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Greenhouse Gas Reductions in the Power Industry Using Domestic Coal and Biomass

Volume 1: IGCC

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Disclaimer

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Final Report

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TABLE OF CONTENTS

LIST OF EXHIBITS

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LIST OF ACRONYMS AND ABBREVIATIONS

AACE	Association for the Advancement of Cost Engineering
acfm	Actual cubic foot per minute
AEO	Annual Energy Outlook
AGR	Acid gas removal
AR	As Received
ASU	Air separation unit
BACT	Best available control technology
BEC	Bare erected cost
BFD	Block flow diagram
BFW	Boiler feed water
Btu	British thermal unit
Btu/h	British thermal unit per hour
Btu/kWh	British thermal unit per kilowatt hour
Btu/lb	British thermal unit per pound
CA	California
CCF	Capital Charge Factor
CCS	Carbon Capture and Sequestration
CF	Capacity factor
CFM	Cubic feet per minute
CFR	Code of Federal Regulations
CGE	Cold gas efficiency
CH_4	Methane
cm	Centimeter
CO_2	Carbon dioxide
CO_{2e}	Carbon dioxide equivalent
COE	Cost of electricity
CoP	ConocoPhillips
COS	Carbonyl sulfide
CRP	Conservation Reserve Program
CRT	Cathode ray tube
CT	Combustion turbine
CTG	Combustion Turbine-Generator
CWT	Cold water temperature
DCS	Distributed control system
Dia.	Diameter
DOE	Department of Energy
EAF	Equivalent availability factor
E-Gas™	ConocoPhillips gasifier technology
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPC	Engineer/Procure/Construct
EPCM	Engineering/Procurement/Construction Management

EPRI	Electric Power Research Institute
FOAK	First of a kind
ft	Foot, Feet
gal	Gallon
GDP	Gross domestic product
GHG	Greenhouse gas
gpm	Gallons per minute
GT	Gas turbine
GW	Gigawatt
GWP	Global Warming Potential
h	Hour
H_2	Hydrogen
Hg	Mercury
HHV	Higher heating value
hp	Horsepower
HP	High pressure
HRSG	Heat recovery steam generator
HVAC	Heating, ventilating, and air conditioning
IGVs	Inlet guide vanes
IGCC	Integrated gasification combined cycle
IOU	Investor-owned utility
IP	Intermediate pressure
ISO	International Standards Organization
kg/GJ	Kilogram per gigajoule
kg/h	Kilogram per hour
kJ	Kilojoules
kJ/kg	Kilojoules per kilogram
KO	Knockout
kPa	Kilopascal absolute
kV	Kilovolt
kW	Kilowatt
kWe	Kilowatts electric
kWh	Kilowatt-hour
kWt	Kilowatts thermal
LAER	Lowest Achievable Emission Rate
lb	Pound
lb/h	Pounds per hour
lb/MMBtu	Pounds per million British thermal units
lb/MWh	Pounds per megawatt hour
LCOE	Levelized cost of electricity
LF_{Fn}	Levelization factor for category n fixed operating cost
LF_{Vn}	Levelization factor for category n variable operating cost
LHV	Lower heating value

LNB	Low NOx burner
LP	Low pressure
m	Meters
MM$	Millions of Dollars
m/min	Meters per minute
m^3/min	Cubic meter per minute
MDEA	Methyldiethanolamine
MHz	Megahertz
MMBtu	Million British thermal units (also shown as 10^6 Btu)
MMBtu/h	Million British thermal units (also shown as 10^6 Btu) per hour
MPa	Megapascals
Mpg	Miles per gallon
MW	Megawatt
MWe	Megawatts electric
MWh	Megawatt-hour
net-MWh	Net megawatt-hour
NERC	North American Electric Reliability Council
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
NOx	Oxides of nitrogen
NSPS	New Source Performance Standards
NSR	New Source Review
NREL	National Renewable Energy Laboratory
O&M	Operation and maintenance
OC_{Fn}	Category n fixed operating cost for the initial year of operation
PC	Pulverized coal
PM	Particulate matter
PM_{10}	Particulate matter measuring 10 µm or less
POTW	Publicly Owned Treatment Works
ppm	Parts per million
ppmd	Parts per million, dry
ppmv	Parts per million volume
PRB	Powder River Basin coal region
psia	Pounds per square inch absolute
psig	Pounds per square inch gage
R&D	Research and Development
RDS	Research and Development Solutions, LLC
SCR	Selective catalytic reduction
SGS	Sour gas shift
SO_2	Sulfur dioxide
STG	Steam turbine generator
TGTU	Tail gas treating unit
Tonne	Metric Ton (1000 kg)

TPC	Total plant cost
TPD	Tons per day
TPH	Tons per hour
TPI	Total plant investment
TS&M	Transport, storage and monitoring
USDA	United States Department of Agriculture
vol%	Volume percent
wt%	Weight percent
$/AR ton	Dollars per As Received ton
$/dry ton	Dollars per dry ton
$/kW	Dollars per kilowatt
$/MMBtu	Dollars per million British thermal units
$/MMkJ	Dollars per million kilojoule
$/MWh	Dollars per Megawatt-hour
$/ton	Dollars per ton

EXECUTIVE SUMMARY

The objective of this study was to simulate biomass co-firing in a dry-fed, entrained-flow gasifier in an integrated gasification combined cycle (IGCC) power plant and examine the performance, environmental response, and economic response under two scenarios:

- 0 ft of elevation (ISO conditions) co-fired with Illinois #6 coal
- 3,400 ft of elevation co-fired with Powder River Basin (PRB) coal

In lieu of comparing identical system configurations from case to case, system configuration and operation both were adjusted in ways considered to reflect those anticipated to be the most practical and appropriate as feed composition and degree of carbon capture were varied. Technologies used were limited to currently available state-of–the–art processes.

Both scenarios co-fired varying degrees of biomass to determine overall system sensitivity to biomass. Although there are a number of options for biomass fuels, to maintain a manageable study scope switchgrass was selected as the sole biomass feed for the study.

In order to develop a more complete understanding of the impact of co-feeding biomass, each case was examined using a limited life cycle greenhouse gas (GHG) analysis, which examines GHG emissions beyond the plant stack. Included in the limited life cycle GHG analysis were anthropogenic greenhouse gas emission sources from the plant stack as well as GHG emissions from the production, processing, transportation, and fertilization of biomass and from mining, transporting and handling coal. Emissions reported in this study are limited life cycle GHG emissions representing the global warming potential of various species equivalent to that of an equal mass of CO_2; these are most often expressed in units of lb CO_2e/net-MWh. Non-stack emissions such as CH_4 and N_2O from switchgrass and coal production are considered in addition to CO_2.

The methodology included performing steady-state process simulations of the technology using the Aspen Plus (Aspen) modeling program. Each system modeled was designed as a greenfield plant specifically to meet the individual requirements of each case. The resulting mass and energy balance data from the Aspen models were used to size major pieces of equipment. These equipment sizes formed the basis for cost estimating.

Each IGCC plant is designed to accept the amount of thermal input required to fully load the chosen combustion turbine model, and so the total combined cycle output varies. Any thermal energy liberated is recovered to the maximum extent possible and routed to the Rankine cycle to raise steam to generate additional power. The net plant output varies from case to case because the combustion turbines are manufactured in discrete sizes. Consequently, the net power for the two-train, high-altitude cases (3,400 ft) ranges from 451 to 599 MW while the range for the two-train plants operating at ISO conditions is from 494 to 654 MW. The range in net output is caused not only by the discrete sizes of available CT sizes, but also the wide variance of CO_2 capture auxiliary loads required from case-to-case. The differences in auxiliary loads are primarily attributed to CO_2 removal and compression. An additional cause of variation is the need for extraction steam in the water-gas shift reactions, which reduces steam turbine output potential.

The study matrix presented in Exhibit ES-1 contains 47 system studies. The first 32 cases have emission targets which are explained in the second study objective below.

Case Study Naming Convention

For the first 32 cases, a naming convention of "xYz" is assigned as follows:

- **"x"** - designates the life cycle GHG emission target (1 for 0 lb CO_2e/net-MWh, 2 for 1,100 lb CO_2e/net-MWh, etc.)
- **"Y"** - designates Sub-bituminous (S) or Bituminous (B) depending on the coal type (or associated site location for 100% switchgrass cases)
- **"z"** - designates the case within a subset

The same naming convention follows for the final 15 cases except the prefix x in those cases designates the objective of the case subset.

The purpose of each case was to help achieve one of the following study goals:

1. **Determine technical and economic benefits of adding strategic levels of biomass feedstock to achieve net zero life cycle GHG emissions in an IGCC power plant.**

2. **Determine the technical and economic benefits of adding strategic levels of biomass feedstock in an IGCC power plant to achieve GHG emission levels matching or closely representing: California's GHG emission performance standard (1,100 lb CO_2/net-MWh), a state-of-the-art NGCC plant (800 lb CO_2/net-MWh), and an IGCC plant (350 lb CO_2/net-MWh) with 90% CO_2 capture.**

3. **Quantify economy-of-scale limitations of a 100% biomass IGCC power plant, and the economic benefits of co-feeding coal.**

4. **Determine the techno-economic performance and life cycle GHG emissions of a state-of-the-art IGCC power plant that employs full (~90%) CO_2 capture while also co-feeding biomass.**

5. **Determine whether CCS or biomass co-feeding is economically preferred to achieve very low levels of CO_2 capture in an IGCC power plant.**

Exhibit ES-1 Study Matrix

Objective	Case	Limited Life Cycle CO_2e Emissions [lb/net-MWh]	Feed Composition [Coal/Biomass]	% Biomass in Feed	No. of Gasifier Trains	CO_2 Capture Strategy[1]	Plant Configuration Scheme[3]
Determine technical and economic benefits of adding strategic levels of biomass to achieve net zero life cycle GHG emissions.	1S1	0	PRB/Switchgrass	100%wt	1	(Calculated)	MINSG
	1S2	0	PRB/Switchgrass	Max Supply	2	(Calculated)	PART
	1S3	0	PRB/Switchgrass	30%wt	2	(Calculated)	PART
	1S4	0	PRB/Switchgrass	(Calculate)	2	Maximum[2]	MAX
	1B1	0	Ill # 6/Switchgrass	100%wt	1	(Calculated)	MINSG
	1B2	0	Ill # 6/Switchgrass	Max Supply	2	(Calculated)	PART
	1B3	0	Ill # 6/Switchgrass	30%wt	2	(Calculated)	MAX
	1B4	0	Ill # 6/Switchgrass	(Calculate)	2	Maximum[2]	MAX
Determine the technical and economic benefits of adding strategic levels of biomass to achieve carbon dioxide emission levels corresponding to: CA's GHG emission performance standard, stack emissions of a state-of-the-art NGCC plant, and stack emissions of a full	2S1	1,100	PRB/Switchgrass	0%wt	2	(Calculated)	PART
	2S2	1,100	PRB/Switchgrass	30%wt	2	(Calculated)	PART
	2S3	1,100	PRB/Switchgrass	Max Supply	2	(Calculated)	NC
	2S4	1,100	PRB/Switchgrass	Calculate	2	None	NC
	2B1	1,100	Ill # 6/Switchgrass	0%wt	2	(Calculated)	PART
	2B2	1,100	Ill # 6/Switchgrass	30%wt	2	(Calculated)	PART
	2B3	1,100	Ill # 6/Switchgrass	Max Supply	2	(Calculated)	NC
	2B4	1,100	Ill # 6/Switchgrass	Calculate	2	None	NC

Objective	Case	Limited Life Cycle CO_2e Emissions [lb/net-MWh]	Feed Composition [Coal/Biomass]	% Biomass in Feed	No. of Gasifier Trains	CO_2 Capture Strategy[1]	Plant Configuration Scheme[3]
capture IGCC plant.	3S1	800	PRB/Switchgrass	0%wt	2	(Calculated)	PART
	3S2	800	PRB/Switchgrass	30%wt	2	(Calculated)	PART
	3S3	800	PRB/Switchgrass	Max Supply	2	(Calculated)	HYB
	3S4	800	PRB/Switchgrass	Calculate	2	None	NC
	3B1	800	Ill # 6/Switchgrass	0%wt	2	(Calculated)	PART
	3B2	800	Ill # 6/Switchgrass	30%wt	2	(Calculated)	PART
	3B3	800	Ill # 6/Switchgrass	Max Supply	2	(Calculated)	HYB
	3B4	800	Ill # 6/Switchgrass	Calculate	2	None	NC
	4S1	350	PRB/Switchgrass	0%wt	2	(Calculated)	MAX
	4S2	350	PRB/Switchgrass	30%wt	2	(Calculated)	PART
	4S3	350	PRB/Switchgrass	Max Supply	2	(Calculated)	PART
	4S4	350	PRB/Switchgrass	Calculate	2	None	NC
	4B1	350	Ill # 6/Switchgrass	0%wt	2	(Calculated)	MAX
	4B2	350	Ill # 6/Switchgrass	30%wt	2	(Calculated)	PART
	4B3	350	Ill # 6/Switchgrass	Max Supply	2	(Calculated)	PART
	4B4	350	Ill # 6/Switchgrass	Calculate	2	None	NC

Objective	Case	Limited Life Cycle CO_2e Emissions [lb/net-MWh]	Feed Composition [Coal/Biomass]	% Biomass in Feed	No. of Gasifier Trains	CO_2 Capture Strategy[1]	Plant Configuration Scheme[3]
Quantify economy-of-scale limitations of a 100% biomass to power plant, and the economic benefits of co-feeding coal.	5B1	(Calculate)	Ill # 6/Switchgrass	100%wt	1	None	NCSG
	5B2	(Calculate)	Ill # 6/Switchgrass	100%wt	1	Maximum[2]	MAXSG
	5B3	Same as 5B1	Ill # 6/Switchgrass	30%wt	1	(Calculated)	PART
Determine the techno-economic performance and life-cycle GHG emissions of a state of the art IGCC plant that employs full (~90%) CO_2 capture while also co-feeding biomass. Two scenarios will be considered: Renewable Electricity Standard (15%HHV biomass) and Technical Limit (30%wt biomass).	6S1	(Calculate)	PRB/Switchgrass	0%wt	2	Maximum[2]	MAX
	6S2	(Calculate)	PRB/Switchgrass	15%HHV	2	Maximum[2]	MAX
	6S3	(Calculate)	PRB/Switchgrass	30%wt	2	Maximum[2]	MAX
	6S4	(Calculate)	PRB/Switchgrass	Max Supply	2	Maximum[2]	MAX
	6B1	(Calculate)	Ill # 6/Switchgrass	0%wt	2	Maximum[2]	MAX
	6B2	(Calculate)	Ill # 6/Switchgrass	15%HHV	2	Maximum[2]	MAX
	6B3	(Calculate)	Ill # 6/Switchgrass	30%wt	2	Maximum[2]	MAX
	6B4	(Calculate)	Ill # 6/Switchgrass	Max Supply	2	Maximum[2]	MAX
Determine whether CCS or biomass co-feeding is economically preferred to achieve very low levels of CO_2 capture.	7B1	(Calculate)	Ill # 6/Switchgrass	0%wt	2	Maximum[2] (2-Stage Selexol Only)	HYBH
	7B2	Same as 7B1	Ill # 6/Switchgrass	(Calculate)	2	None	NCH

Objective	Case	Limited Life Cycle CO_2e Emissions [lb/net-MWh]	Feed Composition [Coal/Biomass]	% Biomass in Feed	No. of Gasifier Trains	CO_2 Capture Strategy[1]	Plant Configuration Scheme[3]
Establish a performance baseline for each coal type for comparison purposes.	8S1	(Calculate)	PRB/Switchgrass	0	2	None	NC
	8B1	(Calculate)	Ill # 6/Switchgrass	0	2	None	NCH

Note 1: Unless specified otherwise, the CO_2 capture system in this study consists of a 2-stage water-gas shift reactor plus a dual stage Selexol system and is designed for 90% CO_2 capture. Where "Calculated" is noted, bypass around the water gas shift system is adjusted to achieve target CO_2 emissions.

Note 2: Maximum biomass supply is assumed to be 5,000 dry tons/day. This assumption is further explained in Section 2.3.2.

Note 3: Plant Configuration Schemes are defined in Exhibit 4-10

PERFORMANCE

Many of the following plots are segmented into three distinct regimes. The "Demonstrated" regime includes cases with switchgrass feeds of 30 wt% or less. To date, the highest demonstrated proportion of biomass fed into an operating IGCC facility is 30 wt% at NUON Power's Buggenum Plant. The "Maximum Logistical" regime extends from 30 to 66 wt% switchgrass. This study assumes that plants accept biomass delivery by truck and accounts for a logistical constraint to the frequency that trucks can arrive and unload at the plant. A delivery rate of 5,000 dry tons/day is assumed to be the logistical maximum delivery and feed to any plant. Sixty-six percent represents the average feed composition for dual-gasifier plants feeding 5,000 dry tons/day of switchgrass. Plants within this regime have not been demonstrated commercially but are assumed to be technically feasible. The "Logistically Constrained" regime extends beyond the Maximum Logistical regime (above 66 wt%). Logistical constraints such as switchgrass storage, transport capacity, and the frequency of trucks unloading at the plant become roadblocks for operation within this regime for plants of this size.

Energy Efficiency

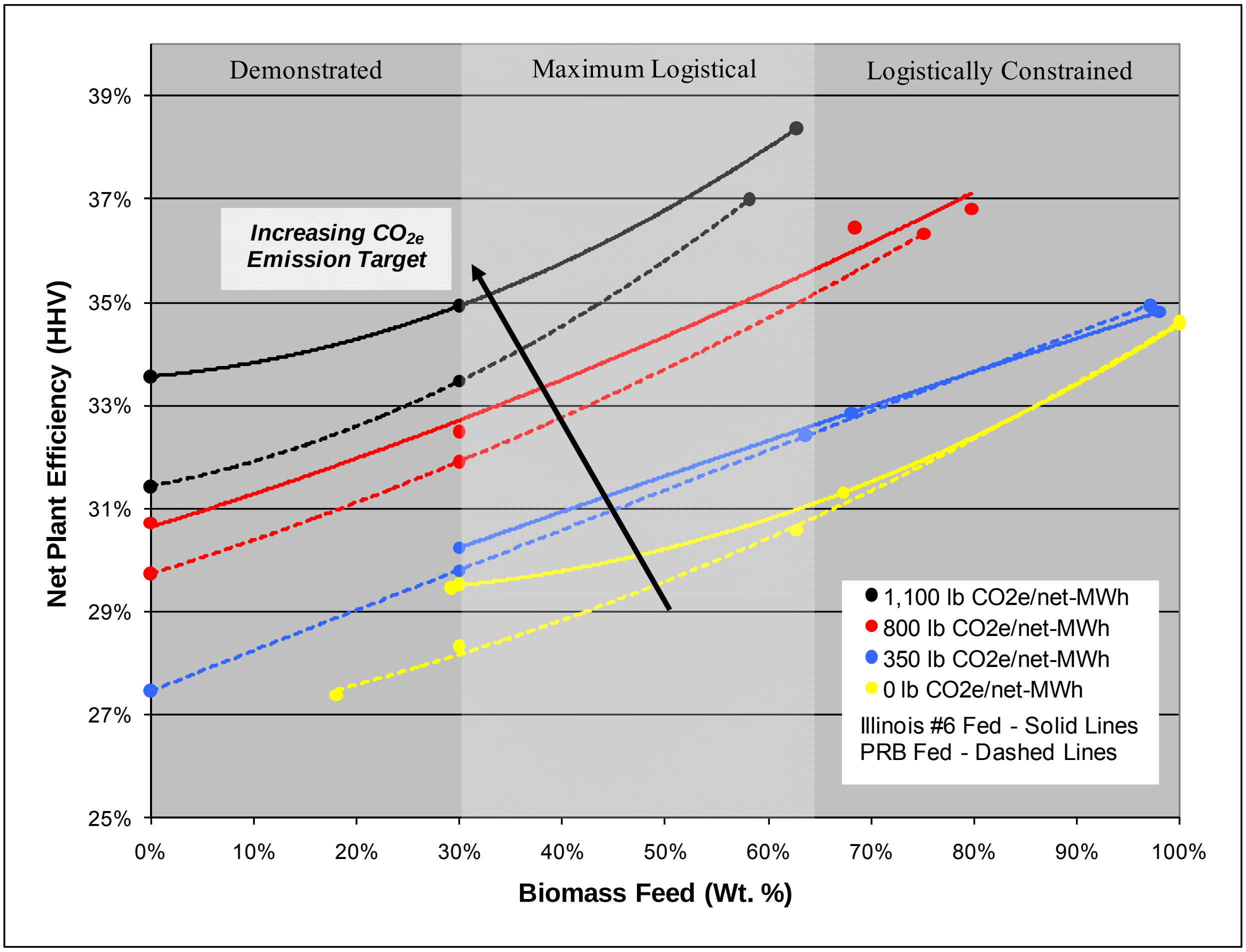
Exhibit ES-2 illustrates the net plant efficiency according to the biomass percentage in the feedstock for facilities operating at each of the following target emission levels: 0, 350, 800 and 1,100 lb CO_2e/net-MWh. The primary conclusions that can be drawn concerning net plant efficiencies (HHV) are as follows:

For plants operating at a fixed lifecycle emission level, the net plant efficiency increases as the proportion of biomass in the plant feedstock increases. This is because adding biomass reduces water-gas shift steam requirements, as well as auxiliaries associated with CO_2 capture and compression.

Given a feedstock of a certain composition, the net plant efficiency will decrease as the plant limited life cycle emissions decrease due to the higher levels of CO_2 capture that are required.

Efficiency trends are similar for both PRB and Illinois #6 fed plants. However, plant efficiencies are lower at the high-elevation site due to the lower ambient pressure as well as from co-feeding PRB, which is a lower rank coal than Illinois #6. The highest plant efficiencies are realized by plants at the Midwestern site while operating at ISO conditions and employing no CO_2 capture and feeding Illinois #6 coal.

Exhibit ES-2 Net Plant Efficiency vs. Feed Composition



<u>CO_2 Capture</u>

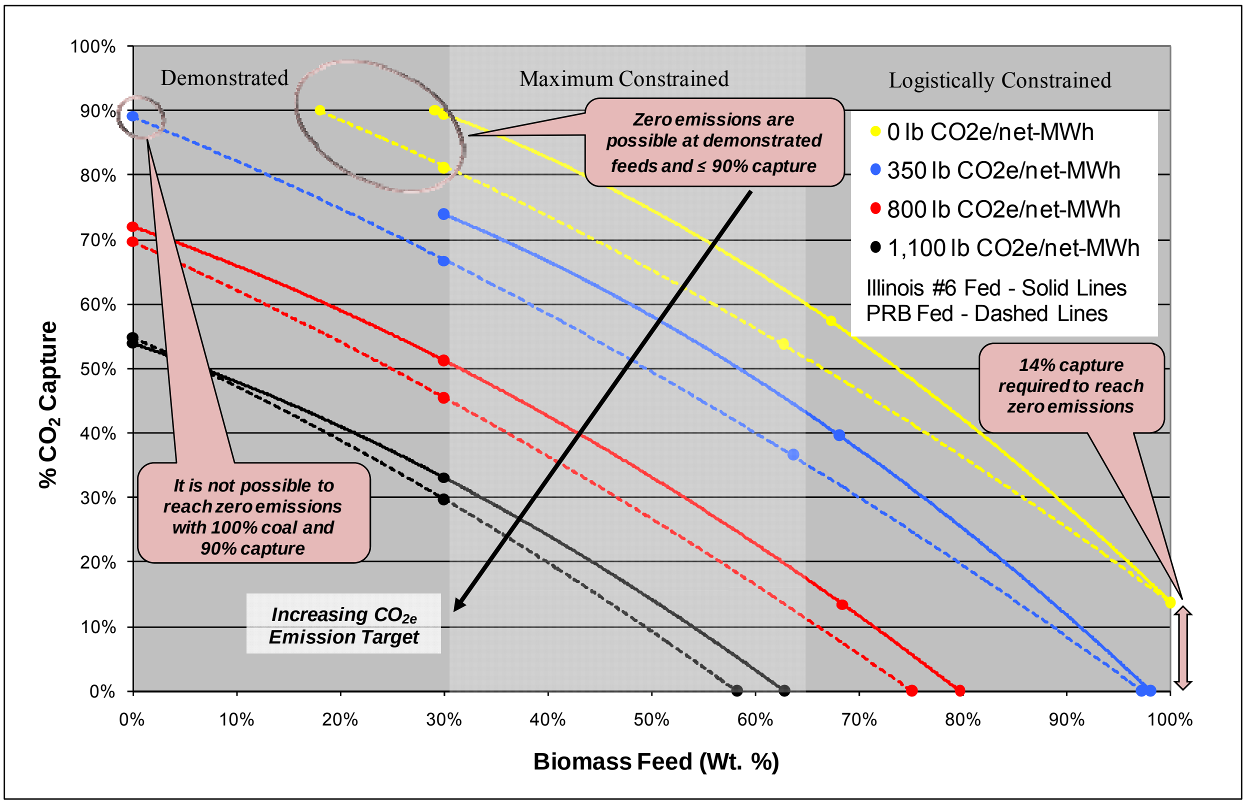
Exhibit ES-3 shows the percentage of plant carbon capture needed in order to achieve different targeted emission levels for plants employing various levels of cofiring. In general, the more biomass that is fed into a plant, the less CO_2 capture is required. Major conclusions from this study can be observed in this graph and are as follows:

It is theoretically possible to achieve <u>net zero life cycle emissions</u> at demonstrated levels of biomass cofiring (30 wt %) and ≤ 90 percent CO_2 capture (81.2 percent with PRB and 89.4 percent with Illinois #6).

It is not possible to achieve net zero life cycle emissions in a 100 percent switchgrass-fed plant without CO_2 capture. The GHG emissions associated with growing, harvesting and transporting the switchgrass require approximately 14 percent of the power plant carbon emissions to be captured.

Without biomass addition, it is not possible to achieve net zero life cycle emissions with coal and any degree of conventional CO_2 capture (up to 90 percent). The emissions associated with mining and transporting the coal, as well as the absence of a carbon-neutral feed, result in life cycle emissions of 327 lb CO_2e/net-MWh for PRB coal and 410 lb CO_2e/net-MWh for Illinois #6 coal.

Exhibit ES-3 Percent CO_2 Capture vs. Feed Composition



ECONOMICS

Capital and production cost estimates were factored estimates developed for each plant based on previous estimates for dry-fed, entrained-flow IGCC systems using PRB and Illinois #6 coal. Costs were factored using process parameters and scaling exponents derived from pre-existing cost data. Performance and process limits were based upon published reports, information obtained from vendors and users of the technology, and cost and performance data from design/build utility projects. Baseline coal costs for this analysis were determined using data from the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2007. The first year (2015) costs used are $12.96/AR ton ($0.76/MMBtu) for PRB coal and $41.94/AR ton ($1.80/MMBtu) for Illinois #6 coal, both on a higher heating value (HHV) basis and in 2007 U.S. dollars. Switchgrass cost was determined to be dependent on the switchgrass feed to the plant. Switchgrass cost ranged from $73.43/AR ton ($5.48/MMBtu) to $87.51/AR ton ($6.61/MMBtu), depending on demand.

Levelized Cost of Electricity

The revenue requirement figure-of-merit in this report is cost of electricity (COE) levelized over a 20 year period and expressed in $/MWh (numerically equivalent to mills/kWh). The 20-year LCOE was calculated using a simplified model derived from the NETL Power Systems Financial Model. TS&M costs were included for capture cases. All costs are expressed in June 2007 dollars, and the resulting LCOE is also expressed in June 2007 year dollars.

Exhibit ES-4 and Exhibit ES-5 show the LCOEs for the high-elevation cases and Midwestern cases operating at the four emission levels. The point in the upper right-hand corner of each plot represents the LCOE for a single gasifier train, 100 percent switchgrass fed plant operating at 0 lb CO_2e/net-MWh. The LCOE is elevated significantly because of a reverse economy-of-scale effect. The rest of the points represent two train plants. The primary conclusions that can be made are:

Without a GHG tax, for any feed composition, power plants emitting less life cycle GHGs have higher LCOEs than those emitting more.

The net plant efficiency increases as the proportion of switchgrass is increased when targeting a fixed GHG emission level. Despite this benefit, today's high switchgrass production and transport costs still drive up the LCOE of a plant not subject to GHG tax. This is largely attributable to the scarcity of biomass, its low energy density, and large distances required to gather and to transport adequate amounts.

<u>Without a carbon tax</u>, current switchgrass prices result in conventional capture with coal-only IGCC being a less expensive carbon abatement method, at all GHG levels. (The effect of carbon tax and the points of economic reversal will be presented later in the report.)

Exhibit ES-4 Levelized Cost of Electricity (High-Elevation Cases)

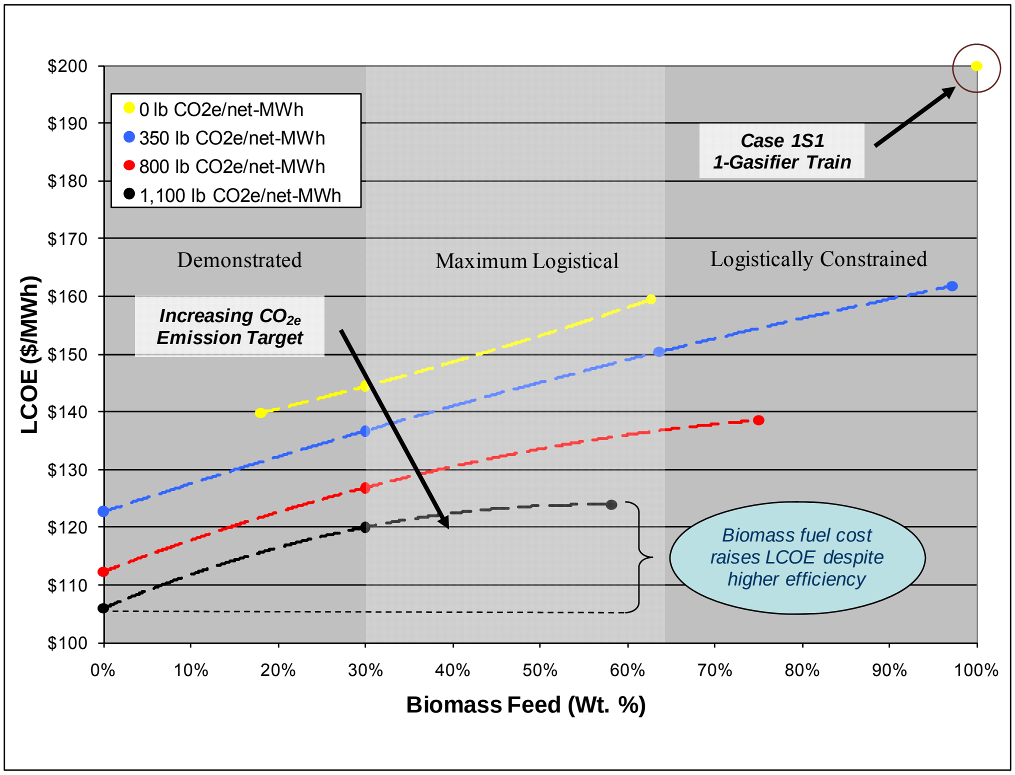
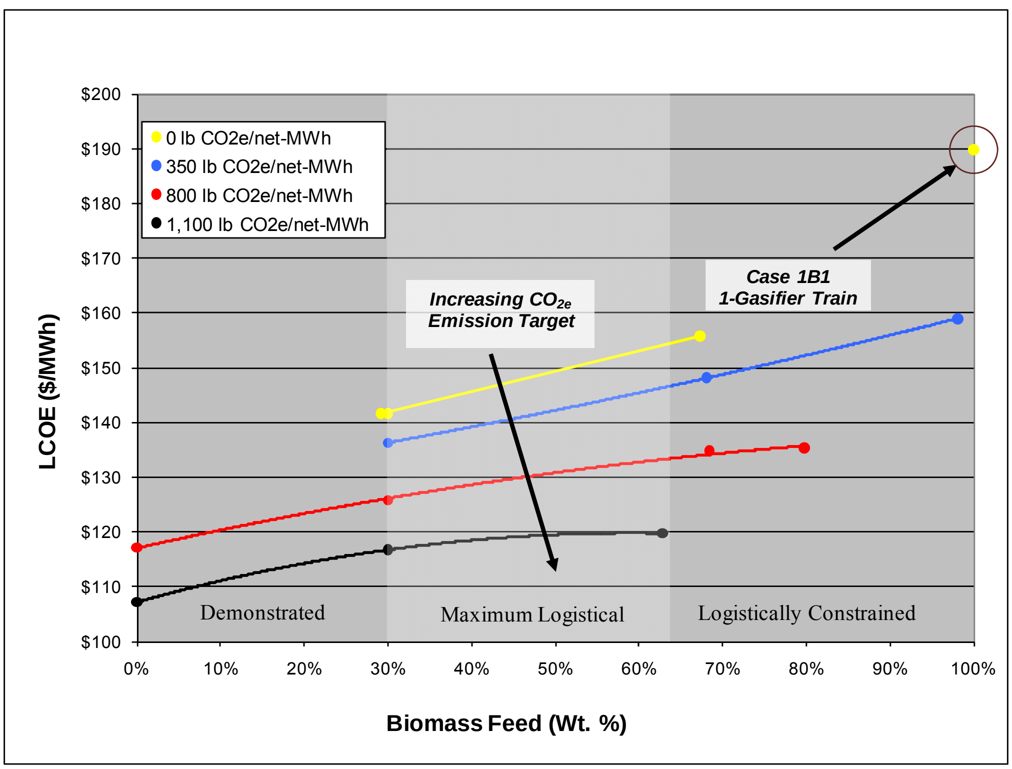


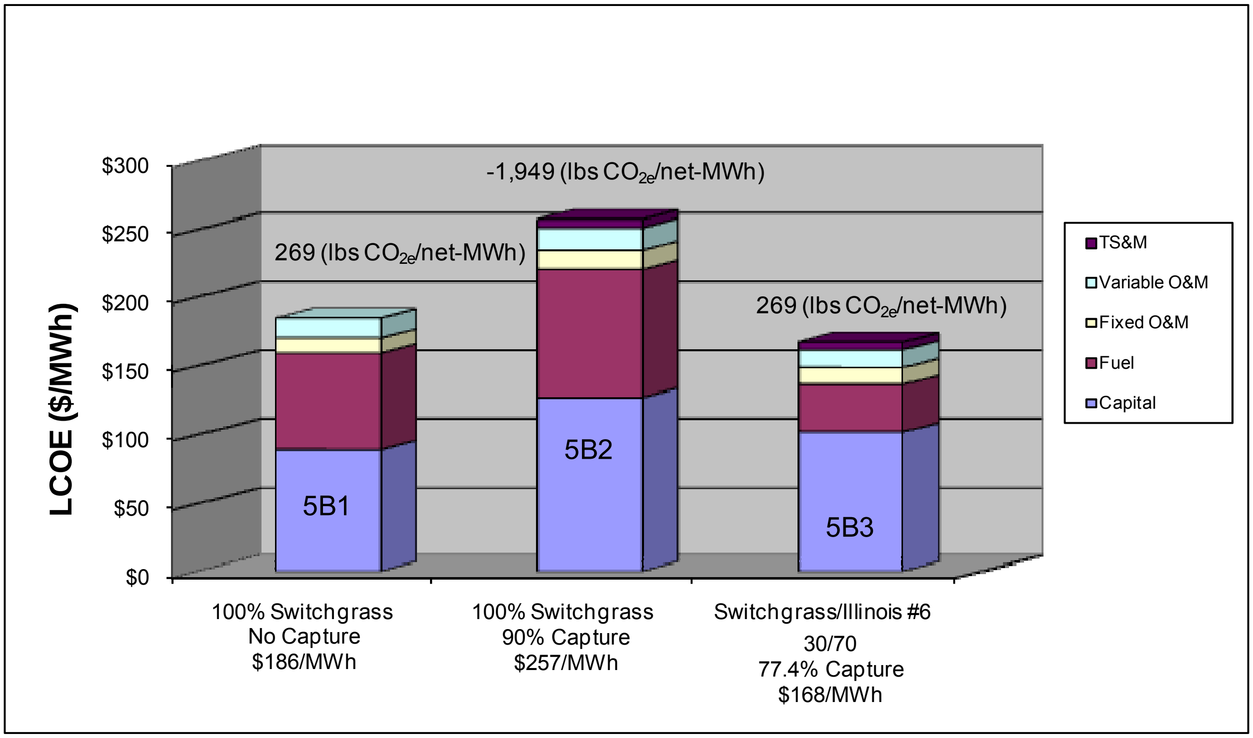
Exhibit ES-5 Levelized Cost of Electricity (Midwestern Cases)



In the absence of GHG tax, cofiring coal is essential for economic power production. As seen in the previous two charts, feeding higher concentrations of coal with conventional CCS is the less expensive method of CO_2 abatement. Exhibit ES-6 compares the LCOE breakdown of two single-gasifier train plants at equal emission levels (Cases 5B1 and 5B3) as well as an extreme capture scenario (Case 5B2). The primary conclusion is as follows:

Cofiring coal results in lower fuel costs than for a plant fed with 100 percent switchgrass plant operating at identical emissions. The resultant LCOE is thus lower despite the cost of adding conventional CCS.

Exhibit ES-6 Economic Benefits of Co-feeding Coal



CO_2 Tax

As mentioned above, when required to capture carbon in the absence of a GHG tax, conventional CCS techniques (90% capture) using coal as the sole feedstock results in the most economic low-carbon power generation.

Cofiring biomass as a means of GHG abatement becomes economically attractive:

1. Only after implementing traditional carbon capture and sequestration *and*,
2. At elevated GHG taxes.

Cofiring will become a more attractive option than conventional, coal-only CCS as the level of taxation increases. Exhibit ES-7 below shows the effect that a tax on all life cycle GHG emissions has on the LCOE of various Illinois#6-fed plants cofiring different levels of switchgrass. This analysis assumes that in GHG-negative cases, GHG credits can be earned and sold such that the tax (on positive emissions) becomes a source of revenue for the plant with negative emissions. The major conclusions that can be taken away from this graph are as follows:

Without a GHG tax or Renewable Performance Standard, feeding coal alone without GHG abatement is the lowest-cost option for selling power.

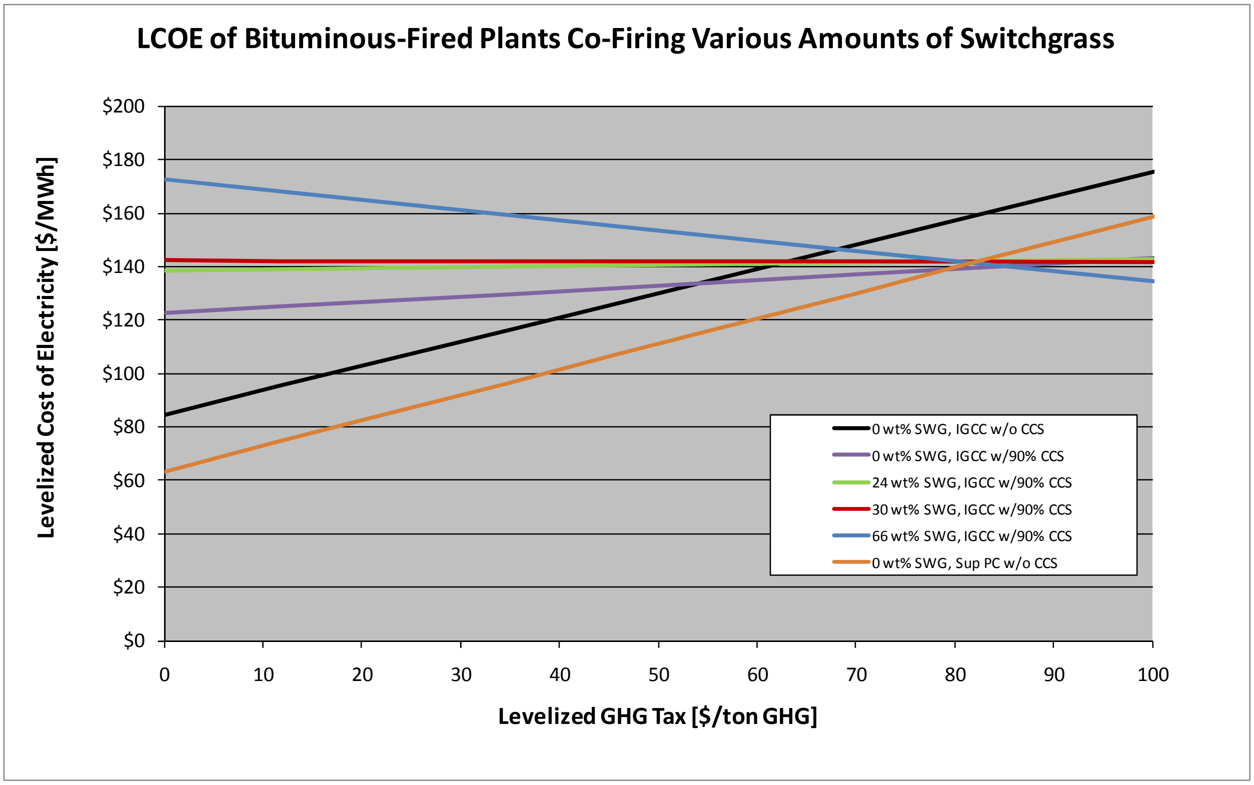
A tax of less than approximately $79/ton GHG provides no motivation for IGCC-based power systems to reduce GHG emissions. Up to this tax level, feeding 100 percent coal without abatement while simply paying the emissions penalty remains the lowest-cost option for selling power using IGCC.

Once a GHG tax of ~$79/ton GHG is levied, conventional CCS becomes the most economic option for low-GHG IGCC plants until approximately $82/ton GHG.

At ~$82/ton GHG, cofiring switchgrass with maximum CO_2 capture becomes the lowest-cost option. This level of taxation encourages plants to operate at the lowest possible (negative) life cycle GHG emissions. This is done by capturing 90 percent CO_2 and cofiring the maximum possible switchgrass feed.

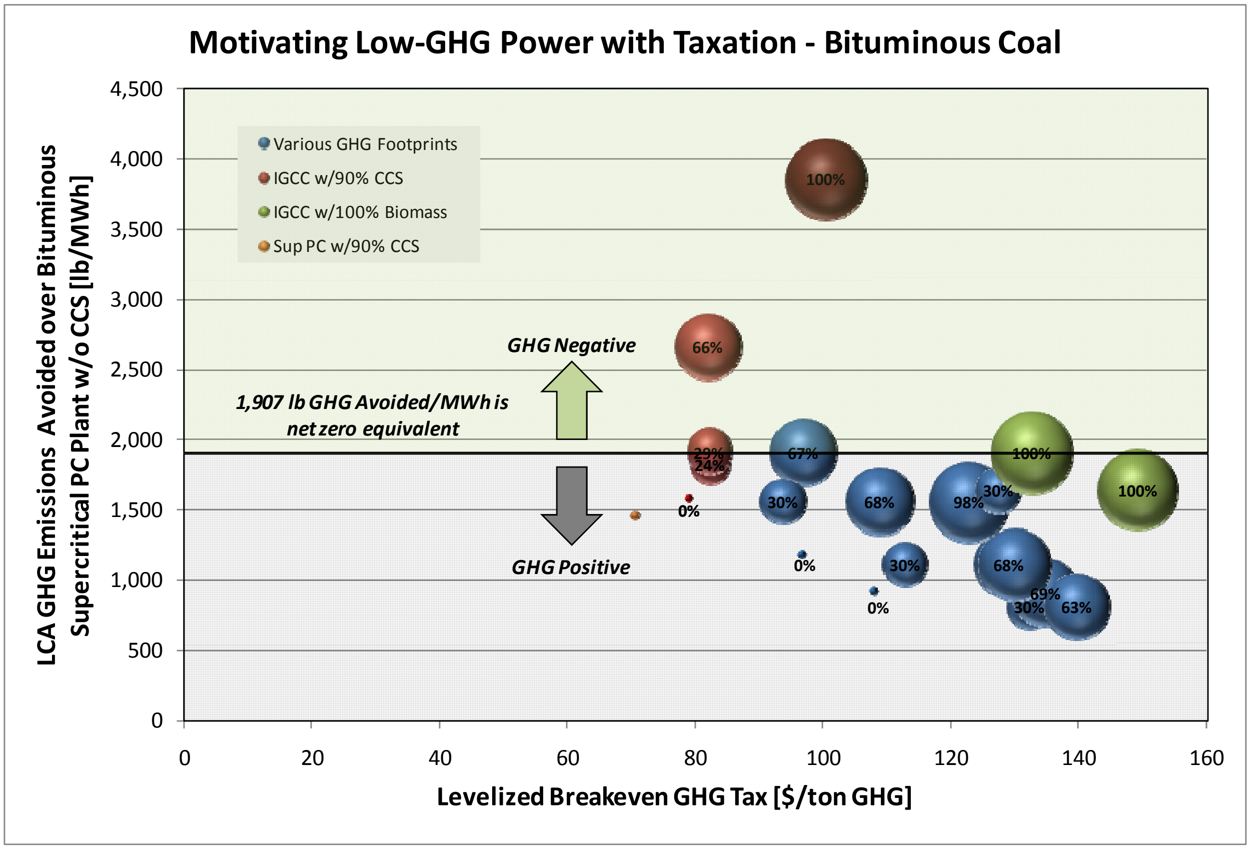
Analogous results for sub-bituminous coal cases are very similar and so are eliminated for brevity.

Exhibit ES-7 Motivating GHG Abatement with GHG Taxes



Examining only LCOE does not provide complete perspective on the degree to which a GHG tax promotes low-GHG footprints for power generation. To show how effective a GHG tax can be in motivating low-carbon power, Exhibit ES-8 illustrates how an economic demand for low GHG power is created as tax is increased.

Exhibit ES-8 Motivating Low-GHG Power Generation with GHG Taxes[1]



If a utility were to build its next greenfield plant to address future power needs, presumably the least expensive power generation option would be preferred. According to NETL's, "Cost and Performance Baseline for Fossil Energy Plants, Volume 1", this least expensive option is supercritical PC without carbon capture at \$63.3/MWh. This system has a LCA GHG emission footprint of 1,907 $lbCO_2e$/MWh, such that subtracting the y-axis value for each plant configuration in Exhibit ES-8 from 1,907 gives the net GHG footprint of the respective configuration.

Exhibit ES-8 shows how an increasing tax will promote lower GHG footprints for future power generation. The size of the bubbles qualitatively represents the biomass feed weight percentage (quantified in text within the bubble). The Exhibit shows that the lowest cost CBIGCC configuration for GHG mitigation is actually a coal-only IGCC plant incorporating the maximum 90% conventional CCS. However, there is no market for any low-GHG, coal-fired applications represented here until the GHG tax reaches at least \$71/ton, at which point Supercritical PC

[1] Supercritical PC data point provided by the NETL report, "Cost and Performance Baseline for Fossil Energy Plants". The group titled, "Various GHG Emissions" represents cases produced in this study that are sub-optimal choices in the context of cost and emissions reduction so are not discussed here.

w/90% CCS becomes cost effective with a GHG footprint 80% lower than a Supercritical system w/o CCS. This means paying the tax without capturing any CO_2 is the most economic option for coal based technologies at tax values less than $71/ton. While the lowest cost CBIGCC biomass feed percentage is 0% at $79/ton, this option also has the least potential for GHG mitigation of the CBIGCC options. For a relatively small (~4%) increase in GHG tax penalties (to ~$82/ton), it becomes economically favorable to begin adding significant amounts of switchgrass to an IGCC system. Small GHG tax increases to ~$82/ton promote an additional 60% avoidance of the supercritical PC plant's emissions by leveraging switchgrass' carbon-neutral benefits. Taxes at this level begin to create a market for GHG-negative plants, showing a very large GHG benefit for the additional penalty.

For a fixed co-firing percentage, plant size is limited by biomass availability, which limits economy of scale benefits for LCOE. For a plant with a single gasifier train, increasing GHG tax to ~$100/ton is shown to create a complete economic preference for switchgrass over coal as the sole IGCC plant feedstock, effectively resulting in the elimination of GHG's emitted by two equally-sized supercritical PC plants. The GHG tax is likely to be more in the range of $80-90/ton for a larger, dual-train gasifier plant that has the same GHG footprint.

Low-GHG power is not motivated for any bituminous coal-based technologies represented here until GHG taxes reach ~$71/ton, at which point supercritical PC w/90% CCS results in 80% less GHG emissions per MW. An additional 15% tax increase to ~$82/ton motivates CBIGCC technology with a 140% reduction in supercritical PC GHG emissions, promoting GHG-negative power generation.

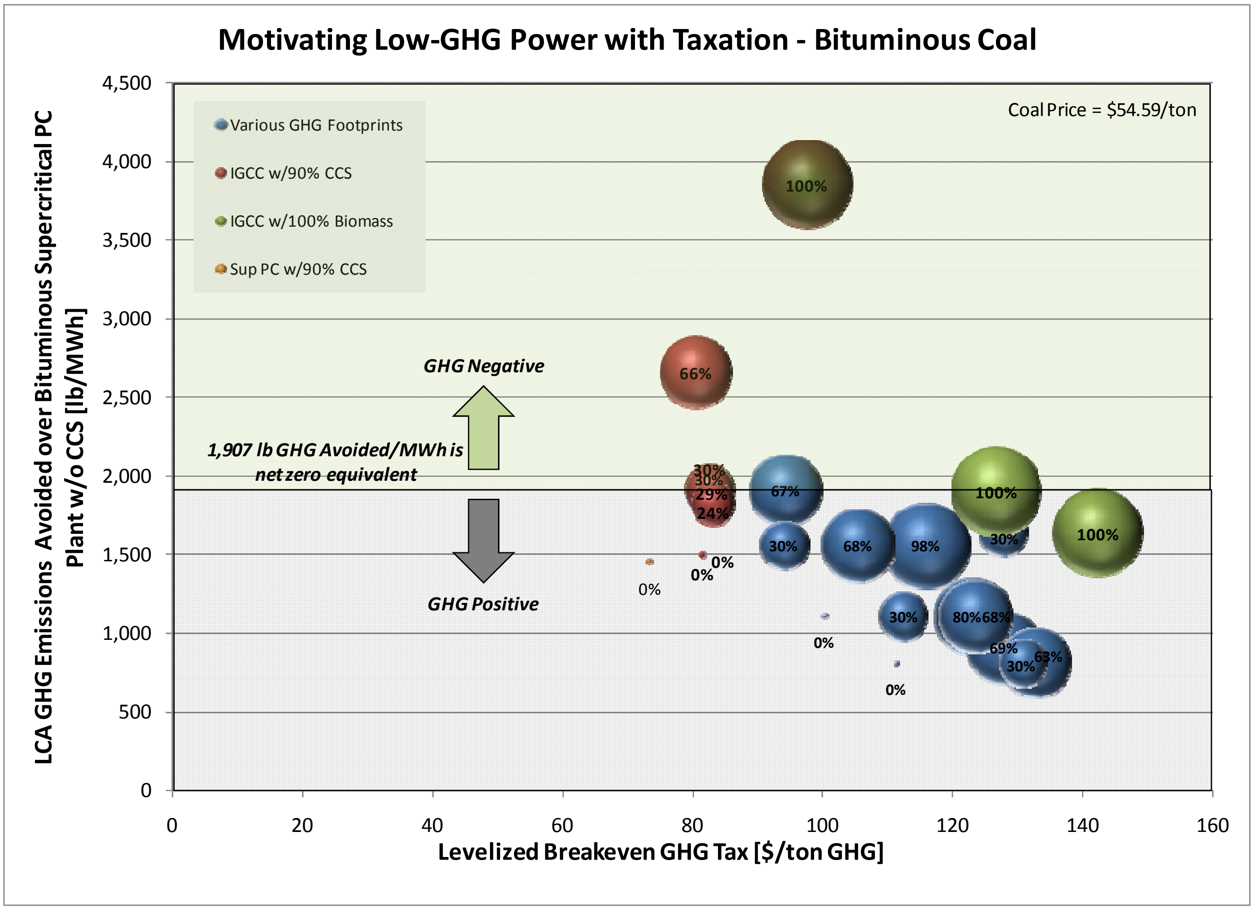
Coal Price Sensitivity

Values assumed for fuel prices impact the LCOEs and the levelized breakeven GHG tax values. Increasing the price of coal increases the LCOE for all coal cases by varying degrees depending on the percent contribution of the annual fuel cost to the overall LCOE for each case. Increasing coal prices will change the breakeven GHG tax cost for each case, the direction and magnitude depends on the technology efficiency as well as the relative amounts of coal and biomass consumed.

The sensitivities of the LCOEs calculated in this study were examined by using newly estimated coal prices of $54.59/ton for Illinois #6 and $28.32/ton for Montana Rosebud (PRB) instead of the originally assumed $41.94/ton and $12.96/ton, respectively. The new values were estimated using minemouth and transportation data developed from Ventyx Corporation's Energy Velocity (EV) Suite, a meta-database [17], and presented in Appendix B. The values were assumed to be in 2007 dollars to simplify the sensitivity calculation. The results show that the LCOE values increase between one and seven percent for the thirty percent increase in the bituminous coal price and between two and eleven percent for the 118 percent increase in the subbituminous coal price.

The impact of the higher bituminous coal price on the levelized breakeven GHG tax value is illustrated by comparing Exhibit ES-9 to Exhibit ES-8 above. Again, the higher subbituminous coal price has a similar impact and so is not shown for brevity. At the higher coal prices, the levelized breakeven tax for cases with lower percentages of biomass increases, and those with higher percentages of biomass decrease. When higher coal prices are used in the estimates, the differences in the breakeven values are reduced, and the cases utilizing more biomass become more economically favorable in comparison to those cases utilizing more coal.

Exhibit ES-9 GHG Breakeven Tax at Higher Bituminous Coal Price ($54.59/ton)



A second sensitivity calculation was performed to estimate the coal price values that would generate the same breakeven GHG Tax values for the cases representing coal-only with CCS as those for the maximum percentage biomass case using comparable technologies. The results are illustrated in Exhibit ES-10 for bituminous coal cases and Exhibit ES-11 for subbituminous cases, which show the original values for all the cases and the position the bubbles in the chart would move to if the higher coal prices were then used in the calculations, indicated by the vertical lines. Note the coal-only cases move toward higher breakeven GHG taxes (to the right), while the biomass cases move toward the lower breakeven GHG taxes (to the left). For the bituminous coal cases, parity with the biomass cases is reached at coal prices between $51/ton and $100/ton of coal for breakeven GHG Tax values of between $80/ton and $115/ton GHG depending on the case specific technologies. For the subbituminous coal cases, parity with the biomass cases is reached at coal prices between $48/ton and $62/ton of coal for breakeven GHG Tax values of between $78/ton and $110/ton GHG depending on the case specific technologies. As coal prices increase, the price gap for the two fuels closes and biomass becomes more economically attractive by comparison, resulting in lower potential GHG breakeven taxes.

Exhibit ES-10 Sensitivity of Breakeven GHG Tax to Bituminous Coal Price

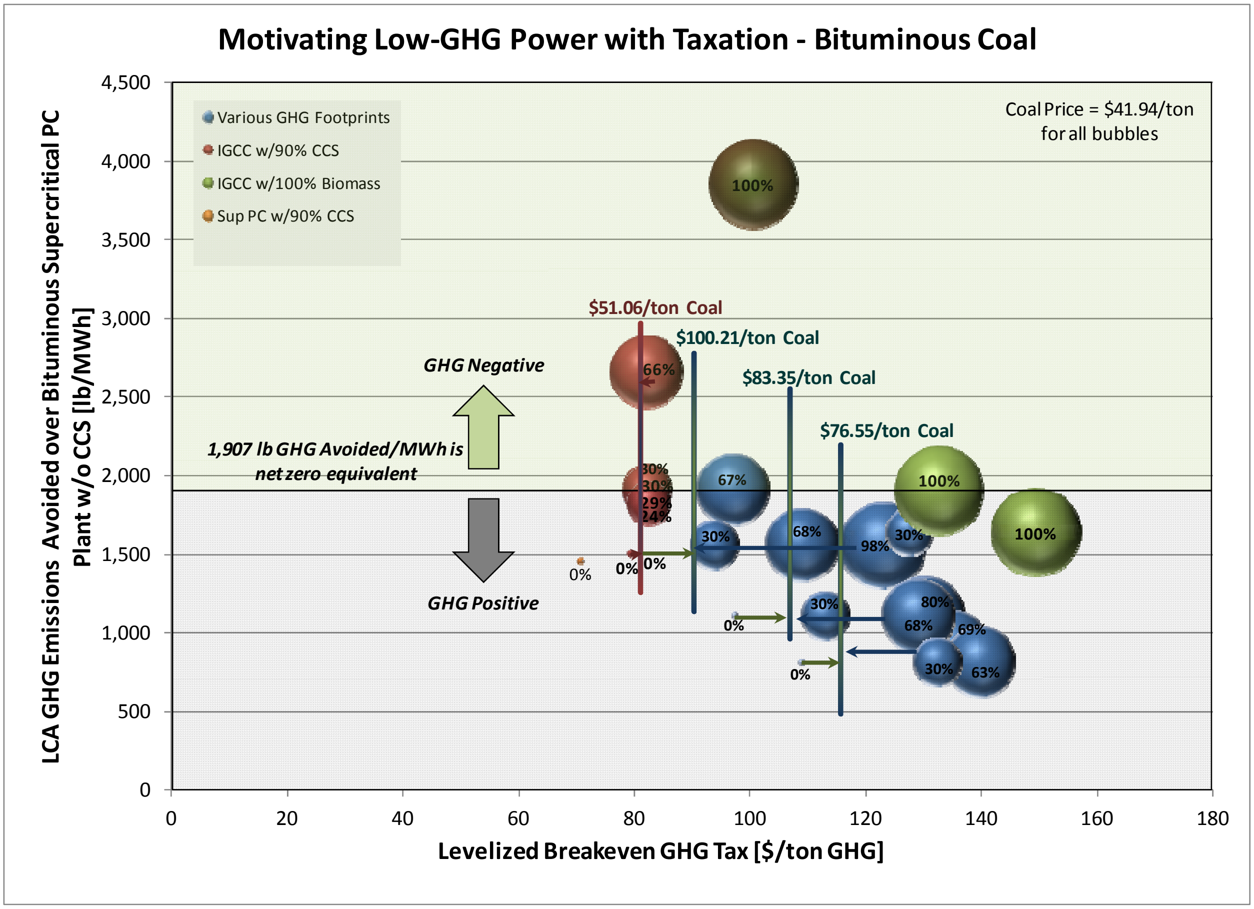
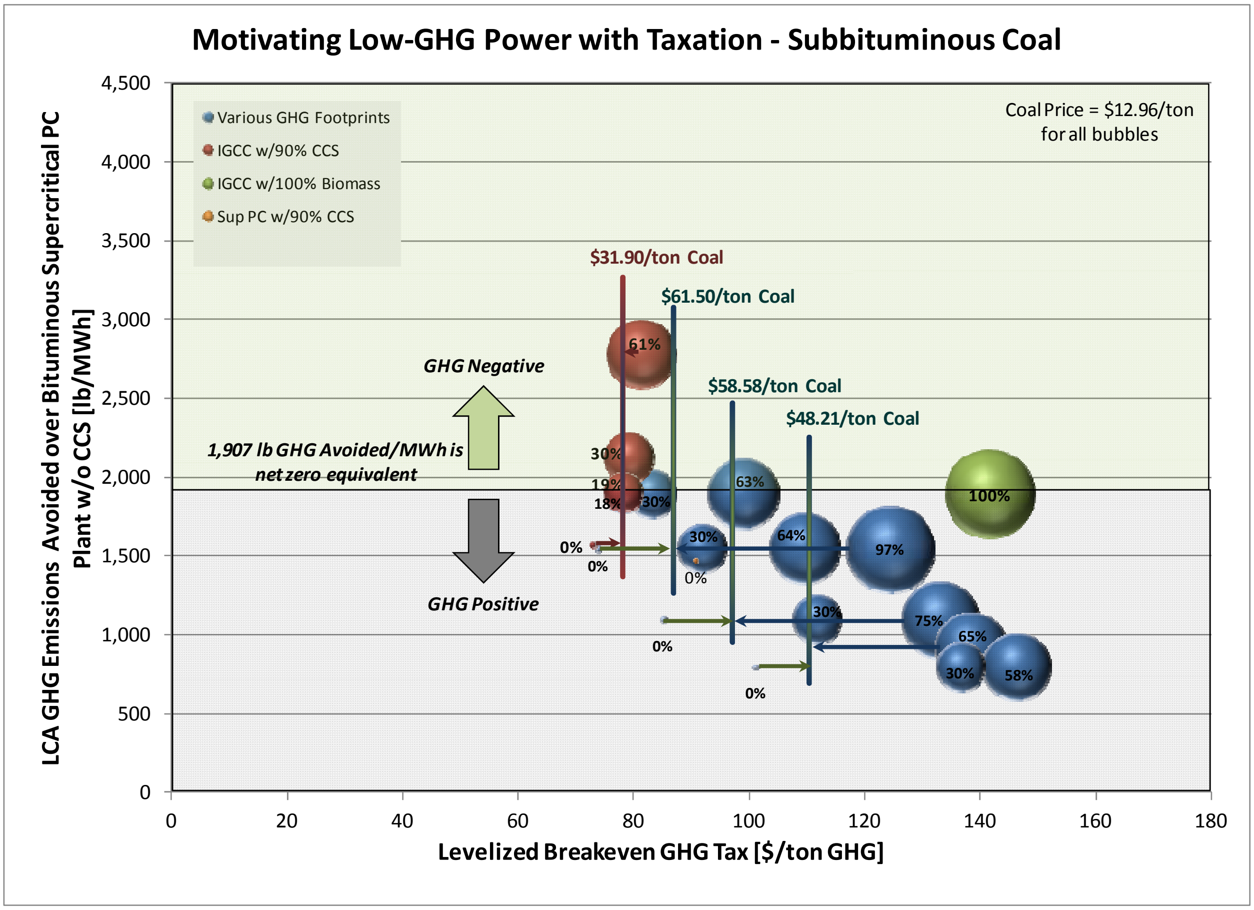


Exhibit ES-11 Sensitivity of Breakeven GHG Tax to Subbituminous Coal Price



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1. INTRODUCTION

1.1 STUDY BACKGROUND

Carbon dioxide emissions caused by burning biomass are considered to be GHG-neutral. The photosynthetic process removes atmospheric CO_2 and fixes it to a growing biomass feedstock much faster than atmospheric CO_2 becomes part of fossil fuels; therefore CO_2 emissions from biomass combustion do not contribute to a sustained, net accumulation of atmospheric CO_2. However, the cultivation, harvesting and delivery processes to provide both coal and biomass feedstocks currently utilize fossil fuels and produce emissions that cannot be considered GHG-neutral over anything less than a geological timescale. For power plants, these indirect fossil fuel-related emissions must be considered when evaluating life cycle greenhouse gas emissions to gain a more accurate understanding of the GHG footprint of power generation. This study examines the emission of CO_2 and other important GHGs resulting from the production, transportation, and combustion of the coal and biomass fuels to provide a GHG life cycle analysis of the process.

Results from the Nuon IGCC plant in the Netherlands [1] have demonstrated that it is possible to co-feed coal with up to 30% biomass by total feed weight. This study examines how an IGCC plant cofiring biomass while employing conventional carbon capture and sequestration (CCS) might play a role in the future of low carbon power generation. For the purposes of this conceptual study, which in part were to determine system responses to increasing biomass percent in the feed, it was assumed that percentages of biomass higher than 30% feed weight are feasible as required to meet GHG targets.

Coal fired power plants account for approximately 50% of the power generation in the United States and approximately 80% of the GHG emissions produced by the power generation sector [2]. Because coal fired power generation is such a large contributor to both national energy security as well as overall GHG emissions, it is very important to develop methods for reducing the carbon footprint of coal fired power plants to mitigate environmental concerns while continuing to reliably satisfy power demand. Effects of GHG reduction in the power industry could even be felt well into the transportation industry if plug in hybrid electric vehicles, fueled by low-GHG power, play a larger role.

IGCC plants with carbon capture have shown great promise for providing low carbon electricity at a more affordable price than conventional pulverized coal (PC) plants with carbon capture [3]. This study therefore utilizes as a greenfield plant basis an IGCC system employing a dry-fed entrained flow gasifier.

All technologies used in the systems analyses presented here are currently commercially viable; however, the mode of operation or scale in some cases may have yet to be demonstrated. With some demonstration, particularly in biomass feeding systems, slagging/fouling behavior and proving sustainable CO_2 sequestration, these IGCC plants can be considered state of the art. The results of this study show, in theory, that cofiring demonstrated amounts of biomass in state of the art IGCC plants employing carbon capture and sequestration can produce extremely low GHG footprints. It is important to note that while this study focuses on switchgrass, which may or may not be an ideal low-carbon feedstock, other types of biomass as well as wood and municipal wastes will have similar, though not identical, GHG reduction advantages over coal.

1.2 PROJECT OBJECTIVES

The objective of this study was to simulate biomass co-firing in a dry-fed, entrained-flow gasifier in an integrated gasification combined cycle (IGCC) power plant and examine the performance, environmental response, and economic response under two scenarios:

- 0 ft of elevation (ISO conditions) co-fired with Illinois #6 coal
- 3,400 ft of elevation co-fired with Powder River Basin (PRB) coal

In lieu of comparing identical system configurations from case to case, system configuration and operation both were adjusted in ways considered to reflect those anticipated to be the most practical and appropriate as feed composition and degree of carbon capture were varied. Technologies used were limited to currently available state-of –the-art processes.

