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Comprehensive Analysis of Coal and Biomass Conversion to Jet Fuel: Oxygen Blown, Transport Reactor Integrated Gasifier (TRIG) and Fischer-Tropsch (F-T) Catalyst Configurations Modeled and Validated Scenarios

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Acronyms and Abbreviations

AGR	Acid gas removal
ARR	Annual revenue requirement
ASU	Air separation unit
bbl	Barrel
Bcf	Billion cubic feet
BEC	Bare erected cost
BOE	Barrel of oil equivalent
bpd	Barrel per day
Btu	British thermal unit
CBTL	Coal biomass to liquids
CCAT	Connecticut Center for Advanced Technology
CCF	Capital charge factor
cf	Cubic feet
CH_4	Methane
COE	Crude oil equivalent
COS	Carbonyl sulfide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
CTL	Coal to liquids
CUBE	Calculating Uncertainty in Biomass Emissions
DFB	Dual Fluidized Bed
DLA	Defense Logistics Agency
DOD	Department of Defense
DOE	Department of Energy
eGRID	Emissions & Generation Resource Integrated Database
EC	Energy Conversion Facility
ECN	Energy Research Centre of the Netherlands
EIA	Energy Information Administration
EISA	Energy Independence and Security Act
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
EPC	Engineering, procurement and construction
EPCC	Engineering, procurement and construction cost
EU	End use
FOM	Fixed Operating and Maintenance Cost
F-T	Fischer-Tropsch
g	Gram
gal	Gallon
GHG	Greenhouse gas
GREET	Greenhouse Gas, Regulated Emissions and Energy Use in Transportation
GT	Gas turbine
GWP	Global warming potential
HEHTR	High Efficiency HydroThermal Reformation
HHV	High heating value
HRSG	Heat recovery steam generator
INL	Idaho National Laboratory
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
KBR	Kellogg, Brown and Root
kg	Kilogram
km	Kilometer
kWh	Kilowatt-hour
lb, lbs	Pound, pounds
LC	Life cycle
LCA	Life cycle assessment, analysis
LHV	Low heating value
LPG	Liquefied petroleum gas
m	Meter
m^3	Meters cubed
Mcf	Thousand cubic feet
MDEA	Methyldiethanolamine
MJ	Megajoule
MM	Million
MW	Megawatt
MWh	Megawatt-hour
N/A	Not applicable
N_2O	Nitrous oxide
NCCC	National Carbon Capture Center
NETL	National Energy Technology Laboratory
NGL	Natural gas liquids
NMVOC	Non-methane volatile organic compound
ORNL	Oak Ridge National Laboratory
PE	PE International
PFD	Process Flow Diagram
PRB	Powder River Basin
PSA	Pressure Separation Unit
psia	Pounds per square inch absolute
psig	Pounds per square inch gauge
PT	Product transport

RD&D	Research Development and Demonstration
RMA	Raw material acquisition
RMT	Raw material transport
RSP	Required selling price
SOM	Soil organic matter
SO_x	Sulfur Oxides
SRWC	Short rotation woody crop
T&D	Transmission and distribution
T&S	Transmission and storage
Tcf	Trillion cubic feet
TOC	Total overnight cost
TPC	Total plant cost
TPD	Ton per day
ton	Short ton (2,000 lb)
tonne	Metric ton (1,000 kg)
TRIG	Transport Reactor Integrated Gasifier
USDA	United States Department of Agriculture
WAG	Water alternating gas
WTI	West Texas Intermediate
WWTP	Waste water treatment plant

Executive Summary

The Connecticut Center for Advanced Technology (CCAT) has received funding from the Defense Logistics Agency (DLA) Energy to demonstrate whether liquid fuel can be produced from coal and meet the Energy Independence and Security Act (EISA) of 2007 greenhouse gas (GHG) requirement for Department of Defense (DOD) fuel purchases of synthetic fuel. Section 526 of EISA requires that any fuel purchases have a life-cycle CO_2 emission less than or equal to conventional petroleum fuel. Specifically, Section 526 of EISA provides that:

> *No Federal agency shall enter into a contract for procurement of an alternative or synthetic fuel, including a fuel produced from nonconventional petroleum sources, for any mobility-related use, other than for research or testing, unless the contract specifies that the life cycle greenhouse gas emissions associated with the production and combustion of the fuel supplied under the contract must, on an ongoing basis, be less than or equal to such emissions from the equivalent conventional fuel produced from conventional petroleum sources (Energy Independence and Security Act of 2007).*

Prior conceptual studies of coal-to-liquids (CTL) fuel production configurations have shown that it is possible to produce diesel and jet fuel using coal gasification followed by Fischer-Tropsch (F-T) synthesis and meet the requirements of Section 526. However, compliance requires aggressive capture (80 to 90 percent) and sequestration of carbon dioxide streams generated during the production of these fuels in a CTL facility (NETL, 2011b).

In addition to capture, another approach to achieving compliance that has been investigated is the use of a mixture of coal and biomass to produce F-T fuels. Life cycle GHG emissions from coal/biomass mixtures would be less than coal alone, because biomass is considered to be an approximately carbon-neutral feedstock (NETL modeling accounts for all emissions in the supply chain associated with the production and harvesting of biomass, thus it is not considered to be entirely carbon neutral) – biomass carbon is derived from recently removed carbon dioxide from the atmosphere via photosynthesis. Recent studies of conceptual coal/biomass-to-liquids (CBTL) configurations have shown that this combination, combined with carbon dioxide capture and management, can produce fuels with life cycle GHG emissions significantly less than those from conventional petroleum (NETL, 2011b).

Alongside technological and emissions considerations, economic values are of key importance to the viability of a potential CBTL facility – ideally, produced F-T fuels would be similar in cost to conventional products, in order to ensure commercial viability. Determining quality estimates of economic valuations for a CBTL facility is therefore needed to support further technological development, including demonstration and eventual commercialization.

In order to evaluate key considerations for F-T jet fuel production - technological process, compliance with EISA with respect to life cycle GHG emissions, and fuel cost/economic viability, this study incorporates results from technological/process, life cycle environmental, and economic models in order to evaluate 20 discrete F-T jet fuel production scenarios, as shown in **Table ES-1**: Overview of Study Scenarios. Boundaries considered for the analysis of F-T jet fuels production scenarios include geographic, temporal, material, and economic. Briefly, the assumed geographic system boundary considered for the purposes of this study includes all regions where modeled facilities would be located – specifically, the Southeastern U.S. for most facilities and processes, the Powder River Basin in Montana for coal extraction, and the Permian Basin in Texas for enhanced oil recovery. The temporal system boundary considered includes a 30-year operating time period (the study period). The material system boundary includes all physical processes and procedures considered in support of the modeled analysis, as shown in **Figure ES-1**.

Table ES-1: Overview of Study Scenarios

Scenario Property	Scenario Number and Name													
	1	2	3	4	5	6	7	8	9	10	11	12	13	14
	CBTL, 0% Biomass	CBTL, 10% Biomass, Chipped	CBTL, 20% Biomass, Chipped	CBTL, 10% Biomass, Torrefied	CBTL, 20% Biomass, Torrefied	CBTL, 10% Biomass, Microchipped, Separate Gasifiers	CBTL, 30% Biomass, Chipped	CBTL, 30% Biomass, Torrefied	CBTL, 11.7% Biomass, Chipped	CBTL, 19.2% Biomass, Chipped	CBTL, 28.3% Biomass, Chipped	CBTL, 16.5% Biomass, Torrefied	CBTL, 19.6% Biomass, Torrefied	CBTL, 28.3% Biomass, Torrefied
CBTL Facility Location	Southeastern U.S.													
Biomass Type	N/A	Short Rotation Woody Crops (Southern Yellow Pine)												
Coal Type	Montana Rosebud													
Biomass Pretreatment	N/A	Dry and Grind (from Wood Chips)		Torrefaction		Separate Gasifier	Dry and Grind (from Wood Chips)	Torrefaction	Dry and Grind (from Wood Chips)			Torrefaction		
Biomass Feed (by weight)	0%	10%	20%	10%	20%	10%	30%	30%	11.7%	19.2%	28.3%	16.5%	19.6%	28.3%
Gasifier Type	Single Feed, Transport, O_2 Blown					Separate Biomass Gasifier	Single Feed, Transport, O_2 Blown							
Liquefaction Type	Indirect													
F-T Reactor Type	Slurry Iron Catalyst													
Product Slate	Maximize F-T Jet Fuel Production													
CO_2 Capture	Acid Gas Removal (H_2S and CO_2 – i.e., Selexol) – 80-90%													
Default CO_2 Management	Carbon Capture and CO_2 Enhanced Oil Recovery													
Validated[1]	X								X	X	X	X	X	X

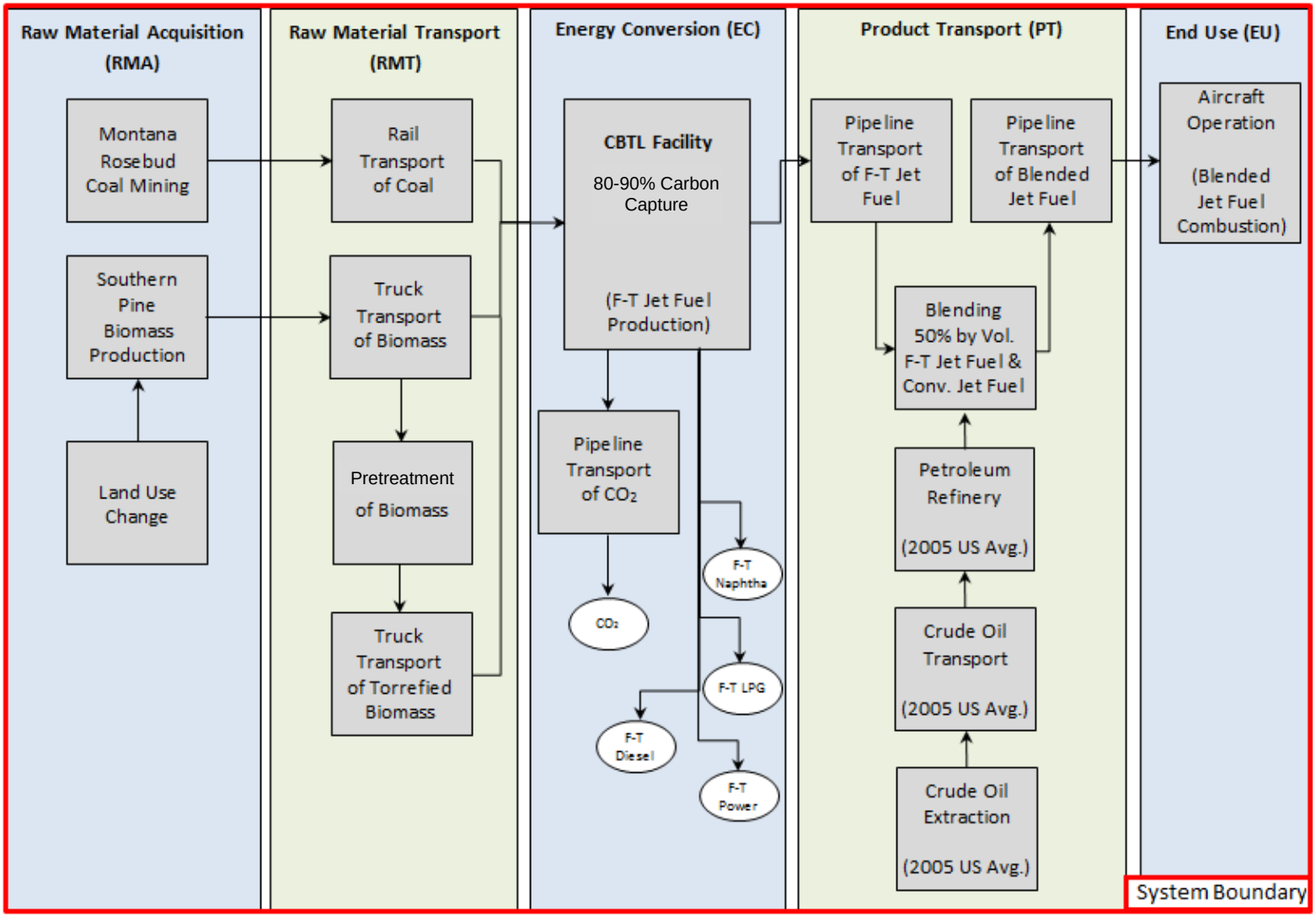
[1] The thirteen scenarios validated correspond to the experimental runs made at the Energy & Environmental Research Center (EERC) in Grand Forks, ND. A version of the EFG model was created that corresponded to the actual experimental conditions, including feed stream compositions and flows.

Table ES-1 Continued: Overview of Study Scenarios

Scenario Property	Scenario Number and Name					
	15	16	17	18	19	20
	CBTL, 11.7% Biomass, Pellets	CBTL, 19.2% Biomass, Pellets	CBTL, 28.3% Biomass, Pellets	CBTL, 16.5% Biomass, Torrefied, Pellets	CBTL, 19.6% Biomass, Torrefied, Pellets	CBTL, 28.3% Biomass, Torrefied, Pellets
CBTL Facility Location	Southeastern U.S.					
Biomass Type	Short Rotation Woody Crops (Southern Yellow Pine)					
Coal Type	Montana Rosebud					
Biomass Pretreatment	Pelleted			Torrefaction and Pelleted		
Biomass Feed (by weight)	11.7%	19.2%	28.3%	16.5%	19.6%	28.3%
Gasifier Type	Single Feed, Transport, O_2 Blown					
Liquefaction Type	Indirect					
F-T Reactor Type	Slurry Iron Catalyst					
Product Slate	Maximize F-T Jet Fuel Production					
CO_2 Capture	Acid Gas Removal (H_2S and CO_2 – i.e., Selexol) – 80-90%					
Default CO_2 Management	Carbon Capture and CO_2 Enhanced Oil Recovery					
Validated[1]	X	X	X	X	X	X

[1] The thirteen scenarios validated correspond to the experimental runs made at the Energy & Environmental Research Center (EERC) in Grand Forks, ND. ", a version of the EFG model was created that corresponded to the actual experimental conditions, including feed stream compositions and flows.

Figure ES-1: Material System Boundary for the Study



The technological/process model provides a process level evaluation of the 20 alternate CBTL facility scenarios considered in this study. The CBTL facility configuration considered in support of the technological analysis and process model design for the CBTL facility consider both biomass and coal feedstock supplies, as those would be processed through the CBTL facility into a suite of co-products, including F-T jet fuel, F-T diesel, F-T naphtha, F-T liquefied petroleum gas (LPG), F-T power, and captured carbon dioxide. The facility incorporates aggressive carbon capture, which ranges from 88 to 90 percent across the scenarios evaluated. Aspen Plus® simulation models for the CBTL facility scenarios were developed to determine the composition and flows of all of the major streams in the plants. These were used to develop conceptual level cost estimates for capital and operating costs for the major process units. Site specific data was incorporated into the Aspen Plus® models for an assumed plant location in the Southeastern United States. Thus, results from the technological/process model were used to inform the economic and life cycle models, and also assist with refining key considerations for a development and demonstration/trial of the CBTL process, that is also being considered concurrent to this effort.

One of the primary aims of the experimental testing done for this project was to verify that the performance predictions made by the model were consistent with the experimental observations. To perform this "validation", a version of the TRIG model was created that corresponded to the actual experimental conditions, including feed stream compositions and flows. A data regression was then performed to fit the gasifier heat loss, carbon conversion, and chemistry model to the experimental data.

Thirteen of the scenarios validated correspond to the experimental runs made at the National Carbon Capture Center (NCCC). In addition to a coal-only case (Scenario 1), three cases using coal and pelletized Southern Pine biomass at different biomass fractions (11.7 percent, 19.2 percent, and 28.3 percent - Scenarios 15, 16, and 17) as well as three cases using coal and pelletized torrefied Southern Pine biomass at different mass fractions (16.5 percent, 19.6 percent, and 28.3 percent - Scenarios 18, 19, and 20) were analyzed . In addition to these seven scenarios, six scenarios using non-pelletized Southern Pine biomass were validated. Three cases used coal and raw Southern Pine biomass at different biomass fractions (11.7 percent, 19.2 percent, and 28.3 percent – Scenarios 9, 10, and 11) as well as three cases using coal and torrefied Southern Pine biomass at different biomass fractions (16.5 percent, 19.6 percent, and 28.3 percent – Scenarios 12, 13, and 14). Torrefaction is the process of heating biomass in a very low oxygen environment so that pyrolysis of the biomass occurs through thermochemical reactions. This heating removes both unbound and bound water, and it increases the calorific value of the biomass.

The validation results were compared to the modeled results for all 13 scenarios listed above. The average deviation in calculated process outputs was less than 1.5 percent for every case. The torrefied biomass cases (chipped and pelleted)this were slightly closer in agreement than the both the raw and pelleted biomass cases. The most significant deviation was in the syngas H_2:CO ratio. The impact of this was to require a slight increase in capital equipment cost for the validation cases resulting in a slight increase in the estimated RSP of jet fuel of between 0.10 and 0.50 $/bbl. For the remainder of the report, the modeled and validated results will be shown together where applicable.

The economic model completed in support of this study calculates required selling price (RSP) of F-T jet fuel, based on an array of economic factors and cost estimates. RSP is the minimum price at which the products must be sold to recover the annual revenue requirement (ARR) of the plant. The ARR is the annual revenue needed to pay the operating costs, service the debt, and provide the expected rate of return for the investors. The baseline economic model assumes that that 50% of the project capital costs are financed by debt service at an interest rate of 8%. If the market price of the

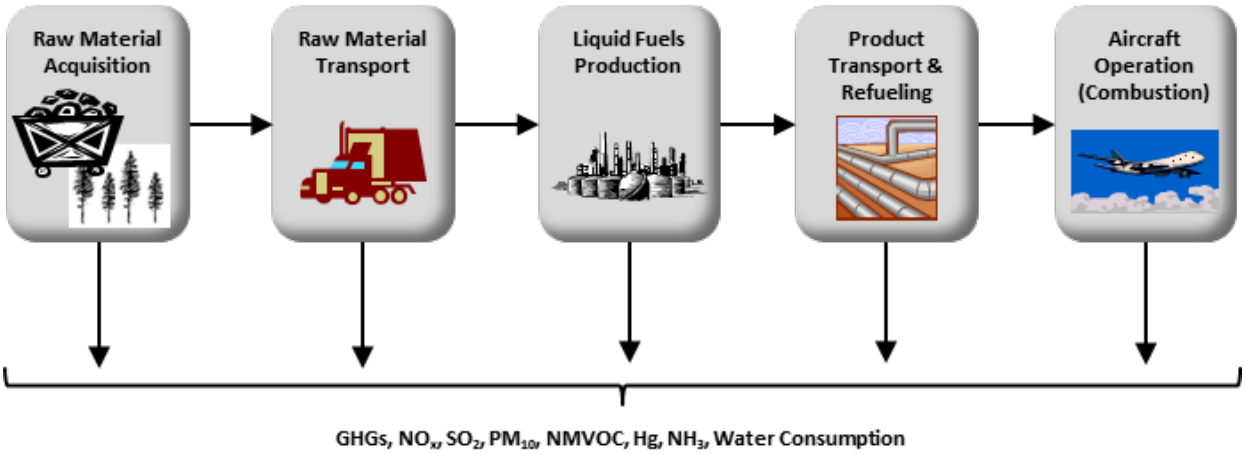
products is equal to or above the calculated RSP, the CBTL project is considered economically viable.

The environmental life cycle assessment model provides a comprehensive analysis of life cycle GHG emissions, including the extraction/production of raw materials (coal and biomass), the transport of raw materials, the production of F-T fuels, the transport of produced fuels, and final jet fuel combustion associated with end use. Environmental flows for each of these categories are considered, including operational emissions that result from the various processes included within the material system boundary for the study, and the construction of equipment and other facilities required for these processes. All of the co-products produced from the facility (diesel, naphtha, LPG, electric power, and captured CO_2) are managed by expanding the boundaries of the system. Using co-product allocation to apportion emissions does not provide for an accurate accounting of the differences in useful energy between the electric power and liquid products produced from the facility.Thus, system expansion with co-product displacement was utilized as the recommended method. Drawbacks include the complex interactions of market supply and demand that may negate any real world displacement from occurring.

When CO_2 is directed to EOR, it is assumed that it displaces CO_2 from a natural dome which is already being utilized for EOR. As illustrated by **Figure ES-1**, the boundaries of the EOR operation are not included in the system diagram for this study. The justification for the exclusion is based on the assumption that EOR will proceed regardless of whether or not this new source of CO_2 (the CBTL plant) is available. This assumption is valid because there are natural sources of CO_2 that are already available and are being utilized by EOR operators. Approximately 90 percent of CO_2 for EOR is sourced from natural sources (P. DiPietro, Balash, P., Wallace, M., 2012). With this assumption, it is not necessary to include the full extent of EOR operations in the boundary and thus, displacement of natural dome CO_2 is appropriate.

System expansion expands the boundaries of an LCA until the functional unit is the only product that exits the system and all other co-products are contained within the system. For system expansion to be effective, it is often necessary to include the displacement of a parallel supply chain within the system boundaries. Displacement assumes that a co-product displaces a product having the same function, but is produced by a different process, typically at an unrelated facility. The primary advantage of system expansion is that it evaluates the change in environmental burdens from producing the alternative product and entering it into the marketplace. Life cycle emissions estimates focus on life cycle GHG emissions, but other emissions were also considered, including select criteria air pollutants (NO_X, SO_2, and PM), other pollutants of concern, and water consumption. Life cycle emissions are evaluated and broken down according to five discrete life cycle stages, as shown in **Figure ES-2**.

Figure ES-2: Life Cycle Stages Schematic for the Study

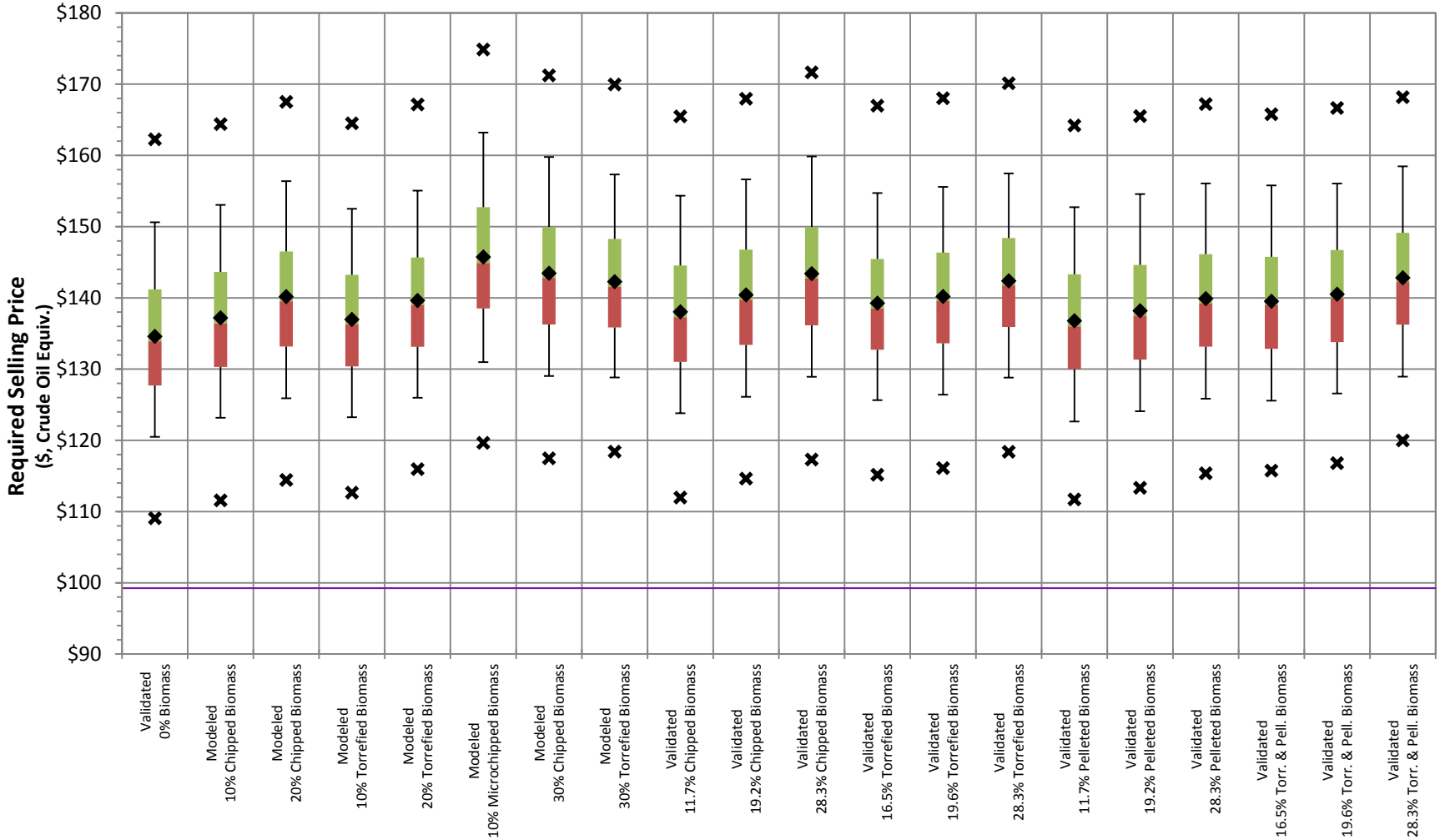


Source: Adapted From (Aviation Fuel Life Cycle Assessment Working Group, 2011)

RSP values (crude oil equivalent basis) for F-T jet fuel are summarized in **Figure ES-3**, for each of the 20 production scenarios described previously. Here, the solid horizontal line does not indicate a baseline value or requirement. There are no baseline EISA requirements with respect to fuel cost. Instead, the solid horizontal line provides a simple comparison point, and represents Cushing, OK West Texas Intermediate (WTI) spot pricing for crude oil from early 2014 scaled to 2011 dollars; $99.24/bbl of crude oil (EIA, 2014).

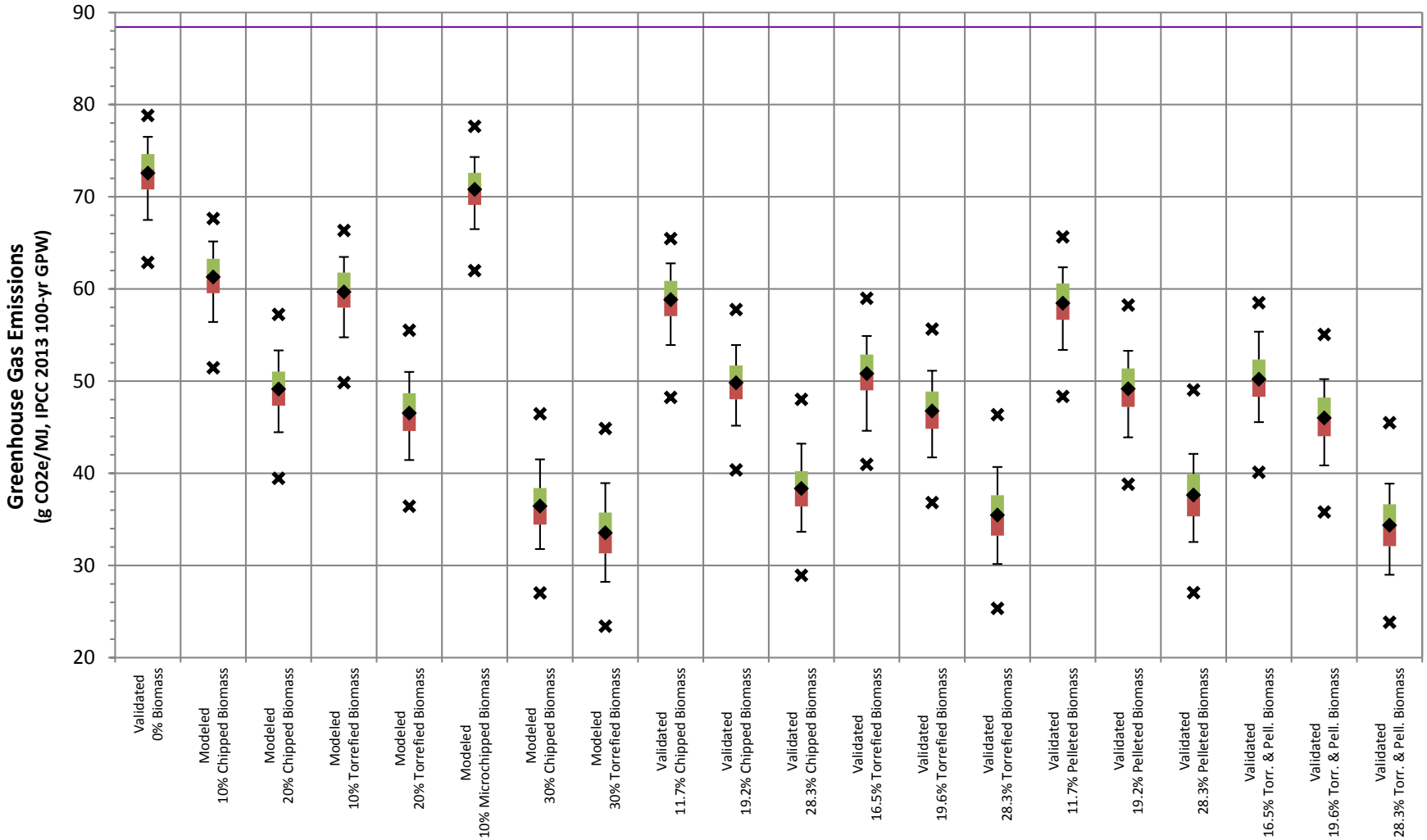
Results from the life cycle GHG emissions model are summarized in **Figure ES-4** for each of the 20 production scenarios described previously. The solid horizontal line indicates the estimated life cycle emissions level for baseline conventional jet fuel, consistent with EISA requirements.

Figure ES-3: F-T Jet Fuel, Required Selling Price ($, Crude Oil Equivalent)



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel spot price value.

Figure ES-4: Summary of GHG Emissions derived from Combined Co-product Management, All Scenarios



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

The following conclusions have resulted from the technical, economic, and life cycle environmental analysis of the 20 F-T jet fuel production scenarios considered in this study.

Technical Analysis Conclusions:

- The CBTL, 0 percent Biomass CBTL facility configuration is estimated to have an overall HHV efficiency of 53.2 percent. A very aggressive pinch analysis[1] was used in the simulations for optimal heat integration, utilization, and recovery. This procedure is likely to result in higher overall efficiencies for a conceptual plant than would be expected for a commercially operating facility. The CBTL facility processes 30,500 tons per day of Montana Rosebud subbituminous coal to produce 50,000 barrels per day of products, of which jet fuel constitutes about 49 percent by volume (remaining products were diesel at 10 percent, naphtha at 34 percent, and LPG at 7 percent).
- Co-gasification of chipped and coal in the same gasification system results in a slight lowering of the overall efficiency, in comparison to coal only, coal/pelleted biomass and, coal/torrefied biomass scenarios. This is because of the lower quality of the chipped biomass compared to coal, pelleted, or torrefied biomass, with respect to carbon content, moisture content, and heating value, and because more parasitic power is required for chipped biomass preparation.

Economic Analysis Conclusions:

- The average required selling price of the jet fuel product for the 20 scenarios has an estimated 25th to 75th percentile range of $133 to $146/bbl on a crude oil equivalent basis. This required selling price is above current world oil prices. For comparison, WTI spot pricing from early 2014 scaled to 2011 dollars was $99.24/bbl.
- The Total Overnight Cost (TOC) for the configurations evaluated in this study range from $7.4 to $12 billion spanning the range of uncertainty in all of the economic parameters considered.
- Under the financial structure for a loan guarantee scenario (60% of capital cost financied by debt service at an interest rate of 4.56% resulting in a capital charge factor = 0.1591), the RSP results for the scenarios range from $96/bbl to $116/bbl based on the 25th percentile/75th percentile values. These results are 4% lower to 17% higher than current crude oil prices. The mean values for each of the scenarios decreases by approximately $33/bbl or a 23.5% reduction. For example, the mean RSP for the 100% coal scenario decreases to $101/bbl. These differences illustrate the importance of the financing structure.
- Higher percentages of biomass utilized in the gasification process results in increased overall RSP. For example, the RSP of the jet fuel product for the CBTL, 0 percent Biomass scenario has an estimated 25th to 75th percentile range of $127 to $140/bbl, mean $134/bbl, while the CBTL, 10 percent Chipped Biomass scenario has a range of $130 to $144/bbl, mean $137/bbl, and the CBTL, 20 percent Chipped Biomass scenario has an RSP range of $133 to $147/bbl, mean $140/bbl. Thus, on average, use of 10 percent and 20 percent chipped

[1] Pinch analysis is an algorithm that was used in support of optimization for the modeled heat exchanger network. The analysis is used to reduce energy consumption of a process by first setting a feasible energy consumption target, then optimizing plant systems to attempt to meet those targets. CBTL facility systems included in the pinch analysis include the heat recovery systems, energy supply methods, and process operating conditions (Kemp, 2007; Leng, Abbas, & Khalilpour, 2010).

biomass drive an increase in RSP of about $3/bbl and $6/bbl over the CBTL, 0 percent Biomass scenario, respectively. The elevated cost results from the higher capital cost of the CBTL facilities under the biomass scenarios, mostly because of the costs of the biomass preparation and feeding. Another factor is the high cost of the delivered woody biomass feedstock to the plant on a dollars per MMBtu basis compared to coal.

- The use of torrefied biomass may result in a slight net decrease in RSP, in comparison to chipped biomass. For example, based on mean values of $143/bbl for the CBTL, 30 percent Chipped Biomass scenario and $142/bbl for the CBTL, 30 percent Torrefied Biomass scenario, torrefaction results in a total cost savings of about one dollars per barrel. Similarly, for the 10 percent biomass scenarios, comparing mean values of $137/bbl for chipped biomass to $137/bbl for torrefied biomass also results in a total cost savings of about a dollar per barrel. Note, however, that based on the observed range of RSP results for torrefaction and biomass grinding, under real world scenarios, cost savings associated with torrefaction versus grinding may not be differentiable.
- The RSP of the jet fuel product for the separate gasifier scenario is higher compared to the other scenarios that consider chipped or torrefied biomass at a 10 percent feed rate. The 25th to 75th percentile RSP range for the separate gasifiers scenario is $138 to $152/bbl, mean $146/bbl, compared to $130 to $144/bbl, mean $137/bbl for the 10 percent Chipped Biomass scenario, and $130 to $143/bbl, mean $137/bbl for the 10 percent Torrefied Biomass scenario. This is due to the higher capital cost for the CBTL facility under the separate gasification scenario. The additional costs for the ClearFuels® and DFB systems are not compensated for by the lower cost of the TRIG coal gasification system that now processes less feed material. The BEC of the ClearFuels®/DFB combination would have to be reduced by 44 percent to give the same RSP of jet fuel obtained for the other 10 percent biomass scenarios.
- There are two sets of three scenarios that examine the difference in biomass preparation, focusing on either chipped or pelletized biomass (11.7, 19.2, and 28.3 percent biomass). There is a slight reduction in the expected RSP when shifting from chipped to pelleted biomass in those scenarios, though the uncertainty bars generally overlap. Pelleted biomass is more expensive than chipped biomass due to the additional processing requirements upstream of the facility. However, because the pelleted biomass arrives at the plant with less moisture, the parasitic drying requirements are lower, which increases the overall efficiency of the plant and leads to the production of more export power than in the chipped cases. Additionally, there is a small reduction in the capital cost associated with biomass preparation/handling equipment and the gasifiers. The difference in the expected RSP values for the chipped and pelleted cases increases as the percentage of biomass in the feed increases.

Environmental Analysis Conclusions:

- All of the 20 scenarios indicated life cycle emissions that were entirely below the EISA baseline value of 88.41 g CO_2e/MJ, over the entire distribution of modeled results.
- For all scenarios, the mean total range of GHG emissions predicted by this study produced is 72.83 g CO_2e/MJ in the case of CBTL, 0% Biomass ,15.58 g CO_2e/MJ below the baseline or an 17.6% reduction and 33.52 g CO_2e/MJ in the case of CBTL, 30% Torrefied Biomass, 54.89 g CO_2e/MJ below the baseline or a 62.1% reduction. Therefore, results from this study indicate that all investigated scenarios would likely meet EISA requirements.

- Life cycle GHG emissions results underscore the importance of biological carbon sequestration during Southern pine production, and its effect on the overall life cycle emissions from jet fuel. Note that here, mean values alone are discussed in order to facilitate comparison among scenarios. Comparing the CBTL, 0% Biomass scenario to the CBTL, 20% Chipped Biomass scenario indicates that a 20% increase in biomass results in a 32.6% reduction in life cycle GHG emissions, from a mean value of 72.8 g CO_2e/MJ to 49.1 g CO_2e/MJ. The use of torrefied biomass provides a similar level of GHG emissions reduction, although the rate of emission reduction is dampened slightly due to the additional energy requirements of the torrefaction process. Thus, comparing the CBTL, 0% Biomass scenario to the CBTL, 20% Biomass, Torrefied scenario indicates that the latter provides a 36.1% reduction in life cycle GHG emissions, to a mean value of 46.5 g CO_2e/MJ for the latter scenario.
- There is a linear relationship between the percentage of biomass that is fed to the CBTL facility and the resulting life cycle GHG emissions. The exact percentage reduction differs depending on the biomass preparation methods, but for each 10% increase in the amount of biomass fed, there is roughly a 15% decrease in life cycle GHG emissions.
- A similar comparison cannot be directly drawn for the pelleted and pelleted/torrefied scenarios because of the inconsistencies in percent biomass, though similar trends are observed. Finally, incorporation of biomass provides a lesser degree of GHG emissions benefit for the separate gasifiers scenario. Life cycle GHG emissions from that scenario average 70.8 g CO_2e/MJ, based on a 10% rate of biomass co-feeding. This represents a 2.76% reduction in life cycle emissions in comparison to the CBTL, 0% Biomass scenario. Reliance on a single coal plus biomass gasifier, as modeled for the other 10% biomass scenarios, results in an additional net reduction in GHG emissions of up to 13.4% over and above the dual gasifiers scenario.
- The biomass content contained in the CBTL facility feedstock was also a key consideration with respect to life cycle GHG emissions. The results for the scenarios that utilized 30 percent biomass to generate F-T fuels had the lowest overall life cycle GHG emissions. The scenario that utilized 0 percent biomass feedstock had the highest overall life cycle GHG emissions, while scenarios that utilized 10 and 20 percent biomass feedstock had intermediary life cycle GHG emissions values. Incorporating biomass reduces life cycle GHG emissions because total carbon emissions are partially offset by the uptake of atmospheric carbon during biomass cultivation. Even considering GHG emissions associated with land use change that results from the cultivation of Southern pine biomass, utilization of biomass still results in a net reduction in life cycle GHG emissions, in comparison to the coal-only scenario.
- In the CBTL, 10 percent Biomass, Microchipped, Separate Gasifiers scenario, the chipped biomass is gasified in a separate gasification system from the coal. Because the ClearFuels® gasification and the Dual Fluid Bed reformer require significant fuel gas for heating and because this system operates at essentially atmospheric pressure, the overall efficiency of this configuration is lower than any of the other configurations. This configuration has 63.6 percent higher direct GHG emissions from the CBTL facility is because the combustion emissions from fuel gas required to heat the ClearFuels® gasifier and the DFB reformer are vented to atmosphere. With respect to life cycle GHG emissions, the separate gasifiers scenario results in comparatively higher life cycle GHG emissions than the other biomass scenarios considered, but on average still shows a net benefit over the CBTL, 0 percent

Biomass scenario. The separate gasifiers scenario results in a 25th to 75th percentile range in life cycle GHG emissions of 69.2 to 72.6 g CO_2e/MJ, mean 70.8 g CO_2e/MJ, while the CBTL, 0 percent biomass scenario results in a range of 71.1 to 74.8 g CO_2e/MJ.

- There are two sets of three scenarios that examine the difference in biomass preparation, focusing on either chipped or pelletized biomass (11.7, 19.2, and 28.3 percent biomass). Given the range of uncertainty associated with the life cycle GHG results, there is no statistically significant difference between chipped and pelletized biomass.

All of the cases are below the baseline requirements of EISA and additions of biomass result in an even larger reduction. The CBTL, 0 percent Biomass scenario had the lowest overall cost with an mean RSP of $134/bbl, but the highest overall life cycle GHG emissions at mean value of 72.8 g CO_2e/MJ, which was still 17.6 percent lower than the baseline requirement of 88.41 g CO_2e/MJ. Conversely, the 30 percent torrefied biomass scenario had an RSP of $142/bbl, but had the lowest life cycle GHG emissions at 33.5 g CO_2e/MJ. As discussed previously, variability in scenario performance, based on results from the stochastic analyses considered, could potentially support the viability of any of the 20 scenarios, given careful attention to design and financial parameters that inform life cycle GHG emissions and cost considerations.

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1 Introduction

This chapter provides background information for this study, including basic definitions, an overview of the scenarios considered, study boundaries, methods for technological/process, economic, and environmental models, an overview of the coal/biomass-to-liquids CBTL Jet Fuel Model, a summary of key study assumptions, and an overview of report structure.

1.1 About This Study

The Connecticut Center for Advanced Technology (CCAT) has received funding from the Defense Logistics Agency (DLA) to demonstrate how liquid fuel can be produced from coal and meet the Energy Independence and Security Act (EISA) of 2007 greenhouse gas (GHG) requirement for Department of Defense (DOD) fuel purchases of synthetic fuel. Section 526 of EISA requires that any fuel purchases have a life-cycle CO_2 emission less or equal to than conventional petroleum fuel. Specifically, Section 526 of EISA provides that:

> *No Federal agency shall enter into a contract for procurement of an alternative or synthetic fuel, including a fuel produced from nonconventional petroleum sources, for any mobility-related use, other than for research or testing, unless the contract specifies that the life cycle greenhouse gas emissions associated with the production and combustion of the fuel supplied under the contract must, on an ongoing basis, be less than or equal to such emissions from the equivalent conventional fuel produced from conventional petroleum sources (Energy Independence and Security Act of 2007).*

The next steps toward producing liquid fuels from coal in meaningful volumes include analysis and demonstration of alternative fuel production pathways, or key technology components within pathways, to produce synthetic fuel from coal and biomass gasification and Fischer-Tropsch synthesis. These steps are needed to:

1. Validate that CBTL pathways can produce a “Section 526” compliant fuel.
2. Demonstrate the domestic viability of co-feeding coal and biomass mixtures into a gasifier to produce a quality synthesis gas suitable for fuel production.
3. Improve the scientific knowledge-base and general understanding of coal and biomass synthetic fuel production options through targeted demonstration results, understanding of modeling uncertainty, and dissemination of project results to key stakeholders and the public.

1.2 Study Background, Scenarios, Validation and Boundaries

The following discussion of background for the study includes an overview of pertinent study background information, a review of the 20 scenarios considered, and a summary of the various categories of system boundaries that were considered in support of this analysis.

1.2.1 Study Background

Prior conceptual studies of coal-to-liquids (CTL) fuel production configurations have shown that it is possible to produce diesel and jet fuel using coal gasification followed by Fischer-Tropsch (F-T) synthesis and meet the requirements of Section 526 (States, 2007). However, compliance requires aggressive capture (80 to 90 percent) and sequestration of carbon dioxide streams generated during the production of these fuels in a CTL facility (NETL, 2011b).

A potential approach to achieving compliance could be based on feeding a mixture of coal and biomass to produce F-T fuels. Life cycle GHG emissions from coal/biomass mixtures would be less than coal alone, because biomass is considered to be an approximately carbon-neutral feedstock (NETL modeling accounts for all emissions in the supply chain associated with the production and harvesting of biomass, thus it is not considered to be entirely carbon neutral) – biomass carbon is derived from recently removed carbon dioxide from the atmosphere via photosynthesis. Recent studies of conceptual CBTL configurations have shown that this combination, combined with carbon dioxide capture and sequestration/utilization, can produce fuels with life cycle GHG emissions significantly less than those from conventional petroleum (NETL, 2011b). The LCA approach is discussed in detail in **Section 1.5**. The LCA methods are consistent with the previous analysis of the TRIG scenarios completed by NETL in 2013; however there are some differences in the management of the co-products from the CBTL facility. The details of the co-product management scheme utilized in this analysis are presented in **Section 1.5.6** and differences between the current and prior analysis are presented in **Section 1.8**.

These CBTL studies have been conceptual in nature and to date no commercial demonstration has been attempted. However, smaller bench, process development unit, and pilot scale experimental studies have been performed that have at least demonstrated the feasibility of using coal/biomass mixtures in this manner. Because CBTL technologies remain under early stages of development, there remain many technological uncertainties with respect to the production of liquid fuels from coal and biomass. For example, the sequential operations needed to progress from biomass and coal to fungible liquid fuels have not been demonstrated at larger production scales. However there is much that is already well established in commercial practice. For example woody biomass is commercially harvested in great quantities for pulp and paper manufacture. Similarly, coal is routinely used as a gasification feedstock to produce electric power, F-T fuels, fertilizers, and chemicals.

Economic values are of key importance to the viability of a potential CBTL facility. As discussed for the technological analysis above, no commercial scale demonstration of CBTL jet fuels production has been completed to date. As such, key economic factors, including the required selling price of product fuels needed to repay costs and investment returns, have not yet been demonstrated. Determining high-quality estimates of economic valuations for a CBTL facility is needed to support further technological development, including demonstration and, presumably, eventual commercialization.

The primary goals of the economic analysis provided here include determination of the required selling price (RSP) values for the 20 CBTL facility scenarios, and quantification of the key economic variables that most directly inform RSP for product fuels. The economic modeling that was completed in support of this study draws on the results of the technological analysis described above, in order to generate estimated RSP values for each scenario. RSP values are determined based on a combination of cost factors that account for feedstock supply, feedstock handling, and CBTL facility site infrastructure/construction costs, operations and maintenance costs, process contingency, and other relevant factors.

As discussed previously, Section 526 of EISA requires that potential alternative fuel sources demonstrate GHG emissions that are equal to or lower than conventional fuel, on a *life cycle* basis, prior to contractual procurement by a federal agency. Life cycle emissions are evaluated via Life Cycle Analysis (LCA), a method used to estimate and compare the environmental flows associated with the production of a product or service.

The LCA method used here is in compliance with the International Organization for Standardization (ISO) 14044: 2006(E) (2006), which requires the goal and scope of a study to be clearly defined and

consistent with the level of detail and intended use of the study results, and specifies procedural standards and reporting methodologies for the LCA. For additional background on the LCA method used in this study, please refer to **Chapter 4** of this document, and to ISO documentation (ISO, 2006). Additionally, this analysis demonstrates the evaluation of CBTL jet fuel production scenarios, based on common and accepted LCA method, to inform and evaluate potential for compliance with EISA Section 526.

1.2.2 Functional Unit

The functional unit is the basis of comparison for an LCA. The functional unit of this analysis is the combustion of 1 MJ LHV of blended jet fuel at 50/50 by volume. All results are expressed on the basis of this functional unit.

1.2.3 Scenarios Considered

This study models 20 jet fuel production scenarios, as show in **Table 1-1**. Each of the 20 scenarios relies on Powder River Basin Montana Rosebud subbituminous coal as a source of fossil energy. Aside from Scenario 1, all other scenarios utilize some amount of short rotation woody biomass ranging from approximately 10 to 30 percent by weight. The biomass scenarios are further specified by the pretreatment methods as shown in **Table 1-1**. As shown in **Table 1-1**, 13 of the 20 scenarios were also validated based on actual test data, but with PRB coal and Southern pine, meaning that there are a total of 33 sets of results. The validation methods will be discussed further in **Section 1.3.2**. All scenarios use indirect liquefaction with a slurry iron catalyst F-T reactor, and Selexol based CO_2 capture. Key differences among the scenarios include the biomass versus coal feed rate, as shown below, and use of dry and grind biomass preparation for the conventional chipping scenarios versus pelletization and/or torrefaction for the other scenarios. Biomass under the CBTL, 10 percent Biomass, Microchipped, Separate Gasifiers scenario would be fed into a separate gasifier. The biomass mass percentage is based on dried and prepared feedstocks. In all scenarios, the coal gasification used is the Transport Integrated Gasification (TRIG™) process. In the separate gasifiers scenario, the ClearFuels® High Efficiency HydroThermal Reformation (HEHTR) process combined with the Ni-DFB (Dual Fluidized Bed) tar reformer process is used. This process configuration is modeled after one previously in operation at a Rentech demonstration plant that is no longer in operation. Currently there are no other facilities operating with a similar configuration so there is no means to validate this scenario against actual operational conditions. The conceptual plants are assumed to be located in the Southeastern United States close to the harvested Southern pine biomass.

Table 1-1: Overview of Study Scenarios

Scenario Property	Scenario Number and Name													
	1	2	3	4	5	6	7	8	9	10	11	12	13	14
	CBTL, 0% Biomass	CBTL, 10% Biomass, Chipped	CBTL, 20% Biomass, Chipped	CBTL, 10% Biomass, Torrefied	CBTL, 20% Biomass, Torrefied	CBTL, 10% Biomass, Microchipped, Separate Gasifiers	CBTL, 30% Biomass, Chipped	CBTL, 30% Biomass, Torrefied	CBTL, 11.7% Biomass, Chipped	CBTL, 19.2% Biomass, Chipped	CBTL, 28.3% Biomass, Chipped	CBTL, 16.5% Biomass, Torrefied	CBTL, 19.6% Biomass, Torrefied	CBTL, 28.3% Biomass, Torrefied
CBTL Facility Location	Southeastern U.S.													
Biomass Type	N/A	Short Rotation Woody Crops (Southern Yellow Pine)												
Coal Type	Montana Rosebud													
Biomass Pretreatment	N/A	Dry and Grind (from Wood Chips)		Torrefaction		Separate Gasifier	Dry and Grind (from Wood Chips)	Torrefaction	Dry and Grind (from Wood Chips)			Torrefaction		
Biomass Feed (by weight)	0%	10%	20%	10%	20%	10%	30%	30%	11.7%	19.2%	28.3%	16.5%	19.6%	28.3%
Gasifier Type	Single Feed, Transport, O_2 Blown					Separate Biomass Gasifier	Single Feed, Transport, O_2 Blown							
Liquefaction Type	Indirect													
F-T Reactor Type	Slurry Iron Catalyst													
Product Slate	Maximize F-T Jet Fuel Production													
CO_2 Capture	Acid Gas Removal (H_2S and CO_2 – i.e., Selexol) – 80-90%													
Default CO_2 Management	Carbon Capture and CO_2 Enhanced Oil Recovery													
Validated[1]	X								X	X	X	X	X	X

[1] The thirteen scenarios validated correspond to the experimental runs made at the Energy & Environmental Research Center (EERC) in Grand Forks, ND. A version of the EFG model was created that corresponded to the actual experimental conditions, including feed stream compositions and flows.

Table 1-1 Continued: Overview of Study Scenarios

Scenario Property	Scenario Number and Name					
	15	16	17	18	19	20
	CBTL, 11.7% Biomass, Pellets	CBTL, 19.2% Biomass, Pellets	CBTL, 28.3% Biomass, Pellets	CBTL, 16.5% Biomass, Torrefied, Pellets	CBTL, 19.6% Biomass, Torrefied, Pellets	CBTL, 28.3% Biomass, Torrefied, Pellets
CBTL Facility Location	Southeastern U.S.					
Biomass Type	Short Rotation Woody Crops (Southern Yellow Pine)					
Coal Type	Montana Rosebud					
Biomass Pretreatment	Pelleted			Torrefaction and Pelleted		
Biomass Feed (by weight)	11.7%	19.2%	28.3%	16.5%	19.6%	28.3%
Gasifier Type	Single Feed, Transport, O_2 Blown					
Liquefaction Type	Indirect					
F-T Reactor Type	Slurry Iron Catalyst					
Product Slate	Maximize F-T Jet Fuel Production					
CO_2 Capture	Acid Gas Removal (H_2S and CO_2 – i.e., Selexol) – 80-90%					
Default CO_2 Management	Carbon Capture and CO_2 Enhanced Oil Recovery					
Validated[1]	X	X	X	X	X	X

[1] The thirteen scenarios validated correspond to the experimental runs made at the Energy & Environmental Research Center (EERC) in Grand Forks, ND. ", a version of the EFG model was created that corresponded to the actual experimental conditions, including feed stream compositions and flows.

1.2.4 Study Boundaries

The system boundary for this study is considered in terms of its geographical, temporal, material, and economic extents, which are discussed in the following text.

Geographic System Boundary: The geographic system boundary considered in this study includes all regions where modeled facilities would be located. The following regions are considered for the facilities that were evaluated in support of this study:

- Southeastern U.S.: Biomass production, biomass transport, CBTL facility, product transport, end use
- Powder River Basin, Montana: Coal extraction
- Permian Basin, Texas: Enhanced oil recovery

Temporal System Boundary: The temporal system boundary considered in this study includes a 30-year operating time period, referred to as the study period. The base year for the study period is flexible; however, the data incorporated into the study are intended to reflect current technology as of 2012. The study also incorporates a construction period, which is assumed to occur overnight, and which all economic and environmental flows are assumed to occur immediately at the time of study initiation.

Material System Boundary: The material system boundary for the study includes all physical processes and procedures considered in support of the modeled analysis. The materials system boundary includes modeled technology scenarios, as well as all energy production, transport, conversion, and end use processes that are included in the study. **Figure 1-1** provides a summary of the overall material system boundary for the study.

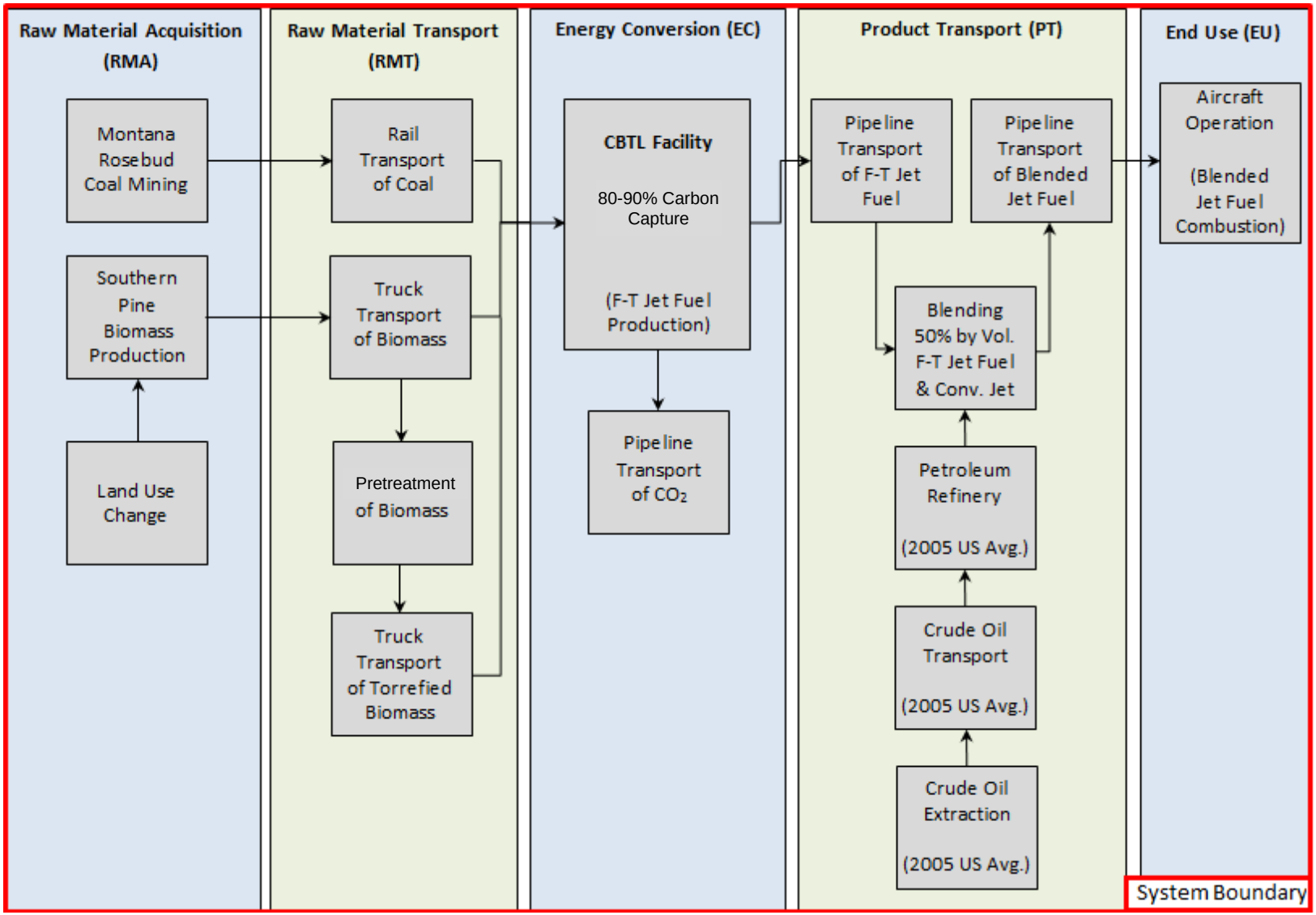
Economic System Boundary: The economic system boundary for the study includes costs and costing factors associated with the production, preparation, and transport of biomass, the delivered cost of coal, and the conversion of biomass and coal into liquid fuels. Additional considerations within the economic system boundary include current market costs for energy, fuels, raw materials, labor, debt, and other economic factors considered within the economic analysis. All values are expressed with 2011 as the base year.

1.3 Technological Analysis and Process Model Overview

The purpose of the technological analysis and process model was to provide a process level evaluation of the 20 alternate CBTL facility scenarios discussed in **Table 1-1**. Results from the process model are intended to inform the economic and life cycle models, and also assist with refining key considerations for a development and demonstration/trial of the CBTL process, that is also being considered concurrent to this effort.

The CBTL facility configuration considered in support of the technological analysis and process model design for the CBTL facility consider both biomass and coal feedstock supplies, as those would be processed through the CBTL facility into a suite of co-products, including F-T jet fuel, F-T diesel, F-T naphtha, F-T LPG, F-T electricity, and carbon dioxide.

Figure 1-1: Material System Boundary for the Study



Coal is routinely used as a gasification feedstock, and many commercial gasification systems have been developed to use all ranks of coal. Gasification systems for using woody biomass, although several are commercially available, are not so well developed. This is especially so for high-pressure operation. Woody biomass when reduced in size is still typically very fibrous with a long narrow aspect ratio. Unlike coal, which when ground is more spherical, the needle like fibrous structure of wood which can more easily block and bridge lock hoppers when feeding into high-pressure systems.

To overcome this, biomass gasifiers tend to operate at atmospheric pressure where pulp size wood chips or pellets can be successfully fed. Under prior investigations unrelated to this study, successful feeding of woody biomass to a high-pressure Shell entrained flow gasifier has been achieved (Ariyapadi, Shires, Bhargava, & Ebbern, 2008), but this required grinding the raw, green wood to very fine particle sizes (essentially sawdust), an expensive and energy intensive process.

An approach to overcome these unfavorable properties of green woody biomass is to use torrefaction. Torrefaction is the process of heating biomass in a very low oxygen environment so that carbonization of the biomass occurs through thermochemical reactions. This heating removes both unbound and bound water, and it increases the calorific value of the biomass. It lowers the oxygen to carbon ratio of the biomass and thermally decomposes the hemicellulose, which is primarily responsible for the long narrow aspect ratio of ground biomass. When heated between 180 and 260 degrees Celsius, release of volatiles occurs including carbon monoxide, carbon dioxide, methane, phenols, acetic acid, and higher hydrocarbons. The carbonized biomass is in many respects similar to coal. It has similar grinding energy requirements to coal and the ground biomass has an aspect ratio similar to coal particles. It should then be possible to feed the torrefied biomass to a pressurized gasification system as easily as it is to feed coal.

Another goal of this study is to determine if it is more efficient and economical to use a mixture of green biomass and coal in the same pressurized gasifier to produce fuels or to use torrefied biomass and coal. Using biomass and coal as feed to the same pressurized gasifier is called co-gasification in the context of this study. The result will largely depend on the relative costs of green versus torrefied woody biomass and on the relative energy savings from fine grinding green versus torrefied biomass.

Another option for producing F-T fuels from coal and woody biomass is to use separate gasification systems to produce synthesis gas from the coal and the biomass. In this study the ClearFuels® High Efficiency HydroThermal Reformation (HEHTR) gasification process combined with the Ni-DFB Dual Fluid Bed tar reformer process is used for the synthesis gas production from biomass (Wright & Ibsen, 2012). Both processes were under development by Rentech Inc. but the plant experimenting with the HEHTR configuration has stopped operations. Currently there are no other facilities operating with a similar configuration so there is no means to validate this scenario against actual operational conditions. The modeled HEHTR process operates at about 40 psia pressure and can accept green wood microchips (~5-10 mm) as feed. The Ni-DFB process is essentially a reformer for the tars and hydrocarbon gases that are produced in the HEHTR reactor.

The coal gasification process used in all the case studies is the TRIG process under development by Southern Company and KBR, Inc. in association with the DOE and Electric Power Research Institute. TRIG is a dry feed, fast circulating fluid bed, non-slagging, single stage gasifier especially suited for production of synthesis gas from low rank coals. A large scale pilot plant (approximately 50 tons per day) has been operating at the National Carbon Capture Center (NCCC) in Wilsonville, Alabama since 1995.

1.3.1 Process Performance Estimates via Aspen Plus® Modeling

The conceptual process designs for all of the CBTL facility scenarios considered here were based on systems level models for indirect coal liquefaction technology. Aspen Plus® simulation models for the CBTL facility scenarios were developed to determine the composition and flows of all of the major streams in the plants. These were used to develop conceptual level cost estimates for capital and operating costs for the major process units. Site specific data was incorporated into the Aspen Plus® models for an assumed plant location in the Southeastern United States.

Where appropriate, additional specialized software packages were used to extrapolate the performance of certain unit operations under site-specific conditions, such as validation of the gas turbine and steam cycle operating conditions and performance under the specific plant conditions and validation of simulation of operations like sour water stripping. These performance predictions were then incorporated into the Aspen Plus® systems models. The Aspen Plus® model results were validated against vendor data where possible and/or predictions from more detailed design models.

1.3.2 Validation

The performance assessments is based on the results of a computer model of the CBTL process written in Aspen Plus®. The model of the TRIG gasifier used in the CBTL model was based on performance projections for the TRIG gasifier in a commercial integrated gasification combined cycle (IGCC) application made by Kellogg, Brown and Root (KBR). One of the primary aims of the experimental testing done for this project was to verify that the performance predictions made by the model were consistent with the experimental observations. To perform this "validation", a version of the TRIG model was created that corresponded to the actual experimental conditions, including feed stream compositions and flows. A data regression was then performed to fit the gasifier heat loss, carbon conversion, and chemistry model to the experimental data.

Seven of the scenarios validated correspond to the experimental runs made at NCCC. In addition to a coal-only case (Scenario 1), three cases using coal and pelletized biomass at different biomass fractions (11.7 percent, 19.2 percent, and 28.3 percent - Scenarios 15, 16, and 17) as well as three cases using coal and pelletized torrefied biomass at different mass fractions (16.5 percent, 19.6 percent, and 28.3 percent - Scenarios 18, 19, and 20) were analyzed[1]. In addition to these seven scenarios, six scenarios using non-pelletized biomass were validated. Three cases used coal and raw biomass at different biomass fractions (11.7 percent, 19.2 percent, and 28.3 percent – Scenarios 9, 10, and 11) as well as three cases using coal and torrefied biomass at different biomass fractions (16.5 percent, 19.6 percent, and 28.3 percent – Scenarios 12, 13, and 14).

A stand-alone TRIG model was created representing the experimental configuration at NCCC. The primary adjustments made were to use nitrogen as transport gas instead of recycled syngas and to use the feed stream compositions, coal and biomass compositional analyses, and flow rates as were used at NCCC. The gasifier temperature and pressure were adjusted to match the NCCC conditions at each of the cases. The overall mass and energy balance was used to determine the carbon conversion and heat loss. The TRIG chemistry model is based on an approach to chemical equilibrium. This method calculates an equilibrium composition based on user-specified temperature approaches. The equilibrium constant used in the model is calculated at the approach temperature, rather than the gasifier temperature which allows the modeling of reactions that do not attain a true equilibrium

[1] The actual NCCC data consisted of 14 steady state periods. For scenarios with more than one steady state period, the data was averaged.

condition. The final approach temperatures were selected to give the best overall fit to the measured syngas compositions.

The final step in the validation was to incorporate the tuned model parameters in the commercial TRIG model with appropriate adjustments due to commercial scaling. The experimental carbon conversion and average heat loss were reasonably close to the values used in the original process model so no adjustments were made for those parameters. For the chemistry model, the calculated temperature approaches for most of the reactions were close to those used in the original model so the experimentally regressed values were used in the validated model. An exception to this was the temperature approach for the methanation reaction. The regressed value was so large that it indicated that this reaction was rate controlled and that the temperature approach formulation was not appropriate. The temperature approach used in the validation cases was set to give a reasonable agreement in the syngas methane mole fraction with the values measured experimentally.

The validation results were compared to the modeled results for all thirteen scenarios listed above. The average deviation in calculated process outputs was less than 1.5 percent for every case. For the pelletized biomass cases, the average deviation was less than 1.1 percent. The torrefied biomass cases were slightly closer in agreement than the biomass cases. The most significant deviation was in the syngas H_2:CO ratio. In the validation cases, this ratio was approximately 4 percent lower for the biomass cases and from 4 to 14 percent lower for the torrefied biomass cases. The impact of this was to require a slight increase in capital equipment cost for the validation cases resulting in a slight increase in the estimated RSP of jet fuel averaging about 0.55 $/bbl. For the remainder of the report, the modeled and validated results will be shown together where applicable. For more information on the validation procedure, see Appendix C.

1.4 Economic Model Overview

The economic model completed in support of this study calculates RSP of F-T jet fuel, based on an array of economic factors and cost estimates. RSP is the minimum price at which the products must be sold to recover the annual revenue requirement (ARR) of the plant. The ARR is the annual revenue needed to pay the operating costs, service the debt, and provide the expected rate of return for the investors. If the market price of the products is equal to or above the calculated RSP, the CBTL project is considered economically viable.

In most cases, modeled capital and operating cost estimates were obtained from conceptual level cost algorithms that scale costs based on one or more measures of unit capacity. In some cases, cost estimates were based on vendor quotes. In all cases, costs were adjusted to a June 2011 dollar basis. The method used to determine total capital requirement is as follows. The bare erected cost (BEC) estimates for the various conceptual plants consist of equipment cost, material cost, and installation labor costs. These three components are added to give the BEC of the individual unit operations. The engineering, procurement, and construction cost (EPCC) is the sum of the BEC and the home office costs. The home office costs include detailed design costs and construction and project management costs. Home office costs were estimated as 9.5 percent of the BEC.

The total plant cost (TPC) is the sum of the EPCC, the process contingencies, and the overall project contingency. The TPC is a depreciable capital expense. The process contingencies are added to the plant sections and the amount of the contingency depends on an engineering assessment of the level of commercial maturity of the process. The overall project contingency was assumed to be 15 percent of the sum of the BEC and process contingencies. This is added to compensate for uncertainty in the overall cost estimate. The Total Overnight Cost (TOC) of the plants is defined as the sum of the TPC and the Owner’s Cost.

The annual operating expenses for the plants are composed of fuel costs and variable and fixed operating costs. Fuel cost is the cost of the coal and woody biomass feedstocks to the plants based on assumed delivered prices. Non-fuel variable operating costs include catalysts and chemicals, water, solids disposal and maintenance materials. The small quantities of natural gas and electric power needed for start-up are not included. Fixed operating costs include labor, administrative and overhead costs, local taxes and insurance and fixed CO_2 transport costs. Gross annual operating costs are the sum of the fuel, variable, and fixed operating costs and are expressed in million dollars per year based on a given capacity factor expressed as a percentage of 365 days in one year. The capacity factor therefore represents the on-stream time for the plant that is the number of days in the year when the plant is producing products.

By-product credits include any sales of electric power to the grid. There is no credit assigned for the sale of elemental sulfur. It is assumed that the captured carbon dioxide will be used for enhanced oil recovery (EOR) operations and thus a value is assumed for the carbon dioxide captured.

1.5 Environmental Model Overview

The following provides a summary overview of the environmental life cycle assessment (LCA) model completed in support of this study.

1.5.1 Definition and Scope of Life Cycle Assessment

LCA refers to a series of methods used to estimate the environmental flows and burdens associated with the production of a specific product or service. LCA involves modeling various component processes that together comprise the full life cycle of the product or service in question, from the initial extraction of raw materials needed for the product or service, through to the final use and disposition of the product or service. The scope of an LCA reflects its purpose. This study presents a focused LCA that evaluates GHG emissions, select additional airborne emissions, and water consumption that result from the production of liquid fuels from coal and biomass feedstocks. GHG emissions in particular are important to the analysis, because life cycle GHG emissions from fuel production must comply with EISA, as described above, in order for the process to be viable.

1.5.2 Greenhouse Gases

GHGs are a suite of atmospheric gases that, through a complex series of physical and chemical interactions, serve to increase the rate at which the earth's atmosphere absorbs and/or retains heat. GHGs include a wide array of gases, many of which may be released from natural or anthropogenic sources, and some of which are released only by anthropogenic sources.

With respect to this study, quantification of life cycle GHG emissions focused on carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and sulfur hexafluoride (SF_6). These pollutants are generated during the production of alternative liquid fuels from coal and biomass. Hydrofluorocarbons and perfluorocarbons are not generated in large quantities during alternative liquid fuels production, and therefore were not considered further.

GHGs in this inventory are reported on a common mass basis of carbon dioxide equivalents (CO_2e) using the global warming potentials (GWP) of each gas from the 2013 Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5) (IPCC, 2013). The default GWP used is the 100-year time frame. **Table 1-2** shows the GWPs used for the GHGs inventoried in this study. Note that the AR5 GWP value used for fossil methane emissions was 30. There are no biogenic methane releases in the natural gas or coal models. The AR5 GWP for biogenic methane is 28.

Table 1-2: IPCC AR5 Global Warming Potentials (IPCC, 2013)

GHG	AR5 (IPCC 2013) 100-year (Default)
CO_2	1
CH_4	30
N_2O	265
SF_6	23,500

1.5.3 Other LCA Metrics

Various other potential metrics are commonly reported in support of LCAs. Other reported metrics range widely, based on the goals and purpose of a particular LCA. Select additional metrics have been considered here, based on availability of data and relevance to the life cycle scenarios considered in this analysis. The additional metrics considered are shown in **Table 1-3**, along with a brief definition.

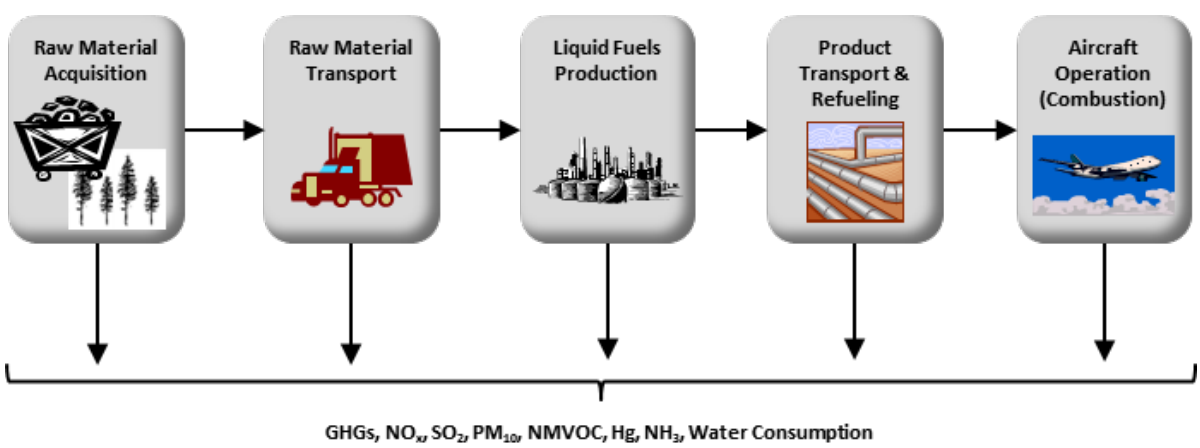
Table 1-3: Non-GHG LCA Reporting Metrics Included in this Study

LCA Metric	Category	Definition
Nitrogen oxide (NO_x)	Criteria Air Pollutant	Gaseous emissions of nitrogen oxide gases
Sulfur dioxide (SO_2)	Criteria Air Pollutant	Gaseous emissions of sulfur dioxide gas
Particular Matter (PM_{10})	Criteria Air Pollutant	Particle emissions to the atmosphere having a diameter of less than or equal to 10 microns
Non-Methane Volatile Organic Carbons (NMVOC)	Pollutant of Concern	Gaseous emissions of volatile organics, not including methane
Mercury (Hg)	Pollutant of Concern	Gaseous emissions of mercury
Ammonia (NH_3)	Pollutant of Concern	Gaseous emissions of ammonia
Water Consumption	Water	Volume of water consumed

1.5.4 Life Cycle Stages

Five discrete life cycle stages were considered within the scope of the LCA presented here. These are represented in the following figure, and described below in **Figure 1-2**:

Figure 1-2: Life Cycle Stages Schematic



Source: Adapted From (Aviation Fuel Life Cycle Assessment Working Group, 2011)

Raw Material Acquisition (RMA): Raw material acquisition includes all construction and operations activities associated with the extraction of coal from a coal mine, and the production and harvesting of biomass. RMA also includes land use requirements and GHG emissions associated with land use change, that result from the conversion of land from existing conditions, in support of relevant RMA activities.

Raw Material Transport (RMT): Raw material transport includes construction and operations activities associated with the transport of coal and biomass from the downstream boundary of RMA to the energy conversion facility. RMT includes construction and operation of trains and trucks used for the transport of feedstock, but does not include construction of main line rails or roadways. For scenarios that include torrefaction, torrefaction facility construction and operations are also considered within the boundaries of RMT.

Energy Conversion (EC): Energy conversion is the process by which feedstock is converted into product fuels. EC includes construction and operations activities associated with this conversion process, as well as carbon management. As such, EC considers construction and operation of the CBTL facility and carbon dioxide transport pipelines.

Product Transport (PT): Product transport includes the construction and operations activities associated with the transport of product jet fuel from the downstream boundary of the CBTL facility to the point of end use. This includes select pipelines and, for sensitivity analysis, trucks used for the transport of blended jet fuel. Within this study, PT also includes upstream emissions associated with the production and transport of conventional petroleum jet fuel, which is blended with F-T jet fuel within this life cycle stage.

End Use (EU): End use includes the construction and operation of a jet airplane, which consumes blended jet fuel produced within the scope of the LCA.

1.5.5 Methods

The method utilized in support of this study is in compliance with the International Organization for Standardization (ISO) 14044: 2006(E) (2006), which requires the goal and scope of a study to be clearly defined and consistent with the level of detail and intended use of the study results, and specifies procedural standards and reporting methodologies for the LCA. Additionally, this analysis demonstrates the evaluation of CBTL jet fuel production scenarios, based on common and accepted LCA method, to inform and evaluate potential for compliance with EISA Section 526.

1.5.6 Co-Product Management

The purpose of an LCA is to account for the environmental burdens associated with a product or service. When more than one product exits the system boundary of an LCA, it is necessary to re-define the system boundaries or apply some sort of allocation that splits life cycle burdens between products. To this end, ISO 14044 (2006b) states that inputs and outputs shall be allocated to the different co-products using process disaggregation, system expansion, or allocation. ISO's recommendations encourage the avoidance of co-products, which is why disaggregation and system expansion are recommended before allocation. In cases when there are strong relationships between co-products' physical or economic properties and their production requirements, allocation is an appropriate co-product management approach. When such relationships do not exist or when it is important to understand the broader consequences that co-products may have within an industry or throughout an entire economy, the expansion of system boundaries to envelop co-products is an appropriate co-product management approach.

Managing the co-production of electricity and liquid fuel is not straightforward. Allocation cannot be used to split burdens between electricity and captured CO_2 at the CBTL plant boundary because there is not a physical basis for comparing electrical energy to a mass of CO_2. Energy can be used as a basis for allocating between the electricity and liquid fuel that exit boundary of CBTL plant; however, doing so requires a comparison of two forms of energy – electricity and heat of combusted fuel (diesel, or jet fuel). Further, a megajoule of electricity accounts for the efficiency losses of thermoelectric power generation, while, within the boundaries of this analysis, one MJ of combustion heat does not account for the efficiency of converting heat to useful work. Since a MJ of electricity and a MJ of heat from combusted fuel are not providing equivalent services, it is hard to defend the use energy allocation in this case.

System expansion expands the boundaries of an LCA until the functional unit is the only product that exits the system and all other co-products are contained within the system. For system expansion to be effective, it is often necessary to include the displacement of a parallel supply chain within the system boundaries. Displacement assumes that a co-product displaces a product having the same function, but is produced by a different process, typically at an unrelated facility. The primary advantage of system expansion is that it evaluates the change in environmental burdens from producing the alternative product and entering it into the marketplace. Drawbacks include the complex interactions of market supply and demand that may negate any real world displacement from occurring. **Figure 1-3** provides a summary of the system expansion system boundary that was used in support of this study. Note that all co-products from the CBTL facility are included within the system boundary. F-T jet fuel is the only product that exits the system. The other products (F-T diesel, F-T naphtha, LPG, electricity and captured CO_2) are included within the boundaries by considering the products they could potentially displace. This analysis assumes 100 percent displacement of all co-products. The model provides the flexibility to model the uncertainty regarding this assumption for electricity, diesel, and captured CO_2 if better data are available.

When CO_2 is directed to EOR, it is assumed that it displaces CO_2 from a natural dome which is already being utilized for EOR. As illustrated by **Figure 1-3**, the boundaries of the EOR operation are not included in the system diagram for this study. The justification for the exclusion is based on the assumption that EOR will proceed regardless of whether or not this new source of CO_2 (the CBTL plant) is available. This assumption is valid because there are natural sources of CO_2 that are already available and are being utilized by EOR operators. Approximately 90 percent of CO_2 for EOR is sourced from natural sources (P. DiPietro, Balash, P., Wallace, M., 2012). With this assumption, it is not necessary to include the full extent of EOR operations in the boundary and thus, displacement of natural dome CO_2 is appropriate. CO_2 domes are reservoirs that contain high-purity carbon dioxide. Existing CO_2 domes include McElmo, Sheep Mountain, Jackson, and Bravo domes in the western United States. The displacement value utilized is based on an NETL model for emissions associated with the production of CO_2 from natural domes (NETL, 2013b). Since the study boundary for the CBTL facility includes the compression of the CO_2 to a supercritical state so that it is pipeline-ready, the conventional source (natural dome), must also be compressed. The majority of the displacement comes from the difference in the source of the power that is utilized to compress the CO_2. In the case of the natural dome, the U.S. grid mix is assumed to be the source of electricity, while the CO_2 compressors at the CBTL facility are powered by co-produced power, which has much lower emissions per MWh since it comes from a facility that is capturing CO_2.

Displacement factors for electricity account the cradle-to-gate generation of electricity at the power plant busbar and are based on the average U.S. grid mix from 2010. However, to account model uncertainty, extreme life cycle values for electricity are also used. Fleet coal is used to represent a high value for displaced electricity, and the Environmental Information Agency (EIA) Annual

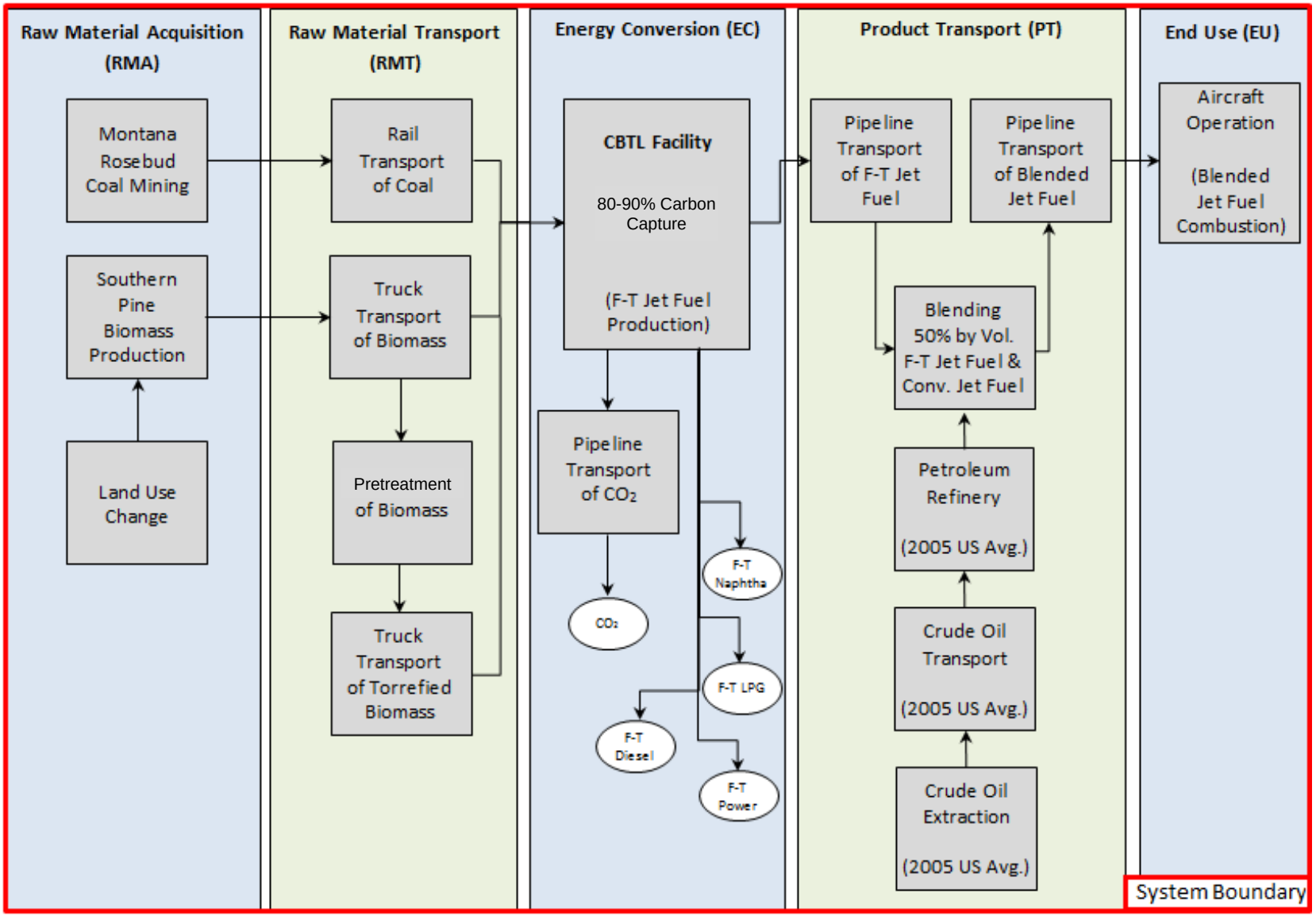
Energy Outlook (AEO) 2035 U.S. grid mix is used to represent a low value of displaced electricity. Displacement factors for diesel account for the cradle-to-gate production of petroleum fuel, beginning with crude oil extraction and ending with refined products exiting a petroleum refinery. The values for these displacement factors were generated using NETL's baseline petroleum model. Production of diesel fuel from imported (non-North American) crude was used to represent a high value for displaced diesel. There is no uncertainty applied to the source of the displacement credit for the naphtha, LPG, and captured CO_2 co-products.

Table 1-4 shows the displacement scenarios for CBTL co-products. The low and high scenarios represent the upper and lower bounds from an input perspective, and not necessarily the low and high values from a results perspective. Since the magnitude of a displacement value has an inverse relationship with a life cycle result, the low displacement values in **Table 1-4** correspond to the *high* values in the final LCA results, and the high displacement values in **Table 1-4** correspond to the *low* values in the final LCA results.

Table 1-4: Displacement Values Used for System Expansion

Co-product	Low	Expected	High	Units	Source
Electricity	AEO 2035 U.S. Grid Mix 558	2010 U.S. Grid Mix 605	Fleet Coal 1,049	kg CO_2e/ MWh busbar	NETL 2011
Diesel	U.S. Consumption Mix 0.75		Non-North American Crude Mix 0.81	kg CO_2e/ kg	NETL 2008
Naphtha	0.65			kg CO_2e/ kg	PE 2006
LPG	1.41			kg CO_2e/ kg	NETL 2008
Captured CO_2	0.09			kg CO_2e/ kg	NETL 2013

Figure 1-3: Study System Boundary, System Expansion



1.6 CBTL Jet Fuel Model

The Microsoft® Excel CBTL Jet Fuel Model (CBTL Jet Fuel Model) was developed as a summary tool to allow users to explore study results in detail. The following text provides an overview of the CBTL Jet Fuel Model, and the stochastic analyses that are included in model functionality.

1.6.1 Model Overview

A Microsoft® Excel-based model was developed to allow in-depth user access to the technological process, economic, and life cycle environmental results that were completed in support of this study, for each of the 20 different CBTL jet fuel production scenarios (total of 33 unique result sets when counting the validated scenarios). The CBTL Jet Fuel Model incorporates a stochastic analysis of modeled results, drawing on input statistical distributions for the 17 environmental and 40 economic parameters shown in **Table 1-6** and **Table 1-5**. A stochastic analysis was performed by using the Palisade® Corporation's @RISK Microsoft® Excel add-in, as discussed in the following subsection. Thus, in order to access full functionality of the CBTL Jet Fuel Model, users must have installed an appropriate @RISK license. Doing so allows users to enter their own parameter values and distribution types, or accept the model defaults, to generate detailed analytical results.

Environmental results from the model include a complete life cycle stage and sub-stage greenhouse gas analysis. Economic results include the required selling price of all of the F-T products (jet, diesel, naphtha, LPG), as well as the operating and capital costs associated with the facility. Results from the separate Aspen Plus® process modeling are also reported. The main page of the model displays the results of the stochastic analysis for greenhouse gases and the required selling price of jet fuel on a box and whisker plot. The CBTL Jet Fuel Model also contains an analysis of the detailed life cycle process contributions to the overall GHG result and individual cost contributions to the required selling price of F-T jet fuel. As part of the stochastic analysis, users are provided with tornado plots to determine the most sensitive parameters in the CBTL Jet Fuel Model. Detailed plant data, including process flows, utility demands, and component by component capital expenditure and contingency are available to the user as well. Finally, the model contains a reporting feature that allows the user to export the detailed results, including graphical displays of the distributions and full statistical results.

1.6.2 Stochastic Analyses

The purpose of providing stochastic analysis capabilities in the CBTL Jet Fuel Model is to capture the effect of the underlying uncertainty in parameter values on the main outputs of the model like life cycle GHG emissions and RSP of jet fuel. Stochastic analysis provides a more robust method of quantifying uncertainty than simply displaying minimum and maximum results for those outputs and it achieves the benefits much more efficiently. Additionally, the stochastic analysis provides added value to decision makers by illustrating the estimated level of certainty for modeled output.

Stochastic modeling was performed within the CBTL Jet Fuel Model, based on stochastic analyses completed in support of the technological/process, economic, and environmental models discussed above. Stochastic modeling within the CBTL Jet Fuel Model was developed to allow in-depth user access to the results of the technological/process, economic and environmental results for the 20 different CBTL jet fuel production scenarios considered in this study. The model performs a stochastic analysis of the results utilizing the input statistical distributions for 17 environmental and 40 economic parameters, as shown in **Table 1-6** and **Table 1-5** respectively.

The technological/process modeling completed in support of this study included three separate Aspen Plus® process simulations for each of the 20 scenarios discussed in this report. The separate

simulations were designed based on minimum, maximum and best estimate values for the required selling price of F-T jet fuel. The corresponding GHG emissions for those scenarios behaved in the opposite way. That is, the low RSP case resulted in the highest GHG emissions, while the high RSP case resulted in the lowest GHG emissions. Each of the 20 scenarios has a parameter denoted as the "CBTL Facility Operations Scenario," corresponding to each of the Aspen Plus® simulations runs. The default distribution for that parameter is modeled as a discrete distribution with probabilities of 20 percent, 60 percent, and 20 percent for the low, expected, and high GHG scenarios. The "CBTL Facility Operations Scenario" choice also feeds values to the economic model for calculation of the RSP of jet fuel. These values include the feed rates of coal and biomass, the corresponding amounts of product generated, the amount of electricity produced, and the amount of CO_2 captured and sold.

Table 1-5: Adjustable Economic Parameters Included in the Results Summary Tool

Parameters	Default Distribution	Values Expected (Low, High)
Economic		
Global Capital Cost Factor	Triangular	1 (0.85, 1.3)
Capacity Factor	Triangular	0.9 (0.85, 0.92)
EPC Services	Triangular	0.095 (0.09, 0.1)
Labor Cost Index	Triangular	1 (0.9, 1.2)
TASC Multiplier (Constant)	Triangular	1.14 (1.14, 1.14)
Admin Overhead (Fraction of Labor)	Triangular	0.25 (0.2, 0.3)
Taxes and Insurance (Fraction of TPC)	Triangular	0.02 (0.016, 0.024)
Land Costs ($/acre)	Triangular	3,000 (2,000, 4,000)
Make-up Water ($/1000 gal)	Triangular	1.08 (0.92, 1.24)
F-T Catalyst ($/lb)	Triangular	3 (2.1, 3.9)
Project Contingency	Triangular	0.15 (0.1, 0.2)
Coal Cost ($/ton)	Triangular	36.26 (34.45, 38.07)
Raw Chipped Biomass Cost ($/dry ton)	Triangular	43.6 (39.2, 48.0)
Raw Microchipped Biomass Cost ($/dry ton)	Triangular	46.3 (41.7, 50.9)
Torrefied Biomass Cost ($/ton)	Triangular	134.6 (121.1, 148.1)
Raw Pelletized Biomass Cost ($/dry ton)	Triangular	84.04 (75.63, 92.44)
Torrefied Pelletized Biomass Cost ($/ton)	Triangular	141.3 (127.2, 155.5)
Financing Fee (Fraction of TPC)	Triangular	0.027 (0.024, 0.03)
Other Owner's Costs (Fraction of TPC)	Triangular	0.15 (0.12, 0.18)
Other Preproduction Costs (Fraction of TPC)	Triangular	0.02 (0.016, 0.024)
Spare Parts (Fraction of TPC)	Triangular	0.005 (0.003, 0.006)
Power Credit ($/MWh)	Triangular	-70.5 (-77.6, -63.5)
Sulfur Credit ($/ton)	Triangular	0 (-5, 5)
CO_2-T&S Cost ($/tonne)	Triangular	0 (0, 0)
CO_2-EOR Credit ($/tonne)	Triangular	-40 (-52, -28)
Diesel: Jet Fuel Equivalent	Triangular	0.99 (0.99, 0.99)
Naphtha: Jet Fuel Equivalent	Triangular	0.69 (0.69, 0.69)
LPG: Jet Fuel Equivalent	Triangular	0.4 (0.4, 0.4)
Crude Oil Equivalent Diesel/Oil	Triangular	1.143 (1.143, 1.143)
Clear Fuels Gasifier Process Contingency	Triangular	0.15 (0, 0.3)
Tar Reformer Process Contingency	Triangular	0.15 (0, 0.3)
Autothermal Reformer Process Contingency	Triangular	0.2 (0, 0.4)
Cryogenic Hydrocarbon Recovery Process Contingency	Triangular	0 (-0.2, 0.2)
Biomass Grinding Cost Factor	Triangular	1 (0.8, 1.3)

Internal Rate of Return on Equity (%)	None	20 (20, 20)
Percent Debt (%)	None	50 (50, 50)
Debt Interest Rate (%)	None	8 (8, 8)
Tax Rate (%)	None	38 (38, 38)
Depreciation Schedule (Declining Balance - Year)	None	20 (20, 20)
Investment Tax Credit (%)	None	0 (0, 0)

Table 1-6: Adjustable Environmental Parameters Included in the Results Summary Tool

Parameters	Default Distribution	Values Expected (Low, High)
Environmental		
Coal Mine Methane (scf of methane/ton of coal at mine mouth)	Triangular	8 (4, 40)
Biomass Yield as harvested (kg/acre-yr)	Triangular	6,350 (2,993, 7,620)
Chip Type (0 = Conventional Chipper and 1 = Microchipper)	Discrete	0 (0, 1)
Rail Distance (mile)	Triangular	1,600 (1,280, 1,920)
Biomass Truck Distance: Farm to CBTL Plant (mile)	Triangular	40 (20, 50)
Biomass Truck Distance: Farm to Torrefaction Facility (mile)	Triangular	40 (20, 50)
Biomass Truck Distance: Torrefaction Facility to CBTL Facility (mile)	Triangular	50 (40, 60)
CBTL Plant Operations Scenario (0.2 = low/high and 0.6 = expected)	Discrete	0.6 (0.2, 0.2)
CO_2 Pipeline Distance (mile)	Triangular	775 (620, 930)
CO_2 Pipeline Loss Rate (kg/mi-yr)	Triangular	3,843 (384.3, 38,430)
Blended Jet Fuel Transport Pipeline Length (mile)	Triangular	225 (180, 270)
Blended Jet Fuel Transport Scenario (1 = 100% pipeline, and 0 = 60% pipeline and 40% Truck Transportation)	Discrete	0 (0, 1)
Diesel Displacement Type (1 - U.S. Consumption Mix; 2 - U.S. Import Mix)	None	1 (1, 2)
Diesel Displacement Factor	None	1 (1, 1)
CO_2 Displacement Type (1 = Natural Dome)	None	1 (1, 1)
CO_2 Displacement Factor	None	1 (1, 1)
Electricity Displacement Factor (20%-60%-20%)	Discrete	605 (558, 1049)

The sampling procedure for the stochastic model was Latin Hypercube with a seed value. The environmental and economic parameters are shown in **Table 1-6** and **Table 1-5**, along with the default distribution used in the modeling. As noted therein, the majority of parameters have been modeled using a triangular distribution. The CBTL Jet Fuel Model allows the user to enter custom low, expected, and high values for the parameter distributions as well as select other types of distributions.

1.7 Summary of Key Study Assumptions

Table 1-7 provides a summary of key modeling assumptions that were assumed or otherwise utilized in support of the technological, economic, and environmental modeling completed in support of this study.

1.8 Updates to Previous Modeling

A previous version of this report evaluated the life cycle GHG emissions and RSP for the first six scenarios listed in **Table 1-1** (NETL, 2014).This analysis supersedes the previous analysis due to modifications to all three facets of the underlying models (environmental, economic, and technical). The environmental model was updated based on modified approaches to the management of the co-products produced from the F-T facility. As discussed in **Section 1.5.6**, using co-product allocation to apportion emissions ignores the differences in useful energy between the electric power and liquid products produced from the facility. Thus, system expansion with co-product displacement was utilized as the recommended method. Additionally, the system boundary of the study was modified to exclude EOR operations. Instead, the captured and compressed CO_2 was assumed to displace natural sources of CO_2 that are currently utilized for EOR. This approach is consistent with other LCA studies conducted by NETL on systems that produce captured CO_2 and was presented at the annual American Center for Life Cycle Assessment Conference in 2013 (NETL, 2013a).

There were two primary changes to the economic model. The first was the change in the basis year from 2007 to 2011 dollars. Secondly, many of the capital cost algorithms were updated based on either recent vendor quotes or the recently completed NETL Quality Guidelines report on capital cost estimating. There were also some changes applied to the Aspen Plus® modeling. The methodology for water balances was made consistent with the approach used in IGCC applications regarding which streams are recycled after processing and the exclusion of some vented water in the water balance. The Selexol model was replaced with an improved model based on a recent vendor quote. Additional streams were added, as requested by CCAT. An additional parameter was added for the optimistic, pessimistic, and expected range cases (gasifier heat loss).

Table 1-7: Key Study and Modeling Assumptions

Primary Subject	Default Value
Study Boundary	
Temporal Boundary	30 years
Region	U.S. Southeast and Permian Basin, Texas
CBTL Facility Capacity (combined products)	50,000 bpd
Technology/Process	
Gasification System	TRIG gasification
Carbon Capture Technology	2-Stage Selexol
Carbon Capture Rate	88 (81 – 90) percent
Sulfur Recovery	Claus unit
Syngas Conversion	Fischer-Tropsch (F-T) reactors
F-T Catalyst	Iron
Overhead Gas Carbon Removal	Methyldiethanolamine (MDEA) unit
Product Separation	Cryogenic Separation
CBTL Product Suite	F-T Jet Fuel, F-T Diesel, F-T Naphtha, F-T LPG
Electricity Generation	Gas Turbine, Heat Recovery Steam Generator
Cooling	Cooling Tower
Economic	
Biomass Chipping Method	Standard or Microchip
Debt/Equity Ratio	50/50
Interest Rate on Debt	8%
Natural Gas Cost	$4/Mcf
F-T Diesel Value Relative to F-T Jet Fuel	0.99
F-T Naphtha Value Relative to F-T Jet Fuel	0.69
F-T LPG Value Relative to F-T Jet Fuel	0.40
Environmental	
Coal Feedstock	Montana Rosebud Sub-Bituminous Coal
Coal Heating Value	9,079 Btu/lb (LHV), as fed to CBTL Facility
Biomass Feedstock	Southern Pine Biomass
Biomass Cultivation Period	13 years
Biomass Pretreatment	Chip/Microchip and Grind, Pelletization, or Torrefaction
Biomass Heating Value	6,514 Btu/lb (LHV), as fed to CBTL Facility
Land Use Type	Converted Cropland and Pastureland
Land Use Scope	Direct and Indirect GHG Emissions
Coal Transport Distance	1,600 miles
Raw Biomass Transport Distance	Field to CBTL Facility: 40 miles (one-way); Field to Torrefaction: 50 miles (one-way);
CO_2-EOR CO_2 Transport Distance	775 miles
F-T Jet Fuel Pipeline Transport Distance	225miles
F-T/Conventional Fuels Blending Ratio	1:1 (volume)
Blended Jet Fuel Pipeline Transport Distance	245 miles
Blended Jet Fuel Truck Transport Distance	50 miles (one-way)
CO_2 Pipeline Leakage Factor	3,843 kg/mi-yr

2 Technologies and Processes

This section presents a summary of the technologies and processes that were considered in support of the operation of the CBTL facility, which is used to produce F-T jet fuel from a combination of coal and biomass. The technologies and processes discussed in this section were evaluated within a series of Aspen Plus® model runs, as discussed in Chapter 1. The following sub-sections provide details regarding the modeling process, for each of the 20 modeled scenarios. Details are also provided regarding the 13 validation cases. Each scenario sub-section includes a written description, a CBTL facility block flow diagram (**Figure 2-1**, **Figure 2-2**, **Figure 2-3**, **Figure 2-4**, **Figure 2-5**, and **Figure 2-6**) and the associated Aspen Plus® streams tables for the modeled and validated case where applicable (**Table 2-1**, **Table 2-2**, **Table 2-3**, **Table 2-4**, **Table 2-5**, **Table 2-12**, **Table 2-13**, **Table 2-21**, **Table 2-22, Table 2-23, Table 2-24, Table 2-25, Table 2-26, Table 2-27, Table 2-28, Table 2-29, Table 2-30, Table 2-31, Table 2-32, Table 2-33, Table 2-22, Table 2-23, Table 2-24, Table 2-25, Table 2-26**, **Table 2-27, Table 2-28, Table 2-29, Table 2-30, Table 2-31, Table 2-32, Table 2-33**).

2.2 Scenario 1: CBTL, 0 Percent Biomass and Validation

Figure 2-1 shows the block flow schematic for the CBTL, 0 percent Biomass configuration where the only feedstock is Montana Rosebud coal. The coal (30,485 TPD) is brought from the storage area and sent to milling and drying. Here, the coal is dried from the as-received value of 26 percent moisture down to 18 percent for feeding to the TRIG gasifier at approximately 400 microns. The coal is then injected into the TRIG gasifier just above the mixing zone. Steam and oxygen are added to the gasifier, and the coal is transformed into raw synthesis gas (syngas). Sensible heat from the hot syngas is recovered in a waste heat boiler/superheater and the gas is cooled for feeding to the raw shift and COS hydrolysis units. A portion of the cooled syngas is recycled to the TRIG gasifier. The shifted syngas is further cooled and sent to mercury removal. Upon exiting mercury removal, the syngas enters the two-stage Selexol unit. Here, hydrogen sulfide and carbon dioxide are removed in separate absorbers. The hydrogen sulfide stream is sent to the Claus unit for sulfur recovery via the Sour Water Stripper. The Claus offgas enters Claus Offgas Treating to reduce breakthrough sulfur dioxide. The hydrogen sulfide from this process is recycled to the Selexol unit. The CO_2 stream is sent to dehydration and compression to produce a high-pressure CO_2 stream suitable for pipeline transport and carbon management.

The cleaned syngas exiting the Selexol unit is further reduced in sulfur by a zinc oxide sulfur polisher. The syngas would then contain less than 30 parts per billion of sulfur. The cleaned syngas then enters the slurry-phase, iron-based catalytic Fischer-Tropsch (F-T) reactors. The raw F-T products and unconverted synthesis gas are separated in the raw product separation unit into overhead gases that include CO_2, CO, H_2, light hydrocarbons, aqueous stream containing oxygenates, naphtha, distillate, and wax.

The overhead gas is sent to a methyldiethanolamine (MDEA) unit for CO_2 removal and then sent to a cryogenic separation unit to separate methane-rich gas, hydrogen-rich gas, and liquefied petroleum gas (LPG). The methane rich gas that includes CO is sent to an oxygen-blown autothermal reformer (ATR), the exit gas of which contains some methane, CO, H_2, and CO_2. This gas stream is divided so that some of the gas is used for plant fuel gas needs, some is recycled to the F-T reactors, and the remainder is sent to the gas turbine combustors to generate electric power. The hydrogen-rich gas is sent to the pressure swing adsorption (PSA) unit to produce a pure hydrogen stream for the refinery and a low-pressure fuel gas. The F-T LPG stream is separated as a co-product of the plant.

The aqueous stream from the Sour Water Stripper contains the oxygenate compounds like alcohols, acids, and ketones. This stream is sent to the wastewater treatment plant (WWTP). The naphtha is distilled from the distillate stream and receives no further treatment. The distillate is hydrotreated to remove olefins and becomes the diesel fuel product. The wax is hydrocracked to a jet fuel product. Jet fuel has a very narrow boiling point range and, hence, has a small range of carbon numbers, typically from C_{10} to C_{16}. When the F-T wax, which has a wide range of carbon numbers (~C_{23} to C_{400}), is hydrocracked to be within the narrow jet fuel range a large amount of over cracking occurs. This produces, in addition to the jet fuel, a significant amount of light hydrocarbon gases including LPG and additional naphtha. The final products from the refinery are jet fuel, diesel, naphtha, and LPG.

Refinery fired heaters for distillation and feed heating for hydrotreating and hydrocracking are heated using flue gases. The flue gases from these heaters are vented to the atmosphere. The separate fuel gases sent to the gas turbines generate electric power for the plant. Heat is recovered from the turbine exhaust in HRSGs and the steam raised is used in the steam turbine for additional power generation. The exhaust flue gas from the HRSG is vented to the stack. Power produced in excess of plant parasitic requirements is sold. Steam turbine exhaust is condensed using conventional mechanical draft cooling towers.

Table 2-1 shows the stream table results for the streams identified in **Figure 2-1**. These results correspond to the original Aspen Plus® model and parameters. A second run for this configuration was made using the Aspen Plus® model parameters derived from fitting the TRIG model to experimental data. These validated results are shown in **Table 2-2**. The differences in the two tables are small and minor and do not significantly impact the study results. The average deviation in bulk stream properties is approximately 1.6 percent and the average deviation in the stream mole fractions is less than 6 percent.

