineralizer	Anion, cation, and mixed bed	227 lpm (60 gpm)	2	0
19	Liquid Waste Treatment System		10 years, 24-hour storm	1	0

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

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gasifier	Pressurized slurry-feed, entrained bed	2,903 tonne/day, 5.6 MPa (3,200 tpd, 814.96 psia)	2	0
2	Synthesis Gas Quench	Pressurized quench tank	255,826 kg/hr (564,000 lb/hr)	2	0
3	Syngas Scrubber Including Sour Water Stripper	Vertical upflow	475,365 kg/hr (1,048,000 lb/hr)	2	0
4	Raw Gas Coolers	Shell and tube with condensate drain	399,615 kg/hr (881,000 lb/hr)	8	0
5	Raw Gas Knockout Drum	Vertical with mist eliminator	304,360 kg/hr, 35°C, 5.2 MPa (671,000 lb/hr, 95°F, 755 psia)	2	0
6	Synthesis Gas Reheater	Shell and tube	49,895 kg/hr (110,000 lb/hr)	2	0
7	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	475,365 kg/hr (1,048,000 lb/hr) syngas	2	0
8	ASU Main Air Compressor	Centrifugal, multi-stage	5,947 m3/min @ 1.3 MPa (210,000 scfm @ 190 psia)	2	0
9	Cold Box	Vendor design	2,359 tonne/day (2,600 tpd) of 95% purity oxygen	2	0
10	Oxygen Compressor	Centrifugal, multi-stage	1,189 m3/min (42,000 scfm) Suction - 0.9 MPa (130 psia) Discharge - 6.5 MPa (940 psia)	2	0
11	Primary Nitrogen Compressor	Centrifugal, multi-stage	3,794 m3/min (134,000 scfm) Suction - 0.4 MPa (60 psia) Discharge - 2.7 MPa (390 psia)	2	0
12	Secondary Nitrogen Compressor	Centrifugal, single-stage	538 m3/min (19,000 scfm) Suction - 1.2 MPa (180 psia) Discharge - 2.7 MPa (390 psia)	2	0
13	Syngas Dilution Nitrogen Boost Compressor	Centrifugal, single-stage	1,982 m3/min (70,000 scfm) Suction - 2.6 MPa (380 psia) Discharge - 3.2 MPa (470 psia)	2	0

ACCOUNT 5   SYNGAS CLEANUP

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Mercury Adsorber	Sulfated carbon bed	303,453 kg/hr (669,000 lb/hr) 35°C (95°F) 5.2 MPa (750 psia)	2	0
2	Sulfur Plant	Claus type	146 tonne/day (161 tpd)	1	0
3	Water Gas Shift Reactors	Fixed bed, catalytic	399,615 kg/hr (881,000 lb/hr) 232°C (450°F) 5.5 MPa (800 psia)	4	0
4	Shift Reactor Heat Recovery Exchangers	Shell and Tube	Exchanger 1: 154 GJ/hr (146 MMBtu/hr) Exchanger 2: 4 GJ/hr (4 MMBtu/hr)	4	0
5	Acid Gas Removal Plant	Two-stage Selexol	310,711 kg/hr (685,000 lb/hr) 35°C (95°F) 5.1 MPa (745 psia)	2	0
6	Hydrogenation Reactor	Fixed bed, catalytic	18,308 kg/hr (40,363 lb/hr) 232°C (450°F) 0.1 MPa (12.3 psia)	1	0
7	Tail Gas Recycle Compressor	Centrifugal	13,878 kg/hr (30,597 lb/hr)	1	0

ACCOUNT 5B   CO$_2$ COMPRESSION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CO2 Compressor	Integrally geared, multi-stage centrifugal	1,130 m3/min @ 15.3 MPa (39,900 scfm @ 2,215 psia)	4	1

ACCOUNT 6   COMBUSTION TURBINE AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Gas Turbine	Advanced F class	230 MW	2	0
2	Gas Turbine Generator	TEWAC	260 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	2	0
3	Syngas Expansion Turbine/Generator	Turbo Expander	49,759 kg/h (109,700 lb/h) 5.1 MPa (740 psia) Inlet 3.2 MPa (460 psia) Outlet	2	0

ACCOUNT 7   HRSG, DUCTING AND STACK

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	CS plate, type 409SS liner	76 m (250 ft) high x 8.5 m (28 ft) diameter	1	0
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 198,270 kg/hr, 12.4 MPa/534°C (437,111 lb/hr, 1,800 psig/994°F) Reheat steam - 265,278 kg/hr, 3.1 MPa/534°C (584,838 lb/hr, 452 psig/994°F)	2	0

ACCOUNT 8   STEAM TURBINE GENERATOR AND AUXILIARIES

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	225 MW 12.4 MPa/534°C/534°C (1800 psig/ 994°F/994°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitiation	250 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Steam Bypass	One per HRSG	50% steam flow @ design steam conditions	2	0
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	1,593 GJ/hr (1,510 MMBtu/hr), Inlet water temperature 16°C (60°F), Water temperature rise 11°C (20°F)	1	0

ACCOUNT 9   COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Circulating Water Pumps	Vertical, wet pit	484,533 lpm @ 30 m (128,000 gpm @ 100 ft)	2	1
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	11°C (51.5°F) wet bulb / 16°C (60°F) CWT / 27°C (80°F) HWT / 2690 GJ/hr (2550 MMBtu/hr) heat duty	1	0

ACCOUNT 10   SLAG RECOVERY AND HANDLING

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Slag Quench Tank	Water bath	253,623 liters (67,000 gal)	2	0
2	Slag Crusher	Roll	14 tonne/hr (15 tph)	2	0
3	Slag Depressurizer	Lock Hopper	14 tonne/hr (15 tph)	2	0
4	Slag Receiving Tank	Horizontal, weir	151,416 liters (40,000 gal)	2	0
5	Black Water Overflow Tank	Shop fabricated	68,137 liters (18,000 gal)	2	
6	Slag Conveyor	Drag chain	14 tonne/hr (15 tph)	2	0
7	Slag Separation Screen	Vibrating	14 tonne/hr (15 tph)	2	0
8	Coarse Slag Conveyor	Belt/bucket	14 tonne/hr (15 tph)	2	0
9	Fine Ash Settling Tank	Vertical, gravity	215,768 liters (57,000 gal)	2	0
10	Fine Ash Recycle Pumps	Horizontal centrifugal	38 lpm @ 14 m H2O (10 gpm @ 46 ft H2O)	2	2
11	Grey Water Storage Tank	Field erected	68,137 liters (18,000 gal)	2	0
12	Grey Water Pumps	Centrifugal	227 lpm @ 564 m H2O (60 gpm @ 1,850 ft H2O)	2	2
13	Slag Storage Bin	Vertical, field erected	998 tonne (1,100 tons)	2	0
14	Unloading Equipment	Telescoping chute	109 tonne/hr (120 tph)	1	0

ACCOUNT 11   ACCESSORY ELECTRIC PLANT

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	CTG Step-up Transformer	Oil-filled	24 kV/345 kV, 260 MVA, 3-ph, 60 Hz	2	0
2	STG Step-up Transformer	Oil-filled	24 kV/345 kV, 250 MVA, 3-ph, 60 Hz	1	0
3	High Voltage Auxiliary Transformer	Oil-filled	345 kV/13.8 kV, 80 MVA, 3-ph, 60 Hz	2	0
4	Medium Voltage Auxiliary Transformer	Oil-filled	24 kV/4.16 kV, 48 MVA, 3-ph, 60 Hz	1	1
5	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 7 MVA, 3-ph, 60 Hz	1	1
6	CTG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	2	0
7	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
8	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
9	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
10	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

ACCOUNT 12   INSTRUMENTATION AND CONTROLS

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

8.1.4   Case 2A – Cost Estimating

The cost estimating methodology was described previously in Section 2.7. Exhibit 8-13 shows the TPC summary organized by cost account and Exhibit 8-14 shows a more detailed breakdown of the capital costs. Exhibit 8-15 shows the initial and annual O&M costs.