In order to gain an understanding of the GHG effects of required plant operations lying outside of the classical plant boundary, the system studies presented in this report were performed using a limited life cycle GHG analysis. The life cycle boundaries were defined specifically to include technical, economic, and environmental information on feedstock (coal & biomass) production, transport, and environmental effects. For example, biomass farming and transport costs and related GHG emissions were considered in the system results. Life cycle emissions not included in this analysis include but are not limited to those associated with the plant construction, worker transport emissions, emissions associated with plant maintenance, etc. A life cycle GHG analysis permits not only consideration of the GHG benefits of co-firing biomass, but also consideration of the GHG contributions of co-firing biomass. The specific objectives of this study were to:

1. **Determine technical and economic benefits of adding strategic levels of biomass feedstock to achieve net zero life cycle GHG emissions in an IGCC power plant.**
2. **Determine the technical and economic benefits of adding strategic levels of biomass feedstock in an IGCC power plant to achieve GHG emission levels matching or closely representing: CA's GHG emission performance standard (1,100 lb CO_2/net-MWh), a state-of-the-art NGCC plant (800 lb CO_2/net-MWh), and a full CO_2 capture (90%) IGCC plant (350 lb CO_2/net-MWh).**
3. **Quantify economy-of-scale limitations of a 100% biomass IGCC power plant, and the economic benefits of co-feeding coal.**
4. **Determine the techno-economic performance and life-cycle GHG emissions of a state-of-the-art IGCC power plant that employs full (~90%) CO_2 capture while also co-feeding biomass.**
5. **Determine whether CCS or biomass co-feeding is economically preferred to achieve very low levels of CO_2 capture in an IGCC power plant.**

1.3 STATE-OF-THE-ART EXPERIENCE IN BIOMASS CO-FIRING

Biomass co-fire tests have been conducted at Tampa Electric's Polk Power Station and are on-going at NUON Power's Buggenum Plant. The NUON experience includes co-gasification of 30 wt% biomass, including wood, paper sludge, sewage sludge and chicken litter in a dry fed Shell gasifier. The plant was retrofitted with a sewage sludge silo and feed system along with a milled/dust products silo and feed system. Both feed systems discharge into the existing coal mills. Detailed operating results using biomass are lacking in the literature, although the information available indicates that the biomass was co-fed with the coal. To meet the CO_2 emissions reduction target imposed by the Dutch Coal Covenant, the Buggenum plant would consume about 185,000 tonnes of biomass per year (560 short tons per day) [4]. While providing valuable information on IGCC performance when co-firing similar proportions of biomass in this study, the quantities are an order of magnitude smaller than contemplated here.

The Polk Power Station uses a slurry-fed GE gasifier, and the biomass co-fire test was conducted in December 2001. The biomass consisted of 8.8 tons of eucalyptus trees, which were slurried with recycle solids from the gasifier and blended with the main coal/petcoke slurry. The biomass was fed at a rate of 1 TPH over an 8½ hour period, representing 1.2 percent of the plant's fuel. Plant performance was statistically indistinguishable from operation on the plant's base fuel [5]. While the test provided valuable information on harvesting, processing, and gasifying the eucalyptus trees, the scale was too small to be meaningful for the levels of biomass gasification contemplated in this study.

Co-firing biomass at larger scales has been demonstrated in conventional combustion processes as detailed below. However, even in these cases the amount of biomass consumed is significantly less than contemplated for this study. The logistics of biomass harvesting and transportation still remain a major impediment to commercial-scale deployment of this technology.

Biomass Experience in Conventional Combustion Processes

Biomass co-firing is not a new concept. In May 2004, DOE's Office of Energy Efficiency and Renewable Energy reported that at least 182 separate boilers in the United States had co-fired biomass with fossil fuels. Much of the experience was gained in the 1970's as a result of the energy crisis when many boiler operators were looking to lower costs. Of the 182 co-firing operations, 63 percent were at industrial facilities, 18 percent at utility-owned power plants and the balance at municipal boilers, educational institutions and federal facilities [6]. As of 2007 biomass fueled over 3.5 GW of domestic power production [7]. The biomass sources include bagasse (the fibers remaining after sugar juice is squeezed out of sugar cane), animal manure, fish oil, ethanol, digester gas, railroad ties, utility poles, wood and wood chips. These opportunity fuels are used primarily at the source of their production or use, namely sugar mills, lumber mills, paper mills and farms. Much of the power produced is consumed internally, but excess power is sent to the grid. Because biomass is considered a carbon neutral fuel, there is again increased interest in using it as an energy source to reduce carbon emissions. Recent examples abound of utilities using biomass in test burns and converting boilers to handle biomass co-fire or to accept 100 percent biomass:

- Willmar Municipal Utilities in Minnesota recently completed a test burn of over 10 tons of corn cobs in a 50-year old, 18 MW stoker boiler. Over 400 additional tons of corn cobs were procured for additional testing. If successful, the utility hopes to burn up to 25,000 tons of biofuels annually [8].
- First Energy announced plans in April 2009 to repower Units 4 and 5 of the R.E. Burger plant with local biomass fired between 80-100%. The conversion will cost an estimated $200 million and the two units will generate a combined 312 MW of electricity [9].
- Xcel Energy announced plans in February 2009 to convert Bay Front Unit 5 from coal to wood-fired. The other two boilers at the Bay Front plant already burn primarily biomass [10].
- A switchgrass co-fire test burn was conducted at the Ottumwa Generating Station in late 2000 and early 2001. Over 1,200 tons of switchgrass were successfully co-fired (17 tph), representing about 3 percent of the heat input to the 725 MW plant [11].

2. GENERAL EVALUATION BASIS

This study is designed to assess technical and economic impacts of co-firing strategic levels of switchgrass and PRB or Illinois #6 coal in a dry-fed entrained flow gasifier-based IGCC plant to achieve varying levels of limited life cycle GHG emissions.

For each of the plant configurations in this study, an AspenPlus model was developed and used to generate material and energy balances. The material and energy balances were used as the basis for generating the capital and operating cost estimates. Ultimately a 20-year levelized cost of electricity (LCOE) was calculated for each of the cases and is reported as the revenue requirement figure-of-merit.

The balance of this section provides details on the site characteristics, feedstock characteristics and costs, life cycle boundary description, the study environmental targets, assumed capacity factor, raw water usage, cost estimating methodology and a description of each process system.

2.1 SITE CHARACTERISTICS

Two site locations are considered in this study: a Midwestern site and a generic High-Altitude site. Plants using Illinois #6 and PRB coal are assumed to be located at the Midwestern and generic High-Altitude sites, respectively. Both sites assume an adequate local supply of switchgrass. Ambient conditions are shown in Exhibit 2-1 and Exhibit 2-2. Site characteristics for both sites are shown in Exhibit 2-3 [12,13].

Exhibit 2-1 Site Ambient Conditions, Midwestern, Illinois #6 Coal

Average Elevation, ft	0
Barometric Pressure, psia	14.696
Design Ambient Temperature, Dry Bulb, °F	59
Design Ambient Temperature, Wet Bulb, °F	51.5
Design Ambient Relative Humidity, %	60

Exhibit 2-2 Site Ambient Conditions, High-Altitude, PRB Coal

Average Elevation, ft	3,400
Barometric Pressure, psia	13.0
Design Ambient Temperature, Dry Bulb, °F	42
Design Ambient Temperature, Wet Bulb, °F	37
Design Ambient Relative Humidity, %	62

Exhibit 2-3 General Site Characteristics

Location	Greenfield
Topography	Level
Size, acres	300
Transportation	Rail
Ash Disposal	Off Site
Water	Municipal (50%)/ Groundwater (50%)
Access	Land locked, having also access by train and highway

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

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

2.2 COAL CHARACTERISTICS AND COST

All but four of the cases described in this report either exclusively fire coal or co-fire coal and switchgrass. The four remaining cases exclusively fire switchgrass. Of the cases firing coal, 20 fire PRB while 23 fire Illinois #6. Coal compositions for Illinois #6 and PRB are shown in Exhibit 2-4 [14]. The coal mercury concentrations used for this study did not come from reference [14], but rather were determined from the Environmental Protection Agency's (EPA) Information Collection Request (ICR) database. The ICR database reports Montana Rosebud subbituminous coal with an average Hg concentration of 0.056 ppm (dry) and a standard deviation of 0.025 ppm. Illinois #6 bituminous coal is reported with an average Hg concentration of 0.09 ppm (dry) and a standard deviation of 0.06 ppm. The mercury values in Exhibit 2-4 are the respective means plus one standard deviation, or 0.081 ppm (dry) for PRB coal and 0.15 ppm (dry) for Illinois #6 coal [15]. The dry-fed entrained flow gasifier assumed in this study requires surface moisture be removed from the coal. For this study, PRB coal is assumed to be fed to the gasifier at 6% moisture [16] while Illinois #6 coal is fed at 5% moisture [3].

Exhibit 2-4 Design Coal Analyses

Rank	Sub-Bituminous		Bituminous	
Seam	Montana Rosebud (PRB)		Illinois #6 (Herrin)	
Source	Western Energy Co.		Old Ben Mine	
Proximate Analysis (weight %)				
	AR	Dry	AR	Dry
Moisture	25.77	0.00	11.12	0.00
Ash	8.19	11.03	9.70	10.91
Volatile Matter	30.34	40.87	34.99	39.37
Fixed Carbon	35.70	48.09	44.19	49.72
Total	100.00	100.00	100.0	100.0
HHV, Btu/lb	8,564	11,516	11,666	13,126
LHV, Btu/lb	8,252	11,096	11,252	12,660
Ultimate Analysis (weight %)				
Moisture	25.77	0.0000	11.15	0.0000
Carbon	50.08	67.4616	63.94	71.9607
Hydrogen	3.38	4.5540	4.51	5.0796
Nitrogen	0.71	0.9566	1.25	1.4110
Chlorine	0.00	0.0000	0.00	0.0000
Sulfur	0.73	0.9836	2.52	2.8333
Ash	8.19	11.0348	9.73	10.9493
Oxygen[1]	11.14	15.0094	6.89	7.7661
Total	100.00	100.0000	100.00	100.0000
Ash Mineral Analysis (weight %)				
Silica	38.09		45.0	
Aluminum Oxide	16.73		18.0	
Titanium Dioxide	0.72		1.0	
Iron Oxide	6.46		20.0	
Calcium Oxide	16.56		7.0	
Magnesium Oxide	4.25		1.0	
Sodium Oxide	0.54		0.6	
Potassium Oxide	0.38		1.9	
Phosphorus Pentoxide	0.35		0.2	
Sulfur Trioxide	15.08		3.5	
Barium Oxide	0.00		0.00	
Strontium Oxide	0.00		0.00	
Manganese Dioxide	0.00		0.00	
Unknown	0.84		1.8	
Trace Components (ppmd)				
Mercury[2]	---	0.081	---	0.15

Notes: 1. By Difference
2. Mercury value is the mean plus one standard deviation using EPA's ICR data

The first year delivered costs for PRB and Illinois #6 coals used in this study are $12.96/ton and $41.94/ton respectively (2015 cost of coal in 2007 dollars). The cost was determined using the following information from the Energy Information Administration's (EIA) 2007 Annual Energy Outlook (AEO):

- The 2015 minemouth costs of PRB and Illinois #6 in 2005 dollars, $9.84/ton and $31.85/ton respectively, were obtained from the Energy Information Administration's (EIA) 2007 Annual Energy Outlook (AEO).
- The delivery costs were assumed to be 25 percent of the minemouth cost for both coal types delivered to their respective Midwestern and high-altitude site (it was assumed that locating the plant close to an abundant switchgrass site would take priority over establishing a minemouth location). The assumed transport distance was 200 miles for both locations.
- The 2015 delivered costs ($12.30/ton for PRB and $39.81/ton for Illinois #6) were escalated to 2007 dollars using the gross domestic product (GDP) chain-type price index from AEO 2007, resulting in delivered 2015 prices in 2007 dollars of $12.96/ton for PRB and $41.94/ton for Illinois #6.

The coal prices used for the estimates in this report are based on the values extracted from the 2007 AEO and used in the initial version of the "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity," Report No. DOE/NETL-2007/1281, Final Report Revision 1, August 2007. This bituminous baseline report was revised in November 2010 to include updated coal prices as well as other changes to calculation methodologies. In anticipation of an upgrade to the calculations in this report, current coal prices were estimated based on minemouth and transportation data developed from Ventyx Corporation's Energy Velocity (EV) Suite, a meta-database [17]. The results of that study are included in this report as Appendix B. The study estimates that the delivered price of Illinois #6 is $54.59/ton and the delivered price of Montana Rosebud (PRB) is $28.32/ton in 2011 dollars. Sensitivity calculations were performed using these new values and included on Section 5.8 of this report, but the new values were assumed to be in 2007 dollars to simplify the sensitivity calculations.

2.3 SWITCHGRASS CHARACTERISTICS AND COST

Switchgrass grown on Conservation Reserve Program (CRP) lands is the sole biofeed used in this study. The CRP program is administered by the United States Department of Agriculture (USDA) Farm Service Agency (FSA) and provides incentive for farmers to address soil, water, and related issues by converting marginal or degraded lands to vegetative cover [18]. The current use of CRP lands in proximity of each plant site is unknown; because of the great deal of uncertainty in actual land cover and resultant land use changes, for the purposes of this study, the assumption was made that switchgrass could be grown without land-use changes on CRP lands that support this growth. Switchgrass is not a food source so using it as a fuel does not compete with food markets. Exhibit 2-5 shows the composition of the design biofeed, which examines the supply and characterization of different biomass types and the life cycle greenhouse gas emissions associated with their production and transportation.

Exhibit 2-5 Switchgrass Design Analysis

Ultimate Analysis	Dry Basis, %	As Received, %
Carbon	42.60	36.21
Hydrogen	6.55	5.57
Nitrogen	1.31	1.11
Sulfur	0.01	0.01
Chlorine	0.00	0.00
Ash	7.45	6.33
Moisture	0.00	15.00
Oxygen	42.08	35.77
Total	100.0	100.0
Heating Value	**Dry Basis,**	**As Received, %**
HHV, kJ/kg	18,113	15,396
HHV, Btu/lb	7,787	6,619
LHV, kJ/kg	16,242	13,806
LHV, Btu/lb	6,983	5,935

The cost of the switchgrass (in 2007 dollars) was calculated as a function of quantity consumed as follows:

$$Switchgrass\ Cost\ (\$/dry\ ton) = 1.286\times10^{-11}\bullet X^3 - 3.028\times10^{-7}\bullet X^2 + 3.569\times10^{-3}\bullet X + 85.32$$

where X = Switchgrass production rate, dry ton/day.

The price of switchgrass is dependent on cultivation costs as well as the distance needed to transport it to the plant site. Although there may be multiple, perhaps less expensive options in certain areas, the cost function above assumes switchgrass delivery in trucks. This is described in more detail in later parts of this report section.

Demands for large switchgrass feed rates require large areas of cultivation and in turn higher cost for collection and transportation to the plant. Exhibit 2-6 shows the relationship switchgrass cost and transport distance has with the required production.

Exhibit 2-6 Switchgrass Cost and Transportation

Exhibit 2-7 provides a comparison for the fuel prices in this study. PRB and Illinois #6 costs do not change with demand and are presented as is. A range of switchgrass prices, from the minimum feed to the maximum feed used in this study, are presented.

Exhibit 2-7 Fuel Price Comparison

Coal Cost		
	$/AR ton	$/MMBtu
PRB Cost	12.96	0.76
Illinois #6 Cost	41.94	1.80
Switchgrass Cost		
Minimum Feed	73.43	5.48
5,000 Dry TPD	82.62	6.24
Maximum Feed	87.51	6.61

Switchgrass Selection:

Several biomass types have been successfully gasified in commercial IGCC facilities. Switchgrass was chosen as the sole biomass feedstock in this study in lieu of other feeds for a number of reasons. Switchgrass is not a food source and since it is able to grow on marginal or depleted lands its cultivation does not compete for agricultural lands. It is a robust, relatively fast growing crop that has shown potential for use as a fuel easily cofired with coal in existing plants in the short-term.

While switchgrass is attractive for the reasons stated above, future research must confirm the ability to co-fire switchgrass without major consequence in long-term operation.

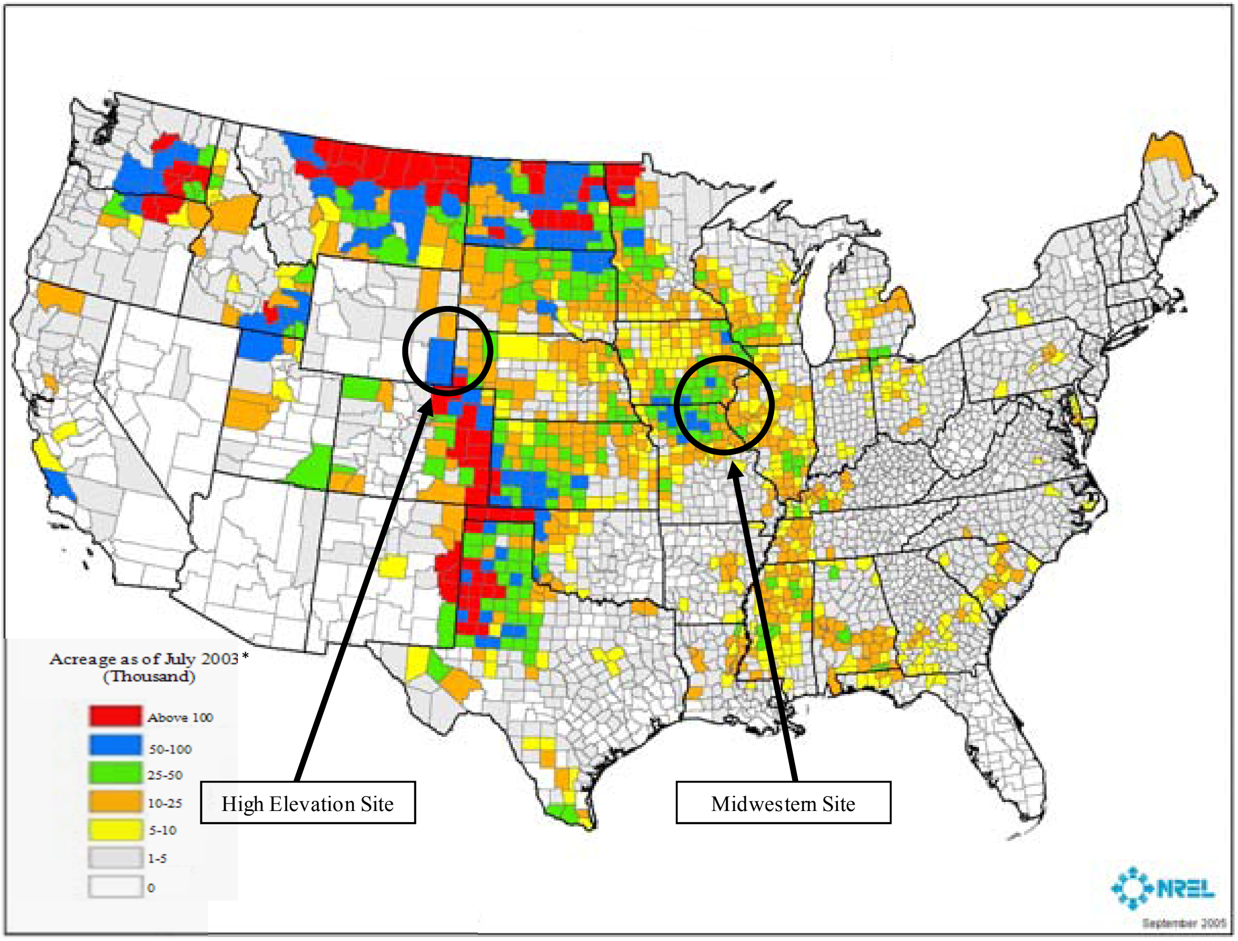
2.3.1 Switchgrass Availability

Switchgrass is a perennial, warm season grass crop that is one of the dominant tallgrass species in central North America. It is a hearty and versatile crop that thrives in various weather, soil, and land conditions. Switchgrass is a diverse species in which different strands thrive in different regions. Upon maturity, switchgrass establishes an extensive root system which provides drought resistance as well as erosion prevention. The regional availability of switchgrass is an important consideration for power plants intent on cofiring the crop.

The Natural Resources Conservation Service (NRCS) has sectioned the U.S. into land resource regions and further into land resource areas [19]. The intention is to classify land regions of the U.S. and characterize the physiography, geology, biological resources, etc. of each land resource area in the region. The plant locations assumed in this study are characterized as high-elevation (3,400 ft. elevation) and Midwestern (0 ft. elevation). Referring to the NRCS classifications, several land resource areas at high elevation are able to support switchgrass growth in the Wyoming, Nebraska, and South Dakota local. These most notably include the "Central High Plains" (3,200-5,500 ft. elevation range) and "Mixed Sandy and Silty Tableland and Badlands" (2,950-3,940 ft. elevation range) regions. Midwestern regions supporting switchgrass growth are concentrated in the Iowa, Missouri, and Illinois local. These most notably include the "Central Claypan Areas" and "Illinois and Iowa Deep Loess and Drift" land resource areas.

Both plant locations are assumed to be located in regions with adequate switchgrass growth potential on CRP lands. A study conducted by the National Renewable Energy Laboratory (NREL) has compiled data generated by the USDA's Farm Service Agency in order to create the map shown in Exhibit 2-8 which shows the acreage density of CRP lands throughout the U.S. [20] and general site locations. This report does not assume that sufficient switchgrass currently exists for commercial power generation in the study site locations, only that there is adequate potential for cultivation thereon as supported by the NRCS land classifications and NREL CRP records.

Exhibit 2-8 Conservation Reserve Program (CRP) Acres



*Data source: USDA Farm Service Agency, County CRP Signup 26 Information [20]

2.3.2 Maximum Switchgrass Supply

In order to supply 5,000 dry ton/day of switchgrass, the required acreage for cultivation on CRP lands is approximately 357,500 acres. This assumes a yield of 5.1 dry ton/acre/yr of switchgrass and an 80% land cultivation factor. From Exhibit 2-8, it is clear that the concentration of CRP lands is greater in the Midwestern locale than in the high elevation locale. The same maximum feed was assumed for both plant locations, each of which has varying CRP land availability. Therefore it is worthwhile to confirm if there is sufficient CRP acreage available in proximity of the high elevation site. Platte, Goshen, and Laramie counties in southeast Wyoming and Banner County in west Nebraska each contain up to 100 thousand acres of CRP lands. These counties combined with Niobrara County, WY and Scotts Bluff County, NE, each with up to 25 thousand acres of CRP lands, can provide a total of up to 450,000 acres. The total land area of these counties is approximately 7 million acres. Therefore, CRP lands potentially occupy up to 6 percent of the total available land in the vicinity of the high elevation site. For comparison, an equivalent amount of CRP lands are potentially available on an area of 2.3 million acres in north-central Missouri, which equates to about 19 percent of the total available land. Because

Exhibit 2-8 represents a range of total CRP acres per county, only 1% land availability was assumed for the high elevation site. In generating the design basis for this study, the same CRP land availability was assumed for the mid western site for the purposes of comparison, although research throughout the progress of this study strongly suggest switchgrass land availability and thus, prices are likely to be regionally dependent. This assumption on land availability was used to determine emissions from transportation of the switchgrass to the plant gate for both sites, so it is very likely transportation emissions will vary regionally as well.

A potential requirement for CBIGCC facilities is the integration of satellite torrefaction/densification facilities in order to reduce the cost of transportation and streamline the biomass supply chain in situations where biomass cultivation areas are not localized. Satellite facilities may reduce the number of trucks needed to deliver fuel to the plant, which may enable greater supplies of biomass. Nevertheless, switchgrass availability can present feed restrictions if used as the sole biomass feedstock. Therefore other biofeeds may be needed to supplement switchgrass in order to increase the availability of a plant's carbon-neutral fuel options. Feeds such as woody waste and forest residues offer CO_2 credit and may be more readily available in some regions.

2.3.3 Maximum Switchgrass Feed Rate

The maximum logistical switchgrass feed rate assumed in this study was 5,000 dry tons/day (490,196 lb switchgrass/hr with a delivered moisture content of 15 wt%) based on logistical constraints. Harvesting and transporting this quantity of biomass presents significant challenges and represents a primary barrier in the successful adoption of the technology at this scale. Assuming a delivery truck capacity of 34,000 lb and year-round switchgrass harvest ability, this feed would equate to about 1 full truck arriving at the plant every 4 minutes around the clock. The authors acknowledge that in order to support feeds of this magnitude, it is necessary to develop switchgrass storage capabilities at the plant to satisfy demand during times of minimal or no harvest as well as improve shipping logistics in order to make transporting the fuel to the facility feasible.

Logistical issues of transporting and efficiently feeding large quantities of biomass to gasification facilities are currently being examined with major focuses on pelletization and torrefaction [21,22]. Processes such as these produce a dried, compacted, energy densified biomass product which can improve fuel feeding methods as well as improve the logistics of transporting biomass to the plant.

The largest domestic biomass-fueled energy plants currently operating use conventional combustion-based technology and are co-located with paper mills. For example the Mead Coated Board Plant in Alabama used over 1.16 million tons of wood-derived solids and the Gaylord Container Bogalusa Plant used over 1.14 million tons in 2008 [23]. During their peak months, these plants consume between 3,600 and 4,300 TPD of wood-based fuel.

Existing dedicated electricity generating plants burning biomass and not co-located with paper or sugar mills are generally limited to 50 – 80 MW capacity. The largest of these units, the Pittsylvania Power Plant in Virginia (80 MW), the J.C. McNeil Plant in Vermont (59.5 MW), the Kettle Falls Generating Station in Washington (50.7 MW) and the Craven County Wood Energy Plant in North Carolina (50 MW), have peak biomass feed requirements of 1,600 – 2,400 TPD. Larger plants are being planned. Nacogdoches Power, a joint venture between Bay Corporation Holdings, Ltd. and Energy Management, Inc., plans to build a 100 MW plant in Texas fueled entirely by wood (forest residues, whole tree chips, municipal tree waste, and mill residue). Georgia Power plans to convert Plant Mitchell Unit 3 from coal-fired to biomass-fired. Unit 3 currently produces enough steam to generate 96 MW of power. First Energy's recently announced plans for the R.E. Burger Plant will push the envelope for biomass production, harvesting, and transportation even further. The plans include conversion of two PC boilers capable of generating steam for 312 MW of electricity production to soon burn renewable fuels. Assuming the same average biomass intensity as the existing power only plants (1.5 tons of biomass/MWh of electricity); the Burger Plant will require nearly 6,000 TPD of biomass assuming historical generating levels spread out evenly over the entire year. Successful operation of the Burger Plant on biomass could remove a primary barrier to large scale biomass energy production.

Torrefaction: Improving Biomass Logistics

Torrefaction is a pyrolysis treatment that operates within a temperature range of 200 to 300°C. The mechanical effect of torrefaction on biomass is similar to its effect on coffee beans, giving the product a brittle structure. The main torrefaction product is a solid, which is the charred residue (or char) of the processed biomass. Following torrefaction, the biomass char is structurally sound and can be pelletized to improve grindability. Switchgrass specifications from various sources consistently show the volatile content to be around 75 percent [21]. The yield of chemical energy contained in the biomass through torrefaction is of importance because of the particularly high volatile content. One study shows that dried biomass fed to a torrefaction process at 15% moisture can potentially recover 90% of its chemical energy post torrefaction if process temperatures remain between 230 to 270°C [22].

2.3.4 Switchgrass Harvest Timetable and Storage

Typically switchgrass crops require 3 years before they are fully established. Yields of 33 to 66 percent of the full potential can be realized by the second year with maximum yields beginning in the third year. Because switchgrass is a perennial, the growth cycle can continue indefinitely as long as reseeding regularly occurs. Harvesting can occur once or twice annually in regions with long growth seasons with the highest yields occurring consistently if harvested after July [24].

Because harvest times are limited throughout the year, switchgrass storage will be required on-site in large-scale applications. For the purposes of this study, it was assumed that switchgrass is harvested once to twice a year. While it has been found during the progression of this study that storage and collection logistics have potential to limit production, these issues were not addressed in this study. Varying degrees of losses due to decomposition depending on the storage method occur. Studies have indicated that relatively small losses in the range of 2-4% of dry mass were experienced by bales resting on a crushed rock substrate. Greater losses occur when twine wrapped bales are stored on sod for the same length of time (up to 15 percent) [25]. Storage losses of 5% were assumed for this study.

2.3.5 Cases Exceeding the Maximum Switchgrass Feed Rate

Five cases in this study required switchgrass feeds that exceeded the aforementioned maximum logistic switchgrass feed rate in order to meet emission targets. Cases 3S4 and 3B4 met a limited life cycle emissions target of 800 lb CO_2e/net-MWh without the use of CO_2 capture by feeding high proportions of switchgrass to the gasifier. Also without CO_2 capture, Cases 4S4 and 4B4 further increased the switchgrass proportions to reach 350 lb CO_2e/net-MWh. The maximum switchgrass feed was exceeded in these four cases because enough total fuel was required so the combustion turbine could be fully loaded. The resulting fuel mixtures contained switchgrass feeds greater than 5,000 dry tons/day. Case 5B2 was a single gasifier train plant designed for 100 percent switchgrass feed while employing maximum CO_2 capture. The amount of switchgrass needed to fully load the combustion turbine exceeded 5,000 dry tons/day. Exhibit 2-9 compares the five cases that exceeded the maximum switchgrass feed rate.

Exhibit 2-9 Cases Exceeding the Maximum Switchgrass Feed Rate

Case	Percent of Total Feed (wt%)	Switchgrass Feed (lb/hr)	Switchgrass Feed (dry ton/day)	Amount Exceeding (lb/hr)	Amount Exceeding (dry ton/day)
3S4	75.1%	594,909	6,068	104,713	1,068
3B4	79.7%	633,344	6,460	143,148	1,460
4S4	97.2%	845,175	8,621	354,979	3,621
4B4	98.1%	934,000	9,527	443,804	4,527
5B2	100.0%	508,760	5,189	18,564	189

For cases that require greater than 5,000 dry tons per day of switchgrass in order to achieve the specified system performance, the authors acknowledge that advances in biomass collection/delivery/densification will be required to make this possible. However, these cases were still included in order to fully characterize system response to varying biomass levels

2.4 ENVIRONMENTAL TARGETS

The environmental approach for this study is to evaluate each case on the same regulatory design basis, considering differences in fuel and technology. The current enacted process for establishing environmental requirements for new plants is New Source Performance Standards (NSPS) [26]. Since all cases are located at a green-field site, NSPS could be a starting point for design air emission rates. NSPS emission requirements, which apply to all coal types, are summarized in Exhibit 2-10.

Exhibit 2-10 NSPS Emission Requirements Summary

Pollutant	Emission Limits as of June 2007
Particulate Matter (PM)[1],	Option 1: 0.14 lb/MWh *or* 0.015 lb/MMBtu Option 2: 0.03 lb/MMBtu *and* 99.9% reduction
Sulfur Dioxide (SO_2)	1.4 lb/MWh *or* 95% reduction
Nitrogen Oxides (NOx)	1.0 lb/MWh
Mercury	20×10^{-6} lb/MWh

[1] The latest NSPS regulations define heat input for IGCC cases as heat input to the combustion turbine via the syngas, and not the heat input from coal [26].

Permitting a new plant with emission rates controlled by NSPS requirements likely will not be acceptable to the EPA and/or individual states, who would probably invoke the New Source Review (NSR) permitting process. The NSR process is expected to result in allowable emission rates more stringent than NSPS. The NSR process requires installation of emission control technology meeting either Best Available Control Technology (BACT) determinations for new sources being located in areas meeting ambient air quality standards (attainment areas), or Lowest Achievable Emission Rate (LAER) technology for sources being located in areas not meeting ambient air quality standards (non-attainment areas). Environmental area designation varies by county and can be established only for a specific site location. Based on EPA Green Book Non-attainment Area Map [27] relatively few areas in the Midwestern and Western US are classified as "non-attainment". Therefore, for this study the proposed plants are assumed to be in an attainment area and LAER technology is not required. The IGCC emissions limits are based on environmental targets developed by EPRI for their CoalFleet for Tomorrow Initiative and are shown in Exhibit 2-11. Targets were chosen on the basis of the environmental regulations that would most likely apply to plants built in 2015 [28]. The environmental targets are not the same as permit limits. Permit limits will be uniformly higher than the environmental targets to allow for variations in operation and to provide some margin for meeting the permit limits. This is necessary to allow for fluctuations in fuel sulfur content, upsets in pollution control equipment operation and/or other temporary transient conditions.

Exhibit 2-11 Study Environmental Targets

Pollutant	Environmental Target	NSPS Limit	Control Technology
NOx	15 ppmv (dry) @ 15% O_2	1.0 lb/MWh	Low NOx burners and syngas nitrogen dilution
SO_2	0.0128 lb/MMBtu	1.4 lb/MWh	Zinc Oxide Guard Bed (Case 1S1) Dual- stage Selexol (Cases 1S2 – 1S4)

Pollutant	Environmental Target	NSPS Limit	Control Technology
Particulate Matter (Filterable)	0.0071 lb/MMBtu	0.015 lb/MMBtu	Cyclone, candle filter, and water scrubber
Mercury	> 90 % capture	20×10^{-6} lb/MWh	Carbon bed

Based on published vendor literature, it was assumed that low NOx burners (LNB) and nitrogen dilution can achieve 15 ppmv (dry) at 15 percent O_2, and that value was used for all cases [29,30].

To achieve an environmental target of 0.0128 lb/MMBtu of SO_2 requires approximately 28 ppmv sulfur in the sweet syngas. The acid gas removal (AGR) process must have a sulfur capture efficiency of about 99.7 percent to reach the environmental target. Vendor data on both of the AGR processes used indicates that this level of sulfur removal is possible. In the CO_2 capture cases, the two-stage Selexol process was designed for 90 percent plant CO_2 removal which results in a sulfur capture of greater than 99.7 percent, hence the lower sulfur emissions in the CO_2 capture cases.

Most of the coal ash is removed from the gasifier as slag. The ash that remains entrained in the syngas is captured in the downstream equipment, including the syngas scrubber and a cyclone and either ceramic or metallic candle filters (CoP and Shell). The environmental target of 0.0071 lb/MMBtu filterable particulates can be achieved with each combination of particulate control devices so that in each case it was assumed the environmental target was met exactly.

The environmental target for mercury capture is greater than 90 percent capture. Based on experience at the Eastman Chemical plant, the actual mercury removal efficiency used was 95 percent. Sulfur-impregnated activated carbon is used by Eastman as the adsorbent in the packed beds operated at 30°C (86°F) and 6.2 MPa (900 psig). Mercury removal between 90 and 95 percent has been reported with a bed life of 18 to 24 months. Removal efficiencies may be even higher, but at 95 percent the measurement precision limit was reached. Eastman has yet to experience any mercury contamination in its product [31]. Mercury removals of greater than 99 percent can be achieved by the use of dual beds, i.e., two beds in series. However, this study assumes that the use of sulfur-impregnated carbon in a single carbon bed achieves 95 percent reduction of mercury emissions which meets the environmental target and NSPS limits in all cases.

Throughout this report, limited life cycle emission figures are reported on a lb CO_2e/netMWh basis. These figures include plant CO_2 emissions as well as life cycle GHG emissions converted to a mass-equivalent CO_2 value. Further discussion on the plant life cycle emissions is given in Section 2.6. Many of the cases in this study include specific limited life cycle emission targets. Targets of 0, 350, 800 and 1,100 lb CO_2e/net-MWh were considered. During the construction of the study design basis, these targets were selected based on a variety of legislation such as California's GHG emission performance standard (1,100 lb CO_2/net-MWh) and the Lieberman-Warner proposition for receiving CO_2 allowances (800 and 350 lb CO_2/net-MWh). In addition, the feasibility of achieving life cycle emissions of 0 lb CO_2/net-MWh was investigated. The Waxman-Markey bill "American Clean Energy and Security Act of 2009" also includes emission targets of 1,100 and 800 lb CO_2/net-MWh for coal-fired power plants. Plants permitted after January 2015 must meet the higher limit, and plants permitted after January 2020 must meet the lower limit.

Two of the emission targets approximate existing and proposed technology scenarios. A current state-of-the-art NGCC plant has uncontrolled emissions of approximately 800 lb CO_2/net-MWh (plant only). An IGCC plant with 90% CO_2 capture has emissions of 200-250 lb CO_2/net-MWh (plant only). The limited life cycle GHG emissions of an IGCC plant with CO_2 capture is 327 lb CO_2e/net-MWh when fired with 100 percent PRB and 410 lb CO_2e/net-MWh when fired with 100 percent Illinois #6.

2.5 RENEWABLE PORTFOLIO STANDARDS

A Renewable Portfolio Standard (RPS) requires a minimum percentage of power generation to be produced by renewable sources. As of March 2009, 33 states plus the District of Columbia have established their own unique RPS. Each of these states has guidelines or enforced requirements for the amount of renewable energy that must be produced within a pre-determined timeframe and what each state considers to be eligible renewable energy sources. In general these standards vary widely but state by state standards typically require a percentage of total renewable power generated to range anywhere between 10% and 30% of total power generated, with the average nearing 20% by the year 2020 to 2025. The eligible renewable energy sources generally include but are not limited to:

- Biomass
- Wind
- Solar-derived
- Hydro-derived
- Geothermal

> Without high carbon taxes, there is no economic motivation for carbon reduction. An RPS may therefore be a prime motivator for coal and biomass as a strategy for carbon mitigation.

Not all states agree on what energy sources are considered to be renewable. However of the 34 proposed RPS', each one considers biomass to be an eligible renewable energy source for power generation.

Each RPS is constructed to mandate producing what each state considers to be a reasonable percentage of renewable power however this will inevitably drive up the average cost of power generation from that of the typical low cost, high-carbon power mix. A properly structured RPS may need to make allowances or provide cost recovery mechanisms in order to motivate utilities to generate renewable power. Even with these motivators it is critical for the nation to be cognizant of the costs for generating power with each of the eligible renewable sources and the potential choices for utilizing these sources for power generation.

For instance, as this report will show, generating power with 100% biomass is not nearly as cost effective, from an LCOE and carbon avoided perspective, as is generating power with a mixture of coal and biomass. It is important to recognize that combining the renewable properties of biomass with the low-cost of coal power generation will provide large quantities of renewable power at a more affordable cost than if biomass was used exclusively in today's power generation market.

The results of this report should provide a baseline for comparison of biomass-generated power costs to the costs of generating power with the other eligible renewable energy sources so that informed decisions can be made at the utility level to minimize the costs of complying with RPS requirements.

2.6 LIMITED LIFE CYCLE GHG ANALYSIS

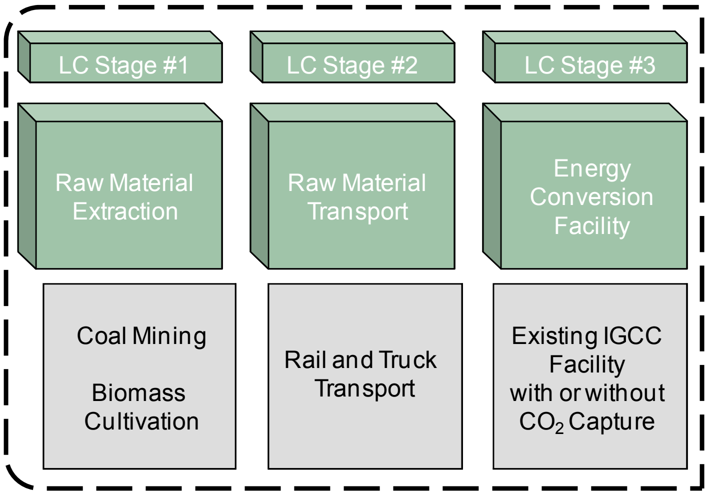
All GHG emissions reported in this study are based on a limited "cradle-to-gate" life cycle analysis. The emissions include anthropogenic CO_2 discharged through the plant stack as well as GHG emissions associated with the production, processing, and transportation of the coal and biomass. The analysis ends at the plant busbar and does not consider CO_2 sequestration losses. It should be noted here that while the targets based on proposed legislation (1,000 lb CO_2e/net-MWh, 800 lb CO_2e/net-MWh and 350 lb CO_2e/net-MWh) are based on CO_2 emitted from the plant only, the achieved targets presented in this report are on the lifecycle basis as presented in this section, which includes the effect of other greenhouse gasses. This means that the system emission results presented in this study actually exceed the proposed emission values by an amount equivalent to the GHG footprint associated with activities outside the plant boundary.

Many activities producing greenhouse gasses were included in the lifecycle analysis, but the analysis still does not produce what might be considered a full life cycle. The following factors are not included in the life cycle boundary:

- Emissions from plant construction
- Fluctuations from plant start-up and shut-down
- Transmission losses
- Emissions associated with power delivery
- Emissions from off-site slag transportation
- Emissions associated with the end user

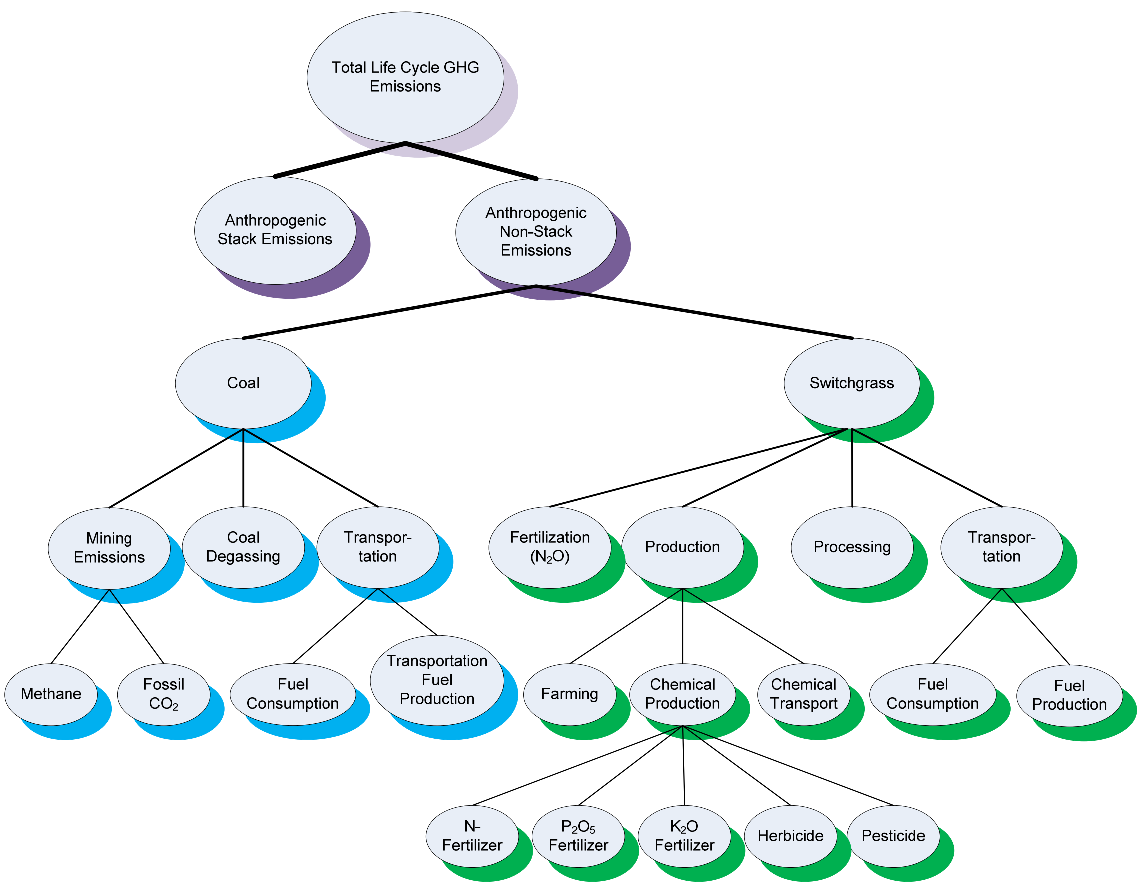
Plant life cycle stages 1-3 as represented below are considered. Excluded are stages 4 and 5 involving the transportation of the electricity product and activities of the end user. Exhibit 2-12 illustrates the study life cycle stages.

Exhibit 2-12 Plant Life Cycle Stages



The limited life cycle emissions totals presented in this report are meant to be viewed as plant "snapshots" during normal, steady-state operation. Exhibit 2-13 is an illustration of the life cycle emissions sources considered in this study. The components of the life cycle analysis are described in more detail in the following sections.

Exhibit 2-13 Limited Life Cycle GHG Analysis Emission Sources



2.6.1 Stack Emissions

Carbon in the syngas is converted to CO_2 in the combustion turbine or the coal dryer incinerator and discharged to atmosphere through the plant stack. Only fossil fuel-based carbon is considered anthropogenic and therefore counted towards the GHG emissions. CO_2 from switchgrass combustion is fixed from the atmosphere during the process of photosynthesis, is considered carbon neutral, and is not counted. In effect the switchgrass acts like an atmospheric CO_2 sink while performing photosynthetic processes. The result of this is a reduction in ambient CO_2 concentrations.

2.6.2 Biomass Fertilization

Nitrous oxide (N_2O), a GHG 298 times more potent than an equivalent weight of CO_2, is emitted from denitrification of N-fertilizers. It is assumed that 1.5 wt% of the nitrogen in the fertilizer used to grow switchgrass is released as nitrogen in N_2O. Although a relatively minor amount of the nitrogen is released as N_2O, its global warming potential (GWP) potency requires consideration of these emissions. The assumptions used to determine the amount of N_2O released are given in Exhibit 2-14.

Exhibit 2-14 Assumptions Used to Determine Biomass Fertilization GHG Emissions

Parameter	Value
Fertilizer Requirement[1]	19.9 lb N-Fertilizer/AR ton biomass
Switchgrass Yield[2]	6.0 AR tons biomass/acre-year
Fertilizer Conversion to N_2O[1]	1.5% (mass nitrogen in fertilizer to mass nitrogen in N_2O)
N_2O GWP	298 lb CO_{2e}/lb N_2O

[1] M.Q. Wang, GREET 1.8b-Transportation Fuel-Cycle Model, Volume 1: Methodology, Development, Use, and Results, Argonne National Laboratory, Transportation, Technology R&D Center, United States Department of energy, 1999.

[2] Graham, R.L. and M.E. Walsh. A national assessment of promising areas for switchgrass, hybrid poplar, or willow energy crop production, ORNL-6944, Oak ridge, TN: Oak Ridge National Laboratory, 1999.

2.6.3 Biomass Production

Biomass production consists of farming activities, chemical production (fertilizers and herbicides) and chemical transport. All depend on the amount of biomass being cultivated for the plant. The assumptions used to calculate GHG emissions from farming activities are shown in Exhibit 2-15.

Exhibit 2-15 Assumptions Used to Determine Biomass Farming GHG Emissions

Parameter	Value
Farming Energy (Total)[1]	1,303,380 Btu/acre
Diesel Component	92%
Electricity Component	8%
Harvest Availability[2,3]	80%
Diesel Fuel Energy Content[1]	128,500 Btu/gal
Diesel Fuel Carbon Intensity[1]	6.2 lb C/gal diesel

[1] M.Q. Wang, GREET 1.8b-Transportation Fuel-Cycle Model, Volume 1: Methodology, Development, Use, and Results, Argonne National Laboratory, Transportation, Technology R&D Center, United States Department of energy, 1999.

[2] McLaughlin, et. al., "Developing Switchgrass as a Bioenergy Crop," *Perspectives on new crops and new uses* ASHS Press, 1999, p. 282-299 and

[3] McLaughlin, S.B., L.A. Kszos, "Development of Switchgrass (Panicum virgatum) as a Bioenergy Feedstock in the United States," *Biomass and Bioenergy,* Vol. 28, No. 6, 2005, p. 515-535

Sustained production of switchgrass requires application of nitrogen-, phosphorous- and potassium-based fertilizers as well as application of herbicides. It was assumed that no pesticides are required. The chemical intensity and energy required to produce the various chemicals are summarized in Exhibit 2-16. The high N-fertilizer chemical intensity is representative of switchgrass used as a livestock feed. While a potentially lower value could be used for fuel applications requiring less fertilization, the higher value was chosen to be conservative.

Exhibit 2-16 Assumptions Used to Determine Biomass Chemical Production GHG Emissions

Chemical	Chemical Intensity	Energy to Produce	Energy Sources
N-Fertilizer[1]	10,630 g/dry ton	46.5 Btu/g	90% Nat. Gas, 10% Elec.
P_2O_5 Fertilizer[1]	142 g/dry ton	10.8 Btu/g	26% Nat. Gas, 47% Elec., 27% Diesel
K_2O Fertilizer[1]	226 g/dry ton	5.0 Btu/g	27% Nat. Gas, 42% Elec., 13% Diesel
Herbicides[1]	28 g/dry ton	225 Btu/g	23% Nat. Gas, 17% Elec., 30% Diesel, 30% RFO

[1] M.Q. Wang, GREET 1.8b-Transportation Fuel-Cycle Model, Volume 1: Methodology, Development, Use, and Results, Argonne National Laboratory, Transportation, Technology R&D Center, United States Department of Energy, 1999.

Transportation of the chemicals from the chemical manufacturing plant to the switchgrass farm is an assumed constant 0.683 Btu/g for all chemicals [32].

2.6.4 Biomass Processing

Biomass processing consists of cutting and sizing the biomass for treatment and requires 120,000 Btu/dry ton. It is assumed that the biomass is field dried to 15 percent moisture with no additional active drying occurring until time of use.

2.6.5 Biomass Transportation

The switchgrass is transported by truck to the IGCC facility. The plant is assumed to be in the middle of a circle that has an area equal to the amount of land needed to grow the requisite switchgrass. The average one way trip for a truck is equal to two-thirds of the radius of the circle. The remaining assumptions used to determine GHG emissions from biomass transport are shown in Exhibit 2-17.

Exhibit 2-17 Assumptions Used to Determine Biomass Transportation GHG Emissions

Parameter	Value
Land Availability[1]	1%
Average Transport Distance	2/3 of Radius (one way)
Winding Road Error Factor	1.4
Truck Capacity[2]	34,000 lb
Truck Fuel Efficiency[3]	4.9 mpg

1 Applies to both the Midwestern and high elevation sites and is explained in Section 2.3.2
2 Capacity is a conservative estimate based on assumed truck bed dimensions (8'x48'x10' from USDT Federal Size Regulations for Commercial Motor Vehicles) and switchgrass density (10 lb/ft^3)
3 M.Q. Wang, GREET 1.8b-Transportation Fuel-Cycle Model, Volume 1: Methodology, Development, Use, and Results, Argonne National Laboratory, Transportation, Technology R&D Center, United States Department of Energy, 1999.

2.6.6 Coal Production

GHG emissions from coal production differ depending on coal type and mining method. In this study it is assumed that the PRB coal is strip mined and that the bituminous coal is recovered from an underground mine and that no methane recovery is achieved in either case. The GHG emission assumptions are summarized in Exhibit 2-18.

Exhibit 2-18 Assumptions Used to Determine Coal Production GHG Emissions

Parameter	Value
CO_2 Mining Emissions[1]	43.5 lb CO_2/ton mined
N_2O Mining Emissions[1]	0.00069 lb CO_2e/ton mined
CH_4 Mining Emissions[2, 3]	243 lb CO_2e/ton (Bit.) 4.3 lb CO_2e/ton (PRB)

[1] GREET ver. 1.8b
[2] Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Profiles of Selected Gassy Underground Coal Mines 1999-2003, EPA Publication: EPA 430-K-04-003
[3] Kirchgessner, et. al., An Improved Inventory of Methane Emissions from Coal Mining in the United States

2.6.7 Coal Handling and Transportation

The mined coal contains in-situ methane, 95 percent of which is assumed to de-gas in the handling and storage process. The transportation emissions are based on rail transport using diesel-fueled locomotives. The GHG emission assumptions for coal handling and transport are summarized in Exhibit 2-19.

Exhibit 2-19 Assumptions Used to Determine Coal Handling and Transportation GHG Emissions

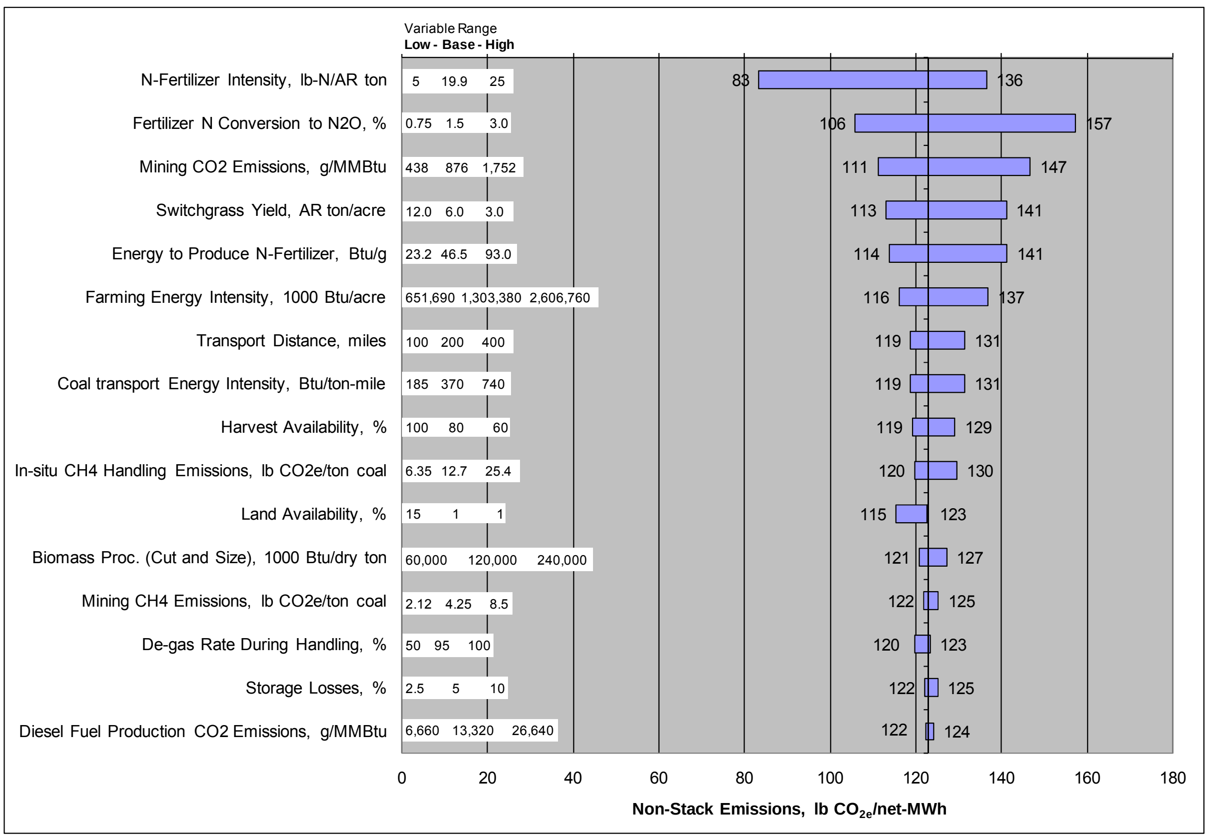
Parameter	Value
In-Situ CH_4 Content[1]	60.4 lb CO_2e /ton (Bit.) 12.7 lb CO_2e /ton (PRB)
De-gas Rate	95%
Transport Distance	200 miles
Transport Energy Intensity[2]	370 Btu/ton-mile
Combustion Emissions (Diesel)[2] CO_2 CH_4 N_2O	 77,632 g/MMBtu 3.94 g/MMBtu 2.0 g/MMBtu
Fuel Production Emissions[2] CO_2 CH_4 N_2O	 13,320 g/MMBtu 106.6 g/MMBtu 0.22 g/MMBtu

[1] Kirchgessner, et. al., An Improved Inventory of Methane Emissions from Coal Mining in the United States
[2] Based on EPA's AP-42 document. Used in GREET to calculate fuel combustion emissions for upstream activities.

2.6.8 Sensitivity Analysis

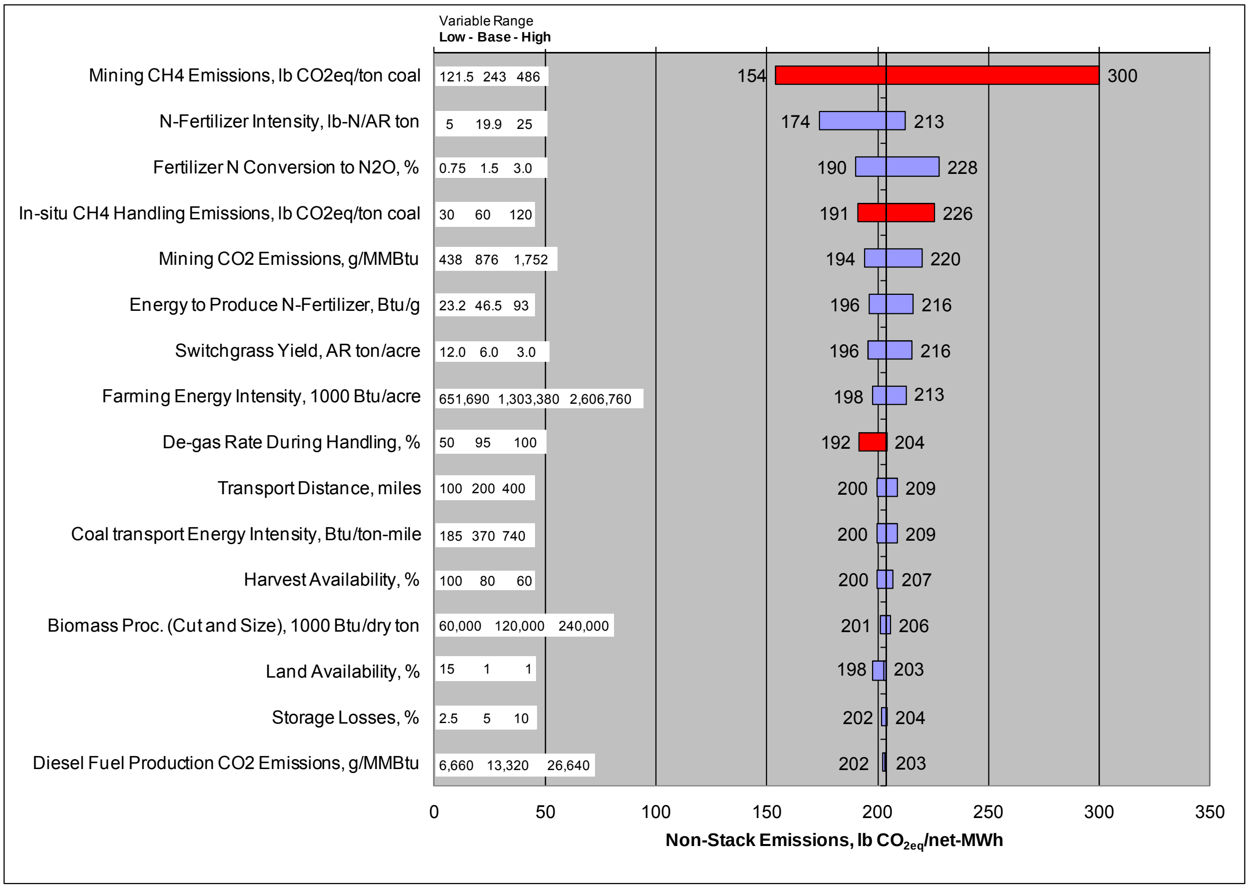
A sensitivity analysis of the GHG emissions outside of the plant, or "non-stack" emissions, was performed on four cases, 6B3 and 6S3 (both 30 percent switchgrass) as well as 6B4 and 6S4 (both maximum switchgrass feed). The intention was to show what response the non-stack emissions had to perturbations in the emission assumptions outlined in Sections 2.6.2 through 2.6.7. The effects of coal type and amount of biomass fed were also examined. Non-stack emissions are the summation of coal and switchgrass production, processing, and transportation as well as switchgrass fertilization emissions, all occurring outside of the plant boundary. Non-stack emissions are expressed as CO_2 equivalent emissions and are normalized according to the net plant output so they are easily comparable to the overall limited life cycle emissions. GHG emission assumptions from these sources were perturbed from their baseline values (halved and doubled in most instances) and plotted on tornado diagrams to show the effect each parameter alone has on the non-stack GHG footprint.

Exhibit 2-20 Non-Stack Emissions Sensitivity-Case 6S3



Using the base value for each assumption, the overall limited life cycle emission rate for case 6S3 is -231 lb CO_{2e}/net-MWh. Non-stack emissions account for 123 lb CO_2e/net-MWh of the total. Enough switchgrass is fed in this case to compensate for the positive non-stack emissions and reach negative overall emissions. Each variable is perturbed over a pre-defined range causing the non-stack emission rate to change. Assumptions having the greatest effect on the emission rate show wider spreads in the plot and are located higher on the chart. In case 6S3, and similarly the following three cases, the assumed quantity of fertilizer needed to grow the switchgrass feed and the amount of nitrogen in the fertilizer converted to N_2O and released into the atmosphere, have significant effects on the non-stack GHG emissions. This can be attributed to the fact that N_2O has a global warming potential 298 times that of CO_2. Even when only small amounts of N_2O are released into the atmosphere from switchgrass fertilization, especially when N-fertilizer intensity is high, there are significant impacts on the non-stack emissions rate.

Exhibit 2-21 Non-Stack Emissions Sensitivity-Case 6B3

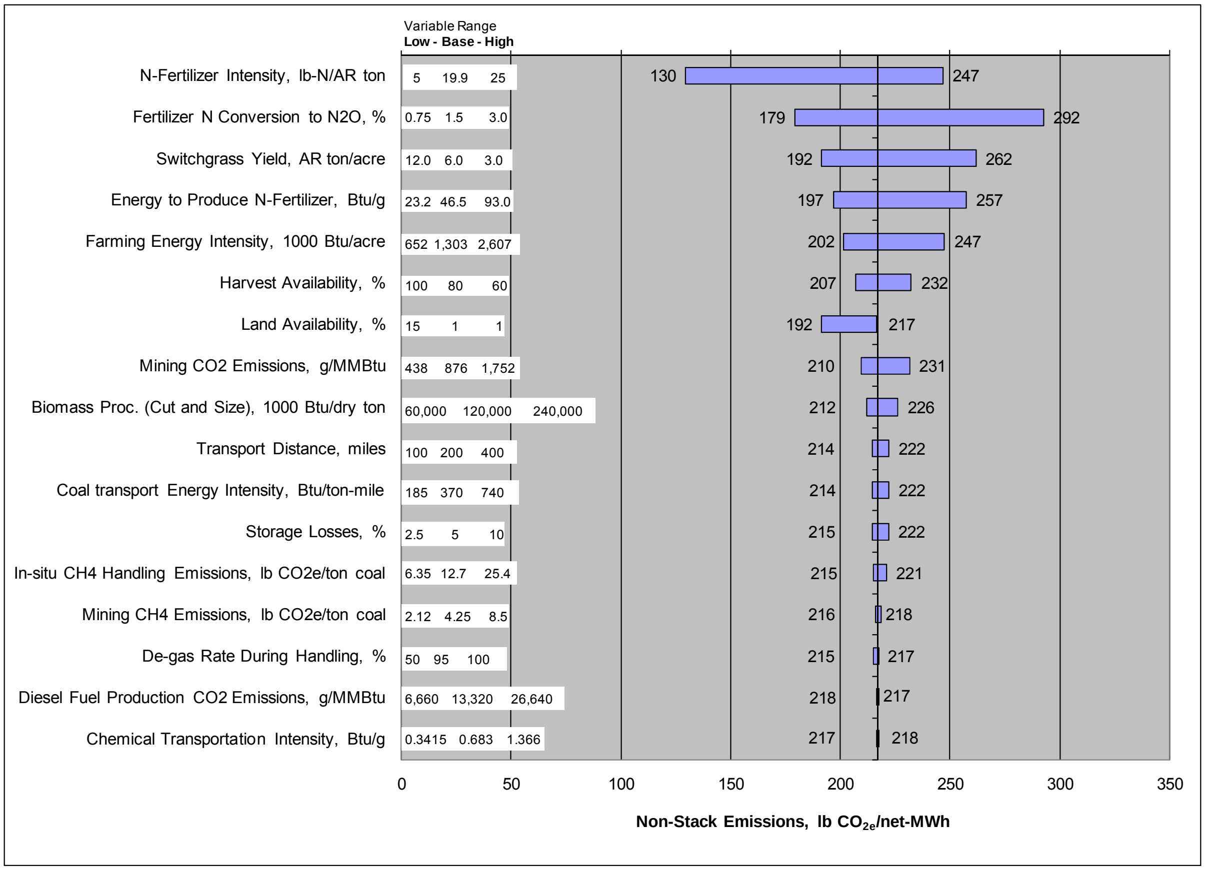


Comparing Exhibit 2-20 (PRB fed) with Exhibit 2-21 (Illinois #6 fed), the effect that coal type has on non-stack emissions can be seen. Major differences in the non-stack emissions sensitivities are shown highlighted in red. Methane mining and handling emissions become larger contributors to the plant's non-stack emissions when Illinois #6 is being fed. The reason being the assumed CH_4 emissions from mining and handling Illinois #6 are higher (base values of 243 and 60 lb CO_{2e}/net-MWh respectively) than those from PRB. Higher rank coals such as

Mine Methane Recovery: About 10% of man-made methane emissions in the U.S. can be attributed to coal mining. Mine methane recovery is an emerging technology that utilizes a mine methane drainage system and can supplement a pre existing mine ventilation system in order to recover mine methane. Depending on the purity of the recovered methane, it can be used for electricity generation (on-site or sold), as an on-site fuel source, or can be pipelined [33].