Figure 2-1: Scenarios 1 and 15 Plant Configuration: CBTL, 0% Biomass: Coal Only Plant Configuration

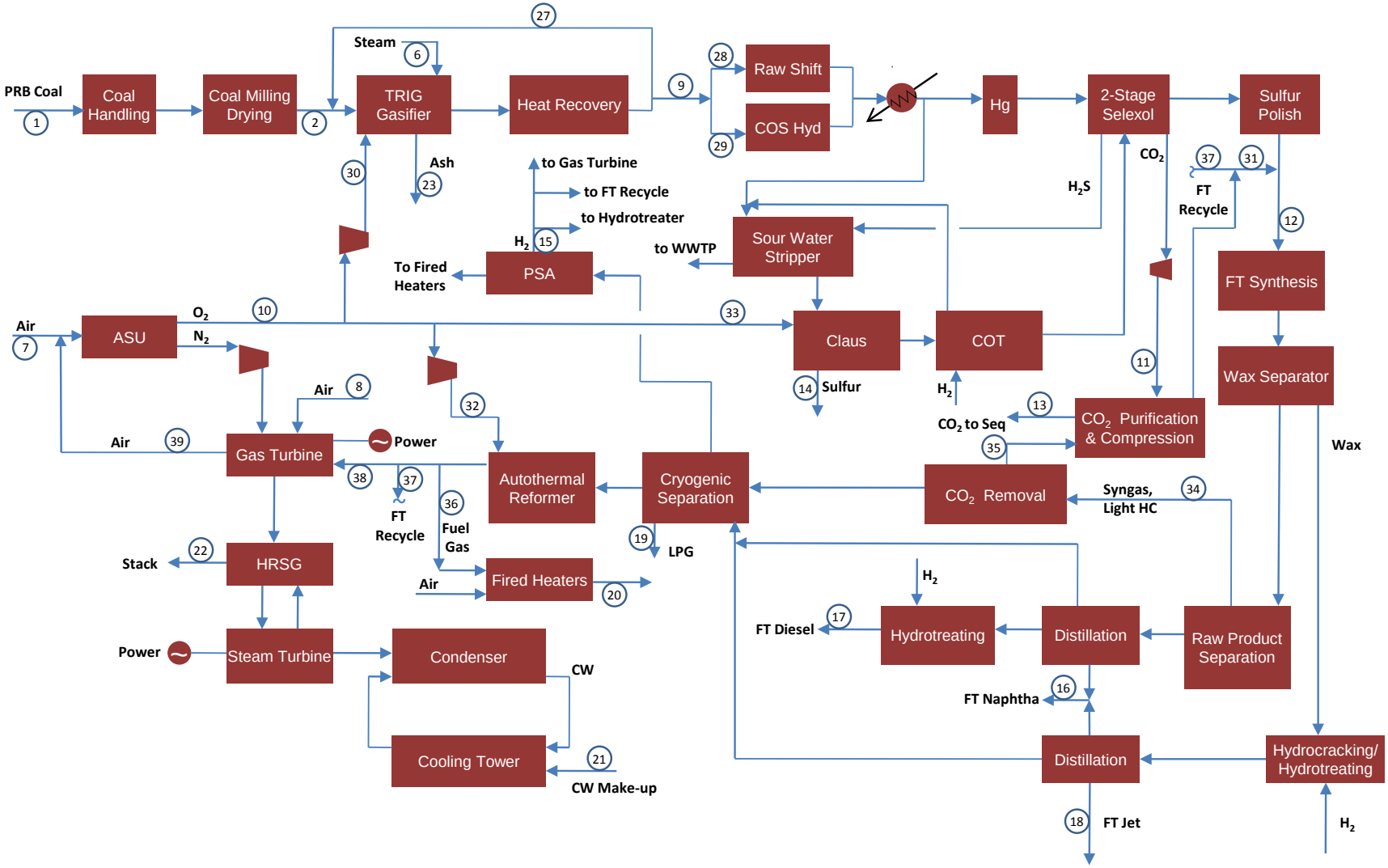


Table 2-1: CBTL, 0% Biomass Modeled: Stream Values

Description	Coal	Dried Coal	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.	Sulfur
PFD Number	**1**	**2**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**
Temperature (F)	59.0	220.0	489.4	59.0	59.0	500.0	90.0	100.0	261.2	100.0	77.0
Pressure (psia)	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7	14.7
Mass Flow (lb/hr)	2,540,389	2,299,672	488,736	6,633,002	3,531,600	3,968,617	1,569,883	1,653,661	2,425,763	2,573,042	9,223
Mole Flow (lbmol/hr)			27,129	229,858	122,383	192,123	48,783	40,120	154,624	58,686	36
Mole Fraction											
H_2O			1.0	9.87E-03	9.87E-03	0.1397	0.0	1.42E-03	6.56E-03	0.0	0.0
Ar			0.0	9.25E-03	9.25E-03	7.32E-03	0.0318	0.0	0.0163	0.0	0.0
CO_2			0.0	3.27E-04	3.27E-04	0.1274	0.0	0.8886	0.0213	0.9926	0.0
O_2			0.0	0.2074	0.2074	0.0	0.9504	0.0	7.55E-18	0.0	0.0
N_2			0.0	0.7732	0.7732	5.50E-03	0.0178	5.03E-04	0.0139	6.55E-05	0.0
CO			0.0	0.0	0.0	0.3958	0.0	0.0681	0.4388	4.87E-03	0.0
COS			0.0	0.0	0.0	7.26E-05	0.0	5.21E-07	9.05E-08	3.55E-07	0.0
H_2			0.0	0.0	0.0	0.3019	0.0	0.0357	0.4826	1.16E-03	0.0
H_2S			0.0	0.0	0.0	1.43E-03	0.0	0.0	3.62E-11	9.21E-11	0.0
HCl			0.0	0.0	0.0	2.77E-05	0.0	0.0	0.0	0.0	0.0
NH_3			0.0	0.0	0.0	3.90E-03	0.0	0.0	3.87E-06	0.0	0.0
SO_2			0.0	0.0	0.0	0.0	0.0	0.0	4.24E-19	0.0	0.0
CH_4			0.0	0.0	0.0	0.0169	0.0	5.67E-03	0.0205	1.35E-03	0.0
C_2H_4			0.0	0.0	0.0	0.0	0.0	0.0	2.02E-09	0.0	0.0
C_2H_6			0.0	0.0	0.0	0.0	0.0	0.0	3.35E-10	0.0	0.0
C_3H_6			0.0	0.0	0.0	0.0	0.0	0.0	1.88E-13	0.0	0.0
C_3H_8			0.0	0.0	0.0	0.0	0.0	0.0	5.78E-15	0.0	0.0
ISOBU-01			0.0	0.0	0.0	0.0	0.0	0.0	3.83E-20	0.0	0.0
N-BUT-01			0.0	0.0	0.0	0.0	0.0	0.0	5.94E-17	0.0	0.0
1-BUT-01			0.0	0.0	0.0	0.0	0.0	0.0	1.87E-16	0.0	0.0
Naphtha			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8			0.0	0.0	0.0	0.0	0.0	0.0	1.61E-42	0.0	1.0

Description	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle	Syngas to WGS
PFD Number	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**	**28**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	294.1	500.0
Pressure (psia)	317.0	14.7	14.7	14.7	227.1	14.7	14.7	14.7	14.7	477.0	477.0
Mass Flow (lb/hr)	39,505	175,107	53,581	273,562	31,236	256,147	4,952,768	4,255,102	242,675	208,863	2,035,249
Mole Flow (lbmol/hr)	19,273	1,657	252	1,288	640	8,181	274,920	150,218		10,111	98,528
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0606	1.0	0.0976		0.1397	0.1397
Ar	1.23E-04	0.0	0.0	0.0	2.02E-05	0.0392	0.0	0.0156		7.32E-03	7.32E-03
CO_2	8.62E-09	0.0	0.0	0.0	0.0600	0.2081	0.0	0.0441		0.1274	0.1274
O_2	0.0	0.0	0.0	0.0	0.0	0.0261	0.0	0.0994		0.0	0.0
N_2	3.39E-04	0.0	0.0	0.0	7.89E-07	0.6659	0.0	0.7432		5.50E-03	5.50E-03
CO	7.84E-04	0.0	0.0	0.0	7.89E-06	0.0	0.0	0.0		0.3957	0.3958
COS	0.0	0.0	0.0	0.0	2.19E-05	1.75E-13	0.0	0.0		7.26E-05	7.26E-05
H_2	0.9988	0.0	0.0	0.0	1.42E-09	0.0	0.0	0.0		0.3019	0.3019
H_2S	0.0	0.0	0.0	0.0	1.53E-10	0.0	0.0	0.0		1.43E-03	1.43E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.77E-05	2.77E-05
NH_3	0.0	0.0	0.0	0.0	9.35E-04	1.97E-06	0.0	4.78E-06		3.90E-03	3.90E-03
SO_2	0.0	0.0	0.0	0.0	0.0	1.28E-13	0.0	3.35E-13		0.0	0.0
CH_4	0.0	0.0	0.0	0.0	3.87E-04	0.0	0.0	0.0		0.0169	0.0169
C_2H_4	0.0	0.0	0.0	0.0	4.36E-03	0.0	0.0	0.0		0.0	0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0	0.0
C_3H_6	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0		0.0	0.0
C_3H_8	0.0	0.0	0.0	0.0	0.3372	0.0	0.0	0.0		0.0	0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.3323	0.0	0.0	0.0		0.0	0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0		0.0	0.0
Naphtha	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
F-T-Jet	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0	0.0
F-T-Diesel	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
S_8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0

Description	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA	Fuel Gas
PFD Number	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**
Temperature (F)	500.0	268.0	360.1	318.1	90.0	100.0	105.0	324.0
Pressure (psia)	477.0	665.0	379.0	360.0	125.0	369.0	25.0	317.0
Mass Flow (lb/hr)	1,933,368	1,422,883	380,461	111,299	35,700	1,610,586	1,041,492	7,307
Mole Flow (lbmol/hr)	93,595	44,215	18,059	3,459	1,109	61,281	23,666	500
Mole Fraction								
H_2O	0.1397	0.0	0.0559	0.0	0.0	0.0	0.0	0.0545
Ar	7.32E-03	0.0318	0.0594	0.0318	0.0318	0.0410	0.0	0.0579
CO_2	0.1274	0.0	0.1130	0.0	0.0	0.4175	0.9999	0.0526
O_2	0.0	0.9504	6.46E-17	0.9504	0.9504	0.0	0.0	6.30E-17
N_2	5.50E-03	0.0178	0.0397	0.0178	0.0178	0.0351	1.15E-05	0.0379
CO	0.3958	0.0	0.3849	0.0	0.0	0.1272	6.04E-05	0.2434
COS	7.26E-05	0.0	3.23E-09	0.0	0.0	2.28E-07	0.0	1.64E-13
H_2	0.3019	0.0	0.3383	0.0	0.0	0.3193	8.52E-08	0.5531
H_2S	1.43E-03	0.0	2.15E-12	0.0	0.0	9.13E-11	2.28E-10	2.10E-12
HCl	2.77E-05	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	3.90E-03	0.0	3.31E-05	0.0	0.0	9.76E-06	0.0	3.23E-05
SO_2	0.0	0.0	3.63E-18	0.0	0.0	0.0	0.0	3.54E-18
CH_4	0.0169	0.0	8.78E-03	0.0	0.0	0.0551	3.50E-05	5.10E-04
C_2H_4	0.0	0.0	1.73E-08	0.0	0.0	1.41E-03	0.0	1.68E-08
C_2H_6	0.0	0.0	2.87E-09	0.0	0.0	4.38E-04	0.0	2.79E-09
C_3H_6	0.0	0.0	1.61E-12	0.0	0.0	1.21E-03	0.0	1.57E-12
C_3H_8	0.0	0.0	4.95E-14	0.0	0.0	3.84E-04	0.0	4.83E-14
ISOBU-01	0.0	0.0	3.28E-19	0.0	0.0	0.0	0.0	3.20E-19
N-BUT-01	0.0	0.0	5.09E-16	0.0	0.0	3.34E-04	0.0	4.96E-16
1-BUT-01	0.0	0.0	1.60E-15	0.0	0.0	1.04E-03	0.0	1.56E-15
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	1.38E-41	0.0	0.0	0.0	0.0	1.34E-41

Description	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	37	38	39
Temperature (F)	424.0	324.0	821.7
Pressure (psia)	317.0	317.0	236.8
Mass Flow (lb/hr)	259,378	324,929	218,628
Mole Flow (lbmol/hr)	13,016	22,234	7,576
Mole Fraction			
H_2O	0.0775	0.0545	9.87E-03
Ar	0.0824	0.0579	9.25E-03
CO_2	0.0749	0.0526	3.27E-04
O_2	8.96E-17	6.30E-17	0.2074
N_2	0.0538	0.0379	0.7732
CO	0.3460	0.2434	0.0
COS	2.33E-13	1.64E-13	0.0
H_2	0.3647	0.5531	0.0
H_2S	2.98E-12	2.10E-12	0.0
HCl	0.0	0.0	0.0
NH_3	4.60E-05	3.23E-05	0.0
SO_2	5.04E-18	3.54E-18	0.0
CH_4	7.26E-04	5.10E-04	0.0
C_2H_4	2.40E-08	1.68E-08	0.0
C_2H_6	3.98E-09	2.79E-09	0.0
C_3H_6	2.23E-12	1.57E-12	0.0
C_3H_8	6.87E-14	5.69E-14	0.0
ISOBU-01	4.55E-19	3.20E-19	0.0
N-BUT-01	7.06E-16	9.14E-15	0.0
1-BUT-01	2.23E-15	1.56E-15	0.0
Naphtha	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0
S_8	1.91E-41	1.34E-41	0.0

Table 2-2: CBTL, 0% Biomass Validated: Stream Values

Description	Coal	Dried Coal	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.	Sulfur
PFD Number	**1**	**2**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**
Temperature (F)	59.0	220.0	489.4	59.0	59.0	500.0	90.0	100.0	263.5	100.0	77.0
Pressure (psia)	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7	14.7
Mass Flow (lb/hr)	2,545,221	2,304,046	489,666	6,663,973	3,531,600	3,972,342	1,577,330	1,664,996	2,443,458	2,587,866	9,240
Mole Flow (lbmol/hr)			27,181	230,931	122,383	191,727	49,015	40,376	155,378	59,029	36
Mole Fraction											
H_2O			1.0	9.87E-03	9.87E-03	0.1466	0.0	1.41E-03	7.32E-03	0.0	0.0
Ar			0.0	9.25E-03	9.25E-03	7.33E-03	0.0318	0.0	0.0169	0.0	0.0
CO_2			0.0	3.27E-04	3.27E-04	0.1224	0.0	0.8894	0.0216	0.9924	0.0
O_2			0.0	0.2074	0.2074	0.0	0.9504	0.0	7.69E-18	0.0	0.0
N_2			0.0	0.7732	0.7732	5.52E-03	0.0178	5.00E-04	0.0143	6.57E-05	0.0
CO			0.0	0.0	0.0	0.4009	0.0	0.0672	0.4366	4.85E-03	0.0
COS			0.0	0.0	0.0	6.70E-05	0.0	4.77E-07	8.30E-08	3.25E-07	0.0
H_2			0.0	0.0	0.0	0.2929	0.0	0.0352	0.4803	1.15E-03	0.0
H_2S			0.0	0.0	0.0	1.44E-03	0.0	0.0	3.61E-11	9.18E-11	0.0
HCl			0.0	0.0	0.0	2.78E-05	0.0	0.0	0.0	0.0	0.0
NH_3			0.0	0.0	0.0	3.92E-03	0.0	0.0	4.60E-06	0.0	0.0
SO_2			0.0	0.0	0.0	0.0	0.0	0.0	3.93E-19	0.0	0.0
CH_4			0.0	0.0	0.0	0.0190	0.0	6.29E-03	0.0229	1.50E-03	0.0
C_2H_4			0.0	0.0	0.0	0.0	0.0	0.0	2.61E-09	0.0	0.0
C_2H_6			0.0	0.0	0.0	0.0	0.0	0.0	4.53E-10	0.0	0.0
C_3H_6			0.0	0.0	0.0	0.0	0.0	0.0	2.61E-13	0.0	0.0
C_3H_8			0.0	0.0	0.0	0.0	0.0	0.0	8.41E-15	0.0	0.0
ISOBU-01			0.0	0.0	0.0	0.0	0.0	0.0	6.02E-20	0.0	0.0
N-BUT-01			0.0	0.0	0.0	0.0	0.0	0.0	6.26E-17	0.0	0.0
1-BUT-01			0.0	0.0	0.0	0.0	0.0	0.0	1.98E-16	0.0	0.0
Naphtha			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8			0.0	0.0	0.0	0.0	0.0	0.0	1.72E-42	0.0	1.0

Description	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle	Syngas to WGS
PFD Number	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**	**28**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	297.3	500.0
Pressure (psia)	317.0	14.7	14.7	14.7	227.4	14.7	14.7	14.7	14.7	477.0	477.0
Mass Flow (lb/hr)	39,504	175,105	53,580	273,558	31,243	251,821	4,982,391	4,253,259	243,136	209,072	2,158,438
Mole Flow (lbmol/hr)	19,278	1,657	252	1,288	640	8,056	276,565	150,226		10,091	104,178
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0623	1.0	0.0980		0.1466	0.1466
Ar	1.25E-04	0.0	0.0	0.0	2.12E-05	0.0401	0.0	0.0157		7.33E-03	7.33E-03
CO_2	8.58E-09	0.0	0.0	0.0	0.0601	0.2054	0.0	0.0435		0.1224	0.1224
O_2	0.0	0.0	0.0	0.0	0.0	0.0261	0.0	0.0993		0.0	0.0
N_2	3.41E-04	0.0	0.0	0.0	8.29E-07	0.6662	0.0	0.7435		5.52E-03	5.52E-03
CO	7.59E-04	0.0	0.0	0.0	7.92E-06	0.0	0.0	0.0		0.4009	0.4009
COS	0.0	0.0	0.0	0.0	2.02E-05	1.61E-13	0.0	0.0		6.70E-05	6.70E-05
H_2	0.9988	0.0	0.0	0.0	1.48E-09	0.0	0.0	0.0		0.2929	0.2929
H_2S	0.0	0.0	0.0	0.0	1.53E-10	0.0	0.0	0.0		1.44E-03	1.44E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.78E-05	2.78E-05
NH_3	0.0	0.0	0.0	0.0	1.12E-03	2.16E-06	0.0	5.15E-06		3.92E-03	3.92E-03
SO_2	0.0	0.0	0.0	0.0	0.0	1.25E-13	0.0	3.20E-13		0.0	0.0
CH_4	0.0	0.0	0.0	0.0	4.28E-04	0.0	0.0	0.0		0.0190	0.0190
C_2H_4	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0		0.0	0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0	0.0
C_3H_6	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0		0.0	0.0
C_3H_8	0.0	0.0	0.0	0.0	0.3370	0.0	0.0	0.0		0.0	0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.3322	0.0	0.0	0.0		0.0	0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0		0.0	0.0
Naphtha	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
F-T-Jet	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0	0.0
F-T-Diesel	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0
S_8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0

Description	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA	Fuel Gas
PFD Number	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**
Temperature (F)	500.0	268.0	370.8	318.1	90.0	100.0	105.0	326.2
Pressure (psia)	477.0	665.0	379.0	360.0	125.0	369.0	25.0	317.0
Mass Flow (lb/hr)	1,813,904	1,421,765	405,370	119,630	35,935	1,626,376	1,044,519	7,251
Mole Flow (lbmol/hr)	87,549	44,181	19,434	3,717	1,117	61,930	23,735	500
Mole Fraction								
H_2O	0.1466	0.0	0.0582	0.0	0.0	0.0	0.0	0.0552
Ar	7.33E-03	0.0318	0.0614	0.0318	0.0318	0.0425	0.0	0.0582
CO_2	0.1224	0.0	0.1075	0.0	0.0	0.4143	0.9999	0.0501
O_2	0.0	0.9504	6.15E-17	0.9504	0.9504	0.0	0.0	5.83E-17
N_2	5.52E-03	0.0178	0.0409	0.0178	0.0178	0.0360	1.18E-05	0.0381
CO	0.4009	0.0	0.3799	0.0	0.0	0.1256	6.01E-05	0.2420
COS	6.70E-05	0.0	2.73E-09	0.0	0.0	2.08E-07	0.0	1.48E-13
H_2	0.2929	0.0	0.3428	0.0	0.0	0.3163	8.50E-08	0.5558
H_2S	1.44E-03	0.0	2.13E-12	0.0	0.0	9.06E-11	2.28E-10	2.02E-12
HCl	2.78E-05	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	3.92E-03	0.0	3.68E-05	0.0	0.0	1.15E-05	0.0	3.49E-05
SO_2	0.0	0.0	3.15E-18	0.0	0.0	0.0	0.0	2.98E-18
CH_4	0.0190	0.0	9.17E-03	0.0	0.0	0.0606	3.88E-05	5.81E-04
C_2H_4	0.0	0.0	2.08E-08	0.0	0.0	1.39E-03	0.0	1.97E-08
C_2H_6	0.0	0.0	3.62E-09	0.0	0.0	4.33E-04	0.0	3.43E-09
C_3H_6	0.0	0.0	2.09E-12	0.0	0.0	1.19E-03	0.0	1.98E-12
C_3H_8	0.0	0.0	6.72E-14	0.0	0.0	3.80E-04	0.0	6.37E-14
ISOBU-01	0.0	0.0	4.81E-19	0.0	0.0	0.0	0.0	4.56E-19
N-BUT-01	0.0	0.0	5.00E-16	0.0	0.0	3.30E-04	0.0	4.74E-16
1-BUT-01	0.0	0.0	1.59E-15	0.0	0.0	1.03E-03	0.0	1.50E-15
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	1.37E-41	0.0	0.0	0.0	0.0	1.30E-41

Description	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	**37**	**38**	**39**
Temperature (F)	427.2	326.2	821.7
Pressure (psia)	317.0	317.0	236.8
Mass Flow (lb/hr)	284,746	321,791	220,162
Mole Flow (lbmol/hr)	14,408	22,191	7,629
Mole Fraction			
H_2O	0.0785	0.0552	9.87E-03
Ar	0.0828	0.0582	9.25E-03
CO_2	0.0713	0.0501	3.27E-04
O_2	8.30E-17	5.83E-17	0.2074
N_2	0.0540	0.0381	0.7732
CO	0.3439	0.2420	0.0
COS	2.11E-13	1.48E-13	0.0
H_2	0.3686	0.5558	0.0
H_2S	2.87E-12	2.02E-12	0.0
HCl	0.0	0.0	0.0
NH_3	4.96E-05	3.49E-05	0.0
SO_2	4.24E-18	2.98E-18	0.0
CH_4	8.27E-04	5.81E-04	0.0
C_2H_4	2.81E-08	1.97E-08	0.0
C_2H_6	4.88E-09	3.43E-09	0.0
C_3H_6	2.82E-12	1.98E-12	0.0
C_3H_8	9.06E-14	7.24E-14	0.0
ISOBU-01	6.49E-19	4.56E-19	0.0
N-BUT-01	6.75E-16	9.13E-15	0.0
1-BUT-01	2.14E-15	1.50E-15	0.0
Naphtha	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0
S_8	1.85E-41	1.30E-41	0.0

2.3 Scenario 2: CBTL, 10 Percent Chipped Biomass, Scenario 3: CBTL, 20 Percent Chipped Biomass, Scenario 7: CBTL, 30 Percent Chipped Biomass, Scenario 9: CBTL, 11.7 Percent Chipped Biomass, Model and Validation, Scenario 10: CBTL, 19.2 Percent Chipped Biomass, Model and Validation, and Scenario 11: CBTL, 28.3 Percent Chipped Biomass, Model and Validation

The overall configuration for these scenarios is very similar to the CBTL, 0 percent Biomass scenario. As shown in **Figure 2-2** the addition of biomass handling and biomass preparation and drying are the only changes. The southern pine woody biomass is delivered to the CBTL facility as whole wood chips with a size range of about 2-3 inches in length. These wood chips are assumed to be produced during biomass harvesting, as discussed previously. The chips enter the CBTL facility with about 50 percent moisture content. After storage at the plant, moisture is lost and on reclaiming the woody biomass is assumed to have an average moisture content of 43.3 percent. The moisture must be reduced to about 18 percent for co-feeding to the TRIG gasification system. The green woody biomass is dried and the chips must be reduced in size to an average particle size of between about 0.4 and 0.8 mm (400-800 microns). This is accomplished in separate hammer mills from the coal milling machines. Such fine grinding of green woody biomass is energy intensive and, depending on the final particle size, the power consumed during this processing can be considerable.

The milled coal and finely ground green woody biomass are both dried to 18 percent moisture and are mixed together before entering the lock hopper feeding system of the TRIG gasifiers. They are then injected into the gasifiers just above the gasifier mixing zone. The coal and biomass react with the steam and oxygen to produce raw synthesis gas.

The raw synthesis gas is treated in the same manner as discussed for the CBTL, 0 percent Biomass scenario—it is cleaned and sent to the F-T reactors. All other downstream processes are the same as discussed previously for the CBTL, 0 percent Biomass scenario.

The stream table results are shown in

Table 2-6 for Scenario 9, **Table 2-8** for Scenario 10, and **Table 2-10** for Scenario 11 for the results from the original Aspen Plus® model. Analogous stream results are also shown in **Table 2-7**, **Table 2-9**, and **Table 2-11** for these three scenarios, respectively, using the Aspen Plus® model validated by experimental data. As with the coal only scenario, the deviation between the modeled and validated stream results is small and insignificant.

Figure 2-2: Scenarios 2, 3, 7, 9, 10, 11 – CBTL, 10%, 20%, 30%, 11.7%, 19.2% 28.3% Chipped Biomass Plant Configurations

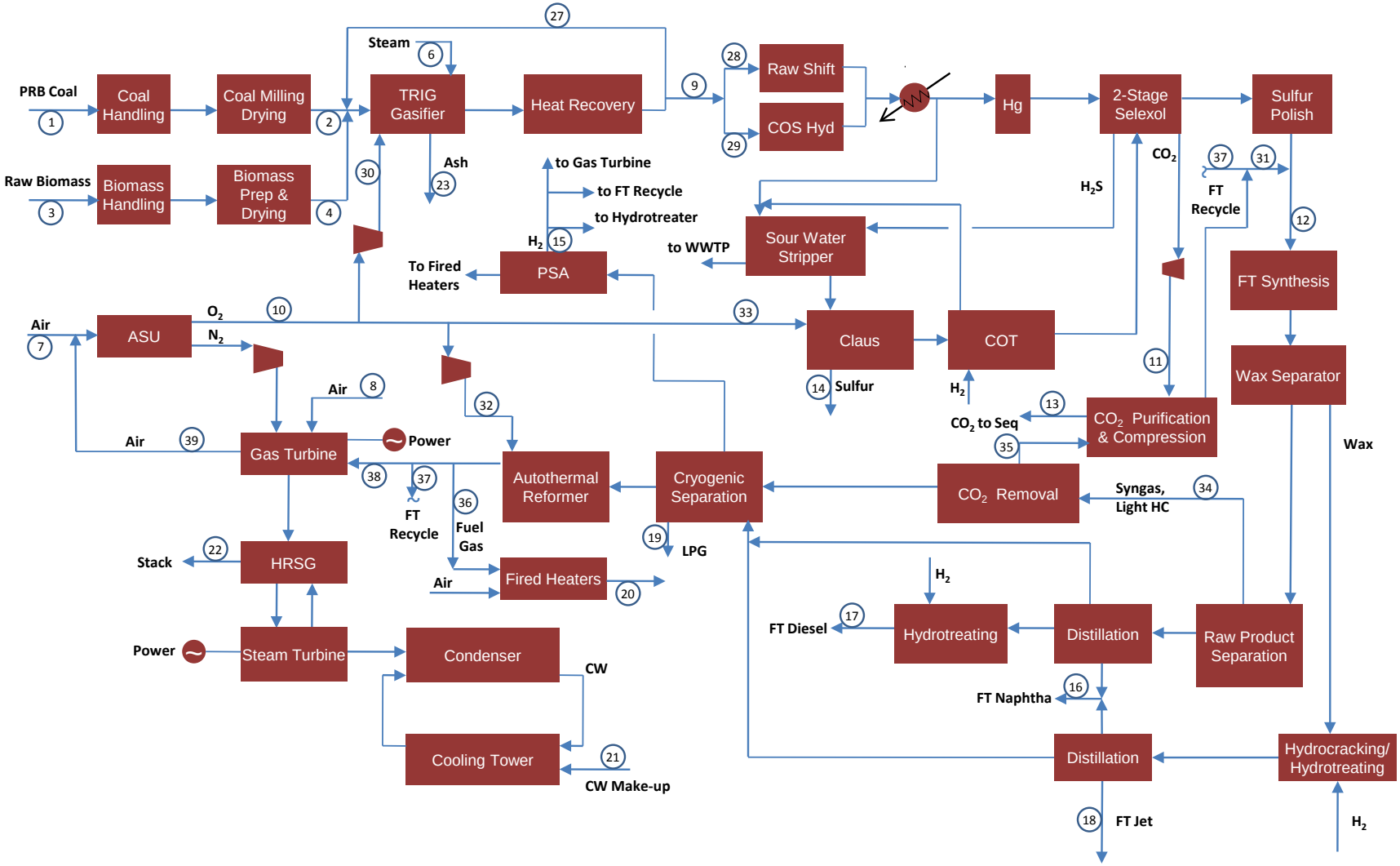


Table 2-3: CBTL, 10% Biomass, Chipped: Stream Values

Description	Coal	Dried Coal	Raw Biomass	Dried Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed
PFD Number	**1**	**2**	**3**	**4**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Temperature (F)	59.0	220.0	59.0	220.0	489.4	59.0	59.0	500.0	90.0	100.0	260.7
Pressure (psia)	14.7	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0
Mass Flow (lb/hr)	2,343,441	2,121,386	340,885	235,710	450,846	6,582,751	3,531,600	3,993,809	1,558,448	1,672,253	2,421,572
Mole Flow (lbmol/hr)					25,026	228,117	122,383	192,964	48,428	40,542	154,455
Mole Fraction											
H_2O					1.0	9.87E-03	9.87E-03	0.1412	0.0	1.41E-03	6.43E-03
Ar					0.0	9.25E-03	9.25E-03	7.24E-03	0.0318	0.0	0.0160
CO_2					0.0	3.27E-04	3.27E-04	0.1289	0.0	0.8898	0.0214
O_2					0.0	0.2074	0.2074	0.0	0.9504	0.0	7.49E-18
N_2					0.0	0.7732	0.7732	5.41E-03	0.0178	4.88E-04	0.0136
CO					0.0	0.0	0.0	0.3947	0.0	0.0675	0.4393
COS					0.0	0.0	0.0	6.70E-05	0.0	4.78E-07	8.40E-08
H_2					0.0	0.0	0.0	0.3009	0.0	0.0354	0.4832
H_2S					0.0	0.0	0.0	1.32E-03	0.0	0.0	3.36E-11
HCl					0.0	0.0	0.0	2.54E-05	0.0	0.0	0.0
NH_3					0.0	0.0	0.0	3.75E-03	0.0	0.0	3.72E-06
SO_2					0.0	0.0	0.0	0.0	0.0	0.0	3.97E-19
CH_4					0.0	0.0	0.0	0.0165	0.0	5.50E-03	0.0202
C_2H_4					0.0	0.0	0.0	0.0	0.0	0.0	1.95E-09
C_2H_6					0.0	0.0	0.0	0.0	0.0	0.0	3.21E-10
C_3H_6					0.0	0.0	0.0	0.0	0.0	0.0	1.80E-13
C_3H_8					0.0	0.0	0.0	0.0	0.0	0.0	5.50E-15
ISOBU-01					0.0	0.0	0.0	0.0	0.0	0.0	3.61E-20
N-BUT-01					0.0	0.0	0.0	0.0	0.0	0.0	5.89E-17
1-BUT-01					0.0	0.0	0.0	0.0	0.0	0.0	1.86E-16
Naphtha					0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet					0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel					0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8					0.0	0.0	0.0	0.0	0.0	0.0	1.69E-42

Description	CO_2 Seq.	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash
PFD Number	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**
Temperature (F)	100.0	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0
Pressure (psia)	2214.7	14.7	317.0	14.7	14.7	14.7	227.0	14.7	14.7	14.7	14.7
Mass Flow (lb/hr)	2,591,638	8,546	39,503	175,108	53,581	273,564	31,235	257,122	4,878,047	4,255,026	228,089
Mole Flow (lbmol/hr)	59,109	33	19,272	1,657	252	1,288	640	8,209	270,773	150,207	
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0604	1.0	0.0976	
Ar	0.0	0.0	1.22E-04	0.0	0.0	0.0	1.99E-05	0.0389	0.0	0.0156	
CO_2	0.9926	0.0	8.63E-09	0.0	0.0	0.0	0.0600	0.2090	0.0	0.0442	
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0262	0.0	0.0994	
N_2	6.42E-05	0.0	3.33E-04	0.0	0.0	0.0	7.66E-07	0.6655	0.0	0.7432	
CO	4.88E-03	0.0	7.91E-04	0.0	0.0	0.0	7.88E-06	0.0	0.0	0.0	
COS	3.27E-07	0.0	0.0	0.0	0.0	0.0	2.03E-05	1.62E-13	0.0	0.0	
H_2	1.16E-03	0.0	0.9988	0.0	0.0	0.0	1.40E-09	0.0	0.0	0.0	
H_2S	8.47E-11	0.0	0.0	0.0	0.0	0.0	1.42E-10	0.0	0.0	0.0	
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
NH_3	0.0	0.0	0.0	0.0	0.0	0.0	8.99E-04	1.93E-06	0.0	4.68E-06	
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.19E-13	0.0	3.13E-13	
CH_4	1.32E-03	0.0	0.0	0.0	0.0	0.0	3.80E-04	0.0	0.0	0.0	
C_2H_4	0.0	0.0	0.0	0.0	0.0	0.0	4.36E-03	0.0	0.0	0.0	
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0	0.0556	0.0	0.0	0.0	
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0	
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.0	0.3372	0.0	0.0	0.0	
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0	0.3323	0.0	0.0	0.0	
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0	
Naphtha	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	
F-T-Jet	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	
F-T-Diesel	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	
S_8	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	

Description	Syngas Recycle	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT
PFD Number	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**
Temperature (F)	294.8	500.0	500.0	268.0	358.1	318.1	90.0	100.0
Pressure (psia)	477.0	477.0	477.0	665.0	379.0	360.0	125.0	369.0
Mass Flow (lb/hr)	210,192	2,030,439	1,963,370	1,413,965	375,448	109,821	34,662	1,606,668
Mole Flow (lbmol/hr)	10,156	98,102	94,862	43,938	17,804	3,413	1,077	61,127
Mole Fraction								
H_2O	0.1412	0.1412	0.1412	0.0	0.0555	0.0	0.0	0.0
Ar	7.24E-03	7.24E-03	7.24E-03	0.0318	0.0587	0.0318	0.0318	0.0405
CO_2	0.1289	0.1289	0.1289	0.0	0.1140	0.0	0.0	0.4185
O_2	0.0	0.0	0.0	0.9504	6.50E-17	0.9504	0.9504	0.0
N_2	5.41E-03	5.41E-03	5.41E-03	0.0178	0.0388	0.0178	0.0178	0.0343
CO	0.3947	0.3947	0.3947	0.0	0.3862	0.0	0.0	0.1276
COS	6.70E-05	6.70E-05	6.70E-05	0.0	2.99E-09	0.0	0.0	2.12E-07
H_2	0.3009	0.3009	0.3009	0.0	0.3381	0.0	0.0	0.3201
H_2S	1.32E-03	1.32E-03	1.32E-03	0.0	2.00E-12	0.0	0.0	8.48E-11
HCl	2.54E-05	2.54E-05	2.54E-05	0.0	0.0	0.0	0.0	0.0
NH_3	3.75E-03	3.75E-03	3.75E-03	0.0	3.23E-05	0.0	0.0	9.41E-06
SO_2	0.0	0.0	0.0	0.0	3.44E-18	0.0	0.0	0.0
CH_4	0.0165	0.0165	0.0165	0.0	8.70E-03	0.0	0.0	0.0542
C_2H_4	0.0	0.0	0.0	0.0	1.69E-08	0.0	0.0	1.41E-03
C_2H_6	0.0	0.0	0.0	0.0	2.78E-09	0.0	0.0	4.39E-04
C_3H_6	0.0	0.0	0.0	0.0	1.56E-12	0.0	0.0	1.21E-03
C_3H_8	0.0	0.0	0.0	0.0	4.77E-14	0.0	0.0	3.85E-04
ISOBU-01	0.0	0.0	0.0	0.0	3.13E-19	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	0.0	5.11E-16	0.0	0.0	3.34E-04
1-BUT-01	0.0	0.0	0.0	0.0	1.61E-15	0.0	0.0	1.04E-03
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	0.0	1.46E-41	0.0	0.0	0.0

Description	CO_2 from MDEA	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	**35**	**36**	**37**	**38**	**39**
Temperature (F)	105.0	323.4	423.3	323.4	821.7
Pressure (psia)	25.0	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	1,041,423	7,306	254,438	324,562	218,975
Mole Flow (lbmol/hr)	23,665	500	12,763	22,212	7,588
Mole Fraction					
H_2O	0.0	0.0544	0.0774	0.0544	9.87E-03
Ar	0.0	0.0575	0.0819	0.0575	9.25E-03
CO_2	0.9999	0.0531	0.0756	0.0531	3.27E-04
O_2	0.0	6.37E-17	9.07E-17	6.37E-17	0.2074
N_2	1.12E-05	0.0372	0.0528	0.0372	0.7732
CO	6.04E-05	0.2439	0.3469	0.2439	0.0
COS	0.0	1.55E-13	2.20E-13	1.55E-13	0.0
H_2	8.52E-08	0.5534	0.3647	0.5534	0.0
H_2S	2.12E-10	1.96E-12	2.79E-12	1.96E-12	0.0
HCl	0.0	0.0	0.0	0.0	0.0
NH_3	0.0	3.16E-05	4.51E-05	3.16E-05	0.0
SO_2	0.0	3.37E-18	4.80E-18	3.37E-18	0.0
CH_4	3.44E-05	5.02E-04	7.14E-04	5.02E-04	0.0
C_2H_4	0.0	1.65E-08	2.35E-08	1.65E-08	0.0
C_2H_6	0.0	2.73E-09	3.88E-09	2.73E-09	0.0
C_3H_6	0.0	1.53E-12	2.17E-12	1.53E-12	0.0
C_3H_8	0.0	4.68E-14	6.66E-14	5.54E-14	0.0
ISOBU-01	0.0	3.07E-19	4.37E-19	3.07E-19	0.0
N-BUT-01	0.0	5.01E-16	7.13E-16	9.15E-15	0.0
1-BUT-01	0.0	1.58E-15	2.25E-15	1.58E-15	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0
S_8	0.0	1.43E-41	2.04E-41	1.43E-41	0.0

Table 2-4: CBTL, 20% Biomass, Chipped: Stream Values

Description	Coal	Dried Coal	Raw Biomass	Dried Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed
PFD Number	1	2	3	4	6	7	8	9	10	11	12
Temperature (F)	59.0	220.0	59.0	220.0	489.4	59.0	59.0	500.0	90.0	100.0	260.3
Pressure (psia)	14.7	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0
Mass Flow (lb/hr)	2,136,386	1,933,951	699,224	483,488	411,012	6,529,963	3,531,600	4,020,246	1,546,428	1,691,740	2,417,249
Mole Flow (lbmol/hr)					22,815	226,287	122,383	193,843	48,054	40,985	154,278
Mole Fraction											
H_2O					1.0	9.87E-03	9.87E-03	0.1428	0.0	1.40E-03	6.30E-03
Ar					0.0	9.25E-03	9.25E-03	7.16E-03	0.0318	0.0	0.0158
CO_2					0.0	3.27E-04	3.27E-04	0.1304	0.0	0.8909	0.0214
O_2					0.0	0.2074	0.2074	0.0	0.9504	0.0	7.43E-18
N_2					0.0	0.7732	0.7732	5.31E-03	0.0178	4.73E-04	0.0132
CO					0.0	0.0	0.0	0.3935	0.0	0.0668	0.4398
COS					0.0	0.0	0.0	6.12E-05	0.0	4.34E-07	7.72E-08
H_2					0.0	0.0	0.0	0.2998	0.0	0.0350	0.4837
H_2S					0.0	0.0	0.0	1.20E-03	0.0	0.0	3.08E-11
HCl					0.0	0.0	0.0	2.31E-05	0.0	0.0	0.0
NH_3					0.0	0.0	0.0	3.60E-03	0.0	0.0	3.58E-06
SO_2					0.0	0.0	0.0	0.0	0.0	0.0	3.67E-19
CH_4					0.0	0.0	0.0	0.0161	0.0	5.33E-03	0.0198
C_2H_4					0.0	0.0	0.0	0.0	0.0	0.0	1.87E-09
C_2H_6					0.0	0.0	0.0	0.0	0.0	0.0	3.07E-10
C_3H_6					0.0	0.0	0.0	0.0	0.0	0.0	1.72E-13
C_3H_8					0.0	0.0	0.0	0.0	0.0	0.0	5.22E-15
ISOBU-01					0.0	0.0	0.0	0.0	0.0	0.0	3.40E-20
N-BUT-01					0.0	0.0	0.0	0.0	0.0	0.0	5.84E-17
1-BUT-01					0.0	0.0	0.0	0.0	0.0	0.0	1.84E-16
Naphtha					0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet					0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel					0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8					0.0	0.0	0.0	0.0	0.0	0.0	1.77E-42

Description	CO_2 Seq.	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash
PFD Number	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**
Temperature (F)	100.0	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0
Pressure (psia)	2214.7	14.7	317.0	14.7	14.7	14.7	227.0	14.7	14.7	14.7	14.7
Mass Flow (lb/hr)	2,611,159	7,835	39,498	175,107	53,580	273,562	31,235	258,136	4,799,393	4,254,975	212,755
Mole Flow (lbmol/hr)	59,554	31	19,270	1,657	252	1,288	640	8,238	266,407	150,196	
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0601	1.0	0.0975	
Ar	0.0	0.0	1.21E-04	0.0	0.0	0.0	1.95E-05	0.0386	0.0	0.0155	
CO_2	0.9926	0.0	8.64E-09	0.0	0.0	0.0	0.0600	0.2099	0.0	0.0444	
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0262	0.0	0.0994	
N_2	6.28E-05	0.0	3.27E-04	0.0	0.0	0.0	7.43E-07	0.6651	0.0	0.7432	
CO	4.90E-03	0.0	7.98E-04	0.0	0.0	0.0	7.87E-06	0.0	0.0	0.0	
COS	2.98E-07	0.0	0.0	0.0	0.0	0.0	1.86E-05	1.48E-13	0.0	0.0	
H_2	1.16E-03	0.0	0.9988	0.0	0.0	0.0	1.38E-09	0.0	0.0	0.0	
H_2S	7.71E-11	0.0	0.0	0.0	0.0	0.0	1.30E-10	0.0	0.0	0.0	
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
NH_3	0.0	0.0	0.0	0.0	0.0	0.0	8.63E-04	1.88E-06	0.0	4.58E-06	
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.10E-13	0.0	2.89E-13	
CH_4	1.29E-03	0.0	0.0	0.0	0.0	0.0	3.73E-04	0.0	0.0	0.0	
C_2H_4	0.0	0.0	0.0	0.0	0.0	0.0	4.36E-03	0.0	0.0	0.0	
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0	0.0556	0.0	0.0	0.0	
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0	
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.0	0.3372	0.0	0.0	0.0	
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0	0.3323	0.0	0.0	0.0	
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0	
Naphtha	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	
F-T-Jet	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	
F-T-Diesel	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	
S_8	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	

Description	Syngas Recycle	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT
PFD Number	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**
Temperature (F)	295.5	500.0	500.0	268.0	355.9	318.1	90.0	100.0
Pressure (psia)	477.0	477.0	477.0	665.0	379.0	360.0	125.0	369.0
Mass Flow (lb/hr)	211,592	2,025,478	1,994,768	1,404,549	370,272	108,308	33,570	1,602,662
Mole Flow (lbmol/hr)	10,202	97,662	96,181	43,646	17,541	3,366	1,043	60,968
Mole Fraction								
H_2O	0.1428	0.1428	0.1428	0.0	0.0551	0.0	0.0	0.0
Ar	7.16E-03	7.16E-03	7.16E-03	0.0318	0.0580	0.0318	0.0318	0.0400
CO_2	0.1304	0.1304	0.1304	0.0	0.1151	0.0	0.0	0.4196
O_2	0.0	0.0	0.0	0.9504	6.54E-17	0.9504	0.9504	0.0
N_2	5.31E-03	5.31E-03	5.31E-03	0.0178	0.0378	0.0178	0.0178	0.0335
CO	0.3935	0.3935	0.3935	0.0	0.3876	0.0	0.0	0.1280
COS	6.12E-05	6.12E-05	6.12E-05	0.0	2.74E-09	0.0	0.0	1.95E-07
H_2	0.2998	0.2998	0.2998	0.0	0.3378	0.0	0.0	0.3208
H_2S	1.20E-03	1.20E-03	1.20E-03	0.0	1.84E-12	0.0	0.0	7.80E-11
HCl	2.31E-05	2.31E-05	2.31E-05	0.0	0.0	0.0	0.0	0.0
NH_3	3.60E-03	3.60E-03	3.60E-03	0.0	3.15E-05	0.0	0.0	9.05E-06
SO_2	0.0	0.0	0.0	0.0	3.23E-18	0.0	0.0	0.0
CH_4	0.0161	0.0161	0.0161	0.0	8.62E-03	0.0	0.0	0.0533
C_2H_4	0.0	0.0	0.0	0.0	1.65E-08	0.0	0.0	1.41E-03
C_2H_6	0.0	0.0	0.0	0.0	2.70E-09	0.0	0.0	4.40E-04
C_3H_6	0.0	0.0	0.0	0.0	1.51E-12	0.0	0.0	1.21E-03
C_3H_8	0.0	0.0	0.0	0.0	4.59E-14	0.0	0.0	3.86E-04
ISOBU-01	0.0	0.0	0.0	0.0	2.99E-19	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	0.0	5.13E-16	0.0	0.0	3.35E-04
1-BUT-01	0.0	0.0	0.0	0.0	1.62E-15	0.0	0.0	1.04E-03
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	0.0	1.56E-41	0.0	0.0	0.0

Description	CO_2 from MDEA	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	**35**	**36**	**37**	**38**	**39**
Temperature (F)	105.0	322.8	422.6	322.8	821.7
Pressure (psia)	25.0	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	1,041,383	7,305	249,339	324,208	219,301
Mole Flow (lbmol/hr)	23,664	500	12,503	22,191	7,600
Mole Fraction					
H_2O	0.0	0.0542	0.0773	0.0542	9.87E-03
Ar	0.0	0.0572	0.0814	0.0572	9.25E-03
CO_2	0.9999	0.0536	0.0763	0.0536	3.27E-04
O_2	0.0	6.44E-17	9.17E-17	6.44E-17	0.2074
N_2	1.09E-05	0.0364	0.0518	0.0364	0.7732
CO	6.05E-05	0.2445	0.3479	0.2445	0.0
COS	0.0	1.45E-13	2.06E-13	1.45E-13	0.0
H_2	8.51E-08	0.5536	0.3647	0.5536	0.0
H_2S	1.94E-10	1.81E-12	2.58E-12	1.81E-12	0.0
HCl	0.0	0.0	0.0	0.0	0.0
NH_3	0.0	3.10E-05	4.41E-05	3.10E-05	0.0
SO_2	0.0	3.18E-18	4.53E-18	3.18E-18	0.0
CH_4	3.37E-05	4.93E-04	7.02E-04	4.93E-04	0.0
C_2H_4	0.0	1.62E-08	2.31E-08	1.62E-08	0.0
C_2H_6	0.0	2.66E-09	3.78E-09	2.66E-09	0.0
C_3H_6	0.0	1.49E-12	2.12E-12	1.49E-12	0.0
C_3H_8	0.0	4.52E-14	6.44E-14	5.39E-14	0.0
ISOBU-01	0.0	2.94E-19	4.19E-19	2.94E-19	0.0
N-BUT-01	0.0	5.05E-16	7.20E-16	9.16E-15	0.0
1-BUT-01	0.0	1.59E-15	2.27E-15	1.59E-15	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0
S_8	0.0	1.53E-41	2.18E-41	1.53E-41	0.0

Table 2-5: CBTL, 30% Biomass, Chipped: Stream Values

Description	Coal	Dried Coal	Raw Biomass	Dried Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed
PFD Number	**1**	**2**	**3**	**4**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Temperature (F)	59.0	220.0	59.0	220.0	489.4	59.0	59.0	500.0	90.0	100.0	259.8
Pressure (psia)	14.7	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0
Mass Flow (lb/hr)	1,918,502	1,736,712	1,076,420	744,305	369,094	6,474,864	3,531,600	4,048,133	1,533,823	1,712,338	2,412,803
Mole Flow (lbmol/hr)					20,488	224,378	122,383	194,769	47,663	41,454	154,097
Mole Fraction											
H_2O					1.0	9.87E-03	9.87E-03	0.1444	0.0	1.38E-03	6.16E-03
Ar					0.0	9.25E-03	9.25E-03	7.08E-03	0.0318	0.0	0.0156
CO_2					0.0	3.27E-04	3.27E-04	0.1320	0.0	0.8922	0.0215
O_2					0.0	0.2074	0.2074	0.0	0.9504	0.0	7.36E-18
N_2					0.0	0.7732	0.7732	5.20E-03	0.0178	4.58E-04	0.0129
CO					0.0	0.0	0.0	0.3924	0.0	0.0662	0.4403
COS					0.0	0.0	0.0	5.51E-05	0.0	3.89E-07	7.00E-08
H_2					0.0	0.0	0.0	0.2986	0.0	0.0347	0.4843
H_2S					0.0	0.0	0.0	1.08E-03	0.0	0.0	2.79E-11
HCl					0.0	0.0	0.0	2.06E-05	0.0	0.0	0.0
NH_3					0.0	0.0	0.0	3.44E-03	0.0	0.0	3.43E-06
SO_2					0.0	0.0	0.0	0.0	0.0	0.0	3.35E-19
CH_4					0.0	0.0	0.0	0.0157	0.0	5.16E-03	0.0194
C_2H_4					0.0	0.0	0.0	0.0	0.0	0.0	1.80E-09
C_2H_6					0.0	0.0	0.0	0.0	0.0	0.0	2.93E-10
C_3H_6					0.0	0.0	0.0	0.0	0.0	0.0	1.64E-13
C_3H_8					0.0	0.0	0.0	0.0	0.0	0.0	4.95E-15
ISOBU-01					0.0	0.0	0.0	0.0	0.0	0.0	3.19E-20
N-BUT-01					0.0	0.0	0.0	0.0	0.0	0.0	5.78E-17
1-BUT-01					0.0	0.0	0.0	0.0	0.0	0.0	1.82E-16
Naphtha					0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet					0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel					0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8					0.0	0.0	0.0	0.0	0.0	0.0	1.82E-42

Description	CO_2 Seq.	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash
PFD Number	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**
Temperature (F)	100.0	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0
Pressure (psia)	2214.7	14.7	317.0	14.7	14.7	14.7	227.0	14.7	14.7	14.7	14.7
Mass Flow (lb/hr)	2,631,790	7,087	39,495	175,108	53,580	273,563	31,234	259,202	4,716,807	4,255,442	196,619
Mole Flow (lbmol/hr)	60,023	28	19,268	1,657	252	1,288	639	8,268	261,823	150,203	
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0599	1.0	0.0974	
Ar	0.0	0.0	1.20E-04	0.0	0.0	0.0	1.92E-05	0.0382	0.0	0.0155	
CO_2	0.9926	0.0	8.65E-09	0.0	0.0	0.0	0.0600	0.2109	0.0	0.0445	
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0263	0.0	0.0994	
N_2	6.14E-05	0.0	3.21E-04	0.0	0.0	0.0	7.19E-07	0.6647	0.0	0.7432	
CO	4.91E-03	0.0	8.06E-04	0.0	0.0	0.0	7.86E-06	0.0	0.0	0.0	
COS	2.68E-07	0.0	0.0	0.0	0.0	0.0	1.69E-05	1.34E-13	0.0	0.0	
H_2	1.17E-03	0.0	0.9988	0.0	0.0	0.0	1.36E-09	0.0	0.0	0.0	
H_2S	6.92E-11	0.0	0.0	0.0	0.0	0.0	1.17E-10	0.0	0.0	0.0	
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
NH_3	0.0	0.0	0.0	0.0	0.0	0.0	8.26E-04	1.83E-06	0.0	4.47E-06	
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.99E-14	0.0	2.64E-13	
CH_4	1.26E-03	0.0	0.0	0.0	0.0	0.0	3.66E-04	0.0	0.0	0.0	
C_2H_4	0.0	0.0	0.0	0.0	0.0	0.0	4.36E-03	0.0	0.0	0.0	
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0	0.0556	0.0	0.0	0.0	
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0	
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.0	0.3372	0.0	0.0	0.0	
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0	0.3324	0.0	0.0	0.0	
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0	
Naphtha	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	
F-T-Jet	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	
F-T-Diesel	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	
S_8	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	

Description	Syngas Recycle	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT
PFD Number	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**
Temperature (F)	296.3	500.0	500.0	268.0	353.7	318.1	90.0	100.0
Pressure (psia)	477.0	477.0	477.0	665.0	379.0	360.0	125.0	369.0
Mass Flow (lb/hr)	213,060	2,020,846	2,027,287	1,394,641	364,937	106,758	32,424	1,598,522
Mole Flow (lbmol/hr)	10,251	97,230	97,540	43,338	17,271	3,317	1,008	60,805
Mole Fraction								
H_2O	0.1444	0.1444	0.1444	0.0	0.0546	0.0	0.0	0.0
Ar	7.08E-03	7.08E-03	7.08E-03	0.0318	0.0573	0.0318	0.0318	0.0395
CO_2	0.1320	0.1320	0.1320	0.0	0.1162	0.0	0.0	0.4207
O_2	0.0	0.0	0.0	0.9504	6.57E-17	0.9504	0.9504	0.0
N_2	5.20E-03	5.20E-03	5.20E-03	0.0178	0.0368	0.0178	0.0178	0.0326
CO	0.3924	0.3924	0.3924	0.0	0.3891	0.0	0.0	0.1285
COS	5.51E-05	5.51E-05	5.51E-05	0.0	2.47E-09	0.0	0.0	1.77E-07
H_2	0.2986	0.2986	0.2986	0.0	0.3375	0.0	0.0	0.3216
H_2S	1.08E-03	1.08E-03	1.08E-03	0.0	1.67E-12	0.0	0.0	7.07E-11
HCl	2.06E-05	2.06E-05	2.06E-05	0.0	0.0	0.0	0.0	0.0
NH_3	3.44E-03	3.44E-03	3.44E-03	0.0	3.06E-05	0.0	0.0	8.69E-06
SO_2	0.0	0.0	0.0	0.0	2.99E-18	0.0	0.0	0.0
CH_4	0.0157	0.0157	0.0157	0.0	8.54E-03	0.0	0.0	0.0524
C_2H_4	0.0	0.0	0.0	0.0	1.61E-08	0.0	0.0	1.42E-03
C_2H_6	0.0	0.0	0.0	0.0	2.61E-09	0.0	0.0	4.41E-04
C_3H_6	0.0	0.0	0.0	0.0	1.46E-12	0.0	0.0	1.22E-03
C_3H_8	0.0	0.0	0.0	0.0	4.41E-14	0.0	0.0	3.87E-04
ISOBU-01	0.0	0.0	0.0	0.0	2.85E-19	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	0.0	5.15E-16	0.0	0.0	3.36E-04
1-BUT-01	0.0	0.0	0.0	0.0	1.62E-15	0.0	0.0	1.04E-03
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	0.0	1.63E-41	0.0	0.0	0.0

Description	CO_2 from MDEA	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	**35**	**36**	**37**	**38**	**39**
Temperature (F)	105.0	322.2	421.9	322.2	821.7
Pressure (psia)	25.0	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	1,041,338	7,304	244,086	323,845	219,386
Mole Flow (lbmol/hr)	23,663	500	12,236	22,169	7,603
Mole Fraction					
H_2O	0.0	0.0541	0.0771	0.0541	9.87E-03
Ar	0.0	0.0567	0.0808	0.0567	9.25E-03
CO_2	0.9999	0.0541	0.0771	0.0541	3.27E-04
O_2	0.0	6.51E-17	9.27E-17	6.51E-17	0.2074
N_2	1.06E-05	0.0356	0.0506	0.0356	0.7732
CO	6.05E-05	0.2451	0.3489	0.2451	0.0
COS	0.0	1.34E-13	1.90E-13	1.34E-13	0.0
H_2	8.51E-08	0.5539	0.3647	0.5539	0.0
H_2S	1.75E-10	1.65E-12	2.36E-12	1.65E-12	0.0
HCl	0.0	0.0	0.0	0.0	0.0
NH_3	0.0	3.03E-05	4.32E-05	3.03E-05	0.0
SO_2	0.0	2.96E-18	4.22E-18	2.96E-18	0.0
CH_4	3.30E-05	4.84E-04	6.90E-04	4.84E-04	0.0
C_2H_4	0.0	1.59E-08	2.27E-08	1.59E-08	0.0
C_2H_6	0.0	2.59E-09	3.69E-09	2.59E-09	0.0
C_3H_6	0.0	1.45E-12	2.06E-12	1.45E-12	0.0
C_3H_8	0.0	4.37E-14	6.23E-14	5.24E-14	0.0
ISOBU-01	0.0	2.82E-19	4.02E-19	2.82E-19	0.0
N-BUT-01	0.0	5.10E-16	7.27E-16	9.18E-15	0.0
1-BUT-01	0.0	1.61E-15	2.29E-15	1.61E-15	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0
S_8	0.0	1.61E-41	2.30E-41	1.61E-41	0.0

Table 2-6: CBTL, 11.7% Biomass, Chipped, Modeled: Stream Values

Description	Coal	Dried Coal	Raw Biomass	Dried Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed
PFD Number	1	2	3	4	6	7	8	9	10	11	12
Temperature (F)	59.0	220.0	59.0	220.0	489.4	59.0	59.0	500.0	90.0	100.0	260.7
Pressure (psia)	14.7	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0
Mass Flow (lb/hr)	2,308,954	2,090,167	400,532	276,953	444,211	6,573,910	3,531,600	3,998,185	1,556,435	1,675,482	2,420,822
Mole Flow (lbmol/hr)					24,657	227,810	122,383	193,109	48,365	40,616	154,424
Mole Fraction											
H_2O					1.0	9.87E-03	9.87E-03	0.1415	0.0	1.41E-03	6.41E-03
Ar					0.0	9.25E-03	9.25E-03	7.23E-03	0.0318	0.0	0.0160
CO_2					0.0	3.27E-04	3.27E-04	0.1291	0.0	0.8900	0.0214
O_2					0.0	0.2074	0.2074	0.0	0.9504	0.0	7.48E-18
N_2					0.0	0.7732	0.7732	5.39E-03	0.0178	4.85E-04	0.0135
CO					0.0	0.0	0.0	0.3945	0.0	0.0674	0.4393
COS					0.0	0.0	0.0	6.60E-05	0.0	4.71E-07	8.29E-08
H_2					0.0	0.0	0.0	0.3007	0.0	0.0353	0.4833
H_2S					0.0	0.0	0.0	1.30E-03	0.0	0.0	3.31E-11
HCl					0.0	0.0	0.0	2.50E-05	0.0	0.0	0.0
NH_3					0.0	0.0	0.0	3.73E-03	0.0	0.0	3.70E-06
SO_2					0.0	0.0	0.0	0.0	0.0	0.0	3.92E-19
CH_4					0.0	0.0	0.0	0.0165	0.0	5.47E-03	0.0201
C_2H_4					0.0	0.0	0.0	0.0	0.0	0.0	1.93E-09
C_2H_6					0.0	0.0	0.0	0.0	0.0	0.0	3.18E-10
C_3H_6					0.0	0.0	0.0	0.0	0.0	0.0	1.78E-13
C_3H_8					0.0	0.0	0.0	0.0	0.0	0.0	5.45E-15
ISOBU-01					0.0	0.0	0.0	0.0	0.0	0.0	3.57E-20
N-BUT-01					0.0	0.0	0.0	0.0	0.0	0.0	5.88E-17
1-BUT-01					0.0	0.0	0.0	0.0	0.0	0.0	1.85E-16
Naphtha					0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet					0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel					0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8					0.0	0.0	0.0	0.0	0.0	0.0	1.70E-42

Description	CO_2 Seq.	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash
PFD Number	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**
Temperature (F)	100.0	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0
Pressure (psia)	2214.7	14.7	317.0	14.7	14.7	14.7	227.0	14.7	14.7	14.7	14.7
Mass Flow (lb/hr)	2,594,864	8,428	39,501	175,106	53,580	273,561	31,235	257,289	4,864,899	4,255,029	225,535
Mole Flow (lbmol/hr)	59,183	33	19,271	1,657	252	1,288	640	8,214	270,043	150,205	
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0603	1.0	0.0976	
Ar	0.0	0.0	1.22E-04	0.0	0.0	0.0	1.98E-05	0.0388	0.0	0.0156	
CO_2	0.9926	0.0	8.63E-09	0.0	0.0	0.0	0.0600	0.2092	0.0	0.0443	
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0262	0.0	0.0994	
N_2	6.39E-05	0.0	3.32E-04	0.0	0.0	0.0	7.63E-07	0.6655	0.0	0.7432	
CO	4.89E-03	0.0	7.92E-04	0.0	0.0	0.0	7.88E-06	0.0	0.0	0.0	
COS	3.22E-07	0.0	0.0	0.0	0.0	0.0	2.00E-05	1.60E-13	0.0	0.0	
H_2	1.16E-03	0.0	0.9988	0.0	0.0	0.0	1.39E-09	0.0	0.0	0.0	
H_2S	8.34E-11	0.0	0.0	0.0	0.0	0.0	1.40E-10	0.0	0.0	0.0	
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
NH_3	0.0	0.0	0.0	0.0	0.0	0.0	8.93E-04	1.92E-06	0.0	4.66E-06	
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.18E-13	0.0	3.09E-13	
CH_4	1.31E-03	0.0	0.0	0.0	0.0	0.0	3.79E-04	0.0	0.0	0.0	
C_2H_4	0.0	0.0	0.0	0.0	0.0	0.0	4.36E-03	0.0	0.0	0.0	
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0	0.0556	0.0	0.0	0.0	
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0	
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.0	0.3372	0.0	0.0	0.0	
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0	0.3323	0.0	0.0	0.0	
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0	
Naphtha	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	
F-T-Jet	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	
F-T-Diesel	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	
S_8	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	

Description	Syngas Recycle	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT
PFD Number	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**
Temperature (F)	294.9	500.0	500.0	268.0	357.7	318.1	90.0	100.0
Pressure (psia)	477.0	477.0	477.0	665.0	379.0	360.0	125.0	369.0
Mass Flow (lb/hr)	210,420	2,029,556	1,968,629	1,412,389	374,567	109,566	34,480	1,605,981
Mole Flow (lbmol/hr)	10,163	98,026	95,083	43,889	17,759	3,405	1,071	61,100
Mole Fraction								
H_2O	0.1415	0.1415	0.1415	0.0	0.0554	0.0	0.0	0.0
Ar	7.23E-03	7.23E-03	7.23E-03	0.0318	0.0586	0.0318	0.0318	0.0404
CO_2	0.1291	0.1291	0.1291	0.0	0.1142	0.0	0.0	0.4187
O_2	0.0	0.0	0.0	0.9504	6.51E-17	0.9504	0.9504	0.0
N_2	5.39E-03	5.39E-03	5.39E-03	0.0178	0.0386	0.0178	0.0178	0.0341
CO	0.3945	0.3945	0.3945	0.0	0.3865	0.0	0.0	0.1277
COS	6.60E-05	6.60E-05	6.60E-05	0.0	2.95E-09	0.0	0.0	2.10E-07
H_2	0.3007	0.3007	0.3007	0.0	0.3380	0.0	0.0	0.3202
H_2S	1.30E-03	1.30E-03	1.30E-03	0.0	1.97E-12	0.0	0.0	8.37E-11
HCl	2.50E-05	2.50E-05	2.50E-05	0.0	0.0	0.0	0.0	0.0
NH_3	3.73E-03	3.73E-03	3.73E-03	0.0	3.22E-05	0.0	0.0	9.35E-06
SO_2	0.0	0.0	0.0	0.0	3.41E-18	0.0	0.0	0.0
CH_4	0.0165	0.0165	0.0165	0.0	8.69E-03	0.0	0.0	0.0541
C_2H_4	0.0	0.0	0.0	0.0	1.68E-08	0.0	0.0	1.41E-03
C_2H_6	0.0	0.0	0.0	0.0	2.77E-09	0.0	0.0	4.39E-04
C_3H_6	0.0	0.0	0.0	0.0	1.55E-12	0.0	0.0	1.21E-03
C_3H_8	0.0	0.0	0.0	0.0	4.74E-14	0.0	0.0	3.85E-04
ISOBU-01	0.0	0.0	0.0	0.0	3.11E-19	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	0.0	5.11E-16	0.0	0.0	3.35E-04
1-BUT-01	0.0	0.0	0.0	0.0	1.61E-15	0.0	0.0	1.04E-03
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	0.0	1.48E-41	0.0	0.0	0.0

Description	CO_2 from MDEA	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	**35**	**36**	**37**	**38**	**39**
Temperature (F)	105.0	323.3	423.2	323.3	821.7
Pressure (psia)	25.0	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	1,041,407	7,306	253,568	324,511	219,027
Mole Flow (lbmol/hr)	23,664	500	12,719	22,209	7,590
Mole Fraction					
H_2O	0.0	0.0544	0.0774	0.0544	9.87E-03
Ar	0.0	0.0575	0.0818	0.0575	9.25E-03
CO_2	0.9999	0.0532	0.0757	0.0532	3.27E-04
O_2	0.0	6.38E-17	9.09E-17	6.38E-17	0.2074
N_2	1.11E-05	0.0371	0.0526	0.0371	0.7732
CO	6.04E-05	0.2440	0.3471	0.2440	0.0
COS	0.0	1.53E-13	2.18E-13	1.53E-13	0.0
H_2	8.52E-08	0.5534	0.3647	0.5534	0.0
H_2S	2.09E-10	1.93E-12	2.75E-12	1.93E-12	0.0
HCl	0.0	0.0	0.0	0.0	0.0
NH_3	0.0	3.15E-05	4.49E-05	3.15E-05	0.0
SO_2	0.0	3.34E-18	4.76E-18	3.34E-18	0.0
CH_4	3.43E-05	5.00E-04	7.12E-04	5.00E-04	0.0
C_2H_4	0.0	1.65E-08	2.35E-08	1.65E-08	0.0
C_2H_6	0.0	2.71E-09	3.86E-09	2.71E-09	0.0
C_3H_6	0.0	1.52E-12	2.16E-12	1.52E-12	0.0
C_3H_8	0.0	4.65E-14	6.62E-14	5.51E-14	0.0
ISOBU-01	0.0	3.05E-19	4.34E-19	3.05E-19	0.0
N-BUT-01	0.0	5.02E-16	7.14E-16	9.15E-15	0.0
1-BUT-01	0.0	1.58E-15	2.25E-15	1.58E-15	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0
S_8	0.0	1.45E-41	2.06E-41	1.45E-41	0.0

Table 2-7: CBTL, 11.7% Biomass, Chipped, Validated: Stream Values

Description	Coal	Dried Coal	Raw Biomass	Dried Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed
PFD Number	**1**	**2**	**3**	**4**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Temperature (F)	59.0	220.0	59.0	220.0	489.4	59.0	59.0	500.0	90.0	100.0	263.0
Pressure (psia)	14.7	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0
Mass Flow (lb/hr)	2,313,288	2,094,090	401,283	277,473	445,045	6,607,182	3,531,600	4,002,031	1,563,813	1,686,581	2,438,307
Mole Flow (lbmol/hr)					24,704	228,963	122,383	192,726	48,595	40,867	155,162
Mole Fraction											
H_2O					1.0	9.87E-03	9.87E-03	0.1484	0.0	1.40E-03	7.15E-03
Ar					0.0	9.25E-03	9.25E-03	7.24E-03	0.0318	0.0	0.0167
CO_2					0.0	3.27E-04	3.27E-04	0.1241	0.0	0.8907	0.0217
O_2					0.0	0.2074	0.2074	0.0	0.9504	0.0	7.64E-18
N_2					0.0	0.7732	0.7732	5.40E-03	0.0178	4.83E-04	0.0139
CO					0.0	0.0	0.0	0.3997	0.0	0.0665	0.4373
COS					0.0	0.0	0.0	6.10E-05	0.0	4.31E-07	7.60E-08
H_2					0.0	0.0	0.0	0.2916	0.0	0.0348	0.4810
H_2S					0.0	0.0	0.0	1.31E-03	0.0	0.0	3.30E-11
HCl					0.0	0.0	0.0	2.51E-05	0.0	0.0	0.0
NH_3					0.0	0.0	0.0	3.74E-03	0.0	0.0	4.40E-06
SO_2					0.0	0.0	0.0	0.0	0.0	0.0	3.64E-19
CH_4					0.0	0.0	0.0	0.0185	0.0	6.08E-03	0.0224
C_2H_4					0.0	0.0	0.0	0.0	0.0	0.0	2.50E-09
C_2H_6					0.0	0.0	0.0	0.0	0.0	0.0	4.31E-10
C_3H_6					0.0	0.0	0.0	0.0	0.0	0.0	2.48E-13
C_3H_8					0.0	0.0	0.0	0.0	0.0	0.0	7.93E-15
ISOBU-01					0.0	0.0	0.0	0.0	0.0	0.0	5.62E-20
N-BUT-01					0.0	0.0	0.0	0.0	0.0	0.0	6.20E-17
1-BUT-01					0.0	0.0	0.0	0.0	0.0	0.0	1.96E-16
Naphtha					0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet					0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel					0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8					0.0	0.0	0.0	0.0	0.0	0.0	1.81E-42

Description	CO_2 Seq.	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash
PFD Number	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**
Temperature (F)	100.0	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0
Pressure (psia)	2214.7	14.7	317.0	14.7	14.7	14.7	227.4	14.7	14.7	14.7	14.7
Mass Flow (lb/hr)	2,609,584	8,444	39,496	175,104	53,580	273,557	31,242	252,966	4,893,987	4,253,547	225,958
Mole Flow (lbmol/hr)	59,523	33	19,274	1,657	252	1,288	640	8,089	271,658	150,222	
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0620	1.0	0.0979	
Ar	0.0	0.0	1.24E-04	0.0	0.0	0.0	2.08E-05	0.0397	0.0	0.0156	
CO_2	0.9924	0.0	8.59E-09	0.0	0.0	0.0	0.0602	0.2064	0.0	0.0436	
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0261	0.0	0.0995	
N_2	6.42E-05	0.0	3.34E-04	0.0	0.0	0.0	8.01E-07	0.6657	0.0	0.7435	
CO	4.86E-03	0.0	7.67E-04	0.0	0.0	0.0	7.91E-06	0.0	0.0	0.0	
COS	2.95E-07	0.0	0.0	0.0	0.0	0.0	1.84E-05	1.47E-13	0.0	0.0	
H_2	1.16E-03	0.0	0.9988	0.0	0.0	0.0	1.46E-09	0.0	0.0	0.0	
H_2S	8.31E-11	0.0	0.0	0.0	0.0	0.0	1.40E-10	0.0	0.0	0.0	
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
NH_3	0.0	0.0	0.0	0.0	0.0	0.0	1.07E-03	2.11E-06	0.0	5.03E-06	
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.15E-13	0.0	2.95E-13	
CH_4	1.47E-03	0.0	0.0	0.0	0.0	0.0	4.19E-04	0.0	0.0	0.0	
C_2H_4	0.0	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0	
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0	
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0	
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.0	0.3370	0.0	0.0	0.0	
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0	0.3322	0.0	0.0	0.0	
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0	
Naphtha	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	
F-T-Jet	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	
F-T-Diesel	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	
S_8	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	

Description	Syngas Recycle	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT
PFD Number	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**
Temperature (F)	298.1	500.0	500.0	268.0	368.5	318.1	90.0	100.0
Pressure (psia)	477.0	477.0	477.0	665.0	379.0	360.0	125.0	369.0
Mass Flow (lb/hr)	210,622	2,153,558	1,848,473	1,411,380	399,053	117,725	34,708	1,621,664
Mole Flow (lbmol/hr)	10,143	103,709	89,017	43,858	19,108	3,658	1,079	61,738
Mole Fraction								
H_2O	0.1484	0.1484	0.1484	0.0	0.0578	0.0	0.0	0.0
Ar	7.24E-03	7.24E-03	7.24E-03	0.0318	0.0606	0.0318	0.0318	0.0419
CO_2	0.1241	0.1241	0.1241	0.0	0.1087	0.0	0.0	0.4156
O_2	0.0	0.0	0.0	0.9504	6.20E-17	0.9504	0.9504	0.0
N_2	5.40E-03	5.40E-03	5.40E-03	0.0178	0.0398	0.0178	0.0178	0.0350
CO	0.3997	0.3997	0.3997	0.0	0.3815	0.0	0.0	0.1261
COS	6.10E-05	6.10E-05	6.10E-05	0.0	2.49E-09	0.0	0.0	1.91E-07
H_2	0.2916	0.2916	0.2916	0.0	0.3425	0.0	0.0	0.3172
H_2S	1.31E-03	1.31E-03	1.31E-03	0.0	1.95E-12	0.0	0.0	8.30E-11
HCl	2.51E-05	2.51E-05	2.51E-05	0.0	0.0	0.0	0.0	0.0
NH_3	3.74E-03	3.74E-03	3.74E-03	0.0	3.57E-05	0.0	0.0	1.11E-05
SO_2	0.0	0.0	0.0	0.0	2.96E-18	0.0	0.0	0.0
CH_4	0.0185	0.0185	0.0185	0.0	9.08E-03	0.0	0.0	0.0595
C_2H_4	0.0	0.0	0.0	0.0	2.03E-08	0.0	0.0	1.40E-03
C_2H_6	0.0	0.0	0.0	0.0	3.50E-09	0.0	0.0	4.34E-04
C_3H_6	0.0	0.0	0.0	0.0	2.02E-12	0.0	0.0	1.20E-03
C_3H_8	0.0	0.0	0.0	0.0	6.44E-14	0.0	0.0	3.81E-04
ISOBU-01	0.0	0.0	0.0	0.0	4.57E-19	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	0.0	5.03E-16	0.0	0.0	3.31E-04
1-BUT-01	0.0	0.0	0.0	0.0	1.59E-15	0.0	0.0	1.03E-03
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	0.0	1.47E-41	0.0	0.0	0.0

Description	CO_2 from MDEA	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	**35**	**36**	**37**	**38**	**39**
Temperature (F)	105.0	325.5	426.4	325.5	821.7
Pressure (psia)	25.0	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	1,044,579	7,250	278,505	321,385	217,958
Mole Flow (lbmol/hr)	23,736	500	14,085	22,164	7,553
Mole Fraction					
H_2O	0.0	0.0551	0.0784	0.0551	9.87E-03
Ar	0.0	0.0578	0.0822	0.0578	9.25E-03
CO_2	0.9999	0.0507	0.0721	0.0507	3.27E-04
O_2	0.0	5.91E-17	8.41E-17	5.91E-17	0.2074
N_2	1.15E-05	0.0372	0.0529	0.0372	0.7732
CO	6.01E-05	0.2427	0.3451	0.2427	0.0
COS	0.0	1.38E-13	1.97E-13	1.38E-13	0.0
H_2	8.50E-08	0.5560	0.3685	0.5560	0.0
H_2S	2.09E-10	1.86E-12	2.65E-12	1.86E-12	0.0
HCl	0.0	0.0	0.0	0.0	0.0
NH_3	0.0	3.41E-05	4.85E-05	3.41E-05	0.0
SO_2	0.0	2.82E-18	4.01E-18	2.82E-18	0.0
CH_4	3.80E-05	5.70E-04	8.12E-04	5.70E-04	0.0
C_2H_4	0.0	1.93E-08	2.75E-08	1.93E-08	0.0
C_2H_6	0.0	3.34E-09	4.75E-09	3.34E-09	0.0
C_3H_6	0.0	1.92E-12	2.74E-12	1.92E-12	0.0
C_3H_8	0.0	6.14E-14	8.74E-14	7.01E-14	0.0
ISOBU-01	0.0	4.35E-19	6.20E-19	4.35E-19	0.0
N-BUT-01	0.0	4.80E-16	6.83E-16	9.15E-15	0.0
1-BUT-01	0.0	1.52E-15	2.16E-15	1.52E-15	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0
S_8	0.0	1.40E-41	1.99E-41	1.40E-41	0.0

Table 2-8: CBTL, 19.2% Biomass, Chipped, Modeled: Stream Values

Description	Coal	Dried Coal	Raw Biomass	Dried Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed
PFD Number	1	2	3	4	6	7	8	9	10	11	12
Temperature (F)	59.0	220.0	59.0	220.0	489.4	59.0	59.0	500.0	90.0	100.0	260.3
Pressure (psia)	14.7	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0
Mass Flow (lb/hr)	2,153,345	1,949,303	669,884	463,201	414,274	6,534,429	3,531,600	4,018,092	1,547,417	1,690,059	2,417,650
Mole Flow (lbmol/hr)					22,996	226,442	122,383	193,772	48,085	40,947	154,292
Mole Fraction											
H_2O					1.0	9.87E-03	9.87E-03	0.1427	0.0	1.40E-03	6.31E-03
Ar					0.0	9.25E-03	9.25E-03	7.17E-03	0.0318	0.0	0.0158
CO_2					0.0	3.27E-04	3.27E-04	0.1303	0.0	0.8908	0.0214
O_2					0.0	0.2074	0.2074	0.0	0.9504	0.0	7.44E-18
N_2					0.0	0.7732	0.7732	5.31E-03	0.0178	4.74E-04	0.0132
CO					0.0	0.0	0.0	0.3936	0.0	0.0669	0.4397
COS					0.0	0.0	0.0	6.17E-05	0.0	4.38E-07	7.77E-08
H_2					0.0	0.0	0.0	0.2999	0.0	0.0351	0.4837
H_2S					0.0	0.0	0.0	1.21E-03	0.0	0.0	3.10E-11
HCl					0.0	0.0	0.0	2.33E-05	0.0	0.0	0.0
NH_3					0.0	0.0	0.0	3.61E-03	0.0	0.0	3.59E-06
SO_2					0.0	0.0	0.0	0.0	0.0	0.0	3.70E-19
CH_4					0.0	0.0	0.0	0.0162	0.0	5.34E-03	0.0198
C_2H_4					0.0	0.0	0.0	0.0	0.0	0.0	1.88E-09
C_2H_6					0.0	0.0	0.0	0.0	0.0	0.0	3.08E-10
C_3H_6					0.0	0.0	0.0	0.0	0.0	0.0	1.72E-13
C_3H_8					0.0	0.0	0.0	0.0	0.0	0.0	5.24E-15
ISOBU-01					0.0	0.0	0.0	0.0	0.0	0.0	3.41E-20
N-BUT-01					0.0	0.0	0.0	0.0	0.0	0.0	5.84E-17
1-BUT-01					0.0	0.0	0.0	0.0	0.0	0.0	1.84E-16
Naphtha					0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet					0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel					0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8					0.0	0.0	0.0	0.0	0.0	0.0	1.76E-42

Description	CO_2 Seq.	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash
PFD Number	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**
Temperature (F)	100.0	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0
Pressure (psia)	2214.7	14.7	317.0	14.7	14.7	14.7	227.0	14.7	14.7	14.7	14.7
Mass Flow (lb/hr)	2,609,530	7,893	39,497	175,107	53,580	273,562	31,235	258,052	4,805,807	4,255,168	214,011
Mole Flow (lbmol/hr)	59,517	31	19,269	1,657	252	1,288	640	8,236	266,763	150,203	
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0602	1.0	0.0975	
Ar	0.0	0.0	1.21E-04	0.0	0.0	0.0	1.96E-05	0.0386	0.0	0.0155	
CO_2	0.9926	0.0	8.64E-09	0.0	0.0	0.0	0.0600	0.2099	0.0	0.0443	
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0262	0.0	0.0994	
N_2	6.29E-05	0.0	3.28E-04	0.0	0.0	0.0	7.45E-07	0.6651	0.0	0.7432	
CO	4.90E-03	0.0	7.98E-04	0.0	0.0	0.0	7.87E-06	0.0	0.0	0.0	
COS	3.00E-07	0.0	0.0	0.0	0.0	0.0	1.88E-05	1.49E-13	0.0	0.0	
H_2	1.16E-03	0.0	0.9988	0.0	0.0	0.0	1.38E-09	0.0	0.0	0.0	
H_2S	7.77E-11	0.0	0.0	0.0	0.0	0.0	1.31E-10	0.0	0.0	0.0	
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
NH_3	0.0	0.0	0.0	0.0	0.0	0.0	8.66E-04	1.88E-06	0.0	4.59E-06	
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.11E-13	0.0	2.91E-13	
CH_4	1.29E-03	0.0	0.0	0.0	0.0	0.0	3.74E-04	0.0	0.0	0.0	
C_2H_4	0.0	0.0	0.0	0.0	0.0	0.0	4.36E-03	0.0	0.0	0.0	
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0	0.0556	0.0	0.0	0.0	
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0	
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.0	0.3372	0.0	0.0	0.0	
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0	0.3323	0.0	0.0	0.0	
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0	
Naphtha	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	
F-T-Jet	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	
F-T-Diesel	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	
S_8	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	

Description	Syngas Recycle	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT
PFD Number	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**
Temperature (F)	295.5	500.0	500.0	268.0	356.1	318.1	90.0	100.0
Pressure (psia)	477.0	477.0	477.0	665.0	379.0	360.0	125.0	369.0
Mass Flow (lb/hr)	211,482	2,025,514	1,992,578	1,405,325	370,686	108,433	33,660	1,603,066
Mole Flow (lbmol/hr)	10,199	97,680	96,092	43,670	17,562	3,369	1,046	60,983
Mole Fraction								
H_2O	0.1427	0.1427	0.1427	0.0	0.0551	0.0	0.0	0.0
Ar	7.17E-03	7.17E-03	7.17E-03	0.0318	0.0580	0.0318	0.0318	0.0400
CO_2	0.1303	0.1303	0.1303	0.0	0.1150	0.0	0.0	0.4195
O_2	0.0	0.0	0.0	0.9504	6.53E-17	0.9504	0.9504	0.0
N_2	5.31E-03	5.31E-03	5.31E-03	0.0178	0.0379	0.0178	0.0178	0.0335
CO	0.3936	0.3936	0.3936	0.0	0.3875	0.0	0.0	0.1280
COS	6.17E-05	6.17E-05	6.17E-05	0.0	2.76E-09	0.0	0.0	1.97E-07
H_2	0.2999	0.2999	0.2999	0.0	0.3378	0.0	0.0	0.3207
H_2S	1.21E-03	1.21E-03	1.21E-03	0.0	1.85E-12	0.0	0.0	7.85E-11
HCl	2.33E-05	2.33E-05	2.33E-05	0.0	0.0	0.0	0.0	0.0
NH_3	3.61E-03	3.61E-03	3.61E-03	0.0	3.15E-05	0.0	0.0	9.08E-06
SO_2	0.0	0.0	0.0	0.0	3.25E-18	0.0	0.0	0.0
CH_4	0.0162	0.0162	0.0162	0.0	8.63E-03	0.0	0.0	0.0534
C_2H_4	0.0	0.0	0.0	0.0	1.65E-08	0.0	0.0	1.41E-03
C_2H_6	0.0	0.0	0.0	0.0	2.70E-09	0.0	0.0	4.40E-04
C_3H_6	0.0	0.0	0.0	0.0	1.51E-12	0.0	0.0	1.21E-03
C_3H_8	0.0	0.0	0.0	0.0	4.61E-14	0.0	0.0	3.86E-04
ISOBU-01	0.0	0.0	0.0	0.0	3.00E-19	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	0.0	5.13E-16	0.0	0.0	3.35E-04
1-BUT-01	0.0	0.0	0.0	0.0	1.62E-15	0.0	0.0	1.04E-03
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	0.0	1.55E-41	0.0	0.0	0.0

Description	CO_2 from MDEA	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	**35**	**36**	**37**	**38**	**39**
Temperature (F)	105.0	322.9	422.7	322.9	821.7
Pressure (psia)	25.0	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	1,041,445	7,306	249,743	324,270	219,153
Mole Flow (lbmol/hr)	23,665	500	12,523	22,193	7,594
Mole Fraction					
H_2O	0.0	0.0543	0.0773	0.0543	9.87E-03
Ar	0.0	0.0572	0.0814	0.0572	9.25E-03
CO_2	0.9999	0.0535	0.0762	0.0535	3.27E-04
O_2	0.0	6.43E-17	9.16E-17	6.43E-17	0.2074
N_2	1.09E-05	0.0365	0.0518	0.0365	0.7732
CO	6.05E-05	0.2444	0.3478	0.2444	0.0
COS	0.0	1.46E-13	2.07E-13	1.46E-13	0.0
H_2	8.51E-08	0.5536	0.3646	0.5536	0.0
H_2S	1.95E-10	1.82E-12	2.60E-12	1.82E-12	0.0
HCl	0.0	0.0	0.0	0.0	0.0
NH_3	0.0	3.10E-05	4.42E-05	3.10E-05	0.0
SO_2	0.0	3.20E-18	4.56E-18	3.20E-18	0.0
CH_4	3.38E-05	4.94E-04	7.03E-04	4.94E-04	0.0
C_2H_4	0.0	1.62E-08	2.31E-08	1.62E-08	0.0
C_2H_6	0.0	2.66E-09	3.79E-09	2.66E-09	0.0
C_3H_6	0.0	1.49E-12	2.12E-12	1.49E-12	0.0
C_3H_8	0.0	4.53E-14	6.46E-14	5.40E-14	0.0
ISOBU-01	0.0	2.95E-19	4.21E-19	2.95E-19	0.0
N-BUT-01	0.0	5.05E-16	7.19E-16	9.16E-15	0.0
1-BUT-01	0.0	1.59E-15	2.27E-15	1.59E-15	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0
S_8	0.0	1.52E-41	2.17E-41	1.52E-41	0.0

Table 2-9: CBTL, 19.2% Biomass, Chipped, Validated: Stream Values

Description	Coal	Dried Coal	Raw Biomass	Dried Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed
PFD Number	**1**	**2**	**3**	**4**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Temperature (F)	59.0	220.0	59.0	220.0	489.4	59.0	59.0	500.0	90.0	100.0	262.6
Pressure (psia)	14.7	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0
Mass Flow (lb/hr)	2,157,373	1,952,949	671,137	464,067	415,049	6,567,498	3,531,600	4,022,058	1,554,754	1,701,454	2,434,656
Mole Flow (lbmol/hr)					23,039	227,588	122,383	193,399	48,313	41,205	155,018
Mole Fraction											
H_2O					1.0	9.87E-03	9.87E-03	0.1496	0.0	1.39E-03	7.04E-03
Ar					0.0	9.25E-03	9.25E-03	7.18E-03	0.0318	0.0	0.0165
CO_2					0.0	3.27E-04	3.27E-04	0.1252	0.0	0.8916	0.0217
O_2					0.0	0.2074	0.2074	0.0	0.9504	0.0	7.59E-18
N_2					0.0	0.7732	0.7732	5.32E-03	0.0178	4.72E-04	0.0137
CO					0.0	0.0	0.0	0.3989	0.0	0.0660	0.4376
COS					0.0	0.0	0.0	5.70E-05	0.0	4.01E-07	7.13E-08
H_2					0.0	0.0	0.0	0.2908	0.0	0.0346	0.4814
H_2S					0.0	0.0	0.0	1.22E-03	0.0	0.0	3.10E-11
HCl					0.0	0.0	0.0	2.34E-05	0.0	0.0	0.0
NH_3					0.0	0.0	0.0	3.63E-03	0.0	0.0	4.27E-06
SO_2					0.0	0.0	0.0	0.0	0.0	0.0	3.43E-19
CH_4					0.0	0.0	0.0	0.0181	0.0	5.94E-03	0.0220
C_2H_4					0.0	0.0	0.0	0.0	0.0	0.0	2.43E-09
C_2H_6					0.0	0.0	0.0	0.0	0.0	0.0	4.17E-10
C_3H_6					0.0	0.0	0.0	0.0	0.0	0.0	2.40E-13
C_3H_8					0.0	0.0	0.0	0.0	0.0	0.0	7.64E-15
ISOBU-01					0.0	0.0	0.0	0.0	0.0	0.0	5.38E-20
N-BUT-01					0.0	0.0	0.0	0.0	0.0	0.0	6.16E-17
1-BUT-01					0.0	0.0	0.0	0.0	0.0	0.0	1.95E-16
Naphtha					0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet					0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel					0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8					0.0	0.0	0.0	0.0	0.0	0.0	1.89E-42

Description	CO_2 Seq.	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash
PFD Number	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**
Temperature (F)	100.0	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0
Pressure (psia)	2214.7	14.7	317.0	14.7	14.7	14.7	227.3	14.7	14.7	14.7	14.7
Mass Flow (lb/hr)	2,624,328	7,908	39,497	175,104	53,579	273,557	31,241	253,741	4,834,910	4,253,683	214,411
Mole Flow (lbmol/hr)	59,859	31	19,275	1,657	252	1,288	640	8,111	268,378	150,221	
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0618	1.0	0.0978	
Ar	0.0	0.0	1.23E-04	0.0	0.0	0.0	2.05E-05	0.0395	0.0	0.0155	
CO_2	0.9925	0.0	8.60E-09	0.0	0.0	0.0	0.0601	0.2071	0.0	0.0437	
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0262	0.0	0.0995	
N_2	6.32E-05	0.0	3.29E-04	0.0	0.0	0.0	7.82E-07	0.6654	0.0	0.7435	
CO	4.88E-03	0.0	7.72E-04	0.0	0.0	0.0	7.90E-06	0.0	0.0	0.0	
COS	2.75E-07	0.0	0.0	0.0	0.0	0.0	1.73E-05	1.38E-13	0.0	0.0	
H_2	1.16E-03	0.0	0.9988	0.0	0.0	0.0	1.44E-09	0.0	0.0	0.0	
H_2S	7.74E-11	0.0	0.0	0.0	0.0	0.0	1.31E-10	0.0	0.0	0.0	
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
NH_3	0.0	0.0	0.0	0.0	0.0	0.0	1.04E-03	2.07E-06	0.0	4.94E-06	
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.08E-13	0.0	2.78E-13	
CH_4	1.44E-03	0.0	0.0	0.0	0.0	0.0	4.13E-04	0.0	0.0	0.0	
C_2H_4	0.0	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0	
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0	
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0	
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.0	0.3371	0.0	0.0	0.0	
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0	0.3322	0.0	0.0	0.0	
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0	
Naphtha	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	
F-T-Jet	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	
F-T-Diesel	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	
S_8	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	

Description	Syngas Recycle	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT
PFD Number	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**
Temperature (F)	298.6	500.0	500.0	268.0	366.9	318.1	90.0	100.0
Pressure (psia)	477.0	477.0	477.0	665.0	379.0	360.0	125.0	369.0
Mass Flow (lb/hr)	211,688	2,151,803	1,870,255	1,404,404	394,780	116,467	33,884	1,618,211
Mole Flow (lbmol/hr)	10,179	103,468	89,930	43,641	18,889	3,619	1,053	61,605
Mole Fraction								
H_2O	0.1496	0.1496	0.1496	0.0	0.0575	0.0	0.0	0.0
Ar	7.18E-03	7.18E-03	7.18E-03	0.0318	0.0601	0.0318	0.0318	0.0415
CO_2	0.1252	0.1252	0.1252	0.0	0.1095	0.0	0.0	0.4164
O_2	0.0	0.0	0.0	0.9504	6.23E-17	0.9504	0.9504	0.0
N_2	5.32E-03	5.32E-03	5.32E-03	0.0178	0.0391	0.0178	0.0178	0.0344
CO	0.3989	0.3989	0.3989	0.0	0.3826	0.0	0.0	0.1264
COS	5.70E-05	5.70E-05	5.70E-05	0.0	2.33E-09	0.0	0.0	1.79E-07
H_2	0.2908	0.2908	0.2908	0.0	0.3423	0.0	0.0	0.3178
H_2S	1.22E-03	1.22E-03	1.22E-03	0.0	1.83E-12	0.0	0.0	7.79E-11
HCl	2.34E-05	2.34E-05	2.34E-05	0.0	0.0	0.0	0.0	0.0
NH_3	3.63E-03	3.63E-03	3.63E-03	0.0	3.51E-05	0.0	0.0	1.08E-05
SO_2	0.0	0.0	0.0	0.0	2.82E-18	0.0	0.0	0.0
CH_4	0.0181	0.0181	0.0181	0.0	9.01E-03	0.0	0.0	0.0587
C_2H_4	0.0	0.0	0.0	0.0	1.99E-08	0.0	0.0	1.40E-03
C_2H_6	0.0	0.0	0.0	0.0	3.43E-09	0.0	0.0	4.35E-04
C_3H_6	0.0	0.0	0.0	0.0	1.97E-12	0.0	0.0	1.20E-03
C_3H_8	0.0	0.0	0.0	0.0	6.27E-14	0.0	0.0	3.82E-04
ISOBU-01	0.0	0.0	0.0	0.0	4.42E-19	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	0.0	5.05E-16	0.0	0.0	3.32E-04
1-BUT-01	0.0	0.0	0.0	0.0	1.60E-15	0.0	0.0	1.03E-03
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	0.0	1.55E-41	0.0	0.0	0.0

Description	CO_2 from MDEA	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	**35**	**36**	**37**	**38**	**39**
Temperature (F)	105.0	325.0	425.8	325.0	821.7
Pressure (psia)	25.0	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	1,044,390	7,249	274,294	321,091	218,104
Mole Flow (lbmol/hr)	23,732	500	13,869	22,148	7,558
Mole Fraction					
H_2O	0.0	0.0550	0.0783	0.0550	9.87E-03
Ar	0.0	0.0575	0.0818	0.0575	9.25E-03
CO_2	0.9999	0.0510	0.0726	0.0510	3.27E-04
O_2	0.0	5.95E-17	8.48E-17	5.95E-17	0.2074
N_2	1.13E-05	0.0367	0.0521	0.0367	0.7732
CO	6.02E-05	0.2431	0.3459	0.2431	0.0
COS	0.0	1.32E-13	1.88E-13	1.32E-13	0.0
H_2	8.50E-08	0.5562	0.3685	0.5562	0.0
H_2S	1.95E-10	1.75E-12	2.50E-12	1.75E-12	0.0
HCl	0.0	0.0	0.0	0.0	0.0
NH_3	0.0	3.35E-05	4.78E-05	3.35E-05	0.0
SO_2	0.0	2.69E-18	3.84E-18	2.69E-18	0.0
CH_4	3.74E-05	5.63E-04	8.02E-04	5.63E-04	0.0
C_2H_4	0.0	1.91E-08	2.72E-08	1.91E-08	0.0
C_2H_6	0.0	3.28E-09	4.66E-09	3.28E-09	0.0
C_3H_6	0.0	1.88E-12	2.68E-12	1.88E-12	0.0
C_3H_8	0.0	5.99E-14	8.54E-14	6.86E-14	0.0
ISOBU-01	0.0	4.22E-19	6.02E-19	4.22E-19	0.0
N-BUT-01	0.0	4.83E-16	6.88E-16	9.16E-15	0.0
1-BUT-01	0.0	1.53E-15	2.18E-15	1.53E-15	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0
S_8	0.0	1.48E-41	2.11E-41	1.48E-41	0.0

Table 2-10: CBTL, 28.3% Biomass, Chipped, Modeled: Stream Values

Description	Coal	Dried Coal	Raw Biomass	Dried Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed
PFD Number	**1**	**2**	**3**	**4**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Temperature (F)	59.0	220.0	59.0	220.0	489.4	59.0	59.0	500.0	90.0	100.0	259.9
Pressure (psia)	14.7	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0
Mass Flow (lb/hr)	1,956,346	1,770,970	1,010,903	699,002	376,374	6,484,468	3,531,600	4,043,289	1,536,011	1,708,730	2,413,573
Mole Flow (lbmol/hr)					20,892	224,711	122,383	194,608	47,731	41,372	154,128
Mole Fraction											
H_2O					1.0	9.87E-03	9.87E-03	0.1441	0.0	1.39E-03	6.18E-03
Ar					0.0	9.25E-03	9.25E-03	7.09E-03	0.0318	0.0	0.0156
CO_2					0.0	3.27E-04	3.27E-04	0.1317	0.0	0.8919	0.0215
O_2					0.0	0.2074	0.2074	0.0	0.9504	0.0	7.38E-18
N_2					0.0	0.7732	0.7732	5.22E-03	0.0178	4.60E-04	0.0129
CO					0.0	0.0	0.0	0.3926	0.0	0.0663	0.4402
COS					0.0	0.0	0.0	5.62E-05	0.0	3.96E-07	7.12E-08
H_2					0.0	0.0	0.0	0.2988	0.0	0.0347	0.4842
H_2S					0.0	0.0	0.0	1.10E-03	0.0	0.0	2.84E-11
HCl					0.0	0.0	0.0	2.10E-05	0.0	0.0	0.0
NH_3					0.0	0.0	0.0	3.47E-03	0.0	0.0	3.45E-06
SO_2					0.0	0.0	0.0	0.0	0.0	0.0	3.41E-19
CH_4					0.0	0.0	0.0	0.0158	0.0	5.19E-03	0.0194
C_2H_4					0.0	0.0	0.0	0.0	0.0	0.0	1.81E-09
C_2H_6					0.0	0.0	0.0	0.0	0.0	0.0	2.95E-10
C_3H_6					0.0	0.0	0.0	0.0	0.0	0.0	1.65E-13
C_3H_8					0.0	0.0	0.0	0.0	0.0	0.0	4.99E-15
ISOBU-01					0.0	0.0	0.0	0.0	0.0	0.0	3.22E-20
N-BUT-01					0.0	0.0	0.0	0.0	0.0	0.0	5.79E-17
1-BUT-01					0.0	0.0	0.0	0.0	0.0	0.0	1.82E-16
Naphtha					0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet					0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel					0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8					0.0	0.0	0.0	0.0	0.0	0.0	1.85E-42

Description	CO_2 Seq.	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash
PFD Number	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**
Temperature (F)	100.0	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0
Pressure (psia)	2214.7	14.7	317.0	14.7	14.7	14.7	227.0	14.7	14.7	14.7	14.7
Mass Flow (lb/hr)	2,628,190	7,217	39,495	175,107	53,580	273,562	31,234	259,018	4,731,156	4,255,419	199,422
Mole Flow (lbmol/hr)	59,942	28	19,268	1,657	252	1,288	639	8,263	262,619	150,203	
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0599	1.0	0.0974	
Ar	0.0	0.0	1.20E-04	0.0	0.0	0.0	1.93E-05	0.0383	0.0	0.0155	
CO_2	0.9926	0.0	8.65E-09	0.0	0.0	0.0	0.0600	0.2107	0.0	0.0445	
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0263	0.0	0.0994	
N_2	6.16E-05	0.0	3.22E-04	0.0	0.0	0.0	7.24E-07	0.6648	0.0	0.7432	
CO	4.91E-03	0.0	8.05E-04	0.0	0.0	0.0	7.86E-06	0.0	0.0	0.0	
COS	2.73E-07	0.0	0.0	0.0	0.0	0.0	1.72E-05	1.36E-13	0.0	0.0	
H_2	1.17E-03	0.0	0.9988	0.0	0.0	0.0	1.36E-09	0.0	0.0	0.0	
H_2S	7.05E-11	0.0	0.0	0.0	0.0	0.0	1.20E-10	0.0	0.0	0.0	
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
NH_3	0.0	0.0	0.0	0.0	0.0	0.0	8.32E-04	1.84E-06	0.0	4.49E-06	
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.02E-13	0.0	2.68E-13	
CH_4	1.26E-03	0.0	0.0	0.0	0.0	0.0	3.67E-04	0.0	0.0	0.0	
C_2H_4	0.0	0.0	0.0	0.0	0.0	0.0	4.36E-03	0.0	0.0	0.0	
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0	0.0556	0.0	0.0	0.0	
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0	
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.0	0.3372	0.0	0.0	0.0	
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0	0.3324	0.0	0.0	0.0	
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0	
Naphtha	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	
F-T-Jet	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	
F-T-Diesel	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	
S_8	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	

Description	Syngas Recycle	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT
PFD Number	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**
Temperature (F)	296.1	500.0	500.0	268.0	354.1	318.1	90.0	100.0
Pressure (psia)	477.0	477.0	477.0	665.0	379.0	360.0	125.0	369.0
Mass Flow (lb/hr)	212,805	2,021,509	2,021,780	1,396,364	365,845	107,025	32,623	1,599,251
Mole Flow (lbmol/hr)	10,243	97,298	97,311	43,391	17,317	3,326	1,014	60,833
Mole Fraction								
H_2O	0.1441	0.1441	0.1441	0.0	0.0547	0.0	0.0	0.0
Ar	7.09E-03	7.09E-03	7.09E-03	0.0318	0.0574	0.0318	0.0318	0.0395
CO_2	0.1317	0.1317	0.1317	0.0	0.1160	0.0	0.0	0.4205
O_2	0.0	0.0	0.0	0.9504	6.57E-17	0.9504	0.9504	0.0
N_2	5.22E-03	5.22E-03	5.22E-03	0.0178	0.0370	0.0178	0.0178	0.0327
CO	0.3926	0.3926	0.3926	0.0	0.3888	0.0	0.0	0.1284
COS	5.62E-05	5.62E-05	5.62E-05	0.0	2.52E-09	0.0	0.0	1.80E-07
H_2	0.2988	0.2988	0.2988	0.0	0.3376	0.0	0.0	0.3214
H_2S	1.10E-03	1.10E-03	1.10E-03	0.0	1.70E-12	0.0	0.0	7.20E-11
HCl	2.10E-05	2.10E-05	2.10E-05	0.0	0.0	0.0	0.0	0.0
NH_3	3.47E-03	3.47E-03	3.47E-03	0.0	3.07E-05	0.0	0.0	8.75E-06
SO_2	0.0	0.0	0.0	0.0	3.03E-18	0.0	0.0	0.0
CH_4	0.0158	0.0158	0.0158	0.0	8.55E-03	0.0	0.0	0.0525
C_2H_4	0.0	0.0	0.0	0.0	1.61E-08	0.0	0.0	1.42E-03
C_2H_6	0.0	0.0	0.0	0.0	2.63E-09	0.0	0.0	4.41E-04
C_3H_6	0.0	0.0	0.0	0.0	1.47E-12	0.0	0.0	1.22E-03
C_3H_8	0.0	0.0	0.0	0.0	4.44E-14	0.0	0.0	3.87E-04
ISOBU-01	0.0	0.0	0.0	0.0	2.87E-19	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	0.0	5.15E-16	0.0	0.0	3.36E-04
1-BUT-01	0.0	0.0	0.0	0.0	1.62E-15	0.0	0.0	1.04E-03
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	0.0	1.64E-41	0.0	0.0	0.0

Description	CO_2 from MDEA	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	**35**	**36**	**37**	**38**	**39**
Temperature (F)	105.0	322.3	422.0	322.3	821.7
Pressure (psia)	25.0	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	1,041,360	7,304	244,982	323,918	219,333
Mole Flow (lbmol/hr)	23,663	500	12,281	22,173	7,601
Mole Fraction					
H_2O	0.0	0.0541	0.0771	0.0541	9.87E-03
Ar	0.0	0.0568	0.0809	0.0568	9.25E-03
CO_2	0.9999	0.0540	0.0769	0.0540	3.27E-04
O_2	0.0	6.49E-17	9.26E-17	6.49E-17	0.2074
N_2	1.06E-05	0.0358	0.0508	0.0358	0.7732
CO	6.05E-05	0.2450	0.3488	0.2450	0.0
COS	0.0	1.36E-13	1.93E-13	1.36E-13	0.0
H_2	8.51E-08	0.5538	0.3647	0.5538	0.0
H_2S	1.79E-10	1.68E-12	2.39E-12	1.68E-12	0.0
HCl	0.0	0.0	0.0	0.0	0.0
NH_3	0.0	3.04E-05	4.33E-05	3.04E-05	0.0
SO_2	0.0	3.00E-18	4.28E-18	3.00E-18	0.0
CH_4	3.32E-05	4.86E-04	6.92E-04	4.86E-04	0.0
C_2H_4	0.0	1.60E-08	2.27E-08	1.60E-08	0.0
C_2H_6	0.0	2.60E-09	3.71E-09	2.60E-09	0.0
C_3H_6	0.0	1.45E-12	2.07E-12	1.45E-12	0.0
C_3H_8	0.0	4.40E-14	6.27E-14	5.26E-14	0.0
ISOBU-01	0.0	2.84E-19	4.05E-19	2.84E-19	0.0
N-BUT-01	0.0	5.10E-16	7.26E-16	9.17E-15	0.0
1-BUT-01	0.0	1.60E-15	2.29E-15	1.60E-15	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0
S_8	0.0	1.63E-41	2.32E-41	1.63E-41	0.0

Table 2-11: CBTL, 28.3% Biomass, Chipped, Validated: Stream Values

Description	Coal	Dried Coal	Raw Biomass	Dried Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed
PFD Number	**1**	**2**	**3**	**4**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Temperature (F)	59.0	220.0	59.0	220.0	489.4	59.0	59.0	500.0	90.0	100.0	262.2
Pressure (psia)	14.7	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0
Mass Flow (lb/hr)	1,959,979	1,774,259	1,012,780	700,300	377,073	6,517,333	3,531,600	4,047,384	1,543,305	1,719,970	2,430,414
Mole Flow (lbmol/hr)					20,931	225,850	122,383	194,247	47,957	41,626	154,842
Mole Fraction											
H_2O					1.0	9.87E-03	9.87E-03	0.1511	0.0	1.38E-03	6.91E-03
Ar					0.0	9.25E-03	9.25E-03	7.10E-03	0.0318	0.0	0.0163
CO_2					0.0	3.27E-04	3.27E-04	0.1266	0.0	0.8927	0.0217
O_2					0.0	0.2074	0.2074	0.0	0.9504	0.0	7.53E-18
N_2					0.0	0.7732	0.7732	5.23E-03	0.0178	4.58E-04	0.0133
CO					0.0	0.0	0.0	0.3978	0.0	0.0654	0.4382
COS					0.0	0.0	0.0	5.19E-05	0.0	3.63E-07	6.53E-08
H_2					0.0	0.0	0.0	0.2898	0.0	0.0343	0.4820
H_2S					0.0	0.0	0.0	1.11E-03	0.0	0.0	2.83E-11
HCl					0.0	0.0	0.0	2.11E-05	0.0	0.0	0.0
NH_3					0.0	0.0	0.0	3.48E-03	0.0	0.0	4.11E-06
SO_2					0.0	0.0	0.0	0.0	0.0	0.0	3.17E-19
CH_4					0.0	0.0	0.0	0.0177	0.0	5.77E-03	0.0216
C_2H_4					0.0	0.0	0.0	0.0	0.0	0.0	2.35E-09
C_2H_6					0.0	0.0	0.0	0.0	0.0	0.0	4.00E-10
C_3H_6					0.0	0.0	0.0	0.0	0.0	0.0	2.30E-13
C_3H_8					0.0	0.0	0.0	0.0	0.0	0.0	7.28E-15
ISOBU-01					0.0	0.0	0.0	0.0	0.0	0.0	5.09E-20
N-BUT-01					0.0	0.0	0.0	0.0	0.0	0.0	6.10E-17
1-BUT-01					0.0	0.0	0.0	0.0	0.0	0.0	1.93E-16
Naphtha					0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet					0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel					0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8					0.0	0.0	0.0	0.0	0.0	0.0	2.90E-42

Description	CO_2 Seq.	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash
PFD Number	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**
Temperature (F)	100.0	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0
Pressure (psia)	2214.7	14.7	317.0	14.7	14.7	14.7	227.3	14.7	14.7	14.7	14.7
Mass Flow (lb/hr)	2,642,931	7,230	39,492	175,105	53,579	273,559	31,241	254,710	4,760,031	4,253,819	199,792
Mole Flow (lbmol/hr)	60,283	28	19,272	1,657	252	1,288	640	8,138	264,222	150,216	
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0616	1.0	0.0978	
Ar	0.0	0.0	1.22E-04	0.0	0.0	0.0	2.02E-05	0.0391	0.0	0.0155	
CO_2	0.9925	0.0	8.61E-09	0.0	0.0	0.0	0.0602	0.2080	0.0	0.0438	
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0262	0.0	0.0995	
N_2	6.18E-05	0.0	3.24E-04	0.0	0.0	0.0	7.59E-07	0.6650	0.0	0.7435	
CO	4.89E-03	0.0	7.79E-04	0.0	0.0	0.0	7.90E-06	0.0	0.0	0.0	
COS	2.50E-07	0.0	0.0	0.0	0.0	0.0	1.58E-05	1.25E-13	0.0	0.0	
H_2	1.16E-03	0.0	0.9988	0.0	0.0	0.0	1.42E-09	0.0	0.0	0.0	
H_2S	7.03E-11	0.0	0.0	0.0	0.0	0.0	1.20E-10	0.0	0.0	0.0	
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
NH_3	0.0	0.0	0.0	0.0	0.0	0.0	9.96E-04	2.02E-06	0.0	4.84E-06	
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.94E-14	0.0	2.56E-13	
CH_4	1.41E-03	0.0	0.0	0.0	0.0	0.0	4.06E-04	0.0	0.0	0.0	
C_2H_4	0.0	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0	
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0	
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0	
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.0	0.3371	0.0	0.0	0.0	
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0	0.3322	0.0	0.0	0.0	
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0	
Naphtha	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	
F-T-Jet	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	
F-T-Diesel	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	
S_8	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	

Description	Syngas Recycle	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT
PFD Number	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**
Temperature (F)	299.3	500.0	500.0	268.0	364.9	318.1	90.0	100.0
Pressure (psia)	477.0	477.0	477.0	665.0	379.0	360.0	125.0	369.0
Mass Flow (lb/hr)	213,020	2,148,607	1,898,777	1,395,544	389,598	114,920	32,841	1,614,301
Mole Flow (lbmol/hr)	10,224	103,119	91,129	43,366	18,623	3,571	1,021	61,448
Mole Fraction								
H_2O	0.1511	0.1511	0.1511	0.0	0.0571	0.0	0.0	0.0
Ar	7.10E-03	7.10E-03	7.10E-03	0.0318	0.0594	0.0318	0.0318	0.0410
CO_2	0.1266	0.1266	0.1266	0.0	0.1105	0.0	0.0	0.4175
O_2	0.0	0.0	0.0	0.9504	6.26E-17	0.9504	0.9504	0.0
N_2	5.23E-03	5.23E-03	5.23E-03	0.0178	0.0381	0.0178	0.0178	0.0336
CO	0.3978	0.3978	0.3978	0.0	0.3839	0.0	0.0	0.1268
COS	5.19E-05	5.19E-05	5.19E-05	0.0	2.13E-09	0.0	0.0	1.65E-07
H_2	0.2898	0.2898	0.2898	0.0	0.3420	0.0	0.0	0.3185
H_2S	1.11E-03	1.11E-03	1.11E-03	0.0	1.68E-12	0.0	0.0	7.14E-11
HCl	2.11E-05	2.11E-05	2.11E-05	0.0	0.0	0.0	0.0	0.0
NH_3	3.48E-03	3.48E-03	3.48E-03	0.0	3.42E-05	0.0	0.0	1.04E-05
SO_2	0.0	0.0	0.0	0.0	2.63E-18	0.0	0.0	0.0
CH_4	0.0177	0.0177	0.0177	0.0	8.94E-03	0.0	0.0	0.0578
C_2H_4	0.0	0.0	0.0	0.0	1.95E-08	0.0	0.0	1.40E-03
C_2H_6	0.0	0.0	0.0	0.0	3.33E-09	0.0	0.0	4.36E-04
C_3H_6	0.0	0.0	0.0	0.0	1.91E-12	0.0	0.0	1.20E-03
C_3H_8	0.0	0.0	0.0	0.0	6.05E-14	0.0	0.0	3.83E-04
ISOBU-01	0.0	0.0	0.0	0.0	4.23E-19	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	0.0	5.08E-16	0.0	0.0	3.33E-04
1-BUT-01	0.0	0.0	0.0	0.0	1.61E-15	0.0	0.0	1.03E-03
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	0.0	2.41E-41	0.0	0.0	0.0

Description	CO_2 from MDEA	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	**35**	**36**	**37**	**38**	**39**
Temperature (F)	105.0	324.5	425.2	324.5	821.7
Pressure (psia)	25.0	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	1,044,412	7,249	269,138	320,794	218,299
Mole Flow (lbmol/hr)	23,733	500	13,603	22,128	7,565
Mole Fraction					
H_2O	0.0	0.0549	0.0782	0.0549	9.87E-03
Ar	0.0	0.0571	0.0813	0.0571	9.25E-03
CO_2	0.9999	0.0514	0.0733	0.0514	3.27E-04
O_2	0.0	6.02E-17	8.57E-17	6.02E-17	0.2074
N_2	1.10E-05	0.0359	0.0511	0.0359	0.7732
CO	6.02E-05	0.2437	0.3469	0.2437	0.0
COS	0.0	1.23E-13	1.75E-13	1.23E-13	0.0
H_2	8.49E-08	0.5564	0.3684	0.5564	0.0
H_2S	1.79E-10	1.62E-12	2.31E-12	1.62E-12	0.0
HCl	0.0	0.0	0.0	0.0	0.0
NH_3	0.0	3.29E-05	4.68E-05	3.29E-05	0.0
SO_2	0.0	2.53E-18	3.61E-18	2.53E-18	0.0
CH_4	3.67E-05	5.54E-04	7.90E-04	5.54E-04	0.0
C_2H_4	0.0	1.87E-08	2.67E-08	1.87E-08	0.0
C_2H_6	0.0	3.20E-09	4.56E-09	3.20E-09	0.0
C_3H_6	0.0	1.84E-12	2.62E-12	1.84E-12	0.0
C_3H_8	0.0	5.81E-14	8.28E-14	6.68E-14	0.0
ISOBU-01	0.0	4.06E-19	5.79E-19	4.06E-19	0.0
N-BUT-01	0.0	4.88E-16	6.95E-16	9.17E-15	0.0
1-BUT-01	0.0	1.54E-15	2.20E-15	1.54E-15	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0
S_8	0.0	2.31E-41	3.30E-41	2.31E-41	0.0

2.4 Scenario 4: CBTL, 10 Percent Torrefied Biomass, Scenario 5: CBTL, 20 Percent Torrefied Biomass, Scenario 8: CBTL 30 Percent Torrefied Biomass, Scenario 12: CBTL, 16.5 Percent Torrefied Biomass, Model and Validation; Scenario 13: CBTL, 19.6 Percent Torrefied Biomass, Model and Validation; and Scenario 14: CBTL, 28.3 Percent Torrefied Biomass, Model and Validation

The overall configuration for these cases is very similar to the CBTL, 10 percent Chipped Biomass scenario. However, in these three cases, torrefied woody biomass is used in place of the green woody biomass used in cases 2, 3 and 7. It is assumed that the torrefaction of the southern pine wood is accomplished in dedicated torrefaction facilities separate from the CBTL facility complex. It is also assumed that these future torrefaction plants produce commercial quantities of torrefied material for use in co-firing for electric power generation as well as for other purposes like gasification. The torrefied woody biomass is delivered to the CBTL facility in trucks and consists of torrefied chips similar in size to the green wood chips. The CBTL facility purchases this torrefied material for a certain cost per ton just as it purchases the green woody biomass and the Montana Rosebud coal.