The estimated TOC of the GEE gasifier with CO_2 capture in quench-only configuration is $3,375/kW. Process contingency represents 3.4 percent of the TOC and project contingency represents 11.0 percent. The COE, including CO_2 TS&M costs of 5.8 mills/kWh, is 108.5 mills/kWh. For comparison, the TOC and COE for Case 2, GEE in radiant-only configuration with CO_2 capture are $3,334/kW and 105.7 mills/kWh.

Exhibit 8-13 Case 2A Total Plant Cost Summary

	Case:	Case 2A - GEE Quench 495 MWnet IGCC w/ CO2									
	Plant Size:	493.9	MW,net	Estimate Type:	Conceptual			Cost Base (Jun)	2007	($x1000)	
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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$14,279	$2,654	$11,074	$0	$0	**$28,007**	$2,542	$0	$6,110	**$36,659**	$74
2	COAL & SORBENT PREP & FEED	$21,755	$4,448	$17,256	$0	$0	**$43,459**	$3,959	$1,577	$9,799	**$58,794**	$119
3	FEEDWATER & MISC. BOP SYSTEMS	$8,849	$6,224	$9,449	$0	$0	**$24,521**	$2,324	$0	$6,359	**$33,204**	$67
4	GASIFIER & ACCESSORIES											
4.1	Quench Gasifier System	$66,598	$0	$57,069	$0	$0	**$123,667**	$11,556	$16,201	$23,572	**$174,996**	$354
4.2	Syngas Scrubber Sys.	w/4.1	$0	w/ 4.1	$0	$0	**$0**	$0	$0	$0	**$0**	$0
4.3	ASU/Oxidant Compression	$193,046	$0	w/equip.	$0	$0	**$193,046**	$18,712	$0	$21,176	**$232,934**	$472
4.4-4.9	Other Gasification Equipment	$7,097	$2,671	$2,230	$0	$0	**$11,999**	$1,125	$0	$2,892	**$16,016**	$32
	SUBTOTAL 4	**$266,741**	**$2,671**	**$59,299**	**$0**	**$0**	**$328,712**	**$31,392**	**$16,201**	**$47,640**	**$423,945**	**$858**
5A	GAS CLEANUP & PIPING	$97,698	$3,331	$82,513	$0	$0	**$183,542**	$17,795	$27,526	$45,888	**$274,751**	$556
5B	CO2 COMPRESSION	$18,242	$0	$11,182	$0	$0	**$29,424**	$2,834	$0	$6,452	**$38,709**	$78
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$92,026	$0	$6,583	$0	$0	**$98,609**	$9,348	$9,861	$11,782	**$129,599**	$262
6.2-6.9	Combustion Turbine Other	$5,547	$887	$1,748	$0	$0	**$8,182**	$775	$0	$1,650	**$10,607**	$21
	SUBTOTAL 6	**$97,573**	**$887**	**$8,331**	**$0**	**$0**	**$106,791**	**$10,123**	**$9,861**	**$13,432**	**$140,206**	**$284**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$33,631	$0	$4,782	$0	$0	**$38,413**	$3,652	$0	$4,206	**$46,271**	$94
7.2-7.9	SCR System, Ductwork and Stack	$3,375	$2,406	$3,152	$0	$0	**$8,933**	$828	$0	$1,588	**$11,350**	$23
	SUBTOTAL 7	**$37,006**	**$2,406**	**$7,934**	**$0**	**$0**	**$47,346**	**$4,480**	**$0**	**$5,795**	**$57,621**	**$117**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$24,314	$0	$4,162	$0	$0	**$28,476**	$2,732	$0	$3,121	**$34,329**	$69
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$8,443	$830	$5,626	$0	$0	**$14,898**	$1,367	$0	$3,064	**$19,330**	$39
	SUBTOTAL 8	**$32,756**	**$830**	**$9,788**	**$0**	**$0**	**$43,374**	**$4,099**	**$0**	**$6,185**	**$53,659**	**$109**
9	COOLING WATER SYSTEM	$10,625	$10,049	$8,616	$0	$0	**$29,290**	$2,720	$0	$6,524	**$38,535**	$78
10	ASH/SPENT SORBENT HANDLING SYS	$14,733	$8,238	$14,937	$0	$0	**$37,909**	$3,652	$0	$4,476	**$46,037**	$93
11	ACCESSORY ELECTRIC PLANT	$31,380	$12,503	$24,392	$0	$0	**$68,275**	$5,874	$0	$14,086	**$88,234**	$179
12	INSTRUMENTATION & CONTROL	$10,977	$2,019	$7,072	$0	$0	**$20,068**	$1,819	$1,003	$3,814	**$26,704**	$54
13	IMPROVEMENTS TO SITE	$3,371	$1,987	$8,317	$0	$0	**$13,675**	$1,350	$0	$4,508	**$19,533**	$40
14	BUILDINGS & STRUCTURES	$0	$6,539	$7,369	$0	$0	**$13,909**	$1,265	$0	$2,492	**$17,666**	$36
	TOTAL COST	**$665,985**	**$64,787**	**$287,529**	**$0**	**$0**	**$1,018,301**	**$96,229**	**$56,168**	**$183,558**	**$1,354,257**	**$2,742**

Exhibit 8-14 Case 2A 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,750	$0	$1,832	$0	$0	$5,582	$500	$0	$1,216	$7,299	$15
1.2	Coal Stackout & Reclaim	$4,846	$0	$1,175	$0	$0	$6,020	$528	$0	$1,310	$7,858	$16
1.3	Coal Conveyors & Yd Crush	$4,505	$0	$1,162	$0	$0	$5,668	$498	$0	$1,233	$7,398	$15
1.4	Other Coal Handling	$1,179	$0	$269	$0	$0	$1,448	$127	$0	$315	$1,889	$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	$2,654	$6,635	$0	$0	$9,289	$890	$0	$2,036	$12,215	$25
	SUBTOTAL 1.	$14,279	$2,654	$11,074	$0	$0	$28,007	$2,542	$0	$6,110	$36,659	$74
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	w/2.3	$0	w/2.3	$0	$0	$0	$0	$0	$0	$0	$0
2.2	Prepared Coal Storage & Feed	$1,602	$383	$251	$0	$0	$2,236	$191	$0	$485	$2,913	$6
2.3	Slurry Prep & Feed	$19,273	$0	$12,273	$0	$0	$31,546	$2,874	$1,577	$7,199	$43,196	$87
2.4	Misc.Coal Prep & Feed	$881	$641	$1,922	$0	$0	$3,443	$316	$0	$752	$4,512	$9
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	$3,423	$2,811	$0	$0	$6,234	$577	$0	$1,362	$8,174	$17
	SUBTOTAL 2.	$21,755	$4,448	$17,256	$0	$0	$43,459	$3,959	$1,577	$9,799	$58,794	$119
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	Feedwater System	$1,916	$3,291	$1,737	$0	$0	$6,944	$643	$0	$1,517	$9,105	$18
3.2	Water Makeup & Pretreating	$744	$78	$416	$0	$0	$1,237	$118	$0	$406	$1,761	$4
3.3	Other Feedwater Subsystems	$1,048	$354	$319	$0	$0	$1,722	$155	$0	$375	$2,252	$5
3.4	Service Water Systems	$426	$876	$3,042	$0	$0	$4,343	$424	$0	$1,430	$6,197	$13
3.5	Other Boiler Plant Systems	$2,284	$885	$2,193	$0	$0	$5,362	$509	$0	$1,174	$7,045	$14
3.6	FO Supply Sys & Nat Gas	$315	$596	$556	$0	$0	$1,467	$141	$0	$322	$1,930	$4
3.7	Waste Treatment Equipment	$1,040	$0	$634	$0	$0	$1,674	$163	$0	$551	$2,388	$5
3.8	Misc. Power Plant Equipment	$1,076	$144	$552	$0	$0	$1,772	$171	$0	$583	$2,527	$5
	SUBTOTAL 3.	$8,849	$6,224	$9,449	$0	$0	$24,521	$2,324	$0	$6,359	$33,204	$67
4	GASIFIER & ACCESSORIES											
4.1	Quench Gasifier System	$66,598	$0	$57,069	$0	$0	$123,667	$11,556	$16,201	$23,572	$174,996	$354
4.2	Syngas Scrubber Sys.	w/4.1	$0	w/ 4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$193,046	$0	w/equip.	$0	$0	$193,046	$18,712	$0	$21,176	$232,934	$472
4.4	Low Temperature Cooling	$7,097	$0	$0	$0	$0	$7,097	$671	$0	$1,554	$9,321	$19
4.5	Black Water & Sour Gas Section	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Flare Stack System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
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	$2,671	$2,230	$0	$0	$4,902	$454	$0	$1,339	$6,695	$14
	SUBTOTAL 4.	$266,741	$2,671	$59,299	$0	$0	$328,712	$31,392	$16,201	$47,640	$423,945	$858

