NATIONAL ENERGY TECHNOLOGY LABORATORY

Cost and Performance Baseline for Fossil Energy Plants
Volume 3c: Natural Gas Combined Cycle at Elevation

March 2011

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COST AND PERFORMANCE BASELINE FOR FOSSIL ENERGY PLANTS VOLUME 3c: NATURAL GAS COMBINED CYCLE AT ELEVATION

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Final Report

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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 report documents an accurate, independent assessment of the cost and performance for Natural Gas Combined Cycle (NGCC) plants with and without carbon dioxide (CO_2) capture and sequestration at two site elevations in Montana and North Dakota. The NGCC cases are a subset of a study that also includes Integrated Gasification Combined Cycle (IGCC) and combustion cases.

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.

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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List of Exhibits

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LIST OF ACRONYMS AND ABBREVIATIONS

AACE	Association for the Advancement of Cost Engineering
AC	Alternating current
acfm	Actual cubic feet per minute
AEO	Annual Energy Outlook
Al	Aluminum
ANSI	American National Standards Institute
Aspen	Aspen Plus®
BACT	Best available control technology
BEC	Bare erected cost
BFD	Block flow diagram
BFW	Boiler feed water
BLS	Bureau of Labor Statistics
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
CCF	Capital charge factor
CDR	Carbon dioxide recovery
CF	Capacity factor
CFB	Circulating fluidized bed
CL	Closed-loop
cm	Centimeter
CO_2	Carbon dioxide
COE	Cost of electricity
CS	Carbon steel
CWP	Circulating water pump
CT	Combustion turbine
CTG	Combustion turbine-generator
CWT	Cold water temperature
DC	Direct current
DCS	Distributed control system
DI	De-ionized
Dia.	Diameter
DLN	Dry low NOx
DOE	Department of Energy
EAF	Equivalent availability factor
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPC	Engineer/procure/construct
EPCM	Engineering/procurement/construction management

FEED	Front-End Engineering Design
FW	Feedwater
FOAK	First-of-a-kind
ft	Foot, feet
gal	Gallon
GCV	Gross calorific value
GDP	Gross domestic product
GJ	Gigajoule
GJ/hr	Gigajoule per hour
gpm	Gallons per minute
gr/100 scf	grains per one hundred standard cubic feet
h, hr	Hour
H_2	Hydrogen
Hg	Mercury
HHV	Higher heating value
hp	Horsepower
HP	High pressure
HRSG	Heat recovery steam generator
HSS	Heat stable salts
HVAC	Heating, ventilating, and air conditioning
HWT	Hot water temperature
Hz	Hertz
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
in	Inches
IOU	Investor-owned utility
IP	Intermediate pressure
ISO	International Standards Organization
kg/GJ	Kilogram per gigajoule
kg/hr	Kilogram per hour
kJ	Kilojoules
kJ/kg	Kilojoules per kilogram
km	Kilometers
kV	Kilovolt
kW	Kilowatt
kWe	Kilowatts electric
kWt	Kilowatts thermal
LAER	Lowest Achievable Emission Rate
CH_4	Methane
lb	Pound
lb/hr	Pounds per hour
lb/MMBtu	Pounds per million British thermal units
lb/MWh	Pounds per megawatt hour

LCOE	Levelized cost of electricity
LHV	Lower heating value
LNB	Low NOx burner
LP	Low pressure
lpm	Liters per minute
m	Meters
m^3/min	Cubic meter per minute
md	Millidarcy (a measure of permeability)
MEA	Monoethanolamine
Mills/kWh	Tenths of a cent per kilowatt-hour
MJ/Nm^3	Megajoule per normal cubic meter
MJ/scm	Megajoule per standard 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
MPa	Megapascals
MVA	Mega volt-amps
MW	Megawatts
MWh	Megawatt-hour
N/A	Not applicable
NAAQS	National Ambient Air Quality Standards
NEMA	National Electrical Manufacturers Association
NERC	North American Electric Reliability Council
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
NH_3	Ammonia
Nm^3	Normal cubic meter
NO_2	Nitrogen oxide
NOAK	N^{th}-of-a-kind
NOx	Oxides of nitrogen
NSPS	New Source Performance Standards
NSR	New Source Review
NDL site	North Dakota Lignite Site
O_2	Oxygen
O&M	Operation and maintenance
OC_{Fn}	Category n fixed operating cost for the initial year of operation
OC_{Vn}	Category n variable operating cost for the initial year of operation
OSAP	Office of Systems, Analyses and Planning
PC	Pulverized coal
PM	Particulate matter
POTW	Publicly Owned Treatment Works
PO	Purchase order

ppmv	Parts per million volume
ppmvd	Parts per million volume dry
PRB	Powder River Basin coal region
PSD	Prevention of Significant Deterioration
psia	Pounds per square inch absolute
psig	Pounds per square inch gage
Qty	Quantity
RDS	Research and Development Solutions, LLC
RH	Reheater
S	Sulfur
SC	Supercritical
scfm	Standard cubic feet per minute
SCR	Selective catalytic reduction process or equipment
SO_2	Sulfur dioxide
SOx	Oxides of sulfur
SS	Stainless steel
STG	Steam turbine generator
TCR	Total capital requirement
TASC	Total as-spent cost
TEWAC	Totally Enclosed Water-to-Air Cooled
TiO_2	Titanium dioxide
tonne	Metric Ton (1000 kg)
TOC	Total overnight cost
TPC	Total plant cost
TPD	Tons per day
tph	Tons per hour
TS&M	Transport, storage and monitoring
U.S.	United States
USC	Ultra-supercritical
yr	Year
V_2O_5	Vanadium pentoxide
vol%	Volume percent
WB	Wet bulb
WO_3	Tungsten trioxide
wt%	Weight percent
$/MMBtu	Dollars per million British thermal units
$/MMkJ	Dollars per million kilojoule
$/MWh	Dollars per megawatt hour
%	Percent

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EXECUTIVE SUMMARY

The objective of this report is to present an accurate, independent assessment of the cost and performance of electricity production from natural gas combined cycle (NGCC) power systems using a consistent technical and economic approach that accurately reflects current market conditions for plants using commercially available technology. This document is Volume 3c of the Low Rank Coal Baseline Reports, which are part of a four volume series consisting 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

Four NGCC plant configurations were analyzed as listed in Exhibit ES-1. Two plants were located in Montana (with and without CO_2 capture) and two in North Dakota (with and without CO_2 capture). The plant locations are the same that were used to evaluate gasification and combustion based systems in Volumes 3a and 3b of this study. The Montana site corresponds to cases that used Powder River Basin (PRB) coal in the gasification and combustion reports while the North Dakota site corresponds to the cases that used lignite coal. While the cases in this report all use natural gas, references to PRB and lignite coals are used to distinguish between the two plant locations with the primary difference being elevation. The Montana site elevation is 1,036 meters (m) (3,400 feet [ft]) and the North Dakota site is 579 m (1,900 ft).

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 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) 2008 Annual Energy Outlook (AEO). The 2007 cost used for natural gas is $6.76/ million kilojoules (MMkJ) ($7.13/ million British thermal units [MMBtu]) on a higher heating value (HHV) basis and in June 2007 United States (U.S.) dollars.

Exhibit ES-1 Case Descriptions

Case	Unit Cycle	Steam Cycle, psig/°F/°F	Boiler Technology	Location	CO_2 Separation
S31A	NGCC	2400/1050/1050	HRSG	Montana	-
S31B	NGCC	2400/1050/1050	HRSG	Montana	Amine Absorber
L31A	NGCC	2400/1050/1050	HRSG	North Dakota	-
L31B	NGCC	2400/1050/1050	HRSG	North Dakota	Amine Absorber

All plant configurations were evaluated based on installation at a greenfield site (Montana or North Dakota). To compare the plants on an equivalent basis, it was assumed that these plants would be dispatched any time they are available. The study capacity factor (CF), 85 percent, was chosen to reflect the maximum availability for NGCC plants. Since variations in fuel costs and other factors can influence dispatch order and CF, sensitivity of levelized COE to CF was evaluated and is presented later in this Executive Summary (Exhibit ES-8).

The nominal net plant output for this study was set to approximately 500 megawatts (MW) to satisfy combustion turbine (CT) constraint as CTs are available in discrete sizes. The actual net output varies by site and carbon capture requirement. The heat recovery boilers and steam turbines in all cases are readily available in a wide range of capacities.

Exhibit ES-2 shows the cost, performance, and environmental profile summary for all cases which are discussed below.

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

	NGCC with Advanced F Class			
PERFORMANCE	**Case S31A**	**Case L31A**	**Case S31B**	**Case L31B**
CO_2 Capture	0%	0%	90%	90%
Gross Power Output (kW_e)	522,100	557,000	470,000	501,600
Auxiliary Power Requirement (kW_e)	9,690	10,020	34,940	36,960
Net Power Output (kW_e)	512,410	546,980	435,060	464,640
Natural Gas Flowrate (lb/hr)	153,559	163,560	153,559	163,560
HHV Thermal Input (kW_{th})	1,014,787	1,080,880	1,014,787	1,080,880
Net Plant HHV Efficiency (%)	50.5%	50.6%	42.9%	43.0%
Net Plant HHV Heat Rate (Btu/kWh)	6,757	6,743	7,959	7,938
Raw Water Withdrawal (gpm/MW_{net})	2.1	2.1	7.1	7.1
Process Water Discharge (gpm/MW_{net})	0.5	0.5	1.8	1.8
Raw Water Consumption (gpm/MW_{net})	1.6	1.6	5.3	5.3
CO_2 Emissions (lb/MMBtu)	118	118	12	12
CO_2 Emissions (lb/MWh_{gross})	784	783	87	87
CO_2 Emissions (lb/MWh_{net})	799	797	94	94
SO_2 Emissions (lb/MMBtu)	Negligible	Negligible	Negligible	Negligible
SO_2 Emissions (lb/MWh_{gross})	Negligible	Negligible	Negligible	Negligible
NOx Emissions (lb/MMBtu)	0.009	0.009	0.009	0.009
NOx Emissions (lb/MWh_{gross})	0.060	0.060	0.067	0.066
PM Emissions (lb/MMBtu)	Negligible	Negligible	Negligible	Negligible
PM Emissions (lb/MWh_{gross})	Negligible	Negligible	Negligible	Negligible
Hg Emissions (lb/TBtu)	Negligible	Negligible	Negligible	Negligible
Hg Emissions (lb/MWh_{gross})	Negligible	Negligible	Negligible	Negligible
COST				
Total Plant Cost (2007$/kW)	666	637	1,315	1,267
Total Overnight Cost (2007$/kW)	817	782	1,607	1,548
Bare Erected Cost	546	521	994	957
Home Office Expenses	46	44	84	81
Project Contingency	74	71	174	168
Process Contingency	0	0	62	61
Owner's Costs	151	145	291	281
Total Overnight Cost (2007$ x 1,000)	418,817	427,473	698,949	719,155
Total As Spent Capital (2007$/kW)	879	840	1,732	1,668
COE (mills/kWh, 2007$)[1]	64.4	63.6	92.9	91.4
CO_2 TS&M Costs	0.0	0.0	3.4	3.3
Fuel Costs	48.2	48.1	56.7	56.6
Variable Costs	1.4	1.3	2.7	2.6
Fixed Costs	3.4	3.2	6.1	5.9
Capital Costs	11.5	11.0	24.0	23.1
LCOE (mills/kWh, 2007$)[1]	81.7	80.6	117.8	115.8

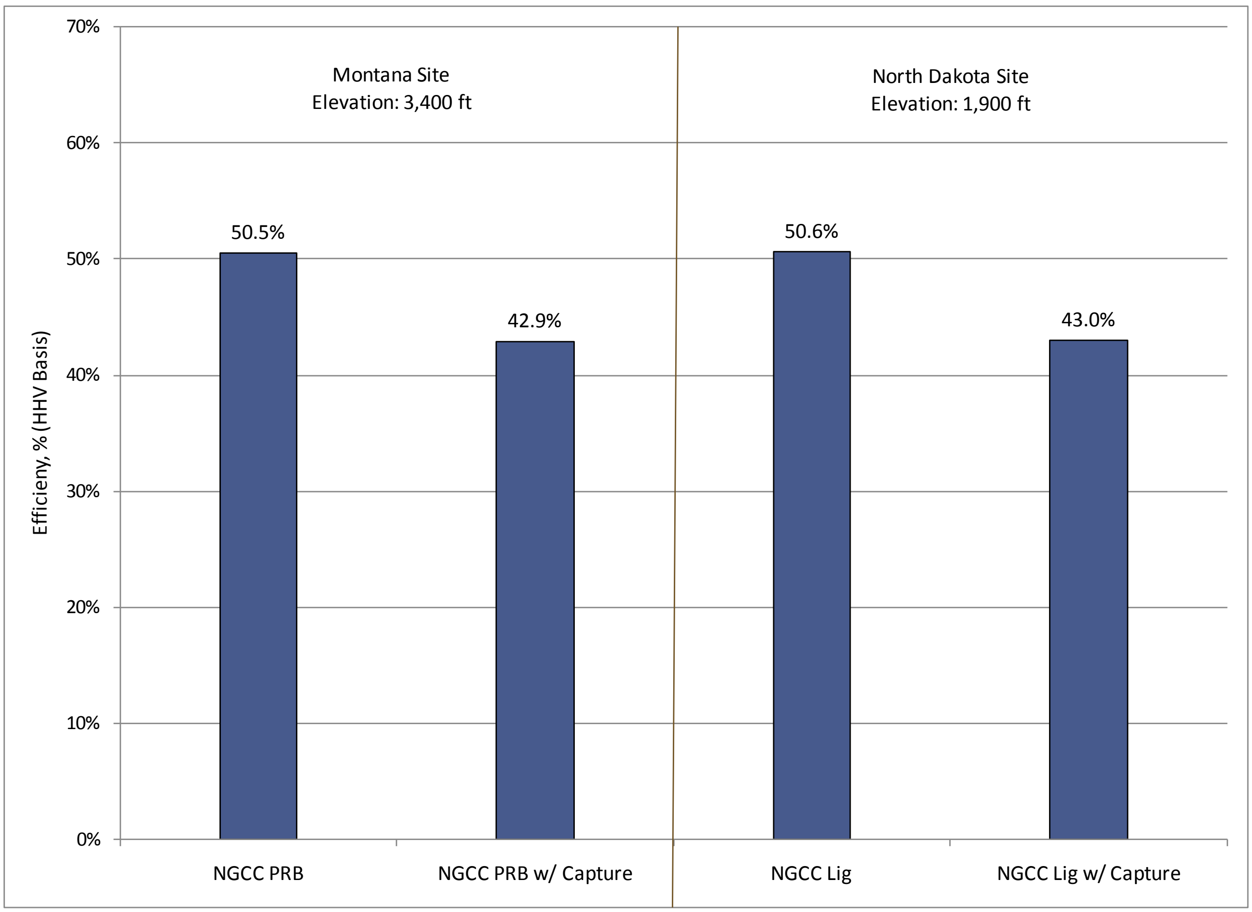
[1] COE and Levelized COE are defined in Section 2.6

Energy Efficiency

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

- The CO_2 capture results in an efficiency penalty of 7.6 absolute percent, relative to the non-capture case at both locations.
- The increase in elevation, going from the NDL to the Montana site, has minimal impact on efficiency but does cause a derate in the gas turbine compressor, reducing the net plant output by six percent for both CO_2 capture and non-capture cases.

Exhibit ES-3 Net Plant Efficiency (HHV Basis)



Cost Results

The Total Plant Cost (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). Owner's costs, including preproduction costs, inventory capital, initial cost for catalyst and chemicals, land, financing costs and other owner's costs were added to TPC to generate total overnight cost (TOC). Property taxes and insurance were included in the fixed operating costs as an additional owner's cost. 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 relative 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:

- Fluor's Econamine FG Plus^SM (Econamine) CO_2 Removal System – 20 percent on both CO_2 capture cases - unproven technology at commercial scale.
- Instrumentation and Controls – five percent on all accounts for CO_2 capture cases.

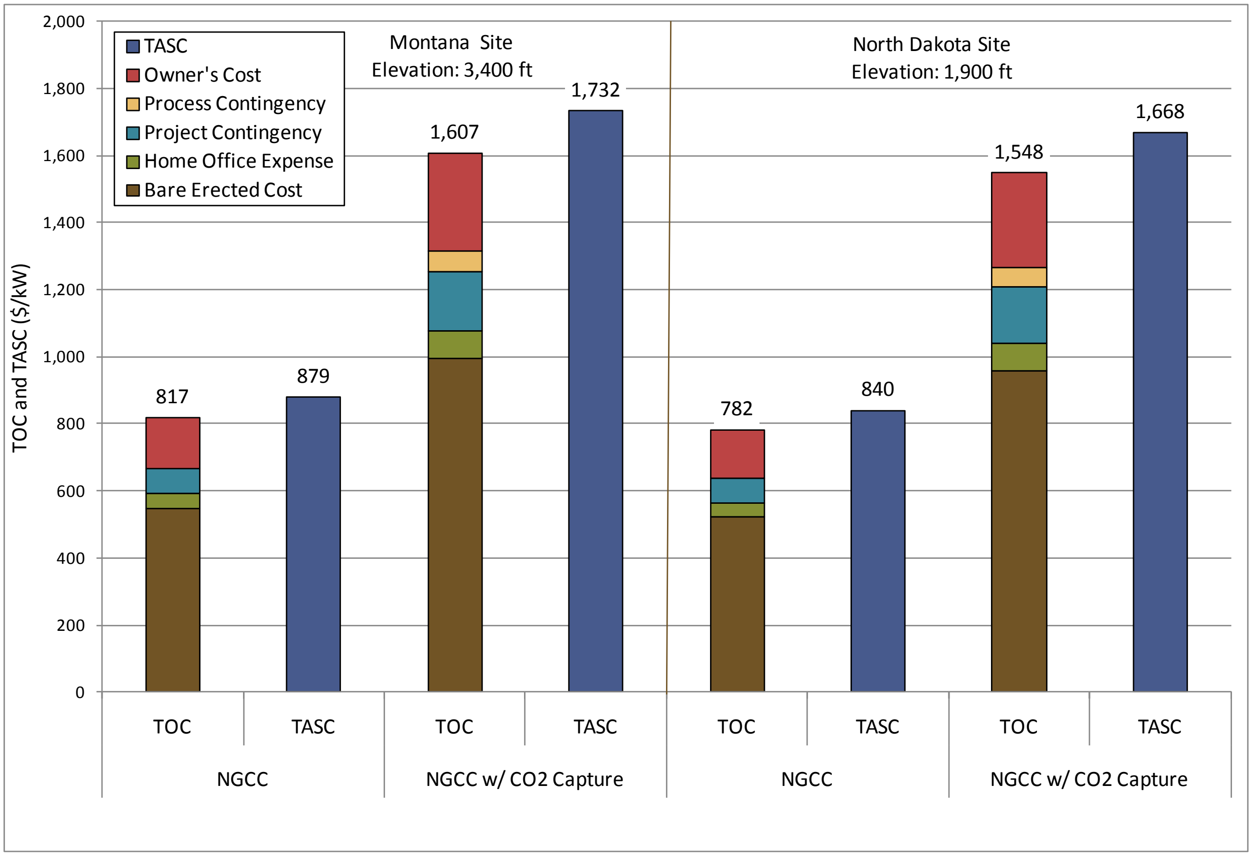
The normalized components of TOC and overall TASC are shown for each plant configuration in Exhibit ES-4. The following conclusions can be drawn:

- Adding CO_2 capture increases the normalized TOC by approximately 97 percent. The Econamine unit and CO_2 compression train add significant capital cost, as well as project and process contingency.

- The normalized TOC for the plants located at the NDL site are 4 percent lower than the plants located at the Montana site. This trend is primarily because of the lower net output at the higher elevation of the Montana site.

- Adding Owner's Costs to the TPC increases the cost of the non-capture plants by approximately 23 percent and the CO_2 capture plants by 22 percent.

Exhibit ES-4 Total Overnight Cost



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) [1] 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-5, which was derived using the PSFM, can also be used to calculate COE using a simplified equation as detailed in Section 2.6.4.

[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.

The project financial structure varies depending on the type of project (high risk or low risk). 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. Cases with CO_2 capture were considered to be high risk. All NGCC cases were assumed to have a 3 year capital expenditure period. The current-dollar, 30-year levelized cost of electricity (LCOE) was also calculated and was shown in Exhibit ES-2, 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 2.6 of the report.

Exhibit ES-5 Economic Parameters Used to Calculate COE

	High Risk (3 year capital expenditure period)	**Low Risk (3 year capital expenditure period)**
First Year Capital Charge Factor	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-6 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:

- The COE is dominated by fuel costs in all cases. The fuel cost component of COE comprises approximately 75 percent in both non-capture cases and 62 percent in both capture cases.

- The capital cost component is relatively minor in all cases, representing approximately 18 percent of the COE costs in the non-capture cases and 25 percent in the CO_2 capture cases.

- Adding CO_2 removal more than doubles the capital cost component and increases the COE by approximately 44 percent for each location.

- The TS&M component of COE in the CO_2 capture cases is about 4 percent for both capture cases.

Exhibit ES-6 COE by Cost Component

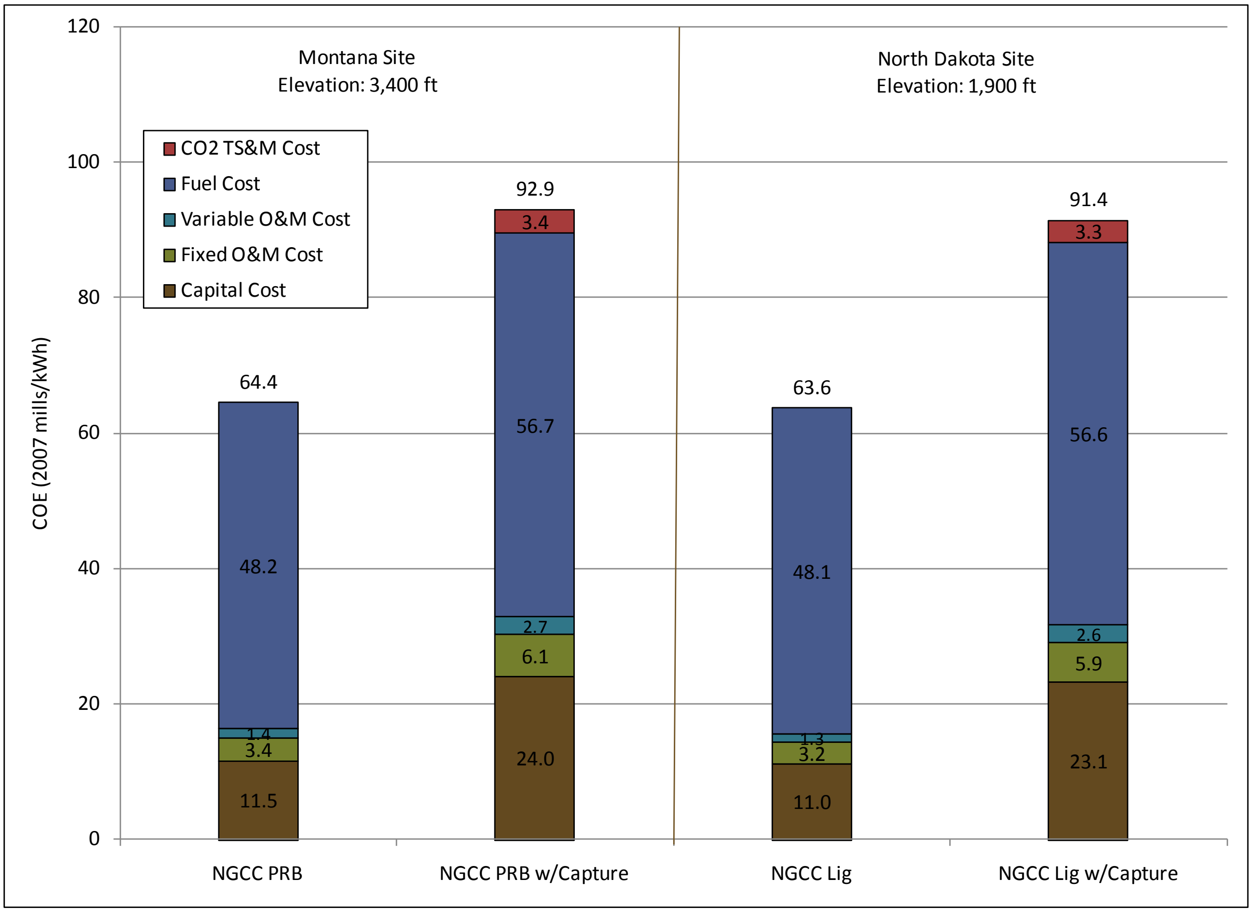
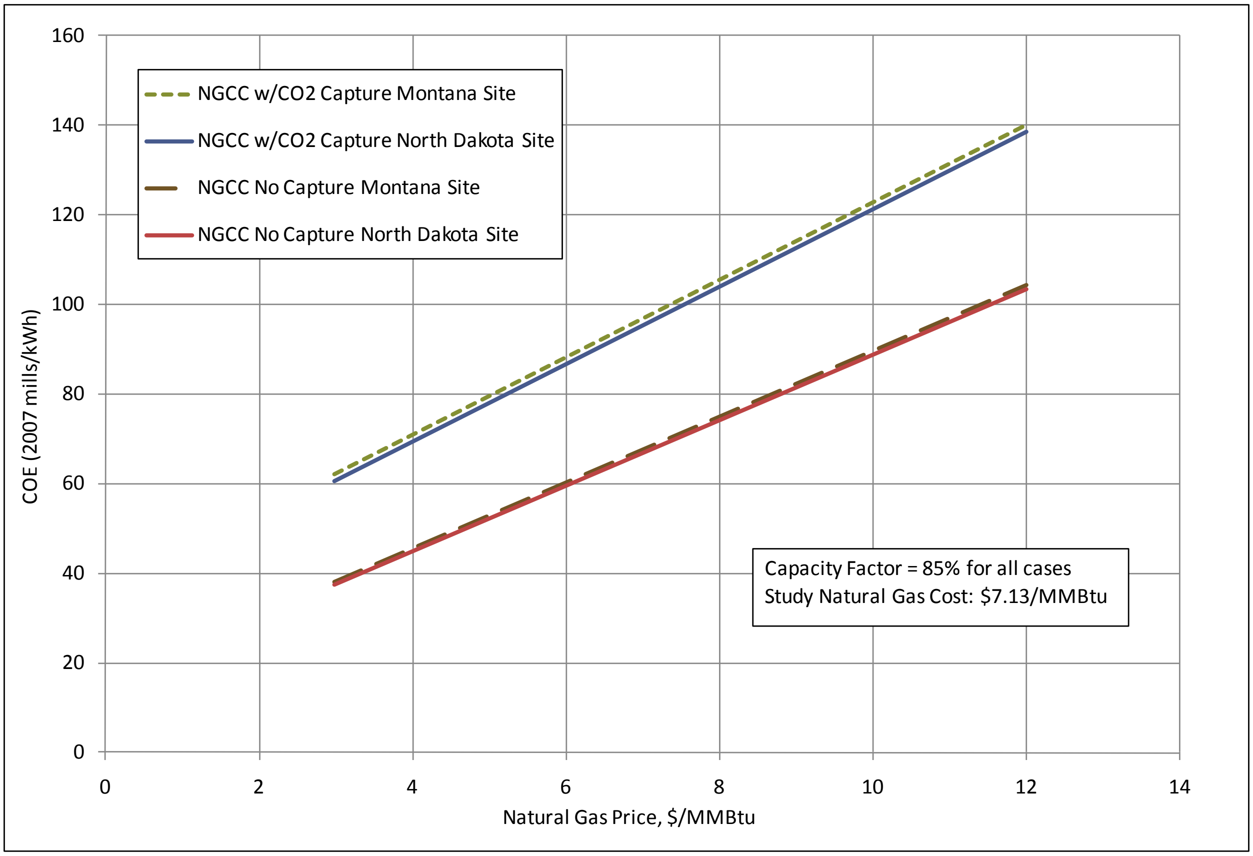


Exhibit ES-7 shows the COE sensitivity to fuel cost. The top set of lines show the COE sensitivity of capture cases, and the bottom set of lines show the sensitivity of non-capture cases. As expected, all cases show a linear increase in COE with the increase in natural gas prices.

The sensitivity of COE to CF is shown in Exhibit ES-8. The top set of lines is the COE of the capture cases. The bottom set of lines is the non-capture cases. All cases show an expected decrease in COE with the increase in CF.

Exhibit ES-7 COE Sensitivity to Fuel Costs



First Year Cost of CO_2 Avoided

The CO_2 emissions per megawatt hour (MWh) in the non-capture cases are about the same for both sites. The first year cost of CO_2 avoided was calculated as follows.

$$Avoided\ Cost = \frac{\{COE_{with\ removal} - COE_{w/o\ removal}\}\ \$/MWh}{\{CO_2Emissions - CO_2Emissions_{with\ removal}\}\ tons/MWh} \quad \text{(ES-1)}$$

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-9 for both sites. The avoided costs are calculated for the CO_2 capture (B) case compared to results from each analogous non-capture plant (A) and compared to a baseline SC PC non-capture plant (SC PC A). The cost of CO_2 avoided averages \$88.0/tonne (\$79.9/ton) compared to the analogous non-capture (A) design and \$38.4/tonne (\$34.8/ton) compared to the baseline SC PC non-capture (SC PC A) design.