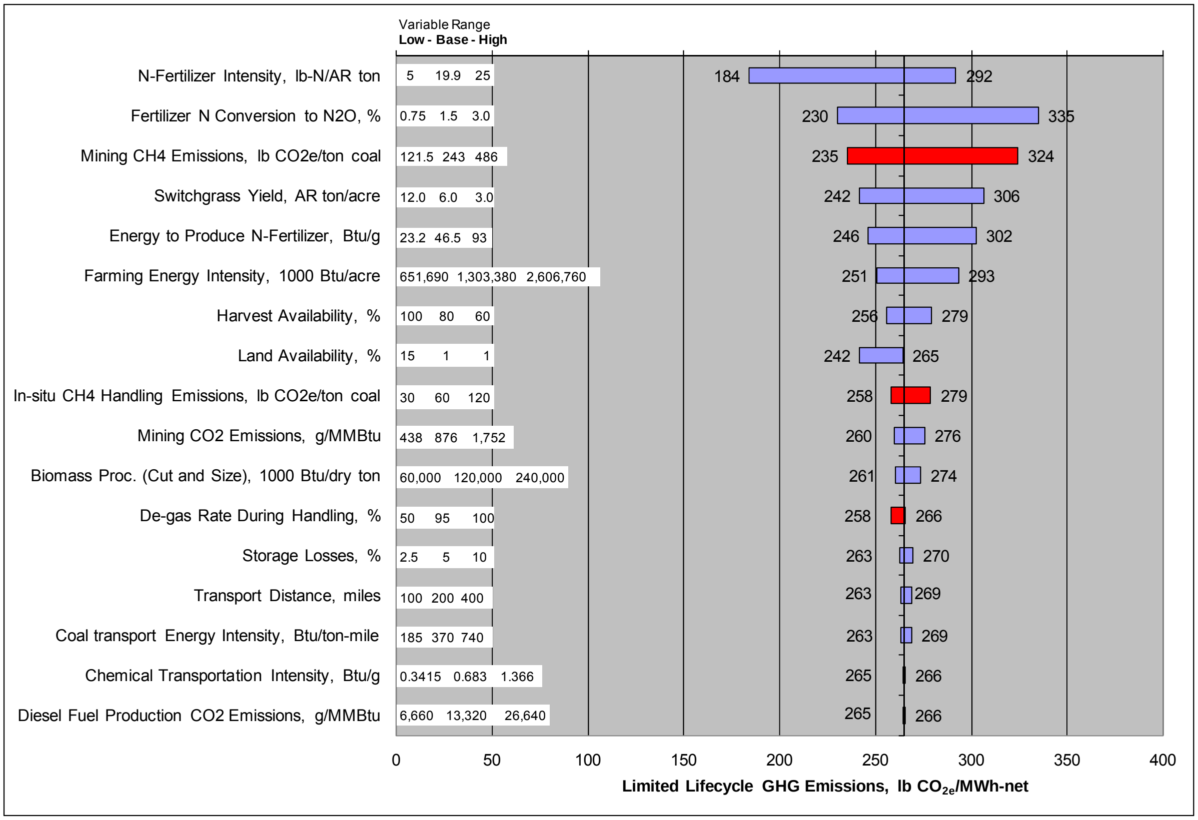
Illinois #6 tend to contain more CH_4 within the coal seam and strata resulting in higher methane release rates from mining the more gaseous seams [33]. In order to represent start-up ready plants, developing technologies to mitigate mine methane emissions such as mine methane recovery were not considered in this study. The overall limited life cycle emissions for case 6B3 were -14 lb CO_{2e}/net-MWh, with 203 lb CO_{2e}/net-MWh coming from non-stack sources.

Exhibit 2-22 Non-Stack Emissions Sensitivity-Case 6S4



Comparing Exhibit 2-22 to Exhibit 2-20 shows the effects of increasing the switchgrass from 30 wt% to the maximum feed rate of 5,000 dry TPD while still feeding PRB coal. Because of the higher switchgrass feed in case 6S4, assumptions associated with GHG emissions from the production, processing, transportation and fertilization of switchgrass have the most significant contribution to the non-stack emissions. Coal associated emission sources such as mining CO_2, handling and mining CH_4 contribute less to the non-stack emissions because of the lower coal feed rate. Non-stack emissions account for 217 lb CO_2e/net-MWh of the -890 lb CO_2e/net-MWh of total limited life cycle emissions. The higher switchgrass feed in case 6S4 compared to 6S3 lends to a more carbon negative emission rate.

Exhibit 2-23 Non-Stack Emissions Sensitivity-Case 6B4



Similar comparisons can be drawn between cases 6S4 and 6B4 in Exhibit 2-22 and Exhibit 2-23. Using Illinois #6 as the coal feed increases the contribution of coal related emission sources to the non-stack emissions. Total emissions for 6B4 were -755 lb CO_2e/net-MWh with 265 lb CO_2e/net-MWh coming from non-stack emissions.

2.7 CO_2 PURITY SPECIFICATIONS

Carbon dioxide (CO_2) is not currently regulated. However, the possibility exists that carbon limits will be imposed in the future and this study examines cases that include a reduction in CO_2 emissions. CO_2 emissions in this study are reduced by adding biomass to create credit for the renewable carbon in the feed and/or by physically capturing and sequestering CO_2. In the cases using sequestration, the CO_2 must be purified and pressurized prior to leaving the plant for sequestration. The following table lists the CO_2 conditions for which the CO_2 will be supplied at the "plant gate".

Exhibit 2-24 CO_2 Transport Specifications

	Design Condition (Remote EOR)
Pipeline material	carbon steel
Compression pressure (psia)	2214.71
CO_2	>95 vol%
Water	(0.015 vol%)
N_2	<4 vol%
O_2	<40 ppmv
Ar	< 10 ppmv
NH_3	<10 ppmv
CO	< 10 ppmv
Hydrocarbons	<5 vol%
H_2S	<1.3 vol%
CH_4	<0.8 vol%
H_2	uncertain
SO_2	<40 ppmv
NOx	uncertain

2.8 CAPACITY FACTOR

The capacity factor used in this study is 80 percent for all cases. This study assumes that each new plant would be dispatched any time it is available and would be capable of generating maximum capacity when online. Therefore capacity factor and availability are equal. The capacity factor is the same as that used in previous studies for IGCC systems with CO_2 capture and is based on input from EPRI and their work on the CoalFleet for Tomorrow Initiative. The addition of biomass was not considered to reduce the capacity factor although commercial-scale demonstration of high percentage biomass feed (up to 100 percent) and gasification has not been demonstrated. The technology for feeding and gasifying the biomass is felt to be similar enough to feeding and gasifying coal to justify maintaining the capacity factor at 80 percent.

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

EPRI examined the historical forced and scheduled outage times for IGCCs and concluded that the reliability factor (which looks at forced or unscheduled outage time only) for a single train IGCC (no spares) would be about 90 percent [34]. To get the availability factor, one has to subtract off the scheduled outage time. In reality the scheduled outage time differs from gasifier technology-to-gasifier technology, but for this study it was assumed to be constant at a 30-day planned outage per year (or two 15-day outages). The planned outage would amount to 8.2 percent of the year, so the availability factor would be (90 percent - 8.2 percent), or 81.2 percent.

There are four operating IGCC's worldwide that use a solid feedstock and are primarily power producers (Polk, Wabash, Buggenum and Puertollano). A 2006 report by Higman et al. examined the reliability of these IGCC power generation units and concluded that typical annual on-stream times are around 80 percent [35]. The capacity factor would be somewhat less than the on-stream time since most plants operate at less than full load for some portion of the operating year. Given the results of the EPRI study and the Higman paper, a capacity factor of 80 percent was chosen for IGCC with no spare gasifier required.

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

2.9 RAW WATER WITHDRAWAL

A water balance was performed around the plant boundary for each case designating the major water consumers in the process. The total water demand for each major plant subsystem was determined; however at the time of this study there was insufficient knowledge to perform a full lifecycle water balance around the feedstock cultivation/mining processes. Unlike the GHG balances, all water balances and usages are presented within the context of the IGCC plant boundary only.

In the plant, internal recycle water available from various sources like boiler feedwater blowdown and condensate from syngas was applied to offset the water demanded by other subsystems. 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 publicly owned treatment works (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, boiler feedwater makeup, quench system makeup, and slag handling makeup.

The difference between water withdrawal and process water returned to the source 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.

The largest consumer of raw water in all cases is cooling tower makeup. The high-altitude cases use a parallel wet/dry cooling system and the cases at ISO conditions use 100 percent conventional wet cooling. Power plant water requirements are larger concerns for plants located in arid regions, typical of Western locations. The major impact of parallel cooling is a significant reduction in water requirement when compared to a wet cooling system. With the relatively low ambient temperature at the high-altitude site, the performance impact from the parallel cooling, as compared to wet cooling, is minor. This impact is included in the water balance presented later in this report.

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

2.10 COST ESTIMATING METHODOLOGY

Capital and production cost estimates were factored estimates developed for each plant based on previous estimates for dry-fed entrained flow IGCC systems using PRB and Illinois #6 coal [16, 3]. The basis for the baseline estimates is described in Section 2.10.1 and the scaling methodology is described in Section 2.10.2.

2.10.1 Reference Cost Estimating Methodology

The methodology used to generate the reference cost estimates is described below:

System Code of Accounts

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

Non-CO_2 Capture Plant Maturity

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

CO_2 Removal Maturity

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

Contingency

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

Contracting Strategy

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

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

The EPCM approach used as the basis for the estimates here is anticipated to be the most cost effective approach for the Owner. While the Owner retains the risks, 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 both generic sites. Site-specific considerations such as unusual soil conditions, special seismic zone requirements, or unique local conditions such as accessibility, local regulatory requirements, etc. are not considered in the estimates.

The estimate boundary limit is defined as the total plant facility within the "fence line" including coal receiving and water supply system, but terminating at the high voltage side of the main power transformers.

Labor costs are based on Merit Shop, in a competitive bidding environment.

Capital Costs

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

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

Other key estimate considerations include the following:

- Labor costs are based on Midwest, Merit Shop. Costs would need to be re-evaluated for projects at different locations or 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. Current indications are that regional craft shortages are likely over the next several years. The types and amounts of incentives will vary based on project location and timing relative to other work. The cost impact resulting from an inadequate local work force can be significant.
- The estimates are based on a greenfield site.
- The sites are 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.
- Engineering and Construction Management were estimated as 10 percent of bare erected cost

All capital costs are presented as "Overnight Costs" in June 2007 dollars. Escalation to period-of-performance is specifically excluded.

Price Escalation

- A significant change in power plant cost occurred in recent years due to the significant increases in the pricing of equipment and bulk materials. This estimate includes these increases. All vendor quotes used to develop these estimates were received within the last two years.

Cross-Comparisons

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

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

- The combustion turbines for capture cases where WGS takes place include an additional cost for firing a high hydrogen content fuel.
- The gasifier syngas cooling configuration is different between the CO_2-capture and non-CO_2-capture cases, resulting in a significant differential in thermal duty between the syngas coolers for the two cases.
- "Hybrid" cases, explained in Section 4.3, include costs for a high thermal duty convective synthesis gas cooler as well as the cost for dual-stage Selexol.
- Cases where emission targets could not be met (cases 2S3, 2B3, 3S3, and 4B1) cannot provide a same basis comparison to cases where the respective emissions target was met.

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:

- Escalation to period-of-performance
- Owner's costs – including, but not limited to land acquisition and right-of-way, permits and licensing, royalty allowances, economic development, project development costs,

allowance for funds-used-during construction, legal fees, Owner's engineering, pre-production costs, initial inventories, furnishings, Owner's contingency, etc.

- All taxes, with the exception of payroll taxes
- 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 a 5-10 work week
- Additional premiums associated with an EPC contracting approach

Contingency

Project Contingency

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

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

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

Based on the AACE International contingency guidelines as presented in NETL's "Quality Guidelines for Energy System Studies" it would appear that the overall project contingencies for the subject cases should be in the range of 30 to 40 percent. [36] However, we believe these to be too high when the basis for the cost numbers is considered. The costs have been extrapolated from an extensive data base of project costs (estimated, quoted, and actual), based on both conceptual and detailed designs for the various technologies. This information has been used to calibrate the costs in the current studies, thus improving the quality of the overall estimates. As such, we feel that the overall project contingencies should be more in the range of 15 to 20 percent with the capture cases being higher than the non-capture cases.

Process Contingency

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

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

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

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

Operating and Maintenance Costs

The operating and maintenance costs for each plant configuration were calculated using consumable rates and unit costs determined from previous system analysis studies [16, 3]. The number of operators was maintained constant for all cases, whether firing 100 percent coal, 100 percent biomass or a combination of the two. The maintenance labor and material cost is the same percentage of BEC as in the Low Rank Coal reference study [16]. Fuel costs are as defined in Section 2.2 and Section 2.3.

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

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

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

Operating Labor

Operating labor cost was determined based on of the number of operators required for each specific case. The average base labor rate used to determine annual cost is $33/hr. The associated labor burden is estimated at 30 percent of the base labor rate.

Maintenance Material and Labor

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

It should be noted that a detailed analysis considering each of the individual gasifier components and gasifier refractory life is beyond the scope of this study. However, to address this at a high level, maintenances factors are applied to the gasifier. The gasifier maintenance factors used for this study are as follows:

- 7.5 percent on the gasifier and related components, and 4.5 percent on the syngas cooling.

Administrative and Support Labor

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

Consumables

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

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

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

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

Waste Disposal

Waste quantities and disposal costs were evaluated similarly to the consumables. In this study gasifier slag is considered a waste with a disposal cost of $17.03/tonne ($15.45/ton). The carbon used for mercury control is considered a hazardous waste with disposal cost of $882/tonne ($800/ton).

Co-Products and By-Products

By-product quantities were also determined similarly to the consumables. However, due to the variable marketability of these by-products, specifically sulfur, no credit was taken for their potential salable value. Nor were any of the technologies penalized for their potential disposal cost. That is, for this evaluation, it is assumed that the by-product or co-product value simply offset disposal costs, for a net zero to operating costs.

It should be noted that by-product credits and/or disposal costs could potentially be an additional determining factor in the choice of technology for some companies and in selecting some sites. A high local value of the product can establish whether or not added capital should be included in the plant costs to produce a particular co-product. Slag is a potential by-product in certain markets. However, as stated above, slag is considered waste in this study with a concomitant disposal cost.

A revenue requirement levelized-cost-of-electricity (LCOE), including CO_2 transport, storage and monitoring, was determined for each case. The capital costs for each cost account were reviewed by comparing individual accounts across all of the other cases and technologies to ensure an accurate representation of the relative cost differences between the cases and accounts.

All overnight capital and O&M costs are presented as expressed in June 2007 dollars.

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

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

Owner's costs are excluded.

2.10.2 Cost Scaling Methodology

Costs were factored using scaling variables and scaling exponents appropriate for each system account as shown in Exhibit 2-25. The general scaling equation used is shown below:

$$Equipment\ Capital\ Cost = Baseline\ Capital\ Cost \times \left(\frac{Equipment\ Scaling\ Variable}{Baseline\ Scaling\ Variable} \right)^n$$

However, different methods were implemented for accounts not previously estimated (biomass accounts) or accounts that required more detailed scaling (gasifier and ASU, e.g.).

Exhibit 2-25 Process Parameters and Cost Scaling Exponents

Account Number	Account Description	Scaling Variable	Scaling Exponent
1.1	Coal Receiving and Unloading	Coal feed rate	0.62
1.2	Coal Stackout and Reclaim	Coal feed rate	0.62
1.3	Coal Conveyors	Coal feed rate	0.62
1.4	Other Coal Handling	Coal feed rate	0.62
1.5	Biomass Receiving and Unloading	Biomass feed rate	0.62
1.6	Biomass Handling	Biomass feed rate	0.62
1.7	Biomass Conveyors	Biomass feed rate	0.62
1.8	Biomass Handling Foundations	Biomass feed rate	0.62
1.9	Coal Handling Foundations	Coal feed rate	0.62
2.1	Coal Crushing and Drying	Coal feed rate	0.66
2.2	Prepared Coal Storage and Feed	Coal feed rate	0.66
2.3	Dry Coal Injection System	Coal feed rate	0.66
2.4	Misc. Coal Prep and Feed	Biomass feed rate	0.66
2.5	Biomass Shredding and Drying	Biomass feed rate	0.66
2.6	Prepared Biomass Storage and Feed	Biomass feed rate	0.66
2.7	Dry Biomass Injection System	Coal feed rate	0.66
2.9	Coal and Biomass Feed Foundation	Coal plus biomass feed rate	0.66
3.1	Feedwater System	Feedwater flow (HP only)	0.72
3.2	Water Makeup and Pretreating	Makeup Water	0.71
3.3	Other Feedwater Subsystems	Feedwater flow (HP only)	0.72
3.4	Service Water Systems	Makeup Water	0.71
3.5	Other Boiler Plant Systems	Makeup Water	0.71
3.6	Fuel Oil/Natural Gas Supply System	Dried Coal Feed Rate	0.23
3.7	Waste Treatment Equipment	Makeup Water	0.71
3.8	Misc. Equipment (cranes, air compressors, etc.)	Dried Coal Feed Rate	0.23
4.1	Gasifier, Syngas Cooler & Auxiliaries	Dried Coal Feed Rate	N/A
4.3	ASU/Oxidant Compression	ASU Capacity	N/A
4.4	Low Temp. Heat Recovery	Dried Coal Feed Rate	N/A

Account Number	Account Description	Scaling Variable	Scaling Exponent
4.6	Other Gasification Equipment	Dried Coal Feed Rate	0.50
4.9	Gasification Foundations	Dried Coal Feed Rate	0.50
5A.1	Double Stage Selexol	Gas flow to AGR	0.79
5A.2	Elemental Sulfur Plant (Cases 1S2-1S4) Zinc Oxide Guard Bed (Case 1S1)	Sulfur Production	N/A
5A.3	Mercury Removal	Hg Carbon Bed Fill	N/A
5A.4	Shift Reactors	WGS Catalyst vol	0.59
5A.5	COS Hydrolysis Reactors	COS Catalyst vol	0.78
5A.6	Blowback Gas Systems	Gas flow to quench	0.75
5A.7	Fuel Gas Piping	Fuel Gas Flow	N/A
5A.9	Gas Cleanup Foundations	Sulfur production	0.52
5B.2	CO2 Compression and Drying	CO_2 Captured	0.75
6.1	Combustion Turbine Generator	Fuel Gas Flow	0.70
6.9	Combustion Turbine Foundations	Fuel Gas Flow	0.70
7.1	Heat Recovery Steam Generator	HRSG Duty	0.70
7.3	Ductwork	Stack flow rate	0.70
7.4	Stack	Stack flow rate	0.70
7.9	HRSG, Duct and Stack Foundations	Stack flow rate	0.70
8.1	Steam Turbine Generator and Accessories	Turbine capacity	0.71
8.2	Turbine Plant Auxiliaries	Turbine capacity	0.73
8.3a	Condenser and Auxiliaries	Surface Condenser Duty	N/A
8.3b	Air-Cooled Condenser	Condenser duty	0.70
8.4	Steam Piping	HP Feedwater Flow	N/A
8.9	Turbine/Generator Foundations	Turbine capacity	0.73
9.1	Cooling Towers	Cooling tower duty	0.70
9.2	Circulating Water Pumps	Circulating water flow rate	N/A
9.3	Circulating Water System Auxiliaries	Circulating water flow rate	0.67
9.4	Circulating Water Piping	Circulating water flow rate	N/A

Account Number	Account Description	Scaling Variable	Scaling Exponent
9.5	Makeup Water System	Raw water makeup	0.60
9.6	Component Cooling Water System	Circulating water flow rate	0.67
9.9	Circulating Water System Foundations and Structures	Circulating water flow rate	0.61
10.1	Slag Dewatering & Cooling	Slag production	0.64
10.6	Ash Storage Silos	Slag production	0.55
10.7	Ash Transport and Feed Equipment	Slag production	0.55
10.8	Misc. Ash Handling Equipment	Slag production	0.55
10.9	Ash/Spent Sorbent Foundation	Slag production	0.55
11.1	Generator Equipment	Total gross output	0.58
11.2	Station Service Equipment	Auxiliary load	0.43
11.3	Switchgear and Motor Control	Auxiliary load	0.43
11.4	Conduit and Cable Tray	Auxiliary load	0.43
11.5	Wire and Cable	Auxiliary load	0.43
11.6	Protective Equipment	Auxiliary load	0.00
11.7	Standby Equipment	Total gross output	0.48
11.8	Main Power Transformers	CTG + STG rating	0.36
11.9	Electrical Foundations	Total gross output	0.70
12.4	Other Major Component Control	Auxiliary load	0.13
12.6	Control Boards, Panels and Racks	Auxiliary load	0.13
12.7	Distributed Control System Equipment	Auxiliary load	0.13
12.8	Instrument Wiring and Tubing	Auxiliary load	0.13
12.9	Other I&C Equipment	Auxiliary load	0.13
13.1	Site Preparation	Total plant cost	0.19
13.2	Site Improvements	Total plant cost	0.19
13.3	Site Facilities	Total plant cost	0.19
14.1	Combustion Turbine Area	CT output	0.00
14.2	Steam Turbine Building	Total plant cost	0.17
14.3	Administration Building	Total plant cost	0.10
14.4	Circulation Water Pumphouse	Circulating water flow rate	0.41
14.5	Water Treatment Buildings	Raw water makeup	0.71
14.6	Machine Shop	Total plant cost	0.02

Account Number	Account Description	Scaling Variable	Scaling Exponent
14.7	Warehouse	Total plant cost	0.02
14.8	Other Buildings and Structures	Total plant cost	0.02
14.9	Waste Treatment Building and Structures	Raw water makeup	0.09

2.10.3 Levelized Cost of Electricity

The revenue requirement method of performing an economic analysis of a prospective power plant has been widely used in the electric utility industry. This method permits the incorporation of the various dissimilar components for a potential new plant into a single value that can be compared to various alternatives. The revenue requirement figure-of-merit in this report is cost of electricity (COE) levelized over a 20 year period and expressed in \$/MWh (numerically equivalent to mills/kWh). The 20-year LCOE was calculated using a simplified model derived from the NETL Power Systems Financial Model [37].

The equation used to calculate LCOE is as follows:

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

Where:

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

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

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

TPC = total plant cost, \$

LF_{Fn} = levelization factor for category n fixed operating cost

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

CF = plant capacity factor

LF_{Vn} = levelization factor for category n variable operating cost

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

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

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

Life cycle emissions beyond the plant busbar excluded from this study. However, costs for TS&M are included in the LCOE calculations for capture cases. The LCOE for TS&M costs was added to the LCOE calculated using the above equation to generate a total cost including CO_2 capture, sequestration, and subsequent monitoring.

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

The technologies modeled in this study were categorized as a high-risk investor owned utility (IOU) high risk. The resulting capital charge factor and levelization factors are shown in Exhibit 2-26. Since projected cost data do not exist for switchgrass, the general O&M levelization factor was used.

Exhibit 2-26 Economic Parameters for LCOE Calculation

	High Risk	Nominal Escalation, %[1]
Capital Charge Factor	0.175	N/A
Illinois #6 Levelization Factor	1.2244	2.58
PRB Levelization Factor	1.1439	1.73
Switchgrass Levelization Factor	1.1607	1.91
General O&M Levelization Factor	1.1607	1.91

[1] Nominal escalation is the real escalation plus the general annual average inflation rate of 1.91 percent.

The economic assumptions used to derive the capital charge factors are shown in Exhibit 2-27. The difference between the high risk and low risk categories is manifested in the debt-to-equity ratio and the weighted cost of capital. The values used to generate the capital charge factors and levelization factors in this study are shown in Exhibit 2-28.

Exhibit 2-27 Parameter Assumptions for Capital Charge Factors

Parameter	Value
Income Tax Rate	38% (Effective 34% Federal, 6% State)
Repayment Term of Debt	15 years
Grace Period on Debt Repayment	0 years
Debt Reserve Fund	None
Depreciation	20 years, 150% declining balance
Working Capital	zero for all parameters
Plant Economic Life	30 years
Investment Tax Credit	0%
Tax Holiday	0 years
Start-Up Costs (% of EPC)[1]	2%
All other additional capital costs ($)	0
EPC escalation	0%
Duration of Construction	3 years

[1] EPC costs equal total plant costs less contingencies

Exhibit 2-28 Financial Structure for Investor Owned Utility High Risk Projects

Type of Security	% of Total	Current (Nominal) Dollar Cost	Weighted Current (Nominal) Cost	After Tax Weighted Cost of Capital
High Risk				
Debt	45	11%	4.95%	3.07%
Equity	55	12%	6.6%	6.6%
Total			11.55%	9.67%

3. SYSTEM DESCRIPTIONS

System descriptions for the major IGCC process areas included in this study are described in this section. A base plant configuration with modifications to the configuration is described in Section 4.

3.1 COAL RECEIVING AND STORAGE

The function of the Coal Receiving and Storage system is to unload, convey, prepare, and store the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to and including the slide gate valves at the outlet of the coal storage silos.

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

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

3.2 BIOMASS RECEIVING AND STORAGE

Switchgrass is received at the plant by truck as bundled bales. For this study it was assumed that there are no logistical barriers to transporting a maximum of 5,000 TPD (dry) of switchgrass to the site. The trucks are unloaded using dedicated forklifts and switchgrass storage consists of covered bales with allowances for water drainage. Each bale is wrapped in plastic net to prevent them from breaking during handling. Switchgrass bales are transferred from long term storage to short term storage, equivalent to 72 hours of uninterrupted production. From short term storage, the bales are conveyed to an unwrapping station and then to the biomass preparation and feed system.

3.3 COAL AND BIOMASS DRYING

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

In a recent Gasification Technologies Conference (GTC) paper, Shell examined drying low rank coals for two cases [38]:

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

In personal correspondence with Shell, they indicated the moisture content of the coal after drying should be 3-14 percent depending on coal type [39].

For the cases in this study it is assumed that the subbituminous coal is dried to 6 percent moisture. This is consistent with the Shell GTC presentation and in the range suggested by the personal correspondence with Shell. Illinois #6 is assumed to be dried to 5 percent moisture to be consistent with previous NETL studies [3].

As-received switchgrass contains 15 percent moisture and also must be dried for material handling considerations. In this study the switchgrass is dried to 5 percent moisture prior to feeding, which is also in the fuel moisture content range indicated by Shell.

Drying is accomplished using conventional IGCC coal drying methods which consist of deriving heat from the combustion of syngas and using the flue gas directly for use in drying the coal and/or switchgrass.

For this study it was assumed that the same techniques and equipment used to dry coal could also be used to dry switchgrass.

3.4 COAL AND BIOMASS PREPARATION AND FEED

The raw coal is crushed in a coal mill then delivered to a surge hopper with an approximate 2-hour capacity, which in turn delivers the coal to the rotary kiln type dryer. The moisture driven from the coal exits the system with the combustion products from the coal dryer incinerator. The dried coal is temporarily stored in surge hoppers.

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

Similarly, biomass bales are fed to a shredder/grinder that reduces the biomass size to 1-25 mm. A hot air stream from the dryer incinerator is used to convey the biomass through the shredder/grinder and the moisture-laden gas stream is separated from the biomass in a baghouse prior to being vented to atmosphere. The biomass is fed into the gasifier using a separate but identical type of pressurization lock hopper system used for coal feeding. Nitrogen from the ASU is used as the transport medium just as for coal.

3.5 AIR SEPARATION UNIT (ASU)

In order to economically and efficiently support IGCC projects, air separation equipment has been modified and improved in response to production requirements and the consistent need to increase single train output. "Elevated pressure" air separation designs have been implemented that result in distillation column operating pressures that are about twice as high as traditional plants. In this study, the main air compressor discharge pressure was set at 190 psia compared to a traditional ASU plant operating pressure of about 105 psia [40]. For IGCC designs the elevated pressure ASU process minimizes power consumption and decreases the size of some of the equipment items.

3.6 GASIFIER

Although there are various coal gasification reactors, with different design and operating characteristics, all are based on one of three generic types that are compared in Exhibit 3-1[41]:

- Moving-bed (sometimes referred to as fixed-bed) reactors
- Fluidized-bed reactors
- Entrained-flow reactors

Gasifiers use either air (air-blown) or high-purity oxygen (oxygen-blown) as the gasification oxidant. Air-blown designs have an advantage in that they save the capital cost and operating expense of the air separation unit (ASU) that generates the oxygen, but the extra inert nitrogen volume going through the plant increases vessel sizes significantly and increases the cost of downstream equipment. Additionally, the dilution of the combustion products with nitrogen makes the separation of CO_2, in particular, a much more expensive exercise. Oxygen-blown designs make use of an ASU to separate oxygen and nitrogen prior to use. They do not introduce the additional nitrogen from the air into the gasifier, which minimizes downstream syngas volume and vessel sizes. The oxygen-blown design also allows CO_2 to be more easily and cheaply separated, if necessary.

Exhibit 3-1 Important Characteristics of Generic Types of Gasifiers Used for Coal Gasification

GASIFIER TYPE	MOVING-BED		FLUIDIZED-BED		ENTRAINED-BED
Ash Conditions	**Dry Ash**	**Slagging**	**Dry Ash**	**Agglomerating**	**Slagging**
FEED COAL CHARACTERISTICS:					
Size	Coarse (-2 inch)	Coarse (-2 inch)	Crushed (-1/4 inch)	Crushed (-1/4 inch)	Pulverized (-100 mesh)
Acceptability of Fines	Limited	Better than dry ash	Good	Better	Unlimited
Acceptability of Caking Coal	Yes (with modifications)	Yes	Possibly	Yes	Yes
Preferred Coal Rank	Low	High	Low	Any	Any
OPERATING CHARACTERISTICS:					
Exit Gas Temperature	Low (800°F – 1200°F)	Low (800°F – 1200°F)	Moderate (1700°F – 1900°F)	Moderate (1700°F – 1900°F)	High (>2300°F)
Oxidant Requirement	Low	Low	Moderate	Moderate	High
Steam Requirement	High	Low	Moderate	Moderate	Low
Key Distinguishing Features	Hydrocarbon liquids in raw gas		Large char recycle		Large amount of sensible heat energy in the hot raw gas
Key Technical Issues	Utilization of fines & hydrocarbon liquids		Carbon conversion		Raw gas cooling

Large-scale gasification-based energy generation systems can incorporate any one of a number of different gasifier designs. Exhibit 3-2 reviews those gasification technologies that are predominantly used in commercial applications for power generation and have been extensively evaluated and tested. These are identified by vendor, type, form of fuel feed and oxidant, along with some major installations that use coal, petcoke, refuse derived fuel (RDF), and heavy oil feedstocks.

Exhibit 3-2 Gasifier Technology Suppliers

TECHNOLOGY SUPPLIER	GASIFIER TYPE	SOLID FUEL FEED TYPE	OXIDANT	INSTALLATIONS
General Electric (Formerly ChevronTexaco), USA	Entrained Flow	Water Slurry	O_2	Tampa Electric IGCC Plant, Cool Water IGCC Plant, ChevronTexaco-Eldorado IGCC Plant, Eastman Chemical, Ube Industries, Motiva Enterprises, Deer Park
ConocoPhillips E-GAS (formerly Global Energy E-GAS), USA	Entrained Flow	Water Slurry	O_2	Wabash River IGCC Plant and Louisiana Gasification Technology IGCC Project
Shell, USA / The Netherlands	Entrained Flow	N2 Carrier/Dry	O_2	Demkolec IGCC plant, (Buggenum, Netherlands), Shell-Pernis IGCC Plant (Netherlands), Harburg
Lurgi, Germany	Moving Bed	Dry	Air	Sasol Chemical Industries and Great Plains Plants
British Gas/Lurgi, Germany/U.K.	Moving Bed	Dry	O_2	Global Energy Power/Methanol Plant (Germany)
Prenflo-Uhde, Germany	Entrained Flow	Dry	O_2	Elcogas, Puertollano IGCC Plant (Spain), Fürstenhausen in Saarland
Noell/GSP, Germany	Entrained Flow	Dry	O_2	Schwarze Pumpe, Germany
HT Winkler (HTW), RWE Rheinbraun/ Uhde, Germany	Fluidized Bed	Dry	Air or O_2	None
KRW, USA	Fluidized Bed	Dry	Air or O_2	Sierra Pacific (Nevada, U.S.A.)
Siemens Power (Formerly Future Energy/Sustec GSP Technology)	Entrained Flow	Dry	O_2	SVZ (Germany) Seal-Sands (UK) Vrezova (CZ)

Entrained-Flow Gasifiers

For large-scale power generation (>50MWe), the gasification field is dominated by plants based on the pressurized, oxygen-blown, entrained flow or moving-bed gasification of fossil fuels. Entrained gasifier operational experience to-date has largely been with well-controlled fuel feedstocks with short-term trial work at low co-gasification ratios and with easily-handled fuels. However, entrained-flow reactors are well suited to gasify a wide range of feedstocks.

Entrained-flow gasifiers react fine coal particles with steam and oxidant. Residence time in this type of reactor is very short. Entrained-flow gasifiers generally use oxygen as the oxidant and operate at high temperatures, well above ash-slagging conditions, to assure high carbon conversion. Entrained-flow gasifiers have the following characteristics:

- Ability to gasify all coals regardless of coal rank, caking characteristics, or amount of coal fines (although feedstocks with lower ash content are favored);
- Uniform temperatures;
- Very short fuel residence time in gasifier;
- Solid fuel must be very finely divided and homogeneous;
- Relatively large oxidant requirements;
- Large amount of sensible heat in the raw gas;
- High-temperature slagging operation; and
- Entrainment of some molten slag in the raw gas.

Differences among entrained-flow gasifiers include the coal feed systems (water slurry or dry coal feed systems can be used), internal design to handle the very hot reaction mixture, and heat recovery configuration. Entrained flow gasifiers have been selected for nearly all the coal- and oil-based IGCC plants currently in operation or under construction.

This study requires the design gasifier to have enough fuel flexibility to handle coals of different ranks such as PRB and Illinois #6 as well as switchgrass. Because high levels of CO_2 capture are required for some of the study cases, the design gasifier must also operate at a high temperature to produce a synthesis gas that is free of organic impurities such as methane. Such impurities cannot be removed during the AGR process and end up being oxidized to CO_2 in the combustion turbine and then contribute to the GHG footprint once emitted. For these reasons, and in order to better represent commercially available technology capable of cofeeding high proportions of biomass such as NUON Power's Buggenum Plant, a dry-fed, entrained flow gasifier was selected as the design gasifier for this study.

The gasifier and syngas cooler arrangement chosen was developed for high IGCC efficiency. Major benefits include:

- The gasifier membrane wall is designed for greater operating flexibility.
    - The gasifier wall is designed for a lifetime of 25 years. The membrane wall is inspected during annual maintenance turnarounds. Areas of high exposure,

specifically around the burner, are equipped with an exchangeable burner muffle.

- Conversion rates and gasifier controllability are enhanced by the use of a dry feeding system.
- Gasifier design includes multiple burners which lead to greater gasifier scalability (up to 280,000 Nm3/hr from a single gasifier vessel). Burners are designed for an operating time of two years, after which point the burner receives a complete overhaul. The total burner lifetime depends on operating conditions and dynamics.
- The gas outlet is separate from the slag outlet. This ensures that high ash coals (up to 30%) in the burner feed can be used.
- Gas quench at the gasifier outlet ensures trouble-free quenching of sticky fly ash/slag particulates.
- The cooling surfaces of the syngas cooler are designed for a lifetime of over 25 years.
- The slag removal system separates carbon-containing particles from courser slag particles.

Operating experience in the Buggenum facility confirms that a once yearly maintenance turnaround is sufficient to achieve high reliability of plant operations. Key components operate within their designed lifetimes so low maintenance cost can be expected.

The gasification process modeled in this study assumes thermodynamic equilibrium is achieved throughout the system of gasification reactions taking place in the gasifier. Many literature references support this modeling strategy [42,43,44]. The same strategy is maintained whether the fuel is 100 percent coal, 100 percent biomass, or a coal/biomass blend. Steam injection is based on published data and is fixed at 3 percent of the dry fuel feed rate independent of fuel type [41]. The oxygen injection is controlled to maintain published heat losses for the gasifier of 4.7 percent of the thermal input [45].

3.7 RAW GAS COOLING AND PARTICULATE REMOVAL

High-temperature heat recovery in each gasifier train is accomplished in either five or three steps depending on whether CO_2 is captured or not. Regardless, the first step includes the gasifier jacket, which cools the syngas by maintaining the reaction temperature at 2,600°F. The product gas from the gasifier is cooled to 2,000°F by adding cooled recycled fuel gas to lower the temperature below the slag melting point followed by a jacketed duct which raises HP steam by cooling the gas to 1,650°F in capture cases and 1,100°F in non-capture cases. In capture cases, the synthesis gas next passes through a water quench which vaporizes water to reduce the syngas temperature to 750°F while providing moisture for the WGS reaction downstream. The syngas is then further cooled in raw gas coolers to 500°F by raising HP steam for the steam cycle. In non-capture cases, shift water is unnecessary, therefore convective raw gas coolers are used in place of the quench to recover sensible heat from the raw gas for IP and LP steam production in order to maximize efficiency. BFD’s for both cooling scenarios are shown in Exhibit 3-3 and Exhibit 3-4.

Exhibit 3-3 Raw Gas Cooling Strategy (Capture Cases)

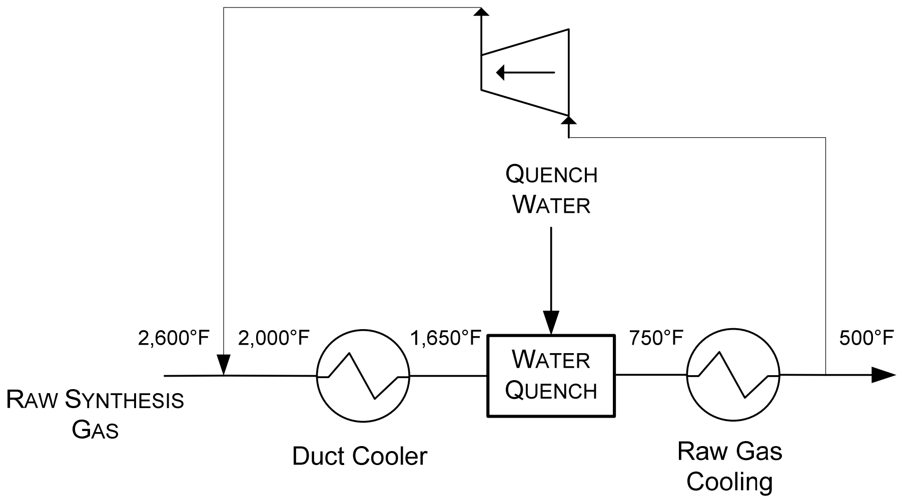
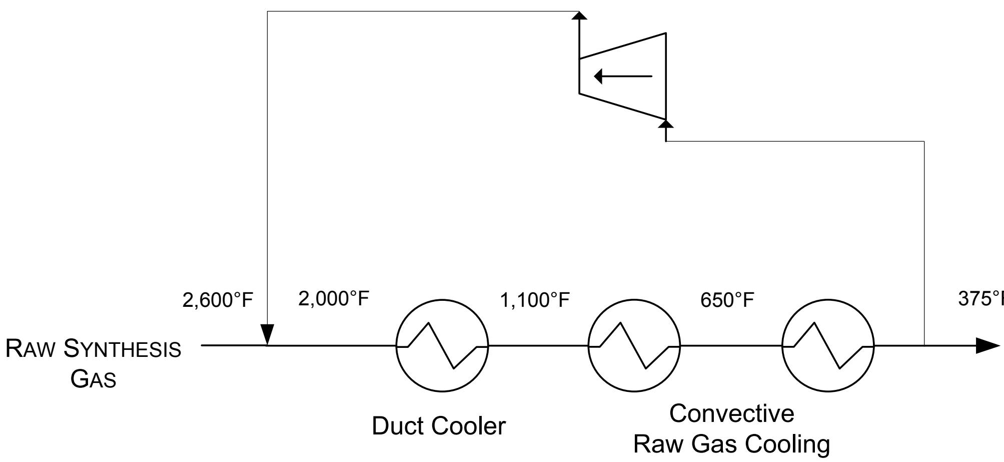


Exhibit 3-4 Raw Gas Cooling Strategy (Non-Capture Cases)



The solids produced by the gasifier are removed as slag and ash. Liquid slag forms in the gasifier and runs down the interior walls, exiting in liquid form. The slag is solidified in a water bath for disposal. Lockhoppers are used to reduce the pressure of the solids from 4.2 MPa (615 psia) to ambient pressure. After the high-temperature heat recovery and before the downstream low-temperature raw gas coolers, the syngas passes through a cyclone and a raw gas candle filter where the majority of the remaining fine ash particles are removed. The filter consists of an array of ceramic candle elements in a pressure vessel. Fines produced by the gasification system are removed via a lock hopper system. The syngas scrubber removes any additional particulate matter further downstream.

3.8 COS HYDROLYSIS

COS is very corrosive and must be removed from the synthesis gas prior to power generation. However, it is not readily absorbed by the solvents commonly used in IGCC acid gas removal processes. Therefore, in order to maximize sulfur capture and minimize corrosion, the COS is first hydrolyzed to H_2S, which is preferentially absorbed. This method was first commercially proven at the Buggenum plant, and was also used at both the Tampa Electric and Wabash River IGCC projects. Several catalyst manufacturers including Haldor Topsoe and Porocel offer catalysts that promote the COS hydrolysis reaction alone. In addition, COS is readily hydrolyzed in the WGS reactors. However, in cases where any portion of the syngas bypasses the WGS reactors, a COS hydrolysis reactor must be located in the bypass stream. The COS reactor design is based on information from Porocel.

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

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

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

Although the reaction is exothermic, the heat of reaction is dissipated among the large amount of non-reacting components. Therefore, the reaction is essentially isothermal. The sensible heat in the product gas is recovered down to ~100°F prior to entering the mercury removal process and the AGR.

3.9 WATER GAS SHIFT REACTORS

In cases with CO_2 separation and capture, it is commonly proposed to convert all carbon in the gasifier product to CO_2 for easier separation in an acid gas removal system because CO is not readily separated. The first step is to convert most of the syngas carbon monoxide (CO) to hydrogen and CO_2 by reacting the CO with water over a bed of catalyst. The H_2O:CO molar ratio in the shift reaction, shown below, is adjusted to a minimum of 2:1 by the addition of steam to the syngas stream, thus promoting a high conversion (>95%) of CO. In non-capture and minimum capture cases, no shift takes place. In other cases, not all CO needs to be shifted to CO_2, so a portion of the syngas stream is bypassed around the WGS reactors. The syngas that bypasses the WGS reactors passes through a COS hydrolysis reactor, which is described in Section 3.8.

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

For this study the CO converter was located upstream of the acid gas removal unit and is therefore referred to as sour gas shift (SGS).

SGS Process Description - The SGS consists of two paths of parallel fixed-bed reactors arranged in series. Two reactors in series are used in each parallel path to achieve sufficient conversion to meet the 90 percent CO_2 capture target. The H_2O:CO ratio is 2:1 in all cases except those in a maximum capture configuration where the H_2O:CO ratio was raised 2.1:1 in order to obtain 90 percent overall plant carbon capture. Specific individual plant configurations are further explained in Section 4 of this report.

The synthesis gas is first preheated prior to entering a high temperature reactor. Doing this maintains a constant temperature going into the high temperature reactor and enables control of the rate of reaction. Cooling via heat recovery is provided between the series of reactors to control the exothermic temperature rise. Cooling the synthesis gas slows the reaction rate in the low temperature reactor but achieves a higher conversion. A higher degree of cooling is required for the cases in maximum capture configurations in order to achieve 90 percent CO_2 capture. The syngas temperature is reduced to temperatures between 467 and 528°F prior to the second shift reactor by raising IP and LP steam. This compares to 530°F in cases not in the maximum capture configuration.

Sweet Shift – Sour gas shift catalysts require 200 – 300ppm of sulfur in the inlet syngas stream in order to for the catalyst to remain sulphided [46]. Plants with high switchgrass (>95 wt%) and requiring CO_2 capture (cases 1S1, 1B1, and 5B2) do not have sulfur concentrations to achieve this. Sweet shift catalysts, which operate after sulfur removal, may be preferable but have not been considered here.

3.10 MERCURY REMOVAL

An IGCC power plant has the potential of removing mercury in a more simple and cost-effective manner than conventional PC plants. This is because mercury can be removed from the syngas at elevated pressure and prior to combustion so that syngas volumes are much smaller than flue gas volumes in comparable PC cases. A conceptual design for a carbon bed adsorption system was developed for mercury control in the IGCC plants being studied. Data on the performance of carbon bed systems were obtained from the Eastman Chemical Company, which uses carbon beds at its syngas facility in Kingsport, Tennessee [31].

Carbon Bed Location – The packed carbon bed vessels are located upstream of the acid gas removal (AGR) process and syngas enters at a temperature near 38°C (100°F).

Process Parameters – An empty vessel basis gas residence time of approximately 20 seconds was used based on Eastman Chemical's experience [31]. Allowable gas velocities are limited by considerations of particle entrainment, bed agitation, and pressure drop. One-foot-per-second superficial velocity is in the middle of the range normally encountered [47] and was selected for this application.

The bed density of 30 lb/ft^3 was based on the Calgon Carbon Corporation HGR-P sulfur-impregnated pelletized activated carbon [48]. These parameters determined the size of the vessels and the amount of carbon required.

Carbon Replacement Time – Eastman Chemicals replaces its bed every 18 to 24 months [31]. However, bed replacement is not because of mercury loading, but for other reasons including:

- A buildup in pressure drop

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

For this study a 24 month carbon replacement cycle was assumed. The mercury laden carbon is considered to be a hazardous waste, and the disposal cost estimate reflects this categorization.

3.11 ACID GAS REMOVAL PROCESSES

3.11.1 Dual Stage Selexol

A two-stage Selexol process was used for cases employing CO_2 capture in this study with a CO_2 capture efficiency of 95 percent. Data for predictive modeling was unavailable so this study uses a non-adjustable AGR.

Untreated syngas is pre cooled by treated gas. The feed gas then enters the first of two absorbers where H_2S is preferentially removed using loaded solvent from the CO_2 absorber. The gas exiting the H_2S absorber passes through the second absorber where CO_2 is removed using first flash regenerated, chilled solvent followed by thermally regenerated lean solvent added near the top of the column. The treated gas exits the absorber and is sent to a splitter directing the gas to the H_2S concentrator or directly to the combustion turbine.

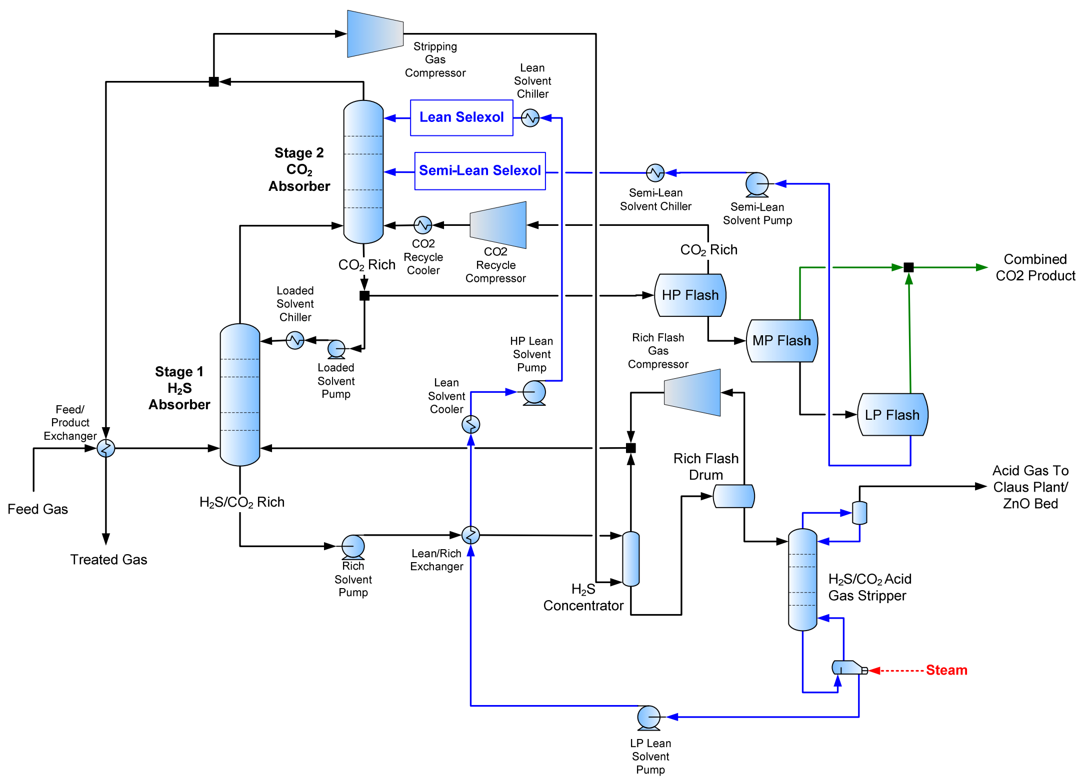
The CO_2 loaded solvent exits the CO_2 absorber where a portion is chilled and pumped back to the H_2S absorber while the remainder is sent to a series of flash drums for regeneration. CO_2 exiting the HP flash is compressed and sent back to the CO_2 absorber. The CO_2 product stream is obtained from the MP and LP flash drums. After flash regeneration the solvent is chilled and returned to the CO_2 absorber.

The rich solvent exiting the H_2S absorber is heated using the lean solvent from the H_2S/CO_2 stripper. The hot, rich solvent enters the H_2S concentrator and partially flashes. The remaining rich liquid is flashed in the rich flash drum. Rich gas from the rich flash drum is compressed and combined with the partially flashed stripped gas from the H_2S concentrator before being sent back to the H_2S absorber. The solvent exiting the rich flash drum is sent to the solvent stripper where the absorbed gases are liberated by hot gases flowing up the column from the steam heated reboiler. Water in the overhead vapor from the stripper is condensed and returned as reflux to the stripper or exported as necessary to maintain the proper water content of the lean solvent. The acid gas from the stripper is sent to the Claus plant or ZnO bed for further processing. The lean solvent exiting the stripper is first cooled by providing heat to the rich solvent, then further cooled by exchange with the product gas and finally chilled in the lean chiller before returning to the top of the CO_2 absorber.

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

In cases 1S1 and 1B1, both of which fire 100 percent biomass, there is enough renewable carbon in the feed that if all of the syngas is fed through the AGR, the IGCC plant would actually have a carbon-negative footprint. Therefore, it was necessary to bypass a portion of the syngas around the AGR process to meet the emission limit of 0 lb/net-MWh and not artificially penalize plant performance for over-compliance. Because the sulfur content of the biomass is extremely low, the sulfur environmental target was still achieved. A Selexol process flow diagram is shown in Exhibit 3-5.

Exhibit 3-5 Generic Two-Stage Selexol Process Flow Diagram



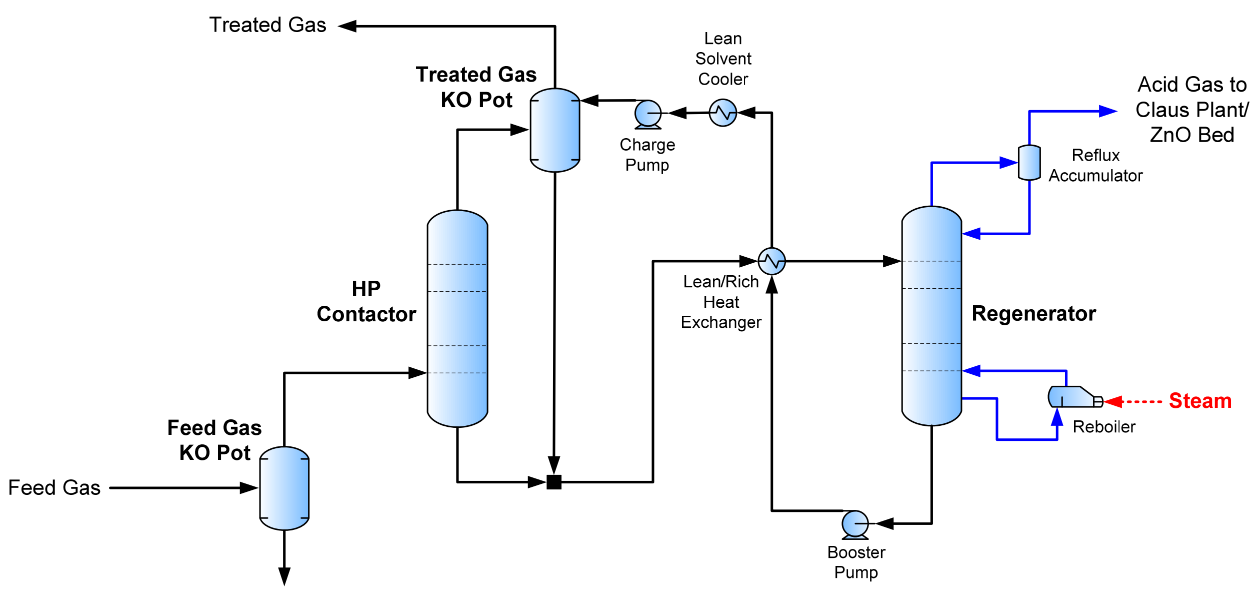
3.11.2 Sulfinol

Cases not employing any CO_2 capture use Sulfinol as the means of meeting the sulfur emissions limit. The Sulfinol process, developed by Shell in the early 1960s, is a combination process that uses a mixture of amines and a physical solvent. The solvent consists of an aqueous amine and sulfolane. Sulfinol-D uses diisopropanolamine (DIPA) as the aqueous amine, while Sulfinol-M uses MDEA. The mixed solvents allow for better solvent loadings at high acid gas partial pressures and higher solubility of COS and organic sulfur compounds than straight aqueous amines. The Sulfinol-D process removes essentially all of the CO_2 along with the H_2S and COS. The CO_2 passes through sulfur removal unit and cannot be used to generate power in the gas turbine, but it is a small fraction of the Shell syngas. The costs of the sulfur recovery/tail gas cleanup are, however, higher than for a sulfur removal process producing an acid gas stream with a higher sulfur concentration. Sulfinol-M is used when a higher degree of H_2S selectivity is needed. Sulfinol-M was selected for this application.

The sour syngas is fed to a feed gas knockout pot before entering into an HP contactor. The HP contactor is an absorption column in which the H_2S, COS, CO_2, and small amounts of H_2 and CO are removed from the gas by the Sulfinol solvent. The treated gas stream from the HP contactor is sent to the combustion turbine.

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

Exhibit 3-6 Generic Sulfinol Process Flow Diagram



3.12 SULFUR RECOVERY PROCESS

3.12.1 Claus Plant

Currently, most of the world's sulfur is produced from the acid gases coming from gas treating. The Claus process remains the mainstay for sulfur recovery. Conventional three-stage Claus plants, with indirect reheat and feeds with a high H_2S content, can approach 98 percent sulfur recovery efficiency. However, since environmental regulations have become more stringent, sulfur recovery plants are required to recover sulfur with over 99.8 percent efficiency. To meet these stricter regulations, the Claus process underwent various modifications and add-ons such as a tail gas treatment unit (TGTU). In the context of an IGCC system, the TGCU is not required for plants employing the maximum CO_2 capture rate of 90 percent because the Claus plant tail gas can be hydrogenated (convert SO_2 to H_2S) and fully recycled to the AGR process inlet in order to reach higher degrees of capture. The Claus tail gas in cases requiring less than 90 percent capture is sent to a TGCU where the separated, concentrated H_2S stream is recycled back to the Claus plant for deeper sulfur removal and the remaining gas is sent to the dryer incinerator and ultimately the dryer stack.

The Claus Process

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

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

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

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

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

The sulfur in the vapor phase exists as S_2, S_6, and S_8 molecular species, with the S_2 predominant at higher temperatures, and S_8 predominant at lower temperatures. Recovered sulfur does have a market value and can be transported off-site to be sold. However, it was assumed that the transportation costs off-set any sale value of the sulfur and resulted in a net zero gain.

A simplified process flow diagram of a typical three-stage, air-blown Claus plant is shown in Exhibit 3-7 [49]. One-third of the H_2S is burned in the furnace with oxygen from the air to give sufficient SO_2 to react with the remaining H_2S. Since these reactions are highly exothermic, a waste heat boiler that recovers this heat to generate high-pressure steam usually follows the furnace. Sulfur is condensed in a condenser that follows the high-pressure steam recovery section. Low-pressure steam is raised in the condenser. The tail gas from the first condenser then goes to several catalytic conversion stages, usually 2 to 3, where the remaining sulfur is recovered via the Claus reaction. Each catalytic stage consists of gas preheat, a catalytic reactor, and a sulfur condenser. The liquid sulfur goes to the sulfur pit, while the tail gas either proceeds for further processing in a TGTU or is fully recycled back to the AGR.

Exhibit 3-7 Typical Three-Stage Claus Sulfur Plant

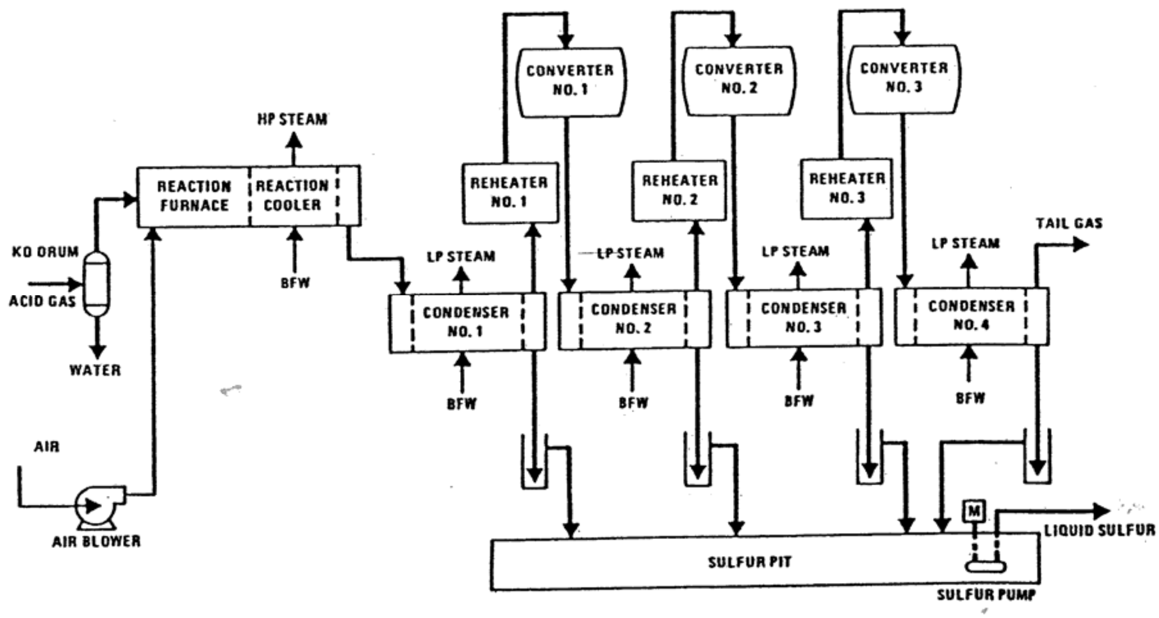


*Image From, NETL, "Process Screening Analysis of Alternative Gas Treating and Sulfur Removal for Gasification," Revised Final Report, December 2002, [49]

Claus Plant Sulfur Recovery Efficiency

The Claus reaction is equilibrium limited, and sulfur conversion is sensitive to the reaction temperature. The highest sulfur conversion in the thermal zone is limited to about 75 percent. Typical furnace temperatures are in the range from 1,093 to 1,427°C (2,000 to 2,600°F), and as the temperature decreases, conversion increases dramatically. However, in cases where ammonia is present, the minimum burner temperature is in the range 2100-2300°F [50, 51]. Since ammonia, which is fed separately from the SWS and is not shown in Exhibit 3-7, is present in all these cases, all cases using a Claus plant targeted a burner temperature of 2,400°F.

Claus plant sulfur recovery efficiency depends on many factors:

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

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

Oxygen-Blown Claus

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

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

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

Flare Stack

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

3.12.2 Zinc Oxide Guard Bed

In the 100 percent biomass cases, the amount of sulfur present is so small (less than one rail car per year) that a Claus plant is not warranted. Instead, the acid gas from the two stage Selexol process passes through a guard bed of zinc oxide where 99.99+ percent of the H_2S is removed. The remaining acid gas is sent to the coal/biomass dryer incinerator where remaining CO and H_2 are combusted along with a slipstream of clean syngas.

Zinc oxide can absorb a maximum of 39.3 pounds of sulfur per pound of pure ZnO. Assuming that the bed is at 70 percent of saturation at breakthrough, a 12-ft diameter by 20.5-ft long vessel would contain enough ZnO to remove 25 lb/hr of H_2S for one year at 80 percent capacity factor. This is the assumed design basis for the ZnO guard bed.

3.13 CO_2 COMPRESSION AND DEHYDRATION

In capture cases, CO_2 from the dual-stage Selexol process is generated at two pressure levels. The LP stream is compressed from 17 psia to 150 psia and then combined with the HP stream at

150 psia. The combined stream is further compressed to a supercritical condition at 2215 psia using a multiple-stage, intercooled compressor. During compression, the CO_2 stream is dehydrated to a dewpoint of -40°F with triethylene glycol. The raw CO_2 stream from the Selexol process contains over 99 percent CO_2. The dehydrated CO_2 is transported to the plant fence line and is considered to be sequestration- ready.

3.14 SLAG HANDLING

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

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

3.15 COMBUSTION TURBINE

All cases in this study use an Advanced F-Class combustion turbine (CT) based on vendor performance estimates. The key process parameters considered when modeling the turbines include:

- Compressor flow limitations
- Turbine inlet temperature
- Lower heating value of the diluted fuel
- Percentage of inlet air devoted to interstage cooling
- Overall efficiency of the combustion turbine stages
- Combustor heat loss

This machine is an axial flow, single spool, and constant speed unit, with variable inlet guide vanes. The turbine includes advanced bucket cooling techniques, compressor aerodynamic design and advanced alloys, enabling a higher firing temperature than the previous generation machines. The standard production version of this machine is fired with natural gas and is also commercially offered for use with IGCC derived syngas, although only earlier versions of the turbine are currently operating on syngas. For the purposes of this study, it was assumed that the advanced F Class turbine will be commercially available to support a 2015 startup date on both conventional and high hydrogen content syngas representative of the cases with CO_2 capture. High H_2 fuel combustion issues like flame stability, flashback and NOx formation are currently being developed [52] and were assumed to be solved in the time frame needed to support deployment.

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

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

3.16 HEAT RECOVERY STEAM GENERATOR

The heat recovery steam generator (HRSG) is a horizontal gas flow, drum-type, multi-pressure design that is matched to the characteristics of the gas turbine exhaust gas when firing medium-Btu gas. High-temperature flue gas exiting the CT is conveyed through the HRSG to recover the large quantity of thermal energy that remains. Flue gas travels through the HRSG gas path and exits at 270°F in all cases. It is necessary for the exiting flue gas to remain at this temperature, which is above the acid dew point, in order to prevent corrosion.

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

3.17 STEAM TURBINE GENERATOR AND AUXILIARIES

The steam turbine consists of an HP section, an IP section, and one double-flow low pressure 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 HRSG and gasifier island is combined in a header, and then passes through the stop valves and control valves and enters the turbine at 1800 psig and is within a temperature range of approximately 1000-1050°F. The main steam has a 50°F approach to the incoming flue gas from the combustion turbine. The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the HRSG for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 467 psia and the same temperature as the main steam. After passing through the IP section, the steam enters a crossover pipe, which transports the steam to the LP section. The steam divides into two paths and flows through the LP sections, exhausting downward into the condenser.

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

The steam turbine generator is controlled by a triple-redundant, microprocessor-based electro-hydraulic control system. The system provides digital control of the unit in accordance with programmed control algorithms, color CRT operator interfacing, and datalink interfaces to the balance-of-plant DCS, and incorporates on-line repair capability.

3.18 CIRCULATING WATER SYSTEM

The circulating water system is a closed-cycle cooling water system that supplies cooling water to the surface condenser to condense main turbine exhaust steam (half of the turbine exhaust where hybrid cooling is employed). The system also supplies cooling water to the AGR plant as required, and to the auxiliary cooling system. The auxiliary cooling system is a closed-loop process that utilizes a higher quality water to remove heat from compressor intercoolers, oil coolers and other ancillary equipment and transfers that heat to the main circulating cooling water system in plate and frame heat exchangers. The heat transferred to the circulating water in the surface condenser and other applications is removed by a mechanical draft cooling tower.

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

The parallel cooling system in the high-altitude cases consists of 50 percent of the steam turbine exhaust being condensed in a conventional condenser using cooling water as the heat transfer medium and 50 percent of the exhaust condensed in an air-cooled condenser. Additional cooling loads (primarily compressor intercoolers and aftercoolers and the sour water stripper condenser) are assigned to the evaporative cooling tower. In the high-altitude cases, the design ambient wet bulb temperature of 37°F was used to achieve a cooling water temperature of 48°F using an approach of 11°F. In the ISO condition cases, the design ambient wet bulb temperature of 51.5°F was used to achieve a cooling water temperature of 60°F using an approach of 8.5°F. The cooling water range was assumed to be 20°F in both cases. The cooling tower makeup rate was determined using the following [53]:

- Evaporative losses of 0.8 percent of the circulating water flow rate per 10°F of range
- Drift losses of 0.001 percent of the circulating water flow rate
- Blowdown losses were calculated as follows:
    - Blowdown Losses = Evaporative Losses / (Cycles of Concentration - 1) Where cycles of concentration is 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, temperature difference between saturated steam at the steam turbine generator exhaust and inlet dry bulb cooling air temperature) of 40-55°F.[54] The ITD at the high-altitude location in this study was 48°F. The fan power requirement is estimated to be 3.5 times the power required for a wet cooling tower with equivalent heat duty [55].