Exhibit 8-14 Case 2A 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5A	GAS CLEANUP & PIPING											
5A.1	Double Stage Selexol	$74,127	$0	$62,899	$0	$0	$137,026	$13,252	$27,405	$35,537	$213,219	$432
5A.2	Elemental Sulfur Plant	$10,328	$2,058	$13,325	$0	$0	$25,712	$2,498	$0	$5,642	$33,851	$69
5A.3	Mercury Removal	$1,372	$0	$1,044	$0	$0	$2,417	$233	$121	$554	$3,325	$7
5A.4	Shift Reactors	$10,045	$0	$4,044	$0	$0	$14,089	$1,351	$0	$3,088	$18,527	$38
5A.5	Particulate Removal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5A.6	Blowback Gas Systems	$1,826	$0	$346	$0	$0	$2,172	$265	$0	$487	$2,924	$6
5A.7	Fuel Gas Piping	$0	$632	$443	$0	$0	$1,075	$100	$0	$235	$1,410	$3
5A.9	HGCU Foundations	$0	$640	$413	$0	$0	$1,053	$97	$0	$345	$1,495	$3
	SUBTOTAL 5A.	$97,698	$3,331	$82,513	$0	$0	$183,542	$17,795	$27,526	$45,888	$274,751	$556
5B	CO2 COMPRESSION											
5B.1	CO2 Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5B.2	CO2 Compression & Drying	$18,242	$0	$11,182	$0	$0	$29,424	$2,834	$0	$6,452	$38,709	$78
	SUBTOTAL 5B.	$18,242	$0	$11,182	$0	$0	$29,424	$2,834	$0	$6,452	$38,709	$78
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$92,026	$0	$6,583	$0	$0	$98,609	$9,348	$9,861	$11,782	$129,599	$262
6.2	Syngas Expander	$5,547	$0	$766	$0	$0	$6,313	$600	$0	$1,037	$7,951	$16
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$887	$982	$0	$0	$1,868	$175	$0	$613	$2,656	$5
	SUBTOTAL 6.	$97,573	$887	$8,331	$0	$0	$106,791	$10,123	$9,861	$13,432	$140,206	$284
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$33,631	$0	$4,782	$0	$0	$38,413	$3,652	$0	$4,206	$46,271	$94
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,730	$1,234	$0	$0	$2,964	$260	$0	$645	$3,869	$8
7.4	Stack	$3,375	$0	$1,268	$0	$0	$4,643	$445	$0	$509	$5,597	$11
7.9	HRSG, Duct & Stack Foundations	$0	$676	$649	$0	$0	$1,326	$123	$0	$435	$1,884	$4
	SUBTOTAL 7.	$37,006	$2,406	$7,934	$0	$0	$47,346	$4,480	$0	$5,795	$57,621	$117
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$24,314	$0	$4,162	$0	$0	$28,476	$2,732	$0	$3,121	$34,329	$69
8.2	Turbine Plant Auxiliaries	$171	$0	$393	$0	$0	$564	$55	$0	$62	$681	$1
8.3	Condenser & Auxiliaries	$4,853	$0	$1,425	$0	$0	$6,277	$600	$0	$688	$7,565	$15
8.4	Steam Piping	$3,419	$0	$2,405	$0	$0	$5,825	$500	$0	$1,581	$7,906	$16
8.9	TG Foundations	$0	$830	$1,403	$0	$0	$2,233	$212	$0	$733	$3,178	$6
	SUBTOTAL 8.	$32,756	$830	$9,788	$0	$0	$43,374	$4,099	$0	$6,185	$53,659	$109

Exhibit 8-14 Case 2A 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$7,359	$0	$1,339	$0	$0	$8,697	$828	$0	$1,429	$10,954	$22
9.2	Circulating Water Pumps	$1,919	$0	$141	$0	$0	$2,060	$174	$0	$335	$2,569	$5
9.3	Circ.Water System Auxiliaries	$160	$0	$23	$0	$0	$183	$17	$0	$30	$230	$0
9.4	Circ.Water Piping	$0	$6,671	$1,729	$0	$0	$8,400	$759	$0	$1,832	$10,991	$22
9.5	Make-up Water System	$400	$0	$572	$0	$0	$972	$93	$0	$213	$1,278	$3
9.6	Component Cooling Water Sys	$787	$942	$670	$0	$0	$2,399	$225	$0	$525	$3,149	$6
9.9	Circ.Water System Foundations	$0	$2,437	$4,143	$0	$0	$6,579	$624	$0	$2,161	$9,364	$19
	SUBTOTAL 9.	$10,625	$10,049	$8,616	$0	$0	$29,290	$2,720	$0	$6,524	$38,535	$78
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$12,136	$6,692	$13,595	$0	$0	$32,423	$3,129	$0	$3,555	$39,107	$79
10.2	Gasifier Ash Depressurization	w/10.1	w/10.1	w/10.1	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	w/10.1	w/10.1	w/10.1	$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	Slag Handling System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$589	$0	$641	$0	$0	$1,229	$119	$0	$202	$1,551	$3
10.7	Ash Transport & Feed Equipment	$790	$0	$190	$0	$0	$980	$91	$0	$161	$1,232	$2
10.8	Misc. Ash Handling Equipment	$1,219	$1,494	$446	$0	$0	$3,160	$301	$0	$519	$3,980	$8
10.9	Ash/Spent Sorbent Foundation	$0	$52	$65	$0	$0	$117	$11	$0	$39	$167	$0
	SUBTOTAL 10.	$14,733	$8,238	$14,937	$0	$0	$37,909	$3,652	$0	$4,476	$46,037	$93
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$909	$0	$899	$0	$0	$1,809	$173	$0	$198	$2,179	$4
11.2	Station Service Equipment	$4,668	$0	$421	$0	$0	$5,089	$469	$0	$556	$6,114	$12
11.3	Switchgear & Motor Control	$8,630	$0	$1,570	$0	$0	$10,199	$946	$0	$1,672	$12,817	$26
11.4	Conduit & Cable Tray	$0	$4,009	$13,225	$0	$0	$17,234	$1,667	$0	$4,725	$23,626	$48
11.5	Wire & Cable	$0	$7,660	$5,033	$0	$0	$12,693	$922	$0	$3,404	$17,018	$34
11.6	Protective Equipment	$0	$686	$2,496	$0	$0	$3,182	$311	$0	$524	$4,017	$8
11.7	Standby Equipment	$226	$0	$221	$0	$0	$446	$43	$0	$73	$562	$1
11.8	Main Power Transformers	$16,946	$0	$137	$0	$0	$17,084	$1,292	$0	$2,756	$21,132	$43
11.9	Electrical Foundations	$0	$149	$391	$0	$0	$540	$52	$0	$177	$769	$2
	SUBTOTAL 11.	$31,380	$12,503	$24,392	$0	$0	$68,275	$5,874	$0	$14,086	$88,234	$179
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	w/6.1	$0	w/6.1	$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	$1,084	$0	$724	$0	$0	$1,807	$171	$90	$310	$2,379	$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	$249	$0	$160	$0	$0	$409	$39	$20	$94	$561	$1
12.7	Computer & Accessories	$5,780	$0	$185	$0	$0	$5,965	$548	$298	$681	$7,492	$15
12.8	Instrument Wiring & Tubing	$0	$2,019	$4,128	$0	$0	$6,147	$521	$307	$1,744	$8,720	$18
12.9	Other I & C Equipment	$3,864	$0	$1,876	$0	$0	$5,740	$540	$287	$985	$7,552	$15
	SUBTOTAL 12.	$10,977	$2,019	$7,072	$0	$0	$20,068	$1,819	$1,003	$3,814	$26,704	$54