Exhibit ES-8 COE Sensitivity to CF

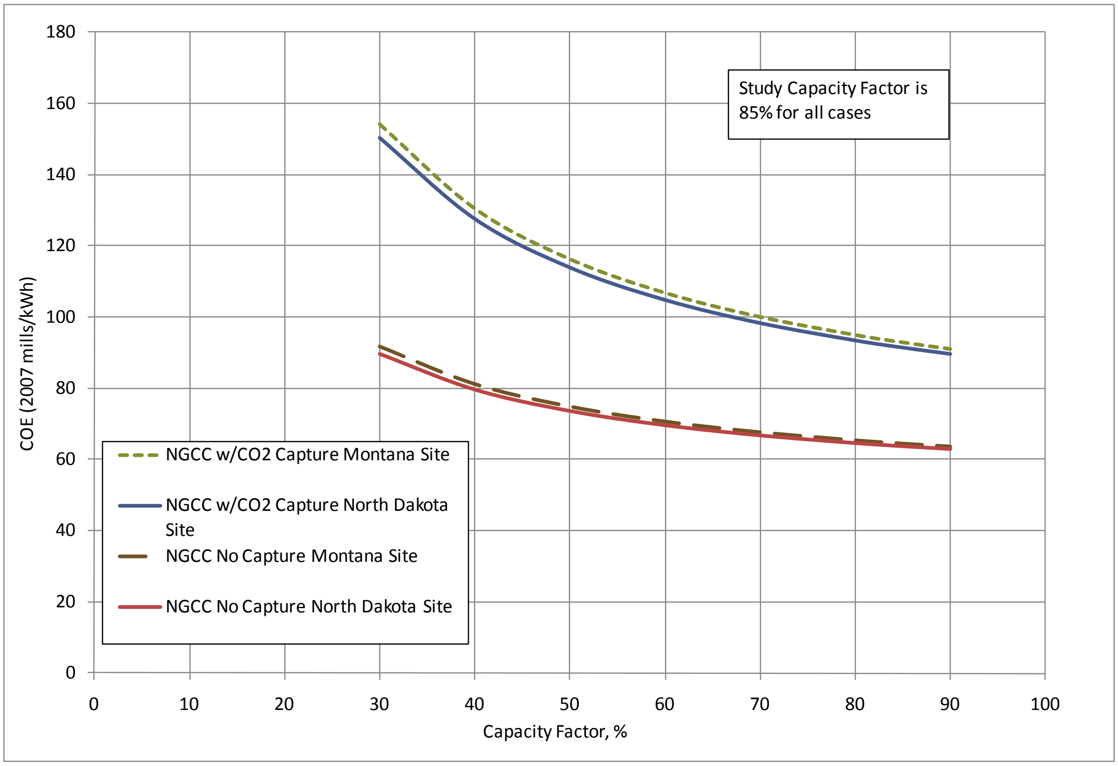
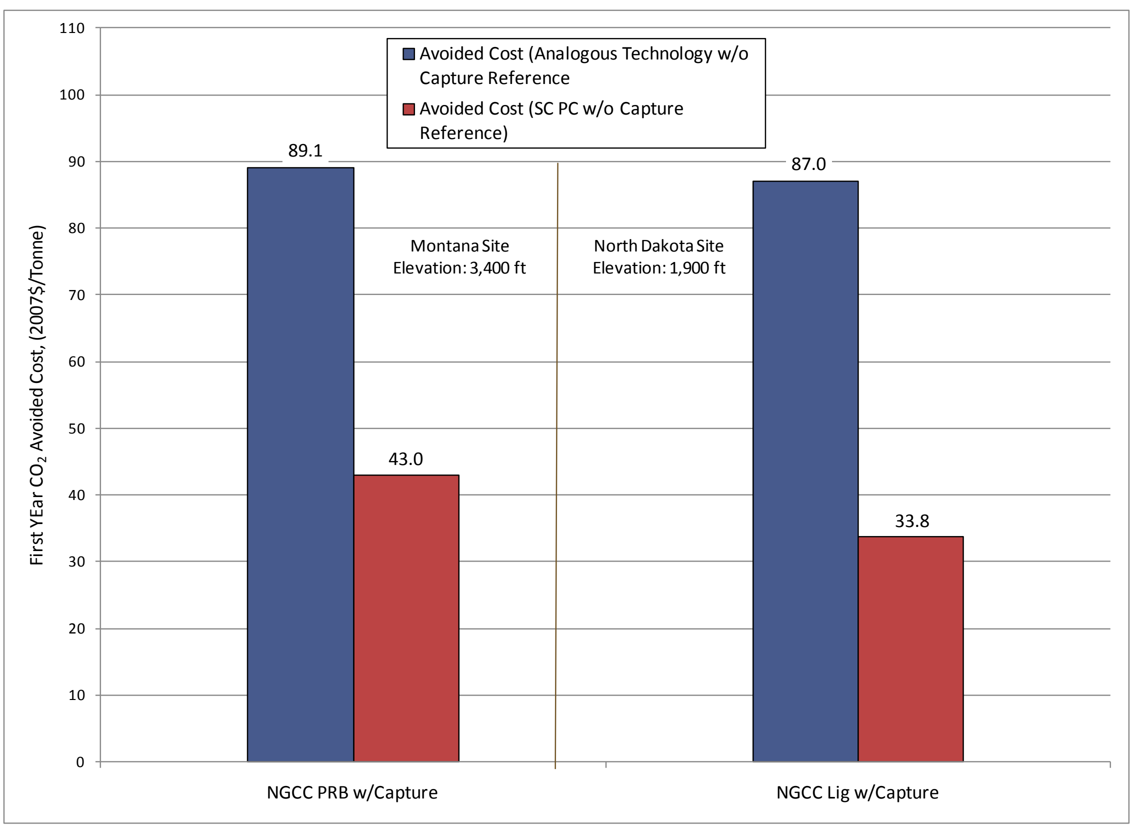


Exhibit ES-9 CO_2 Avoided Costs



1. INTRODUCTION

The objective of this report is to present an accurate, independent assessment of the cost and performance of electricity production from natural gas combined cycle (NGCC) power systems in a consistent technical and economic manner that accurately reflects current market conditions for plants using commercially available technology. This document is Volume 3c of the Low Rank Coal Baseline Reports, which are part of a four volume series consisting of the following:

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- Volume 3: Low Rank Coal and Natural Gas to Electricity
- Volume 4: Bituminous Coal to Liquid Fuels with Carbon Capture

Four NGCC power plant configurations were analyzed as listed in Exhibit ES-1. The list includes two locations corresponding to the Montana Powder River Basin (PRB) site and two locations corresponding to the North Dakota Lignite (NDL) site. The plant locations are the same that were used to evaluate gasification and combustion based systems in Volumes 3a and 3b of this study. The Montana site corresponds to cases that used Powder River Basin (PRB) coal in the gasification and combustion reports while the North Dakota site corresponds to the cases that used lignite coal. While the cases in this report all use natural gas, references to PRB and lignite coals are used to distinguish between the two plant locations with the primary difference being elevation. The Montana site elevation is 1,036 meters (m) (3,400 feet [ft]) and the North Dakota site is 579 m (1,900 ft). Both sites include cases with and without CO_2 capture.

The naming convention for the cases covered in this report is as follows:

- First letter represents location: S = PRB Montana; L = NDL location
- Two digit number represents technology type: 31 = NGCC
- Final letter indicates CO_2 capture: A = no capture; B = capture

Volume 3c covers the four NGCC cases at the Montana and North Dakota sites:

Case S31A – This case is based on natural gas feed where the plant is located at the Montana PRB site.

Case S31B – This case is the same as S31A except it includes CO_2 capture.

Case L31A – This case is based on natural gas feed where the plant is located at the NDL site.

Case L31B – This case is the same as L31A except it includes CO_2 capture.

Generating Unit Configurations

The nominal net plant output for this study is set to approximately 500 MW to satisfy CT constraint as CTs are available in discrete sizes. The actual net output varies by site and CO_2 capture requirement. The heat recovery boilers and steam turbines in all cases are readily available in a wide range of capacities.

The balance of this report is organized as follows:

- Chapter 2 provides the basis for technical, environmental, and cost evaluations.
- Chapter 3 describes the NGCC technologies modeled and presents the results for the four NGCC cases.
- Chapter 4 contains a summary of results.
- Chapter 5 contains the reference list.

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 provided the 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 and scaled estimates from previous design/build projects. Ultimately, a COE was calculated for each of the cases and is reported as the economic figure-of-merit.

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

2.1 SITE CHARACTERISTICS

The plants are located at two different generic plant sites, Montana PRB site and NDL site. The ambient conditions for the two sites are shown in Exhibit 2-1 and Exhibit 2-2.

Exhibit 2-1 Montana Site Ambient Conditions

Elevation, m (ft)	1,036 (3,400)
Barometric Pressure, MPa (psia)	0.09 (13.0)
Design Ambient Temperature, Dry Bulb, °C (°F)	5.6 (42)
Design Ambient Temperature, Wet Bulb, °C (°F)	2.8 (37)
Design Ambient Relative Humidity, %	62

Exhibit 2-2 North Dakota Site Ambient Conditions

Elevation, m (ft)	579 (1,900)
Barometric Pressure, MPa (psia)	0.10 (13.8)
Design Ambient Temperature, Dry Bulb, °C (°F)	4.4 (40)
Design Ambient Temperature, Wet Bulb, °C (°F)	2.2 (36)
Design Ambient Relative Humidity, %	68

The site characteristics are assumed to be the same for both plant locations, as shown in Exhibit 2-3.

Exhibit 2-3 Site Characteristics

Location	Greenfield, Montana PRB site or NDL site
Topography	Level
Size, acres	100
Transportation	Rail
Ash/Slag Disposal	N/A
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 (km) (50 miles), and sequestered in a saline formation at a depth of 1,239 m (4,055 ft)

It was assumed that the plant proper occupies 10 acres providing a 0.15 mile buffer to the plant fence line for a total area of 100 acres.

In all cases it was assumed that buildings house the steam turbine and boiler. The following design parameters are considered site-specific, and are not quantified for this study. Allowances for normal conditions and construction are included in the cost estimates.

- Flood plain considerations
- Existing soil/site conditions
- Water discharges and reuse
- Rainfall/snowfall criteria
- Seismic design
- Buildings/enclosures
- Fire protection
- Local code height requirements
- Noise regulations – Impact on site and surrounding area

2.2 NATURAL GAS CHARACTERISTICS

Natural gas composition for all cases with and without CO_2 capture is presented in Exhibit 2-4. The fuel composition is normalized and heating values are calculated.

Exhibit 2-4 Natural Gas Composition

Component		Vol %
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

The Power Systems Financial Model (PSFM) was used to derive the capital charge factors and levelization factors for this study. 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 first year cost of natural gas used in this study is $6.76/MMkJ ($7.13/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 Mountain region delivered cost of natural gas to electric utilities in 2006 dollars, \$252/1000 m^3 (\$7.14/1000 ft^3), was obtained from the AEO 2008 reference case Table 108 and converted to an energy basis, $6.56/MMkJ ($6.92/MMBtu) [2].
- 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 $6.76/MMkJ ($7.13/MMBtu) [3].

2.3 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, and the status of current best available control technology (BACT).

Natural Gas Combustion Design Targets

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 2-5.

Exhibit 2-5 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 (0.135 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 6,690 Btu/kWh.

Published vendor literature indicates that 25 ppmv NOx at 15 percent oxygen (O_2) is achievable using natural gas and dry low NOx (DLN) technology [4,5]. 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 CH_4 by volume or having a gross calorific value (GCV) of between 35.4 and 40.9 megajoule per normal cubic meter (MJ/Nm^3) (950 and 1,100 Btu/scf) and having a total sulfur content of less than 13.7 milligrams per normal meter cubed (mg/Nm^3) (0.6 gr/100 scf [grains per one hundred standard cubic feet]) [6]. Assuming a sulfur content equal to the EPA limit for pipeline natural gas, resulting SO_2 emissions for the two non-capture NGCC cases in this study would be 9.7 metric ton (1000 kg) (tonnes)/year (yr) (10.7 tons/yr) at 85 percent CF or 0.00073 kilogram per gigajoule (kg/GJ) (0.0017 lb/MMBtu). Thus, for the purpose of this study, SO_2 emissions were considered negligible.

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

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. CO_2 emissions are reported on both a pound (lb)/(gross) MWh and lb/(net) MWh basis in each capture case emissions table.

For the cases in this report volume that have CO_2 capture, the basis is a nominal post-combustion 90 percent removal based on carbon input from the natural gas. It is assumed that all of the fuel carbon becomes CO_2 in the CT flue gas.

The cost of CO_2 capture was calculated as a first year 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.

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

2.4 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 NGCC cases was determined using the Generating Availability Data System (GADS) from the North American Electric Reliability Council (NERC) [7].

NERC defines an equivalent availability factor (EAF) as 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 NGCC plants in the 400-599 MW size range was 84.7 percent in 2004 and averaged 82.7 percent from 2000-2004. The EAF was rounded up to 85 percent and that value was also used as the NGCC plant CF.

The addition of CO_2 capture was assumed not to impact the CF even without redundant pipelines, wells or subsurface infrastructure. 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.

2.5 RAW WATER WITHDRAWAL AND CONSUMPTION

A water balance was performed on the major water consumers in the process for each case. The total water demand for each major subsystem was determined. The internal recycle water available from various sources was used to offset the water demand and determine the total water withdrawal. Discharge water stream quantities were estimated and subtracted from the water withdrawal to determine the water consumption from the environment required for the plant.

Fifty percent of the raw water withdrawal was assumed to be provided by a publicly owned treatment works (POTW) and 50 percent was provided 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 and boiler feedwater (BFW) makeup.

The largest consumer of raw water in all cases is cooling tower makeup. Since plants located in the Western U.S. need to consider limited water supplies, a parallel wet/dry cooling tower was chosen for all plant configurations similar to the system installed at Xcel Energy's Comanche 3 PC plant. In a parallel cooling system half of the turbine exhaust steam is condensed in an air-cooled condenser and half in a water-cooled condenser. The cooling water is provided by a mechanical draft, evaporative cooling tower, and all process blowdown streams were assumed to be treated and recycled to the cooling tower. The cooling tower blowdown was assumed to be treated and 90 percent returned to the water source with the balance sent to a pond for evaporation. The design ambient wet bulb temperature of 3°C (37°F) at the Montana site and 2°C (36°F) at the NDL site (Exhibit 2-1 and Exhibit 2-2) was used to achieve a cooling water temperature of 9°C (48°F) and 8°C (47°F), respectively at the two sites using an approach of 6°C (11°F). The cooling water range was assumed to be 11°C (20°F). The cooling tower makeup rate was determined using the following [8]:

- Evaporative losses = 0.8 percent of the circulating water flow rate per 10°F of range
- Drift losses = 0.001 percent of the circulating water flow rate
- Blowdown losses = Evaporative Losses / (Cycles of Concentration - 1)
  Where cycles of concentration are a measure of water quality, and a mid-range value of 4 was chosen for this study.

Typical design conditions for air-cooled condensers include an initial temperature difference (ITD) of 40-55°F [9]. The ITD is the temperature difference between saturated steam at the steam turbine generator (STG) exhaust and the inlet dry bulb cooling air temperature. The ITDs at the two locations in this study are 48 and 50°F. The fan power requirement is estimated at 3.5 times the power required for a wet cooling tower with equivalent heat duty [10].

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.

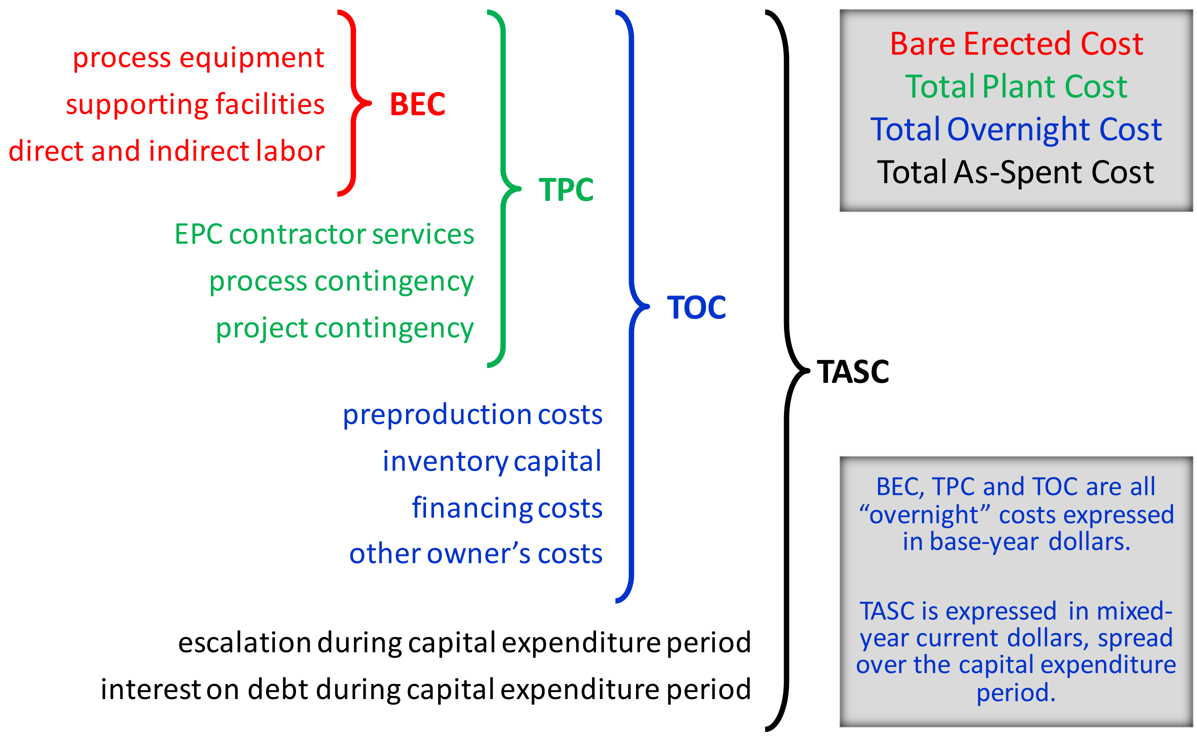
2.6 COST ESTIMATING METHODOLOGY

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.

2.6.1 Capital Costs

As illustrated in Exhibit 2-6, 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 three years for natural gas plants (2007 to 2010).

Exhibit 2-6 Capital Cost Levels and their Elements



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

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

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 [11].

Most techno-economic studies completed by NETL feature cost estimates intended for the purpose of a "Feasibility Study" (AACE Class 4). Exhibit 2-7 describes the characteristics of an AACE Class 4 Cost Estimate. Cost estimates in this study have an expected accuracy range of -15%/+30%.

Exhibit 2-7 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

The capital costs for each cost account were reviewed by comparing individual accounts across all cases to ensure an accurate representation of the relative cost differences between the cases and accounts. All capital costs are presented as "overnight costs" expressed in June 2007 dollars. The dollar values have been held at June 2007 to allow direct comparison with earlier results. Significant pricing fluctuations have occurred between June 2007 and March 2009. A retrospective look suggests that pricing for these commodities peaked in mid 2008 and generally declined during the latter parts of 2008 into 2009. While some pricing is still currently declining, based on published information, pricing at the end of 2008 remains higher than June 2007 values.

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 within the specific system account. (This would not be the case had a facility, area, or commodity account structure been chosen instead).

Non-CO_2 Capture Plant Maturity

Non-capture NGCC cases are based on commercial offerings for a mature technology n^{th}-of-a-kind (NOAK) cost. Thus, each of these cases reflects the expected cost for the next commercial sale of each of this technology.

CO_2 Removal Plant Maturity

While the post-combustion technology used for the NGCC plants has been practiced at smaller scale, it has never been practiced at a scale equivalent to that required in this study. There were domestic amine-based CO_2 capture systems operating on natural gas-derived flue gas at scales up to 1,200 tons per day (TPD) [12]. The plants in this study will capture an average 4,600 TPD of CO_2. Consequently the CO_2 capture cases will be treated as FOAK.

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

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

Estimate Scope

The estimates represent a complete power plant facility on a generic site. The plant boundary limit is defined as the total plant facility within the “fence line” including the 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. This provides a basis for subsequent comparisons and easy modification when comparing between specific case-by-case variations.

Other key estimate considerations include the following:

- Labor costs are based on Midwest, Merit Shop using factors from PAS, Inc [13]. PAS presents information for eight separate regions. Volume 1 of this study used a generic Midwestern site, typical of Region 5 (IL, IN, MI, MN, OH, and WI). The weighted average rate for Region 8 (CO, MT, ND, SD, UT, and WY) is within less than one-half of one percent of that for Region 5. The difference is inconsequential so the same rates used in Volume 1 were maintained in this study. Costs would need to be re-evaluated for projects employing union labor.
- 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 were estimated as a 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 important than the absolute level of TPC. This requires cross-account comparison between technologies to review the consistency of the direction of the costs.

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)

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.

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 2-8, AACE International Recommended Practice 16R-90 provides guidelines for estimating process contingency based on EPRI philosophy [14].

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

- CO_2 Removal System (Econamine) – 20 percent on all CO_2 capture cases - unproven technology at commercial scale in NGCC service.
- Instrumentation and Controls – five percent on all accounts for CO_2 capture cases.

Exhibit 2-8 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.

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

Owner's Costs

Exhibit 2-9 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 [14]. 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.

Exhibit 2-9 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.
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

Owner's Cost	Estimate Basis
	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.
Initial Cost for Catalysts and Chemicals	• All initial fills not included in BEC
Taxes & Insurance	• 2% of TPC (Fixed O&M Cost)

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 2-10.

Exhibit 2-10 TASC/TOC Factors

Finance Structure	IOU High Risk	IOU Low Risk
TASC/TOC	1.078	1.075

2.6.2 Operations and Maintenance Costs

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

- Operating labor
- Maintenance – material and labor
- Administrative and support labor
- Consumables
- Fuel
- Waste disposal

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

Operating Labor

Operating labor cost was determined based on the number of operators required for each specific case. The average base labor rate used to determine annual cost is $34.65/hour (hr). 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 a 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 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 (such as reactor catalyst), which are included with the equipment pricing in the capital cost.

Waste Disposal

No wastes are generated in NGCC cases that require disposal.

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

No co-products or by-products (other than CO_2 in the capture cases) are generated in NGCC cases.

2.6.3 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 2-11 [15]. A glycol dryer located near the mid-point of the compression train is used to meet the moisture specification.

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

Exhibit 2-11 CO_2 Pipeline Specification

Parameter	Units	Parameter Value
Inlet Pressure	MPa (psia)	15.3 (2,215)
Outlet Pressure	MPa (psia)	10.4 (1,515)
Inlet Temperature	°C (°F)	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 and injected as a SC fluid in order to avoid two-phase flow and achieve maximum efficiency [16]. 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 [17]. (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 μm2) and formation pressure of 8.4 MPa (1,220 psig) [15]. 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 [15]. The assumed aquifer characteristics are tabulated in Exhibit 2-12.

Exhibit 2-12 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 (μm^2)	22 (22)
Pipeline Distance	Km (miles)	80 (50)
Injection Rate per Well	Tonne (ton) CO_2/day	9,360 (10,320)

The cost metrics utilized in this study provide a best estimate of TS&M costs for a "typical" 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.

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

TS&M Capital 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 [15, 16, 18]. 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 [18]. 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 [16]. 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 [15]. 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 [15]. 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 [19]. 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 [20]. 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) [21, 22, 23]. 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 [24]. 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.

2.6.4 Finance Structure, Discounted Cash Flow Analysis, and COE

The global economic assumptions are listed in Exhibit 2-13.

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. The NGCC non-capture plants are categorized as low risk and the CO_2 capture cases are categorized as high risk. Exhibit 2-14 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 [25].

Exhibit 2-13 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	Coal Plants: 5 Years
Operational Period	30 years
Economic Analysis Period (used for IRROE)	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)	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] COE, O&M, Fuel

[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 2-14 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 2-15 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

[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.

Exhibit 2-15 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.

- 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 dashed lines in the upper portion of Exhibit 2-15.

Exhibit 2-15 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 2-15, 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.

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.

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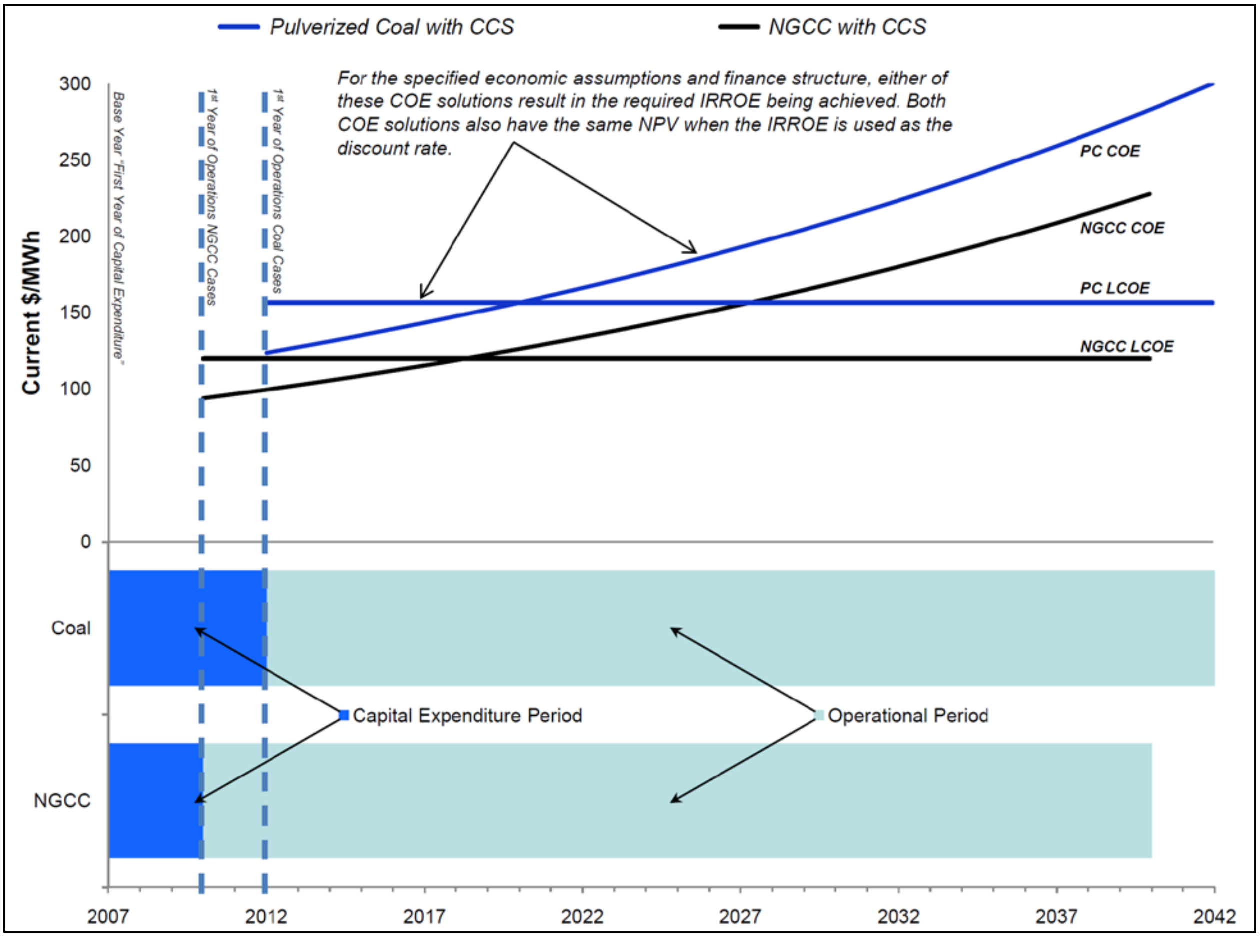
[7] For this current-dollar analysis, the LCOE is uniform in current dollars over the analysis period. In contrast, a constant-dollar analysis would yield an LCOE that is uniform in constant dollars over the analysis period.