Considering the specific ambient temperature for each location, a condenser pressure of 0.698 psia (condensing temperature of 90°F) and 0.9823 psia (condensing temperature of 101°F) is used for the high-altitude and ISO condition systems respectively.

An example water balance is presented in Appendix A and includes 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.

4. PLANT CONFIGURATIONS

A key objective of this study was to determine how a practical IGCC design will respond to the demands of meeting a wide range of GHG targets. A total of 9 distinct plant configurations were used in this study in order to achieve the various GHG goals, while providing the most practical plant design that can be envisioned considering process modeling limitations. Assumptions made regarding plant configuration should be viewed acknowledging a primary interest in thermodynamic analysis rather than commercial plant design. Certain customized configurations, such as the minimum capture configuration, which will be explained, are used to obtain performance and economic trends.

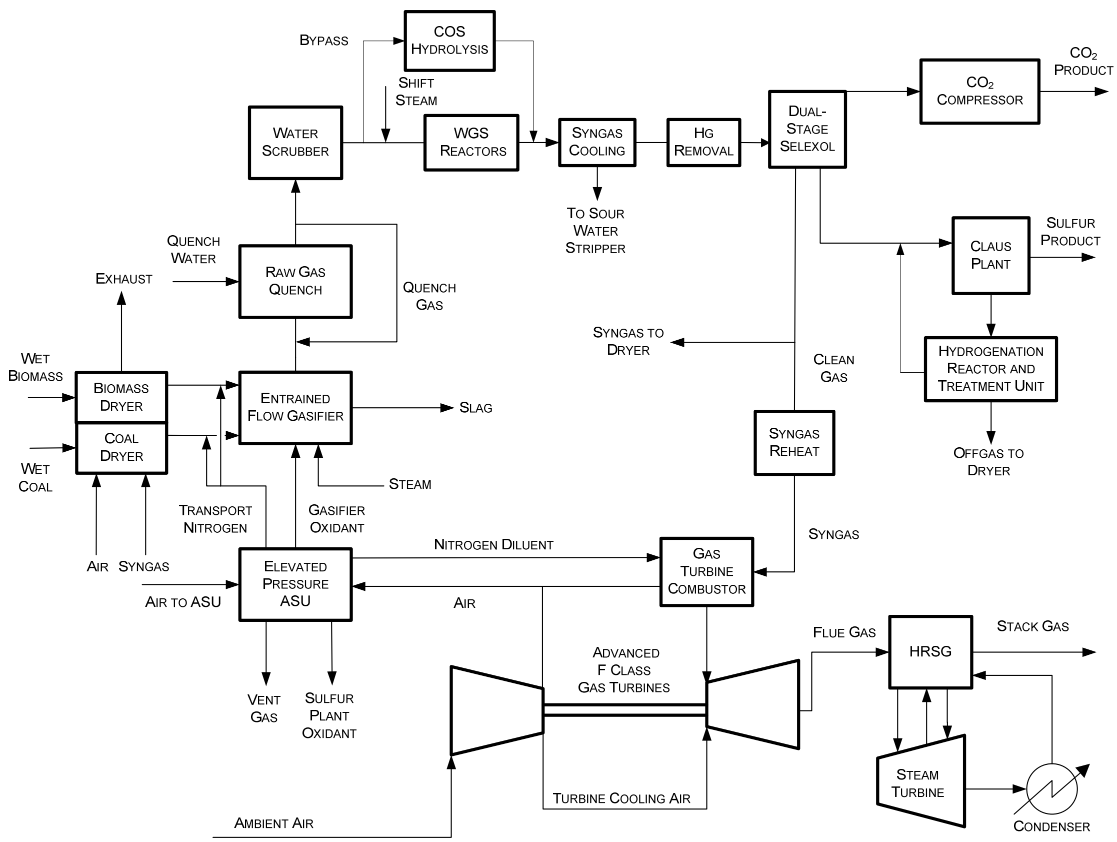
4.1 PARTIAL CAPTURE (BASE CONFIGURATION)

The partial capture plant configuration is shared by 16 of the 47 cases in this study. Out of the 9 different plant configurations, the partial capture configuration is common to the most cases so it is referred to as the base configuration. All other plant configurations are presented as variations of the base configuration.

The base configuration includes cases with feeds of switchgrass and/or coal and varying degrees of CO_2 capture in order to achieve a wide range of limited life cycle GHG emission targets. After fuel gasification, syngas quench water is injected in order to provide water for the shift reaction as well as a means of raw gas cooling. The degree of active CO_2 capture among the 16 base configuration cases is controlled by a WGS reactor bypass; as more capture is required, more syngas is shifted to CO_2 for removal in an AGR specified for 95% CO_2 separation. Doing so adjusts the CO slip past the AGR for emission as CO_2 from the HRSG and fuel dryer stacks so the target emission limit can be precisely met. Regardless of the degree of capture, any raw synthesis gas that bypasses the WGS reactors must be sent through a COS hydrolysis reactor to convert existing COS in the raw gas to H_2S for removal.

The AGR removal process in the base configuration is a dual-stage Selexol unit where CO_2 and H_2S can be removed separately. Separated CO_2 then can be sent to a CO_2 compression train where the captured CO_2 is compressed and prepared for geologic sequestration. Similarly, the separated H_2S is sent to a Claus plant where elemental sulfur can be recovered. Off gas from the Claus plant is treated in a tail gas treatment unit where the sour gas is recycled back to the Claus plant. A simplified BFD for the base configuration is shown in Exhibit 4-1.

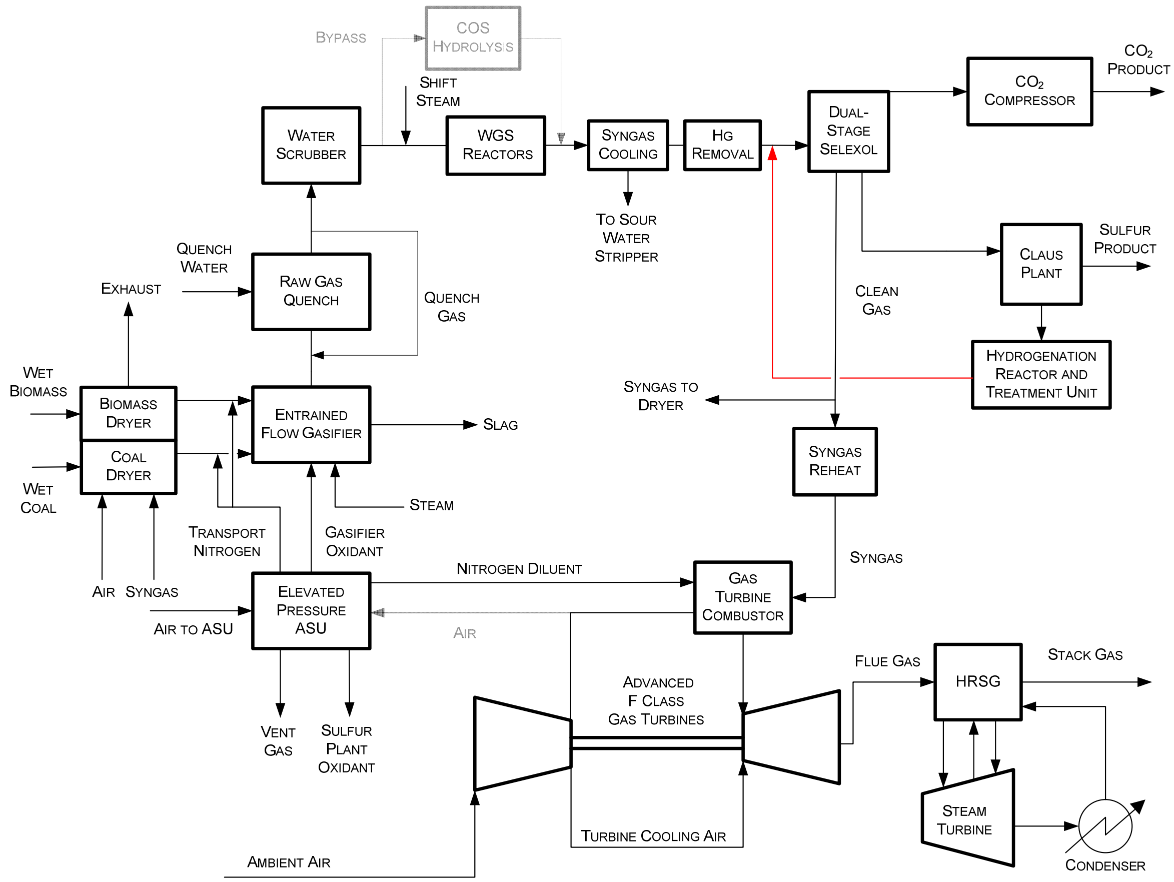
Exhibit 4-1 Partial Capture (Base Configuration)



4.2 MAXIMUM CAPTURE

In this study, a maximum capture plant configuration is considered to be a variation of the base configuration that allows for 90 percent or nearly 90 percent overall carbon capture. Thirteen cases require such a configuration. In maximum capture cases, all of the synthesis gas is sent to the WGS reactors in order to maximize synthesis gas carbon conversion to CO_2. Also, a full recycle of the Claus plant off gas is sent to upstream of the AGR to maximize CO_2 removal. Exhibit 4-2 is the BFD for the maximum capture plant configuration with amendments to the base configuration shown highlighted in red and negations shown as grey.

Exhibit 4-2 Maximum Capture Configuration



Cases 1B3 and 4S1 use the aforementioned maximum capture configuration but require slightly less than 90 percent overall carbon capture in order to meet the emission target. In order to make this minor adjustment in a practical way, less heat for IP steam was removed from the synthesis gas entering the low temperature WGS reactor. Instead of bypassing an impractically small amount of synthesis gas to obtain the required capture rate, the method used lowered the equilibrium conversion of CO to CO_2 in the low temperature WGS reactor as required to achieve just less than maximum carbon capture.

4.3 MINIMUM CAPTURE (HYBRID CONFIGURATION)

In order to meet emission targets, three of the 47 cases required a minimum capture plant configuration. The minimum capture configuration can be thought of as a hybrid between a capture and non-capture plant configuration in the sense that no syngas is shifted to concentrate CO_2 however a dual-stage Selexol unit is included to capture whatever CO_2 is generated by the gasifier (i.e. the "minimum" possible CO_2 generation, hence the "minimum capture" classification). Excluded are the syngas water quench, shift steam injection and WGS reactors. All of the raw synthesis gas exiting the water scrubber enters the COS hydrolysis unit. It should be noted that the dual-stage Selexol removal efficiency could not be properly adjusted for cases in this configuration because sufficient AGR performance data did not exist for the wide range of syngas compositions in this study. Instead, the CO_2 removal efficiency in the AGR was fixed at ~95%. At these low levels of capture, this made precisely achieving the target emission level difficult. In order to achieve exact emission targets, plants can theoretically vent clean, captured CO_2 prior to compression. However, this approach was not taken because venting CO_2 already captured to raise plant emissions was seen as impractical, especially in actual installations where an AGR can be properly designed.

There are some issues worth noting in the maximum biomass cases targeting 800 lb CO_2e/net-MWh. Case 3B3 uses the minimum capture configuration simply so the specified emission target can be met. If designed as non-capture, life cycle GHG emissions would exceed the target, so some degree of capture was needed. In comparison, Case 3S3 could not reach the emissions target specified in the design basis whether a "non-capture" or "minimum capture" arrangement was utilized. Designed as non-capture, the CO_2 emissions were too far above the target. Designed as "minimum capture", *not enough* CO_2 was emitted to meet the target. Once again, an adjustable AGR model was needed, however was unavailable. Results for 3S3 were therefore left out of the results analysis because modeling tools did not exist to achieve this set of predetermined case objectives. Exhibit 4-3 is the BFD for the minimum capture plant configuration with negations to the base configuration shown as grey.

The way Case 7B1 was specified in the design basis requires a minimum capture configuration however it has one adjustment: Supplemental synthesis gas dilution via humidification was needed in case 7B1 in order to provide enough dilution for the CT. Exhibit 4-4 shows the minimum capture plant configuration including humidification, representing Case 7B1.

Exhibit 4-3 Minimum Capture Configuration

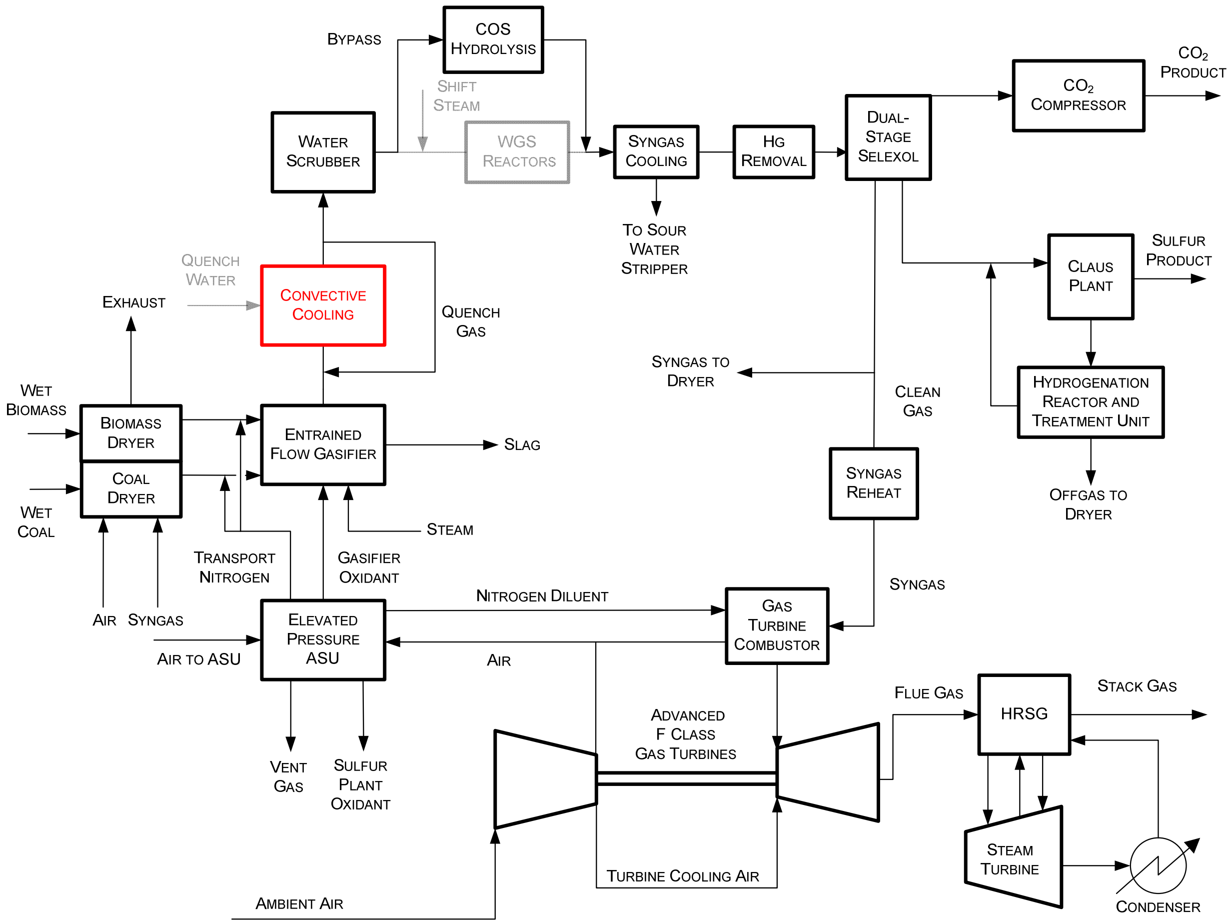
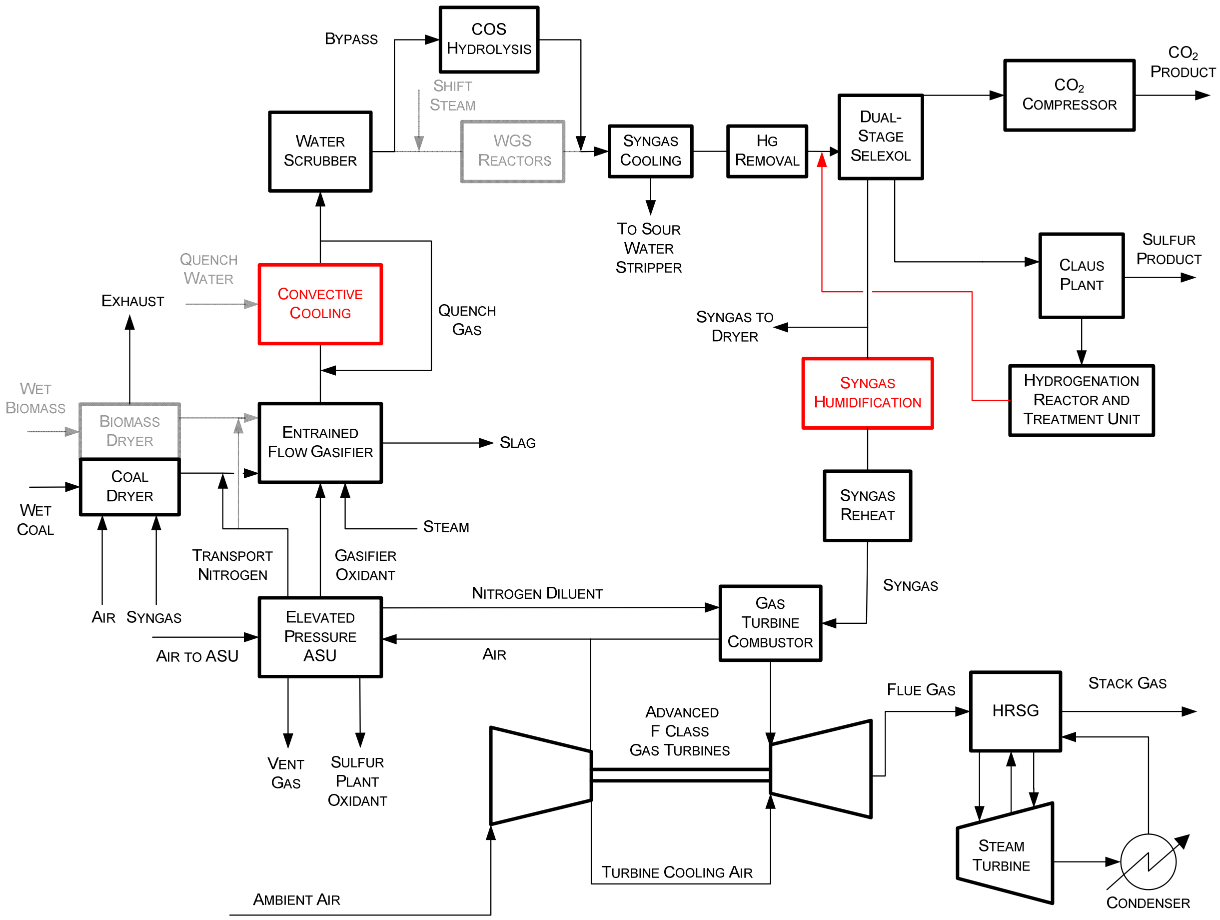


Exhibit 4-4 Minimum Capture Configuration (with Humidification)



4.4 NON-CAPTURE

Eleven cases can be classified as non-capture plant configurations. All but 2 of these 11 are non-capture as specified in the design basis. Cases 2S3 and 2B3 were configured as non-capture in an effort to hit 1,100 lb CO_2e/net-MWh. However, despite the absence of CO_2 removal, these cases were unable to emit enough CO_2 to meet the emissions target because of their high switchgrass feed.

The non-capture plant configuration uses no WGS reactors, and consequently no shift steam injection or raw gas quench. Because no CO_2 capture takes place, Sulfinol replaces the dual-stage Selexol unit as the AGR process because it is more cost effective. Sulfinol maintains H_2S removal but CO_2 is passed through to the CT. The BFD for non-capture cases is shown in Exhibit 4-5.

As a slight variation of the non-capture configuration, Cases 7B2 and 8B1 required supplemental synthesis gas dilution via humidification in order to provide enough dilution for the syngas fuel. The BFD for non-capture cases including humidification is shown in Exhibit 4-6.

Exhibit 4-5 Non-Capture Configuration

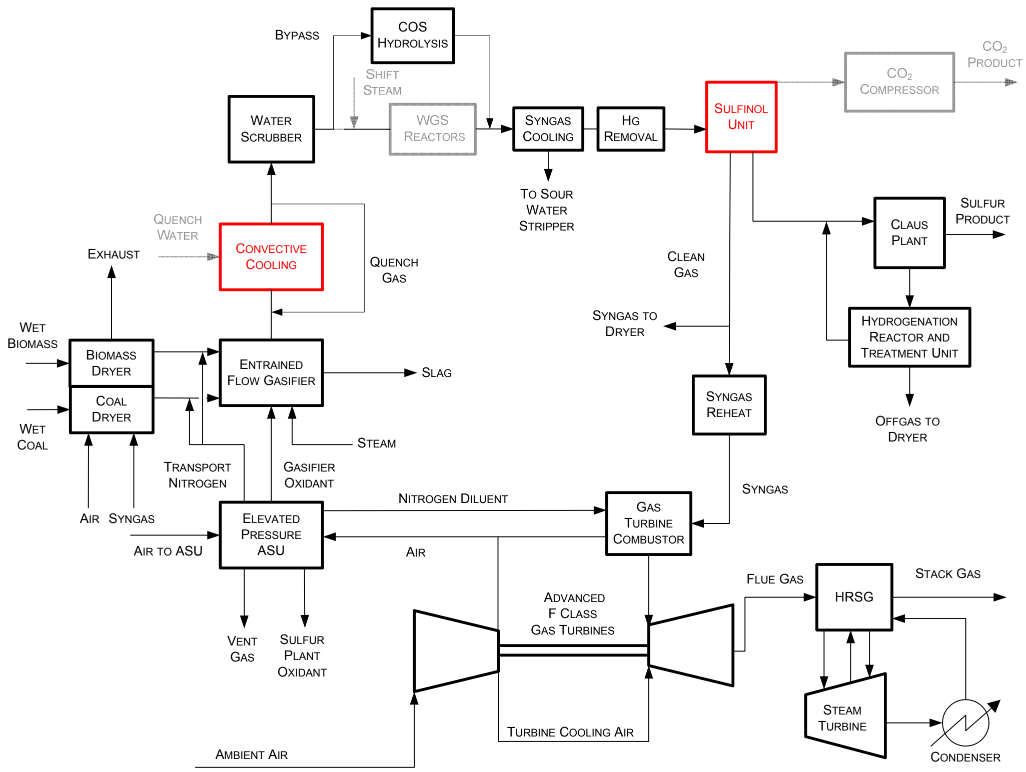
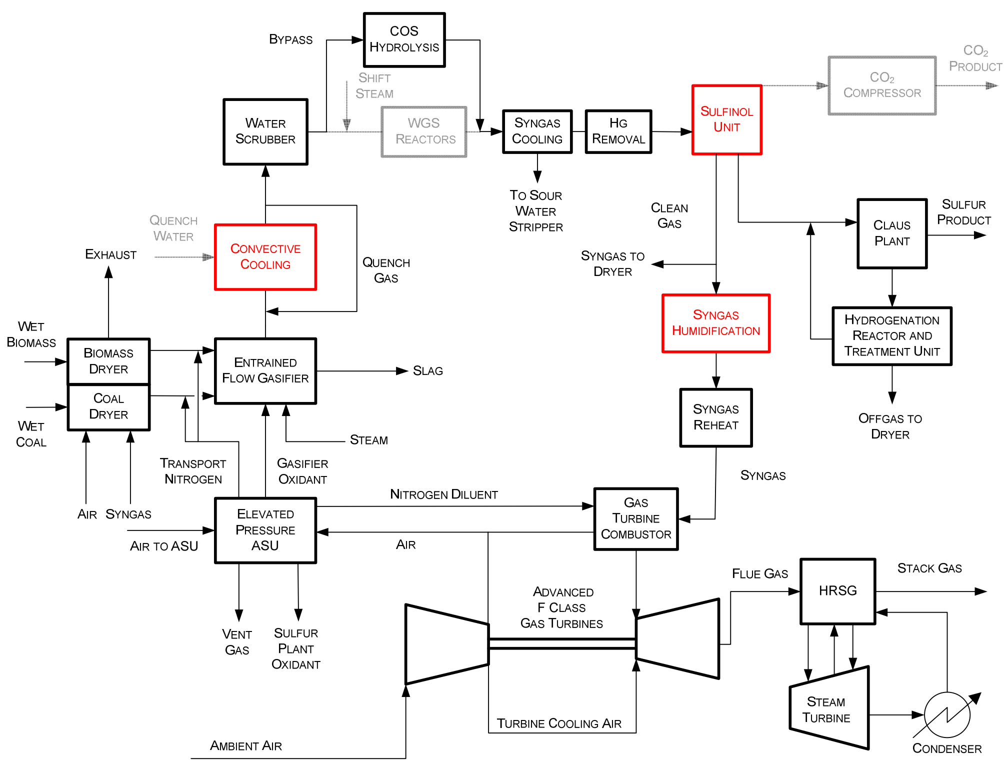


Exhibit 4-6 Non-Capture Configuration (with Humidification)



4.5 100 PERCENT SWITCHGRASS

Four cases in this study, all designed as single-gasifier train plants, required special consideration with regards to plant configuration because they were fed with 100 percent switchgrass. Because the very small amount of sulfur in switchgrass does not economically warrant a Claus plant, each of the four 100 percent switchgrass cases replaces the Claus plant with a ZnO polishing bed and so does not recover any elemental sulfur. This is the primary difference from the other case configurations.

Cases 1S1 and 1B1 require a small amount of capture in order to reach the limited life cycle emission target of 0 lb CO_2e/net-MWh so a minimum capture configuration with no water gas shift system is used. Once again, because a predictive AGR model was unavailable, a portion of the synthesis gas is bypassed around the dual-stage Selexol so the capture rate does not exceed what is required. It should be noted that because of the small sulfur content in these cases, bypassing the AGR does not threaten the sulfur emissions target.

Case 5B2 is specified as a maximum capture case per the design basis. Also per the design basis, case 5B1 is designed as a non-capture case. BFDs with modifications of the base configuration are shown in Exhibit 4-7, Exhibit 4-8, and Exhibit 4-9.

Exhibit 4-7 100 Percent Switchgrass (Minimum Capture Configuration)

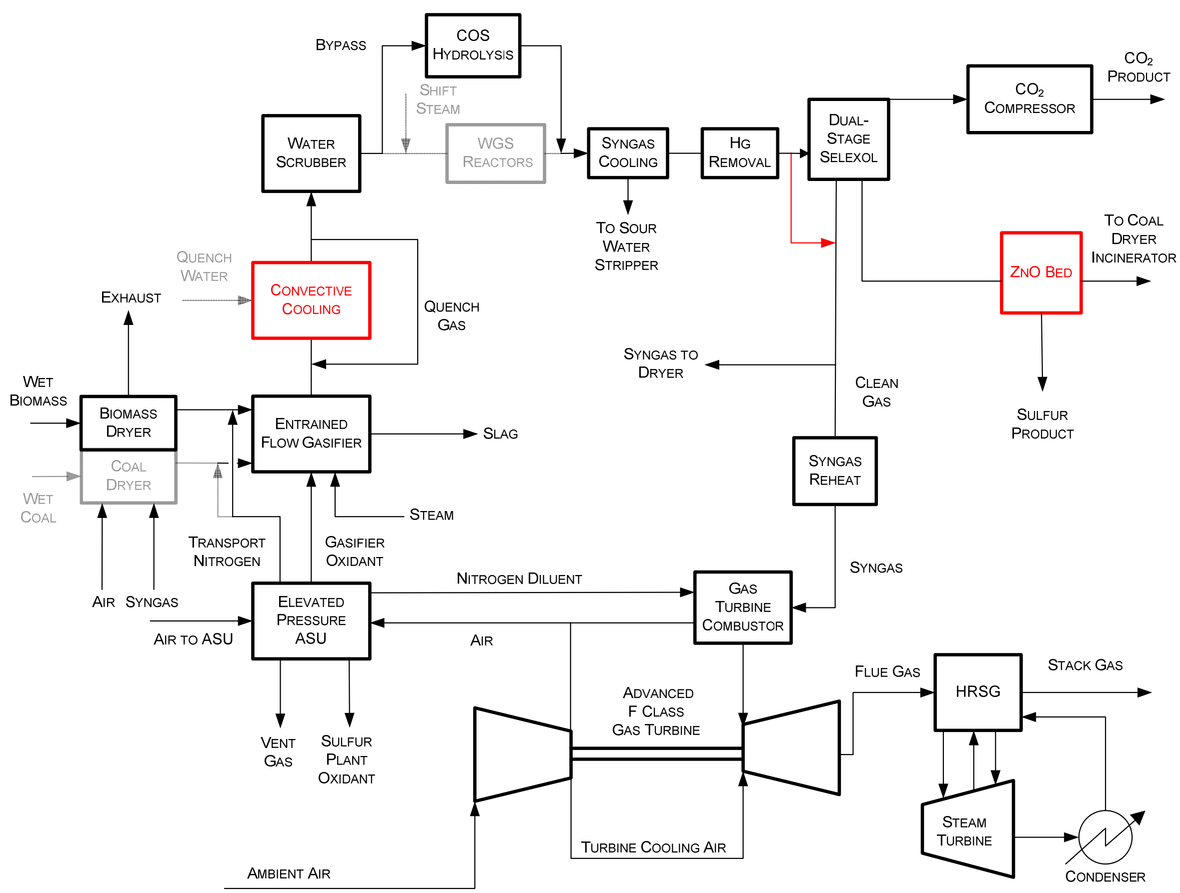


Exhibit 4-8 100 Percent Switchgrass (Maximum Capture Configuration)

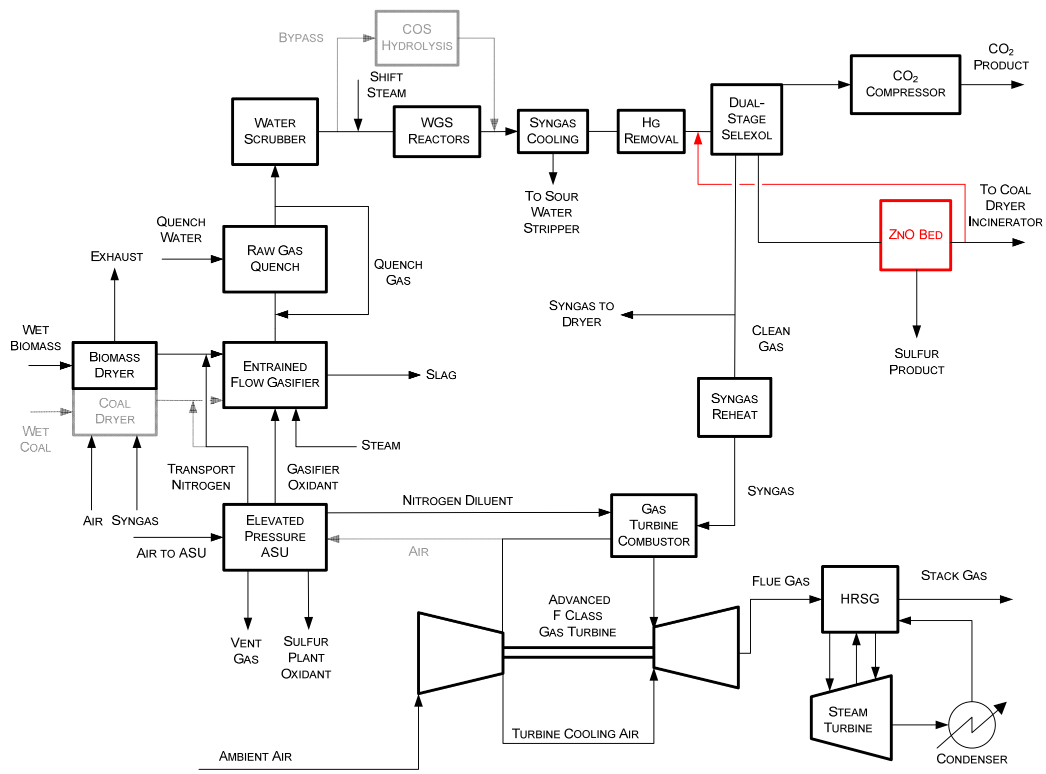
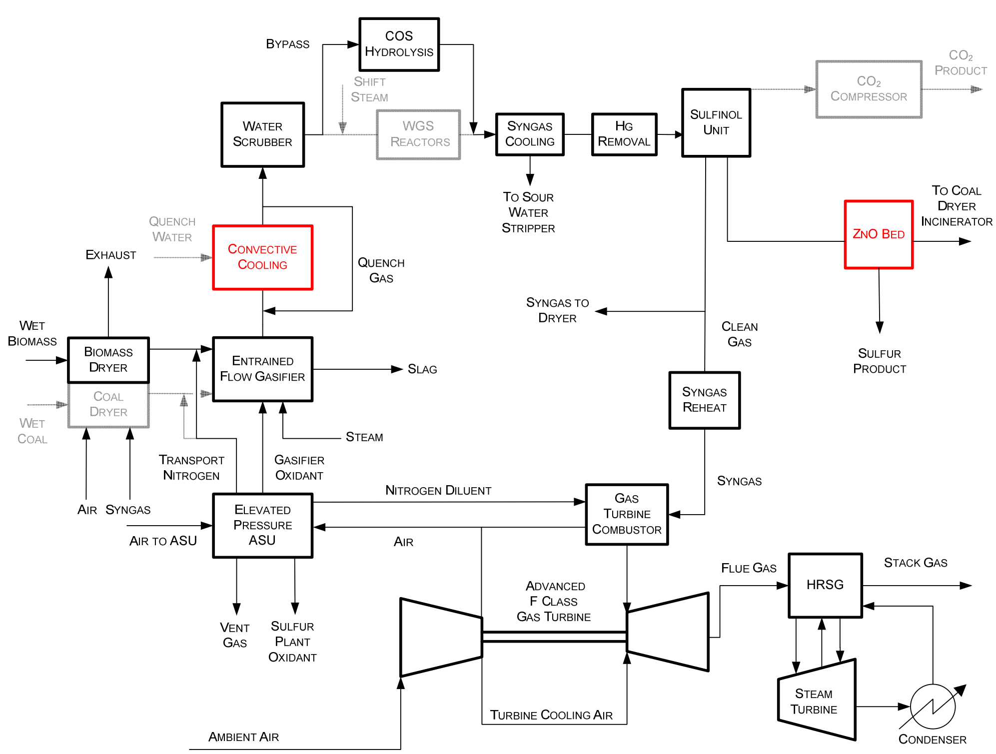


Exhibit 4-9 100 Percent Switchgrass (Non-Capture Configuration)



Because of the wide variety of plant configurations used in this study, Exhibit 4-10 summarizes which of the 47 cases fall under each of the configurations. It can easily be seen that 38 of the 47 study cases fall under the partial, maximum or no capture plant configuration. The remaining 9 cases required modifications to one of these three configurations.

Exhibit 4-10 Case Configuration Summary

Configuration	Abbreviation	Cases Included	Comments
Partial Capture (Base Configuration)	PART	1S2, 1S3, 2S1, 2S2, 3S1, 3S2, 4S2, 4S3, 1B2, 2B1, 2B2, 3B1, 3B2, 4B2, 4B3, 5B3	Cases 2S2 and 4S3 include CT air extraction
Maximum Capture	MAX	1S4, 4S1, 6S1, 6S2, 6S3, 6S4, 1B3, 1B4, 4B1, 6B1, 6B2, 6B3, 6B4	
No Capture	NC	2S3, 2S4, 3S4, 4S4, 8S1, 2B3, 2B4, 3B4, 4B4	All cases include CT air extraction
No Capture (w/Humidification)	NCH	7B2, 8B1	Both cases include CT air extraction
Minimum Capture (Hybrid Configuration)	HYB	3S3, 3B3	Both cases include CT air extraction
Minimum Capture (w/Humidification)	HYBH	7B1	Includes CT air extraction
Minimum Capture (100% Switchgrass)	MINSG	1S1, 1B1	Both cases include CT air extraction, single-train
Maximum Capture (100% Switchgrass)	MAXSG	5B2	single-train
No Capture (100% Switchgrass)	NCSG	5B1	Includes CT air extraction, single-train

5. RESULTS AND ANALYSIS

The following sections present technical and economic data with respect to cofiring switchgrass with either Illinois #6 or PRB coal. The results are presented according to the objectives laid out in the study matrix. In order to provide an accurate comparison between cases, it was necessary to omit cases from some plots due to certain anomalies:

- Cases 1B1 and 1S1 were omitted from the total plant cost (TPC MM$) and raw water consumption plots because both are one gasifier train plants. Comparison of one train plants to two train plants in these instances misrepresents apparent cost trends due to reverse economies of scale.

- Cases 2S3 and 2B3 were omitted from all of the plots because the objective of meeting their emission target of 1,100 lb CO_2e/net-MWh could not be met. Both cases had a maximum logistical switchgrass feed of 5,000 dry ton/day. Because of the CO_2 benefit offered by switchgrass, the maximum possible life cycle emissions for cases 2S3 and 2B3 were 982 and 1,000 lb CO_2e/MWh respectively. Both cases were treated as non-capture plants.

- Case 3S3 was omitted from all of the plots because its emission target was similarly unattainable, but in this instance because proper modeling tools were unavailable. If designed as non-capture plant, 3S3 exceeds the emissions target. However, designed as minimum capture (no shift) yields emissions below the target. It is not possible to simply bypass the AGR process with a portion of the syngas in order to meet the CO_2 target because the sulfur environmental target would be exceeded. A predictive 2-Stage Selexol process model is needed in order to capture a precise amount of CO_2.

- The emission target for case 4B1 was also unattainable and is omitted from all plots. A 100 percent Illinois #6 fed IGCC plant employing a maximum CO_2 capture rate of 90 percent emits cannot achieve emissions lower than 410 lb CO_2e/MWh, which exceeds the target of 350 lb CO_2e/MWh.

Many of the plots are segmented into three distinct regimes. The "Demonstrated" regime includes cases with switchgrass feeds of 30 wt% or less. To date, the highest demonstrated proportion of biomass fed into an operating IGCC facility utilizing an entrained flow gasifier is 30 wt% at NUON Power's Buggenum Plant. The "Maximum Logistical" regime extends to approximately 66 wt% switchgrass in two-train designs. This approximate percentage represents the average feed composition for plants with 5,000 dry ton/day of switchgrass. Plants within this regime have not been demonstrated commercially but are assumed to be logistically feasible even with the understanding that slagging and feeding issues have not yet been resolved. The "Logistically Constrained" regime extends beyond the Maximum Logistical regime. Logistical constraints such as switchgrass storage and transport capacity become roadblocks for operation within this regime.

5.1 TECHNICAL AND ECONOMIC IMPLICATIONS OF COFIRING

The objectives for the first 32 cases in the study were to determine the technical and economic benefits of adding strategic levels of biomass to achieve limited life cycle GHG emissions of 0, 350, 800 and 1,100 lb CO_2e/net-MWh. Study data from these cases yield several key technical and economic trends.

5.1.1 Net Plant Efficiency

Exhibit 5-1 compares the net plant efficiencies of high-elevation plants cofired with PRB and varying amounts of switchgrass while operating at each of the four limited life cycle emission targets. Given any of the emission levels, plant efficiency increases as the amount of switchgrass in the feed is increased. Higher switchgrass feeds offer the substantial benefit of reducing the need to capture and compress large amounts of CO_2 in order to reach a given emission target. Plants with more stringent emission targets, such as the 0 lb CO_2e/net-MWh, have lower efficiencies for a given feed composition because of the need to capture and compress more CO_2, which increases plant auxiliary loads. However, with conventional carbon capture and sequestration it is possible to reach zero net life cycle GHG emissions in the demonstrated cofire regime.

Exhibit 5-1 Net Plant Efficiency (High-Elevation Cases)

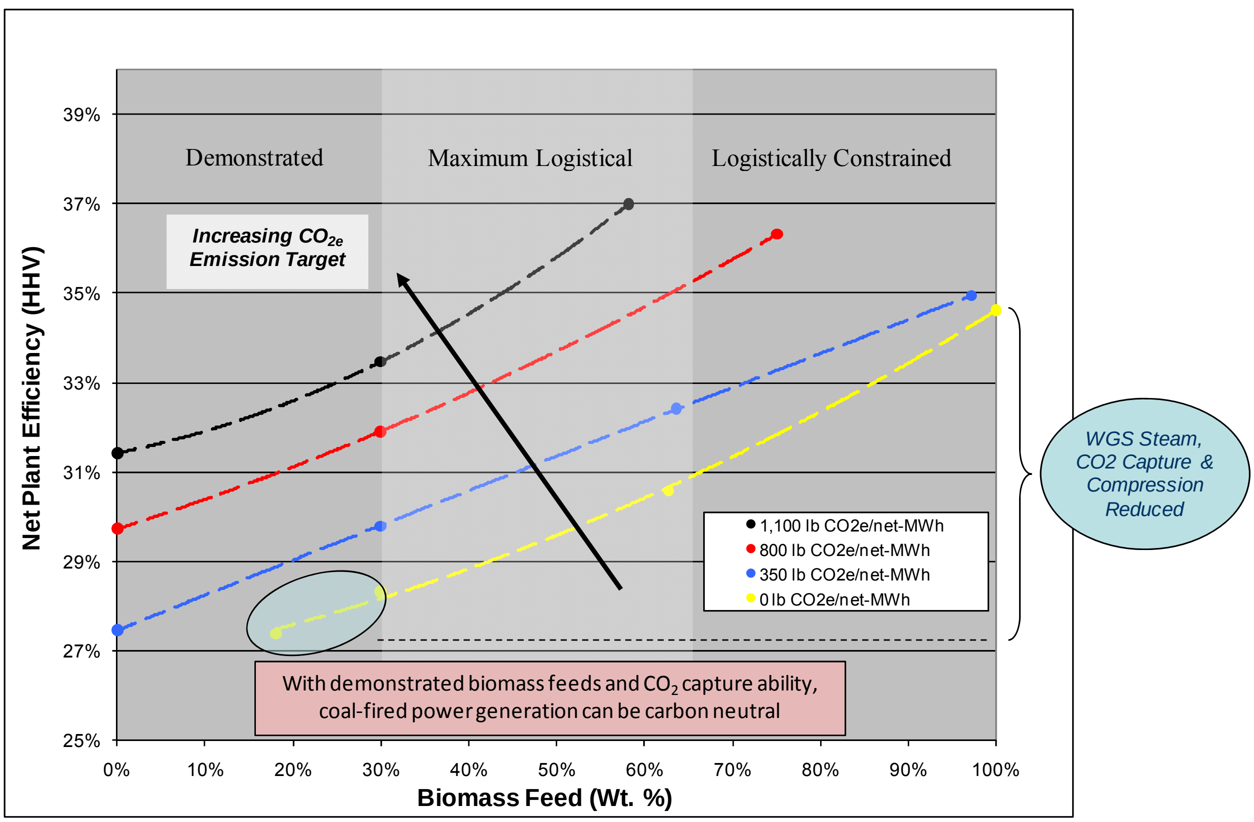
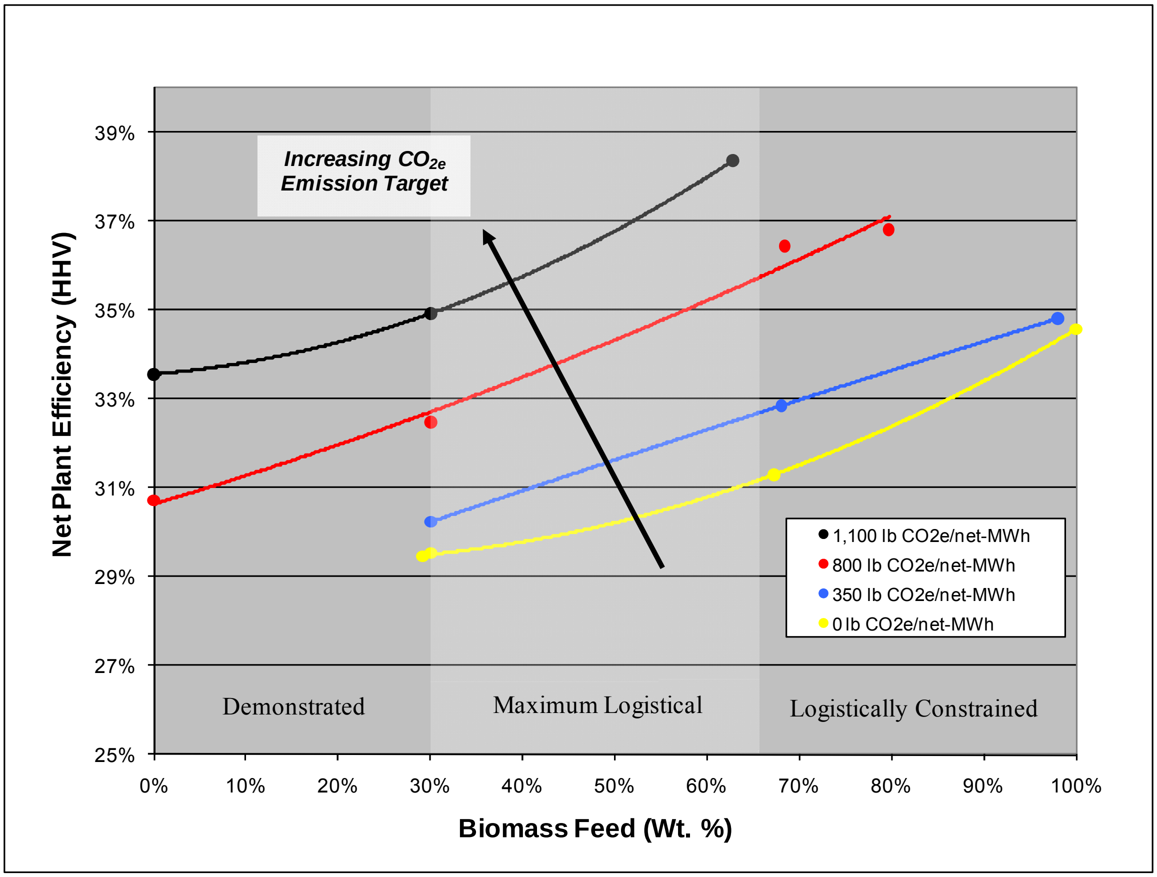


Exhibit 5-2 shows the net plant efficiency correlations for the Midwestern plants cofiring Illinois #6. These plants show the same general trends observed in the high elevation cases. In general, these plants operate at higher efficiencies when compared to the equivalent PRB cases because Illinois #6 coal is a higher quality fuel than PRB. The higher ambient pressure (sea level elevation) in the Illinois #6 cases also improves the combustion turbine performance over the PRB cases which are at an elevation of 3,400 ft. Lower elevations have higher ambient pressures which in turn lead to increased mass flow through the CT inlet compressor.

Exhibit 5-2 Net Plant Efficiency (Midwestern Cases)



5.1.1 Percent CO_2 Capture

Exhibit 5-3 shows the relationship between the feed composition and the necessary amount of plant carbon capture to reach a given emission target for high-elevation plants. It can be seen that the need to capture CO_2 decreases as the switchgrass in the feed increases. The more stringent emission targets require a greater amount of carbon capture for a given feed composition. A 100 wt% switchgrass fed plant is unable to reach zero net life cycle plant emissions because the emissions associated with cultivation of the fuel cannot be readily captured. Approximately 14% plant carbon capture is required to offset these upstream emissions. However, zero net GHG emissions are achievable at demonstrated levels of co-firing with less than 90% carbon capture (81.2% capture with 30% wt. switchgrass).

Similarly, zero net emissions are unattainable for a 100% coal plant due to emissions associated with mining. The maximum 90% plant carbon capture is insufficient to fully offset these emissions.

A significant result is that the near-term limit proposed in the current Waxman-Markey bill (2009), 1,100 lb CO_2/MWh, can be met with 58 percent biomass and no downstream carbon capture and sequestration. The proportion of biomass required is assumed to be logistically possible under this study's biomass supply/delivery assumptions. The Waxman-Markey long term limit of 800 lb CO_2/MWh cannot be met with biomass only and would therefore need to be supplemented with conventional CCS for additional GHG reductions.

Exhibit 5-3 Percent Plant Carbon Capture (High-Elevation Cases)

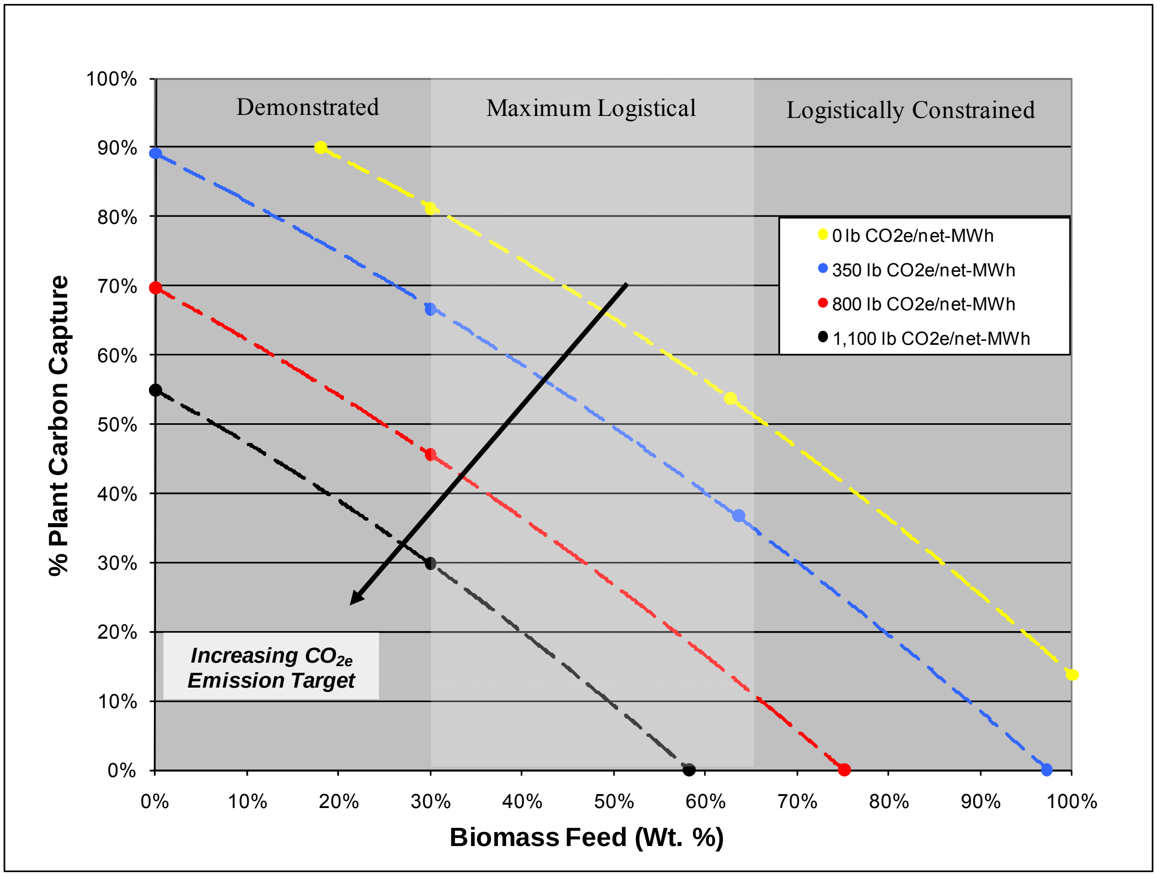


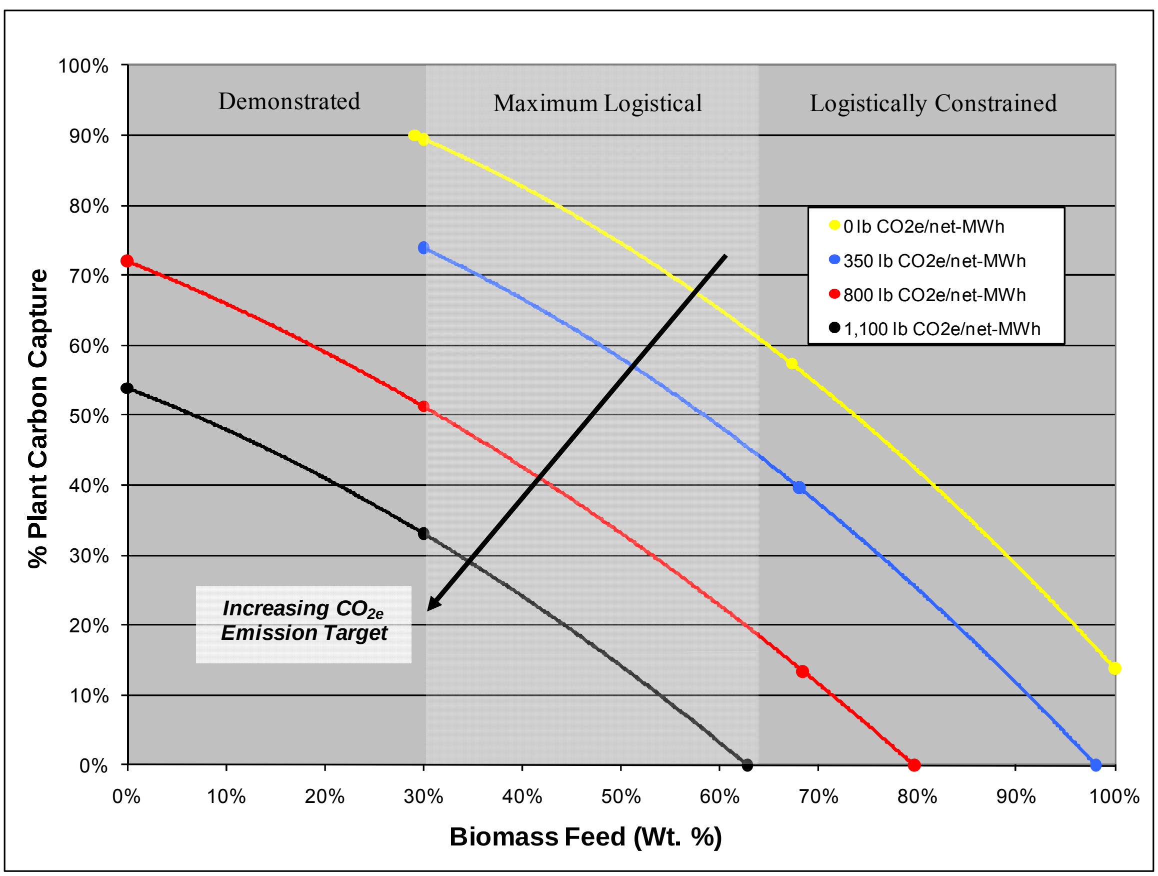
Exhibit 5-4 shows the relationship between the feed composition and the necessary amount of plant carbon capture to reach a given emission target for the Midwestern, Illinois #6 fired cases. Just as with PRB coal, as the amount of switchgrass is increased the amount of CO_2 that must be captured and sequestered decreases. When cofiring switchgrass with Illinois #6 coal, higher amounts of carbon capture are required to meet each emission target for any given feed composition compared to similar PRB cases. This is partially attributable to the higher mining emissions from Illinois #6 than those from PRB. However, zero net emissions are still possible at demonstrated levels of co-firing (30% wt.) and 89.4% capture. Also, when cofiring a feed of a given weight composition, the relative feed rate of renewable biomass carbon in PRB coal cases is greater than Illinois #6 cases because PRB is less carbon dense than Illinois #6. Consequently, the feed rate of switchgrass is proportionally larger with the PRB coal than with the Illinois #6. The larger relative feed rate of renewable carbon offers more CO_2 capture benefit as a result.

While biomass alone can again be used to meet the near term Waxman-Markey limit of 1,100 lb/MWh, it is at the upper limit of the maximum logistical range. The longer term limit of 800 lb/MWh is well into the logistically constrained range with no CO_2 capture and sequestration.

For a given feed composition, more CO_2 capture is required to reach a given emission target when firing Illinois #6 than with PRB for the following reasons:

- Higher mining emissions, primarily degassing methane, result from mining Illinois #6 coal. Methane has a GWP 25 times greater than CO_2, hence the increased need to capture anthropogenic CO_2 to compensate.
- The ratio of non-renewable coal carbon to renewable switchgrass carbon is greater in plants cofiring Illinois #6. Plants firing Illinois #6 are more efficient and need less fuel, but bituminous coal is more carbon dense and produces more anthropogenic CO_2 which needs to be captured above and beyond the CO_2 produced from PRB.

Exhibit 5-4 Percent Plant Carbon Capture (Midwestern Cases)

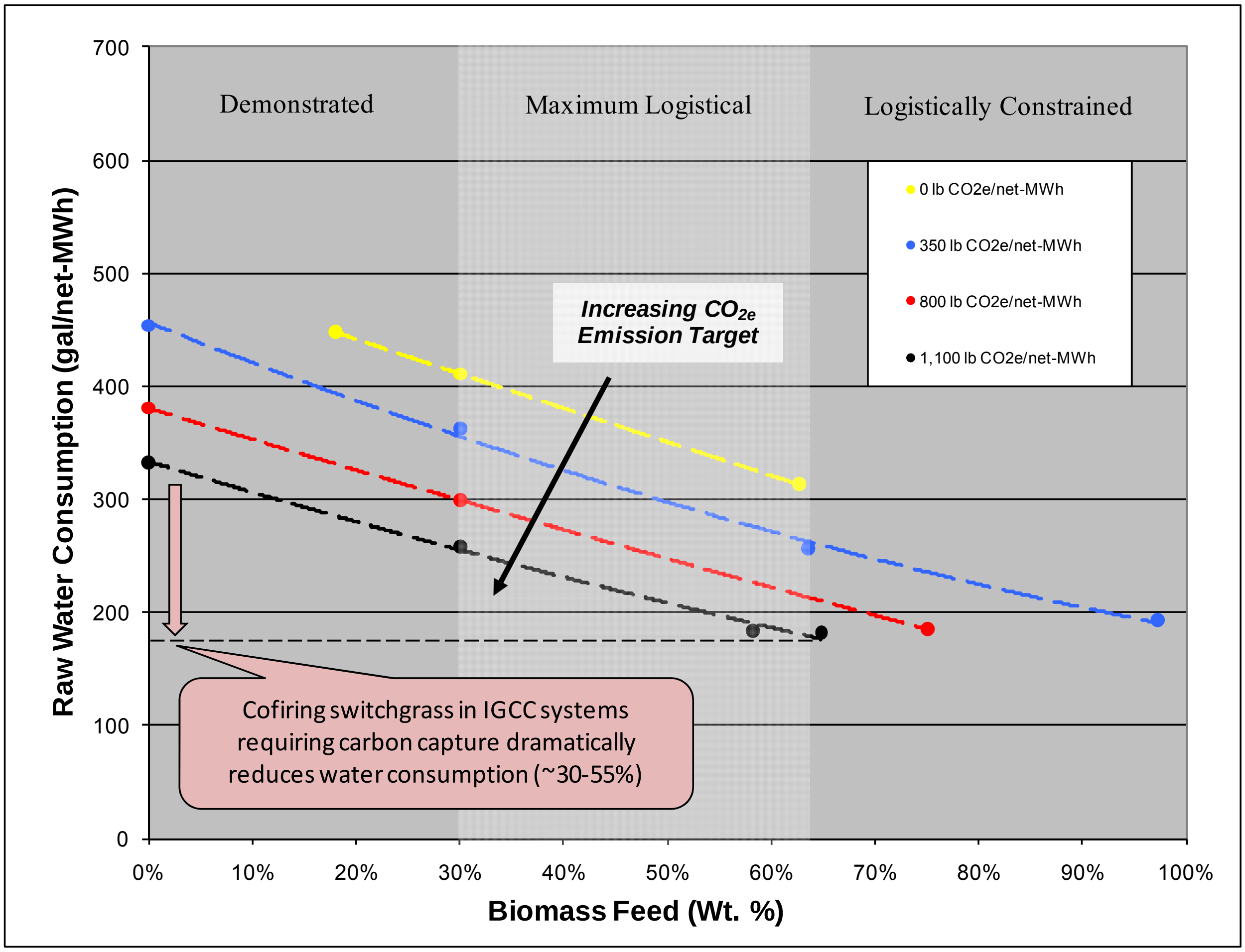


5.1.1 Raw Water Consumption

The water balance methodology and terminology is described in Section 2.9 however it is worth noting that unlike the GHG balances, all water balances and usages in this report are presented within the context of the IGCC plant boundary only.

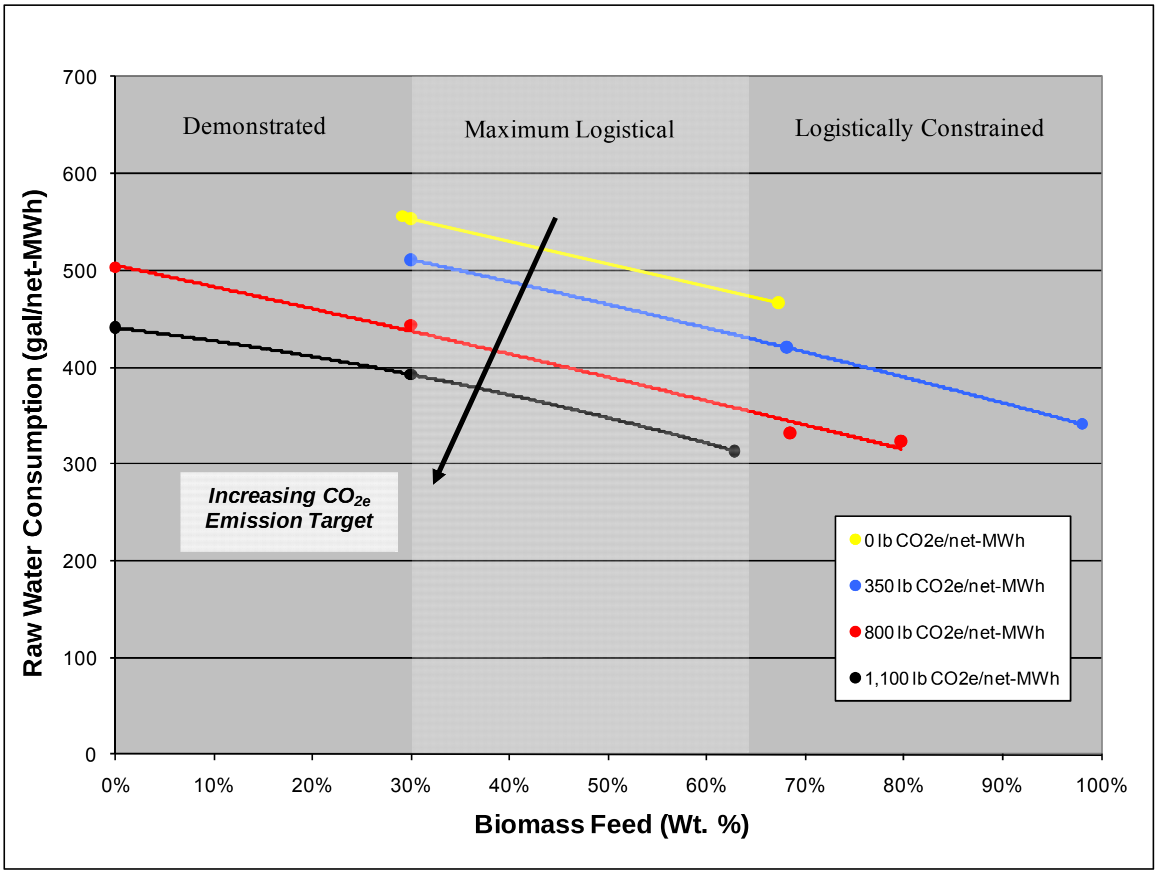
The high-elevation PRB cases use a hybrid cooling system that reduces the water requirement relative to a 100 percent wet cooling system. The amount of raw water consumption varies depending on plant cooling tower makeup, shift steam, and quench water requirements as well as other demands. Exhibit 5-5 illustrates raw water consumption with respect to the gasifier feed composition. It should be noted that the figure only accounts for plant water consumption, therefore excludes life cycle water requirements outside of the plant boundary, such as switchgrass irrigation. Plants with the largest amounts of raw water consumption are those with the most stringent emission targets. This is because demand for shift steam to convert CO to CO_2 increases when high levels of carbon capture are required. Increasing the switchgrass in the feed saves on raw water consumption by avoiding the need to capture CO_2 and consequently, reduces shift steam demand.

Exhibit 5-5 Raw Water Consumption (High-Elevation Cases)



Raw water consumption for the Midwestern, Illinois #6 fired cases shows the same trends seen in the PRB cases. Adding switchgrass reduces the need to consume water in the shift reactors while decreasing life cycle GHG emissions increases water consumption because there is a greater need for syngas shift in order to capture more CO_2. The primary difference is the overall higher water consumption for each Midwestern plant because wet cooling is being utilized as opposed to hybrid cooling in the high-elevation plants. The change in cooling systems raises raw water consumption in the plant approximately 25-40%.