Exhibit 8-14 Case 2A 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$106	$2,261	$0	$0	$2,366	$235	$0	$780	$3,382	$7
13.2	Site Improvements	$0	$1,881	$2,500	$0	$0	$4,381	$432	$0	$1,444	$6,257	$13
13.3	Site Facilities	$3,371	$0	$3,557	$0	$0	$6,928	$683	$0	$2,283	$9,894	$20
	SUBTOTAL 13.	$3,371	$1,987	$8,317	$0	$0	$13,675	$1,350	$0	$4,508	$19,533	$40
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	$2,096	$2,986	$0	$0	$5,081	$468	$0	$832	$6,381	$13
14.3	Administration Building	$0	$862	$625	$0	$0	$1,487	$132	$0	$243	$1,863	$4
14.4	Circulation Water Pumphouse	$0	$162	$86	$0	$0	$247	$22	$0	$40	$310	$1
14.5	Water Treatment Buildings	$0	$622	$606	$0	$0	$1,228	$111	$0	$201	$1,540	$3
14.6	Machine Shop	$0	$441	$302	$0	$0	$743	$66	$0	$121	$930	$2
14.7	Warehouse	$0	$712	$460	$0	$0	$1,172	$104	$0	$191	$1,467	$3
14.8	Other Buildings & Structures	$0	$427	$332	$0	$0	$759	$68	$0	$165	$992	$2
14.9	Waste Treating Building & Str.	$0	$954	$1,823	$0	$0	$2,776	$259	$0	$607	$3,642	$7
	SUBTOTAL 14.	$0	$6,539	$7,369	$0	$0	$13,909	$1,265	$0	$2,492	$17,666	$36
	TOTAL COST	$665,985	$64,787	$287,529	$0	$0	$1,018,301	$96,229	$56,168	$183,558	$1,354,257	$2,742

Owner's Costs								
Preproduction Costs								
6 Months All Labor							$12,023	$24
1 Month Maintenance Materials							$2,632	$5
1 Month Non-fuel Consumables							$400	$1
1 Month Waste Disposal							$318	$1
25% of 1 Months Fuel Cost at 100% CF							$1,697	$3
2% of TPC							$27,085	$55
Total							**$44,154**	**$89**
Inventory Capital								
60 day supply of fuel and consumables at 100% CF							$14,085	$29
0.5% of TPC (spare parts)							$6,771	$14
Total							**$20,856**	**$42**
Initial Cost for Catalyst and Chemicals							$7,292	$15
Land							$900	$2
Other Owner's Costs							$203,139	$411
Financing Costs							$36,565	$74
Total Overnight Costs (TOC)							**$1,667,163**	**$3,375**
TASC Multiplier						(IOU, high-risk, 35 year)	1.140	
Total As-Spent Cost (TASC)							**$1,900,566**	**$3,848**

Exhibit 8-15 Case 2A Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (Jun):	2007
Case 2A - GEE Quench 495 MWnet IGCC w/ CO2					Heat Rate-net (Btu/kWh):	11,502
					MWe-net:	494
					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	$6,313,507	$12.782
Maintenance Labor Cost	$12,922,767	$26.163
Administrative & Support Labor	$4,809,068	$9.736
Property Taxes and Insurance	$27,085,142	$54.835
TOTAL FIXED OPERATING COSTS	**$51,130,484**	**$103.516**

VARIABLE OPERATING COSTS

							$/kWh-net
Maintenance Material Cost						**$25,263,935**	**$0.00730**

Consumables	Consumption Initial Fill	/Day	Unit Cost	Initial Fill Cost			
Water (/1000 gallons)	0	4,404	1.08	$0	$1,391,076	$0.00040	
Chemicals							
MU & WT Chem. (lbs)	0	26,239	0.17	$0	$1,326,020	$0.00038	
Carbon (Mercury Removal) (lb)	79,195	108	1.05	$83,168	$33,267	$0.00001	
COS Catalyst (m3)	0	0	2,397.36	$0	$0	$0.00000	
Water Gas Shift Catalyst (ft3)	6,443	4.41	498.83	$3,213,847	$642,769	$0.00019	
Selexol Solution (gal)	298,200	95	13.40	$3,995,355	$371,115	$0.00011	
SCR Catalyst (m3)	0	0	0.00	$0	$0	$0.00000	
Ammonia (19% NH3) (ton)	0	0	0.00	$0	$0	$0.00000	
Claus Catalyst (ft3)	w/equip	2.01	131.27	$0	$77,204	$0.00002	
Subtotal-Chemicals				$7,292,370	$2,450,376	$0.00071	
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	$13,212	$0.00000	
Flyash (ton)	0	0	0.00	$0	$0	$0.00000	
Slag (ton)	0	641	16.23	$0	$3,037,649	$0.00088	
Subtotal Waste Disposal				$0	$3,050,861	$0.00088	
By-products & Emissions							
Sulfur (ton)	0	146	0.00	$0	$0	$0.00000	
Subtotal By-products				$0	$0	$0.00000	
TOTAL VARIABLE OPERATING COSTS				$7,292,370	$32,156,247	$0.00929	
Fuel (ton)	0	5,844	38.18	$0	$65,156,652	$0.01882	

9. SENSITIVITY TO MEA SYSTEM PERFORMANCE AND COST BITUMINOUS BASELINE CASE 12A

Studies of PC plants with post combustion capture of CO_2 for the 2009 NETL Bituminous and Low Rank Baselines Studies are based on a performance and cost estimate for an Econamine CO_2 capture system provided by Fluor in 2005 [87]. A recent Fluor publication [88] indicates that Fluor has improved the Econamine system. According to Fluor, the improved system is able to achieve a reboiler steam requirement of 1,270 Btu/lb$_{CO2}$ as compared to the 1,530 Btu/lb$_{CO2}$ used in the baseline studies. Fluor also indicated concurrent reductions in auxiliary electrical power requirements and capital costs.

The Fluor publication [88] indicates the improvements in performance and cost are enabled by an improved solvent formulation with an MEA concentration greater than 30 percent and improved corrosion inhibitors. Fluor states that the improved solvent results in increased reaction rates enabling less absorber packing and lower capital cost. Also, the higher solvent carrying capacity results in lower solvent circulation rates, lower steam requirements, and lower capital cost of solvent circulation equipment.

Cost and performance data on the improved system were unavailable directly from Fluor. Using a commercial AGR software package, the CO_2 removal process was simulated using higher MEA concentrations, but the confidence in the generated results and any associated equipment sizing or costing changes were not adequate for use in this analysis. Therefore, a sensitivity analysis was performed using published data from Fluor and best engineering judgment to estimate the impact of an improved MEA CO_2 capture system on the performance and cost of a SC boiler firing bituminous coal with back-end CO_2 capture.

9.1 BASIS FOR SENSITIVITY ANALYSIS

The sensitivity analysis was performed on Case 12 of the Bituminous Baseline Study. This case used a SC PC plant burning bituminous (Illinois #6) coal at ISO conditions. The sensitivity case was labeled Case 12A.

It was assumed, based on qualitative statements by Fluor, that the improved performance and reduced cost were achieved by increasing the MEA concentration from 30 wt% to 36 wt%. It was further assumed that Econamine reboiler steam requirements, power requirements and capital cost were inversely proportional to the increase in MEA concentration. The reboiler steam requirement and electrical auxiliary requirements were reduced by the ratio of $30/36 = 0.83$. The Econamine plant capital cost was scaled using two factors - the first based on the amount of CO_2 captured to the 0.6 power and the second based on the ratio of the increased solvent concentration to the 0.7 power.

The Aspen model for Case 12 was modified for the reduced reboiler steam requirement and calculations were adjusted for the reduced auxiliary power requirement. Performance and cost estimates for Case 12A as compared to Case 12 are included in the following sections.

9.2 PERFORMANCE

The BFD, Stream Tables and Performance Summary for Case 12A are shown in Exhibit 9-1, Exhibit 9-2, and Exhibit 9-3. The Performance Summary from Case 12 is also included in

Exhibit 9-3 for comparison. The net plant efficiency for Case 12A is 29.8 percent compared to 28.4 percent for Case 12.

The auxiliary power for Case 12A is 104 MW compared to 113 MW for Case 12. Gross output was reduced for Case 12A by 9 MW to maintain a 550 MW net output for both cases. The reduction in auxiliary power results primarily from reductions in the Econamine and CO_2 compressor auxiliaries with minor reductions in most other auxiliary loads resulting from a slightly smaller gross plant size.