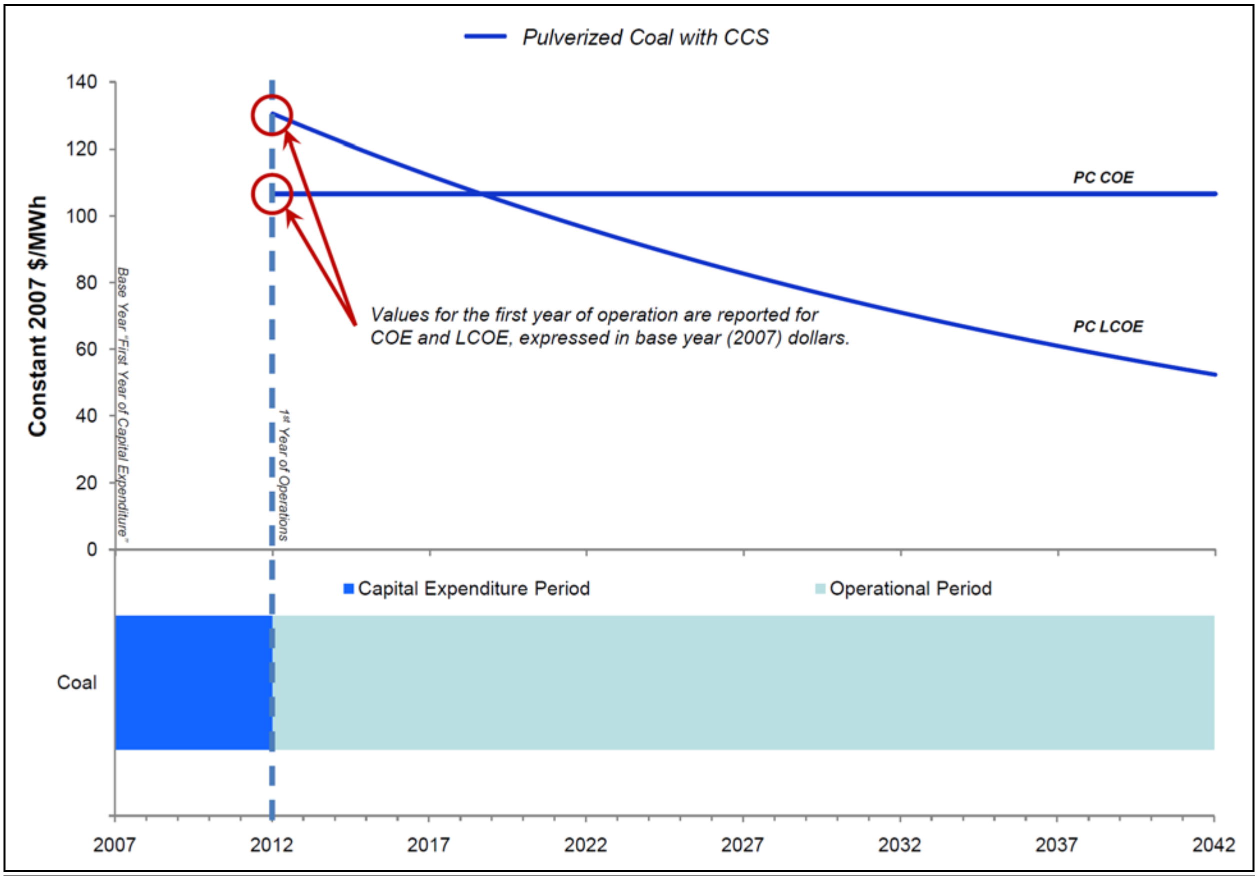
Exhibit 2-15 Illustration of COE Solutions using DCF Analysis



Consistent with our nominal-dollar discounted cash flow methodology, the COEs shown on Exhibit 2-15 are expressed in current dollars. However, they can also be expressed in constant, base year dollars (June 2007) as shown in Exhibit 2-16 by adjusting them with the assumed nominal annual general inflation rate (3 percent).

Exhibit 2-16 illustrates the same information as in Exhibit 2-15 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 2-16 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 2-13 and utilize one of the finance structures listed in Exhibit 2-14, 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 2-17. These CCFs are valid only for the global economic assumptions listed in Exhibit 2-13, the stated finance structure, and the stated capital expenditure period.

[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 2-17 Capital Charge Factors for COE Equation

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

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 2-13, 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.

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

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

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 2-17 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 2-18 presents this cost metric along with the COE escalated to the first year of operation 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 2-18 COE and LCOE Summary

Case	COE (mills/kWh)		LCOE (mills/kWh)	
	Base-Year	First Operational Year	Base-Year	First Operational Year
	2007$	2010$	2007$	2010$
S31A	64.42	74.58	81.66	89.24
S31B	92.91	107.55	117.77	128.69
L31A	63.58	73.60	80.59	88.07
L31B	91.36	105.76	115.81	126.54

First Year CO_2 Avoided Cost with Supercritical PC Reference

The cost of CO_2 removal was calculated in two ways: the cost of CO_2 avoided compared to the analogous non-capture design and the cost of CO_2 avoided compared to a baseline supercritical (SC) PC plant at the same site location as the NGCC plant, using the equation below. The baseline SC PC plant is a 550 MW (net) plant with the results presented in Exhibit 2-19, and in Volume 3b of this study. The cost of electricity in the CO_2 capture cases includes TS&M as well as capture and compression.

Exhibit 2-19 Baseline SC PC Results for CO_2 Cost Calculation

	Montana (S12A)	North Dakota (L12A)
Net Output (MW)	550	550
COE (2007 mills/kWh)	57.80	62.20
Emissions (lb/MWh$_{net}$)	1,892	1,996

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

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3. NGCC POWER PLANT PROCESS DESCRIPTIONS

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. Each design consists of two advanced F class combustion turbine generators (CTG), two HRSGs and one STG in a multi-shaft 2x2x1 configuration.

The NGCC cases are evaluated with and without carbon capture on a common thermal input basis for each site condition. The NGCC designs that include carbon dioxide recovery (CDR) have a smaller plant net output resulting from the additional CDR facility auxiliary loads. Like in 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.

3.1 NGCC COMMON PROCESS AREAS

The four NGCC cases are nearly identical in configuration. With the exception of cases S31B and L31B, which include a CDR facility, the following process descriptions are common to all cases.

3.1.1 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.

3.1.2 Combustion Turbine

The combined cycle plant is based on two CTGs. The CTG is representative of the advanced F Class turbines with an ISO base rating of 184,400 kW when firing natural gas at International Standards Organization (ISO) conditions [26]. As elevation increases, the output is reduced due to the lower air density, resulting in less mass flow through the turbine for a given volumetric flow or rotational velocity. This machine is an axial flow, single spool, constant speed unit, with variable inlet guide vanes 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 3-1.

Exhibit 3-1 Combustion Turbine Typical Scope of Supply

System	System Scope
ENGINE ASSEMBLY	Coupling to Generator, Dry Chemical Exhaust Bearing Fire Protection System, Insulation Blankets, Platforms, Stairs and Ladders
Engine Assembly with Bedplate	Variable Inlet Guide Vane System, Compressor, Bleed System, Purge Air System, Bearing Seal Air System, Combustors, Dual Fuel Nozzles, Turbine Rotor Cooler
Walk-in acoustical enclosure	Heating, ventilating, and air conditioning (HVAC), Lighting, and Low Pressure (LP) CO_2 Fire Protection System
MECHANICAL PACKAGE	HVAC and Lighting, Air Compressor for Pneumatic System, LP CO_2 Fire Protection System
Lubricating Oil System and Control Oil System	Lube Oil Reservoir, Accumulators, 2x100% alternating current (AC) Driven Oil Pumps, direct current (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 and Lighting, AC and DC Motor Control Centers, Generator Voltage Regulating Cabinet, Generator Protective Relay Cabinet, DC Distribution Panel, Battery Charger, Digital Control System with Local Control Panel (all control and monitoring functions as well as data logger and sequence of events recorder), Control System Valves and Instrumentation Communication link for interface with plant Distributed control system (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

System	System Scope
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
N. GAS FUEL SYSTEMS	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 ($H_{2)}$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 kilovolt (kV), 3-phase, 60 hertz (hz), constructed to meet American National Standards Institute (ANSI) and National Electrical Manufacturers Association (NEMA) standards for turbine-driven synchronous generators. The generator is TEWAC, complete with excitation system, cooling, and protective relaying.

3.1.3 <u>Heat Recovery Steam Generator</u>

The heat recovery steam generator (HRSG) is configured with high pressure (HP), intermediate pressure (IP), and LP steam drums, and superheater, reheater (RH), and economizer sections. The HP drum is supplied with feedwater (FW) by the HP boiler feed pump to generate HP steam, which passes to the superheater section for heating to 566°C (1,050°F). The IP drum is supplied with FW from an interstage bleed on the HP boiler feed pump. The IP steam from the drum is superheated to 566°C (1,050°F) and mixed with hot reheat steam from the reheat section at 566°C (1,050ºF). The combined flows are admitted into the IP section of the steam turbine. The LP drum provides steam to the integral deaerator, and also to the LP turbine.

The economizer sections heat condensate and FW (in separate tube bundles). The HRSG tubes are typically comprised of bare surface and/or finned tubing or pipe material. The high-temperature portions are type P91 or P22 ferritic alloy material; the low-temperature portions (< 399°C [750°F]) are carbon steel (CS). Each HRSG exhausts directly to the stack, which is fabricated from CS plate materials and lined with Type 409 stainless steel (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.

3.1.4 NOx Control System

This reference plant is designed to achieve 2.5 parts per million volume dry (ppmvd) NOx emissions (expressed as nitrogen oxide (NO_2) and referenced to 15 percent O_2). Two measures are taken to reduce the NOx. The first is a dry LNB in the CTG. The dry LNB burners are a low NOx design and reduce the emissions to about 25 ppmvd (referenced to 15 percent O_2) [27].

The second measure taken to reduce the NOx emissions was the installation of a SCR system. SCR uses ammonia (NH_3) and a catalyst to reduce NOx to N_2 and H_2O. The SCR system consists of reactor, and (NH_3) 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 flue gas path inside the HRSG between the HP and IP sections. The SCR reactor is equipped with one catalyst layer consisting of catalyst modules stacked in line on a supporting structural frame. The SCR reactor has space for installation of an additional layer. Ammonia is injected into the gas immediately prior to entering the SCR reactor. The ammonia injection grid is arranged into several sections, and consists of multiple pipes with nozzles. Ammonia flow rate into each injection grid section is controlled taking into account imbalances in the flue gas flow distribution across the HRSG. The catalyst contained in the reactor enhances the reaction between the ammonia and the NOx in the gas. The catalyst consists of various active materials such as titanium dioxide (TiO_2), vanadium pentoxide (V_2O_5), and tungsten trioxide (WO_3). The optimum inlet flue gas temperature range for the catalyst is 260°C (500°F) to 343°C (650°F).

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

3.1.5 Carbon Dioxide Recovery Facility

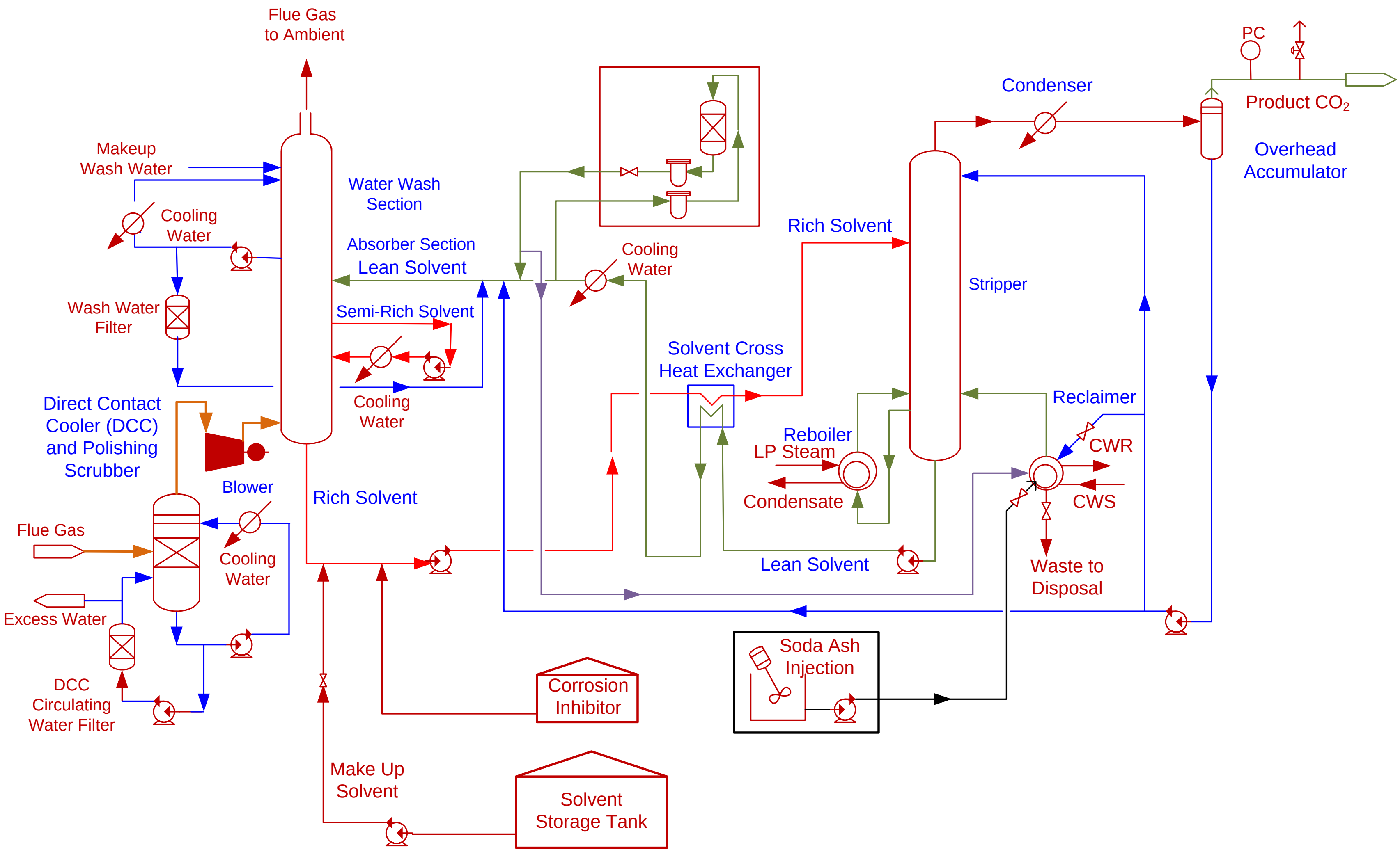
A CDR facility is used in Cases S31B and L31B to remove 90 percent of the CO_2 in the flue gas exiting the HRSG, dry it, and compress it to a SC condition. It is assumed that all of the carbon in the natural gas is converted to CO_2. The CDR is comprised of flue gas supply, CO_2 absorption, solvent stripping and reclaiming, and CO_2 compression and drying.

The CO_2 absorption/stripping/solvent reclaim process for the CO_2 capture cases is based on the Fluor Econamine FG Plus^{SM} technology [28,29]. A typical flowsheet is shown in Exhibit 3-2. The Econamine FG Plus process uses a formulation of monoethanolamine (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 O_2, such as flue gas from coal-fired power plants, gas turbine exhaust gas, and other waste gases. The Econamine process used in this study differs from previous studies, including the 2003 IEA study [30], in the following ways:

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

The above are achieved at the expense of a slightly higher steam requirement in the stripper (3,693 kJ/kg [1,589 Btu/lb] versus 3,242 kJ/kg [1,395 Btu/lb] used in the IEA study) [31].

Exhibit 3-2 Fluor Econamine FG Plus Typical Flow Diagram



Flue Gas Cooling and Supply

The function of the flue gas cooling and supply system is to transport flue gases from the HRSG to the CO_2 absorption tower, and condition flue gas pressure, temperature, and moisture content so it meets the requirements of the Econamine process. Temperature and hence moisture content of the flue gas exiting the HRSG is reduced in the Direct Contact Flue Gas Cooler, where flue gas is cooled using cooling water.

The water condensed from the flue gas is collected in the bottom of the Direct Contact Flue Gas Cooler section and re-circulated to the top of the Direct Contact Flue Gas Cooler section via the Flue Gas Circulation Water Cooler, which rejects heat to the plant circulating water system. Level in the Direct Contact Flue Gas Cooler is controlled by directing the excess water to the cooling water return line. In the Direct Contact Flue Gas Cooler, flue gas is cooled beyond the CO_2 absorption process requirements to 33°C (91°F) to account for the subsequent flue gas temperature increase of 14°C (25°F) in the flue gas blower. Downstream from the Direct Contact Flue Gas Cooler, flue gas pressure is boosted in the flue gas blowers by approximately 0.014 MPa (2 pound per square inch [psi]) to overcome pressure drop in the CO_2 absorber tower.

Circulating Water System

Cooling water is provided from the NGCC plant circulating water system and returned to the NGCC 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, lean solvent cooler, and CO_2 compression interstage cooling.

CO_2 Absorption

The cooled flue gas enters the bottom of the CO_2 Absorber and flows up through the tower countercurrent to a stream of lean MEA-based solvent. Approximately 90 percent of the CO_2 in the feed gas is absorbed into the lean solvent, and the rest leaves the top of the absorber section and flows into the water wash section of the tower. The lean solvent enters the top of the absorber, absorbs the CO_2 from the flue gases, and leaves the bottom of the absorber with the absorbed CO_2. 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 Wash Water 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 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 and is 0.51 MPa (74 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 3-3.

Exhibit 3-3 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 -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 2.6.

3.1.6 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/564°C (360 psia/1047°F). After passing through the IP section, the steam enters a cross-over pipe, which transports the steam to the LP section. A branch line equipped with combined stop/intercept valves conveys LP steam from the HRSG LP drum to a tie-in at the cross-over line. The steam divides into two paths and flows through the LP sections exhausting downward into the condenser.

Turbine bearings are lubricated by a closed-loop (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 low-pressure 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.

3.1.7 Water and Steam Systems

Condensate

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

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 RH and from the HRSG RH 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 RH. Hot reheat steam exits at the HRSG RH through a motor-operated gate valve and is routed to the IP turbines.

Circulating Water System

Exhaust steam from the steam turbine is split 50/50 to a surface condenser cooled with cooling water and to an air-cooled condenser using ambient air and forced convection. A decision to use a parallel wet/dry cooling system was based primarily on the Xcel Energy Comanche 3 PC plant, and the desire to reduce the plant water requirement.

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

Because of the low ambient temperatures at the sites in this study, a condenser pressure of 4.81 kilopascal absolute (kPa) (0.698 psia) (condensing temperature of 32°C [90°F]) is used in the model as compared to 6.77 kPa (0.983 psia) (condensing temperature of 38°C [101°F]) used in Volume 1 of this report.

The CWS is a closed-cycle cooling water system that rejects heat through a wet cooling tower and supplies cooling water to the surface condenser to condense one-half of the main turbine exhaust steam. The system also supplies cooling water to the CDR 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 surface 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 carbon steel (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 surface condenser is a single-pass, horizontal type with divided water boxes. There are two separate circulating water circuits in each box. One-half of the condenser can be removed from service for cleaning or for plugging tubes. This can be done during normal operation at reduced load. The air-cooled condenser utilizes ambient air and forced convection across tube bundles to condense the balance of the turbine exhaust steam.

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

3.1.8 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

3.1.9 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.

3.1.10 Instrumentation and Control

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

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

3.2 NGCC PROCESS DESCRIPTION

This section contains an evaluation of plant designs for each of the four cases. All cases use a single reheat 16.5 MPa/566°C/566°C (2400 psig/1050°F/1050°F) cycle. Cases S31A and L31A as well as S31B and L31B differ from each other by ambient conditions, carbon capture, and hence the amount of natural gas feed to maintain the CT loading to the discrete value provided by the manufacturer.

The balance of Section 3.2 is organized as follows:

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

3.2.1 Key System Assumptions

System assumptions for NGCC with and without CO_2 capture are compiled in Exhibit 3-4.

Exhibit 3-4 NGCC Plant Study Configuration Matrix

	Cases S31A/L31A w/o CO_2 Capture	Cases S31B/L31B 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)	36.0 (1.4)	36.0 (1.4)
Cooling Water to Condenser, °C (ºF)	9 (48)/8 (47)	9 (48)/8 (47)
Cooling Water from Condenser, °C (ºF)	20 (68)/19 (67)	20 (68)/19 (67)
Stack Temperature, °C (°F)	102 (215)/102 (216)	29 (85)
SO_2 Control	Low Sulfur Fuel	Low Sulfur Fuel
NOx Control	LNB and SCR	LNB and SCR
SCR Efficiency, %[1]	90	90
Ammonia Slip (End of Catalyst Life), ppmv	10	10
Particulate Control	N/A	N/A
Hg Control	N/A	N/A
CO_2 Control	N/A	Econamine
CO_2 Capture, %[1]	N/A	90.7
CO_2 Sequestration	N/A	Off-site Saline Formation

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

Balance of Plant

The balance of plant assumptions are common to all NGCC cases and are presented in Exhibit 3-5.

Exhibit 3-5 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 Horsepower (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 de-ionized (DI) water is drawn from municipal sources.
Process Wastewater	Storm water that contacts equipment surfaces is collected and treated for discharge through a permitted discharge.
Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant is sized for 5.68 cubic meters per day (1,500 gallons per day)
Water Discharge	Most of the process wastewater is recycled to the cooling tower basin. Blowdown is treated for chloride and metals, and discharged.

3.2.2 Sparing Philosophy

Dual trains are used to accommodate the size of commercial gas turbines. 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%) (Capture cases)

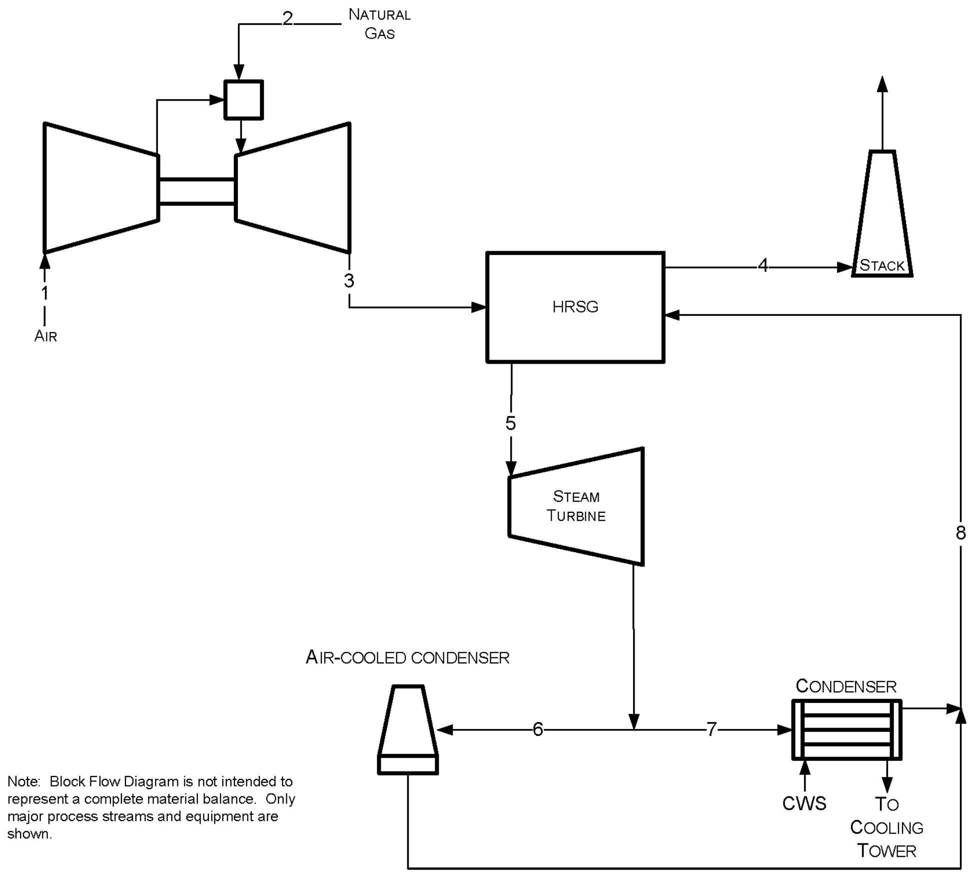
3.3 CASES S31A AND L31A PROCESS DESCRIPTION

In this section the NGCC process without CO_2 capture is described. The system description follows the block flow diagrams (BFD) in Exhibit 3-6.

The stream numbers in the following description reference the BFD in Exhibit 3-6. The tables in Exhibit 3-7 and Exhibit 3-18, for cases S31A and L31A respectively, 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 flue gas exits the turbine around 628°C (1163°F) (stream 3) and passes into the HRSG. The HRSG generates both the main steam and reheat steam for the steam turbine. Flue gas exits the HRSG at 102°C (215°F) and passes to the plant stack.

Exhibit 3-6 Cases S31A and L31A Process Flow Diagram, NGCC without CO_2 Capture



The balance of Section 3.3 is organized as follows:

- Performance Results - provides the main modeling results including the performance summary, environmental performance, water balance, mass and energy balance diagrams, and energy balance table.

- Major Equipment List - provides an itemized list of major equipment with account codes that correspond to the cost accounts in the Cost Estimating section.

- Cost Estimating - provides a summary of capital and operating costs.

3.3.1 Case S31A – Performance Results

The plant produces a net output of 512 MW at a net plant efficiency of 50.5 percent (HHV basis).

Major stream flows are shown in Exhibit 3-7 and overall plant performance is summarized in Exhibit 3-8, which includes auxiliary power requirements.

Exhibit 3-7 Case S31A Stream Table, NGCC without CO_2 Capture

	1	2	3	4	5	6	7	8
V-L Mole Fraction								
Ar	0.0093	0.0000	0.0089	0.0089	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
C_2H_6	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_3H_8	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_4H_{10}	0.0000	0.0040	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
CO_2	0.0003	0.0100	0.0413	0.0413	0.0000	0.0000	0.0000	0.0000
H_2O	0.0064	0.0000	0.0849	0.0849	1.0000	1.0000	1.0000	1.0000
N_2	0.7759	0.0160	0.7451	0.7451	0.0000	0.0000	0.0000	0.0000
O_2	0.2081	0.0000	0.1198	0.1198	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
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	98,174	4,020	102,311	102,311	19,410	12,552	12,552	25,662
V-L Flowrate (kg/hr)	2,836,748	69,653	2,906,401	2,906,401	349,679	226,125	226,125	462,303
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0
Temperature (°C)	6	38	628	102	566	32	32	32
Pressure (MPa, abs)	0.09	3.10	0.09	0.09	16.65	0.005	0.005	0.90
Enthalpy (kJ/kg)[A]	15.26	46.30	832.10	241.77	3,472.36	2,360.91	2,360.91	135.69
Density (kg/m^3)	1.1	22.2	0.4	0.8	47.7	0.04	0.04	995.4
V-L Molecular Weight	28.895	17.328	28.408	28.408	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	216,437	8,862	225,556	225,556	42,792	27,672	27,672	56,574
V-L Flowrate (lb/hr)	6,253,958	153,559	6,407,517	6,407,517	770,911	498,521	498,521	1,019,203
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0
Temperature (°F)	42	100	1,163	215	1,050	90	90	90
Pressure (psia)	13.0	450.0	13.5	13.0	2,414.7	0.7	0.7	130.0
Enthalpy (Btu/lb)[A]	6.6	19.9	357.7	103.9	1,492.8	1,015.0	1,015.0	58.3
Density (lb/ft^3)	0.070	1.384	0.022	0.051	2.977	0.002	0.002	62.141
	A - Reference conditions are 32.02 F & 0.089 PSIA							

Exhibit 3-8 Case S31A Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	335,300
Steam Turbine Power	186,800
TOTAL POWER, kWe	**522,100**
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	150
Boiler Feedwater Pumps	2,450
Circulating Water Pump	1,060
Ground Water Pumps	100
Cooling Tower Fans	700
Air Cooled Condenser Fan	2,330
SCR	10
Gas Turbine Auxiliaries	700
Steam Turbine Auxiliaries	100
Miscellaneous Balance of Plant[1]	500
Transformer Losses	1,590
TOTAL AUXILIARIES, kWe	**9,690**
NET POWER, kWe	**512,410**
Net Plant Efficiency (HHV)	50.5%
Net Plant Efficiency (LHV)	56.0%
Net Plant Heat Rate (HHV), kJ/kWhr (Btu/kWhr)	7,130 (6,757)
Net Plant Heat Rate (LHV), kJ/kWhr (Btu/kWhr)	6,428 (6,093)
CONDENSER COOLING DUTY, 10^6 kJ/h (10^6 Btu/h)	**1,023 (970)**
CONSUMABLES	
Natural Gas Feed Flow, kg/hr (lb/hr)	69,653 (153,559)
Thermal Input (HHV), kW_{th}	1,014,787
Thermal Input (LHV) , kW_{th}	914,961
Raw Water Withdrawal, m^3/min (gpm)	4.1 (1,084)
Raw Water Consumption, m^3/min (gpm)	3.2 (841)

[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 2.3. A summary of the plant air emissions for Case S31A is presented in Exhibit 3-9.

Exhibit 3-9 Case S31A 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 (0.009)	106 (117)	0.027 (0.060)
Particulates	Negligible	Negligible	Negligible
Hg	Negligible	Negligible	Negligible
CO_2	50.8 (118.3)	1,383,150 (1,524,662)	356 (784)
CO_2[1]			363 (799)

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

The operation of the modern, state-of-the-art gas turbine 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 2.3, if the fuel contains the maximum amount of sulfur compounds allowed in pipeline natural gas, the NGCC SO_2 emissions would be 9.7 tonnes/yr (10.7 tons/yr) at 85 percent CF, or 0.00073 kg/GJ (0.0017 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 is shown in Exhibit 3-10. The carbon input to the plant consists of carbon in the air in addition to carbon in the natural gas. One hundred percent carbon conversion is assumed since carbon conversion for NGCC plants is typically about 99.9 percent.

Carbon in the air is not neglected here since the model accounts for air components throughout. Carbon leaves the plant as CO_2 in the stack gas.

Exhibit 3-10 Cases S31A Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Natural Gas	50,310 (110,914)	**Stack Gas**	50,696 (111,766)
Air (CO_2)	387 (852)		
Total	**50,696 (111,766)**	**Total**	**50,696 (111,766)**

Exhibit 3-11 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, such as BFW blowdown, 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. 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 3-11 Case S31A 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	**0.08 (20)**	**0 (0)**	**0.08 (20)**	**0 (0)**	**0.08 (20)**
BFW Makeup	0.08 (20)	0 (0)	0.08 (20)		
Cooling Tower	**4.11 (1,084)**	**0.08 (20)**	**4.03 (1,064)**	**0.92 (244)**	**3.10 (820)**
BFW Blowdown	0 (0)	0.08 (20)	-0.08 (-20)		
Total	**4.18 (1,105)**	**0.08 (20)**	**4.11 (1,084)**	**0.92 (244)**	**3.18 (841)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the NGCC in Exhibit 3-12.

An overall plant energy balance is provided in tabular form in Exhibit 3-13. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-8) is calculated by multiplying the power out by a combined generator efficiency of 98.4 percent.