Exhibit 5-6 Raw Water Consumption (Midwestern Cases)



5.1.1 Levelized Cost of Electricity

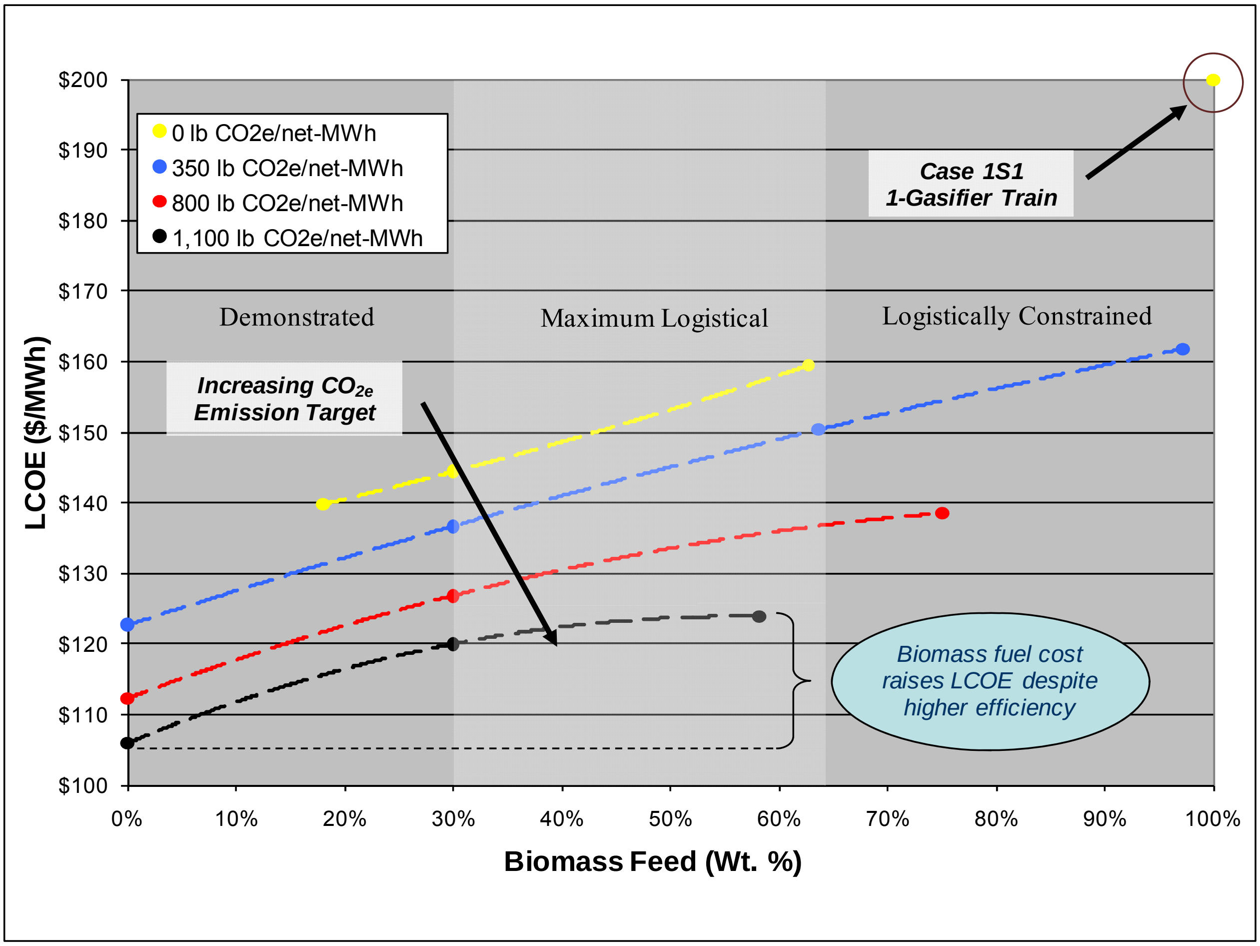
The cost of electricity levelized over a period of 20 years is the economic figure of merit in this study. Exhibit 5-7 shows that for any of the four emission levels, the LCOE increases with higher proportions of switchgrass in the feed. However, for plants with higher emissions, the LCOE tends to level off as biomass is added. This effect can be attributed to economies of scale. Adding switchgrass increases the size of a plant, which introduces economies of scale to the capital costs. Plants with less capital cost associated with capture

> In the absence of GHG tax and with today's anticipated switchgrass prices, coal-fed IGCC plants employing conventional CCS strategies are more cost effective than claiming CO_2 credit for cofiring for capture up to 90%.

and sequestration benefit the most from the economies of scale.

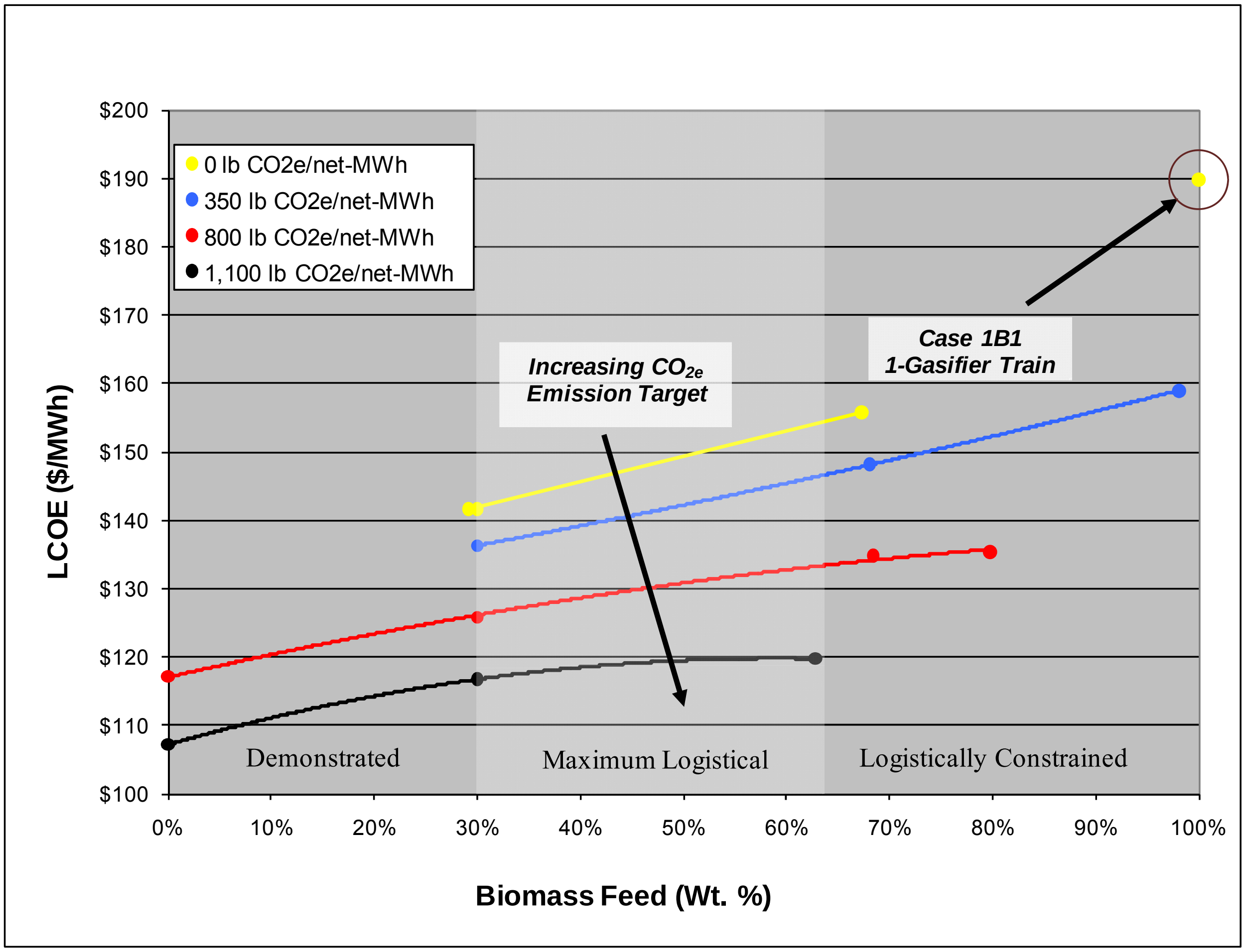
As the emission targets become more stringent, the LCOE also increases. Included in this plot is the LCOE for case 1S1 which is a one-train, 100 percent switchgrass (439,853 lb/hr) fed plant. All other systems are dual-train plants. The LCOE is highly elevated at about $200/MWh because of a reverse economy-of-scale effect that is seen when compared to the other two-train cases. For comparison, case 4S4 is a dual-train case with a near 100 percent switchgrass feed composition (97.2 percent, precisely). Despite a switchgrass feed rate of 845,175 lb/hr, nearly double that of 1S1, the LCOE for case 4S4 is 20% lower at $162/MWh. Even though the fuel costs in 4S4 are above those in 1S1, the reverse economy of scale penalty is more influential on the LCOE.

Exhibit 5-7 Levelized Cost of Electricity (High-Elevation Cases)



The LCOE trends for the Midwestern cases shown in Exhibit 5-8 are consistent with the observations mentioned for the PRB cases, including the reverse economy-of-scale effect for case 1B1. Case 1B1 which is a one-train, 100 percent switchgrass fed plant shows a slightly lower LCOE than its 1S1 counterpart. This relationship holds true for the majority of Illinois #6 cases because of the greater net plant efficiency due to lower plant elevation and higher rank coal.

Exhibit 5-8 Levelized Cost of Electricity (Midwestern Cases)



The levelized cost of electricity for cases meeting each of the four emission targets is broken down into five cost components shown in Exhibit 5-9, Exhibit 5-10, Exhibit 5-11, and Exhibit 5-12:

- Transportation, storage, and monitoring (TS&M) of the sequestered CO_2
- Variable Operations and Maintenance (O&M)
- Fixed Operations and Maintenance
- Fuel cost (includes switchgrass and/or coal costs)
- Capital cost

From each of the diagrams, the following observations can be made:

- For a given GHG target, the total LCOE increases as the proportion of switchgrass in the feed is increased.

- Fuel costs rise as the feed composition shifts towards high switchgrass concentrations. Furthermore, as the switchgrass feed rate increases so does the cost of the switchgrass. This escalation in price drives up the total cost of the fuel mix.

- Capital costs are also affected by the feed composition. Feeding switchgrass reduces the capital cost of the plant by reducing the need for CO_2 compression equipment and reducing the size of the sulfur plant and AGR plant. However, remaining plant equipment sizes are increased because of the need for larger mass flows to fully-load the CT when using the lower quality biomass fuel. These are offsetting effects.

- Non-capture cases do not have TS&M costs. This minor cost savings is offset by the need for higher, more expensive switchgrass feeds to take the place of CO_2 capture.

Exhibit 5-9 LCOE Breakdown 0 lb CO_2e/net-MWh

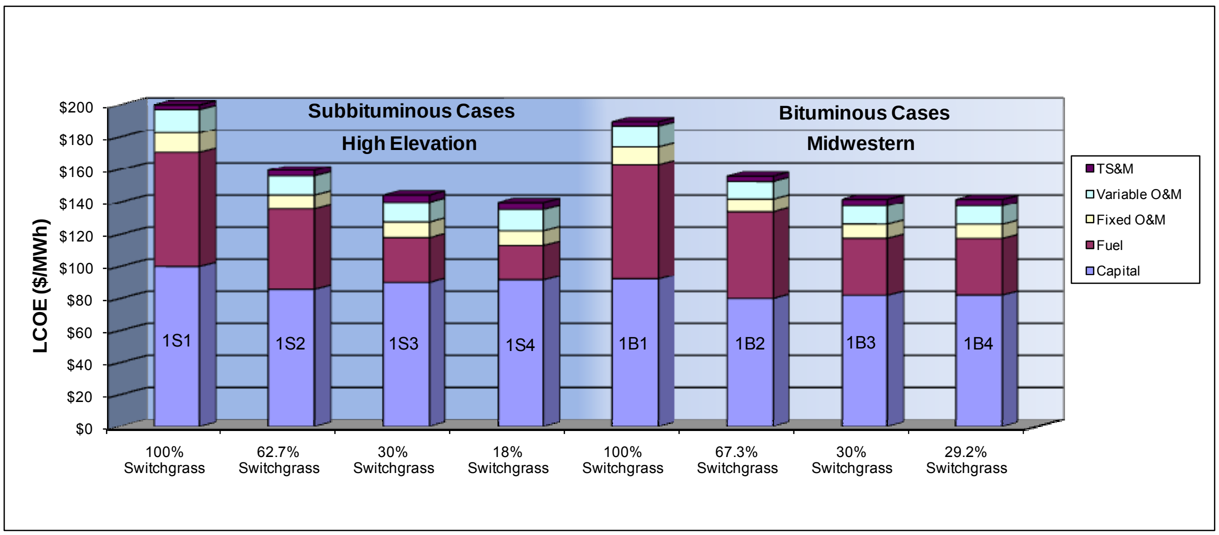


Exhibit 5-10 LCOE Breakdown 350 lb CO_2e/net-MWh

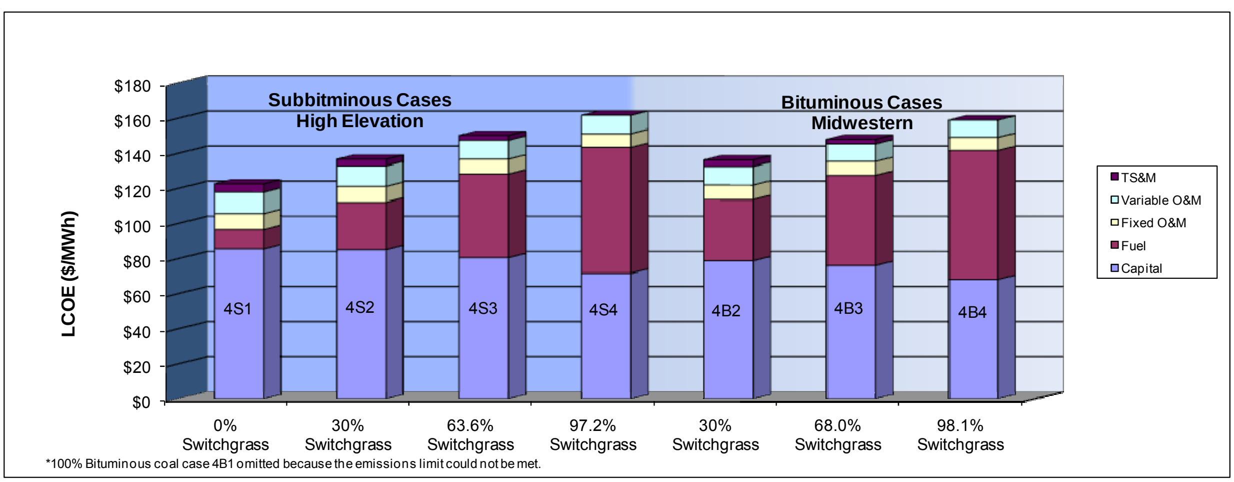


Exhibit 5-11 LCOE Breakdown 800 lb CO_2e/net-MWh

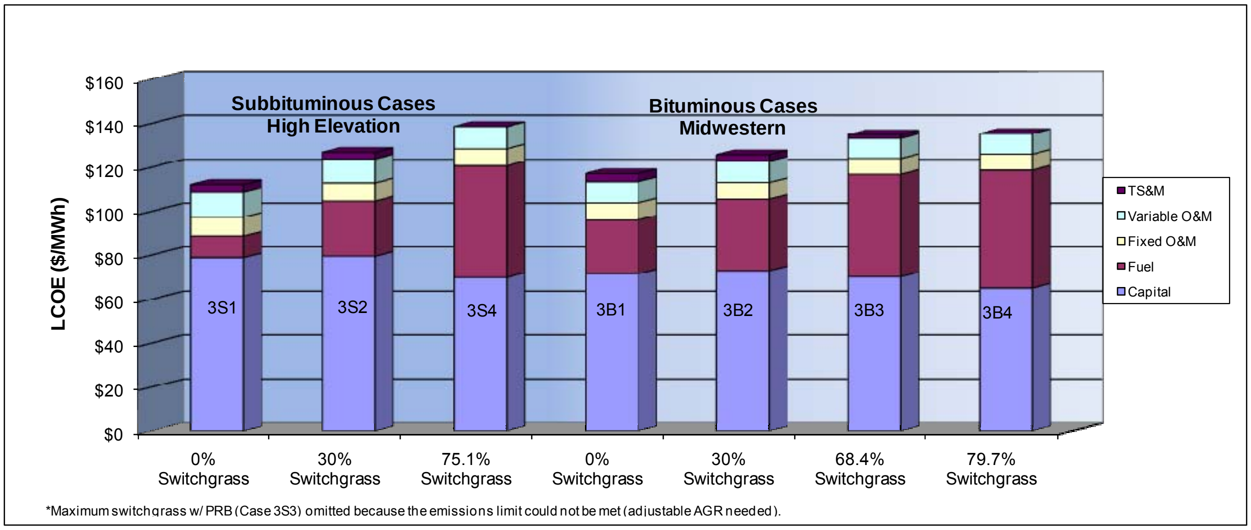
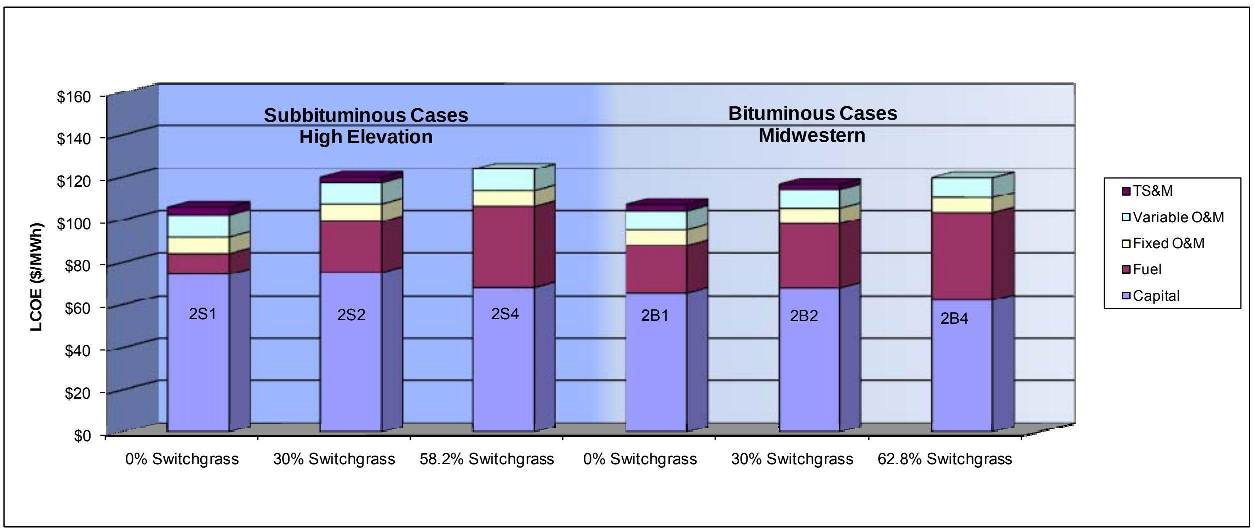


Exhibit 5-12 LCOE Breakdown 1,100 lb CO_2e/net-MWh



5.1.2 Total Plant Cost

Exhibit 5-13 and Exhibit 5-14 show the total plant costs in $/kW and MM$ for the high-elevation cases. Both plots show that the most expensive plants are those with the most stringent emission targets. In other words, as the level of CO_2 captured from a plant increases for a given feed composition, the cost of that plant increases. Included in Exhibit 5-13 is the TPC ($/kW) for case 1S1. Again, a reverse economy-of-scale is in effect, resulting in an elevated TPC. If the amount of switchgrass in the feedstock increases for any emission level, the following observations can be made:

- As the feed percentage of switchgrass increases, the TPC ($/kW) decreases. This is a consequence of efficiency increases for a given emission level as the switchgrass proportion increases.

- TPC (MM$) increases up to a certain point where it levels off and in some cases begins to slightly decrease. The need for larger equipment to handle higher feedstock feed rates with large proportions of switchgrass causes the increase. The subsequent decrease is associated with a reduction in CCS equipment size.

Where appropriate and to represent the most practical system design, adjustments were made in the capital cost estimation for minimum capture and low shift cases. In cases where only a small amount of WGS was necessary, the H_2 concentration in the CT fuel was low enough to justify the use of a "conventional" syngas combustion turbine design instead of a more expensive high hydrogen design. The associated capital costs were used instead of costs for an advanced high-H_2 turbine. Because WGS equipment is absent in the minimum capture cases, the capital cost of a conventional CT as well as the cost for a convective cooler was included.

Exhibit 5-13 Normalized Total Plant Cost (High-Elevation Cases)

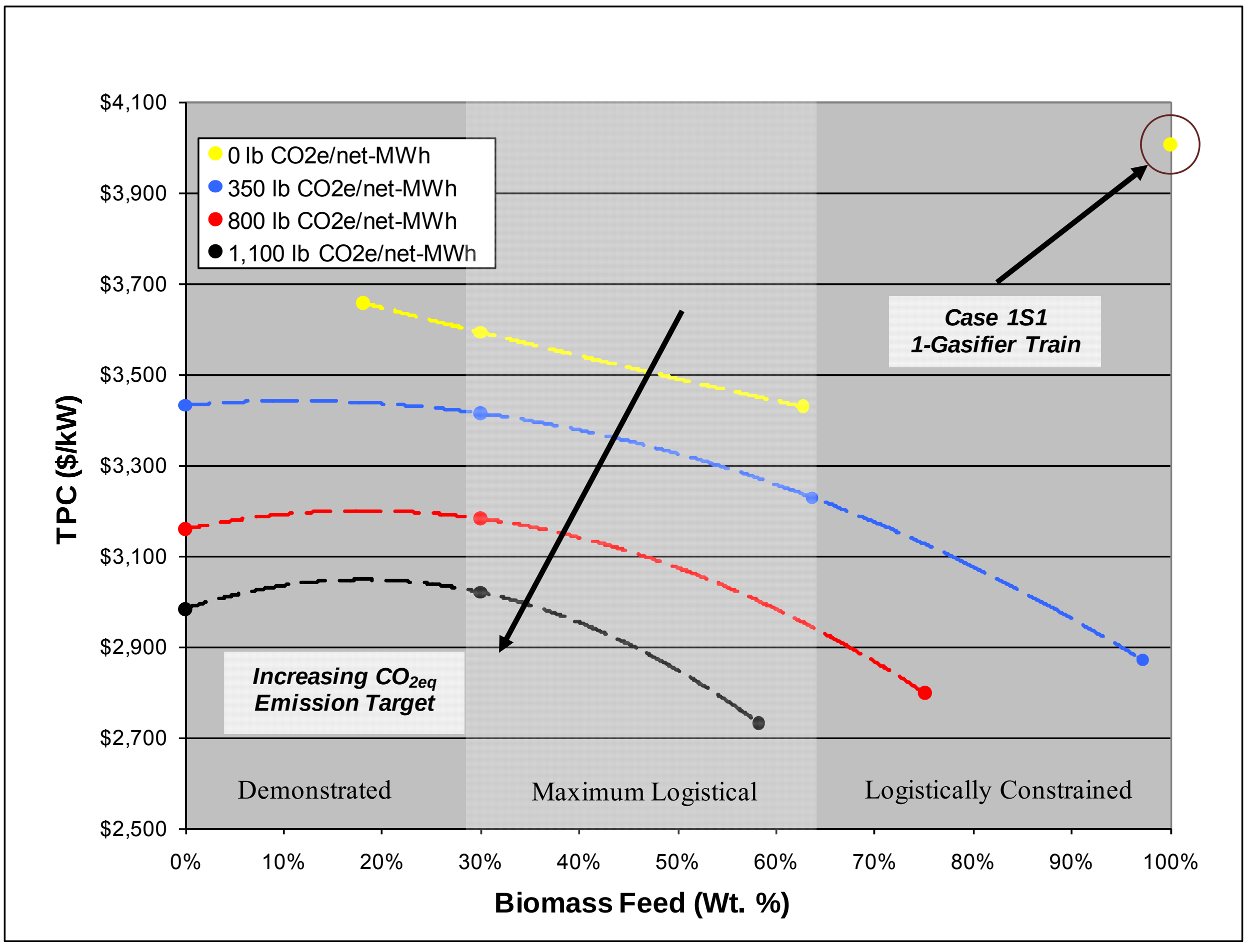
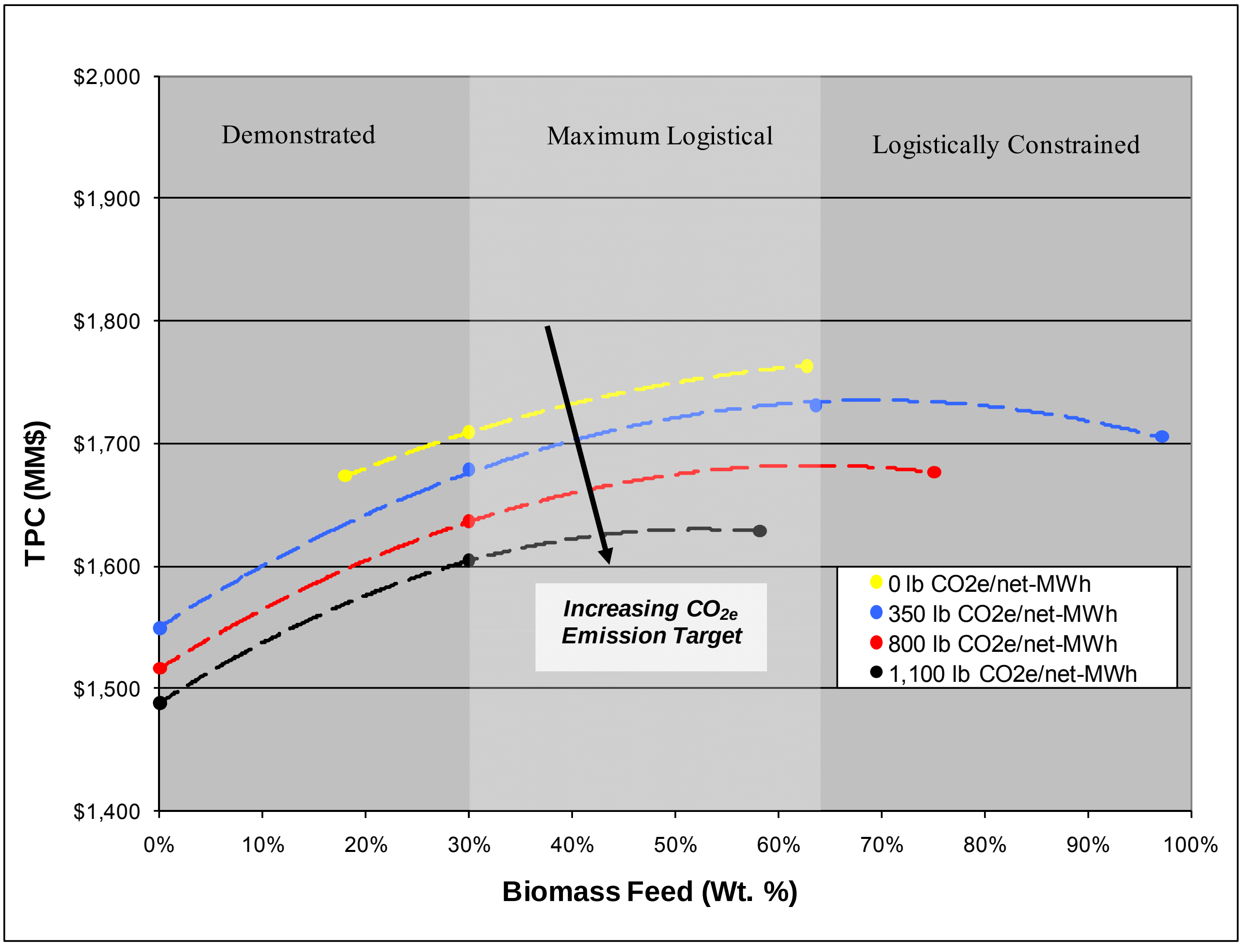


Exhibit 5-14 Total Plant Cost (High-Elevation Cases)



Total plant costs for the Illinois #6 cases are shown in Exhibit 5-15 and Exhibit 5-16. Similar trends as seen for the PRB cases emerge. In general, the TPC for a plant cofiring PRB coal is higher than a plant cofiring Illinois #6. A distinction should be made for Case 3B3 (68.4 wt% biomass, $1,768 million), which is in the minimum capture configuration instead of the partial capture. Included in the TPC is the cost of the convective cooler in place of a water quench. Because of the large associated cooling load, the convective cooler is significantly more costly than a water quench, which is included in the other cases. Material costs elevate the TPC above those of the corresponding 800 lb CO_2e/net-MWh cases. Had Case 3S3 been included in the results, a similar trend may be seen in Exhibit 5-13 and Exhibit 5-14 as well.

Exhibit 5-15 Normalized Total Plant Cost (Midwestern Cases)

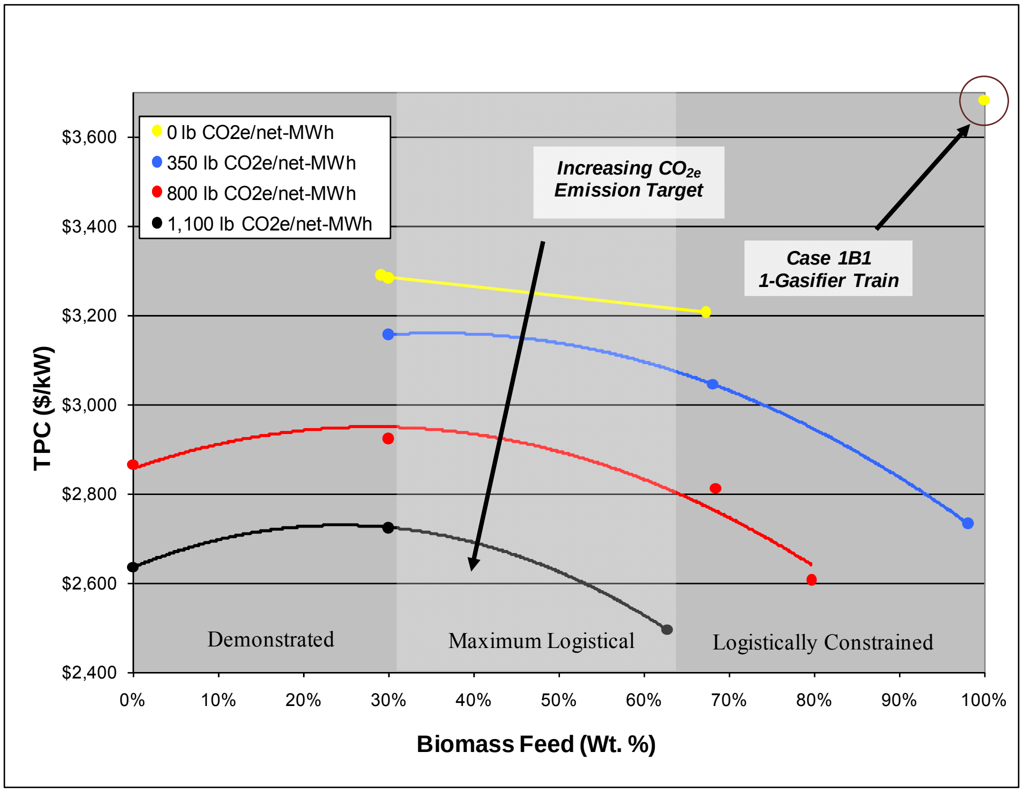
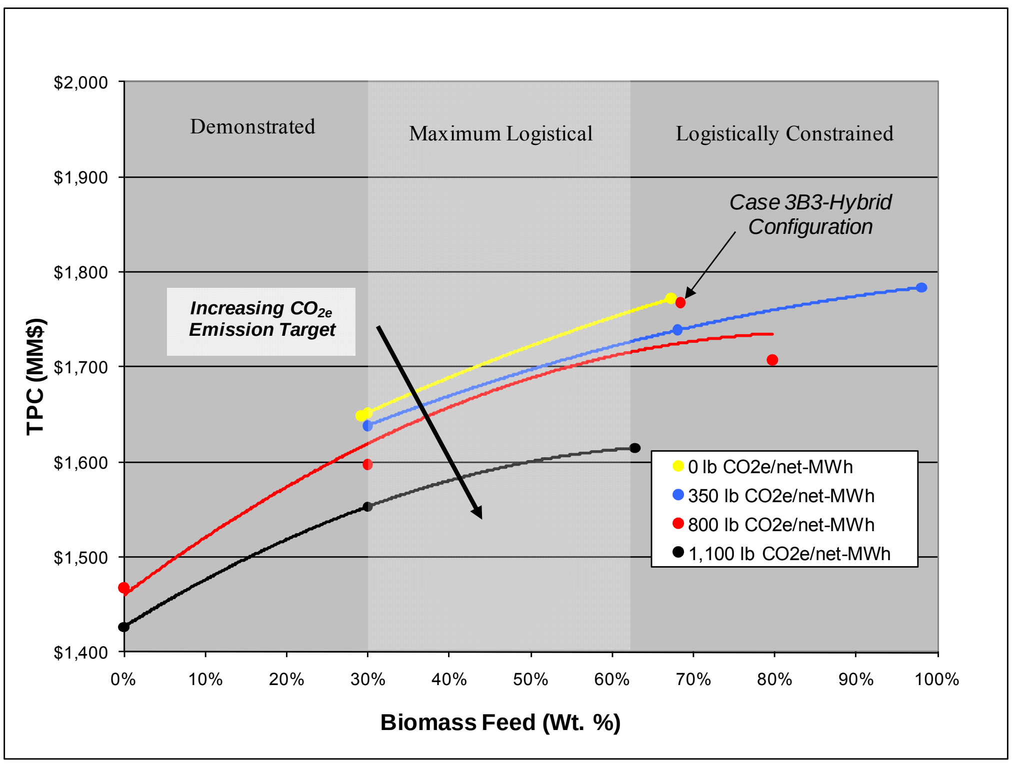


Exhibit 5-16 Total Plant Cost (Midwestern Cases)



5.1.1 Results for Target Emissions Cases

The following exhibits present key study results for the first 36 cases in the study matrix. Each table corresponds to an emission target and is divided by coal type.

Exhibit 5-17 Results for Cases with a Net Zero GHG Target

	Subbituminous				Bituminous			
	1S1	1S2	1S3	1S4	1B1	1B2	1B3	1B4
CO_2e Emitted (lb/MWh)	0	0	0	0	0	0	0	0
Biomass Feed Percentage (wt % of total feed)	100.0%	62.7%	30.0%	18.0%	100.0%	67.3%	30.0%	29.2%
Net Auxiliary Load (kWe)	83,730	190,710	203,560	207,900	90,340	195,240	200,290	201,700
Net Plant Power (kWe)	295,470	514,390	475,740	457,600	320,560	552,660	503,210	501,200
Net Plant Efficiency (HHV)	34.6%	30.6%	28.3%	27.4%	34.6%	31.3%	29.5%	29.5%
Net Plant Heat Rate (HHV) (kJ/kWhr (Btu/kWhr))	10,396 (9,853)	11,771 (11,157)	12,706 (12,043)	13,146 (12,460)	10,414 (9,870)	11,500 (10,900)	12,187 (11,551)	12,220 (11,582)
Coal Feed Flowrate (kg/hr (lb/hr))	0 (0)	132,113 (291,259)	227,948 (502,540)	258,121 (569,059)	0 (0)	108,064 (238,240)	181,797 (400,794)	182,988 (403,420)
Biomass Feed Flowrate (kg/hr (lb/hr))	199,514 (439,853)	222,349 (490,196)	97,692 (215,374)	56,776 (125,169)	216,827 (478,022)	222,349 (490,196)	77,913 (171,769)	75,302 (166,012)
Thermal Input (kWth)	853,237	1,681,914	1,679,092	1,671,066	927,279	1,765,428	1,703,502	1,701,316
Condenser Duty (GJ/hr (MMBtu/hr))	918 (870)	1,614 (1,530)	1,414 (1,340)	1,382 (1,310)	1,002 (950)	1,699 (1,610)	1,467 (1,390)	1,467 (1,390)
Raw Water Withdrawal (m3/min (gpm))	4.8 (1,274)	12.9 (3,403)	15.1 (4,000)	15.8 (4,165)	9.3 (2,451)	20.6 (5,452)	21.7 (5,741)	21.7 (5,744)
Plant Carbon Capture	13.7%	53.8%	81.2%	90.0%	13.8%	57.4%	89.4%	90.0%
Total Plant Cost (MM$)	$1,184	$1,763	$1,709	$1,673	$1,180	$1,772	$1,652	$1,649
Total Plant Cost ($/kW)	$4,006	$3,428	$3,592	$3,657	$3,682	$3,206	$3,283	$3,290
LCOE ($/MWh)	199.90	159.46	144.39	139.79	189.83	155.74	141.71	141.68

Exhibit 5-18 Results for Cases with a GHG Target of 1,000 lb CO_2e/MWh

	Subbituminous				Bituminous			
	2S1	2S2	2S3	2S4	2B1	2B2	2B3	2B4
CO_2e Emitted (lb/MWh)	1,100	1,100	982	1,100	1,100	1,100	1,000	1,100
Biomass Feed Percentage (wt % of total feed)	0.0%	30.0%	64.8%	58.2%	0.0%	30.0%	68.8%	62.8%
Net Auxiliary Load (kWe)	171,120	158,720	144,330	142,890	163,520	158,610	147,760	144,930
Net Plant Power (kWe)	498,880	531,280	597,370	595,910	541,480	570,190	650,240	647,270
Net Plant Efficiency (HHV)	31.4%	33.5%	36.9%	37.0%	33.6%	34.9%	38.0%	38.4%
Net Plant Heat Rate (HHV) (kJ/kWhr (Btu/kWhr))	11,455 (10,857)	10,756 (10,195)	9,752 (9,243)	9,733 (9,225)	10,727 (10,167)	10,307 (9,769)	9,477 (8,983)	9,383 (8,894)
Coal Feed Flowrate (kg/hr (lb/hr))	286,872 (632,444)	215,500 (475,097)	120,599 (265,874)	140,292 (309,291)	214,050 (471,899)	174,224 (384,098)	100,947 (222,551)	114,360 (252,121)
Biomass Feed Flowrate (kg/hr (lb/hr))	0 (0)	92,357 (203,613)	222,349 (490,196)	195,219 (430,384)	0 (0)	74,667 (164,613)	222,349 (490,196)	192,935 (425,349)
Thermal Input (kWth)	1,587,346	1,587,399	1,618,201	1,611,146	1,613,406	1,632,539	1,711,787	1,687,095
Condenser Duty (GJ/hr (MMBtu/hr))	1,372 (1,300)	1,530 (1,450)	1,678 (1,590)	1,667 (1,580)	1,414 (1,340)	1,561 (1,480)	1,825 (1,730)	1,794 (1,700)
Raw Water Withdrawal (m3/min (gpm))	12.9 (3,417)	11.0 (2,909)	9.0 (2,380)	9.0 (2,387)	18.8 (4,959)	17.9 (4,736)	16.9 (4,464)	16.6 (4,394)
Plant Carbon Capture	54.8%	29.8%	0.0%	0.0%	53.9%	33.1%	0.0%	0.0%
Total Plant Cost (MM$)	$1,488	$1,604	$1,643	$1,628	$1,427	$1,553	$1,644	$1,615
Total Plant Cost ($/kW)	$2,983	$3,019	$2,750	$2,732	$2,634	$2,724	$2,528	$2,495
LCOE ($/MWh)	105.94	120.00	128.92	123.88	107.18	116.73	124.49	119.73

Exhibit 5-19 Results for Cases with a GHG Target of 800 lb CO_2e/MWh

	Subbituminous				Bituminous			
	3S1	**3S2**	**3S3**	**3S4**	**3B1**	**3B2**	**3B3**	**3B4**
CO_2e Emitted (lb/MWh)	800	800	N/A	800	800	800	800	800
Biomass Feed Percentage (wt % of total feed)	0.0%	30.0%	N/A	75.1%	0.0%	30.0%	68.4%	79.7%
Net Auxiliary Load (kWe)	184,050	172,030	N/A	149,370	179,540	172,970	161,060	156,280
Net Plant Power (kWe)	480,050	514,170	N/A	599,130	512,260	546,530	628,640	654,920
Net Plant Efficiency (HHV)	29.7%	31.9%	N/A	36.3%	30.7%	32.5%	36.4%	36.8%
Net Plant Heat Rate (HHV) (kJ/kWhr (Btu/kWhr))	12,109 (11,478)	11,281 (10,693)	N/A	9,912 (9,395)	11,719 (11,108)	11,084 (10,505)	9,879 (9,364)	9,780 (9,270)
Coal Feed Flowrate (kg/hr (lb/hr))	291,827 (643,368)	218,741 (482,241)	N/A	89,570 (197,469)	221,238 (487,746)	179,575 (395,894)	102,721 (226,461)	73,061 (161,071)
Biomass Feed Flowrate (kg/hr (lb/hr))	0 (0)	93,746 (206,675)	N/A	269,846 (594,909)	0 (0)	76,961 (169,669)	222,349 (490,196)	287,280 (633,344)
Thermal Input (kWth)	1,614,765	1,611,271	N/A	1,649,638	1,667,588	1,682,678	1,725,157	1,779,272
Condenser Duty (GJ/hr (MMBtu/hr))	1,340 (1,270)	1,488 (1,410)	N/A	1,709 (1,620)	1,361 (1,290)	1,509 (1,430)	1,878 (1,780)	1,889 (1,790)
Raw Water Withdrawal (m3/min (gpm))	14.1 (3,727)	12.2 (3,224)	N/A	9.3 (2,444)	20.1 (5,310)	19.2 (5,081)	17.1 (4,524)	17.5 (4,621)
Plant Carbon Capture	69.6%	45.5%	N/A	0.0%	72.0%	51.3%	13.4%	0.0%
Total Plant Cost (MM$)	$1,516	$1,636	N/A	$1,676	$1,468	$1,597	$1,768	$1,707
Total Plant Cost ($/kW)	$3,159	$3,182	N/A	$2,798	$2,865	$2,923	$2,812	$2,607
LCOE ($/MWh)	112.29	126.84	N/A	138.53	117.14	125.79	134.79	135.30

Exhibit 5-20 Results for Cases with a GHG Target of 350 lbCO$_2$e/MWh

	Subbituminous				Bituminous			
	4S1	**4S2**	**4S3**	**4S4**	**4B1**	**4B2**	**4B3**	**4B4**
CO$_2$e Emitted (lb/MWh)	350	350	350	351	410	350	350	350
Biomass Feed Percentage (wt % of total feed)	0.0%	30.0%	63.6%	97.2%	0.0%	30.0%	68.0%	98.1%
Net Auxiliary Load (kWe)	201,780	190,120	176,380	165,810	190,620	191,450	181,420	182,640
Net Plant Power (kWe)	451,520	491,580	536,420	594,190	494,580	519,250	570,980	652,660
Net Plant Efficiency (HHV)	27.5%	29.8%	32.4%	34.9%	30.0%	30.2%	32.9%	34.8%
Net Plant Heat Rate (HHV) (kJ/kWhr (Btu/kWhr))	13,105 (12,421)	12,086 (11,455)	11,103 (10,523)	10,302 (9,765)	11,981 (11,356)	11,907 (11,285)	10,958 (10,386)	10,341 (9,801)
Coal Feed Flowrate (kg/hr (lb/hr))	297,057 (654,898)	224,049 (493,943)	127,137 (280,288)	11,017 (24,287)	218,369 (481,421)	183,275 (404,053)	104,422 (230,212)	8,348 (18,403)
Biomass Feed Flowrate (kg/hr (lb/hr))	0 (0)	96,021 (211,690)	222,349 (490,196)	383,365 (845,175)	0 (0)	78,547 (173,165)	222,349 (490,196)	423,655 (934,000)
Thermal Input (kWth)	1,643,703	1,650,368	1,654,378	1,700,448	1,645,962	1,717,353	1,737,981	1,874,715
Condenser Duty (GJ/hr (MMBtu/hr))	1,319 (1,250)	1,435 (1,360)	1,720 (1,630)	1,772 (1,680)	1,382 (1,310)	1,456 (1,380)	1,741 (1,650)	2,005 (1,900)
Raw Water Withdrawal (m3/min (gpm))	15.7 (4,147)	13.9 (3,674)	11.2 (2,951)	9.7 (2,559)	21.1 (5,576)	20.8 (5,499)	19.4 (5,131)	18.5 (4,894)
Plant Carbon Capture	89.1%	66.6%	36.7%	0.0%	90.0%	73.9%	39.7%	0.0%
Total Plant Cost (MM$)	$1,549	$1,679	$1,731	$1,706	$1,481	$1,639	$1,739	$1,784
Total Plant Cost ($/kW)	$3,431	$3,415	$3,228	$2,870	$2,995	$3,156	$3,045	$2,733
LCOE ($/MWh)	122.65	136.67	150.35	161.74	122.50	136.29	148.08	158.99

5.2 ECONOMIES OF SCALE AND THE BENEFITS OF COFIRING COAL

Exhibit 5-21 illustrates that cofiring coal with switchgrass has economic benefits. Case 5B1 is a single-train, non-capture facility fed exclusively with switchgrass. The limited life cycle emissions reflect those produced only from switchgrass production, processing and transportation. Case 5B3 is cofired with only 30% switchgrass while operating at the same limited life cycle emission level as 5B1. Since coal constitutes 70 percent of the feed, carbon capture must be employed to reach the same emission level as 5B1. Comparing 5B1 and 5B3, the following observations can be made:

> Coal with CCS can make renewable power production with biomass more affordable while still significantly decreasing the GHG footprint.

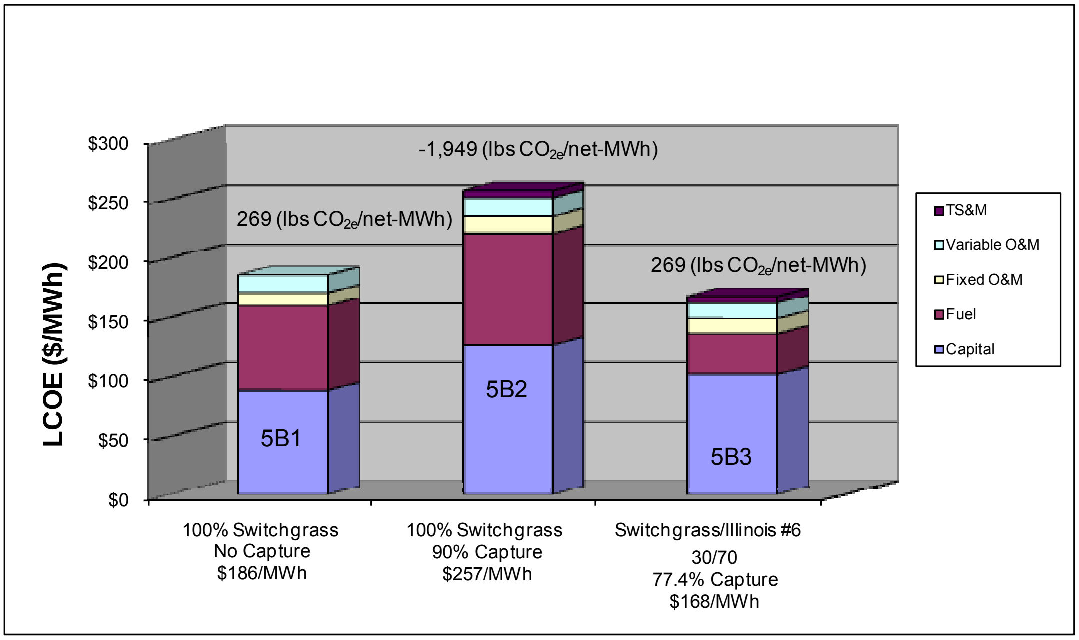
- The capital cost for 5B3 is larger because it includes the cost of a CO_2 compression train as well as a 2-stage Selexol unit. 5B1 has no CO_2 compression equipment and uses Sulfinol, a less expensive AGR system.

- Case 5B1 also avoids TS&M costs because of the absence of CO_2 removal.

- The fuel cost in 5B1 is significantly larger than the respective cost in 5B3. Since switchgrass is the sole feed in 5B1, higher fuel costs are associated with the larger switchgrass feed.

- The benefit of co-feeding coal can be seen when comparing the total LCOE for 5B1 ($186/MWh) to 5B3 ($168/MWh). The savings in fuel cost by co-feeding 70 wt% Illinois #6 offsets the increase in capital cost from the CO_2 removal, compression, and TS&M.

Exhibit 5-21 Economic Benefits of Co-feeding Coal



Case 5B2 is included to show the economic implications of employing the maximum carbon capture rate of 90 percent in a 100 percent switchgrass fed facility. As might be expected, the LCOE is significantly higher than both 5B1 and 5B3. The negative emissions level indicates that non-anthropogenic GHGs are being captured and sequestered, resulting in a net decrease in ambient CO_2 concentration. In effect, this case acts as an ambient CO_2 sink, reducing atmospheric CO_2 levels. The switchgrass absorbs more CO_2 from the atmosphere during its growth cycle than is emitted from the plant. in addition, the amount of carbon sequestered is significantly greater than the CO_2 produced by switchgrass production, processing and transportation.

5.2.1 Results for Cases 5B1, 5B2 and 5B3

Exhibit 5-22 gives the results for Cases 5B1 through 5B3. All cases are single gasifier train plants. Case 5B1, fed with 100 wt% switchgrass, is approximately at the maximum logistical switchgrass feed. This indicates that case 5B1 is at the size limit for a switchgrass fed plant, or approximately 326 MWe. Cofiring coal and adding CCS, as in Case 5B3, reduces the amount of switchgrass needed to meet a given emission target while allowing the plant to expand. Despite being a smaller plant at 258 MWe, Case 5B3 only feeds 17 % of the maximum logistical switchgrass feed rate. Case 5B3 can potentially add a second gasifier train to increase power without being feed-restricted.

Exhibit 5-22 Results for Cases 5B1 through 5B3

	5B1	5B2	5B3
CO_2e Emitted (lb/MWh)	269	-1,949	269
Biomass Feed Percentage (wt % of total feed)	100.0%	100.0%	30.0%
Net Auxiliary Load (kWe)	85,690	128,440	96,440
Net Plant Power (kWe)	325,910	262,460	257,960
Net Plant Efficiency (HHV)	35.0%	26.6%	30.4%
Net Plant Heat Rate (HHV) (kJ/kWhr (Btu/kWhr))	10,296 (9,759)	13,537 (12,830)	11,841 (11,223)
Coal Feed Flowrate (kg/hr (lb/hr))	0 (0)	0 (0)	90,546 (199,620)
Biomass Feed Flowrate (kg/hr (lb/hr))	217,959 (480,518)	230,770 (508,760)	38,805 (85,551)
Thermal Input (kWth)	932,119	986,904	848,447
Condenser Duty (GJ/hr (MMBtu/hr))	992 (940)	971 (920)	739 (700)
Raw Water Withdrawal (m3/min (gpm))	9.4 (2,483)	12.5 (3,297)	10.6 (2,795)
Plant Carbon Capture	0.0%	90.0%	77.4%
Total Plant Cost (MM$)	$1,160	$1,337	$1,053
Total Plant Cost ($/kW)	$3,560	$5,095	$4,083
LCOE ($/MWh)	185.65	257.06	167.76

5.3 TECHNO-ECONOMICS OF COFIRING WITH 90 PERCENT CAPTURE

5.3.1 Technical Results-Maximum Capture Cases

It has been established that the limited life cycle emissions decrease as the proportion of switchgrass in the feedstock increases. Exhibit 5-23 shows that plants utilizing a maximum overall capture rate of 90 percent will eventually realize negative limited life cycle emissions upon increasing the switchgrass percentage. This point occurs at approximately 30% and 18% switchgrass for Illinois #6 and PRB cofired plants respectively. As the switchgrass feed is further increased, net life cycle GHG emission become negative indicating that the switchgrass cultivated for fuel removes more atmospheric CO_2 during photosynthesis than the plant releases over the limited life cycle. Additional observations follow:

> Biomass cofiring coupled with conventional CCS is the only way to reach a carbon-negative footprint.

- The lowest possible emissions for the 100% Illinois #6 and 100% PRB plants are 410 and 327 lb CO_2e/net-MWh, respectively.
- At the maximum logistical switchgrass feed (5,000 dry TPD), emissions are -755 lb CO_2e/net-MWh in the Illinois #6 case and -890 lb CO_{2e}/net-MWh in the PRB coal case.

Exhibit 5-23 Max-Capture Limited Life Cycle Emissions

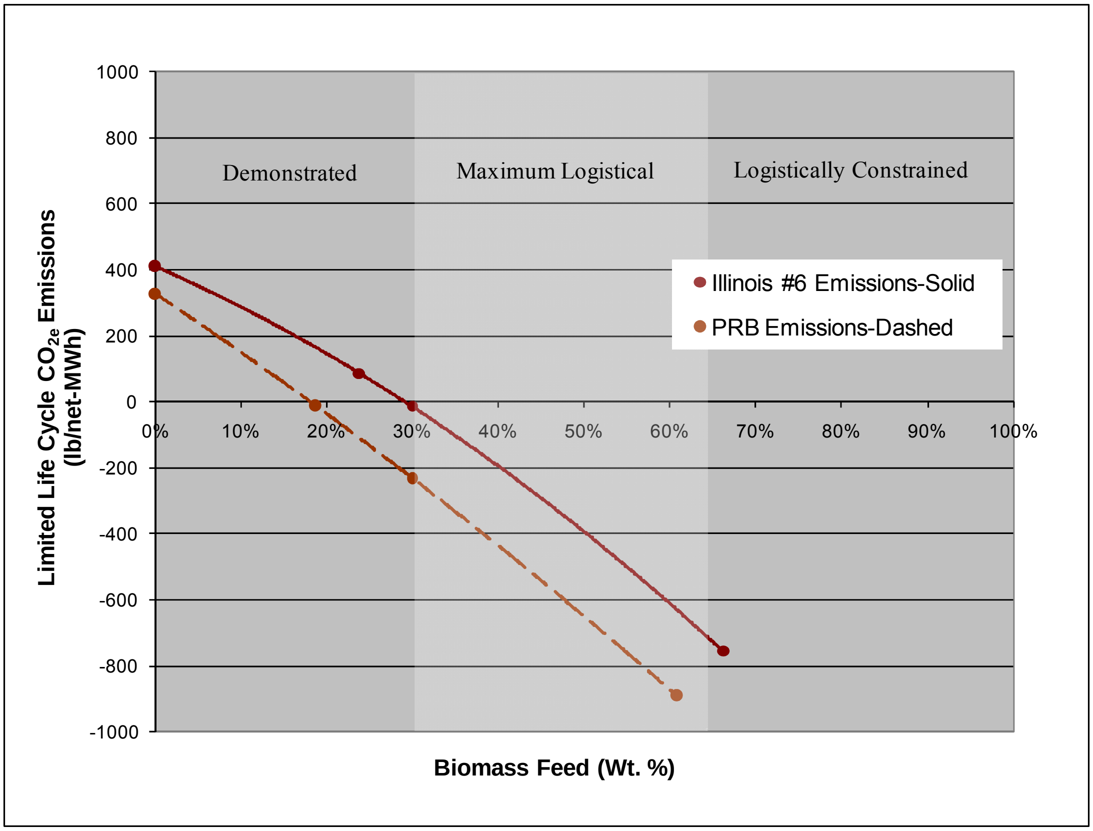
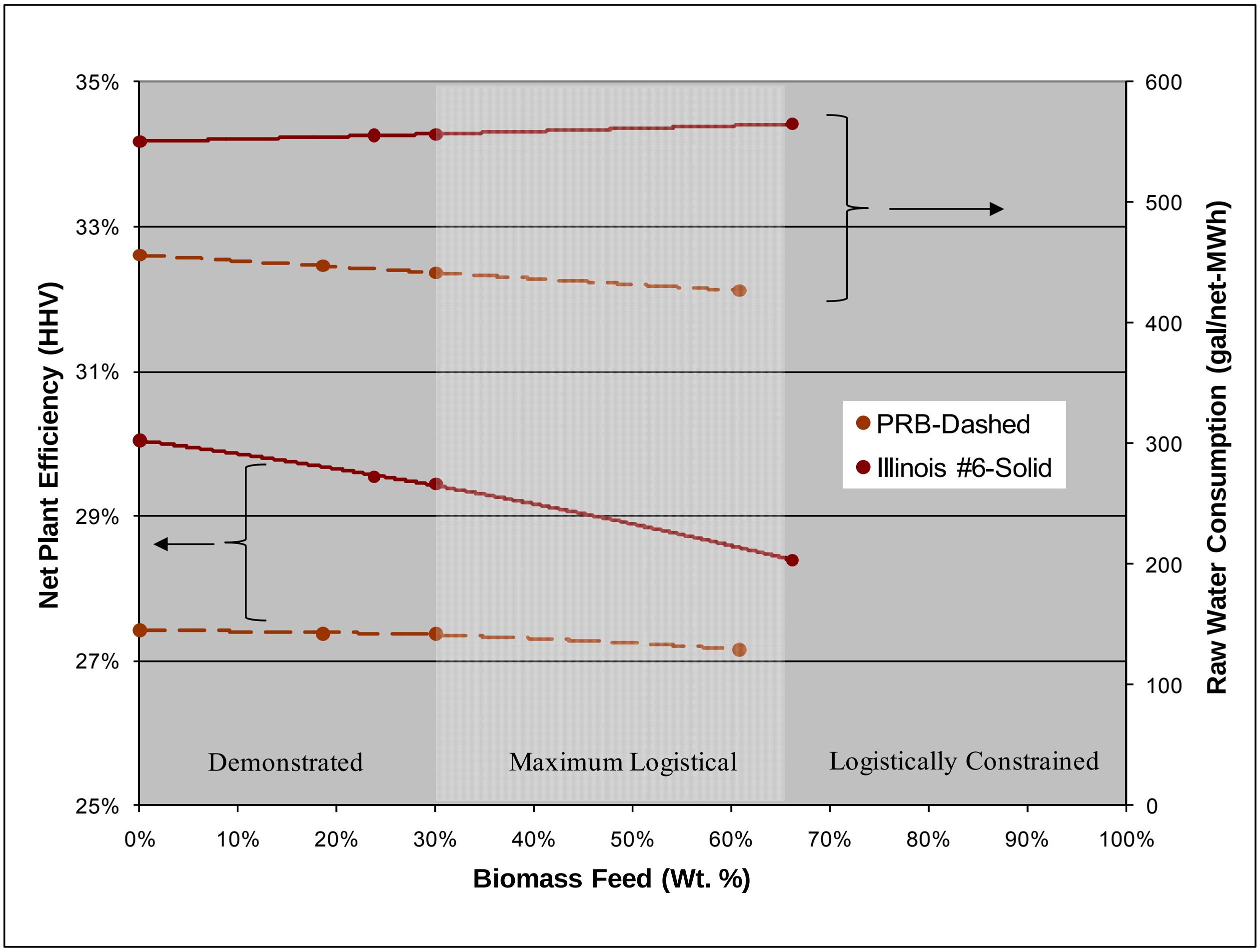


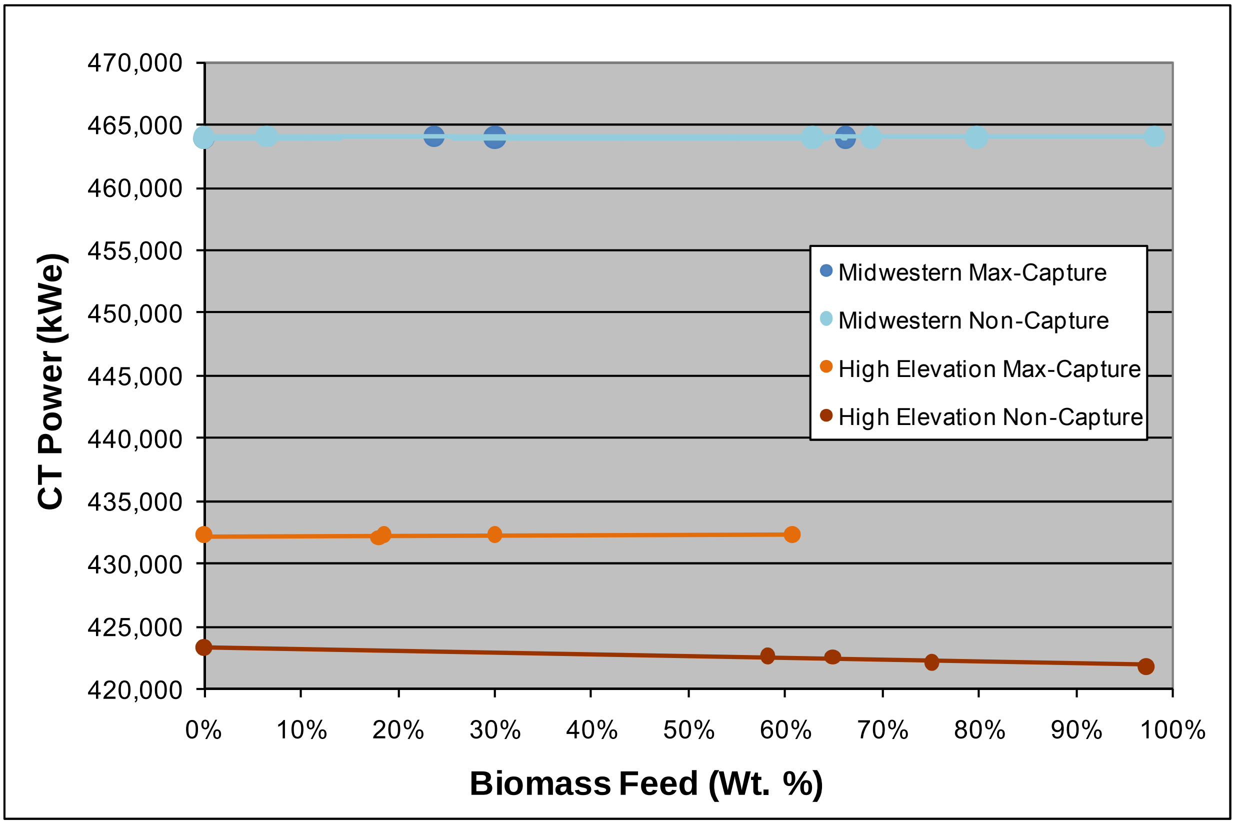
Exhibit 5-24 relates the net plant efficiency and normalized raw water consumption of maximum capture plants (cases 6Sx and 6Bx) to the feed composition. As explained earlier, plant raw water consumption normalized to net plant output decreases for increasing switchgrass at a particular emission level. However, when comparing maximum capture cases, this benefit is diminished because of the decrease in plant efficiency. Only a slight reduction in raw water consumption is realized in the PRB max capture cases. In the Illinois #6 cases, the efficiency penalty outweighs the benefit offered by the switchgrass resulting in an increase in raw water consumption.

Exhibit 5-24 Max-Capture Plant Performance



Feed composition also plays a role in the performance of the combustion turbine depending on the capture scenario. The effects are clear when the CT power output is plotted at the high elevation cases where the CT is compressor flow limited and the power output may vary. At the sea-level Midwestern location, the CT is restricted by its maximum power output and is consistent regardless of the feed composition. Exhibit 5-25 shows that for high-elevation plants employing maximum capture where 100 percent of the synthesis gas is shifted, the power output of the combustion turbine is virtually unaffected by changes in feed composition. However, in non-capture plants, where none of the synthesis gas is shifted, increasing the amount of switchgrass in the feed degrades the CT performance. Increasing the quantity of the lower quality switchgrass fuel in the feed decreases the gasifier's cold gas efficiency and hence the LHV of the synthesis gas. This is not the case for the maximum capture cases where all of the synthesis gas, regardless of initial composition, is shifted to a high-H_2 fuel.

Exhibit 5-25 Combustion Turbine Performance



5.3.2 <u>Economic Results-Maximum Capture Cases</u>

The LCOE for plants employing 90% carbon capture shows the expected increase as the switchgrass proportion is increased. The LCOE for the PRB cases is consistently higher because of the lower overall net plant efficiency. The TPC (MM$) also resembles the trend described for the cases meeting emission targets. However, the TPC ($/kW) increases, unlike the trend observed from the cases operating at each of the emission targets. Recall that, in contrast to cases with a fixed GHG footprint, cases utilizing a constant capture rate experience plant efficiency decreases as switchgrass is increased. This behavior is the reason TPC ($/kW) increases as switchgrass feed increases in the maximum capture cases.