The process of torrefaction dries the wood so that additional drying of this material is not necessary. In this case the wood was dried to 8.2 percent moisture before torrefaction and the torrefied material had a moisture content of 5.72 percent. Torrefaction produces a char-like material that can be easily ground to fine particles, unlike the green woody biomass, which requires considerably higher energy for grinding.

As shown in **Figure 2-3** the addition of torrefied biomass handling and biomass milling or grinding are the only changes to the CBTL facility configuration compared to the CBTL, 10 percent Chipped Biomass scenario. The torrefied chips must be reduced to an average particle size of about 0.8 mm for feeding to the TRIG gasifiers. This is accomplished in separate hammer mills from the coal milling machines. Unlike green woody chips, the fine grinding of torrefied biomass is not very energy intensive and, depending on the final particle size, the power consumed during this processing can be minimal – even less than that required to grind coal.

The milled coal dried to 18 percent moisture and milled torrefied woody biomass are mixed together before entering the lock hopper feeding system of the TRIG gasifiers. They are then injected into the gasifiers just above the gasifier mixing zone. As in the CBTL, 10 percent Chipped Biomass scenario, the coal and biomass react with the steam and oxygen to produce raw synthesis gas.

The raw synthesis gas is treated in the same manner as in previously described scenarios; that is, it is cleaned and sent to the F-T reactors. All other downstream processes are the same.

The stream table results are shown in **Table 2-15** for Scenario 12, **Table 2-17** for Scenario 13, and **Table 2-19** for Scenario 14 for the results from the original Aspen Plus® model. Analogous stream results are also shown in **Table 2-16**, **Table 2-18**, and **Table 2-20** for these three scenarios, respectively, using the Aspen Plus® model validated by experimental data. As with the other validated scenarios, the deviation between the modeled and validated stream results is small and insignificant.

Figure 2-3: Scenarios 4, 5, 8, 12, 13, 14 – CBTL, 10%, 20%, 30% 16.5%, 19.6%, 28.3% Torrefied Biomass Plant Configurations

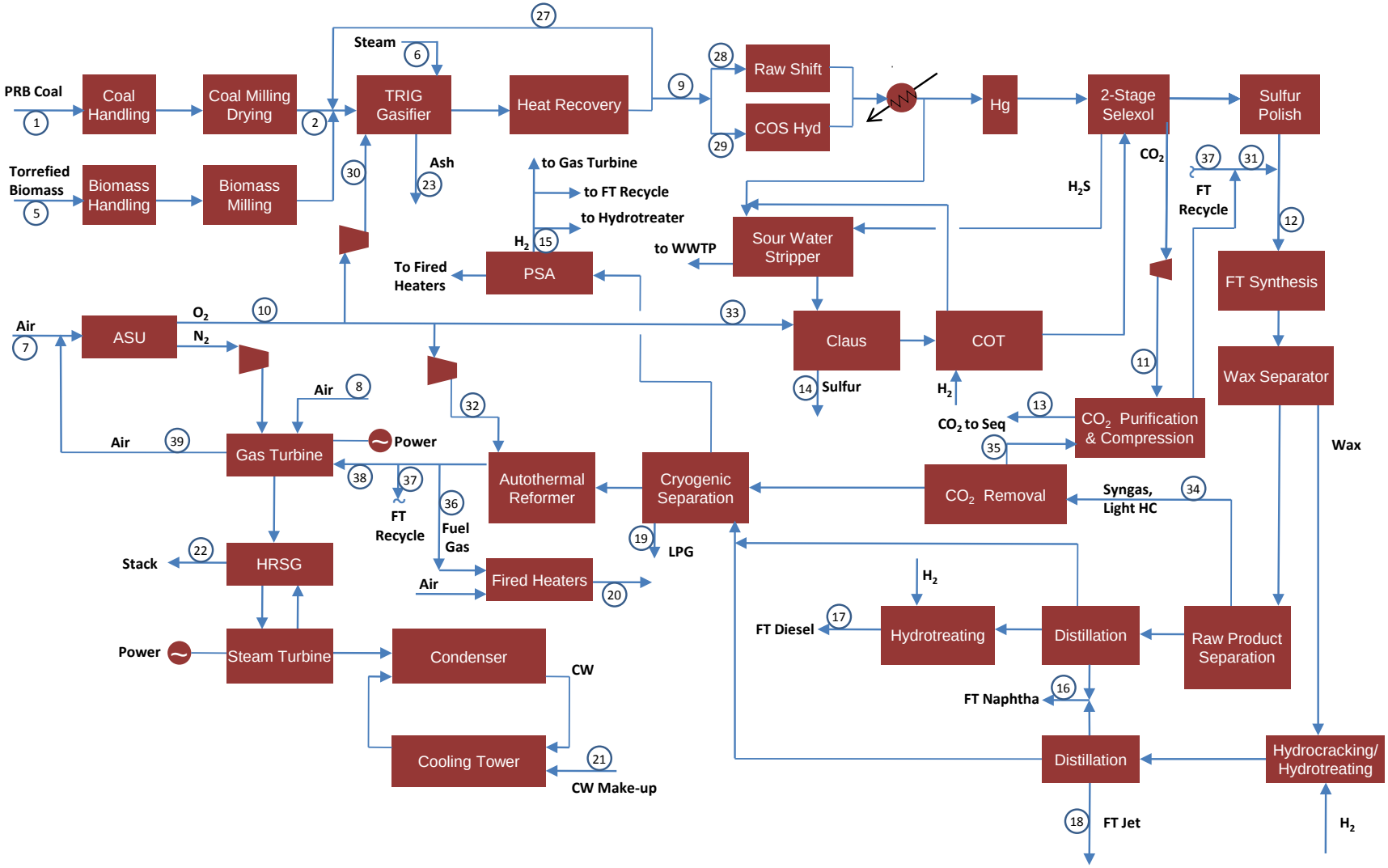


Table 2-12: CBTL, 10% Biomass, Torrefied: Stream Values

Description	Coal	Dried Coal	Torrefied Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.
PFD Number	**1**	**2**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Temperature (F)	59.0	220.0	59.0	489.4	59.0	59.0	500.0	90.0	100.0	262.5	100.0
Pressure (psia)	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7
Mass Flow (lb/hr)	2,264,439	2,049,870	227,763	435,647	6,539,718	3,531,600	3,891,196	1,548,392	1,649,511	2,431,857	2,570,521
Mole Flow (lbmol/hr)				24,182	226,625	122,383	187,905	48,115	40,024	154,939	58,631
Mole Fraction											
H_2O				1.0	9.87E-03	9.87E-03	0.1301	0.0	1.42E-03	7.01E-03	0.0
Ar				0.0	9.25E-03	9.25E-03	7.35E-03	0.0318	0.0	0.0164	0.0
CO_2				0.0	3.27E-04	3.27E-04	0.1234	0.0	0.8884	0.0214	0.9925
O_2				0.0	0.2074	0.2074	0.0	0.9504	0.0	7.56E-18	0.0
N_2				0.0	0.7732	0.7732	5.47E-03	0.0178	4.86E-04	0.0137	6.33E-05
CO				0.0	0.0	0.0	0.4095	0.0	0.0680	0.4379	4.85E-03
COS				0.0	0.0	0.0	6.86E-05	0.0	4.83E-07	8.36E-08	3.29E-07
H_2				0.0	0.0	0.0	0.3005	0.0	0.0356	0.4817	1.15E-03
H_2S				0.0	0.0	0.0	1.30E-03	0.0	0.0	3.22E-11	8.22E-11
HCl				0.0	0.0	0.0	2.52E-05	0.0	0.0	0.0	0.0
NH_3				0.0	0.0	0.0	3.76E-03	0.0	0.0	4.25E-06	0.0
SO_2				0.0	0.0	0.0	0.0	0.0	0.0	3.57E-19	0.0
CH_4				0.0	0.0	0.0	0.0186	0.0	6.08E-03	0.0220	1.44E-03
C_2H_4				0.0	0.0	0.0	0.0	0.0	0.0	2.41E-09	0.0
C_2H_6				0.0	0.0	0.0	0.0	0.0	0.0	4.14E-10	0.0
C_3H_6				0.0	0.0	0.0	0.0	0.0	0.0	2.38E-13	0.0
C_3H_8				0.0	0.0	0.0	0.0	0.0	0.0	7.57E-15	0.0
ISOBU-01				0.0	0.0	0.0	0.0	0.0	0.0	5.33E-20	0.0
N-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	6.15E-17	0.0
1-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	1.95E-16	0.0
Naphtha				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8				0.0	0.0	0.0	0.0	0.0	0.0	1.83E-42	0.0

Description	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle
PFD Number	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	289.5
Pressure (psia)	14.7	317.0	14.7	14.7	14.7	227.2	14.7	14.7	14.7	14.7	477.0
Mass Flow (lb/hr)	8,221	39,509	175,104	53,580	273,556	31,239	254,016	4,913,755	4,253,524	220,204	204,796
Mole Flow (lbmol/hr)	32	19,280	1,657	252	1,288	640	8,120	272,755	150,219		9,890
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0618	1.0	0.0978		0.1301
Ar	0.0	1.22E-04	0.0	0.0	0.0	2.04E-05	0.0393	0.0	0.0155		7.35E-03
CO_2	0.0	8.61E-09	0.0	0.0	0.0	0.0601	0.2072	0.0	0.0437		0.1234
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0262	0.0	0.0995		0.0
N_2	0.0	3.30E-04	0.0	0.0	0.0	7.81E-07	0.6655	0.0	0.7435		5.47E-03
CO	0.0	7.73E-04	0.0	0.0	0.0	7.90E-06	0.0	0.0	0.0		0.4095
COS	0.0	0.0	0.0	0.0	0.0	2.02E-05	1.60E-13	0.0	0.0		6.86E-05
H_2	0.0	0.9988	0.0	0.0	0.0	1.44E-09	0.0	0.0	0.0		0.3005
H_2S	0.0	0.0	0.0	0.0	0.0	1.36E-10	0.0	0.0	0.0		1.30E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.52E-05
NH_3	0.0	0.0	0.0	0.0	0.0	1.03E-03	2.06E-06	0.0	4.93E-06		3.76E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	1.13E-13	0.0	2.90E-13		0.0
CH_4	0.0	0.0	0.0	0.0	0.0	4.11E-04	0.0	0.0	0.0		0.0186
C_2H_4	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0		0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0		0.0
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.3371	0.0	0.0	0.0		0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.3322	0.0	0.0	0.0		0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0		0.0
Naphtha	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
F-T-Jet	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0
F-T-Diesel	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0
S_8	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0

Description	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA
PFD Number	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**
Temperature (F)	500.0	500.0	268.0	366.2	318.1	90.0	100.0	105.0
Pressure (psia)	477.0	477.0	665.0	379.0	360.0	125.0	369.0	25.0
Mass Flow (lb/hr)	2,366,336	1,524,860	1,398,123	393,867	116,089	34,181	1,615,596	1,042,882
Mole Flow (lbmol/hr)	114,270	73,635	43,446	18,842	3,607	1,062	61,537	23,698
Mole Fraction								
H_2O	0.1301	0.1301	0.0	0.0573	0.0	0.0	0.0	0.0
Ar	7.35E-03	7.35E-03	0.0318	0.0597	0.0318	0.0318	0.0413	0.0
CO_2	0.1234	0.1234	0.0	0.1097	0.0	0.0	0.4163	0.9999
O_2	0.0	0.0	0.9504	6.22E-17	0.9504	0.9504	0.0	0.0
N_2	5.47E-03	5.47E-03	0.0178	0.0390	0.0178	0.0178	0.0344	1.13E-05
CO	0.4095	0.4095	0.0	0.3829	0.0	0.0	0.1265	6.02E-05
COS	6.86E-05	6.86E-05	0.0	2.87E-09	0.0	0.0	2.10E-07	0.0
H_2	0.3005	0.3005	0.0	0.3421	0.0	0.0	0.3182	8.51E-08
H_2S	1.30E-03	1.30E-03	0.0	1.91E-12	0.0	0.0	8.11E-11	2.03E-10
HCl	2.52E-05	2.52E-05	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	3.76E-03	3.76E-03	0.0	3.50E-05	0.0	0.0	1.07E-05	0.0
SO_2	0.0	0.0	0.0	2.94E-18	0.0	0.0	0.0	0.0
CH_4	0.0186	0.0186	0.0	9.07E-03	0.0	0.0	0.0585	3.73E-05
C_2H_4	0.0	0.0	0.0	1.99E-08	0.0	0.0	1.40E-03	0.0
C_2H_6	0.0	0.0	0.0	3.41E-09	0.0	0.0	4.36E-04	0.0
C_3H_6	0.0	0.0	0.0	1.96E-12	0.0	0.0	1.20E-03	0.0
C_3H_8	0.0	0.0	0.0	6.23E-14	0.0	0.0	3.83E-04	0.0
ISOBU-01	0.0	0.0	0.0	4.38E-19	0.0	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	5.05E-16	0.0	0.0	3.32E-04	0.0
1-BUT-01	0.0	0.0	0.0	1.60E-15	0.0	0.0	1.03E-03	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	1.50E-41	0.0	0.0	0.0	0.0

Description	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	36	37	38	39
Temperature (F)	324.8	425.7	324.8	821.7
Pressure (psia)	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	7,244	273,043	320,795	218,119
Mole Flow (lbmol/hr)	500	13,809	22,142	7,559
Mole Fraction				
H_2O	0.0549	0.0782	0.0549	9.87E-03
Ar	0.0572	0.0815	0.0572	9.25E-03
CO_2	0.0510	0.0727	0.0510	3.27E-04
O_2	5.96E-17	8.49E-17	5.96E-17	0.2074
N_2	0.0367	0.0521	0.0367	0.7732
CO	0.2430	0.3460	0.2430	0.0
COS	1.37E-13	1.96E-13	1.37E-13	0.0
H_2	0.5565	0.3686	0.5565	0.0
H_2S	1.83E-12	2.60E-12	1.83E-12	0.0
HCl	0.0	0.0	0.0	0.0
NH_3	3.35E-05	4.77E-05	3.35E-05	0.0
SO_2	2.81E-18	4.01E-18	2.81E-18	0.0
CH_4	5.61E-04	8.00E-04	5.61E-04	0.0
C_2H_4	1.90E-08	2.71E-08	1.90E-08	0.0
C_2H_6	3.26E-09	4.65E-09	3.26E-09	0.0
C_3H_6	1.88E-12	2.67E-12	1.88E-12	0.0
C_3H_8	5.96E-14	8.50E-14	6.83E-14	0.0
ISOBU-01	4.20E-19	5.98E-19	4.20E-19	0.0
N-BUT-01	4.84E-16	6.90E-16	9.16E-15	0.0
1-BUT-01	1.53E-15	2.18E-15	1.53E-15	0.0
Naphtha	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0
S_8	1.44E-41	2.05E-41	1.44E-41	0.0

Table 2-13: CBTL, 20% Biomass, Torrefied: Stream Values

Description	Coal	Dried Coal	Torrefied Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.
PFD Number	**1**	**2**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Temperature (F)	59.0	220.0	59.0	489.4	59.0	59.0	500.0	90.0	100.0	264.0	100.0
Pressure (psia)	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7
Mass Flow (lb/hr)	1,993,933	1,804,996	451,249	383,606	6,449,931	3,531,600	3,815,368	1,527,677	1,645,713	2,438,821	2,568,610
Mole Flow (lbmol/hr)				21,293	223,514	122,383	183,741	47,472	39,937	155,290	58,591
Mole Fraction											
H_2O				1.0	9.87E-03	9.87E-03	0.1205	0.0	1.42E-03	7.48E-03	0.0
Ar				0.0	9.25E-03	9.25E-03	7.39E-03	0.0318	0.0	0.0166	0.0
CO_2				0.0	3.27E-04	3.27E-04	0.1191	0.0	0.8883	0.0216	0.9924
O_2				0.0	0.2074	0.2074	0.0	0.9504	0.0	7.58E-18	0.0
N_2				0.0	0.7732	0.7732	5.44E-03	0.0178	4.70E-04	0.0134	6.12E-05
CO				0.0	0.0	0.0	0.4239	0.0	0.0678	0.4369	4.84E-03
COS				0.0	0.0	0.0	6.43E-05	0.0	4.43E-07	7.63E-08	3.01E-07
H_2				0.0	0.0	0.0	0.2985	0.0	0.0355	0.4806	1.15E-03
H_2S				0.0	0.0	0.0	1.17E-03	0.0	0.0	2.83E-11	7.24E-11
HCl				0.0	0.0	0.0	2.27E-05	0.0	0.0	0.0	0.0
NH_3				0.0	0.0	0.0	3.62E-03	0.0	0.0	4.67E-06	0.0
SO_2				0.0	0.0	0.0	0.0	0.0	0.0	2.97E-19	0.0
CH_4				0.0	0.0	0.0	0.0203	0.0	6.53E-03	0.0235	1.55E-03
C_2H_4				0.0	0.0	0.0	0.0	0.0	0.0	2.89E-09	0.0
C_2H_6				0.0	0.0	0.0	0.0	0.0	0.0	5.12E-10	0.0
C_3H_6				0.0	0.0	0.0	0.0	0.0	0.0	3.02E-13	0.0
C_3H_8				0.0	0.0	0.0	0.0	0.0	0.0	9.91E-15	0.0
ISOBU-01				0.0	0.0	0.0	0.0	0.0	0.0	7.41E-20	0.0
N-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	6.35E-17	0.0
1-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	2.02E-16	0.0
Naphtha				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8				0.0	0.0	0.0	0.0	0.0	0.0	3.04E-42	0.0

Description	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle
PFD Number	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	284.6
Pressure (psia)	14.7	317.0	14.7	14.7	14.7	227.4	14.7	14.7	14.7	14.7	477.0
Mass Flow (lb/hr)	7,239	39,511	175,105	53,580	273,558	31,243	251,774	4,867,711	4,252,154	198,180	200,808
Mole Flow (lbmol/hr)	28	19,287	1,657	252	1,288	640	8,055	270,199	150,227		9,671
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0629	1.0	0.0980		0.1205
Ar	0.0	1.22E-04	0.0	0.0	0.0	2.07E-05	0.0395	0.0	0.0154		7.39E-03
CO_2	0.0	8.59E-09	0.0	0.0	0.0	0.0601	0.2062	0.0	0.0432		0.1191
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0262	0.0	0.0995		0.0
N_2	0.0	3.21E-04	0.0	0.0	0.0	7.74E-07	0.6651	0.0	0.7439		5.44E-03
CO	0.0	7.61E-04	0.0	0.0	0.0	7.91E-06	0.0	0.0	0.0		0.4239
COS	0.0	0.0	0.0	0.0	0.0	1.85E-05	1.45E-13	0.0	0.0		6.43E-05
H_2	0.0	0.9988	0.0	0.0	0.0	1.46E-09	0.0	0.0	0.0		0.2985
H_2S	0.0	0.0	0.0	0.0	0.0	1.20E-10	0.0	0.0	0.0		1.17E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.27E-05
NH_3	0.0	0.0	0.0	0.0	0.0	1.13E-03	2.15E-06	0.0	5.09E-06		3.62E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	9.75E-14	0.0	2.47E-13		0.0
CH_4	0.0	0.0	0.0	0.0	0.0	4.38E-04	0.0	0.0	0.0		0.0203
C_2H_4	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0		0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0		0.0
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.3370	0.0	0.0	0.0		0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.3322	0.0	0.0	0.0		0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0		0.0
Naphtha	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
F-T-Jet	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0
F-T-Diesel	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0
S_8	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0

Description	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA
PFD Number	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**
Temperature (F)	500.0	500.0	268.0	372.3	318.1	90.0	100.0	105.0
Pressure (psia)	477.0	477.0	665.0	379.0	360.0	125.0	369.0	25.0
Mass Flow (lb/hr)	2,752,221	1,063,147	1,373,698	408,230	121,272	32,707	1,621,439	1,044,522
Mole Flow (lbmol/hr)	132,542	51,199	42,687	19,686	3,768	1,016	61,825	23,735
Mole Fraction								
H_2O	0.1205	0.1205	0.0	0.0587	0.0	0.0	0.0	0.0
Ar	7.39E-03	7.39E-03	0.0318	0.0601	0.0318	0.0318	0.0416	0.0
CO_2	0.1191	0.1191	0.0	0.1065	0.0	0.0	0.4150	0.9999
O_2	0.0	0.0	0.9504	5.98E-17	0.9504	0.9504	0.0	0.0
N_2	5.44E-03	5.44E-03	0.0178	0.0384	0.0178	0.0178	0.0338	1.11E-05
CO	0.4239	0.4239	0.0	0.3808	0.0	0.0	0.1257	6.00E-05
COS	6.43E-05	6.43E-05	0.0	2.51E-09	0.0	0.0	1.92E-07	0.0
H_2	0.2985	0.2985	0.0	0.3461	0.0	0.0	0.3169	8.50E-08
H_2S	1.17E-03	1.17E-03	0.0	1.67E-12	0.0	0.0	7.11E-11	1.79E-10
HCl	2.27E-05	2.27E-05	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	3.62E-03	3.62E-03	0.0	3.68E-05	0.0	0.0	1.17E-05	0.0
SO_2	0.0	0.0	0.0	2.34E-18	0.0	0.0	0.0	0.0
CH_4	0.0203	0.0203	0.0	9.35E-03	0.0	0.0	0.0622	3.98E-05
C_2H_4	0.0	0.0	0.0	2.28E-08	0.0	0.0	1.39E-03	0.0
C_2H_6	0.0	0.0	0.0	4.04E-09	0.0	0.0	4.34E-04	0.0
C_3H_6	0.0	0.0	0.0	2.38E-12	0.0	0.0	1.20E-03	0.0
C_3H_8	0.0	0.0	0.0	7.82E-14	0.0	0.0	3.81E-04	0.0
ISOBU-01	0.0	0.0	0.0	5.84E-19	0.0	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	5.01E-16	0.0	0.0	3.31E-04	0.0
1-BUT-01	0.0	0.0	0.0	1.59E-15	0.0	0.0	1.03E-03	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	2.40E-41	0.0	0.0	0.0	0.0

Description	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	**36**	**37**	**38**	**39**
Temperature (F)	325.6	427.4	325.6	821.7
Pressure (psia)	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	7,182	287,620	316,744	217,495
Mole Flow (lbmol/hr)	500	14,661	22,052	7,537
Mole Fraction				
H_2O	0.0553	0.0789	0.0553	9.87E-03
Ar	0.0566	0.0807	0.0566	9.25E-03
CO_2	0.0494	0.0705	0.0494	3.27E-04
O_2	5.63E-17	8.04E-17	5.63E-17	0.2074
N_2	0.0355	0.0505	0.0355	0.7732
CO	0.2427	0.3459	0.2427	0.0
COS	1.14E-13	1.62E-13	1.14E-13	0.0
H_2	0.5599	0.3726	0.5599	0.0
H_2S	1.57E-12	2.24E-12	1.57E-12	0.0
HCl	0.0	0.0	0.0	0.0
NH_3	3.47E-05	4.95E-05	3.47E-05	0.0
SO_2	2.20E-18	3.14E-18	2.20E-18	0.0
CH_4	6.17E-04	8.81E-04	6.17E-04	0.0
C_2H_4	2.14E-08	3.06E-08	2.14E-08	0.0
C_2H_6	3.80E-09	5.42E-09	3.80E-09	0.0
C_3H_6	2.24E-12	3.20E-12	2.24E-12	0.0
C_3H_8	7.35E-14	1.05E-13	8.22E-14	0.0
ISOBU-01	5.50E-19	7.84E-19	5.50E-19	0.0
N-BUT-01	4.72E-16	6.73E-16	9.18E-15	0.0
1-BUT-01	1.50E-15	2.14E-15	1.50E-15	0.0
Naphtha	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0
S_8	2.26E-41	3.22E-41	2.26E-41	0.0

Table 2-14: CBTL, 30% Biomass, Torrefied: Stream Values

Description	Coal	Dried Coal	Torrefied Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.
PFD Number	**1**	**2**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Temperature (F)	59.0	220.0	59.0	489.4	59.0	59.0	500.0	90.0	100.0	265.6	100.0
Pressure (psia)	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7
Mass Flow (lb/hr)	1,728,617	1,564,820	670,637	332,562	6,363,516	3,531,600	3,740,976	1,507,692	1,642,524	2,446,301	2,567,310
Mole Flow (lbmol/hr)				18,460	220,519	122,383	179,621	46,851	39,863	155,667	58,564
Mole Fraction											
H_2O				1.0	9.87E-03	9.87E-03	0.1109	0.0	1.41E-03	7.99E-03	0.0
Ar				0.0	9.25E-03	9.25E-03	7.42E-03	0.0318	0.0	0.0168	0.0
CO_2				0.0	3.27E-04	3.27E-04	0.1144	0.0	0.8882	0.0217	0.9923
O_2				0.0	0.2074	0.2074	0.0	0.9504	0.0	7.60E-18	0.0
N_2				0.0	0.7732	0.7732	5.41E-03	0.0178	4.53E-04	0.0132	5.91E-05
CO				0.0	0.0	0.0	0.4388	0.0	0.0676	0.4358	4.82E-03
COS				0.0	0.0	0.0	5.93E-05	0.0	4.01E-07	6.87E-08	2.72E-07
H_2				0.0	0.0	0.0	0.2961	0.0	0.0353	0.4794	1.14E-03
H_2S				0.0	0.0	0.0	1.03E-03	0.0	0.0	2.45E-11	6.28E-11
HCl				0.0	0.0	0.0	2.01E-05	0.0	0.0	0.0	0.0
NH_3				0.0	0.0	0.0	3.47E-03	0.0	0.0	5.13E-06	0.0
SO_2				0.0	0.0	0.0	0.0	0.0	0.0	2.42E-19	0.0
CH_4				0.0	0.0	0.0	0.0223	0.0	7.02E-03	0.0251	1.66E-03
C_2H_4				0.0	0.0	0.0	0.0	0.0	0.0	3.45E-09	0.0
C_2H_6				0.0	0.0	0.0	0.0	0.0	0.0	6.33E-10	0.0
C_3H_6				0.0	0.0	0.0	0.0	0.0	0.0	3.83E-13	0.0
C_3H_8				0.0	0.0	0.0	0.0	0.0	0.0	1.30E-14	0.0
ISOBU-01				0.0	0.0	0.0	0.0	0.0	0.0	1.03E-19	0.0
N-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	6.56E-17	0.0
1-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	2.10E-16	0.0
Naphtha				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8				0.0	0.0	0.0	0.0	0.0	0.0	2.43E-43	0.0

Description	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle
PFD Number	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	279.3
Pressure (psia)	14.7	317.0	14.7	14.7	14.7	227.6	14.7	14.7	14.7	14.7	477.0
Mass Flow (lb/hr)	6,276	39,515	175,102	53,579	273,553	31,247	249,418	4,823,819	4,250,895	176,582	196,894
Mole Flow (lbmol/hr)	24	19,294	1,657	252	1,288	640	7,986	267,763	150,239		9,454
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0642	1.0	0.0982		0.1109
Ar	0.0	1.22E-04	0.0	0.0	0.0	2.10E-05	0.0396	0.0	0.0153		7.42E-03
CO_2	0.0	8.57E-09	0.0	0.0	0.0	0.0602	0.2052	0.0	0.0428		0.1144
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0263	0.0	0.0995		0.0
N_2	0.0	3.12E-04	0.0	0.0	0.0	7.68E-07	0.6647	0.0	0.7442		5.41E-03
CO	0.0	7.48E-04	0.0	0.0	0.0	7.92E-06	0.0	0.0	0.0		0.4388
COS	0.0	0.0	0.0	0.0	0.0	1.67E-05	1.29E-13	0.0	0.0		5.93E-05
H_2	0.0	0.9988	0.0	0.0	0.0	1.49E-09	0.0	0.0	0.0		0.2961
H_2S	0.0	0.0	0.0	0.0	0.0	1.04E-10	0.0	0.0	0.0		1.03E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.01E-05
NH_3	0.0	0.0	0.0	0.0	0.0	1.25E-03	2.25E-06	0.0	5.25E-06		3.47E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	8.31E-14	0.0	2.08E-13		0.0
CH_4	0.0	0.0	0.0	0.0	0.0	4.67E-04	0.0	0.0	0.0		0.0223
C_2H_4	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0		0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0		0.0
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.3369	0.0	0.0	0.0		0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.3321	0.0	0.0	0.0		0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0		0.0
Naphtha	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
F-T-Jet	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0
F-T-Diesel	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0
S_8	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0

Description	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA
PFD Number	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**
Temperature (F)	500.0	500.0	268.0	378.4	318.1	90.0	100.0	105.0
Pressure (psia)	477.0	477.0	665.0	379.0	360.0	125.0	369.0	25.0
Mass Flow (lb/hr)	3,209,497	531,479	1,349,538	423,430	126,880	31,274	1,627,718	1,046,141
Mole Flow (lbmol/hr)	154,103	25,519	41,936	20,591	3,943	972	62,136	23,772
Mole Fraction								
H_2O	0.1109	0.1109	0.0	0.0601	0.0	0.0	0.0	0.0
Ar	7.42E-03	7.42E-03	0.0318	0.0604	0.0318	0.0318	0.0420	0.0
CO_2	0.1144	0.1144	0.0	0.1032	0.0	0.0	0.4135	0.9999
O_2	0.0	0.0	0.9504	5.75E-17	0.9504	0.9504	0.0	0.0
N_2	5.41E-03	5.41E-03	0.0178	0.0377	0.0178	0.0178	0.0331	1.09E-05
CO	0.4388	0.4388	0.0	0.3787	0.0	0.0	0.1248	5.98E-05
COS	5.93E-05	5.93E-05	0.0	2.17E-09	0.0	0.0	1.72E-07	0.0
H_2	0.2961	0.2961	0.0	0.3502	0.0	0.0	0.3156	8.50E-08
H_2S	1.03E-03	1.03E-03	0.0	1.43E-12	0.0	0.0	6.13E-11	1.55E-10
HCl	2.01E-05	2.01E-05	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	3.47E-03	3.47E-03	0.0	3.88E-05	0.0	0.0	1.29E-05	0.0
SO_2	0.0	0.0	0.0	1.83E-18	0.0	0.0	0.0	0.0
CH_4	0.0223	0.0223	0.0	9.65E-03	0.0	0.0	0.0662	4.25E-05
C_2H_4	0.0	0.0	0.0	2.61E-08	0.0	0.0	1.39E-03	0.0
C_2H_6	0.0	0.0	0.0	4.79E-09	0.0	0.0	4.31E-04	0.0
C_3H_6	0.0	0.0	0.0	2.89E-12	0.0	0.0	1.19E-03	0.0
C_3H_8	0.0	0.0	0.0	9.80E-14	0.0	0.0	3.79E-04	0.0
ISOBU-01	0.0	0.0	0.0	7.78E-19	0.0	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	4.96E-16	0.0	0.0	3.29E-04	0.0
1-BUT-01	0.0	0.0	0.0	1.59E-15	0.0	0.0	1.02E-03	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	1.84E-42	0.0	0.0	0.0	0.0

Description	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	**36**	**37**	**38**	**39**
Temperature (F)	326.6	429.1	326.6	821.7
Pressure (psia)	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	7,119	303,095	312,699	216,688
Mole Flow (lbmol/hr)	500	15,577	21,964	7,509
Mole Fraction				
H_2O	0.0556	0.0795	0.0556	9.87E-03
Ar	0.0560	0.0799	0.0560	9.25E-03
CO_2	0.0479	0.0684	0.0479	3.27E-04
O_2	5.32E-17	7.59E-17	5.32E-17	0.2074
N_2	0.0343	0.0489	0.0343	0.7732
CO	0.2422	0.3456	0.2422	0.0
COS	9.24E-14	1.32E-13	9.24E-14	0.0
H_2	0.5633	0.3768	0.5633	0.0
H_2S	1.33E-12	1.90E-12	1.33E-12	0.0
HCl	0.0	0.0	0.0	0.0
NH_3	3.59E-05	5.13E-05	3.59E-05	0.0
SO_2	1.69E-18	2.42E-18	1.69E-18	0.0
CH_4	6.79E-04	9.70E-04	6.79E-04	0.0
C_2H_4	2.42E-08	3.45E-08	2.42E-08	0.0
C_2H_6	4.43E-09	6.33E-09	4.43E-09	0.0
C_3H_6	2.68E-12	3.83E-12	2.68E-12	0.0
C_3H_8	9.07E-14	1.30E-13	9.94E-14	0.0
ISOBU-01	7.20E-19	1.03E-18	7.20E-19	0.0
N-BUT-01	4.59E-16	6.56E-16	9.20E-15	0.0
1-BUT-01	1.47E-15	2.10E-15	1.47E-15	0.0
Naphtha	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0
S_8	1.70E-42	2.43E-42	1.70E-42	0.0

Table 2-15: CBTL, 16.5% Biomass, Torrefied, Modeled: Stream Values

Description	Coal	Dried Coal	Torrefied Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.
PFD Number	**1**	**2**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Temperature (F)	59.0	220.0	59.0	489.4	59.0	59.0	500.0	90.0	100.0	263.5	100.0
Pressure (psia)	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7
Mass Flow (lb/hr)	2,087,996	1,890,145	373,502	401,702	6,480,964	3,531,600	3,841,719	1,534,835	1,646,944	2,436,340	2,569,196
Mole Flow (lbmol/hr)				22,298	224,589	122,383	185,192	47,694	39,965	155,164	58,603
Mole Fraction											
H_2O				1.0	9.87E-03	9.87E-03	0.1239	0.0	1.42E-03	7.31E-03	0.0
Ar				0.0	9.25E-03	9.25E-03	7.38E-03	0.0318	0.0	0.0165	0.0
CO_2				0.0	3.27E-04	3.27E-04	0.1206	0.0	0.8883	0.0215	0.9924
O_2				0.0	0.2074	0.2074	0.0	0.9504	0.0	7.58E-18	0.0
N_2				0.0	0.7732	0.7732	5.45E-03	0.0178	4.75E-04	0.0135	6.19E-05
CO				0.0	0.0	0.0	0.4188	0.0	0.0679	0.4372	4.84E-03
COS				0.0	0.0	0.0	6.58E-05	0.0	4.58E-07	7.89E-08	3.11E-07
H_2				0.0	0.0	0.0	0.2993	0.0	0.0355	0.4810	1.15E-03
H_2S				0.0	0.0	0.0	1.21E-03	0.0	0.0	2.97E-11	7.58E-11
HCl				0.0	0.0	0.0	2.36E-05	0.0	0.0	0.0	0.0
NH_3				0.0	0.0	0.0	3.67E-03	0.0	0.0	4.52E-06	0.0
SO_2				0.0	0.0	0.0	0.0	0.0	0.0	3.17E-19	0.0
CH_4				0.0	0.0	0.0	0.0197	0.0	6.37E-03	0.0229	1.51E-03
C_2H_4				0.0	0.0	0.0	0.0	0.0	0.0	2.71E-09	0.0
C_2H_6				0.0	0.0	0.0	0.0	0.0	0.0	4.76E-10	0.0
C_3H_6				0.0	0.0	0.0	0.0	0.0	0.0	2.78E-13	0.0
C_3H_8				0.0	0.0	0.0	0.0	0.0	0.0	9.02E-15	0.0
ISOBU-01				0.0	0.0	0.0	0.0	0.0	0.0	6.60E-20	0.0
N-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	6.28E-17	0.0
1-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	1.99E-16	0.0
Naphtha				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8				0.0	0.0	0.0	0.0	0.0	0.0	1.87E-42	0.0

Description	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle
PFD Number	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	286.3
Pressure (psia)	14.7	317.0	14.7	14.7	14.7	227.4	14.7	14.7	14.7	14.7	477.0
Mass Flow (lb/hr)	7,580	39,510	175,105	53,580	273,558	31,242	252,570	4,883,561	4,252,666	205,838	202,186
Mole Flow (lbmol/hr)	30	19,284	1,657	252	1,288	640	8,078	271,079	150,225		9,747
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0625	1.0	0.0980		0.1238
Ar	0.0	1.22E-04	0.0	0.0	0.0	2.06E-05	0.0394	0.0	0.0154		7.38E-03
CO_2	0.0	8.60E-09	0.0	0.0	0.0	0.0601	0.2066	0.0	0.0434		0.1206
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0262	0.0	0.0995		0.0
N_2	0.0	3.24E-04	0.0	0.0	0.0	7.77E-07	0.6652	0.0	0.7437		5.45E-03
CO	0.0	7.65E-04	0.0	0.0	0.0	7.90E-06	0.0	0.0	0.0		0.4188
COS	0.0	0.0	0.0	0.0	0.0	1.91E-05	1.50E-13	0.0	0.0		6.58E-05
H_2	0.0	0.9988	0.0	0.0	0.0	1.45E-09	0.0	0.0	0.0		0.2993
H_2S	0.0	0.0	0.0	0.0	0.0	1.26E-10	0.0	0.0	0.0		1.21E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.36E-05
NH_3	0.0	0.0	0.0	0.0	0.0	1.10E-03	2.12E-06	0.0	5.04E-06		3.67E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	1.03E-13	0.0	2.62E-13		0.0
CH_4	0.0	0.0	0.0	0.0	0.0	4.28E-04	0.0	0.0	0.0		0.0197
C_2H_4	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0		0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0		0.0
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.3370	0.0	0.0	0.0		0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.3322	0.0	0.0	0.0		0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0		0.0
Naphtha	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
F-T-Jet	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0
F-T-Diesel	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0
S_8	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0

Description	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA
PFD Number	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**
Temperature (F)	500.0	500.0	268.0	370.1	318.1	90.0	100.0	105.0
Pressure (psia)	477.0	477.0	665.0	379.0	360.0	125.0	369.0	25.0
Mass Flow (lb/hr)	2,609,820	1,231,899	1,382,205	403,125	119,412	33,218	1,619,366	1,043,965
Mole Flow (lbmol/hr)	125,808	59,384	42,951	19,385	3,711	1,032	61,722	23,722
Mole Fraction								
H_2O	0.1239	0.1239	0.0	0.0583	0.0	0.0	0.0	0.0
Ar	7.38E-03	7.38E-03	0.0318	0.0600	0.0318	0.0318	0.0415	0.0
CO_2	0.1206	0.1206	0.0	0.1076	0.0	0.0	0.4155	0.9999
O_2	0.0	0.0	0.9504	6.07E-17	0.9504	0.9504	0.0	0.0
N_2	5.45E-03	5.45E-03	0.0178	0.0386	0.0178	0.0178	0.0340	1.12E-05
CO	0.4188	0.4188	0.0	0.3816	0.0	0.0	0.1260	6.01E-05
COS	6.58E-05	6.58E-05	0.0	2.64E-09	0.0	0.0	1.98E-07	0.0
H_2	0.2993	0.2993	0.0	0.3447	0.0	0.0	0.3174	8.51E-08
H_2S	1.21E-03	1.21E-03	0.0	1.75E-12	0.0	0.0	7.45E-11	1.87E-10
HCl	2.36E-05	2.36E-05	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	3.67E-03	3.67E-03	0.0	3.62E-05	0.0	0.0	1.14E-05	0.0
SO_2	0.0	0.0	0.0	2.54E-18	0.0	0.0	0.0	0.0
CH_4	0.0197	0.0197	0.0	9.25E-03	0.0	0.0	0.0609	3.89E-05
C_2H_4	0.0	0.0	0.0	2.17E-08	0.0	0.0	1.40E-03	0.0
C_2H_6	0.0	0.0	0.0	3.81E-09	0.0	0.0	4.34E-04	0.0
C_3H_6	0.0	0.0	0.0	2.23E-12	0.0	0.0	1.20E-03	0.0
C_3H_8	0.0	0.0	0.0	7.22E-14	0.0	0.0	3.81E-04	0.0
ISOBU-01	0.0	0.0	0.0	5.28E-19	0.0	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	5.03E-16	0.0	0.0	3.31E-04	0.0
1-BUT-01	0.0	0.0	0.0	1.60E-15	0.0	0.0	1.03E-03	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	1.49E-41	0.0	0.0	0.0	0.0

Description	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	36	37	38	39
Temperature (F)	325.3	426.8	325.3	821.7
Pressure (psia)	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	7,204	282,430	318,158	217,703
Mole Flow (lbmol/hr)	500	14,357	22,083	7,544
Mole Fraction				
H_2O	0.0552	0.0787	0.0552	9.87E-03
Ar	0.0568	0.0810	0.0568	9.25E-03
CO_2	0.0500	0.0713	0.0500	3.27E-04
O_2	5.75E-17	8.19E-17	5.75E-17	0.2074
N_2	0.0359	0.0511	0.0359	0.7732
CO	0.2428	0.3459	0.2428	0.0
COS	1.22E-13	1.73E-13	1.22E-13	0.0
H_2	0.5587	0.3712	0.5587	0.0
H_2S	1.66E-12	2.37E-12	1.66E-12	0.0
HCl	0.0	0.0	0.0	0.0
NH_3	3.43E-05	4.88E-05	3.43E-05	0.0
SO_2	2.40E-18	3.43E-18	2.40E-18	0.0
CH_4	5.97E-04	8.52E-04	5.97E-04	0.0
C_2H_4	2.05E-08	2.93E-08	2.05E-08	0.0
C_2H_6	3.60E-09	5.14E-09	3.60E-09	0.0
C_3H_6	2.11E-12	3.00E-12	2.11E-12	0.0
C_3H_8	6.83E-14	9.74E-14	7.70E-14	0.0
ISOBU-01	5.00E-19	7.13E-19	5.00E-19	0.0
N-BUT-01	4.76E-16	6.79E-16	9.17E-15	0.0
1-BUT-01	1.51E-15	2.16E-15	1.51E-15	0.0
Naphtha	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0
S_8	1.41E-41	2.02E-41	1.41E-41	0.0

Table 2-16: CBTL, 16.5% Biomass, Torrefied, Validated: Stream Values

Description	Coal	Dried Coal	Torrefied Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.
PFD Number	**1**	**2**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Temperature (F)	59.0	220.0	59.0	489.4	59.0	59.0	500.0	90.0	100.0	266.0	100.0
Pressure (psia)	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7
Mass Flow (lb/hr)	2,091,871	1,893,653	374,195	402,447	6,513,218	3,531,600	3,844,320	1,542,024	1,657,869	2,454,787	2,583,688
Mole Flow (lbmol/hr)				22,339	225,707	122,383	184,718	47,918	40,212	155,955	58,939
Mole Fraction											
H_2O				1.0	9.87E-03	9.87E-03	0.1303	0.0	1.41E-03	8.10E-03	0.0
Ar				0.0	9.25E-03	9.25E-03	7.38E-03	0.0318	0.0	0.0172	0.0
CO_2				0.0	3.27E-04	3.27E-04	0.1160	0.0	0.8891	0.0218	0.9923
O_2				0.0	0.2074	0.2074	0.0	0.9504	0.0	7.71E-18	0.0
N_2				0.0	0.7732	0.7732	5.46E-03	0.0178	4.72E-04	0.0140	6.22E-05
CO				0.0	0.0	0.0	0.4236	0.0	0.0669	0.4350	4.82E-03
COS				0.0	0.0	0.0	6.07E-05	0.0	4.18E-07	7.22E-08	2.85E-07
H_2				0.0	0.0	0.0	0.2903	0.0	0.0350	0.4785	1.14E-03
H_2S				0.0	0.0	0.0	1.22E-03	0.0	0.0	2.96E-11	7.56E-11
HCl				0.0	0.0	0.0	2.37E-05	0.0	0.0	0.0	0.0
NH_3				0.0	0.0	0.0	3.69E-03	0.0	0.0	5.33E-06	0.0
SO_2				0.0	0.0	0.0	0.0	0.0	0.0	2.94E-19	0.0
CH_4				0.0	0.0	0.0	0.0220	0.0	7.05E-03	0.0254	1.68E-03
C_2H_4				0.0	0.0	0.0	0.0	0.0	0.0	3.46E-09	0.0
C_2H_6				0.0	0.0	0.0	0.0	0.0	0.0	6.34E-10	0.0
C_3H_6				0.0	0.0	0.0	0.0	0.0	0.0	3.81E-13	0.0
C_3H_8				0.0	0.0	0.0	0.0	0.0	0.0	1.29E-14	0.0
ISOBU-01				0.0	0.0	0.0	0.0	0.0	0.0	1.01E-19	0.0
N-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	6.58E-17	0.0
1-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	2.11E-16	0.0
Naphtha				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8				0.0	0.0	0.0	0.0	0.0	0.0	2.40E-45	0.0

Description	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle
PFD Number	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	289.6
Pressure (psia)	14.7	317.0	14.7	14.7	14.7	227.7	14.7	14.7	14.7	14.7	477.0
Mass Flow (lb/hr)	7,594	39,510	175,101	53,579	273,552	31,249	248,253	4,911,985	4,251,104	206,220	202,320
Mole Flow (lbmol/hr)	30	19,290	1,657	252	1,288	640	7,953	272,657	150,239		9,721
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0642	1.0	0.0983		0.1303
Ar	0.0	1.24E-04	0.0	0.0	0.0	2.17E-05	0.0403	0.0	0.0155		7.38E-03
CO_2	0.0	8.55E-09	0.0	0.0	0.0	0.0603	0.2038	0.0	0.0427		0.1160
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0262	0.0	0.0995		0.0
N_2	0.0	3.25E-04	0.0	0.0	0.0	8.16E-07	0.6655	0.0	0.7440		5.46E-03
CO	0.0	7.40E-04	0.0	0.0	0.0	7.94E-06	0.0	0.0	0.0		0.4236
COS	0.0	0.0	0.0	0.0	0.0	1.76E-05	1.38E-13	0.0	0.0		6.07E-05
H_2	0.0	0.9988	0.0	0.0	0.0	1.52E-09	0.0	0.0	0.0		0.2903
H_2S	0.0	0.0	0.0	0.0	0.0	1.26E-10	0.0	0.0	0.0		1.22E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.37E-05
NH_3	0.0	0.0	0.0	0.0	0.0	1.30E-03	2.31E-06	0.0	5.40E-06		3.69E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	1.00E-13	0.0	2.50E-13		0.0
CH_4	0.0	0.0	0.0	0.0	0.0	4.72E-04	0.0	0.0	0.0		0.0220
C_2H_4	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0		0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.1098	0.0	0.0	0.0		0.0
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.3369	0.0	0.0	0.0		0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.3321	0.0	0.0	0.0		0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0		0.0
Naphtha	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
F-T-Jet	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0
F-T-Diesel	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0
S_8	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0

Description	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA
PFD Number	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**
Temperature (F)	500.0	500.0	268.0	380.3	318.1	90.0	100.0	105.0
Pressure (psia)	477.0	477.0	665.0	379.0	360.0	125.0	369.0	25.0
Mass Flow (lb/hr)	2,701,891	1,142,430	1,380,244	429,168	128,320	33,461	1,635,839	1,047,058
Mole Flow (lbmol/hr)	129,825	54,893	42,890	20,846	3,987	1,040	62,404	23,793
Mole Fraction								
H_2O	0.1303	0.1303	0.0	0.0604	0.0	0.0	0.0	0.0
Ar	7.38E-03	7.38E-03	0.0318	0.0618	0.0318	0.0318	0.0430	0.0
CO_2	0.1160	0.1160	0.0	0.1024	0.0	0.0	0.4121	0.9999
O_2	0.0	0.0	0.9504	5.77E-17	0.9504	0.9504	0.0	0.0
N_2	5.46E-03	5.46E-03	0.0178	0.0397	0.0178	0.0178	0.0349	1.15E-05
CO	0.4236	0.4236	0.0	0.3767	0.0	0.0	0.1243	5.98E-05
COS	6.07E-05	6.07E-05	0.0	2.22E-09	0.0	0.0	1.81E-07	0.0
H_2	0.2903	0.2903	0.0	0.3493	0.0	0.0	0.3142	8.49E-08
H_2S	1.22E-03	1.22E-03	0.0	1.73E-12	0.0	0.0	7.39E-11	1.87E-10
HCl	2.37E-05	2.37E-05	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	3.69E-03	3.69E-03	0.0	3.99E-05	0.0	0.0	1.33E-05	0.0
SO_2	0.0	0.0	0.0	2.20E-18	0.0	0.0	0.0	0.0
CH_4	0.0220	0.0220	0.0	9.63E-03	0.0	0.0	0.0667	4.29E-05
C_2H_4	0.0	0.0	0.0	2.59E-08	0.0	0.0	1.38E-03	0.0
C_2H_6	0.0	0.0	0.0	4.74E-09	0.0	0.0	4.30E-04	0.0
C_3H_6	0.0	0.0	0.0	2.85E-12	0.0	0.0	1.19E-03	0.0
C_3H_8	0.0	0.0	0.0	9.63E-14	0.0	0.0	3.77E-04	0.0
ISOBU-01	0.0	0.0	0.0	7.58E-19	0.0	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	4.93E-16	0.0	0.0	3.28E-04	0.0
1-BUT-01	0.0	0.0	0.0	1.58E-15	0.0	0.0	1.02E-03	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	1.79E-44	0.0	0.0	0.0	0.0

Description	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	36	37	38	39
Temperature (F)	327.5	429.9	327.5	821.7
Pressure (psia)	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	7,148	308,950	315,050	216,827
Mole Flow (lbmol/hr)	500	15,837	22,038	7,514
Mole Fraction				
H_2O	0.0557	0.0794	0.0557	9.87E-03
Ar	0.0571	0.0814	0.0571	9.25E-03
CO_2	0.0476	0.0679	0.0476	3.27E-04
O_2	5.33E-17	7.59E-17	5.33E-17	0.2074
N_2	0.0361	0.0513	0.0361	0.7732
CO	0.2413	0.3437	0.2413	0.0
COS	1.10E-13	1.57E-13	1.10E-13	0.0
H_2	0.5614	0.3752	0.5614	0.0
H_2S	1.59E-12	2.27E-12	1.59E-12	0.0
HCl	0.0	0.0	0.0	0.0
NH_3	3.68E-05	5.25E-05	3.68E-05	0.0
SO_2	2.03E-18	2.90E-18	2.03E-18	0.0
CH_4	6.76E-04	9.63E-04	6.76E-04	0.0
C_2H_4	2.39E-08	3.41E-08	2.39E-08	0.0
C_2H_6	4.38E-09	6.24E-09	4.38E-09	0.0
C_3H_6	2.63E-12	3.75E-12	2.63E-12	0.0
C_3H_8	8.89E-14	1.27E-13	9.76E-14	0.0
ISOBU-01	7.00E-19	9.98E-19	7.00E-19	0.0
N-BUT-01	4.55E-16	6.48E-16	9.17E-15	0.0
1-BUT-01	1.46E-15	2.08E-15	1.46E-15	0.0
Naphtha	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0
S_8	1.66E-44	2.36E-44	1.66E-44	0.0

Table 2-17: CBTL, 19.6% Biomass, Torrefied, Modeled: Stream Values

Description	Coal	Dried Coal	Torrefied Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.
PFD Number	**1**	**2**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Temperature (F)	59.0	220.0	59.0	489.4	59.0	59.0	500.0	90.0	100.0	263.9	100.0
Pressure (psia)	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7
Mass Flow (lb/hr)	2,004,638	1,814,686	442,386	385,665	6,453,350	3,531,600	3,818,345	1,528,478	1,645,908	2,438,473	2,568,681
Mole Flow (lbmol/hr)				21,408	223,632	122,383	183,906	47,497	39,941	155,274	58,592
Mole Fraction											
H_2O				1.0	9.87E-03	9.87E-03	0.1209	0.0	1.42E-03	7.46E-03	0.0
Ar				0.0	9.25E-03	9.25E-03	7.39E-03	0.0318	0.0	0.0166	0.0
CO_2				0.0	3.27E-04	3.27E-04	0.1192	0.0	0.8883	0.0215	0.9924
O_2				0.0	0.2074	0.2074	0.0	0.9504	0.0	7.59E-18	0.0
N_2				0.0	0.7732	0.7732	5.44E-03	0.0178	4.70E-04	0.0134	6.13E-05
CO				0.0	0.0	0.0	0.4233	0.0	0.0678	0.4369	4.84E-03
COS				0.0	0.0	0.0	6.44E-05	0.0	4.45E-07	7.66E-08	3.02E-07
H_2				0.0	0.0	0.0	0.2986	0.0	0.0355	0.4806	1.15E-03
H_2S				0.0	0.0	0.0	1.17E-03	0.0	0.0	2.84E-11	7.28E-11
HCl				0.0	0.0	0.0	2.28E-05	0.0	0.0	0.0	0.0
NH_3				0.0	0.0	0.0	3.63E-03	0.0	0.0	4.65E-06	0.0
SO_2				0.0	0.0	0.0	0.0	0.0	0.0	2.99E-19	0.0
CH_4				0.0	0.0	0.0	0.0203	0.0	6.51E-03	0.0234	1.54E-03
C_2H_4				0.0	0.0	0.0	0.0	0.0	0.0	2.87E-09	0.0
C_2H_6				0.0	0.0	0.0	0.0	0.0	0.0	5.08E-10	0.0
C_3H_6				0.0	0.0	0.0	0.0	0.0	0.0	2.99E-13	0.0
C_3H_8				0.0	0.0	0.0	0.0	0.0	0.0	9.80E-15	0.0
ISOBU-01				0.0	0.0	0.0	0.0	0.0	0.0	7.31E-20	0.0
N-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	6.34E-17	0.0
1-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	2.02E-16	0.0
Naphtha				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8				0.0	0.0	0.0	0.0	0.0	0.0	2.75E-42	0.0

Description	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle
PFD Number	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	284.8
Pressure (psia)	14.7	317.0	14.7	14.7	14.7	227.4	14.7	14.7	14.7	14.7	477.0
Mass Flow (lb/hr)	7,278	39,512	175,104	53,580	273,557	31,243	251,866	4,869,489	4,252,146	199,051	200,967
Mole Flow (lbmol/hr)	28	19,287	1,657	252	1,288	640	8,057	270,298	150,225		9,679
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0629	1.0	0.0980		0.1209
Ar	0.0	1.22E-04	0.0	0.0	0.0	2.07E-05	0.0395	0.0	0.0154		7.39E-03
CO_2	0.0	8.59E-09	0.0	0.0	0.0	0.0601	0.2063	0.0	0.0432		0.1192
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0262	0.0	0.0995		0.0
N_2	0.0	3.21E-04	0.0	0.0	0.0	7.75E-07	0.6651	0.0	0.7438		5.44E-03
CO	0.0	7.62E-04	0.0	0.0	0.0	7.91E-06	0.0	0.0	0.0		0.4233
COS	0.0	0.0	0.0	0.0	0.0	1.86E-05	1.46E-13	0.0	0.0		6.44E-05
H_2	0.0	0.9988	0.0	0.0	0.0	1.46E-09	0.0	0.0	0.0		0.2986
H_2S	0.0	0.0	0.0	0.0	0.0	1.21E-10	0.0	0.0	0.0		1.17E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.28E-05
NH_3	0.0	0.0	0.0	0.0	0.0	1.13E-03	2.15E-06	0.0	5.08E-06		3.63E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	9.81E-14	0.0	2.49E-13		0.0
CH_4	0.0	0.0	0.0	0.0	0.0	4.37E-04	0.0	0.0	0.0		0.0203
C_2H_4	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0		0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0		0.0
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.3370	0.0	0.0	0.0		0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.3322	0.0	0.0	0.0		0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0		0.0
Naphtha	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
F-T-Jet	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0
F-T-Diesel	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0
S_8	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0

Description	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA
PFD Number	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**
Temperature (F)	500.0	500.0	268.0	372.0	318.1	90.0	100.0	105.0
Pressure (psia)	477.0	477.0	665.0	379.0	360.0	125.0	369.0	25.0
Mass Flow (lb/hr)	2,735,818	1,082,528	1,374,659	407,632	121,054	32,764	1,621,120	1,044,405
Mole Flow (lbmol/hr)	131,767	52,139	42,717	19,651	3,762	1,018	61,811	23,732
Mole Fraction								
H_2O	0.1209	0.1209	0.0	0.0587	0.0	0.0	0.0	0.0
Ar	7.39E-03	7.39E-03	0.0318	0.0601	0.0318	0.0318	0.0416	0.0
CO_2	0.1192	0.1192	0.0	0.1066	0.0	0.0	0.4150	0.9999
O_2	0.0	0.0	0.9504	5.99E-17	0.9504	0.9504	0.0	0.0
N_2	5.44E-03	5.44E-03	0.0178	0.0384	0.0178	0.0178	0.0338	1.11E-05
CO	0.4233	0.4233	0.0	0.3809	0.0	0.0	0.1257	6.00E-05
COS	6.44E-05	6.44E-05	0.0	2.53E-09	0.0	0.0	1.92E-07	0.0
H_2	0.2986	0.2986	0.0	0.3459	0.0	0.0	0.3170	8.50E-08
H_2S	1.17E-03	1.17E-03	0.0	1.68E-12	0.0	0.0	7.15E-11	1.80E-10
HCl	2.28E-05	2.28E-05	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	3.63E-03	3.63E-03	0.0	3.68E-05	0.0	0.0	1.17E-05	0.0
SO_2	0.0	0.0	0.0	2.36E-18	0.0	0.0	0.0	0.0
CH_4	0.0203	0.0203	0.0	9.34E-03	0.0	0.0	0.0621	3.97E-05
C_2H_4	0.0	0.0	0.0	2.26E-08	0.0	0.0	1.39E-03	0.0
C_2H_6	0.0	0.0	0.0	4.01E-09	0.0	0.0	4.34E-04	0.0
C_3H_6	0.0	0.0	0.0	2.36E-12	0.0	0.0	1.20E-03	0.0
C_3H_8	0.0	0.0	0.0	7.74E-14	0.0	0.0	3.81E-04	0.0
ISOBU-01	0.0	0.0	0.0	5.77E-19	0.0	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	5.01E-16	0.0	0.0	3.31E-04	0.0
1-BUT-01	0.0	0.0	0.0	1.60E-15	0.0	0.0	1.03E-03	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	2.17E-41	0.0	0.0	0.0	0.0

Description	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	36	37	38	39
Temperature (F)	325.6	427.3	325.6	821.7
Pressure (psia)	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	7,184	287,021	316,877	217,573
Mole Flow (lbmol/hr)	500	14,626	22,055	7,540
Mole Fraction				
H_2O	0.0553	0.0789	0.0553	9.87E-03
Ar	0.0566	0.0807	0.0566	9.25E-03
CO_2	0.0495	0.0706	0.0495	3.27E-04
O_2	5.65E-17	8.05E-17	5.65E-17	0.2074
N_2	0.0355	0.0505	0.0355	0.7732
CO	0.2426	0.3459	0.2426	0.0
COS	1.15E-13	1.63E-13	1.15E-13	0.0
H_2	0.5598	0.3725	0.5598	0.0
H_2S	1.58E-12	2.26E-12	1.58E-12	0.0
HCl	0.0	0.0	0.0	0.0
NH_3	3.46E-05	4.94E-05	3.46E-05	0.0
SO_2	2.23E-18	3.18E-18	2.23E-18	0.0
CH_4	6.15E-04	8.78E-04	6.15E-04	0.0
C_2H_4	2.13E-08	3.04E-08	2.13E-08	0.0
C_2H_6	3.78E-09	5.39E-09	3.78E-09	0.0
C_3H_6	2.23E-12	3.18E-12	2.23E-12	0.0
C_3H_8	7.29E-14	1.04E-13	8.16E-14	0.0
ISOBU-01	5.44E-19	7.76E-19	5.44E-19	0.0
N-BUT-01	4.72E-16	6.74E-16	9.18E-15	0.0
1-BUT-01	1.50E-15	2.14E-15	1.50E-15	0.0
Naphtha	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0
S_8	2.05E-41	2.92E-41	2.05E-41	0.0

Table 2-18: CBTL, 19.6% Biomass, Torrefied, Validated: Stream Values

Description	Coal	Dried Coal	Torrefied Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.
PFD Number	**1**	**2**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Temperature (F)	59.0	220.0	59.0	489.4	59.0	59.0	500.0	90.0	100.0	266.5	100.0
Pressure (psia)	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7
Mass Flow (lb/hr)	2,008,345	1,818,042	443,204	386,378	6,485,538	3,531,600	3,820,749	1,535,626	1,656,678	2,457,123	2,583,089
Mole Flow (lbmol/hr)				21,447	224,748	122,383	183,417	47,719	40,185	156,073	58,926
Mole Fraction											
H_2O				1.0	9.87E-03	9.87E-03	0.1272	0.0	1.41E-03	8.26E-03	0.0
Ar				0.0	9.25E-03	9.25E-03	7.40E-03	0.0318	0.0	0.0173	0.0
CO_2				0.0	3.27E-04	3.27E-04	0.1147	0.0	0.8891	0.0218	0.9923
O_2				0.0	0.2074	0.2074	0.0	0.9504	0.0	7.71E-18	0.0
N_2				0.0	0.7732	0.7732	5.45E-03	0.0178	4.67E-04	0.0139	6.15E-05
CO				0.0	0.0	0.0	0.4280	0.0	0.0669	0.4347	4.81E-03
COS				0.0	0.0	0.0	5.94E-05	0.0	4.07E-07	7.01E-08	2.77E-07
H_2				0.0	0.0	0.0	0.2897	0.0	0.0349	0.4782	1.14E-03
H_2S				0.0	0.0	0.0	1.18E-03	0.0	0.0	2.84E-11	7.26E-11
HCl				0.0	0.0	0.0	2.29E-05	0.0	0.0	0.0	0.0
NH_3				0.0	0.0	0.0	3.64E-03	0.0	0.0	5.48E-06	0.0
SO_2				0.0	0.0	0.0	0.0	0.0	0.0	2.77E-19	0.0
CH_4				0.0	0.0	0.0	0.0226	0.0	7.20E-03	0.0259	1.72E-03
C_2H_4				0.0	0.0	0.0	0.0	0.0	0.0	3.65E-09	0.0
C_2H_6				0.0	0.0	0.0	0.0	0.0	0.0	6.75E-10	0.0
C_3H_6				0.0	0.0	0.0	0.0	0.0	0.0	4.08E-13	0.0
C_3H_8				0.0	0.0	0.0	0.0	0.0	0.0	1.39E-14	0.0
ISOBU-01				0.0	0.0	0.0	0.0	0.0	0.0	1.12E-19	0.0
N-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	6.65E-17	0.0
1-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	2.13E-16	0.0
Naphtha				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8				0.0	0.0	0.0	0.0	0.0	0.0	9.76E-46	0.0

Description	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle
PFD Number	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	288.0
Pressure (psia)	14.7	317.0	14.7	14.7	14.7	227.8	14.7	14.7	14.7	14.7	477.0
Mass Flow (lb/hr)	7,291	39,511	175,101	53,579	273,552	31,250	247,553	4,897,709	4,250,600	199,420	201,094
Mole Flow (lbmol/hr)	28	19,292	1,657	252	1,288	640	7,932	271,864	150,238		9,654
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0646	1.0	0.0983		0.1272
Ar	0.0	1.24E-04	0.0	0.0	0.0	2.18E-05	0.0404	0.0	0.0154		7.40E-03
CO_2	0.0	8.54E-09	0.0	0.0	0.0	0.0603	0.2035	0.0	0.0426		0.1147
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0262	0.0	0.0995		0.0
N_2	0.0	3.23E-04	0.0	0.0	0.0	8.14E-07	0.6654	0.0	0.7441		5.45E-03
CO	0.0	7.36E-04	0.0	0.0	0.0	7.94E-06	0.0	0.0	0.0		0.4280
COS	0.0	0.0	0.0	0.0	0.0	1.71E-05	1.34E-13	0.0	0.0		5.94E-05
H_2	0.0	0.9988	0.0	0.0	0.0	1.52E-09	0.0	0.0	0.0		0.2897
H_2S	0.0	0.0	0.0	0.0	0.0	1.21E-10	0.0	0.0	0.0		1.18E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.29E-05
NH_3	0.0	0.0	0.0	0.0	0.0	1.34E-03	2.34E-06	0.0	5.45E-06		3.64E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	9.57E-14	0.0	2.38E-13		0.0
CH_4	0.0	0.0	0.0	0.0	0.0	4.81E-04	0.0	0.0	0.0		0.0226
C_2H_4	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0		0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.1098	0.0	0.0	0.0		0.0
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.3369	0.0	0.0	0.0		0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.3320	0.0	0.0	0.0		0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0992	0.0	0.0	0.0		0.0
Naphtha	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
F-T-Jet	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0
F-T-Diesel	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0
S_8	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0

Description	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA
PFD Number	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**
Temperature (F)	500.0	500.0	268.0	382.0	318.1	90.0	100.0	105.0
Pressure (psia)	477.0	477.0	665.0	379.0	360.0	125.0	369.0	25.0
Mass Flow (lb/hr)	2,820,624	1,000,125	1,372,542	433,898	130,075	33,009	1,637,806	1,047,568
Mole Flow (lbmol/hr)	135,406	48,012	42,651	21,129	4,042	1,026	62,502	23,804
Mole Fraction								
H_2O	0.1272	0.1272	0.0	0.0607	0.0	0.0	0.0	0.0
Ar	7.40E-03	7.40E-03	0.0318	0.0619	0.0318	0.0318	0.0432	0.0
CO_2	0.1147	0.1147	0.0	0.1015	0.0	0.0	0.4117	0.9999
O_2	0.0	0.0	0.9504	5.70E-17	0.9504	0.9504	0.0	0.0
N_2	5.45E-03	5.45E-03	0.0178	0.0395	0.0178	0.0178	0.0347	1.15E-05
CO	0.4280	0.4280	0.0	0.3761	0.0	0.0	0.1240	5.97E-05
COS	5.94E-05	5.94E-05	0.0	2.13E-09	0.0	0.0	1.75E-07	0.0
H_2	0.2897	0.2897	0.0	0.3506	0.0	0.0	0.3138	8.49E-08
H_2S	1.18E-03	1.18E-03	0.0	1.65E-12	0.0	0.0	7.08E-11	1.80E-10
HCl	2.29E-05	2.29E-05	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	3.64E-03	3.64E-03	0.0	4.05E-05	0.0	0.0	1.37E-05	0.0
SO_2	0.0	0.0	0.0	2.05E-18	0.0	0.0	0.0	0.0
CH_4	0.0226	0.0226	0.0	9.71E-03	0.0	0.0	0.0679	4.38E-05
C_2H_4	0.0	0.0	0.0	2.69E-08	0.0	0.0	1.38E-03	0.0
C_2H_6	0.0	0.0	0.0	4.98E-09	0.0	0.0	4.29E-04	0.0
C_3H_6	0.0	0.0	0.0	3.02E-12	0.0	0.0	1.18E-03	0.0
C_3H_8	0.0	0.0	0.0	1.03E-13	0.0	0.0	3.77E-04	0.0
ISOBU-01	0.0	0.0	0.0	8.25E-19	0.0	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	4.91E-16	0.0	0.0	3.27E-04	0.0
1-BUT-01	0.0	0.0	0.0	1.58E-15	0.0	0.0	1.02E-03	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	7.21E-45	0.0	0.0	0.0	0.0

Description	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	36	37	38	39
Temperature (F)	327.8	430.4	327.8	821.7
Pressure (psia)	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	7,129	313,758	313,805	216,581
Mole Flow (lbmol/hr)	500	16,123	22,011	7,505
Mole Fraction				
H_2O	0.0558	0.0796	0.0558	9.87E-03
Ar	0.0569	0.0811	0.0569	9.25E-03
CO_2	0.0472	0.0673	0.0472	3.27E-04
O_2	5.24E-17	7.47E-17	5.24E-17	0.2074
N_2	0.0357	0.0508	0.0357	0.7732
CO	0.2412	0.3437	0.2412	0.0
COS	1.04E-13	1.48E-13	1.04E-13	0.0
H_2	0.5625	0.3765	0.5625	0.0
H_2S	1.52E-12	2.16E-12	1.52E-12	0.0
HCl	0.0	0.0	0.0	0.0
NH_3	3.72E-05	5.30E-05	3.72E-05	0.0
SO_2	1.88E-18	2.68E-18	1.88E-18	0.0
CH_4	6.95E-04	9.91E-04	6.95E-04	0.0
C_2H_4	2.48E-08	3.53E-08	2.48E-08	0.0
C_2H_6	4.58E-09	6.53E-09	4.58E-09	0.0
C_3H_6	2.77E-12	3.95E-12	2.77E-12	0.0
C_3H_8	9.46E-14	1.35E-13	1.03E-13	0.0
ISOBU-01	7.58E-19	1.08E-18	7.58E-19	0.0
N-BUT-01	4.51E-16	6.43E-16	9.18E-15	0.0
1-BUT-01	1.45E-15	2.07E-15	1.45E-15	0.0
Naphtha	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0
S_8	6.63E-45	9.45E-45	6.63E-45	0.0

Table 2-19: CBTL, 28.3% Biomass, Torrefied, Modeled: Stream Values

Description	Coal	Dried Coal	Torrefied Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.
PFD Number	**1**	**2**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Temperature (F)	59.0	220.0	59.0	489.4	59.0	59.0	500.0	90.0	100.0	265.3	100.0
Pressure (psia)	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7
Mass Flow (lb/hr)	1,773,357	1,605,321	633,620	341,170	6,377,966	3,531,600	3,753,513	1,511,034	1,642,991	2,445,012	2,567,475
Mole Flow (lbmol/hr)				18,938	221,020	122,383	180,318	46,955	39,874	155,601	58,568
Mole Fraction											
H_2O				1.0	9.87E-03	9.87E-03	0.1126	0.0	1.42E-03	7.90E-03	0.0
Ar				0.0	9.25E-03	9.25E-03	7.42E-03	0.0318	0.0	0.0167	0.0
CO_2				0.0	3.27E-04	3.27E-04	0.1152	0.0	0.8882	0.0216	0.9923
O_2				0.0	0.2074	0.2074	0.0	0.9504	0.0	7.60E-18	0.0
N_2				0.0	0.7732	0.7732	5.41E-03	0.0178	4.56E-04	0.0133	5.95E-05
CO				0.0	0.0	0.0	0.4362	0.0	0.0676	0.4360	4.82E-03
COS				0.0	0.0	0.0	6.02E-05	0.0	4.08E-07	7.01E-08	2.77E-07
H_2				0.0	0.0	0.0	0.2966	0.0	0.0354	0.4796	1.14E-03
H_2S				0.0	0.0	0.0	1.06E-03	0.0	0.0	2.51E-11	6.45E-11
HCl				0.0	0.0	0.0	2.06E-05	0.0	0.0	0.0	0.0
NH_3				0.0	0.0	0.0	3.50E-03	0.0	0.0	5.05E-06	0.0
SO_2				0.0	0.0	0.0	0.0	0.0	0.0	2.51E-19	0.0
CH_4				0.0	0.0	0.0	0.0219	0.0	6.93E-03	0.0248	1.64E-03
C_2H_4				0.0	0.0	0.0	0.0	0.0	0.0	3.35E-09	0.0
C_2H_6				0.0	0.0	0.0	0.0	0.0	0.0	6.11E-10	0.0
C_3H_6				0.0	0.0	0.0	0.0	0.0	0.0	3.68E-13	0.0
C_3H_8				0.0	0.0	0.0	0.0	0.0	0.0	1.24E-14	0.0
ISOBU-01				0.0	0.0	0.0	0.0	0.0	0.0	9.73E-20	0.0
N-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	6.52E-17	0.0
1-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	2.09E-16	0.0
Naphtha				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8				0.0	0.0	0.0	0.0	0.0	0.0	4.47E-44	0.0

Description	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle
PFD Number	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	280.3
Pressure (psia)	14.7	317.0	14.7	14.7	14.7	227.6	14.7	14.7	14.7	14.7	477.0
Mass Flow (lb/hr)	6,438	39,513	175,103	53,579	273,554	31,246	249,826	4,831,133	4,251,157	180,224	197,556
Mole Flow (lbmol/hr)	25	19,292	1,657	252	1,288	640	7,998	268,169	150,238		9,491
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0640	1.0	0.0982		0.1126
Ar	0.0	1.22E-04	0.0	0.0	0.0	2.10E-05	0.0396	0.0	0.0153		7.42E-03
CO_2	0.0	8.58E-09	0.0	0.0	0.0	0.0602	0.2054	0.0	0.0428		0.1152
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0263	0.0	0.0995		0.0
N_2	0.0	3.13E-04	0.0	0.0	0.0	7.69E-07	0.6648	0.0	0.7441		5.41E-03
CO	0.0	7.51E-04	0.0	0.0	0.0	7.92E-06	0.0	0.0	0.0		0.4362
COS	0.0	0.0	0.0	0.0	0.0	1.70E-05	1.32E-13	0.0	0.0		6.02E-05
H_2	0.0	0.9988	0.0	0.0	0.0	1.48E-09	0.0	0.0	0.0		0.2966
H_2S	0.0	0.0	0.0	0.0	0.0	1.07E-10	0.0	0.0	0.0		1.06E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.06E-05
NH_3	0.0	0.0	0.0	0.0	0.0	1.23E-03	2.23E-06	0.0	5.22E-06		3.50E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	8.55E-14	0.0	2.14E-13		0.0
CH_4	0.0	0.0	0.0	0.0	0.0	4.62E-04	0.0	0.0	0.0		0.0219
C_2H_4	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0		0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0		0.0
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.3370	0.0	0.0	0.0		0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.3321	0.0	0.0	0.0		0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0		0.0
Naphtha	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
F-T-Jet	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0
F-T-Diesel	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0
S_8	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0

Description	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA
PFD Number	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**
Temperature (F)	500.0	500.0	268.0	377.3	318.1	90.0	100.0	105.0
Pressure (psia)	477.0	477.0	665.0	379.0	360.0	125.0	369.0	25.0
Mass Flow (lb/hr)	3,125,767	627,746	1,353,624	420,797	125,895	31,515	1,626,647	1,045,886
Mole Flow (lbmol/hr)	150,161	30,157	42,063	20,433	3,912	979	62,082	23,766
Mole Fraction								
H_2O	0.1126	0.1126	0.0	0.0599	0.0	0.0	0.0	0.0
Ar	7.42E-03	7.42E-03	0.0318	0.0604	0.0318	0.0318	0.0419	0.0
CO_2	0.1152	0.1152	0.0	0.1038	0.0	0.0	0.4138	0.9999
O_2	0.0	0.0	0.9504	5.79E-17	0.9504	0.9504	0.0	0.0
N_2	5.41E-03	5.41E-03	0.0178	0.0378	0.0178	0.0178	0.0332	1.10E-05
CO	0.4362	0.4362	0.0	0.3791	0.0	0.0	0.1250	5.99E-05
COS	6.02E-05	6.02E-05	0.0	2.23E-09	0.0	0.0	1.76E-07	0.0
H_2	0.2966	0.2966	0.0	0.3495	0.0	0.0	0.3158	8.50E-08
H_2S	1.06E-03	1.06E-03	0.0	1.47E-12	0.0	0.0	6.30E-11	1.59E-10
HCl	2.06E-05	2.06E-05	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	3.50E-03	3.50E-03	0.0	3.85E-05	0.0	0.0	1.27E-05	0.0
SO_2	0.0	0.0	0.0	1.91E-18	0.0	0.0	0.0	0.0
CH_4	0.0219	0.0219	0.0	9.59E-03	0.0	0.0	0.0655	4.20E-05
C_2H_4	0.0	0.0	0.0	2.55E-08	0.0	0.0	1.39E-03	0.0
C_2H_6	0.0	0.0	0.0	4.65E-09	0.0	0.0	4.32E-04	0.0
C_3H_6	0.0	0.0	0.0	2.80E-12	0.0	0.0	1.19E-03	0.0
C_3H_8	0.0	0.0	0.0	9.43E-14	0.0	0.0	3.79E-04	0.0
ISOBU-01	0.0	0.0	0.0	7.41E-19	0.0	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	4.97E-16	0.0	0.0	3.29E-04	0.0
1-BUT-01	0.0	0.0	0.0	1.59E-15	0.0	0.0	1.02E-03	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	3.40E-43	0.0	0.0	0.0	0.0

Description	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	36	37	38	39
Temperature (F)	326.4	428.8	326.4	821.7
Pressure (psia)	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	7,130	300,395	313,399	216,822
Mole Flow (lbmol/hr)	500	15,416	21,979	7,514
Mole Fraction				
H_2O	0.0556	0.0794	0.0556	9.87E-03
Ar	0.0561	0.0800	0.0561	9.25E-03
CO_2	0.0481	0.0687	0.0481	3.27E-04
O_2	5.37E-17	7.67E-17	5.37E-17	0.2074
N_2	0.0345	0.0491	0.0345	0.7732
CO	0.2423	0.3457	0.2423	0.0
COS	9.58E-14	1.37E-13	9.58E-14	0.0
H_2	0.5627	0.3760	0.5627	0.0
H_2S	1.37E-12	1.95E-12	1.37E-12	0.0
HCl	0.0	0.0	0.0	0.0
NH_3	3.57E-05	5.10E-05	3.57E-05	0.0
SO_2	1.77E-18	2.53E-18	1.77E-18	0.0
CH_4	6.68E-04	9.54E-04	6.68E-04	0.0
C_2H_4	2.37E-08	3.38E-08	2.37E-08	0.0
C_2H_6	4.32E-09	6.17E-09	4.32E-09	0.0
C_3H_6	2.60E-12	3.71E-12	2.60E-12	0.0
C_3H_8	8.75E-14	1.25E-13	9.62E-14	0.0
ISOBU-01	6.87E-19	9.82E-19	6.87E-19	0.0
N-BUT-01	4.61E-16	6.59E-16	9.20E-15	0.0
1-BUT-01	1.48E-15	2.11E-15	1.48E-15	0.0
Naphtha	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0
S_8	3.16E-43	4.51E-43	3.16E-43	0.0

Table 2-20: CBTL, 28.3% Biomass, Torrefied, Validated: Stream Values

Description	Coal	Dried Coal	Torrefied Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.
PFD Number	**1**	**2**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Temperature (F)	59.0	220.0	59.0	489.4	59.0	59.0	500.0	90.0	100.0	267.9	100.0
Pressure (psia)	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7
Mass Flow (lb/hr)	1,776,619	1,608,274	634,786	341,797	6,409,460	3,531,600	3,755,382	1,518,060	1,653,802	2,463,881	2,581,791
Mole Flow (lbmol/hr)				18,973	222,111	122,383	179,791	47,173	40,118	156,421	58,900
Mole Fraction											
H_2O				1.0	9.87E-03	9.87E-03	0.1187	0.0	1.40E-03	8.71E-03	0.0
Ar				0.0	9.25E-03	9.25E-03	7.43E-03	0.0318	0.0	0.0175	0.0
CO_2				0.0	3.27E-04	3.27E-04	0.1109	0.0	0.8890	0.0219	0.9922
O_2				0.0	0.2074	0.2074	0.0	0.9504	0.0	7.72E-18	0.0
N_2				0.0	0.7732	0.7732	5.42E-03	0.0178	4.53E-04	0.0137	5.97E-05
CO				0.0	0.0	0.0	0.4408	0.0	0.0667	0.4337	4.80E-03
COS				0.0	0.0	0.0	5.55E-05	0.0	3.73E-07	6.41E-08	2.53E-07
H_2				0.0	0.0	0.0	0.2877	0.0	0.0348	0.4771	1.14E-03
H_2S				0.0	0.0	0.0	1.07E-03	0.0	0.0	2.50E-11	6.42E-11
HCl				0.0	0.0	0.0	2.07E-05	0.0	0.0	0.0	0.0
NH_3				0.0	0.0	0.0	3.52E-03	0.0	0.0	5.92E-06	0.0
SO_2				0.0	0.0	0.0	0.0	0.0	0.0	2.33E-19	0.0
CH_4				0.0	0.0	0.0	0.0244	0.0	7.64E-03	0.0274	1.82E-03
C_2H_4				0.0	0.0	0.0	0.0	0.0	0.0	4.23E-09	0.0
C_2H_6				0.0	0.0	0.0	0.0	0.0	0.0	8.05E-10	0.0
C_3H_6				0.0	0.0	0.0	0.0	0.0	0.0	4.97E-13	0.0
C_3H_8				0.0	0.0	0.0	0.0	0.0	0.0	1.74E-14	0.0
ISOBU-01				0.0	0.0	0.0	0.0	0.0	0.0	1.47E-19	0.0
N-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	6.82E-17	0.0
1-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	2.21E-16	0.0
Naphtha				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8				0.0	0.0	0.0	0.0	0.0	0.0	4.12E-44	0.0

Description	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle
PFD Number	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	283.6
Pressure (psia)	14.7	317.0	14.7	14.7	14.7	227.9	14.7	14.7	14.7	14.7	477.0
Mass Flow (lb/hr)	6,450	39,518	175,101	53,579	273,551	31,254	245,543	4,858,927	4,249,516	180,556	197,655
Mole Flow (lbmol/hr)	25	19,300	1,657	252	1,288	640	7,874	269,711	150,249		9,463
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0657	1.0	0.0985		0.1187
Ar	0.0	1.23E-04	0.0	0.0	0.0	2.21E-05	0.0405	0.0	0.0153		7.43E-03
CO_2	0.0	8.53E-09	0.0	0.0	0.0	0.0604	0.2025	0.0	0.0422		0.1109
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0262	0.0	0.0996		0.0
N_2	0.0	3.15E-04	0.0	0.0	0.0	8.09E-07	0.6650	0.0	0.7444		5.42E-03
CO	0.0	7.25E-04	0.0	0.0	0.0	7.95E-06	0.0	0.0	0.0		0.4408
COS	0.0	0.0	0.0	0.0	0.0	1.57E-05	1.21E-13	0.0	0.0		5.55E-05
H_2	0.0	0.9988	0.0	0.0	0.0	1.55E-09	0.0	0.0	0.0		0.2877
H_2S	0.0	0.0	0.0	0.0	0.0	1.07E-10	0.0	0.0	0.0		1.07E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.07E-05
NH_3	0.0	0.0	0.0	0.0	0.0	1.45E-03	2.43E-06	0.0	5.58E-06		3.52E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	8.34E-14	0.0	2.04E-13		0.0
CH_4	0.0	0.0	0.0	0.0	0.0	5.08E-04	0.0	0.0	0.0		0.0244
C_2H_4	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0		0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.1098	0.0	0.0	0.0		0.0
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.3368	0.0	0.0	0.0		0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.3320	0.0	0.0	0.0		0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0992	0.0	0.0	0.0		0.0
Naphtha	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
F-T-Jet	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0
F-T-Diesel	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0
S_8	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0

Description	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA
PFD Number	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**
Temperature (F)	500.0	500.0	268.0	387.0	318.1	90.0	100.0	105.0
Pressure (psia)	477.0	477.0	665.0	379.0	360.0	125.0	369.0	25.0
Mass Flow (lb/hr)	3,190,104	565,278	1,351,076	447,587	135,220	31,764	1,643,430	1,048,902
Mole Flow (lbmol/hr)	152,728	27,063	41,984	21,956	4,202	987	62,786	23,835
Mole Fraction								
H_2O	0.1187	0.1187	0.0	0.0618	0.0	0.0	0.0	0.0
Ar	7.43E-03	7.43E-03	0.0318	0.0621	0.0318	0.0318	0.0435	0.0
CO_2	0.1109	0.1109	0.0	0.0987	0.0	0.0	0.4103	0.9999
O_2	0.0	0.0	0.9504	5.50E-17	0.9504	0.9504	0.0	0.0
N_2	5.42E-03	5.42E-03	0.0178	0.0388	0.0178	0.0178	0.0341	1.13E-05
CO	0.4408	0.4408	0.0	0.3743	0.0	0.0	0.1232	5.95E-05
COS	5.55E-05	5.55E-05	0.0	1.88E-09	0.0	0.0	1.60E-07	0.0
H_2	0.2877	0.2877	0.0	0.3542	0.0	0.0	0.3126	8.48E-08
H_2S	1.07E-03	1.07E-03	0.0	1.45E-12	0.0	0.0	6.24E-11	1.59E-10
HCl	2.07E-05	2.07E-05	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	3.52E-03	3.52E-03	0.0	4.21E-05	0.0	0.0	1.47E-05	0.0
SO_2	0.0	0.0	0.0	1.66E-18	0.0	0.0	0.0	0.0
CH_4	0.0244	0.0244	0.0	9.96E-03	0.0	0.0	0.0715	4.62E-05
C_2H_4	0.0	0.0	0.0	3.02E-08	0.0	0.0	1.37E-03	0.0
C_2H_6	0.0	0.0	0.0	5.73E-09	0.0	0.0	4.27E-04	0.0
C_3H_6	0.0	0.0	0.0	3.54E-12	0.0	0.0	1.18E-03	0.0
C_3H_8	0.0	0.0	0.0	1.24E-13	0.0	0.0	3.75E-04	0.0
ISOBU-01	0.0	0.0	0.0	1.05E-18	0.0	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	4.86E-16	0.0	0.0	3.26E-04	0.0
1-BUT-01	0.0	0.0	0.0	1.57E-15	0.0	0.0	1.01E-03	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	2.94E-43	0.0	0.0	0.0	0.0

Description	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	36	37	38	39
Temperature (F)	328.5	431.8	328.5	821.8
Pressure (psia)	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	7,074	327,684	310,307	215,995
Mole Flow (lbmol/hr)	500	16,959	21,934	7,485
Mole Fraction				
H_2O	0.0561	0.0800	0.0561	9.87E-03
Ar	0.0564	0.0804	0.0564	9.25E-03
CO_2	0.0459	0.0655	0.0459	3.27E-04
O_2	4.99E-17	7.12E-17	4.99E-17	0.2074
N_2	0.0346	0.0493	0.0346	0.7732
CO	0.2407	0.3434	0.2407	0.0
COS	8.69E-14	1.24E-13	8.69E-14	0.0
H_2	0.5655	0.3802	0.5655	0.0
H_2S	1.31E-12	1.87E-12	1.31E-12	0.0
HCl	0.0	0.0	0.0	0.0
NH_3	3.82E-05	5.46E-05	3.82E-05	0.0
SO_2	1.50E-18	2.15E-18	1.50E-18	0.0
CH_4	7.52E-04	1.07E-03	7.52E-04	0.0
C_2H_4	2.73E-08	3.90E-08	2.73E-08	0.0
C_2H_6	5.20E-09	7.42E-09	5.20E-09	0.0
C_3H_6	3.21E-12	4.59E-12	3.21E-12	0.0
C_3H_8	1.13E-13	1.61E-13	1.21E-13	0.0
ISOBU-01	9.47E-19	1.35E-18	9.47E-19	0.0
N-BUT-01	4.41E-16	6.29E-16	9.20E-15	0.0
1-BUT-01	1.43E-15	2.04E-15	1.43E-15	0.0
Naphtha	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0
S_8	2.67E-43	3.81E-43	2.67E-43	0.0

2.5 Scenario 6: CBTL, 10 Percent Biomass, Microchipped, Separate Gasifiers

Figure 2-4 shows the schematic for this scenario. Here the chipped biomass is gasified separately from the coal. In this configuration the ClearFuels® High Efficiency HydroThermal Reformation (HEHTR) gasification process is used to essentially steam reform and gasify the wood into synthesis gas and other products like higher molecular weight organic compounds, methane, higher hydrocarbons, various oxygen-containing species, and tar-like material. ClearFuels® is an indirectly heated gasification system where fuel gas or F-T recycle gas is used to fire the gasification reactor and heat the tubes through which the wood and transport and reaction steam is passed. In principle this is similar to an indirectly fired steam methane reformer, however in the case of the ClearFuels® system the tubes do not contain any catalyst. The hot flue gas after transferring heat to the reactor tubes passes through heat exchangers to generate steam before being vented to atmosphere.

The products emerging from the heated tubes are synthesis gas, hydrocarbons, higher molecular weight organics and gas phase liquid particulates, tars, and some unconverted woody biomass and ash. After passing through a cyclone to remove ash and unconverted wood, the gas and tars are sent to a Dual Fluid Bed Reformer (the Ni-DFB tar reformer process). This process has two fluid bed reactors and in many ways is similar to a catalytic cracker in design. In the reformer fluid bed, hot nickel catalyst reacts with and reforms the tars and hydrocarbons into additional synthesis gas. The reformed gas exits the bed, passes through a cyclone to disengage particulates, and is cooled and scrubbed with water to remove fine particles. The spent nickel catalyst is transferred to the second fluid bed (the regenerator) where fuel gas is combusted with air to burn off the accumulated carbon on the catalyst and prepare it to be transferred back into the reformer. The hot flue gas passes through heat exchangers to generate steam before being vented to the atmosphere.

Both processes were under development by Rentech Inc. but the plant experimenting with the HEHTR configuration has stopped operations. Currently there are no other facilities operating with a similar configuration so there is no means to validate this scenario against actual operational conditions. The modeled HEHTR process operates at about 40 psia pressure and can accept green wood microchips (~5-10 mm) as feed. The purpose of the Ni-DFB process, also operating in the same pressure regime, is essentially to act as a reformer for the tars and hydrocarbon gases that are produced in the HEHTR reactor. This combination can then produce a clean synthesis gas that is at low-pressure and must be compressed so that this syngas can be combined with the high-pressure syngas coming from the TRIG coal gasification process. However, because this technology is not undergoing further testing at the present, its viability in the near future is not likely.

Figure 2-4: Scenario 6: CBTL, 10% Biomass, Microchipped, Separate Gasifiers Plant Configuration

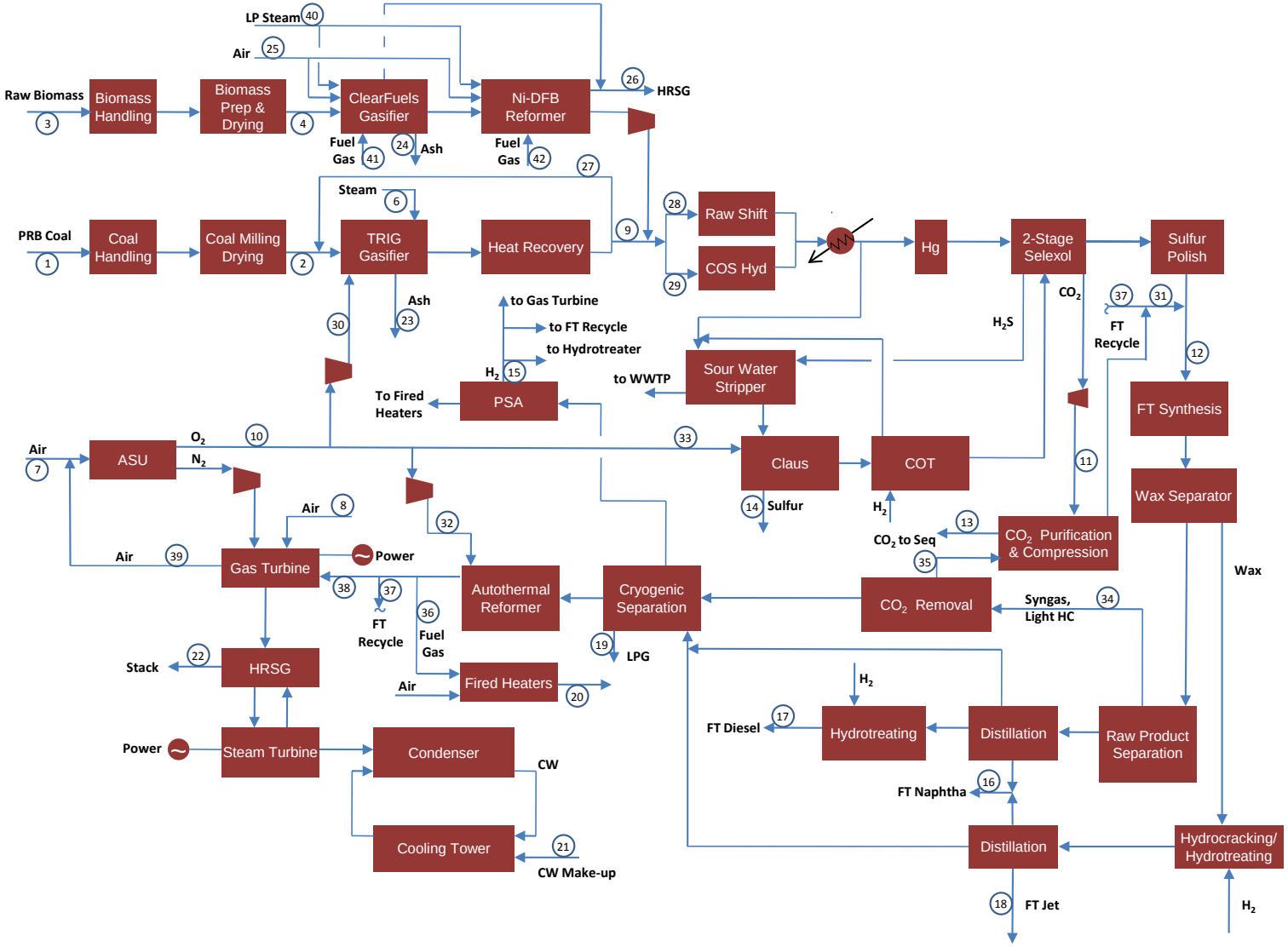


Table 2-21: CBTL, 10% Biomass, Microchipped, Separate Gasifiers: Stream Values

Description	Coal	Dried Coal	Raw Biomass	Dried Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed
PFD Number	1	2	3	4	6	7	8	9	10	11	12
Temperature (F)	59.0	220.0	77.0	216.0	489.4	59.0	59.0	500.0	90.0	100.0	241.0
Pressure (psia)	14.7	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0
Mass Flow (lb/hr)	2,387,663	2,161,417	360,024	240,157	459,354	6,234,076	3,531,600	3,730,024	1,480,696	1,581,359	2,302,114
Mole Flow (lbmol/hr)					25,498	216,034	122,383	180,573	46,012	38,644	150,991
Mole Fraction											
H_2O					1.0	9.87E-03	9.87E-03	0.1397	0.0	1.52E-03	9.29E-05
Ar					0.0	9.25E-03	9.25E-03	7.32E-03	0.0318	0.0	9.02E-03
CO_2					0.0	3.27E-04	3.27E-04	0.1274	0.0	0.8767	0.0156
O_2					0.0	0.2074	0.2074	0.0	0.9504	0.0	5.34E-20
N_2					0.0	0.7732	0.7732	5.50E-03	0.0178	5.02E-04	9.25E-03
CO					0.0	0.0	0.0	0.3958	0.0	0.0758	0.4500
COS					0.0	0.0	0.0	7.26E-05	0.0	5.12E-07	8.77E-08
H_2					0.0	0.0	0.0	0.3019	0.0	0.0396	0.4949
H_2S					0.0	0.0	0.0	1.43E-03	0.0	0.0	3.49E-11
HCl					0.0	0.0	0.0	2.77E-05	0.0	0.0	0.0
NH_3					0.0	0.0	0.0	3.90E-03	0.0	0.0	2.99E-08
SO_2					0.0	0.0	0.0	0.0	0.0	0.0	2.78E-21
CH_4					0.0	0.0	0.0	0.0169	0.0	5.93E-03	0.0212
C_2H_4					0.0	0.0	0.0	0.0	0.0	0.0	2.67E-11
C_2H_6					0.0	0.0	0.0	0.0	0.0	0.0	4.86E-12
C_3H_6					0.0	0.0	0.0	0.0	0.0	0.0	3.17E-15
C_3H_8					0.0	0.0	0.0	0.0	0.0	0.0	1.06E-16
ISOBU-01					0.0	0.0	0.0	0.0	0.0	0.0	9.04E-22
N-BUT-01					0.0	0.0	0.0	0.0	0.0	0.0	5.24E-19
1-BUT-01					0.0	0.0	0.0	0.0	0.0	0.0	1.68E-18
Naphtha					0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet					0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel					0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8					0.0	0.0	0.0	0.0	0.0	0.0	1.09E-43

Description	CO_2 Seq.	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash
PFD Number	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**
Temperature (F)	100.0	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0
Pressure (psia)	2214.7	14.7	317.0	14.7	14.7	14.7	224.4	14.7	14.7	14.7	14.7
Mass Flow (lb/hr)	2,450,100	8,750	39,606	175,137	53,588	273,609	31,164	276,164	4,972,506	5,294,645	228,085
Mole Flow (lbmol/hr)	55,886	34	19,342	1,657	252	1,288	638	9,770	276,016	185,191	
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2040	1.0	0.1040	
Ar	0.0	0.0	7.31E-05	0.0	0.0	0.0	1.08E-05	0.0206	0.0	0.0144	
CO_2	0.9924	0.0	9.23E-09	0.0	0.0	0.0	0.0578	0.1211	0.0	0.0686	
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0276	0.0	0.0875	
N_2	6.03E-05	0.0	2.43E-04	0.0	0.0	0.0	4.91E-07	0.6267	0.0	0.7256	
CO	5.01E-03	0.0	8.74E-04	0.0	0.0	0.0	7.88E-06	0.0	0.0	0.0	
COS	3.53E-07	0.0	0.0	0.0	0.0	0.0	2.08E-05	6.26E-14	0.0	1.60E-14	
H_2	1.19E-03	0.0	0.9988	0.0	0.0	0.0	1.24E-09	0.0	0.0	0.0	
H_2S	9.11E-11	0.0	0.0	0.0	0.0	0.0	1.45E-10	0.0	0.0	0.0	
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
NH_3	0.0	0.0	0.0	0.0	0.0	0.0	7.09E-06	1.17E-05	0.0	5.69E-06	
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.12E-13	0.0	4.18E-13	
CH_4	1.34E-03	0.0	0.0	0.0	0.0	0.0	3.90E-04	0.0	0.0	0.0	
C_2H_4	0.0	0.0	0.0	0.0	0.0	0.0	4.37E-03	0.0	0.0	0.0	
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0	0.0557	0.0	0.0	0.0	
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.0	0.1103	0.0	0.0	0.0	
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.0	0.3383	0.0	0.0	0.0	
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0	0.3334	0.0	0.0	0.0	
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0997	0.0	0.0	0.0	
Naphtha	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	
F-T-Jet	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	
F-T-Diesel	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	
S_8	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	

Description	CF Ash	Air	Stack	Syngas Recycle	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT
PFD Number	**24**	**25**	**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**
Temperature (F)	100.0	60.0	1067.9	294.1	500.0	500.0	268.0	87.4	318.1	90.0	100.0
Pressure (psia)	14.7	19.7	14.7	477.0	477.0	477.0	665.0	379.0	360.0	125.0	369.0
Mass Flow (lb/hr)	4,301	816,720	1,021,865	196,327	1,685,512	2,044,513	1,337,340	132,598	108,365	34,990	1,503,682
Mole Flow (lbmol/hr)		28,302	35,160	9,504	81,597	98,976	41,557	5,537	3,367	1,087	58,570
Mole Fraction											
H_2O		9.87E-03	0.1595	0.1397	0.1397	0.1397	0.0	1.48E-03	0.0	0.0	0.0
Ar		9.25E-03	0.0214	7.32E-03	7.32E-03	7.32E-03	0.0318	9.24E-04	0.0318	0.0318	0.0232
CO_2		3.27E-04	0.1405	0.1274	0.1274	0.1274	0.0	0.2087	0.0	0.0	0.4196
O_2		0.2074	0.0357	0.0	0.0	0.0	0.9504	1.46E-18	0.9504	0.9504	0.0
N_2		0.7732	0.6430	5.50E-03	5.50E-03	5.50E-03	0.0178	3.61E-03	0.0178	0.0178	0.0238
CO		0.0	0.0	0.3958	0.3958	0.3958	0.0	0.4855	0.0	0.0	0.1356
COS		0.0	8.40E-14	7.26E-05	7.26E-05	7.26E-05	0.0	1.18E-08	0.0	0.0	2.26E-07
H_2		0.0	0.0	0.3019	0.3019	0.3019	0.0	0.2717	0.0	0.0	0.3347
H_2S		0.0	0.0	1.43E-03	1.43E-03	1.43E-03	0.0	5.68E-14	0.0	0.0	9.00E-11
HCl		0.0	0.0	2.77E-05	2.77E-05	2.77E-05	0.0	0.0	0.0	0.0	0.0
NH_3		0.0	8.78E-06	3.90E-03	3.90E-03	3.90E-03	0.0	8.16E-07	0.0	0.0	7.72E-08
SO_2		0.0	6.10E-13	0.0	0.0	0.0	0.0	7.58E-20	0.0	0.0	0.0
CH_4		0.0	0.0	0.0169	0.0169	0.0169	0.0	0.0280	0.0	0.0	0.0580
C_2H_4		0.0	0.0	0.0	0.0	0.0	0.0	7.29E-10	0.0	0.0	1.47E-03
C_2H_6		0.0	0.0	0.0	0.0	0.0	0.0	1.33E-10	0.0	0.0	4.58E-04
C_3H_6		0.0	0.0	0.0	0.0	0.0	0.0	8.65E-14	0.0	0.0	1.26E-03
C_3H_8		0.0	0.0	0.0	0.0	0.0	0.0	2.90E-15	0.0	0.0	4.02E-04
ISOBU-01		0.0	0.0	0.0	0.0	0.0	0.0	2.47E-20	0.0	0.0	0.0
N-BUT-01		0.0	0.0	0.0	0.0	0.0	0.0	1.43E-17	0.0	0.0	3.49E-04
1-BUT-01		0.0	0.0	0.0	0.0	0.0	0.0	4.59E-17	0.0	0.0	1.08E-03
Naphtha		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8		0.0	0.0	0.0	0.0	0.0	0.0	2.96E-42	0.0	0.0	0.0

Description	CO_2 from MDEA	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract	LP Steam	CF Fuel Gas	Ni-DFB Fuel Gas
PFD Number	**35**	**36**	**37**	**38**	**39**	**40**	**41**	**42**
Temperature (F)	105.0	353.1	418.6	353.1	821.3	900.0	282.7	353.1
Pressure (psia)	25.0	317.0	317.0	317.0	236.5	55.0	14.7	317.0
Mass Flow (lb/hr)	1,000,419	51,222	1,976	334,918	228,306	104,544	173,392	31,753
Mole Flow (lbmol/hr)	22,733	3,317	105	21,686	7,912	5,803	9,280	2,056
Mole Fraction								
H_2O	0.0	0.0624	0.0781	0.0624	9.87E-03	1.0	0.0466	0.0624
Ar	0.0	0.0389	0.0487	0.0389	9.25E-03	0.0	0.0441	0.0389
CO_2	0.9999	0.0595	0.0745	0.0595	3.27E-04	0.0	0.0444	0.0595
O_2	0.0	6.13E-17	7.67E-17	6.13E-17	0.2074	0.0	4.57E-17	6.13E-17
N_2	7.75E-06	0.0290	0.0362	0.0290	0.7732	0.0	0.0718	0.0290
CO	6.41E-05	0.2956	0.3695	0.2956	0.0	0.0	0.4008	0.2956
COS	0.0	1.84E-13	2.31E-13	1.84E-13	0.0	0.0	2.78E-13	1.84E-13
H_2	8.88E-08	0.5136	0.3920	0.5136	0.0	0.0	0.3851	0.5136
H_2S	2.24E-10	2.39E-12	2.99E-12	2.39E-12	0.0	0.0	1.78E-12	2.39E-12
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	0.0	3.44E-05	4.30E-05	3.44E-05	0.0	0.0	2.56E-05	3.44E-05
SO_2	0.0	3.19E-18	3.99E-18	3.19E-18	0.0	0.0	2.38E-18	3.19E-18
CH_4	3.67E-05	8.00E-04	1.00E-03	8.00E-04	0.0	0.0	7.21E-03	8.00E-04
C_2H_4	0.0	3.07E-08	3.84E-08	3.07E-08	0.0	0.0	3.56E-07	3.07E-08
C_2H_6	0.0	5.59E-09	6.99E-09	5.59E-09	0.0	0.0	1.49E-07	5.59E-09
C_3H_6	0.0	3.65E-12	4.56E-12	3.65E-12	0.0	0.0	5.61E-10	3.65E-12
C_3H_8	0.0	1.22E-13	1.53E-13	1.31E-13	0.0	0.0	9.99E-10	1.22E-13
ISOBU-01	0.0	1.04E-18	1.30E-18	1.04E-18	0.0	0.0	7.75E-19	1.04E-18
N-BUT-01	0.0	6.02E-16	7.53E-16	9.46E-15	0.0	0.0	5.05E-12	6.02E-16
1-BUT-01	0.0	1.94E-15	2.42E-15	1.94E-15	0.0	0.0	6.05E-13	1.94E-15
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	1.25E-40	1.56E-40	1.25E-40	0.0	0.0	9.30E-41	1.25E-40

2.6 Scenario 15: CBTL, 11.7 Percent Biomass, Pellets, Model and Validation; Scenario 16: CBTL, 19.2 Percent Biomass, Pellets, Model and Validation; and Scenario 17: CBTL, 28.3 Percent Biomass, Pellets, Model and Validation

The overall configuration for these scenarios is very similar to the CBTL and raw biomass scenarios (Scenarios 2, 3, 7, 9, 10, 11). The only difference is that the biomass is delivered to the plant in the form of pellets instead of raw biomass chips. As shown in **Figure 2-5** the biomass pellets no longer need to be dried prior to grinding. The average moisture content of the pellets is 6.26 percent, much lower than the moisture content required for feeding to the gasifier. The pellets must be reduced in size to an average particle size of between about 0.4 and 0.8 mm (400-800 microns). This is accomplished in separate hammer mills from the coal milling machines. Such fine grinding of pelletized biomass is energy intensive but significantly less than what is required to grind green biomass.