Exhibit 3-12 Case S31A Heat and Mass Balance, NGCC without CO_2 Capture

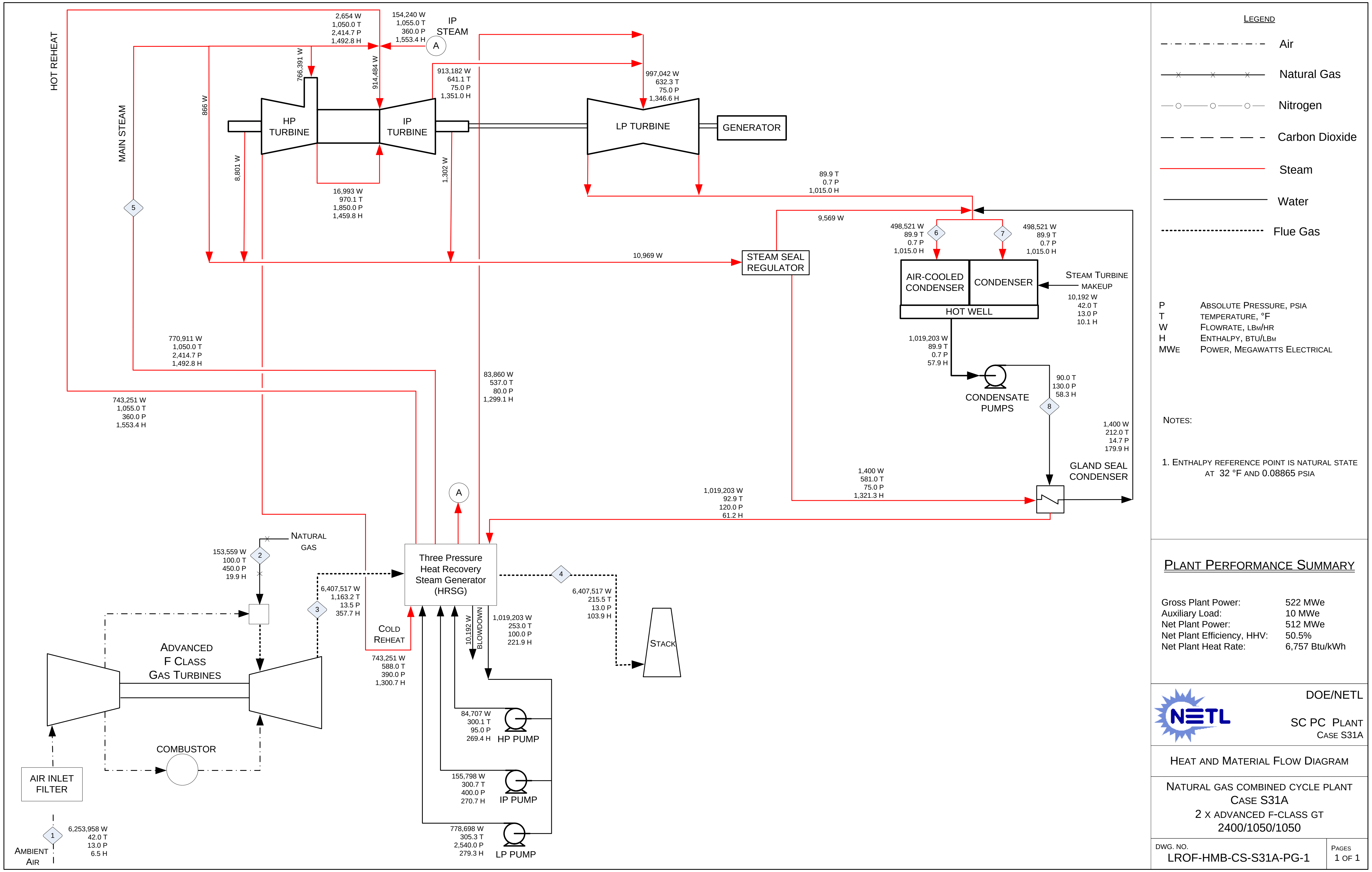


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Exhibit 3-13 Case S31A Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Natural Gas	3,653 (3,463)	0.9 (0.9)		3,654 (3,463)
GT Air		43.3 (41.0)		43 (41)
Raw Water Withdrawal		5.7 (5.4)		6 (5)
Auxiliary Power			35 (33)	35 (33)
Totals	**3,653 (3,463)**	**49.9 (47.3)**	**35 (33)**	**3,738 (3,543)**
Heat Out GJ/hr (MMBtu/hr)				
Cooling Tower BD		5.1 (4.9)		5 (5)
Stack Gas		703 (666)		703 (666)
Condenser		1,019 (966)		1,019 (966)
Process Losses[1]		*131 (124)*		*131 (124)*
Power			1,880 (1,781)	1,880 (1,781)
Totals	**0 (0)**	**1,858 (1,761)**	**1,880 (1,781)**	**3,738 (3,543)**

[1] Process Losses are calculated by difference and reflect various turbine and other heat and work losses not modeled in Aspen.

3.3.2 Case S31A – 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 3.3.3. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 FUEL HANDLING

N/A

ACCOUNT 2 FUEL AND SORBENT PREPARATION AND FEED

N/A

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	609,456 liters (161,000 gal)	2 (0)
2	Condensate Pumps	Vertical canned	4,278 lpm @ 110 m H_2O (1,130 gpm @ 360 ft H_2O)	2 (1)
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP water: 3,255 lpm @ 2,103 m H_2O (860 gpm @ 6,900 ft H_2O) IP water: 644 lpm @ 283 m H_2O (170 gpm @ 930 ft H_2O) LP water: 341 lpm @ 24.4 m H_2O (90 gpm @ 80 ft H_2O)	2 (1)
4	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)

Equipment No.	Description	Type	Design Condition	Operating Qty (Spares)
5	Service Air Compressors	Flooded Screw	13 m^3/min @ 0.7 MPa (450 scfm @ 100 psig)	2 (1)
6	Instrument Air Dryers	Duplex, regenerative	13 m^3/min (450 scfm)	2 (1)
7	Closed Cycle Cooling Heat Exchangers	Plate and frame	13 MMkJ/hr (13 MMBtu/hr)	2(0)
8	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	5,300 lpm @ 21 m H_2O (1,400 gpm @ 70 ft H_2O)	2 (1)
9	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H_2O (1,000 gpm @ 350 ft H_2O)	1 (1)
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H_2O (700 gpm @ 250 ft H_2O)	1 (1)
11	Raw Water Pumps	Stainless steel, single suction	2,271 lpm @ 18 m H_2O (600 gpm @ 60 ft H_2O)	2 (1)
12	Filtered Water Pumps	Stainless steel, single suction	151 lpm @ 49 m H_2O (40 gpm @ 160 ft H_2O)	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)

Equipment No.	Description	Type	Design Condition	Operating Qty (Spares)
15	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	58 m^3/min @ 3.1 MPa (2,033 acfm @ 450 psia) 41 cm (16 in) standard wall pipe	16 km (0)
16	Gas Metering Station	--	58 m^3/min (2,033 acfm)	1 (0)
17	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	170 MW	2 (0)
2	Gas Turbine Generator	TEWAC	190 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 - 192,324 kg/hr, 16.5 MPa/566°C (424,001 lb/hr, 2,400 psig/1,050°F)	2 (0)
			Reheat steam - 223,903 kg/hr, 2.4 MPa/566°C (493,620 lb/hr, 345 psig/1,050°F)	
3	SCR Reactor	Space for spare layer	1,596,647 kg/h (3,520,000 lb/h)	2 (0)
4	SCR Catalyst	--	Space available for an additional catalyst layer	1 layer (0)
5	Dilution Air Blowers	Centrifugal	10 m^3/min @ 107 cm WG (350 scfm @ 42 in WG)	2 (1)
6	Ammonia Feed Pump	Centrifugal	3.8 lpm @ 91 m H_2O (1 gpm @ 300 ft H_2O)	2 (1)
7	Ammonia Storage Tank	Horizontal tank	60,567 liter (16,000 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	197 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	220 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)

Equipment No.	Description	Type	Design Condition	Operating Qty. (Spares)
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	560 MMkJ/hr, (530 MMBtu/hr), Inlet water temperature 9°C (48°F), Water temperature rise 11°C (20°F)	1 (0)
5	Air-cooled Condenser	---	560 GJ/hr (530 MMBtu/hr), Condensing temperature 32°C (90°F), Ambient temperature 6°C (42°F)	1 (0)

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty (Spares)
1	Circulating Water Pumps	Vertical, wet pit	105,992 lpm @ 30.5 m (28,000 gpm @ 100 ft)	2 (1)
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	3°C (37°F) wet bulb / 9°C (48°F) CWT / 20°C (68°F) HWT 1,149 MMkJ/hr (1,090 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	L12A Design Condition	Operating Qty. (Spares)
1	CTG Transformer	Oil-filled	24 kV/345 kV, 190 MVA, 3-ph, 60 Hz	2 (0)

Equipment No.	Description	Type	L12A Design Condition	Operating Qty. (Spares)
2	STG Transformer	Oil-filled	24 kV/345 kV, 210 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	L12A Design Condition	Operating Qty (Spares)
1	DCS - Main Control	Monitor/keyboard, Operator printer, Engineering printer	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)

3.3.3 Case S31A – Cost Estimating

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-14 shows the total plant capital cost summary organized by cost account and Exhibit 3-15 shows a more detailed breakdown of the capital costs. Exhibit 3-16 itemizes the owner's costs and Exhibit 3-17 shows the initial and annual O&M costs.

The estimated TOC of the NGCC with no CO_2 capture is $817/kW. No process contingency was included in this case because all elements of the technology are commercially proven. The project contingency is 9.1 percent of TOC. The COE is 64.4 mills/kWh.

Exhibit 3-14 Case S31A Total Plant Cost Summary

Client: USDOE/NETL | **Report Date:** 2009-Oct-09

Project: Low Rank Western Coal Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case S31A - 1x512 MWnet 2x1 7FB NGCC

Plant Size: 512.4 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	$20,716	$3,813	$4,914	$0	$0	**$29,442**	$2,480	$0	$5,018	**$36,941**	$72
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	$75,295	$0	$4,804	$0	$0	**$80,099**	$6,800	$0	$8,690	**$95,589**	$187
6.2-6.9	Combustion Turbine Other	$0	$719	$744	$0	$0	**$1,462**	$122	$0	$317	**$1,901**	$4
	SUBTOTAL 6	**$75,295**	**$719**	**$5,548**	**$0**	**$0**	**$81,561**	**$6,922**	**$0**	**$9,007**	**$97,491**	**$190**
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**	$87
7.2-7.9	SCR System, Ductwork and Stack	$1,006	$851	$978	$0	$0	**$2,835**	$241	$0	$505	**$3,582**	$7
	SUBTOTAL 7	**$33,964**	**$851**	**$5,257**	**$0**	**$0**	**$40,071**	**$3,412**	**$0**	**$4,546**	**$48,029**	**$94**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$22,586	$0	$3,614	$0	$0	**$26,200**	$2,251	$0	$2,845	**$31,297**	$61
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$27,599	$753	$8,980	$0	$0	**$37,331**	$3,509	$0	$7,451	**$48,290**	$94
	SUBTOTAL 8	**$50,185**	**$753**	**$12,594**	**$0**	**$0**	**$63,531**	**$5,760**	**$0**	**$10,296**	**$79,587**	**$155**
9	COOLING WATER SYSTEM	$4,569	$3,118	$3,227	$0	$0	**$10,914**	$912	$0	$1,693	**$13,519**	$26
10	ASH/SPENT SORBENT HANDLING SYS	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
11	ACCESSORY ELECTRIC PLANT	$16,014	$3,593	$8,565	$0	$0	**$28,172**	$2,160	$0	$3,223	**$33,555**	$65
12	INSTRUMENTATION & CONTROL	$5,631	$578	$4,679	$0	$0	**$10,888**	$907	$0	$1,352	**$13,147**	$26
13	IMPROVEMENTS TO SITE	$1,659	$901	$4,414	$0	$0	**$6,974**	$617	$0	$1,518	**$9,109**	$18
14	BUILDINGS & STRUCTURES	$0	$3,885	$4,135	$0	$0	**$8,020**	$652	$0	$1,301	**$9,973**	$19
	TOTAL COST	**$208,031**	**$18,210**	**$53,333**	**$0**	**$0**	**$279,574**	**$23,822**	**$0**	**$37,954**	**$341,350**	$666

Exhibit 3-15 Case S31A Total Plant Cost Details

	Client:	USDOE/NETL								**Report Date:**	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case S31A - 1x512 MWnet 2x1 7FB NGCC										
	Plant Size:	512.4	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	$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	$2,247	$2,315	$1,904	$0	$0	$6,466	$533	$0	$1,050	$8,049	$16
3.2	Water Makeup & Pretreating	$843	$88	$440	$0	$0	$1,371	$117	$0	$298	$1,786	$3
3.3	Other Feedwater Subsystems	$1,025	$346	$291	$0	$0	$1,662	$134	$0	$269	$2,065	$4
3.4	Service Water Systems	$100	$205	$666	$0	$0	$970	$85	$0	$211	$1,266	$2
3.5	Other Boiler Plant Systems	$668	$259	$600	$0	$0	$1,527	$130	$0	$249	$1,906	$4
3.6	Natural Gas, incl. pipeline	$14,655	$482	$420	$0	$0	$15,557	$1,319	$0	$2,531	$19,407	$38
3.7	Waste Treatment Equipment	$304	$0	$173	$0	$0	$478	$42	$0	$104	$623	$1
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$874	$117	$419	$0	$0	$1,410	$122	$0	$306	$1,838	$4
	SUBTOTAL 3.	**$20,716**	**$3,813**	**$4,914**	**$0**	**$0**	**$29,442**	**$2,480**	**$0**	**$5,018**	**$36,941**	**$72**
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 3-15 Case S31A Total Plant Cost Details (Continued)

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case S31A - 1x512 MWnet 2x1 7FB NGCC										
	Plant Size:	512.4	MW,net	Estimate Type:		Conceptual		Cost Base (Jun)		2007	($x1000)	
Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/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	$75,295	$0	$4,804	$0	$0	$80,099	$6,800	$0	$8,690	$95,589	$187
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.	**$75,295**	**$719**	**$5,548**	**$0**	**$0**	**$81,561**	**$6,922**	**$0**	**$9,007**	**$97,491**	**$190**
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	$87
7.2	SCR System	$1,006	$422	$593	$0	$0	$2,022	$174	$0	$329	$2,525	$5
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.	**$33,964**	**$851**	**$5,257**	**$0**	**$0**	**$40,071**	**$3,412**	**$0**	**$4,546**	**$48,029**	**$94**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$22,586	$0	$3,614	$0	$0	$26,200	$2,251	$0	$2,845	$31,297	$61
8.2	Turbine Plant Auxiliaries	$152	$0	$348	$0	$0	$500	$44	$0	$54	$598	$1
8.3a	Condenser & Auxiliaries	$2,332	$0	$696	$0	$0	$3,028	$259	$0	$329	$3,616	$7
8.3b	Air Cooled Condenser	$21,369	$0	$4,284	$0	$0	$25,654	$2,565	$0	$5,644	$33,863	$66
8.4	Steam Piping	$3,746	$0	$2,463	$0	$0	$6,208	$476	$0	$1,003	$7,687	$15
8.9	TG Foundations	$0	$753	$1,189	$0	$0	$1,941	$165	$0	$421	$2,527	$5
	SUBTOTAL 8.	**$50,185**	**$753**	**$12,594**	**$0**	**$0**	**$63,531**	**$5,760**	**$0**	**$10,296**	**$79,587**	**$155**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$3,592	$0	$459	$0	$0	$4,052	$345	$0	$440	$4,836	$9
9.2	Circulating Water Pumps	$662	$0	$29	$0	$0	$691	$52	$0	$74	$817	$2
9.3	Circ.Water System Auxiliaries	$58	$0	$8	$0	$0	$66	$6	$0	$7	$79	$0
9.4	Circ.Water Piping	$0	$1,700	$412	$0	$0	$2,112	$171	$0	$342	$2,625	$5
9.5	Make-up Water System	$143	$0	$191	$0	$0	$335	$29	$0	$55	$418	$1
9.6	Component Cooling Water Sys	$113	$135	$90	$0	$0	$338	$28	$0	$55	$421	$1
9.9	Circ.Water System Foundations	$0	$1,283	$2,038	$0	$0	$3,320	$281	$0	$720	$4,322	$8
	SUBTOTAL 9.	**$4,569**	**$3,118**	**$3,227**	**$0**	**$0**	**$10,914**	**$912**	**$0**	**$1,693**	**$13,519**	**$26**

Exhibit 3-15 Case S31A Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 2009-Oct-09
Project: Low Rank Western Coal Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case S31A - 1x512 MWnet 2x1 7FB NGCC
Plant Size: 512.4 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
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	$3,886	$0	$2,335	$0	$0	$6,221	$527	$0	$506	$7,254	$14
11.2	Station Service Equipment	$1,192	$0	$100	$0	$0	$1,292	$107	$0	$105	$1,504	$3
11.3	Switchgear & Motor Control	$1,469	$0	$250	$0	$0	$1,718	$143	$0	$186	$2,047	$4
11.4	Conduit & Cable Tray	$0	$702	$2,164	$0	$0	$2,865	$248	$0	$467	$3,580	$7
11.5	Wire & Cable	$0	$2,235	$1,372	$0	$0	$3,607	$232	$0	$576	$4,415	$9
11.6	Protective Equipment	$0	$533	$1,814	$0	$0	$2,347	$205	$0	$255	$2,808	$5
11.7	Standby Equipment	$99	$0	$91	$0	$0	$190	$16	$0	$21	$227	$0
11.8	Main Power Transformers	$9,368	$0	$138	$0	$0	$9,506	$645	$0	$1,015	$11,166	$22
11.9	Electrical Foundations	$0	$123	$302	$0	$0	$425	$36	$0	$92	$554	$1
	SUBTOTAL 11.	**$16,014**	**$3,593**	**$8,565**	**$0**	**$0**	**$28,172**	**$2,160**	**$0**	**$3,223**	**$33,555**	**$65**
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	$716	$0	$447	$0	$0	$1,163	$98	$0	$189	$1,451	$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	$214	$0	$128	$0	$0	$342	$29	$0	$56	$427	$1
12.7	Computer & Accessories	$3,425	$0	$102	$0	$0	$3,527	$290	$0	$382	$4,199	$8
12.8	Instrument Wiring & Tubing	$0	$578	$1,105	$0	$0	$1,683	$127	$0	$271	$2,081	$4
12.9	Other I & C Equipment	$1,277	$0	$2,897	$0	$0	$4,173	$363	$0	$454	$4,990	$10
	SUBTOTAL 12.	**$5,631**	**$578**	**$4,679**	**$0**	**$0**	**$10,888**	**$907**	**$0**	**$1,352**	**$13,147**	**$26**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$89	$1,770	$0	$0	$1,858	$165	$0	$405	$2,428	$5
13.2	Site Improvements	$0	$812	$1,009	$0	$0	$1,821	$161	$0	$396	$2,379	$5
13.3	Site Facilities	$1,659	$0	$1,636	$0	$0	$3,294	$291	$0	$717	$4,302	$8
	SUBTOTAL 13.	**$1,659**	**$901**	**$4,414**	**$0**	**$0**	**$6,974**	**$617**	**$0**	**$1,518**	**$9,109**	**$18**
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	$1,879	$2,502	$0	$0	$4,381	$360	$0	$711	$5,452	$11
14.3	Administration Building	$0	$443	$300	$0	$0	$743	$59	$0	$120	$923	$2
14.4	Circulation Water Pumphouse	$0	$148	$73	$0	$0	$221	$17	$0	$36	$274	$1
14.5	Water Treatment Buildings	$0	$182	$166	$0	$0	$348	$28	$0	$56	$432	$1
14.6	Machine Shop	$0	$384	$246	$0	$0	$630	$50	$0	$102	$782	$2
14.7	Warehouse	$0	$248	$150	$0	$0	$398	$31	$0	$64	$494	$1
14.8	Other Buildings & Structures	$0	$74	$54	$0	$0	$128	$10	$0	$21	$159	$0
14.9	Waste Treating Building & Str.	$0	$291	$519	$0	$0	$810	$67	$0	$132	$1,009	$2
	SUBTOTAL 14.	**$0**	**$3,885**	**$4,135**	**$0**	**$0**	**$8,020**	**$652**	**$0**	**$1,301**	**$9,973**	**$19**
	TOTAL COST	**$208,031**	**$18,210**	**$53,333**	**$0**	**$0**	**$279,574**	**$23,822**	**$0**	**$37,954**	**$341,350**	**$666**

Exhibit 3-16 Case S31A Owner's Costs

Owner's Costs	$x1000	$/kW
Preproduction Costs		
6 Months Fixed O&M	$3,038	$6
1 Month Variable O&M	$508	$1
25% of 1 Months Fuel Cost at 100% CF	$4,505	$9
2% of TPC	$6,827	$13
Total	**$14,878**	**$29**
Inventory Capital		
60 day supply of consumables at 100% CF	$164	$0
0.5% of TPC (spare parts)	$1,707	$3
Total	**$1,871**	**$4**
Initial Cost for Catalyst and Chemicals	**$0**	**$0**
Land	**$300**	**$1**
Other Owner's Costs	**$51,202**	**$100**
Financing Costs	**$9,216**	**$18**
Total Owner's Costs	**$77,468**	**$151**
Total Overnight Cost (TOC)	**$418,817**	**$817**
TASC Multiplier	1.075	
Total As-Spent Cost (TASC)	**$450,229**	**$879**

Exhibit 3-17 Case S31A Initial and Annual Operating and Maintenance Cost Summary

INITIAL & ANNUAL O&M EXPENSES						Cost Base (Jun):	2007
Case S31A - 1x512 MWnet 2x1 7FB NGCC						Heat Rate-net (Btu/kWh):	6,757
						MWe-net:	512
						Capacity Factor (%):	85
OPERATING & MAINTENANCE LABOR							
Operating Labor							
Operating Labor Rate(base):	34.65	$/hour					
Operating Labor Burden:	30.00	% of base					
Labor O-H Charge Rate:	25.00	% of labor					
			Total				
Skilled Operator	1.0		1.0				
Operator	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	$3.850
Maintenance Labor Cost						$2,888,333	$5.637
Administrative & Support Labor						$1,215,326	$2.372
Property Taxes and Insurance						$6,826,992	$13.323
TOTAL FIXED OPERATING COSTS						**$12,903,622**	**$25.182**
VARIABLE OPERATING COSTS							
							$/kWh-net
Maintenance Material Cost						**$4,332,499**	**$0.00114**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost			
Water (/1000 gallons)	0.00	780.48	1.08		**$0**	**$261,921**	**$0.00007**
Chemicals							
MU & WT Chem. (lbs)	0.00	4649.87	0.17		$0	$249,672	$0.00007
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.	0.06	5775.94		$0	$116,099	$0.00003
Ammonia (19% NH3) ton	0.00	5.45	129.80		$0	$219,434	$0.00006
Subtotal Chemicals					**$0**	**$585,205**	**$0.00015**
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**	**$5,179,625**	**$0.00136**
Fuel (MMBtu)	0	83,097	7.13		**$0**	**$183,795,700**	**$0.04817**

3.3.4 Case L31A – Performance Results

The plant produces a net output of 547 MW at a net plant efficiency of 50.6 percent (HHV basis).

Major stream flows are described in Exhibit 3-18 and overall plant performance is summarized in Exhibit 3-19**,** which includes auxiliary power requirements.

Exhibit 3-18 Case L31A Stream Table, NGCC without CO_2 Capture

	1	2	3	4	5	6	7	8
V-L Mole Fraction								
Ar	0.0093	0.0000	0.0089	0.0089	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
C_2H_6	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_3H_8	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_4H_{10}	0.0000	0.0040	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
CO_2	0.0003	0.0100	0.0413	0.0413	0.0000	0.0000	0.0000	0.0000
H_2O	0.0064	0.0000	0.0851	0.0851	1.0000	1.0000	1.0000	1.0000
N_2	0.7759	0.0160	0.7451	0.7451	0.0000	0.0000	0.0000	0.0000
O_2	0.2081	0.0000	0.1196	0.1196	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
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	104,424	4,282	108,830	108,830	20,569	13,340	13,340	27,253
V-L Flowrate (kg/hr)	3,017,333	74,190	3,091,523	3,091,523	370,555	240,318	240,318	490,976
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0
Temperature (°C)	4	38	628	102	566	32	32	32
Pressure (MPa, abs)	0.10	3.10	0.10	0.10	16.65	0.005	0.005	0.90
Enthalpy (kJ/kg)^A	14.12	46.30	831.54	242.05	3,472.36	2,360.98	2,360.98	135.69
Density (kg/m^3)	1.2	22.2	0.4	0.9	47.7	0.04	0.04	995.4
V-L Molecular Weight	28.895	17.328	28.407	28.407	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	230,215	9,439	239,928	239,928	45,347	29,409	29,409	60,083
V-L Flowrate (lb/hr)	6,652,082	163,560	6,815,642	6,815,642	816,935	529,812	529,812	1,082,416
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0
Temperature (°F)	40	100	1,162	216	1,050	90	90	90
Pressure (psia)	13.8	450.0	14.3	13.8	2,414.7	0.7	0.7	130.0
Enthalpy (Btu/lb)^A	6.1	19.9	357.5	104.1	1,492.8	1,015.0	1,015.0	58.3
Density (lb/ft^3)	0.074	1.384	0.023	0.054	2.977	0.002	0.002	62.141
	A - Reference conditions are 32.02 F & 0.089 PSIA							

Exhibit 3-19 Case L31A Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	358,600
Steam Turbine Power	198,400
TOTAL POWER, kWe	**557,000**
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	160
Boiler Feedwater Pumps	2,600
Circulating Water Pump	1,120
Ground Water Pumps	100
Cooling Tower Fans	700
Air Cooled Condenser Fan	2,340
SCR	10
Gas Turbine Auxiliaries	700
Steam Turbine Auxiliaries	100
Miscellaneous Balance of Plant[1]	500
Transformer Losses	1,690
TOTAL AUXILIARIES, kWe	**10,020**
NET POWER, kWe	**546,980**
Net Plant Efficiency (HHV)	50.6%
Net Plant Efficiency (LHV)	56.1%
Net Plant Heat Rate (HHV), kJ/kWhr (Btu/kWhr)	7,114 (6,743)
Net Plant Heat Rate (LHV), kJ/kWhr (Btu/kWhr)	6,414 (6,079)
CONDENSER COOLING DUTY, 10^6 kJ/h (10^6 Btu/h)	**1,087 (1,030)**
CONSUMABLES	
Natural Gas Feed Flow, kg/hr (lb/hr)	74,190 (163,560)
Thermal Input (HHV), kW_{th}	1,080,880
Thermal Input (LHV) , kW_{th}	974,553
Raw Water Withdrawal, m^3/min (gpm)	4.3 (1,148)
Raw Water Consumption, m^3/min (gpm)	3.4 (890)

[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 2.3. A summary of the plant air emissions for Case L31A is presented in Exhibit 3-20.

Exhibit 3-20 Case L31A 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 (0.009)	113 (124)	0.027 (0.060)
Particulates	Negligible	Negligible	Negligible
Hg	Negligible	Negligible	Negligible
CO_2	50.8 (118.3)	1,473,220 (1,623,947)	355 (783)
CO_2[1]			362 (797)

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

The operation of the modern, state-of-the-art gas turbine 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.

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 is shown in Exhibit 3-21. The carbon input to the plant consists of carbon in the air in addition to carbon in the natural gas. One hundred percent carbon conversion is assumed since carbon conversion for NGCC plants is typically about 99.9 percent.

Carbon in the air is not neglected here since the model accounts for air components throughout. Carbon leaves the plant as CO_2 in the stack gas.

Exhibit 3-21 Cases L31A Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Natural Gas	53,586 (118,138)	**Stack Gas**	53,998 (119,044)
Air (CO_2)	411 (907)		
Total	53,998 (119,044)	**Total**	53,998 (119,044)

Exhibit 3-22 shows the overall water balance for the plant. The exhibit is presented in an identical manner as was for Case S31A.

Exhibit 3-22 Case L31A 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	**0.08 (22)**	**0 (0)**	**0.08 (22)**	**0 (0)**	**0.08 (22)**
BFW Makeup	0.08 (22)	0 (0)	0.08 (22)		
Cooling Tower	**4.35 (1,148)**	**0.08 (22)**	**4.27 (1,127)**	**0.98 (258)**	**3.29 (868)**
BFW Blowdown	0 (0)	0.08 (22)	-0.08 (-22)		
Total	**4.43 (1,170)**	**0.08 (22)**	**4.35 (1,148)**	**0.98 (258)**	**3.37 (890)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the NGCC in Exhibit 3-23.

An overall plant energy balance is provided in tabular form in Exhibit 3-24. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-19) is calculated by multiplying the power out by a combined generator efficiency of 98.4 percent.