Exhibit 5-26 Max-Capture LCOE

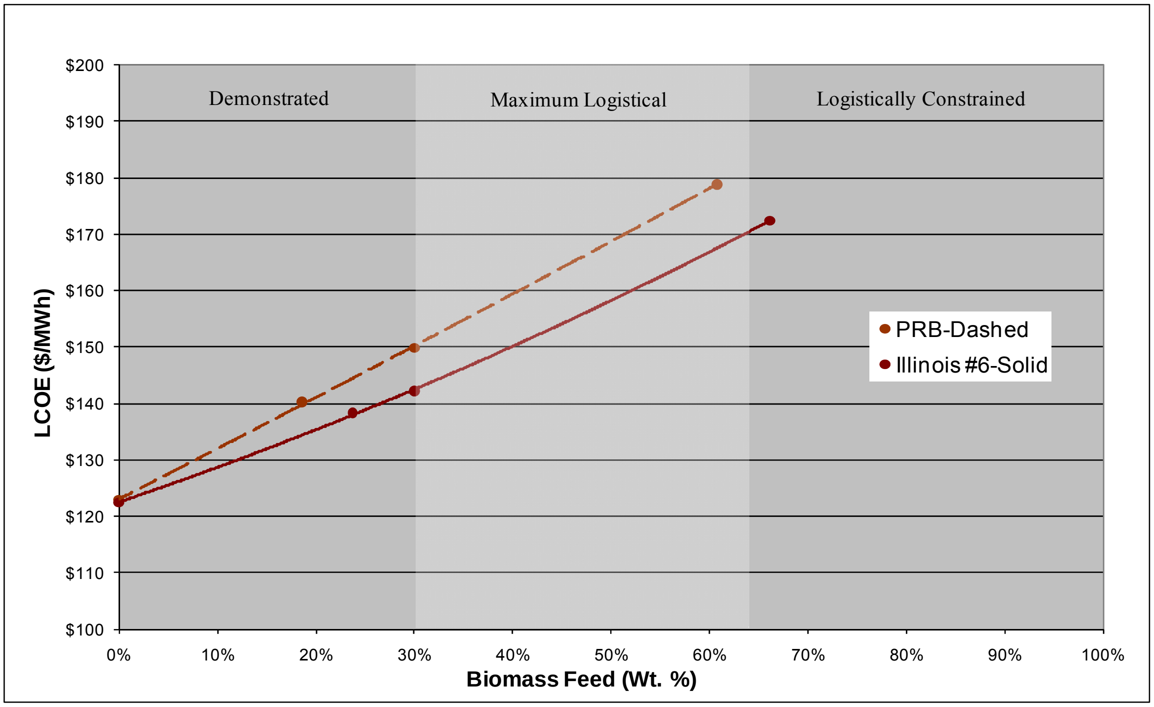
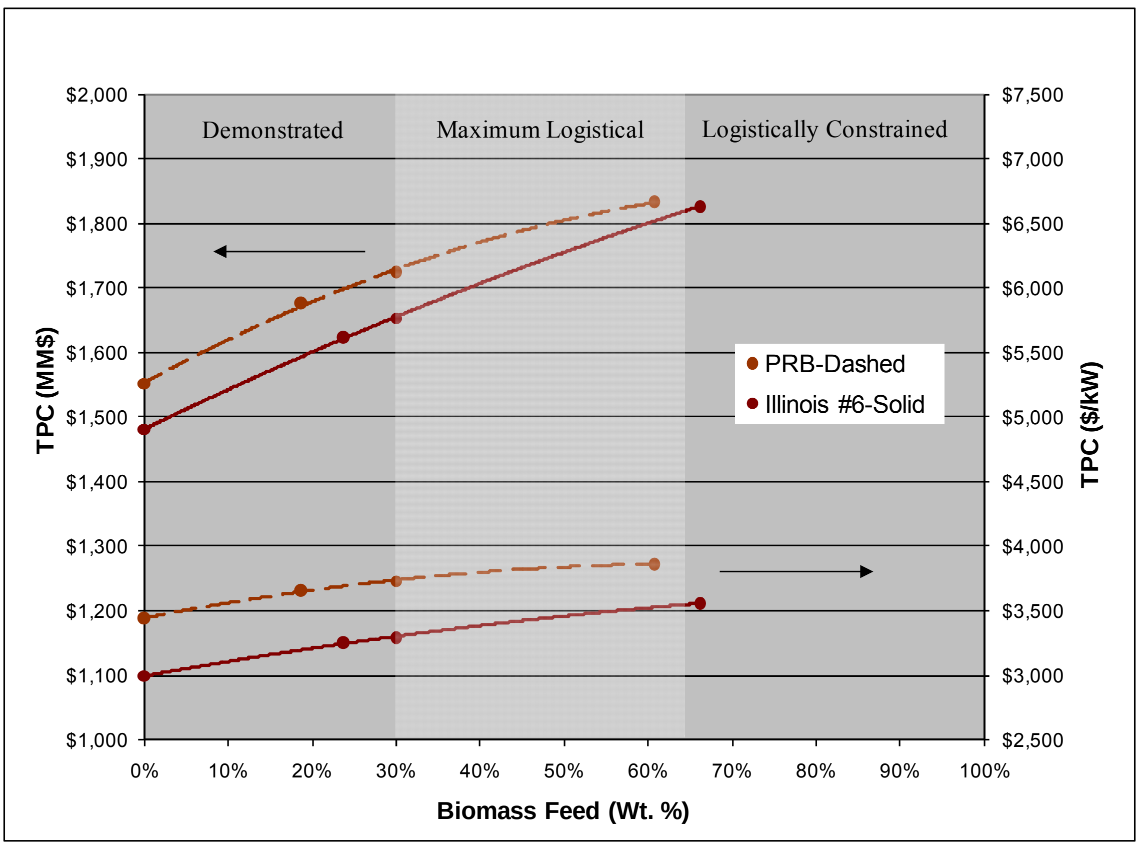


Exhibit 5-27 Maximum Capture TPC



5.3.3 Results for Cases 6S1 through 6S4 and 6B1 through 6B4

Exhibit 5-28 displays results for IGCC systems employing maximum conventional carbon capture and varying degrees of biomass co-firing.

Exhibit 5-28 Results for Maximum Capture IGCC Cases

	6S1	6S2	6S3	6S4	6B1	6B2	6B3	6B4
CO_2e Emitted (lb/MWh)	327	-11	-231	-890	410	86	-14	-755
Biomass Feed Percentage (wt % of total feed)	0.0%	18.6%	30.0%	60.7%	0.0%	23.7%	30.0%	66.2%
Net Auxiliary Load (kWe)	202,550	208,180	212,040	224,020	190,620	199,610	202,050	223,230
Net Plant Power (kWe)	451,050	457,920	462,760	474,380	494,580	499,590	501,550	513,470
Net Plant Efficiency (HHV)	27.4%	27.4%	27.4%	27.2%	30.0%	29.5%	29.4%	28.4%
Net Plant Heat Rate (HHV) (kJ/kWhr (Btu/kWhr))	13,131 (12,446)	13,148 (12,462)	13,152 (12,466)	13,256 (12,565)	11,981 (11,355)	12,187 (11,551)	12,225 (11,587)	12,679 (12,018)
Coal Feed Flowrate (kg/hr (lb/hr))	297,324 (655,487)	256,906 (566,380)	229,519 (506,002)	143,842 (317,117)	218,367 (481,416)	190,730 (420,487)	181,763 (400,719)	113,772 (250,825)
Biomass Feed Flowrate (kg/hr (lb/hr))	0 (0)	58,664 (129,333)	98,365 (216,858)	222,349 (490,196)	0 (0)	59,309 (130,755)	77,898 (171,737)	222,349 (490,196)
Thermal Input (kWth)	1,645,182	1,672,417	1,690,661	1,746,814	1,645,946	1,691,273	1,703,182	1,808,454
Condenser Duty (GJ/hr (MMBtu/hr))	1,319 (1,250)	1,382 (1,310)	1,424 (1,350)	1,551 (1,470)	1,382 (1,310)	1,445 (1,370)	1,467 (1,390)	1,646 (1,560)
Raw Water Withdrawal (m3/min (gpm))	15.8 (4,163)	15.8 (4,165)	15.8 (4,168)	15.8 (4,175)	21.1 (5,576)	21.6 (5,715)	21.8 (5,750)	22.9 (6,043)
Plant Carbon Capture	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%
Total Plant Cost (MM$)	$1,552	$1,676	$1,724	$1,833	$1,481	$1,625	$1,653	$1,827
Total Plant Cost ($/kW)	$3,440	$3,661	$3,726	$3,864	$2,995	$3,252	$3,295	$3,558
LCOE ($/MWh)	122.96	140.25	149.82	178.87	122.50	138.28	142.21	172.44

5.4 CAPTURING LOW LEVELS OF CO_2

In order to determine if there is any benefit to adding biomass to capture relatively small amounts of CO_2 Exhibit 5-29 compares the LCOE breakdown of case 7B1, which employs no WGS and only captures CO_2 produced in the gasifier, with case 7B2. Case 7B2 feeds enough switchgrass to match the life cycle emissions of case 7B1 without CCS. The LCOE for both cases are competitive with one another signifying that cofiring small proportions of switchgrass can provide a means of reducing CO_2 emissions at reasonable costs for low levels of CO_2 capture. The differences being the slight increase in fuel cost in 7B2 and the slight capital increase in 7B1. Case 7B2 also has no associated TS&M costs. While adding biomass at these GHG reduction levels is cost competitive with conventional CCS, the environmental impact is comparatively small and should not be considered a significant mitigation strategy.

Exhibit 5-29 LCOE at Low Capture vs. Low Switchgrass Feeds

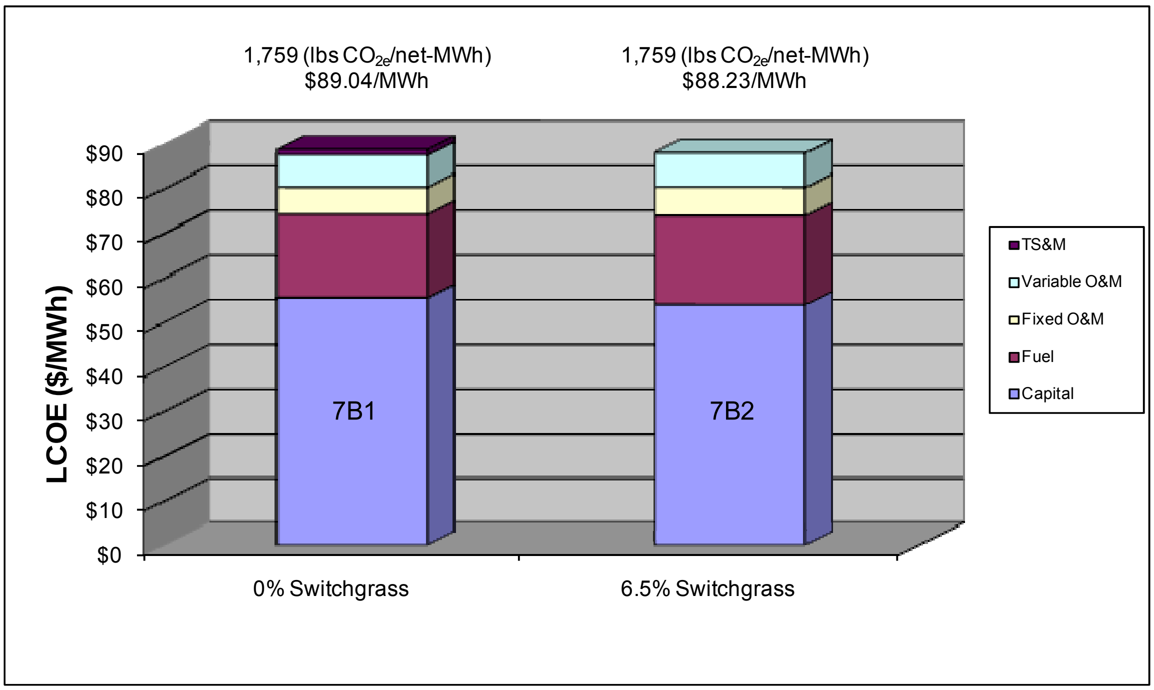


Exhibit 5-30 gives the results for cases employing low levels (4-5%) of CO_2 reduction.

Exhibit 5-30 Results for Cases 7B1 and 7B2

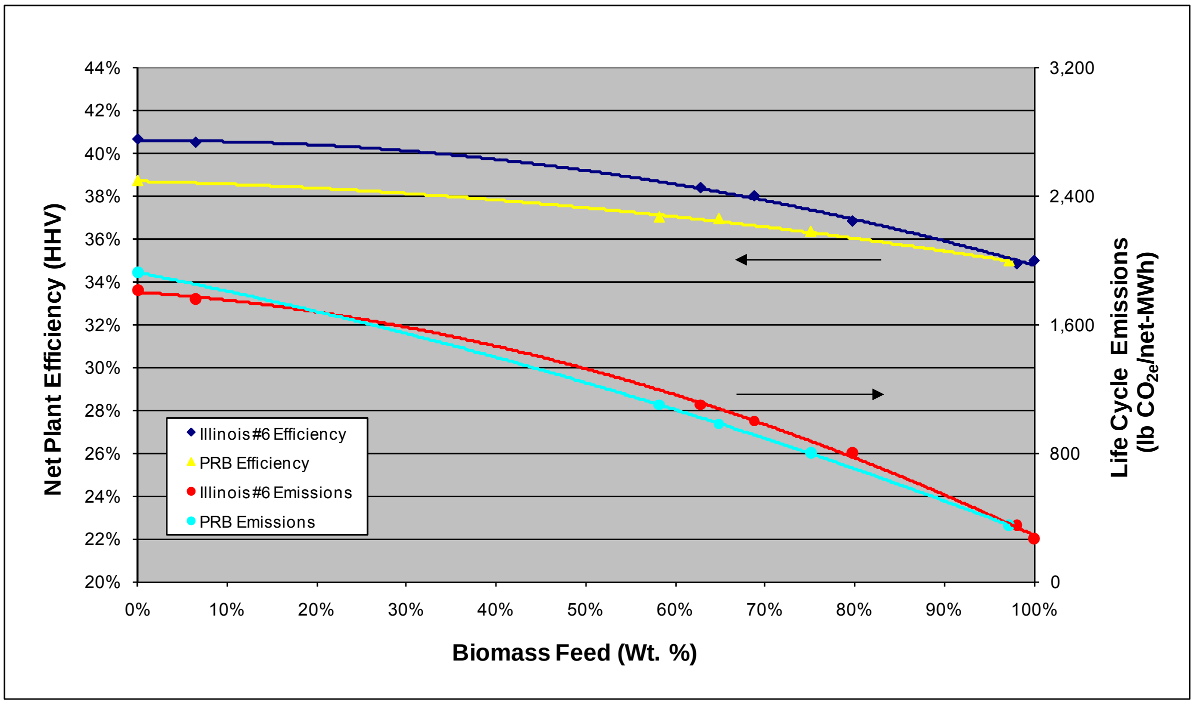
	7B1	7B2
CO_2e Emitted (lb/MWh)	1,759	1,759
Biomass Feed Percentage (wt % of total feed)	0.0%	6.5%
Net Auxiliary Load (kWe)	125,150	123,260
Net Plant Power (kWe)	626,550	628,640
Net Plant Efficiency (HHV)	40.2%	40.5%
Net Plant Heat Rate (HHV) (kJ/kWhr (Btu/kWhr))	8,952 (8,485)	8,893 (8,429)
Coal Feed Flowrate (kg/hr (lb/hr))	206,703 (455,701)	198,257 (437,081)
Biomass Feed Flowrate (kg/hr (lb/hr))	0 (0)	13,698 (30,200)
Biomass Feed Percentage (wt % of total feed)	0.0%	6.5%
Thermal Input (kWth)	1,558,028	1,552,950
Condenser Duty (GJ/hr (MMBtu/hr))	1,551 (1,470)	1,530 (1,450)
Raw Water Withdrawal (m3/min (gpm))	15.2 (4,015)	15.3 (4,046)
Plant Carbon Capture	4.3%	0.0%
Total Plant Cost (MM$)	$1,396	$1,362
Total Plant Cost ($/kW)	$2,228	$2,166
LCOE ($/MWh)	89.04	88.23

5.5 BIOMASS COFIRING WITHOUT CO_2 CAPTURE

Examining performance characteristics of plants with identical carbon capture rates, as opposed to identical emission levels, reveals correlations not seen otherwise. Exhibit 5-31 shows the relationships that the net plant efficiency and limited life cycle GHG emissions have with the feed composition for all non-capture case varieties (summarized in Exhibit 4-10). By simply adding switchgrass as a carbon mitigation strategy, plant efficiency suffers as the switchgrass proportion is increased. Since switchgrass is a lower quality fuel than both Illinois #6 and PRB coal, cofiring it in plants with fixed capture rates degrades efficiency. However the efficiency penalty is smaller when cofiring with PRB, as opposed to Illinois #6, because of the smaller difference in the LHVs of the two fuels. The efficiency penalty correlations shown in Exhibit 5-1 and Exhibit 5-2 show an opposing trend because those cases target a fixed emission level and adding biomass reduces the need to capture and sequester carbon. Decreases in CCS auxiliary load are the major drivers in those earlier comparisons. The cases in this section do not employ CCS and so are not subject to these same auxiliary load savings or resultant efficiency increases. However, the cases presented here show a continuous drop in GHG emissions as a result of co-firing increases.

As expected, with no downstream CO_2 capture the emissions decrease as switchgrass feed is increased. When comparing the emissions of the 100 percent coal-fed plants, the normalized emissions are higher for the PRB plant because it produces less power at higher elevation than the Illinois #6 plant at sea level. Once the feed composition is approximately 20 percent switchgrass, the normalized emissions in the PRB cases are lower than those for the Illinois #6 cases. There is a lack of intermediate data to fill out the trends across the range of biomass feed percentages, but this phenomenon appears to be caused by a combination of factors involving; the relative ratio of renewable carbon to fossil-carbon in the composite feedstock, the relative differences in heating values between the biomass and coal feedstocks and the difference in upstream GHG emissions between the two coal types. While PRB emissions begin higher than Illinois #6 at lower biomass percentages, as the switchgrass percentage is increased, coal plays less of a role in the overall emissions so the difference between the two types of plants converges to zero, but at different rates.

Exhibit 5-31 Non-Capture Plant Performance



5.5.1 Results for Baseline Cases 8S1 and 8B1

Two baseline coal-fed, IGCC cases were included in this study for comparison to cases cofiring switchgrass. Exhibit 5-32 gives the results for these cases.

Exhibit 5-32 Results for Cases 8S1 and 8B1

	8S1	8B1
CO_2e Emitted (lb/MWh)	1,924	1,814
Biomass Feed Percentage (wt % of total feed)	0.0%	0.0%
Net Auxiliary Load (kWe)	125,330	122,000
Net Plant Power (kWe)	584,870	627,500
Net Plant Efficiency (HHV)	38.7%	40.6%
Net Plant Heat Rate (HHV) (kJ/kWhr (Btu/kWhr))	9,304 (8,818)	8,860 (8,398)
Coal Feed Flowrate (kg/hr (lb/hr))	273,175 (602,248)	204,899 (451,725)
Biomass Feed Flowrate (kg/hr (lb/hr))	0 (0)	0 (0)
Thermal Input (kWth)	1,511,558	1,544,434
Condenser Duty (GJ/hr (MMBtu/hr))	1,509 (1,430)	1,509 (1,430)
Raw Water Withdrawal (m3/min (gpm))	8.6 (2,263)	15.2 (4,023)
Plant Carbon Capture	0.0%	0.0%
Total Plant Cost (MM$)	$1,367	$1,311
Total Plant Cost ($/kW)	$2,337	$2,089
LCOE ($/MWh)	81.44	84.73

5.6 FLOW OF LIFE CYCLE GREENHOUSE GASES

In order to provide visual representations of the major GHG flows for several cases in this study, Sankey diagrams are presented. These diagrams are intended to represent relative flows of GHGs created within and carried outside each system life cycle boundary. They are not meant to provide complete mass balances of each system.

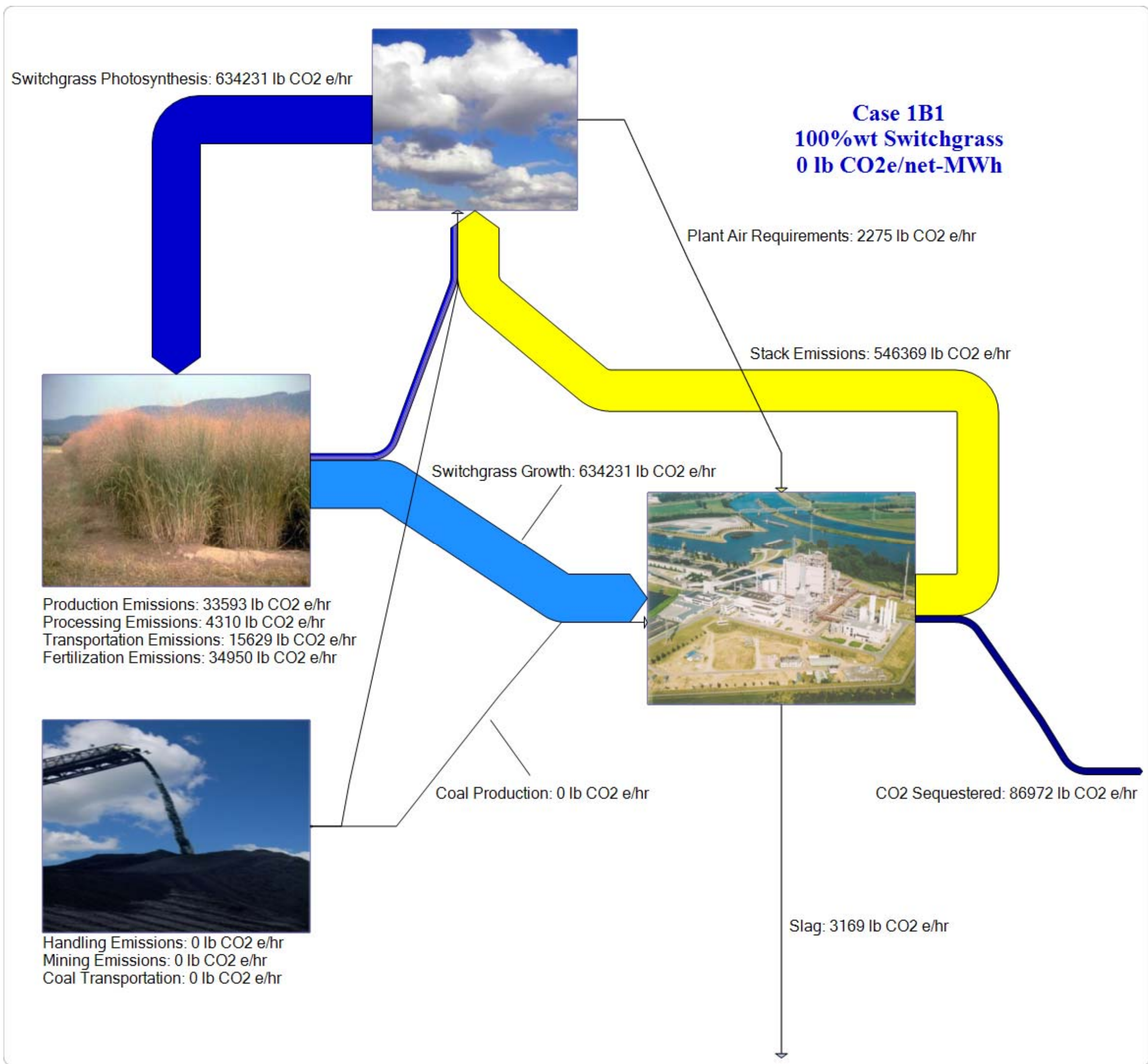
CO_2 equivalent values (expressed on a lb CO_2e/hr basis) are assigned to each material stream in order to provide an equal basis comparison among streams. The values given to carbon containing streams such as coal, switchgrass, and slag are representative of the amount of CO_2 that would be created if all of the carbon in the stream was fully oxidized to CO_2; since this is indeed the fate of nearly all carbon in the feedstock, expressing these streams as the aforementioned GHG "potential" is appropriate. Streams containing non-CO_2 GHG emissions, such as N_2O from N-fertilizer denitrification and methane from coal bed degassing, are converted to CO_2 equivalent values by using their CO_2 global warming equivalent values. Stack emissions from the plant include CO_2 from the HRSG exhaust as well as from the fuel dryer incinerator stack. CO_2 equivalent values for non-stack emissions, as illustrated in Exhibit 2-13, result from coal and switchgrass production and are also shown. A CO_2 credit equal to the CO_2 equivalent value of the switchgrass fed to the plant is given in cases cofeeding switchgrass. This credit represents CO_2 absorbed from the atmosphere via photosynthesis by the regrowth of the switchgrass feed. It should be noted that CO_2 is the sole GHG able to be credited to switchgrass photosynthesis. Net life cycle emissions cross the life cycle boundary.

Eleven Sankey diagrams are presented below with boundaries representing limited life cycle boundaries of specific case studies. Specific study cases were chosen in order to illustrate the effects that carbon capture, switchgrass feed rates, and coal type have on the life cycle emissions of significantly different plant arrangements.

5.6.1 100 Percent Switchgrass

Exhibit 5-33 is the Sankey diagram for case 1B1 which is a 100% switchgrass fed plant operating at 0 lb CO_2e/net-MWh. Life cycle emissions here come exclusively from switchgrass production, processing, transportation and fertilization as well as from the switchgrass fuel itself. In order to reach 0 net emissions, the amount of CO_2 captured from the plant, including slag, must be equal to the emissions created outside of the plant because these are not included in the switchgrass CO_2 credit.

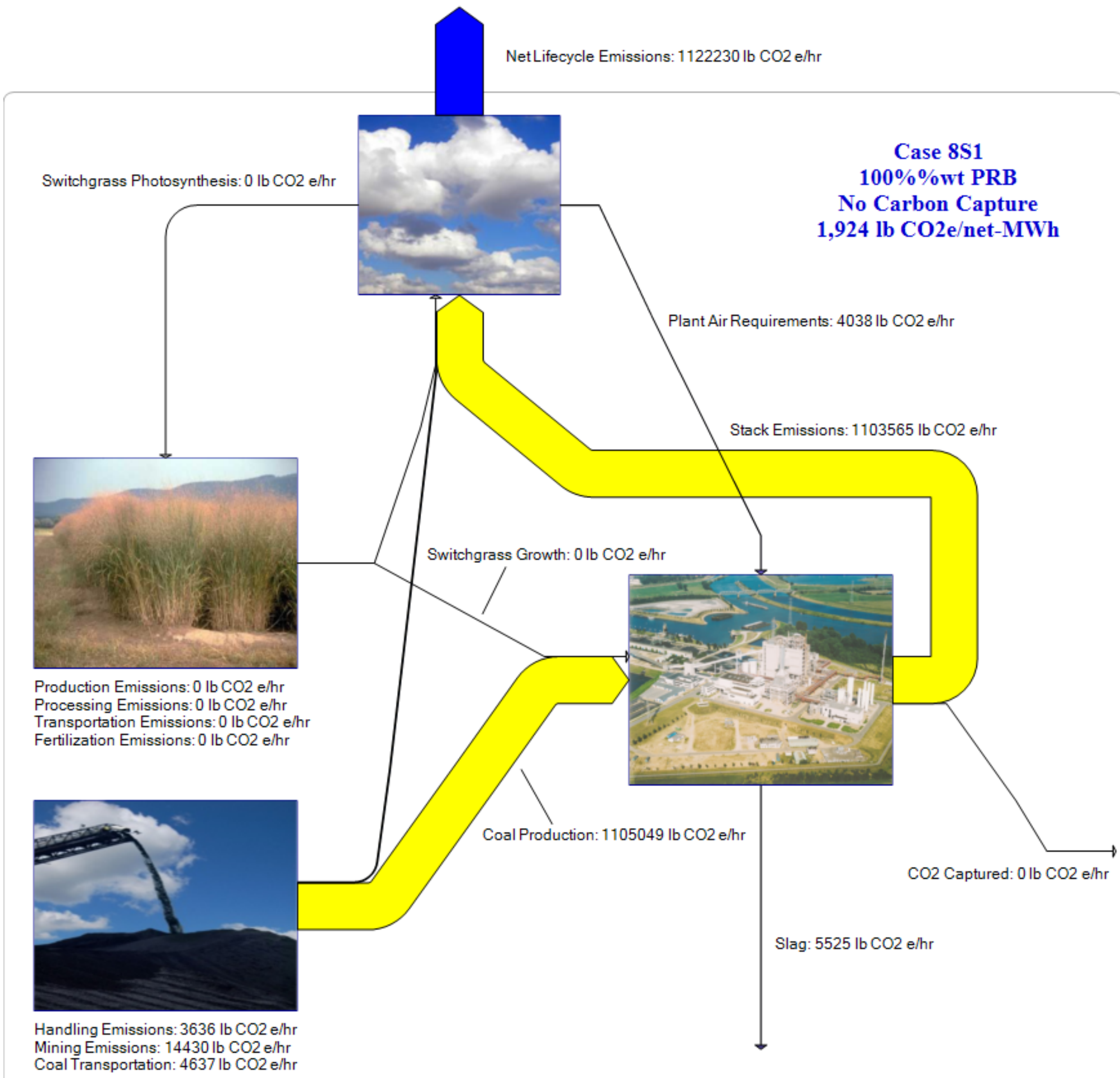
Exhibit 5-33 Case 1B1 Sankey Diagram



5.6.2 100 Percent Coal without Capture

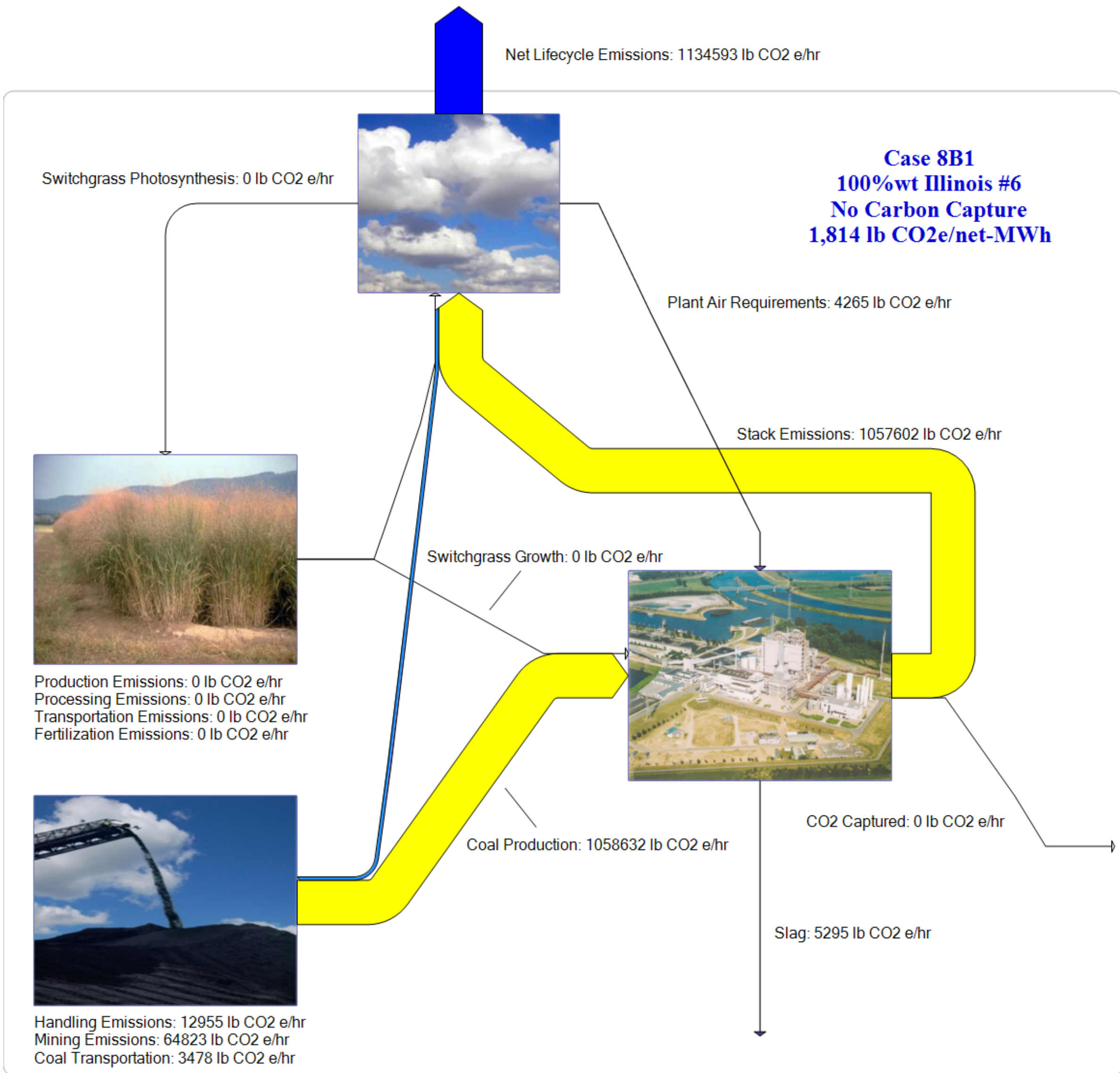
Exhibit 5-34 shows the life cycle emissions of a 100% coal case for comparison to a 100% switchgrass case to. In case 8S1 the coal feed is PRB. Emissions associated with mining the coal contribute a small but not insignificant fraction of the total GHG's produced over the life cycle. Since there is no switchgrass fed to this plant, no emissions are produced from switchgrass cultivation and no credit from switchgrass growth is given. Carbon capture is not employed in this case and consequently all of the stack emissions are released to the atmosphere.

Exhibit 5-34 Case 8S1 Sankey Diagram



Changing the coal type in a non-capture 100% coal fed plant from PRB to Illinois #6 does not change the overall flow of GHG's over the life cycle, but does change the contribution of the mining and handling emissions. The GHG footprint associated with mining Illinois #6 coal is larger compared to mining PRB coal. Illinois #6 mining and handling emissions, most significantly methane, are more prominent than those associated with surface mining PRB. This difference is small when compared to the overall plant life cycle but is noticeable when comparing emission sources based on the different coals.

Exhibit 5-35 Case 8B1 Sankey Diagram



5.6.3 <u>100 Percent Coal with 90 Percent Capture</u>

Employing a maximum or near maximum carbon capture scheme to a 100% coal fed plant was necessary in cases 4S1 and 4B1. As seen in Exhibit 5-36 and Exhibit 5-37, a large portion of the plant-produced CO_2 is captured. Only a fraction of the potential emissions are released to the atmosphere. This results in low plant emissions.

Exhibit 5-36 Case 4S1 Sankey Diagram

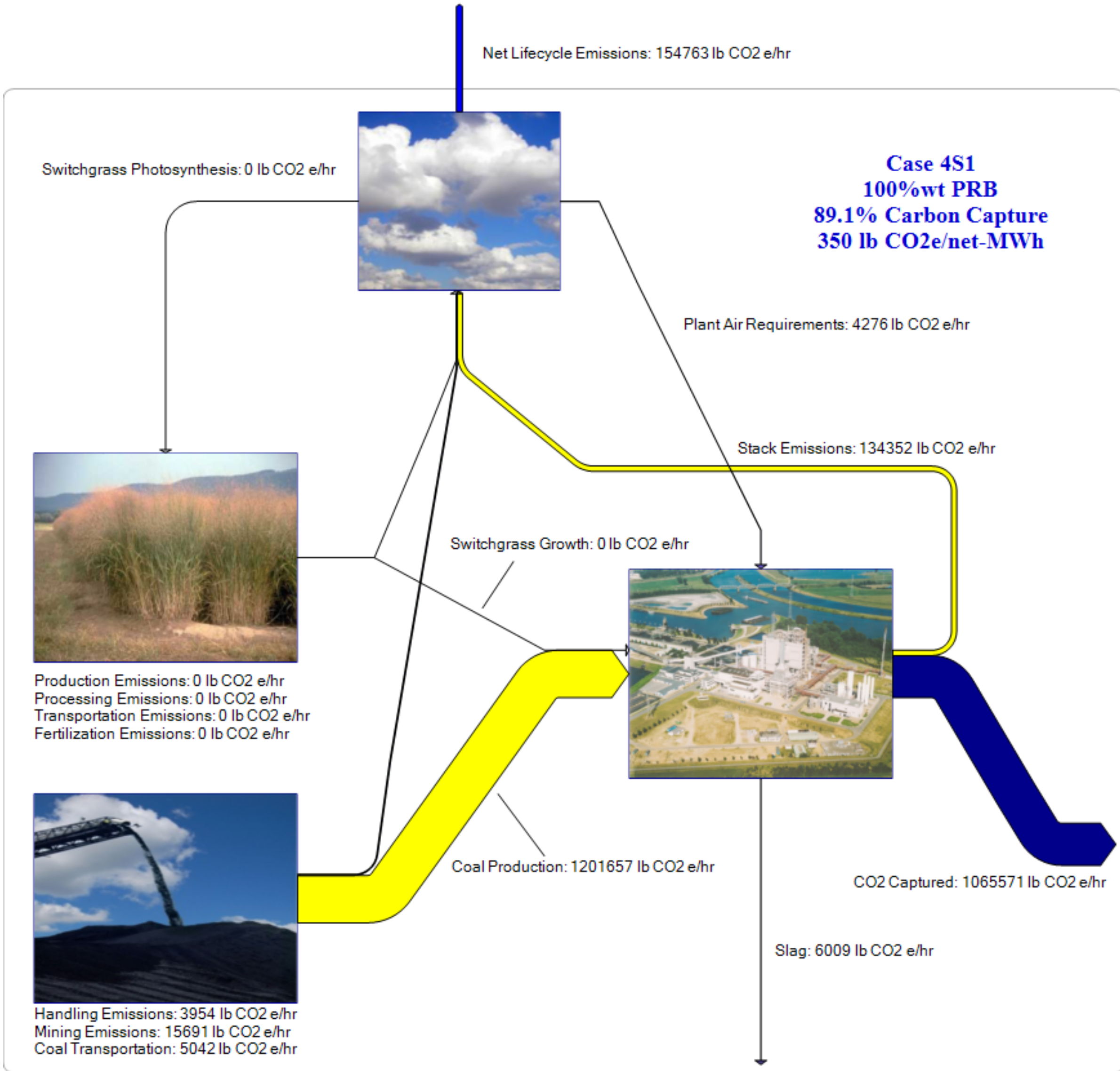
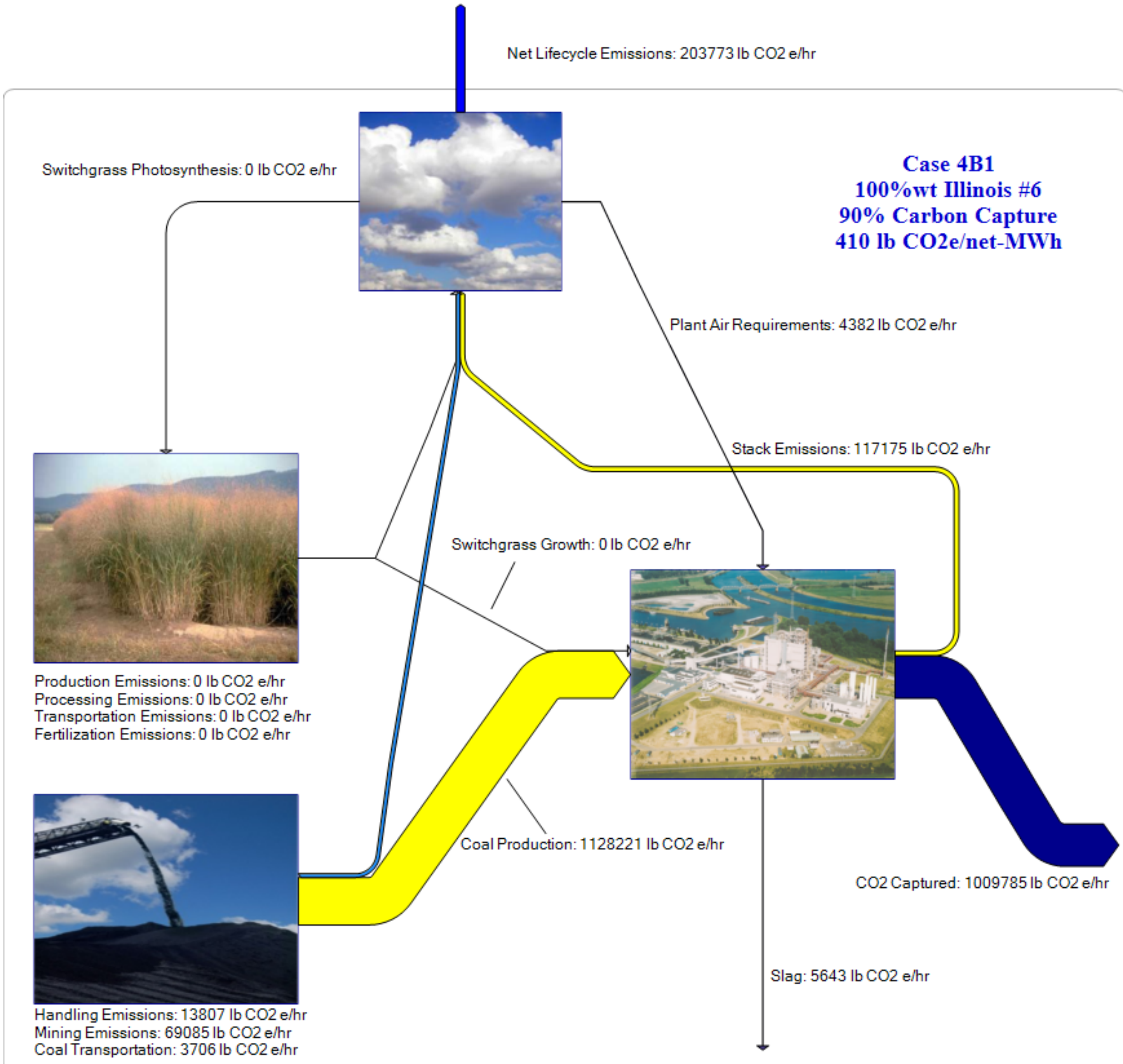


Exhibit 5-37 Case 4B1 Sankey Diagram



5.6.4 30 wt% Biomass with Net Zero Emissions

Increasing the proportion of switchgrass feed in a high capture plant introduces higher levels of life cycle emissions from the production, processing, transportation and fertilization of the switchgrass. Also introduced is a CO_2 credit equal to the amount of potential CO_2 contained in the switchgrass feed. Exhibit 5-38 and Exhibit 5-39 are each zero net emissions. Both employ large amounts of carbon capture in order to reduce stack emissions so that the total CO_2 equivalent life cycle emissions are equal to the CO_2 switchgrass growth benefit.

Exhibit 5-38 Case 1S3 Sankey Diagram

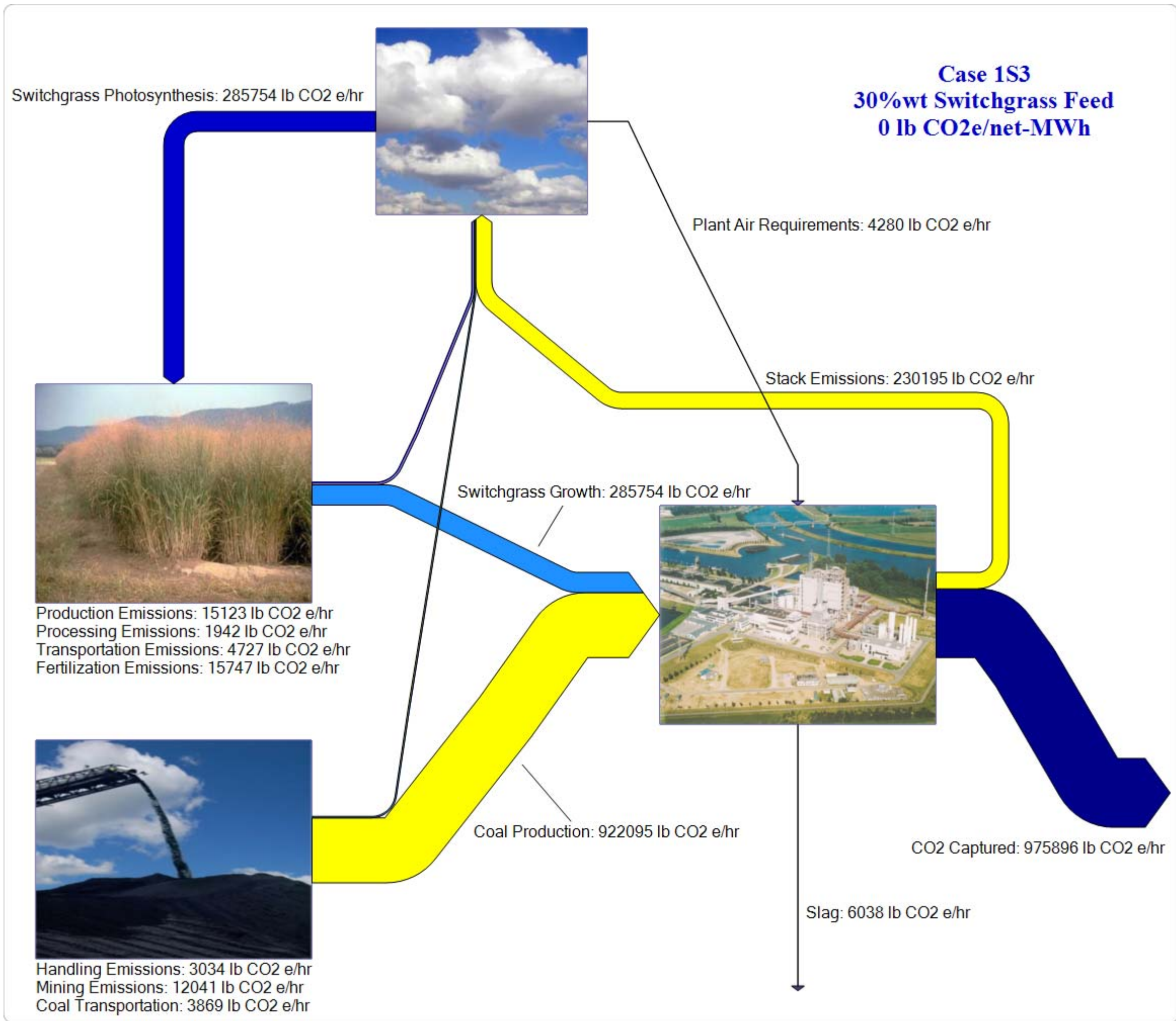
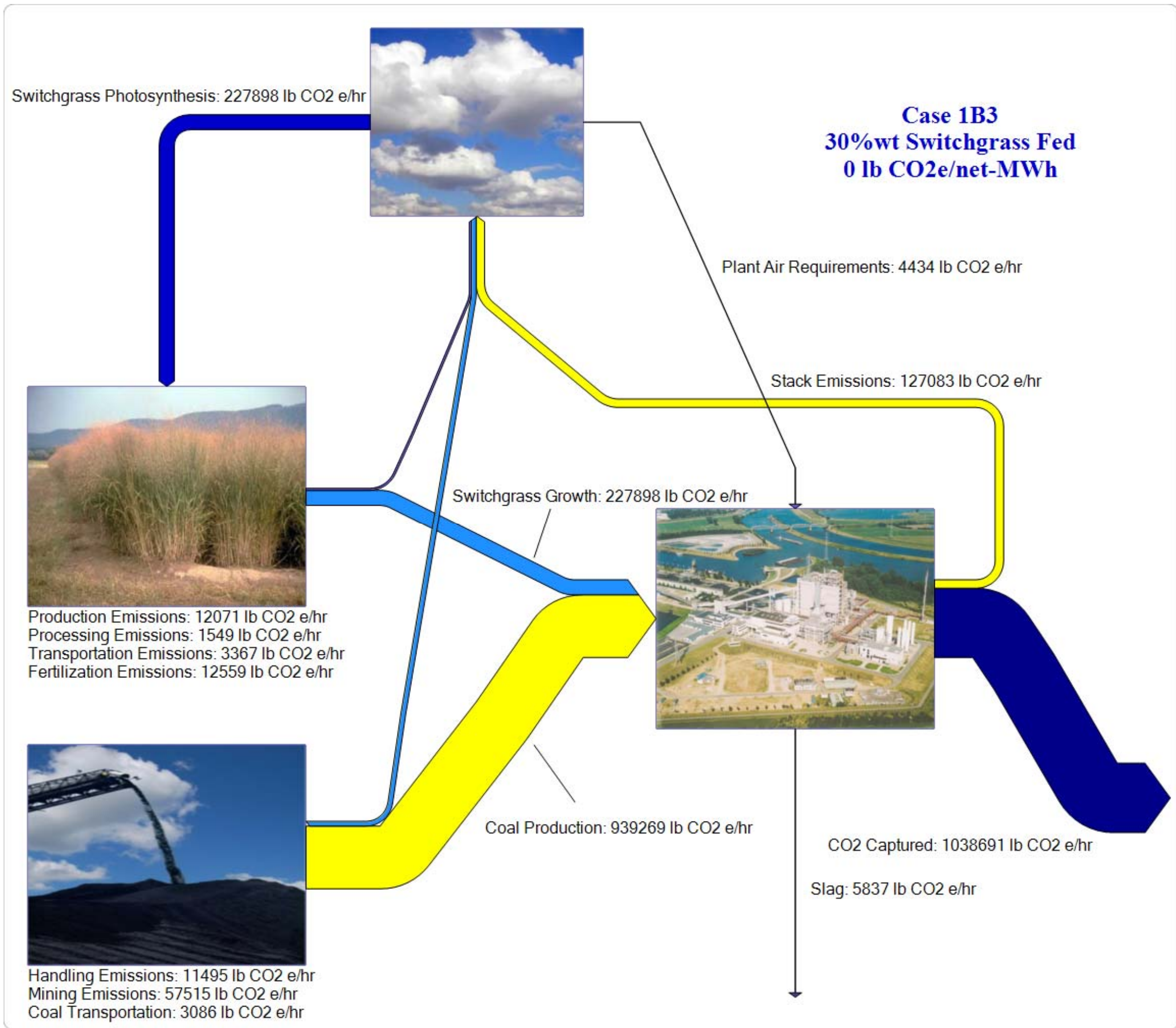


Exhibit 5-39 Case 1B3 Sankey Diagram



A smaller amount of carbon capture is required to meet CA's GHG emission standard of 1,100 lb CO_2e/net-MWh, therefore allowing the release of more CO_2 through the plant stack. Cases 2S2 and 2B2, shown in Exhibit 5-40 and Exhibit 5-41 both have feeds 30% wt. switchgrass but only employ enough carbon capture to reach the CA target. The primary difference in the drawings is the increase in stack emissions.

Exhibit 5-40 Case 2S2 Sankey Diagram

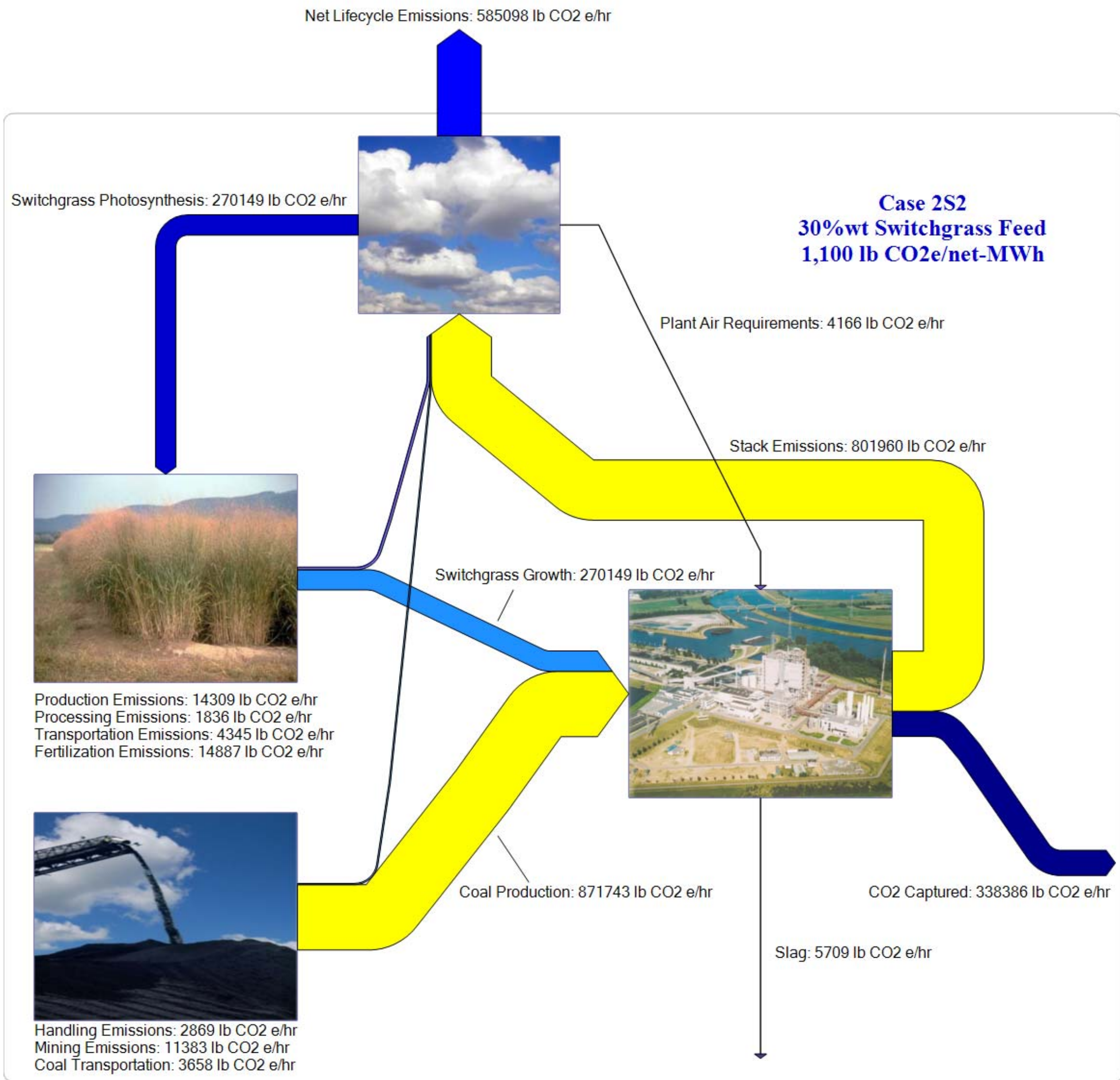


Exhibit 5-41 Case 2B2 Sankey Diagram

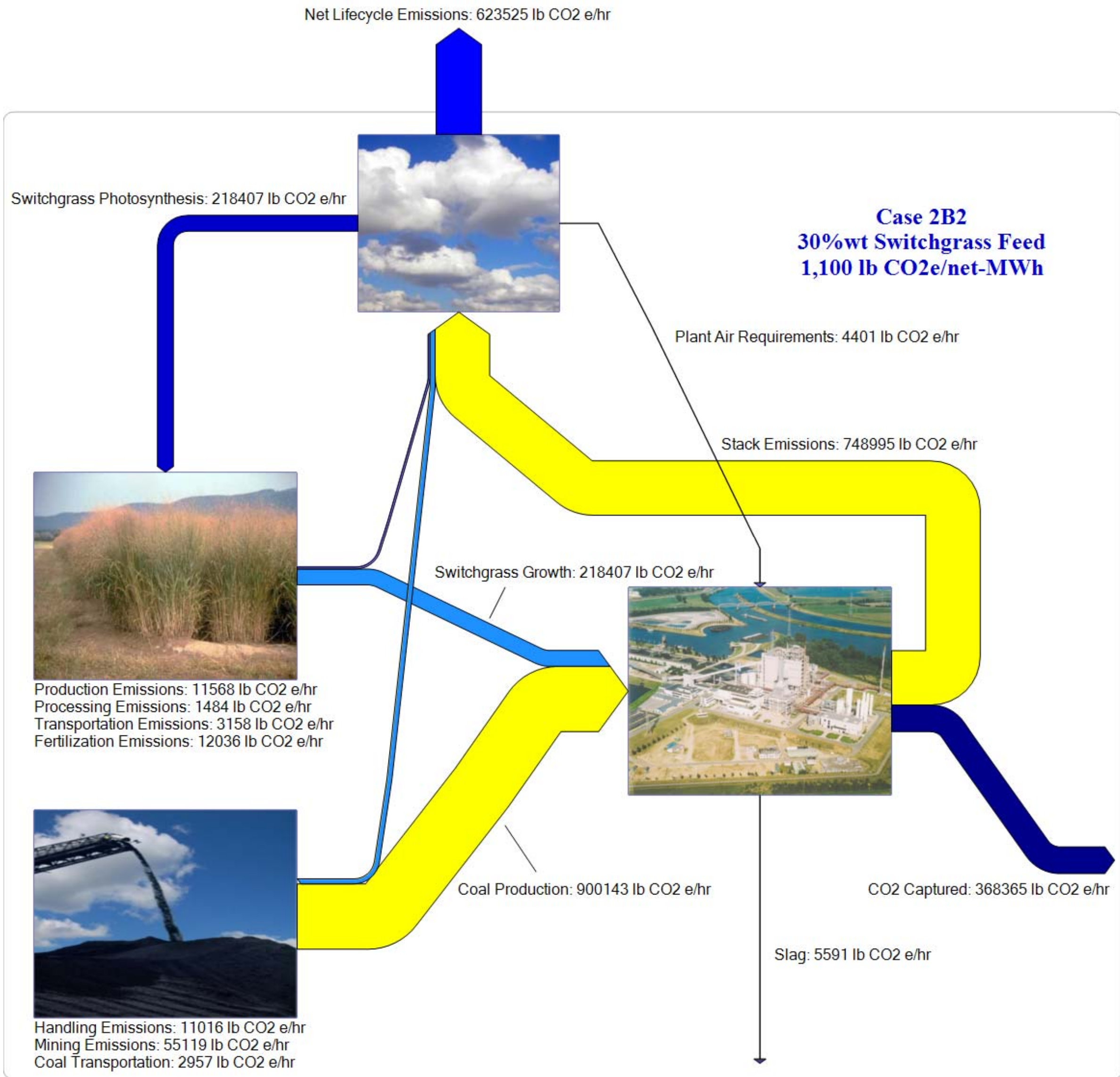


Exhibit 5-42 and Exhibit 5-43 show an extreme case of full 90% capture while cofiring the maximum logistical feed of 5,000 dry ton/day of switchgrass with PRB or Illinois #6 coal. When large amounts of switchgrass are cultivated and carbon capture is at its peak, stack emissions are reduced to the point where they only contribute approximately half of the life cycle emissions. Because of the volume of switchgrass being cultivated, the CO_2 credit from photosynthesis outweighs the GHG emissions produced. Over the limited life cycle, the plant acts as an atmospheric CO_2 sink because it emits less GHG's than it consumes from switchgrass growth.

> Cofiring biomass only slows, but can also *reverse* atmospheric GHG accumulation.

Exhibit 5-42 Case 6S4 Sankey Diagram

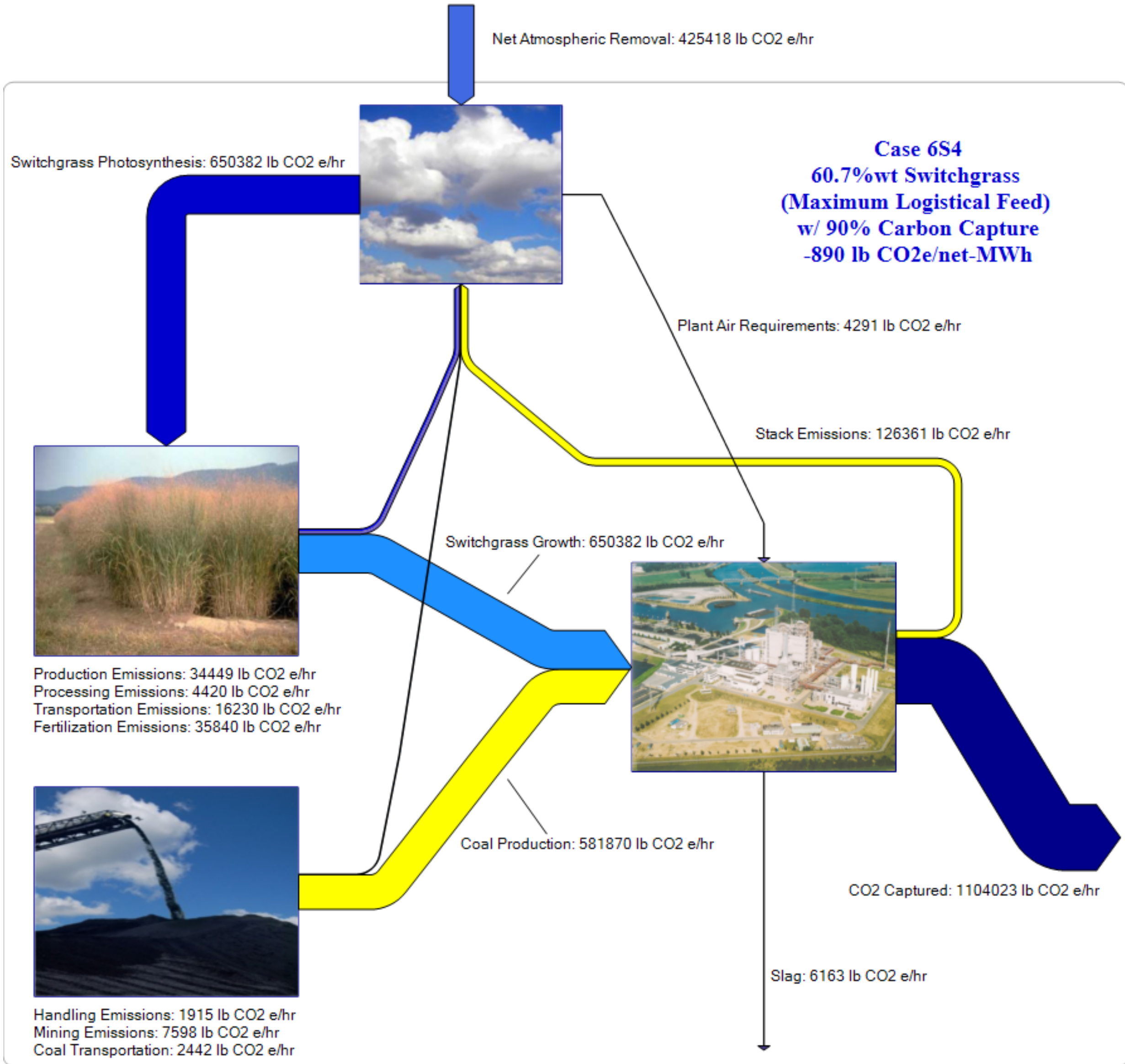
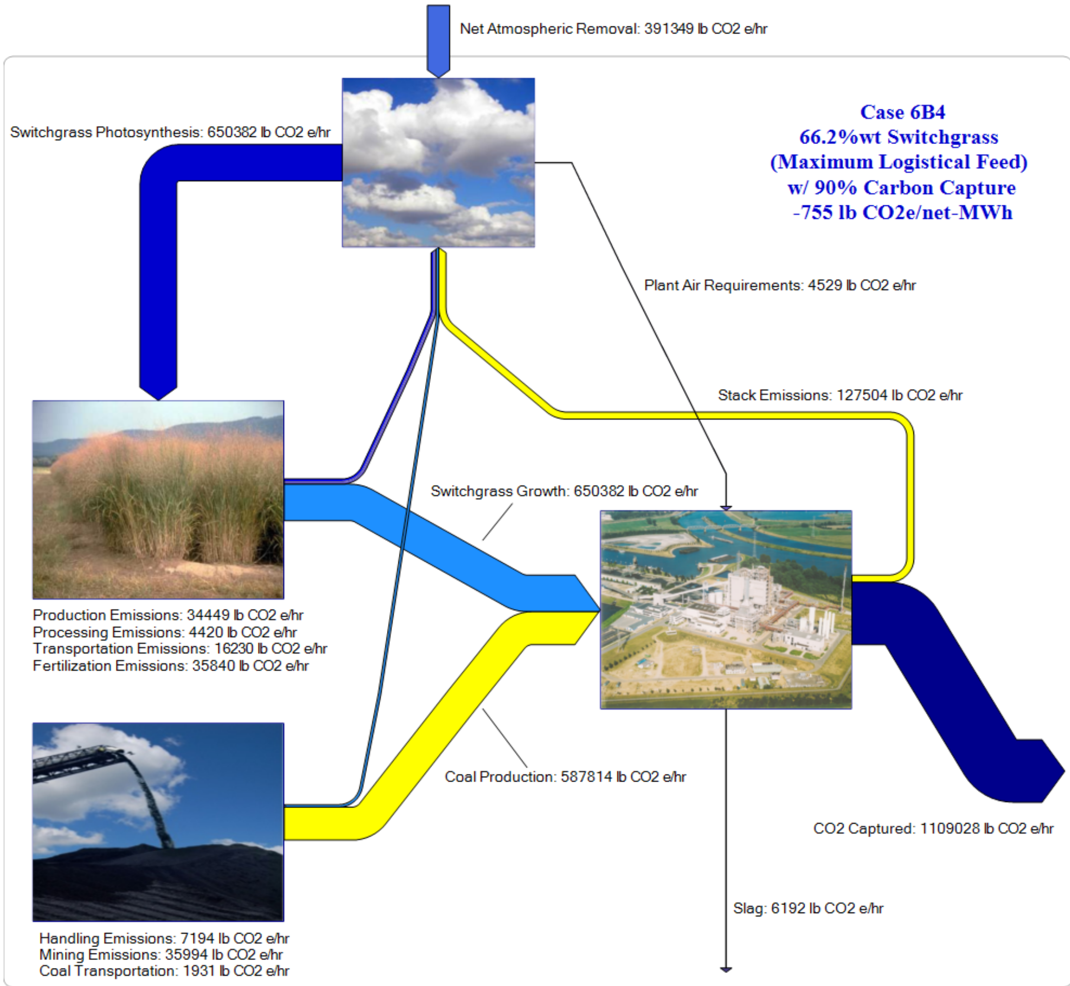


Exhibit 5-43 Case 6B4 Sankey Diagram



5.7 GHG IMPLICATIONS

As mentioned, most if not all GHG mitigation strategies increase the cost of electricity. As a result, legislation must be passed that mandates a GHG tax or cap-and-trade scenario in order to motivate real GHG reduction. In the case of a GHG tax with a "cap" set at zero emissions, all emissions might be taxed directly according to a certain rate (\$/ton CO_2e). If the plant were to cofire a carbon-neutral biomass, the CO_2 associated with the biomass would not be taxed. GHG taxes could also extend beyond the plant to cover emission sources from coal mining, and in the realm of this study, emissions from switchgrass cultivation. Taxes accumulated prior to the plant gate by mining companies and/or farmers would inevitably be passed along to the power plant, most likely in the form of higher coal and switchgrass prices. Consequently, the production cost of electricity would increase, and in turn, the LCOE paid by the customer.

When switchgrass is co-fed, the level of impact that the GHG tax has depends on the amount of GHG the plant emits over the defined life cycle. Some of the factors influencing plant GHG footprint are the level of plant CO_2 capture, composition of the feed, what type of coal is being mined and what type of biomass is being grown.