The milled coal is dried to 18 percent moisture and mixed with the finely ground biomass before entering the lock hopper feeding system of the TRIG gasifiers. The mixture is then injected into the gasifiers just above the gasifier mixing zone. The coal and biomass react with the steam and oxygen to produce raw synthesis gas.

Like previous scenarios, the raw syngas is cleaned and sent to the F-T reactors. All other downstream processes are the same as well.

The stream table results are shown in **Table 2-22** for Scenario 15, **Table 2-24** for Scenario 16, and **Table 2-26** for Scenario 17 for the results from the original Aspen Plus® model. Analogous stream results are also shown in **Table 2-23**, **Table 2-25**, and **Table 2-27** for these three scenarios, respectively, using the Aspen Plus® model validated by experimental data. As with the coal only scenario, the deviation between the modeled and validated stream results is small and insignificant.

Figure 2-5: Scenarios 9, 10 and 11 Plant Configuration: CBTL, 11.7%, 19.2% and 28.3% Biomass Pellet Plant Configurations

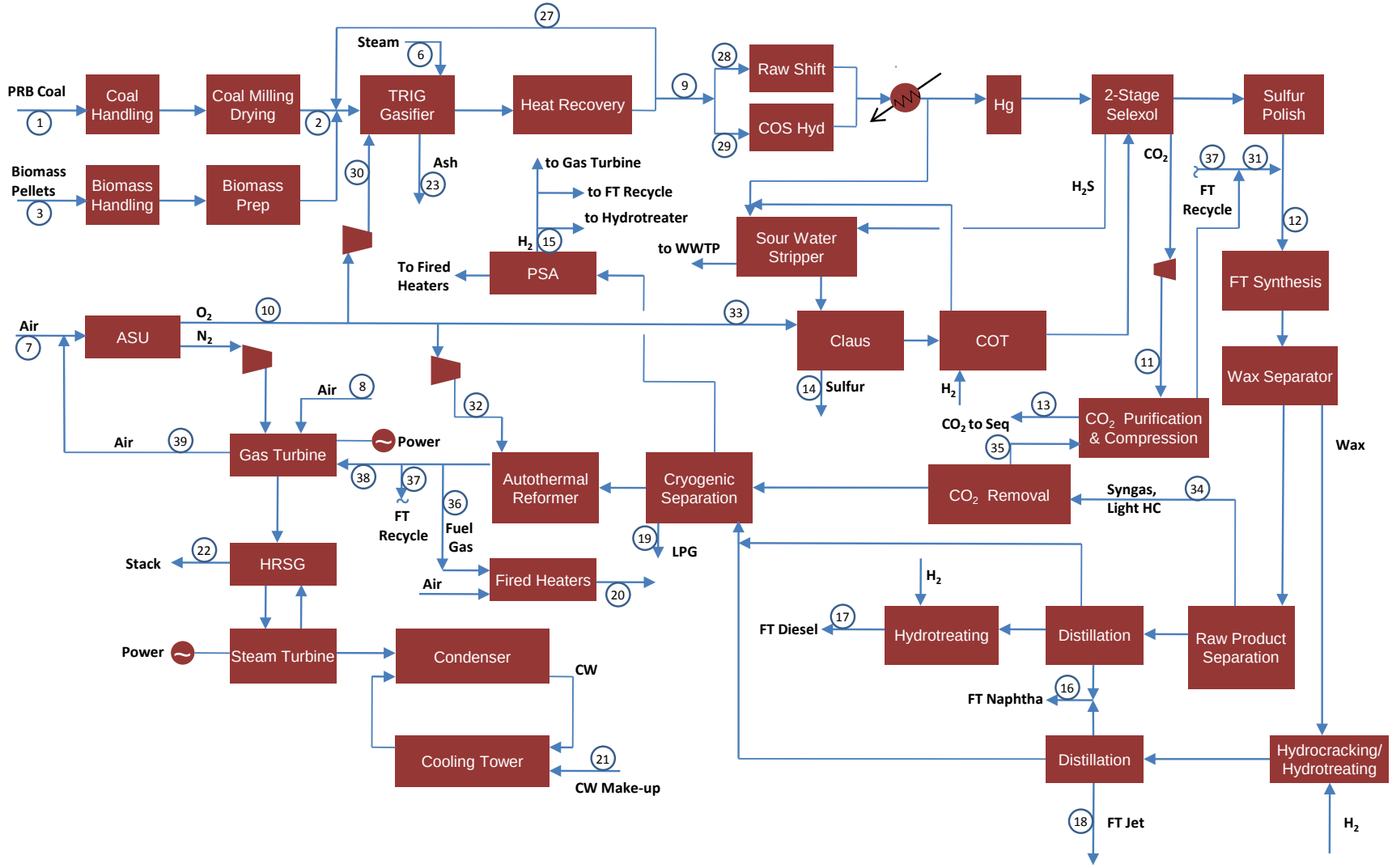


Table 2-22: CBTL, 11.7% Biomass, Pellets, Modeled: Stream Values

Description	Coal	Dried Coal	Pelletized Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.
PFD Number	**1**	**2**	**3**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Temperature (F)	59.0	220.0	59.0	489.4	59.0	59.0	500.0	90.0	100.0	261.5	100.0
Pressure (psia)	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7
Mass Flow (lb/hr)	2,274,829	2,059,275	272,860	437,646	6,514,414	3,531,600	3,943,531	1,542,714	1,651,778	2,423,018	2,571,454
Mole Flow (lbmol/hr)				24,293	225,748	122,383	190,832	47,939	40,076	154,572	58,650
Mole Fraction											
H_2O				1.0	9.87E-03	9.87E-03	0.1372	0.0	1.42E-03	6.68E-03	0.0
Ar				0.0	9.25E-03	9.25E-03	7.23E-03	0.0318	0.0	0.0161	0.0
CO_2				0.0	3.27E-04	3.27E-04	0.1264	0.0	0.8885	0.0213	0.9925
O_2				0.0	0.2074	0.2074	0.0	0.9504	0.0	7.48E-18	0.0
N_2				0.0	0.7732	0.7732	5.32E-03	0.0178	4.75E-04	0.0132	6.19E-05
CO				0.0	0.0	0.0	0.3996	0.0	0.0681	0.4389	4.87E-03
COS				0.0	0.0	0.0	6.67E-05	0.0	4.76E-07	8.26E-08	3.24E-07
H_2				0.0	0.0	0.0	0.3018	0.0	0.0357	0.4828	1.16E-03
H_2S				0.0	0.0	0.0	1.30E-03	0.0	0.0	3.27E-11	8.33E-11
HCl				0.0	0.0	0.0	2.50E-05	0.0	0.0	0.0	0.0
NH_3				0.0	0.0	0.0	3.53E-03	0.0	0.0	3.91E-06	0.0
SO_2				0.0	0.0	0.0	0.0	0.0	0.0	3.73E-19	0.0
CH_4				0.0	0.0	0.0	0.0174	0.0	5.79E-03	0.0210	1.37E-03
C_2H_4				0.0	0.0	0.0	0.0	0.0	0.0	2.17E-09	0.0
C_2H_6				0.0	0.0	0.0	0.0	0.0	0.0	3.66E-10	0.0
C_3H_6				0.0	0.0	0.0	0.0	0.0	0.0	2.09E-13	0.0
C_3H_8				0.0	0.0	0.0	0.0	0.0	0.0	6.52E-15	0.0
ISOBU-01				0.0	0.0	0.0	0.0	0.0	0.0	4.45E-20	0.0
N-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	6.01E-17	0.0
1-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	1.90E-16	0.0
Naphtha				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8				0.0	0.0	0.0	0.0	0.0	0.0	1.76E-42	0.0

Description	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle
PFD Number	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	292.9
Pressure (psia)	14.7	317.0	14.7	14.7	14.7	227.1	14.7	14.7	14.7	14.7	477.0
Mass Flow (lb/hr)	8,335	39,509	175,107	53,580	273,562	31,236	256,027	4,957,503	4,254,063	223,251	207,557
Mole Flow (lbmol/hr)	32	19,279	1,657	252	1,288	640	8,177	275,183	150,209		10,044
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0611	1.0	0.0977		0.1372
Ar	0.0	1.22E-04	0.0	0.0	0.0	1.99E-05	0.0389	0.0	0.0155		7.23E-03
CO_2	0.0	8.62E-09	0.0	0.0	0.0	0.0600	0.2088	0.0	0.0439		0.1264
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0263	0.0	0.0994		0.0
N_2	0.0	3.23E-04	0.0	0.0	0.0	7.48E-07	0.6649	0.0	0.7434		5.32E-03
CO	0.0	7.86E-04	0.0	0.0	0.0	7.88E-06	0.0	0.0	0.0		0.3996
COS	0.0	0.0	0.0	0.0	0.0	2.00E-05	1.58E-13	0.0	0.0		6.67E-05
H_2	0.0	0.9988	0.0	0.0	0.0	1.40E-09	0.0	0.0	0.0		0.3018
H_2S	0.0	0.0	0.0	0.0	0.0	1.38E-10	0.0	0.0	0.0		1.30E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.50E-05
NH_3	0.0	0.0	0.0	0.0	0.0	9.44E-04	1.96E-06	0.0	4.73E-06		3.53E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	1.15E-13	0.0	3.00E-13		0.0
CH_4	0.0	0.0	0.0	0.0	0.0	3.94E-04	0.0	0.0	0.0		0.0174
C_2H_4	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0		0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0		0.0
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.3372	0.0	0.0	0.0		0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.3323	0.0	0.0	0.0		0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0		0.0
Naphtha	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
F-T-Jet	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0
F-T-Diesel	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0
S_8	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0

Description	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA
PFD Number	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**
Temperature (F)	500.0	500.0	268.0	361.3	318.1	90.0	100.0	105.0
Pressure (psia)	477.0	477.0	665.0	379.0	360.0	125.0	369.0	25.0
Mass Flow (lb/hr)	2,115,667	1,827,864	1,397,001	382,540	112,400	33,313	1,607,559	1,041,688
Mole Flow (lbmol/hr)	102,379	88,452	43,411	18,229	3,493	1,035	61,213	23,671
Mole Fraction								
H_2O	0.1372	0.1372	0.0	0.0563	0.0	0.0	0.0	0.0
Ar	7.23E-03	7.23E-03	0.0318	0.0588	0.0318	0.0318	0.0406	0.0
CO_2	0.1264	0.1264	0.0	0.1122	0.0	0.0	0.4180	0.9999
O_2	0.0	0.0	0.9504	6.34E-17	0.9504	0.9504	0.0	0.0
N_2	5.32E-03	5.32E-03	0.0178	0.0377	0.0178	0.0178	0.0333	1.09E-05
CO	0.3996	0.3996	0.0	0.3854	0.0	0.0	0.1273	6.04E-05
COS	6.67E-05	6.67E-05	0.0	2.92E-09	0.0	0.0	2.09E-07	0.0
H_2	0.3018	0.3018	0.0	0.3406	0.0	0.0	0.3198	8.52E-08
H_2S	1.30E-03	1.30E-03	0.0	1.95E-12	0.0	0.0	8.26E-11	2.06E-10
HCl	2.50E-05	2.50E-05	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	3.53E-03	3.53E-03	0.0	3.31E-05	0.0	0.0	9.86E-06	0.0
SO_2	0.0	0.0	0.0	3.17E-18	0.0	0.0	0.0	0.0
CH_4	0.0174	0.0174	0.0	8.90E-03	0.0	0.0	0.0562	3.57E-05
C_2H_4	0.0	0.0	0.0	1.84E-08	0.0	0.0	1.41E-03	0.0
C_2H_6	0.0	0.0	0.0	3.11E-09	0.0	0.0	4.38E-04	0.0
C_3H_6	0.0	0.0	0.0	1.77E-12	0.0	0.0	1.21E-03	0.0
C_3H_8	0.0	0.0	0.0	5.53E-14	0.0	0.0	3.85E-04	0.0
ISOBU-01	0.0	0.0	0.0	3.78E-19	0.0	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	5.10E-16	0.0	0.0	3.34E-04	0.0
1-BUT-01	0.0	0.0	0.0	1.61E-15	0.0	0.0	1.04E-03	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	1.49E-41	0.0	0.0	0.0	0.0

Description	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	36	37	38	39
Temperature (F)	323.6	424.2	323.6	821.7
Pressure (psia)	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	7,261	261,555	321,487	218,639
Mole Flow (lbmol/hr)	500	13,189	22,138	7,577
Mole Fraction				
H_2O	0.0546	0.0778	0.0546	9.87E-03
Ar	0.0571	0.0813	0.0571	9.25E-03
CO_2	0.0521	0.0743	0.0521	3.27E-04
O_2	6.15E-17	8.76E-17	6.15E-17	0.2074
N_2	0.0359	0.0510	0.0359	0.7732
CO	0.2439	0.3473	0.2439	0.0
COS	1.46E-13	2.08E-13	1.46E-13	0.0
H_2	0.5559	0.3674	0.5559	0.0
H_2S	1.89E-12	2.69E-12	1.89E-12	0.0
HCl	0.0	0.0	0.0	0.0
NH_3	3.21E-05	4.58E-05	3.21E-05	0.0
SO_2	3.07E-18	4.38E-18	3.07E-18	0.0
CH_4	5.33E-04	7.60E-04	5.33E-04	0.0
C_2H_4	1.79E-08	2.55E-08	1.79E-08	0.0
C_2H_6	3.01E-09	4.29E-09	3.01E-09	0.0
C_3H_6	1.72E-12	2.45E-12	1.72E-12	0.0
C_3H_8	5.36E-14	7.64E-14	6.22E-14	0.0
ISOBU-01	3.66E-19	5.22E-19	3.66E-19	0.0
N-BUT-01	4.94E-16	7.05E-16	9.17E-15	0.0
1-BUT-01	1.56E-15	2.22E-15	1.56E-15	0.0
Naphtha	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0
S_8	1.45E-41	2.07E-41	1.45E-41	0.0

Table 2-23: CBTL, 11.7% Biomass, Pellets, Validated: Stream Values

Description	Coal	Dried Coal	Pelletized Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.
PFD Number	**1**	**2**	**3**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Temperature (F)	59.0	220.0	59.0	489.4	59.0	59.0	500.0	90.0	100.0	263.9	100.0
Pressure (psia)	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7
Mass Flow (lb/hr)	2,279,091	2,063,133	273,371	438,466	6,547,394	3,531,600	3,946,973	1,550,042	1,662,852	2,440,764	2,586,123
Mole Flow (lbmol/hr)				24,339	226,891	122,383	190,418	48,167	40,327	155,325	58,990
Mole Fraction											
H_2O				1.0	9.87E-03	9.87E-03	0.1440	0.0	1.41E-03	7.44E-03	0.0
Ar				0.0	9.25E-03	9.25E-03	7.24E-03	0.0318	0.0	0.0168	0.0
CO_2				0.0	3.27E-04	3.27E-04	0.1215	0.0	0.8893	0.0216	0.9924
O_2				0.0	0.2074	0.2074	0.0	0.9504	0.0	7.62E-18	0.0
N_2				0.0	0.7732	0.7732	5.33E-03	0.0178	4.72E-04	0.0136	6.21E-05
CO				0.0	0.0	0.0	0.4047	0.0	0.0672	0.4368	4.85E-03
COS				0.0	0.0	0.0	6.15E-05	0.0	4.36E-07	7.57E-08	2.97E-07
H_2				0.0	0.0	0.0	0.2928	0.0	0.0352	0.4805	1.15E-03
H_2S				0.0	0.0	0.0	1.31E-03	0.0	0.0	3.26E-11	8.30E-11
HCl				0.0	0.0	0.0	2.51E-05	0.0	0.0	0.0	0.0
NH_3				0.0	0.0	0.0	3.54E-03	0.0	0.0	4.64E-06	0.0
SO_2				0.0	0.0	0.0	0.0	0.0	0.0	3.46E-19	0.0
CH_4				0.0	0.0	0.0	0.0195	0.0	6.42E-03	0.0233	1.53E-03
C_2H_4				0.0	0.0	0.0	0.0	0.0	0.0	2.80E-09	0.0
C_2H_6				0.0	0.0	0.0	0.0	0.0	0.0	4.94E-10	0.0
C_3H_6				0.0	0.0	0.0	0.0	0.0	0.0	2.90E-13	0.0
C_3H_8				0.0	0.0	0.0	0.0	0.0	0.0	9.44E-15	0.0
ISOBU-01				0.0	0.0	0.0	0.0	0.0	0.0	6.97E-20	0.0
N-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	6.33E-17	0.0
1-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	2.01E-16	0.0
Naphtha				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8				0.0	0.0	0.0	0.0	0.0	0.0	2.49E-42	0.0

Description	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle
PFD Number	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	296.1
Pressure (psia)	14.7	317.0	14.7	14.7	14.7	227.4	14.7	14.7	14.7	14.7	477.0
Mass Flow (lb/hr)	8,351	39,506	175,103	53,579	273,555	31,243	251,669	4,986,689	4,252,539	223,669	207,738
Mole Flow (lbmol/hr)	33	19,283	1,657	252	1,288	640	8,050	276,803	150,224		10,022
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0628	1.0	0.0980		0.1440
Ar	0.0	1.23E-04	0.0	0.0	0.0	2.10E-05	0.0398	0.0	0.0155		7.24E-03
CO_2	0.0	8.58E-09	0.0	0.0	0.0	0.0602	0.2060	0.0	0.0433		0.1215
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0262	0.0	0.0995		0.0
N_2	0.0	3.24E-04	0.0	0.0	0.0	7.85E-07	0.6651	0.0	0.7437		5.33E-03
CO	0.0	7.60E-04	0.0	0.0	0.0	7.91E-06	0.0	0.0	0.0		0.4047
COS	0.0	0.0	0.0	0.0	0.0	1.84E-05	1.45E-13	0.0	0.0		6.15E-05
H_2	0.0	0.9988	0.0	0.0	0.0	1.47E-09	0.0	0.0	0.0		0.2928
H_2S	0.0	0.0	0.0	0.0	0.0	1.38E-10	0.0	0.0	0.0		1.31E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.51E-05
NH_3	0.0	0.0	0.0	0.0	0.0	1.13E-03	2.15E-06	0.0	5.09E-06		3.54E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	1.13E-13	0.0	2.86E-13		0.0
CH_4	0.0	0.0	0.0	0.0	0.0	4.35E-04	0.0	0.0	0.0		0.0195
C_2H_4	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0		0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0		0.0
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.3370	0.0	0.0	0.0		0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.3322	0.0	0.0	0.0		0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0		0.0
Naphtha	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
F-T-Jet	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0
F-T-Diesel	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0
S_8	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0

Description	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA
PFD Number	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**
Temperature (F)	500.0	500.0	268.0	371.9	318.1	90.0	100.0	105.0
Pressure (psia)	477.0	477.0	665.0	379.0	360.0	125.0	369.0	25.0
Mass Flow (lb/hr)	2,233,613	1,713,361	1,395,672	407,529	120,825	33,545	1,623,449	1,044,822
Mole Flow (lbmol/hr)	107,758	82,659	43,370	19,615	3,755	1,042	61,865	23,742
Mole Fraction								
H_2O	0.1440	0.1440	0.0	0.0586	0.0	0.0	0.0	0.0
Ar	7.24E-03	7.24E-03	0.0318	0.0608	0.0318	0.0318	0.0421	0.0
CO_2	0.1215	0.1215	0.0	0.1068	0.0	0.0	0.4148	0.9999
O_2	0.0	0.0	0.9504	6.03E-17	0.9504	0.9504	0.0	0.0
N_2	5.33E-03	5.33E-03	0.0178	0.0389	0.0178	0.0178	0.0342	1.12E-05
CO	0.4047	0.4047	0.0	0.3805	0.0	0.0	0.1257	6.00E-05
COS	6.15E-05	6.15E-05	0.0	2.47E-09	0.0	0.0	1.90E-07	0.0
H_2	0.2928	0.2928	0.0	0.3451	0.0	0.0	0.3167	8.50E-08
H_2S	1.31E-03	1.31E-03	0.0	1.92E-12	0.0	0.0	8.19E-11	2.06E-10
HCl	2.51E-05	2.51E-05	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	3.54E-03	3.54E-03	0.0	3.67E-05	0.0	0.0	1.16E-05	0.0
SO_2	0.0	0.0	0.0	2.74E-18	0.0	0.0	0.0	0.0
CH_4	0.0195	0.0195	0.0	9.28E-03	0.0	0.0	0.0618	3.95E-05
C_2H_4	0.0	0.0	0.0	2.22E-08	0.0	0.0	1.39E-03	0.0
C_2H_6	0.0	0.0	0.0	3.91E-09	0.0	0.0	4.33E-04	0.0
C_3H_6	0.0	0.0	0.0	2.29E-12	0.0	0.0	1.20E-03	0.0
C_3H_8	0.0	0.0	0.0	7.48E-14	0.0	0.0	3.81E-04	0.0
ISOBU-01	0.0	0.0	0.0	5.52E-19	0.0	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	5.01E-16	0.0	0.0	3.30E-04	0.0
1-BUT-01	0.0	0.0	0.0	1.59E-15	0.0	0.0	1.03E-03	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	1.97E-41	0.0	0.0	0.0	0.0

Description	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	36	37	38	39
Temperature (F)	325.9	427.3	325.9	821.7
Pressure (psia)	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	7,205	287,003	318,366	217,644
Mole Flow (lbmol/hr)	500	14,594	22,094	7,542
Mole Fraction				
H_2O	0.0553	0.0788	0.0553	9.87E-03
Ar	0.0574	0.0817	0.0574	9.25E-03
CO_2	0.0496	0.0708	0.0496	3.27E-04
O_2	5.69E-17	8.11E-17	5.69E-17	0.2074
N_2	0.0360	0.0512	0.0360	0.7732
CO	0.2425	0.3453	0.2425	0.0
COS	1.32E-13	1.88E-13	1.32E-13	0.0
H_2	0.5586	0.3714	0.5586	0.0
H_2S	1.81E-12	2.59E-12	1.81E-12	0.0
HCl	0.0	0.0	0.0	0.0
NH_3	3.46E-05	4.94E-05	3.46E-05	0.0
SO_2	2.59E-18	3.68E-18	2.59E-18	0.0
CH_4	6.07E-04	8.65E-04	6.07E-04	0.0
C_2H_4	2.09E-08	2.98E-08	2.09E-08	0.0
C_2H_6	3.69E-09	5.26E-09	3.69E-09	0.0
C_3H_6	2.16E-12	3.08E-12	2.16E-12	0.0
C_3H_8	7.05E-14	1.01E-13	7.92E-14	0.0
ISOBU-01	5.21E-19	7.42E-19	5.21E-19	0.0
N-BUT-01	4.72E-16	6.73E-16	9.17E-15	0.0
1-BUT-01	1.50E-15	2.14E-15	1.50E-15	0.0
Naphtha	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0
S_8	1.86E-41	2.65E-41	1.86E-41	0.0

Table 2-24: CBTL, 19.2% Biomass, Pellets, Modeled: Stream Values

Description	Coal	Dried Coal	Pelletized Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.
PFD Number	**1**	**2**	**3**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Temperature (F)	59.0	220.0	59.0	489.4	59.0	59.0	500.0	90.0	100.0	261.6	100.0
Pressure (psia)	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7
Mass Flow (lb/hr)	2,100,652	1,901,603	451,866	404,137	6,437,144	3,531,600	3,927,125	1,524,922	1,650,472	2,421,205	2,570,384
Mole Flow (lbmol/hr)				22,433	223,071	122,383	189,986	47,386	40,046	154,534	58,626
Mole Fraction											
H_2O				1.0	9.87E-03	9.87E-03	0.1356	0.0	1.42E-03	6.75E-03	0.0
Ar				0.0	9.25E-03	9.25E-03	7.18E-03	0.0318	0.0	0.0160	0.0
CO_2				0.0	3.27E-04	3.27E-04	0.1258	0.0	0.8885	0.0214	0.9925
O_2				0.0	0.2074	0.2074	0.0	0.9504	0.0	7.43E-18	0.0
N_2				0.0	0.7732	0.7732	5.20E-03	0.0178	4.57E-04	0.0127	5.95E-05
CO				0.0	0.0	0.0	0.4022	0.0	0.0681	0.4390	4.86E-03
COS				0.0	0.0	0.0	6.27E-05	0.0	4.46E-07	7.74E-08	3.04E-07
H_2				0.0	0.0	0.0	0.3018	0.0	0.0357	0.4829	1.16E-03
H_2S				0.0	0.0	0.0	1.21E-03	0.0	0.0	3.04E-11	7.75E-11
HCl				0.0	0.0	0.0	2.32E-05	0.0	0.0	0.0	0.0
NH_3				0.0	0.0	0.0	3.28E-03	0.0	0.0	3.93E-06	0.0
SO_2				0.0	0.0	0.0	0.0	0.0	0.0	3.41E-19	0.0
CH_4				0.0	0.0	0.0	0.0177	0.0	5.87E-03	0.0212	1.39E-03
C_2H_4				0.0	0.0	0.0	0.0	0.0	0.0	2.28E-09	0.0
C_2H_6				0.0	0.0	0.0	0.0	0.0	0.0	3.89E-10	0.0
C_3H_6				0.0	0.0	0.0	0.0	0.0	0.0	2.24E-13	0.0
C_3H_8				0.0	0.0	0.0	0.0	0.0	0.0	7.05E-15	0.0
ISOBU-01				0.0	0.0	0.0	0.0	0.0	0.0	4.92E-20	0.0
N-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	6.05E-17	0.0
1-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	1.91E-16	0.0
Naphtha				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8				0.0	0.0	0.0	0.0	0.0	0.0	1.87E-42	0.0

Description	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle
PFD Number	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	292.1
Pressure (psia)	14.7	317.0	14.7	14.7	14.7	227.1	14.7	14.7	14.7	14.7	477.0
Mass Flow (lb/hr)	7,753	39,509	175,105	53,579	273,559	31,236	255,937	4,959,000	4,253,983	210,512	206,691
Mole Flow (lbmol/hr)	30	19,282	1,657	252	1,288	640	8,173	275,266	150,223		9,999
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0614	1.0	0.0977		0.1356
Ar	0.0	1.21E-04	0.0	0.0	0.0	1.98E-05	0.0388	0.0	0.0154		7.18E-03
CO_2	0.0	8.62E-09	0.0	0.0	0.0	0.0600	0.2093	0.0	0.0438		0.1258
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0263	0.0	0.0995		0.0
N_2	0.0	3.12E-04	0.0	0.0	0.0	7.20E-07	0.6642	0.0	0.7436		5.20E-03
CO	0.0	7.87E-04	0.0	0.0	0.0	7.87E-06	0.0	0.0	0.0		0.4022
COS	0.0	0.0	0.0	0.0	0.0	1.87E-05	1.47E-13	0.0	0.0		6.27E-05
H_2	0.0	0.9988	0.0	0.0	0.0	1.40E-09	0.0	0.0	0.0		0.3018
H_2S	0.0	0.0	0.0	0.0	0.0	1.29E-10	0.0	0.0	0.0		1.21E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.32E-05
NH_3	0.0	0.0	0.0	0.0	0.0	9.49E-04	1.96E-06	0.0	4.70E-06		3.28E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	1.07E-13	0.0	2.77E-13		0.0
CH_4	0.0	0.0	0.0	0.0	0.0	3.98E-04	0.0	0.0	0.0		0.0177
C_2H_4	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0		0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0		0.0
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.3371	0.0	0.0	0.0		0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.3323	0.0	0.0	0.0		0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0		0.0
Naphtha	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
F-T-Jet	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0
F-T-Diesel	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0
S_8	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0

Description	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA
PFD Number	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**
Temperature (F)	500.0	500.0	268.0	362.1	318.1	90.0	100.0	105.0
Pressure (psia)	477.0	477.0	665.0	379.0	360.0	125.0	369.0	25.0
Mass Flow (lb/hr)	2,169,906	1,757,220	1,380,032	383,820	113,142	31,748	1,605,609	1,041,863
Mole Flow (lbmol/hr)	104,975	85,011	42,884	18,338	3,516	987	61,169	23,675
Mole Fraction								
H_2O	0.1356	0.1356	0.0	0.0566	0.0	0.0	0.0	0.0
Ar	7.18E-03	7.18E-03	0.0318	0.0585	0.0318	0.0318	0.0403	0.0
CO_2	0.1258	0.1258	0.0	0.1117	0.0	0.0	0.4184	0.9999
O_2	0.0	0.0	0.9504	6.26E-17	0.9504	0.9504	0.0	0.0
N_2	5.20E-03	5.20E-03	0.0178	0.0364	0.0178	0.0178	0.0322	1.05E-05
CO	0.4022	0.4022	0.0	0.3858	0.0	0.0	0.1273	6.03E-05
COS	6.27E-05	6.27E-05	0.0	2.72E-09	0.0	0.0	1.95E-07	0.0
H_2	0.3018	0.3018	0.0	0.3420	0.0	0.0	0.3200	8.52E-08
H_2S	1.21E-03	1.21E-03	0.0	1.81E-12	0.0	0.0	7.69E-11	1.92E-10
HCl	2.32E-05	2.32E-05	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	3.28E-03	3.28E-03	0.0	3.31E-05	0.0	0.0	9.92E-06	0.0
SO_2	0.0	0.0	0.0	2.87E-18	0.0	0.0	0.0	0.0
CH_4	0.0177	0.0177	0.0	8.98E-03	0.0	0.0	0.0569	3.61E-05
C_2H_4	0.0	0.0	0.0	1.92E-08	0.0	0.0	1.41E-03	0.0
C_2H_6	0.0	0.0	0.0	3.27E-09	0.0	0.0	4.38E-04	0.0
C_3H_6	0.0	0.0	0.0	1.88E-12	0.0	0.0	1.21E-03	0.0
C_3H_8	0.0	0.0	0.0	5.94E-14	0.0	0.0	3.85E-04	0.0
ISOBU-01	0.0	0.0	0.0	4.14E-19	0.0	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	5.10E-16	0.0	0.0	3.34E-04	0.0
1-BUT-01	0.0	0.0	0.0	1.61E-15	0.0	0.0	1.04E-03	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	1.58E-41	0.0	0.0	0.0	0.0

Description	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	36	37	38	39
Temperature (F)	323.5	424.3	323.5	821.7
Pressure (psia)	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	7,232	262,895	319,338	218,259
Mole Flow (lbmol/hr)	500	13,300	22,080	7,563
Mole Fraction				
H_2O	0.0547	0.0780	0.0547	9.87E-03
Ar	0.0565	0.0806	0.0565	9.25E-03
CO_2	0.0518	0.0739	0.0518	3.27E-04
O_2	6.05E-17	8.63E-17	6.05E-17	0.2074
N_2	0.0345	0.0491	0.0345	0.7732
CO	0.2442	0.3482	0.2442	0.0
COS	1.34E-13	1.92E-13	1.34E-13	0.0
H_2	0.5577	0.3693	0.5577	0.0
H_2S	1.75E-12	2.50E-12	1.75E-12	0.0
HCl	0.0	0.0	0.0	0.0
NH_3	3.20E-05	4.56E-05	3.20E-05	0.0
SO_2	2.78E-18	3.96E-18	2.78E-18	0.0
CH_4	5.49E-04	7.84E-04	5.49E-04	0.0
C_2H_4	1.86E-08	2.65E-08	1.86E-08	0.0
C_2H_6	3.16E-09	4.51E-09	3.16E-09	0.0
C_3H_6	1.82E-12	2.60E-12	1.82E-12	0.0
C_3H_8	5.74E-14	8.19E-14	6.61E-14	0.0
ISOBU-01	4.00E-19	5.71E-19	4.00E-19	0.0
N-BUT-01	4.93E-16	7.03E-16	9.19E-15	0.0
1-BUT-01	1.56E-15	2.22E-15	1.56E-15	0.0
Naphtha	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0
S_8	1.52E-41	2.17E-41	1.52E-41	0.0

Table 2-25: CBTL, 19.2% Biomass, Pellets, Validated: Stream Values

Description	Coal	Dried Coal	Pelletized Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.
PFD Number	**1**	**2**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Temperature (F)	59.0	220.0	59.0	489.4	59.0	59.0	500.0	90.0	100.0	264.1	100.0
Pressure (psia)	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7
Mass Flow (lb/hr)	2,104,573	1,905,151	452,709	404,891	6,469,733	3,531,600	3,930,428	1,532,186	1,661,605	2,438,902	2,585,065
Mole Flow (lbmol/hr)				22,475	224,200	122,383	189,562	47,612	40,298	155,291	58,966
Mole Fraction											
H_2O				1.0	9.87E-03	9.87E-03	0.1424	0.0	1.41E-03	7.52E-03	0.0
Ar				0.0	9.25E-03	9.25E-03	7.19E-03	0.0318	0.0	0.0167	0.0
CO_2				0.0	3.27E-04	3.27E-04	0.1209	0.0	0.8893	0.0216	0.9924
O_2				0.0	0.2074	0.2074	0.0	0.9504	0.0	7.57E-18	0.0
N_2				0.0	0.7732	0.7732	5.21E-03	0.0178	4.54E-04	0.0131	5.97E-05
CO				0.0	0.0	0.0	0.4072	0.0	0.0672	0.4369	4.84E-03
COS				0.0	0.0	0.0	5.79E-05	0.0	4.08E-07	7.09E-08	2.78E-07
H_2				0.0	0.0	0.0	0.2927	0.0	0.0351	0.4806	1.15E-03
H_2S				0.0	0.0	0.0	1.22E-03	0.0	0.0	3.04E-11	7.72E-11
HCl				0.0	0.0	0.0	2.32E-05	0.0	0.0	0.0	0.0
NH_3				0.0	0.0	0.0	3.30E-03	0.0	0.0	4.66E-06	0.0
SO_2				0.0	0.0	0.0	0.0	0.0	0.0	3.16E-19	0.0
CH_4				0.0	0.0	0.0	0.0198	0.0	6.51E-03	0.0236	1.55E-03
C_2H_4				0.0	0.0	0.0	0.0	0.0	0.0	2.94E-09	0.0
C_2H_6				0.0	0.0	0.0	0.0	0.0	0.0	5.24E-10	0.0
C_3H_6				0.0	0.0	0.0	0.0	0.0	0.0	3.10E-13	0.0
C_3H_8				0.0	0.0	0.0	0.0	0.0	0.0	1.02E-14	0.0
ISOBU-01				0.0	0.0	0.0	0.0	0.0	0.0	7.68E-20	0.0
N-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	6.37E-17	0.0
1-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	2.03E-16	0.0
Naphtha				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8				0.0	0.0	0.0	0.0	0.0	0.0	2.49E-42	0.0

Description	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle
PFD Number	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	295.3
Pressure (psia)	14.7	317.0	14.7	14.7	14.7	227.5	14.7	14.7	14.7	14.7	477.0
Mass Flow (lb/hr)	7,768	39,509	175,103	53,579	273,555	31,243	251,565	4,988,078	4,252,252	210,905	206,865
Mole Flow (lbmol/hr)	30	19,287	1,657	252	1,288	640	8,047	276,880	150,232		9,977
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0631	1.0	0.0980		0.1424
Ar	0.0	1.23E-04	0.0	0.0	0.0	2.08E-05	0.0397	0.0	0.0154		7.19E-03
CO_2	0.0	8.58E-09	0.0	0.0	0.0	0.0602	0.2065	0.0	0.0432		0.1209
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0263	0.0	0.0995		0.0
N_2	0.0	3.14E-04	0.0	0.0	0.0	7.57E-07	0.6645	0.0	0.7439		5.21E-03
CO	0.0	7.61E-04	0.0	0.0	0.0	7.91E-06	0.0	0.0	0.0		0.4073
COS	0.0	0.0	0.0	0.0	0.0	1.72E-05	1.35E-13	0.0	0.0		5.79E-05
H_2	0.0	0.9988	0.0	0.0	0.0	1.46E-09	0.0	0.0	0.0		0.2927
H_2S	0.0	0.0	0.0	0.0	0.0	1.29E-10	0.0	0.0	0.0		1.22E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.32E-05
NH_3	0.0	0.0	0.0	0.0	0.0	1.13E-03	2.14E-06	0.0	5.05E-06		3.30E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	1.05E-13	0.0	2.65E-13		0.0
CH_4	0.0	0.0	0.0	0.0	0.0	4.40E-04	0.0	0.0	0.0		0.0198
C_2H_4	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0		0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0		0.0
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.3370	0.0	0.0	0.0		0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.3322	0.0	0.0	0.0		0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0		0.0
Naphtha	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
F-T-Jet	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0
F-T-Diesel	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0
S_8	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0

Description	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA
PFD Number	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**
Temperature (F)	500.0	500.0	268.0	372.7	318.1	90.0	100.0	105.0
Pressure (psia)	477.0	477.0	665.0	379.0	360.0	125.0	369.0	25.0
Mass Flow (lb/hr)	2,285,180	1,645,249	1,378,581	408,875	121,626	31,979	1,621,398	1,044,945
Mole Flow (lbmol/hr)	110,213	79,349	42,839	19,734	3,779	994	61,820	23,745
Mole Fraction								
H_2O	0.1424	0.1424	0.0	0.0589	0.0	0.0	0.0	0.0
Ar	7.19E-03	7.19E-03	0.0318	0.0604	0.0318	0.0318	0.0418	0.0
CO_2	0.1209	0.1209	0.0	0.1062	0.0	0.0	0.4152	0.9999
O_2	0.0	0.0	0.9504	5.96E-17	0.9504	0.9504	0.0	0.0
N_2	5.21E-03	5.21E-03	0.0178	0.0375	0.0178	0.0178	0.0330	1.08E-05
CO	0.4072	0.4072	0.0	0.3809	0.0	0.0	0.1257	6.00E-05
COS	5.79E-05	5.79E-05	0.0	2.30E-09	0.0	0.0	1.78E-07	0.0
H_2	0.2927	0.2927	0.0	0.3466	0.0	0.0	0.3170	8.50E-08
H_2S	1.22E-03	1.22E-03	0.0	1.79E-12	0.0	0.0	7.63E-11	1.92E-10
HCl	2.32E-05	2.32E-05	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	3.30E-03	3.30E-03	0.0	3.67E-05	0.0	0.0	1.17E-05	0.0
SO_2	0.0	0.0	0.0	2.49E-18	0.0	0.0	0.0	0.0
CH_4	0.0198	0.0198	0.0	9.36E-03	0.0	0.0	0.0625	4.00E-05
C_2H_4	0.0	0.0	0.0	2.31E-08	0.0	0.0	1.39E-03	0.0
C_2H_6	0.0	0.0	0.0	4.12E-09	0.0	0.0	4.34E-04	0.0
C_3H_6	0.0	0.0	0.0	2.44E-12	0.0	0.0	1.20E-03	0.0
C_3H_8	0.0	0.0	0.0	8.02E-14	0.0	0.0	3.81E-04	0.0
ISOBU-01	0.0	0.0	0.0	6.04E-19	0.0	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	5.01E-16	0.0	0.0	3.31E-04	0.0
1-BUT-01	0.0	0.0	0.0	1.60E-15	0.0	0.0	1.03E-03	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	1.96E-41	0.0	0.0	0.0	0.0

Description	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	36	37	38	39
Temperature (F)	325.7	427.4	325.7	821.7
Pressure (psia)	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	7,175	288,415	316,158	217,374
Mole Flow (lbmol/hr)	500	14,714	22,033	7,533
Mole Fraction				
H_2O	0.0553	0.0789	0.0553	9.87E-03
Ar	0.0568	0.0810	0.0568	9.25E-03
CO_2	0.0493	0.0704	0.0493	3.27E-04
O_2	5.60E-17	7.99E-17	5.60E-17	0.2074
N_2	0.0347	0.0493	0.0347	0.7732
CO	0.2428	0.3462	0.2428	0.0
COS	1.21E-13	1.73E-13	1.21E-13	0.0
H_2	0.5604	0.3732	0.5604	0.0
H_2S	1.68E-12	2.40E-12	1.68E-12	0.0
HCl	0.0	0.0	0.0	0.0
NH_3	3.45E-05	4.92E-05	3.45E-05	0.0
SO_2	2.34E-18	3.34E-18	2.34E-18	0.0
CH_4	6.24E-04	8.91E-04	6.24E-04	0.0
C_2H_4	2.17E-08	3.10E-08	2.17E-08	0.0
C_2H_6	3.87E-09	5.53E-09	3.87E-09	0.0
C_3H_6	2.29E-12	3.27E-12	2.29E-12	0.0
C_3H_8	7.54E-14	1.08E-13	8.41E-14	0.0
ISOBU-01	5.68E-19	8.11E-19	5.68E-19	0.0
N-BUT-01	4.71E-16	6.72E-16	9.19E-15	0.0
1-BUT-01	1.50E-15	2.14E-15	1.50E-15	0.0
Naphtha	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0
S_8	1.84E-41	2.62E-41	1.84E-41	0.0

Table 2-26: CBTL, 28.3% Biomass, Pellets, Modeled: Stream Values

Description	Coal	Dried Coal	Pelletized Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.
PFD Number	**1**	**2**	**3**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Temperature (F)	59.0	220.0	59.0	489.4	59.0	59.0	500.0	90.0	100.0	261.9	100.0
Pressure (psia)	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7
Mass Flow (lb/hr)	1,884,970	1,706,358	673,500	362,643	6,341,028	3,531,600	3,906,756	1,502,885	1,648,925	2,419,001	2,569,114
Mole Flow (lbmol/hr)				20,130	219,740	122,383	188,934	46,701	40,010	154,492	58,598
Mole Fraction											
H_2O				1.0	9.87E-03	9.87E-03	0.1336	0.0	1.42E-03	6.85E-03	0.0
Ar				0.0	9.25E-03	9.25E-03	7.11E-03	0.0318	0.0	0.0158	0.0
CO_2				0.0	3.27E-04	3.27E-04	0.1249	0.0	0.8884	0.0214	0.9925
O_2				0.0	0.2074	0.2074	0.0	0.9504	0.0	7.37E-18	0.0
N_2				0.0	0.7732	0.7732	5.05E-03	0.0178	4.34E-04	0.0122	5.65E-05
CO				0.0	0.0	0.0	0.4054	0.0	0.0681	0.4391	4.86E-03
COS				0.0	0.0	0.0	5.76E-05	0.0	4.08E-07	7.08E-08	2.78E-07
H_2				0.0	0.0	0.0	0.3016	0.0	0.0357	0.4831	1.16E-03
H_2S				0.0	0.0	0.0	1.11E-03	0.0	0.0	2.76E-11	7.03E-11
HCl				0.0	0.0	0.0	2.09E-05	0.0	0.0	0.0	0.0
NH_3				0.0	0.0	0.0	2.97E-03	0.0	0.0	3.95E-06	0.0
SO_2				0.0	0.0	0.0	0.0	0.0	0.0	3.03E-19	0.0
CH_4				0.0	0.0	0.0	0.0181	0.0	5.97E-03	0.0216	1.42E-03
C_2H_4				0.0	0.0	0.0	0.0	0.0	0.0	2.43E-09	0.0
C_2H_6				0.0	0.0	0.0	0.0	0.0	0.0	4.18E-10	0.0
C_3H_6				0.0	0.0	0.0	0.0	0.0	0.0	2.44E-13	0.0
C_3H_8				0.0	0.0	0.0	0.0	0.0	0.0	7.77E-15	0.0
ISOBU-01				0.0	0.0	0.0	0.0	0.0	0.0	5.56E-20	0.0
N-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	6.11E-17	0.0
1-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	1.94E-16	0.0
Naphtha				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8				0.0	0.0	0.0	0.0	0.0	0.0	2.66E-42	0.0

Description	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle
PFD Number	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	291.2
Pressure (psia)	14.7	317.0	14.7	14.7	14.7	227.2	14.7	14.7	14.7	14.7	477.0
Mass Flow (lb/hr)	7,032	39,512	175,105	53,579	273,558	31,237	255,811	4,957,495	4,253,254	194,737	205,619
Mole Flow (lbmol/hr)	27	19,286	1,657	252	1,288	640	8,168	275,183	150,219		9,944
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0618	1.0	0.0978		0.1336
Ar	0.0	1.20E-04	0.0	0.0	0.0	1.96E-05	0.0385	0.0	0.0153		7.11E-03
CO_2	0.0	8.62E-09	0.0	0.0	0.0	0.0600	0.2098	0.0	0.0437		0.1249
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0264	0.0	0.0995		0.0
N_2	0.0	2.99E-04	0.0	0.0	0.0	6.86E-07	0.6634	0.0	0.7438		5.05E-03
CO	0.0	7.89E-04	0.0	0.0	0.0	7.86E-06	0.0	0.0	0.0		0.4054
COS	0.0	0.0	0.0	0.0	0.0	1.71E-05	1.33E-13	0.0	0.0		5.76E-05
H_2	0.0	0.9988	0.0	0.0	0.0	1.39E-09	0.0	0.0	0.0		0.3016
H_2S	0.0	0.0	0.0	0.0	0.0	1.17E-10	0.0	0.0	0.0		1.11E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.09E-05
NH_3	0.0	0.0	0.0	0.0	0.0	9.54E-04	1.94E-06	0.0	4.65E-06		2.97E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	9.70E-14	0.0	2.50E-13		0.0
CH_4	0.0	0.0	0.0	0.0	0.0	4.04E-04	0.0	0.0	0.0		0.0181
C_2H_4	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0		0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0		0.0
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.3371	0.0	0.0	0.0		0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.3323	0.0	0.0	0.0		0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0		0.0
Naphtha	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
F-T-Jet	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0
F-T-Diesel	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0
S_8	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0

Description	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA
PFD Number	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**
Temperature (F)	500.0	500.0	268.0	363.1	318.1	90.0	100.0	105.0
Pressure (psia)	477.0	477.0	665.0	379.0	360.0	125.0	369.0	25.0
Mass Flow (lb/hr)	2,239,553	1,667,203	1,358,992	385,536	114,081	29,812	1,603,192	1,042,061
Mole Flow (lbmol/hr)	108,307	80,628	42,230	18,480	3,545	926	61,115	23,679
Mole Fraction								
H_2O	0.1336	0.1336	0.0	0.0570	0.0	0.0	0.0	0.0
Ar	7.11E-03	7.11E-03	0.0318	0.0580	0.0318	0.0318	0.0400	0.0
CO_2	0.1249	0.1249	0.0	0.1110	0.0	0.0	0.4188	0.9999
O_2	0.0	0.0	0.9504	6.16E-17	0.9504	0.9504	0.0	0.0
N_2	5.05E-03	5.05E-03	0.0178	0.0348	0.0178	0.0178	0.0307	1.00E-05
CO	0.4054	0.4054	0.0	0.3862	0.0	0.0	0.1274	6.03E-05
COS	5.76E-05	5.76E-05	0.0	2.47E-09	0.0	0.0	1.79E-07	0.0
H_2	0.3016	0.3016	0.0	0.3439	0.0	0.0	0.3203	8.52E-08
H_2S	1.11E-03	1.11E-03	0.0	1.65E-12	0.0	0.0	6.98E-11	1.74E-10
HCl	2.09E-05	2.09E-05	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	2.97E-03	2.97E-03	0.0	3.30E-05	0.0	0.0	9.98E-06	0.0
SO_2	0.0	0.0	0.0	2.53E-18	0.0	0.0	0.0	0.0
CH_4	0.0181	0.0181	0.0	9.07E-03	0.0	0.0	0.0579	3.67E-05
C_2H_4	0.0	0.0	0.0	2.03E-08	0.0	0.0	1.41E-03	0.0
C_2H_6	0.0	0.0	0.0	3.50E-09	0.0	0.0	4.39E-04	0.0
C_3H_6	0.0	0.0	0.0	2.04E-12	0.0	0.0	1.21E-03	0.0
C_3H_8	0.0	0.0	0.0	6.50E-14	0.0	0.0	3.85E-04	0.0
ISOBU-01	0.0	0.0	0.0	4.65E-19	0.0	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	5.11E-16	0.0	0.0	3.34E-04	0.0
1-BUT-01	0.0	0.0	0.0	1.62E-15	0.0	0.0	1.04E-03	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	2.23E-41	0.0	0.0	0.0	0.0

Description	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	36	37	38	39
Temperature (F)	323.2	424.4	323.2	821.7
Pressure (psia)	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	7,194	264,691	316,589	218,199
Mole Flow (lbmol/hr)	500	13,446	22,003	7,561
Mole Fraction				
H_2O	0.0548	0.0783	0.0548	9.87E-03
Ar	0.0558	0.0797	0.0558	9.25E-03
CO_2	0.0514	0.0734	0.0514	3.27E-04
O_2	5.92E-17	8.47E-17	5.92E-17	0.2074
N_2	0.0328	0.0468	0.0328	0.7732
CO	0.2446	0.3493	0.2446	0.0
COS	1.20E-13	1.72E-13	1.20E-13	0.0
H_2	0.5600	0.3716	0.5600	0.0
H_2S	1.58E-12	2.26E-12	1.58E-12	0.0
HCl	0.0	0.0	0.0	0.0
NH_3	3.18E-05	4.54E-05	3.18E-05	0.0
SO_2	2.43E-18	3.48E-18	2.43E-18	0.0
CH_4	5.69E-04	8.14E-04	5.69E-04	0.0
C_2H_4	1.95E-08	2.79E-08	1.95E-08	0.0
C_2H_6	3.36E-09	4.81E-09	3.36E-09	0.0
C_3H_6	1.96E-12	2.80E-12	1.96E-12	0.0
C_3H_8	6.25E-14	8.93E-14	7.12E-14	0.0
ISOBU-01	4.47E-19	6.39E-19	4.47E-19	0.0
N-BUT-01	4.91E-16	7.02E-16	9.22E-15	0.0
1-BUT-01	1.56E-15	2.22E-15	1.56E-15	0.0
Naphtha	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0
S_8	2.14E-41	3.06E-41	2.14E-41	0.0

Table 2-27: CBTL, 28.3% Biomass, Pellets, Validated: Stream Values

Description	Coal	Dried Coal	Pelletized Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.
PFD Number	**1**	**2**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Temperature (F)	59.0	220.0	59.0	489.4	59.0	59.0	500.0	90.0	100.0	264.3	100.0
Pressure (psia)	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7
Mass Flow (lb/hr)	1,888,644	1,709,684	674,812	363,349	6,374,445	3,531,600	3,910,388	1,510,309	1,660,295	2,436,704	2,584,086
Mole Flow (lbmol/hr)				20,169	220,898	122,383	188,515	46,932	40,268	155,250	58,945
Mole Fraction											
H_2O				1.0	9.87E-03	9.87E-03	0.1403	0.0	1.41E-03	7.62E-03	0.0
Ar				0.0	9.25E-03	9.25E-03	7.12E-03	0.0318	0.0	0.0165	0.0
CO_2				0.0	3.27E-04	3.27E-04	0.1201	0.0	0.8893	0.0217	0.9924
O_2				0.0	0.2074	0.2074	0.0	0.9504	0.0	7.51E-18	0.0
N_2				0.0	0.7732	0.7732	5.06E-03	0.0178	4.32E-04	0.0125	5.68E-05
CO				0.0	0.0	0.0	0.4104	0.0	0.0672	0.4370	4.84E-03
COS				0.0	0.0	0.0	5.32E-05	0.0	3.73E-07	6.48E-08	2.54E-07
H_2				0.0	0.0	0.0	0.2926	0.0	0.0351	0.4807	1.15E-03
H_2S				0.0	0.0	0.0	1.11E-03	0.0	0.0	2.75E-11	7.01E-11
HCl				0.0	0.0	0.0	2.10E-05	0.0	0.0	0.0	0.0
NH_3				0.0	0.0	0.0	2.98E-03	0.0	0.0	4.68E-06	0.0
SO_2				0.0	0.0	0.0	0.0	0.0	0.0	2.81E-19	0.0
CH_4				0.0	0.0	0.0	0.0202	0.0	6.62E-03	0.0240	1.58E-03
C_2H_4				0.0	0.0	0.0	0.0	0.0	0.0	3.12E-09	0.0
C_2H_6				0.0	0.0	0.0	0.0	0.0	0.0	5.62E-10	0.0
C_3H_6				0.0	0.0	0.0	0.0	0.0	0.0	3.37E-13	0.0
C_3H_8				0.0	0.0	0.0	0.0	0.0	0.0	1.12E-14	0.0
ISOBU-01				0.0	0.0	0.0	0.0	0.0	0.0	8.65E-20	0.0
N-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	6.42E-17	0.0
1-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	2.05E-16	0.0
Naphtha				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8				0.0	0.0	0.0	0.0	0.0	0.0	2.51E-42	0.0

Description	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle
PFD Number	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	294.4
Pressure (psia)	14.7	317.0	14.7	14.7	14.7	227.5	14.7	14.7	14.7	14.7	477.0
Mass Flow (lb/hr)	7,046	39,510	175,103	53,579	273,555	31,244	251,432	4,986,880	4,251,777	195,108	205,810
Mole Flow (lbmol/hr)	27	19,291	1,657	252	1,288	640	8,041	276,814	150,237		9,922
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0635	1.0	0.0981		0.1403
Ar	0.0	1.22E-04	0.0	0.0	0.0	2.06E-05	0.0394	0.0	0.0153		7.12E-03
CO_2	0.0	8.58E-09	0.0	0.0	0.0	0.0602	0.2071	0.0	0.0430		0.1201
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0264	0.0	0.0995		0.0
N_2	0.0	3.00E-04	0.0	0.0	0.0	7.21E-07	0.6636	0.0	0.7441		5.06E-03
CO	0.0	7.63E-04	0.0	0.0	0.0	7.90E-06	0.0	0.0	0.0		0.4104
COS	0.0	0.0	0.0	0.0	0.0	1.57E-05	1.22E-13	0.0	0.0		5.32E-05
H_2	0.0	0.9988	0.0	0.0	0.0	1.45E-09	0.0	0.0	0.0		0.2926
H_2S	0.0	0.0	0.0	0.0	0.0	1.17E-10	0.0	0.0	0.0		1.11E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.10E-05
NH_3	0.0	0.0	0.0	0.0	0.0	1.14E-03	2.13E-06	0.0	5.00E-06		2.98E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	9.46E-14	0.0	2.38E-13		0.0
CH_4	0.0	0.0	0.0	0.0	0.0	4.46E-04	0.0	0.0	0.0		0.0202
C_2H_4	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0		0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0		0.0
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.3370	0.0	0.0	0.0		0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.3322	0.0	0.0	0.0		0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0		0.0
Naphtha	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
F-T-Jet	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0
F-T-Diesel	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0
S_8	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0

Description	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA
PFD Number	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**
Temperature (F)	500.0	500.0	268.0	373.6	318.1	90.0	100.0	105.0
Pressure (psia)	477.0	477.0	665.0	379.0	360.0	125.0	369.0	25.0
Mass Flow (lb/hr)	2,350,766	1,559,622	1,357,650	410,562	122,618	30,041	1,618,995	1,045,197
Mole Flow (lbmol/hr)	113,328	75,188	42,188	19,881	3,810	934	61,768	23,750
Mole Fraction								
H_2O	0.1403	0.1403	0.0	0.0592	0.0	0.0	0.0	0.0
Ar	7.12E-03	7.12E-03	0.0318	0.0599	0.0318	0.0318	0.0415	0.0
CO_2	0.1201	0.1201	0.0	0.1056	0.0	0.0	0.4156	0.9999
O_2	0.0	0.0	0.9504	5.86E-17	0.9504	0.9504	0.0	0.0
N_2	5.06E-03	5.06E-03	0.0178	0.0359	0.0178	0.0178	0.0315	1.03E-05
CO	0.4104	0.4104	0.0	0.3814	0.0	0.0	0.1258	6.00E-05
COS	5.32E-05	5.32E-05	0.0	2.08E-09	0.0	0.0	1.63E-07	0.0
H_2	0.2926	0.2926	0.0	0.3485	0.0	0.0	0.3173	8.50E-08
H_2S	1.11E-03	1.11E-03	0.0	1.63E-12	0.0	0.0	6.92E-11	1.74E-10
HCl	2.10E-05	2.10E-05	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	2.98E-03	2.98E-03	0.0	3.65E-05	0.0	0.0	1.18E-05	0.0
SO_2	0.0	0.0	0.0	2.19E-18	0.0	0.0	0.0	0.0
CH_4	0.0202	0.0202	0.0	9.46E-03	0.0	0.0	0.0635	4.05E-05
C_2H_4	0.0	0.0	0.0	2.44E-08	0.0	0.0	1.40E-03	0.0
C_2H_6	0.0	0.0	0.0	4.39E-09	0.0	0.0	4.34E-04	0.0
C_3H_6	0.0	0.0	0.0	2.63E-12	0.0	0.0	1.20E-03	0.0
C_3H_8	0.0	0.0	0.0	8.75E-14	0.0	0.0	3.81E-04	0.0
ISOBU-01	0.0	0.0	0.0	6.75E-19	0.0	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	5.01E-16	0.0	0.0	3.31E-04	0.0
1-BUT-01	0.0	0.0	0.0	1.60E-15	0.0	0.0	1.03E-03	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	1.96E-41	0.0	0.0	0.0	0.0

Description	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	36	37	38	39
Temperature (F)	325.4	427.6	325.4	821.7
Pressure (psia)	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	7,137	290,183	313,454	217,179
Mole Flow (lbmol/hr)	500	14,865	21,959	7,526
Mole Fraction				
H_2O	0.0554	0.0792	0.0554	9.87E-03
Ar	0.0561	0.0801	0.0561	9.25E-03
CO_2	0.0489	0.0699	0.0489	3.27E-04
O_2	5.49E-17	7.84E-17	5.49E-17	0.2074
N_2	0.0330	0.0470	0.0330	0.7732
CO	0.2432	0.3472	0.2432	0.0
COS	1.09E-13	1.55E-13	1.09E-13	0.0
H_2	0.5627	0.3755	0.5627	0.0
H_2S	1.52E-12	2.18E-12	1.52E-12	0.0
HCl	0.0	0.0	0.0	0.0
NH_3	3.42E-05	4.89E-05	3.42E-05	0.0
SO_2	2.05E-18	2.93E-18	2.05E-18	0.0
CH_4	6.46E-04	9.24E-04	6.46E-04	0.0
C_2H_4	2.28E-08	3.26E-08	2.28E-08	0.0
C_2H_6	4.11E-09	5.87E-09	4.11E-09	0.0
C_3H_6	2.46E-12	3.52E-12	2.46E-12	0.0
C_3H_8	8.18E-14	1.17E-13	9.06E-14	0.0
ISOBU-01	6.32E-19	9.03E-19	6.32E-19	0.0
N-BUT-01	4.69E-16	6.71E-16	9.22E-15	0.0
1-BUT-01	1.50E-15	2.14E-15	1.50E-15	0.0
Naphtha	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0
S_8	1.83E-41	2.62E-41	1.83E-41	0.0

2.7 Scenario 18: CBTL, 16.5 Percent Biomass, Torrefied Pellets, Model and Validation; Scenario 19: CBTL, 19.6 Percent Biomass, Torrefied Pellets, Model and Validation; and Scenario 20: CBTL, 28.3 Percent Biomass, Torrefied Pellets, Model and Validation

The overall configuration for these scenarios is essentially identical to the CBTL and torrefied biomass scenarios (Scenarios 4, 5, and 8). The only difference is that the torrefied biomass is delivered to the plant in the form of pellets. This increases the biomass density and reduces transportation costs. As shown in **Figure 2-6** the biomass pellets only need to be ground prior to feeding to the gasifier. The average moisture content of the pellets is 6.26 percent, much lower than the moisture content required for feeding to the gasifier. The torrefied chips must be reduced in size to an average particle size of about 0.8 mm for feeding to the TRIG gasifiers. This is accomplished in separate hammer mills from the coal milling machines. It is assumed that the same specific power requirement is required to grind torrefied biomass pellets as torrefied biomass chips.

The milled coal is dried to 18 percent moisture and mixed with the finely ground biomass before entering the lock hopper feeding system of the TRIG gasifiers. The mixture is then injected into the gasifiers just above the gasifier mixing zone. The coal and biomass react with the steam and oxygen to produce raw synthesis gas.

Like previous scenarios, the raw syngas is cleaned and sent to the F-T reactors. All other downstream processes are the same as well.

The stream table results are shown in **Table 2-28** for Scenario 18, **Table 2-30** for Scenario 19, and **Table 2-32** for Scenario 20 for the results from the original Aspen Plus® model. Analogous stream results are also shown in **Table 2-29**, **Table 2-31**, and **Table 2-33** for these three scenarios, respectively, using the Aspen Plus® model validated by experimental data. As with the other validated scenarios, the deviation between the modeled and validated stream results is small and insignificant.

Figure 2-6: Scenarios 12, 13 and 14 Plant Configuration: CBTL, 16.5%, 19.6% and 28.3% Biomass, Torrefied Pellet Plant Configurations

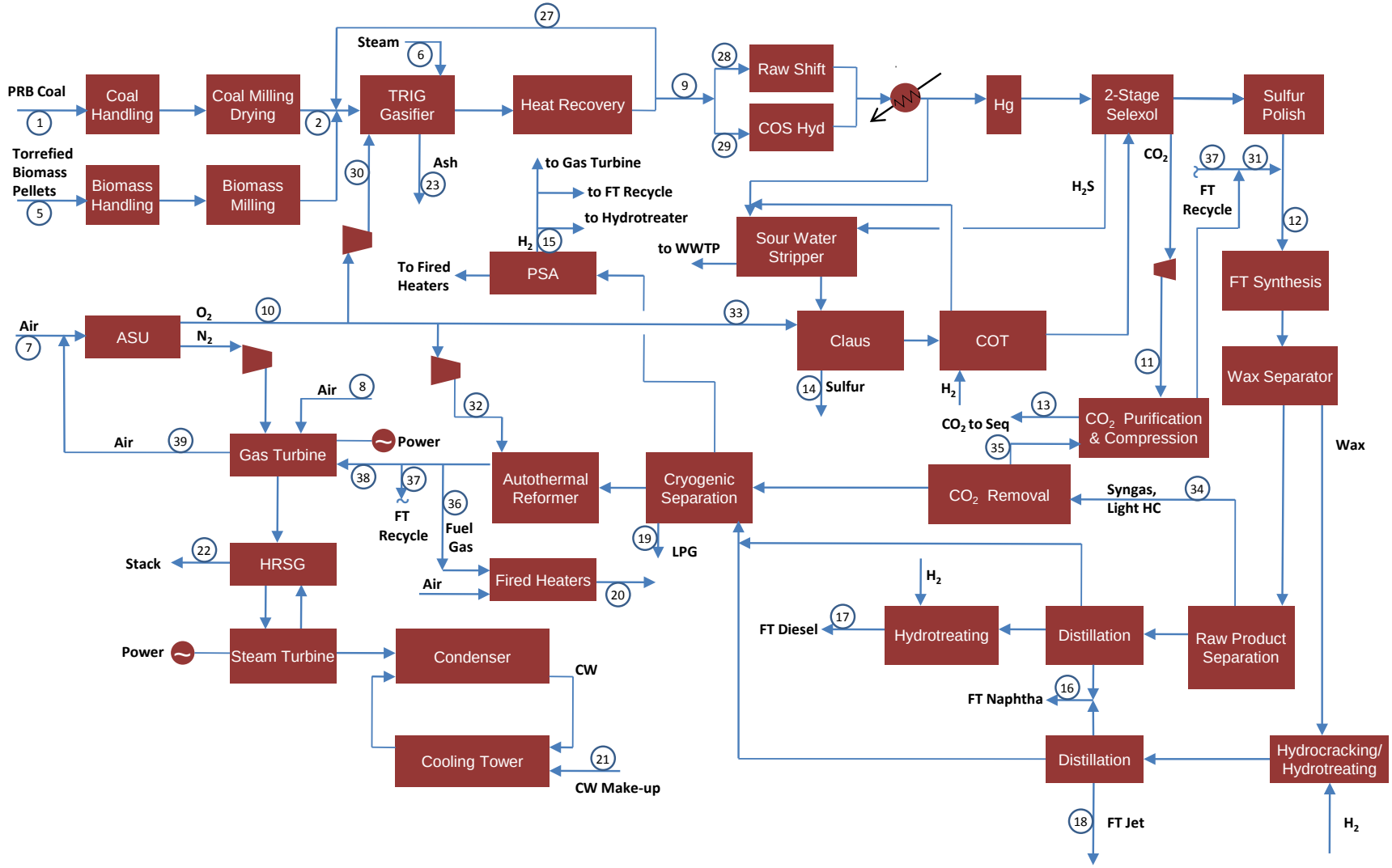


Table 2-28: CBTL, 16.5% Biomass, Torrefied Pellets, Modeled: Stream Values

Description	Coal	Dried Coal	Torrefied Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.
PFD Number	**1**	**2**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Temperature (F)	59.0	220.0	59.0	489.4	59.0	59.0	500.0	90.0	100.0	264.2	100.0
Pressure (psia)	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7
Mass Flow (lb/hr)	2,091,515	1,893,331	374,131	402,379	6,303,484	3,531,600	3,788,910	1,494,084	1,603,788	2,434,277	2,525,490
Mole Flow (lbmol/hr)				22,335	218,439	122,383	183,709	46,428	38,983	155,190	57,607
Mole Fraction											
H_2O				1.0	9.87E-03	9.87E-03	0.1224	0.0	1.45E-03	7.56E-03	0.0
Ar				0.0	9.25E-03	9.25E-03	7.21E-03	0.0318	0.0	0.0163	0.0
CO_2				0.0	3.27E-04	3.27E-04	0.1181	0.0	0.8856	0.0214	0.9924
O_2				0.0	0.2074	0.2074	0.0	0.9504	0.0	7.51E-18	0.0
N_2				0.0	0.7732	0.7732	5.25E-03	0.0178	4.60E-04	0.0129	5.87E-05
CO				0.0	0.0	0.0	0.4193	0.0	0.0694	0.4372	4.82E-03
COS				0.0	0.0	0.0	6.62E-05	0.0	4.68E-07	7.87E-08	3.16E-07
H_2				0.0	0.0	0.0	0.3025	0.0	0.0363	0.4809	1.14E-03
H_2S				0.0	0.0	0.0	1.23E-03	0.0	0.0	2.98E-11	7.76E-11
HCl				0.0	0.0	0.0	2.38E-05	0.0	0.0	0.0	0.0
NH_3				0.0	0.0	0.0	3.38E-03	0.0	0.0	4.70E-06	0.0
SO_2				0.0	0.0	0.0	0.0	0.0	0.0	3.06E-19	0.0
CH_4				0.0	0.0	0.0	0.0206	0.0	6.78E-03	0.0238	1.57E-03
C_2H_4				0.0	0.0	0.0	0.0	0.0	0.0	3.06E-09	0.0
C_2H_6				0.0	0.0	0.0	0.0	0.0	0.0	5.49E-10	0.0
C_3H_6				0.0	0.0	0.0	0.0	0.0	0.0	3.28E-13	0.0
C_3H_8				0.0	0.0	0.0	0.0	0.0	0.0	1.09E-14	0.0
ISOBU-01				0.0	0.0	0.0	0.0	0.0	0.0	8.33E-20	0.0
N-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	6.40E-17	0.0
1-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	2.04E-16	0.0
Naphtha				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8				0.0	0.0	0.0	0.0	0.0	0.0	2.53E-42	0.0

Description	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle
PFD Number	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	285.6
Pressure (psia)	14.7	317.0	14.7	14.7	14.7	227.4	14.7	14.7	14.7	14.7	477.0
Mass Flow (lb/hr)	7,629	39,524	175,104	53,580	273,557	31,241	251,908	4,833,507	4,251,453	221,169	199,407
Mole Flow (lbmol/hr)	30	19,296	1,657	252	1,288	640	8,059	268,300	150,229		9,668
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0633	1.0	0.0981		0.1224
Ar	0.0	1.20E-04	0.0	0.0	0.0	2.03E-05	0.0390	0.0	0.0152		7.21E-03
CO_2	0.0	8.61E-09	0.0	0.0	0.0	0.0601	0.2068	0.0	0.0431		0.1181
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0263	0.0	0.0995		0.0
N_2	0.0	3.10E-04	0.0	0.0	0.0	7.43E-07	0.6646	0.0	0.7441		5.25E-03
CO	0.0	7.63E-04	0.0	0.0	0.0	7.89E-06	0.0	0.0	0.0		0.4193
COS	0.0	0.0	0.0	0.0	0.0	1.91E-05	1.48E-13	0.0	0.0		6.62E-05
H_2	0.0	0.9988	0.0	0.0	0.0	1.45E-09	0.0	0.0	0.0		0.3025
H_2S	0.0	0.0	0.0	0.0	0.0	1.27E-10	0.0	0.0	0.0		1.23E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.38E-05
NH_3	0.0	0.0	0.0	0.0	0.0	1.14E-03	2.14E-06	0.0	5.05E-06		3.38E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	1.03E-13	0.0	2.59E-13		0.0
CH_4	0.0	0.0	0.0	0.0	0.0	4.43E-04	0.0	0.0	0.0		0.0206
C_2H_4	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0		0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0		0.0
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.3370	0.0	0.0	0.0		0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.3322	0.0	0.0	0.0		0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0		0.0
Naphtha	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
F-T-Jet	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0
F-T-Diesel	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0
S_8	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0

Description	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA
PFD Number	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**
Temperature (F)	500.0	500.0	268.0	372.7	318.1	90.0	100.0	105.0
Pressure (psia)	477.0	477.0	665.0	379.0	360.0	125.0	369.0	25.0
Mass Flow (lb/hr)	2,551,930	1,236,980	1,340,246	409,231	122,036	31,802	1,616,799	1,043,528
Mole Flow (lbmol/hr)	123,733	59,976	41,647	19,803	3,792	988	61,720	23,712
Mole Fraction								
H_2O	0.1224	0.1224	0.0	0.0590	0.0	0.0	0.0	0.0
Ar	7.21E-03	7.21E-03	0.0318	0.0591	0.0318	0.0318	0.0409	0.0
CO_2	0.1181	0.1181	0.0	0.1060	0.0	0.0	0.4153	0.9999
O_2	0.0	0.0	0.9504	5.88E-17	0.9504	0.9504	0.0	0.0
N_2	5.25E-03	5.25E-03	0.0178	0.0369	0.0178	0.0178	0.0325	1.07E-05
CO	0.4193	0.4193	0.0	0.3815	0.0	0.0	0.1258	6.00E-05
COS	6.62E-05	6.62E-05	0.0	2.67E-09	0.0	0.0	1.98E-07	0.0
H_2	0.3025	0.3025	0.0	0.3479	0.0	0.0	0.3176	8.51E-08
H_2S	1.23E-03	1.23E-03	0.0	1.76E-12	0.0	0.0	7.50E-11	1.89E-10
HCl	2.38E-05	2.38E-05	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	3.38E-03	3.38E-03	0.0	3.68E-05	0.0	0.0	1.18E-05	0.0
SO_2	0.0	0.0	0.0	2.40E-18	0.0	0.0	0.0	0.0
CH_4	0.0206	0.0206	0.0	9.50E-03	0.0	0.0	0.0631	4.03E-05
C_2H_4	0.0	0.0	0.0	2.39E-08	0.0	0.0	1.40E-03	0.0
C_2H_6	0.0	0.0	0.0	4.30E-09	0.0	0.0	4.34E-04	0.0
C_3H_6	0.0	0.0	0.0	2.57E-12	0.0	0.0	1.20E-03	0.0
C_3H_8	0.0	0.0	0.0	8.51E-14	0.0	0.0	3.81E-04	0.0
ISOBU-01	0.0	0.0	0.0	6.53E-19	0.0	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	5.02E-16	0.0	0.0	3.31E-04	0.0
1-BUT-01	0.0	0.0	0.0	1.60E-15	0.0	0.0	1.03E-03	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	1.98E-41	0.0	0.0	0.0	0.0

Description	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	36	37	38	39
Temperature (F)	325.2	427.3	325.2	821.7
Pressure (psia)	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	7,139	288,423	313,683	217,328
Mole Flow (lbmol/hr)	500	14,771	21,971	7,531
Mole Fraction				
H_2O	0.0553	0.0791	0.0553	9.87E-03
Ar	0.0555	0.0793	0.0555	9.25E-03
CO_2	0.0491	0.0701	0.0491	3.27E-04
O_2	5.52E-17	7.88E-17	5.52E-17	0.2074
N_2	0.0340	0.0485	0.0340	0.7732
CO	0.2430	0.3470	0.2430	0.0
COS	1.19E-13	1.69E-13	1.19E-13	0.0
H_2	0.5624	0.3751	0.5624	0.0
H_2S	1.65E-12	2.36E-12	1.65E-12	0.0
HCl	0.0	0.0	0.0	0.0
NH_3	3.45E-05	4.93E-05	3.45E-05	0.0
SO_2	2.25E-18	3.21E-18	2.25E-18	0.0
CH_4	6.39E-04	9.13E-04	6.39E-04	0.0
C_2H_4	2.25E-08	3.21E-08	2.25E-08	0.0
C_2H_6	4.03E-09	5.76E-09	4.03E-09	0.0
C_3H_6	2.41E-12	3.44E-12	2.41E-12	0.0
C_3H_8	7.99E-14	1.14E-13	8.86E-14	0.0
ISOBU-01	6.12E-19	8.75E-19	6.12E-19	0.0
N-BUT-01	4.71E-16	6.73E-16	9.21E-15	0.0
1-BUT-01	1.50E-15	2.15E-15	1.50E-15	0.0
Naphtha	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0
S_8	1.86E-41	2.66E-41	1.86E-41	0.0

Table 2-29: CBTL, 16.5% Biomass, Torrefied Pellets, Validated: Stream Values

Description	Coal	Dried Coal	Torrefied Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.
PFD Number	**1**	**2**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Temperature (F)	59.0	220.0	59.0	489.4	59.0	59.0	500.0	90.0	100.0	266.8	100.0
Pressure (psia)	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7
Mass Flow (lb/hr)	2,095,431	1,896,877	374,832	403,132	6,335,592	3,531,600	3,791,188	1,501,245	1,614,634	2,453,071	2,539,985
Mole Flow (lbmol/hr)				22,377	219,552	122,383	183,205	46,650	39,229	156,001	57,944
Mole Fraction											
H_2O				1.0	9.87E-03	9.87E-03	0.1288	0.0	1.44E-03	8.37E-03	0.0
Ar				0.0	9.25E-03	9.25E-03	7.22E-03	0.0318	0.0	0.0170	0.0
CO_2				0.0	3.27E-04	3.27E-04	0.1135	0.0	0.8864	0.0216	0.9923
O_2				0.0	0.2074	0.2074	0.0	0.9504	0.0	7.63E-18	0.0
N_2				0.0	0.7732	0.7732	5.26E-03	0.0178	4.58E-04	0.0134	5.89E-05
CO				0.0	0.0	0.0	0.4240	0.0	0.0684	0.4349	4.79E-03
COS				0.0	0.0	0.0	6.11E-05	0.0	4.28E-07	7.20E-08	2.89E-07
H_2				0.0	0.0	0.0	0.2935	0.0	0.0357	0.4784	1.14E-03
H_2S				0.0	0.0	0.0	1.24E-03	0.0	0.0	2.98E-11	7.74E-11
HCl				0.0	0.0	0.0	2.39E-05	0.0	0.0	0.0	0.0
NH_3				0.0	0.0	0.0	3.39E-03	0.0	0.0	5.53E-06	0.0
SO_2				0.0	0.0	0.0	0.0	0.0	0.0	2.83E-19	0.0
CH_4				0.0	0.0	0.0	0.0230	0.0	7.50E-03	0.0264	1.75E-03
C_2H_4				0.0	0.0	0.0	0.0	0.0	0.0	3.89E-09	0.0
C_2H_6				0.0	0.0	0.0	0.0	0.0	0.0	7.30E-10	0.0
C_3H_6				0.0	0.0	0.0	0.0	0.0	0.0	4.48E-13	0.0
C_3H_8				0.0	0.0	0.0	0.0	0.0	0.0	1.55E-14	0.0
ISOBU-01				0.0	0.0	0.0	0.0	0.0	0.0	1.28E-19	0.0
N-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	6.71E-17	0.0
1-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	2.16E-16	0.0
Naphtha				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8				0.0	0.0	0.0	0.0	0.0	0.0	2.25E-45	0.0

Description	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle
PFD Number	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	288.8
Pressure (psia)	14.7	317.0	14.7	14.7	14.7	227.7	14.7	14.7	14.7	14.7	477.0
Mass Flow (lb/hr)	7,643	39,525	175,103	53,579	273,554	31,249	247,522	4,862,002	4,249,810	221,583	199,525
Mole Flow (lbmol/hr)	30	19,302	1,657	252	1,288	640	7,932	269,882	150,240		9,642
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0650	1.0	0.0984		0.1288
Ar	0.0	1.22E-04	0.0	0.0	0.0	2.14E-05	0.0399	0.0	0.0152		7.22E-03
CO_2	0.0	8.56E-09	0.0	0.0	0.0	0.0603	0.2040	0.0	0.0424		0.1135
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0263	0.0	0.0996		0.0
N_2	0.0	3.11E-04	0.0	0.0	0.0	7.81E-07	0.6648	0.0	0.7444		5.26E-03
CO	0.0	7.37E-04	0.0	0.0	0.0	7.93E-06	0.0	0.0	0.0		0.4240
COS	0.0	0.0	0.0	0.0	0.0	1.75E-05	1.36E-13	0.0	0.0		6.11E-05
H_2	0.0	0.9988	0.0	0.0	0.0	1.51E-09	0.0	0.0	0.0		0.2935
H_2S	0.0	0.0	0.0	0.0	0.0	1.27E-10	0.0	0.0	0.0		1.24E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.39E-05
NH_3	0.0	0.0	0.0	0.0	0.0	1.35E-03	2.34E-06	0.0	5.41E-06		3.39E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	9.99E-14	0.0	2.47E-13		0.0
CH_4	0.0	0.0	0.0	0.0	0.0	4.89E-04	0.0	0.0	0.0		0.0230
C_2H_4	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0		0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.1098	0.0	0.0	0.0		0.0
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.3369	0.0	0.0	0.0		0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.3320	0.0	0.0	0.0		0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0992	0.0	0.0	0.0		0.0
Naphtha	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
F-T-Jet	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0
F-T-Diesel	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0
S_8	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0

Description	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA
PFD Number	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**
Temperature (F)	500.0	500.0	268.0	382.8	318.1	90.0	100.0	105.0
Pressure (psia)	477.0	477.0	665.0	379.0	360.0	125.0	369.0	25.0
Mass Flow (lb/hr)	2,643,447	1,147,740	1,337,941	435,834	131,254	32,050	1,633,570	1,046,695
Mole Flow (lbmol/hr)	127,741	55,463	41,576	21,309	4,079	996	62,419	23,785
Mole Fraction								
H_2O	0.1288	0.1288	0.0	0.0610	0.0	0.0	0.0	0.0
Ar	7.22E-03	7.22E-03	0.0318	0.0609	0.0318	0.0318	0.0425	0.0
CO_2	0.1135	0.1135	0.0	0.1008	0.0	0.0	0.4119	0.9999
O_2	0.0	0.0	0.9504	5.59E-17	0.9504	0.9504	0.0	0.0
N_2	5.26E-03	5.26E-03	0.0178	0.0379	0.0178	0.0178	0.0334	1.11E-05
CO	0.4240	0.4240	0.0	0.3767	0.0	0.0	0.1241	5.97E-05
COS	6.11E-05	6.11E-05	0.0	2.25E-09	0.0	0.0	1.80E-07	0.0
H_2	0.2935	0.2935	0.0	0.3527	0.0	0.0	0.3144	8.50E-08
H_2S	1.24E-03	1.24E-03	0.0	1.73E-12	0.0	0.0	7.44E-11	1.88E-10
HCl	2.39E-05	2.39E-05	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	3.39E-03	3.39E-03	0.0	4.05E-05	0.0	0.0	1.38E-05	0.0
SO_2	0.0	0.0	0.0	2.07E-18	0.0	0.0	0.0	0.0
CH_4	0.0230	0.0230	0.0	9.88E-03	0.0	0.0	0.0691	4.45E-05
C_2H_4	0.0	0.0	0.0	2.85E-08	0.0	0.0	1.38E-03	0.0
C_2H_6	0.0	0.0	0.0	5.34E-09	0.0	0.0	4.30E-04	0.0
C_3H_6	0.0	0.0	0.0	3.28E-12	0.0	0.0	1.19E-03	0.0
C_3H_8	0.0	0.0	0.0	1.13E-13	0.0	0.0	3.77E-04	0.0
ISOBU-01	0.0	0.0	0.0	9.33E-19	0.0	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	4.91E-16	0.0	0.0	3.27E-04	0.0
1-BUT-01	0.0	0.0	0.0	1.58E-15	0.0	0.0	1.02E-03	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	1.64E-44	0.0	0.0	0.0	0.0

Description	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	36	37	38	39
Temperature (F)	327.4	430.5	327.4	821.7
Pressure (psia)	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	7,082	315,506	310,562	216,473
Mole Flow (lbmol/hr)	500	16,296	21,925	7,502
Mole Fraction				
H_2O	0.0559	0.0798	0.0559	9.87E-03
Ar	0.0558	0.0796	0.0558	9.25E-03
CO_2	0.0467	0.0668	0.0467	3.27E-04
O_2	5.11E-17	7.31E-17	5.11E-17	0.2074
N_2	0.0342	0.0487	0.0342	0.7732
CO	0.2415	0.3448	0.2415	0.0
COS	1.07E-13	1.53E-13	1.07E-13	0.0
H_2	0.5652	0.3792	0.5652	0.0
H_2S	1.59E-12	2.26E-12	1.59E-12	0.0
HCl	0.0	0.0	0.0	0.0
NH_3	3.71E-05	5.30E-05	3.71E-05	0.0
SO_2	1.90E-18	2.71E-18	1.90E-18	0.0
CH_4	7.22E-04	1.03E-03	7.22E-04	0.0
C_2H_4	2.61E-08	3.73E-08	2.61E-08	0.0
C_2H_6	4.89E-09	6.99E-09	4.89E-09	0.0
C_3H_6	3.00E-12	4.29E-12	3.00E-12	0.0
C_3H_8	1.04E-13	1.48E-13	1.12E-13	0.0
ISOBU-01	8.54E-19	1.22E-18	8.54E-19	0.0
N-BUT-01	4.49E-16	6.42E-16	9.21E-15	0.0
1-BUT-01	1.45E-15	2.07E-15	1.45E-15	0.0
Naphtha	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0
S_8	1.51E-44	2.15E-44	1.51E-44	0.0

Table 2-30: CBTL, 19.6% Biomass, Torrefied Pellets, Modeled: Stream Values

Description	Coal	Dried Coal	Torrefied Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.
PFD Number	**1**	**2**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Temperature (F)	59.0	220.0	59.0	489.4	59.0	59.0	500.0	90.0	100.0	264.8	100.0
Pressure (psia)	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7
Mass Flow (lb/hr)	2,008,658	1,818,326	443,273	386,439	6,243,199	3,531,600	3,755,678	1,480,229	1,594,722	2,436,284	2,516,963
Mole Flow (lbmol/hr)				21,451	216,350	122,383	182,135	45,997	38,777	155,315	57,414
Mole Fraction											
H_2O				1.0	9.87E-03	9.87E-03	0.1191	0.0	1.45E-03	7.77E-03	0.0
Ar				0.0	9.25E-03	9.25E-03	7.19E-03	0.0318	0.0	0.0163	0.0
CO_2				0.0	3.27E-04	3.27E-04	0.1162	0.0	0.8850	0.0214	0.9924
O_2				0.0	0.2074	0.2074	0.0	0.9504	0.0	7.50E-18	0.0
N_2				0.0	0.7732	0.7732	5.20E-03	0.0178	4.52E-04	0.0127	5.74E-05
CO				0.0	0.0	0.0	0.4239	0.0	0.0696	0.4368	4.80E-03
COS				0.0	0.0	0.0	6.49E-05	0.0	4.57E-07	7.64E-08	3.08E-07
H_2				0.0	0.0	0.0	0.3024	0.0	0.0364	0.4805	1.14E-03
H_2S				0.0	0.0	0.0	1.19E-03	0.0	0.0	2.87E-11	7.49E-11
HCl				0.0	0.0	0.0	2.31E-05	0.0	0.0	0.0	0.0
NH_3				0.0	0.0	0.0	3.27E-03	0.0	0.0	4.87E-06	0.0
SO_2				0.0	0.0	0.0	0.0	0.0	0.0	2.86E-19	0.0
CH_4				0.0	0.0	0.0	0.0214	0.0	7.01E-03	0.0245	1.62E-03
C_2H_4				0.0	0.0	0.0	0.0	0.0	0.0	3.31E-09	0.0
C_2H_6				0.0	0.0	0.0	0.0	0.0	0.0	6.02E-10	0.0
C_3H_6				0.0	0.0	0.0	0.0	0.0	0.0	3.64E-13	0.0
C_3H_8				0.0	0.0	0.0	0.0	0.0	0.0	1.22E-14	0.0
ISOBU-01				0.0	0.0	0.0	0.0	0.0	0.0	9.64E-20	0.0
N-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	6.49E-17	0.0
1-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	2.08E-16	0.0
Naphtha				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8				0.0	0.0	0.0	0.0	0.0	0.0	2.53E-45	0.0

Description	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle
PFD Number	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	283.8
Pressure (psia)	14.7	317.0	14.7	14.7	14.7	227.4	14.7	14.7	14.7	14.7	477.0
Mass Flow (lb/hr)	7,335	39,527	175,104	53,580	273,557	31,243	251,033	4,810,366	4,250,677	217,204	197,668
Mole Flow (lbmol/hr)	29	19,300	1,657	252	1,288	640	8,033	267,016	150,228		9,586
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0638	1.0	0.0982		0.1191
Ar	0.0	1.20E-04	0.0	0.0	0.0	2.04E-05	0.0389	0.0	0.0151		7.19E-03
CO_2	0.0	8.60E-09	0.0	0.0	0.0	0.0601	0.2065	0.0	0.0429		0.1162
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0264	0.0	0.0996		0.0
N_2	0.0	3.04E-04	0.0	0.0	0.0	7.34E-07	0.6643	0.0	0.7443		5.20E-03
CO	0.0	7.59E-04	0.0	0.0	0.0	7.90E-06	0.0	0.0	0.0		0.4239
COS	0.0	0.0	0.0	0.0	0.0	1.85E-05	1.44E-13	0.0	0.0		6.49E-05
H_2	0.0	0.9988	0.0	0.0	0.0	1.46E-09	0.0	0.0	0.0		0.3024
H_2S	0.0	0.0	0.0	0.0	0.0	1.22E-10	0.0	0.0	0.0		1.19E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.31E-05
NH_3	0.0	0.0	0.0	0.0	0.0	1.18E-03	2.17E-06	0.0	5.10E-06		3.27E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	9.79E-14	0.0	2.46E-13		0.0
CH_4	0.0	0.0	0.0	0.0	0.0	4.55E-04	0.0	0.0	0.0		0.0214
C_2H_4	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0		0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0		0.0
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.3370	0.0	0.0	0.0		0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.3322	0.0	0.0	0.0		0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0		0.0
Naphtha	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
F-T-Jet	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0
F-T-Diesel	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0
S_8	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0

Description	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA
PFD Number	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**
Temperature (F)	500.0	500.0	268.0	375.1	318.1	90.0	100.0	105.0
Pressure (psia)	477.0	477.0	665.0	379.0	360.0	125.0	369.0	25.0
Mass Flow (lb/hr)	2,667,713	1,087,966	1,324,843	415,162	124,298	31,089	1,618,341	1,044,005
Mole Flow (lbmol/hr)	129,373	52,762	41,169	20,167	3,862	966	61,819	23,723
Mole Fraction								
H_2O	0.1191	0.1191	0.0	0.0596	0.0	0.0	0.0	0.0
Ar	7.19E-03	7.19E-03	0.0318	0.0591	0.0318	0.0318	0.0409	0.0
CO_2	0.1162	0.1162	0.0	0.1047	0.0	0.0	0.4148	0.9999
O_2	0.0	0.0	0.9504	5.78E-17	0.9504	0.9504	0.0	0.0
N_2	5.20E-03	5.20E-03	0.0178	0.0364	0.0178	0.0178	0.0320	1.05E-05
CO	0.4239	0.4239	0.0	0.3808	0.0	0.0	0.1255	6.00E-05
COS	6.49E-05	6.49E-05	0.0	2.57E-09	0.0	0.0	1.92E-07	0.0
H_2	0.3024	0.3024	0.0	0.3498	0.0	0.0	0.3172	8.51E-08
H_2S	1.19E-03	1.19E-03	0.0	1.69E-12	0.0	0.0	7.20E-11	1.81E-10
HCl	2.31E-05	2.31E-05	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	3.27E-03	3.27E-03	0.0	3.75E-05	0.0	0.0	1.22E-05	0.0
SO_2	0.0	0.0	0.0	2.20E-18	0.0	0.0	0.0	0.0
CH_4	0.0214	0.0214	0.0	9.64E-03	0.0	0.0	0.0648	4.14E-05
C_2H_4	0.0	0.0	0.0	2.55E-08	0.0	0.0	1.39E-03	0.0
C_2H_6	0.0	0.0	0.0	4.64E-09	0.0	0.0	4.34E-04	0.0
C_3H_6	0.0	0.0	0.0	2.80E-12	0.0	0.0	1.20E-03	0.0
C_3H_8	0.0	0.0	0.0	9.42E-14	0.0	0.0	3.81E-04	0.0
ISOBU-01	0.0	0.0	0.0	7.42E-19	0.0	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	5.00E-16	0.0	0.0	3.31E-04	0.0
1-BUT-01	0.0	0.0	0.0	1.60E-15	0.0	0.0	1.03E-03	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	1.95E-44	0.0	0.0	0.0	0.0

Description	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	36	37	38	39
Temperature (F)	325.5	428.0	325.5	821.7
Pressure (psia)	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	7,107	294,411	311,584	217,147
Mole Flow (lbmol/hr)	500	15,138	21,922	7,525
Mole Fraction				
H_2O	0.0555	0.0793	0.0555	9.87E-03
Ar	0.0550	0.0787	0.0550	9.25E-03
CO_2	0.0484	0.0692	0.0484	3.27E-04
O_2	5.38E-17	7.70E-17	5.38E-17	0.2074
N_2	0.0333	0.0475	0.0333	0.7732
CO	0.2429	0.3472	0.2429	0.0
COS	1.11E-13	1.59E-13	1.11E-13	0.0
H_2	0.5642	0.3771	0.5642	0.0
H_2S	1.57E-12	2.25E-12	1.57E-12	0.0
HCl	0.0	0.0	0.0	0.0
NH_3	3.49E-05	5.00E-05	3.49E-05	0.0
SO_2	2.05E-18	2.94E-18	2.05E-18	0.0
CH_4	6.67E-04	9.54E-04	6.67E-04	0.0
C_2H_4	2.37E-08	3.39E-08	2.37E-08	0.0
C_2H_6	4.32E-09	6.18E-09	4.32E-09	0.0
C_3H_6	2.61E-12	3.73E-12	2.61E-12	0.0
C_3H_8	8.78E-14	1.26E-13	9.65E-14	0.0
ISOBU-01	6.91E-19	9.89E-19	6.91E-19	0.0
N-BUT-01	4.66E-16	6.66E-16	9.23E-15	0.0
1-BUT-01	1.49E-15	2.13E-15	1.49E-15	0.0
Naphtha	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0
S_8	1.82E-44	2.60E-44	1.82E-44	0.0

Table 2-31: CBTL, 19.6% Biomass, Torrefied Pellets, Validated: Stream Values

Description	Coal	Dried Coal	Torrefied Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.
PFD Number	**1**	**2**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Temperature (F)	59.0	220.0	59.0	489.4	59.0	59.0	500.0	90.0	100.0	267.5	100.0
Pressure (psia)	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7
Mass Flow (lb/hr)	2,012,398	1,821,711	444,099	387,158	6,275,124	3,531,600	3,757,660	1,487,326	1,605,598	2,455,157	2,531,410
Mole Flow (lbmol/hr)				21,491	217,456	122,383	181,609	46,218	39,023	156,135	57,749
Mole Fraction											
H_2O				1.0	9.87E-03	9.87E-03	0.1254	0.0	1.44E-03	8.59E-03	0.0
Ar				0.0	9.25E-03	9.25E-03	7.20E-03	0.0318	0.0	0.0170	0.0
CO_2				0.0	3.27E-04	3.27E-04	0.1118	0.0	0.8859	0.0216	0.9922
O_2				0.0	0.2074	0.2074	0.0	0.9504	0.0	7.62E-18	0.0
N_2				0.0	0.7732	0.7732	5.21E-03	0.0178	4.49E-04	0.0132	5.77E-05
CO				0.0	0.0	0.0	0.4285	0.0	0.0686	0.4345	4.78E-03
COS				0.0	0.0	0.0	5.98E-05	0.0	4.18E-07	6.99E-08	2.81E-07
H_2				0.0	0.0	0.0	0.2934	0.0	0.0358	0.4780	1.13E-03
H_2S				0.0	0.0	0.0	1.20E-03	0.0	0.0	2.86E-11	7.46E-11
HCl				0.0	0.0	0.0	2.32E-05	0.0	0.0	0.0	0.0
NH_3				0.0	0.0	0.0	3.29E-03	0.0	0.0	5.73E-06	0.0
SO_2				0.0	0.0	0.0	0.0	0.0	0.0	2.65E-19	0.0
CH_4				0.0	0.0	0.0	0.0238	0.0	7.75E-03	0.0271	1.80E-03
C_2H_4				0.0	0.0	0.0	0.0	0.0	0.0	4.20E-09	0.0
C_2H_6				0.0	0.0	0.0	0.0	0.0	0.0	7.98E-10	0.0
C_3H_6				0.0	0.0	0.0	0.0	0.0	0.0	4.95E-13	0.0
C_3H_8				0.0	0.0	0.0	0.0	0.0	0.0	1.74E-14	0.0
ISOBU-01				0.0	0.0	0.0	0.0	0.0	0.0	1.47E-19	0.0
N-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	6.79E-17	0.0
1-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	2.20E-16	0.0
Naphtha				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8				0.0	0.0	0.0	0.0	0.0	0.0	9.52E-46	0.0

Description	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle
PFD Number	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	287.1
Pressure (psia)	14.7	317.0	14.7	14.7	14.7	227.8	14.7	14.7	14.7	14.7	477.0
Mass Flow (lb/hr)	7,349	39,530	175,101	53,579	273,552	31,250	246,644	4,838,697	4,249,125	217,609	197,774
Mole Flow (lbmol/hr)	29	19,307	1,657	252	1,288	640	7,906	268,589	150,242		9,559
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0656	1.0	0.0985		0.1254
Ar	0.0	1.21E-04	0.0	0.0	0.0	2.14E-05	0.0399	0.0	0.0152		7.20E-03
CO_2	0.0	8.55E-09	0.0	0.0	0.0	0.0603	0.2037	0.0	0.0422		0.1118
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0263	0.0	0.0996		0.0
N_2	0.0	3.06E-04	0.0	0.0	0.0	7.73E-07	0.6646	0.0	0.7446		5.21E-03
CO	0.0	7.33E-04	0.0	0.0	0.0	7.93E-06	0.0	0.0	0.0		0.4285
COS	0.0	0.0	0.0	0.0	0.0	1.70E-05	1.32E-13	0.0	0.0		5.98E-05
H_2	0.0	0.9988	0.0	0.0	0.0	1.52E-09	0.0	0.0	0.0		0.2934
H_2S	0.0	0.0	0.0	0.0	0.0	1.22E-10	0.0	0.0	0.0		1.20E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.32E-05
NH_3	0.0	0.0	0.0	0.0	0.0	1.40E-03	2.37E-06	0.0	5.46E-06		3.29E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	9.54E-14	0.0	2.34E-13		0.0
CH_4	0.0	0.0	0.0	0.0	0.0	5.02E-04	0.0	0.0	0.0		0.0238
C_2H_4	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0		0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.1098	0.0	0.0	0.0		0.0
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.3369	0.0	0.0	0.0		0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.3320	0.0	0.0	0.0		0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0992	0.0	0.0	0.0		0.0
Naphtha	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
F-T-Jet	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0
F-T-Diesel	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0
S_8	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0

Description	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA
PFD Number	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**
Temperature (F)	500.0	500.0	268.0	385.1	318.1	90.0	100.0	105.0
Pressure (psia)	477.0	477.0	665.0	379.0	360.0	125.0	369.0	25.0
Mass Flow (lb/hr)	2,752,780	1,004,880	1,322,301	442,046	133,685	31,340	1,635,135	1,047,085
Mole Flow (lbmol/hr)	133,043	48,566	41,090	21,698	4,154	974	62,524	23,793
Mole Fraction								
H_2O	0.1254	0.1254	0.0	0.0615	0.0	0.0	0.0	0.0
Ar	7.20E-03	7.20E-03	0.0318	0.0608	0.0318	0.0318	0.0425	0.0
CO_2	0.1118	0.1118	0.0	0.0995	0.0	0.0	0.4114	0.9999
O_2	0.0	0.0	0.9504	5.49E-17	0.9504	0.9504	0.0	0.0
N_2	5.21E-03	5.21E-03	0.0178	0.0373	0.0178	0.0178	0.0329	1.09E-05
CO	0.4285	0.4285	0.0	0.3760	0.0	0.0	0.1237	5.96E-05
COS	5.98E-05	5.98E-05	0.0	2.16E-09	0.0	0.0	1.75E-07	0.0
H_2	0.2934	0.2934	0.0	0.3547	0.0	0.0	0.3139	8.50E-08
H_2S	1.20E-03	1.20E-03	0.0	1.66E-12	0.0	0.0	7.14E-11	1.81E-10
HCl	2.32E-05	2.32E-05	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	3.29E-03	3.29E-03	0.0	4.12E-05	0.0	0.0	1.43E-05	0.0
SO_2	0.0	0.0	0.0	1.91E-18	0.0	0.0	0.0	0.0
CH_4	0.0238	0.0238	0.0	0.0100	0.0	0.0	0.0709	4.57E-05
C_2H_4	0.0	0.0	0.0	3.02E-08	0.0	0.0	1.38E-03	0.0
C_2H_6	0.0	0.0	0.0	5.74E-09	0.0	0.0	4.29E-04	0.0
C_3H_6	0.0	0.0	0.0	3.56E-12	0.0	0.0	1.18E-03	0.0
C_3H_8	0.0	0.0	0.0	1.25E-13	0.0	0.0	3.77E-04	0.0
ISOBU-01	0.0	0.0	0.0	1.06E-18	0.0	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	4.89E-16	0.0	0.0	3.27E-04	0.0
1-BUT-01	0.0	0.0	0.0	1.58E-15	0.0	0.0	1.02E-03	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	6.85E-45	0.0	0.0	0.0	0.0

Description	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	**36**	**37**	**38**	**39**
Temperature (F)	327.7	431.1	327.7	821.7
Pressure (psia)	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	7,050	321,787	308,447	216,192
Mole Flow (lbmol/hr)	500	16,688	21,875	7,492
Mole Fraction				
H_2O	0.0560	0.0800	0.0560	9.87E-03
Ar	0.0553	0.0791	0.0553	9.25E-03
CO_2	0.0461	0.0659	0.0461	3.27E-04
O_2	4.99E-17	7.13E-17	4.99E-17	0.2074
N_2	0.0334	0.0477	0.0334	0.7732
CO	0.2414	0.3449	0.2414	0.0
COS	1.00E-13	1.44E-13	1.00E-13	0.0
H_2	0.5670	0.3813	0.5670	0.0
H_2S	1.51E-12	2.16E-12	1.51E-12	0.0
HCl	0.0	0.0	0.0	0.0
NH_3	3.75E-05	5.36E-05	3.75E-05	0.0
SO_2	1.73E-18	2.48E-18	1.73E-18	0.0
CH_4	7.52E-04	1.08E-03	7.52E-04	0.0
C_2H_4	2.75E-08	3.93E-08	2.75E-08	0.0
C_2H_6	5.22E-09	7.47E-09	5.22E-09	0.0
C_3H_6	3.24E-12	4.64E-12	3.24E-12	0.0
C_3H_8	1.14E-13	1.62E-13	1.22E-13	0.0
ISOBU-01	9.60E-19	1.37E-18	9.60E-19	0.0
N-BUT-01	4.44E-16	6.36E-16	9.23E-15	0.0
1-BUT-01	1.44E-15	2.06E-15	1.44E-15	0.0
Naphtha	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0
S_8	6.23E-45	8.91E-45	6.23E-45	0.0

Table 2-32: CBTL, 28.3% Biomass, Torrefied Pellets, Modeled: Stream Values

Description	Coal	Dried Coal	Torrefied Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.
PFD Number	**1**	**2**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Temperature (F)	59.0	220.0	59.0	489.4	59.0	59.0	500.0	90.0	100.0	266.7	100.0
Pressure (psia)	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7
Mass Flow (lb/hr)	1,778,547	1,610,019	635,475	342,168	6,077,163	3,531,600	3,663,229	1,442,005	1,570,025	2,442,458	2,493,779
Mole Flow (lbmol/hr)				18,993	210,596	122,383	177,725	44,810	38,214	155,696	56,889
Mole Fraction											
H_2O				1.0	9.87E-03	9.87E-03	0.1099	0.0	1.47E-03	8.38E-03	0.0
Ar				0.0	9.25E-03	9.25E-03	7.13E-03	0.0318	0.0	0.0164	0.0
CO_2				0.0	3.27E-04	3.27E-04	0.1108	0.0	0.8835	0.0214	0.9923
O_2				0.0	0.2074	0.2074	0.0	0.9504	0.0	7.48E-18	0.0
N_2				0.0	0.7732	0.7732	5.06E-03	0.0178	4.29E-04	0.0122	5.39E-05
CO				0.0	0.0	0.0	0.4373	0.0	0.0702	0.4358	4.77E-03
COS				0.0	0.0	0.0	6.09E-05	0.0	4.25E-07	6.99E-08	2.85E-07
H_2				0.0	0.0	0.0	0.3019	0.0	0.0367	0.4793	1.13E-03
H_2S				0.0	0.0	0.0	1.08E-03	0.0	0.0	2.54E-11	6.72E-11
HCl				0.0	0.0	0.0	2.10E-05	0.0	0.0	0.0	0.0
NH_3				0.0	0.0	0.0	2.98E-03	0.0	0.0	5.40E-06	0.0
SO_2				0.0	0.0	0.0	0.0	0.0	0.0	2.35E-19	0.0
CH_4				0.0	0.0	0.0	0.0238	0.0	7.73E-03	0.0265	1.76E-03
C_2H_4				0.0	0.0	0.0	0.0	0.0	0.0	4.13E-09	0.0
C_2H_6				0.0	0.0	0.0	0.0	0.0	0.0	7.83E-10	0.0
C_3H_6				0.0	0.0	0.0	0.0	0.0	0.0	4.89E-13	0.0
C_3H_8				0.0	0.0	0.0	0.0	0.0	0.0	1.71E-14	0.0
ISOBU-01				0.0	0.0	0.0	0.0	0.0	0.0	1.46E-19	0.0
N-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	6.74E-17	0.0
1-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	2.18E-16	0.0
Naphtha				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8				0.0	0.0	0.0	0.0	0.0	0.0	4.82E-45	0.0