Exhibit 3-23 Case L31A Heat and Mass Balance, NGCC without CO_2 Capture

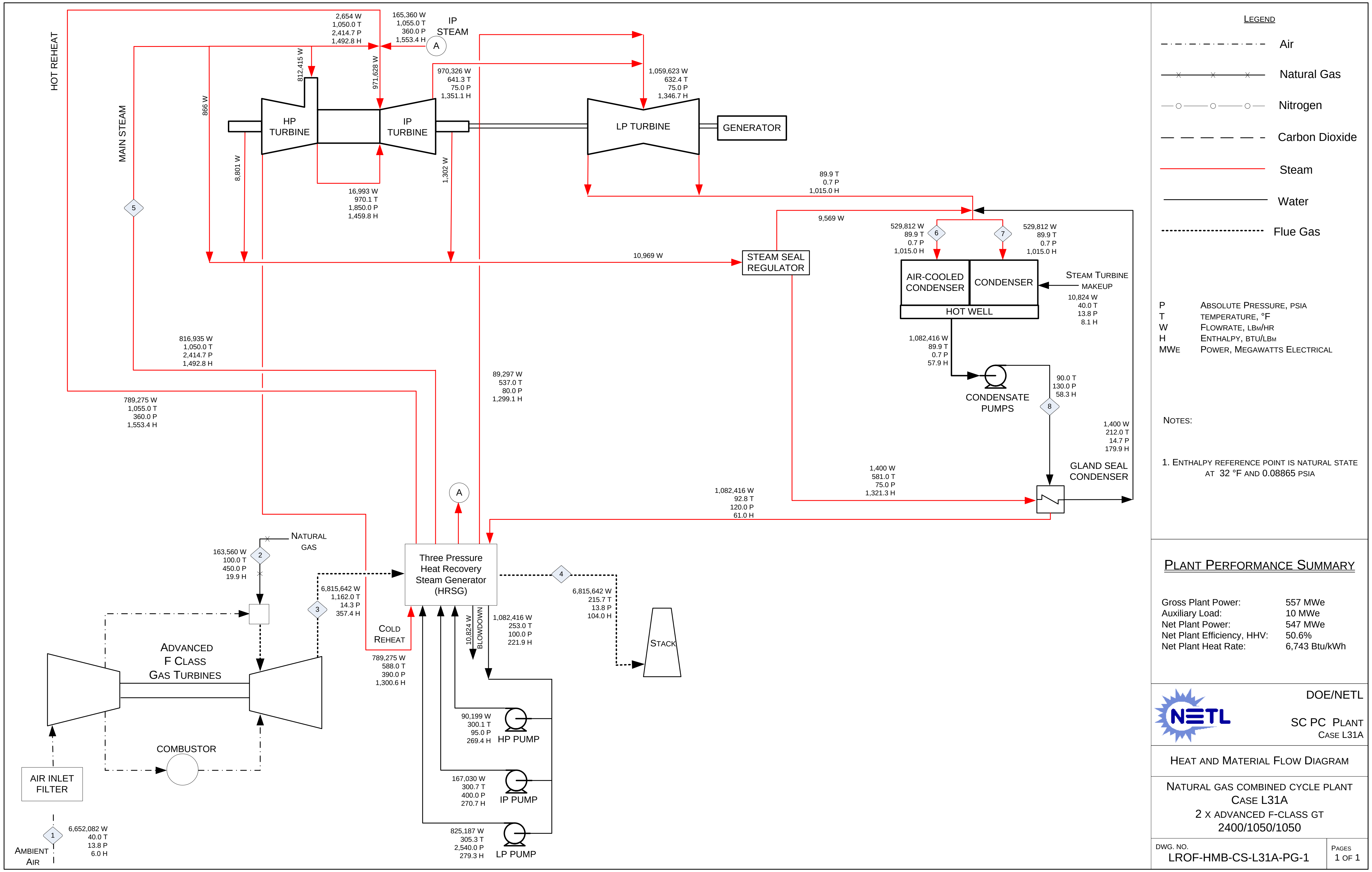

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Exhibit 3-24 Case L31A Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Natural Gas	3,891 (3,688)	0.8 (0.7)		3,892 (3,689)
GT Air		42.6 (40.4)		43 (40)
Raw Water Withdrawal		4.8 (4.6)		5 (5)
Auxiliary Power			36 (34)	36 (34)
Totals	**3,891 (3,688)**	**48.2 (45.7)**	**36 (34)**	**3,975 (3,768)**
Heat Out GJ/hr (MMBtu/hr)				
Cooling Tower Blowdown		5.3 (5.0)		5 (5)
Stack Gas		748 (709)		748 (709)
Condenser		1,083 (1,026)		1,083 (1,026)
Process Losses[1]		*134 (127)*		*134 (127)*
Power			2,005 (1,901)	2,005 (1,901)
Totals	**0 (0)**	**1,970 (1,867)**	**2,005 (1,901)**	**3,975 (3,768)**

[1] Process Losses are calculated by difference and reflect various turbine and other heat and work losses not modeled in Aspen.

3.3.5 Case L31A – 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 3.3.6. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 FUEL HANDLING

N/A

ACCOUNT 2 FUEL AND SORBENT PREPARATION AND FEED

N/A

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	647,310 liters (171,000 gal)	2 (0)
2	Condensate Pumps	Vertical canned	4,543 lpm @ 110 m H_2O (1,200 gpm @ 360 ft H_2O)	2 (1)
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP water: 3,445 lpm @ 2,103 m H_2O (910 gpm @ 6,900 ft H_2O) IP water: 681 lpm @ 283 m H_2O (180 gpm @ 930 ft H_2O) LP water: 379 lpm @ 24.4 m H_2O (100 gpm @ 80 ft H_2O)	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 m^3/min @ 0.7 MPa (450 scfm @ 100 psig)	2 (1)
6	Instrument Air Dryers	Duplex, regenerative	13 m^3/min (450 scfm)	2 (1)
7	Closed Cycle Cooling Heat Exchangers	Plate and frame	13 MMkJ/hr (13 MMBtu/hr)	2 (0)
8	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	5,300 lpm @ 21 m H_2O (1,400 gpm @ 70 ft H_2O)	2 (1)

Equipment No.	Description	Type	Design Condition	Operating Qty (Spares)
9	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H_2O (1,000 gpm @ 350 ft H_2O)	1 (1)
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H_2O (700 gpm @ 250 ft H_2O)	1 (1)
11	Raw Water Pumps	Stainless steel, single suction	2,650 lpm @ 18 m H_2O (700 gpm @ 60 ft H_2O)	2 (1)
12	Filtered Water Pumps	Stainless steel, single suction	151 lpm @ 49 m H_2O (40 gpm @ 160 ft H_2O)	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	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	61 m^3/min @ 3.1 MPa (2,166 acfm @ 450 psia) 41 cm (16 in) standard wall pipe	16 km (0)
16	Gas Metering Station	--	61 m^3/min (2,166 acfm)	1 (0)
17	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	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 7.5 m (25 ft) diameter	2 (0)
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 203,806 kg/h, 16.5 MPa/566°C (449,314 lb/h, 2,400 psig/1,050°F)	2 (0)
			Reheat steam - 238,159 kg/h, 2.4 MPa/566°C (525,049 lb/h, 345 psig/1,050°F)	
3	SCR Reactor	Space for spare layer	1,700,973 kg/h (3,750,000 lb/h)	2 (0)
4	SCR Catalyst	--	Space available for an additional catalyst layer	1 layer (0)
5	Dilution Air Blowers	Centrifugal	10 m^3/min @ 107 cm WG (370 scfm @ 42 in WG)	2 (1)
6	Ammonia Feed Pump	Centrifugal	3.8 lpm @ 91 m H_2O (1 gpm @ 300 ft H_2O)	2 (1)
7	Ammonia Storage Tank	Horizontal tank	64,353 liter (17,000 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	209 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	230 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	590 MMkJ/hr (560 MMBtu/hr), Inlet water temperature 8°C (47°F), Water temperature rise 11°C (20°F)	1 (0)
5	Air-cooled Condenser	---	590 GJ/hr (560 MMBtu/hr), Condensing temperature 32°C (90°F), Ambient temperature 4°C (40°F)	1 (0)

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty (Spares)
1	Circulating Water Pumps	Vertical, wet pit	113,563 lpm @ 30.5 m (30,000 gpm @ 100 ft)	2 (1)
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	2°C (36°F) wet bulb / 8°C (47°F) CWT / 19°C (67°F) HWT 1,219 MMkJ/hr (1,156 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	L12A 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, 220 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	L12A Design Condition	Operating Qty (Spares)
1	DCS - Main Control	Monitor/keyboard, Operator printer, Engineering printer	Operator stations/printers and engineering stations/printers	1 (0)
2	DCS - Processor	Microprocessor with redundant input/output	N/A	1 (0)
3	DCS - Data Highway	Fiber optic	Fully redundant, 25% spare	1 (0)

3.3.6 Case L31A – Cost Estimating

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-25 shows the total plant capital cost summary organized by cost account and Exhibit 3-26 shows a more detailed breakdown of the capital costs. Exhibit 3-27 itemizes the owner's costs and Exhibit 3-28 shows the initial and annual O&M costs.

The estimated TOC of the NGCC with no CO_2 capture is \$782/kW. No process contingency was included in this case because all elements of the technology are commercially proven. The project contingency is 9.1 percent of TOC. The COE is 63.6 mills/kWh.

Exhibit 3-25 Case L31A Total Plant Cost Summary

Client: USDOE/NETL | **Report Date:** 2009-Oct-09

Project: Low Rank Western Coal Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case L31A - 1x547 MWnet 2x1 7FB NGCC

Plant Size: 547.0 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	$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	$20,979	$3,972	$5,118	$0	$0	**$30,069**	$2,533	$0	$5,129	**$37,732**	$69
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**	$175
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**	**$178**
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**	$81
7.2-7.9	SCR System, Ductwork and Stack	$1,138	$906	$1,056	$0	$0	**$3,100**	$264	$0	$549	**$3,913**	$7
	SUBTOTAL 7	**$34,096**	**$906**	**$5,335**	**$0**	**$0**	**$40,337**	**$3,434**	**$0**	**$4,589**	**$48,361**	**$88**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$23,537	$0	$3,793	$0	$0	**$27,329**	$2,349	$0	$2,968	**$32,646**	$60
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$28,692	$786	$9,346	$0	$0	**$38,825**	$3,649	$0	$7,748	**$50,222**	$92
	SUBTOTAL 8	**$52,229**	**$786**	**$13,139**	**$0**	**$0**	**$66,154**	**$5,997**	**$0**	**$10,716**	**$82,868**	**$152**
9	COOLING WATER SYSTEM	$4,765	$3,241	$3,350	$0	$0	**$11,356**	$949	$0	$1,760	**$14,065**	$26
10	ASH/SPENT SORBENT HANDLING SYS	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
11	ACCESSORY ELECTRIC PLANT	$16,538	$3,697	$8,860	$0	$0	**$29,096**	$2,231	$0	$3,326	**$34,653**	$63
12	INSTRUMENTATION & CONTROL	$5,758	$591	$4,785	$0	$0	**$11,134**	$927	$0	$1,382	**$13,443**	$25
13	IMPROVEMENTS TO SITE	$1,710	$929	$4,552	$0	$0	**$7,191**	$636	$0	$1,566	**$9,393**	$17
14	BUILDINGS & STRUCTURES	$0	$3,996	$4,263	$0	$0	**$8,259**	$671	$0	$1,340	**$10,270**	$19
	TOTAL COST	**$211,369**	**$18,839**	**$54,950**	**$0**	**$0**	**$285,158**	**$24,302**	**$0**	**$38,816**	**$348,275**	$637

Exhibit 3-26 Case L31A Total Plant Cost Details

	Client:	USDOE/NETL								**Report Date:**	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
					TOTAL PLANT COST SUMMARY							
	Case:	Case L31A - 1x547 MWnet 2x1 7FB NGCC										
	Plant Size:	547.0	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	$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	$2,343	$2,414	$1,985	$0	$0	$6,742	$556	$0	$1,095	$8,392	$15
3.2	Water Makeup & Pretreating	$878	$92	$459	$0	$0	$1,429	$122	$0	$310	$1,860	$3
3.3	Other Feedwater Subsystems	$1,068	$361	$304	$0	$0	$1,733	$139	$0	$281	$2,153	$4
3.4	Service Water Systems	$104	$214	$693	$0	$0	$1,011	$88	$0	$220	$1,319	$2
3.5	Other Boiler Plant Systems	$696	$270	$625	$0	$0	$1,591	$135	$0	$259	$1,985	$4
3.6	Natural Gas, incl. pipeline	$14,665	$501	$436	$0	$0	$15,602	$1,322	$0	$2,539	$19,463	$36
3.7	Waste Treatment Equipment	$317	$0	$181	$0	$0	$498	$43	$0	$108	$649	$1
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$908	$121	$436	$0	$0	$1,465	$127	$0	$318	$1,909	$3
	SUBTOTAL 3.	**$20,979**	**$3,972**	**$5,118**	**$0**	**$0**	**$30,069**	**$2,533**	**$0**	**$5,129**	**$37,732**	**$69**
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 3-26 Case L31A Total Plant Cost Details (Continued)

	Client:	USDOE/NETL								Report Date:	2009-Oct-09	
	Project:	Low Rank Western Coal Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case L31A - 1x547 MWnet 2x1 7FB NGCC										
	Plant Size:	547.0	MW,net	Estimate Type:		Conceptual			Cost Base (Jun)	2007	($x1000)	
Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/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	$175
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**	**$178**
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	$81
7.2	SCR System	$1,138	$478	$671	$0	$0	$2,288	$197	$0	$373	$2,857	$5
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.	**$34,096**	**$906**	**$5,335**	**$0**	**$0**	**$40,337**	**$3,434**	**$0**	**$4,589**	**$48,361**	**$88**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$23,537	$0	$3,793	$0	$0	$27,329	$2,349	$0	$2,968	$32,646	$60
8.2	Turbine Plant Auxiliaries	$159	$0	$363	$0	$0	$522	$46	$0	$57	$625	$1
8.3a	Condenser & Auxiliaries	$2,423	$0	$724	$0	$0	$3,147	$270	$0	$342	$3,758	$7
8.3b	Air Cooled Condenser	$22,209	$0	$4,453	$0	$0	$26,662	$2,666	$0	$5,866	$35,193	$64
8.4	Steam Piping	$3,901	$0	$2,565	$0	$0	$6,466	$495	$0	$1,044	$8,005	$15
8.9	TG Foundations	$0	$786	$1,242	$0	$0	$2,029	$172	$0	$440	$2,641	$5
	SUBTOTAL 8.	**$52,229**	**$786**	**$13,139**	**$0**	**$0**	**$66,154**	**$5,997**	**$0**	**$10,716**	**$82,868**	**$152**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$3,743	$0	$479	$0	$0	$4,222	$359	$0	$458	$5,039	$9
9.2	Circulating Water Pumps	$695	$0	$31	$0	$0	$726	$55	$0	$78	$859	$2
9.3	Circ.Water System Auxiliaries	$61	$0	$8	$0	$0	$69	$6	$0	$7	$82	$0
9.4	Circ.Water Piping	$0	$1,772	$429	$0	$0	$2,201	$178	$0	$357	$2,736	$5
9.5	Make-up Water System	$148	$0	$198	$0	$0	$346	$30	$0	$56	$433	$1
9.6	Component Cooling Water Sys	$118	$141	$94	$0	$0	$352	$30	$0	$57	$439	$1
9.9	Circ.Water System Foundations	$0	$1,329	$2,111	$0	$0	$3,440	$292	$0	$746	$4,477	$8
	SUBTOTAL 9.	**$4,765**	**$3,241**	**$3,350**	**$0**	**$0**	**$11,356**	**$949**	**$0**	**$1,760**	**$14,065**	**$26**

Exhibit 3-26 Case L31A Total Plant Cost Details (Continued)

Client: USDOE/NETL **Report Date:** 2009-Oct-09
Project: Low Rank Western Coal Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case L31A - 1x547 MWnet 2x1 7FB NGCC
Plant Size: 547.0 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
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	$4,036	$0	$2,425	$0	$0	$6,461	$547	$0	$526	$7,534	$14
11.2	Station Service Equipment	$1,222	$0	$103	$0	$0	$1,325	$109	$0	$108	$1,541	$3
11.3	Switchgear & Motor Control	$1,506	$0	$256	$0	$0	$1,762	$146	$0	$191	$2,099	$4
11.4	Conduit & Cable Tray	$0	$719	$2,218	$0	$0	$2,937	$254	$0	$479	$3,670	$7
11.5	Wire & Cable	$0	$2,291	$1,407	$0	$0	$3,698	$238	$0	$590	$4,526	$8
11.6	Protective Equipment	$0	$558	$1,898	$0	$0	$2,456	$215	$0	$267	$2,938	$5
11.7	Standby Equipment	$102	$0	$93	$0	$0	$196	$17	$0	$21	$234	$0
11.8	Main Power Transformers	$9,672	$0	$144	$0	$0	$9,817	$666	$0	$1,048	$11,531	$21
11.9	Electrical Foundations	$0	$129	$316	$0	$0	$445	$38	$0	$97	$580	$1
	SUBTOTAL 11.	**$16,538**	**$3,697**	**$8,860**	**$0**	**$0**	**$29,096**	**$2,231**	**$0**	**$3,326**	**$34,653**	**$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	$732	$0	$457	$0	$0	$1,189	$101	$0	$193	$1,483	$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	$219	$0	$131	$0	$0	$350	$30	$0	$57	$436	$1
12.7	Computer & Accessories	$3,502	$0	$105	$0	$0	$3,607	$297	$0	$390	$4,293	$8
12.8	Instrument Wiring & Tubing	$0	$591	$1,130	$0	$0	$1,721	$130	$0	$278	$2,128	$4
12.9	Other I & C Equipment	$1,305	$0	$2,962	$0	$0	$4,268	$371	$0	$464	$5,102	$9
	SUBTOTAL 12.	**$5,758**	**$591**	**$4,785**	**$0**	**$0**	**$11,134**	**$927**	**$0**	**$1,382**	**$13,443**	**$25**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$91	$1,825	$0	$0	$1,916	$170	$0	$417	$2,504	$5
13.2	Site Improvements	$0	$838	$1,040	$0	$0	$1,878	$166	$0	$409	$2,453	$4
13.3	Site Facilities	$1,710	$0	$1,687	$0	$0	$3,397	$300	$0	$739	$4,436	$8
	SUBTOTAL 13.	**$1,710**	**$929**	**$4,552**	**$0**	**$0**	**$7,191**	**$636**	**$0**	**$1,566**	**$9,393**	**$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	$1,948	$2,594	$0	$0	$4,542	$373	$0	$737	$5,652	$10
14.3	Administration Building	$0	$452	$307	$0	$0	$759	$60	$0	$123	$943	$2
14.4	Circulation Water Pumphouse	$0	$151	$75	$0	$0	$226	$18	$0	$37	$280	$1
14.5	Water Treatment Buildings	$0	$190	$173	$0	$0	$362	$29	$0	$59	$450	$1
14.6	Machine Shop	$0	$393	$251	$0	$0	$644	$51	$0	$104	$799	$1
14.7	Warehouse	$0	$254	$153	$0	$0	$406	$32	$0	$66	$504	$1
14.8	Other Buildings & Structures	$0	$76	$55	$0	$0	$131	$10	$0	$21	$163	$0
14.9	Waste Treating Building & Str.	$0	$297	$531	$0	$0	$828	$69	$0	$134	$1,031	$2
	SUBTOTAL 14.	**$0**	**$3,996**	**$4,263**	**$0**	**$0**	**$8,259**	**$671**	**$0**	**$1,340**	**$10,270**	**$19**
	TOTAL COST	**$211,369**	**$18,839**	**$54,950**	**$0**	**$0**	**$285,158**	**$24,302**	**$0**	**$38,816**	**$348,275**	**$637**

Exhibit 3-27 Case L31A Owner's Costs

Owner's Costs	$x1000	$/kW
Preproduction Costs		
6 Months Fixed O&M	$3,056	$6
1 Month Variable O&M	$517	$1
25% of 1 Months Fuel Cost at 100% CF	$4,799	$9
2% of TPC	$6,966	$13
Total	**$15,337**	**$28**
Inventory Capital		
60 day supply of consumables at 100% CF	$174	$0
0.5% of TPC (spare parts)	$1,741	$3
Total	**$1,915**	**$4**
Initial Cost for Catalyst and Chemicals	**$0**	**$0**
Land	**$300**	**$1**
Other Owner's Costs	**$52,241**	**$96**
Financing Costs	**$9,403**	**$17**
Total Owner's Costs	**$79,197**	**$145**
Total Overnight Cost (TOC)	**$427,473**	**$782**
TASC Multiplier	1.075	
Total As-Spent Cost (TASC)	**$459,533**	**$840**

Exhibit 3-28 Case L31A Initial and Annual Operating and Maintenance Cost Summary

INITIAL & ANNUAL O&M EXPENSES		
	Cost Base (Jun):	2007
Case L31A - 1x547 MWnet 2x1 7FB NGCC	Heat Rate-net (Btu/kWh):	6,743
	MWe-net:	547
	Capacity Factor (%):	85

OPERATING & MAINTENANCE LABOR

Operating Labor

Operating Labor Rate(base):	34.65	$/hour
Operating Labor Burden:	30.00	% of base
Labor O-H Charge Rate:	25.00	% of labor

		Total
Skilled Operator	1.0	1.0
Operator	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	$3.607
Maintenance Labor Cost	$2,916,909	$5.333
Administrative & Support Labor	$1,222,470	$2.235
Property Taxes and Insurance	$6,965,508	$12.734
TOTAL FIXED OPERATING COSTS	**$13,077,858**	**$23.909**

VARIABLE OPERATING COSTS

						$/kWh-net
Maintenance Material Cost					**$4,375,364**	**$0.00107**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water (/1000 gallons)	0.00	826.56	1.08	**$0**	**$277,385**	**$0.00007**
Chemicals						
MU & WT Chem. (lbs)	0.00	4924.41	0.17	$0	$264,413	$0.00006
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	$123,497	$0.00003
Ammonia (19% NH3) ton	0.00	5.80	129.80	$0	$233,416	$0.00006
Subtotal Chemicals				**$0**	**$621,326**	**$0.00015**
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**	**$5,274,074**	**$0.00129**
Fuel (MMBtu)	0	88,519	7.13	**$0**	**$195,789,067**	**$0.04807**

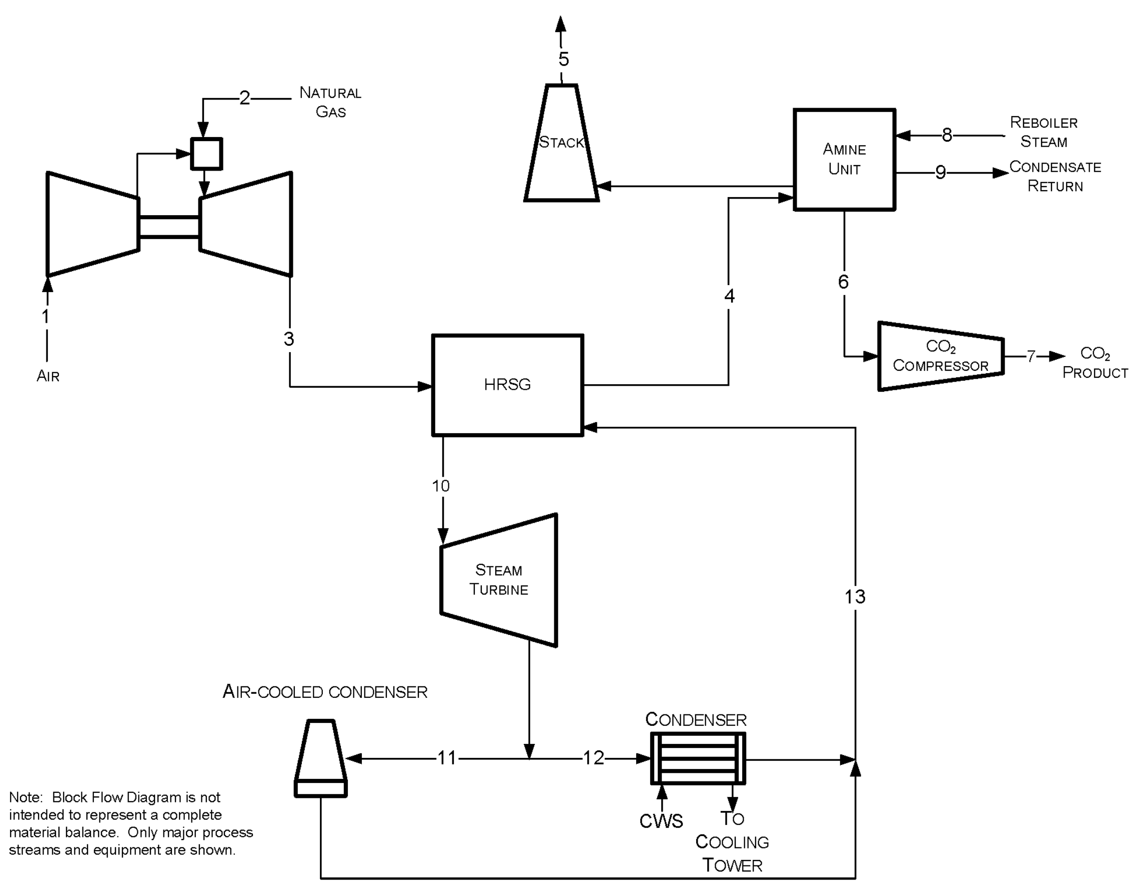
3.4 CASES S31B AND L31B PROCESS DESCRIPTION

The plant configuration for these cases is the same as cases S31A and L31A with the exception being the Econamine FG Plus CDR technology was added for CO_2 capture. The nominal net output decreases because the CT fixes the output and the CDR facility significantly increases the auxiliary power load.

A BFD is shown in Exhibit 3-29. Flue gas from the heat recovery system is processed in the Econamine system before exiting the stack. Since the CDR facility process description was provided in Section 3.1.5, it is not repeated here.

The tables in Exhibit 3-30 and Exhibit 3-41, for cases S31B and L31B respectively, 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.

Exhibit 3-29 Cases S31B and L31B Process Flow Diagram, NGCC with CO_2 Capture



The balance of Section 3.4 is organized as follows:

- Performance Results - provides the main modeling results including the performance summary, environmental performance, water balance, mass and energy balance diagrams, and energy balance table.
- Major Equipment List - provides an itemized list of major equipment with account codes that correspond to the cost accounts in the Cost Estimating section.
- Cost Estimating - provides a summary of capital and operating costs.

3.4.1 Case S31B – Performance Results

The plant produces a net output of 435 MW at a net plant efficiency of 42.9 percent (HHV basis).

Major stream flows are described in Exhibit 3-30 and overall plant performance is summarized in Exhibit 3-31, which includes auxiliary power requirements.

Exhibit 3-30 Case S31B Stream Table, NGCC with CO_2 Capture

	1	2	3	4	5	6	7	8	9	10	11	12	13
V-L Mole Fraction													
Ar	0.0093	0.0000	0.0089	0.0089	0.0098	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH_4	0.0000	0.9310	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_2H_6	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_3H_8	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_4H_{10}	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0003	0.0100	0.0413	0.0413	0.0045	0.9893	1.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0064	0.0000	0.0849	0.0849	0.0385	0.0107	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.7759	0.0160	0.7451	0.7451	0.8161	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2081	0.0000	0.1198	0.1198	0.1312	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
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	98,174	4,020	102,311	102,311	93,416	3,840	3,799	16,400	16,400	19,410	5,646	5,646	11,850
V-L Flowrate (kg/hr)	2,836,748	69,653	2,906,401	2,906,401	2,647,417	167,925	167,182	295,457	295,457	349,679	101,713	101,713	213,479
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	6	38	628	142	30	21	51	152	151	566	32	32	32
Pressure (MPa, abs)	0.09	3.10	0.09	0.09	0.09	0.16	15.27	0.51	0.49	16.65	0.005	0.005	0.90
Enthalpy (kJ/kg)[A]	15.26	46.30	832.10	284.57	91.45	26.65	-164.90	2,746.79	635.72	3,472.36	2,354.18	2,354.18	135.69
Density (kg/m^3)	1.1	22.2	0.4	0.7	1.0	2.9	653.5	2.7	915.8	47.7	0.04	0.04	995.4
V-L Molecular Weight	28.895	17.328	28.408	28.408	28.340	43.731	44.010	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	216,437	8,862	225,556	225,556	205,947	8,466	8,375	36,157	36,157	42,792	12,447	12,447	26,124
V-L Flowrate (lb/hr)	6,253,958	153,559	6,407,517	6,407,517	5,836,555	370,210	368,573	651,371	651,371	770,911	224,240	224,240	470,640
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	42	100	1,163	288	85	69	124	306	304	1,050	90	90	90
Pressure (psia)	13.0	450.0	13.5	13.0	13.0	23.5	2,214.7	73.5	71.0	2,414.7	0.7	0.7	130.0
Enthalpy (Btu/lb)[A]	6.6	19.9	357.7	122.3	39.3	11.5	-70.9	1,180.9	273.3	1,492.8	1,012.1	1,012.1	58.3
Density (lb/ft^3)	0.070	1.384	0.022	0.046	0.063	0.183	40.800	0.169	57.172	2.977	0.002	0.002	62.141
	A - Reference conditions are 32.02 F & 0.089 PSIA												

Exhibit 3-31 Case S31B Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	335,300
Steam Turbine Power	134,700
TOTAL POWER, kWe	**470,000**
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	70
Boiler Feedwater Pumps	2,440
Amine System Auxiliaries	8,800
CO_2 Compression	13,950
Circulating Water Pump	3,400
Ground Water Pumps	280
Cooling Tower Fans	2,210
Air Cooled Condenser Fan	1,040
SCR	10
Gas Turbine Auxiliaries	700
Steam Turbine Auxiliaries	100
Miscellaneous Balance of Plant[1]	500
Transformer Losses	1,440
TOTAL AUXILIARIES, kWe	**34,940**
NET POWER, kWe	**435,060**
Net Plant Efficiency (HHV)	42.9%
Net Plant Efficiency (LHV)	47.5%
Net Plant Heat Rate (HHV), kJ/kWhr (Btu/kWhr)	8,397 (7,959)
Net Plant Heat Rate (LHV), kJ/kWhr (Btu/kWhr)	7,571 (7,176)
CONDENSER COOLING DUTY, 10^6 kJ/h (10^6 Btu/h)	**464 (440)**
CONSUMABLES	
Natural Gas Feed Flow, kg/hr (lb/hr)	69,653 (153,559)
Thermal Input (HHV), kW_{th}	1,014,787
Thermal Input (LHV) , kW_{th}	914,961
Raw Water Withdrawal, m^3/min (gpm)	11.8 (3,107)
Raw Water Consumption, m^3/min (gpm)	8.8 (2,315)

[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 2.3. A summary of the plant air emissions for Case S31B is presented in Exhibit 3-32.