Exhibit 9-1 Case 12A Block Flow Diagram, Supercritical Unit with CO$_2$ Capture (MEA Sensitivity)

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

Exhibit 9-2 Case 12A Stream Table, Supercritical Unit with CO$_2$ Capture

	1	2	3	4	5	6	7	8	9	10	11	12	13	14
V-L Mole Fraction														
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000
CO$_2$	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.1450	0.0000	0.1450	0.1450	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$_2$O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0870	0.0000	0.0870	0.0870	1.0000
N$_2$	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.7324	0.0000	0.7324	0.7324	0.0000
O$_2$	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0247	0.0000	0.0247	0.0247	0.0000
SO$_2$	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0021	0.0000	0.0021	0.0021	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	1.0000	1.0000	1.0000
V-L Flowrate (kg$_{mol}$/hr)	63,824	63,824	1,899	19,606	19,606	2,690	1,475	0	0	89,812	0	89,812	89,812	3,349
V-L Flowrate (kg/hr)	1,841,767	1,841,767	54,801	565,772	565,772	77,613	42,569	0	0	2,671,294	0	2,671,294	2,671,294	60,334
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	244,938	4,750	19,001	19,001	0	0	24,719
Temperature (°C)	15	19	19	15	25	25	15	15	15	169	15	169	182	15
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.11	0.10
Enthalpy (kJ/kg)^A	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	327.40	---	308.96	322.83	---
Density (kg/m^3)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	0.8	---	0.8	0.8	---
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	29.743	---	29.743	29.743	---
V-L Flowrate (lb$_{mol}$/hr)	140,708	140,708	4,187	43,224	43,224	5,930	3,252	0	0	198,001	0	198,001	198,001	7,383
V-L Flowrate (lb/hr)	4,060,401	4,060,401	120,816	1,247,313	1,247,313	171,108	93,850	0	0	5,889,196	0	5,889,196	5,889,196	133,014
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	539,995	10,472	41,890	41,890	0	0	54,497
Temperature (°F)	59	66	66	59	78	78	59	59	59	337	59	337	360	59
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.7	14.4	14.7	14.2	15.4	15.0
Enthalpy (Btu/lb)^A	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	140.8	---	132.8	138.8	---
Density (lb/ft^3)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	0.050	---	0.049	0.052	---

A - Reference conditions are 32.02 F & 0.089 PSIA

Exhibit 9-2 Case 12A Stream Table, Supercritical Unit with CO_2 Capture (Continued)

	15	16	17	18	19	20	21	22	23	24	25	26	27	28
V-L Mole Fraction														
Ar	0.0000	0.0128	0.0000	0.0081	0.0108	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO₂	0.0000	0.0005	0.0004	0.1351	0.0179	0.9961	0.9985	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H₂	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
H₂O	1.0000	0.0062	0.9996	0.1537	0.0383	0.0039	0.0015	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N₂	0.0000	0.7506	0.0000	0.6793	0.9013	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O₂	0.0000	0.2300	0.0000	0.0238	0.0316	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO₂	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	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg₍mol₎/hr)	12,734	913	236	97,848	73,741	11,940	11,911	35,621	35,621	120,750	98,499	98,499	53,856	53,856
V-L Flowrate (kg/hr)	229,411	26,510	4,260	2,821,044	2,077,415	524,270	523,755	641,731	641,731	2,175,344	1,774,495	1,774,495	970,240	970,240
Solids Flowrate (kg/hr)	0	0	38,244	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	15	181	58	58	32	21	35	291	151	593	354	593	38	39
Pressure (MPa, abs)	0.10	0.31	0.10	0.10	0.10	0.16	15.27	0.51	0.92	24.23	4.90	4.52	0.01	1.69
Enthalpy (kJ/kg)[A]	-46.80	191.58	---	301.42	93.86	19.49	-211.71	3,045.10	636.31	3,476.62	3,081.96	3,652.22	2,111.17	166.38
Density (kg/m³)	1,003.1	2.4	---	1.1	1.1	2.9	795.9	2.0	916.0	69.2	18.7	11.6	0.1	993.2
V-L Molecular Weight	18.015	29.029	---	28.831	28.172	43.908	43.971	18.015	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb₍mol₎/hr)	28,074	2,013	521	215,717	162,571	26,323	26,260	78,532	78,532	266,208	217,154	217,154	118,733	118,733
V-L Flowrate (lb/hr)	505,766	58,445	9,392	6,219,337	4,579,917	1,155,818	1,154,682	1,414,774	1,414,774	4,795,812	3,912,091	3,912,091	2,139,012	2,139,012
Solids Flowrate (lb/hr)	0	0	84,314	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	59	357	136	136	89	69	95	556	304	1,100	669	1,100	101	103
Pressure (psia)	14.7	45.0	14.9	14.9	14.7	23.5	2,214.5	73.5	133.6	3,514.7	710.8	655.8	1.0	245.0
Enthalpy (Btu/lb)[A]	-20.1	82.4	---	129.6	40.4	8.4	-91.0	1,309.2	273.6	1,494.7	1,325.0	1,570.2	907.6	71.5
Density (lb/ft³)	62.622	0.149	---	0.067	0.070	0.184	49.685	0.123	57.184	4.319	1.165	0.722	0.004	62.004

Exhibit 9-3 Case 12A Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)		
Bituminous Baseline Case	12	12A
Steam Turbine Power	662,800	654,200
TOTAL (STEAM TURBINE) POWER, kWe	**662,800**	**654,200**
AUXILIARY LOAD SUMMARY, kWe		
Coal Handling and Conveying	510	500
Pulverizers	3,850	3,670
Sorbent Handling & Reagent Preparation	1,250	1,190
Ash Handling	740	700
Primary Air Fans	1,800	1,720
Forced Draft Fans	2,300	2,190
Induced Draft Fans	11,120	10,610
SCR	70	60
Baghouse	100	90
Wet FGD	4,110	3,920
Econamine FG Plus Auxiliaries	20,600	16,400
CO_2 Compression	44,890	42,840
Miscellaneous Balance of Plant[2,3]	2,000	2,000
Steam Turbine Auxiliaries	400	400
Condensate Pumps	560	610
Circulating Water Pumps	10,100	9,390
Ground Water Pumps	920	850
Cooling Tower Fans	5,230	4,860
Transformer Losses	2,290	2,240
TOTAL AUXILIARIES, kWe	**112,840**	**104,240**
NET POWER, kWe	**549,960**	**549,960**
Net Plant Efficiency (HHV)	28.4%	29.8%
Net Plant Heat Rate, kJ/kWh (Btu/kWh)	12,663 (12,002)	12,085 (11,455)
CONDENSER COOLING DUTY, 10^6 kJ/hr (10^6 Btu/hr)	**1,737 (1,646)**	1,893 (1,794)
CONSUMABLES		
As-Received Coal Feed, kg/hr (lb/hr)	256,652 (565,820)	244,938 (539,995)
Limestone Sorbent Feed, kg/hr (lb/hr)	25,966 (57,245)	24,720 (54,497)
Thermal Input, kWt[1]	1,934,519	1,846,224
Raw Water Withdrawal, m^3/min (gpm)	38.1 (10,071)	35.4 (9,350)
Raw Water Consumption, m^3/min (gpm)	29.3 (7,733)	27.2 (7,177)

1. HHV of As-Received Illinois No. 6 coal is 27,135 kJ/kg (11,666 Btu/lb)
2. Boiler feed pumps are turbine driven
3. Includes plant control systems, lighting, HVAC, and miscellaneous low voltage loads

9.3   COST ESTIMATING

The cost estimating methodology was described in Section 2.7 of this report. Exhibit 9-4 shows the TPC summary organized by cost account and Exhibit 9-5 shows a more detailed breakdown of the capital costs including the TOC and TASC. Exhibit 9-6 shows the initial and annual O&M costs.

The TPC was estimated using a factored cost method with Case 12 as the reference. Account 5B.1 was scaled based on CO_2 captured to the 0.6 power and additionally reduced by 12 percent as discussed previously to account for capital cost reductions resulting from the reduced solvent circulation rate.