Description	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle
PFD Number	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	278.7
Pressure (psia)	14.7	317.0	14.7	14.7	14.7	227.6	14.7	14.7	14.7	14.7	477.0
Mass Flow (lb/hr)	6,518	39,539	175,103	53,579	273,556	31,247	248,439	4,747,310	4,248,873	206,203	192,802
Mole Flow (lbmol/hr)	25	19,313	1,657	252	1,288	640	7,958	263,516	150,239		9,354
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0654	1.0	0.0984		0.1099
Ar	0.0	1.18E-04	0.0	0.0	0.0	2.05E-05	0.0389	0.0	0.0149		7.13E-03
CO_2	0.0	8.59E-09	0.0	0.0	0.0	0.0602	0.2056	0.0	0.0423		0.1108
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0265	0.0	0.0996		0.0
N_2	0.0	2.89E-04	0.0	0.0	0.0	7.11E-07	0.6636	0.0	0.7448		5.06E-03
CO	0.0	7.46E-04	0.0	0.0	0.0	7.90E-06	0.0	0.0	0.0		0.4373
COS	0.0	0.0	0.0	0.0	0.0	1.70E-05	1.30E-13	0.0	0.0		6.09E-05
H_2	0.0	0.9988	0.0	0.0	0.0	1.48E-09	0.0	0.0	0.0		0.3019
H_2S	0.0	0.0	0.0	0.0	0.0	1.08E-10	0.0	0.0	0.0		1.08E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.10E-05
NH_3	0.0	0.0	0.0	0.0	0.0	1.31E-03	2.27E-06	0.0	5.23E-06		2.98E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	8.52E-14	0.0	2.10E-13		0.0
CH_4	0.0	0.0	0.0	0.0	0.0	4.91E-04	0.0	0.0	0.0		0.0238
C_2H_4	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0		0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.1099	0.0	0.0	0.0		0.0
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.3369	0.0	0.0	0.0		0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.3321	0.0	0.0	0.0		0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0993	0.0	0.0	0.0		0.0
Naphtha	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
F-T-Jet	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0
F-T-Diesel	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0
S_8	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0

Description	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA
PFD Number	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**
Temperature (F)	500.0	500.0	268.0	382.0	318.1	90.0	100.0	105.0
Pressure (psia)	477.0	477.0	665.0	379.0	360.0	125.0	369.0	25.0
Mass Flow (lb/hr)	3,035,353	627,876	1,281,767	432,733	131,115	29,124	1,623,089	1,045,320
Mole Flow (lbmol/hr)	147,263	30,462	39,830	21,258	4,074	905	62,121	23,753
Mole Fraction								
H_2O	0.1099	0.1099	0.0	0.0611	0.0	0.0	0.0	0.0
Ar	7.13E-03	7.13E-03	0.0318	0.0589	0.0318	0.0318	0.0410	0.0
CO_2	0.1108	0.1108	0.0	0.1009	0.0	0.0	0.4133	0.9999
O_2	0.0	0.0	0.9504	5.48E-17	0.9504	0.9504	0.0	0.0
N_2	5.06E-03	5.06E-03	0.0178	0.0348	0.0178	0.0178	0.0307	1.01E-05
CO	0.4373	0.4373	0.0	0.3788	0.0	0.0	0.1246	5.97E-05
COS	6.09E-05	6.09E-05	0.0	2.28E-09	0.0	0.0	1.75E-07	0.0
H_2	0.3019	0.3019	0.0	0.3554	0.0	0.0	0.3159	8.51E-08
H_2S	1.08E-03	1.08E-03	0.0	1.49E-12	0.0	0.0	6.37E-11	1.61E-10
HCl	2.10E-05	2.10E-05	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	2.98E-03	2.98E-03	0.0	3.95E-05	0.0	0.0	1.35E-05	0.0
SO_2	0.0	0.0	0.0	1.72E-18	0.0	0.0	0.0	0.0
CH_4	0.0238	0.0238	0.0	0.0100	0.0	0.0	0.0697	4.48E-05
C_2H_4	0.0	0.0	0.0	3.02E-08	0.0	0.0	1.39E-03	0.0
C_2H_6	0.0	0.0	0.0	5.74E-09	0.0	0.0	4.32E-04	0.0
C_3H_6	0.0	0.0	0.0	3.58E-12	0.0	0.0	1.19E-03	0.0
C_3H_8	0.0	0.0	0.0	1.25E-13	0.0	0.0	3.79E-04	0.0
ISOBU-01	0.0	0.0	0.0	1.07E-18	0.0	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	4.94E-16	0.0	0.0	3.29E-04	0.0
1-BUT-01	0.0	0.0	0.0	1.60E-15	0.0	0.0	1.02E-03	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	3.53E-44	0.0	0.0	0.0	0.0

Description	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	**36**	**37**	**38**	**39**
Temperature (F)	326.3	430.0	326.3	821.7
Pressure (psia)	317.0	317.0	317.0	236.8
Mass Flow (lb/hr)	7,016	312,160	305,697	216,356
Mole Flow (lbmol/hr)	500	16,235	21,785	7,498
Mole Fraction				
H_2O	0.0558	0.0800	0.0558	9.87E-03
Ar	0.0538	0.0771	0.0538	9.25E-03
CO_2	0.0465	0.0667	0.0465	3.27E-04
O_2	5.00E-17	7.17E-17	5.00E-17	0.2074
N_2	0.0313	0.0448	0.0313	0.7732
CO	0.2425	0.3474	0.2425	0.0
COS	9.14E-14	1.31E-13	9.14E-14	0.0
H_2	0.5692	0.3830	0.5692	0.0
H_2S	1.36E-12	1.94E-12	1.36E-12	0.0
HCl	0.0	0.0	0.0	0.0
NH_3	3.61E-05	5.17E-05	3.61E-05	0.0
SO_2	1.57E-18	2.26E-18	1.57E-18	0.0
CH_4	7.51E-04	1.08E-03	7.51E-04	0.0
C_2H_4	2.76E-08	3.96E-08	2.76E-08	0.0
C_2H_6	5.24E-09	7.51E-09	5.24E-09	0.0
C_3H_6	3.27E-12	4.69E-12	3.27E-12	0.0
C_3H_8	1.15E-13	1.64E-13	1.23E-13	0.0
ISOBU-01	9.73E-19	1.40E-18	9.73E-19	0.0
N-BUT-01	4.51E-16	6.47E-16	9.27E-15	0.0
1-BUT-01	1.46E-15	2.09E-15	1.46E-15	0.0
Naphtha	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0
S_8	3.40E-44	4.87E-44	3.40E-44	0.0

Table 2-33: CBTL, 28.3% Biomass, Torrefied Pellets, Validated: Stream Values

Description	Coal	Dried Coal	Torrefied Biomass	Steam	ASU Air	GT Air	Raw Syngas	O_2	Selexol CO_2	FT Feed	CO_2 Seq.
PFD Number	**1**	**2**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
Temperature (F)	59.0	220.0	59.0	489.4	59.0	59.0	500.0	90.0	100.0	269.5	100.0
Pressure (psia)	14.7	14.7	14.7	625.0	14.7	14.7	477.0	125.0	179.5	369.0	2214.7
Mass Flow (lb/hr)	1,781,858	1,613,016	636,658	342,805	6,108,596	3,531,600	3,664,485	1,448,977	1,580,616	2,461,864	2,508,009
Mole Flow (lbmol/hr)				19,029	211,685	122,383	177,142	45,026	38,453	156,545	57,220
Mole Fraction											
H_2O				1.0	9.87E-03	9.87E-03	0.1159	0.0	1.46E-03	9.23E-03	0.0
Ar				0.0	9.25E-03	9.25E-03	7.13E-03	0.0318	0.0	0.0171	0.0
CO_2				0.0	3.27E-04	3.27E-04	0.1066	0.0	0.8843	0.0217	0.9921
O_2				0.0	0.2074	0.2074	0.0	0.9504	0.0	7.59E-18	0.0
N_2				0.0	0.7732	0.7732	5.07E-03	0.0178	4.26E-04	0.0126	5.41E-05
CO				0.0	0.0	0.0	0.4417	0.0	0.0692	0.4334	4.75E-03
COS				0.0	0.0	0.0	5.62E-05	0.0	3.88E-07	6.39E-08	2.60E-07
H_2				0.0	0.0	0.0	0.2930	0.0	0.0361	0.4767	1.12E-03
H_2S				0.0	0.0	0.0	1.10E-03	0.0	0.0	2.53E-11	6.70E-11
HCl				0.0	0.0	0.0	2.11E-05	0.0	0.0	0.0	0.0
NH_3				0.0	0.0	0.0	3.00E-03	0.0	0.0	6.31E-06	0.0
SO_2				0.0	0.0	0.0	0.0	0.0	0.0	2.18E-19	0.0
CH_4				0.0	0.0	0.0	0.0265	0.0	8.52E-03	0.0293	1.96E-03
C_2H_4				0.0	0.0	0.0	0.0	0.0	0.0	5.20E-09	0.0
C_2H_6				0.0	0.0	0.0	0.0	0.0	0.0	1.03E-09	0.0
C_3H_6				0.0	0.0	0.0	0.0	0.0	0.0	6.59E-13	0.0
C_3H_8				0.0	0.0	0.0	0.0	0.0	0.0	2.40E-14	0.0
ISOBU-01				0.0	0.0	0.0	0.0	0.0	0.0	2.18E-19	0.0
N-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	7.04E-17	0.0
1-BUT-01				0.0	0.0	0.0	0.0	0.0	0.0	2.31E-16	0.0
Naphtha				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8				0.0	0.0	0.0	0.0	0.0	0.0	3.16E-42	0.0

Description	Sulfur	H_2 to Hydrotr	F-T Naphtha	F-T Diesel	F-T Jet	F-T LPG	Exhaust	Make-up Water	Stack Gas	Ash	Syngas Recycle
PFD Number	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**27**
Temperature (F)	77.0	77.0	77.0	77.0	77.0	77.0	270.0	59.0	270.0	100.0	282.1
Pressure (psia)	14.7	317.0	14.7	14.7	14.7	228.0	14.7	14.7	14.7	14.7	477.0
Mass Flow (lb/hr)	6,530	39,542	175,100	53,578	273,549	31,254	244,053	4,775,148	4,247,352	206,587	192,868
Mole Flow (lbmol/hr)	25	19,320	1,657	252	1,288	640	7,831	265,061	150,252		9,323
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0672	1.0	0.0987		0.1159
Ar	0.0	1.20E-04	0.0	0.0	0.0	2.16E-05	0.0398	0.0	0.0149		7.13E-03
CO_2	0.0	8.54E-09	0.0	0.0	0.0	0.0603	0.2027	0.0	0.0417		0.1066
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0264	0.0	0.0997		0.0
N_2	0.0	2.90E-04	0.0	0.0	0.0	7.48E-07	0.6638	0.0	0.7451		5.07E-03
CO	0.0	7.20E-04	0.0	0.0	0.0	7.93E-06	0.0	0.0	0.0		0.4417
COS	0.0	0.0	0.0	0.0	0.0	1.56E-05	1.19E-13	0.0	0.0		5.62E-05
H_2	0.0	0.9989	0.0	0.0	0.0	1.55E-09	0.0	0.0	0.0		0.2930
H_2S	0.0	0.0	0.0	0.0	0.0	1.08E-10	0.0	0.0	0.0		1.10E-03
HCl	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		2.11E-05
NH_3	0.0	0.0	0.0	0.0	0.0	1.54E-03	2.46E-06	0.0	5.58E-06		3.00E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	8.30E-14	0.0	2.00E-13		0.0
CH_4	0.0	0.0	0.0	0.0	0.0	5.40E-04	0.0	0.0	0.0		0.0265
C_2H_4	0.0	0.0	0.0	0.0	0.0	4.35E-03	0.0	0.0	0.0		0.0
C_2H_6	0.0	0.0	0.0	0.0	0.0	0.0555	0.0	0.0	0.0		0.0
C_3H_6	0.0	0.0	0.0	0.0	0.0	0.1098	0.0	0.0	0.0		0.0
C_3H_8	0.0	0.0	0.0	0.0	0.0	0.3368	0.0	0.0	0.0		0.0
ISOBU-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
N-BUT-01	0.0	0.0	0.0	0.0	0.0	0.3319	0.0	0.0	0.0		0.0
1-BUT-01	0.0	0.0	0.0	0.0	0.0	0.0992	0.0	0.0	0.0		0.0
Naphtha	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0
F-T-Jet	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0		0.0
F-T-Diesel	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0		0.0
S_8	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		0.0

Description	Syngas to WGS	Syngas to COS	O_2 to Gasifier	FT Recycle	O_2 to ATR	O_2 to Claus	Light HC from FT	CO_2 from MDEA
PFD Number	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**
Temperature (F)	500.0	500.0	268.0	391.6	318.1	90.0	100.0	105.0
Pressure (psia)	477.0	477.0	665.0	379.0	360.0	125.0	369.0	25.0
Mass Flow (lb/hr)	3,098,114	566,370	1,278,591	460,425	141,003	29,383	1,640,370	1,048,459
Mole Flow (lbmol/hr)	149,764	27,378	39,732	22,858	4,382	913	62,853	23,825
Mole Fraction								
H_2O	0.1159	0.1159	0.0	0.0629	0.0	0.0	0.0	0.0
Ar	7.13E-03	7.13E-03	0.0318	0.0605	0.0318	0.0318	0.0426	0.0
CO_2	0.1066	0.1066	0.0	0.0959	0.0	0.0	0.4097	0.9999
O_2	0.0	0.0	0.9504	5.20E-17	0.9504	0.9504	0.0	0.0
N_2	5.07E-03	5.07E-03	0.0178	0.0357	0.0178	0.0178	0.0315	1.05E-05
CO	0.4417	0.4417	0.0	0.3741	0.0	0.0	0.1228	5.94E-05
COS	5.62E-05	5.62E-05	0.0	1.92E-09	0.0	0.0	1.59E-07	0.0
H_2	0.2930	0.2930	0.0	0.3604	0.0	0.0	0.3126	8.49E-08
H_2S	1.10E-03	1.10E-03	0.0	1.45E-12	0.0	0.0	6.31E-11	1.61E-10
HCl	2.11E-05	2.11E-05	0.0	0.0	0.0	0.0	0.0	0.0
NH_3	3.00E-03	3.00E-03	0.0	4.32E-05	0.0	0.0	1.57E-05	0.0
SO_2	0.0	0.0	0.0	1.49E-18	0.0	0.0	0.0	0.0
CH_4	0.0265	0.0265	0.0	0.0104	0.0	0.0	0.0761	4.93E-05
C_2H_4	0.0	0.0	0.0	3.56E-08	0.0	0.0	1.37E-03	0.0
C_2H_6	0.0	0.0	0.0	7.04E-09	0.0	0.0	4.27E-04	0.0
C_3H_6	0.0	0.0	0.0	4.51E-12	0.0	0.0	1.18E-03	0.0
C_3H_8	0.0	0.0	0.0	1.64E-13	0.0	0.0	3.75E-04	0.0
ISOBU-01	0.0	0.0	0.0	1.49E-18	0.0	0.0	0.0	0.0
N-BUT-01	0.0	0.0	0.0	4.82E-16	0.0	0.0	3.25E-04	0.0
1-BUT-01	0.0	0.0	0.0	1.58E-15	0.0	0.0	1.01E-03	0.0
Naphtha	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S_8	0.0	0.0	0.0	2.16E-41	0.0	0.0	0.0	0.0

Description	Fuel Gas	Recycle to FT	Fuel Gas to GT	GT Air Extract
PFD Number	36	37	38	39
Temperature (F)	328.5	433.0	328.5	821.8
Pressure (psia)	317.0	317.0	317.0	236.9
Mass Flow (lb/hr)	6,961	340,367	302,650	215,350
Mole Flow (lbmol/hr)	500	17,856	21,740	7,463
Mole Fraction				
H_2O	0.0562	0.0806	0.0562	9.87E-03
Ar	0.0541	0.0774	0.0541	9.25E-03
CO_2	0.0443	0.0635	0.0443	3.27E-04
O_2	4.64E-17	6.65E-17	4.64E-17	0.2074
N_2	0.0314	0.0449	0.0314	0.7732
CO	0.2410	0.3450	0.2410	0.0
COS	8.29E-14	1.19E-13	8.29E-14	0.0
H_2	0.5721	0.3873	0.5721	0.0
H_2S	1.30E-12	1.86E-12	1.30E-12	0.0
HCl	0.0	0.0	0.0	0.0
NH_3	3.86E-05	5.53E-05	3.86E-05	0.0
SO_2	1.33E-18	1.91E-18	1.33E-18	0.0
CH_4	8.43E-04	1.21E-03	8.43E-04	0.0
C_2H_4	3.18E-08	4.56E-08	3.18E-08	0.0
C_2H_6	6.29E-09	9.01E-09	6.29E-09	0.0
C_3H_6	4.03E-12	5.78E-12	4.03E-12	0.0
C_3H_8	1.47E-13	2.10E-13	1.56E-13	0.0
ISOBU-01	1.33E-18	1.91E-18	1.33E-18	0.0
N-BUT-01	4.31E-16	6.17E-16	9.27E-15	0.0
1-BUT-01	1.41E-15	2.03E-15	1.41E-15	0.0
Naphtha	0.0	0.0	0.0	0.0
F-T-Jet	0.0	0.0	0.0	0.0
F-T-Diesel	0.0	0.0	0.0	0.0
S_8	1.93E-41	2.77E-41	1.93E-41	0.0

3 Economic Model

The following text provides a summary of data sources and modeling choices incorporated into the economic model that was generated in support of this study.

3.1 Raw Material (Feedstock) Costing and Economics

The following text provides a summary of background information and data sources, as well as cost information, for the various steps included in feedstock costing.

3.1.1 Feedstock Cost Description and Data Sources

The following provides a summary of feedstock cost and cost data sources, for both the coal and biomass feedstocks considered in support of this study.

3.1.1.1 Coal Feedstock

The cost of coal is influenced by several factors including the heating value, sulfur content, and distance from the mine to the point of use. Coal obtained by surface mining methods tends to be cheaper than that obtained by underground mining because the cost to extract the resource is less (EIA, 2012). There tends to be a linear relationship between coal price and both heating value and sulfur content. Transportation costs comprise a significant fraction of the final delivered coal cost. In some cases, transportation costs can be higher than the cost of the coal at the mine (EIA, 2012). Based on data from EIA, the average sales price of coal at the mine was $35.61 per short ton with average transportation costs adding an additional $9.48 per short ton, 21 percent of the delivered cost (EIA, 2012). For the purposes of this study, the coal cost is estimated per year assuming that the cost of the Montana Rosebud sub-bituminous coal delivered to the plant is $36.26 per ton, equivalent to $2.00 per MMBtu.

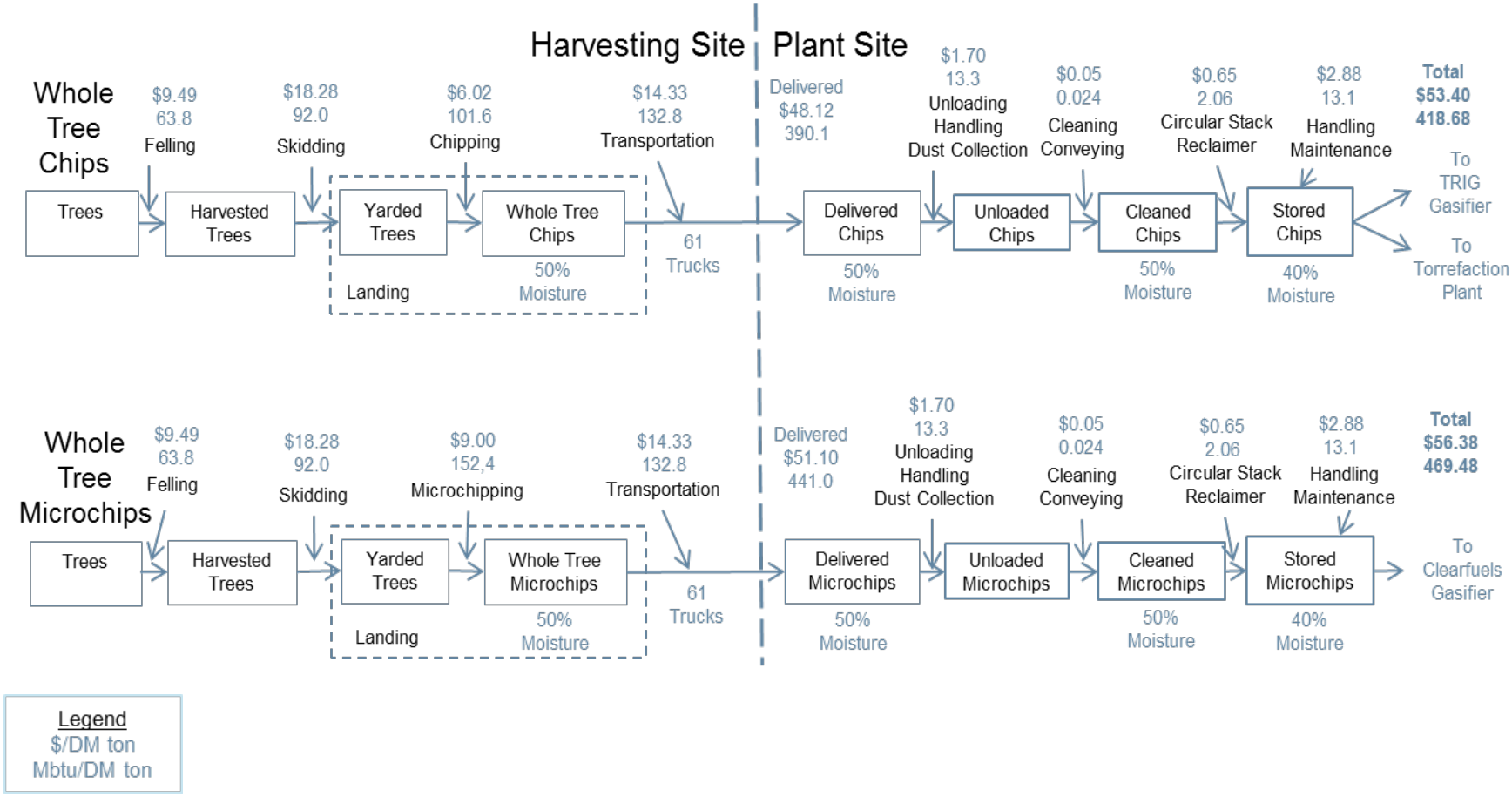
3.1.1.2 Biomass Feedstock

The cost of biomass is variable based on biomass source and harvesting method. Therefore, a close evaluation of biomass cost was completed in support of this study. Herein, the Idaho National Laboratory (INL) Bioenergy Program has conducted a detailed analysis of the woodchip supply chain for energy production (Searcy & Hess, 2010). The purpose of the study segment is to establish a woody biomass feedstock supply system design that uses conventional technologies and operations.

Figure 3-1 shows the costs and energy use for the green woodchip supply chains analyzed in this study. Whole tree woodchips of typical pulpwood industry size are suitable as feedstock for the torrefaction plants but additional grinding to finer sizes are necessary for feeding to TRIG gasification, as discussed previously. Whole tree microchips are used as the feedstock supply for the ClearFuels® gasifier. Standard whole tree chips require different energy and cost values, as shown in **Figure 3-1**.

Microchipping is a developing commercial capability to serve the bioenergy market (Baker, 2011). A main microchip customer currently is the wood pellet industry (Arcowood Corporation, No Date; Hein, 2011; Steiner & Robinson, 2011), but microchips are also of value in the torrefaction process (Hagen, 2011). Commercial transportable microchippers that can be used for chipping at the harvest site are available from several manufacturers (examples include Bandit, Continental Biomass Industries, Morebark, and Peterson).

Figure 3-1: Unit Operations (Costs and Energy Use) for the Southern Pine Wood Chip Supply Chain



Note: DM stands for dry matter.

Source: (Mitchell, 2011; Rummer, 2011; Searcy & Hess, 2010).

Because microchipping at the biomass harvesting site is a developing capability, few data are currently available in the open literature on the cost and energy use for this unit operation. The USDA Forest Service in Auburn, Alabama is conducting research on whole tree microchipping cost and energy use of Southern pine at the harvesting site. Initial data are available from field studies using a prototype chipping machine (Mitchell, 2011; Rummer, 2011). Capital investment was found to be about the same for microchippers because currently available chippers can be modified to produce microchips. Machine maintenance is greater for microchippers because of the larger number of chipping blades that must be sharpened and maintained. Fuel consumption was 30 percent greater per green ton for microchips than for regular pulpwood chips. Microchip bulk density was similar to regular pulpwood chips. Microchip cost per green ton was about 17 percent greater than regular pulpwood chips considering only chipper operation and operator labor costs.

The microchipping analysis provided within this study is based on these data, however, the study authors recognize that data on energy and cost estimates for microchippers is limited and preliminary. Therefore, to provide conservative estimates, this study incorporates energy and cost estimates that are 50 percent greater than the value provided by INL (Searcy & Hess, 2010) for the chipping operation for whole tree chips of regular size. Because the bulk density of microchips was about the same as regular chips, it is assumed that the transportation, handling, and storage costs and energy use for microchips are the same as for regular wood chips.

Pelletization of biomass is assumed to occur at a third-party facility. RAND specified the additional costs associated with the densification or pelletization of biomass as $33/dry metric tonne(S.Ortiz, Curtright, Samaras, Litovitz, & Burger, 2011). Of that $33/dry metric tonne, $27 was associated with the operating costs of drying and pelletizing the biomass. That value was scaled according to the amount of drying that occurs in this analysis compared to that assumed in the RAND study. The resulting value used as the default for this study was $84/dry short ton.

3.1.2 Feedstock Milling Capacity

Table 3-1 shows results obtained by the Energy Research Centre of the Netherlands (ECN) of the comparison of mill throughput capacity for various feedstocks. As shown, the torrefied material grinds considerably faster than untreated green wood or coal. The results shown are for production of 0.4 mm sized particles. Based on these data it is assumed that the chipped woody biomass would require just over two times (71/34.8) the mill capacity to grind the same flow as coal. Thus, the BEC would be $92.87/lb/hr. For scenarios with coal and chipped biomass co-gasification it is assumed that separate mills and dryers are used for the coal and the biomass. For the torrefied woody biomass the mill capacity, in pounds per hour, is assumed to be over four times (340/71) that of coal ($9.5/lb/hr). For co-gasification of coal and torrefied biomass, it is assumed that the coal and torrefied biomass are ground in separate mills before being fed to the TRIG gasifiers.

Table 3-1: Mill Capacity per Feedstock (Grinding to 0.4 mm Particles) (J. Kiel, 2011a)

Feedstock	Mill Capacity (kW_{th})
Torrefied Willow	340
Pelletized Torrefied Willow	340
Chipped Wood	34.8
Pelletized Wood	34.8
Coal	71

3.2 Torrefaction Process Costing and Economics

Integro Earth Fuels, Inc. provided an estimate of base costs for a 63 kiloton per year torrefaction system that processes Southern pine. The BEC for this system - which includes the front end loaders, storage, and conveying equipment, combined drying and torrefaction reactor vessels, the gas combustor, and an induced draft fan – is quoted at about $10.5 MM (Childs, 2012). For a 2,500 tons per day target torrefied wood production rate this will therefore require 13 units at a capacity factor of 90 percent for a total BEC estimate of $136 MM. After adding 10 percent home office and 15 percent process contingency and project contingency, the capital cost will be $191 MM. Annual operation and maintenance costs are estimated in four categories: (1) raw Southern pine wood, (2) natural gas, (3) electric power, and (4) labor.

Table 3-2: Biomass Torrefaction System Economic Summary

Process Parameters/Category	Value	Units
Feed Prep and Drying		
Raw Wood Feed Rate	5,375	tons/day
Raw Wood Moisture	43.3	weight %
Dried Wood Moisture	8.2	weight %
Dryer Thermal Capacity	259	MMBtu/hr
Torrefaction		
Feed Mass Flow	3,320	tons/day
Mass Yield	75.3	lb torrefied solid/lb feed
Energy Yield to Mass Yield Ratio	1.185	N/A
Torrefied Product Higher Heating Value (HHV)	10,340	Btu/lb
CO_2 Emissions Rate	829	tons/day
SO_2 Emissions Rate	2.4	tons/day
Torrefied Solids Product	2,500	tons/day
Capacity Factor	90	% annual availability
Cost Estimate		
Capital Cost of Torrefaction Equipment	190.8	$, million
Capital Charge Factor	0.1872	N/A
Capital Component	45.1	$, millions per year
Raw Wood (@$22.63/ton)	40.0	$, millions per year
Natural Gas (@$4/MMBtu)	5.89	$, millions per year
Electric Power (8.84 MW @ $70.6/MWh)	4.92	$, millions per year
Operation and Maintenance Costs	6.8	$, millions per year
Annual Revenue Requirement	105.4	$, millions per year
Required Selling Price (Torrefaction Plant Gate)	128.9	$ per ton

The price for raw Southern pine delivered to the torrefaction plant is estimated as the sum of the costs for tree felling ($4.75 per dry ton), wood skidding ($9.14 per dry ton), wood chipping ($3.01 per dry ton), and transport ($5.73 per dry ton) for a total of $22.63 per ton (Searcy & Hess, 2010).

Natural gas required is estimated by determining the difference between the amount of heat needed to operate the drying and torrefaction units and the amount of heat available when the heating value of the torrefaction product gas is 5.2 percent that of the feed. A heating value for natural gas of 950 BTUs per standard cubic foot is assumed. A natural gas cost of $4 per thousand cubic feet is assumed.

Electric power requirements are approximated by scaling estimates provided by ECN (P. C. A. Bergman, Boersma, A. R., Zwart, R. W. R., & Kiel, J. H. A., 2005) for a 227 kiloton per year torrefaction system using a directly-heated moving bed. There, the Energy Research Center of the Netherlands (ECN) estimates an electric power requirement of 2.61 MW. The system under consideration here is 3.4 times larger at a product rate of 775,545 tons per year, making for a total power of 8.8 MW. An electric power cost of $70.6 per megawatt hour is assumed.

The levelized total capital cost combined with annual operation and maintenance costs provide an estimate of the annual revenue requirement (ARR). The ARR divided by the annual production rate gives the estimate for the required selling price (RSP) of torrefied biomass product. The capital charge factor used for capital costs is 0.1872. **Table 3-2** summarizes, as an example, the results and costs for a torrefaction system that produces 2,500 tons per day of torrefied biomass from Southern pine.

The cost of torrefied wood of $128.9/ton is at the torrefaction plant gate. An additional cost of $5.73 per ton must be added for transportation of the torrefied biomass to the CBTL facility. This brings the total delivered cost of the torrefied wood to $134.66 per ton. It was assumed that pelleted torrefied biomass has a cost that is 5 percent higher than just torrefied biomass.

3.3 CBTL Facility Costing and Economics

In most cases, the capital and operating cost estimates were obtained from conceptual level cost algorithms that scale costs based on one or more measures of unit capacity. These algorithms have been developed based on literature sources (NETL, 2010a, 2010b). In some cases, cost estimates were based on vendor quotes. All costs are reported in June 2011 dollars.

The method used to determine total capital requirement is as follows: the bare erected cost (BEC) estimates for each of the conceptual plants, consist of equipment cost, material cost, and installation labor costs. These three components are added to give the BEC of the individual unit operations. The engineering, procurement, and construction cost (EPCC) is the sum of the BEC and the home office costs. The home office costs include detailed design costs and construction and project management costs. Home office costs were estimated as 9.5 percent of the BEC.

The total plant cost (TPC) is the sum of the EPCC, the process contingencies, and the overall project contingency. The TPC is a depreciable capital expense. The process contingencies are added to the plant sections and the amount of the contingency depends on an engineering assessment of the level of commercial maturity of the process. The overall project contingency was assumed to be 15 percent of the sum of the BEC and process contingencies. This is added to compensate for uncertainty in the overall cost estimate.

The Total Overnight Cost (TOC) of the plants is defined as the sum of the TPC and the Owner’s Cost. **Table 3-3** shows the components of the Owner’s Costs; **Table 3-4** shows components of the total as-spent capital.

Table 3-3: Components of Owners Costs

Owners Cost Components
Initial Cost of Catalysts & Chemicals
Land Cost ($3,000/Acre)
Financing Fee (2.7% of TPC)
Other Owners Cost (15% TPC)
Pre-Production Costs
1 Month Maintenance Materials
1 Month Non-Fuel Consumables
25% of 1 Month Fuel Cost (100% Cap Factor)
6 Months Plant Labor
1 Month Waste Disposal
2% of TPC
Inventory Costs
60 Day Fuel/Consumables at 100% Cap Factor
Spare Parts (0.5% of TPC)

Table 3-4: Components of the Total As-Spent Capital

Parameter	Description
Bare Erected Cost (BEC)	Sum of the installed equipment costs for the various plant sections
Engineering, Procurement, and Construction Cost (EPCC)	BEC + Home Office Costs
Total Plant Cost (TPC)	EPCC + Process Contingency + Project Contingency
Total Overnight Cost (TOC)	TPC + Owner's Costs
Total As Spent Capital (TASC)	TOC * TASC Multiplier of 1.14

The annual operating expenses for the plants are composed of fuel costs and variable and fixed operating costs. Fuel cost is the cost of the coal and woody biomass feedstocks to the plants based on assumed delivered prices. Non-fuel variable operating costs include catalysts and chemicals, water, solids disposal and maintenance materials. The small quantities of natural gas and electric power needed for start-up are not included. Fixed operating costs include labor, administrative and overhead costs, local taxes, insurance, and fixed CO_2 transport costs. Gross annual operating costs are the sum of the fuel, variable, and fixed operating costs and are expressed in million dollars per annum based on a given capacity factor, expressed as a percentage of 365 days in one year. The capacity factor therefore represents the on-stream time for the plant that is the number of days in the year when the plant is producing products.

Table 3-5: Feedstock Costs

Feedstock	Cost ($/ton)	Cost ($/MMBtu)
Montana Rosebud PRB Coal (As Received)	36.26	2.00
Green Woody Biomass Chips (Dry)	43.65	3.35
Green Woody Biomass Microchips (Dry)	46.36	3.56
Torrefied Woody Biomass (As Received)	134.66	6.51
Pelleted Woody Biomass (Dry)	84.04	5.14
Torrefied Pelleted Woody Biomass (As Received)	141.39	6.83

Table 3-6: By-Product Value

By-Product	Value
Electricity ($/MWh)	70.59
Sulfur ($/ton)	0.00
Carbon Dioxide ($/tonne)	40.0

By-product credits include any sales of electric power to the grid. No credit is taken for the sale of elemental sulfur. The captured carbon dioxide will be used for CO_2 enhanced oil recovery operations, and thus this represents an additional revenue source for the facility at an expected value of $40/tonne is assumed for the carbon dioxide captured (NETL, 2011e). Feedstock costs delivered to the plant, on an as-received basis, are shown in **Table 3-5** and the credits for electric power and CO_2 are shown in **Table 3-6**.

3.4 Capital Charge Factor Calculation

A previous version of this report utilized the NETL Power Systems Financial Model (PSFM) to calculate the capital charge factor (CCF) (NETL, 2014). This version utilizes a new approach to calculate the CCF based on a set of equations instead of utilizing the goal-seek method in the current version of PSFM. The advantage of this approach is that it utilizes functions, resulting in a more transparent model with repeatable results. The Free Cash Flow to the Firm Discounted Cash Flow methodology generates CCF values that are independent of operating and maintenance costs as well as by-product costs and credits (Berk, 2011) (Brealey, 2003) . This value is a constant for a given set of economic assumptions at a constant or levelized capacity factor and constant escalation rate for all cost of production (COP) components. With this new approach, the following six parameters replace the CCF in **Table 1-5**: tax rate (state and federal), depreciation schedule, internal rate of return on equity (IRROE), percent of capital financed by debt, interest rate on debt, and investment tax credit. Users have access to these parameters in the corresponding Excel model for this analysis.

The default economic assumptions for this analysis are based on a commercial fuels application (NETL, 2011d). For that application, the percent of capital financed by debt is 50 percent and the interest rate on debt is 8 percent. Alternatively, under a loan guarantee scenario, the percent of capital financed by debt increases to 60 percent and the interest rate decreases to 4.56 percent (NETL, 2009). Both scenarios are based on an IRROE of 20 percent, an effective tax rate of 38 percent, with a 20-year declining balance depreciation schedule, and no investment tax credit (NETL, 2011c). The economic results in **Section 5** are based on the commercial fuels application; however, the RSP for jet fuel under the second scenario is also reported. The commercial fuels financial structure results in

a capital charge factor of 0.1872, while the loan guarantee structure yields a capital charge factor of 0.1591

The constant CCF function was developed based on the assumptions that all COP components vary at a constant annual rate and at the same annual rate for all components. If it is desirable to estimate the impact of differing escalation rates, PSFM must be used to calculate the CCF instead. The equations below depict the details for the calculation of the CCF.

$$CCF = \frac{\sum_{n=1}^{Y_B+Y_C}((Capital_n - Depreciation_n * TaxRate - ITC_n) * (1/(1+ATWACC)^{(n-Y_C)}))}{TOC * \sum_{n=1}^{Y_B+Y_C}((1+Escalation)^{(n-1)} * (1-TaxRate)) * (1/(1+ATWACC)^{(n-Y_C)}}$$

Where:

$$Capital_n = TOC * \% \frac{Capital}{yr}_n * (1 + Capital\ Esc.)^{(n-1)} + TOC * \sum_{1}^{n}\left(\frac{(1-\%Equity_{TOC}) * \%Capital/yr_n * (1+Capital\ Esc.)^{(n-1)}}{Payperyr} * \sum_{m=1}^{Payperyr}\left(\frac{Interest}{Payperyr}\right)^m\right)$$

$$TASC = TOC * \%Equity_{TOC} * \sum_{n=1}^{Y_C} \% \frac{Capital}{yr}_n * (1 + Capital\ Esc.)^{(n-1)} + TOC * (1 - \%Equity_{TOC}) * \sum_{n=1}^{Y_C}\left(\frac{\%Capital/yr_n * (1+Capital\ Esc.)^{(n-1)}}{Payperyr} * \sum_{m=1}^{Payperyr}(1+\frac{Interest}{Payperyr})^{(Yc+1-n)*(Payperyr+1-m)}\right)$$

$$Depreciation_n = \sum_{n=1}^{Y_D}(TASC * \%Depreciation\ per\ yr_n)$$

$$ATWACC = \%Equity_{TASC} * IRROE * + \%\ Debt_{TASC} * (1 - Tax\ Rate) * (1 + Interest)$$

$$ITC_{N=Y_C+1} = \%ITC * TOC * \sum_{n=1}^{Y_C} \% \frac{Capital}{yr}_{n} * (1 + Capital\ Esc.)^{(n-1)}$$

And

ATWACC = After tax weighted average cost of capital.

Capital Esc = Assumed constant escalation percent per year of capital costs during construction period.

$Capital_n$ = Capital Charges in nth year including escalation and interest during construction (zero after last year of capital expenditures).

% Capital/Year = Percent of TOC expended in year n

$Depreciation_n$ = Depreciated Charges in nth year (zero until first year of operation).

% Depreciation per year = Percent of TASC depreciated in year n.

% $Debt_X$ = Percent of Capital X (where X = TOC or TASC) financed by Debt

%$Equity_X$= Percent of Capital X (where X = TOC or TASC) financed by Equity

Escalation = Assumed constant escalation rate (percent per year) for COP and all operation and maintenance (O&M) components including fixed, variable, fuel, and byproducts.

Interest = Interest rate percent per year on Debt

ITC = Investment tax credit as a percent of TOC
(one time credit in first year of operation, N = Yc + 1)

IRROE = Internal rate of return on equity percent per year

Payperyr = Assumed number of capital payments per year (12 = monthly)

TASC = Total as spent capital

Tax Rate = Marginal tax rate percent per year

TOC = Total overnight capital cost

Y_B = Number of years of book life

Y_C = Number of years of capital expenditure

Y_D = Number of years of Depreciation

3.5 Required Selling Price Estimates for Products

The key measure of the economic viability of the CBTL facilities under each of the 20 scenarios is the estimated required selling price (RSP) of the products. The RSP is the minimum price at which the products must be sold to recover the annual revenue requirement (ARR) of the plant. The ARR is the annual revenue needed to pay the operating costs, service the debt, and provide the expected rate of return for the investors. If the market price of the products is equal to or above the calculated RSP, the CBTL project is considered economically viable.

The ARR is the sum of the fuel cost, variable operating cost, fixed operating cost, and annual capital component minus the by-product credits for electric power and CO_2 revenues.

The annual capital component of the ARR is determined as the product of the total overnight cost (TOC) and the capital charge factor. The default capital charge factor used in this financial analysis is 0.1872.

The conceptual CBTL facility under each of the Scenarios produces at most six products for sales. These products are F-T jet fuel, F-T diesel fuel, F-T naphtha, F-T LPG, F-T electric power, and CO_2. A portion of light gases including F-T LPG are used within the plant. F-T naphtha, although it has a similar boiling range to gasoline, has not traditionally been considered to be suited for refining into high octane gasoline because of its highly paraffinic nature. It is, however, an excellent feed to an ethylene cracker.

This analysis assumes that the diesel, naphtha, and LPG can be sold at a discounted price compared to the jet fuel. These relative values are used to determine the equivalent jet fuel yield from the CBTL facility in terms of barrels per year. The quotient of the ARR and the jet fuel equivalent barrels gives the RSP for the jet fuel product. Dividing this value by 42 gives the RSP of the jet on a $/gallon basis. **Table 3-7** shows the relative values for the products compared to jet fuel based on an average volumetric price.

Table 3-7: Product Relative Values

Fuel Type	Relative Value
F-T Jet Fuel	1.0
F-T Diesel	0.99
F-T Naphtha	0.69
F-T LPG	0.40

It is often convenient to express the RSP in terms of an equivalent crude oil price. Historically the ratio of the price of diesel to the crude oil price has been about 1.2. This ratio was checked by averaging the ratios of refined diesel product price to the price of West Texas Intermediate crude for the years 2009 and 2010. This ratio needs to be further adjusted by multiplying it by the ratio of heating values for FT diesel and petroleum derived diesel. This yields a crude oil equivalent ratio of 1.1433

4 Life Cycle Environmental Model

As discussed in Chapter 1, the life cycle environmental model considers environmental flows, including inputs and emissions, for five life cycle stages: raw material acquisition (RMA), raw material transport (RMT), energy conversion (EC), product transport (PT), and end use (EU). Each of these stages is broken down into model units, for both construction and operation as applicable. Modeling approach and data sources for each of the five life cycle stages are presented in the following text.

4.1 Raw Material Acquisition

Raw material acquisition includes acquisition of feedstocks used for the production of F-T jet fuel at the CBTL facility. These include Montana Rosebud coal and Southern pine biomass. Land use requirements associated with Southern pine biomass are also documented.

4.1.1 Montana Rosebud Sub-Bituminous Coal Mining

Montana Rosebud sub-bituminous coal was selected for this study because its properties are considered optimal for use in the gasification and F-T conversion processes evaluated within this study.

Table 4-1: Analysis of Montana Rosebud PRB Sub-Bituminous Coal[1]

Property	As Received	Dry Basis	As Fed to CBTL Facility
Proximate Analysis			
Moisture (%)	25.77	0.00	18.00
Ash (%)	8.19	11.04	9.05
Volatile Matter (%)	30.34	40.87	33.51
Fixed Carbon (%)	35.70	48.09	39.43
Total (%)	100.00	100.00	100.00
Ultimate Analysis			
C (%)	50.07	67.45	55.31
H (%)	3.38	4.56	3.74
O (%)	11.14	15.01	12.31
N (%)	0.71	0.96	0.79
S (%)	0.73	0.98	0.80
Cl (%)	0.01	0.01	0.01
Ash (%)	8.19	11.03	9.04
Moisture (%)	25.77	0.00	18.00
Total (%)	100.00	100.00	100.00
Heating Value			
HHV (Btu/lb)	8,564	11,516	9,443
LHV (Btu/lb)	8,252	11,096	9,079

Montana Rosebud sub-bituminous coal is derived from the Rosebud Coal Mine, which is located in the northern portion of the Powder River Basin, near Colstrip, Montana. The surface mine has an average annual production capacity of 12.3 million tons, and has been in operation since 1968 (Westmoreland Coal Company, 2012). **Table 4-1** summarizes Montana Rosebud coal properties on an as-received, dry, and as fed basis.

4.1.1.1 Construction

Construction processes modeled for the Montana Rosebud Coal mine include the various equipment and major facilities required at the surface mine site, as well as emissions associated with the initial land clearing and facilities installation associated with mine installation. Equipment and facilities were apportioned per the total study period production rate for Montana Rosebud coal, in consideration of estimated equipment replacement rates. **Table 4-2** provides a summary of the facilities and equipment considered, the number of each that is required for the mine, and the estimated replacement rate for each equipment/facility type.

[1] Coal properties are consistent with those included in the NETL Quality Guidelines for Energy Systems Studies. The properties included are an expansion of the ASTM D-3176 standard and are not intended to conform to that specification.

Table 4-2: Montana Rosebud Coal Mine Construction Properties

Property	Value	Units	Reference
Annual mine production	11,158,372,302	kg/yr	(Westmoreland Coal Company, 2012)
Mine lifetime (study period)	30	years	Study Assumption
Total amount of Rosebud coal produced over mine lifetime	334,751,169,060	kg	(Westmoreland Coal Company, 2012)
Dragline lifetime	15	years	NETL Engineering Judgment
Shovel lifetime	15	years	NETL Engineering Judgment
Loader lifetime	15	years	NETL Engineering Judgment
Conveyor lifetime	20	years	NETL Engineering Judgment
Drill lifetime	15	years	NETL Engineering Judgment
Crusher lifetime	15	years	NETL Engineering Judgment
Silo lifetime	30	years	NETL Engineering Judgment
Truck lifetime	10	years	NETL Engineering Judgment
Number of draglines	4	draglines	(Westmoreland Coal Company, 2012)
Number of shovels	1	shovels	(Westmoreland Coal Company, 2012)
Number of loaders	10	loaders	(Westmoreland Coal Company, 2012)
Number of conveyors	1	conveyors	(Westmoreland Coal Company, 2012)
Number of drills	3	drills	(Westmoreland Coal Company, 2012)
Number of crushers	1	crushers	(Westmoreland Coal Company, 2012)
Number of silos	6	silos	(Westmoreland Coal Company, 2012)
Number of trucks	12	trucks	(Westmoreland Coal Company, 2012)

4.1.1.2 Operations

Operations of the coal mine are based on operations from a compilation of the three largest producers of Powder River Basin coal (Peabody Energy's North Antelope-Rochelle mine, Arch Coal, Inc.'s Black Thunder Mine, and Kennecott Energy's Cordero Rojo Operation), of which Rosebud is a coal seam. The Rosebud coal mine is located in southern Montana, near the town of Colstrip. Sources reviewed in assessing coal mine operations include facility and equipment needs, production raters, electricity usage, particulate air emissions, methane emissions, explosives usage, and additional governmental publications on coal and mines.

Coal is extracted from the surface coal seam through an open pit mining process. Blasting with ammonium nitrate fuel oil explosives occurs in drilled holes to remove the overburden and expose the coal seam for extraction. The removal of the overburden occurs with the use of draglines, powered by electricity, which pile the overburden in a different location to enable extraction of the coal. After the dragline has removed as much as possible, large electric shovels are used for the removal of the remaining overburden. The coal is removed using a truck and shovel approach. The trucks move the coal 3.2 km (2 miles) to the preparation facility for grinding and crushing to the proper size for transport. No cleaning of the coal occurs based on the coal properties. A conveyor belt

carries the crushed coal from the preparation facility to the loading silo. The coal is then loaded into rail cars for rail transport.

Coalbed methane emissions from the coal mine, and from the extracted coal during processing and storage, were estimated based on U.S. EPA estimates of methane release for the Rosebud coal mine. No methane is captured from the Rosebud coal mine prior to coal mining (USEPA, 2008). Therefore, it is assumed that all emitted methane is released to the atmosphere. The Rosebud mine releases 8 standard cubic feet of methane per short ton of coal produced. Other types of coal may have up to 360 standard cubic feet of methane emissions per short ton of coal (USEPA, 2008).

Electricity and diesel use were based on data points published by Peabody Energy in reference to their North Antelope Rochelle Mine in Wyoming (Burley, 2008; Peabody Energy Company, 2005). The data were linearly scaled down such that they were applicable to the size of the mine being modeled.

Emissions of criteria pollutants were based on emissions associated with the combustion of diesel. U.S. EPA Tier 4 diesel standards for non-road diesel engines were used, since these standards would go into effect within a few years of commissioning of the mine for this study (USEPA, 2004). Diesel is assumed to be ultra-low sulfur diesel (15 ppm sulfur). Emissions of particulate matter included those due to the combustion of diesel, as well as fugitive coal dust from the mining process. Total coal dust emissions were obtained from the EPA's AP 42's Mineral Products Industry section (USEPA, 2009).

Water use was estimated based on an environmental impact study completed on West Antelope II mine located in the Powder River Basin of Wyoming (Bureau of Land Management, 2008). Water emissions, including flows and concentrations of relevant inorganic constituents and solids entering the water stream, were taken from available National Pollutant Discharge Elimination System permit reporting documentation (USEPA, 2009).

4.1.2 Southern Pine Biomass Production

Southern pine biomass production (operation) was apportioned into three sub-processes: land preparation, cultivation, and harvesting. These are discussed in the following text. Construction of equipment required for Southern pine biomass production is also considered. Land use change associated with biomass production is discussed in the following subsection.

Southern yellow pine (Southern pine) biomass refers to several species of softwood pine species that are commercially grown in the U.S. Southeast. The two most common species of Southern pine are loblolly pine (*Pinus tadea*) and longleaf pine (*Pinus palustris*). Other common species include shortleaf pine (*Pinus echinata*), and slash pine (*Pinus elliotii*). Southern pine species are currently grown primarily under 20 to 30+ year rotations for a well-established lumber and wood products industry, with rotations for pulpwood ranging in some cases down to approximately 15 years (Dickens, D Moorhead, Dangerfield, & Chapman, 2008; Schimleck, 2008). However, Southern pine's rapid growth rate, relatively high productivity, and suitable compositional properties have attracted interest in its potential for use as a dedicated energy crop.

In support of CBTL fuels production, raw Southern pine biomass must be chipped and ground prior to use in a conversion facility. **Table 4-3** summarizes properties of Southern pine biomass as received, on a dry basis, and as fed to the CBTL facility. The properties of ground and pelleted biomass are assumed the same. Torrefaction (discussed in greater detail below) provides an alternative to grinding or pelleting, and involves heating the biomass under minimal oxygen to create a char. **Table 4-4** summarizes properties of torrefied Southern pine biomass as received, on a dry

basis, and as fed to the CBTL facility. The moisture content of pelletized biomass was modeled as 6.26 percent, with a carbon content of 47.13 percent.

Table 4-3: Analysis of Southern Pine Biomass (Non-Torrefied)

	As Received	Dry Basis	As Fed to CBTL Facility
Ultimate Analysis			
C (%)	30.55	53.88	44.18
H (%)	3.02	5.33	4.37
O (%)	22.25	39.25	32.19
N (%)	0.23	0.41	0.34
S (%)	0.02	0.04	0.03
Cl (%)	0	0	0
Ash (%)	0.62	1.09	0.89
Moisture (%)	43.3	0	18.00
Total (%)	100.00	100.00	100.00
Heating Value			
HHV (Btu/lb)	4,922	8,681	7,118
LHV (Btu/lb)	4,178	8,175	6,514

Table 4-4: Analysis of Torrefied Southern Pine Biomass

	As Received	Dry Basis	As Fed to CBTL Facility
Ultimate Analysis			
C (%)	59.89	63.52	59.89
H (%)	5.11	5.42	5.11
O (%)	28.36	30.08	28.36
N (%)	0.41	0.44	0.41
S (%)	0	0	0
Cl (%)	0	0	0
Ash (%)	0.51	0.54	0.51
Moisture (%)	5.72	0	5.72
Total (%)	100.00	100.00	100.00
Heating Value			
HHV (Btu/lb)	9,749	10,340	9,749
LHV (Btu/lb)	9,203	9,825	9,203

4.1.2.1 Construction

The construction unit processes for Southern pine biomass production consider the mass of steel and other key materials required for the construction of the various machinery needed for biomass production, including land preparation, cultivation, and harvesting. **Table 4-5** provides a summary of the equipment that was considered. Equipment construction requirements were apportioned per kg of biomass produced over the study period.

Table 4-5: Equipment Considered for Southern Pine Biomass Production Construction

Property	Value	Units	Reference
Lifetime, Diesel Tractor, 165 horsepower	15	years	NETL Engineering Judgment
Lifetime, Tiller (Tractor Driven), 5,015 lbs	15	years	NETL Engineering Judgment
Lifetime, Tree Planter (Tractor Driven), 4,500 lbs	15	years	NETL Engineering Judgment
Lifetime, Tree Harvester	10	years	NETL Engineering Judgment
Lifetime, Skidder	15	years	NETL Engineering Judgment
Lifetime, Standard Drum Chipper	10	years	NETL Engineering Judgment
Lifetime, Disc Wood Micro-Chipper	10	years	NETL Engineering Judgment

4.1.2.2 Operation: Land Preparation

Land preparation accounts for the initial soil tilling and land preparation required prior to planting of each Southern pine crop rotation. The process considers diesel consumption required for these activities, and quantifies air emissions from the combustion of diesel fuel and fugitive dust emissions from the land preparation process. Diesel consumption is based on the manufacturer's diesel consumption rate for a 165 horsepower diesel powered tractor (John Deere Inc., 2009). Diesel combustion emissions were estimated based on several sources. GHG emissions were derived from the U.S. Department of Energy emission factors for non-road diesel engines, for the voluntary reporting of GHG emissions (DOE, 2010). Emissions factors for particulate matter from diesel, NO_x, and VOCs were estimated based on EPA regulatory limits for air emissions from non-road diesel engines for 2011 (National Archives and Records Administration, 2004). Emissions of SO_2 sulfur dioxide were calculated stoichiometrically by assuming that diesel has a sulfur content of 15 ppm (DieselNet, 2009a) and that all sulfur in diesel is converted to SO_2 upon combustion.

The emissions of carbon monoxide (CO) were calculated based on Tier 4 emission standards, which specify an array of CO emissions factors across a range of engine sizes (DieselNet, 2009b). Fugitive dust emissions are generated by the disturbance of surface soil during land preparation. Fugitive dust emissions from land preparation are estimated using an emissions factor specified by the Western Regional Air Program (Countess Environmental, 2004), which conducted air sampling studies on ripping and sub-soiling practices used for breaking up soil compaction. Mercury and ammonia emissions from diesel combustion were also estimated. Mercury estimates were based on emission rates for diesel combustion from on-road vehicles located in the San Francisco Bay Area, California (Conaway, Mason, Steding, & Flegal, 2005). Ammonia emissions from diesel combustion were estimated based on EPA emissions estimates for diesel fired engines, published in 1994 (Battye, Battye, Overcash, & Fudge, 1994). This was the most recent reliable dataset identified for ammonia emissions from diesel combustion.

4.1.2.3 Operation: Cultivation

Cultivation entails planting of young pine trees using a tractor driven tree planter, as well as other cultivation activities including water application, fertilizer application, and herbicide/pesticide application. The cultivation process modeled in support of this analysis assumes a 13 year planting cycle, consistent with typical pulping biomass cycles for Southern pine production. This would imply a 13 year harvesting cycle as well, although this parameter is not explicit in the model. Note that Southern pine grown for lumber is typically grown under longer rotations of 20 years or more.

Yield is a key parameter for biomass cultivation. Yield for Southern pine has been shown to vary considerably based on local growing conditions, as well as the degree of fertilization and weed removal that is applied to the trees during cultivation. Southern pine yield information was available from a variety of sources. However, a review of yield data deemed most relevant to this study indicated a range in annualize yield as harvested basis from 2,994 kg/acre to 7,620 kg/acre, with a best estimate value of 6,350 kg/acre (Jokela, 2004; Kline & Coleman, 2010; ORNL, 2011).[1] Lower end yields were due to a combination of poorer quality cultivation practices, including minimal weeding and reduced fertilization. Highest yields reflect optimal levels of weeding, herbicide/pesticide application, and fertilization, which may not always be feasible due to cost and access constraints.

The NETL/RAND CUBE (Calculating Uncertainty in Biomass Emissions) model provided data points for diesel and electricity consumption in support of biomass production, indicating expected usage values of 31.3 L/acre-year of diesel and 19.2 kWh/acre-year of electricity consumption (NETL, 2011a). These rates of energy consumption were apportioned per kg of biomass, based on yield values discussed above. Emissions from diesel combustion were estimated based on the data sources discussed for land preparation.

Herbicide use was also quantified for the cultivation process. Herbicide use varies considerably based on local conditions. For instance, some herbicides are more effective than others depending on the types of weeds that occur in a given area. Herbicide application data for Southern pine biomass reflect this trend. Atrazine is a commonly applied herbicide in support of Southern pine production, and due to the availability of data (including a previously compiled upstream emissions profile within the GaBi model), Atrazine was assumed to be the sole herbicide applied on site, at a rate of 3 lbs/acre-year (Nelson, 2002).

Based on a review of applicable fertilization data for Southern pine management, it was assumed that nitrogen, phosphorous, and potassium would be applied in support of fertilization during cultivation. Fertilization rates were based on nutrient application rates for loblolly and slash pines (both considered Southern pine species). Based on available data, the fertilizer application rates shown in **Table 4-6** were assumed for Southern pine cultivation. Emissions of nitrous oxide resulting from fertilizer application were also estimated, based on emissions ratios contained in the NETL/RAND CUBE model, wherein 1.325 percent of applied nitrogen is assumed to be converted to nitrous oxide (NETL, 2011a).

Table 4-6: Southern Pine Biomass Fertilization Rates

Fertilizer Type	Fertilization Rate	Units	Reference
Nitrogen Fertilizer (as N)	232.5	kg/acre-rotation	(Jokela, 2004)
Phosphorous Fertilizer (as P)	75	kg/acre-rotation	(Jokela, 2004)
Potassium Fertilizer (as K)	130	kg/acre-rotation	(Jokela, 2004)

Water use was also considered. Water is supplied to the plantings via a combination of rainfall and irrigation water, with the irrigation water assumed to be a 1:1 mix of surface water and groundwater.

[1] The annualized yields reported here are calculated by dividing the total harvestable Southern pine biomass at the end of a single rotation, divided by the number of years per rotation. Thus it is assumed that plantings would be staggered to support harvest each year.

Herein, irrigation water is assumed to be used supplemental to rainfall in order to minimize water stress of the plantation. Based on regionalized estimates of rainfall and crop water requirements, estimated surface plus groundwater use for cultivation amounted to 86 L/kg biomass, while stormwater/rainfall application rates were 348L/kg biomass. Of the 348 L/kg biomass of rainfall, 11 L/kg of biomass were presumed to leave the site as runoff, rather than being consumed by evapotranspiration.

4.1.2.4 Operation: Harvesting

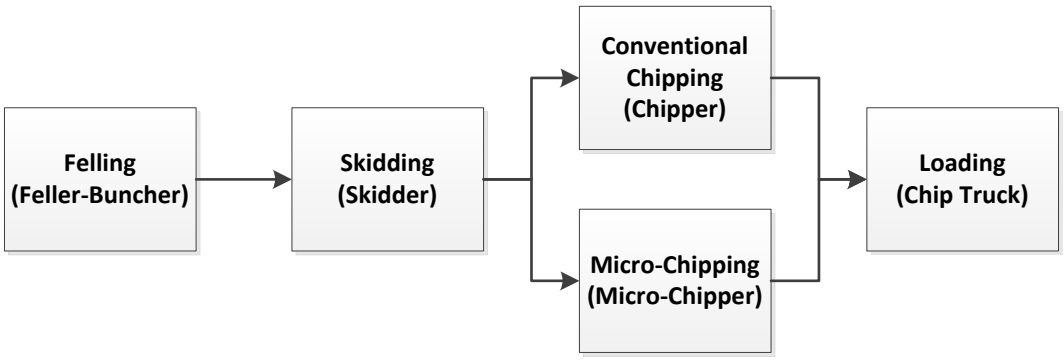
Southern pine harvesting involves felling (cutting) of trees using a wheeled, drive-to tree harvester, which is a common type of equipment used in the pulp wood industry. The tree harvester grips the tree with an accumulating felling head and cuts the tree at the ground level using a shear head or a rotary/disc saw cutting blade on the felling head. It is assumed, though not explicitly contained in the model, that tree limbs and bark are removed prior to transport off the site. These operational assumptions may differ from those used in practice, but would not be expected to shift the results by any significant amount. This material is further assumed to be left to decompose in place. When a few cut trees are collected, the bunch is laid down as a pile to be collected by a skidder. The skidder drags (skids) the whole trees to a nearby collection location, which is typically located 1,500 to 2,000 feet from the tree harvester. From the collection location, whole trees are gathered and fed into a chipping machine, to generate wood chips. Chipping increases the density of the wood material to increase the efficiency of transporting the material instead of transporting the whole tree. Wood chips are blown directly from the chipping machine into a truck trailer (chip truck) for transport from the site. These chips are called green chips because the moisture content at this stage in the process is still the same as the moisture content of the felled tree.

Two sizes of wood chips were evaluated. Normal woodchips produced by typical chipping machines used in the pulpwood industry are 1-2 inches on a side by about ¼ inch thick. Microchips are ¼ to 3/8 inches in size. Machines to produce microchips have been recently developed to supply the wood pellet industry, and are commercially available. Following chipping, the chipped biomass is ready for transport from the production area via chip truck. **Figure 4-1** provides a summary of the harvesting process for Southern pine. The procedure shown therein is a well-established commercial forestry operation that uses equipment that is widely available and is currently in use for Southern pine pulpwood (Searcy & Hess, 2010).

4.1.2.5 Operation: Pelletization

The impacts associated with pelletization primarily include the acquisition and combustion of natural gas for drying the raw chipped biomass as well as electricity for operating the pellet mill. The model uses 0.1 kg of combusted natural gas to remove every 1 kg of water from the biomass input(Ciolkosz & Wallace, 2011). Additionally, 92.3 kWh of electricity/tonne of biomass is used to run the pellet mill(Enegis, 2011).

Figure 4-1: Southern Pine Harvesting Procedure



Source: (Searcy & Hess, 2010)

4.1.3 Land Use Requirements and GHG Emissions for Southern Pine Biomass Cultivation

Land use GHG emissions were evaluated for Southern pine biomass cultivation. Briefly, initiation of cultivation activities for Southern pine biomass in areas where Southern pine biomass is not presently grown would result in a net change in land use, from the pre-existing land use type to the new land use type (i.e., Southern pine cultivation). A given land area may contain certain carbon stocks – these may include aboveground biomass, belowground biomass (roots), and soil organic matter. When an existing land use type is altered, or transformed, to a new land use type, changes in the amount of carbon stored in these carbon stocks can occur. For example, clearing/grading a forest or scrubland would result in the loss from the site of carbon that was previously stored in aboveground biomass.

Potential effects of land use change can be categorized into direct and indirect effects. Direct effects occur as an immediate result of land use change, at the site where the change occurs. Land clearing/grading discussed above is an example of direct land use change. Indirect land use change occurs as a result of direct land use change, typically offsite from areas that would suffer direct land use change. For example, if a Southern pine plantation displaces row crops, new areas may be put into production for row crops, but at a different location. Indirect land use is often more difficult to quantify than direct land use. However, like direct land use, indirect land use can also result in important changes to carbon stocks at the affected site.

The procedure followed here for the evaluation of net CO_2 emissions from direct land use is based on a similar analysis promulgated by the U.S. Air Force Research Laboratory (Aviation Fuel Life Cycle Assessment Working Group, 2011), which is in turn based on the methods utilized by EPA in support of its Renewable Fuel Standard program (RFS2). The analysis contained here was updated to reflect the specific parameters of this study (Southern pine production, in the Southeastern U.S.), based on recently published data available from NETL/RAND (NETL, 2011a). Direct land use change emissions were evaluated based on changes in carbon stored in aboveground, belowground, and soil organic matter (SOM) carbon stocks. Existing land use is assumed to be either cropland or pasture. The net change in carbon stored in each of the three carbon stocks indicated was estimated by comparing estimated carbon stock values for the existing land use to estimated carbon stock values for the new land use, accounting for changes in carbon storage that occur over time. Key values used for this analysis are shown in **Table 4-7**.

Briefly, aboveground biomass carbon storage for existing and new land use types was estimated by assuming that any existing aboveground biomass would be oxidized during transformation to the new

land use type. The resulting carbon debt is factored into overall net GHG emissions resulting from direct land use change. Following the initial land use change event, on site growth of vegetation and changes in soil carbon dynamics drive either carbon uptake or emission during the biomass cultivation period. As shown in **Table 4-7**, carbon uptake is indicated for the conversion of cropland to Southern pine, while carbon emission is indicated for conversion of pastureland to Southern pine.

Table 4-7: Key Values for the Direct and Indirect Land Use Analysis

Flow	Value	Units	Reference
Carbon Emitted from Aboveground Biomass Removal for Existing Cropland[1]	0.00	kg C/ha	(NETL, 2011a)
Carbon Emitted from Aboveground Biomass Removal for Existing Pastureland	1643	kg C/ha	(NETL, 2011a)
Carbon Uptake (negative value) for Roots Plus SOM, Conversion of Cropland to SRWC	-473	kg C/ha-yr	(NETL, 2011a)
Carbon Emission (positive value) for Roots Plus SOM, Conversion of Pastureland to SRWC	220	kg C/ha-yr	(NETL, 2011a)
Fraction of Crop Land Directly Converted to Southern Pine that is Indirectly Converted Back to Cropland (Default Value)	0.30	Unitless	(Aviation Fuel Life Cycle Assessment Working Group, 2011)
Fraction of Pasture Land Directly Converted to Southern Pine that is Indirectly Converted Back to Pasture (Default Value)	0.30	Unitless	(Aviation Fuel Life Cycle Assessment Working Group, 2011)

Indirect land use was calculated assuming that conversion would occur at a remote location, and that a default value of 30 percent of all cropland and pasture lost during direct land use would be replaced at a remote location. Carbon uptake or emissions were then calculated based on the same procedure discussed for direct land use, except using uptake and emission values for transformation to cropland or pasture, rather than to Southern pine production.

4.2 Raw Materials Transport

The following discussion provides an overview of raw materials transport, including transport of coal and biomass to the CBTL facility. For scenarios that include torrefaction, transport to and from the torrefaction facility is also considered, as is the torrefaction process.

4.2.1 Montana Rosebud Coal Train Transport

Transport of Montana Rosebud coal from the coal mine to the CBTL facility would occur via train. Train transport would carry coal from the coal mine, located in southern Montana, to the CBTL facility, located in the Southeastern U.S. Construction and operation of the coal train used for the transport of Montana Rosebud coal are discussed in the following text.

4.2.1.1 Construction

Montana Rosebud coal is assumed to be transported by rail, via unit train, where the unit train is comprised of five diesel-fired locomotives plus coal 100 rail cars. Modeled construction flows

[1] Presumes that all aboveground biomass would be harvested or otherwise removed during the normal agricultural cycle, prior to the occurrence of land transformation associated with the study.

include the mass of materials required for the construction of the diesel locomotives and the rail cars. Total weight for a single, 4,400 horsepower diesel locomotives, is estimated to be 415,000 lbs (GE Transportation, 2008), which is assumed to be composed of 41,500 lbs of stainless steel and the remaining weight as steel plate. Each 120 ton capacity coal railcar was estimated to contain approximately 15,600 lbs aluminum and 3,400 lbs steel plate (Amsted Rail, 2008; FreightCar America, 2008; Trinity Rail, 2008).

Materials requirements for a unit train were calculated based on these values. Total construction mass for the unit train was calculated for the study period, assuming a 20-year lifetime for the locomotives and a 30-year lifetime for the rail cars. Total construction materials were then apportioned over the total coal transport mass, in order to evaluate the amount of construction materials required for the transport of a single kilogram of coal. Construction of train tracks was not considered, as these were assumed to be pre-existing.

4.2.1.2 Operation

A default one-way transport distance of 1,600 miles was assumed, based on the approximate distance between southern Montana and the U.S. Southeast, where the CBTL facility is located. As discussed for train construction, coal is transported via unit train, which consists of 100 railcars pulled by five diesel locomotives. Diesel consumption and transport emissions are considered. Emissions from train transport derive from the combustion of diesel by the locomotive engine, plus fugitive dust from the coal. Loss of coal during transport is assumed to be equal to the fugitive coal dust emissions. Loss during loading at the mine is assumed to be negligible, as is loss during unloading. Loss of coal to fugitive dust was calculated as 1.22×10^{-7} kg coal dust lost per kg-km of coal transported.

4.2.2 Southern Pine Biomass Truck Transport

Harvested Southern pine biomass is transported by chip truck (i.e., semi-truck with a trailer suitable for carrying wood chips) from the harvesting site to either the CBTL facility or the torrefaction facility. The following text describes construction and operation flows considered for transport of Southern pine biomass.

4.2.2.2 Construction

Chip trucks are composed of a semi-truck tractor plus a separate trailer. Detailed information was available for the construction of this equipment. Construction materials considered for the tractor include steel plate, aluminum, plastics, and other metals, based on data available from Volvo (Volvo, 2001). Trailer materials were assumed to be composed of a combination of steel and aluminum (Pinnacle Trailers, 2009). Based on these data sources, total construction weight for the tractor was 15,432 lbs, while total weight for the chip trailer ranged from 10,500 to 12,500 lbs. Based on the mass of chips that could be carried by a single chip truck, chip truck lifetime, and daily transport requirements, total construction mass was apportioned according to the mass required to transport a single kg of biomass.

4.2.2.3 Operation

Operation of the chip truck considers diesel consumption by the truck, as well as emissions from the combustion of diesel fuel. A one-way default transport distance of 40 miles (to the CBTL facility) or 50 miles (to the torrefaction facility) was considered. Loss of biomass during transport was assumed to be negligible. The truck is assumed to be loaded to capacity on the initial haul from the harvesting site, and to return empty from its destination. Emissions from diesel combustion were calculated based on values derived from the GREET model (ANL, 2011).

4.2.3 Southern Pine Biomass Torrefaction

The basic torrefaction process assumed within this study is discussed within Chapter 2. The following text provides additional detail that is relevant to the life cycle analysis documented here.

4.2.3.1 Construction

Construction data, including specific plant sizes and materials composition, were not readily available for a torrefaction facility. Therefore, the materials requirements for the construction of a torrefaction facility were estimated by using data from an industrial water tube boiler, having 150,000 lbs/hr steam production capacity. The entire mass of the boiler, 130,000 lbs (Nationwide Boiler Incorporated, 2011), was assumed to be constructed entirely of steel plate. Boiler mass was apportioned to the total mass of torrefied biomass that would be produced over the study period.

4.2.3.2 Operation

This study assumes that torrefaction of Southern pine takes place in a directly heated moving bed reactor at temperatures between 200 and 300°C, in the absence of oxygen. The ensuing thermal degradation of Southern pine wood removes most of the moisture content and eliminates its fibrous structure. The hemicellulose component of the wood is essentially thermally destroyed by the torrefaction process. This improves both the grindability and calorific value of the torrefied biomass product while also making it resistant to water absorption. The product material is therefore easier to grind, pelletize, package, and transport. These properties make the torrefied biomass product suitable for use as a standalone or blend material with coal in combustion and gasification applications.

The time and temperature requirements for torrefaction can be varied depending on the desired characteristics of the torrefied biomass. The relationship between torrefaction time and temperature may be qualitatively described as follows:

1. As the torrefaction time and temperature increases, the yield of torrefied biomass decreases while the yield of gaseous products such as volatiles and water vapor increases.
2. As the torrefaction time and temperature increases, the calorific value of the torrefied biomass increases.
3. As torrefaction time and temperature increases, the production of CO, CH_4, and C_2 hydrocarbons in the gaseous products increase while the production of CO_2 decreases.
4. At any torrefaction time and temperature, water vapor is always a significant gaseous product – on the order of 50 to 60 percent by mass of the gas stream - even when the biomass is dried to zero or near-zero moisture content. Typically, about 5 to 10 percent of the energy contained in the raw biomass is driven off as part of the gaseous products.

Comprehensive operating data from a commercial existing torrefaction process are not available but Integro Earth Fuels, Inc. has provided ultimate and proximate analyses and calorific values for raw and torrefied Southern pine solids from their test facility in Ashville, North Carolina (Childs, 2012). These data were used as the basis for the mass and energy balances used in developing the torrefaction simulation model.

Figure 4-2 shows the schematic of the directly heated torrefaction system assumed for this study. This system is under development by ECN of the Netherlands (P. C. A. Bergman, Boersma, Zwart, & Kiel, 2005). In this system some or most of the necessary heat for drying and torrefaction comes from the combustion of the volatile gases emitted during torrefaction. Additional heat when required to balance the heat load can be supplied by using natural gas, other biomass, or other available utility

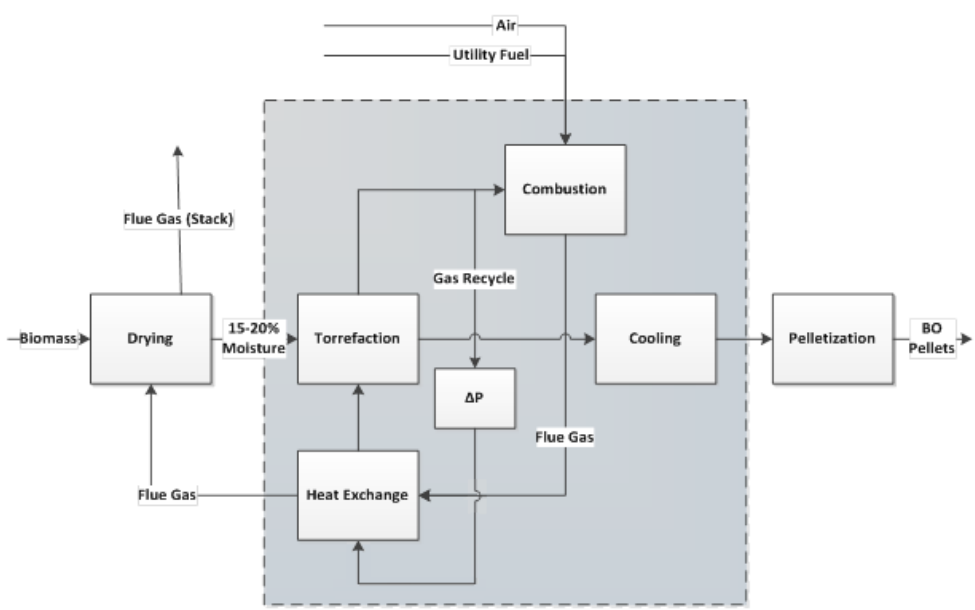
fuels. Air, fuel, and a portion of the torrefaction gases are combusted in the combustion section of the plant. The remainder of the torrefaction gases are repressurized, passed through the heat exchanger, and used as the torrefaction heating gas to torrefy the biomass. The flue gas from combustion is passed through a heat exchanger that heats the torrefaction gas recycle stream. The flue gas exiting the heat exchanger is used to dry the biomass before it enters the torrefaction reactor. The cooled flue gas is then discharged through the stack. The heated recycle gas directly contacts the biomass in the torrefaction reactor to supply the heat required for further dehydration and torrefaction. This also acts as the essentially oxygen-free blanket gas. The gases leave the torrefaction reactor and some of the gas is recycled to the torrefaction reactor via the heat exchanger and the rest is sent to the combustor. The solid torrefied biomass product leaves the reactor and is cooled.

In the ECN process the torrefied product is pelletized to produce their BO_2 pellets. In this study, the unpelletized torrefied material is transported from the torrefaction facility to the CBTL facility where it is ground, mixed with coal and gasified to produce synthesis gas.

Within this study, conceptually the Southern pine is dried to about 10 percent moisture prior to being fed to the torrefaction step. Torrefaction is accomplished in the directly heated moving bed torrefaction chamber at a temperature of 536ºF (280ºC). Heat for torrefaction is provided from a portion of the torrefaction product gas that is recycled and re-pressurized via a forced draft fan or blower, and heat exchanged with flue gas. A combustion chamber with air and natural gas as supplemental fuel burns the combustible portion of the torrefaction gas stream.

Although the torrefaction product gas consists of a wide variety of combustible components, the main constituents are the non-combustibles water and carbon dioxide. The heat content of torrefied solids and gases are dependent on a combination of the type of raw materials and torrefaction operating conditions (temperature and residence time). The heating value of the torrefaction volatiles can be too low to provide the necessary heat for drying and torrefaction in which case supplemental fuel is necessary. Some torrefaction producers like Integro Earth Fuels claim that the process can run autothermally and therefore does not need any supplemental fuel.

Figure 4-2: ECN Torrefaction Scenario



Source: (J. Kiel, 2011a)

Integro Earth Fuels, Inc. has an existing system for torrefaction of Southern pine that combines the drying and torrefaction steps into a single unit and requires supplemental fuel only during system start-up. At steady-state, their torrefaction process operates auto-thermally (Childs, 2012). In a torrefaction systems study, Bergman and Boersma of ECN estimate the heat content of the torrefaction product gas to be 5.2 and 14.7 percent the value of the dry feed to the torrefaction reactor for woodcuttings and demolition wood, respectively (P. C. A. Bergman, Boersma, Zwart, et al., 2005). In that study, a portion of the raw wood is burned to provide process heat for the drying and torrefaction steps. For the purposes of this current analysis it is assumed that the default value for the heating content of the volatiles is set at 5.2 percent of the heating value of the feed to estimate the amount of supplemental fuel required.

There is an absence of relevant literature data for the composition of the volatiles from Southern pine biomass. However, very detailed torrefaction gas composition data are available for woods other than Southern pine. Kiel reports a torrefaction product gas composition from willow at 260°C for 32 minutes. These include mass yields for a torrefaction gas that contains CO, CO_2, H_2O, acetic acid, furfural, methanol, formic acid and the remainder CH_4, C_xH_y, toluene and benzene (J. Kiel, 2011b). Bergman and Kiel *et al* provide mass yields for torrefaction reaction products for willow at 280°C for 17.5 minutes (P. C. A. Bergman, Boersma, Kiel, Prins, & Ptasinski, 2005; P. C. A. Bergman & Kiel, 2005). These data are in the form of mass distributions for solids, lipids (terpenes, phenols, fatty acids, waxes, and tannins), organics (sugars, polysugars, acids, alcohols, furans, and ketones), gases (H_2, CO, CO_2, CH_4, C_xH_y, and benzenes), and water. Emissions of CO_2 and SO_2 are based on the oxidation of combustible constituents in the torrefaction product gas and the natural gas burned as supplemental fuel.

Torrefaction gases are assumed to be captured and combusted in order to provide heat for the torrefaction process. However, combustion of these gases generates various air quality pollutants, which are emitted to the atmosphere. **Table 4-8** provides a summary of the various emissions that are emitted during the torrefaction process.

Table 4-8: Airborne Emissions from Torrefaction Operations (kg/kg Torrefied Biomass Produced)

Airborne Emission	Value
Carbon Dioxide (CO_2)	6.98E-02
Methane (CH_4)	5.62E-07
Nitrous Oxide (N_2O)	5.38E-07
Particulate Matter (PM_{10})	1.86E-06
Carbon Monoxide (CO)	9.59E-05
Ammonia (NH_3)	7.82E-07
Nitrogen Oxides (NO_x)	6.84E-05
Sulfur Oxides (SO_x)	1.47E-07
Non-Methane Volatile Organic Carbons	1.34E-06
Lead (Pb)	2.44E-08
Mercury (Hg)	1.27E-08

4.2.4 Torrefied Southern Pine Biomass Truck Transport

Torrefied biomass is assumed to be transported from the torrefaction facility to the CBTL facility via semi-truck. Torrefied biomass transport is presumed to require the use of similar trucks as discussed for the transport of chipped Southern pine biomass. The transport distance from the torrefaction facility to the CBTL facility was assumed to be 50 miles, which is consistent with the economic model. For additional discussion of truck transport, please refer to the prior discussion of chipped Southern pine biomass transport.

4.3 Energy Conversion

The following discussion provides an overview of processes considered under the energy conversion segment of the life cycle analysis. These include construction and operation of the CBTL facility and carbon dioxide transport pipelines.

4.3.1 CBTL Facility

All of the 20 CBTL facility scenarios analyzed in this conceptual study are assumed to be located in the Southeastern United States. The CBTL facility site is a Greenfield facility occupying approximately 1,300 acres. Access is by road and rail and CBTL facility water requirements are assumed to be available via a combination of municipal water supply and groundwater. Treated wastewater is allowed to be discharged from the CBTL facility. The ambient conditions and site characteristics are summarized in **Table 4-9**. The ambient conditions are the same as ISO conditions for these configurations.

Table 4-9: Site Conditions for the CBTL Facility, All Scenarios

Site Characteristic	Site Condition
Elevation (Feet)	0
Barometric Pressure (PSIA)	14.7
Design Ambient Temperature, Dry Bulb (F)	60
Wet Bulb Temperature (F)	52
Ambient Relative Humidity (%)	60
Location	Greenfield, Southeastern USA
Topography	Level
Size, Acres	1,300
Transportation	Rail and Road
Ash Disposal	Off Site
Water	Municipal (assumed to be surface water) 50%: Groundwater 50%
Access	Landlocked; Access by rail and highway
CO_2 Disposition	Compressed to 2215 psia on site then transported by pipeline to an EOR facility

4.3.1.1 Construction

Because no existing commercial scale CBTL energy conversion facilities have been produced, there are no real world data sources for construction requirements of the modeled CBTL facility.

Therefore, the analysis provided here relies on proxy data to estimate the total construction materials required for the construction of the CBTL facility. Specifically, construction requirements for concrete, steel, pipe, iron, and aluminum were quantified based on prior estimates for a hypothetical CBTL facility, as previously estimated by NETL for a separate modeling effort (NETL, 2010d).

4.3.1.2 Operation

Operational processes considered for the CBTL facility include feedstock handling, biomass grinding, and fuels production via a F-T process. These processes are described below.

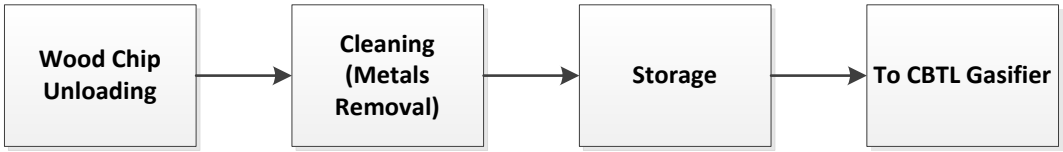
4.3.1.2.1 Feedstock Handling at the CBTL Facility

Coal feedstock arrives at the CBTL facility by rail from Montana. PRB coal is routinely transported by rail in large quantities from the Powder River Basin mines to Georgia and other locations for firing in pulverized coal electric power generation plants (Winschel, 2012). At the CBTL facility site, coal is unloaded from the rail cars and transferred to temporary storage using a circular stacker-reclaimer. This machine uses a large arm to pile coal around the stationary location of the machine. The circular stacker-reclaimer is also used to remove (reclaim) coal from the piles and convey it to the gasifier unit.

Southern pine biomass would arrive via loaded chip or pellet trucks arriving at the CBTL facility or torrefaction plant site. The biomass chip and pellet handling is assumed to be the same for this study and is henceforth described as chip handling in this section. These would be weighed then unloaded into a receiving hopper, potentially using a truck tipper. Chips from the hopper are typically conveyed past a stationary magnet to remove any ferrous metal that has been transported with the chips. Non-ferrous metal detectors may also be used during cleaning. After cleaning, chips are conveyed to the storage location where the chips are poured into large piles using a circular-stack reclaimer, similar to that described for coal.

The chip storage piles produced by the circular-stack reclaimer are usually placed on an asphalt pad. The piles are managed and moved using a front-end loader. Green chips placed into storage piles usually still contain about 50 percent moisture, as did the whole tree when it was felled. Chips normally experience some ambient drying during storage before the chips are conveyed to the gasifier. Chip moisture content is typically about 43 percent by the time the chips are removed from a storage pile to be processed. **Figure 4-3** provides a summary of the biomass handling process at the CBTL facility.

Figure 4-3: Biomass Handling at the CBTL Facility



4.3.1.2.2 Biomass Grinding and Preparation

Under Scenario 2, CBTL, 10 percent Chipped Biomass, Scenario 3: CBTL, 20 percent Chipped Biomass and Scenario 7: CBTL, 30 percent Chipped Biomass the Southern pine biomass feedstock arrives at the CBTL facility in chips of 2 to 3 inch length. These chip sizes are typical/widely practiced in the pulp and paper industry. Once the chips are delivered to the CBTL facility they must

be further reduced both in size and in water content so that they can be fed to the pressurized TRIG gasification system.

It is very difficult, expensive, and energy intensive to grind green raw wood to very small sizes. Wood is fibrous in structure and when the particles are further reduced in size they retain their aspect ratio so that the small particles are needle like. This can cause bridging in pressurized lock hopper systems with resulting blockage of flow.

The most extensive evaluation of grinding energy requirements for green and torrefied biomass has been conducted by ECN in the Netherlands (P. C. A. Bergman, Boersma, Zwart, et al., 2005; J. Kiel, 2011a, 2011b; J. H. A. Kiel, Verhoeff, Gerhauser, Daalen, & Meuleman, 2009). ECN has been developing a torrefaction/pelletization process, termed "BO_2," for several years and they have published extensively on the results of this development. In their experimental grinding tests they have conclusively shown that torrefied wood can reduce grinding energy requirements compared to green wood by tenfold or more. They have also shown that mill capacity can be increased by a similar order of magnitude. This fact, combined with the large increase in energy density of torrefied biomass, has motivated the continuing development of the BO_2 process. In applications where co-firing of coal and biomass will be needed for electric power generation a power plant operator will be able to treat the torrefied biomass in the same way as coal.

Other organizations have also studied grindability of biomass. German attempts have used Loesche mills to show that co-grinding of biomass and coal is a feasible option, although fine grinding of biomass alone was not so successful (Dijen & Loesche-Electrobel, 2004). ORNL has also investigated the power requirements for grinding various green woody biomass to particle sizes as low as one millimeter (Sokhansanj & Webb, 2011). Their power requirements are very much in line with the data from ECN. French researchers have also investigated the comparative grinding energy required for green and torrefied wood. They have also shown that the grinding energy can be reduced by a factor of ten compared to green beech by torrefying beech wood at 280°C (Govin, Repellin, Roland, & Duplan, 2009). Again the actual values of energy use are very similar to those of ECN and ORNL.

The grinding energy data used in this study is taken from the ECN work. Using a hammer mill they measured the grinding energy required to produce powders from the biomass feeds with an average particle size of 0.2 mm. They measured the Biomass Grindability Index that represents the net electricity consumption (in kWe/MWth) for a large variety of green and torrefied biomass samples. They produced plots of energy consumption versus average particle size produced for sizes ranging from 0.1mm (100 microns) to 1.4 mm (P. C. A. Bergman, Boersma, Zwart, et al., 2005). They found that the influence of torrefaction on the energy consumption to produce fine particles was substantial. By comparing green willow wood with torrefied willow they found a reduction in power consumption of up to 80-90 percent. They also examined the impact of torrefaction on the capacity of the mill. They found that a capacity increase was observed of up to ten times that of the untreated biomass. This clearly has a considerable impact on the size or number of mills required to process the torrefied material.

Finally, the influence of the torrefaction operating conditions (residence time and temperature) was found to be limited. Variations in torrefaction time and temperature did not have a very pronounced impact on the grinding energy. Most of the torrefied data on the plots were bunched together at the low end of the grinding energy curves (P. C. A. Bergman, Boersma, Zwart, et al., 2005). For comparison purposes, ECN also used Australian bituminous coal to carry out size reduction experiments. They found that data for the grinding energy required for the coal matched almost

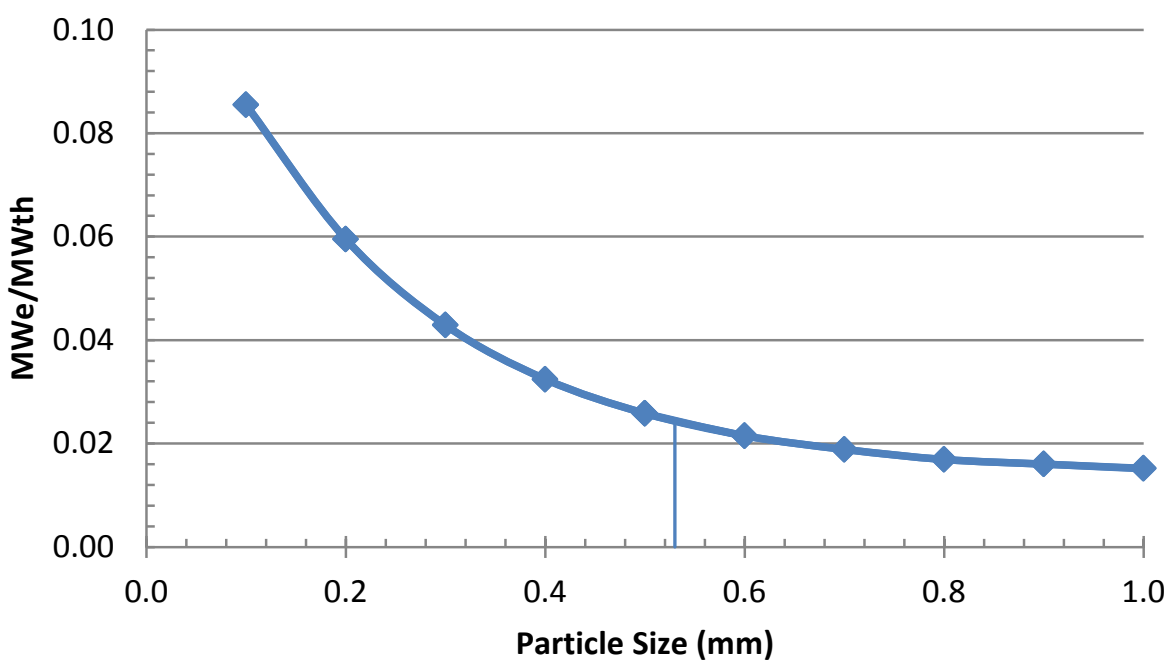
exactly with the data from torrefied wood. This shows that similar grinding energy is needed for coal and torrefied biomass (P. C. A. Bergman, Boersma, Zwart, et al., 2005).

Figure 4-4 shows the results obtained from the ECN grinding experiments expressed in MWe/MWth of biomass plotted against final average particle size. The curve fit log equation shows good correlation. This equation is used to estimate the power required to reduce the green untreated woody biomass to various final particle sizes needed for feeding to the gasifier.

Based on the data from ECN, the grinding energy requirements for the torrefied woody biomass was shown to lie on the same power consumption versus particle size curves as the coal (J. Kiel, 2011a). The analysis in this study assumes that the grinding energies of coal and torrefied biomass are the same per ton of feed.

It is worth noting that most of the studies that have ground wood to very fine particles have used small scale milling and grinding equipment. It is not certain that the energy use measurements from these tests can be extrapolated to full size commercial grinding equipment. Most commercial grinders and hogs have large heavy flywheels that have large energy storage in momentum. This attribute is missing in small scale equipment. Because the data from green biomass grinding used in this study comes from small equipment it is cautioned that the estimates for energy use in grinding must be considered uncertain until further R&D at larger scale can validate the assumptions.

Figure 4-4: Grinding Energy Required versus Average Particle Size, Non-Torrefied Biomass



Data Source: (P. C. A. Bergman, Boersma, Zwart, et al., 2005; J. Kiel, 2011a, 2011b; J. H. A. Kiel, et al., 2009)

4.3.1.2.3 Fuels Production

Select emissions were quantified during Aspen Plus® modeling for the 20 CBTL facility scenarios considered. These included, as relevant to the environmental analysis, GHG emissions, carbon monoxide, ammonia, and sulfur dioxide. Water use was also modeled in this context. Please refer to Chapter 2 for more information, including a detailed discussion of the modeled CBTL facility processes, parameters, and modeling assumptions for each of the scenarios considered.

Additional airborne emissions were also modeled for the CBTL facility in support of the environmental analysis. These included NO_x, particulate matter (PM_{10}), mercury, and non-methane volatile organic carbons. These additional flows were estimated based on prior life cycle analyses completed by NETL in support of CBTL fuels production (NETL, 2010c). The analysis from which these data were drawn contains different modeling choices with respect the CBTL process and feedstock types. For instance, the prior study considers liquid fuels production from a combination of bituminous coal and switchgrass biomass, in varying proportions. This is considered a data limitation.

4.3.2 Carbon Dioxide Transport

The supercritical CO_2 pipeline transport scenario modeled in support of this study presumes a transport distance of 775 miles, from the Southeastern U.S. to the Permian Basin, Texas. The following text describes the modeled CO_2 pipeline transport process, including a summary of key calculations and model assumptions.

4.3.2.1 Construction

Pipeline construction is characterized as originating from two sources: indirect emissions associated with construction of pipe and pump station materials, which require knowledge concerning the weight of the material and emissions from installation operations.

Pipeline construction considers the materials and upstream emissions associated with the production of pipeline components, including booster pumps, as well as fuel use and emissions that would occur during pipeline installation. The pipeline is assumed to be constructed of American National Standards Institute schedule 40 pipe (16-inch nominal, 15-inch internal diameter), with a mass of 116.08 kg/m using welded carbon steel. The pump station was assumed to be composed of 316 stainless steel plus a concrete pad, with a pump rating of approximately 590 to 2100 horsepower. Airborne emissions were estimated for CO_2 pipeline installation/deinstallation, where deinstallation emissions were assumed to be 10 percent of installation emissions.

4.3.2.2 Operation

Pipeline operations considers potential emissions from three sources: CO_2 emissions from fugitive loss, CO_2 emissions from intermittent venting during operation, and indirect emissions associated with the upstream production and delivery of electricity. Pressure drop through the pipeline was estimated based frictional forces and head loss. Calculations indicated that pressure drop was expected to be minimal. Therefore, the CO_2 would arrive at its destination under sufficient pressure to support CO_2-EOR without additional in-line boost compression for CO_2 transport.

A very small fraction of the transported CO_2 is expected to be released to the atmosphere during standard pipeline operations (IPCC, 2007). CO_2 pipelines are constructed from long sections of carbon steel that are welded together. Pigging stations with valves and flanges to facilitate shut off and access, respectively, are located at 30-mile intervals and these stations use highly impermeable seals to ensure that CO_2 losses are minimal. Based on guidelines from IPCC, the pipeline leakage

factor was calculated to be 3.84E+03 kg/mi-year. (Holloway, Karimjee, Akai, Pipatti, & Rypdal, 2006)

Over the 30 year study period, it would be necessary to inspect the pipeline to verify its integrity, ensure that fugitive losses are minimal, and ensure the safety of workers and the public. Therefore, pipeline operations also considers pigging operations. CO_2 pipelines are "pigged" to check for corrosion once every 5 years. A pig is a device that is inserted into and moved through a pipeline to allow inspection of the internal surface of the pipe to verify its integrity. In pigging operations, the CO_2 pipeline is shut off upstream of the section to be inspected, and the pipeline downstream is allowed to bleed to a lower pressure limit (assumed to be 7.38 MPa). When the downstream pressure is at this limit, the downstream valve is closed and the contents of the pipeline section to be inspected (sections are typically 30 km in length) are vented to the atmosphere.

The mass of CO_2 emitted to the atmosphere in these venting operations is calculated as the density of CO_2 at a pressure of 7.38 MPa at 70 °C times the volume of the pipeline section (pipeline internal cross-sectional area times section length). However, since inspection is conducted on the full pipeline, each inspection event will vent a volume equivalent to the full pipeline volume. The total vented volume is multiplied by the number of inspections carried out of the 30-year study period (30/5 years, or six inspection events). The total emission rate for the 30-year study period is 5.81E-06 kg CO_2/kg CO_2-km transported. Catastrophic events, including leakage of large volumes of CO_2 from CO_2 transport pipelines, are excluded from this study.

4.4 Product Transport

Product transport includes transport of F-T jet fuel produced at the CBTL facility to a blending station, where the F-T jet fuel is blended with conventional petroleum jet fuel. From that point, the blended jet fuel is transported via pipeline to an airport for use in a jet driven airplane. A second scenario considers truck transport of a portion of the total blended jet fuel, with pipeline transport of the remaining portion.

4.4.1 F-T Jet Fuel Transport

F-T Jet Fuel transport includes pipeline transport of F-T jet fuel from the CBTL facility to a petroleum refinery/blending station. At the refinery, the F-T jet fuel is blended with conventional, petroleum-based jet fuel (refer to next subsection). Here, transport of the F-T jet fuel to the refinery/blending station is considered.

The pipeline used for transporting the F-T jet fuel to the refinery/blending station is assumed to be a pre-existing pipeline used to transport petroleum products. However, it is assumed that an approximately 20 mile length of pipeline will need to be constructed to connect the CBTL facility to the existing portion of the petroleum pipeline. Construction related materials and emissions are included for this 20-mile pipeline segment. Total distance from the CBTL facility to the refinery/blending station was assumed to be 225 miles.

It is assumed that electrical powered pumps would be used to move the fuels through the pipeline, and energy intensity consistent with petroleum pipeline transport is assumed: 2.77E-5 kWh/kg-mi, according to Franklin and Associates, Inc. as reported in an Oregon Department of Environmental Quality report (Oregon DEQ, 2004). The energy intensity number will differ slightly due to the varying densities of the fuels as the energy consumption values are based on the mass of flow through the pipe. A mass efficiency of 100 percent is assumed for pipeline transport – that is, the analysis assumes zero loss of fuel during transport. The emissions associated with the electricity used for pipeline transport is modeled using the regional power grid mix, where regional power grid mix is

defined by the North American Energy Reliability Corporation region in which the facility is located (i.e., the Southeastern Electric Reliability Council).

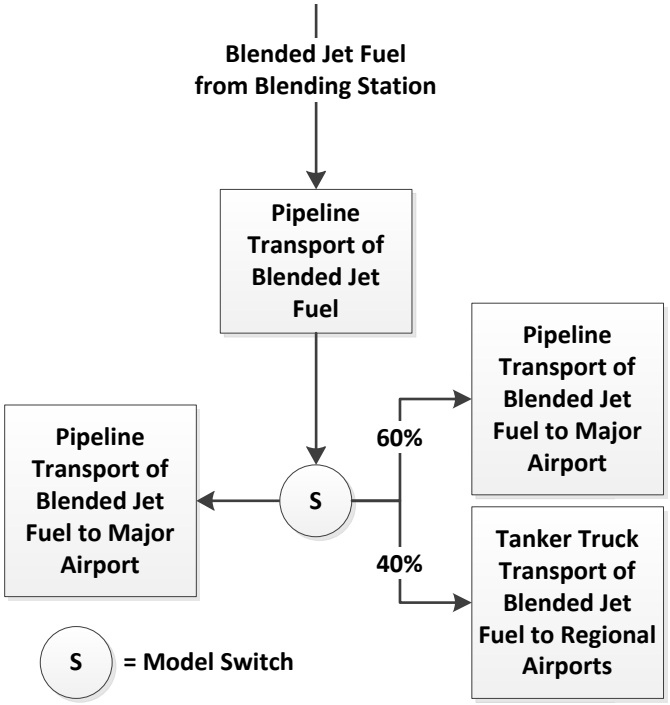
4.4.2 F-T Jet Fuel / Conventional Petroleum Jet Fuel Blending

F-T jet fuel is blended with conventional jet fuel on a 1:1 basis (by volume). However, the upstream environmental flows and emissions associated with conventional crude oil extraction, transport, refining, and conventional jet fuel transport to this point are not considered previously. Therefore, upstream emissions associated with conventional jet fuel production are accounted for here. As a result, emission values considered here are large relative emissions for the other facets of product transport considered in this study. Blended jet fuel, which is the resulting fuel following blending, is tracked through the remainder of the life cycle model.

Upstream emissions from extraction, transport and refining of crude oil are incorporated into the results for product transport. Upstream emissions estimates for the production of petroleum jet fuel were based on prior life cycle modeling completed by NETL (2009), but updated to adhere to the assumptions of this study. Crude oil supply profiles considered within the conventional jet fuel production life cycle were updated for consistency with the 2010 fuel sourcing profile for the U.S. Other data sources and assumptions related to conventional petroleum jet fuel production are documented in detail by NETL (NETL, 2009).

All facilities required for the blending of F-T jet fuel with 50 percent conventional jet fuel are assumed to exist. Therefore, construction material and energy requirements and associated emissions are not considered for the blending station.

Figure 4-5: Blended Jet Fuels Transport Model Options



4.4.3 Blended Fuels Transport

Blended fuels transport is modeled according to two separate options. The first option includes exclusive pipeline delivery of the blended jet fuel to a single large airport, while the second includes pipeline delivery to a single large airport, plus tanker truck delivery to additional smaller regional airports. **Figure 4-5** summarizes the environmental model options for blended fuels transport, as discussed below.

4.4.3.1 Option 1: Pipeline Transport to a Single Major Airport (Default Analysis)

Under Option 1, pipeline transport would be used to transport blended jet fuel from the refinery/blending station directly to a single major airport. This option is included as the default analysis option. The airport is assumed to be located 245 miles from the blending station. This option considers operation of a pipeline that connects the blending station to the airport, as well as fuel handling and transport operations at the airport. Electricity input and emissions associated with electricity production are considered for the pumps needed to pump the blended jet fuel along transport pipelines.

The model assumes, for Option 1, that all facilities needed for handling and transport operations, from the refinery through fuel handling and transport at the airport, would be pre-existing, and that no construction or manufacture of new facilities or infrastructure would be required. The airport is also considered existing for this study. The airport is defined as the fuel storage tank, fuel pumps, and dispensing stations. The energy needed within the airport to deliver the blended jet fuel to the aircraft fuel tank is considered negligible in this evaluation. The emissions at the airport associated with handling the blended jet fuel are also assumed to be negligible. Electricity supplied by the regional electrical grid is assumed to power all pumps in the pipeline.

4.4.3.2 Option 2: 60 Percent Pipeline Transport to Major Airport and 40 Percent Truck Transport to Regional Airports (Sensitivity Analysis Only)

This option evaluates the potential for additional life cycle emissions to occur as a result of distributing blended jet fuel to several airports, including smaller regional airports that could potentially be provided with such fuel, and is included solely for the purpose of sensitivity analysis. Under this option, transport of the blended jet fuel includes (1) operation of a pipeline from Wood River refinery that transports blended jet fuel to a bulk terminal facility 100 miles distant; (2) operation of a pipeline from the bulk terminal facility transporting 60 percent of the blended product to the single major airport located 160 miles distant; and (3) tanker truck transport operations that ship 40 percent of the blended jet fuel to regional airports, located 50 miles distant (one way). Fuel handling, transport operations and associated emissions at the airports are assumed to be negligible for this evaluation.

Electricity input and emissions associated with electricity production are considered for the pumps needed to pump the blended jet fuel from the blending station to the bulk terminal facility, and then from the terminal facility to major airport. The emissions associated with the electricity used for operation of the bulk terminal facility are modeled using regional electrical grid data. Because no operational electricity use data were found for a bulk terminal facility, the energy use is assumed to be equivalent to that of a refueling station (fuel processing energy use only). This assumption is considered valid because of the similar energy consuming components operating in a bulk terminal facility and in the fuel processing portions of a refueling station.

Construction and operation of the diesel powered tanker trucks needed to transport the blended jet fuel to regional airports are considered. Trucks are assumed to be Class 8B (> 60,000 lbs gross

vehicle weight) truck-trailer combinations to transport fuel to regional airports and then return (empty) to the bulk terminal facility. The tanker truck transport process assumes that any potential loss of transported fuel during transport would be negligible, due to the relatively short distance traveled and the characteristics of the tanker trucks (they are designed to minimize volatile emissions). The trucks are assumed to be powered by 100 percent conventional diesel fuel. The fuel economy for Class 8B trucks ranges from 5 mpg with a full trailer to 9 mpg with the trailer empty based on recent US Department of Transportation statistics. These modeling assumptions are consistent with the fuel economy parameter used in the GREET model for heavy-duty truck transport (ANL, 2009).

4.5 Fuel Consumption

Fuel consumption includes construction and operation of a commercial jet aircraft, wherein blended jet fuel is consumed. The following discussion provides applicable details regarding construction and operation assumptions and data sources for fuel consumption.

4.5.1 Construction

Construction materials for the jet aircraft are based on data available from Boeing (Boeing, 2010), representative of commercial jet airplane. The estimated lifetime distance traveled by the vehicle and energy intensity per unit distance of travel is used to apportion the construction material requirements to a basis of 1 MJ of diesel combustion. Airplane gross weight (approximately 41,400 kg) was estimated based on data for a Boeing 737 aircraft, assuming that the plane is constructed entirely of aluminum. Assuming a 20 year lifetime, total lifetime fuel consumption was estimated, and construction mass was apportioned per kg of jet fuel consumption.

4.5.2 Operations

The principal products of jet fuel combustion are CO_2 and water. Other combustion components include criteria air pollutants such as SO_x, NOx, CO, and PM_{10}. Other emissions may also occur, and the following additional air emissions species are also quantified within this study: methane, nitrous oxide, non-methane volatile organic carbons (NMVOCs), ammonia, and mercury. It is worth noting that emission rates for PM_{10}, CO, NMVOCs, and NOx can vary considerably based on engine operation, which varies during idle, takeoff, landing, and cruise operations (Kim et al., 2007).

The operations process that accounts for airplane combustion of jet fuel calculates CO_2 emissions based on the carbon content of blended jet fuel, and assuming that all carbon contained in the combusted jet fuel is converted into CO_2. This assumption results in a slight overestimate of CO_2 emissions for blended jet fuel, yet was utilized due to lack of data available for field tests of blended jet fuel combustion in a jet airplane, where fuel properties are similar to those calculated for the blended jet fuel considered here.

Alternative fuels may change the emissions produced by aircraft. For example, because the chemical composition of the F-T jet fuel considered differs from that of conventional jet fuel, there will be changes in the combustion products, as compared to petroleum-derived fuels. Knowledge of these changes varies with our fundamental understanding of how these pollutants are created. The emissions of CO_2, H_2O, and SO_X can be estimated for any fuel composition, including F-T jet fuel, based on complete combustion. Because complete combustion of the fuel has been assumed, (i.e., all fuel carbon is assumed to be converted to CO_2 via combustion), the aircraft CO_2 emissions would be the same whether the fuel were used in a jet aircraft or another application.