Exhibit 3-32 Case S31B 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 (0.009)	106 (117)	0.030 (0.067)
Particulates	Negligible	Negligible	Negligible
Hg	Negligible	Negligible	Negligible
CO_2	5.1 (11.8)	138,315 (152,466)	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 gas turbine 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 2.3, if the fuel contains the maximum amount of sulfur compounds allowed in pipeline natural gas, the NGCC SO_2 emissions would be 9.7 tonnes/yr (10.7 tons/yr) at 85 percent CF, or 0.00073 kg/GJ (0.0017 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.

The carbon balance is shown in Exhibit 3-33. The carbon input to the plant consists of carbon in the air in addition to carbon in the natural gas. One hundred percent carbon conversion is assumed since carbon conversion for NGCC plants is typically about 99.9 percent.

Carbon in the air is not neglected here since the model accounts for air components throughout. Carbon leaves the plant as CO_2 in the stack gas. 90.7 percent of carbon is separated in the MEA process, compressed and sent to sequestration, reducing CO_2 emissions to 94 lb/net-MWh. 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 natural gas, represented by the following fraction:

(Carbon in CO_2 Product)/(Carbon in the Natural Gas)*100 or
100,590/(110,914) *100 or
90.7 percent

Exhibit 3-33 Cases S31B Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Natural Gas	50,310 (110,914)	**Stack Gas**	5,070 (11,177)
Air (CO_2)	387 (852)	**CO_2 Product**	45,627 (100,590)
Total	**50,696 (111,766)**	**Total**	**50,696 (111,766)**

Exhibit 3-34 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, such as BFW blowdown, 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. 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 3-34 Case S31B 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	**0.04 (11)**	**0 (0)**	**0.04 (11)**	**0 (0)**	**0.04 (11)**
Condenser Makeup	**0.08 (20)**	**0 (0)**	**0.08 (20)**	**0 (0)**	**0.08 (20)**
BFW Makeup	0.08 (20)	0 (0)	0.08 (20)		
Cooling Tower	**13.23 (3,494)**	**1.61 (425)**	**11.62 (3,069)**	**2.97 (786)**	**8.64 (2,283)**
BFW Blowdown	0 (0)	0.08 (20)	-0.08 (-20)		
Flue Gas Condensate	0 (0)	1.51 (398)	-1.51 (-398)		
CO_2 Product Condensate	0 (0)	0.03 (7)	-0.03 (-7)		
Total	**13.35 (3,526)**	**1.61 (425)**	**11.74 (3,100)**	**2.97 (786)**	**8.76 (2,315)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the NGCC in Exhibit 3-35.

An overall plant energy balance is provided in tabular form in Exhibit 3-36. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-31) is calculated by multiplying the power out by a combined generator efficiency of 98.4 percent.

Exhibit 3-35 Case S31B Heat and Mass Balance, NGCC with CO_2 Capture

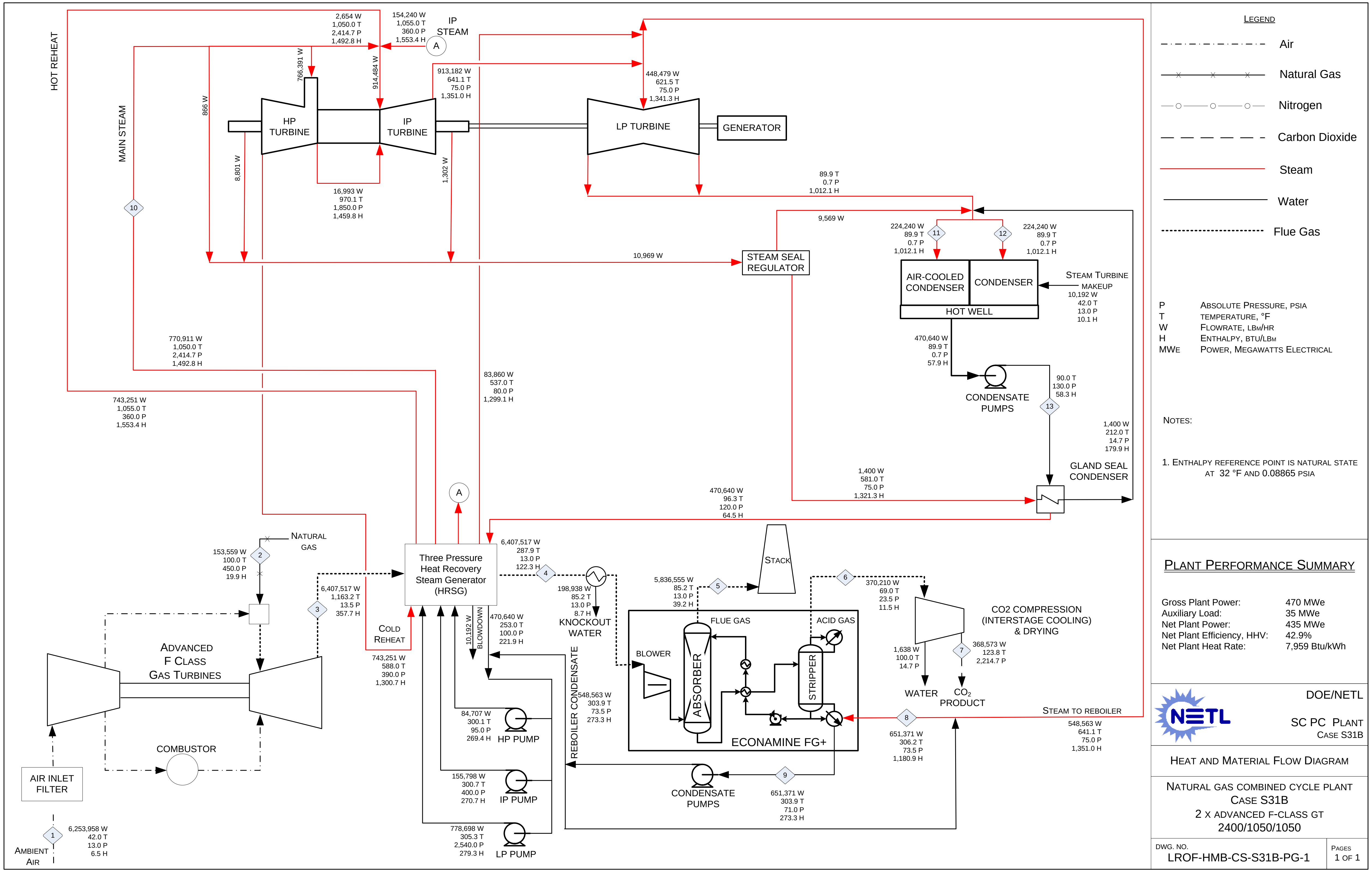


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Exhibit 3-36 Case S31B Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Natural Gas	3,653 (3,463)	0.9 (0.9)		3,654 (3,463)
GT Air		43.3 (41.0)		43 (41)
Raw Water Withdrawal		16.4 (15.5)		16 (16)
Auxiliary Power			126 (119)	126 (119)
Totals	**3,653 (3,463)**	**60.6 (57.4)**	**126 (119)**	**3,840 (3,639)**
Heat Out GJ/hr (MMBtu/hr)				
CO_2		-27.6 (-26.1)		-28 (-26)
Cooling Tower Blowdown		16.6 (15.7)		17 (16)
Econamine Losses		891.3 (844.8)		891 (845)
CO_2 Compression Intercooling		77.9 (73.9)		78 (74)
Stack Gas		242 (229)		242 (229)
Condenser		464 (440)		464 (440)
Process Losses[1]		*483 (458)*		*483 (458)*
Power			1,692 (1,604)	1,692 (1,604)
Totals	**0 (0)**	**2,148 (2,036)**	**1,692 (1,604)**	**3,840 (3,639)**

[1] Process Losses are calculated by difference and reflect various turbine and other heat and work losses not modeled in Aspen.

3.4.2 Case S31B – 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 3.4.3. In general, the design conditions include a 10 percent contingency for flows and heat duties and a 21 percent contingency for heads on pumps and fans.

ACCOUNT 1 FUEL HANDLING

N/A

ACCOUNT 2 FUEL AND SORBENT PREPARATION AND FEED

N/A

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	609,456 liters (161,000 gal)	2 (0)
2	Condensate Pumps	Vertical canned	1,968 lpm @ 110 m H_2O (520 gpm @ 6,900 ft H_2O)	2 (1)
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP water: 3,255 lpm @ 2,103 m H_2O (860 gpm @ 6,900 ft H_2O) IP water: 644 lpm @ 283 m H_2O (170 gpm @ 930 ft H_2O) LP water: 341 lpm @ 24.4 m H_2O (90 gpm @ 80 ft H_2O)	2 (1)
4	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)

Equipment No.	Description	Type	Design Condition	Operating Qty (Spares)
5	Service Air Compressors	Flooded Screw	13 m^3/min @ 0.7 MPa (450 scfm @ 100 psig)	2 (1)
6	Instrument Air Dryers	Duplex, regenerative	13 m^3/min (450 scfm)	2 (1)
7	Closed Cycle Cooling Heat Exchangers	Plate and frame	13 MMkJ/hr (13 MMBtu/hr)	2 (0)
8	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	5,300 lpm @ 21 m H_2O (1,400 gpm @ 70 ft H_2O)	2 (1)
9	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H_2O (1,000 gpm @ 350 ft H_2O)	1 (1)
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H_2O (700 gpm @ 250 ft H_2O)	1 (1)
11	Raw Water Pumps	Stainless steel, single suction	6,435 lpm @ 18 m H_2O (1,700 gpm @ 60 ft H_2O)	2 (1)
12	Filtered Water Pumps	Stainless steel, single suction	151 lpm @ 49 m H_2O (40 gpm @ 160 ft H_2O)	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	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	58 m^3/min @ 3.1 MPa (2,033 acfm @ 450 psia) 41 cm (16 in) standard wall pipe	16 km (0)

Equipment No.	Description	Type	Design Condition	Operating Qty (Spares)
16	Gas Metering Station	--	58 m^3/min (2,033 acfm)	1 (0)
17	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	170 MW	2 (0)
2	Gas Turbine Generator	TEWAC	190 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 6.5 m (21 ft) diameter	2 (0)
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 192,324 kg/hr, 16.5 MPa/566°C (424,001 lb/hr, 2,400 psig/1,050°F)	2 (0)
			Reheat steam - 223,903 kg/hr, 2.4 MPa/566°C (493,620 lb/hr, 345 psig/1,050°F)	
3	SCR Reactor	Space for spare layer	1,456,033 kg/h (3,210,000 lb/h)	2 (0)

Equipment No.	Description	Type	Design Condition	Operating Qty (Spares)
4	SCR Catalyst	--	Space available for an additional catalyst layer	1 layer (0)
5	Dilution Air Blowers	Centrifugal	10 m^3/min @ 107 cm WG (350 scfm @ 42 in WG)	2 (1)
6	Ammonia Feed Pump	Centrifugal	3.8 lpm @ 91 m H_2O (1 gpm @ 300 ft H_2O)	2 (1)
7	Ammonia Storage Tank	Horizontal tank	60,567 liter (16,000 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	142 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	160 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	250 MMkJ/hr, (240 MMBtu/hr), Inlet H_2O temperature 9°C (48°F), H_2O temperature rise 11°C (20°F)	1 (0)
5	Air-cooled Condenser	---	250 GJ/hr (240 MMBtu/hr), Condensing temperature 32°C (90°F), Ambient temperature 6°C (42°F)	1 (0)

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty (Spares)
1	Circulating Water Pumps	Vertical, wet pit	340,690 lpm @ 30.5 m (90,000 gpm @ 100 ft)	2 (1)
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	3°C (37°F) wet bulb / 9°C (48°F) CWT / 20°C (68°F) HWT 539 MMkJ/hr (511 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	L12A Design Condition	Operating Qty (Spares)
1	CTG Transformer	Oil-filled	24 kV/345 kV, 190 MVA, 3-ph, 60 Hz	2 (0)
2	STG Transformer	Oil-filled	24 kV/345 kV, 130 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 (1)
4	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 22 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)

Equipment No.	Description	Type	L12A Design Condition	Operating Qty (Spares)
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	L12A Design Condition	Operating Qty (Spares)
1	DCS - Main Control	Monitor/keyboard, Operator printer, Engineering printer	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)

3.4.3 Case S31B – Cost Estimating

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-37 shows the total plant capital cost summary organized by cost account and Exhibit 3-38 shows a more detailed breakdown of the capital costs. Exhibit 3-39 itemizes the owner's costs and Exhibit 3-40 shows the initial and annual O&M costs.

The estimated TOC of the NGCC with CO_2 capture is $1,607/kW. Process contingency accounts for 3.9 percent of the TOC. The project contingency is 10.9 percent of TOC. The COE, including CO_2 TS&M costs of 3.4 mills/kWh, is 92.9 mills/kWh.

Exhibit 3-37 Case S31B Total Plant Cost Summary

	Client:	USDOE/NETL								Report Date:	2009-Oct-19	
	Project:	Low Rank Western Coal Baseline Study										
TOTAL PLANT COST SUMMARY												
	Case:	Case S31B - 1x435 MWnet 2x1 7FB NGCC w/ CO2 Capture										
	Plant Size:	435.1	MW,net	Estimate Type:		Conceptual		Cost Base (Jun)		2007	($x1000)	
Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/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	$22,829	$4,396	$6,973	$0	$0	**$34,198**	$2,888	$0	$5,963	**$43,049**	$99
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	$115,518	$0	$35,189	$0	$0	**$150,707**	$12,909	$26,586	$38,040	**$228,242**	$525
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$75,295	$0	$4,804	$0	$0	**$80,099**	$6,800	$0	$8,690	**$95,589**	$220
6.2-6.9	Combustion Turbine Other	$0	$719	$744	$0	$0	**$1,462**	$122	$0	$317	**$1,901**	$4
	SUBTOTAL 6	**$75,295**	**$719**	**$5,548**	**$0**	**$0**	**$81,561**	**$6,922**	**$0**	**$9,007**	**$97,491**	**$224**
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**	$102
7.2-7.9	SCR System, Ductwork and Stack	$1,006	$851	$978	$0	$0	**$2,835**	$241	$0	$505	**$3,582**	$8
	SUBTOTAL 7	**$33,963**	**$851**	**$5,257**	**$0**	**$0**	**$40,071**	**$3,412**	**$0**	**$4,546**	**$48,029**	**$110**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$17,924	$0	$3,200	$0	$0	**$21,124**	$1,816	$0	$2,294	**$25,234**	$58
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$17,489	$593	$6,554	$0	$0	**$24,636**	$2,265	$0	$4,811	**$31,712**	$73
	SUBTOTAL 8	**$35,413**	**$593**	**$9,754**	**$0**	**$0**	**$45,760**	**$4,081**	**$0**	**$7,105**	**$56,946**	**$131**
9	COOLING WATER SYSTEM	$7,217	$5,431	$4,875	$0	$0	**$17,523**	$1,456	$0	$2,686	**$21,664**	$50
10	ASH/SPENT SORBENT HANDLING SYS	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
11	ACCESSORY ELECTRIC PLANT	$19,399	$5,344	$11,597	$0	$0	**$36,341**	$2,798	$0	$4,235	**$43,373**	$100
12	INSTRUMENTATION & CONTROL	$6,097	$626	$5,066	$0	$0	**$11,789**	$982	$589	$1,531	**$14,891**	$34
13	IMPROVEMENTS TO SITE	$1,657	$900	$4,409	$0	$0	**$6,966**	$616	$0	$1,516	**$9,098**	$21
14	BUILDINGS & STRUCTURES	$0	$3,767	$3,888	$0	$0	**$7,656**	$621	$0	$1,242	**$9,519**	$22
	TOTAL COST	**$317,388**	**$22,627**	**$92,556**	**$0**	**$0**	**$432,571**	**$36,686**	**$27,175**	**$75,870**	**$572,302**	$1,315

Exhibit 3-38 Case S31B Total Plant Cost Details

Client:	USDOE/NETL			Report Date:	2009-Oct-19
Project:	Low Rank Western Coal Baseline Study				

TOTAL PLANT COST SUMMARY

Case:	Case S31B - 1x435 MWnet 2x1 7FB NGCC w/ CO2 Capture						
Plant Size:	435.1	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											
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	$2,247	$2,315	$1,904	$0	$0	$6,466	$533	$0	$1,050	$8,049	$19
3.2	Water Makeup & Pretreating	$1,776	$186	$928	$0	$0	$2,889	$246	$0	$627	$3,763	$9
3.3	Other Feedwater Subsystems	$1,025	$346	$291	$0	$0	$1,662	$134	$0	$269	$2,065	$5
3.4	Service Water Systems	$210	$432	$1,402	$0	$0	$2,044	$179	$0	$445	$2,668	$6
3.5	Other Boiler Plant Systems	$1,408	$546	$1,264	$0	$0	$3,218	$273	$0	$524	$4,015	$9
3.6	Natural Gas, incl. pipeline	$14,640	$453	$395	$0	$0	$15,488	$1,313	$0	$2,520	$19,320	$44
3.7	Waste Treatment Equipment	$641	$0	$365	$0	$0	$1,006	$88	$0	$219	$1,313	$3
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$883	$118	$424	$0	$0	$1,424	$123	$0	$309	$1,857	$4
	SUBTOTAL 3.	**$22,829**	**$4,396**	**$6,973**	**$0**	**$0**	**$34,198**	**$2,888**	**$0**	**$5,963**	**$43,049**	**$99**
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 3-38 Case S31B Total Plant Cost Details (Continued)

	Client:	USDOE/NETL								Report Date:	2009-Oct-19	
	Project:	Low Rank Western Coal Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case S31B - 1x435 MWnet 2x1 7FB NGCC w/ CO2 Capture										
	Plant Size:	435.1	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
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	$101,984	$0	$30,944	$0	$0	$132,928	$11,386	$26,586	$34,180	$205,079	$471
5B.2	CO2 Compression & Drying	$13,534	$0	$4,246	$0	$0	$17,779	$1,523	$0	$3,861	$23,163	$53
	SUBTOTAL 5.	**$115,518**	**$0**	**$35,189**	**$0**	**$0**	**$150,707**	**$12,909**	**$26,586**	**$38,040**	**$228,242**	**$525**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$75,295	$0	$4,804	$0	$0	$80,099	$6,800	$0	$8,690	$95,589	$220
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.	**$75,295**	**$719**	**$5,548**	**$0**	**$0**	**$81,561**	**$6,922**	**$0**	**$9,007**	**$97,491**	**$224**
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	$102
7.2	SCR System	$1,006	$422	$593	$0	$0	$2,022	$174	$0	$329	$2,525	$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.	**$33,963**	**$851**	**$5,257**	**$0**	**$0**	**$40,071**	**$3,412**	**$0**	**$4,546**	**$48,029**	**$110**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$17,924	$0	$3,200	$0	$0	$21,124	$1,816	$0	$2,294	$25,234	$58
8.2	Turbine Plant Auxiliaries	$131	$0	$294	$0	$0	$426	$37	$0	$46	$510	$1
8.3	Condenser & Auxiliaries	$1,339	$0	$400	$0	$0	$1,739	$149	$0	$189	$2,077	$5
8.3b	Air Cooled Condenser	$12,273	$0	$2,461	$0	$0	$14,733	$1,473	$0	$3,241	$19,448	$45
8.4	Steam Piping	$3,746	$0	$2,463	$0	$0	$6,208	$476	$0	$1,003	$7,687	$18
8.9	TG Foundations	$0	$593	$936	$0	$0	$1,529	$130	$0	$332	$1,990	$5
	SUBTOTAL 8.	**$35,413**	**$593**	**$9,754**	**$0**	**$0**	**$45,760**	**$4,081**	**$0**	**$7,105**	**$56,946**	**$131**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$5,103	$0	$653	$0	$0	$5,756	$490	$0	$625	$6,871	$16
9.2	Circulating Water Pumps	$1,500	$0	$83	$0	$0	$1,583	$119	$0	$170	$1,872	$4
9.3	Circ.Water System Auxiliaries	$117	$0	$16	$0	$0	$133	$11	$0	$14	$159	$0
9.4	Circ.Water Piping	$0	$3,426	$830	$0	$0	$4,256	$344	$0	$690	$5,290	$12
9.5	Make-up Water System	$269	$0	$359	$0	$0	$628	$54	$0	$102	$784	$2
9.6	Component Cooling Water Sys	$227	$272	$181	$0	$0	$681	$57	$0	$111	$848	$2
9.9	Circ.Water System Foundations	$0	$1,733	$2,753	$0	$0	$4,486	$380	$0	$973	$5,840	$13
	SUBTOTAL 9.	**$7,217**	**$5,431**	**$4,875**	**$0**	**$0**	**$17,523**	**$1,456**	**$0**	**$2,686**	**$21,664**	**$50**

Exhibit 3-38 Case S31B Total Plant Cost Details (Continued)

	Client:	USDOE/NETL								Report Date:	2009-Oct-19	
	Project:	Low Rank Western Coal Baseline Study										
	TOTAL PLANT COST SUMMARY											
	Case:	Case S31B - 1x435 MWnet 2x1 7FB NGCC w/ CO2 Capture										
	Plant Size:	435.1	MW,net	Estimate Type:		Conceptual			Cost Base (Jun)	2007	($x1000)	
Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
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	$5,116	$0	$3,074	$0	$0	$8,190	$694	$0	$666	$9,550	$22
11.2	Station Service Equipment	$1,906	$0	$161	$0	$0	$2,066	$171	$0	$168	$2,405	$6
11.3	Switchgear & Motor Control	$2,349	$0	$399	$0	$0	$2,748	$228	$0	$298	$3,274	$8
11.4	Conduit & Cable Tray	$0	$1,122	$3,460	$0	$0	$4,583	$397	$0	$747	$5,726	$13
11.5	Wire & Cable	$0	$3,574	$2,195	$0	$0	$5,769	$372	$0	$921	$7,062	$16
11.6	Protective Equipment	$0	$533	$1,814	$0	$0	$2,347	$205	$0	$255	$2,808	$6
11.7	Standby Equipment	$94	$0	$86	$0	$0	$181	$15	$0	$20	$216	$0
11.8	Main Power Transformers	$9,934	$0	$128	$0	$0	$10,062	$683	$0	$1,074	$11,819	$27
11.9	Electrical Foundations	$0	$114	$281	$0	$0	$395	$34	$0	$86	$515	$1
	SUBTOTAL 11.	**$19,399**	**$5,344**	**$11,597**	**$0**	**$0**	**$36,341**	**$2,798**	**$0**	**$4,235**	**$43,373**	**$100**
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	$775	$0	$484	$0	$0	$1,259	$107	$63	$214	$1,643	$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	$139	$0	$0	$370	$31	$19	$63	$483	$1
12.7	Computer & Accessories	$3,708	$0	$111	$0	$0	$3,819	$314	$191	$432	$4,756	$11
12.8	Instrument Wiring & Tubing	$0	$626	$1,196	$0	$0	$1,822	$137	$91	$308	$2,358	$5
12.9	Other I & C Equipment	$1,382	$0	$3,136	$0	$0	$4,519	$393	$226	$514	$5,651	$13
	SUBTOTAL 12.	**$6,097**	**$626**	**$5,066**	**$0**	**$0**	**$11,789**	**$982**	**$589**	**$1,531**	**$14,891**	**$34**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$89	$1,768	$0	$0	$1,856	$165	$0	$404	$2,425	$6
13.2	Site Improvements	$0	$811	$1,008	$0	$0	$1,819	$161	$0	$396	$2,376	$5
13.3	Site Facilities	$1,657	$0	$1,634	$0	$0	$3,291	$291	$0	$716	$4,297	$10
	SUBTOTAL 13.	**$1,657**	**$900**	**$4,409**	**$0**	**$0**	**$6,966**	**$616**	**$0**	**$1,516**	**$9,098**	**$21**
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	$1,544	$2,056	$0	$0	$3,600	$296	$0	$584	$4,480	$10
14.3	Administration Building	$0	$449	$305	$0	$0	$754	$60	$0	$122	$936	$2
14.4	Circulation Water Pumphouse	$0	$143	$71	$0	$0	$214	$17	$0	$35	$265	$1
14.5	Water Treatment Buildings	$0	$383	$350	$0	$0	$733	$59	$0	$119	$911	$2
14.6	Machine Shop	$0	$390	$249	$0	$0	$639	$51	$0	$103	$793	$2
14.7	Warehouse	$0	$252	$152	$0	$0	$404	$32	$0	$65	$501	$1
14.8	Other Buildings & Structures	$0	$75	$55	$0	$0	$130	$10	$0	$21	$162	$0
14.9	Waste Treating Building & Str.	$0	$295	$527	$0	$0	$822	$68	$0	$133	$1,023	$2
	SUBTOTAL 14.	**$0**	**$3,767**	**$3,888**	**$0**	**$0**	**$7,656**	**$621**	**$0**	**$1,242**	**$9,519**	**$22**
	TOTAL COST	**$317,388**	**$22,627**	**$92,556**	**$0**	**$0**	**$432,571**	**$36,686**	**$27,175**	**$75,870**	**$572,302**	**$1,315**

Exhibit 3-39 Case S31B Owner's Costs

Owner's Costs	$x1000	$/kW
Preproduction Costs		
6 Months Fixed O&M	$4,197	$10
1 Month Variable O&M	$844	$2
25% of 1 Months Fuel Cost at 100% CF	$4,505	$10
2% of TPC	$11,446	$26
Total	**$20,992**	**$48**
Inventory Capital		
60 day supply of consumables at 100% CF	$441	$1
0.5% of TPC (spare parts)	$2,862	$7
Total	**$3,303**	**$8**
Initial Cost for Catalyst and Chemicals	**$755**	**$2**
Land	**$300**	**$1**
Other Owner's Costs	**$85,845**	**$197**
Financing Costs	**$15,452**	**$36**
Total Owner's Costs	**$126,647**	**$291**
Total Overnight Cost (TOC)	**$698,949**	**$1,607**
TASC Multiplier	1.078	
Total As-Spent Cost (TASC)	**$753,467**	**$1,732**

Exhibit 3-40 Case S31B Initial and Annual Operating and Maintenance Cost Summary

INITIAL & ANNUAL O&M EXPENSES

Case S31B - 1x435 MWnet 2x1 7FB NGCC w/ CO2 Capture				Cost Base (Jun):		2007
				Heat Rate-net (Btu/kWh):		7,959
				MWe-net:		435
				Capacity Factor (%):		85

OPERATING & MAINTENANCE LABOR

Operating Labor

Operating Labor Rate(base):	34.65	$/hour
Operating Labor Burden:	30.00	% of base
Labor O-H Charge Rate:	25.00	% of labor

		Total
Skilled Operator	1.0	1.0
Operator	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	$5.741
Maintenance Labor Cost	$4,216,800	$9.692
Administrative & Support Labor	$1,678,645	$3.858
Property Taxes and Insurance	$11,446,039	$26.309
TOTAL FIXED OPERATING COSTS	**$19,839,265**	**$45.601**

VARIABLE OPERATING COSTS

						$/kWh-net
Maintenance Material Cost					**$6,325,200**	**$0.00195**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water (/1000 gallons)	0.00	2,229.12	1.08	**$0**	**$748,070**	**$0.00023**
Chemicals						
MU & WT Chem.(lbs)	0.00	13,280.45	0.17	$0	$713,086	$0.00022
MEA Solvent (ton)	316.29	0.44	2,249.89	$711,622	$310,049	$0.00010
Activated Carbon (lb)	0.00	530.59	1.05	$0	$172,875	$0.00005
Corrosion Inhibitor	0.00	0.00	0.00	$43,332	$2,063	$0.00000
SCR Catalyst (m3)	w/equip.	0.06	5,775.94	$0	$116,099	$0.00004
Ammonia (19% NH3) (ton)	0.00	5.45	129.80	$0	$219,434	$0.00007
Subtotal Chemicals				**$754,953**	**$1,533,607**	**$0.00047**
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				**$754,953**	**$8,606,876**	**$0.00266**
Fuel (MMBtu)	0	83,103	7.13	**$0**	**$183,810,997**	**$0.05674**

3.4.4 Case L31B – Performance Results

The plant produces a net output of 465 MW at a net plant efficiency of 43.0 percent (HHV basis).

Major stream flows are described in Exhibit 3-41 and overall plant performance is summarized in Exhibit 3-42 which includes auxiliary power requirements.