The estimated TOC for Case 12A is $3,364/kW. This represents a reduction from Case 12 of 6 percent. Process contingency represents 2.6 percent of the TOC and project contingency represents 10.0 percent. The COE, including CO_2 TS&M costs of 5.3 mills/kWh, is 100.8 mills/kWh. This COE is 5.5 percent less than the Baseline Case 12 COE of 106.6 mills/kWh.

Exhibit 9-4 Case 12A Total Plant Cost Summary

Client:		USDOE/NETL								**Report Date:**	2010-Jan-14	
Project:		Bituminous Baseline Study										
					TOTAL PLANT COST SUMMARY							
Case:		Case 12A - 1x550 MWnet Super-Critical PC w/ CO2 Capture (MEA Sensitivity)										
Plant Size:		550.0 MW,net		**Estimate Type:**		Conceptual				**Cost Base (Jun)**	2007	($x1000)

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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING	$19,514	$5,244	$11,671	$0	$0	**$36,429**	$3,268	$0	$5,955	**$45,652**	$83
2	COAL & SORBENT PREP & FEED	$13,252	$772	$3,366	$0	$0	**$17,391**	$1,524	$0	$2,837	**$21,753**	$40
3	FEEDWATER & MISC. BOP SYSTEMS	$52,950	$0	$24,940	$0	$0	**$77,890**	$7,138	$0	$13,939	**$98,967**	$180
4	PC BOILER											
4.1	PC Boiler & Accessories	$189,629	$0	$106,401	$0	$0	**$296,030**	$28,810	$0	$32,484	**$357,324**	$650
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
4.4-4.9	Boiler BoP (w/ ID Fans)	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
	SUBTOTAL 4	**$189,629**	**$0**	**$106,401**	**$0**	**$0**	**$296,030**	**$28,810**	**$0**	**$32,484**	**$357,324**	**$650**
5	FLUE GAS CLEANUP	$97,431	$0	$33,251	$0	$0	**$130,682**	$12,508	$0	$14,319	**$157,509**	$286
5B	CO$_2$ REMOVAL & COMPRESSION	$204,675	$0	$62,416	$0	$0	**$267,091**	$25,537	$46,378	$67,801	**$406,807**	$740
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A	$0	N/A	$0	$0	**$0**	$0	$0	$0	**$0**	$0
6.2-6.9	Combustion Turbine Other	$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
7.2-7.9	HRSG Accessories, Ductwork and Stack	$17,413	$958	$11,797	$0	$0	**$30,168**	$2,764	$0	$4,326	**$37,258**	$68
	SUBTOTAL 7	**$17,413**	**$958**	**$11,797**	**$0**	**$0**	**$30,168**	**$2,764**	**$0**	**$4,326**	**$37,258**	**$68**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$56,268	$0	$7,467	$0	$0	**$63,735**	$6,108	$0	$6,984	**$76,827**	$140
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$26,997	$1,189	$15,089	$0	$0	**$43,276**	$3,779	$0	$6,723	**$53,778**	$98
	SUBTOTAL 8	**$83,265**	**$1,189**	**$22,556**	**$0**	**$0**	**$107,010**	**$9,887**	**$0**	**$13,707**	**$130,605**	**$237**
9	COOLING WATER SYSTEM	$19,662	$9,537	$17,647	$0	$0	**$46,846**	$4,410	$0	$6,916	**$58,171**	$106
10	ASH/SPENT SORBENT HANDLING SYS	$5,135	$163	$6,865	$0	$0	**$12,163**	$1,169	$0	$1,372	**$14,705**	$27
11	ACCESSORY ELECTRIC PLANT	$24,767	$10,309	$29,247	$0	$0	**$64,322**	$5,686	$0	$8,780	**$78,788**	$143
12	INSTRUMENTATION & CONTROL	$9,915	$0	$10,054	$0	$0	**$19,969**	$1,811	$998	$2,798	**$25,575**	$47
13	IMPROVEMENTS TO SITE	$3,281	$1,886	$6,612	$0	$0	**$11,779**	$1,162	$0	$2,588	**$15,529**	$28
14	BUILDINGS & STRUCTURES	$0	$24,540	$23,290	$0	$0	**$47,830**	$4,315	$0	$7,822	**$59,967**	$109
	TOTAL COST	**$740,888**	**$54,598**	**$370,114**	**$0**	**$0**	**$1,165,600**	**$109,989**	**$47,376**	**$185,644**	**$1,508,610**	**$2,743**

Exhibit 9-5 Case 12A 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,998	$0	$1,826	$0	$0	$5,823	$520	$0	$952	$7,295	$13
1.2	Coal Stackout & Reclaim	$5,166	$0	$1,171	$0	$0	$6,337	$554	$0	$1,034	$7,925	$14
1.3	Coal Conveyors	$4,803	$0	$1,158	$0	$0	$5,961	$522	$0	$973	$7,456	$14
1.4	Other Coal Handling	$1,257	$0	$268	$0	$0	$1,525	$133	$0	$249	$1,907	$3
1.5	Sorbent Receive & Unload	$163	$0	$49	$0	$0	$212	$19	$0	$35	$265	$0
1.6	Sorbent Stackout & Reclaim	$2,625	$0	$481	$0	$0	$3,106	$270	$0	$506	$3,883	$7
1.7	Sorbent Conveyors	$937	$203	$230	$0	$0	$1,369	$118	$0	$223	$1,710	$3
1.8	Other Sorbent Handling	$566	$133	$297	$0	$0	$995	$88	$0	$162	$1,245	$2
1.9	Coal & Sorbent Hnd.Foundations	$0	$4,909	$6,192	$0	$0	$11,101	$1,043	$0	$1,822	$13,966	$25
	SUBTOTAL 1.	$19,514	$5,244	$11,671	$0	$0	$36,429	$3,268	$0	$5,955	$45,652	$83
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$2,315	$0	$451	$0	$0	$2,766	$241	$0	$451	$3,458	$6
2.2	Coal Conveyor to Storage	$5,927	$0	$1,294	$0	$0	$7,221	$631	$0	$1,178	$9,030	$16
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	$4,471	$193	$929	$0	$0	$5,593	$487	$0	$912	$6,991	$13
2.6	Sorbent Storage & Feed	$539	$0	$206	$0	$0	$745	$66	$0	$122	$933	$2
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	$579	$486	$0	$0	$1,066	$99	$0	$175	$1,339	$2
	SUBTOTAL 2.	$13,252	$772	$3,366	$0	$0	$17,391	$1,524	$0	$2,837	$21,753	$40
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$22,174	$0	$7,163	$0	$0	$29,337	$2,564	$0	$4,785	$36,686	$67
3.2	Water Makeup & Pretreating	$6,639	$0	$2,137	$0	$0	$8,776	$830	$0	$1,921	$11,526	$21
3.3	Other Feedwater Subsystems	$6,789	$0	$2,869	$0	$0	$9,658	$865	$0	$1,578	$12,101	$22
3.4	Service Water Systems	$1,301	$0	$708	$0	$0	$2,009	$189	$0	$440	$2,638	$5
3.5	Other Boiler Plant Systems	$8,379	$0	$8,272	$0	$0	$16,651	$1,582	$0	$2,735	$20,968	$38
3.6	FO Supply Sys & Nat Gas	$273	$0	$341	$0	$0	$613	$58	$0	$101	$772	$1
3.7	Waste Treatment Equipment	$4,501	$0	$2,566	$0	$0	$7,066	$688	$0	$1,551	$9,305	$17
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$2,894	$0	$884	$0	$0	$3,779	$363	$0	$828	$4,970	$9
	SUBTOTAL 3.	$52,950	$0	$24,940	$0	$0	$77,890	$7,138	$0	$13,939	$98,967	$180
4	PC BOILER											
4.1	PC Boiler & Accessories	$189,629	$0	$106,401	$0	$0	$296,030	$28,810	$0	$32,484	$357,324	$650
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.	$189,629	$0	$106,401	$0	$0	$296,030	$28,810	$0	$32,484	$357,324	$650