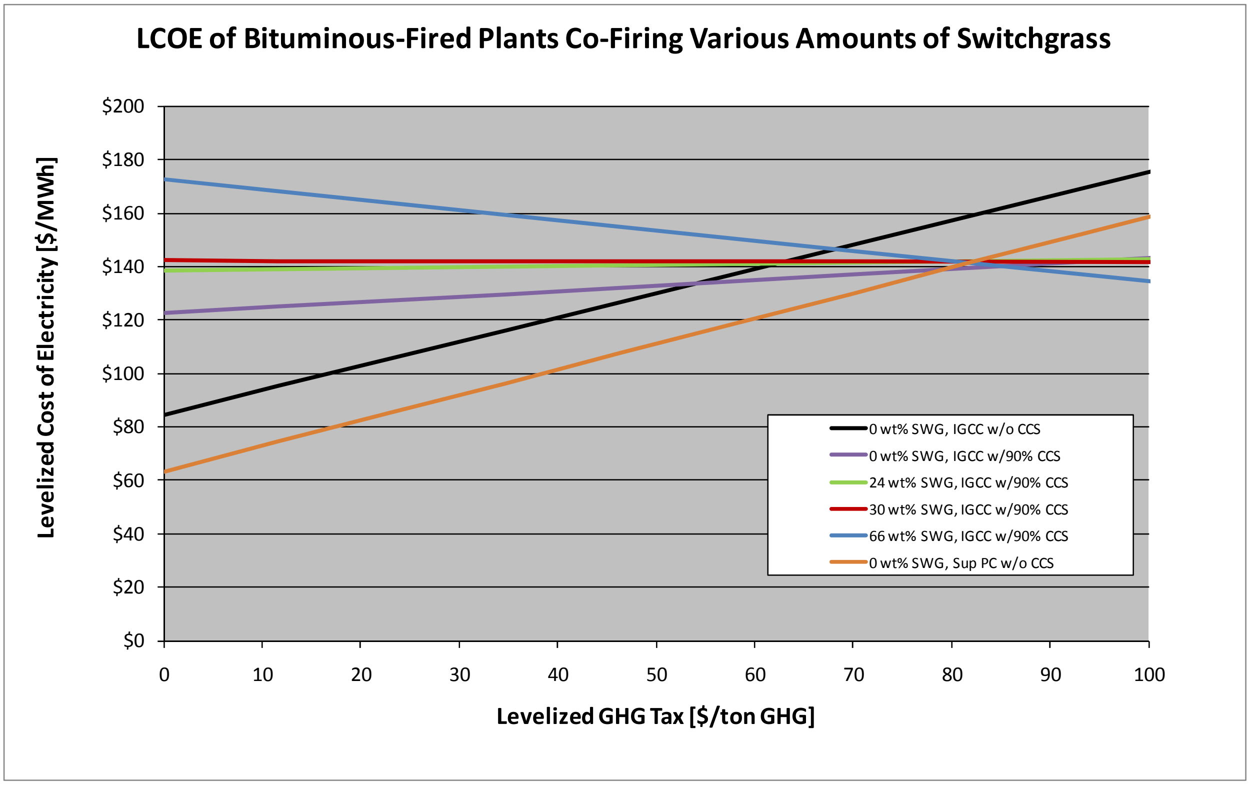
It is assumed in this study that a positive GHG footprint will result in a cost to the plant and that a negative GHG footprint will result in revenue for the plant in the form of earned GHG credits that can be sold at the same value a plant would otherwise have to pay. In other words, a GHG emissions cap was set at zero emissions. A cap set at any other emissions level will alter the economics of the below charts.

5.7.1 Sensitivity of LCOE to GHG Tax

Results above have shown that the most cost effective way to generate low GHG-power is to first employ conventional CCS technologies in a coal-only application. Only after conventional CCS has been maximized, do the economics provide a market for biomass co-firing. Therefore, this section will only highlight the IGCC plants with 90% CCS, which provide the best incentive for co-firing.

Exhibit 5-44 shows that when LCOE is the sole economic metric, there is no motivation for IGCC plants firing bituminous coal to install 90% CCS until they are made to pay at least \$47/ton GHG (~\$55/ton in levelized tax terms, as shown in the chart). However, it can be seen that Supercritical PC plants w/o CCS are the preferred power generation technology until \$79/ton GHG (levelized). Results are very similar for bituminous applications. At values below this, it is more economic to simply pay the tax and not make any effective GHG reductions. IGCC plants using the maximum capture efficiency of 90% while feeding only bituminous coal are cost competitive in a tax range between \$79/ton GHG and \$82/ton, providing a very narrow operating margin for coal-only IGCC w/CCS. Above \$82/ton, co-feeding any amount of switchgrass (preferably the maximum amount of switchgrass, where possible) becomes the most economic, encouraging GHG-negative power generation. Under the economic assumptions in this report, the LCOE at these tax levels is over two times higher than "pre-tax" LCOE's. However, at tax levels lower than this, there is no market for low-GHG power. The results here suggest that if a tax high enough to motivate low-GHG power in IGCC applications is applied, it makes the most economic sense to co-fire biomass and maximize reductions to the fullest extent possible.

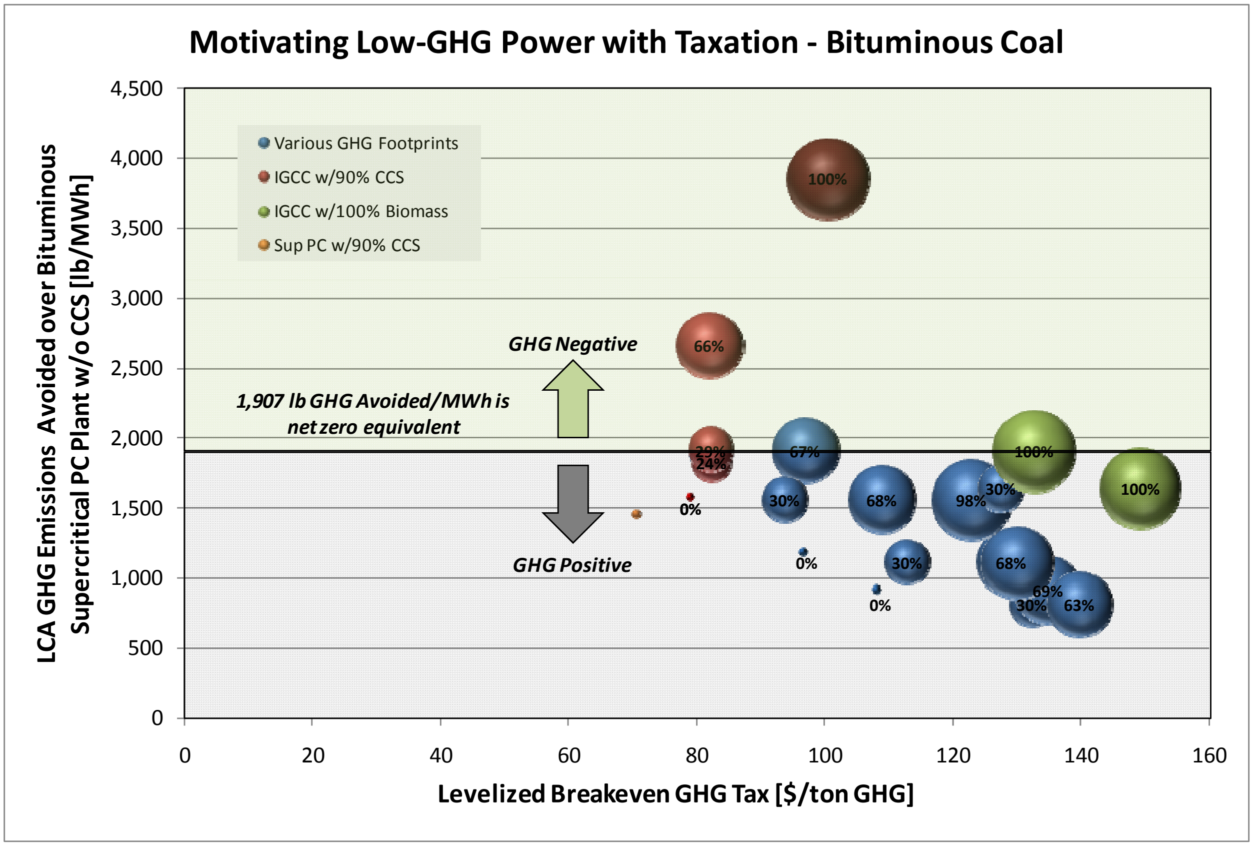
Exhibit 5-44 LCOE vs. GHG Tax at Varying Co-feed Levels (Maximum Capture)



5.7.2 Using a GHG Tax to Motivate Low-GHG Power Production

Examining only LCOE does not provide complete perspective on the degree to which a GHG tax promotes low-GHG footprints for power generation. Without a tax, low-GHG power generation technologies are, in general, more expensive than higher-emitting power generation technologies so there is no market for low-GHG power without taxing emissions. To show how effective a GHG tax can be in motivating low-GHG power, Exhibit 5-45 illustrates how an economic demand for low GHG power is created as tax is increased. A supercritical PC plant without CCS is the baseline for comparison in Exhibit 5-45.

Exhibit 5-45 Motivating Low-GHG Power Generation with GHG Taxes[2]



If a utility were to build its next greenfield plant to address future power needs, presumably the least expensive power generation option might be preferred. According to NETL's, "Cost and Performance Baseline for Fossil Energy Plants, Volume 1", this least expensive option is supercritical PC without carbon capture at $63.3/MWh, therefore it is chosen as the baseline in Exhibit 5-45. This system has a LCA GHG emission footprint of 1,907 lbCO_2e/MWh, such that subtracting the y-axis value for each plant configuration in Exhibit 5-45 from 1,907 gives the net GHG footprint of the respective configuration.

Exhibit 5-45 shows how an increasing tax will promote lower GHG footprints for future power generation; the size of the bubbles qualitatively represents the biomass feed weight percentage (quantified in text within the bubble). First it should be recognized that **there is no market for low-GHG, coal-fired applications represented here until the GHG tax reaches at least $71/ton**. This means paying the tax without capturing any CO_2 is the most economic option for coal based technologies at tax values less than $71/ton, at which point Supercritical PC w/90%

[2] Supercritical PC data point provided by the NETL report, "Cost and Performance Baseline for Fossil Energy Plants". The group titled, "Various GHG Emissions" represents cases produced in this study that are sub-optimal choices in the context of cost and emissions reduction.

CCS becomes cost effective with a LCA GHG footprint 80% lower than a Supercritical system w/o CCS.

The Exhibit shows that the lowest cost CBIGCC configuration is actually a coal-only IGCC plant incorporating the maximum 90% conventional CCS. While the lowest cost CBIGCC biomass feed percentage is 0% at $79/ton, this option also has the least potential for GHG mitigation of the CBIGCC options. For a relatively small (~4%) increase in GHG tax penalties, it becomes economically favorable to begin adding significant amounts of switchgrass to an IGCC system. Small GHG tax increases to ~$82/ton promote an additional 60% avoidance of the supercritical PC plant's emissions by leveraging switchgrass' carbon-neutral benefits. Taxes at this level begin to create a market for GHG-negative plants, showing a very large GHG benefit for the additional penalty. Increasing GHG tax to ~$100/ton creates a complete economic preference for switchgrass over coal as the sole IGCC plant feedstock, effectively resulting in the elimination of GHG's emitted by two equally-sized supercritical PC plants.

If GHG taxes are already high enough to begin motivating low-GHG power, there may be societal benefit in making small tax increases above this level to motivate maximum co-firing and GHG-negative plants.

5.8 COAL PRICE SENSITIVITIES

Values assumed for fuel prices impact the LCOEs and the levelized breakeven GHG tax values discussed in sections 5.1.1 and 5.7 above. The levelized breakeven GHG Tax is equivalent to the levelized GHG avoided cost. Increasing the price of coal increases the LCOE for all coal cases by varying degrees depending on the percent contribution of the annual fuel cost to the overall LCOE for each case and the ratio of coal to biomass used. Increasing coal prices can also increase the levelized breakeven GHG tax value for cases using coal but decrease it for those utilizing biomass because of the increased reference case LCOE value as shown by the following equation:

$$\text{Levelized GHG Avoided Cost} = \frac{(\text{LCOE}_{\text{Case}} - \text{LCOE}_{\text{Reference}})\ \$/\text{MWh}}{(\text{LCA GHG Emissions}_{\text{Reference}} - \text{LCA GHG Emissions}_{\text{Case}})\ \text{tons/MWh}}$$

The sensitivities of the LCOEs and levelized GHG avoided costs calculated in this study were examined by using a newly estimated coal price of $54.59/ton for Illinois #6 and $28.32/ton for Montana Rosebud (PRB). These values were estimated using minemouth and transportation data developed from Ventyx Corporation's Energy Velocity (EV) Suite, a meta-database [17], and presented in Appendix B. The values were assumed to be in 2007 dollars to simplify the sensitivity calculations. The results of the sensitivity calculations are presented in Exhibit 5-46 and illustrated in Exhibit 5-48 for the bituminous coal cases and in Exhibit 5-47 and Exhibit 5-49 for the subbituminous cases. The calculations show that the LCOE values increase between one and seven percent for a thirty percent increase in the bituminous coal price and between two and eleven percent for a 118 percent increase in the subbituminous coal price. The impact on the levelized GHG avoided costs varies between decreasing by six percent to increasing by three percent for the bituminous cases and between decreasing by ten percent to increasing by six percent for the subbituminous cases depending on the percentage of biomass included in each case. The higher the percentage of biomass the less overall impact on the GHG avoided cost.

Exhibit 5-46 Sensitivity of Costs to Bituminous Coal Price

		Original Study Coal Price = $41.94/ton			New Coal Price= $54.59/ton	
Case	% Biomass	LCOE ($/MWh)	GHG Avoided Cost ($/ton)	Emission Reduction (lb/MWh)	LCOE ($/MWh)	GHG Avoided Cost ($/ton)
1B1	100%	189.83	132.73	1,907	189.83	126.71
1B2	67%	155.74	96.92	1,907	158.94	94.26
1B3	30%	141.71	82.22	1,907	147.73	82.52
1B4	29%	141.68	82.20	1,907	147.78	82.57
2B1	0%	107.18	108.74	807	113.93	111.24
2B2	30%	116.73	132.37	807	121.83	130.78
2B3	69%	124.49	134.89	907	127.03	127.84
2B4	63%	119.73	139.79	807	122.62	132.74
3B1	0%	117.14	97.24	1,107	124.51	100.19
3B2	30%	125.79	112.89	1,107	131.27	112.42
3B3	68%	134.79	129.14	1,107	137.47	123.60
3B4	80%	135.30	130.11	1,107	137.12	123.02
4B1	0%	122.50	79.11	1,497	130.04	81.51
4B2	30%	136.29	93.75	1,557	142.18	93.94
4B3	68%	148.08	108.91	1,557	151.07	105.38
4B4	98%	158.99	122.92	1,557	159.19	115.81
5B1	100%	185.65	149.35	1,638	185.65	142.34
5B2	100%	257.06	100.49	3,856	257.06	97.51
5B3	30%	167.76	127.51	1,638	173.62	127.66
6B1	0%	122.50	79.11	1,497	130.04	81.51
6B2	24%	138.28	82.34	1,821	144.67	83.06
6B3	30%	142.21	82.17	1,921	148.26	82.49
6B4	66%	172.44	81.99	2,662	176.06	80.40
7B1	0%	89.04	347.91	148	94.67	346.46
7B2	6%	88.23	337.37	148	93.58	332.15
8B1	0%	84.73	458.88	93	90.30	455.35

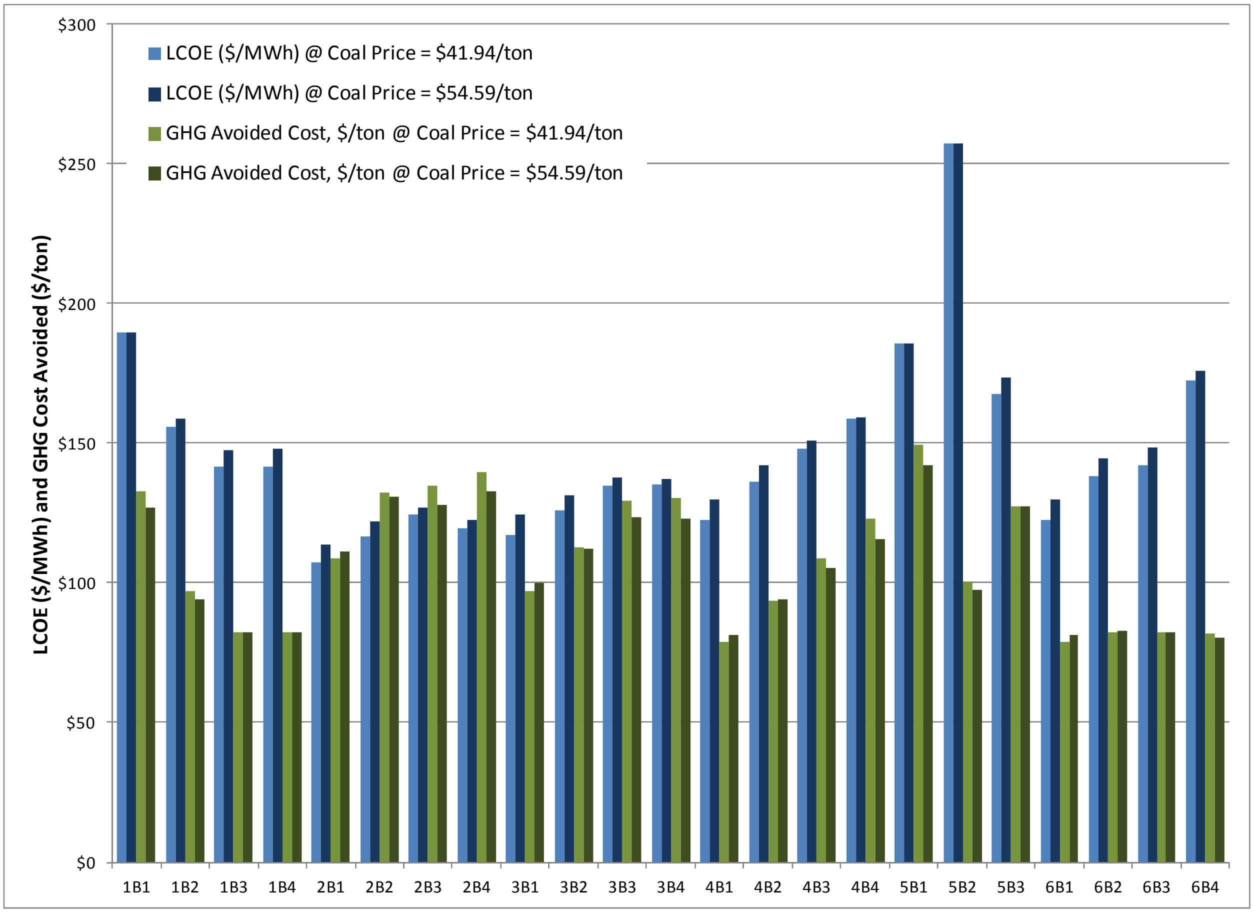
Note - Supercritical Plant LCOE and Emissions based on "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity," Report No. DOE/NETL-2007/1281, Final Report Revision 1, August 2007.

Exhibit 5-47 Sensitivity of Costs to Subbituminous Coal Price

		Original Study Coal Price = $12.96/ton			New Coal Price = $28.32/ton	
Case	% Biomass	LCOE ($/MWh)	GHG Avoided Cost ($/ton)	Emission Reduction (lb/MWh)	LCOE ($/MWh)	GHG Avoided Cost ($/ton)
1S1	100%	199.90	141.65	1,893	199.90	131.56
1S2	63%	159.46	98.92	1,894	164.50	94.16
1S3	30%	144.39	83.01	1,894	153.77	82.83
1S4	18%	139.79	78.15	1,894	150.81	79.70
2S1	0%	105.94	101.13	794	117.08	105.12
2S2	30%	120.00	136.54	794	127.94	132.47
2S3	65%	128.92	138.42	912	132.88	126.16
2S4	58%	123.88	146.43	793	128.50	133.99
3S1	0%	112.29	85.05	1,093	124.06	89.11
3S2	30%	126.84	111.66	1,093	135.17	109.42
3S4	75%	138.53	133.08	1,093	141.46	120.97
4S1	0%	122.65	73.67	1,543	135.39	77.80
4S2	30%	136.67	91.83	1,544	145.59	91.01
4S3	64%	150.35	109.55	1,544	155.00	103.20
4S4	97%	161.74	124.38	1,543	162.11	112.46
6S1	0%	122.96	73.00	1,566	135.73	77.10
6S2	19%	140.25	78.21	1,904	151.21	79.68
6S3	30%	149.82	79.10	2,125	159.53	79.24
6S4	61%	178.87	81.25	2,783	184.82	78.66
8S1	0%	81.44	N/A	-31	90.48	N/A

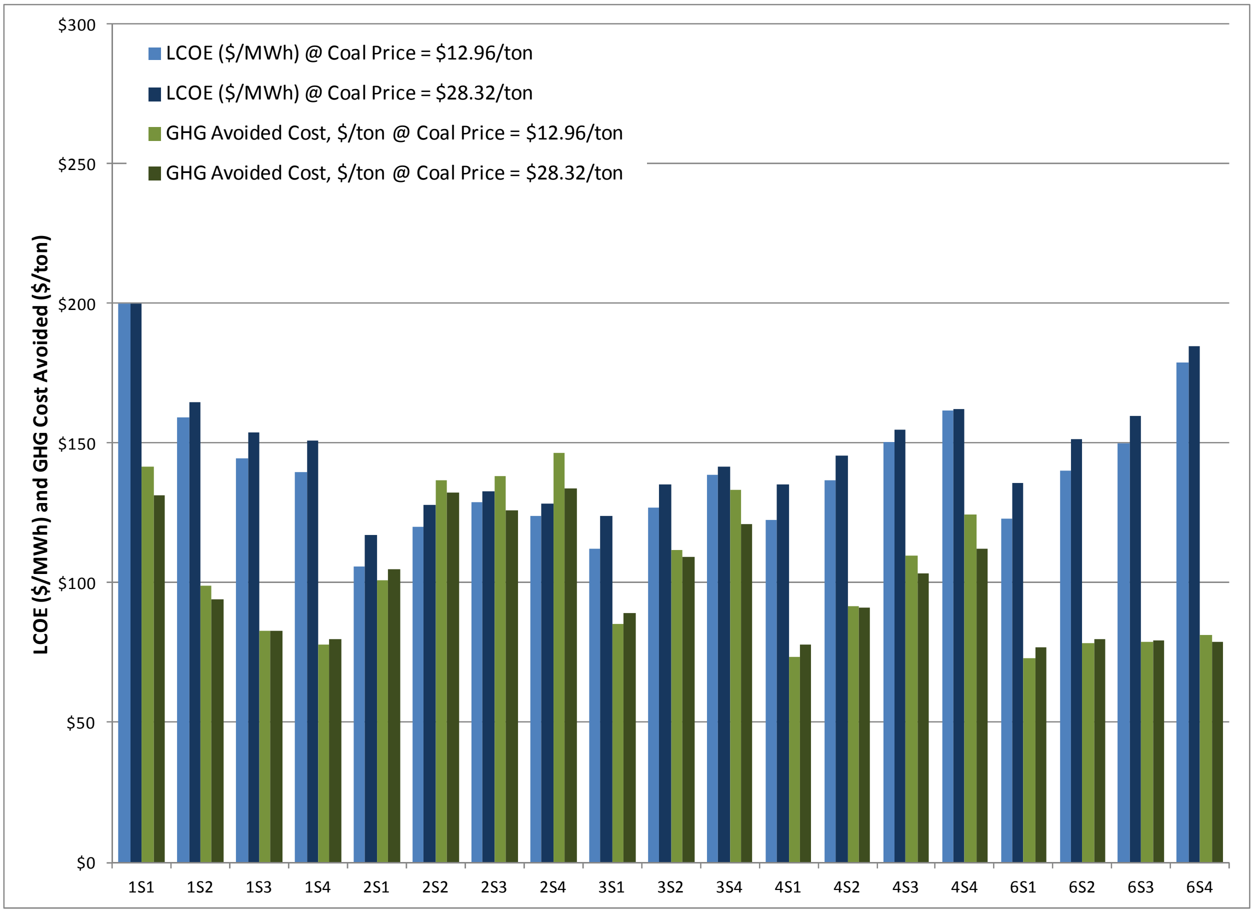
Note - Supercritical Plant LCOE and Emissions based on a preliminary version of "Cost and Performance Baseline for Fossil Energy Plants Volume 3a: Low Rank Coal to Electricity: IGCC Cases," Report No. DOE/NETL-2010/1399, Final Report, May 2011.

Exhibit 5-48 Sensitivity of LCOE and GHG Avoided Costs to Bituminous Coal Prices



Note Supercritical Plant LCOE and Emissions based on "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity," Report No. DOE/NETL-2007/1281, Final Report Revision 1, August 2007

Exhibit 5-49 Sensitivity of LCOE and GHG Avoided Costs to Subbituminous Coal Prices



Note Supercritical Plant LCOE and Emissions based on a preliminary version of "Cost and Performance Baseline for Fossil Energy Plants Volume 3a: Low Rank Coal to Electricity: IGCC Cases," Report No. DOE/NETL-2010/1399, Final Report, May 2011

The impact of the higher coal prices on the breakeven GHG tax values is illustrated by comparing Exhibit 5-50 to Exhibit 5-44 in Section 5.7 for the bituminous coal cases and Exhibit 5-51 and Exhibit 5-52 for the subbituminous cases. At the higher coal price, the breakeven GHG Tax for cases with lower percentages of biomass increases, and those with higher percentages of biomass decrease bringing the breakeven GHG tax estimates closer together. As discussed in section 5.7, the levelized breakeven GHG taxes in the original estimates were higher for the biomass cases and indicated that the coal cases were economically favored. When higher coal prices are used in the estimates, the differences in the breakeven values are reduced, and the biomass cases become more economically favorable.

Exhibit 5-50 GHG Breakeven Tax at Higher Bituminous Coal Price

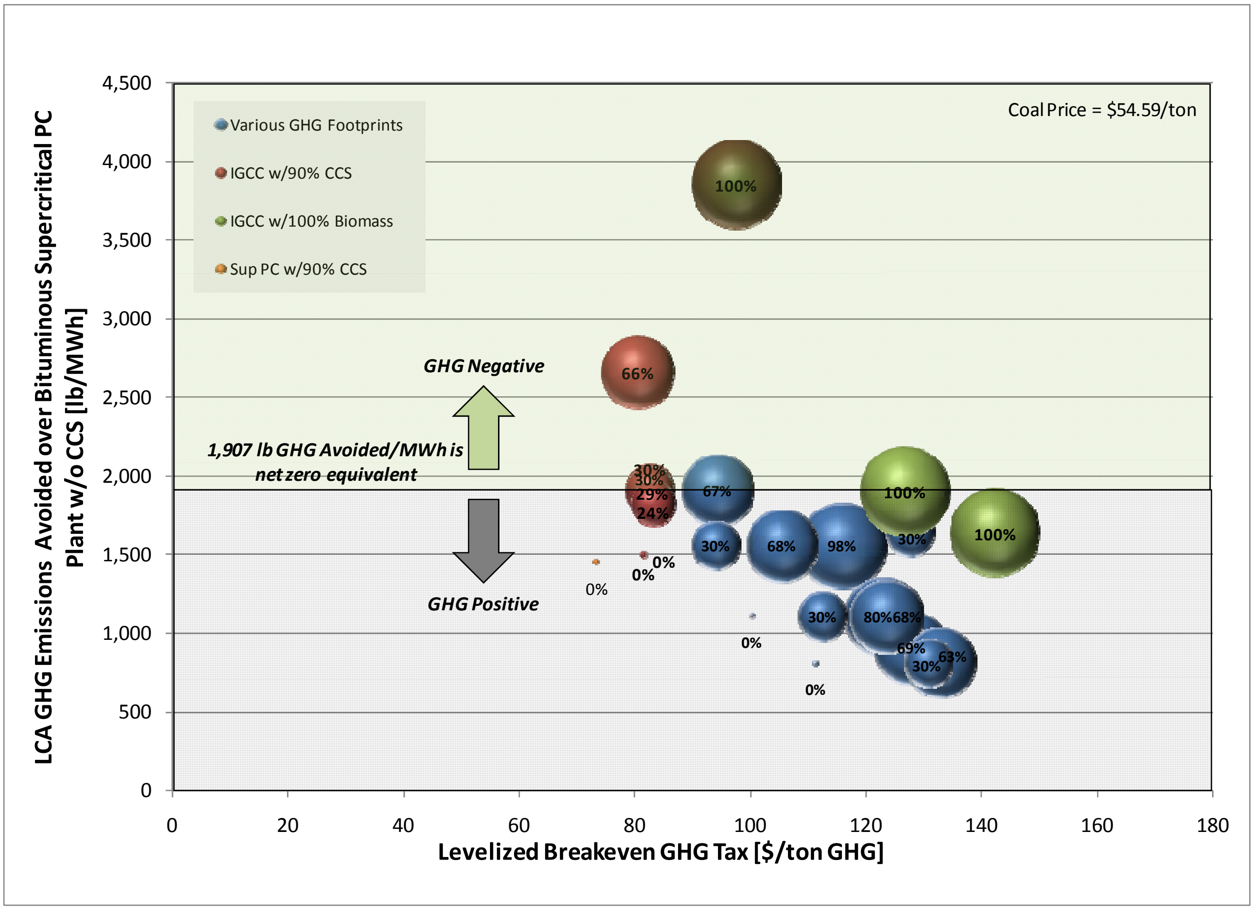


Exhibit 5-51 GHG Breakeven Tax at Original Subbituminous Coal Price

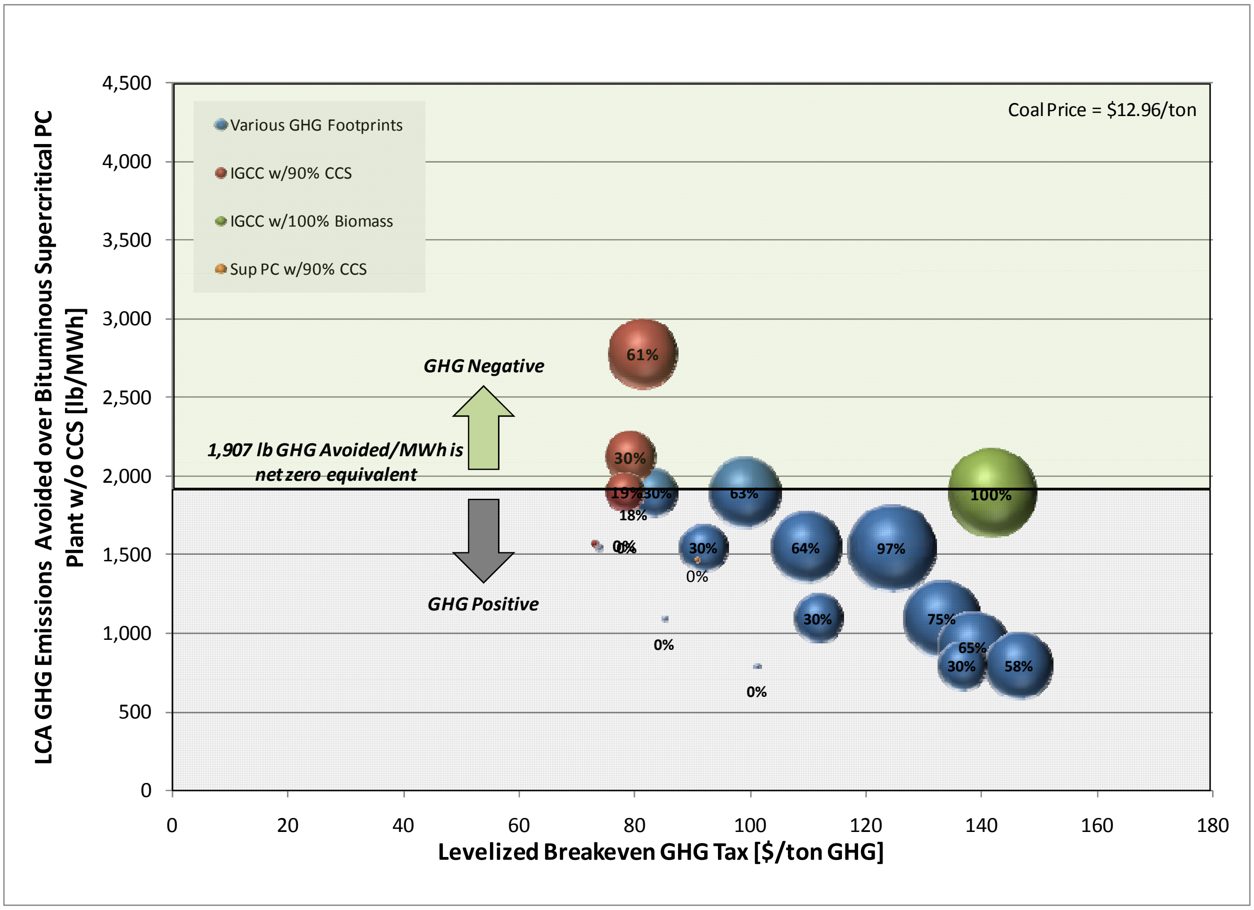
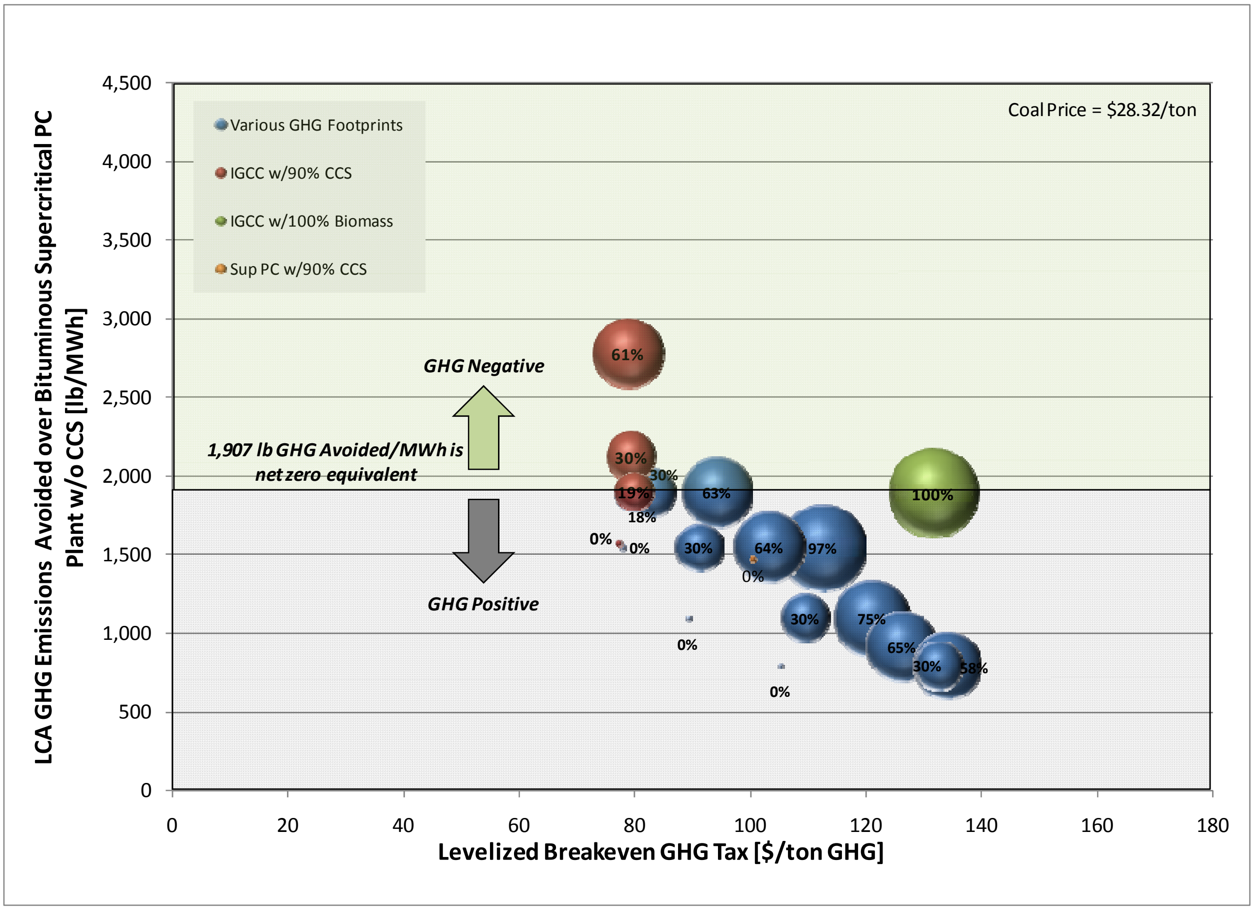


Exhibit 5-52 GHG Breakeven Tax at Higher Subbituminous Coal Price



A second sensitivity calculation was performed to estimate the coal prices that would generate the same breakeven GHG Tax values for the coal only with CCS cases (2B1, 3B1, 4B1, and 6B1 for bituminous coal and 2S1, 3S1, 4S1, and 6S1 for subbituminous) as those for the maximum biomass cases using comparable technologies (2B3, 3B4, 4B4, 6B4, 2S3, 3S4, 4S4, and 6S4). The results are illustrated in Exhibit 5-53 for bituminous coal cases and Exhibit 5-54 for subbituminous cases, which show the original values for all the cases and the position the bubbles in the chart would move to if the higher coal prices were then used in the calculations, indicated by the vertical lines. Note the coal-only cases move toward higher breakeven GHG taxes (to the right), while the biomass cases move toward the lower breakeven GHG taxes (to the left). For the bituminous coal cases, parity with the biomass cases is reached at coal prices between $51/ton and $100/ton of coal for breakeven GHG Tax values of between $80/ton and $115/ton GHG depending on the case specific technologies. For the subbituminous coal cases, parity with the biomass cases is reached at coal prices between $48/ton and $62/ton of coal for breakeven GHG Tax values of between $78/ton and $110/ton GHG depending on the case specific technologies. As coal prices increase, the biomass cases become more economically attractive due to lower potential GHG breakeven taxes.

Exhibit 5-53 Sensitivity of Breakeven GHG Tax to Bituminous Coal Price

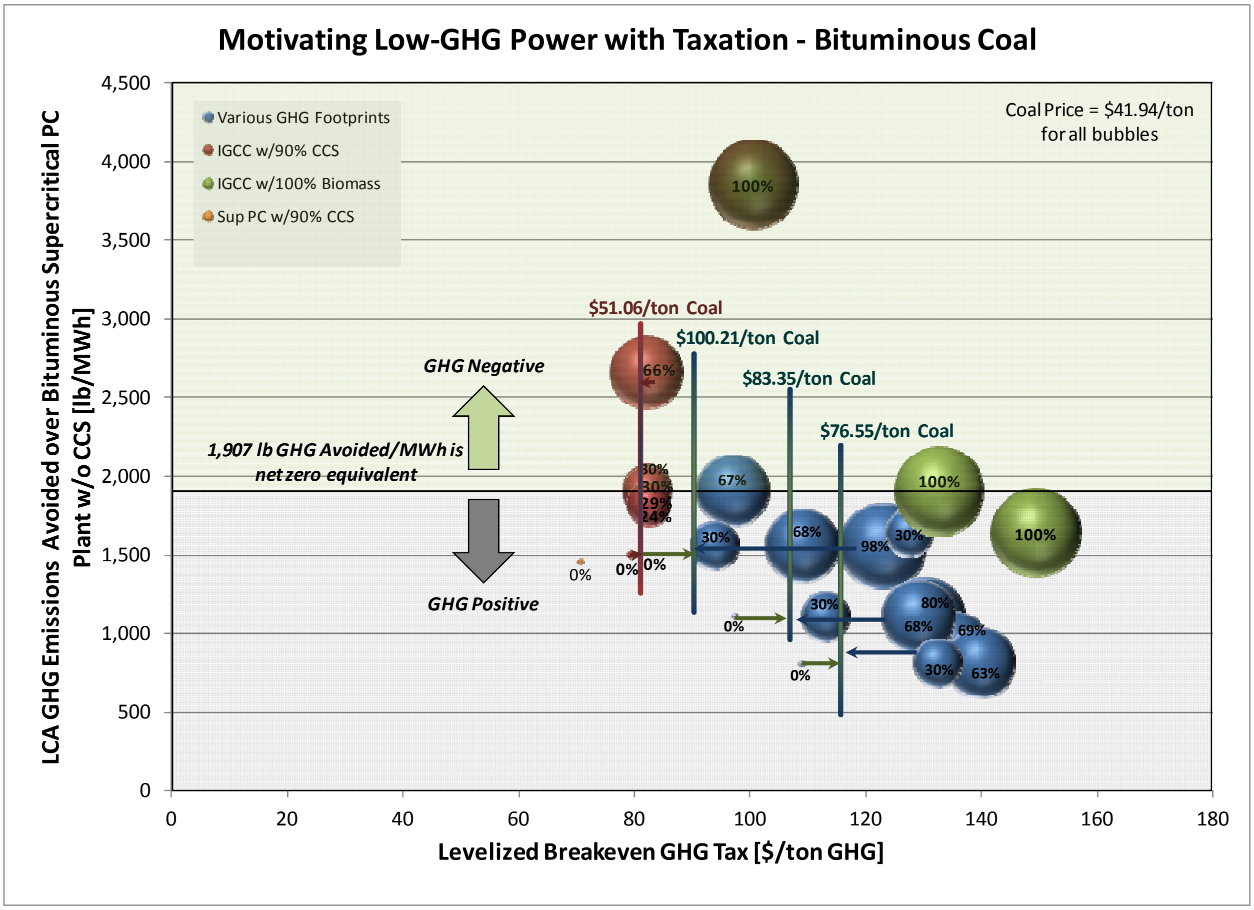
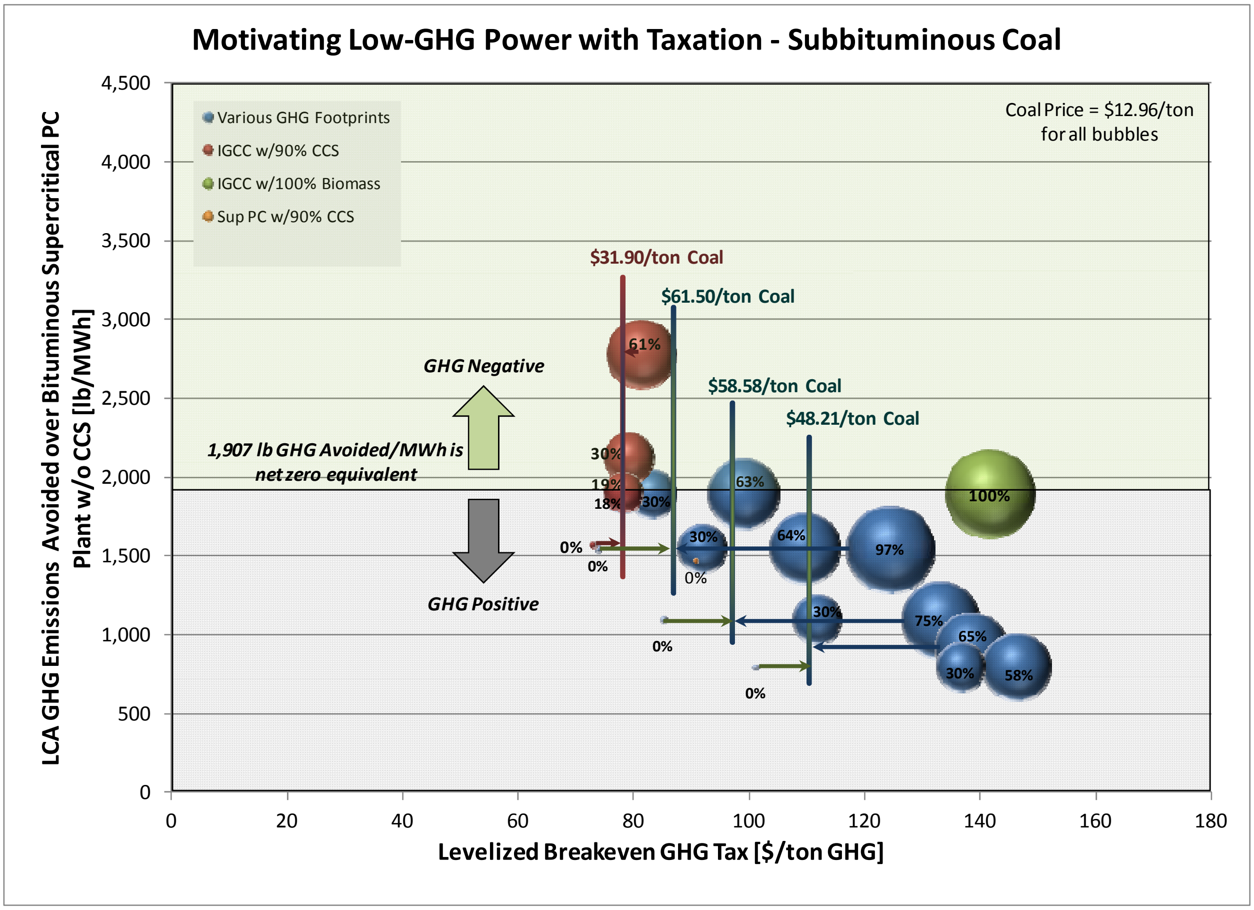


Exhibit 5-54 Sensitivity of Breakeven GHG Tax to Subbituminous Coal Price



5.9 JOB CREATION STATISTICS

The job creation statistics presented below give estimates of the gross jobs created from constructing and operating a CBIGCC facility. The authors acknowledge that a net loss of jobs is possible when considering the rise in electricity costs associated with cofiring, and the sectors affected by such a cost increase.

To further assess the economic impacts of constructing and operating an IGCC plant co-fired with switchgrass, a job estimation analysis was conducted using an input-output (IO) modeling[3] approach. IO modeling supports an assessment of direct, indirect and induced[4] jobs that are

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[3] IMPLAN Professional Version 2.0 software was used in constructing the 2007 I-O Models.

[4] Direct jobs result from an increase in final demand. Indirect jobs result as producers increase their output, there will be an increase in demand on their suppliers and so on down the supply chain. As a result of the direct and

supported within the economy as a result of the short-term impact of plant construction and the long-term impact of plant operation.

The analysis discussed here reflects the construction and operation & maintenance (O&M) parameters for a bituminous coal-fired IGCC plant employing maximum carbon capture (90%) and maximum demonstrated co-fire (30wt%), as represented in Case 6B3 of this study. Construction costs (as well as related jobs) are assumed to occur over a four-year period and are temporary. O&M costs and resulting jobs supported are assumed to occur over the thirty-year economic life of the plant. It should be recognized that jobs are a lagging economic indicator. As such, in reality, indirect and induced jobs will not all occur in the study period. Given the nature of IO modeling, however, this lagging characteristic is not captured in the results and thus the results should be interpreted as representing jobs supported by the plant's activities over time, but not a specific period of time.

Exhibit 5-55 Construction Cost Data – Case 6B3

Acct	Description	Equipment	Material	Labor	Bare Erected	Engineering/CM	Total Plant Cost ($1000)
1	COAL & SORBENT HANDLING	$14,933	$4,194	$11,731	$30,858	$2,764	**$33,622**
2	COAL & SORBENT PREP & FEED	$199,622	$10,791	$27,165	$237,578	$20,569	**$258,148**
3	FEEDWATER & MISC. BOP SYSTEMS	$9,742	$7,564	$9,929	$27,235	$2,554	**$29,788**
4	GASIFIER & ACCESSORIES	$307,902	$11,094	$68,136	$387,132	$35,877	**$423,009**
5A	GAS CLEANUP & PIPING	$89,259	$4,477	$75,914	$169,650	$16,260	**$185,910**
5B	CO2 REMOVAL & COMPRESSION	$18,689	$0	$11,051	$29,740	$2,842	**$32,582**
6	COMBUSTION TURBINE/ACCESSORIES	$92,061	$715	$6,368	$99,145	$9,325	**$108,470**
7	HRSG, DUCTING & STACK	$36,805	$2,360	$7,924	$47,089	$4,427	**$51,516**
8	STEAM TURBINE GENERATOR	$37,615	$893	$11,705	$50,214	$4,712	**$54,925**
9	COOLING WATER SYSTEM	$9,173	$10,146	$8,269	$27,588	$2,531	**$30,119**
10	ASH/SPENT SORBENT HANDLING SYS	$19,680	$1,506	$9,770	$30,956	$2,947	**$33,903**
11	ACCESSORY ELECTRIC PLANT	$24,850	$8,873	$24,861	$58,584	$5,434	**$64,018**
12	INSTRUMENTATION & CONTROL	$10,854	$2,032	$7,286	$20,172	$1,859	**$22,031**
13	IMPROVEMENTS TO SITE	$3,415	$2,013	$8,490	$13,918	$1,367	**$15,285**
14	BUILDI NGS & STRUCTURES	$0	$6,549	$7,538	$14,087	$1,280	**$15,367**
	Total Cost	**$874,601**	**$73,206**	**$296,136**	**$1,243,943**	**$114,750**	**$1,358,693**

indirect effects, level of household income will increase and part of this increased income will be re-spent on final goods and services; the jobs that result from this activity are induced jobs.

Exhibit 5-56 Fixed O&M Data – Case 6B3

	$/hr - burdened	Average Annual - burdened
Operating Labor	$45.05	$93,694
Maintenance Labor	$36.32	$75,550
Administrative & Support Labor	$20.14	$41,885

	Annual Cost ($)
Operating Labor Costs	$ 6,313,507
Maintenance Labor Costs	$ 14,513,690
Administrative & Support Labor Costs	$ 5,206,799
Total Labor Cost	$26,033,997

Exhibit 5-57 Variable O&M Cost Data – Case 6B3

	Annual Cost ($)
Maintenance Materials	$ 27,120,117
Water	$ 1,307,618
Chemicals	$ 2,483,873
Waste Disposal	$ 2,948,962
Coal	$ 58,888,712
Biomass	$ 46,399,124
Total Variable O&M Costs	**$139,148,406**

Employment impacts for three regions are presented to illustrate the range of potential impacts that could be derived from constructing and operating a CBIGCC plant. The differences in the results are due to varying regional economic characteristics (e.g. industry concentrations, regional resources) which alter the regions' ability to meet plant construction and operation demands. In all three cases, the model's regional purchase coefficients (RPCs) were maintained. This is in contrast to assuming the region can support 100 percent of a purchase demand from the project. Using modeled RPCs allows the analysis to better reflect regional resource constraints and leads to a more conservative estimate of jobs that will be supported throughout the study region's economy.

This study assumes two potential site locations– a Midwestern site using Illinois #6 coal and a high-altitude site using PRB coal. Case 6B3-a in this section presents the impact of siting a CBIGCC plant in an average Midwest state (e.g. IA, IL, MO) while Case 6B3-b presents the impact of siting a CBIGCC plant in an average high-altitude state (e.g. CO, NV, WY). Both of these cases reflect the states' regional capacity to meet the project's product and labor demand with trade leakages to both intra- and international markets. The final employment impact case - 6B3-c – reflects the country's capacity to meet the project's product and labor demands. Leakages in this latter case are confined to international trade and thus, for industries where the national average RPC is higher than the analyzed state-level RPC, job impacts will be higher than in the two state-level analyses. In all three cases, both project and process contingencies were excluded from the total and component costs of plant construction. Contingencies are unknown costs that reflect risk premiums and do not lend themselves to job creation. Excluding contingencies allows the job analysis to be both more straightforward and more conservative.

IO Modeling of Case 6B3

As described above, the IO model used to analyze the gross job impacts of constructing and operating a CBIGCC plant were conducted using the 2007 version of the IMPLAN model. For each analysis the average regional purchase coefficients were used to reflect each region's specific capacity to meet the project's final demand requirements. Exhibit 5-58 outlines how specific cost components were allocated to commodity or industry sectors. The results of the analysis are presented in terms of gross jobs and gross job years[5]. This analysis does not attempt to estimate the number of jobs that could be negatively affected through industry displacement.

Exhibit 5-58 IO Modeling Cost Components

Impact Category	Cost Component	Industry Title
Construction		
	Gasifiers	Other industrial machinery manufacturing
	Steam & Combustion Turbines	Turbine & turbine generator set units manufacturing
	Gasifier & Accessories	Other engine equipment manufacturing
	Other construction	Construction - other new nonresidential structures
Fixed O&M		
	Labor	Electric power generation, transmission and distribution
Variable O&M		
	Maintenance	Maintenance and repair construction of nonresidential structures
	Water	Water, sewage & other systems
	Chemicals	All other basic inorganic chemical manufacturing
	Waste Disposal	Waste management & remediation services
	Coal	Coal mining
	Biomass	All other crop farming

Case 6B3-a: Midwest State Impacts

To represent the job impacts in a typical Midwestern state, the project purchase requirements for plant construction and O&M were run through three separate versions of the IO model – one

5 *Jobs – average annual jobs; Job years – average annual jobs as a function of project duration*

each for Iowa, Illinois and Missouri. The average of the results is presented in Exhibit 5-59 and Exhibit 5-60.

Exhibit 5-59 Construction Employment Impacts – Midwest

	Direct	Indirect	Induced	Total
Jobs	1,563	688	947	**3,198**
Job Years (4 years)	6,253	2,754	3,787	**12,794**

Exhibit 5-60 O&M Employment Impacts – Midwest

	Direct	Indirect	Induced	Total
Jobs	383	925	753	**2,061**
Job Years (30 years)	11,490	27,746	22,581	**61,817**

Case 6B3-b: High-Altitude State Impacts

To represent the job impact on a typical high-altitude state, the project purchase requirements for plant construction and O&M were run through three separate versions of the IO model – one each for Colorado, Nevada and Wyoming. The average of the results is presented in Exhibit 5-61 and Exhibit 5-62.

Exhibit 5-61 Construction Employment Impacts – High-Altitude

	Direct	Indirect	Induced	Total
Jobs	1,380	464	604	**2,448**
Job Years (4 years)	5,519	1,857	2,416	**9,792**

Exhibit 5-62 O&M Employment Impacts – High-Altitude

	Direct	Indirect	Induced	Total
Jobs	383	888	535	**1,806**
Job Years (30 years)	11,490	26,641	16,059	**54,190**

Case 6B3-c: United States National Average Impacts

To provide a national average perspective of potential job impacts of siting a CBIGCC plant, construction and O&M costs were analyzed in a national (US) IO model (Exhibit 5-63 and Exhibit 5-64). As with the state-level analyses, the US model was exercised using model-generated RPCs which reflects the national average of industries' ability to meet purchase demands with the remainder being met through international trade through which no non-margin[6] US-based jobs are supported.

Exhibit 5-63 Construction Employment Impacts – United States

	Direct	Indirect	Induced	Total
Jobs	1,664	1,413	2,138	**5,215**
Job Years (4 years)	6,654	5,653	8,552	**20,859**

Exhibit 5-64 O&M Employment Impacts – United States

	Direct	Indirect	Induced	Total
Jobs	383	1,731	1,919	**4,033**
Job Years (30 years)	11,490	51,933	57,570	**120,993**

Comparative Analyses

As evidenced in the results tables above, the location of a plant affects the regional employment impacts due to variances in a region's economic characteristics and capacities. A comparison of the national (6B3-c) and the state-level results provides insight into the number of jobs supported by the plant's construction and operation that fall outside the plant's home state but within the US. The difference between the cases, however, should be interpreted as a close approximation, and used for a direct calculation, of these employment leakages.

As a second point of comparison, the results of the IO-modeled employment impacts are contrasted with the results that would be obtained by applying a government-wide standardized factor of $92,000 per job year[7] – 6B3-d (Exhibit 5-65 and Exhibit 5-66). Critical methodology differences that drive the contrasts in results are described below.

Four key points stand as notable distinctions between the IO modeling approach used in employment cases 6B3-a through 6B3-c and the standard factor approach shown in case 6B3-d. The first is that the $92,000/job year factor represents a US-average impact and can therefore not be applied at a sub-national region. This eliminates a direct comparison of cases 6B3–a and

6 Margin industries include retail and wholesale trade and transportation industries.

7 Executive Office of the President, Council of Economic Advisers. "Estimates of Job Creation from the American Recovery and Reinvestment Act of 2009." May 2009.

6B3–b with case 6B3–d and reduces the understanding of how a unique regional economy may be impacted by having a CBIGCC sited within its boundaries.

Exhibit 5-65 Construction Job Years (4 Years) – Comparison

	Direct	Indirect	Induced	Total
6B3-c (IO model – US)	6,654	5,653	8,552	**20,859**
6B3-d ($92,000/job year - US)	9,452		5,317	**14,768**
Impact Difference	-2,855 (-23%)		-3,235 (-38%)	**-6,091 (-29%)**

Exhibit 5-66 O&M Job Years (30 Years) – Comparison

	Direct	Indirect	Induced	Total
6B3-c (IO model – US)	11,490	51,933	57,570	**120,993**
6B3-d ($92,000/job year - US)	34,473		12,410	**53,864**
Impact Difference	-28,950 (-46%)		-45,104 (-78%)	**-67,129 (-55%)**

A second contrast is that through the methodology guiding case 6B3-d, separate estimates for direct (i.e. plant-level and construction) and indirect (i.e. supply chain) employment impacts cannot be discerned. The consequential obscurity in the meaning of the results detracts from the analysis and understanding of the plant's employment requirements and inter-industry relationships.

The final points of distinction, which together stand as the two most significant, lie in the application and the level of the methodology's factor - $92,000/job year. First, the methodology holds as a core assumption that a single value represents the funding level sufficient to support all job types in all industries. More simply, the methodology used in employment case 6B3-d assumes that $92,000 is equally applicable to jobs in construction in the construction industry as well as administration, operation and plant maintenance jobs in the utility industry. This is likely to be an oversimplification for the purposes of this study. Lastly, the $92,000/job year serves as an average final demand requirement for jobs in each sector. As shown in Exhibit 5-65 and Exhibit 5-66[8], this average across all job impacts is too high. The breakdown of the average requirements actually show that final demand requirements for job support in the industries affected by plant construction and operation should actually be higher than the $92,000/job year. A review of this study's plant-level systems analysis and the Bureau of Labor Statistics (BLS) yield an average annual burdened salary for direct plant labor of nearly $68,000 per job. For

[8] A comparison is not made between the fixed O&M results because the methodologies vary so greatly. For the IO modeling, the salary data is used to determine the direct plant employee requirement. The model then determines the final demand requirements for the industry to support these employees and executes the model using these demand levels ($). The 6B3-d methodology applies the $92,000/job factor directly to the salary requirements and, in doing so, ignores the larger final demand requirements necessary to employ the plant workers.

direct jobs, applying the $92,000 figure leaves less than $25,000 per year for use in purchasing inputs and covering profits and taxes which is likely an insufficient level of final demand. As the money allocated to salaries and supply chain purchases cycles through the economy, however, there is a diminishing impact and thus a diminishing average final demand requirement. This occurs in part because not all the money earned through salaries is redistributed throughout the economy and in part because induced impacts exist largely in relatively high-employment, low-wage service sectors. The significant level of induced impacts severely reduces the average final demand requirement, and for application in a plant construction and operation analysis, is more on the order of $65,000 and $74,000 respectively.

Exhibit 5-67 Average Final Demand Requirements - $/job year

	Direct	Indirect	Induced	Average	Pattern
Construction					
6B3-c (IO model – US)	$204,186	$110,402	$65,137	$65,137	Diminishing
6B3-d ($92,000/job year - US)	N/A	N/A	N/A	$92,000	Static Average
Variable O&M					
6B3-c (IO model – US)	N/A	$120,319	$73,542	$73,542	Diminishing
6B3-d ($92,000/job year - US)	N/A	N/A	N/A	$92,000	Static Average

The analysis of job impacts of constructing and operating a CBIGCC plant reveal that over the life of the two phases, gross job impacts on a regional and a national level are significant – 2,000-3,000 construction driven regional jobs and roughly 2,000 O&M driven jobs per year at the sub-national level. The level of the impact is affected by the chosen region's regional resources and thus its capacity to meet project demand. Understanding regional differences is an important component in understanding the overall effect of bringing this project to bear.

This analysis also reveals that it is imperative to conduct project-specific analyses to estimate job impacts so as to capture the project's unique industry requirements and inter-industry relationships. Applying single factors that are blind to regional resource variations, industry requirements and inter-industry relationships may often be insufficient.

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6. CONCLUSIONS

The objective of this study was to simulate biomass co-firing in a dry-fed, entrained-flow gasifier in an integrated gasification combined cycle (IGCC) power plant and examine the performance, environmental response and economic response under two scenarios:

- 0 ft of elevation (ISO conditions) co-fired with Illinois #6 coal
- 3,400 ft of elevation co-fired with Powder River Basin (PRB) coal

Much of the study focused on examining the technical and economic benefits of adding strategic levels of biomass feedstock in an IGCC power plant to achieve GHG emission levels corresponding to or closely resembling CA's GHG emission performance standard (1,100 lb CO_2/net-MWh), a state-of-the-art NGCC plant (800 lb CO_2/net-MWh), a full capture IGCC plant (350 lb CO_2/net-MWh), and a net-zero limited life cycle emissions plant. Many observations held true for all systems and included:

- The net plant efficiency increases as the concentration of switchgrass in the feed increases for plant designs targeting a given life cycle emission level. This is largely because requirements for active carbon capture and compression decrease.
- For a feedstock of a given composition, the net plant efficiency decreases as the emission target becomes more stringent and additional carbon capture is necessary.
- Plants operating at lower elevation and cofiring higher rank coals see higher efficiencies (due to increased CT output and higher fuel quality).
- Raw water consumption in the plant decreases as switchgrass feed increases, primarily because less shift steam is required as the amount of carbon capture required decreases. All else being equal, water consumption is less for the PRB cases than the equivalent Illinois #6 cases because the PRB cases employ a hybrid cooling system while the Illinois #6 cases use 100 percent wet cooling. A full lifecycle water analysis is required to gain a better understanding of the total water requirements for cultivating switchgrass and thus, the total water consumption associated with co-firing applications.
- Fuel cost increases with increasing switchgrass demand, which results in the LCOE increasing for higher proportions of switchgrass feeds. Depending on how much switchgrass is fed to the plant, switchgrass is \$4.72 to \$5.85/MMBtu more costly than PRB and \$3.68 to \$4.81/MMBtu more costly than Illinois #6 coal.
- LCOE increases as emission targets become more stringent. A higher carbon capture rate requires increases in capital investment and/or higher feeds of more costly switchgrass.

Study results yielded several observations concerning the feasibility as well as the technical and economic benefits of a net zero life cycle emissions plant. These included:

- It is not possible to achieve net zero life cycle emissions in a 100% switchgrass fed plant without CO_2 capture and sequestration. The GHG emissions associated with growing, harvesting and transporting the switchgrass necessitate approximately 14 percent of the plant carbon to be captured for both the Midwestern and high elevation sites.

- It is not possible to achieve net zero life cycle emissions with coal only and maximum CO_2 capture (90 percent) due the emissions associated with feedstock production and transport as well as the absence of a carbon-neutral feed.

- It is possible to achieve zero net life cycle emissions at demonstrated levels of biomass cofiring and less than 90 percent capture in both the PRB and Illinois #6 coal cases. A higher level of CO_2 capture is required in the Illinois #6 coal cases compared to the PRB coal case due in part to the higher emissions associated with mining Illinois #6 coal.
- LCOE increases as more stringent emission levels are required.

Economy-of-scale limitations exist for plants operating on a feed of 100% switchgrass. The observations that follow describe these limitations as well as the benefits of cofeeding coal:

- The size of a 100 percent switchgrass plant is restricted due to logistical restrictions on the maximum feasible supply of switchgrass. The maximum feasible amount of switchgrass (5,000 dry TPD) can produce approximately 326 MW in an IGCC plant (at sea-level altitude).

- Because of size limitations, 100 percent switchgrass plants suffer a reverse economy-of-scale and consequently higher TPC ($/MWh) and higher LCOE than larger plants.

- Cofiring coal increases plant capital costs but results in a lower LCOE when compared to a 100% switchgrass fed plant because of economies of scale and savings in fuel costs.

Utilizing 90 percent CO_2 capture in a state-of-the-art IGCC power plant while co-feeding varying proportions of switchgrass yields several noteworthy techno-economic trends:

- At fixed CO_2 capture levels, net plant efficiencies decrease with increasing switchgrass in the feed. Varying the switchgrass content will vary net GHG footprint.

- The lowest life cycle emissions that can be achieved in a coal-only IGCC system with 90 percent CO_2 capture are 410 and 327 lb CO_2e/net-MWh for Illinois#6 and PRB respectively. Lower net life cycle emissions can only be achieved by replacing coal feed with switchgrass.

- It is possible to have a maximum capture plant operating at negative life cycle emissions by increasing the switchgrass proportion. At the maximum CO_2 capture and maximum logistical switchgrass feed, emissions are -755 lb CO_2e/net-MWh when cofired with Illinois #6 and -890 lb CO_2e/net-MWh when cofired with PRB coal.

- The lowest level of GHG emissions achieved in this study was -1,949 lb CO_2e/net-MWh (Case 5B2, single train, 100 percent switchgrass and 90 percent CO_2 capture). It also represents the highest LCOE of any case at $257/MWh.

Most of the study matrix addressed relatively large levels of GHG mitigation and concluded that biomass co-firing is cost-prohibitive without a GHG tax. Low levels of CO_2 capture were also studied to determine if an economic crossover occurred as GHG mitigation approached zero. This was done by studying a coal-only plant capturing the minimum amount of CO_2 (only that amount produced by the gasifier, no water gas shift) resulting in overall 4.3% plant capture and a GHG footprint of 1,759 lb/MWh. This plant was compared to the performance of a plant matching the GHG footprint of 1,759 lb/MWh by co-feeding switchgrass (6.5% wt) without carbon capture. Results showed that:

- The savings in capital and TS&M costs balanced the increase in fuel costs when going from coal-only with capture to cofired with switchgrass.