Exhibit 3-41 Case L31B Stream Table, NGCC without CO_2 Capture

	1	2	3	4	5	6	7	8	9	10	11	12	13
V-L Mole Fraction													
Ar	0.0093	0.0000	0.0089	0.0089	0.0098	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CH_4	0.0000	0.9310	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_2H_6	0.0000	0.0320	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_3H_8	0.0000	0.0070	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
C_4H_{10}	0.0000	0.0040	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.0003	0.0100	0.0413	0.0413	0.0045	0.9893	1.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0064	0.0000	0.0851	0.0851	0.0362	0.0107	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.7759	0.0160	0.7451	0.7451	0.8181	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.2081	0.0000	0.1196	0.1196	0.1314	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
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg_{mol}/hr)	104,424	4,282	108,830	108,830	99,118	4,090	4,046	17,468	17,468	20,569	5,985	5,985	12,543
V-L Flowrate (kg/hr)	3,017,333	74,190	3,091,523	3,091,523	2,811,389	178,860	178,068	314,689	314,689	370,555	107,817	107,817	225,973
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°C)	4	38	628	142	30	21	51	152	151	566	32	32	32
Pressure (MPa, abs)	0.10	3.10	0.10	0.10	0.10	0.16	15.27	0.51	0.49	16.65	0.005	0.005	0.90
Enthalpy (kJ/kg)[A]	14.12	46.30	831.54	284.90	87.73	26.65	-164.90	2,746.79	635.72	3,472.36	2,354.20	2,354.20	135.69
Density (kg/m^3)	1.2	22.2	0.4	0.8	1.1	2.9	653.5	2.7	915.8	47.7	0.04	0.04	995.4
V-L Molecular Weight	28.895	17.328	28.407	28.407	28.364	43.731	44.010	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb_{mol}/hr)	230,215	9,439	239,928	239,928	218,518	9,017	8,920	38,510	38,510	45,347	13,194	13,194	27,653
V-L Flowrate (lb/hr)	6,652,082	163,560	6,815,642	6,815,642	6,198,051	394,318	392,574	693,772	693,772	816,935	237,696	237,696	498,185
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	0	0	0	0	0
Temperature (°F)	40	100	1,162	288	85	69	124	306	304	1,050	90	90	90
Pressure (psia)	13.8	450.0	14.3	13.8	13.8	23.5	2,214.7	73.5	71.0	2,414.7	0.7	0.7	130.0
Enthalpy (Btu/lb)[A]	6.1	19.9	357.5	122.5	37.7	11.5	-70.9	1,180.9	273.3	1,492.8	1,012.1	1,012.1	58.3
Density (lb/ft^3)	0.074	1.384	0.023	0.049	0.067	0.183	40.800	0.169	57.172	2.977	0.002	0.002	62.141
	A - Reference conditions are 32.02 F & 0.089 PSIA												

Exhibit 3-42 Case L31B Plant Performance Summary

POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine Power	358,600
Steam Turbine Power	143,000
TOTAL POWER, kWe	**501,600**
AUXILIARY LOAD SUMMARY, kWe	
Condensate Pumps	70
Boiler Feedwater Pumps	2,580
Amine System Auxiliaries	9,400
CO_2 Compression	14,860
Circulating Water Pump	3,640
Ground Water Pumps	300
Cooling Tower Fans	2,230
Air Cooled Condenser Fan	1,040
SCR	10
Gas Turbine Auxiliaries	700
Steam Turbine Auxiliaries	100
Miscellaneous Balance of Plant[1]	500
Transformer Losses	1,530
TOTAL AUXILIARIES, kWe	**36,960**
NET POWER, kWe	**464,640**
Net Plant Efficiency (HHV)	43.0%
Net Plant Efficiency (LHV)	47.7%
Net Plant Heat Rate (HHV), kJ/kWhr (Btu/kWhr)	8,375 (7,938)
Net Plant Heat Rate (LHV), kJ/kWhr (Btu/kWhr)	7,551 (7,157)
CONDENSER COOLING DUTY, 10^6 kJ/h (10^6 Btu/h)	**496 (470)**
CONSUMABLES	
Natural Gas Feed Flow, kg/hr (lb/hr)	74,190 (163,560)
Thermal Input (HHV), kW_{th}	1,080,880
Thermal Input (LHV) , kW_{th}	974,553
Raw Water Withdrawal, m^3/min (gpm)	12.5 (3,309)
Raw Water Consumption, m^3/min (gpm)	9.3 (2,461)

[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 2.3. A summary of the plant air emissions for Case L31B is presented in Exhibit 3-43.

Exhibit 3-43 Case L31B 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 (0.009)	113 (124)	0.030 (0.066)
Particulates	Negligible	Negligible	Negligible
Hg	Negligible	Negligible	Negligible
CO_2	5.1 (11.8)	147,322 (162,395)	39 (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 gas turbine 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.

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.

The carbon balance is shown in Exhibit 3-44. The carbon input to the plant consists of carbon in the air in addition to carbon in the natural gas. One hundred percent carbon conversion is assumed since carbon conversion for NGCC plants is typically about 99.9 percent.

Carbon in the air is not neglected here since the model accounts for air components throughout. Carbon leaves the plant as CO_2 in the stack gas. 90.7 percent of carbon is separated in the MEA process, compressed and sent to sequestration, reducing CO_2 emissions to 94 lb/MWh of net power. 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 natural gas, represented by the following fraction:

(Carbon in CO_2 Product)/(Carbon in the Natural Gas)*100 or
107,140/(118,138) *100 or
90.7 percent

Exhibit 3-44 Case L31B Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Natural Gas	53,586 (118,138)	**Stack Gas**	5,400 (11,904)
Air (CO_2)	411 (907)	**CO_2 Product**	48,598 (107,140)
Total	53,998 (119,044)	**Total**	53,998 (119,044)

Exhibit 3-45 shows the overall water balance for the plant. The exhibit is presented in an identical manner as was for Case S31B.

Exhibit 3-45 Case L31B 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	**0.04 (12)**	**0 (0)**	**0.04 (12)**	**0 (0)**	**0.04 (12)**
Condenser Makeup	**0.08 (22)**	**0 (0)**	**0.08 (22)**	**0 (0)**	**0.08 (22)**
BFW Makeup	0.08 (22)	0 (0)	0.08 (22)		
Cooling Tower	**14.16 (3,740)**	**1.79 (472)**	**12.37 (3,269)**	**3.18 (841)**	**9.19 (2,427)**
BFW Blowdown	0 (0)	0.08 (22)	-0.08 (-22)		
Flue Gas Condensate	0 (0)	1.68 (443)	-1.68 (-443)		
CO_2 Product Condensate	0 (0)	0.03 (7)	-0.03 (-7)		
Total	**14.28 (3,773)**	**1.79 (472)**	**12.50 (3,302)**	**3.18 (841)**	**9.31 (2,461)**

Heat and Mass Balance Diagrams

A heat and mass balance diagram is shown for the NGCC in Exhibit 3-46.

An overall plant energy balance is provided in tabular form in Exhibit 3-47. The power out is the combined CT and steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 3-42) is calculated by multiplying the power out by a combined generator efficiency of 98.4 percent.

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Exhibit 3-46 Case L31B Heat and Mass Balance, NGCC without CO_2 Capture

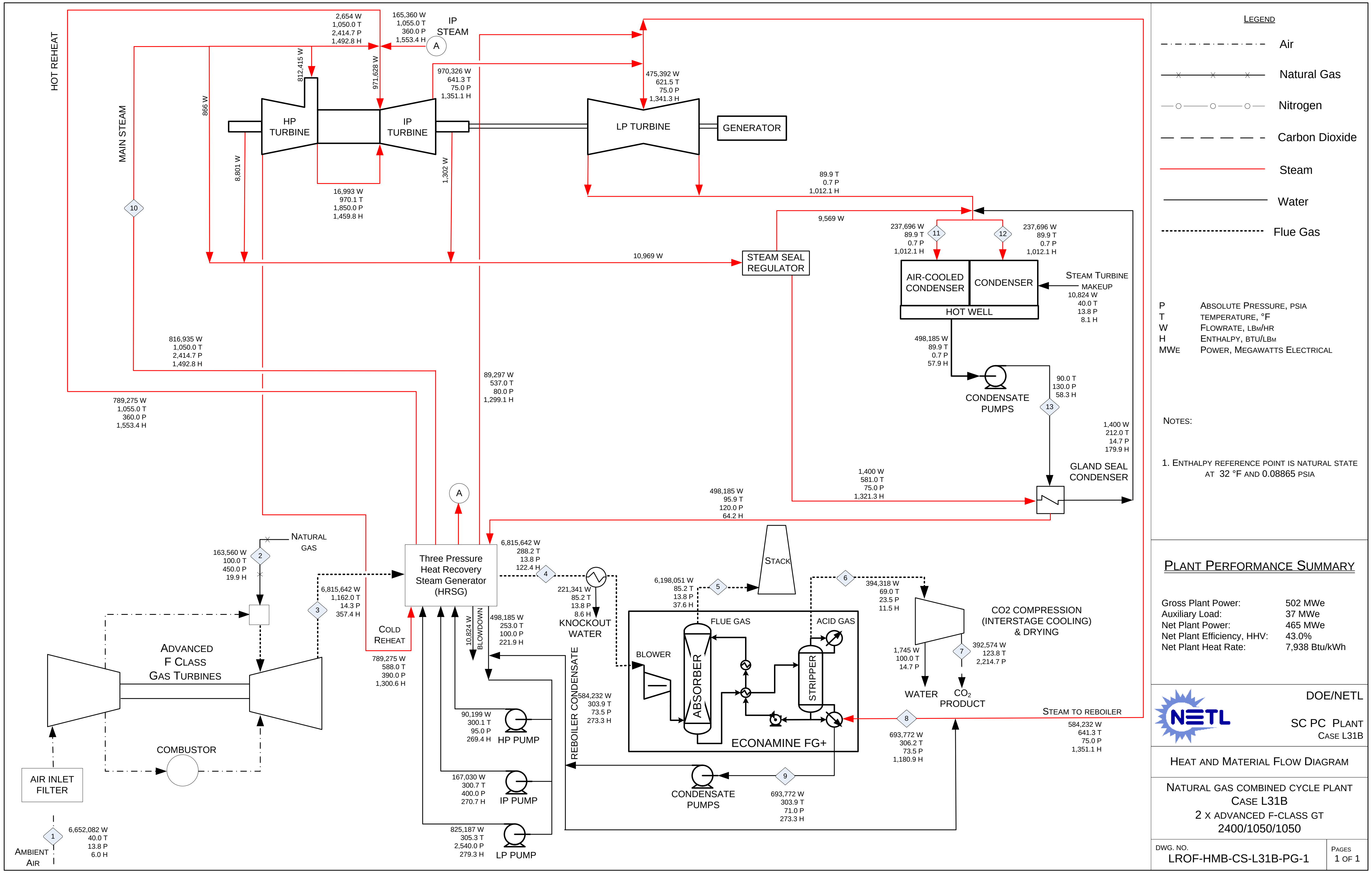

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Exhibit 3-47 Case L31B Overall Energy Balance (0°C [32°F] Reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Natural Gas	3,891 (3,688)	0.8 (0.7)		3,892 (3,689)
GT Air		42.6 (40.4)		43 (40)
Raw Water Withdrawal		13.9 (13.2)		14 (13)
Auxiliary Power			133 (126)	133 (126)
Totals	**3,891 (3,688)**	**57.3 (54.3)**	**133 (126)**	**4,082 (3,869)**
Heat Out GJ/hr (MMBtu/hr)				
CO_2		-29.4 (-27.8)		-29 (-28)
Cooling Tower Blowdown		17.2 (16.3)		17 (16)
Econamine Losses		960.6 (910.5)		961 (911)
CO_2 Compression Intercooling		83.0 (78.7)		83 (79)
Stack Gas		247 (234)		247 (234)
Condenser		491 (465)		491 (465)
Process Losses[1]		*506 (480)*		*506 (480)*
Power			1,806 (1,712)	1,806 (1,712)
Totals	**0 (0)**	**2,276 (2,157)**	**1,806 (1,712)**	**4,082 (3,869)**

[1] Process Losses are calculated by difference and reflect various turbine and other heat and work losses not modeled in Aspen.

3.4.5 Case L31B – 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 3.4.6. 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 HANDLING

N/A

ACCOUNT 2 FUEL AND SORBENT PREPARATION AND FEED

N/A

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	647,310 liters (171,000 gal)	2 (0)
2	Condensate Pumps	Vertical canned	2,082 lpm @ 110 m H_2O (550 gpm @ 360 ft H_2O)	2 (1)
3	Boiler Feedwater Pump	Horizontal, split case, multi-stage, centrifugal, with interstage bleed for IP and LP feedwater	HP water: 3,445 lpm @ 2,103 m H_2O (910 gpm @ 6,900 ft H_2O) IP water: 681 lpm @ 283 m H_2O (180 gpm @ 930 ft H_2O) LP water: 379 lpm @ 24.4 m H_2O (100 gpm @ 80 ft H_2O)	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 m^3/min @ 0.7 MPa (450 scfm @ 100 psig)	2 (1)
6	Instrument Air Dryers	Duplex, regenerative	13 m^3/min (450 scfm)	2 (1)
7	Closed Cycle Cooling Heat Exchangers	Plate and frame	13 MMkJ/hr (13 MMBtu/hr)	2 (0)
8	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	5,300 lpm @ 21 m H_2O (1,400 gpm @ 70 ft H_2O)	2 (1)

Equipment No.	Description	Type	Design Condition	Operating Qty (Spares)
9	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 107 m H_2O (1,000 gpm @ 350 ft H_2O)	1 (1)
10	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 76 m H_2O (700 gpm @ 250 ft H_2O)	1 (1)
11	Raw Water Pumps	Stainless steel, single suction	6,814 lpm @ 18 m H_2O (1,800 gpm @ 60 ft H_2O)	2 (1)
12	Filtered Water Pumps	Stainless steel, single suction	151 lpm @ 49 m H_2O (40 gpm @ 160 ft H_2O)	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	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	61 m^3/min @ 3.1 MPa (2,166 acfm @ 450 psia) 41 cm (16 in) standard wall pipe	16 km (0)
16	Gas Metering Station	--	61 m^3/min (2,166 acfm)	1 (0)
17	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	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 6.5 m (21 ft) diameter	2 (0)
2	Heat Recovery Steam Generator	Drum, multi-pressure with economizer section and integral deaerator	Main steam - 203,806 kg/h, 16.5 MPa/566°C (449,314 lb/h, 2,400 psig/1,050°F)	2 (0)
			Reheat steam - 238,159 kg/h, 2.4 MPa/566°C (525,049 lb/h, 345 psig/1,050°F)	
3	SCR Reactor	Space for spare layer	1,546,752 kg/h (3,410,000 lb/h)	2 (0)
4	SCR Catalyst	--	Space available for an additional catalyst layer	1 layer (0)
5	Dilution Air Blowers	Centrifugal	10 m^3/min @ 107 cm WG (370 scfm @ 42 in WG)	2 (1)
6	Ammonia Feed Pump	Centrifugal	3.8 lpm @ 91 m H_2O (1 gpm @ 300 ft H_2O)	2 (1)
7	Ammonia Storage Tank	Horizontal tank	64,353 liter (17,000 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	151 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)

Equipment No.	Description	Type	Design Condition	Operating Qty (Spares)
4	Surface Condenser	Single pass, divided waterbox including vacuum pumps	270 MMkJ/hr, (260 MMBtu/hr), Inlet water temperature 8°C (47°F), Water temperature rise 11°C (20°F)	1 (0)
5	Air-cooled Condenser	--	270 GJ/hr (260 MMBtu/hr), Condensing temperature 32°C (90°F), Ambient temperature 4°C (40°F)	1 (0)

ACCOUNT 9 COOLING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Operating Qty (Spares)
1	Circulating Water Pumps	Vertical, wet pit	363,402 lpm @ 30.5 m (96,000 gpm @ 100 ft)	2 (1)
2	Cooling Tower	Evaporative, mechanical draft, multi-cell	2°C (36°F) wet bulb / 8°C (47°F) CWT / 19°C (67°F) HWT 569 MMkJ/hr (540 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	L12A 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, 140 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	1 (1)
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)

Equipment No.	Description	Type	L12A Design Condition	Operating Qty (Spares)
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	L12A Design Condition	Operating Qty (Spares)
1	DCS - Main Control	Monitor/keyboard, Operator printer, Engineering printer	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)

3.4.6 Case L31B – Cost Estimating

The cost estimating methodology was described previously in Section 2.6. Exhibit 3-48 shows the total plant capital cost summary organized by cost account and Exhibit 3-49 shows a more detailed breakdown of the capital costs. Exhibit 3-50 itemizes the owner's costs and Exhibit 3-51 shows the initial and annual O&M costs.

The estimated TOC of the NGCC with CO_2 capture is $1,548/kW. Process contingency accounts for 3.9 percent of the TOC. The project contingency is 10.9 percent of TOC. The COE, including CO_2 TS&M costs of 3.3 mills/kWh, is 91.4 mills/kWh.

Exhibit 3-48 Case L31B Total Plant Cost Summary

Client: USDOE/NETL — **Report Date:** 2009-Oct-19
Project: Low Rank Western Coal Baseline Study

TOTAL PLANT COST SUMMARY

Case: Case L31B - 1x465 MWnet 2x1 7FB NGCC w/ CO2 Capture
Plant Size: 464.6 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	$23,198	$4,585	$7,280	$0	$0	**$35,063**	$2,961	$0	$6,122	**$44,146**	$95
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	$119,974	$0	$36,547	$0	$0	**$156,521**	$13,407	$27,611	$39,508	**$237,047**	$510
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**	$206
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**	**$210**
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**	$96
7.2-7.9	SCR System, Ductwork and Stack	$1,138	$906	$1,056	$0	$0	**$3,100**	$264	$0	$549	**$3,913**	$8
	SUBTOTAL 7	**$34,096**	**$906**	**$5,335**	**$0**	**$0**	**$40,337**	**$3,434**	**$0**	**$4,589**	**$48,361**	**$104**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$18,712	$0	$3,357	$0	$0	**$22,068**	$1,897	$0	$2,397	**$26,362**	$57
8.2-8.9	Turbine Plant Auxiliaries and Steam Piping	$18,435	$619	$6,876	$0	$0	**$25,930**	$2,386	$0	$5,067	**$33,382**	$72
	SUBTOTAL 8	**$37,147**	**$619**	**$10,232**	**$0**	**$0**	**$47,998**	**$4,283**	**$0**	**$7,464**	**$59,744**	**$129**
9	COOLING WATER SYSTEM	$7,556	$5,648	$5,090	$0	$0	**$18,293**	$1,520	$0	$2,801	**$22,614**	$49
10	ASH/SPENT SORBENT HANDLING SYS	$0	$0	$0	$0	$0	**$0**	$0	$0	$0	**$0**	$0
11	ACCESSORY ELECTRIC PLANT	$20,098	$5,521	$12,017	$0	$0	**$37,636**	$2,898	$0	$4,383	**$44,917**	$97
12	INSTRUMENTATION & CONTROL	$6,236	$640	$5,181	$0	$0	**$12,057**	$1,004	$603	$1,566	**$15,230**	$33
13	IMPROVEMENTS TO SITE	$1,709	$928	$4,547	$0	$0	**$7,184**	$636	$0	$1,564	**$9,384**	$20
14	BUILDINGS & STRUCTURES	$0	$3,876	$4,009	$0	$0	**$7,885**	$640	$0	$1,279	**$9,804**	$21
	TOTAL COST	**$325,306**	**$23,444**	**$95,786**	**$0**	**$0**	**$444,536**	**$37,706**	**$28,214**	**$78,282**	**$588,738**	$1,267

Exhibit 3-49 Case L31B Total Plant Cost Details

Client:	USDOE/NETL			Report Date:	2009-Oct-19
Project:	Low Rank Western Coal Baseline Study				

TOTAL PLANT COST SUMMARY

Case:	Case L31B - 1x465 MWnet 2x1 7FB NGCC w/ CO2 Capture						
Plant Size:	464.6	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											
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	$2,343	$2,414	$1,985	$0	$0	$6,742	$556	$0	$1,095	$8,392	$18
3.2	Water Makeup & Pretreating	$1,858	$194	$970	$0	$0	$3,022	$258	$0	$656	$3,935	$8
3.3	Other Feedwater Subsystems	$1,068	$361	$304	$0	$0	$1,733	$139	$0	$281	$2,153	$5
3.4	Service Water Systems	$220	$452	$1,467	$0	$0	$2,138	$187	$0	$465	$2,790	$6
3.5	Other Boiler Plant Systems	$1,473	$571	$1,322	$0	$0	$3,366	$286	$0	$548	$4,199	$9
3.6	Natural Gas, incl. pipeline	$14,649	$471	$410	$0	$0	$15,530	$1,316	$0	$2,527	$19,373	$42
3.7	Waste Treatment Equipment	$670	$0	$382	$0	$0	$1,053	$92	$0	$229	$1,373	$3
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$917	$123	$440	$0	$0	$1,480	$128	$0	$322	$1,930	$4
	SUBTOTAL 3.	**$23,198**	**$4,585**	**$7,280**	**$0**	**$0**	**$35,063**	**$2,961**	**$0**	**$6,122**	**$44,146**	**$95**
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 3-49 Case L31B Total Plant Cost Details (Continued)

	Client:	USDOE/NETL								Report Date:	2009-Oct-19	
	Project:	Low Rank Western Coal Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case L31B - 1x465 MWnet 2x1 7FB NGCC w/ CO2 Capture										
	Plant Size:	464.6	MW,net	Estimate Type:		Conceptual			Cost Base (Jun)	2007	($x1000)	
Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/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	$105,919	$0	$32,137	$0	$0	$138,056	$11,825	$27,611	$35,498	$212,990	$458
5B.2	CO2 Compression & Drying	$14,056	$0	$4,409	$0	$0	$18,465	$1,582	$0	$4,009	$24,057	$52
	SUBTOTAL 5.	**$119,974**	**$0**	**$36,547**	**$0**	**$0**	**$156,521**	**$13,407**	**$27,611**	**$39,508**	**$237,047**	**$510**
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	$206
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**	**$210**
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	$96
7.2	SCR System	$1,138	$478	$671	$0	$0	$2,288	$197	$0	$373	$2,857	$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.	**$34,096**	**$906**	**$5,335**	**$0**	**$0**	**$40,337**	**$3,434**	**$0**	**$4,589**	**$48,361**	**$104**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$18,712	$0	$3,357	$0	$0	$22,068	$1,897	$0	$2,397	$26,362	$57
8.2	Turbine Plant Auxiliaries	$137	$0	$308	$0	$0	$445	$39	$0	$48	$532	$1
8.3	Condenser & Auxiliaries	$1,416	$0	$423	$0	$0	$1,839	$158	$0	$200	$2,196	$5
8.3b	Air Cooled Condenser	$12,980	$0	$2,602	$0	$0	$15,583	$1,558	$0	$3,428	$20,569	$44
8.4	Steam Piping	$3,901	$0	$2,565	$0	$0	$6,466	$495	$0	$1,044	$8,005	$17
8.9	TG Foundations	$0	$619	$978	$0	$0	$1,597	$135	$0	$347	$2,079	$4
	SUBTOTAL 8.	**$37,147**	**$619**	**$10,232**	**$0**	**$0**	**$47,998**	**$4,283**	**$0**	**$7,464**	**$59,744**	**$129**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$5,349	$0	$684	$0	$0	$6,033	$514	$0	$655	$7,201	$15
9.2	Circulating Water Pumps	$1,569	$0	$99	$0	$0	$1,668	$126	$0	$179	$1,973	$4
9.3	Circ.Water System Auxiliaries	$122	$0	$16	$0	$0	$138	$12	$0	$15	$165	$0
9.4	Circ.Water Piping	$0	$3,561	$863	$0	$0	$4,424	$358	$0	$717	$5,499	$12
9.5	Make-up Water System	$279	$0	$373	$0	$0	$652	$56	$0	$106	$815	$2
9.6	Component Cooling Water Sys	$236	$283	$188	$0	$0	$707	$59	$0	$115	$882	$2
9.9	Circ.Water System Foundations	$0	$1,804	$2,867	$0	$0	$4,671	$396	$0	$1,013	$6,080	$13
	SUBTOTAL 9.	**$7,556**	**$5,648**	**$5,090**	**$0**	**$0**	**$18,293**	**$1,520**	**$0**	**$2,801**	**$22,614**	**$49**

Exhibit 3-49 Case L31B Total Plant Cost Details (Continued)

	Client:	USDOE/NETL								Report Date:	2009-Oct-19	
	Project:	Low Rank Western Coal Baseline Study										
		TOTAL PLANT COST SUMMARY										
	Case:	Case L31B - 1x465 MWnet 2x1 7FB NGCC w/ CO2 Capture										
	Plant Size:	464.6	MW,net	Estimate Type:		Conceptual			Cost Base (Jun)	2007	($x1000)	
Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/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	$5,314	$0	$3,193	$0	$0	$8,507	$721	$0	$692	$9,920	$21
11.2	Station Service Equipment	$1,965	$0	$166	$0	$0	$2,131	$176	$0	$173	$2,480	$5
11.3	Switchgear & Motor Control	$2,422	$0	$412	$0	$0	$2,834	$235	$0	$307	$3,376	$7
11.4	Conduit & Cable Tray	$0	$1,157	$3,569	$0	$0	$4,726	$409	$0	$770	$5,905	$13
11.5	Wire & Cable	$0	$3,686	$2,263	$0	$0	$5,949	$383	$0	$950	$7,282	$16
11.6	Protective Equipment	$0	$558	$1,898	$0	$0	$2,456	$215	$0	$267	$2,938	$6
11.7	Standby Equipment	$97	$0	$89	$0	$0	$186	$16	$0	$20	$222	$0
11.8	Main Power Transformers	$10,298	$0	$134	$0	$0	$10,432	$708	$0	$1,114	$12,254	$26
11.9	Electrical Foundations	$0	$120	$294	$0	$0	$414	$35	$0	$90	$539	$1
	SUBTOTAL 11.	**$20,098**	**$5,521**	**$12,017**	**$0**	**$0**	**$37,636**	**$2,898**	**$0**	**$4,383**	**$44,917**	**$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	$793	$0	$495	$0	$0	$1,288	$109	$64	$219	$1,680	$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	$237	$0	$142	$0	$0	$379	$32	$19	$64	$494	$1
12.7	Computer & Accessories	$3,792	$0	$113	$0	$0	$3,906	$321	$195	$442	$4,864	$10
12.8	Instrument Wiring & Tubing	$0	$640	$1,223	$0	$0	$1,864	$140	$93	$315	$2,412	$5
12.9	Other I & C Equipment	$1,414	$0	$3,208	$0	$0	$4,622	$401	$231	$525	$5,779	$12
	SUBTOTAL 12.	**$6,236**	**$640**	**$5,181**	**$0**	**$0**	**$12,057**	**$1,004**	**$603**	**$1,566**	**$15,230**	**$33**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation	$0	$91	$1,823	$0	$0	$1,914	$170	$0	$417	$2,501	$5
13.2	Site Improvements	$0	$837	$1,039	$0	$0	$1,876	$166	$0	$408	$2,451	$5
13.3	Site Facilities	$1,709	$0	$1,685	$0	$0	$3,394	$300	$0	$739	$4,432	$10
	SUBTOTAL 13.	**$1,709**	**$928**	**$4,547**	**$0**	**$0**	**$7,184**	**$636**	**$0**	**$1,564**	**$9,384**	**$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	$1,601	$2,131	$0	$0	$3,732	$307	$0	$606	$4,644	$10
14.3	Administration Building	$0	$459	$311	$0	$0	$770	$61	$0	$125	$956	$2
14.4	Circulation Water Pumphouse	$0	$146	$72	$0	$0	$218	$17	$0	$35	$271	$1
14.5	Water Treatment Buildings	$0	$401	$366	$0	$0	$766	$62	$0	$124	$953	$2
14.6	Machine Shop	$0	$398	$255	$0	$0	$653	$52	$0	$106	$810	$2
14.7	Warehouse	$0	$257	$155	$0	$0	$412	$33	$0	$67	$512	$1
14.8	Other Buildings & Structures	$0	$77	$56	$0	$0	$133	$11	$0	$22	$165	$0
14.9	Waste Treating Building & Str.	$0	$301	$538	$0	$0	$839	$70	$0	$136	$1,046	$2
	SUBTOTAL 14.	**$0**	**$3,876**	**$4,009**	**$0**	**$0**	**$7,885**	**$640**	**$0**	**$1,279**	**$9,804**	**$21**
	TOTAL COST	**$325,306**	**$23,444**	**$95,786**	**$0**	**$0**	**$444,536**	**$37,706**	**$28,214**	**$78,282**	**$588,738**	**$1,267**

Exhibit 3-50 Case L31B Owner's Costs

Owner's Costs	$x1000	$/kW
Preproduction Costs		
6 Months Fixed O&M	$4,249	$9
1 Month Variable O&M	$871	$2
25% of 1 Months Fuel Cost at 100% CF	$4,799	$10
2% of TPC	$11,775	$25
Total	**$21,693**	**$47**
Inventory Capital		
60 day supply of consumables at 100% CF	$470	$1
0.5% of TPC (spare parts)	$2,944	$6
Total	**$3,414**	**$7**
Initial Cost for Catalyst and Chemicals	**$804**	**$2**
Land	**$300**	**$1**
Other Owner's Costs	**$88,311**	**$190**
Financing Costs	**$15,896**	**$34**
Total Owner's Costs	**$130,417**	**$281**
Total Overnight Cost (TOC)	**$719,155**	**$1,548**
TASC Multiplier	1.078	
Total As-Spent Cost (TASC)	**$775,249**	**$1,668**

Exhibit 3-51 Case L31B Initial and Annual Operating and Maintenance Cost Summary

INITIAL & ANNUAL O&M EXPENSES						
					Cost Base (Jun):	2007
Case L31B - 1x465 MWnet 2x1 7FB NGCC w/ CO2 Capture					Heat Rate-net (Btu/kWh):	7,938
					MWe-net:	465
					Capacity Factor (%):	85
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	34.65	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Skilled Operator	1.0		1.0			
Operator	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	$5.376
Maintenance Labor Cost					$4,300,603	$9.256
Administrative & Support Labor					$1,699,596	$3.658
Property Taxes and Insurance					$11,774,756	$25.342
TOTAL FIXED OPERATING COSTS					**$20,272,736**	**$43.631**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost					**$6,450,905**	**$0.00186**
Consumables	Consumption Initial	Consumption /Day	Unit Cost	Initial Cost		
Water (/1000 gallons)	0.00	2,374.56	1.08	**$0**	**$796,878**	**$0.00023**
Chemicals						
MU & WT Chem.(lbs)	0.00	14,146.94	0.17	$0	$759,611	$0.00022
MEA Solvent (ton)	336.89	0.47	2,249.89	$757,962	$330,240	$0.00010
Activated Carbon (lb)	0.00	565.14	1.05	$0	$184,133	$0.00005
Corrosion Inhibitor	0.00	0.00	0.00	$46,153	$2,198	$0.00000
SCR Catalyst (m3)	w/equip.	0.07	5,775.94	$0	$123,497	$0.00004
Ammonia (19% NH3) (ton)	0.00	5.80	129.80	$0	$233,416	$0.00007
Subtotal Chemicals				**$804,115**	**$1,633,094**	**$0.00047**
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				**$804,115**	**$8,880,877**	**$0.00257**
Fuel (MMBtu)	0	88,519	7.13	**$0**	**$195,790,457**	**$0.05659**

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4. SUMMARY

The performance results of the four NGCC plant configurations modeled in this study are summarized in Exhibit 4-1.