Exhibit 9-5 Case 12A 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	$67,660	$0	$14,566	$0	$0	$82,226	$7,839	$0	$9,006	$99,071	$180
5.2	Other FGD	$3,531	$0	$4,001	$0	$0	$7,532	$731	$0	$826	$9,089	$17
5.3	Bag House & Accessories	$19,454	$0	$12,346	$0	$0	$31,801	$3,065	$0	$3,487	$38,352	$70
5.4	Other Particulate Removal Materials	$1,317	$0	$1,409	$0	$0	$2,725	$264	$0	$299	$3,289	$6
5.5	Gypsum Dewatering System	$5,469	$0	$929	$0	$0	$6,398	$609	$0	$701	$7,708	$14
5.6	Mercury Removal System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
5.9	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	SUBTOTAL 5.	$97,431	$0	$33,251	$0	$0	$130,682	$12,508	$0	$14,319	$157,509	$286
5B	CO$_2$ REMOVAL & COMPRESSION											
5B.1	CO$_2$ Removal System	$177,879	$0	$54,009	$0	$0	$231,888	$22,171	$46,378	$60,087	$360,524	$656
5B.2	CO$_2$ Compression & Drying	$26,796	$0	$8,406	$0	$0	$35,202	$3,367	$0	$7,714	$46,283	$84
	SUBTOTAL 5B.	$204,675	$0	$62,416	$0	$0	$267,091	$25,537	$46,378	$67,801	$406,807	$740
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	$9,063	$0	$5,823	$0	$0	$14,886	$1,298	$0	$2,428	$18,611	$34
7.4	Stack	$8,350	$0	$4,886	$0	$0	$13,236	$1,274	$0	$1,451	$15,962	$29
7.9	Duct & Stack Foundations	$0	$958	$1,088	$0	$0	$2,046	$192	$0	$448	$2,685	$5
	SUBTOTAL 7.	$17,413	$958	$11,797	$0	$0	$30,168	$2,764	$0	$4,326	$37,258	$68
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$56,268	$0	$7,467	$0	$0	$63,735	$6,108	$0	$6,984	$76,827	$140
8.2	Turbine Plant Auxiliaries	$379	$0	$812	$0	$0	$1,191	$116	$0	$131	$1,438	$3
8.3	Condenser & Auxiliaries	$5,837	$0	$2,151	$0	$0	$7,988	$765	$0	$875	$9,629	$18
8.4	Steam Piping	$20,781	$0	$10,247	$0	$0	$31,028	$2,607	$0	$5,045	$38,680	$70
8.9	TG Foundations	$0	$1,189	$1,879	$0	$0	$3,069	$290	$0	$672	$4,031	$7
	SUBTOTAL 8.	$83,265	$1,189	$22,556	$0	$0	$107,010	$9,887	$0	$13,707	$130,605	$237

Exhibit 9-5 Case 12A 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$14,675	$0	$4,570	$0	$0	$19,245	$1,840	$0	$2,109	$23,194	$42
9.2	Circulating Water Pumps	$3,023	$0	$233	$0	$0	$3,255	$275	$0	$353	$3,884	$7
9.3	Circ.Water System Auxiliaries	$754	$0	$100	$0	$0	$854	$81	$0	$94	$1,029	$2
9.4	Circ.Water Piping	$0	$5,974	$5,789	$0	$0	$11,763	$1,101	$0	$1,930	$14,794	$27
9.5	Make-up Water System	$613	$0	$819	$0	$0	$1,433	$137	$0	$235	$1,805	$3
9.6	Component Cooling Water Sys	$597	$0	$475	$0	$0	$1,072	$102	$0	$176	$1,350	$2
9.9	Circ.Water System Foundations& Structures	$0	$3,563	$5,661	$0	$0	$9,224	$873	$0	$2,019	$12,116	$22
	SUBTOTAL 9.	**$19,662**	**$9,537**	**$17,647**	**$0**	**$0**	**$46,846**	**$4,410**	**$0**	**$6,916**	**$58,171**	**$106**
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	$687	$0	$2,117	$0	$0	$2,804	$275	$0	$308	$3,387	$6
10.7	Ash Transport & Feed Equipment	$4,448	$0	$4,556	$0	$0	$9,004	$861	$0	$986	$10,851	$20
10.8	Misc. Ash Handling Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.9	Ash/Spent Sorbent Foundation	$0	$163	$192	$0	$0	$356	$33	$0	$78	$467	$1
	SUBTOTAL 10.	**$5,135**	**$163**	**$6,865**	**$0**	**$0**	**$12,163**	**$1,169**	**$0**	**$1,372**	**$14,705**	**$27**
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$1,714	$0	$278	$0	$0	$1,993	$185	$0	$163	$2,341	$4
11.2	Station Service Equipment	$4,791	$0	$1,574	$0	$0	$6,366	$595	$0	$522	$7,483	$14
11.3	Switchgear & Motor Control	$5,508	$0	$936	$0	$0	$6,445	$597	$0	$704	$7,746	$14
11.4	Conduit & Cable Tray	$0	$3,454	$11,941	$0	$0	$15,395	$1,490	$0	$2,533	$19,418	$35
11.5	Wire & Cable	$0	$6,517	$12,580	$0	$0	$19,097	$1,609	$0	$3,106	$23,811	$43
11.6	Protective Equipment	$261	$0	$888	$0	$0	$1,149	$112	$0	$126	$1,388	$3
11.7	Standby Equipment	$1,352	$0	$31	$0	$0	$1,383	$127	$0	$151	$1,660	$3
11.8	Main Power Transformers	$11,140	$0	$187	$0	$0	$11,327	$859	$0	$1,219	$13,405	$24
11.9	Electrical Foundations	$0	$339	$830	$0	$0	$1,168	$112	$0	$256	$1,536	$3
	SUBTOTAL 11.	**$24,767**	**$10,309**	**$29,247**	**$0**	**$0**	**$64,322**	**$5,686**	**$0**	**$8,780**	**$78,788**	**$143**
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	$511	$0	$306	$0	$0	$816	$77	$41	$140	$1,074	$2
12.7	Distributed Control System Equipment	$5,154	$0	$901	$0	$0	$6,055	$561	$303	$692	$7,611	$14
12.8	Instrument Wiring & Tubing	$2,794	$0	$5,542	$0	$0	$8,336	$710	$417	$1,420	$10,883	$20
12.9	Other I & C Equipment	$1,456	$0	$3,305	$0	$0	$4,761	$462	$238	$546	$6,007	$11
	SUBTOTAL 12.	**$9,915**	**$0**	**$10,054**	**$0**	**$0**	**$19,969**	**$1,811**	**$998**	**$2,798**	**$25,575**	**$47**

Exhibit 9-5 Case 12A 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	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$55	$1,103	$0	$0	$1,158	$115	$0	$255	$1,528	$3
13.2	Site Improvements	$0	$1,831	$2,274	$0	$0	$4,105	$405	$0	$902	$5,411	$10
13.3	Site Facilities	$3,281	$0	$3,235	$0	$0	$6,516	$642	$0	$1,432	$8,590	$16
	SUBTOTAL 13.	$3,281	$1,886	$6,612	$0	$0	$11,779	$1,162	$0	$2,588	$15,529	$28
14	BUILDINGS & STRUCTURES											
14.1	Boiler Building	$0	$8,791	$7,731	$0	$0	$16,522	$1,485	$0	$2,701	$20,708	$38
14.2	Turbine Building	$0	$12,699	$11,836	$0	$0	$24,535	$2,211	$0	$4,012	$30,758	$56
14.3	Administration Building	$0	$637	$673	$0	$0	$1,310	$119	$0	$214	$1,644	$3
14.4	Circulation Water Pumphouse	$0	$168	$134	$0	$0	$302	$27	$0	$49	$378	$1
14.5	Water Treatment Buildings	$0	$842	$768	$0	$0	$1,610	$145	$0	$263	$2,018	$4
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	$452	$1,372	$0	$0	$1,825	$173	$0	$300	$2,298	$4
	SUBTOTAL 14.	$0	$24,540	$23,290	$0	$0	$47,830	$4,315	$0	$7,822	$59,967	$109
	TOTAL COST	$740,888	$54,598	$370,114	$0	$0	$1,165,600	$109,989	$47,376	$185,644	$1,508,610	$2,743
	BEC, Categories 1-12						$1,105,992					
	Owner's Costs											
	Preproduction Costs											
	6 Months All Labor										$10,153	$18
	1 Month Maintenance Materials										$1,457	$3
	1 Month Non-fuel Consumables										$1,478	$3
	1 Month Waste Disposal										$309	$1
	25% of 1 Months Fuel Cost at 100% CF										$1,882	$3
	2% of TPC										$30,172	$55
	Total										$45,451	$83
	Inventory Capital											
	60 day supply of fuel and consumables at 100% CF										$18,151	$33
	0.5% of TPC (spare parts)										$7,543	$14
	Total										$25,694	$47
	Initial Cost for Catalyst and Chemicals										$2,383	$4
	Land										$900	$2
	Other Owner's Costs										$226,291	$411
	Financing Costs										$40,732	$74
	Total Overnight Costs (TOC)										$1,850,062	$3,364
	TASC Multiplier									(IOU, low risk, 35 year)	1.140	
	Total As-Spent Cost (TASC)										$2,109,071	$3,835