Mercury emissions estimates were also based on fuel properties. Total mercury content was estimated for the F-T fraction of blended jet fuel based on the concentration of mercury contained in Montana Rosebud coal feedstock (0.081 ppm, dry basis), assuming that 10 percent of total incoming mercury is passed into product fuel during the F-T process at the CBTL facility. One hundred percent of mercury contained in the F-T jet fuel fraction of blended jet fuel was assumed to be emitted to the atmosphere during combustion. Mercury content of conventional petroleum jet fuel was considered to be negligible.

Criteria air pollutant emissions were estimated based on emission factors available for the combustion of conventional jet fuel in jet airplanes available from IPCC and the U.S. Transportation Research Board (Rypdal, 2000; Whitefield, Lobo, & Hagen, 2008). Ammonia emissions were estimated based on data available for commercial aircraft operations (Herndon et al., 2006).

5 Scenario Results

The following provides a discussion of results from each of the 20 scenarios modeled in support of this study. Results from the analytical/process evaluation, economic evaluation, and life cycle analysis are presented, for each scenario. For scenarios in which validations were performed, the validation case results are also provided with comparisons to the modeled case.

5.1 Scenario 1: CBTL, 0 Percent Biomass and Validation

The purpose of this scenario is to evaluate potential process values, economic factors, and environmental emissions associated with the production of F-T jet fuels solely from sub-bituminous coal. This scenario evaluates a 1:1 (volume) blend of F-T jet fuels and conventional U.S. average jet fuel, based on a 30-year study period. Coal feedstock is derived from the Rosebud seam in southern Montana, and is transported by train to the CBTL facility, located in the Southeastern U.S. The F-T process employed uses a slurry-based iron catalyst using a single feed, oxygen blown Transport Reactor Integrated Gasifier (TRIG™; refer to Chapter 2 for additional discussion). Carbon dioxide is captured at the CBTL facility using a Selexol process to segregate carbon dioxide. Additional carbon dioxide is stripped from overhead gas downstream of the F-T synthesis process, using a methyldiethanolamine (MDEA) unit. Captured carbon dioxide is then routed to a purification and compression system, where it is compressed to a supercritical state. F-T jet fuel produced by the F-T facility is then conveyed to a blending facility, where it is blended with conventional jet fuel, and transported to an airport. Finally, the blended jet fuel is combusted in a jet airplane.

The following text provides a summary of process model, economic model, and environmental model results for this scenario.

5.1.1 Process Results

As discussed in Chapter 2, three Aspen Plus® model cases were run for this scenario: low RSP, expected RSP, and high RSP. Process summary results, both modeled and validated, for each of the three cases are reported in **Table 5-1**. Results obtained from the Aspen Plus® simulations are based on a 50,000 barrel per day (bpd) production rate for total F-T products (F-T jet fuel, F-T diesel, F-T naphtha, and F-T LPG) for the CBTL, 0 percent Biomass configuration under all three RSP cases. Fuel production breakdowns are minimally variable among the three RSP cases. For all three RSP cases, approximately 49 percent (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34 percent by volume of total products) being F-T naphtha. F-T jet fuel is produced by hydrocracking the F-T wax to a final boiling point of about 300°C. Hydrocracking also produces naphtha boiling range liquids and LPG. Relatively smaller quantities of F-T diesel (10 percent of total products) and F-T LPG (7 percent of total products) are produced as a result of hydrocracking. These proportions assume that straight run F-T output would be sold as a product. Results from each of the three Aspen Plus® model cases were incorporated into the economic and environmental analyses, the results of which are displayed below. For additional information regarding the application of low, expected, and high RSP values to the stochastic analysis provided here, refer to Chapter 1.

Table 5-1: Scenario 1: CBTL, 0% Biomass: Process Summary

Property	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
CBTL Facility Design and Operating Data							
Plant Design Capacity	50,000	50,000	50,000	50,000	50,000	50,000	bpd
Plant Capacity Factor	85	85	90	90	92	92	%
Plant Efficiency, HHV	55	55	53	53	51	51	%
Carbon Capture Rate	88	88	89	89	90	90	%
Gasifier Modules	9	9	9	9	9	9	Count
F-T Modules	10	10	10	10	10	10	Count
CBTL Facility Inputs/Feed							
Coal Feed, Montana Rosebud, As Received	29,884	29,930	30,485	30,543	31,337	31,411	tons/ day
Biomass Feed, Southern Pine, As Received	0	0	0	0	0	0	tons/ day
Water Feed (Total Withdrawal)	15,209,309	15,281,357	15,016,588	15,099,827	14,796,311	14,889,324	gallons/day
CBTL Facility Outputs/Production							
F-T Jet Fuel Production	24,649	24,649	24,647	24,647	24,645	24,644	bpd
F-T Diesel Fuel Production	4,767	4,767	4,767	4,767	4,766	4,766	bpd
F-T Naphtha Production	16,973	16,973	16,972	16,972	16,970	16,970	bpd
F-T LPG Production	3,612	3,612	3,615	3,615	3,619	3,620	bpd
Total Liquid Product Output	50,000	50,000	50,000	50,001	50,000	50,000	bpd
Export Power	262	261	222	222	179	178	MW
CO2 Captured and Compressed	30,082	30,235	30,877	31,054	31,528	31,725	tons/ day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,297	49,297	49,294	49,294	49,289	49,288	bpd

CBTL facility fuels production capacity was fixed at 50,000 bpd for all three RSP cases. An expected capacity factor of 90 percent was included, ranging from 85 to 92 percent for low and high RSP cases, respectively. In the modeled case the overall expected plant efficiency of 53.2 percent (range of 51.1 percent to 54.9 percent) is defined as the heating value of the liquid products (HHV basis), F-T LPG, and export power divided by the higher heating value of the input coal. In the validation case the overall expected plant efficiency is 53.1 percent (range of 51.0 to 54.8 percent) , a variation of less than 1 percent from the modeled case. In the modeled case, makeup water for the CBTL facility, as modeled in Aspen Plus®, is estimated to be approximately 15.0 million gallons per day (mgd; expected RSP case), of which 94.9 percent (14.3 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 7.15 bbl water/bbl F-T product, based on the expected RSP modeled case. In the validated case, makeup water for the CBTL facility is estimated to be approximately 15.1 million gallons per day (mgd; expected RSP case), of which 95.0 percent (14.3 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 7.19 bbl water/bbl F-T product, based on the expected RSP validated case. Here there is strong agreement between the modeled and validated case with a variation of makeup water for the CBTL facility of 0.08 million gallon per day (0.55 percent) and a normalized variation of 0.04 bbl water/bbl F-T product (0.55 percent).

Under the modeled case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 179 to 262 MW, with an expected value of 222 MW. Based on the expected RSP case, gross power production for the CBTL facility is 794 MW, based on power generated from steam (562 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (249 MW), carbon dioxide compressors (91.6 MW), the Selexol unit (60.8 MW), hydrocarbon recovery/refrigeration (43.1 MW), and oxygen compression (32.4 MW). Total auxiliaries consume 572 MW, for a net power output of 222 MW under the expected RSP case.

Under the validated case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 178 to 261 MW, with an expected value of 222 MW. Based on the expected RSP case, gross power production for the CBTL facility is 797 MW, based on power generated from steam (565 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (250 MW), carbon dioxide compressors (92.1 MW), the Selexol unit (61.1 MW), hydrocarbon recovery/refrigeration (44.0 MW), and oxygen compression (32.5 MW). Total auxiliaries consume 575MW, for a net power output of 222 MW under the expected RSP case.

Carbon balance for both the modeled and validated case of the CBTL facility is shown in **Table 5-2,** for all three RSP cases. As shown, carbon inputs were within 0.2 percent of carbon outputs for each of the three RSP cases. Carbon dioxide produced during the production of fuels and electric power is separated from the syngas stream prior to entering the F-T unit. The Selexol unit and the MDEA unit both produce the concentrated CO_2 streams that are dehydrated and compressed to 2,200 psi for pipeline delivery and carbon management. Other flue gas streams containing CO_2 are vented to the atmosphere. These include the flue gases from the heat recovery steam generator (HRSG) units and from the fired heaters that are utilized during the F-T process. A small proportion (approximately 2%) of total carbon is output to slag/ash from the TRIG gasifier.

Table 5-2: Scenario 1: CBTL, 0% Biomass: Conversion Facility Carbon Balance

Input Flow	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
Coal Carbon	14,962	14,986	15,263	15,292	15,690	15,727	TPD
Biomass Carbon	0	0	0	0	0	0	TPD
Total Carbon Input	14,962	14,986	15,263	15,292	15,690	15,727	**TPD**
F-T Products	5,284	5,284	5,284	5,284	5,284	5,284	TPD
Slag/Ash	150	150	306	306	628	630	TPD
Stack Gas	1,004	991	956	942	907	894	TPD
Fuel Gas	271	265	245	238	218	211	TPD
WWTP	30	31	31	31	30	30	TPD
Carbon Capture, Sequestered	8,228	8,270	8,447	8,497	8,629	8,684	TPD
Total Carbon Output	**14,967**	**14,991**	**15,269**	**15,298**	**15,695**	**15,732**	**TPD**
Carbon Capture	**86.3**	**86.5**	**87.3**	**87.5**	**88.2**	**88.4**	**%**

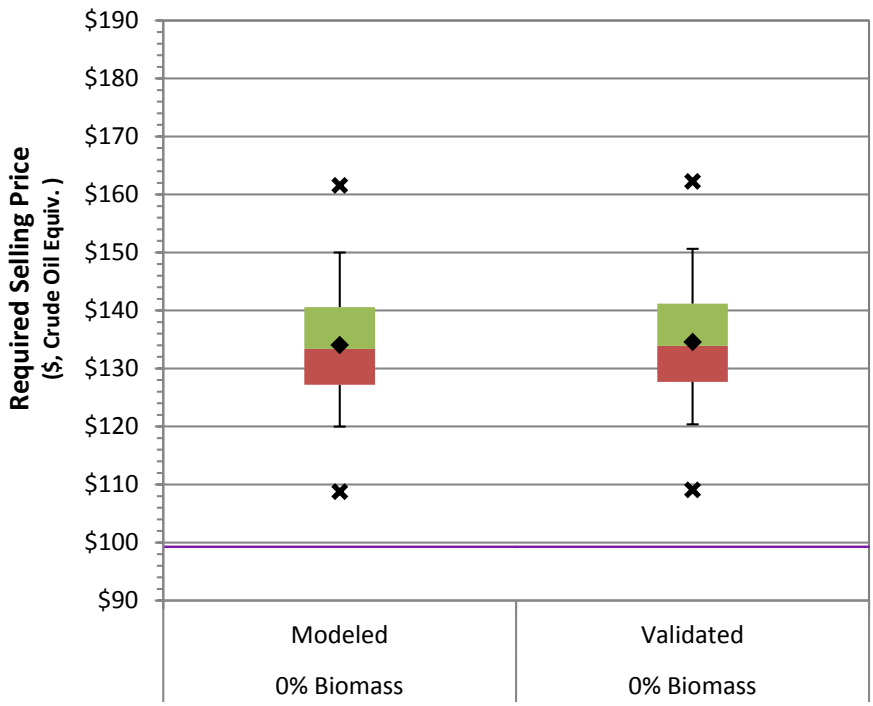
5.1.2 Economic Results

Results from the economic model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Figure 5-1 provides a summary of the estimated RSP for the F-T jet fuel produced under this scenario. As shown, RSP ranges from $127 to $141/bbl for the modeled case, with a mean value of $134/bbl, on a crude oil equivalent basis and for the validation, case the RSP ranges from $128 to $141/bbl, with a mean value of $135/bbl. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 40 economic parameters shown in **Table 1-5**. As shown, 25th and 75th percentile values are relatively close to the mean value, however, selling price distributions are characterized by long tails, with an overall range for the modeled case of $109 to $162/bbl ($109/bbl to $162/bbl validated), on a crude oil equivalent basis.

Cost of the F-T jet fuel product is estimated on a crude oil equivalent basis. This is defined as the RSP of the diesel product divided by a factor of 1.1433. Thus if the average world oil price were below or equal to the calculated crude oil equivalent price the CBTL plant would be economically viable. Key contributors to the variability shown for RSP results are discussed below.

Figure 5-1: Scenario 1: CBTL, 0% Biomass: F-T Jet Fuel RSP, Crude Oil Equivalent Basis



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel spot price value.

It is clear from **Figure 5-1** that there is minimal variation between the modeled and validated RSP results. **Table 5-3** provides a summary of the economic estimated performance of the CBTL facility under the validated case of this scenario, including the key contributing factors to the calculation of RSP. Total operating and maintenance costs represent an average of $551 million/yr. Of this amount, $306 to $334 million/yr, mean $321 million/yr (58.2 percent), results from fixed costs, while $222 to $239 million/year, mean $230 million/yr (41.8 percent) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, ranging from $8,765 to $9,625 million, mean $9,204 million. Feedstock costs for this scenario are limited to coal cost, which range from $352 to $368 million/yr, mean value of $360 million/yr. No biomass costs are incurred, and feedstock costs are approximately $191 million lower than total operating and maintenance costs, on average. Projected revenues include credits and product sales revenue. Power credit, from the sale of produced electricity, amounts to $115 to $129 million/yr, mean $122 million/yr, while CO_2 credit is estimated to be $334 to $398 million/yr, mean $366 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,040 to $2,249 million/yr, mean $2,147 million/yr.

Required product sales prices in the validated case are also provided in **Table 5-3**. Crude oil equivalent RSP is discussed above for **Figure 5-1**. On a straight basis, RSP for F-T jet fuel was calculated to be $147 to $163/bbl, mean $155/bbl, with F-T diesel at $146 to $161bbl, mean $154/bbl, F-T naphtha at $102 to $113/bbl, mean $107/bbl, and F-T LPG at $59.0 to $65.2/bbl, mean $62.2/bbl. The default capital charge factor (CCF) used in the analysis was 0.1872.

Table 5-3: Scenario 1: CBTL, 0% Biomass, Validated: Summary of Economics

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	321	265	383	306	334	$MM/yr
Variable Operating and Maintenance Cost (VOM)	230	197	273	222	239	$MM/yr
Capital: Total Overnight Cost (TOC)	9,204	7,796	11,218	8,765	9,625	$MM
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	360	330	394	352	368	$MM/yr
Biomass Cost, Southern Pine, Chips, As Received	0	0	0	0	0	$MM/yr
Biomass Cost, Southern Pine, Torrefied, As Received	0	0	0	0	0	$MM/yr
Credits and Revenue						
Power Credit	(122)	(159)	(86)	(129)	(115)	$MM/yr
Credit @ $40/ton for CO_2	(366)	(473)	(257)	(398)	(334)	$MM/yr
Annual Revenue Required	2,147	1,733	2,601	2,040	2,249	$MM/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	155	126	187	147	163	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	154	125	186	146	161	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	107	87	129	102	113	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	62	50	75	59	65	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	135	109	162	128	141	$/bbl

Figure 5-2 provides breakdowns for the cost factors in the validated case that contribute to the RSP. As shown, capital cost is the primary factor in determining RSP, and accounts for approximately 80.2 percent of total RSP, or $108/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 22.4 percent of total RSP, or $30.2/bbl, while feedstock costs represent 14.7 percent of total RSP, or $19.7/bbl, on a crude oil equivalent basis. As shown, variability in total RSP is driven largely by potential variability in capital costs, and to a much lesser extent by variability in operations and maintenance and feedstock costs. The negative credits bar comprises the sale of the co-produced electricity and compressed CO_2. Electricity accounts for 25.1 percent of the total credit, while captured and compressed CO_2 accounts for 74.9 percent.

Figure 5-2: Scenario 1: CBTL, 0% Biomass, Validated: Economic Results Breakdowns: RSP, Crude Oil Equivalent Basis

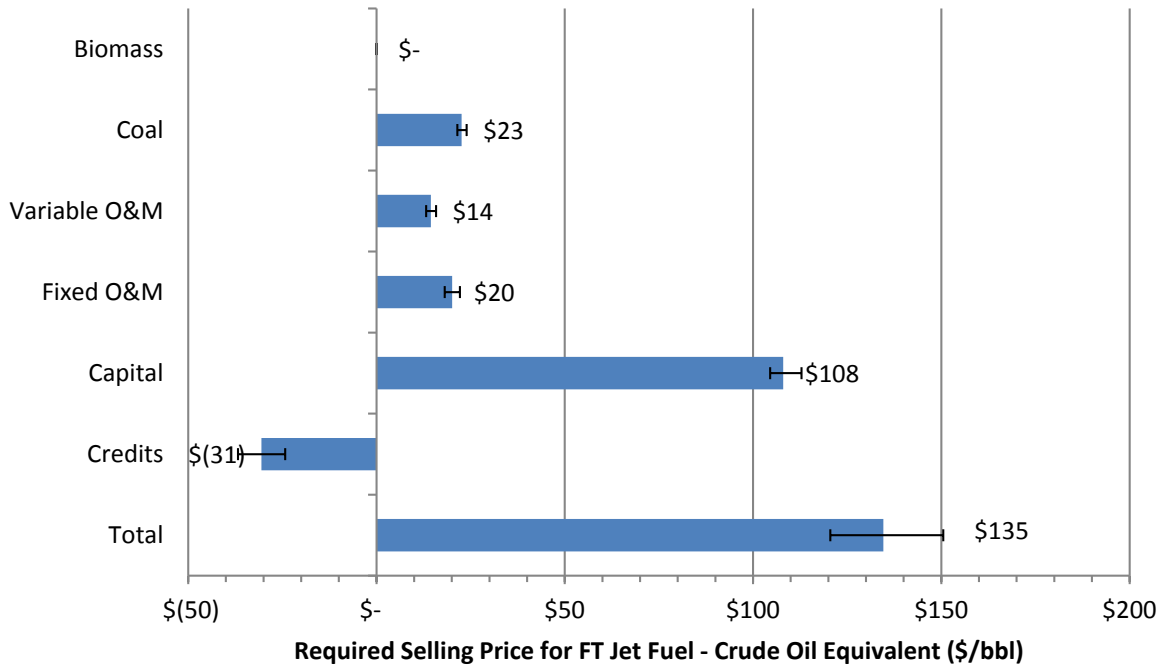
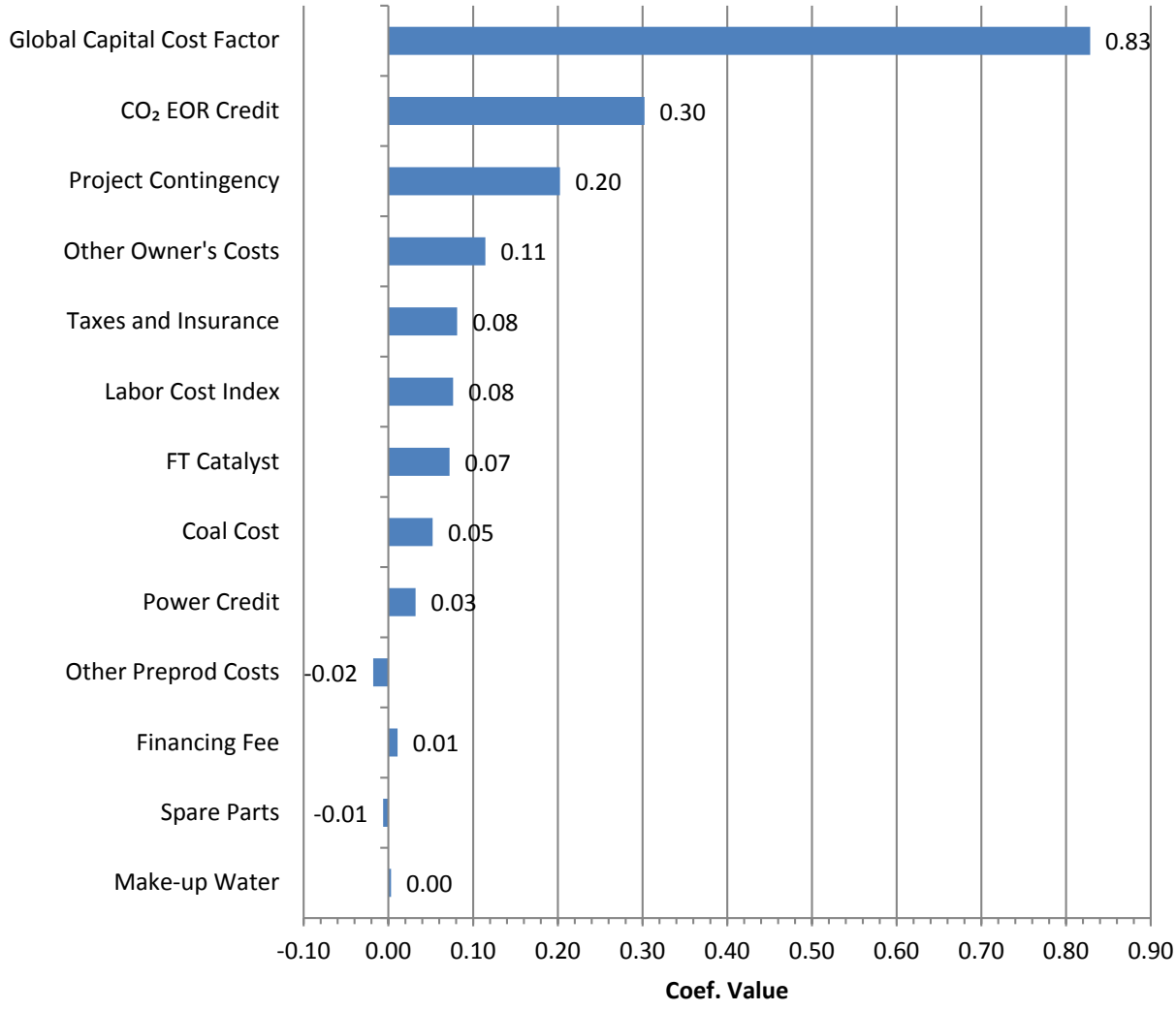


Figure 5-3 provides a summary of model sensitivity, in the validated case, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.83. Other key factors that account for at least 10 percent of the observed variability in RSP include the CO_2 EOR credit, the project contingency, and other owner's costs. Parameters that caused minimal influence on RSP included the coal cost, power credit, other preproduction costs, financing fees, cost of spare parts, and cost of makeup water.

Figure 5-3: Scenario 1: CBTL, 0% Biomass, Validated: Sensitivity of RSP to Modeled Variables

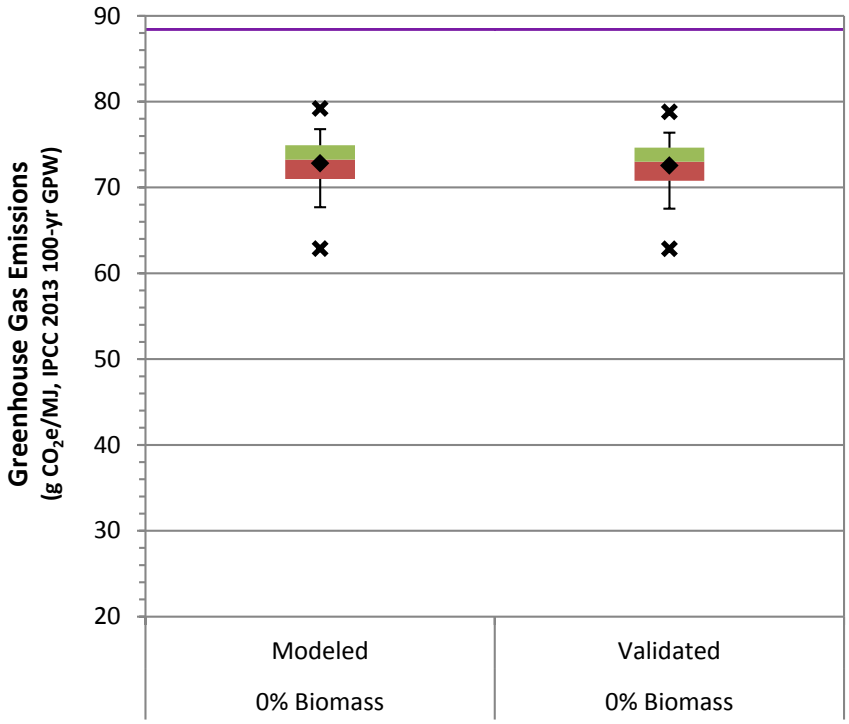


5.1.3 Environmental Results

Results from the environmental model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Results from the environmental life cycle analysis include GHG missions and other emissions, including select criteria air pollutants, other pollutants of concern, and water consumption. **Figure 5-4** provides a summary life cycle GHG emissions for this scenario, in comparison to conventional jet fuel life cycle GHG emissions of 88.41 g CO_2e/MJ. In the modeled case the resulting range is 71.0 to 74.9 g CO_2e/MJ, mean 72.8 g CO_2e/MJ or approximately 16.7 percent less than conventional jet fuel. In the validated case the resulting range is 70.8 to 74.6 g CO_2e/MJ, mean 72.6 g CO_2e/MJ or approximately 17.0 percent less than conventional jet fuel.

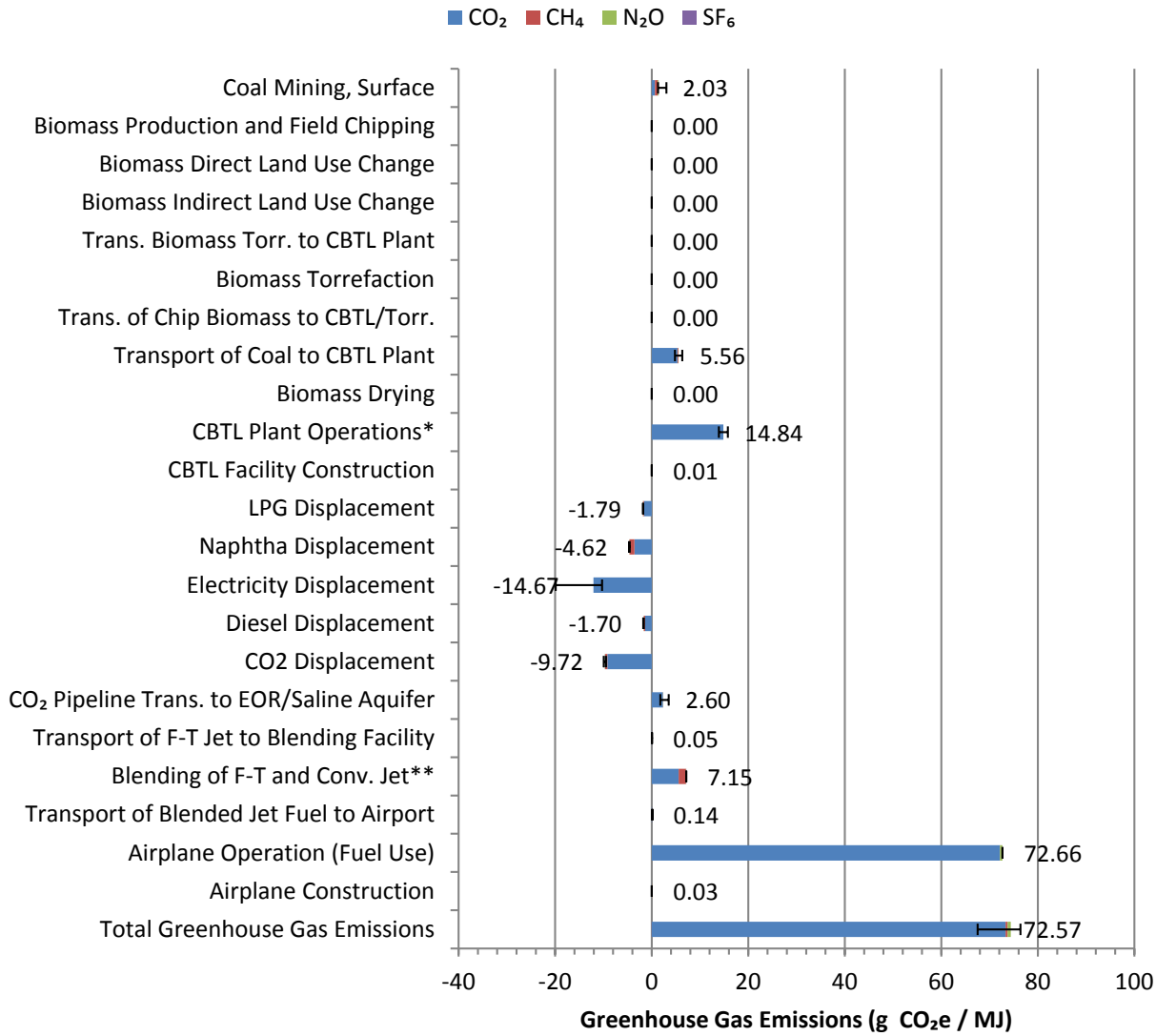
Figure 5-4: Scenario 1: CBTL, 0% Biomass: Summary of LC GHG Emissions



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

It is clear from **Figure 5-4** that there is minimal variation between the modeled and validated LC GHG emission results. **Figure 5-5** provides detail regarding the importance of the various LCA components in the validated case, with respect to gross GHG emissions contributions. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 68.7 percent of gross life cycle GHG emissions. Second in importance to fuel combustion are upstream emissions associated with CBTL plant operations, which represent 14.1 percent of gross life cycle emissions, while the blending of F-T and conventional jet fuel accounts for 5.33 percent of gross life cycle GHG emissions. Emissions from the transport of coal to the CBTL plant represent approximately 5.07 percent of gross emissions, while the pipeline transport of CO_2 accounted for approximately 2.22 percent of gross life cycle emissions. Other contributors to gross emissions were less than 1 percent individually.

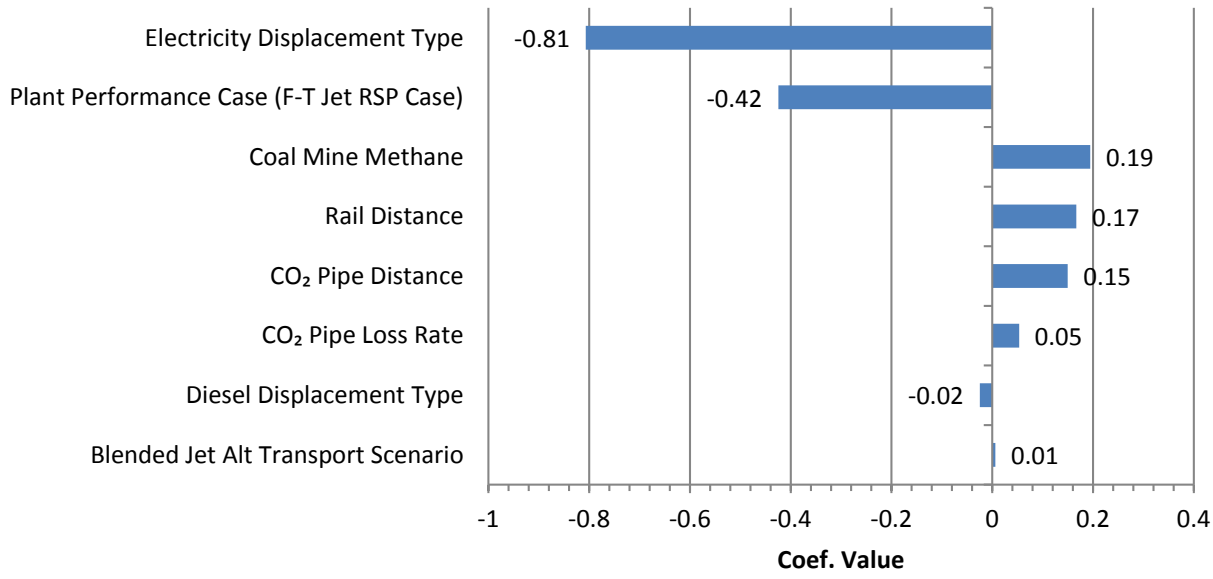
Figure 5-5: Scenario 1: CBTL, 0% Biomass, Validated: LC GHG Emissions Breakdowns



** Includes CO_2 Compression*
*** Includes conventional jet fuel profile*

The error bars shown in **Figure 5-5** reflect variability in model output based on the stochastic analyses (for more information, refer to Chapter 1). The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-6**. As shown, variability in emissions resulted primarily from the type of electricity displacement used. Another key contributor to variability in model output is the F-T jet fuel RSP case. **Figure 5-6** summarizes the key factors contributing to variability identified in the model sensitivity analysis, for GHG emissions. Values provided in the figure show the correlation coefficient between the indicated parameter and total life cycle GHG emissions. Other important factors included the and coal mine methane emissions, the rail transport distance, the blended jetfuel pipe length, the CO_2 pipe loss rate, the diesel displacement type and the blended jet fuel transport scenario. All other parameters had negligible effects on model output.

Figure 5-6: Scenario 1: CBTL, 0% Biomass, Validated: LC GHG Emissions Sensitivity



In addition to GHG emissions, other life cycle environmental emissions and flows were also considered. **Table 5-4** provides a summary of these flows. As shown, Airplane operation is the primary source of carbon monoxide and NOx within the life cycle. Particulate matter (PM_{10}) derives primarily from the combustion of diesel under raw materials transport and product transport operations. Non-methane volatile organic carbons (NMVOCs) result from product transport, including upstream conventional jet fuel emissions, and end use. The highest levels of mercury emissions occur during energy conversion and end use. For this scenario only, most water consumption occurs during energy conversion, due to water consumption at the CBTL facility. Makeup water to the CBTL facility cooling towers is the primary water demand within the CBTL facility. Note that mass units displayed for water consumption (kg/MJ jet fuel) are equivalent to volume units for water consumption (L/MJ jet fuel).

Table 5-4: Scenario 1: CBTL, 0% Biomass, Validated: Non-GHG Emissions

LC Stage	Carbon monoxide	NO_x	SO2	PM10	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	1.91E-05	2.00E-04	2.07E-05	2.03E-06	1.17E-05	3.26E-10	1.95E-06	1.73E-02	kg/MJ Jet Fuel
RMT	6.26E-04	5.74E-04	1.29E-04	7.34E-04	1.08E-04	3.54E-10	8.29E-06	1.99E-01	kg/MJ Jet Fuel
EC	-5.27E-04	-1.63E-03	-2.82E-03	-1.78E-04	-7.13E-04	6.38E-08	1.44E-05	-1.18E+00	kg/MJ Jet Fuel
PT	2.76E-04	4.38E-04	6.25E-04	3.28E-05	8.45E-04	5.80E-10	2.92E-06	1.08E+00	kg/MJ Jet Fuel
EU	7.72E-03	1.21E-02	5.56E-04	9.50E-07	7.72E-04	3.01E-08	7.16E-09	2.81E-02	kg/MJ Jet Fuel
Total	**8.11E-03**	**1.17E-02**	**-1.49E-03**	**5.92E-04**	**1.02E-03**	**9.51E-08**	**2.76E-05**	**1.46E-01**	**kg/MJ Jet Fuel**

5.2 Scenario 2: CBTL, 10 Percent Chipped Biomass

The purpose of this scenario is to evaluate potential process values, economic factors, and environmental emissions associated with the production of F-T jet fuels from a combination of 90 percent sub-bituminous coal and 10 percent chipped biomass. This scenario evaluates a 1:1 (volume) blend of F-T jet fuels and conventional U.S. average jet fuel, based on a 30-year study period. Coal feedstock is derived from the Rosebud seam in southern Montana, and is transported by train to the CBTL facility, located in the Southeastern U.S. Biomass feedstock is field-chipped Southern pine biomass, cultivated and harvested in the Southeastern U.S. and transported, via chip truck, to the CBTL facility. The F-T process employed uses a slurry-based iron catalyst using a single feed, oxygen blown Transport Reactor Integrated Gasifier (TRIG™; refer to Chapter 2 for additional discussion). Carbon dioxide is captured at the CBTL facility using a Selexol process to segregate carbon dioxide. Additional carbon dioxide is stripped from overhead gas downstream of the F-T synthesis process, using a methyldiethanolamine (MDEA) unit. Captured carbon dioxide is then routed to a purification and compression system, where it is compressed to a supercritical state. F-T jet fuel produced by the F-T facility is then conveyed to a blending facility, where it is blended with conventional jet fuel, and transported to an airport. Finally, the blended jet fuel is combusted in a jet airplane.

The following text provides a summary of process model, economic model, and environmental model results for this scenario.

5.2.1 Process Results

As discussed in Chapter 2, three Aspen Plus® model cases were run for this scenario: low RSP, expected RSP, and high RSP. Process summary results for each of the three cases are reported in **Table 5-5**. Results obtained from the Aspen Plus® simulations are based on a 50,000 barrel per day (bpd) production rate for total F-T products (F-T jet fuel, F-T diesel, F-T naphtha, and F-T LPG) for the CBTL, 10 percent Chipped Biomass configuration under all three RSP cases. Fuel production breakdowns are minimally variable among the three RSP cases. For all three RSP cases, approximately 49 percent (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34 percent by volume of total products) being F-T naphtha. F-T jet fuel is produced by hydrocracking the F-T wax to a final boiling point of about 300°C. Hydrocracking also produces naphtha boiling range liquids and F-T LPG. Relatively smaller quantities of F-T diesel (10 percent of total products) and F-T LPG (7 percent of total products) are produced as a result of hydrocracking. These proportions assume that straight run F-T output would be sold as a product. Results from each of the three Aspen Plus® model cases were incorporated into the economic and environmental analyses, the results of which are displayed below. For additional information regarding the application of low, expected, and high RSP values to the stochastic analysis provided here, refer to Chapter 1.

Table 5-5: Scenario 2: CBTL, 10% Chipped Biomass: Process Summary

Property	Low RSP Case	Expected RSP Case	High RSP Case	Units
CBTL Facility Design and Operating Data				
Plant Design Capacity	50,000	50,000	50,000	bpd
Plant Capacity Factor	85	90	92	%
Plant Efficiency, HHV	55	53	51	%
Carbon Capture Rate	88	89	90	%
Gasifier Modules	9	9	9	Count
F-T Modules	10	10	10	Count
CBTL Facility Inputs/Feed				
Coal Feed, Montana Rosebud, As Received	27,546	28,121	28,870	tons/ day
Biomass Feed, Southern Pine, As Received	4,107	4,091	4,200	tons/ day
Water Feed (Total Withdrawal)	14,879,357	14,689,544	14,428,558	gallons/day
CBTL Facility Outputs/Production				
F-T Jet Fuel Production	24,649	24,647	24,645	bpd
F-T Diesel Fuel Production	4,767	4,767	4,766	bpd
F-T Naphtha Production	16,973	16,972	16,970	bpd
F-T LPG Production	3,612	3,615	3,619	bpd
Total Liquid Product Output	50,000	50,001	50,001	bpd
Export Power	242	203	153	MW
CO2 Captured and Compressed	30,371	31,100	31,687	tons/ day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,298	49,295	49,290	bpd

CBTL facility fuels production capacity was fixed at 50,000 bpd for all three modeled cases. An expected capacity factor of 90 percent was included, ranging from 85 to 92 percent for low and high RSP cases, respectively. The overall expected plant efficiency of 53.0 percent (range of 50.8 to 54.6 percent) is defined as the heating value of the liquid products (HHV basis), F-T LPG, and export power divided by the higher heating value of the input coal and biomass. Makeup water for the CBTL facility, as modeled in Aspen Plus®, is estimated to be approximately 14.7 million gallons per day (mgd; expected RSP case), of which 95.6 percent (14.0 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 7.00 bbl water/bbl F-T product, based on the expected RSP case.

Under this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 153 to 242 MW, with an expected value of 203 MW. Based on the expected RSP case, gross power production for the CBTL facility is 782 MW, including power generated from steam (550 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads.

Major auxiliary loads include air separation (247 MW), carbon dioxide compressors (92.2 MW), the Selexol unit (61.5 MW), hydrocarbon recovery/refrigeration (42.8 MW), and oxygen compression (32.1 MW). Total auxiliaries consume 579 MW, for a net power output of 203MW under the expected RSP case.

Carbon balance for the CBTL facility is shown in **Table 5-6**, for all three RSP cases. As shown, carbon inputs were within 0.2 percent of carbon outputs for each of the three RSP cases. Carbon dioxide produced during the production of fuels and electric power is separated from the syngas stream prior to entering the F-T unit. The Selexol unit and the MDEA unit both produce concentrated CO_2 streams that are dehydrated and compressed to 2,200 psi for pipeline delivery and carbon management. Other flue gas streams containing CO_2 are vented to the atmosphere. These include the flue gases from the HRSG units and from the fired heaters that are utilized during the F-T process. For the expected RSP case, approximately 2 percent of total carbon (range of 1 percent for the low RSP case to 4 percent for the high RSP case) is output to slag/ash from the TRIG gasifier.

Table 5-6: Scenario 2: CBTL, 10% Chipped Biomass: Conversion Facility Carbon Balance

Input Flow	Low RSP Case	Expected RSP Case	High RSP Case	Units
Coal Carbon	13,792	14,080	14,455	TPD
Biomass Carbon	1,255	1,250	1,283	TPD
Total Carbon Input	**15,046**	**15,329**	**15,738**	**TPD**
F-T Products	5,284	5,284	5,284	TPD
Slag/Ash	151	307	630	TPD
Stack Gas	1,007	958	907	TPD
Fuel Gas	273	247	219	TPD
WWTP	31	32	31	TPD
Carbon Capture, Sequestered	8,307	8,508	8,673	TPD
Total Carbon Output	**15,052**	**15,336**	**15,744**	**TPD**
Carbon Capture	**88%**	**89%**	**90%**	**%**

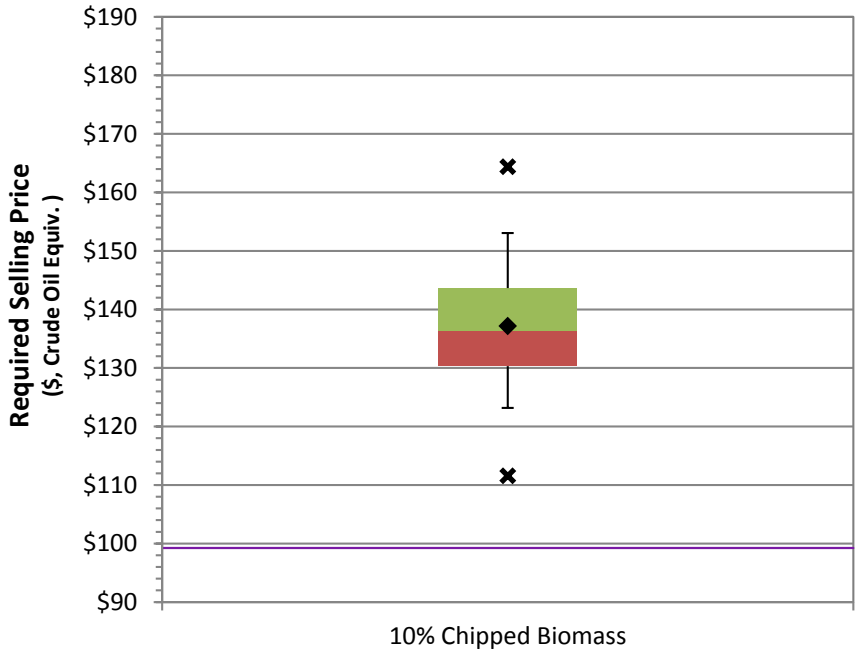
5.2.2 Economic Results

Results from the economic model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Figure 5-7 provides a summary of the estimated RSP for the F-T jet fuel produced under this scenario. As shown, RSP ranges from $130 to $144/bbl, with a mean value of $137/bbl, on a crude oil equivalent basis. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 40 economic parameters shown in **Table 1-5**. As shown, 25th and 75th percentile values are relatively close to the mean value, however, selling price distributions are characterized by long tails, with an overall range of $112 to $164/bbl, on a crude oil equivalent basis.

Cost of the F-T jet fuel product is estimated on a crude oil equivalent basis. This is defined as the RSP of the diesel product divided by a factor of 1.1433. Thus if the average world oil price were below or equal to the calculated crude oil equivalent price the CBTL plant would be economically viable. Key contributors to the variability shown for RSP results are discussed below.

Figure 5-7: Scenario 2: CBTL, 10% Chipped Biomass: F-T Jet Fuel RSP, Crude Oil Equivalent Basis



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel spot price value.

Table 5-7 provides a summary of the economic estimated performance of the CBTL facility under this scenario, including the key contributing factors to the calculation of RSP. Total operating and maintenance costs represent an average of $563 million/yr. Of this amount, $317 to $240 million/yr, mean $232 million/yr (58.8 percent), results from fixed costs, while $223 to $240 million/year, mean $232 million/yr (41.2 percent) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, range from $8,842 to $9,706 million, mean $9,284 million. Coal feedstock costs for this scenario range from $324 to $339 million/yr, mean $332 million/yr. Biomass feedstock costs range from $31.1 to $33.7 million/yr, mean $32.4 million/yr. Total feedstock costs are approximately $199 million lower than total operating and maintenance costs, on average. Projected revenues include credits and product sales revenue. Power credit, from the sale of produced electricity, amounts to $105 to $119 million/yr, mean $111 million/yr, while CO_2 credit is estimated to be $335 to $398 million/yr, mean $366 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,080 to $2,292 million/yr, mean $2,188 million/yr.

Required product sales prices are also provided in **Table 5-7**. Crude oil equivalent RSP is discussed above for **Figure 5-7**. On a straight basis, RSP for F-T jet fuel was calculated to be $150 to $166/bbl, mean $158/bbl, with F-T diesel at $149 to $164/bbl, mean $157/bbl, F-T naphtha at $104 to $114/bbl, mean $109/bbl, and F-T LPG at $60.2 to $66.4/bbl, mean $63.4/bbl. The default capital charge factor (CCF) used in the analysis was 0.1872.

Table 5-7: Scenario 2: CBTL, 10% Chipped Biomass: Summary of Economics

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	331	274	395	317	345	$MM/yr
Variable Operating and Maintenance Cost (VOM)	232	198	275	223	240	$MM/yr
Capital: Total Overnight Cost (TOC)	9,284	7,877	11,325	8,842	9,706	$MM
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	332	304	362	324	339	$MM/yr
Biomass Cost, Southern Pine, Chips, As Received	32	27	37	31	34	$MM/yr
Biomass Cost, Southern Pine, Torrefied, As Received	0	0	0	0	0	$MM/yr
Credits and Revenue						
Power Credit	(111)	(148)	(74)	(119)	(105)	$MM/yr
Credit @ $40/ton for CO_2	(366)	(473)	(258)	(398)	(335)	$MM/yr
Annual Revenue Required	2,188	1,772	2,648	2,080	2,292	$MM/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	158	129	190	150	166	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	157	128	188	149	164	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	109	89	131	104	114	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	63	52	76	60	66	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	137	112	164	130	144	$/bbl

Figure 5-8 provides breakdowns for the cost factors that contribute to the RSP. As shown, capital cost is the primary factor in determining RSP, and accounts for approximately 79.4 percent of total RSP, or $109/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 22.5 percent of total RSP, or $30.9/bbl, while feedstock costs represent 14.5 percent of total RSP, or $20.0/bbl, on a crude oil equivalent basis. As shown, variability in total RSP is driven largely by potential variability in capital costs, and to a much lesser extent by variability in operations and maintenance and feedstock costs. The negative credits bar comprises the sale of the co-produced electricity and compressed CO_2. Electricity accounts for 23.2 percent of the total credit, while captured and compressed CO_2 accounts for 76.8 percent.

Figure 5-8: Scenario 2: CBTL, 10% Chipped Biomass: RSP, Crude Oil Equivalent Basis

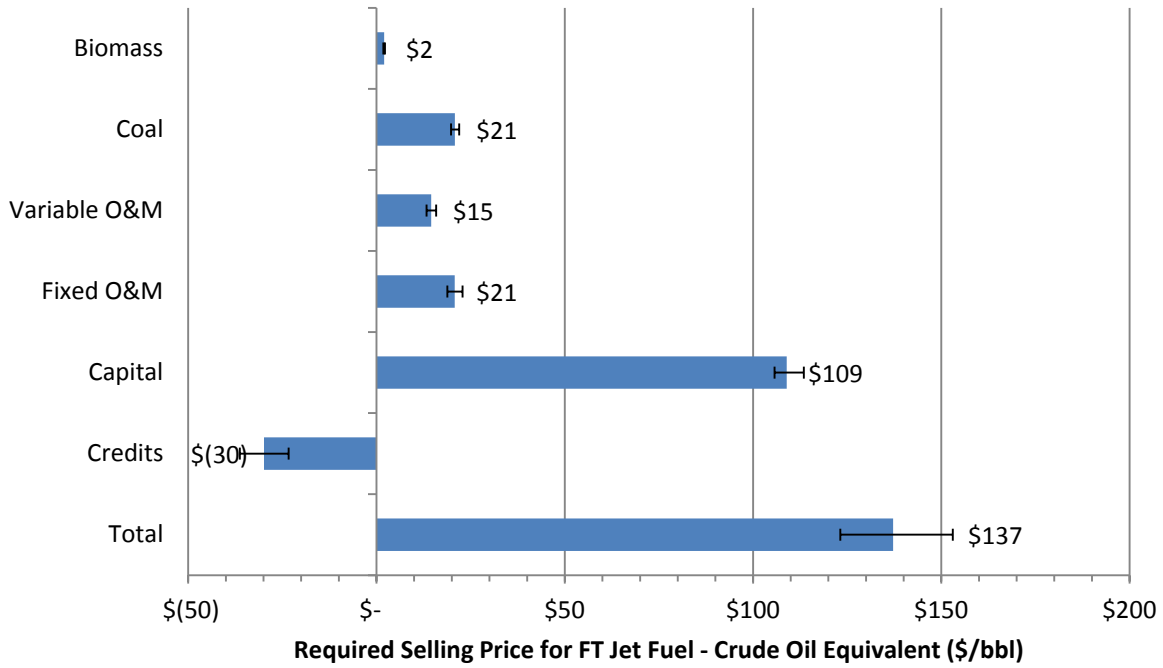
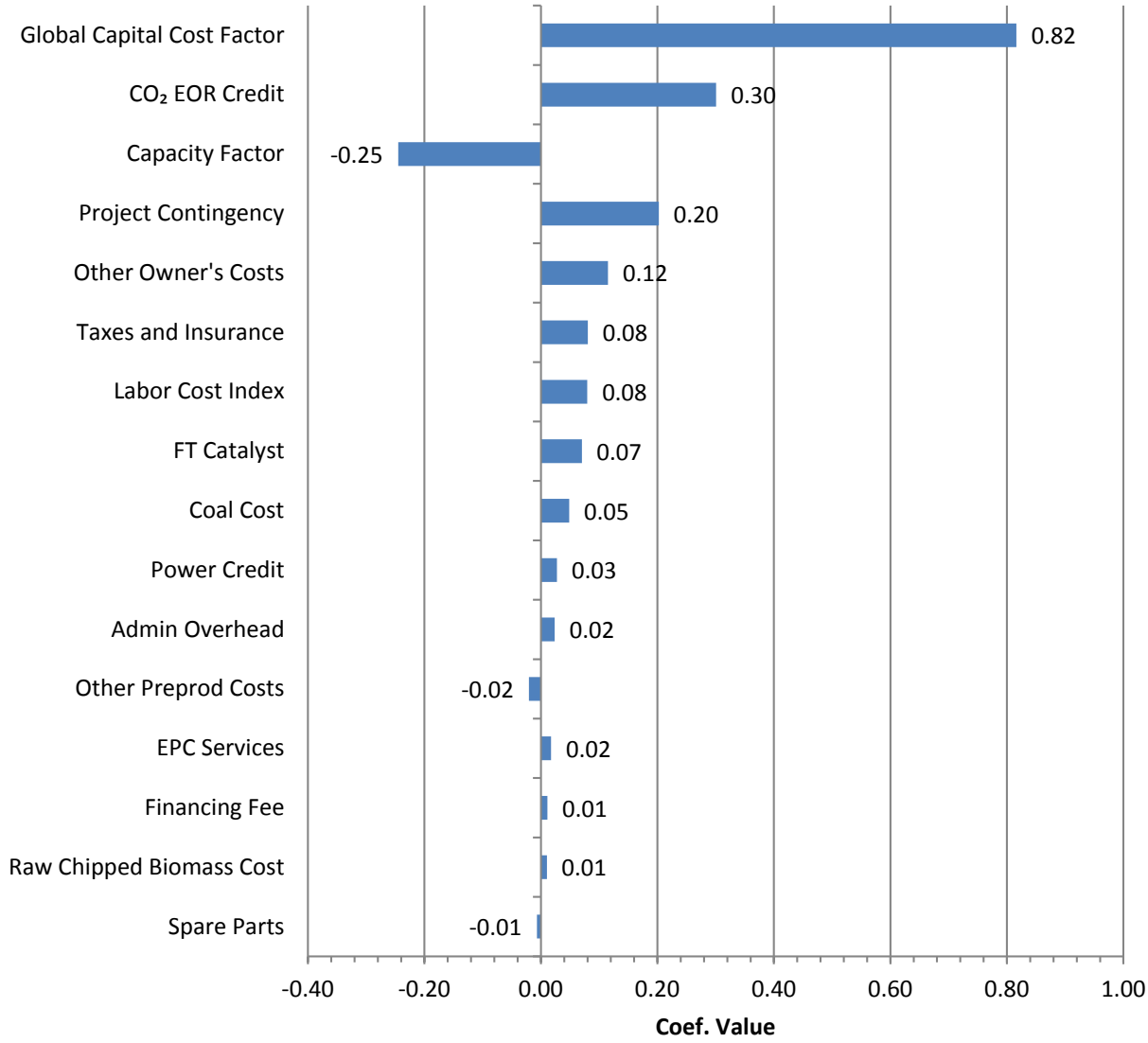


Figure 5-9 provides a summary of model sensitivity, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.82. Other key factors that account for at least 10 percent of the observed variability in RSP include the CO_2 EOR credit, the capacity factor, project contingency, and other owner's costs. Parameters that caused minimal influence on RSP included EPC services, administrative overhead expenditures, financing fees, the cost of spare parts, the cost of raw chipped biomass, and others as shown.

Figure 5-9: Scenario 2: CBTL, 10% Chipped Biomass: Sensitivity of RSP to Modeled Variables

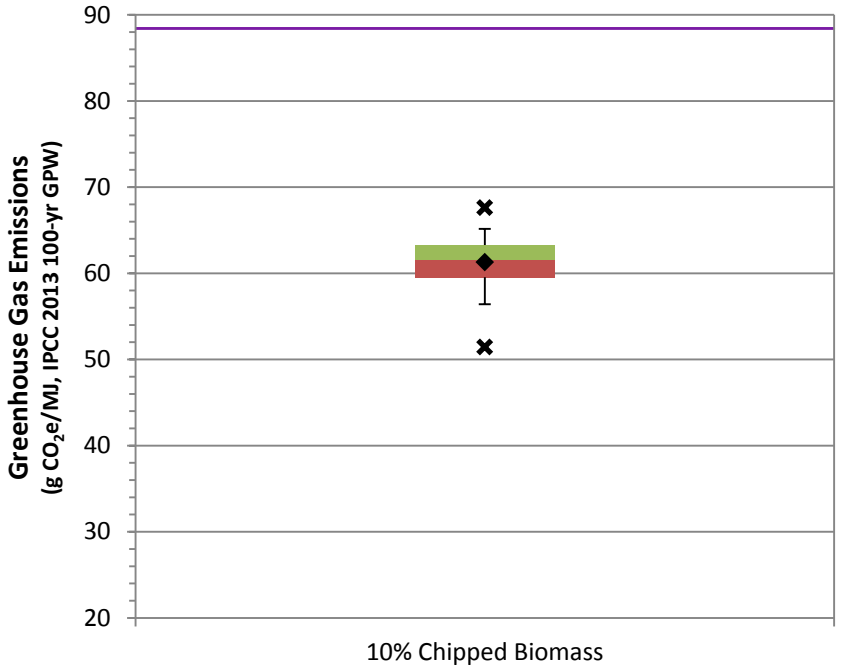


5.2.3 Environmental Results

Results from the environmental model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Results from the environmental life cycle analysis include GHG emissions and other emissions, including select criteria air pollutants, other pollutants of concern, and water consumption. **Figure 5-10** provides a summary life cycle GHG emissions for this scenario, in comparison to conventional jet fuel life cycle GHG emissions of 88.41 g CO_2e/MJ. Using the system expansion method discussed in Chapter 1 the resulting range is 59.5 to 63.3 g CO_2e/MJ, mean 61.3 g CO_2e/MJ or approximately 29.9 percent less than conventional jet fuel.

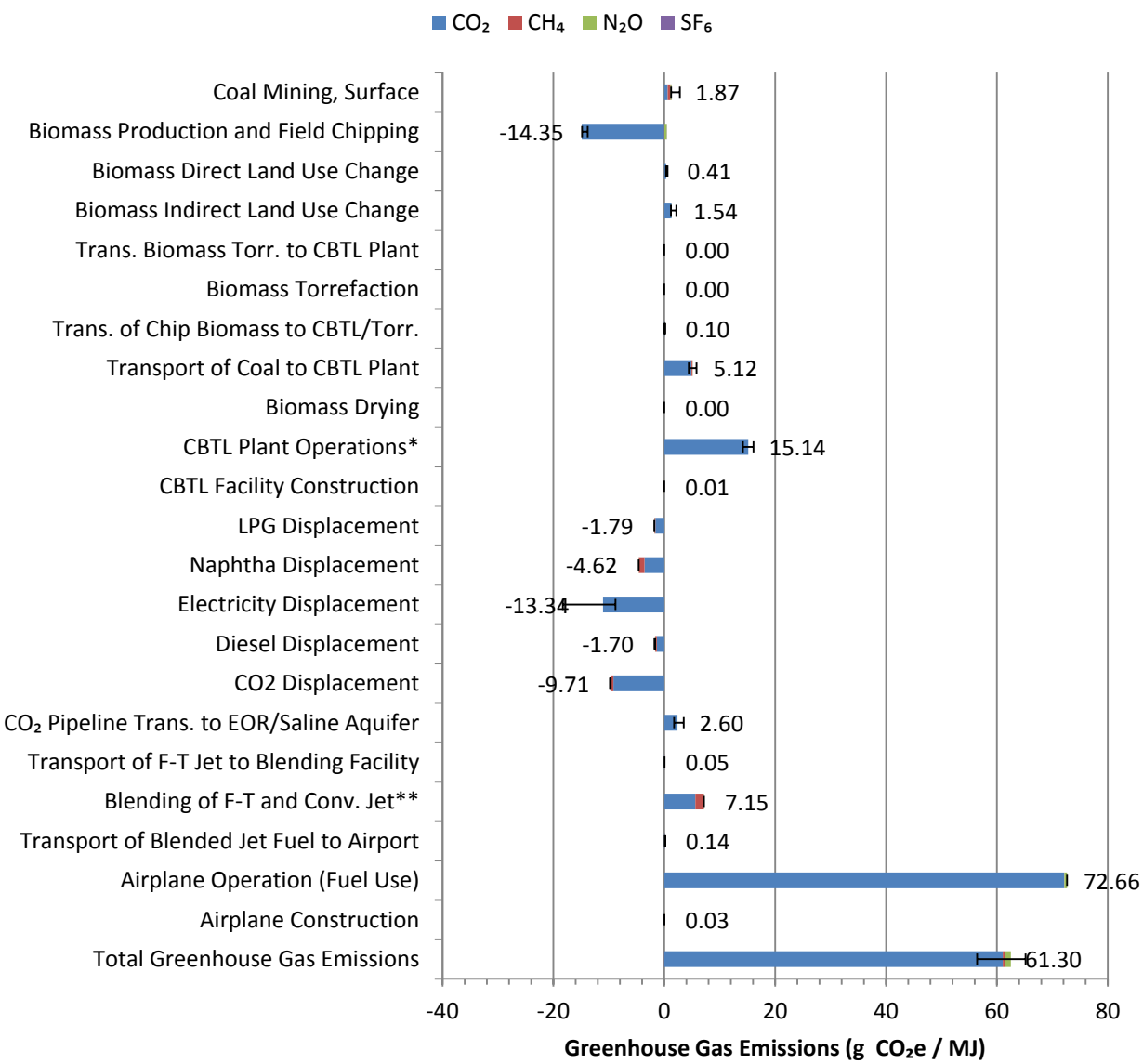
Figure 5-10: Scenario 2: CBTL, 10% Chipped Biomass: Summary of LC GHG Emissions



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

Figure 5-11 provides detail regarding the importance of the various LCA components that were modeled, with respect to gross GHG emissions contributions. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 67.5 percent of gross life cycle GHG emissions. Second in importance to fuel combustion are CBTL plant operations, which represent 14.2 percent of gross life cycle emissions, while blending of F-T and conventional jet fuel represented 5.25 percent of gross life cycle emissions. The transport of coal to the CBTL plant accounts for 4.59 percent of gross life cycle GHG emissions. Emissions from the pipeline transport of CO_2 represents approximately 2.18 percent of gross emissions, while biomass indirect land use change accounted for approximately 1.22 percent and percent of gross life cycle emissions respectively. Other contributors to gross emissions were less than 1 percent individually.

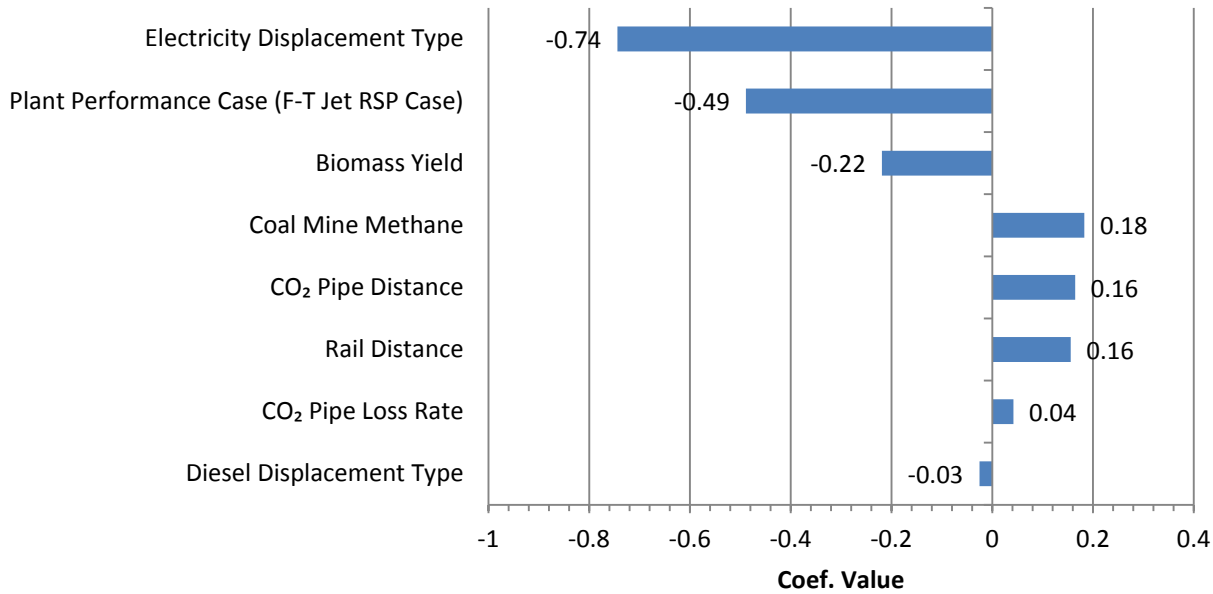
Figure 5-11: Scenario 2: CBTL, 10% Chipped Biomass: LC GHG Emissions Breakdowns



** Includes CO_2 Compression*
*** Includes conventional jet fuel profile*

The error bars shown in **Figure 5-11** reflect variability in model output based on the stochastic analyses (for more information, refer to Chapter 1). The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-6**. As shown, variability in emissions resulted primarily from the type of electricity displacement used. Other key contributors to variability in model output include the F-T jet fuel RSP case, and the biomass yield. **Figure 5-12** summarizes the key factors contributing to variability identified in the model sensitivity analysis, for GHG emissions. Values provided in the figure show the correlation coefficient between the indicated parameter and total life cycle GHG emissions. Other important factors included, coal mine methane emissions, the CO_2 pipe distance, the rail transport distance, the CO_2 pipe loss rate and the diesel displacement type. Other parameters had minimal to negligible effect on life cycle GHG emissions.

Figure 5-12: Scenario 2: CBTL, 10% Chipped Biomass: LC GHG Emissions Sensitivity



In addition to GHG emissions, other life cycle environmental emissions and flows were also considered. **Table 5-8** provides a summary of these flows. As shown, end use (jet fuel combustion) is the primary source of carbon monoxide and NOx within the life cycle. Particulate matter (PM_{10}) derives primarily from the combustion of diesel under raw materials transport and product transport operations. Non-methane volatile organic carbons (NMVOCs) result from product transport, including upstream conventional jet fuel emissions, and end use. The highest levels of mercury emissions occur during energy conversion and end use. Most water consumption occurs during biomass cultivation. Note that mass units displayed for water consumption (kg/MJ jet fuel) are equivalent to volume units for water consumption (L/MJ jet fuel).

Table 5-8: Scenario 2: CBTL, 10% Chipped Biomass: Non-GHG Emissions

LC Stage	Carbon monoxide	NO_x	SO2	PM10	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	1.18E-04	2.73E-04	8.71E-05	3.37E-06	1.11E-05	4.40E-10	2.67E-05	5.55E+02	kg/MJ Jet Fuel
RMT	7.21E-04	6.53E-04	1.48E-04	8.32E-04	1.25E-04	4.45E-10	9.42E-06	2.31E-01	kg/MJ Jet Fuel
EC	-5.07E-04	-1.49E-03	-2.58E-03	-1.37E-04	-7.00E-04	6.22E-08	2.73E-05	6.98E-02	kg/MJ Jet Fuel
PT	2.79E-04	4.39E-04	6.27E-04	3.29E-05	8.46E-04	6.38E-10	2.93E-06	1.09E+00	kg/MJ Jet Fuel
EU	7.72E-03	1.21E-02	5.56E-04	9.50E-07	7.72E-04	3.01E-08	7.16E-09	2.81E-02	kg/MJ Jet Fuel
Total	**8.33E-03**	**1.20E-02**	**-1.16E-03**	**7.33E-04**	**1.05E-03**	**9.38E-08**	**6.63E-05**	**5.56E+02**	**kg/MJ Jet Fuel**

5.3 Scenario 3: CBTL, 20 Percent Chipped Biomass

The purpose of this scenario is to evaluate potential process values, economic factors, and environmental emissions associated with the production of F-T jet fuels from a combination of 80 percent sub-bituminous coal and 20 percent chipped biomass. This scenario evaluates a 1:1 (volume) blend of F-T jet fuels and conventional U.S. average jet fuel, based on a 30-year study period. Coal feedstock is derived from the Rosebud seam in southern Montana, and is transported by train to the CBTL facility, located in the Southeastern U.S. Biomass feedstock is field-chipped Southern pine biomass, cultivated and harvested in the Southeastern U.S. and transported, via chip truck, to the CBTL facility. The F-T process employed uses a slurry-based iron catalyst using a single feed, oxygen blown Transport Reactor Integrated Gasifier (TRIG™; refer to Chapter 2 for additional discussion). Carbon dioxide is captured at the CBTL facility using a Selexol process to segregate carbon dioxide. Additional carbon dioxide is stripped from overhead gas downstream of the F-T synthesis process, using a methyldiethanolamine (MDEA) unit. Captured carbon dioxide is then routed to a purification and compression system, where it is compressed to a supercritical state. F-T jet fuel produced by the F-T facility is then conveyed to a blending facility, where it is blended with conventional jet fuel, and transported to an airport. Finally, the blended jet fuel is combusted in a jet airplane.

The following text provides a summary of process model, economic model, and environmental model results for this scenario.

5.3.1 Process Results

As discussed in Chapter 2, three Aspen Plus® model cases were run for this scenario: low RSP, expected RSP, and high RSP. Process summary results for each of the three cases are reported in **Table 5-9**. Results obtained from the Aspen Plus® simulations are based on a 50,000 barrel per day (bpd) production rate for total F-T products (F-T jet fuel, F-T diesel, F-T naphtha, and F-T LPG) for the CBTL, 20 percent Chipped Biomass configuration under all three RSP cases. Fuel production breakdowns are minimally variable among the three RSP cases. For all three RSP cases, approximately 49 percent (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34 percent by volume of total products) being F-T naphtha. F-T jet fuel is produced by hydrocracking the F-T wax to a final boiling point of about 300°C. Hydrocracking also produces naphtha boiling range liquids and F-T LPG. Relatively smaller quantities of F-T diesel (10 percent of total products) and F-T LPG (7 percent of total products) are produced as a result of hydrocracking. These proportions assume that straight run F-T output would be sold as a product. Results from each of the three Aspen Plus® model cases were incorporated into the economic and environmental analyses, the results of which are displayed below. For additional information regarding the application of low, expected, and high RSP values to the stochastic analysis provided here, refer to Chapter 1.

Table 5-9: Scenario 3: CBTL, 20% Chipped Biomass: Process Summary

Property	Low RSP Case	Expected RSP Case	High RSP Case	Units
CBTL Facility Design and Operating Data				
Plant Design Capacity	50,000	50,000	50,000	bpd
Plant Capacity Factor	85	90	92	%
Plant Efficiency, HHV	54	53	51	%
Carbon Capture Rate	88	89	90	%
Gasifier Modules	9	9	9	Count
F-T Modules	10	10	10	Count
CBTL Facility Inputs/Feed				
Coal Feed, Montana Rosebud, As Received	25,092	25,637	26,283	tons/ day
Biomass Feed, Southern Pine, As Received	8,418	8,391	8,602	tons/ day
Water Feed (Total Withdrawal)	14,533,198	14,345,490	14,000,603	gallons/day
CBTL Facility Outputs/Production				
F-T Jet Fuel Production	24,649	24,647	24,645	bpd
F-T Diesel Fuel Production	4,767	4,767	4,766	bpd
F-T Naphtha Production	16,973	16,972	16,970	bpd
F-T LPG Production	3,612	3,614	3,619	bpd
Total Liquid Product Output	50,000	50,000	50,000	bpd
Export Power	222	183	130	MW
CO2 Captured and Compressed	30,674	31,334	31,854	tons/ day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,297	49,294	49,289	bpd

CBTL facility fuels production capacity was fixed at 50,000 bpd for all three modeled cases. An expected capacity factor of 90 percent was included, ranging from 85 to 92 percent for low and high RSP cases, respectively. The overall expected plant efficiency of 52.7 percent (range of 50.5 to 54.2 percent) is defined as the heating value of the liquid products (HHV basis), F-T LPG, and export power divided by the higher heating value of the input coal and biomass. Makeup water for the CBTL facility, as modeled in Aspen Plus®, is estimated to be approximately 14.3 million gallons per day (mgd; expected RSP case), of which 96.3 percent (13.8 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.83 bbl water/bbl F-T product, based on the expected RSP case.

Under this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 153 to 242 MW, with an expected value of 183 MW. Based on the expected RSP case, gross power production for the CBTL facility is 770 MW, including power generated from steam (538 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads.

Major auxiliary loads include air separation (245 MW), carbon dioxide compressors (92.8 MW), the Selexol unit (62.2 MW), hydrocarbon recovery/refrigeration (42.5 MW), and oxygen compression (31.9 MW). Total auxiliaries consume 586 MW, for a net power output of 183MW under the expected RSP case.

Carbon balance for the CBTL facility is shown in **Table 5-10**, for all three RSP cases. As shown, carbon inputs were within 0.2 percent of carbon outputs for each of the three RSP cases. Carbon dioxide produced during the production of fuels and electric power is separated from the syngas stream prior to entering the F-T unit. The Selexol unit and the MDEA unit both produce the concentrated CO_2 streams that are dehydrated and compressed to 2,200 psi for pipeline delivery and carbon management. Other flue gas streams containing CO_2 are vented to the atmosphere. These include the flue gases from the HRSG units and from the fired heaters that are utilized during the F-T process. For the expected RSP case, approximately 2 percent of total carbon (range of 1 percent for the low RSP case to 4 percent for the high RSP case) is output to slag/ash from the TRIG gasifier.

Table 5-10: Scenario 3: CBTL, 20% Chipped Biomass: Conversion Facility Carbon Balance

Input Flow	Low RSP Case	Expected RSP Case	High RSP Case	Units
Coal Carbon	12,563	12,836	13,159	TPD
Biomass Carbon	2,572	2,563	2,628	TPD
Total Carbon Input	**15,135**	**15,399**	**15,787**	**TPD**
F-T Products	5,284	5,284	5,284	TPD
Slag/Ash	152	308	632	TPD
Stack Gas	1,010	960	908	TPD
Fuel Gas	275	249	221	TPD
WWTP	31	31	30	TPD
Carbon Capture, Sequestered	8,389	8,572	8,718	TPD
Total Carbon Output	**15,140**	**15,405**	**15,792**	**TPD**
Carbon Capture	**88%**	**89%**	**90%**	**%**

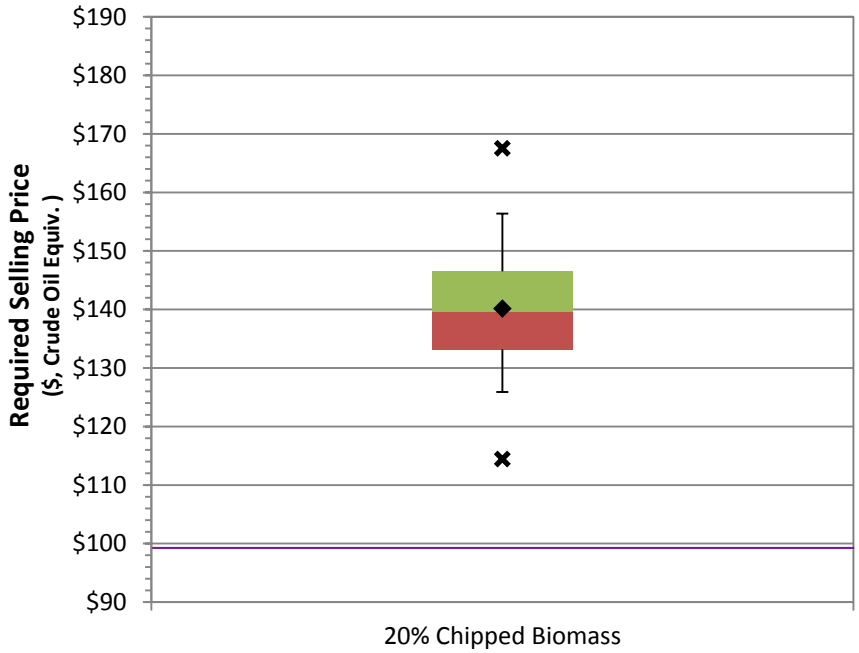
5.3.2 Economic Results

Results from the economic model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Figure 5-13 provides a summary of the estimated RSP for the F-T jet fuel produced under this scenario. As shown, RSP ranges from $133 to $147/bbl, with a mean value of $140/bbl, on a crude oil equivalent basis. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 40 economic parameters shown in **Table 1-5**. As shown, 25th and 75th percentile values are relatively close to the mean value, however, selling price distributions are characterized by long tails, with an overall range of $114 to $168/bbl, on a crude oil equivalent basis.

Cost of the F-T jet fuel product is estimated on a crude oil equivalent basis. This is defined as the RSP of the diesel product divided by a factor of 1.1433. Thus if the average world oil price were below or equal to the calculated crude oil equivalent price the CBTL plant would be economically viable. Key contributors to the variability shown for RSP results are discussed below.

Figure 5-13: Scenario 3: CBTL, 20% Chipped Biomass: F-T Jet Fuel RSP, Crude Oil Equivalent Basis



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel spot price value.

Table 5-11 provides a summary of the economic estimated performance of the CBTL facility under this scenario, including the key contributing factors to the calculation of RSP. Total operating and maintenance costs represent an average of $577 million/yr. Of this amount, $328 to $357 million/yr, mean $343 million/yr (59.5 percent), results from fixed costs, while $226 to $242 million/year, mean $234 million/yr (40.5 percent) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, range from $8,953 to $9,818 million, mean $9,392 million. Coal feedstock costs for this scenario range from $296 to $309 million/yr, mean $302 million/yr. Biomass feedstock costs range from $63.8 to $69.2 million/yr, mean $66.5 million/yr. Total feedstock costs are approximately $209 million lower than total operating and maintenance costs, on average. Projected revenues include credits and product sales revenue. Power credit, from the sale of produced electricity, amounts to $94.9 to $107 million/yr, mean $99.2 million/yr, while CO_2 credit is estimated to be $337 to $401 million/yr, mean $369 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,126 to $2,341 million/yr, mean $2,236 million/yr.

Required product sales prices are also provided in **Table 5-11**. Crude oil equivalent RSP is discussed above for **Figure 5-13**. On a straight basis, RSP for F-T jet fuel was calculated to be $154 to $169/bbl, mean $162/bbl, with F-T diesel at $168 to $168/bbl, mean $160/bbl, F-T naphtha at $106 to $117/bbl, mean $112/bbl, and F-T LPG at $61.5 to $67.7/bbl, mean $64.8/bbl. The default capital charge factor (CCF) used in the analysis was 0.1872.

Table 5-11: Scenario 3: CBTL, 20% Chipped Biomass: Summary of Economics

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	343	284	409	328	357	$MM/yr
Variable Operating and Maintenance Cost (VOM)	234	200	278	226	242	$MM/yr
Capital: Total Overnight Cost (TOC)	9,392	7,970	11,491	8,953	9,818	$MM
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	302	277	329	296	309	$MM/yr
Biomass Cost, Southern Pine, Chips, As Received	67	55	77	64	69	$MM/yr
Biomass Cost, Southern Pine, Torrefied, As Received	0	0	0	0	0	$MM/yr
Credits and Revenue						
Power Credit	(99)	(135)	(63)	(107)	(95)	$MM/yr
Credit @ $40/ton for CO_2	(369)	(475)	(260)	(401)	(337)	$MM/yr
Annual Revenue Required	2,236	1,817	2,706	2,126	2,341	$MM/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	162	132	193	154	169	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	160	131	192	152	168	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	112	91	133	106	117	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	65	53	77	62	68	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	140	114	168	133	147	$/bbl

Figure 5-14 provides breakdowns for the cost factors that contribute to the RSP. As shown, capital cost is the primary factor in determining RSP, and accounts for approximately 78.6 percent of total RSP, or $110/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 22.6 percent of total RSP, or $31.6/bbl, while feedstock costs represent 14.4 percent of total RSP, or $20.2/bbl, on a crude oil equivalent basis. As shown, variability in total RSP is driven largely by potential variability in capital costs, and to a much lesser extent by variability in operations and maintenance and feedstock costs. The negative credits bar comprises the sale of the co-produced electricity and compressed CO_2. Electricity accounts for 21.2 percent of the total credit, while captured and compressed CO_2 accounts for 78.8 percent.

Figure 5-14: Scenario 3: CBTL, 20% Chipped Biomass: RSP, Crude Oil Equivalent Basis

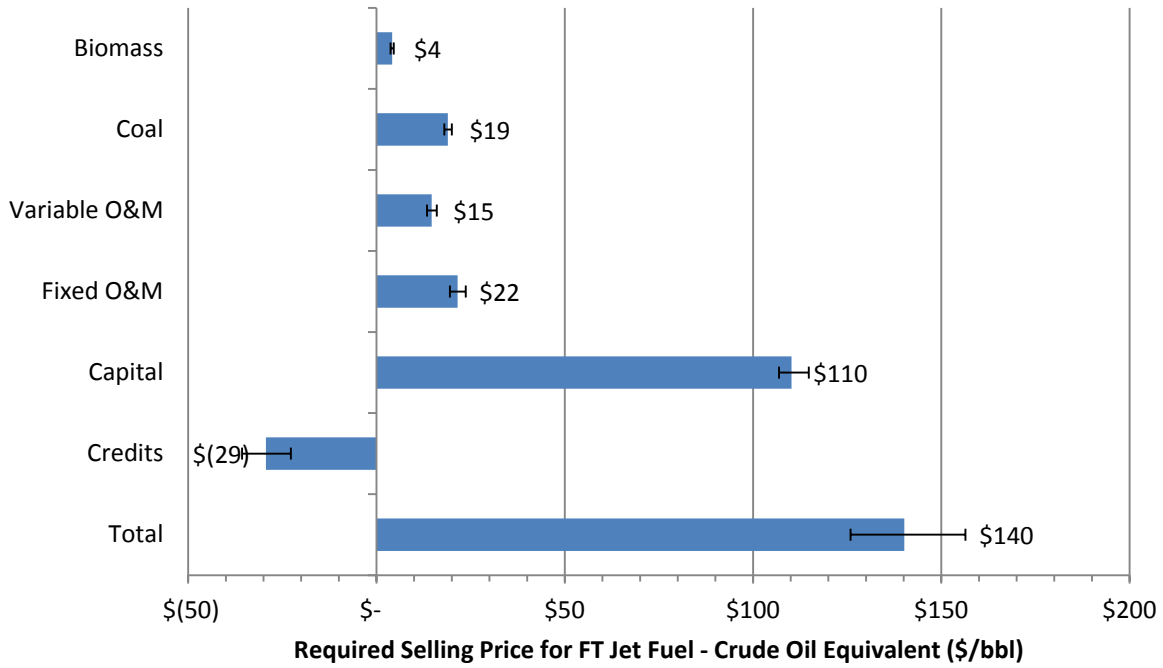
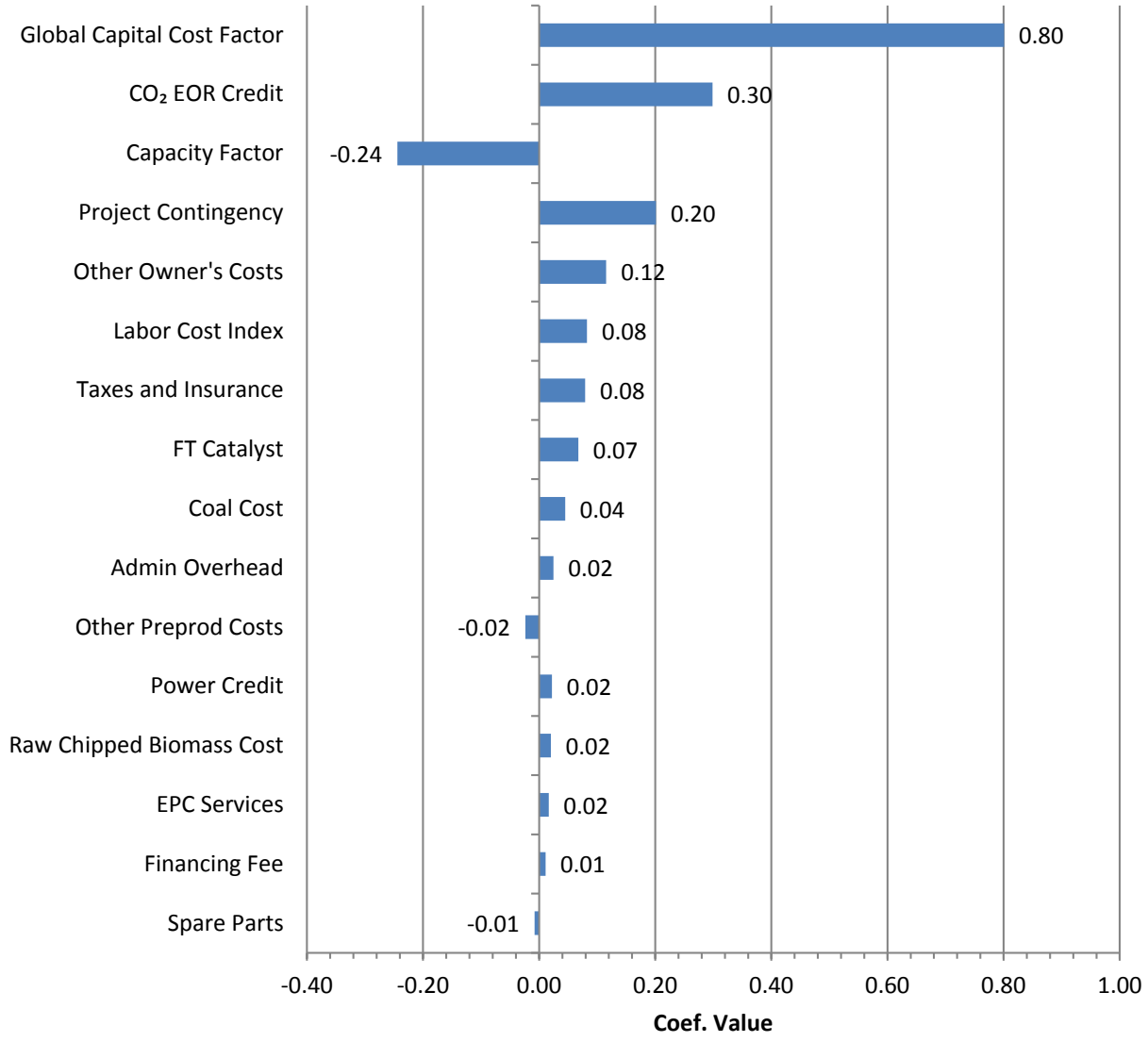


Figure 5-15 provides a summary of model sensitivity, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.80. Other key factors that account for at least 10 percent of the observed variability in RSP include the CO_2 EOR credit, the capacity factor, project contingency and other owner's costs. Parameters that caused minimal influence on RSP included EPC services, administrative overhead expenditures, cost of raw chipped biomass, financing fees, and others as shown.

Figure 5-15: Scenario 3: CBTL, 20% Chipped Biomass: Sensitivity of RSP to Modeled Variables

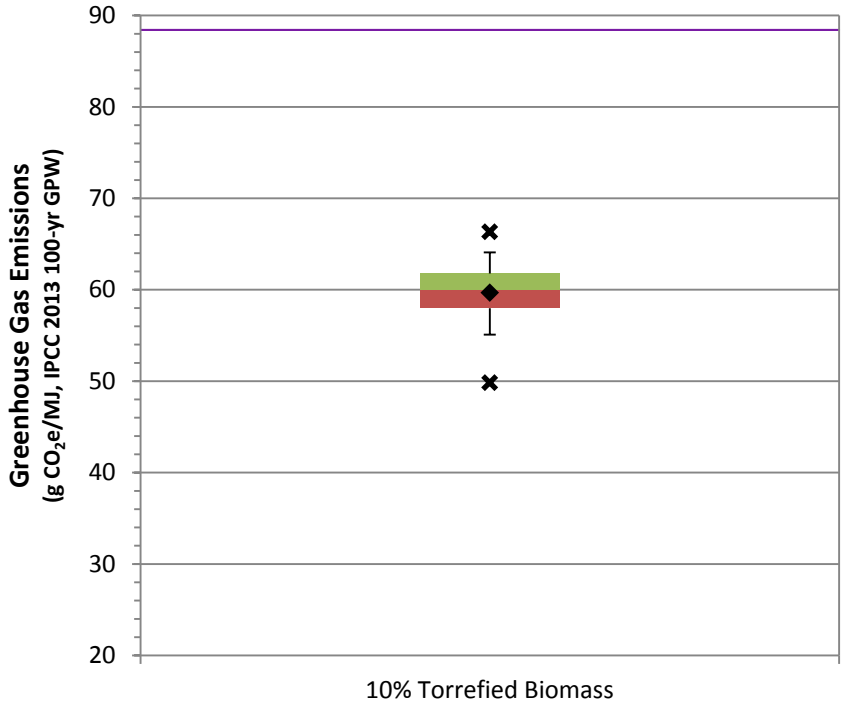


5.3.3 Environmental Results

Results from the environmental model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Results from the environmental life cycle analysis include GHG emissions and other emissions, including select criteria air pollutants, other pollutants of concern, and water consumption. **Figure 5-16** provides a summary life cycle GHG emissions for this scenario, in comparison to conventional jet fuel life cycle GHG emissions of 88.41 g CO_2e/MJ. Using the system expansion method discussed in Chapter 1 the resulting range is 47.3 to 51.0 g CO_2e/MJ, mean 49.1 g CO_2e/MJ or approximately 43.8 percent less than conventional jet fuel.

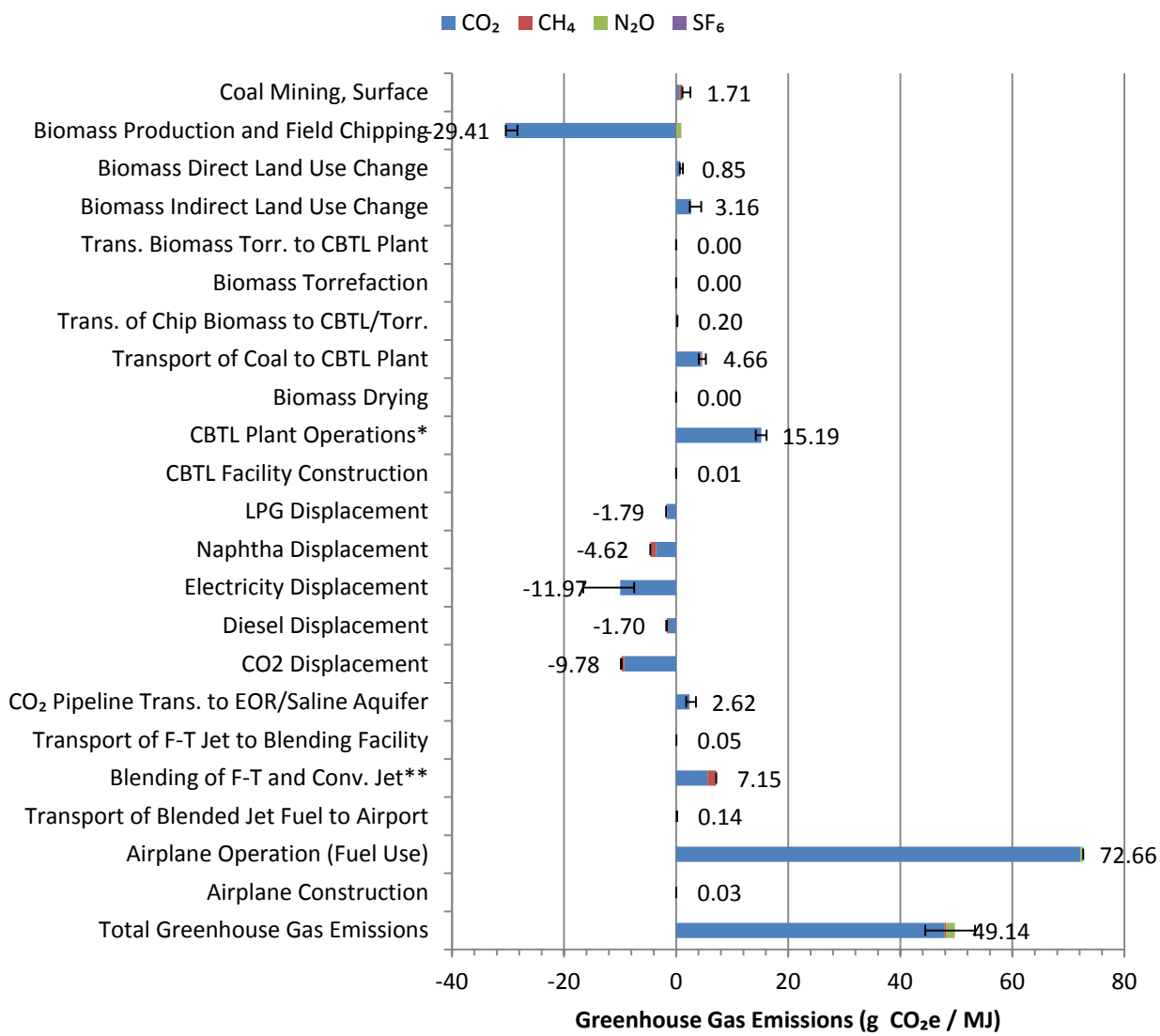
Figure 5-16: Scenario 3: CBTL, 20% Chipped Biomass: Summary of LC GHG Emissions



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

Figure 5-17 provides detail regarding the importance of the various LCA components that were modeled, with respect to gross GHG emissions contributions. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 66.5 percent of gross life cycle GHG emissions. Second in importance to fuel combustion is CBTL plant operations, at 14.0 percent of gross life cycle emissions, while emissions associated with blending of F-T and conventional jet fuel represent 5.17 percent of gross life cycle emissions. The transport of coal to the CBTL plant accounts for 4.12 percent of gross life cycle GHG emissions. Emissions from the biomass indirect land use change represent approximately 2.47 percent of gross emissions. GHG emissions associated with pipeline transport of CO_2 generate 2.17 percent of gross life cycle emissions, while biomass drying generates 0.67 percent and biomass direct land use change generates 0.52 percent. Other contributors to gross emissions were less than 1 percent individually.

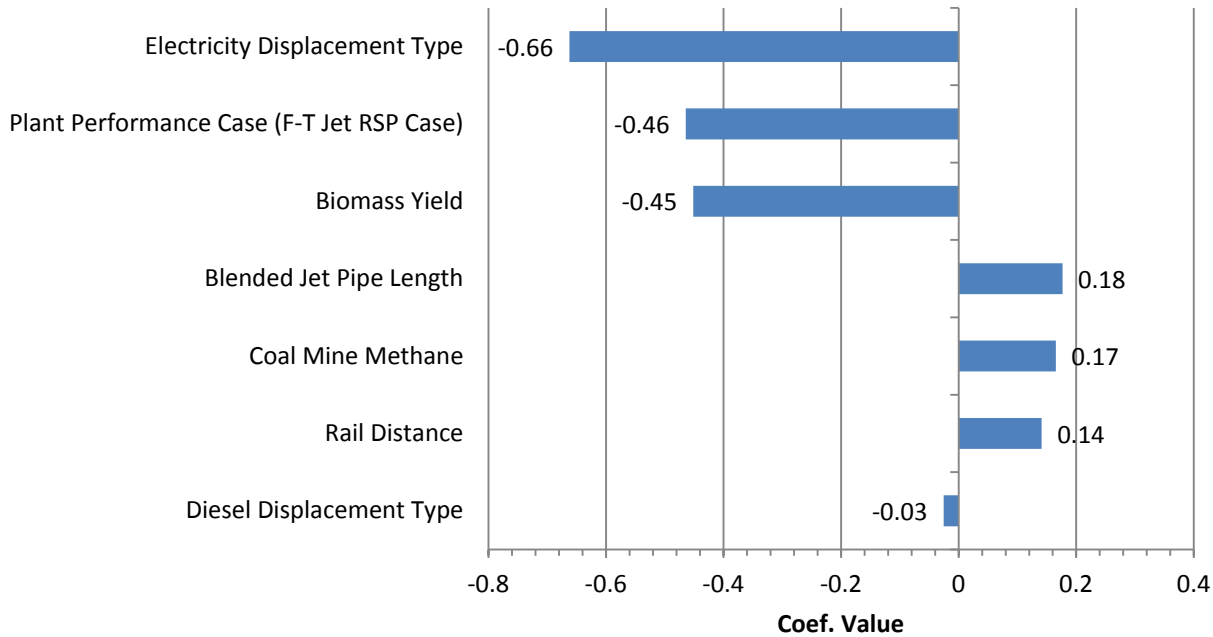
Figure 5-17: Scenario 3: CBTL, 20% Chipped Biomass: LC GHG Emissions Breakdowns



**Includes CO_2 Compression*
*** Includes conventional jet fuel profile*

The error bars shown in **Figure 5-17** reflect variability in model output based on the stochastic analyses (for more information, refer to Chapter 1). The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-6**. As shown, variability in emissions resulted primarily from the type of electricity displacement used. Other key contributors to variability in model output include biomass yield and the F-T jet fuel RSP case. **Figure 5-18** summarizes the key factors contributing to variability identified in the model sensitivity analysis, for GHG emissions. Values provided in the figure show the correlation coefficient between the indicated parameter and total life cycle GHG emissions. Other important factors included the CO_2 pipe loss rate, coal mine methane emissions, and the rail transport distance. Other parameters had minimal to negligible effect on life cycle GHG emissions.

Figure 5-18: Scenario 3: CBTL, 20% Chipped Biomass: LC GHG Emissions Sensitivity



In addition to GHG emissions, other life cycle environmental emissions and flows were also considered. **Table 5-12** provides a summary of these flows. As shown, Airplane operation is the primary source of carbon monoxide and NOx within the life cycle. Particulate matter (PM_{10}) derives primarily from the combustion of diesel under raw materials transport and product transport operations. Non-methane volatile organic carbons (NMVOCs) result from product transport, including upstream conventional jet fuel emissions, and end use. The highest levels of mercury emissions occur during energy conversion and end use. Most water consumption occurs during biomass cultivation. Note that mass units displayed for water consumption (kg/MJ jet fuel) are equivalent to volume units for water consumption (L/MJ jet fuel).

Table 5-12: Scenario 3: CBTL, 20% Chipped Biomass: Non-GHG Emissions

LC Stage	Carbon monoxide	NO_x	SO2	PM10	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	2.21E-04	3.45E-04	1.56E-04	4.71E-06	1.01E-05	5.51E-10	5.26E-05	1.14E+03	kg/MJ Jet Fuel
RMT	6.67E-04	5.97E-04	1.39E-04	7.58E-04	1.16E-04	4.76E-10	8.59E-06	2.22E-01	kg/MJ Jet Fuel
EC	-5.00E-04	-1.44E-03	-2.50E-03	-1.23E-04	-6.96E-04	5.64E-08	2.75E-05	2.99E-01	kg/MJ Jet Fuel
PT	2.79E-04	4.39E-04	6.27E-04	3.29E-05	8.46E-04	6.38E-10	2.93E-06	1.09E+00	kg/MJ Jet Fuel
EU	7.72E-03	1.21E-02	5.56E-04	9.50E-07	7.72E-04	3.01E-08	7.16E-09	2.81E-02	kg/MJ Jet Fuel
Total	**8.39E-03**	**1.21E-02**	**-1.02E-03**	**6.74E-04**	**1.05E-03**	**8.82E-08**	**9.16E-05**	**1.14E+03**	**kg/MJ Jet Fuel**

5.4 Scenario 4: CBTL, 10 Percent Torrefied Biomass

The purpose of this scenario is to evaluate potential process values, economic factors, and environmental emissions associated with the production of F-T jet fuels from a combination of 90 percent sub-bituminous coal and 10 percent Torrefied Biomass. This scenario evaluates a 1:1 (volume) blend of F-T jet fuels and conventional U.S. average jet fuel, based on a 30-year study period. Coal feedstock is derived from the Rosebud seam in southern Montana, and is transported by train to the CBTL facility, located in the Southeastern U.S. Southern pine biomass feedstock is produced and harvested in the Southeastern U.S., field-chipped, and then transported by chip truck to a separate torrefaction facility, where the biomass is torrefied. Torrefaction increases energy density of the biomass, and greatly reduces grinding energy required, as discussed in greater detail in Chapter 4. Torrefied biomass is then transported by truck to the CBTL facility. The F-T process employed uses a slurry-based iron catalyst using a single feed, oxygen blown Transport Reactor Integrated Gasifier (TRIG™; refer to Chapter 2 for additional discussion). Carbon dioxide is captured at the CBTL facility using a Selexol process to segregate carbon dioxide. Additional carbon dioxide is stripped from overhead gas downstream of the F-T synthesis process, using a methyldiethanolamine (MDEA) unit. Captured carbon dioxide is then routed to a purification and compression system, where it is compressed to a supercritical state. F-T jet fuel produced by the F-T facility is then conveyed to a blending facility, where it is blended with conventional jet fuel, and transported to an airport. Finally, the blended jet fuel is combusted in a jet airplane.

The following text provides a summary of process model, economic model, and environmental model results for this scenario.

5.4.1 Process Results

As discussed in Chapter 2, three Aspen Plus® model cases were run for this scenario: low RSP, expected RSP, and high RSP. Process summary results for each of the three cases are reported in **Table 5-13**. Results obtained from the Aspen Plus® simulations are based on a 50,000 barrel per day (bpd) production rate for total F-T products (F-T jet fuel, F-T diesel, F-T naphtha, and F-T LPG) for the CBTL, 10 percent Torrefied Biomass configuration under all three RSP cases. Fuel production breakdowns are minimally variable among the three RSP cases. For all three RSP cases, approximately 49 percent (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34 percent by volume of total products) being F-T naphtha. F-T jet fuel is produced by hydrocracking the F-T wax to a final boiling point of about 300°C. Hydrocracking also produces naphtha boiling range liquids and F-T LPG. Relatively smaller quantities of F-T diesel (10 percent of total products) and F-T LPG (7 percent of total products) are produced as a result of hydrocracking. These proportions assume that straight run F-T output would be sold as a product. Results from each of the three Aspen Plus® model cases were incorporated into the economic and environmental analyses, the results of which are displayed below. For additional information regarding the application of low, expected, and high RSP values to the stochastic analysis provided here, refer to Chapter 1.

Table 5-13: Scenario 4: CBTL, 10% Torrefied Biomass: Process Summary

Property	Low RSP Case	Expected RSP Case	High RSP Case	Units
CBTL Facility Design and Operating Data				
Plant Design Capacity	50,000	50,000	50,000	bpd
Plant Capacity Factor	85	90	92	%
Plant Efficiency, HHV	55	54	52	%
Carbon Capture Rate	88	89	90	%
Gasifier Modules	9	9	9	Count
F-T Modules	10	10	10	Count
CBTL Facility Inputs/Feed				
Coal Feed, Montana Rosebud, As Received	26,598	27,173	27,978	tons/ day
Biomass Feed, Southern Pine, As Received	2,742	2,733	2,747	tons/ day
Water Feed (Total Withdrawal)	14,952,810	14,747,637	14,522,032	gallons/day
CBTL Facility Outputs/Production				
F-T Jet Fuel Production	24,649	24,647	24,644	bpd
F-T Diesel Fuel Production	4,767	4,767	4,766	bpd
F-T Naphtha Production	16,973	16,971	16,970	bpd
F-T LPG Production	3,612	3,615	3,620	bpd
Total Liquid Product Output	50,000	50,000	50,000	bpd
Export Power	257	223	183	MW
CO2 Captured and Compressed	30,113	30,846	31,454	tons/ day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,297	49,293	49,289	bpd

CBTL facility fuels production capacity was fixed at 50,000 bpd for all three modeled cases. An expected capacity factor of 90 percent was included, ranging from 85 to 92 percent for low and high RSP cases, respectively. The overall expected plant efficiency of 53.6 percent (range of 51.5 to 55.1 percent) is defined as the heating value of the liquid products (HHV basis), F-T LPG, and export power divided by the higher heating value of the input coal and biomass. Makeup water for the CBTL facility, as modeled in Aspen Plus®, is estimated to be approximately 14.7 million gallons per day (mgd; expected RSP case), of which 95.9 percent (14.1 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 7.02 bbl water/bbl F-T product, based on the expected RSP case.

Under this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from153 to 242 MW, with an expected value of 223 MW. Based on the expected RSP case, gross power production for the CBTL facility is 791 MW, including power generated from steam (559 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads.

Major auxiliary loads include air separation (246 MW), carbon dioxide compressors (91.5 MW), the Selexol unit (61.8 MW), hydrocarbon recovery/refrigeration (43.3 MW), and oxygen compression (31.9 MW). Total auxiliaries consume 569 MW, for a net power output of 223 MW under the expected RSP case.

Carbon balance for the CBTL facility is shown in **Table 5-14**, for all three RSP cases. Carbon dioxide produced during the production of fuels and electric power is separated from the syngas stream prior to entering the F-T unit. The Selexol unit and the MDEA unit both produce the concentrated CO_2 streams that are dehydrated and compressed to 2,200 psi for pipeline delivery and carbon management. Other flue gas streams containing CO_2 are vented to the atmosphere. These include the flue gases from the HRSG units and from the fired heaters that are utilized during the F-T process. For the expected RSP case, approximately 2 percent of total carbon (range of 1 percent for the low RSP case to 4 percent for the high RSP case) is output to slag/ash from the TRIG gasifier.

Table 5-14: Scenario 4: CBTL, 10% Torrefied Biomass: Conversion Facility Carbon Balance

Input Flow	Low RSP Case	Expected RSP Case	High RSP Case	Units
Coal Carbon	13,317	13,605	14,008	TPD
Biomass Carbon	1,642	1,637	1,645	TPD
Total Carbon Input	**14,959**	**15,242**	**15,653**	**TPD**
F-T Products	5,284	5,284	5,284	TPD
Slag/Ash	150	305	627	TPD
Stack Gas	995	946	894	TPD
Fuel Gas	268	242	215	TPD
WWTP	30	31	29	TPD
Carbon Capture, Sequestered	8,237	8,440	8,610	TPD
Total Carbon Output	**14,965**	**15,248**	**15,658**	**TPD**
Carbon Capture	**88%**	**89%**	**90%**	**%**

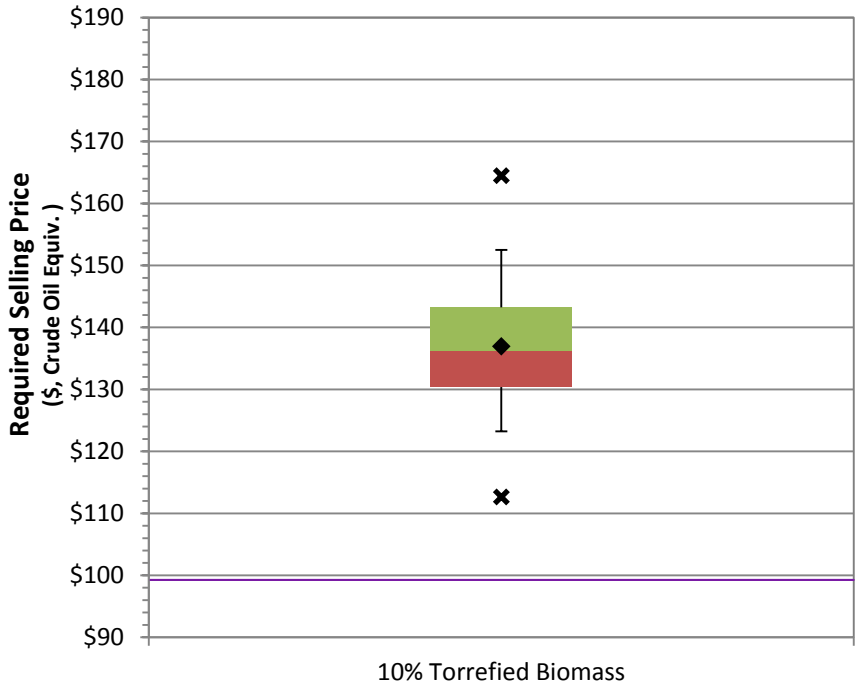
5.4.2 Economic Results

Results from the economic model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Figure 5-19 provides a summary of the estimated RSP for the F-T jet fuel produced under this scenario. As shown, RSP ranges from $130 to $143/bbl, with a mean value of $137/bbl, on a crude oil equivalent basis. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 40 economic parameters shown in **Table 1-6**. As shown, 25th and 75th percentile values are relatively close to the mean value, however, selling price distributions are characterized by long tails, with an overall range of $113 to $165/bbl, on a crude oil equivalent basis.