Exhibit 4-1 Performance and Cost Results for NGCC Cases

	NGCC with Advanced F Class			
PERFORMANCE	**Case S31A**	**Case L31A**	**Case S31B**	**Case L31B**
CO_2 Capture	0%	0%	90%	90%
Gross Power Output (kW_e)	522,100	557,000	470,000	501,600
Auxiliary Power Requirement (kW_e)	9,690	10,020	34,940	36,960
Net Power Output (kW_e)	512,410	546,980	435,060	464,640
Natural Gas Flowrate (lb/hr)	153,559	163,560	153,559	163,560
HHV Thermal Input (kW_{th})	1,014,787	1,080,880	1,014,787	1,080,880
Net Plant HHV Efficiency (%)	50.5%	50.6%	42.9%	43.0%
Net Plant HHV Heat Rate (Btu/kWh)	6,757	6,743	7,959	7,938
Raw Water Withdrawal (gpm/MW_{net})	2.1	2.1	7.1	7.1
Process Water Discharge (gpm/MW_{net})	0.5	0.5	1.8	1.8
Raw Water Consumption (gpm/MW_{net})	1.6	1.6	5.3	5.3
CO_2 Emissions (lb/MMBtu)	118	118	12	12
CO_2 Emissions (lb/MWh_{gross})	784	783	87	87
CO_2 Emissions (lb/MWh_{net})	799	797	94	94
SO_2 Emissions (lb/MMBtu)	Negligible	Negligible	Negligible	Negligible
SO_2 Emissions (lb/MWh_{gross})	Negligible	Negligible	Negligible	Negligible
NOx Emissions (lb/MMBtu)	0.009	0.009	0.009	0.009
NOx Emissions (lb/MWh_{gross})	0.060	0.060	0.067	0.066
PM Emissions (lb/MMBtu)	Negligible	Negligible	Negligible	Negligible
PM Emissions (lb/MWh_{gross})	Negligible	Negligible	Negligible	Negligible
Hg Emissions (lb/TBtu)	Negligible	Negligible	Negligible	Negligible
Hg Emissions (lb/MWh_{gross})	Negligible	Negligible	Negligible	Negligible
COST				
Total Plant Cost (2007$/kW)	666	637	1,315	1,267
Total Overnight Cost (2007$/kW)	817	782	1,607	1,548
Bare Erected Cost	546	521	994	957
Home Office Expenses	46	44	84	81
Project Contingency	74	71	174	168
Process Contingency	0	0	62	61
Owner's Costs	151	145	291	281
Total Overnight Cost (2007$ x 1,000)	418,817	427,473	698,949	719,155
Total As Spent Capital (2007$/kW)	879	840	1,732	1,668
COE (mills/kWh, 2007$)[1]	64.4	63.6	92.9	91.4
CO_2 TS&M Costs	0.0	0.0	3.4	3.3
Fuel Costs	48.2	48.1	56.7	56.6
Variable Costs	1.4	1.3	2.7	2.6
Fixed Costs	3.4	3.2	6.1	5.9
Capital Costs	11.5	11.0	24.0	23.1
LCOE (mills/kWh, 2007$)[1]	81.7	80.6	117.8	115.8

[1] COE and Levelized COE are defined in Section 2.6.

The TOC for each of the four NGCC cases is shown in Exhibit 4-2. The TOC of the NDL site non-capture case, $782/kW, is the lowest of the four NGCC cases. The TOC of the non-capture NGCC plant at the Montana site is $817/kW, or approximately four percent greater. Addition of CO_2 capture nearly doubles the TOC at each location. The process contingency included for the Econamine process averages $60/kW for the capture cases, which represents approximately 8 percent of the incremental cost due to the addition of CO_2 capture and 4 percent of the total TOC.

The COE for NGCC plants is heavily dependent on the price of natural gas as shown in Exhibit 4-3. The fuel component of COE represents 75 percent of the total in the non-capture cases and 62 percent of the total in the CO_2 capture case.

Exhibit 4-2 Total Overnight Costs

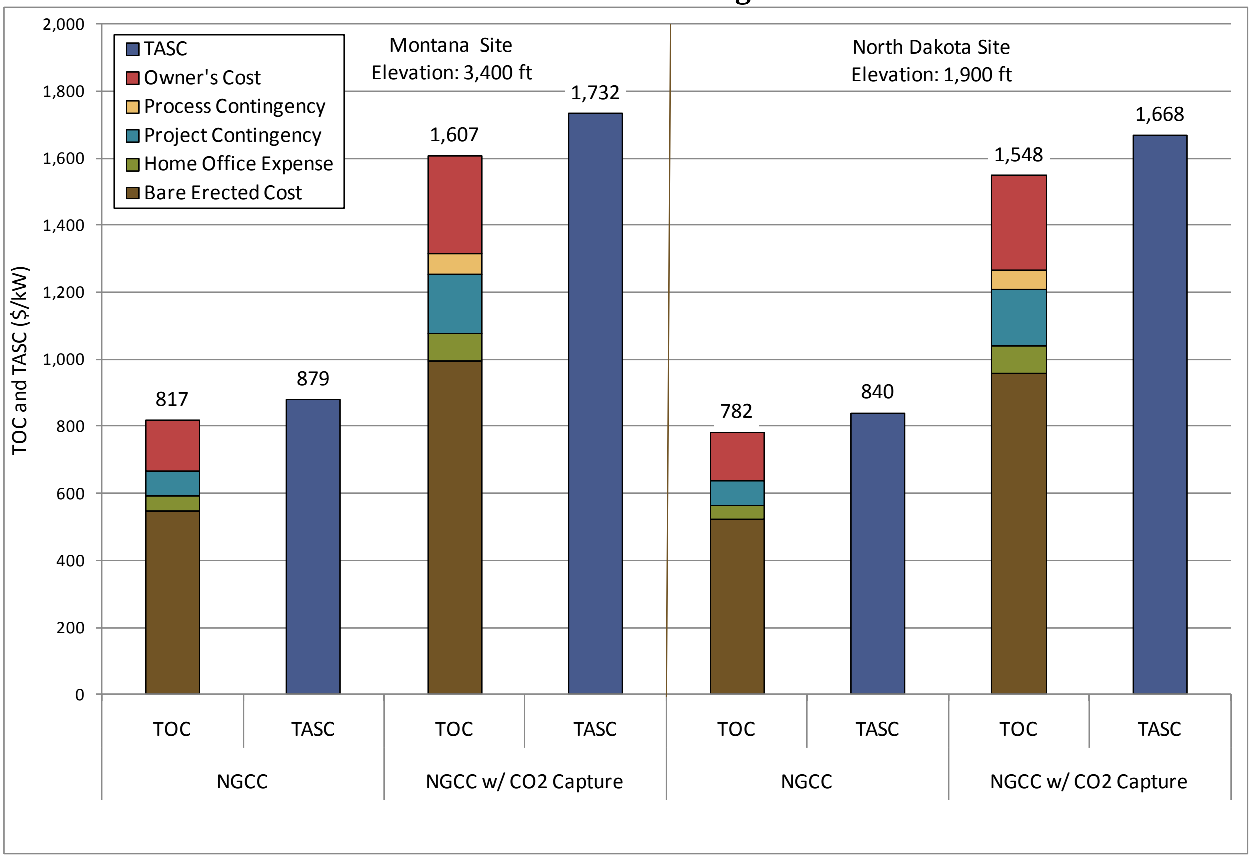
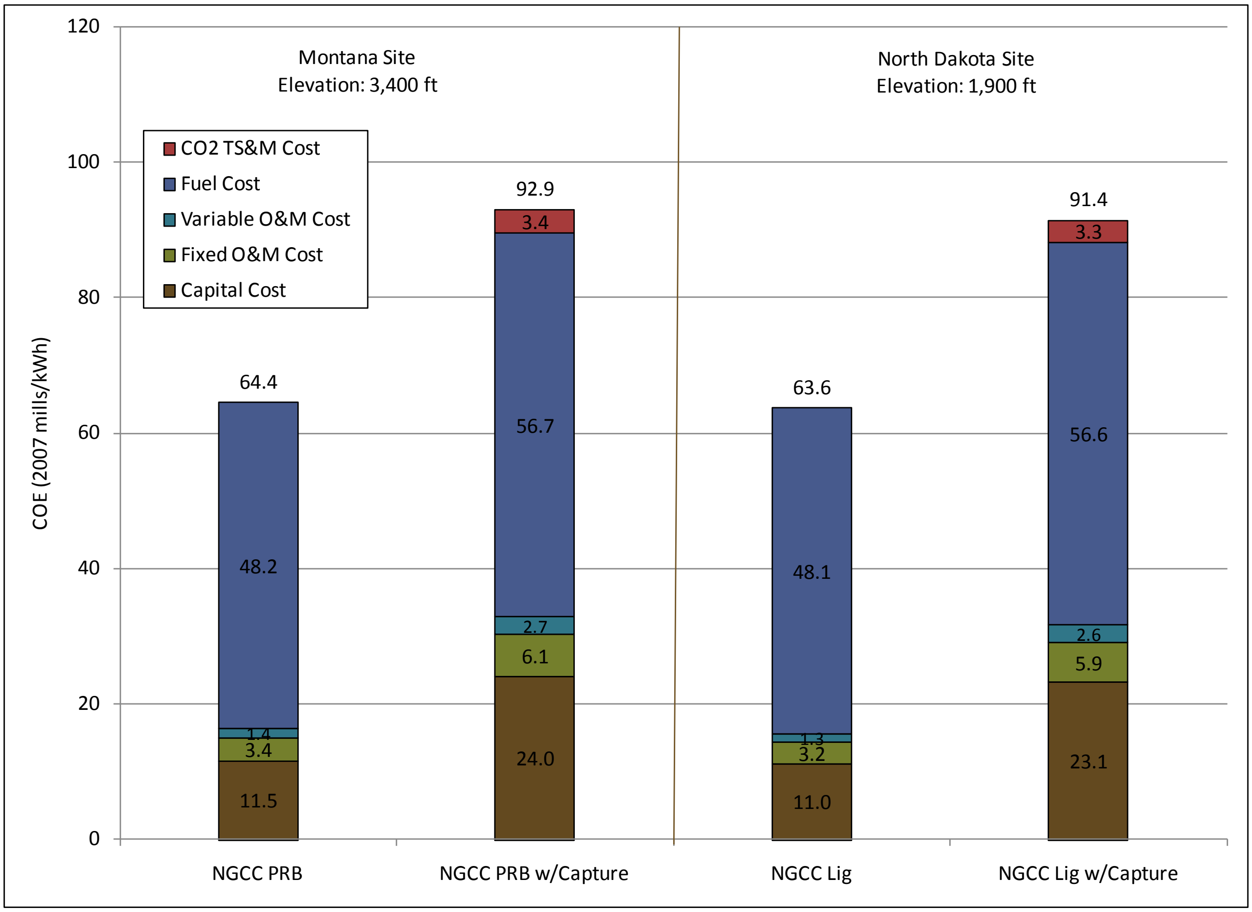


Exhibit 4-3 COE of NGCC Cases



Because the NGCC COE has a relatively small capital component, it is less sensitive to CF changes than it is to changes in fuel prices. The sensitivity of NGCC to CF is shown in Exhibit 4-4 while the sensitivity of NGCC to natural gas price is shown in Exhibit 4-5. A 50 percent reduction in CF (80 percent to 40 percent) results in approximately a 24 percent increase in COE for the non-capture cases and a 37 percent increase for the capture cases. The capture cases are more capital intensive and are more sensitive to changes in the CF.

Increasing the price of natural gas 50 percent (from $7.13 to $10.70/MMBtu) results in a COE increase of 38 percent in the non-capture cases and 32 percent in the CO_2 capture cases. Because the fuel costs are a smaller proportion of the total COE in the CO_2 capture cases, the impact of fuel price variations is less for those cases.

Exhibit 4-4 Sensitivity of COE to Capacity Factor in NGCC Cases

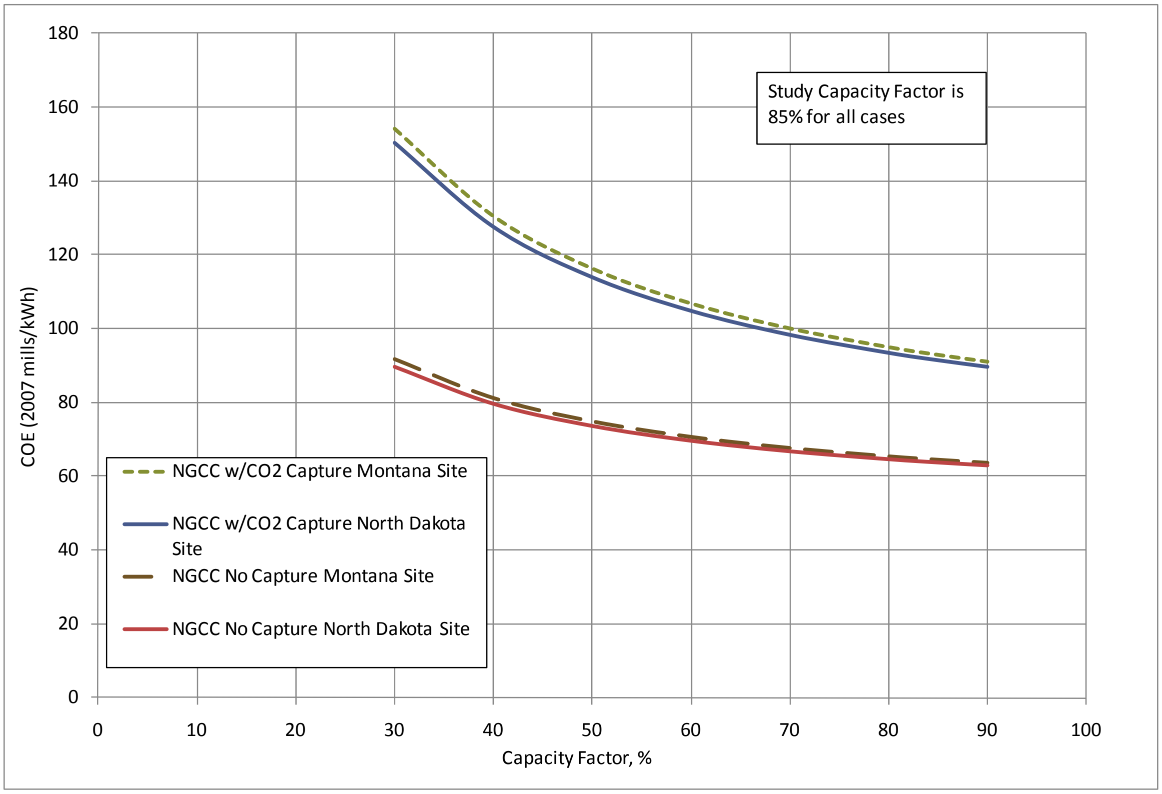
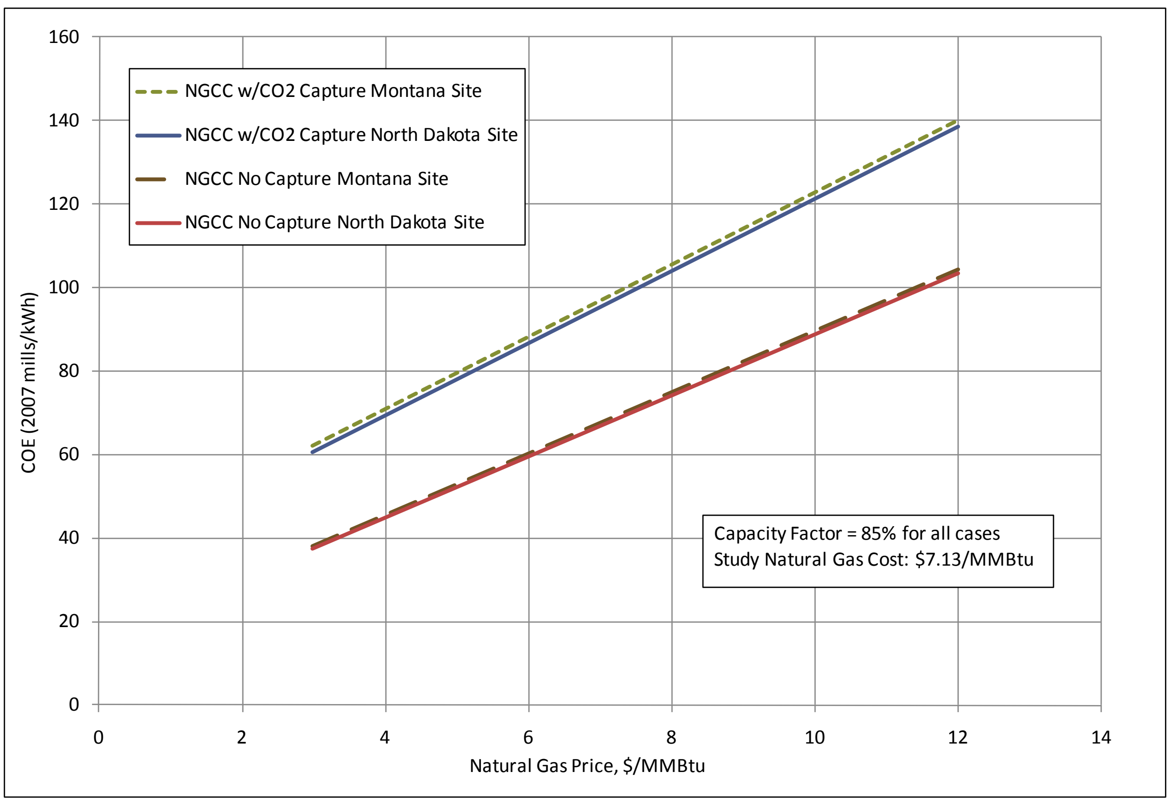


Exhibit 4-5 Sensitivity of COE to Fuel Price in NGCC Cases



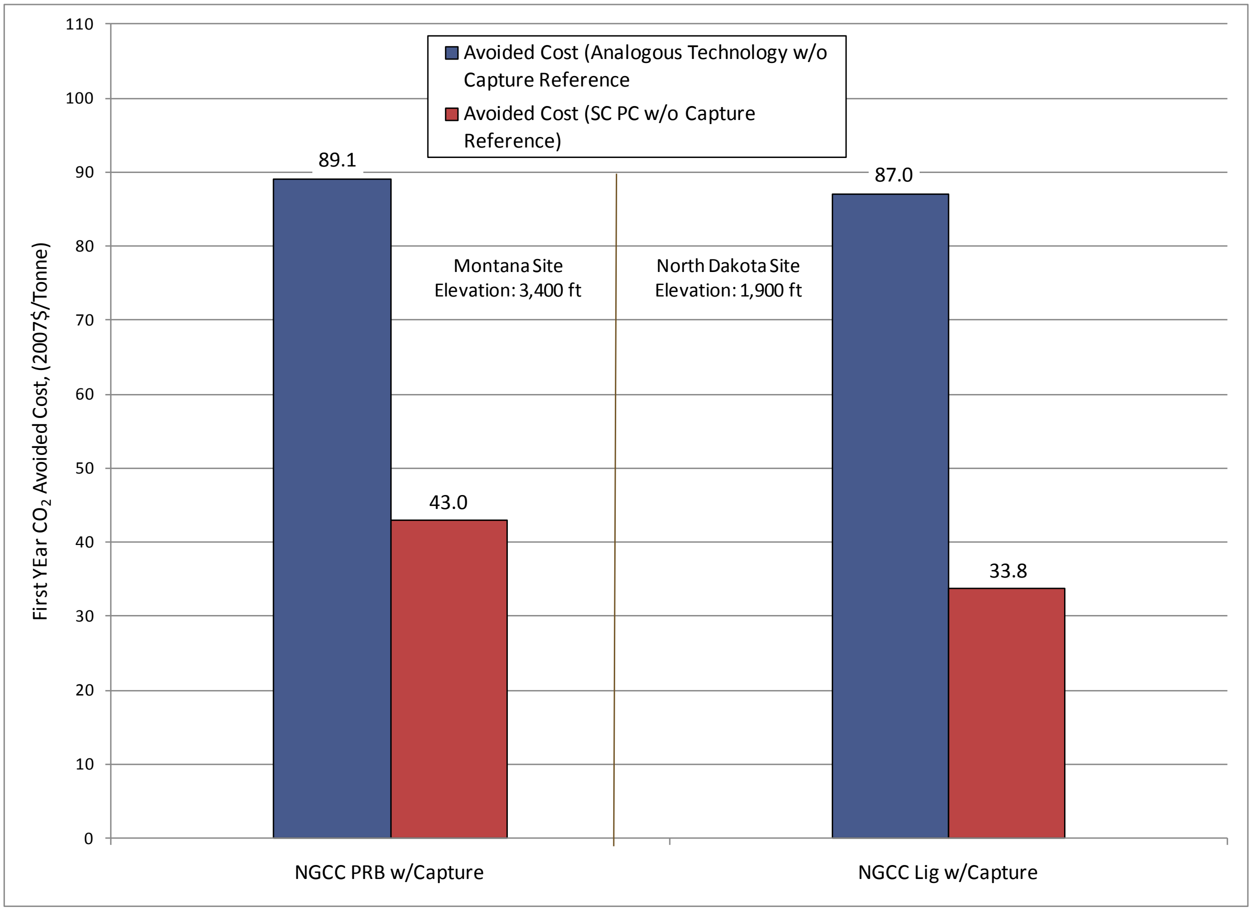
The following observations can be made regarding plant performance with reference to Exhibit 4-1:

The efficiency for cases S31A and L31A are 50.5 and 50.6 percent (HHV basis), respectively. 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) [32]. Adjusting the results from this study to an LHV basis results in efficiencies of 56.0 and 56.1 percent for cases S31A and L31A, respectively. A portion of the efficiency difference can be attributed to the higher condenser pressure used in this study relative to the Gas Turbine World reference case.

- The increase in elevation, going from the NDL to the Montana site, has minimal impact on efficiency but does cause a derate in the gas turbine compressor, reducing the net plant output by six percent for both CO_2 capture and non-capture cases. As the air becomes less dense at higher elevations, the maximum volumetric capacity of the compressor results in less mass flow through the combustion turbine.
- The efficiency penalty to add CO_2 capture in the NGCC cases is 7.6 percentage points (a relative reduction of 15 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 25 and 27 MW increase in auxiliary load compared to the Montana and ND site non-capture cases, respectively. Additionally, the extraction steam required to regenerate the Econamine solvent results in a reduction of steam turbine output of over 50 MW at both site locations.
- 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 9.7 tonnes/yr (10.7 tons/yr) at 85 percent CF, or 0.00073 kg/GJ (0.0017 lb/MMBtu).
- NOx emissions are similar for the two non-capture NGCC cases on a mass basis. This is a result of the fixed output from the gas turbine (25 ppmv at 15 percent O_2) and the fixed efficiency of the SCR (90 percent). The capture cases have slightly higher NOx emissions because they are normalized by a smaller gross power output.

As presented in Section 2.6 the cost of CO_2 avoided was compared in two ways, relative to the analogous plant design and compared to a baseline SC PC plant. The cost of CO_2 avoided, shown in Exhibit 4-6, averages \$88.0/tonne (\$79.9/ton) compared to the analogous non-capture (A) design and \$38.4/tonne (\$34.8/ton) compared to the baseline SC PC non-capture (SC PC A) design. NGCC plants have low carbon emissions, even before capturing CO_2, so the cost of CO_2 avoided compared to a baseline SC PC plant is very low. The cost of avoiding CO_2 compared to the analogous non-capture NGCC case shows costs comparable to the addition of a typical post combustion CO_2 capture process.

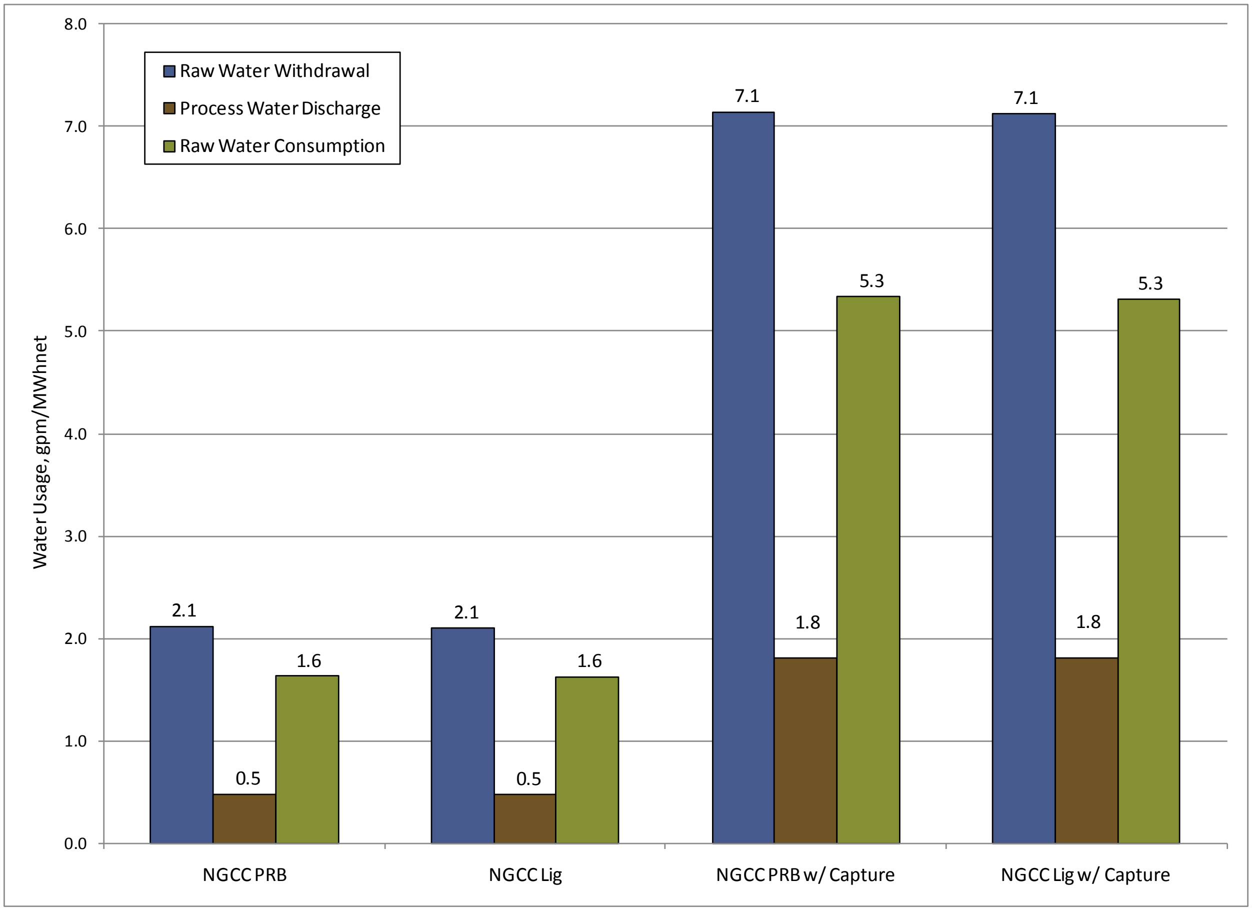
Exhibit 4-6 CO_2 Avoided Costs



The normalized water withdrawal, process discharge and raw water consumption are shown in Exhibit 4-7 for each case. The following observations can be made:

- Normalized water withdrawal and normalized raw water consumption more than triple when CO_2 capture technology is added. The high cooling water demand of the Econamine process results in a large increase in cooling tower makeup requirements.
- The use of the parallel wet/dry cooling system reduces water demand relative to an all wet cooling tower system. For the non-capture cases, the reductions are approximately 3.1 m^3/min (820 gpm) resulting in a 49 percent reduction. For the CO_2 capture cases, the reductions are 2.1 m^3/min (370 gpm) resulting in a 14 percent reduction. The water savings is less in the CO_2 capture cases because a significant amount of extraction steam is used in the Econamine system and therefore not condensed in the surface condenser.
- Cooling tower makeup comprises over 97 percent of the raw water consumption in each case. The only internal recycle stream in the non-capture case is the BFW blowdown, which is recycled to the cooling tower. In the CO_2 capture cases condensate is recovered from the flue gas as it is cooled to the absorber temperature of 32°C (89°F) as well as from the CO_2 product stream during compression. These streams are also recycled to the cooling tower.

Exhibit 4-7 Water Usage in NGCC Costs



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