Exhibit 9-6 Case 12A Initial and Annual Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES						Cost Base (Jun):	2007
Case 12A - 1x550 MWnet Super-Critical PC w/ CO2 Capture (MEA Sensitivity)						Heat Rate-net (Btu/kWh):	11,455
						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			
Operating Labor Requirements(O.J.)per Shift:		1 unit/mod.		Plant			
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						$6,444,907	$11.719
Maintenance Labor Cost						$9,800,561	$17.820
Administrative & Support Labor						$4,061,367	$7.385
Property Taxes and Insurance						$30,172,197	$54.863
TOTAL FIXED OPERATING COSTS						**$50,479,031**	**$91.787**
VARIABLE OPERATING COSTS							
							$/kWh-net
Maintenance Material Cost						**$14,863,811**	**$0.00363**
Consumables		Consumption		Unit	Initial		
		Initial	/Day	Cost	Cost		
Water(/1000 gallons)		0	6,801	1.08	**$0**	**$2,282,387**	**$0.00056**
Chemicals							
MU & WT Chem.(lb)		0	32,922	0.17	$0	$1,767,714	$0.00043
Limestone (ton)		0	654	21.63	$0	$4,389,274	$0.00107
Carbon (Mercury Removal) (lb)		0	0	1.05	$0	$0	$0.00000
MEA Solvent (ton)		981	1.39	2,249.89	$2,208,132	$971,338	$0.00024
NaOH (tons)		69	6.93	433.68	$30,065	$932,782	$0.00023
H2SO4 (tons)		66	6.62	138.78	$9,181	$284,854	$0.00007
Corrosion Inhibitor		0	0	0.00	$135,751	$0	$0.00000
Activated Carbon(lb)		0	1,662	1.05	$0	$541,593	$0.00013
Ammonia (28% NH3) ton		0	97	129.80	$0	$3,904,140	$0.00095
Subtotal Chemicals					$2,383,130	$12,791,695	$0.00312
Other							
Supplemental Fuel (MBtu)		0	0	0.00	$0	$0	$0.00000
SCR Catalyst (m3)		w/equip.	0.41	5,775.94	$0	$730,089	$0.00018
Emission Penalties		0	0	0.00	$0	$0	$0.00000
Subtotal Other					$0	$730,089	$0.00018
Waste Disposal							
Fly Ash (ton)		0	502	16.23	$0	$2,524,978	$0.00062
Bottom Ash (ton)		0	125	16.23	$0	$628,224	$0.00015
Subtotal-Waste Disposal					$0	$3,153,202	$0.00077
By-products & Emissions							
Gypsum (tons)		0	1,013	0.00	$0	$0	$0.00000
Subtotal By-Products					$0	$0	$0.00000
TOTAL VARIABLE OPERATING COSTS					$2,383,130	$33,821,185	$0.00826
Fuel(ton)		0	6,480	38.18	$0	$76,766,172	$0.01875

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10. REVISION CONTROL

The initial issue of this report was published on May 15, 2007. Subsequent to the issue date, updates have been made to various report sections. These additions were made for clarification and aesthetic purposes and to correct an error made in determining the Econamine cooling water requirement in the PC and NGCC CO_2 capture cases. The water balances and water consumption comparison exhibits were updated accordingly. In addition, the PC and NGCC energy balance tables contained errors, which have been corrected in this version of the report. None of the changes affect the conclusions in version 1 of the report.

This second revision to this report includes more extensive changes. In the two years since the first version was released, improved modeling algorithms were developed, additional vendor information became available and numerous minor errors were identified.

Several studies were initiated that build on the baseline results generated here. The studies include:

- Impact of parallel and dry cooling systems

- Performance of a GE IGCC with CO_2 capture operated in a quench only mode

- COE sensitivity to Econamine cost and reboiler steam requirements

- Natural gas price sensitivity analysis

- Impact of dispatch-based CFs

All of these studies are reported as supplemental chapters to the original report. Because they were not part of the original study, they are not addressed in the Executive Summary or elsewhere throughout the report.

Exhibit 10-1 contains information added, changed or deleted in successive revisions.

Exhibit 10-1 Record of Revisions

Revision Number	Revision Date	Description of Change	Comments
1	8/23/07	Added disclaimer to Executive Summary and Introduction	Disclaimer involves clarification on extent of participation of technology vendors.
		Removed reference to Cases 7 and 8 in Exhibits ES-1 and 1-1.	SNG cases moved to Volume 2 of this report as explained in the Executive Summary and Section 1.
		Added Section 2.8	Explains differences in IGCC TPC estimates in this study versus costs reported by other sources.

Revision Number	Revision Date	Description of Change	Comments
		Added Exhibit ES-14	Mercury emissions are now shown in a separate exhibit from SO_2, NOx and PM because of the different y-axis scale.
		Corrected PC and NGCC CO_2 capture case water balances	The Econamine process cooling water requirement for the PC and NGCC CO_2 capture cases was overstated and has been revised.
		Replaced Exhibits ES-4, 3-121, 4-52 and 5-30	The old water usage figures were in gpm (absolute) and in the new figures the water numbers are normalized by net plant output.
		Updated Selexol process description	Text was added to Section 3.1.5 to describe how H_2 slip was handled in the models.
		Revised PC and NGCC CO_2 capture case energy balances (Exhibits 4-21, 4-42 and 5-21)	The earlier version of the energy balances improperly accounted for the Econamine process heat losses. The heat removed from the Econamine process is rejected to the cooling tower.
		Corrected Exhibit 5-12 and Exhibit 5-23.	Sensible heat for combustion air in the two NGCC cases was for only one of the two combustion turbines – corrected to account for both turbines
2	10/27/10	Updated circulating water flow rate values in Section 4.1.7.	Revision 1 changes to Econamine cooling water flow rate were not made in the text in Section 4.1.7 (Circulating Water System).
		Added Supplmental Chapter 6 "Effect of Higher Natural Gas Prices and Dispatch-Based Capacity Factors"	

Revision Number	Revision Date	Description of Change	Comments
		Added Supplemental Chapter 7 "Dry and Parallel Cooling"	
		Added Supplemental Chapter 8 "GEE IGCC in Quench-Only Configuration with CO_2 Capture"	
		Added Supplemental Chapter 9 "Sensitivity to MEA System Performance and Cost Bituminous Baseline Case 12A"	
		Updated Aspen models	Major Aspen model updates included: • Converting FORTRAN code based steam cycles to Aspen blocks • Using the Peng-Robinson property method in the Aspen gasifier section • Modifying the AGR used in the IGCC cases to more closely represent commercially available technology • Increasing the capture efficiency of the CoP plant with capture to achieve 90 percent • Correcting a steam condition error in the supercritical PC cases with capture
		Updated case performance results	Major updates included: • Revising the water balances to include withdrawal and consumption • CAD-based HMB diagrams were replaced with Visio versions

Revision Number	Revision Date	Description of Change	Comments
		Completed updating case economic results	Major updates included: • Adding owner's costs to the total plant costs to generate total overnight cost • Updating fuel costs • Revising the TS&M methodology to include the July, 2007 Handy-Whitman Index, pore space acquisition costs, and liability costs • Re-costing of cases based on the updated performance results • Switching to COE as the primary cost metric (as opposed to levelized COE)
		Updated report tables, figures and text to reflect the revision 2 changes	
2a	9/19/2013	Section 2.7.1 was revised to clarify the text that explains the level of technology maturity reflected in the plant level cost estimates.	

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