- The resulting LCOEs for both cases were very comparable to one another

- Limiting GHG reduction to these very low levels simply to keep co-firing competitive cannot be considered an effective carbon mitigation strategy.

When increasing the GHG taxes applied to all lifecycle emissions of the cases studied in this report, the economics of co-firing biomass become more favorable. Some conclusions of applying a range of GHG taxes to lifecycle emissions include:

- The GHG tax values at economic crossover points are very similar between Illinois #6 (sea level) and PRB (high altitude) applications.

- When determining how implementing a GHG tax affects the avoided cost of GHG, the performance of power generation employing GHG mitigation must be compared to that of the least expensive power generation option in the absence of a GHG tax. The NETL report, "Cost and Performance Baseline for Fossil Energy Plants" indicates that this baseline, lowest-cost option for coal-fired applications is a supercritical PC plant. The supercritical PC plant in this report has an LCOE of $63.3/MWh and a GHG emissions footprint of 1,907 lbsCO_2e/MWh.

- If LCOE is the prime economic driver, among the cases studied here the GHG tax at which any real GHG mitigation is motivated using an IGCC system is ~$80/ton GHG. Conventional CCS (0% biomass) provides the lowest cost of electricity for IGCC systems at this point.

- The GHG tax at which co-fired IGCC power costs become economic is ~$82/ton GHG. An additional $2-4 of GHG tax quickly motivates maximum switchgrass co-feed and maximum GHG reductions.

- Supercritical PC w/90% CCS is likely to generate the most cost effective "low GHG power" in terms of breakeven GHG tax (at $71/ton). However, this GHG reduction is limited to 80% less than supercritical PC w/o CCS. An additional 15% tax increase to ~$82/ton motivates CBIGCC technology with *a 140% reduction* over supercritical PC GHG emissions, promoting GHG-negative power generation.

- Because maximum biomass may not be available in all regions to leverage the economic benefits of GHG-negative footprints, Renewable Portfolio Standards may provide the most impetus for switchgrass co-firing as a near-term, effective carbon mitigation strategy.

7. FUTURE WORKS

To bridge the gap between the existing and proven technology for coal and the implementation of combined coal-biomass co-gasification, an R&D strategy is necessary that will focus on four interrelated areas as laid out in ECN's "Biosyngas – Description of R&D Trajectory Necessary to Reach Large-Scale Implementation of Renewable Syngas from Biomass." [56]

- Biomass pretreatment & feeding:
  - Reduce cost of milling to obtain particle size less than 1 mm for entrained-flow gasifiers.
  - Pre-treat to obtain feed material that is "coal-like" and able to be fed with coal at gasification pressures, and to reduce storage and transportation costs.
- Gasification & burner design
- Ash and slag behavior:
  - Characterize behavior based on the ash speciation.
  - Characterize based on the relative levels of the feedstock.
  - Predict and manage partitioning of ash species between bottom ash/slag and entrained ash carried into syngas clean-up train.
  - Characterize potential for fouling of downstream equipment (e.g., syngas cooler).
- Effect of trace constituents on hot gas treatment (cooling, cleaning, and conditioning):

Buggenum Plant Experience:

- Fouling of the syngas cooler has occurred due to a high percentage of sewage sludge in the feedstock. Wood does not cause this problem therefore fuel mix optimization may help mitigate this as well as similar problems.

- Fuel preparation: Investigate possibilities of torrefaction as a pre-treatment technique to improve biomass milling characteristics.

- Fouling: elucidate the mechanisms of syngas cooler fouling and find mitigation solutions. This is not a problem for woody biomass.

- Fouling is enhanced by formation of low-melting Fe-P-Si-rich phases associated with sewage sludge -- Mitigation: reduce Fe and P content in fuel mix, capture Fe and P to form high-melting phases, avoid high Si/Al coals [57].

The main R&D issue is how to feed a variety of biomass materials into the gasifier with minimum pretreatment and inert gas consumption. The four different routes that may be addressed in R&D are:

1. Milling of (woody) biomass, pressurization in a piston compressor with negligible inert gas consumption, and feeding to the gasifier burner with a screw feed system with low inert gas consumption.
2. Pre-conversion of grassy and straw biomass materials into bio-slurry by flash pyrolysis; bio-slurry is easily pressurized and fed into the gasifier.
3. Pre-conversion by torrefaction, which can be applied to all types of biomass and also homogenizes other heterogeneous (waste) streams. The torrefied material is pressurized in a piston compressor and fed either by a screw (preferred) or a pneumatic feeding system.
4. Gasification of the feed material in a fluidized bed gasifier into a product gas that is directly fed in the gasifier.

Exhibit 7-1 specifically lays out a strategic flow diagram for entrained-flow co-gasification [56].

Exhibit 7-1 Overall System for Gasification of Multiple Biomass Feedstocks to Produce Clean and Conditioned Syngas – R&D Areas

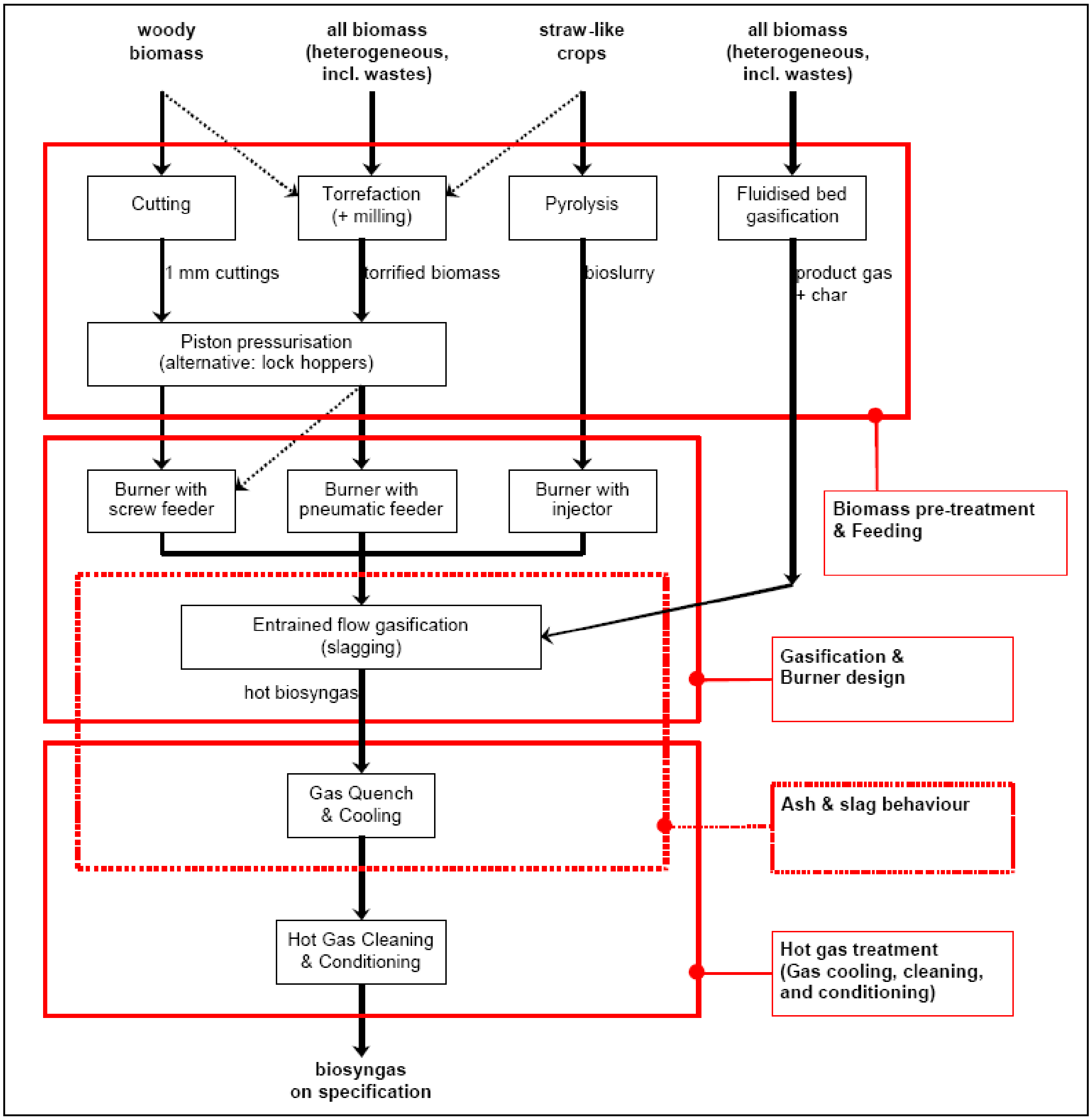


*Image taken from, Boerrigter, H. and A. Van Der Drift, "*Biosyngas – Description of R&D Trajectory Necessary to Reach Large-Scale Implementation of Renewable Syngas from Biomass*."[56]

7.1 BIOMASS PRETREATMENT & FEEDING

Biomass cannot be handled and fed similar to coals, as the biomass properties are completely different (*i.e.* biomass has a fibrous structure and high compressibility). Therefore, either biomass has to be pretreated to make it behave similar to coal or dedicated biomass handling systems have to be developed. The advantage of pre-treating the biomass to more closely match coal properties (*i.e.* by torrefaction), is that it allows short-term implementation of biomass firing in existing plants. The efficiency may be improved if a dedicated feeding system for solid biomass can be developed.

It is recommended to further study the technical and economic feasibility of a biomass-to-syngas production chain including torrefaction as a biomass pre-treatment step. Torrefaction may add to plant and O&M costs, but feedstock costs, a significant contributor to LCOE, may be reduced. Torrefaction also has the possibility of increasing “logistical maximum” biomass supply rates. Additionally it is recommended to study the gasification characteristics (e.g., carbon conversion, cold-gas efficiency) of torrefied biomass experimentally.

Further optimization of the torrefaction conditions is recommended to further increase the powder quality for optimal feeding. The torrefaction temperature is considered the most important parameter in this respect. The higher this temperature, the thinner and shorter and hence more spherical particles can be obtained after size reduction. In previous research, 270 °C was the highest temperature explored and further optimization should be focused on the temperature range of 270-300° C. In previous work, the length-to-diameter was qualitatively evaluated by visual observations. It is also recommended to apply a quantitative method (e.g., optical microscope) in future research.

In further improving the knowledge base on torrefaction, it is recommended to focus on the polymeric composition of the feed biomass. Available analysis methods known from biology-oriented research fields to determine this composition could be used. Knowledge about the relationship between the exact polymeric composition and torrefaction characteristics such as mass and energy yield and production of volatiles would be very important for the development of predictive tools to optimize the process.

The analysis method to determine the heating value of feed and product (adiabatic bomb calorimeter) has an inaccuracy of ±1.5%. Since the difference in heating value between feed and product is not very high, such an inaccuracy complicates the interpretation and understanding of experimental data. Statistically justified conclusions seem only to be possible on the basis of a high number of experiments. It is recommended to investigate whether this measurement can be improved.

In addition to making the fuel more physically suitable for feed into a gasifier, complications related to high pressure gasification feed requirements may also need to be overcome.

7.2 GASIFICATION & BURNER DESIGN

The general objective of the R&D on gasification and burner design is to determine the optimum burner design for solid biomass feeding and the optimum gasification conditions with respect to biomass particle size (does 1 mm biomass suffice?), maximum efficiency, maximum heat recovery, minimum flux use, minimum inert gas consumption, complete conversion, production of biosyngas with desired quality (*i.e.* low CH_4 and no tars) [56].

The gasifier should fulfill the following requirements:

- The heart of the system is a pressurized oxygen-blown slagging entrained flow gasifier.

- The gasifier is suitable for a large variety of feed materials, varying from wood particles, grass and straw-based bio-slurries, and heterogeneous biomass streams after homogenization by torrefaction.

- The gasifier is operated at lowest temperature possible to obtain high cold-gas efficiencies and oxygen consumption, yet hot enough to avoid methane formation.

- The gasifier produces a tar-free biosyngas with a low nitrogen concentration.

Complete conversion of the biomass is required to obtain a high efficiency and a carbon-free slag. To minimize oxygen consumption and heat losses, the lowest gasification temperature must be determined at which complete conversion to the desired products H_2 and CO is achieved. Correlations with the biomass properties and particle size have to be determined.

The critical step in the gasification is the stable operation of the gasifier burners. With respect to burner design the critical issue is to ensure a constant flow of biomass material to prevent dangerous situations of excess oxygen. Furthermore, high levels of atomization and mixing of the biomass and the gasification gases with the oxygen are required. For liquid biomass (*i.e*. the bio-slurry) feeding to the burner and injecting with sufficient atomization is the key challenge. For solid biomass stable feeding with a constant flow and density (*i.e*. mixture of biomass and inert gas) is crucial. Also the inert gas consumption is of importance for the efficiency of the process.

R&D activities may comprise: (i) pilot-scale gasification tests (with solid feeding system) to prove conversion, (ii) conversion experiments in lab-scale EF simulators (atmospheric and pressurized) to determine correlations between temperature, particle size, type of biomass, CH_4 (and small amounts of tars) content of the biosyngas, and conversion, and (iii) modeling of gasification hydrodynamics.

7.3 ASH AND SLAG BEHAVIOR

In a slagging gasifier the ash and flux are present as a molten slag that protects the gasifier inner wall against high temperatures. The slag must have the right properties (*e.g*. flow behavior and viscosity) at the temperature in the gasifier. It is crucial to have a good understanding of the slag behavior as function of the gasification temperature, biomass ash properties, and selected flux [58]. Research activities may comprise:

- Deposition experiments in lab-scale EF simulators (atmospheric and pressurized) to determine behavior of ash and slag, and interactions between both, as function of temperature, type of biomass, and selected flux.
- Based on the experimental work, thermodynamic modeling is carried out to support the selection of gasification conditions and flux materials.
- Gasification tests in a pilot EF gasifier to validate and prove slag and ash behavior under realistic gasification conditions. In the first experiments bio-slurry, with added minerals, is used as biomass feed. The slurry has the same chemical composition as solid biomass, but the advantage of liquid feeding system. Therefore, these tests can be performed

independent of the progress in the solid feeding project topic. Later experiments (after installation of a new feeding system) will be carried out with solid biomass feed, to prove the integrated concept for solid biomass.

- CFD analysis could be used to look for local temperature increases in biomass-rich zones because of its high reactivity and volatility.

The biosyngas is cooled to approximately 800°C by a water or gas quench. The gas is cooled further with a heat exchanger to about 200°C to recover heat. Potential fouling of the heat exchangers is a major issue to be addressed; this has also been the major problem in co-gasification tests with biomass in the large scale IGCCs. Deposition tests will be carried out in the lab-scale EF simulator at the temperature range of the gas heat exchanger to study fouling phenomena. Soot may also be a research subject since the formation or suppression of soot significantly influences the efficiency [59].

7.4 GAS TREATMENT

Gas cooling from the gasifier outlet temperature (1000-1300°C) is normally done by a partial gas quench (to 800°C) with recycled clean gas or water injection. A gas quench is preferred considering the higher efficiency and amount of energy that can be recovered. However, it requires a large gas recycle (typically 1:1 to the raw gas) resulting in a much larger gas cleaning section, compared to a system without gas recycle. Therefore, there is a large incentive to develop an innovative hot gas cooler for cooling of the hot gas with energy recovery and to make the recycle superfluous. The syngas is further cooled to the level necessary for the gas cleaning. R&D activities may focus on the development of a fluidized bed gas cooler.

Syngas that will be utilized for chemical processes or liquid fuel synthesis needs to meet the restrictive catalyst specifications. Hot gas cleaning, if employed, has to remove all components that may be harmful to the catalysts or other parts of the plant by corrosion, erosion or fouling.

Preferably the gas cleaning should be operated at the same temperature of the downstream gas application to minimize efficiency loss by cooling. Significant efficiency improvements are possible when water is not condensed from the biosyngas, which happens in ‘wet’ gas cleaning (*i.e*. below water dew point). Due to the large spectrum and the broad variety of biomasses taken into consideration for gasification, an efficient gas cleaning at temperatures of about 200°C appears to be ideal. Therefore *warm gas cleaning* is a more appropriate definition and avoids reference to the poor results in the developments of real hot gas cleaning for coal applications (*i.e*. above 500-600°C). Activities comprise lab-scale experiments are carried out to evaluate absorbents for high temperature gas cleaning from inorganic impurities [56].

7.5 PRAIRIE GRASSES AND SWITCHGRASS VS. SHORT ROTATION WOODY CROPS

Biomass type affects various aspects of the gasification process. The most significant being the pre-treatment requirements and ash/slag behavior in the gasifier. The primary differences between grasses and SRWC biomass for co-gasification in a large entrained-flow gasifier are as follows:

- Pre-treatment requirements differ with respect to possible pre-treatment methods:
    - Wood is denser material and may be pre-treated to produce wood chips, torrefied wood, torrefied wood pellets
    - Grasses are lower density material and may be pre-treated by baling into large blocks for transport, pre-treated to produce pellets for transport (needs to be cut and not shredded for stronger pellet)
- Wood pulverization: wood chips should be pulverized to at least 1 mm size or less, but more energy is required for smaller sizes. Can be potentially performed in coal pulverizer, but feeding with coal will likely cause problems. Better to feed separately via screw feed and piston compressor. Torrefied wood should be co-pulverized and fed with coal.
- Switchgrass pulverization: switchgrass can be co-pulverized with coal, but the energy consumption is much higher than coal-only for bituminous coal. For Powder River Basin coal, co-pulverization energy consumption is much lower than for bituminous coal.
- Low ash fusion temperature of crop-based biomass can cause problems for non-slagging gasifiers if the temperature is not maintained below the melting temperature. It fuses together to form slag and this clinker stops or inhibits the downward flow of biomass feed. Experience with lignite gasification has shown that the ash fusion temperature fluctuates as the sodium content changes. Therefore, high sodium/potassium SRWC (e.g., birch) may cause problems for fixed/moving and fluidized bed gasifiers. While entrained flow gasifiers may have problems with the biomass ash, appropriate flux material can be added to yield adequate slag flow.

Since the ash content of woody biomass is generally quite low, the ash quality should not be impacted significantly depending on the relative levels of biomass feed. This will be more of an issue with higher ash grasses. The higher levels of the alkali metals may be enriched in the entrained ash leaving the gasifier with the raw syngas, especially for high chloride levels found in switchgrass.

7.6 PC COFIRING

Biomass cofiring in existing PC boilers is a nearest-term option for converting biomass and coal into electricity. Testing has been conducted on all common, industrially used boiler types. Just as with cofiring in an IGCC plant, economics depend on plant location, plant type, and availability of the biomass fuel. Technical challenges such as the fuel feeding method and ash characteristics are shared with IGCC cofiring. PC cofiring has small boiler efficiency losses associated with cofiring higher moisture biomass, but these can be minimized or eliminated after adjusting the combustion output.

Allegheny Energy Experience:

Cofiring tests with sawdust were conducted by Allegheny Energy Supply Co. with support from DOE and EPRI. Sawdust was cofed into the Willow Island #2 boiler (188MWe cyclone unit) and the Albright #3 boiler (150 MWe, tangentially fired PC boiler) with Pittsburgh seam coal. 10 percent sawdust by mass was used in both tests but had different feeding strategies. The Albright project utilized separate injection of the sawdust into the furnace fireball while the Willow Island project blended the sawdust with the coal feed [60].

Gadsden Power Plant Experience:

Cofiring tests with switchgrass have been conducted at the Gadsden Power Plant in Gadsden, AL. Dried switchgrass was formed into cubed pellets in order to be co-milled with the coal feed. It was found that pelletizing the switchgrass reduced plant capital, transportation, labor, and dust production. The prepared switchgrass feed was sent to a tub grinder which fed to a metering bin. The fuel was then fed to a transport fan via screw feeding. Pneumatic transport lines carried the switchgrass to the boiler where it was in injected into the boiler through burners. Efficiency was slightly lower when cofiring. According to electricity cost predictions, cofiring at 7% of the heat input to the boiler would increase the cost of electricity from 2.6¢/kWh to 3.0¢/kWh [61].

Ottumwa Experience (Chariton Valley Biomass Project):

The Chariton Valley Biomass Project has run tests at the Ottumwa Generating Station in Centerville, Iowa. The plant produces 675 net-MW of electricity while running on PRB subbituminous coal. The tests fired 2-3% of the overall boiler heat input as switchgrass. A separate feed system devoted to switchgrass feed was used including a modified Eliminator that was used for switchgrass size reduction. Qualitative observations from the test runs were as follows [62]:

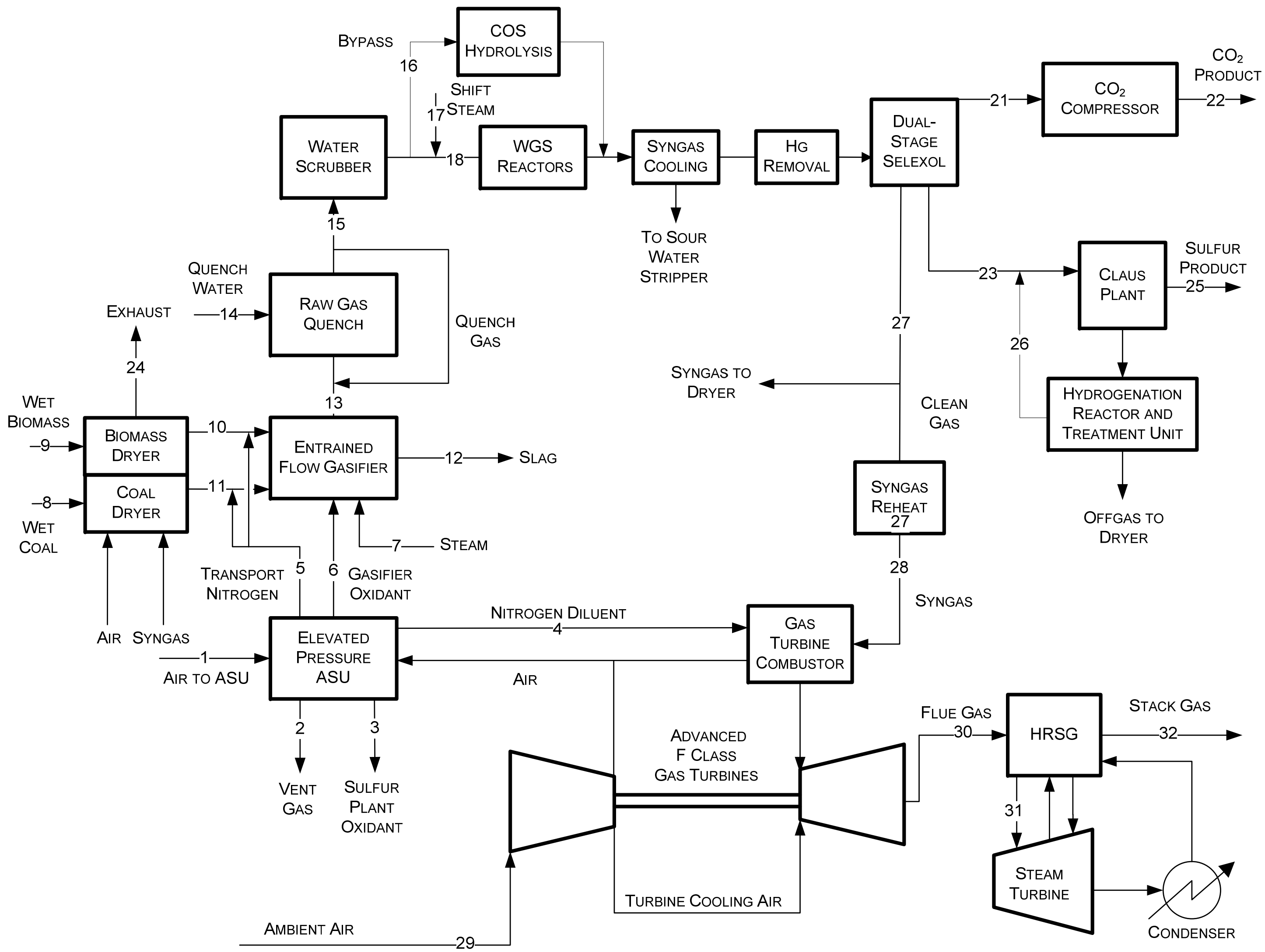
- No difference in slag or buildup was noticeable in the boiler.
- Cofiring had no noticeable effect on fly ash composition and unburned carbon
- No evidence of increase in PM emissions

APPENDIX A

Because this study consists of 47 individual cases, it is not practical to include the stream table, performance summary, carbon balance, sulfur balance, water balance, emissions summary, energy balance, capital cost summary and O&M cost summary for every case. The length of the report would be prohibitive. In this appendix complete information is provided for a select case (3B2-Illinois#6 coal cofired with 30 wt% switchgrass at 800 lb CO_2e/net-MWh), and it is representative of the information that was developed for each case in the study.

The reference capital costs are from a previous systems analysis study and are in December 2006 dollars. The case 3B2 individual account totals are scaled from the December 2006 reference costs. The sum of the individual accounts is escalated to June 2007 dollars using the Chemical Engineering Plant Cost Index; hence the individual account totals do not sum to the total plant cost in the spreadsheet.

Appendix A-1 Case 3B2 Block Flow Diagram



Appendix A-2 Case 3B2 Stream Table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
V-L Mole Fraction																
Ar	0.0093	0.0122	0.0318	0.0023	0.0023	0.0318	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0087	0.0000	0.0056	0.0058
CH_4	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0001	0.0001
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	0.5337	0.0000	0.3391	0.3567
CO_2	0.0003	0.0037	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0434	0.0000	0.0276	0.0290
COS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0006	0.0000	0.0004	0.0004
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.2705	0.0000	0.1718	0.1808
H_2O	0.0071	0.0782	0.0000	0.0003	0.0003	0.0000	1.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0747	1.0000	0.4121	0.3815
H_2S	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0063	0.0000	0.0040	0.0042
N_2	0.7753	0.8112	0.0178	0.9921	0.9921	0.0178	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0619	0.0000	0.0394	0.0414
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000
O_2	0.2080	0.0946	0.9504	0.0054	0.0054	0.9504	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	0.0000	0.0000	0.0000	1.0000	1.0000	1.0000	1.0000
SI Units																
V-L Flowrate (kg_{mol}/hr)	27,819	2,464	108	18,568	1,055	5,623	394	0	0	0	0	0	20,462	11,743	32,206	13,639
V-L Flowrate (kg/hr)	803,623	68,545	3,487	521,019	29,608	180,964	7,106	0	0	0	0	0	431,481	211,556	643,037	273,697
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	179,575	76,961	68,859	168,006	23,063	0	0	0	0
Temperature (°C)	15	17	32	93	197	32	343	15	15	77	71	1,427	1,427	167	260	232
Pressure (MPa, abs)	0.10	0.11	0.86	2.65	5.62	0.86	5.10	0.10	0.10	0.10	0.10	4.24	4.17	2.24	3.86	3.72
Enthalpy (kJ/kg)	25.89	35.20	26.67	92.42	201.79	26.67	3,063.97	---	---	---	---	---	2,434.18	656.09	1,322.04	1,200.89
Density (kg/m^3)	1.2	1.4	11.0	24.4	39.6	11.0	20.1	---	---	---	---	---	6.2	843.3	17.7	18.1
V-L Molecular Weight	28.887	27.813	32.181	28.060	28.060	32.181	18.015	---	---	---	---	---	21.087	18.015	19.967	20.068
English Units																
V-L Flowrate (lb_{mol}/hr)	61,331	5,433	239	40,935	2,326	12,397	870	0	0	0	0	0	45,112	25,889	71,001	30,068
V-L Flowrate (lb/hr)	1,771,686	151,116	7,687	1,148,651	65,275	398,957	15,666	0	0	0	0	0	951,253	466,401	1,417,654	603,400
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	395,894	169,669	151,809	370,390	50,845	0	0	0	0
Temperature (°F)	59	62	90	199	387	90	650	59	59	170	160	2,600	2,600	332	500	450
Pressure (psia)	14.7	16.4	125.0	384.0	815.0	125.0	740.0	14.7	14.7	14.7	14.4	614.7	604.7	325.0	559.7	539.7
Enthalpy (Btu/lb)	11.1	15.1	11.5	39.7	86.8	11.5	1,317.3	---	---	---	---	---	1,046.5	282.1	568.4	516.3
Density (lb/ft^3)	0.076	0.087	0.687	1.521	2.475	0.687	1.257	---	---	---	---	---	0.386	52.648	1.105	1.131
	A - Reference conditions are 32.02 F & 0.089 PSIA															

Appendix A-2 Case 3B2 Stream Table (continued)

	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
V-L Mole Fraction																
Ar	0.0000	0.0044	0.0044	0.0072	0.0002	0.0002	0.0022	0.0082	0.0000	0.0000	0.0097	0.0097	0.0093	0.0089	0.0000	0.0089
CH_4	0.0000	0.0001	0.0001	0.0001	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000
CO	0.0000	0.2678	0.0122	0.2075	0.0075	0.0076	0.0697	0.0000	0.0000	0.0000	0.2775	0.2775	0.0000	0.0000	0.0000	0.0000
CO_2	0.0000	0.0218	0.2777	0.2697	0.9815	0.9860	0.4073	0.0872	0.0000	0.9204	0.0278	0.0278	0.0003	0.0392	0.0000	0.0392
COS	0.0000	0.0003	0.0000	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2	0.0000	0.1357	0.3914	0.4568	0.0057	0.0057	0.0977	0.0000	0.0000	0.0000	0.6157	0.6157	0.0000	0.0000	0.0000	0.0000
H_2O	1.0000	0.5357	0.2797	0.0018	0.0045	0.0000	0.0374	0.3550	0.0000	0.0568	0.0001	0.0001	0.0071	0.0842	1.0000	0.0842
H_2S	0.0000	0.0032	0.0035	0.0056	0.0000	0.0000	0.3782	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.0000	0.0311	0.0311	0.0512	0.0004	0.0004	0.0072	0.4899	0.0000	0.0000	0.0691	0.0691	0.7753	0.7587	0.0000	0.7587
NH_3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0597	0.0000	0.0000	0.0000	0.0000	0.2080	0.1091	0.0000	0.1091
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0228	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
SI Units																
V-L Flowrate (kg_{mol}/hr)	5,634	22,610	22,610	24,767	6,135	6,107	369	4,407	0	67	18,262	17,586	109,700	138,002	31,736	138,002
V-L Flowrate (kg/hr)	101,506	442,169	442,169	509,007	267,023	266,521	12,534	115,430	0	2,880	229,450	220,948	3,168,936	3,910,903	571,728	3,910,903
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	0	4,518	0	0	0	0	0	0	0
Temperature (°C)	343	258	265	35	16	75	48	143	173	53	31	176	15	575	547	131
Pressure (MPa, abs)	5.10	3.72	3.53	3.22	1.0	15.270	0.163	0.098	0.119	0.207	3.238	2.917	0.101	0.105	12.512	0.105
Enthalpy (kJ/kg)	3,063.97	1,628.59	1,091.39	44.64	7.0	-83.033	97.263	783.545	---	103.302	66.993	412.394	25.887	768.370	3,467.101	272.024
Density (kg/m^3)	20.1	17.1	15.6	26.2	20.0	430.3	2.1	0.7	5,289.6	3.3	15.9	9.7	1.2	0.4	35.9	0.9
V-L Molecular Weight	18.015	19.556	19.556	20.552	44	43.641	33.943	26.195	---	42.991	12.564	12.564	28.887	28.339	18.015	28.339
English Units																
V-L Flowrate (lb_{mol}/hr)	12,422	49,847	49,847	54,601	13,525	13,464	814	9,715	0	148	40,262	38,770	241,848	304,243	69,965	304,243
V-L Flowrate (lb/hr)	223,783	974,816	974,816	1,122,169	588,685	587,578	27,633	254,480	0	6,350	505,852	487,108	6,986,307	8,622,066	1,260,444	8,622,066
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	0	9,960	0	0	0	0	0	0	0
Temperature (°F)	650	496	509	94	60	167	119	290	344	127	87	349	59	1,067	1,017	268
Pressure (psia)	740.0	539.7	512.6	467.6	149.7	2,214.7	23.7	14.2	17.3	30.0	469.6	423.1	14.7	15.2	1,814.7	15.2
Enthalpy (Btu/lb)	1,317.3	700.2	469.2	19.2	3.0	-35.7	41.8	336.9	---	44.4	28.8	177.3	11.1	330.3	1,490.6	116.9
Density (lb/ft^3)	1.257	1.066	0.973	1.636	1	26.863	0.130	0.046	330.218	0.207	0.995	0.606	0.076	0.026	2.244	0.055

Appendix A-3 Case 3B2 Plant Performance Summary (100 Percent Load)

CASE	3B2	Units
Plant Output		
Gas Turbine Power	464,100	kWe
Steam Turbine Power	255,400	kWe
Total	**719,500**	**kWe**
Auxiliary Loads		
Coal Handling	430	kWe
Coal Milling	1,850	kWe
Biomass Handling	180	kWe
Biomass Processing	5,920	kWe
Slag Handling	600	kWe
Air Separation Unit Auxiliaries	1,000	kWe
Air Separation Unit Main Air Compressor	68,490	kWe
Oxygen Compressor	9,500	kWe
Nitrogen Compressors	33,940	kWe
CO2 Compressor	19,590	kWe
Boiler Feedwater Pumps	3,860	kWe
Condensate Pump	270	kWe
Quench Water Pump	560	kWe
Syngas Recycle Compressor	1,320	kWe
Circulating Water Pump	4,450	kWe
Cooling Tower Fans	2,300	kWe
Air Cooled Condenser Fans	0	kWe
Scrubber Pumps	560	kWe
Acid Gas Removal	11,170	kWe
Gas Turbine Auxiliaries	1,000	kWe
Steam Turbine Auxiliaries	100	kWe
Claus Plant/TGTU Auxiliaries	250	kWe
Miscellaneous Balance of Plant[1]	3,000	kWe
Transformer Losses	2,630	kWe
Total	**172,970**	**kWe**

CASE	3B2	Units
Plant Performance		
Net Auxiliary Load	172,970	kWe
Net Plant Power	546,530	kWe
Net Plant Efficiency (HHV)	32.5%	
Net Plant Heat Rate (HHV)	11,084 (10,505)	kJ/kWhr (Btu/kWhr)
Coal Feed Flowrate	179,575 (395,894)	kg/hr (lb/hr)
Biomass Feed Flowrate	76,961 (169,669)	kg/hr (lb/hr)
Biomass Feed Percentage	30.0%	wt % of total feed
GHG Emitted	800	Lb CO_2e/MWh
Thermal Input	1,682,678	kWth
Condenser Duty	1,509 (1,430)	GJ/hr (MMBtu/hr)
Raw Water Usage	19.2 (5,081)	m3/min (gpm)
% Syngas Bypassing WGS	44.5%	
% Syngas Carbon Captured	51.3%	

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

Appendix A-4 Case 3B2 Carbon Balance

Carbon In, kg/hr (lb/hr)		Carbon Out, kg/hr (lb/hr)	
Coal	114,854 (253,209)	**Slag**	714 (1,573)
Biomass	27,867 (61,437)	**Stack Gas**	64,948 (143,185)
Air (CO_2)	552 (1,217)	**ASU Vent**	109 (241)
		CO_2 Product	72,885 (160,685)
		Dryer Stack	4,617 (10,178)
Total	**143,273 (315,863)**	**Total**	**143,273 (315,863)**

Appendix A-5 Case 3B2 Sulfur Balance

Sulfur In, kg/hr (lb/hr)		Sulfur Out, kg/hr (lb/hr)	
Coal	4,522 (9,969)	**Elemental Sulfur**	4,518 (9,960)
Biomass	7 (14)	**HRSG Stack**	2 (5)
		Dryer Stack	0 (0)
		CO_2 Product	9 (19)
Total	**4,529 (9,984)**	**Total**	**4,529 (9,984)**

Appendix A-6 Case 3B2 Air Emissions Summary

	kg/GJ ($lb/10^6$ Btu)	Tonne/year (tons/year) @ 80% capacity factor	kg/gross MWh (lb/gross MWh)
SO_2	0.0008 (0.0018)	32 (35)	0.006 (0.014)
NO_X	0.0218 (0.0507)	926 (1,021)	0.184 (0.405)
Particulates	0.0031 (0.0071)	130 (143)	0.026 (0.057)
Hg	1.98E-07 (4.60E-07)	0.0084 (0.0092)	1.66E-06 (3.67E-06)
Life Cycle GHG Emissions (CO_2 Equivalent)	50 (115)	2,105,367 (2,320,770)	418 (921)
Anthropogenic Life Cycle GHG emissions (CO_2 Equivalent)	33 (76)	1,389,783 (1,531,973)	276 (608)

Appendix A-7 Case 3B2 Water Balance Summary

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)
Slag Handling	**0.50 (132)**	**0.50 (132)**	**0.0 (0)**	**0.0 (0)**	**0.0 (0)**
Quench Water	**3.5 (933)**	**3.1 (814)**	**0.45 (119)**	**0.0 (0)**	**0.45 (119)**
SWS Blowdown	**N/A**	**N/A**	**N/A**	**0.04 (9)**	**N/A**
Condenser Makeup	**2.0 (525)**	**0.0 (0)**	**2.0 (525)**	**0.0 (0)**	**2.0 (525)**
• *Gasifier Steam*	*0.12 (31)*				
• *Shift Steam*	*1.7 (448)*				
• *BFW Makeup*	*0.17 (46)*				
Cooling Tower Makeup	**17.3 (4,577)**	**0.53 (140)**	**16.8 (4,437)**	**3.9 (1,029)**	**12.9 (3,407)**
• *Coal Drying*		*0.0 (0)*			
• *BFW Blowdown*		*0.17 (46)*			
• *SWS Blowdown*		*0.36 (95)*			
• *SWS Excess*		*0.0 (0)*			
Total	**23.3 (6,167)**	**4.1 (1,086)**	**19.2 (5,081)**	**3.9 (1,029)**	**15.3 (4,042)**

Appendix A-8 Case 3B2 Energy Balance

	HHV	Sensible + Latent	Power	Total
Coal	4,873 (4,619)	5.0 (4.7)		4,878 (4,623)
Biomass	1,185 (1,123)	2.1 (2.0)		1,187 (1,125)
ASU Air		21 (20)		21 (20)
GT Air		82 (78)		82 (78)
Raw Water Makeup		72 (69)		72 (69)
Auxiliary Power			623 (590)	623 (590)
Totals	**6,058 (5,742)**	**182 (173)**	**623 (590)**	**6,863 (6,504)**
ASU Vent		2.4 (2.3)		2.4 (2.3)
Slag	23 (22)	39 (37)		62 (59)
Sulfur	42 (40)	0.5 (0.5)		42.4 (40.2)
CO_2 Product		-22 (-21)		-22 (-21)
Cooling Tower Blowdown		29 (27)		29 (27)
Gasifier Heat Loss		188 (178)		188 (178)
Combustion Turbine Heat Loss		63 (60)		63 (60)
HRSG Flue Gas		1,064 (1,008)		1,064 (1,008)
Dryer Stack Gas		90 (86)		90 (86)
Condenser		1,512 (1,433)		1,512 (1,433)
Non-Condenser Cooling Tower Loads[1]		622 (589)		622 (589)
Process Losses[2]		619 (586)		619 (586)
Power			2,590 (2,455)	2,590 (2,455)
Totals	**65 (62)**	**4,207 (3,988)**	**2,590 (2,455)**	**6,863 (6,504)**

Appendix A-9 Case 3B2 Total Plant Cost Estimate

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		ACTUAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	M$	$/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	$3,109	$0	$1,535	$0	$0	$4,643	$416	$0	$1,012	$6,071	$11
1.2	Coal Stackout & Reclaim	$4,017	$0	$984	$0	$0	$5,001	$438	$0	$1,088	$6,527	$12
1.3	Coal Conveyors	$3,735	$0	$974	$0	$0	$4,708	$413	$0	$1,024	$6,146	$11
1.4	Other Coal Handling	$977	$0	$225	$0	$0	$1,202	$105	$0	$262	$1,569	$3
1.5	Biomass Receive & Unload	$259	$0	$65	$0	$0	$324	$26	$0	$70	$419	$1
1.6	Biomass Handling	$90	$0	$0	$0	$0	$90	$7	$0	$20	$117	$0
1.7	Biomass Conveyors	$1,981	$0	$508	$0	$0	$2,489	$199	$0	$538	$3,226	$6
1.8	Biomass Hnd. Foundations	$0	$1,244	$0	$0	$0	$1,244	$99	$0	$269	$1,612	$3
1.9	Coal Hnd.Foundations	$0	$2,735	$6,840	$0	$0	$9,575	$918	$0	$2,099	$12,591	$23
	SUBTOTAL 1.	**$14,167**	**$3,979**	**$11,130**	**$0**	**$0**	**$29,276**	**$2,622**	**$0**	**$6,380**	**$38,278**	**$70**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	$35,386	$2,114	$5,210	$0	$0	$42,710	$3,691	$0	$9,280	$55,681	$102
2.2	Prepared Coal Storage & Feed	$1,676	$399	$266	$0	$0	$2,340	$201	$0	$508	$3,049	$6
2.3	Dry Coal Injection System	$55,159	$646	$5,176	$0	$0	$60,981	$5,260	$0	$13,248	$79,490	$145
2.4	Misc.Coal Prep & Feed	$922	$667	$2,032	$0	$0	$3,621	$332	$0	$791	$4,743	$9
2.5	Biomass Shredding & Drying	$2,148	$128	$316	$0	$0	$2,592	$224	$0	$563	$3,380	$6
2.6	Prepared Biomasss Storage & Feed	$2,772	$660	$439	$0	$0	$3,871	$332	$0	$841	$5,043	$9
2.7	Dry Biomass Injection System	$91,233	$1,069	$8,561	$0	$0	$100,863	$8,700	$0	$21,913	$131,476	$241
2.8	Booster Air Supply System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2.9	Coal & Biomass Feed Foundation	$0	$4,549	$3,761	$0	$0	$8,310	$766	$0	$1,815	$10,891	$20
	SUBTOTAL 2.	**$189,296**	**$10,232**	**$25,760**	**$0**	**$0**	**$225,289**	**$19,505**	**$0**	**$48,959**	**$293,753**	**$537**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	$2,515	$4,373	$2,310	$0	$0	$9,198	$849	$0	$2,009	$12,056	$22
3.2	Water Makeup & Pretreating	$620	$65	$346	$0	$0	$1,031	$97	$0	$339	$1,467	$3
3.3	Other Feedwater Subsystems	$1,389	$471	$424	$0	$0	$2,284	$204	$0	$498	$2,985	$5
3.4	Service Water Systems	$357	$729	$2,533	$0	$0	$3,620	$350	$0	$1,191	$5,162	$9
3.5	Other Boiler Plant Systems	$1,920	$737	$1,827	$0	$0	$4,483	$420	$0	$981	$5,884	$11
3.6	FO Supply Sys & Nat Gas	$288	$545	$508	$0	$0	$1,341	$128	$0	$294	$1,763	$3
3.7	Waste Treatment Equipment	$862	$0	$528	$0	$0	$1,390	$135	$0	$457	$1,982	$4
3.8	Misc. Equip.(cranes,AirComp.,Comm.)	$983	$132	$509	$0	$0	$1,624	$156	$0	$534	$2,315	$4
	SUBTOTAL 3.	**$8,934**	**$7,051**	**$8,986**	**$0**	**$0**	**$24,971**	**$2,340**	**$0**	**$6,303**	**$33,614**	**$62**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier, Syngas Cooler & Auxiliaries	$111,851	$0	$48,246	$0	$0	$160,097	$14,335	$21,886	$30,224	$226,542	$415
4.2	Syngas Cooling (w/4.1)	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0	$0
4.3	ASU/Oxidant Compression	$152,758	$0	w/equip.	$0	$0	$152,758	$14,540	$0	$16,730	$184,028	$337
4.4	LT Heat Recovery & FG Saturation	$28,451	$0	$10,705	$0	$0	$39,155	$3,763	$0	$8,584	$51,502	$94
4.5	Misc. Gasification Equipment w/4.1 & 4.2	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.6	Other Gasification Equipment	$0	$1,737	$707	$0	$0	$2,444	$233	$0	$535	$3,212	$6
4.8	Major Component Rigging	w/4.1&4.2	$0	w/4.1&4.2	$0	$0	$0	$0	$0	$0	$0	$0
4.9	Gasification Foundations	$0	$8,803	$5,059	$0	$0	$13,862	$1,265	$0	$3,782	$18,909	$35
	SUBTOTAL 4.	**$293,060**	**$10,540**	**$64,717**	**$0**	**$0**	**$368,317**	**$34,135**	**$21,886**	**$59,855**	**$484,193**	**$886**

Appendix A-9 Case 3B2 Total Plant Cost Estimate (continued)

5A	GAS CLEANUP & PIPING											
5A.1	Double Stage Selexol	$52,948	$0	$45,417	$0	$0	$98,365	$9,443	$19,673	$25,496	$152,977	$280
5A.2	Elemental Sulfur Plant	$8,210	$1,629	$10,601	$0	$0	$20,440	$1,971	$0	$4,482	$26,894	$49
5A.3	Mercury Removal	$2,299	$0	$1,751	$0	$0	$4,049	$388	$202	$928	$5,568	$10
5A.4	Shift Reactors	$6,269	$0	$2,525	$0	$0	$8,795	$837	$0	$1,926	$11,558	$21
5A.5	COS Hydrolysis	$2,038	$0	$2,663	$0	$0	$4,701	$454	$0	$1,031	$6,185	$11
5A.5	Blowback Gas Systems	$1,755	$295	$166	$0	$0	$2,217	$209	$0	$485	$2,910	$5
5A.6	Fuel Gas Piping	$0	$1,240	$855	$0	$0	$2,095	$191	$0	$457	$2,743	$5
5A.9	HGCU Foundations	$0	$1,045	$678	$0	$0	$1,723	$158	$0	$564	$2,445	$4
	SUBTOTAL 5A.	**$73,518**	**$4,210**	**$64,656**	**$0**	**$0**	**$142,384**	**$13,650**	**$19,875**	**$35,370**	**$211,279**	**$387**
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	$11,594	$0	$6,856	$0	$0	$18,449	$1,763	$0	$4,043	$24,255	$44
	SUBTOTAL 5B.	**$11,594**	**$0**	**$6,856**	**$0**	**$0**	**$18,449**	**$1,763**	**$0**	**$4,043**	**$24,255**	**$44**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	$88,000	$0	$5,325	$0	$0	$93,325	$8,779	$9,332	$11,144	$122,580	$224
6.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.3	Compressed Air Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
6.9	Combustion Turbine Foundations	$0	$684	$762	$0	$0	$1,446	$135	$0	$477	$2,055	$4
	SUBTOTAL 6.	**$88,000**	**$684**	**$6,087**	**$0**	**$0**	**$94,771**	**$8,914**	**$9,332**	$0	**$124,635**	**$228**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	$32,691	$0	$4,652	$0	$0	$37,342	$3,525	$0	$4,087	$44,954	$82
7.2	Open	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
7.3	Ductwork	$0	$1,603	$1,191	$0	$0	$2,794	$246	$0	$608	$3,648	$7
7.4	Stack	$3,174	$0	$1,193	$0	$0	$4,367	$415	$0	$478	$5,261	$10
7.9	HRSG,Duct & Stack Foundations	$0	$632	$611	$0	$0	$1,243	$115	$0	$408	$1,766	$3
	SUBTOTAL 7.	**$35,865**	**$2,235**	**$7,648**	**$0**	**$0**	**$45,747**	**$4,301**	**$0**	**$5,580**	**$55,629**	**$102**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	$26,505	$0	$4,426	$0	$0	$30,931	$2,964	$0	$3,389	$37,284	$68
8.2	Turbine Plant Auxiliaries	$181	$0	$416	$0	$0	$598	$58	$0	$66	$721	$1
8.3a	Condenser & Auxiliaries	$5,785	$0	$1,764	$0	$0	$7,550	$717	$0	$827	$9,093	$17
8.3b	Air Cooled Condenser	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
8.4	Steam Piping	$4,772	$0	$3,363	$0	$0	$8,136	$694	$0	$2,207	$11,037	$20
8.9	TG Foundations	$0	$894	$1,522	$0	$0	$2,416	$228	$0	$793	$3,437	$6
	SUBTOTAL 8.	**$37,244**	**$894**	**$11,492**	**$0**	**$0**	**$49,630**	**$4,661**	**$0**	**$7,282**	**$61,573**	**$113**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	$5,358	$0	$1,177	$0	$0	$6,534	$619	$0	$1,073	$8,226	$15
9.2	Circulating Water Pumps	$1,833	$0	$115	$0	$0	$1,949	$167	$0	$317	$2,433	$4
9.3	Circ.Water System Auxiliaries	$147	$0	$21	$0	$0	$168	$16	$0	$28	$212	$0
9.4	Circ.Water Piping	$0	$6,416	$1,637	$0	$0	$8,052	$713	$0	$1,753	$10,518	$19
9.5	Make-up Water System	$343	$0	$486	$0	$0	$829	$79	$0	$182	$1,090	$2
9.6	Component Cooling Water Sys	$733	$876	$619	$0	$0	$2,228	$206	$0	$487	$2,921	$5
9.9	Circ.Water System Foundations& Structures	$0	$2,073	$3,549	$0	$0	$5,622	$530	$0	$1,846	$7,998	$15
	SUBTOTAL 9.	**$8,414**	**$9,365**	**$7,604**	**$0**	**$0**	**$25,383**	**$2,329**	**$0**	**$5,685**	**$33,397**	**$61**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	$16,262	$0	$8,025	$0	$0	$24,287	$2,316	$0	$2,660	$29,264	$54
10.2	Gasifier Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.3	Cleanup Ash Depressurization	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.4	High Temperature Ash Piping	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.5	Other Ash Rrecovery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
10.6	Ash Storage Silos	$544	$0	$593	$0	$0	$1,137	$110	$0	$187	$1,434	$3
10.7	Ash Transport & Feed Equipment	$735	$0	$176	$0	$0	$912	$84	$0	$149	$1,145	$2
10.8	Misc. Ash Handling Equipment	$1,128	$1,382	$413	$0	$0	$2,923	$276	$0	$480	$3,679	$7
10.9	Ash/Spent Sorbent Foundation	$0	$48	$61	$0	$0	$108	$10	$0	$36	$154	$0
	SUBTOTAL 10.	**$18,669**	**$1,430**	**$9,268**	**$0**	**$0**	**$29,367**	**$2,796**	**$0**	**$3,512**	**$35,675**	**$65**

Appendix A-9 Case 3B2 Total Plant Cost Estimate (continued)

11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	$885	$0	$882	$0	$0	$1,767	$168	$0	$194	$2,129	$4
11.2	Station Service Equipment	$4,095	$0	$384	$0	$0	$4,480	$425	$0	$490	$5,395	$10
11.3	Switchgear & Motor Control	$7,826	$0	$1,435	$0	$0	$9,260	$858	$0	$1,518	$11,636	$21
11.4	Conduit & Cable Tray	$0	$372	$12,088	$0	$0	$12,460	$1,512	$0	$3,493	$17,465	$32
11.5	Wire & Cable	$0	$6,838	$4,600	$0	$0	$11,438	$836	$0	$3,069	$15,343	$28
11.6	Protective Equipment	$0	$627	$2,378	$0	$0	$3,005	$294	$0	$495	$3,793	$7
11.7	Standby Equipment	$211	$0	$215	$0	$0	$427	$41	$0	$70	$538	$1
11.8	Main Power Transformers	$10,054	$0	$134	$0	$0	$10,188	$772	$0	$1,644	$12,604	$23
11.9	Electrical Foundations	$0	$146	$385	$0	$0	$531	$51	$0	$174	$756	$1
	SUBTOTAL 11.	**$23,071**	**$7,983**	**$22,502**	**$0**	**$0**	**$53,556**	**$4,956**	**$0**	**$11,147**	**$69,658**	**$127**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0	$0
12.2	Combustion Turbine Control	N/A	$0	N/A	$0	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0	$0
12.4	Other Major Component Control	$1,004	$0	$698	$0	$0	$1,702	$164	$85	$293	$2,243	$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	$231	$0	$154	$0	$0	$385	$37	$19	$88	$529	$1
12.7	Computer & Accessories	$5,354	$0	$179	$0	$0	$5,533	$524	$277	$633	$6,967	$13
12.8	Instrument Wiring & Tubing	$0	$1,903	$3,984	$0	$0	$5,887	$499	$294	$1,670	$8,351	$15
12.9	Other I & C Equipment	$3,579	$0	$1,811	$0	$0	$5,390	$517	$269	$926	$7,103	$13
	SUBTOTAL 12.	**$10,167**	**$1,903**	**$6,825**	**$0**	**$0**	**$18,896**	**$1,741**	**$945**	**$3,611**	**$25,193**	**$46**
13	Improvements to Site											
13.1	Site Preparation	$0	$102	$2,191	$0	$0	$2,293	$226	$0	$756	$3,274	$6
13.2	Site Improvements	$0	$1,810	$2,423	$0	$0	$4,233	$416	$0	$1,395	$6,043	$11
13.3	Site Facilities	$3,243	$0	$3,448	$0	$0	$6,691	$657	$0	$2,204	$9,552	$17
	SUBTOTAL 13.	**$3,243**	**$1,912**	**$8,062**	**$0**	**$0**	**$13,217**	**$1,298**	**$0**	**$4,355**	**$18,870**	**$35**
14	Buildings & Structures											
14.1	Combustion Turbine Area	$0	$221	$127	$0	$0	$348	$31	$0	$76	$454	$1
14.2	Steam Turbine Building	$0	$2,079	$3,002	$0	$0	$5,081	$466	$0	$832	$6,379	$12
14.3	Administration Building	$0	$818	$602	$0	$0	$1,420	$126	$0	$232	$1,779	$3
14.4	Circulation Water Pumphouse	$0	$170	$91	$0	$0	$261	$23	$0	$43	$327	$1
14.5	Water Treatment Buildings	$0	$494	$488	$0	$0	$981	$89	$0	$161	$1,231	$2
14.6	Machine Shop	$0	$417	$289	$0	$0	$706	$63	$0	$115	$884	$2
14.7	Warehouse	$0	$673	$440	$0	$0	$1,114	$99	$0	$182	$1,394	$3
14.8	Other Buildings & Structures	$0	$403	$318	$0	$0	$721	$64	$0	$157	$943	$2
14.9	Waste Treating Building & Str.	$0	$909	$1,761	$0	$0	$2,670	$248	$0	$584	$3,501	$6
	SUBTOTAL 14.	**$0**	**$6,185**	**$7,118**	**$0**	**$0**	**$13,302**	**$1,209**	**$0**	**$2,381**	**$16,892**	**$31**
	TOTAL COST										**$1,597,361**	**$2,923**

Appendix A-10 Case 3B2 Operating and Maintenance Costs

INITIAL & ANNUAL O&M EXPENSES					Cost Base (June)	2007
Case 3B2 - Illinois #6 Coal and 30% Switchgrass w/ 800 lb/MWh Net GHG Emissions					Heat Rate-net(Btu/kWh):	10,505
					MWe-net:	547
					Capacity Factor: (%):	80
OPERATING & MAINTENANCE LABOR						
Operating Labor						
Operating Labor Rate(base):	34.65	$/hour				
Operating Labor Burden:	30.00	% of base				
Labor O-H Charge Rate:	25.00	% of labor				
			Total			
Skilled Operator	2.0		2.0			
Operator	10.0		10.0			
Foreman	1.0		1.0			
Lab Tech's, etc.	3.0		3.0			
TOTAL-O.J.'s	16.0		16.0			
					Annual Cost	Annual Unit Cost
					$	$/kW-net
Annual Operating Labor Cost	Maintenance labor cost		% of BEC	1.1649	$6,313,507	$11.552
Maintenance Labor Cost			BEC	$1,204,097	$14,026,829	$25.665
Administrative & Support Labor					$5,085,084	$9.304
TOTAL FIXED OPERATING COSTS					**$25,425,420**	**$46.522**
VARIABLE OPERATING COSTS						
						$/kWh-net
Maintenance Material Cost			% of BEC	2.1768	**$26,210,373**	**$0.00684**
Consumables	Consumption Initial	/Day	Unit Cost	Initial Cost		
Water (/1000 gallons)	0	3,658	1.08	**$0**	**$1,155,412**	**$0.00030**
Chemicals		5.959				
MU & WT Chem.(lb)	152,595	21,799	0.17	$26,409	$1,101,644	$0.00029
Carbon (Mercury Removal) (lb)	112,048	153	1.05	$117,670	$47,068	$0.00001
COS Catalyst (m3)	204	0.14	2,397.36	$490,259	$97,985	$0.00003
Water Gas Shift Catalyst (ft3)	3,872	2.7	498.83	$1,931,311	$385,998	$0.00010
Selexol Solution (gal.)	386	55	13.40	$5,166	$215,504	$0.00006
MDEA Solution (gal)	0	0	8.70	$0	$0	$0.00000
Sulfinol Solution (gal)	0	0	10.05	$0	$0	$0.00000
SCR Catalyst (m3)	0	0	0.00	$0	$0	$0.00000
Aqueous Ammonia (ton)	0	0	0.00	$0	$0	$0.00000
Claus Catalyst (ft3)	w/equip.	1.81	131.27	$0	$69,413	$0.00002
Subtotal Chemicals				**$2,570,816**	**$1,917,612**	**$0.00050**
Other						
Supplemental Fuel (MBtu)	0	0	0.00	$0	$0	$0.00000
Gases,N2 etc. (/100scf)	0	0	0.00	$0	$0	$0.00000
L.P. Steam (/1000 pounds)	0	0	0.00	$0	$0	$0.00000
Subtotal Other				**$0**	**$0**	**$0.00000**
Waste Disposal						
Spent Mercury Catalyst (lb)	0	153	0.42	$0	$18,693	$0.00000
Slag (ton)	0	610	16.23	$0	$2,890,680	$0.00075
Subtotal-Waste Disposal				**$0**	**$2,909,373**	**$0.00076**
By-products & Emissions						
Sulfur (tons)	0	119.5	0.00	$0	$0	$0.00000
Subtotal By-Products				**$0**	**$0**	**$0.00000**
TOTAL VARIABLE OPERATING COSTS				**$2,570,816**	**$32,192,771**	**$0.00841**
Coal (ton)	142,522	4,751	41.94	**$5,977,372**	**$58,179,753**	**$0.01519**
Biomass (ton)	61,081	2,036	77.06	**$4,706,762**	**$45,812,482**	**$0.01196**

APPENDIX B

Update of Coal Pricing Estimates for Select Coals

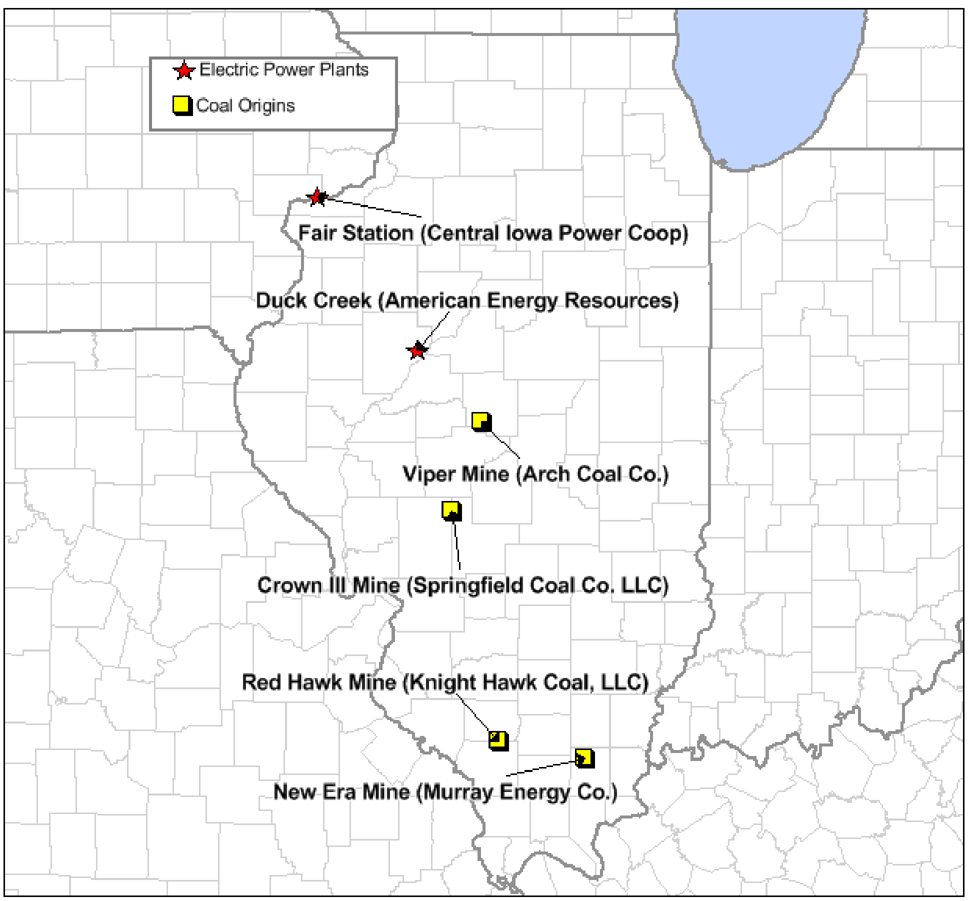
The source for data presented in this Appendix/Report is Ventyx Corporation's Energy Velocity (EV) Suite, a meta-database, which is a compilation of energy industry and market databases containing ten years of historical data [17].

Illinois Basin Coal (delivered to IL/MO/IA region)

Only one plant in this region, Duck Creek, took deliveries of Illinois basin coal in 2010 and 2011 (the others burned Southern PRB coal). Two plants (Duck Creek and Fair Station) took deliveries in 2009.

	2009	2010	2011 (through May)
Average delivered coal price, \$/MMBtu	2.01 ± 0.13	2.35 ± 0.05	2.59 ± 0.05
Average delivered coal price, \$/ton	43.38 ± 2.83	49.28 ± 0.89	54.59 ± 1.08
Average transportation cost, \$/ton	5.72 ± 1.29	5.77 ± 0.03	5.82 ± 0.01
Average coal price, FOB mine, \$/ton	37.66 ± 3.46	43.50 ± 0.92	48.77 ± 1.07

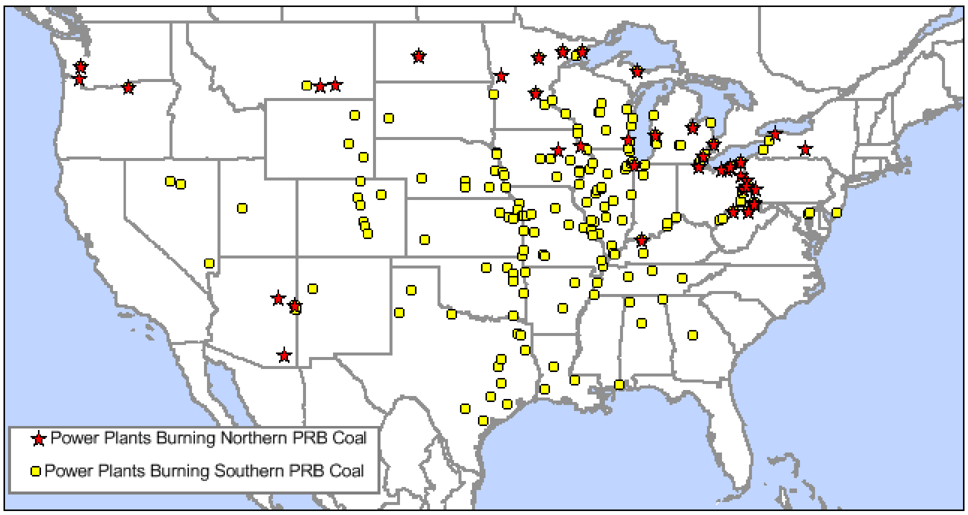
Note: (± represents 1 standard deviation)



Montana Rosebud PRB Coal (delivered to WY/NE region)

Montana Rosebud is a Northern Powder River Basin (NPRB) coal. NPRB coal is not delivered to eastern Wyoming/western Nebraska because this region is in the back yard of the Southern PRB (SPRB); NPRB's slightly higher heat content (ca. 9,500 Btu/lb compared to SPRB's 8,400-8,800 Btu/lb) is not enough to justify the additional transportation cost to this region.

NPRB coal represents around 10% of the total PRB production. In general, NPRB's market is limited because (1) it is dependent solely on the BNSF railroad for deliveries (SPRB is served by BNSF and the Union Pacific), and (2) its high sodium content cannot be tolerated by many coal-fired boilers. A map showing PRB power plant deliveries in 2009-2011 is shown below.



The Rosebud mine is essentially tied into a minemouth power plant (over 80% of the Rosebud mine's annual production is delivered by belt to the Colstrip power plant); therefore, to get a proper estimate of the cost of NPRB coal delivered to the WY/NE region, other NPRB coals should be included. The approach taken was to use Energy Velocity's estimated rail cost (in mills/ton-mile) multiplied by 525 miles (the approximate distance to the WY/NE region). This transportation cost was added to the average FOB mine prices estimated by Energy Velocity for the Absaloka, Decker, Rosebud, and Spring Creek mines. The results are in the following table.

	2009	2010	2011 (through May)
Average transportation cost, mills/ton-mile	15.64 ± 5.23	17.51 ± 4.93	19.26 ± 4.17
Average transportation cost, $/ton	8.21 ± 2.74	9.19 ± 2.59	10.11 ± 2.19
Average coal price, FOB mine, $/ton	14.45 ± 3.26	15.33 ± 2.79	18.21 ± 2.85
Average delivered coal price, $/ton	22.66 ± 4.26	24.52 ± 3.80	28.32 ± 3.59
Average delivered coal price, $/MMBtu	1.26 ± 0.24	1.41 ± 0.22	1.63 ± 0.21

Note: (± represents 1 standard deviation)

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