Cost of the F-T jet fuel product is estimated on a crude oil equivalent basis. This is defined as the RSP of the diesel product divided by a factor of 1.1433. Thus if the average world oil price were below or equal to the calculated crude oil equivalent price the CBTL plant would be economically viable. Key contributors to the variability shown for RSP results are discussed below.

Figure 5-19: Scenario 4: CBTL, 10% Torrefied Biomass: F-T Jet Fuel RSP, Crude Oil Equivalent Basis



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel spot price value.

Table 5-15 provides a summary of the economic estimated performance of the CBTL facility under this scenario, including the key contributing factors to the calculation of RSP. Total operating and maintenance costs represent an average of $541 million/yr. Of this amount, $300 to $326 million/yr, mean $314 million/yr (58.0 percent), results from fixed costs, while $219 to $236 million/year, mean $227 million/yr (42.0 percent) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, ranging from $8,597 to $9,431 million, mean $9,023 million. Coal feedstock costs for this scenario range from $313 to $327 million/yr, mean $321 million/yr. Biomass feedstock costs range from $115 to $122 million/yr, mean $119 million/yr. Total feedstock costs are approximately $102 million less than total operating and maintenance costs, on average. Projected revenues include credits and product sales revenue. Power credit, from the sale of produced electricity, amounts to $115 to $130 million/yr, mean $122 million/yr, while CO_2 credit is estimated to be $332 to $395 million/yr, mean $363 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,081 to $2,286 million/yr, mean $2,185 million/yr.

Required product sales prices are also provided in **Table 5-15**. Crude oil equivalent RSP is discussed above for **Figure 5-19.** On a straight basis, RSP for F-T jet fuel was calculated to be $151 to $165/bbl, mean $158/bbl, with F-T diesel at $149 to $164/bbl, mean $157/bbl, F-T naphtha at $104 to $114/bbl, mean $109/bbl, and F-T LPG at $60.2 to $66.2/bbl, mean $63.3//bbl. The default capital charge factor (CCF) used in the analysis was 0.1872.

Table 5-15: Scenario 4: CBTL, 10% Torrefied Biomass: Summary of Economics

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	314	259	374	300	326	$MM/yr
Variable Operating and Maintenance Cost (VOM)	227	194	269	219	236	$MM/yr
Capital: Total Overnight Cost (TOC)	9,023	7,649	10,966	8,597	9,431	$MM
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	321	293	351	313	327	$MM/yr
Biomass Cost, Southern Pine, Chips, As Received	0	0	0	0	0	$MM/yr
Biomass Cost, Southern Pine, Torrefied, As Received	119	105	136	115	122	$MM/yr
Credits and Revenue						
Power Credit	(122)	(157)	(89)	(130)	(115)	$MM/yr
Credit @ $40/ton for CO_2	(363)	(469)	(256)	(395)	(332)	$MM/yr
Annual Revenue Required	2,185	1,790	2,612	2,081	2,286	$MM/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	158	130	190	151	165	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	157	129	188	149	164	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	109	90	131	104	114	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	63	52	76	60	66	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	137	113	165	130	143	$/bbl

Figure 5-20 provides breakdowns for the cost factors that contribute to the RSP. As shown, capital cost is the primary factor in determining RSP, and accounts for approximately 77.3 percent of total RSP, or $106/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 21.7 percent of total RSP, or $29.7/bbl, while feedstock costs represent 17.6 percent of total RSP, or $24.1/bbl, on a crude oil equivalent basis. As shown, variability in total RSP is driven largely by potential variability in capital costs, and to a much lesser extent by variability in operations and maintenance and feedstock costs. The negative credits bar comprises the sale of the co-produced electricity and compressed CO_2. Electricity accounts for 25.1 percent of the total credit, while captured and compressed CO_2 accounts for 74.9 percent.

Figure 5-20: Scenario 4: CBTL, 10% Torrefied Biomass: RSP, Crude Oil Equivalent Basis

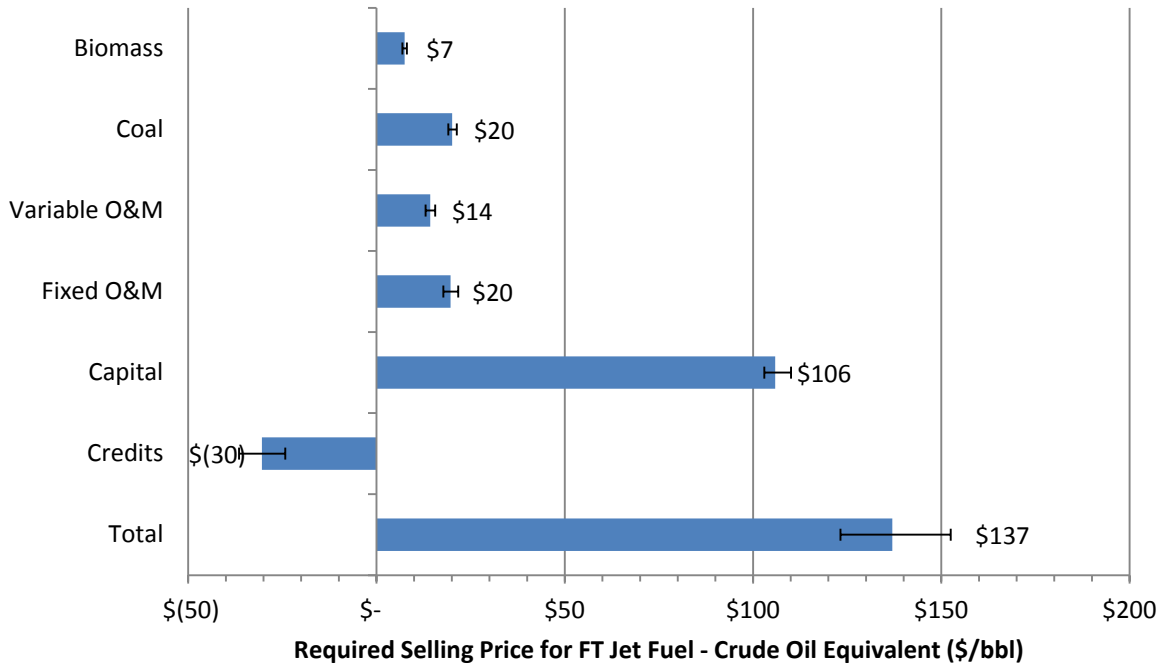
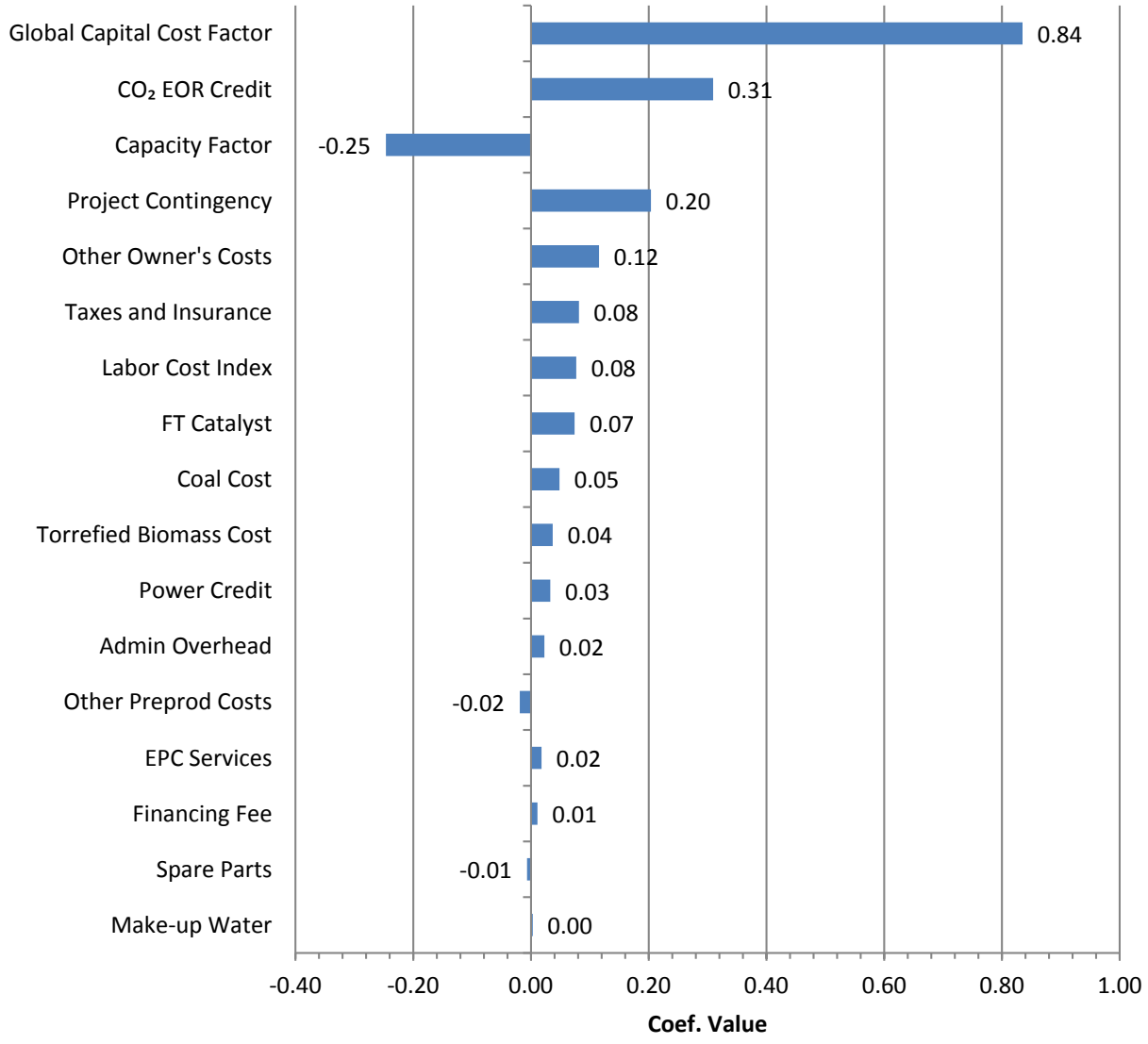


Figure 5-21 provides a summary of model sensitivity, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.84. Other key factors that account for at least 10 percent of the observed variability in RSP include the CO_2 EOR credit, capacity factor, project contingency and other owner's costs. Parameters that caused minimal influence on RSP included the coal cost, power credit, EPC services, other preproduction costs, and others as shown.

Figure 5-21: Scenario 4: CBTL, 10% Torrefied Biomass: Sensitivity of RSP to Modeled Variables

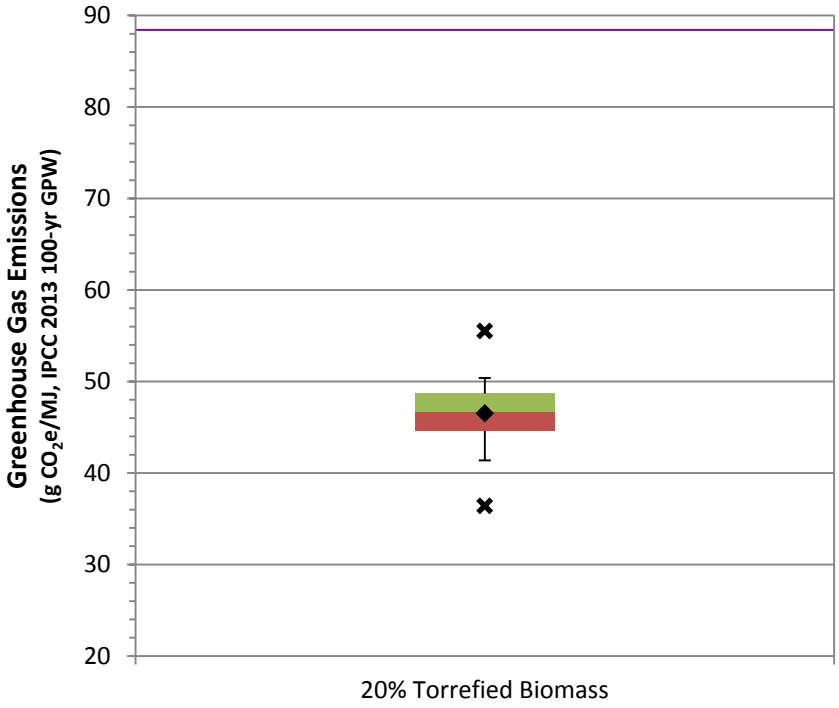


5.4.3 Environmental Results

Results from the environmental model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Results from the environmental life cycle analysis include GHG emissions and other emissions, including select criteria air pollutants, other pollutants of concern, and water consumption. **Figure 5-22** provides a summary life cycle GHG emissions for this scenario, in comparison to conventional jet fuel life cycle GHG emissions of 88.41 g CO_2e/MJ. Using the system expansion method discussed in Chapter 1 the resulting range is 58.0 to 61.8 g CO_2e/MJ, mean 59.7 g CO_2e/MJ or approximately 31.7 percent less than conventional jet fuel.

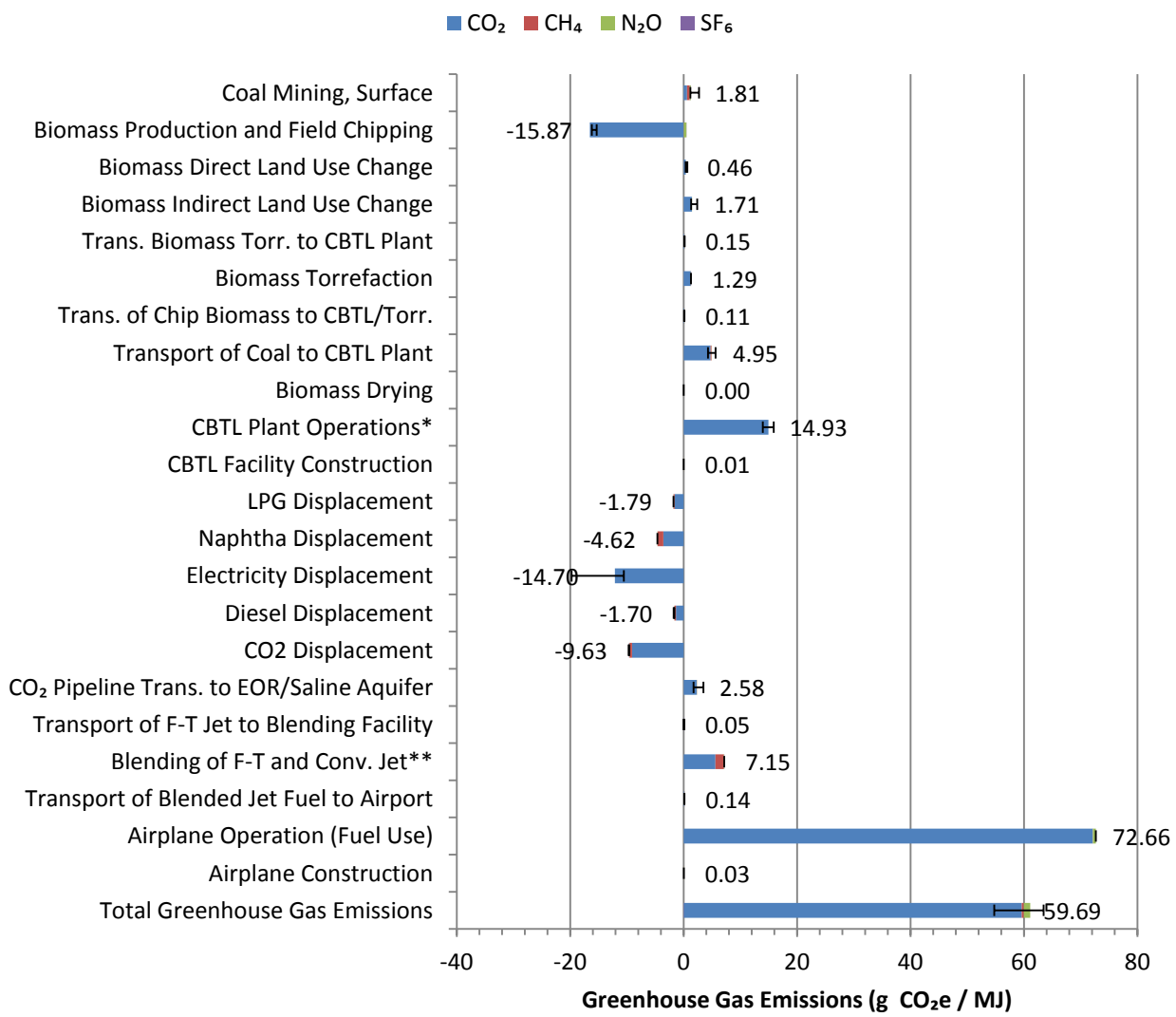
Figure 5-22: Scenario 4: CBTL, 10% Torrefied Biomass: Summary of LC GHG Emissions



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

Figure 5-23 provides detail regarding the importance of the various LCA components that were modeled, with respect to gross GHG emissions contributions. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 66.8 percent of gross life cycle GHG emissions. Second in importance to fuel combustion are upstream emissions associated with CBTL plant operations, which represent 13.8 percent of gross life cycle emissions, while blending of F-T and conventional jet fuel represented 5.19 percent of gross life cycle emissions. The transport of coal to the CBTL plant accounts for 4.39 percent of gross life cycle GHG emissions. Emissions from the pipeline transport of CO_2 represents approximately 2.14 percent of gross emissions, while biomass indirect land use change accounted for approximately 1.34 percent of gross life cycle emissions. Other contributors to gross emissions were less than 1 percent individually.

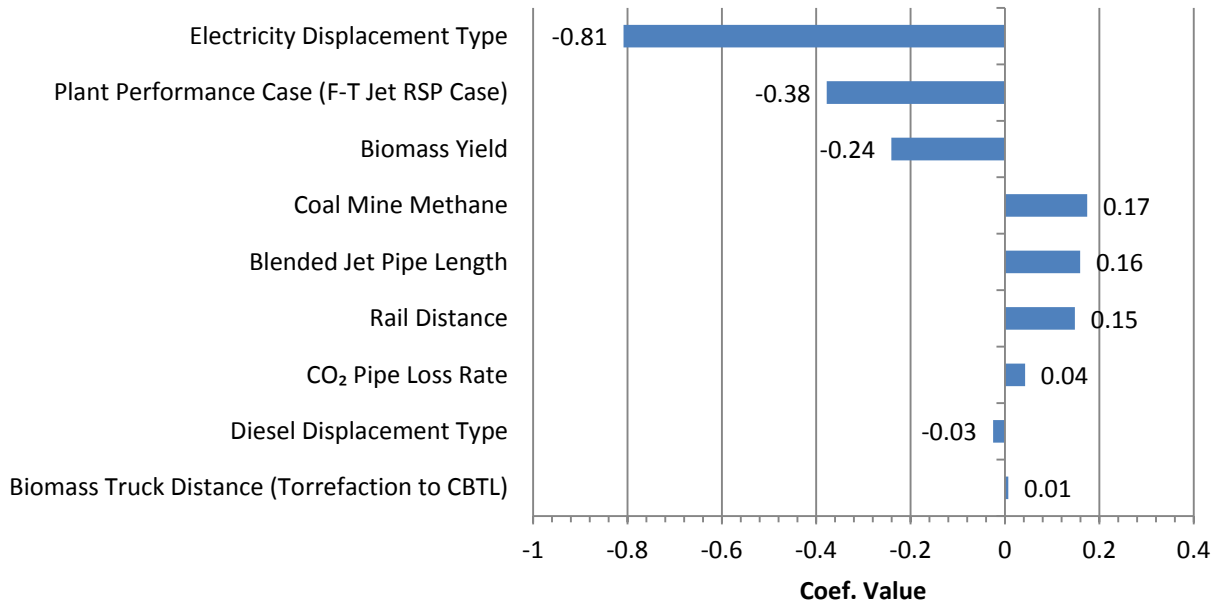
Figure 5-23: Scenario 4: CBTL, 10% Torrefied Biomass: LC GHG Emissions Breakdowns



** Includes CO_2 Compression*
*** Includes conventional jet fuel profile*

The error bars shown in **Figure 5-23** reflect variability in model output based on the stochastic analyses (for more information, refer to Chapter 1), based on combined allocation. The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-6**. As shown, variability in emissions resulted primarily from the type of electricity displacement used. Another key contributor to variability in model output is the F-T jet fuel RSP case. **Figure 5-24** summarizes the key factors contributing to variability identified in the model sensitivity analysis, for GHG emissions. Values provided in the figure show the correlation coefficient between the indicated parameter and total life cycle GHG emissions. Other important factors included the biomass yield, the coal mine methane emissions, the blended jet fuel pipe length, the rail transport distance, the CO_2 pipe loss rate, the diesel displacement type and the biomass truck transport distance between the torrefaction facility and the CBTL plant. Other parameters had minimal to negligible effect on life cycle GHG emissions.

Figure 5-24: Scenario 4: CBTL, 10% Torrefied Biomass: LC GHG Emissions Sensitivity



In addition to GHG emissions, other life cycle environmental emissions and flows were also considered. **Table 5-16** provides a summary of these flows. As shown, Airplane operation is the primary source of carbon monoxide and NOx within the life cycle. Particulate matter (PM_{10}) derives primarily from the combustion of diesel under raw materials transport and product transport operations. Non-methane volatile organic carbons (NMVOCs) result from product transport, including upstream conventional jet fuel emissions, and end use. The highest levels of mercury emissions occur during energy conversion and end use. Most water consumption occurs during biomass cultivation. Note that mass units displayed for water consumption (kg/MJ jet fuel) are equivalent to volume units for water consumption (L/MJ jet fuel).

Table 5-16: Scenario 4: CBTL, 10% Torrefied Biomass: Non-GHG Emissions

LC Stage	Carbon monoxide	NO_x	SO2	PM10	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	1.75E-05	1.83E-04	1.89E-05	1.86E-06	1.08E-05	2.99E-10	1.79E-06	1.58E-02	kg/MJ Jet Fuel
RMT	6.89E-04	6.31E-04	1.41E-04	8.06E-04	1.18E-04	3.70E-10	9.11E-06	2.14E-01	kg/MJ Jet Fuel
EC	-5.15E-04	-1.55E-03	-2.68E-03	-1.56E-04	-7.05E-04	5.86E-08	2.73E-05	-5.13E-01	kg/MJ Jet Fuel
PT	2.79E-04	4.39E-04	6.27E-04	3.29E-05	8.46E-04	6.38E-10	2.93E-06	1.09E+00	kg/MJ Jet Fuel
EU	7.72E-03	1.21E-02	5.56E-04	9.50E-07	7.72E-04	3.01E-08	7.16E-09	2.81E-02	kg/MJ Jet Fuel
Total	**8.19E-03**	**1.18E-02**	**-1.34E-03**	**6.87E-04**	**1.04E-03**	**8.99E-08**	**4.12E-05**	**8.36E-01**	**kg/MJ Jet Fuel**

5.5 Scenario 5: CBTL, 20 Percent Torrefied Biomass

The purpose of this scenario is to evaluate potential process values, economic factors, and environmental emissions associated with the production of F-T jet fuels from a combination of 80 percent sub-bituminous coal and 20 percent Torrefied Biomass. This scenario evaluates a 1:1 (volume) blend of F-T jet fuels and conventional U.S. average jet fuel, based on a 30-year study period. Coal feedstock is derived from the Rosebud seam in southern Montana, and is transported by train to the CBTL facility, located in the Southeastern U.S. Southern pine biomass feedstock is produced and harvested in the Southeastern U.S., field-chipped, and then transported by chip truck to a separate torrefaction facility, where the biomass is torrefied. Torrefaction increases energy density of the biomass, and greatly reduces grinding energy required, as discussed in greater detail in Chapter 4. Torrefied biomass is then transported by truck to the CBTL facility. The F-T process employed uses a slurry-based iron catalyst using a single feed, oxygen blown Transport Reactor Integrated Gasifier (TRIG™; refer to Chapter 2 for additional discussion). Carbon dioxide is captured at the CBTL facility using a Selexol process to segregate carbon dioxide. Additional carbon dioxide is stripped from overhead gas downstream of the F-T synthesis process, using a methyldiethanolamine (MDEA) unit. Captured carbon dioxide is then routed to a purification and compression system, where it is compressed to a supercritical state. F-T jet fuel produced by the F-T facility is then conveyed to a blending facility, where it is blended with conventional jet fuel, and transported to an airport. Finally, the blended jet fuel is combusted in a jet airplane.

The following text provides a summary of process model, economic model, and environmental model results for this scenario.

5.5.1 Process Results

As discussed in Chapter 2, three Aspen Plus® model cases were run for this scenario: low RSP, expected RSP, and high RSP. Process summary results for each of the three cases are reported in **Table 5-17**. Results obtained from the Aspen Plus® simulations are based on a 50,000 barrel per day (bpd) production rate for total F-T products (F-T jet fuel, F-T diesel, F-T naphtha, and F-T LPG) for the CBTL, 20 percent Torrefied Biomass configuration under all three RSP cases. Fuel production breakdowns are minimally variable among the three RSP cases. For all three RSP cases, approximately 49 percent (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34 percent by volume of total products) being F-T naphtha. F-T jet fuel is produced by hydrocracking the F-T wax to a final boiling point of about 300°C. Hydrocracking also produces naphtha boiling range liquids and F-T LPG. Relatively smaller quantities of F-T diesel (10 percent of total products) and F-T LPG (7 percent of total products) are produced as a result of hydrocracking. These proportions assume that straight run F-T output would be sold as a product. Results from each of the three Aspen Plus® model cases were incorporated into the economic and environmental analyses, the results of which are displayed below. For additional information regarding the application of low, expected, and high RSP values to the stochastic analysis provided here, refer to Chapter 1.

Table 5-17: Scenario 5: CBTL, 20% Torrefied Biomass: Process Summary

Property	Low RSP Case	Expected RSP Case	High RSP Case	Units
CBTL Facility Design and Operating Data				
Plant Design Capacity	50,000	50,000	50,000	bpd
Plant Capacity Factor	85	90	92	%
Plant Efficiency, HHV	55	54	52	%
Carbon Capture Rate	88	89	90	%
Gasifier Modules	9	9	9	Count
F-T Modules	10	10	10	Count
CBTL Facility Inputs/Feed				
Coal Feed, Montana Rosebud, As Received	23,385	23,927	24,683	tons/ day
Biomass Feed, Southern Pine, As Received	5,425	5,415	5,453	tons/ day
Water Feed (Total Withdrawal)	14,642,969	14,461,949	14,265,374	gallons/day
CBTL Facility Outputs/Production				
F-T Jet Fuel Production	24,649	24,647	24,644	bpd
F-T Diesel Fuel Production	4,767	4,767	4,766	bpd
F-T Naphtha Production	16,973	16,972	16,970	bpd
F-T LPG Production	3,612	3,615	3,620	bpd
Total Liquid Product Output	50,000	50,001	50,000	bpd
Export Power	258	227	189	MW
CO2 Captured and Compressed	30,150	30,823	31,392	tons/ day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,297	49,294	49,288	bpd

CBTL facility fuels production capacity was fixed at 50,000 bpd for all three modeled cases. An expected capacity factor of 90 percent was included, ranging from 85 to 92 percent for low and high RSP cases, respectively. The overall expected plant efficiency of 54.0 percent (range of 52.0 to 55.5 percent) is defined as the heating value of the liquid products (HHV basis), F-T LPG, and export power divided by the higher heating value of the input coal and biomass. Makeup water for the CBTL facility, as modeled in Aspen Plus®, is estimated to be approximately 14.5 million gallons per day (mgd; expected RSP case), of which 96.9 percent (14.0 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.89 bbl water/bbl F-T product, based on the expected RSP case.

Under this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 153 to 242 MW, with an expected value of 227 MW. Based on the expected RSP case, gross power production for the CBTL facility is 791 MW, including power generated from steam 559 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads.

Major auxiliary loads include air separation (242 MW), carbon dioxide compressors (91.5 MW), the Selexol unit (61.3 MW), hydrocarbon recovery/refrigeration (43.6 MW), and oxygen compression (31.4 MW). Total auxiliaries consume 564 MW, for a net power output of 227 MW under the expected RSP case.

Carbon balance for the CBTL facility is shown in **Table 5-18**, for all three RSP cases. Carbon dioxide produced during the production of fuels and electric power is separated from the syngas stream prior to entering the F-T unit. The Selexol unit and the MDEA unit both produce the concentrated CO_2 streams that are dehydrated and compressed to 2,200 psi for pipeline delivery and carbon management. Other flue gas streams containing CO_2 are vented to the atmosphere. These include the flue gases from the HRSG units and from the fired heaters that are utilized during the F-T process. For the expected RSP case, approximately 2 percent of total carbon (range of 1 percent for the low RSP case to 4 percent for the high RSP case) is output to slag/ash from the TRIG gasifier.

Table 5-18: Scenario 5: CBTL, 20% Torrefied Biomass: Conversion Facility Carbon Balance

Input Flow	Low RSP Case	Expected RSP Case	High RSP Case	Units
Coal Carbon	11,709	11,980	12,358	TPD
Biomass Carbon	3,249	3,243	3,266	TPD
Total Carbon Input	**14,957**	**15,223**	**15,624**	**TPD**
F-T Products	5,284	5,284	5,284	TPD
Slag/Ash	150	305	626	TPD
Stack Gas	986	936	885	TPD
Fuel Gas	266	239	212	TPD
WWTP	31	31	29	TPD
Carbon Capture, Sequestered	8,247	8,434	8,593	TPD
Total Carbon Output	**14,963**	**15,229**	**15,629**	**TPD**
Carbon Capture	**88%**	**89%**	**90%**	**%**

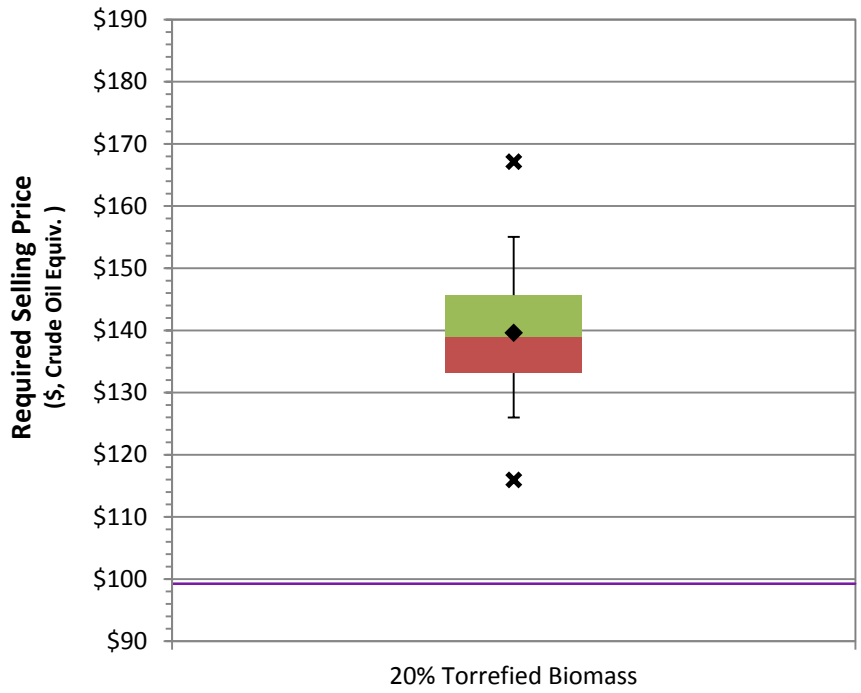
5.5.2 Economic Results

Results from the economic model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Figure 5-25 provides a summary of the estimated RSP for the F-T jet fuel produced under this scenario. As shown, RSP ranges from $133 to $146/bbl, with a mean value of $140/bbl, on a crude oil equivalent basis. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 40 economic parameters shown in **Table 1-6**. As shown, 25th and 75th percentile values are relatively close to the mean value, however, selling price distributions are characterized by long tails, with an overall range of $116 to $167/bbl, on a crude oil equivalent basis.

Cost of the F-T jet fuel product is estimated on a crude oil equivalent basis. This is defined as the RSP of the diesel product divided by a factor of 1.1433. Thus if the average world oil price were below or equal to the calculated crude oil equivalent price the CBTL plant would be economically viable. Key contributors to the variability shown for RSP results are discussed below.

Figure 5-25: Scenario 5: CBTL, 20% Torrefied Biomass: F-T Jet Fuel RSP, Crude Oil Equivalent Basis



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel spot price value.

Table 5-19 provides a summary of the economic estimated performance of the CBTL facility under this scenario, including the key contributing factors to the calculation of RSP. Total operating and maintenance costs represent an average of $533 million/yr. Of this amount, $295 to $320 million/yr, mean $308 million/yr (57.8 percent), results from fixed costs, while $217 to $233 million/year, mean $225 million/yr (42.2 percent) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, ranging from $8,463 to $9,284 million, mean $8,884 million. Coal feedstock costs for this scenario range from $276 to $288 million/yr, mean $282 million/yr. Biomass feedstock costs range from $228 to $243 million/yr, mean $236 million/yr. Total feedstock costs are approximately $15.2 million lower than total operating and maintenance costs, on average. Projected revenues include credits and product sales revenue. Power credit, from the sale of produced electricity, amounts to $117 to $132 million/yr, mean $124 million/yr, while CO_2 credit is estimated to be $332 to $394 million/yr, mean $363 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,126 to $2,328 million/yr, mean $2,227 million/yr.

Required product sales prices are also provided in **Table 5-19**. Crude oil equivalent RSP is discussed above for **Figure 5-25**. On a straight basis, RSP for F-T jet fuel was calculated to be $154 to $168/bbl, mean $161/bbl, with F-T diesel at $152 to $167/bbl, mean $160/bbl, F-T naphtha at $106 to $116/bbl, mean $111/bbl, and F-T LPG at $61.5 to $67.3/bbl, mean $64.5/bbl. The default capital charge factor (CCF) used in the analysis was 0.1872.

Table 5-19: Scenario 5: CBTL, 20% Torrefied Biomass: Summary of Economics

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	308	255	367	295	320	$MM/yr
Variable Operating and Maintenance Cost (VOM)	225	192	267	217	233	$MM/yr
Capital: Total Overnight Cost (TOC)	8,884	7,530	10,810	8,463	9,284	$MM
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	282	258	309	276	288	$MM/yr
Biomass Cost, Southern Pine, Chips, As Received	0	0	0	0	0	$MM/yr
Biomass Cost, Southern Pine, Torrefied, As Received	236	207	271	228	243	$MM/yr
Credits and Revenue						
Power Credit	(124)	(157)	(92)	(132)	(117)	$MM/yr
Credit @ $40/ton for CO_2	(363)	(468)	(256)	(394)	(332)	$MM/yr
Annual Revenue Required	2,227	1,842	2,642	2,126	2,328	$MM/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	161	134	193	154	168	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	160	133	191	152	167	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	111	92	133	106	116	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	65	54	77	62	67	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	140	116	167	133	146	$/bbl

Figure 5-26 provides breakdowns for the cost factors that contribute to the RSP. As shown, capital cost is the primary factor in determining RSP, and accounts for approximately 74.7 percent of total RSP, or $104/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 20.9 percent of total RSP, or $29.2/bbl, while feedstock costs represent 20.3 percent of total RSP, or $28.4/bbl, on a crude oil equivalent basis. As shown, variability in total RSP is driven largely by potential variability in capital costs, and to a much lesser extent by variability in operations and maintenance and feedstock costs. The negative credits bar comprises the sale of the co-produced electricity and compressed CO_2. Electricity accounts for 25.5 percent of the total credit, while captured and compressed CO_2 accounts for 74.5 percent.

Figure 5-26: Scenario 5: CBTL, 20% Torrefied Biomass: RSP, Crude Oil Equivalent Basis

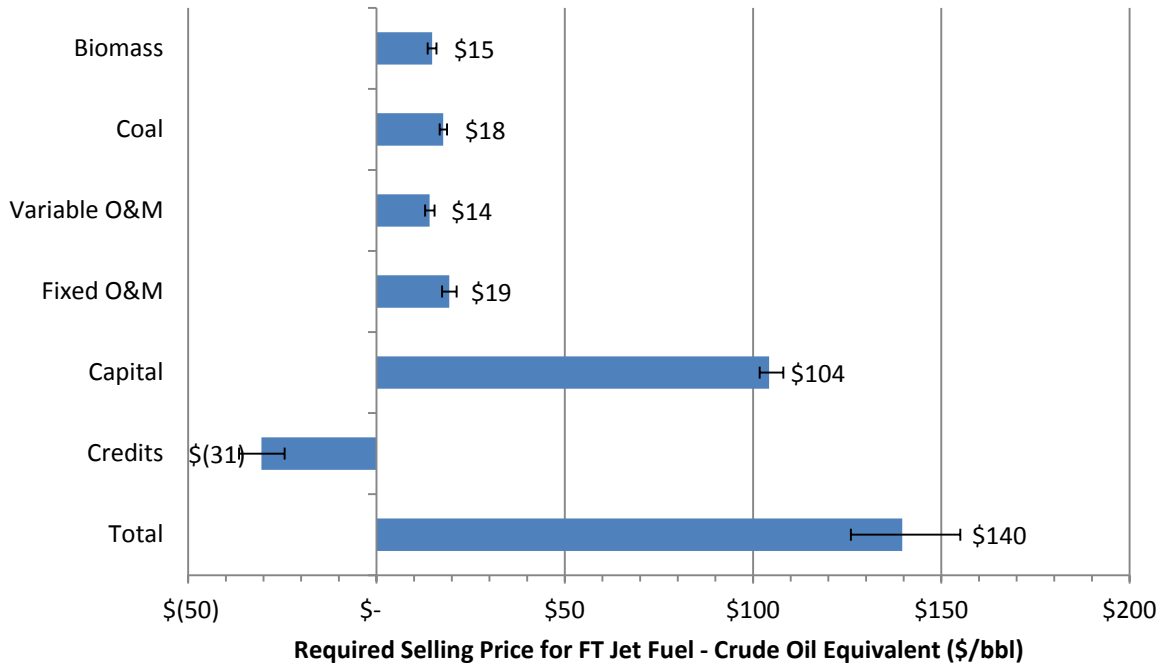
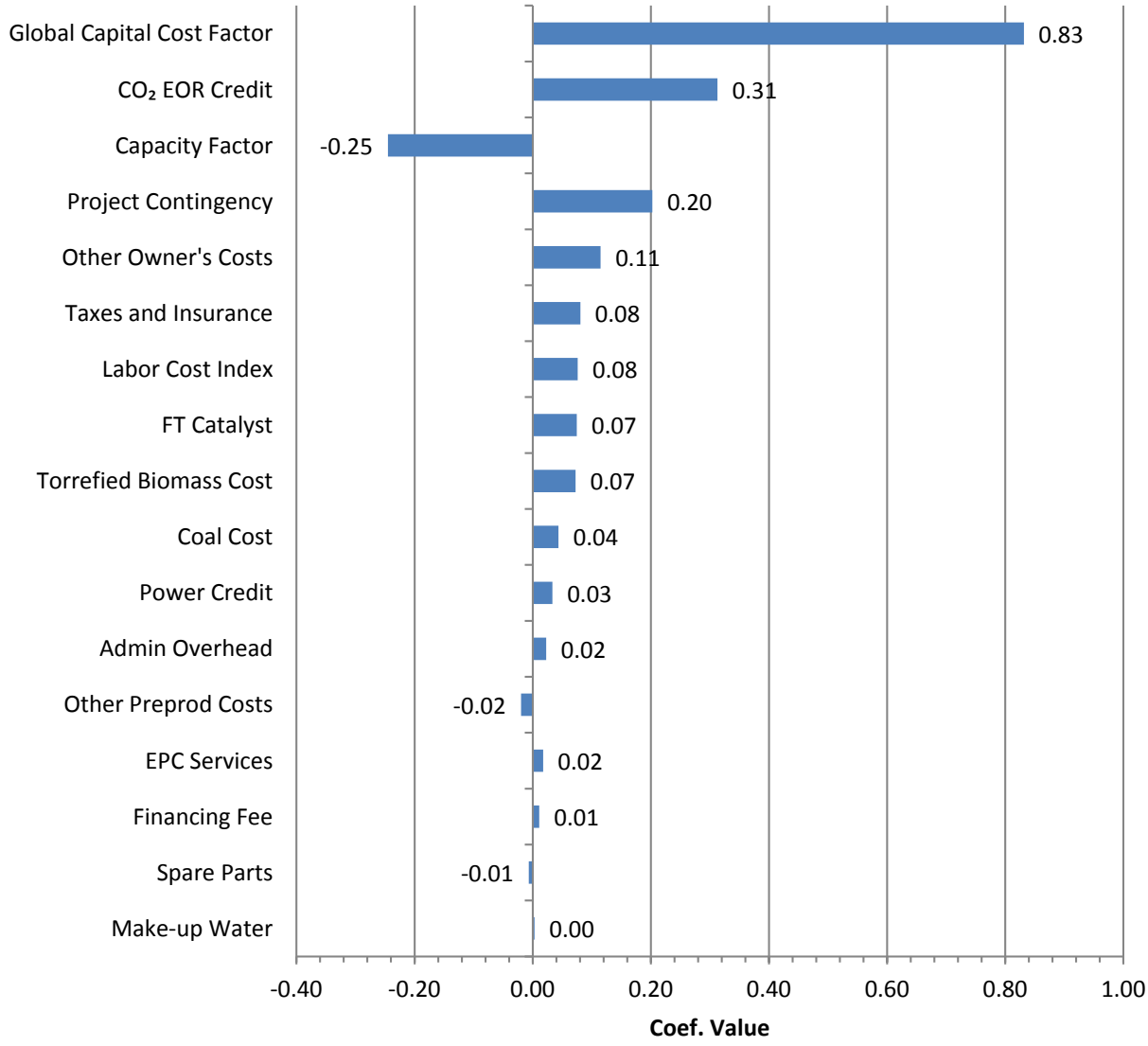


Figure 5-27 provides a summary of model sensitivity, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.83. Other key factors that account for at least 10 percent of the observed variability in RSP include the CO_2 EOR credit, capacity factor, project contingency, and other owner's costs. Parameters that caused minimal influence on RSP included EPC services, other preproduction costs, financing fees, cost of spare parts, and others as shown.

Figure 5-27: Scenario 5: CBTL, 20% Torrefied Biomass: Sensitivity of RSP to Modeled Variables

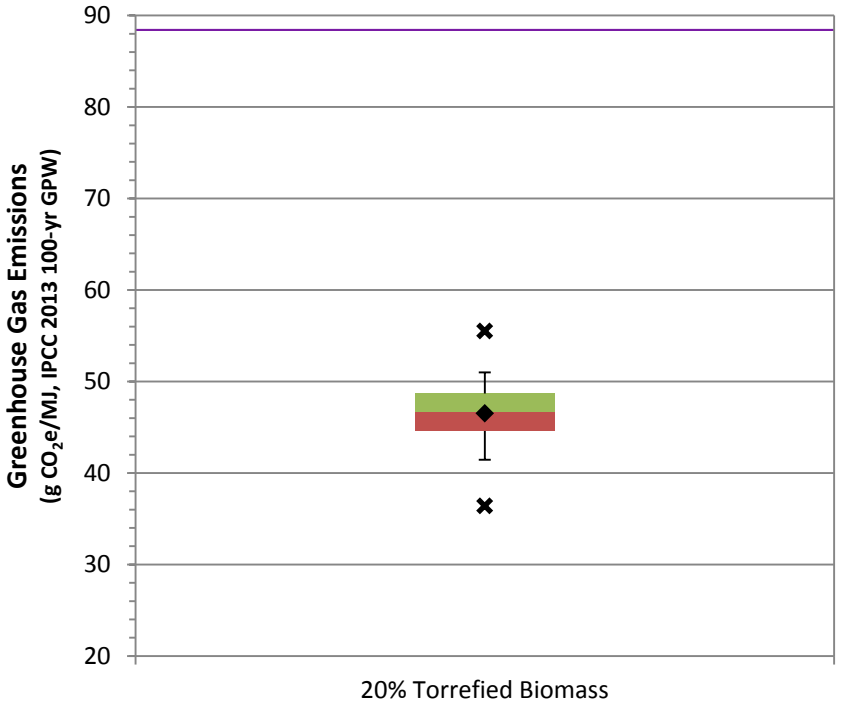


5.5.3 Environmental Results

Results from the environmental model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Results from the environmental life cycle analysis include GHG emissions and other emissions, including select criteria air pollutants, other pollutants of concern, and water consumption. **Figure 5-28** provides a summary life cycle GHG emissions for this scenario, in comparison to conventional jet fuel life cycle GHG emissions of 88.41 g CO_2e/MJ. . Using the system expansion method discussed in Chapter 1 the resulting range is 44.6 to 48.7 g CO_2e/MJ, mean 46.5 g CO_2e/MJ or approximately 46.8 percent less than conventional jet fuel.

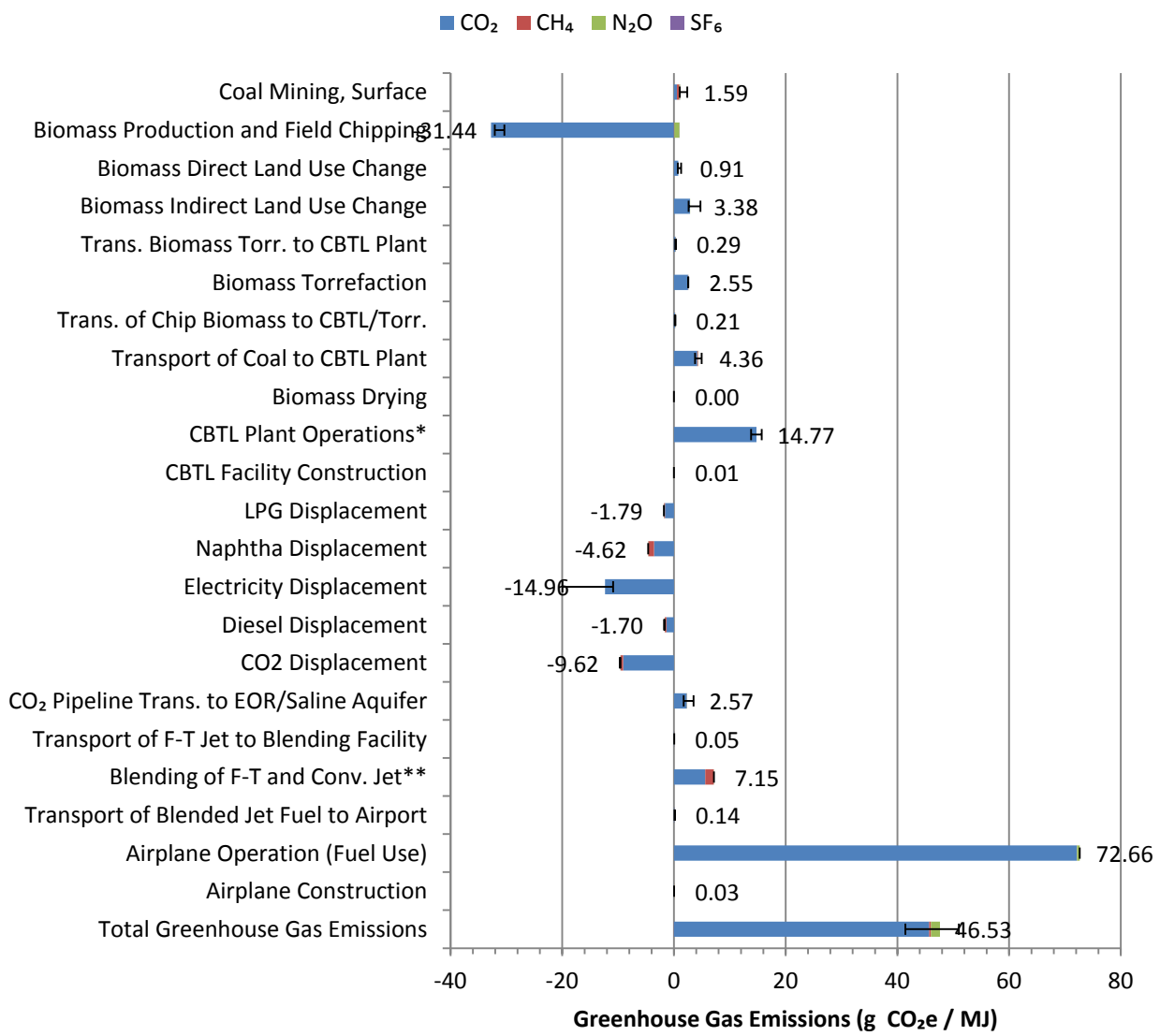
Figure 5-28: Scenario 5: CBTL, 20% Torrefied Biomass: Summary of LC GHG Emissions



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

Figure 5-29 provides detail regarding the importance of the various LCA components that were modeled, with respect to gross GHG emissions contributions. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 65.2 percent of gross life cycle GHG emissions. Second in importance to fuel combustion is CBTL plant operations, at 13.4 percent of gross life cycle emissions, while emissions associated with blending of F-T and conventional jet fuel represent 5.06 percent of gross life cycle emissions. The transport of coal to the CBTL plant accounts for 3.77 percent of gross life cycle GHG emissions. Emissions from the pipeline transport of CO_2 represents approximately 2.60 percent of gross emissions. GHG emissions associated with biomass indirect land use change generate 2.28 percent of gross life cycle emissions, while the torrefaction of biomass generates 2.09 percent. Other contributors to gross emissions were less than 1 percent individually.

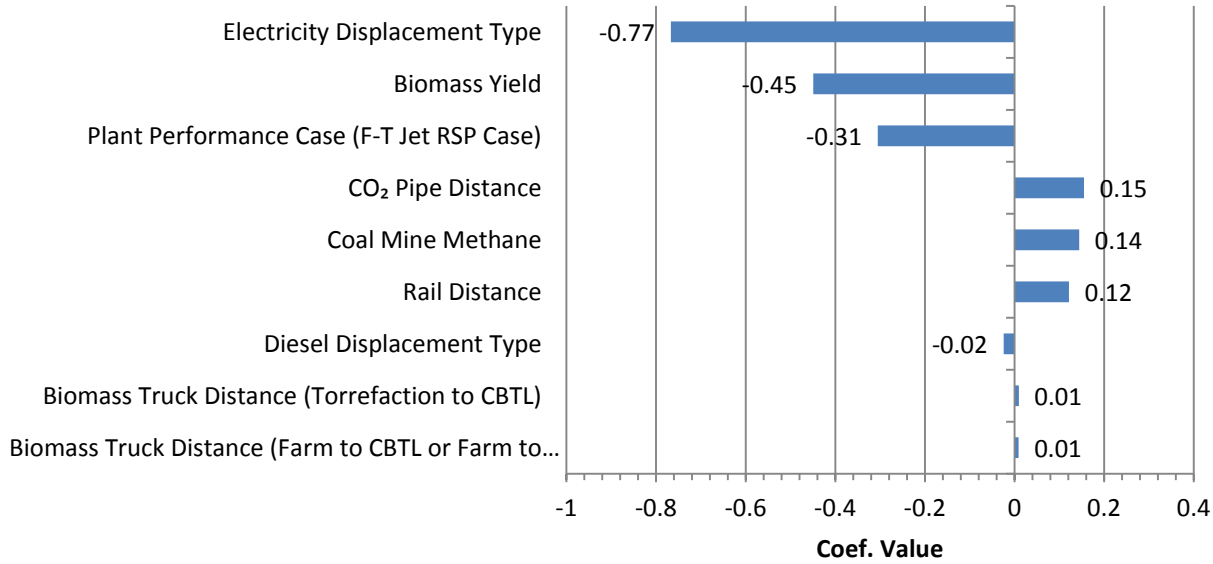
Figure 5-29: Scenario 5: CBTL, 20% Torrefied Biomass: LC GHG Emissions Breakdowns



** Includes CO_2 Compression*
*** Includes conventional jet fuel profile*

The error bars shown in **Figure 5-29** reflect variability in model output based on the stochastic analyses (for more information, refer to Chapter 1). The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-6**. As shown, variability in emissions resulted primarily from the type of electricity displacement used. Other key contributors to variability in model output include biomass yield and the F-T jet fuel RSP case. **Figure 5-30** summarizes the key factors contributing to variability identified in the model sensitivity analysis, for GHG emissions. Values provided in the figure show the correlation coefficient between the indicated parameter and total life cycle GHG emissions. Other important factors included the blended jet fuel pipe length, the coal mine methane emissions, the rail transportation distance, the diesel displacement type and the biomass truck transportation distances. Other parameters had minimal to negligible effect on life cycle GHG emissions.

Figure 5-30: Scenario 5: CBTL, 20% Torrefied Biomass: LC GHG Emissions Sensitivity



In addition to GHG emissions, other life cycle environmental emissions and flows were also considered. **Table 5-20** provides a summary of these flows. As shown, Airplane operation is the primary source of carbon monoxide and NOx within the life cycle. Particulate matter (PM_{10}) derives primarily from the combustion of diesel under raw materials transport and product transport operations. Non-methane volatile organic carbons (NMVOCs) result from product transport, including upstream conventional jet fuel emissions, and end use. The highest levels of mercury emissions occur during energy conversion and end use. Most water consumption occurs during biomass cultivation. Note that mass units displayed for water consumption (kg/MJ jet fuel) are equivalent to volume units for water consumption (L/MJ jet fuel).

Table 5-20: Scenario 5: CBTL, 20% Torrefied Biomass: Non-GHG Emissions

LC Stage	Carbon monoxide	NO_x	SO2	PM10	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	1.54E-05	1.61E-04	1.67E-05	1.64E-06	9.49E-06	2.64E-10	1.58E-06	1.40E-02	kg/MJ Jet Fuel
RMT	6.07E-04	5.57E-04	1.24E-04	7.12E-04	1.04E-04	3.26E-10	8.04E-06	1.89E-01	kg/MJ Jet Fuel
EC	-5.17E-04	-1.56E-03	-2.70E-03	-1.60E-04	-7.06E-04	4.96E-08	2.78E-05	-8.08E-01	kg/MJ Jet Fuel
PT	2.79E-04	4.39E-04	6.27E-04	3.29E-05	8.46E-04	6.38E-10	2.93E-06	1.09E+00	kg/MJ Jet Fuel
EU	7.72E-03	1.21E-02	5.56E-04	9.50E-07	7.72E-04	3.01E-08	7.16E-09	2.81E-02	kg/MJ Jet Fuel
Total	**8.10E-03**	**1.17E-02**	**-1.38E-03**	**5.87E-04**	**1.03E-03**	**8.09E-08**	**4.04E-05**	**5.14E-01**	**kg/MJ Jet Fuel**

5.6 Scenario 6: CBTL, 10 Percent Chipped Biomass, Microchipped, Separate Gasifiers

The purpose of this scenario is to evaluate potential process values, economic factors, and environmental emissions associated with the production of F-T jet fuels from a combination of 90 percent sub-bituminous coal and 10 percent microchipped biomass. This scenario evaluates a 1:1 (volume) blend of F-T jet fuels and conventional U.S. average jet fuel, based on a 30-year study period. Coal feedstock is derived from the Rosebud seam in southern Montana, and is transported by train to the CBTL facility, located in the Southeastern U.S. Biomass feedstock is field-microchipped Southern pine biomass, cultivated and harvested in the Southeastern U.S. and transported, via chip truck, to the CBTL facility. In this scenario, the chipped biomass is gasified separately from the coal, using a ClearFuels® High Efficiency Hydro Thermal Reformation (HEHTR) gasification process to produce syngas and other products. ClearFuels® uses fuel gas or F-T recycle gas to fire the gasification reactor. Products are routed through a Dual Fluid Bed Reformer with a nickel catalyst. This process configuration is modeled after one previously in operation at a Rentech demonstration plant that is no longer in operation. Currently there are no other facilities operating with a similar configuration so there is no means to validate this scenario against actual operational conditions. Coal gasification employs a method similar to the other scenarios considered, relying on a slurry-based iron catalyst using a single feed, oxygen blown Transport Reactor Integrated Gasifier (TRIG™; refer to Chapter 2 for additional discussion).

Carbon dioxide is captured at the CBTL facility using a Selexol process to segregate carbon dioxide. Additional carbon dioxide is stripped from overhead gas downstream of the F-T synthesis process, using a methyldiethanolamine (MDEA) unit. Captured carbon dioxide is then routed to a purification and compression system, where it is compressed to a supercritical state. F-T jet fuel produced by the F-T facility is then conveyed to a blending facility, where it is blended with conventional jet fuel, and transported to an airport. Finally, the blended jet fuel is combusted in a jet airplane.

The following text provides a summary of process model, economic model, and environmental model results for this scenario.

5.6.1 Process Results

As discussed in Chapter 2, three Aspen Plus® model cases were run for this scenario: low RSP, expected RSP, and high RSP. Process summary results for each of the three cases are reported in **Table 5-21**. Results obtained from the Aspen Plus® simulations are based on a 50,000 barrel per day (bpd) production rate for total F-T products (F-T jet fuel, F-T diesel, F-T naphtha, and F-T LPG) for the CBTL, 10 percent Biomass, Microchipped, Separate Gasifiers configuration under all three RSP cases. Fuel production breakdowns are minimally variable among the three RSP cases. For all three RSP cases, approximately 49 percent (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34 percent by volume of total products) being F-T naphtha. F-T jet fuel is produced by hydrocracking the F-T wax to a final boiling point of about 300°C. Hydrocracking also produces naphtha boiling range liquids and F-T LPG. Relatively smaller quantities of F-T diesel (10 percent of total products) and F-T LPG (7 percent of total products) are produced as a result of hydrocracking. These proportions assume that straight run F-T output would be sold as a product. Results from each of the three Aspen Plus® model cases were incorporated into the economic and environmental analyses, the results of which are displayed below. For additional information regarding the application of low, expected, and high RSP values to the stochastic analysis provided here, refer to Chapter 1.

Table 5-21: Scenario 6: CBTL, 10% Biomass, Microchipped, Sep. Gasifiers: Process Summary

Property	Low RSP Case	Expected RSP Case	High RSP Case	Units
CBTL Facility Design and Operating Data				
Plant Design Capacity	50,000	50,000	50,000	bpd
Plant Capacity Factor	85	90	92	%
Plant Efficiency, HHV	53	52	50	%
Carbon Capture Rate	81	81	83	%
Gasifier Modules	9	9	9	Count
F-T Modules	10	10	10	Count
CBTL Facility Inputs/Feed				
Coal Feed, Montana Rosebud, As Received	28,009	28,652	29,563	tons/ day
Biomass Feed, Southern Pine, As Received	4,176	4,320	4,505	tons/ day
Water Feed (Total Withdrawal)	15,175,096	15,041,690	15,130,443	gallons/day
CBTL Facility Outputs/Production				
F-T Jet Fuel Production	24,651	24,652	24,623	bpd
F-T Diesel Fuel Production	4,767	4,767	4,792	bpd
F-T Naphtha Production	16,974	16,975	16,969	bpd
F-T LPG Production	3,608	3,606	3,616	bpd
Total Liquid Product Output	50,000	50,000	50,000	bpd
Export Power	209	197	176	MW
CO2 Captured and Compressed	28,748	29,401	30,574	tons/ day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,302	49,303	49,247	bpd

CBTL facility fuels production capacity was fixed at 50,000 bpd for all three modeled cases. An expected capacity factor of 90 percent was included, ranging from 85 to 92 percent for low and high RSP cases, respectively. The overall expected plant efficiency of 51.7 percent (range of 49.8 to 53.2 percent) is defined as the heating value of the liquid products (HHV basis), F-T LPG, and export power divided by the higher heating value of the input coal and biomass. Makeup water for the CBTL facility, as modeled in Aspen Plus®, is estimated to be approximately 15.0 million gallons per day (mgd; expected RSP case), of which 95.1 percent (14.3 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 7.16 bbl water/bbl F-T product, based on the expected RSP case.

Under this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 153 to 242 MW, with an expected value of 197 MW. Based on the expected RSP case, gross power production for the CBTL facility is 766 MW, including power generated from steam (534 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads.

Major auxiliary loads include air separation (234 MW), carbon dioxide compressors (88.7 MW), the Selexol unit (59.7 MW), hydrocarbon recovery/refrigeration (38.3 MW), and oxygen compression (30.5 MW). Total auxiliaries consume 545MW, for a net power output of 197 MW under the expected RSP case.

Carbon balance for the CBTL facility is shown in **Table 5-22**, for all three RSP cases. As shown, carbon inputs were within 0.2 percent of carbon outputs, for all three RSP cases. Carbon dioxide produced during the production of fuels and electric power is separated from the syngas stream prior to entering the F-T unit. The Selexol unit and the MDEA unit both produce the concentrated CO_2 streams that are dehydrated and compressed to 2,200 psi for pipeline delivery and carbon management. Other flue gas streams containing CO_2 are vented to the atmosphere. These include the flue gases from the HRSG units and from the fired heaters that are utilized during the F-T process. For the expected RSP case, approximately 2 percent of total carbon (range of 1 percent for the low RSP case to 4 percent for the high RSP case) is output to slag/ash from the TRIG gasifier.

Table 5-22: Scenario 6: CBTL, 10% Biomass, Microchipped, Sep. Gasifiers: Conversion Facility Carbon Balance

Input Flow	Low RSP Case	Expected RSP Case	High RSP Case	Units
Coal Carbon	14,024	14,345	14,802	TPD
Biomass Carbon	1,276	1,320	1,376	TPD
Total Carbon Input	**15,300**	**15,665**	**16,178**	**TPD**
F-T Products	5,284	5,284	5,284	TPD
Slag/Ash	153	314	648	TPD
Stack Gas	1,795	1,830	1,701	TPD
Fuel Gas	168	171	153	TPD
WWTP	26	28	30	TPD
Carbon Capture, Sequestered	7,863	8,044	8,369	TPD
Total Carbon Output	**15,290**	**15,671**	**16,184**	**TPD**
Carbon Capture	**81%**	**81%**	**83%**	**%**

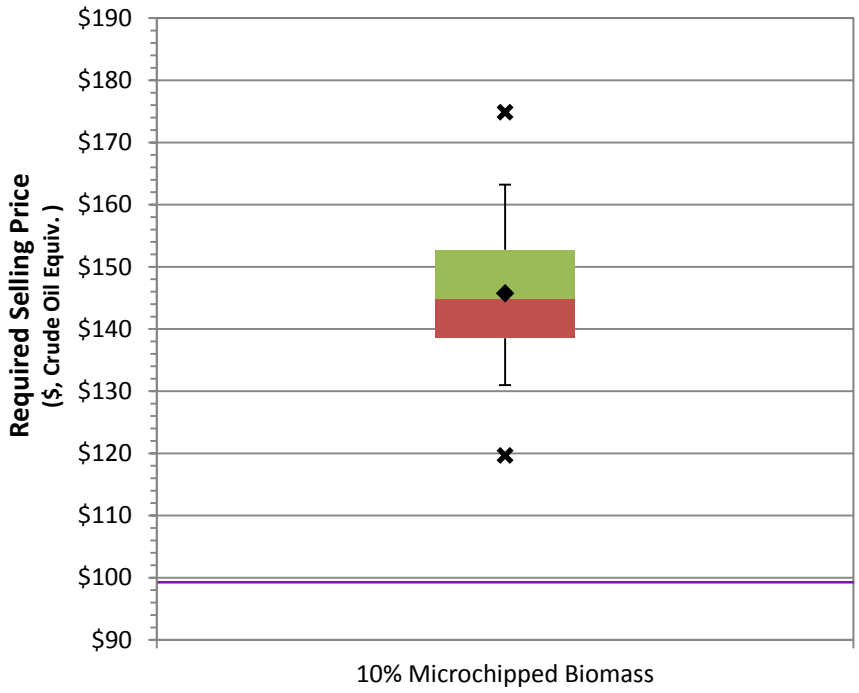
5.6.2 Economic Results

Results from the economic model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Figure 5-31 provides a summary of the estimated RSP for the F-T jet fuel produced under this scenario. As shown, RSP ranges from $139 to $153/bbl, with a mean value of $146/bbl, on a crude oil equivalent basis. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 40 economic parameters shown in **Table 1-6**. As shown, 25th and 75th percentile values are relatively close to the mean value, however, selling price distributions are characterized by long tails, with an overall range of $120 to $175/bbl, on a crude oil equivalent basis.

Cost of the F-T jet fuel product is estimated on a crude oil equivalent basis. This is defined as the RSP of the diesel product divided by a factor of 1.1433. Thus if the average world oil price were below or equal to the calculated crude oil equivalent price the CBTL plant would be economically viable. Key contributors to the variability shown for RSP results are discussed below.

Figure 5-31: Scenario 6: CBTL, 10 percent Biomass, Microchipped, Sep. Gasifiers: F-T Jet Fuel RSP, Crude Oil Equivalent Basis



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel spot price value.

Table 5-23 provides a summary of the economic estimated performance of the CBTL facility under this scenario, including the key contributing factors to the calculation of RSP. Total operating and maintenance costs represent an average of $581 million/yr. Of this amount, $328 to $357 million/yr, mean $343 million/yr (59.1 percent), results from fixed costs, while $229 to $246 million/year, mean $238 million/yr (40.9 percent) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, ranging from $9,260 to $10,212million, mean $9,747 million. Coal feedstock costs for this scenario range from $330 to $345 million/yr, mean $338 million/yr. Biomass feedstock costs range from $34.7 to $37.7 million/yr, mean $36.3 million/yr. Total feedstock costs are approximately $207 million lower than total operating and maintenance costs, on average. Projected revenues include credits and product sales revenue. Power credit, from the sale of produced electricity, amounts to $102 to $113 million/yr, mean $107 million/yr, while CO_2 credit is estimated to be $317 to $379 million/yr, mean $348 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,209 to $2,435 million/yr, mean $2,325 million/yr.

Required product sales prices are also provided in **Table 5-23**. Crude oil equivalent RSP is discussed above for **Figure 5-31**. On a straight basis, RSP for F-T jet fuel was calculated to be $160 to $176bbl, mean $168/bbl, with F-T diesel at $158 to $175/bbl, mean $167/bbl, F-T naphtha at $110to $120/bbl, mean $112/bbl, and F-T LPG at $64.0 to $70.6/bbl, mean $67.3/bbl. The default capital charge factor (CCF) used in the analysis was 0.1872.

Table 5-23: Scenario 6: CBTL, 10% Biomass, Microchipped, Sep. Gasifiers: Summary of Economics

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	343	283	413	328	357	$MM/yr
Variable Operating and Maintenance Cost (VOM)	238	203	284	229	246	$MM/yr
Capital: Total Overnight Cost (TOC)	9,747	8,200	12,050	9,260	10,212	$MM
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	338	309	370	330	345	$MM/yr
Biomass Cost, Southern Pine, Chips, As Received	36	30	44	35	38	$MM/yr
Biomass Cost, Southern Pine, Torrefied, As Received	0	0	0	0	0	$MM/yr
Credits and Revenue						
Power Credit	(107)	(128)	(85)	(113)	(102)	$MM/yr
Credit @ $40/ton for CO_2	(348)	(456)	(245)	(379)	(317)	$MM/yr
Annual Revenue Required	2,325	1,896	2,825	2,209	2,435	$MM/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	168	138	202	160	176	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	167	137	200	158	175	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	116	95	139	110	122	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	67	55	81	64	71	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	146	120	175	139	153	$/bbl

Figure 5-32 provides breakdowns for the cost factors that contribute to the RSP. As shown, capital cost is the primary factor in determining RSP, and accounts for approximately 78.5 percent of total RSP, or $114/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 21.8 percent of total RSP, or $31.8/bbl, while feedstock costs represent 14.1 percent of total RSP, or $20.5/bbl, on a crude oil equivalent basis. As shown, variability in total RSP is driven largely by potential variability in capital costs, and to a much lesser extent by variability in operations and maintenance and feedstock costs. The negative credits bar comprises the sale of the co-produced electricity and compressed CO_2. Electricity accounts for 23.6 percent of the total credit, while captured and compressed CO_2 accounts for 76.4 percent.

Figure 5-32: Scenario 6: CBTL, 10% Biomass, Microchipped, Sep. Gasifiers: RSP, Crude Oil Equivalent Basis

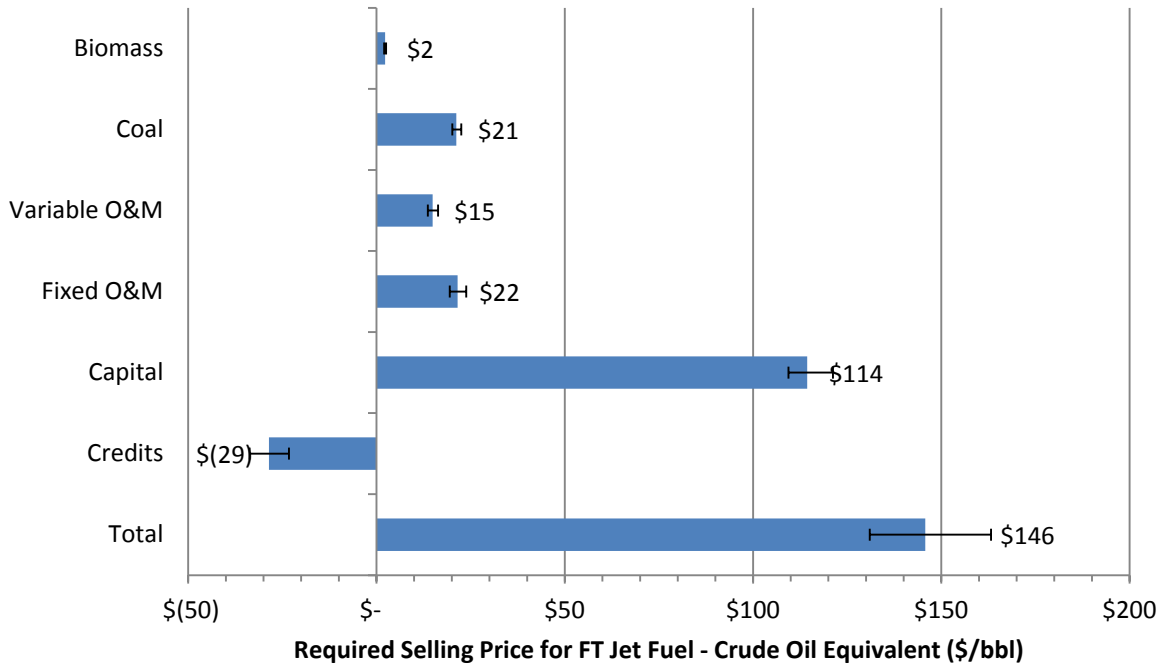
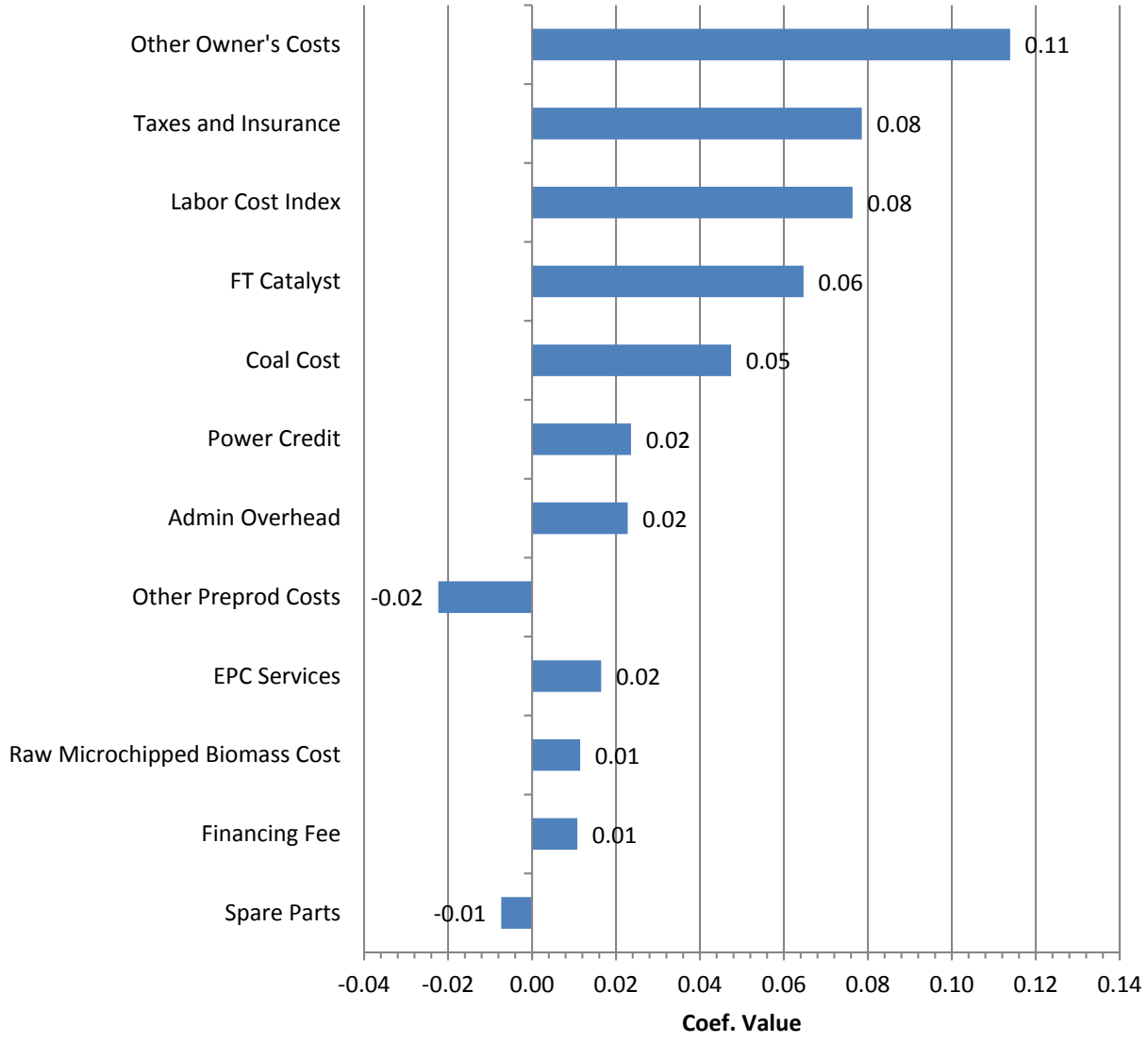


Figure 5-33 provides a summary of model sensitivity, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.84. Other key factors that account for at least 10 percent of the observed variability in RSP include the CO_2 EOR credit, capacity factor, project contingency and other owner's costs. Parameters that caused minimal influence on RSP included the power credit, EPC services, other preproduction costs, financing fees, the cost of torrefied biomass, and others as shown.

Figure 5-33: Scenario 6: CBTL, 10% Biomass, Microchipped, Sep. Gasifiers: Sensitivity of RSP to Modeled Variables

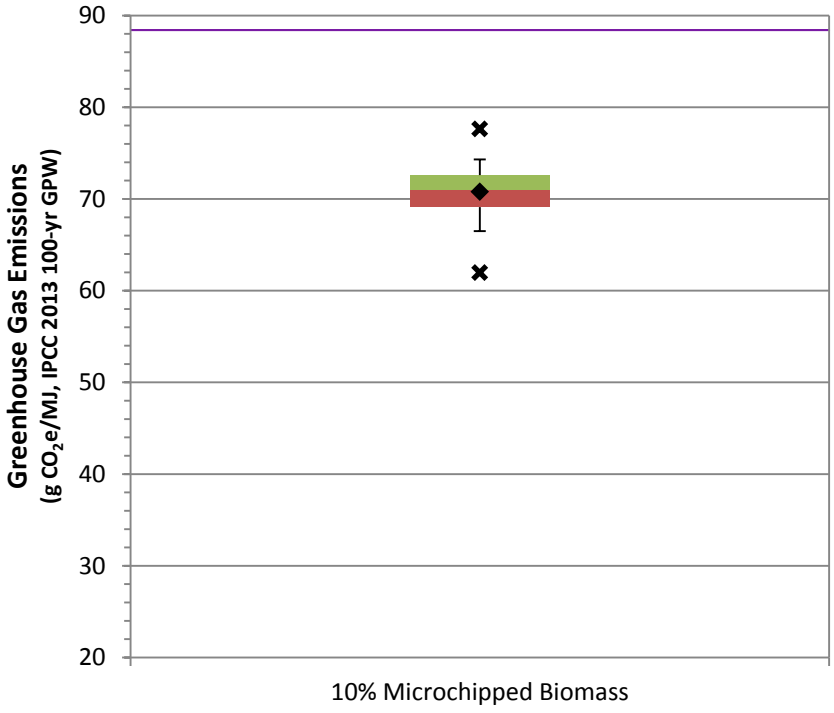


5.6.3 Environmental Results

Results from the environmental model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Results from the environmental life cycle analysis include GHG emissions and other emissions, including select criteria air pollutants, other pollutants of concern, and water consumption. **Figure 5-34** provides a summary life cycle GHG emissions for this scenario, in comparison to conventional jet fuel life cycle GHG emissions of 88.41 g CO_2e/MJ. Using the system expansion method discussed in Chapter 1 the resulting range is 69.1 to 72.6g CO_2e/MJ, mean 70.8 g CO_2e/MJ or approximately 19.0 percent less than conventional jet fuel.

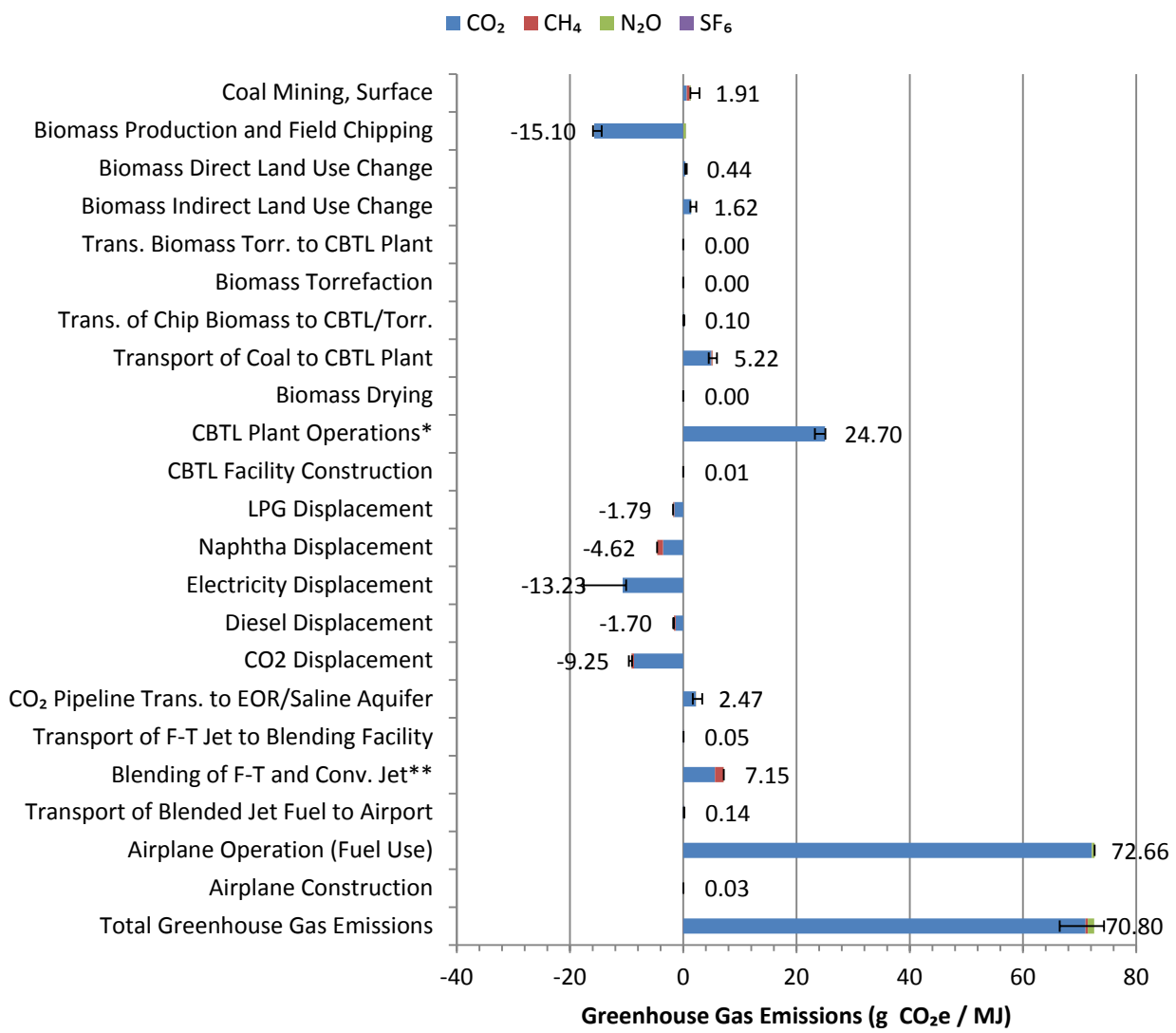
Figure 5-34: Scenario 6: CBTL, 10% Biomass, Microchipped, Sep. Gasifiers: Summary of LC GHG Emissions



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

Figure 5-35 provides detail regarding the importance of the various LCA components that were modeled, with respect to gross GHG emissions contributions. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 61.9 percent of gross life cycle GHG emissions. Second in importance to fuel combustion are upstream emissions associated with CBTL plant operations, which represent 21.5 percent of gross life cycle emissions, while blending of F-T and conventional jet fuel represented 4.81 percent of gross life cycle emissions. The transport of coal to the CBTL plant accounts for 4.29 percent of gross life cycle GHG emissions. Emissions from the pipeline transport of CO_2 represents 1.90 percent of gross life cycle emissions, while biomass indirect land use change represents approximately 1.18 percent of gross emissions. Other contributors to gross emissions were less than 1 percent individually.

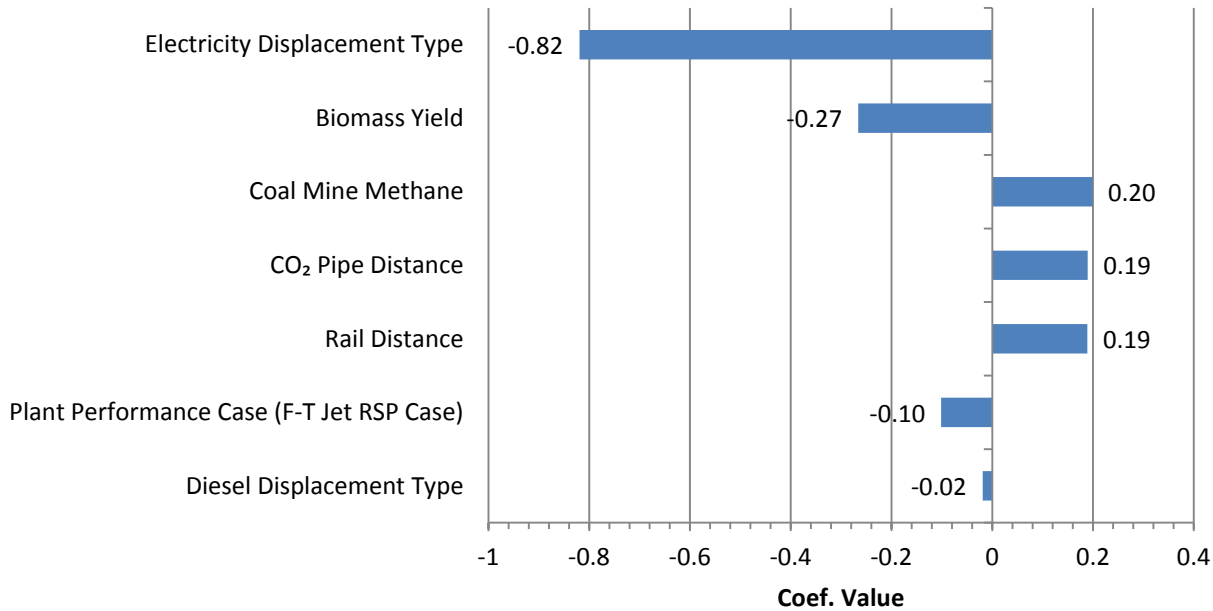
Figure 5-35: Scenario 6: CBTL, 10% Biomass, Microchipped, Sep. Gasifiers: LC GHG Emissions Breakdowns



** Includes CO_2 Compressions*
*** Includes conventional jet fuel profile*

The error bars shown in **Figure 5-35** reflect variability in model output based on the stochastic analyses (for more information, refer to Chapter 1). The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-6**. As shown, variability in emissions resulted primarily from the type of electricity displacement used. Another key contributor to variability in model output is biomass yield. **Figure 5-36** summarizes the key factors contributing to variability identified in the model sensitivity analysis, for GHG emissions. Values provided in the figure show the correlation coefficient between the indicated parameter and total life cycle GHG emissions. Other important factors included the coal mine methane emissions, the blended jet fuel pipe length, the rail transport distance, the F-T jet fuel RSP case, and the diesel displacement type. Other parameters had minimal to negligible effect on life cycle GHG emissions.

Figure 5-36: Scenario 6: CBTL, 10% Biomass, Microchipped, Sep. Gasifiers: LC GHG Emissions Sensitivity



In addition to GHG emissions, other life cycle environmental emissions and flows were also considered. **Table 5-25** provides a summary of these flows. As shown, end use (jet fuel combustion) is the primary source of carbon monoxide and NOx within the life cycle. Particulate matter (PM_{10}) derives primarily from the combustion of diesel under raw materials transport and product transport operations. Non-methane volatile organic carbons (NMVOCs) result from product transport, including upstream conventional jet fuel emissions, and end use. The highest levels of mercury emissions occur during energy conversion and end use. Most water consumption occurs during biomass cultivation. Note that mass units displayed for water consumption (kg/MJ jet fuel) are equivalent to volume units for water consumption (L/MJ jet fuel).

Table 5-24: Scenario 6: CBTL, 10% Biomass, Microchipped, Sep. Gasifiers: Non-GHG Emissions

LC Stage	Carbon monoxide	NO_x	SO2	PM10	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	1.26E-04	2.84E-04	9.25E-05	3.52E-06	1.14E-05	4.58E-10	2.86E-05	5.95E+02	kg/MJ Jet Fuel
RMT	7.39E-04	6.69E-04	1.52E-04	8.53E-04	1.28E-04	4.59E-10	9.65E-06	2.37E-01	kg/MJ Jet Fuel
EC	-5.13E-04	-1.53E-03	-2.63E-03	-1.52E-04	-7.05E-04	6.33E-08	5.03E-05	1.16E-01	kg/MJ Jet Fuel
PT	2.79E-04	4.39E-04	6.27E-04	3.29E-05	8.46E-04	6.38E-10	2.93E-06	1.09E+00	kg/MJ Jet Fuel
EU	7.72E-03	1.21E-02	5.56E-04	9.50E-07	7.72E-04	3.01E-08	7.16E-09	2.81E-02	kg/MJ Jet Fuel
Total	**8.35E-03**	**1.20E-02**	**-1.20E-03**	**7.39E-04**	**1.05E-03**	**9.49E-08**	**9.15E-05**	**5.97E+02**	**kg/MJ Jet Fuel**

5.7 Scenario 7: CBTL, 30 Percent Chipped Biomass

The purpose of this scenario is to evaluate potential process values, economic factors, and environmental emissions associated with the production of F-T jet fuels from a combination of 70 percent sub-bituminous coal and 30 percent chipped biomass. This scenario evaluates a 1:1 (volume) blend of F-T jet fuels and conventional U.S. average jet fuel, based on a 30-year study period. Coal feedstock is derived from the Rosebud seam in southern Montana, and is transported by train to the CBTL facility, located in the Southeastern U.S. Biomass feedstock is field-chipped Southern pine biomass, cultivated and harvested in the Southeastern U.S. and transported, via chip truck, to the CBTL facility. The F-T process employed uses a slurry-based iron catalyst using a single feed, oxygen blown Transport Reactor Integrated Gasifier (TRIG™; refer to Chapter 2 for additional discussion). Carbon dioxide is captured at the CBTL facility using a Selexol process to segregate carbon dioxide. Additional carbon dioxide is stripped from overhead gas downstream of the F-T synthesis process, using a methyldiethanolamine (MDEA) unit. Captured carbon dioxide is then routed to a purification and compression system, where it is compressed to a supercritical state. F-T jet fuel produced by the F-T facility is then conveyed to a blending facility, where it is blended with conventional jet fuel, and transported to an airport. Finally, the blended jet fuel is combusted in a jet airplane.

The following text provides a summary of process model, economic model, and environmental model results for this scenario.

5.7.1 Process Results

As discussed in Chapter 2, three Aspen Plus® model cases were run for this scenario: low RSP, expected RSP, and high RSP. Process summary results for each of the three cases are reported in **Table 5-25**. Results obtained from the Aspen Plus® simulations are based on a 50,000 barrel per day (bpd) production rate for total F-T products (F-T jet fuel, F-T diesel, F-T naphtha, and F-T LPG) for the CBTL, 30 percent Chipped Biomass configuration under all three RSP cases. Fuel production breakdowns are minimally variable among the three RSP cases. For all three RSP cases, approximately 49 percent (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34 percent by volume of total products) being F-T naphtha. F-T jet fuel is produced by hydrocracking the F-T wax to a final boiling point of about 300°C. Hydrocracking also produces naphtha boiling range liquids and F-T LPG. Relatively smaller quantities of F-T diesel (10 percent of total products) and F-T LPG (7 percent of total products) are produced as a result of hydrocracking. These proportions assume that straight run F-T output would be sold as a product. Results from each of the three Aspen Plus® model cases were incorporated into the economic and environmental analyses, the results of which are displayed below. For additional information regarding the application of low, expected, and high RSP values to the stochastic analysis provided here, refer to Chapter 1.

Table 5-25: Scenario 7: CBTL, 30% Chipped Biomass: Process Summary

Property	Low RSP Case	Expected RSP Case	High RSP Case	Units
CBTL Facility Design and Operating Data				
Plant Design Capacity	50,000	50,000	50,000	bpd
Plant Capacity Factor	85	90	92	%
Plant Efficiency, HHV	54	52	50	%
Carbon Capture Rate	88	89	90	%
Gasifier Modules	9	9	9	Count
F-T Modules	10	10	10	Count
CBTL Facility Inputs/Feed				
Coal Feed, Montana Rosebud, As Received	22,513	23,022	23,566	tons/ day
Biomass Feed, Southern Pine, As Received	12,947	12,917	13,222	tons/ day
Water Feed (Total Withdrawal)	14,169,475	13,983,906	13,635,444	gallons/day
CBTL Facility Outputs/Production				
F-T Jet Fuel Production	24,649	24,647	24,645	bpd
F-T Diesel Fuel Production	4,767	4,767	4,766	bpd
F-T Naphtha Production	16,973	16,972	16,970	bpd
F-T LPG Production	3,612	3,614	3,619	bpd
Total Liquid Product Output	50,000	50,000	50,000	bpd
Export Power	200	162	96	MW
CO2 Captured and Compressed	30,993	31,581	32,029	tons/ day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,297	49,295	49,289	bpd

CBTL facility fuels production capacity was fixed at 50,000 bpd for all three modeled cases. An expected capacity factor of 90 percent was included, ranging from 85 to 92 percent for low and high RSP cases, respectively. The overall expected plant efficiency of 52.3 percent (range of 50.1 to 53.8 percent) is defined as the heating value of the liquid products (HHV basis), F-T LPG, and export power divided by the higher heating value of the input coal and biomass. Makeup water for the CBTL facility, as modeled in Aspen Plus®, is estimated to be approximately 14.0 million gallons per day (mgd; expected RSP case), of which 97.1 percent (13.6mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.66 bbl water/bbl F-T product, based on the expected RSP case.

Under this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 153 to 242 MW, with an expected value of 162 MW. Based on the expected RSP case, gross power production for the CBTL facility is 757 MW, including power generated from steam (525 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads.

Major auxiliary loads include air separation (243 MW), carbon dioxide compressors (93.4 MW), the Selexol unit (63.0 MW), hydrocarbon recovery/refrigeration (42.2 MW), and oxygen compression (31.7 MW). Total auxiliaries consume 595 MW, for a net power output of 162 MW under the expected RSP case.

Carbon balance for the CBTL facility is shown in **Table 5-26**, for all three RSP cases. As shown, carbon inputs were within 0.2 percent of carbon outputs for each of the three RSP cases. Carbon dioxide produced during the production of fuels and electric power is separated from the syngas stream prior to entering the F-T unit. The Selexol unit and the MDEA unit both produce the concentrated CO_2 streams that are dehydrated and compressed to 2,200 psi for pipeline delivery and carbon management. Other flue gas streams containing CO_2 are vented to the atmosphere. These include the flue gases from the HRSG units and from the fired heaters that are utilized during the F-T process. For the expected RSP case, approximately 2 percent of total carbon (range of 1 percent for the low RSP case to 4 percent for the high RSP case) is output to slag/ash from the TRIG gasifier.

Table 5-26: Scenario 7: CBTL, 30% Chipped Biomass: Conversion Facility Carbon Balance

Input Flow	Low RSP Case	Expected RSP Case	High RSP Case	Units
Coal Carbon	11,272	11,527	11,799	TPD
Biomass Carbon	3,955	3,946	4,039	TPD
Total Carbon Input	**15,227**	**15,473**	**15,838**	**TPD**
F-T Products	5,284	5,284	5,284	TPD
Slag/Ash	152	310	634	TPD
Stack Gas	1,012	963	907	TPD
Fuel Gas	277	251	222	TPD
WWTP	30	31	30	TPD
Carbon Capture, Sequestered	8,477	8,640	8,766	TPD
Total Carbon Output	**15,232**	**15,479**	**15,844**	**TPD**
Carbon Capture	**88%**	**89%**	**90%**	**%**

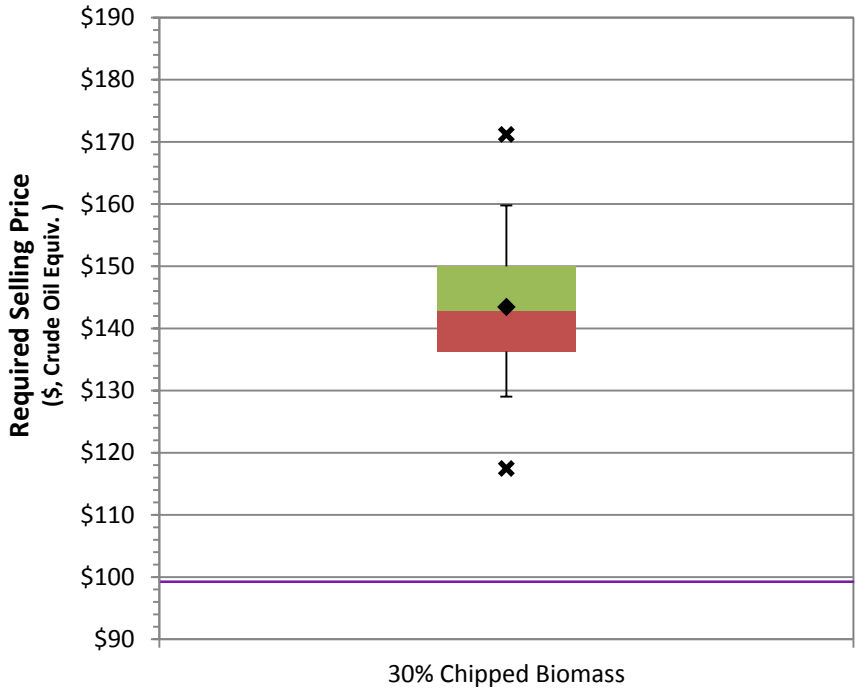
5.7.2 Economic Results

Results from the economic model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Figure 5-37 provides a summary of the estimated RSP for the F-T jet fuel produced under this scenario. As shown, RSP ranges from $136 to $150/bbl, with a mean value of $143/bbl, on a crude oil equivalent basis. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 40 economic parameters shown in **Table 1-5**. As shown, 25th and 75th percentile values are relatively close to the mean value, however, selling price distributions are characterized by long tails, with an overall range of $117 to $171/bbl, on a crude oil equivalent basis.

Cost of the F-T jet fuel product is estimated on a crude oil equivalent basis. This is defined as the RSP of the diesel product divided by a factor of 1.1433. Thus if the average world oil price were below or equal to the calculated crude oil equivalent price the CBTL plant would be economically viable. Key contributors to the variability shown for RSP results are discussed below.

Figure 5-37: Scenario 7: CBTL, 30% Chipped Biomass: F-T Jet Fuel RSP, Crude Oil Equivalent Basis



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel spot price value.

Table 5-27 provides a summary of the economic estimated performance of the CBTL facility under this scenario, including the key contributing factors to the calculation of RSP. Total operating and maintenance costs represent an average of $592 million/yr. Of this amount, $341 to $370 million/yr, mean $356 million/yr (60.1 percent), results from fixed costs, while $228 to $244 million/year, mean $236 million/yr (39.9 percent) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, range from $9,073 to $9,942 million, mean $9,512 million. Coal feedstock costs for this scenario range from $265 to $277 million/yr, mean $271 million/yr. Biomass feedstock costs range from $98.2 to $106 million/yr, mean $102 million/yr. Total feedstock costs are approximately $219 million lower than total operating and maintenance costs, on average. Projected revenues include credits and product sales revenue. Power credit, from the sale of produced electricity, amounts to $84.0 to $94.8 million/yr, mean $86.1 million/yr, while CO_2 credit is estimated to be $339 to $404 million/yr, mean $372 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,178 to $2,394 million/yr, mean $2,288 million/yr.

Required product sales prices are also provided in **Table 5-27**. Crude oil equivalent RSP is discussed above for **Figure 5-37**. On a straight basis, RSP for F-T jet fuel was calculated to be $157 to $173/bbl, mean $166/bbl, with F-T diesel at $156 to $171/bbl, mean $164/bbl, F-T naphtha at $109 to $120/bbl, mean $114/bbl, and F-T LPG at $62.9 to $69.3/bbl, mean $66.3/bbl. The default capital charge factor (CCF) used in the analysis was 0.1872.

Table 5-27: Scenario 7: CBTL, 30% Chipped Biomass: Summary of Economics

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	356	295	424	341	370	$MM/yr
Variable Operating and Maintenance Cost (VOM)	236	203	280	228	244	$MM/yr
Capital: Total Overnight Cost (TOC)	9,512	8,082	11,636	9,073	9,942	$MM
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	271	248	295	265	277	$MM/yr
Biomass Cost, Southern Pine, Chips, As Received	102	84	118	98	106	$MM/yr
Biomass Cost, Southern Pine, Torrefied, As Received	0	0	0	0	0	$MM/yr
Credits and Revenue						
Power Credit	(86)	(122)	(46)	(95)	(84)	$MM/yr
Credit @ $40/ton for CO_2	(372)	(478)	(262)	(404)	(339)	$MM/yr
Annual Revenue Required	2,288	1,864	2,765	2,178	2,394	$MM/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	166	136	198	157	173	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	164	134	196	156	171	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	114	94	136	109	120	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	66	54	79	63	69	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	143	117	171	136	150	$/bbl

Figure 5-38 provides breakdowns for the cost factors that contribute to the RSP. As shown, capital cost is the primary factor in determining RSP, and accounts for approximately 77.8 percent of total RSP, or $112/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 22.6 percent of total RSP, or $32.5/bbl, while feedstock costs represent 14.3 percent of total RSP, or $20.5/bbl, on a crude oil equivalent basis. As shown, variability in total RSP is driven largely by potential variability in capital costs, and to a much lesser extent by variability in operations and maintenance and feedstock costs. The negative credits bar comprises the sale of the co-produced electricity and compressed CO_2. Electricity accounts for 18.8 percent of the total credit, while captured and compressed CO_2 accounts for 81.2 percent.

Figure 5-38: Scenario 7: CBTL, 30% Chipped Biomass: RSP, Crude Oil Equivalent Basis

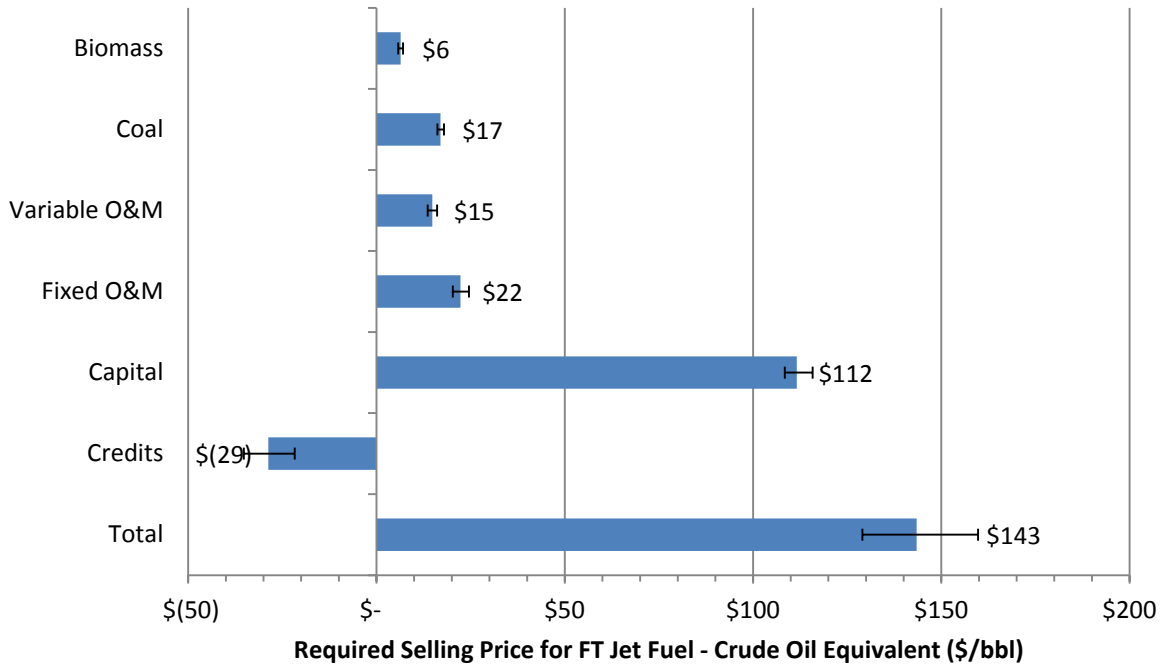
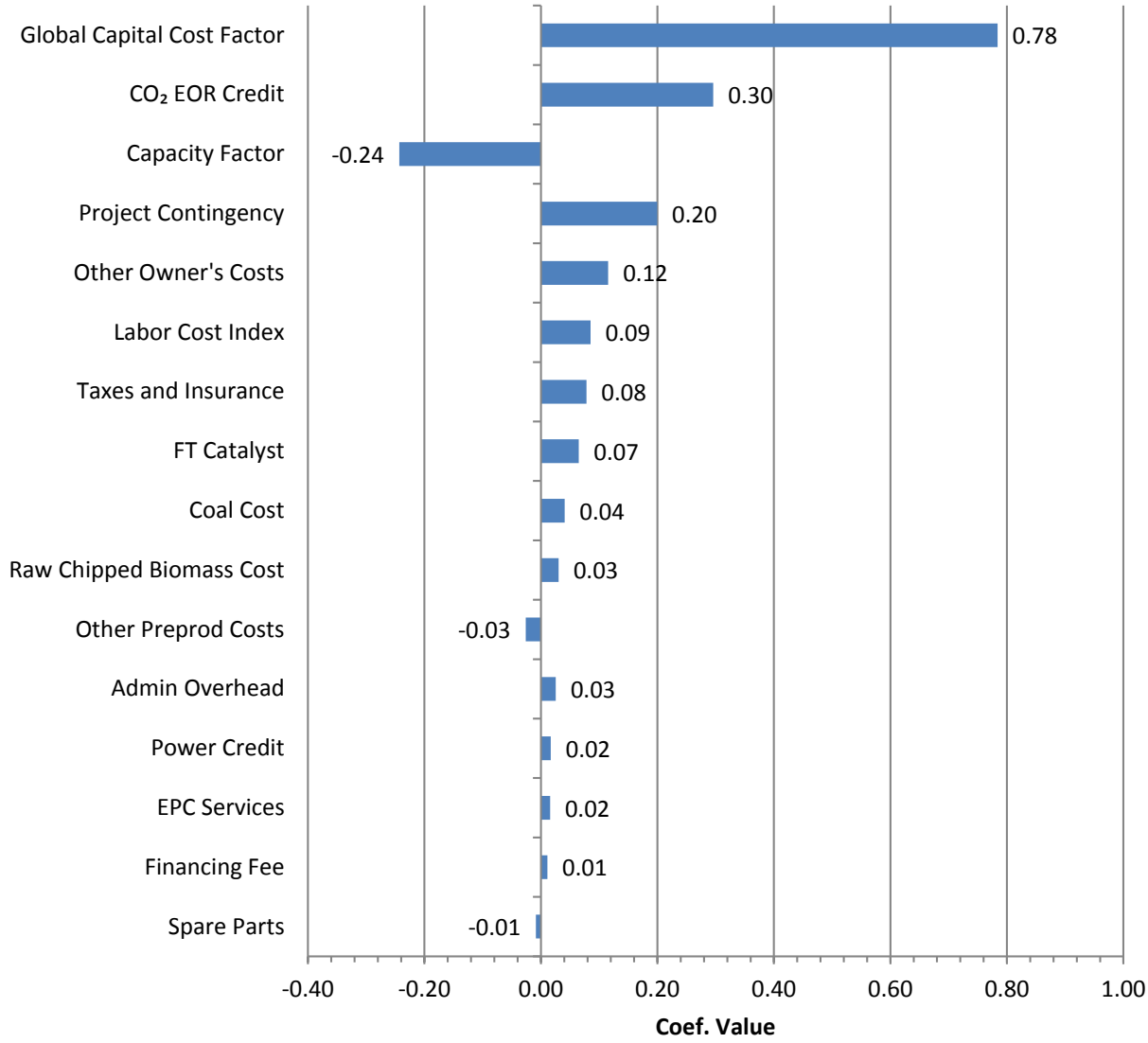


Figure 5-39 provides a summary of model sensitivity, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.78. Other key factors that account for at least 10 percent of the observed variability in RSP include the CO_2 EOR credit, the capacity factor, project contingency, and other owner's costs. Parameters that caused minimal influence on RSP included EPC services, power credits, financing fees, cost of spare parts, and others as shown.

Figure 5-39: Scenario 7: CBTL, 30% Chipped Biomass: Sensitivity of RSP to Modeled Variables

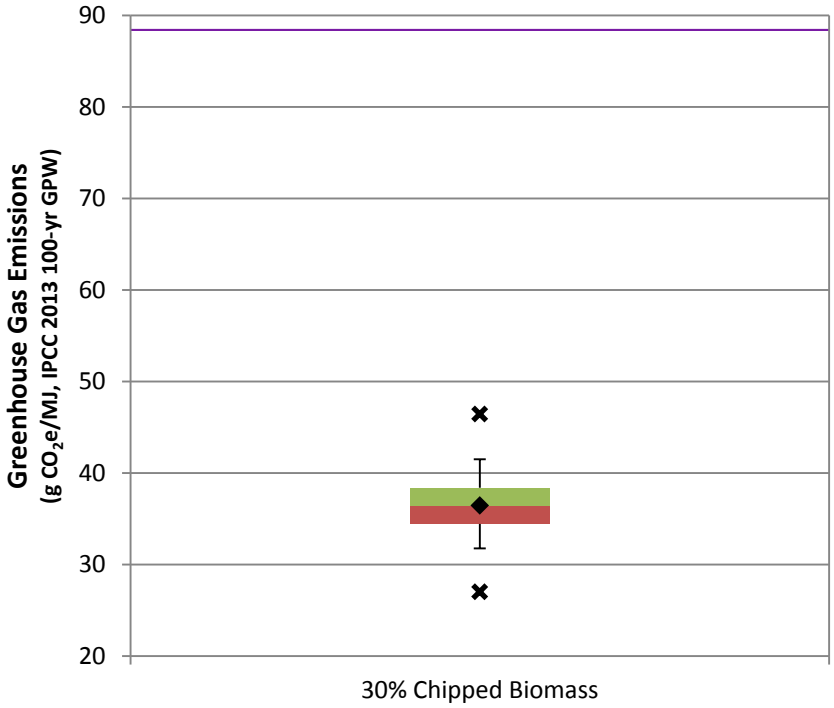


5.7.3 Environmental Results

Results from the environmental model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Results from the environmental life cycle analysis include GHG emissions and other emissions, including select criteria air pollutants, other pollutants of concern, and water consumption. **Figure 5-40** provides a summary life cycle GHG emissions for this scenario, in comparison to conventional jet fuel life cycle GHG emissions of 88.41 g CO_2e/MJ. Using the system expansion method discussed in Chapter 1 the resulting range is 34.4 to 38.4 g CO_2e/MJ, mean 36.5 g CO_2e/MJ or approximately 58.3 percent less than conventional jet fuel.

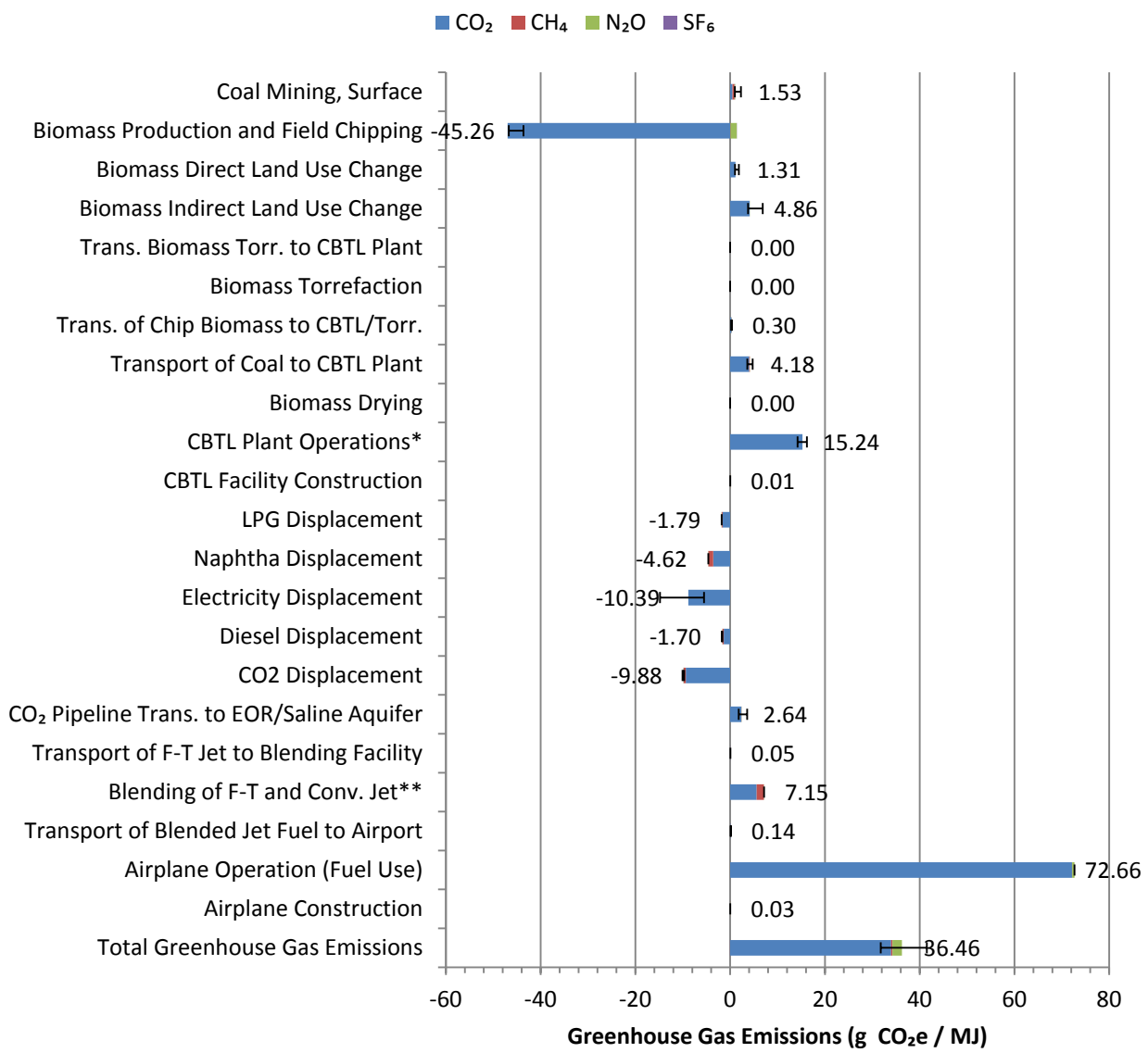
Figure 5-40: Scenario 7: CBTL, 30% Chipped Biomass: Summary of LC GHG Emissions



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

Figure 5-41 provides detail regarding the importance of the various LCA components that were modeled, with respect to gross GHG emissions contributions. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 65.5 percent of gross life cycle GHG emissions. Second in importance to fuel combustion is CBTL plant operations, at 13.9 percent of gross life cycle emissions, while emissions associated with blending of F-T and conventional jet fuel represents 5.09 percent of gross life cycle emissions. The biomass indirect land use change accounts for 3.75 percent of gross life cycle GHG emissions. Emissions from the transport of coal to the CBTL plant represent approximately 3.65 percent of gross emissions. GHG emissions associated with biomass drying generate 2.16 percent of gross life cycle emissions, while pipeline transport of CO_2 and biomass direct land use change generate 1.02 percent and 0.46 percent respectively. Other contributors to gross emissions were less than 1 percent individually.

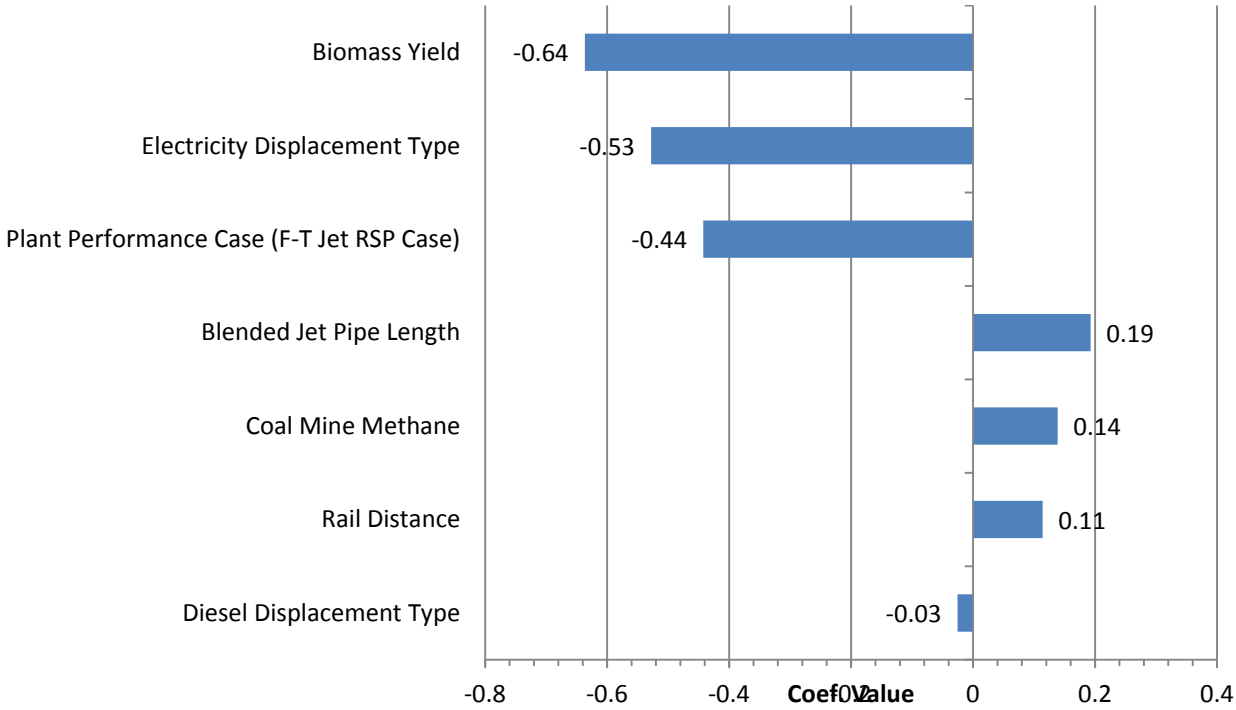
Figure 5-41: Scenario 7: CBTL, 30% Chipped Biomass: LC GHG Emissions Breakdowns



** Includes CO_2 Compression*
** Includes conventional jet fuel profile*

The error bars shown in **Figure 5-41** reflect variability in model output based on the stochastic analyses (for more information, refer to Chapter 1). The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-6**. As shown, variability in emissions resulted primarily from biomass yield. Other key contributors to variability in model output are the type of electricity displacement used and the F-T jet fuel RSP case and **Figure 5-42** summarizes the key factors contributing to variability identified in the model sensitivity analysis, for GHG emissions. Values provided in the figure show the correlation coefficient between the indicated parameter and total life cycle GHG emissions. Other important factors included blended jet fuel pipe length, the coal mine methane emissions, the rail transport distance, and the diesel displacement type. Other parameters had minimal to negligible effect on life cycle GHG emissions.

Figure 5-42: Scenario 7: CBTL, 30% Chipped Biomass: LC GHG Emissions Sensitivity



In addition to GHG emissions, other life cycle environmental emissions and flows were also considered. **Table 5-28** provides a summary of these flows. As shown, Airplane operation is the primary source of carbon monoxide and NOx within the life cycle. Particulate matter (PM_{10}) derives primarily from the combustion of diesel under raw materials transport and product transport operations. Non-methane volatile organic carbons (NMVOCs) result from product transport, including upstream conventional jet fuel emissions, and end use. The highest levels of mercury emissions occur during energy conversion and end use. Most water consumption occurs during biomass cultivation. Note that mass units displayed for water consumption (kg/MJ jet fuel) are equivalent to volume units for water consumption (L/MJ jet fuel).

Table 5-28: Scenario 7: CBTL, 30% Chipped Biomass: Non-GHG Emissions

LC Stage	Carbon monoxide	NO_x	SO2	PM10	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	3.29E-04	4.20E-04	2.29E-04	6.12E-06	9.06E-06	6.67E-10	7.98E-05	1.75E+03	kg/MJ Jet Fuel
RMT	6.12E-04	5.38E-04	1.28E-04	6.80E-04	1.07E-04	5.10E-10	7.72E-06	2.12E-01	kg/MJ Jet Fuel
EC	-4.90E-04	-1.37E-03	-2.38E-03	-1.01E-04	-6.89E-04	5.08E-08	2.81E-05	8.12E-01	kg/MJ Jet Fuel
PT	2.79E-04	4.39E-04	6.27E-04	3.29E-05	8.46E-04	6.38E-10	2.93E-06	1.09E+00	kg/MJ Jet Fuel
EU	7.72E-03	1.21E-02	5.56E-04	9.50E-07	7.72E-04	3.01E-08	7.16E-09	2.81E-02	kg/MJ Jet Fuel
Total	**8.45E-03**	**1.22E-02**	**-8.41E-04**	**6.19E-04**	**1.04E-03**	**8.27E-08**	**1.19E-04**	**1.75E+03**	**kg/MJ Jet Fuel**

5.8 Scenario 8: CBTL, 30 Percent Torrefied Biomass

The purpose of this scenario is to evaluate potential process values, economic factors, and environmental emissions associated with the production of F-T jet fuels from a combination of 70 percent sub-bituminous coal and 30 percent Torrefied Biomass. This scenario evaluates a 1:1 (volume) blend of F-T jet fuels and conventional U.S. average jet fuel, based on a 30-year study period. Coal feedstock is derived from the Rosebud seam in southern Montana, and is transported by train to the CBTL facility, located in the Southeastern U.S. Southern pine biomass feedstock is produced and harvested in the Southeastern U.S., field-chipped, and then transported by chip truck to a separate torrefaction facility, where the biomass is torrefied. Torrefaction increases energy density of the biomass, and greatly reduces grinding energy required, as discussed in greater detail in Chapter 4. Torrefied biomass is then transported by truck to the CBTL facility. The F-T process employed uses a slurry-based iron catalyst using a single feed, oxygen blown Transport Reactor Integrated Gasifier (TRIG™; refer to Chapter 2 for additional discussion). Carbon dioxide is captured at the CBTL facility using a Selexol process to segregate carbon dioxide. Additional carbon dioxide is stripped from overhead gas downstream of the F-T synthesis process, using a methyldiethanolamine (MDEA) unit. Captured carbon dioxide is then routed to a purification and compression system, where it is compressed to a supercritical state. F-T jet fuel produced by the F-T facility is then conveyed to a blending facility, where it is blended with conventional jet fuel, and transported to an airport. Finally, the blended jet fuel is combusted in a jet airplane.

The following text provides a summary of process model, economic model, and environmental model results for this scenario.

5.8.1 Process Results

As discussed in Chapter 2, three Aspen Plus® model cases were run for this scenario: low RSP, expected RSP, and high RSP. Process summary results for each of the three cases are reported in **Table 5-29**. Results obtained from the Aspen Plus® simulations are based on a 50,000 barrel per day (bpd) production rate for total F-T products (F-T jet fuel, F-T diesel, F-T naphtha, and F-T LPG) for the CBTL, 30 percent Torrefied Biomass configuration under all three RSP cases. Fuel production breakdowns are minimally variable among the three RSP cases. For all three RSP cases, approximately 49 percent (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34 percent by volume of total products) being F-T naphtha. F-T jet fuel is produced by hydrocracking the F-T wax to a final boiling point of about 300°C. Hydrocracking also produces naphtha boiling range liquids and F-T LPG. Relatively smaller quantities of F-T diesel (10 percent of total products) and F-T LPG (7 percent of total products) are produced as a result of hydrocracking. These proportions assume that straight run F-T output would be sold as a product. Results from each of the three Aspen Plus® model cases were incorporated into the economic and environmental analyses, the results of which are displayed below. For additional information regarding the application of low, expected, and high RSP values to the stochastic analysis provided here, refer to Chapter 1.

Table 5-29: Scenario 8: CBTL, 30% Torrefied Biomass: Process Summary

Property	Low RSP Case	Expected RSP Case	High RSP Case	Units
CBTL Facility Design and Operating Data				
Plant Design Capacity	50,000	50,000	50,000	bpd
Plant Capacity Factor	85	90	92	%
Plant Efficiency, HHV	56	54	52	%
Carbon Capture Rate	88	89	90	%
Gasifier Modules	9	9	9	Count
F-T Modules	10	10	10	Count
CBTL Facility Inputs/Feed				
Coal Feed, Montana Rosebud, As Received	20,244	20,743	21,439	tons/ day
Biomass Feed, Southern Pine, As Received	8,050	8,048	8,120	tons/ day
Water Feed (Total Withdrawal)	14,343,555	14,185,117	13,990,742	gallons/day
CBTL Facility Outputs/Production				
F-T Jet Fuel Production	24,648	24,646	24,644	bpd
F-T Diesel Fuel Production	4,767	4,767	4,766	bpd
F-T Naphtha Production	16,972	16,971	16,969	bpd
F-T LPG Production	3,613	3,616	3,621	bpd
Total Liquid Product Output	50,000	50,000	50,000	bpd
Export Power	259	231	198	MW
CO2 Captured and Compressed	30,195	30,808	31,336	tons/ day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,296	49,293	49,287	bpd

CBTL facility fuels production capacity was fixed at 50,000 bpd for all three modeled cases. An expected capacity factor of 90 percent was included, ranging from 85 to 92 percent for low and high RSP cases, respectively. The overall expected plant efficiency of 54.4 percent (range of 52.5 to 55.8 percent) is defined as the heating value of the liquid products (HHV basis), F-T LPG, and export power divided by the higher heating value of the input coal and biomass. Makeup water for the CBTL facility, as modeled in Aspen Plus®, is estimated to be approximately 14.2 million gallons per day (mgd; expected RSP case), of which 97.9 percent (13.9 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.75 bbl water/bbl F-T product, based on the expected RSP case.

Under this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 153 to 242 MW, with an expected value of 231 MW. Based on the expected RSP case, gross power production for the CBTL facility is 791MW, including power generated from steam (559 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads.

Major auxiliary loads include air separation (239 MW), carbon dioxide compressors (91.4 MW), the Selexol unit (60.8 MW), hydrocarbon recovery/refrigeration (44.0 MW), and oxygen compression 31.0 MW). Total auxiliaries consume 560 MW, for a net power output of 231 MW under the expected RSP case.

Carbon balance for the CBTL facility is shown in **Table 5-30**, for all three RSP cases. Carbon dioxide produced during the production of fuels and electric power is separated from the syngas stream prior to entering the F-T unit. The Selexol unit and the MDEA unit both produce the concentrated CO_2 streams that are dehydrated and compressed to 2,200 psi for pipeline delivery and carbon management. Other flue gas streams containing CO_2 are vented to the atmosphere. These include the flue gases from the HRSG units and from the fired heaters that are utilized during the F-T process. For the expected RSP case, approximately 2 percent of total carbon (range of 1 percent for the low RSP case to 4 percent for the high RSP case) is output to slag/ash from the TRIG gasifier.

Table 5-30: Scenario 8: CBTL, 30% Torrefied Biomass: Conversion Facility Carbon Balance

Input Flow	Low RSP Case	Expected RSP Case	High RSP Case	Units
Coal Carbon	10,136	10,386	10,734	TPD
Biomass Carbon	4,821	4,820	4,863	TPD
Total Carbon Input	**14,957**	**15,206**	**15,597**	**TPD**
F-T Products	5,284	5,284	5,284	TPD
Slag/Ash	150	304	625	TPD
Stack Gas	976	926	877	TPD
Fuel Gas	262	236	209	TPD
WWTP	30	31	29	TPD
Carbon Capture, Sequestered	8,260	8,430	8,579	TPD
Total Carbon Output	**14,962**	**15,211**	**15,602**	**TPD**
Carbon Capture	**88%**	**89%**	**90%**	**%**

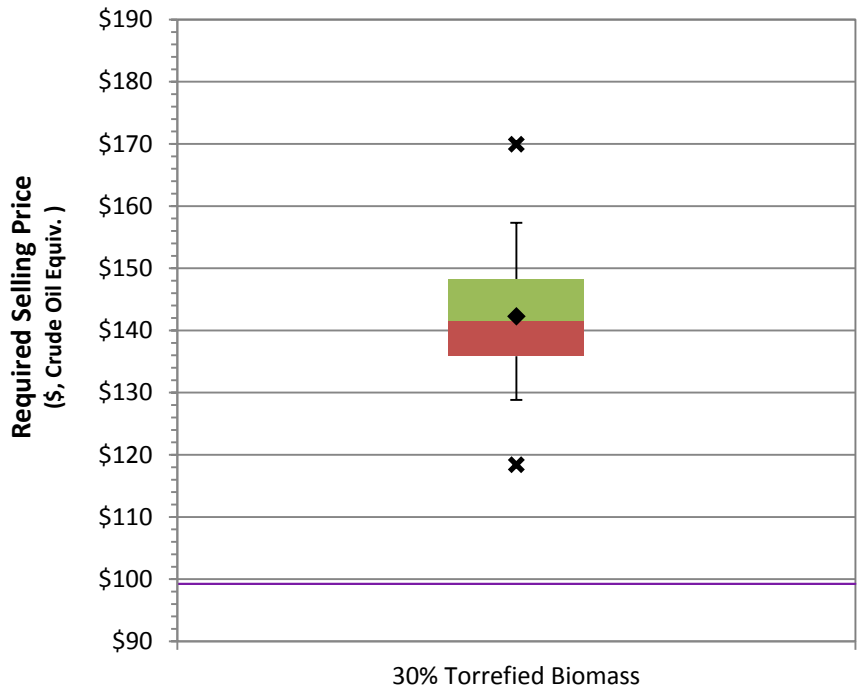
5.8.2 Economic Results

Results from the economic model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Figure 5-43 provides a summary of the estimated RSP for the F-T jet fuel produced under this scenario. As shown, RSP ranges from $136 to $148/bbl, with a mean value of $142/bbl, on a crude oil equivalent basis. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 40 economic parameters shown in **Table 1-5**. As shown, 25th and 75th percentile values are relatively close to the mean value, however, selling price distributions are characterized by long tails, with an overall range of $118 to $170/bbl, on a crude oil equivalent basis.

Cost of the F-T jet fuel product is estimated on a crude oil equivalent basis. This is defined as the RSP of the diesel product divided by a factor of 1.1433. Thus if the average world oil price were below or equal to the calculated crude oil equivalent price the CBTL plant would be economically viable. Key contributors to the variability shown for RSP results are discussed below.

Figure 5-43: Scenario 8: CBTL, 30% Torrefied Biomass: F-T Jet Fuel RSP, Crude Oil Equivalent Basis



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel spot price value.

Table 5-31 provides a summary of the economic estimated performance of the CBTL facility under this scenario, including the key contributing factors to the calculation of RSP. Total operating and maintenance costs represent an average of $526 million/yr. Of this amount, $289 to $315 million/yr, mean $303 million/yr (57.6 percent), results from fixed costs, while $215 to $231 million/year, mean $223 million/yr (42.4 percent) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, ranging from $8,337 to $9,140 million, mean $8,750 million. Coal feedstock costs for this scenario range from $239 to $250 million/yr, mean $245 million/yr. Biomass feedstock costs range from $339 to $361 million/yr, mean $350 million/yr. Total feedstock costs are approximately $69.5 million higher than total operating and maintenance costs, on average. Projected revenues include credits and product sales revenue. Power credit, from the sale of produced electricity, amounts to $119 to $134 million/yr, mean $126 million/yr, while CO_2 credit is estimated to be $331 to $394 million/yr, mean $363 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,171 to $2,369 million/yr, mean $2,269 million/yr.

Required product sales prices are also provided in **Table 5-31**. Crude oil equivalent RSP is discussed above for **Figure 5-43**. On a straight basis, RSP for F-T jet fuel was calculated to be $157 to $171/bbl, mean $164/bbl, with F-T diesel at $155 to $170/bbl, mean $163/bbl, F-T naphtha at $108 to $118/bbl, mean $113/bbl, and F-T LPG at $62.8 to $68.5/bbl, mean $65.7/bbl. The default capital charge factor (CCF) used in the analysis was 0.1872.

Table 5-31: Scenario 8: CBTL, 30% Torrefied Biomass: Summary of Economics

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	303	250	360	289	315	$MM/yr
Variable Operating and Maintenance Cost (VOM)	223	190	264	215	231	$MM/yr
Capital: Total Overnight Cost (TOC)	8,750	7,422	10,609	8,337	9,140	$MM
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	245	223	269	239	250	$MM/yr
Biomass Cost, Southern Pine, Chips, As Received	0	0	0	0	0	$MM/yr
Biomass Cost, Southern Pine, Torrefied, As Received	350	308	403	339	361	$MM/yr
Credits and Revenue						
Power Credit	(126)	(158)	(96)	(134)	(119)	$MM/yr
Credit @ $40/ton for CO_2	(363)	(467)	(256)	(394)	(331)	$MM/yr
Annual Revenue Required	2,269	1,895	2,687	2,171	2,369	$MM/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	164	137	196	157	171	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	163	135	194	155	170	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	113	94	135	108	118	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	66	55	79	63	68	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	142	118	170	136	148	$/bbl

Figure 5-44 provides breakdowns for the cost factors that contribute to the RSP. As shown, capital cost is the primary factor in determining RSP, and accounts for approximately72.2 percent of total RSP, or $103/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 20.2 percent of total RSP, or $28.8/bbl, while feedstock costs represent 22.9 percent of total RSP, or $32.6/bbl, on a crude oil equivalent basis. As shown, variability in total RSP is driven largely by potential variability in capital costs, and to a much lesser extent by variability in operations and maintenance and feedstock costs. The negative credits bar comprises the sale of the co-produced electricity and compressed CO_2. Electricity accounts for 25.8 percent of the total credit, while captured and compressed CO_2 accounts for 74.2 percent.

Figure 5-44: Scenario 8: CBTL, 30% Torrefied Biomass: RSP, Crude Oil Equivalent Basis

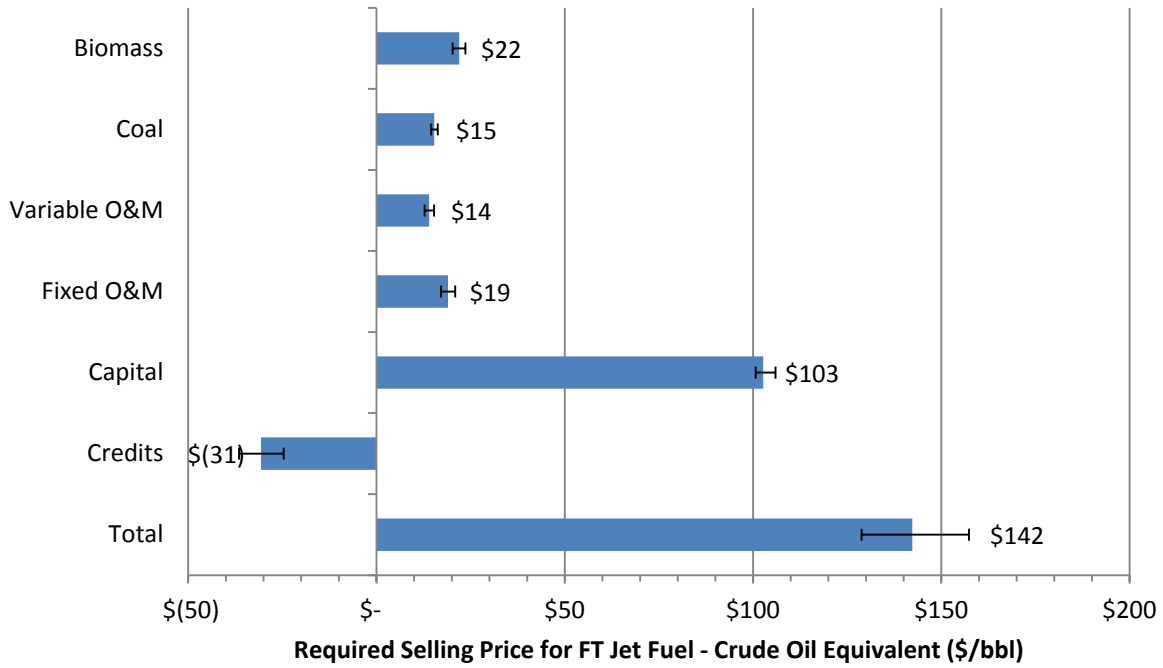
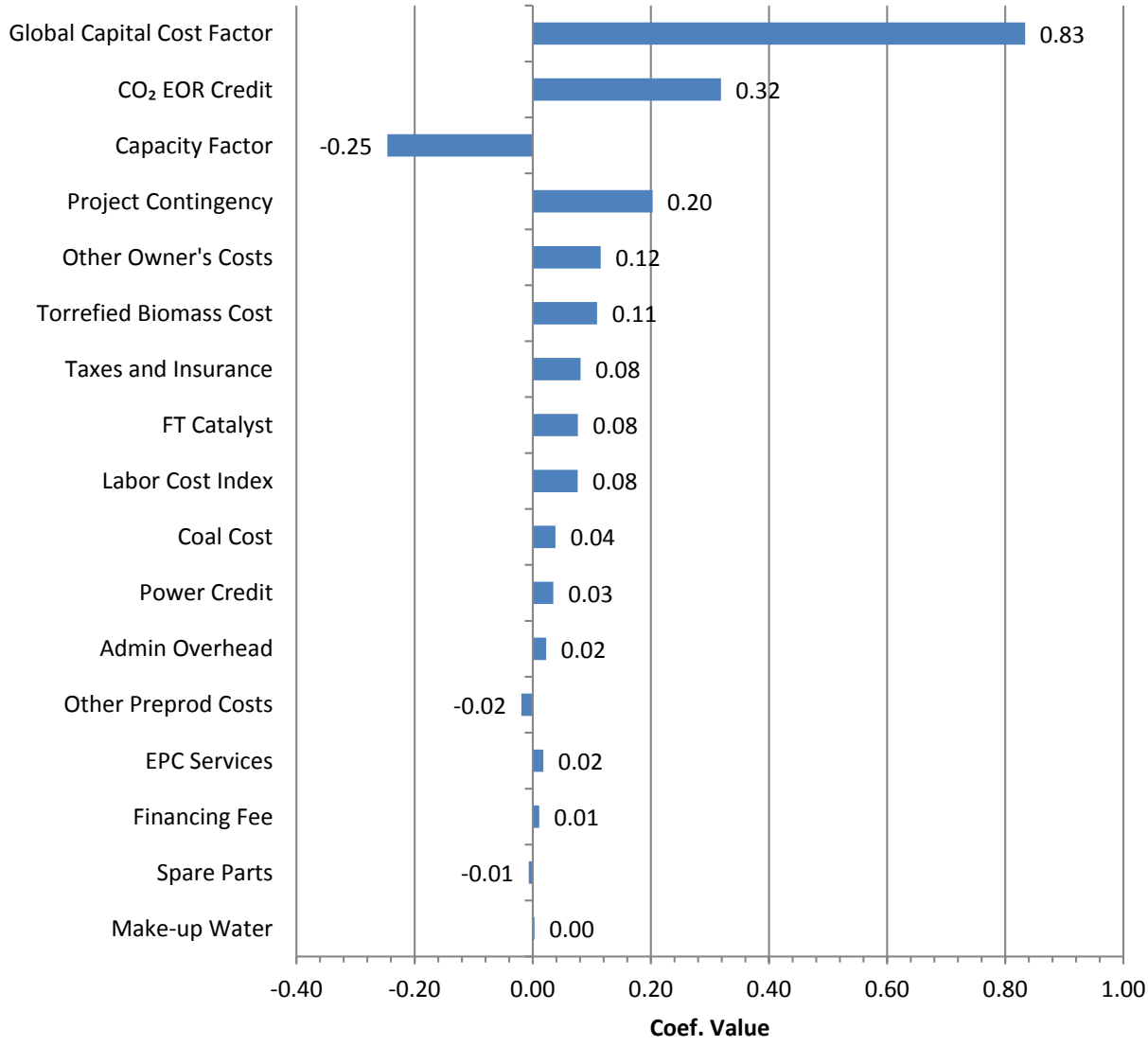


Figure 5-45 provides a summary of model sensitivity, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.83. Other key factors that account for at least 10 percent of the observed variability in RSP include the CO_2 EOR credit, capacity factor, project contingency, other owner's costs, and torrefied biomass costs. Parameters that caused minimal influence on RSP included theadmin overhead costs, other preproduction costs, EPC services costs, financing fees, the cost of spare parts, and others as shown.

Figure 5-45: Scenario 8: CBTL, 30% Torrefied Biomass: Sensitivity of RSP to Modeled Variables

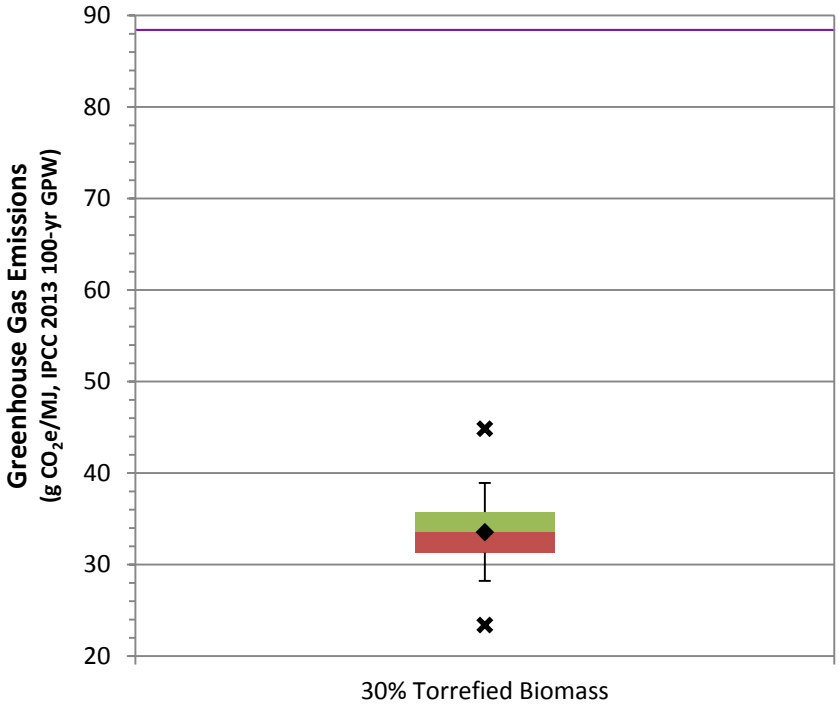


5.8.3 Environmental Results

Results from the environmental model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Results from the environmental life cycle analysis include GHG emissions and other emissions, including select criteria air pollutants, other pollutants of concern, and water consumption. **Figure 5-46** provides a summary life cycle GHG emissions for this scenario, in comparison to conventional jet fuel life cycle GHG emissions of 88.41 g CO_2e/MJ. Using the system expansion method discussed in Chapter 1 the resulting range is 31.3 to 35.7 g CO_2e/MJ, mean 33.6 g CO_2e/MJ or approximately 61.6 percent less than conventional jet fuel.

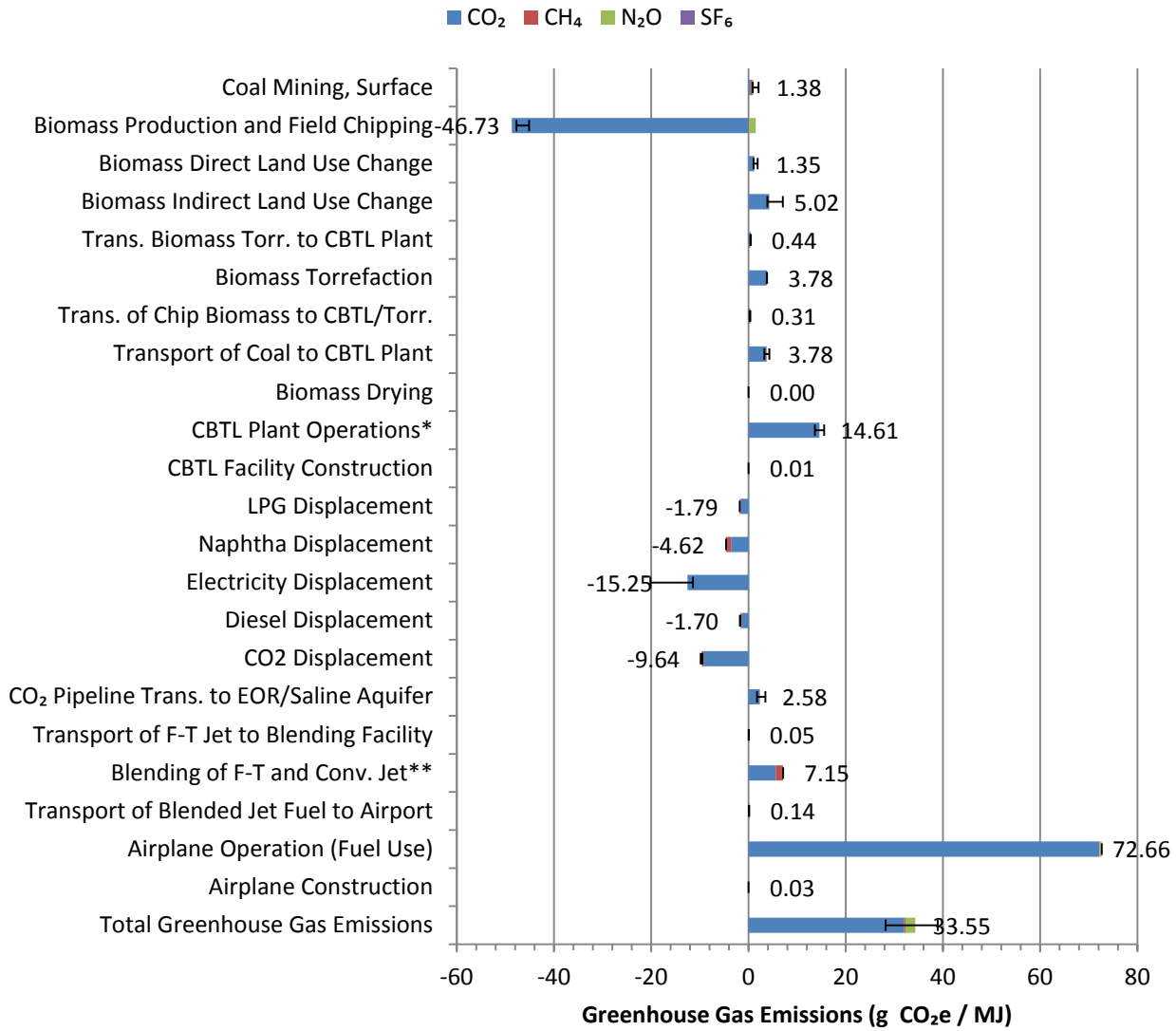
Figure 5-46: Scenario 8: CBTL, 30% Torrefied Biomass: Summary of LC GHG Emissions



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

Figure 5-47 provides detail regarding the importance of the various LCA components that were modeled, with respect to gross GHG emissions contributions. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 63.7 percent of gross life cycle GHG emissions. Second in importance to fuel combustion are upstream emissions associated with CBTL plant operations, which represent 12.9 percent of gross life cycle emissions, while blending of F-T and conventional jet fuel represented 4.95 percent of gross life cycle emissions. The transport of coal to the CBTL plant accounts for 3.77 percent of gross life cycle GHG emissions. Emissions from biomass indirect land use change represent approximately 3.32 percent of gross emissions, while pipeline transport of CO_2 accounted for approximately 3.19 percent of gross life cycle emissions. The torrefaction of biomass represents only 2.04 percent of gross emissions and all other contributors to gross emissions were less than 1 percent individually.

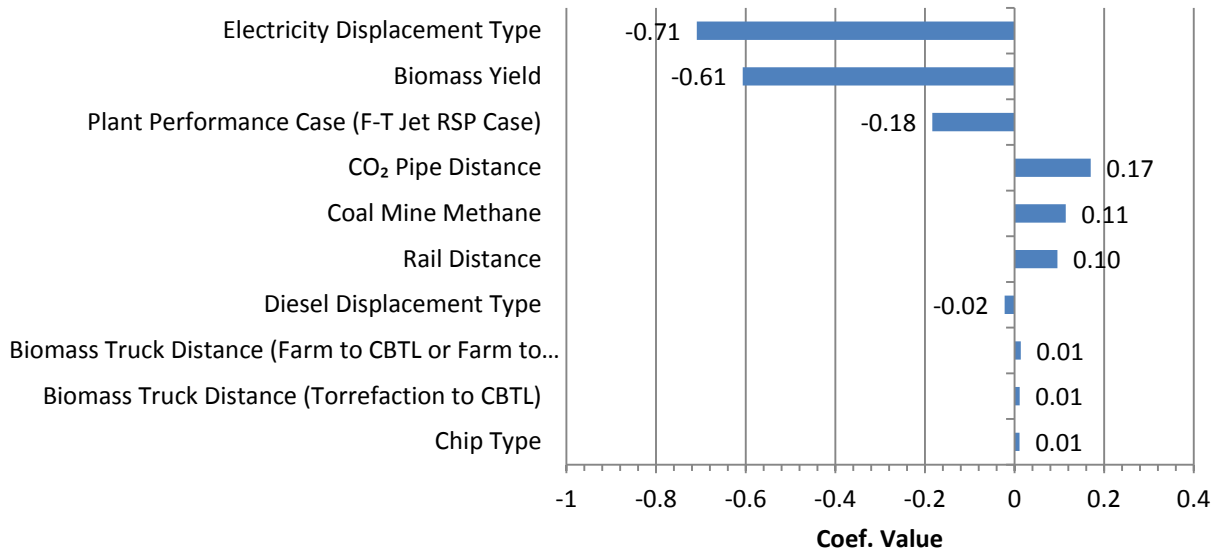
Figure 5-47: Scenario 8: CBTL, 30% Torrefied Biomass: LC GHG Emissions Breakdowns



** Includes CO_2 Compression*
*** Includes conventional jet fuel profile*

The error bars shown in **Figure 5-47** reflect variability in model output based on the stochastic analyses (for more information, refer to Chapter 1), based on combined allocation. The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-6**. As shown, variability in emissions resulted primarily from the type of electricity displacement used. Another key contributor to variability in model output is biomass yield. **Figure 5-48** summarizes the key factors contributing to variability identified in the model sensitivity analysis, for GHG emissions. Values provided in the figure show the correlation coefficient between the indicated parameter and total life cycle GHG emissions. Other important factors included the F-T jet fuel RSP case, the coal mine methane emissions, the rail transport distance, the diesel displacement type, the biomass truck transportation distances, and the biomass chip type. Other parameters had minimal to negligible effect on life cycle GHG emissions.

Figure 5-48: Scenario 8: CBTL, 30% Torrefied Biomass: LC GHG Emissions Sensitivity



In addition to GHG emissions, other life cycle environmental emissions and flows were also considered.

Table 5-32 provides a summary of these flows. As shown, Airplane operation is the primary source of carbon monoxide and NOx within the life cycle. Particulate matter (PM_{10}) derives primarily from the combustion of diesel under raw materials transport and product transport operations. Non-methane volatile organic carbons (NMVOCs) result from product transport, including upstream conventional jet fuel emissions, and end use. The highest levels of mercury emissions occur during energy conversion and end use. Most water consumption occurs during biomass cultivation. Note that mass units displayed for water consumption (kg/MJ jet fuel) are equivalent to volume units for water consumption (L/MJ jet fuel).

Table 5-32: Scenario 8: CBTL, 30% Torrefied Biomass: Non-GHG Emissions

LC Stage	Carbon monoxide	NO_x	SO2	PM10	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	1.34E-05	1.40E-04	1.45E-05	1.43E-06	8.25E-06	2.29E-10	1.37E-06	1.21E-02	kg/MJ Jet Fuel
RMT	5.28E-04	4.83E-04	1.08E-04	6.18E-04	9.07E-05	2.83E-10	6.98E-06	1.64E-01	kg/MJ Jet Fuel
EC	-5.20E-04	-1.58E-03	-2.73E-03	-1.65E-04	-7.08E-04	4.07E-08	2.82E-05	-1.17E+00	kg/MJ Jet Fuel
PT	2.79E-04	4.39E-04	6.27E-04	3.29E-05	8.46E-04	6.38E-10	2.93E-06	1.09E+00	kg/MJ Jet Fuel
EU	7.72E-03	1.21E-02	5.56E-04	9.50E-07	7.72E-04	3.01E-08	7.16E-09	2.81E-02	kg/MJ Jet Fuel
Total	**8.02E-03**	**1.16E-02**	**-1.43E-03**	**4.88E-04**	**1.01E-03**	**7.19E-08**	**3.94E-05**	**1.21E-01**	**kg/MJ Jet Fuel**

5.9 Scenario 9: CBTL, 11.7 Percent Chipped Biomass and Validation

The purpose of this scenario is to evaluate potential process values, economic factors, and environmental emissions associated with the production of F-T jet fuels from a combination of 88.3 percent sub-bituminous coal and 11.7 percent chipped biomass. This scenario evaluates a 1:1 (volume) blend of F-T jet fuels and conventional U.S. average jet fuel, based on a 30-year study period. Coal feedstock is derived from the Rosebud seam in southern Montana, and is transported by train to the CBTL facility, located in the Southeastern U.S. Biomass feedstock is field-chipped Southern pine biomass, cultivated and harvested in the Southeastern U.S. and transported, via chip truck, to the CBTL facility. The F-T process employed uses a slurry-based iron catalyst using a single feed, oxygen blown Transport Reactor Integrated Gasifier (TRIG™; refer to Chapter 2 for additional discussion). Carbon dioxide is captured at the CBTL facility using a Selexol process to segregate carbon dioxide. Additional carbon dioxide is stripped from overhead gas downstream of the F-T synthesis process, using a methyldiethanolamine (MDEA) unit. Captured carbon dioxide is then routed to a purification and compression system, where it is compressed to a supercritical state. F-T jet fuel produced by the F-T facility is then conveyed to a blending facility, where it is blended with conventional jet fuel, and transported to an airport. Finally, the blended jet fuel is combusted in a jet airplane.

The following text provides a summary of process model, economic model, and environmental model results for this scenario.

5.9.1 Process Results

As discussed in Chapter 2, three Aspen Plus® model cases were run for this scenario: low RSP, expected RSP, and high RSP. Process summary results, both modeled and validated, for each of the three cases are reported in **Table 5-33**. Results obtained from the Aspen Plus® simulations are based on a 50,000 barrel per day (bpd) production rate for total F-T products (F-T jet fuel, F-T diesel, F-T naphtha, and F-T LPG) for the CBTL, 11.7 percent Chipped Biomass configuration under all three RSP cases. Fuel production breakdowns are minimally variable among the three RSP cases. For all three RSP cases, approximately 49 percent (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34 percent by volume of total products) being F-T naphtha. F-T jet fuel is produced by hydrocracking the F-T wax to a final boiling point of about 300°C. Hydrocracking also produces naphtha boiling range liquids and F-T LPG. Relatively smaller quantities of F-T diesel (10 percent of total products) and F-T LPG (7 percent of total products) are produced as a result of hydrocracking. These proportions assume that straight run F-T output would be sold as a product. Results from each of the three Aspen Plus® model cases were incorporated into the economic and environmental analyses, the results of which are displayed below. For additional information regarding the application of low, expected, and high RSP values to the stochastic analysis provided here, refer to Chapter 1.

Table 5-33: Scenario 9: CBTL, 11.7% Chipped Biomass: Process Summary

Property	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
CBTL Facility Design and Operating Data							
Plant Design Capacity	50,000	50,000	50,000	50,000	50,000	50,000	bpd
Plant Capacity Factor	85	85	90	90	92	92	%
Plant Efficiency, HHV	55	55	53	53	51	51	%
Carbon Capture Rate	88	88	89	89	90	90	%
Gasifier Modules	8	8	8	8	8	8	Count
F-T Modules	10	10	10	10	10	10	Count
CBTL Facility Inputs/Feed							
Coal Feed, Montana Rosebud, As Received	27,137	27,178	27,707	27,759	28,439	28,505	tons/ day
Biomass Feed, Southern Pine, As Received	4,825	4,832	4,806	4,815	4,933	4,945	tons/ day
Water Feed (Total Withdrawal)	14,821,555	14,780,489	14,632,116	14,713,816	14,364,289	14,455,820	gallons/day
CBTL Facility Outputs/Production							
F-T Jet Fuel Production	24,649	24,649	24,647	24,647	24,645	24,644	bpd
F-T Diesel Fuel Production	4,767	4,767	4,767	4,767	4,766	4,766	bpd
F-T Naphtha Production	16,973	16,973	16,972	16,971	16,970	16,970	bpd
F-T LPG Production	3,612	3,612	3,615	3,615	3,619	3,620	bpd
Total Liquid Product Output	50,000	50,000	50,000	50,000	50,000	50,000	bpd
Export Power	239	251	200	199	148	147	MW
CO2 Captured and Compressed	30,421	30,573	31,138	31,315	31,715	31,913	tons/ day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,298	49,297	49,294	49,294	49,290	49,288	bpd

CBTL facility fuels production capacity was fixed at 50,000 bpd for all three RSP cases. An expected capacity factor of 90 percent was included, ranging from 85 to 92 percent for low and high RSP cases, respectively. In the modeled case the overall expected plant efficiency of 52.9 percent (range of 50.7 to 54.5 percent) is defined as the heating value of the liquid products (HHV basis), F-T LPG, and export power divided by the higher heating value of the input coal and biomass. In the validation case the overall expected plant efficiency is 52.8 percent (range of 50.6 to 54.6 percent) , a variation of less than 1 percent from the modeled case. In the modeled case, makeup water for the CBTL facility, as modeled in Aspen Plus®, is estimated to be approximately 14.6 million gallons per day (mgd; expected RSP case), of which 95.7 percent (14.0 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.97 bbl water/bbl F-T product, based on the expected RSP modeled case. In the validated case, makeup water for the CBTL facility is estimated to be approximately 14.7 million gallons per day (mgd; expected RSP case), of which 95.7 percent (14.1 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 7.01 bbl water/bbl F-T product, based on the expected RSP validated case. Here there is strong agreement between the modeled and validated case with a variation of makeup water for the CBTL facility of 0.08 million gallon per day (0.56 percent) and a normalized variation of 0.04 bbl water/bbl F-T product (0.56 percent).

Under the modeled case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 148 to 239 MW, with an expected value of 200 MW. Based on the expected RSP case, gross power production for the CBTL facility is 780 MW, including power generated from steam (548 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (247 MW), carbon dioxide compressors (92.3 MW), the Selexol unit (61.6 MW), hydrocarbon recovery/refrigeration (42.8 MW), and oxygen compression (32.1 MW). Total auxiliaries consume 580 MW, for a net power output of 200 MW under the expected RSP case.

Under the validated case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 147 to 251 MW, with an expected value of 199 MW. Based on the expected RSP case, gross power production for the CBTL facility is 783 MW, including power generated from steam (551 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (248 MW), carbon dioxide compressors (92.7 MW), the Selexol unit (61.9 MW), hydrocarbon recovery/refrigeration (43.7 MW), and oxygen compression (32.2 MW). Total auxiliaries consume 584 MW, for a net power output of 199 MW under the expected RSP case.

Carbon balance for both the modeled and validated case of the CBTL facility is shown in **Table 5-34**, for all three RSP cases. As shown, carbon inputs were within 0.2 percent of carbon outputs for each of the three RSP cases. Carbon dioxide produced during the production of fuels and electric power is separated from the syngas stream prior to entering the F-T unit. The Selexol unit and the MDEA unit both produce the concentrated CO_2 streams that are dehydrated and compressed to 2,200 psi for pipeline delivery and carbon management. Other flue gas streams containing CO_2 are vented to the atmosphere. These include the flue gases from the HRSG units and from the fired heaters that are utilized during the F-T process. For the expected RSP case, approximately 2 percent of total carbon (range of 1 percent for the low RSP case to 4 percent for the high RSP case) is output to slag/ash from the TRIG gasifier.

Table 5-34: Scenario 9: CBTL, 11.7% Chipped Biomass: Conversion Facility Carbon Balance

Input Flow	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
Coal Carbon	13,587	13,608	13,873	13,899	14,239	14,272	TPD
Biomass Carbon	1,474	1,476	1,468	1,471	1,507	1,511	TPD
Total Carbon Input	15,061	15,084	15,341	15,370	15,746	15,783	**TPD**
F-T Products	5,284	5,284	5,284	5,284	5,284	5,284	TPD
Slag/Ash	151	151	307	308	631	632	TPD
Stack Gas	1,007	994	958	944	907	894	TPD
Fuel Gas	273	267	248	241	219	212	TPD
WWTP	31	31	30	30	30	31	TPD
Carbon Capture, Sequestered	8,320	8,362	8,519	8,568	8,680	8,736	TPD
Total Carbon Output	**15,066**	**15,089**	**15,346**	**15,375**	**15,752**	**15,789**	**TPD**
Carbon Capture	**86.4**	**86.6**	**87.3**	**87.6**	**88.2**	**88.5**	**%**

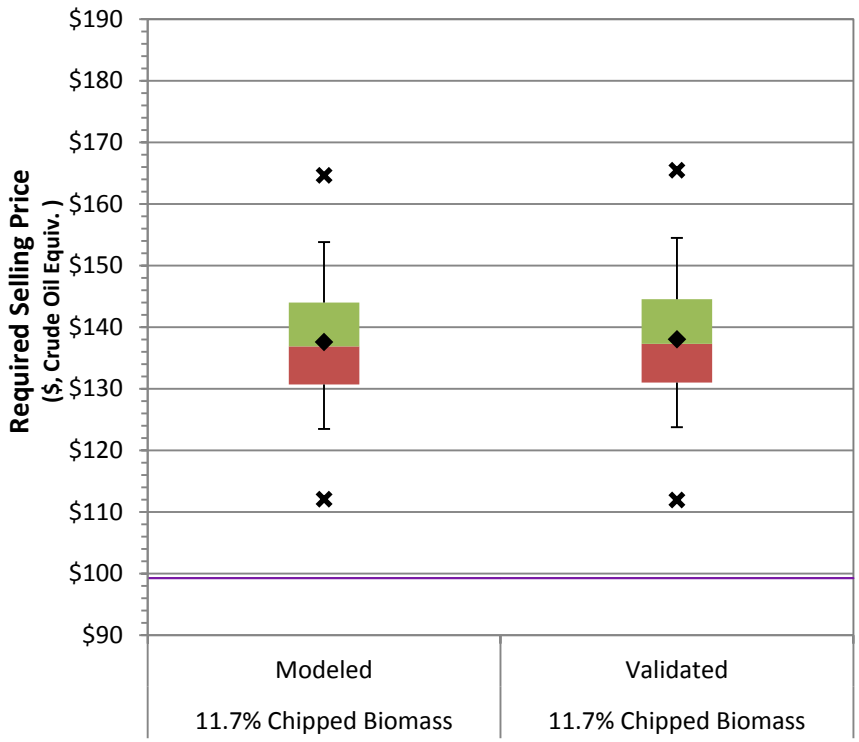
5.9.2 Economic Results

Results from the economic model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Figure 5-49 provides a summary of the estimated RSP for the F-T jet fuel produced under this scenario. As shown, RSP ranges from $131 to $144/bbl for the modeled case, with a mean value of $138/bbl, on a crude oil equivalent basis and for the variation, case the RSP ranges from $131 to $145/bbl, with a mean value of $138/bbl. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 40 economic parameters shown in **Table 1-5**. As shown, 25th and 75th percentile values are relatively close to the mean value, however, selling price distributions are characterized by long tails, with an overall range of $112 to $165/bbl, on a crude oil equivalent basis.

Cost of the F-T jet fuel product is estimated on a crude oil equivalent basis. This is defined as the RSP of the diesel product divided by a factor of 1.1433. Thus if the average world oil price were below or equal to the calculated crude oil equivalent price the CBTL plant would be economically viable. Key contributors to the variability shown for RSP results are discussed below.

Figure 5-49: Scenario 9: CBTL, 11.7% Chipped Biomass: F-T Jet Fuel RSP, Crude Oil Equivalent Basis



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel spot price value.

It is clear from **Figure 5-49** that there is minimal variation between the modeled and validated RSP results. **Table 5-35** provides a summary of the economic estimated performance of the CBTL facility under the validated case of this scenario, including the key contributing factors to the calculation of RSP. Total operating and maintenance costs represent an average of $567 million/yr. Of this amount, $320 to $348 million/yr, mean $334 million/yr (58.9 percent), results from fixed costs, while $224 to $241 million/year, mean $233 million/yr (41.1 percent) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, range from $8,893 to $9,762 million, mean $9,336 million. Coal feedstock costs for this scenario range from $320 to $334 million/yr, mean $327 million/yr. Biomass feedstock costs range from $36.6 to $39.7 million/yr, mean $38.2 million/yr. Total feedstock costs are approximately $201 million lower than total operating and maintenance costs, on average. Projected revenues include credits and product sales revenue. Power credit, from the sale of produced electricity, amounts to $103 to $116 million/yr, mean $110 million/yr, while CO_2 credit is estimated to be $337 to $401 million/yr, mean $369 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,090 to $2,308 million/yr, mean $2,202 million/yr.

Required product sales prices in the validated case are also provided in **Table 5-35**. Crude oil equivalent RSP is discussed above for **Figure 5-49**. On a straight basis, RSP for F-T jet fuel was calculated to be $151 to $167/bbl, mean $159/bbl, with F-T diesel at $150 to $165/bbl, mean $158/bbl, F-T naphtha at $104 to $115/bbl, mean $110/bbl, and F-T LPG at $60.5 to $66.8/bbl, mean $63.8/bbl. The default capital charge factor (CCF) used in the analysis was 0.1872.

Table 5-35: Scenario 9: CBTL, 11.7% Chipped Biomass: Summary of Economics

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	334	277	399	320	348	$MM/yr
Variable Operating and Maintenance Cost (VOM)	233	199	276	224	241	$MM/yr
Capital: Total Overnight Cost (TOC)	9,336	7,913	11,423	8,893	9,762	$MM
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	327	300	357	320	334	$MM/yr
Biomass Cost, Southern Pine, Chips, As Received	38	31	44	37	40	$MM/yr
Biomass Cost, Southern Pine, Torrefied, As Received	0	0	0	0	0	$MM/yr
Credits and Revenue						
Power Credit	(110)	(153)	(71)	(116)	(103)	$MM/yr
Credit @ $40/ton for CO_2	(369)	(476)	(260)	(401)	(337)	$MM/yr
Annual Revenue Required	2,202	1,779	2,673	2,090	2,308	$MM/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	159	129	191	151	167	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	158	128	189	150	165	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	110	89	132	104	115	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	64	52	76	61	67	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	138	112	165	131	145	$/bbl

Figure 5-50 provides breakdowns for the cost factors in the validated case that contribute to the RSP. As shown, capital cost is the primary factor in determining RSP, and accounts for approximately 79.4 percent of total RSP, or $110/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 22.5 percent of total RSP, or $31.1/bbl, while feedstock costs represent 14.5 percent of total RSP, or $20.0/bbl, on a crude oil equivalent basis. As shown, variability in total RSP is driven largely by potential variability in capital costs, and to a much lesser extent by variability in operations and maintenance and feedstock costs. The negative credits bar comprises the sale of the co-produced electricity and compressed CO_2. Electricity accounts for 22.8 percent of the total credit, while captured and compressed CO_2 accounts for 77.2 percent.

Figure 5-50: Scenario 9: CBTL, 11.7% Chipped Biomass, Validated: RSP, Crude Oil Equivalent Basis

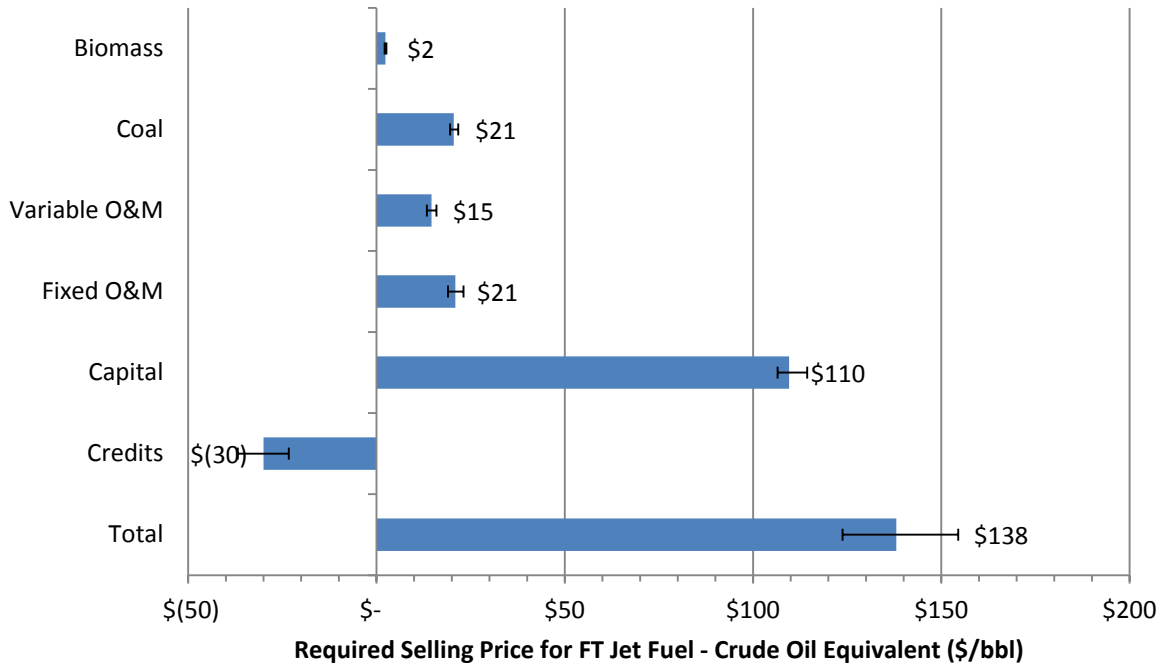
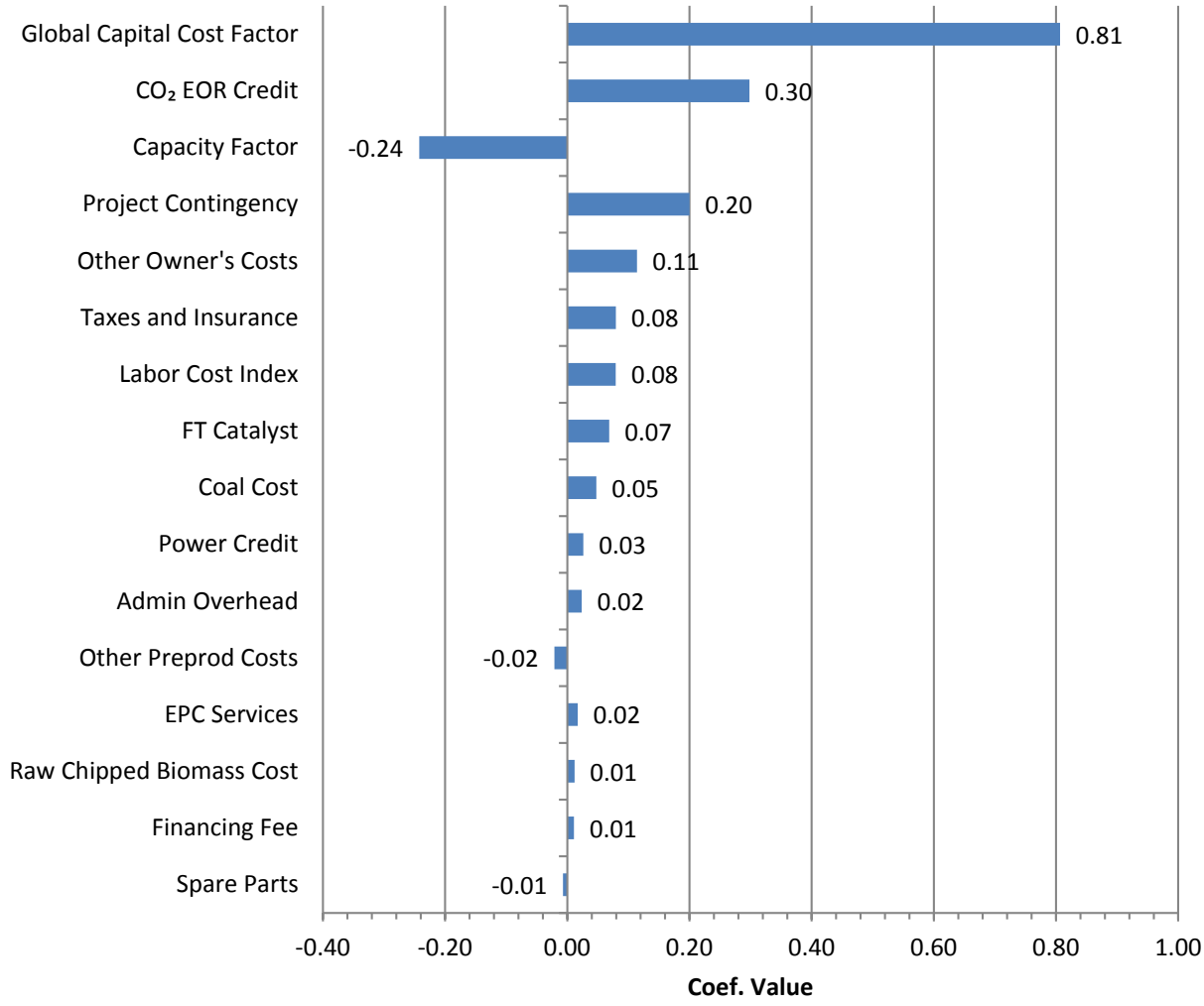


Figure 5-51 provides a summary of model sensitivity in the validated case, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.81. Other key factors that account for at least 10 percent of the observed variability in RSP include the CO_2 EOR credit, capacity factor, project contingency, and other owner's costs. Parameters that caused minimal influence on RSP included the power credit, EPC services, administrative overhead expenditures, financing fees, cost of spare parts, and others as shown.

Figure 5-51: Scenario 9: CBTL, 11.7% Chipped Biomass, Validated: Sensitivity of RSP to Modeled Variables

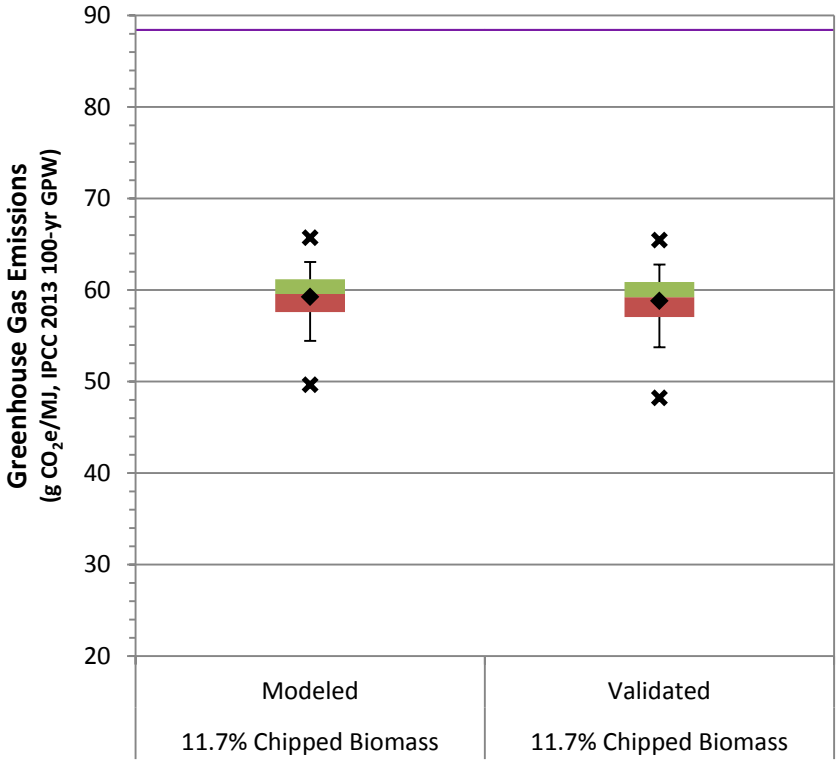


5.9.3 Environmental Results

Results from the environmental model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Results from the environmental life cycle analysis include GHG emissions and other emissions, including select criteria air pollutants, other pollutants of concern, and water consumption. **Figure 5-52** provides a summary life cycle GHG emissions for this scenario, in comparison to conventional jet fuel life cycle GHG emissions of 88.41 g CO_2e/MJ. In the modeled case the resulting range is 57.6 to 61.2 g CO_2e/MJ, mean 59.3 g CO_2e/MJ or approximately 32.2 percent less than conventional jet fuel. In the validated case the resulting range is 57.0 to 60.9 g CO_2e/MJ, mean 58.8 g CO_2e/MJ or approximately 32.7 percent less than conventional jet fuel.

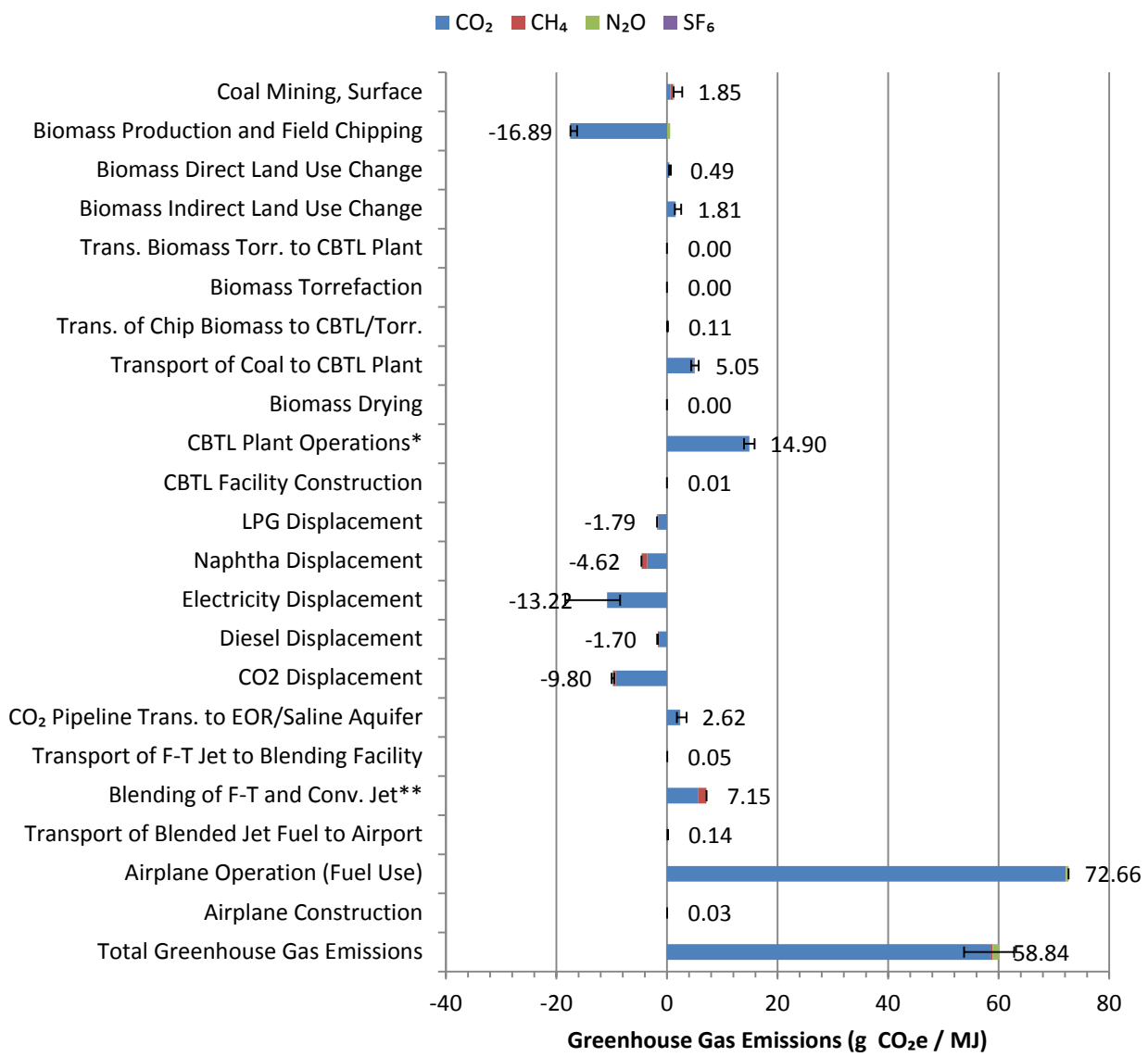
Figure 5-52: Scenario 9: CBTL, 11.7% Chipped Biomass, Validated: Summary of LC GHG Emissions



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

It is clear from **Figure 5-52** that there is minimal variation between the modeled and validated LC GHG emission results. **Figure 5-53** provides detail regarding the importance of the various LCA components in the validated case that were modeled, with respect to gross GHG emissions contributions. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 67.5 percent of gross life cycle GHG emissions. Second in importance to fuel combustion is CBTL plant operations, at 13.9 percent of gross life cycle emissions, while emissions associated with blending of F-T and conventional jet fuel represent 5.24 percent of gross life cycle emissions. The transport of coal to the CBTL plant accounts for 4.53 percent of gross life cycle GHG emissions. Emissions from the pipeline transport of CO_2 represents approximately 2.20 percent of gross emissions. GHG emissions associated with biomass indirect land use change generate 1.44 percent of gross life cycle emissions, while biomass drying generates 0.57 percent. Other contributors to gross emissions were less than 1 percent individually.

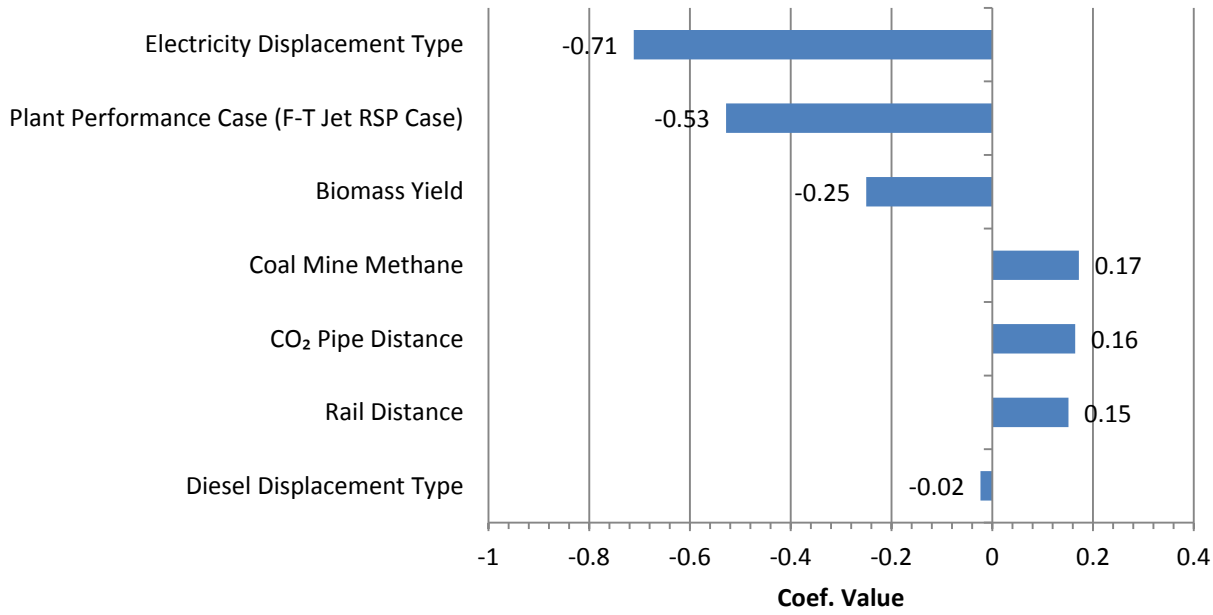
Figure 5-53: Scenario 9: CBTL, 11.7% Chipped Biomass, Validated: LC GHG Emissions Breakdowns



** Includes CO_2 Compression*
*** Includes conventional jet fuel profile*

The error bars shown in **Figure 5-53** reflect variability in model output based on the stochastic analyses (for more information, refer to Chapter 1). The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-6**. As shown, variability in emissions resulted primarily from the type of electricity displacement used. Other key contributors to variability in model output include the F-T jet fuel RSP case, and biomass yield. **Figure 5-54** summarizes the key factors contributing to variability identified in the model sensitivity analysis, for GHG emissions. Values provided in the figure show the correlation coefficient between the indicated parameter and total life cycle GHG emissions. Other important factors include coal mine methane emissions, the blended jet fuel pipe length, the rail transport distance, and the diesel displacement type. Other parameters had minimal to negligible effect on life cycle GHG emissions.

Figure 5-54: Scenario 9: CBTL, 11.7% Chipped Biomass, Validated: LC GHG Emissions Sensitivity



In addition to GHG emissions, other life cycle environmental emissions and flows were also considered. **Table 5-36** provides a summary of these flows. As shown, Airplane operation is the primary source of carbon monoxide and NOx within the life cycle. Particulate matter (PM_{10}) derives primarily from the combustion of diesel under raw materials transport and product transport operations. Non-methane volatile organic carbons (NMVOCs) result from product transport, including upstream conventional jet fuel emissions, and end use. The highest levels of mercury emissions occur during energy conversion and end use. Most water consumption occurs during biomass cultivation. Note that mass units displayed for water consumption (kg/MJ jet fuel) are equivalent to volume units for water consumption (L/MJ jet fuel).

Table 5-36: Scenario 9: CBTL, 11.7% Chipped Biomass, Validated: Non-GHG Emissions

LC Stage	Carbon monoxide	NO_x	SO2	PM10	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	8.10E-05	2.29E-04	5.63E-05	2.68E-06	1.07E-05	3.70E-10	1.52E-05	3.00E+02	kg/MJ Jet Fuel
RMT	5.79E-04	5.24E-04	1.20E-04	6.67E-04	1.00E-04	3.94E-10	7.55E-06	1.92E-01	kg/MJ Jet Fuel
EC	-5.21E-04	-1.59E-03	-2.74E-03	-1.64E-04	-7.09E-04	5.74E-08	1.44E-05	-9.36E-01	kg/MJ Jet Fuel
PT	2.76E-04	4.38E-04	6.25E-04	3.28E-05	8.45E-04	5.80E-10	2.92E-06	1.08E+00	kg/MJ Jet Fuel
EU	7.72E-03	1.21E-02	5.56E-04	9.50E-07	7.72E-04	3.01E-08	7.16E-09	2.81E-02	kg/MJ Jet Fuel
Total	**8.13E-03**	**1.17E-02**	**-1.39E-03**	**5.40E-04**	**1.02E-03**	**8.88E-08**	**4.01E-05**	**3.00E+02**	**kg/MJ Jet Fuel**

5.10 Scenario 10: CBTL, 19.2 Percent Chipped Biomass and Validation

The purpose of this scenario is to evaluate potential process values, economic factors, and environmental emissions associated with the production of F-T jet fuels from a combination of 80.8 percent sub-bituminous coal and 19.2 percent chipped biomass. This scenario evaluates a 1:1 (volume) blend of F-T jet fuels and conventional U.S. average jet fuel, based on a 30-year study period. Coal feedstock is derived from the Rosebud seam in southern Montana, and is transported by train to the CBTL facility, located in the Southeastern U.S. Biomass feedstock is field-chipped Southern pine biomass, cultivated and harvested in the Southeastern U.S. and transported, via chip truck, to the CBTL facility. The F-T process employed uses a slurry-based iron catalyst using a single feed, oxygen blown Transport Reactor Integrated Gasifier (TRIG™; refer to Chapter 2 for additional discussion). Carbon dioxide is captured at the CBTL facility using a Selexol process to segregate carbon dioxide. Additional carbon dioxide is stripped from overhead gas downstream of the F-T synthesis process, using a methyldiethanolamine (MDEA) unit. Captured carbon dioxide is then routed to a purification and compression system, where it is compressed to a supercritical state. F-T jet fuel produced by the F-T facility is then conveyed to a blending facility, where it is blended with conventional jet fuel, and transported to an airport. Finally, the blended jet fuel is combusted in a jet airplane.

The following text provides a summary of process model, economic model, and environmental model results for this scenario.

5.10.1 Process Results

As discussed in Chapter 2, three Aspen Plus® model cases were run for this scenario: low RSP, expected RSP, and high RSP. Process summary results, both modeled and validated, for each of the three cases are reported in **Table 5-37**. Results obtained from the Aspen Plus® simulations are based on a 50,000 barrel per day (bpd) production rate for total F-T products (F-T jet fuel, F-T diesel, F-T naphtha, and F-T LPG) for the CBTL, 19.2 percent Chipped Biomass configuration under all three RSP cases. Fuel production breakdowns are minimally variable among the three RSP cases. For all three RSP cases, approximately 49 percent (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34 percent by volume of total products) being F-T naphtha. F-T jet fuel is produced by hydrocracking the F-T wax to a final boiling point of about 300°C. Hydrocracking also produces naphtha boiling range liquids and F-T LPG. Relatively smaller quantities of F-T diesel (10 percent of total products) and F-T LPG (7 percent of total products) are produced as a result of hydrocracking. These proportions assume that straight run F-T output would be sold as a product. Results from each of the three Aspen Plus® model cases were incorporated into the economic and environmental analyses, the results of which are displayed below. For additional information regarding the application of low, expected, and high RSP values to the stochastic analysis provided here, refer to Chapter 1.

Table 5-37: Scenario 10: CBTL, 19.2% Chipped Biomass: Process Summary

Property	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
CBTL Facility Design and Operating Data							
Plant Design Capacity	50,000	50,000	50,000	50,000	50,000	50,000	bpd
Plant Capacity Factor	85	85	90	90	92	92	%
Plant Efficiency, HHV	54	54	53	53	50	50	%
Carbon Capture Rate	88	88	89	89	90	90	%
Gasifier Modules	7	7	7	7	7	7	Count
F-T Modules	10	10	10	10	10	10	Count
CBTL Facility Inputs/Feed							
Coal Feed, Montana Rosebud, As Received	25,292	25,331	25,840	25,888	26,494	26,556	tons/ day
Biomass Feed, Southern Pine, As Received	8,065	8,077	8,039	8,054	8,242	8,261	tons/ day
Water Feed (Total Withdrawal)	14,561,218	14,632,188	14,373,672	14,455,063	14,074,245	14,115,526	gallons/day
CBTL Facility Outputs/Production							
F-T Jet Fuel Production	24,649	24,648	24,647	24,647	24,645	24,644	bpd
F-T Diesel Fuel Production	4,767	4,767	4,767	4,767	4,766	4,766	bpd
F-T Naphtha Production	16,973	16,972	16,972	16,971	16,970	16,970	bpd
F-T LPG Production	3,612	3,612	3,614	3,615	3,619	3,620	bpd
Total Liquid Product Output	50,000	50,000	50,000	50,000	50,000	50,000	bpd
Export Power	223	223	185	184	127	132	MW
CO2 Captured and Compressed	30,649	30,801	31,314	31,492	31,841	32,038	tons/ day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,297	49,297	49,294	49,294	49,290	49,288	bpd

CBTL facility fuels production capacity was fixed at 50,000 bpd for all three RSP cases. An expected capacity factor of 90 percent was included, ranging from 85 to 92 percent for low and high RSP cases, respectively. In the modeled case the overall expected plant efficiency of 52.7 percent (range of 50.5to 54.2 percent) is defined as the heating value of the liquid products (HHV basis), F-T LPG, and export power divided by the higher heating value of the input coal and biomass. In the validation case the overall expected plant efficiency is 52.6 percent (range of 50.4to 54.1 percent) , a variation of less than 1 percent from the modeled case. In the modeled case, makeup water for the CBTL facility, as modeled in Aspen Plus®, is estimated to be approximately 14.4 million gallons per day (mgd; expected RSP case), of which 96.2 percent (13.8mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.84 bbl water/bbl F-T product, based on the expected RSP modeled case. In the validated case, makeup water for the CBTL facility is estimated to be approximately 14.5 million gallons per day (mgd; expected RSP case), of which 96.3 percent (13.9mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.88 bbl water/bbl F-T product, based on the expected RSP validated case. Here there is strong agreement between the modeled and validated case with a variation of makeup water for the CBTL facility of 0.08 million gallon per day 0.56 percent) and a normalized variation of 0.04 bbl water/bbl F-T product (0.56 percent).

Under the modeled case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 127 to 223MW, with an expected value of 185 MW. Based on the expected RSP case, gross power production for the CBTL facility is 771 MW, including power generated from steam (539 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (246 MW), carbon dioxide compressors (92.7 MW), the Selexol unit (62.2 MW), hydrocarbon recovery/refrigeration (42.5 MW), and oxygen compression (31.9 MW). Total auxiliaries consume 586 MW, for a net power output of 185 MW under the expected RSP case.

Under the validated case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 132 to 223 MW, with an expected value of 184 MW. Based on the expected RSP case, gross power production for the CBTL facility is 774 MW, including power generated from steam (542 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (247 MW), carbon dioxide compressors (93.2 MW), the Selexol unit (62.5 MW), hydrocarbon recovery/refrigeration (43.4 MW), and oxygen compression (32.0 MW). Total auxiliaries consume 590 MW, for a net power output of 184 MW under the expected RSP case.

Carbon balance for both the modeled and validated case of the CBTL facility is shown in **Table 5-38**, for all three RSP cases. As shown, carbon inputs were within 0.2 percent of carbon outputs for each of the three RSP cases. Carbon dioxide produced during the production of fuels and electric power is separated from the syngas stream prior to entering the F-T unit. The Selexol unit and the MDEA unit both produce the concentrated CO_2 streams that are dehydrated and compressed to 2,200 psi for pipeline delivery and carbon management. Other flue gas streams containing CO_2 are vented to the atmosphere. These include the flue gases from the HRSG units and from the fired heaters that are utilized during the F-T process. For the expected RSP case, approximately 2 percent of total carbon (range of 1 percent for the low RSP case to 4 percent for the high RSP case) is output to slag/ash from the TRIG gasifier.

Table 5-38: Scenario 10: CBTL, 19.2% Chipped Biomass: Conversion Facility Carbon Balance

Input Flow	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
Coal Carbon	12,663	12,683	12,938	12,962	13,265	13,296	TPD
Biomass Carbon	2,464	2,468	2,456	2,460	2,518	2,524	TPD
Total Carbon Input	15,127	15,150	15,393	15,422	15,783	15,820	**TPD**
F-T Products	5,284	5,284	5,284	5,284	5,284	5,284	TPD
Slag/Ash	151	152	308	309	632	633	TPD
Stack Gas	1,009	996	960	946	908	895	TPD
Fuel Gas	274	268	249	242	221	214	TPD
WWTP	31	31	31	31	29	30	TPD
Carbon Capture, Sequestered	8,383	8,425	8,567	8,616	8,715	8,770	TPD
Total Carbon Output	**15,133**	**15,157**	**15,400**	**15,428**	**15,788**	**15,825**	**TPD**
Carbon Capture	**86.4**	**86.7**	**87.4**	**87.6**	**88.3**	**88.5**	**%**

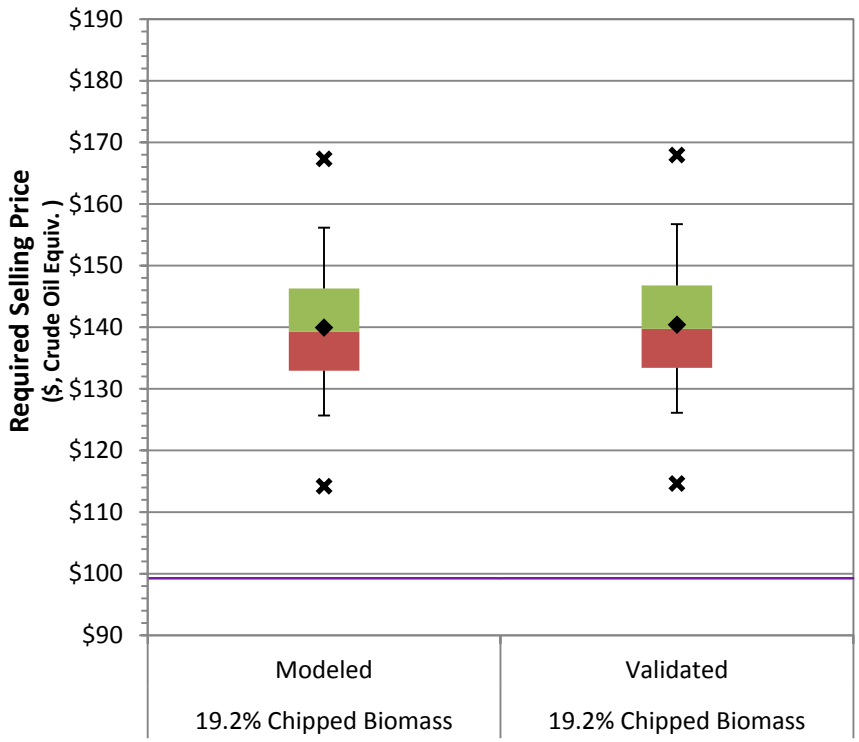
5.10.2 Economic Results

Results from the economic model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Figure 5-55 provides a summary of the estimated RSP for the F-T jet fuel produced under this scenario. As shown, RSP ranges from $133 to $146/bbl for the modeled case, with a mean value of $140/bbl, on a crude oil equivalent basis and for the variation, case the RSP ranges from $133 to $147/bbl, with a mean value of $140/bbl. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 40 economic parameters shown in **Table 1-5**. As shown, 25th and 75th percentile values are relatively close to the mean value, however, selling price distributions are characterized by long tails, with an overall range of $115 to $168/bbl, on a crude oil equivalent basis.

Cost of the F-T jet fuel product is estimated on a crude oil equivalent basis. This is defined as the RSP of the diesel product divided by a factor of 1.1433. Thus if the average world oil price were below or equal to the calculated crude oil equivalent price the CBTL plant would be economically viable. Key contributors to the variability shown for RSP results are discussed below.

Figure 5-55: Scenario 10: CBTL, 19.2% Chipped Biomass: F-T Jet Fuel RSP, Crude Oil Equivalent Basis



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel spot price value.

It is clear from **Figure 5-55** that there is minimal variation between the modeled and validated RSP results. **Table 5-39** provides a summary of the economic estimated performance of the CBTL facility under the validated case of this scenario, including the key contributing factors to the calculation of RSP. Total operating and maintenance costs represent an average of $578 million/yr. Of this amount, $328 to $357 million/yr, mean $343 million/yr (59.4 percent), results from fixed costs, while $226 to $234 million/year, mean $172 million/yr (40.6 percent) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, range from $8,981 to $9,849million, mean $9,423 million. Coal feedstock costs for this scenario range from $298 to $312million/yr, mean $305 million/yr. Biomass feedstock costs range from $61.2 to $66.4 million/yr, mean $63.8 million/yr. Total feedstock costs are approximately $209 million lower than total operating and maintenance costs, on average. Projected revenues include credits and product sales revenue. Power credit, from the sale of produced electricity, amounts to $95.4 to $108 million/yr, mean $99.9 million/yr, while CO_2 credit is estimated to be $339 to $403 million/yr, mean $371 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,130 to $2,345 million/yr, mean $2,240 million/yr.

Required product sales prices in the validated case are also provided in **Table 5-39**. Crude oil equivalent RSP is discussed above for **Figure 5-55**. On a straight basis, RSP for F-T jet fuel was calculated to be $154 to $170/bbl, mean $162/bbl, with F-T diesel at $153 to $168bbl, mean $161/bbl, F-T naphtha at $106 to $117/bbl, mean $112/bbl, and F-T LPG at $61.6 to $67.8/bbl, mean $64.9/bbl. The default capital charge factor (CCF) used in the analysis was 0.1872.

Table 5-39: Scenario 10: CBTL, 19.2% Chipped Biomass: Summary of Economics

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	355	294	423	339	369	$MM/yr
Variable Operating and Maintenance Cost (VOM)	236	203	281	228	245	$MM/yr
Capital: Total Overnight Cost (TOC)	9,530	8,089	11,691	9,085	9,965	$MM
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	277	254	302	271	283	$MM/yr
Biomass Cost, Southern Pine, Chips, As Received	96	79	111	92	100	$MM/yr
Biomass Cost, Southern Pine, Torrefied, As Received	0	0	0	0	0	$MM/yr
Credits and Revenue						
Power Credit	(88)	(124)	(48)	(97)	(86)	$MM/yr
Credit @ $40/ton for CO_2	(374)	(480)	(263)	(405)	(341)	$MM/yr
Annual Revenue Required	2,287	1,862	2,773	2,175	2,394	$MM/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	166	135	198	157	173	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	164	134	196	156	171	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	114	93	137	108	119	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	66	54	79	63	69	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	143	117	172	136	150	$/bbl

Figure 5-56 provides breakdowns for the cost factors in the validated case that contribute to the RSP. As shown, capital cost is the primary factor in determining RSP, and accounts for approximately 78.7 percent of total RSP, or $111/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 22.5 percent of total RSP, or $31.7/bbl, while feedstock costs represent 14.4 percent of total RSP, or $20.2/bbl, on a crude oil equivalent basis. As shown, variability in total RSP is driven largely by potential variability in capital costs, and to a much lesser extent by variability in operations and maintenance and feedstock costs. The negative credits bar comprises the sale of the co-produced electricity and compressed CO_2. Electricity accounts for 19.1 percent of the total credit, while captured and compressed CO_2 accounts for 80.9 percent.

Figure 5-56: Scenario 10: CBTL, 19.2% Chipped Biomass, Validated: RSP, Crude Oil Equivalent Basis

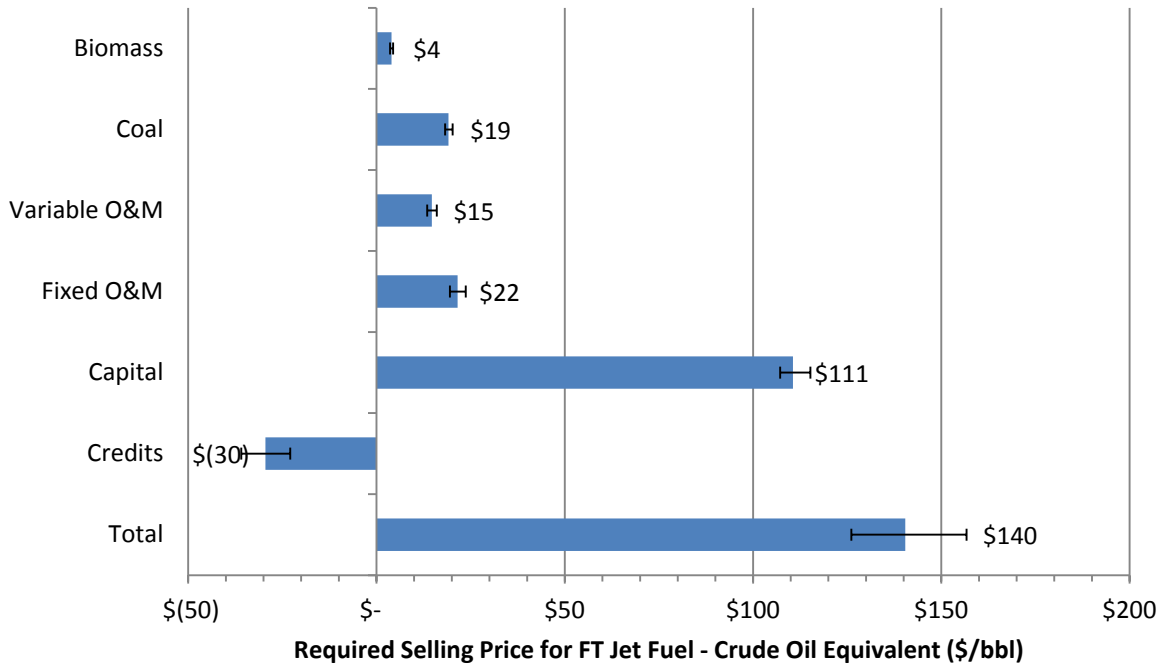
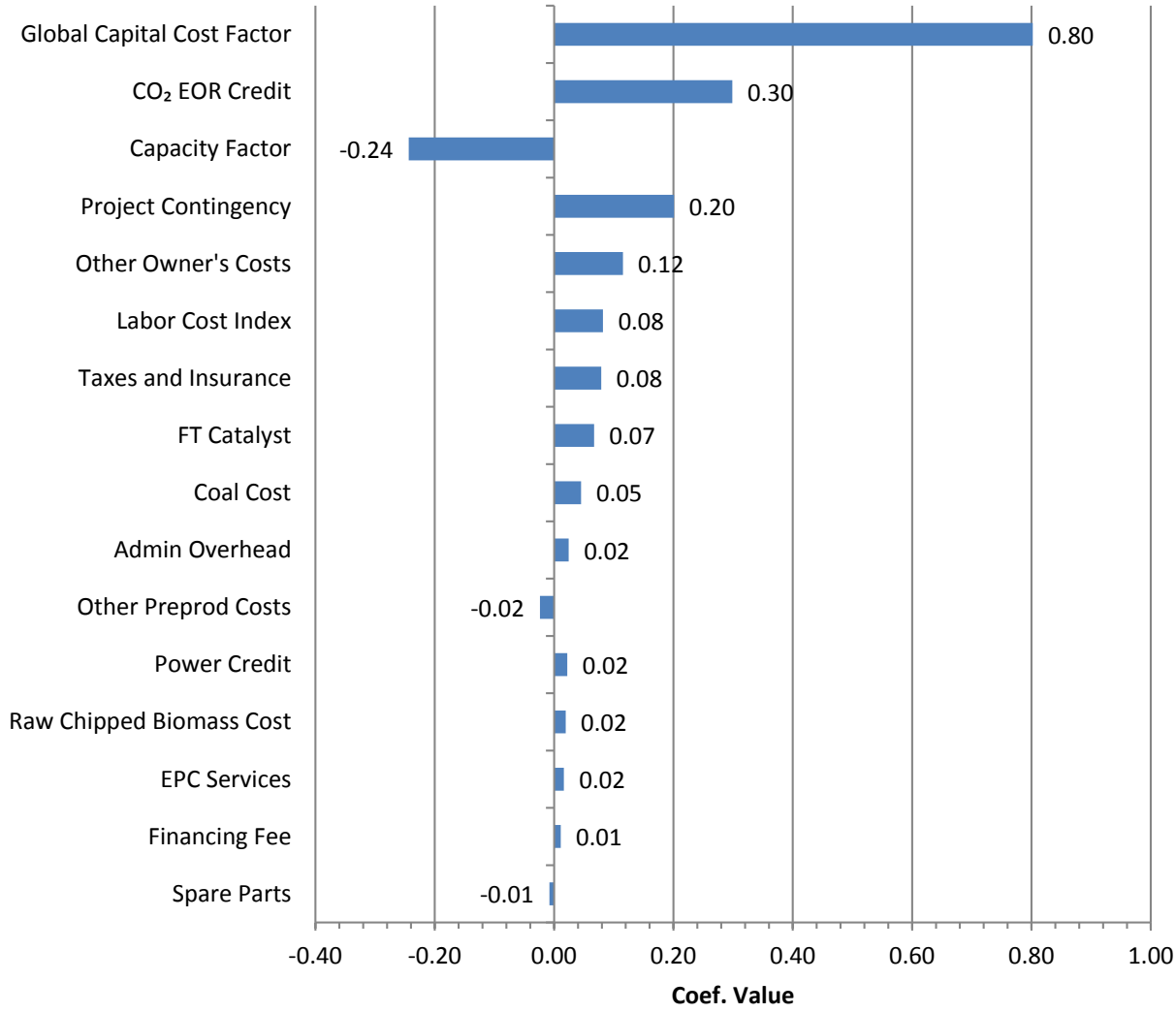


Figure 5-57 provides a summary of model sensitivity in the validated case, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.80. Other key factors that account for at least 10 percent of the observed variability in RSP include the CO_2 EOR credit, capacity factor, project contingency and other owner's costs. Parameters that caused minimal influence on RSP included EPC services, administrative overhead expenditures, financing fees, the cost of raw chipped biomass, and others as shown.

Figure 5-57: Scenario 10: CBTL, 19.2% Chipped Biomass, Validated: Sensitivity of RSP to Modeled Variables

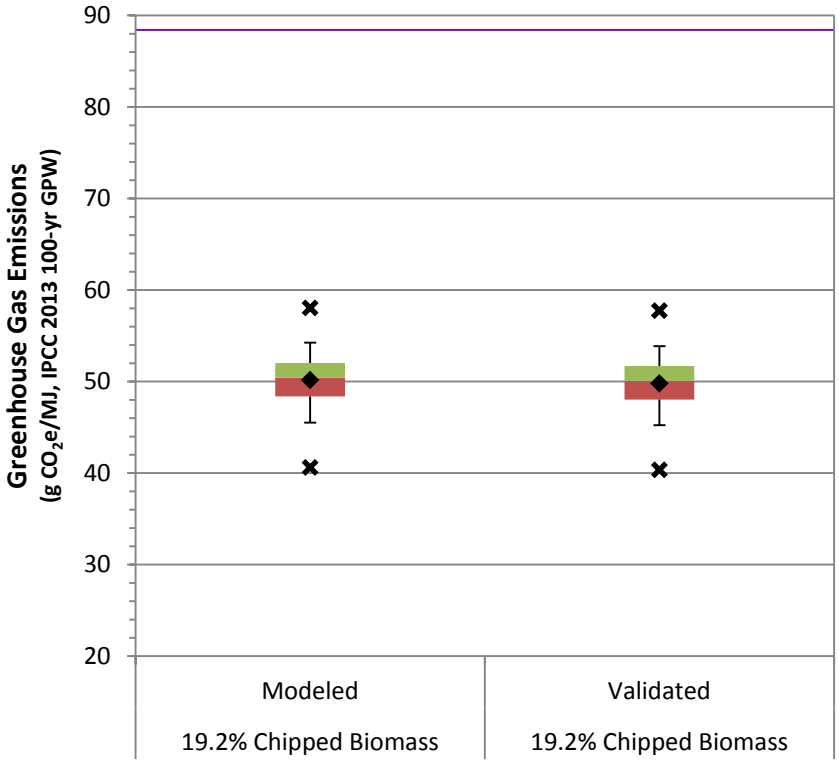


5.10.3 Environmental Results

Results from the environmental model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Results from the environmental life cycle analysis include GHG emissions and other emissions, including select criteria air pollutants, other pollutants of concern, and water consumption. **Figure 5-58** provides a summary life cycle GHG emissions for this scenario, in comparison to conventional jet fuel life cycle GHG emissions of 88.41 g CO_2e/MJ. In the modeled case the resulting range is 48.4 to 52.0 g CO_2e/MJ, mean 50.2 g CO_2e/MJ or approximately 42.6 percent less than conventional jet fuel. In the validated case the resulting range is 48.0 to 51.7 g CO_2e/MJ, mean 49.8 g CO_2e/MJ or approximately 43.0 percent less than conventional jet fuel.

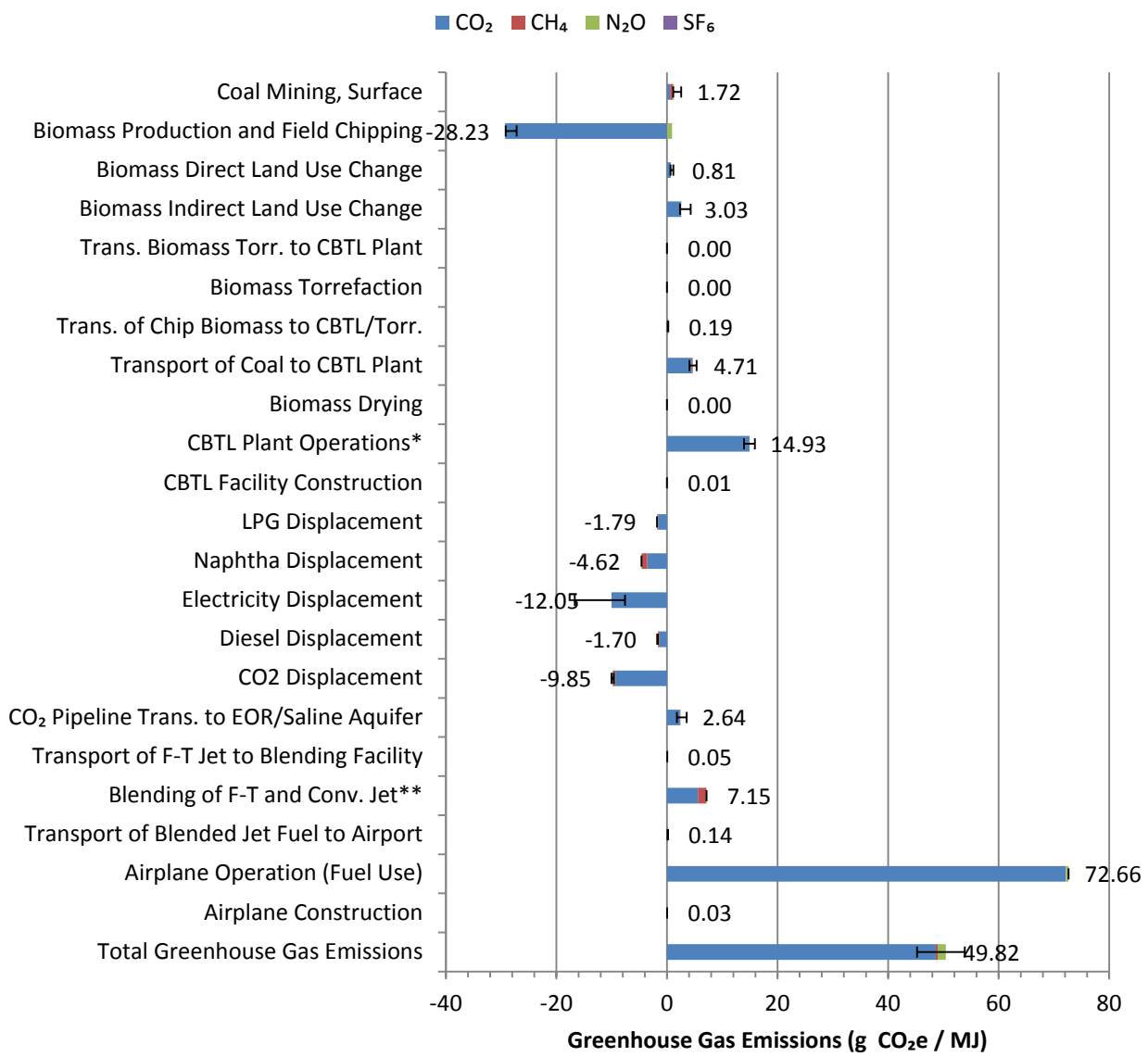
Figure 5-58: Scenario 10: CBTL, 19.2% Chipped Biomass, Validated: Summary of LC GHG Emissions



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

It is clear from **Figure 5-58** that there is minimal variation between the modeled and validated LC GHG emission results. **Figure 5-59** provides detail regarding the importance of the various LCA components in the validated case that were modeled, with respect to gross GHG emissions contributions. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 66.8 percent of gross life cycle GHG emissions. Second in importance to fuel combustion is CBTL plant operations, at 13.8 percent of gross life cycle emissions, while emissions associated with blending of F-T and conventional jet fuel represent 5.19 percent of gross life cycle emissions. The transport of coal to the CBTL plant accounts for 4.18 percent of gross life cycle GHG emissions. Emissions from biomass indirect land use change represent approximately 2.38 percent of gross emissions. GHG emissions associated with pipeline transport of CO_2 generates 2.19 percent of gross life cycle emissions, while biomass drying generates 0.64 percent. Other contributors to gross emissions were less than 1 percent individually.

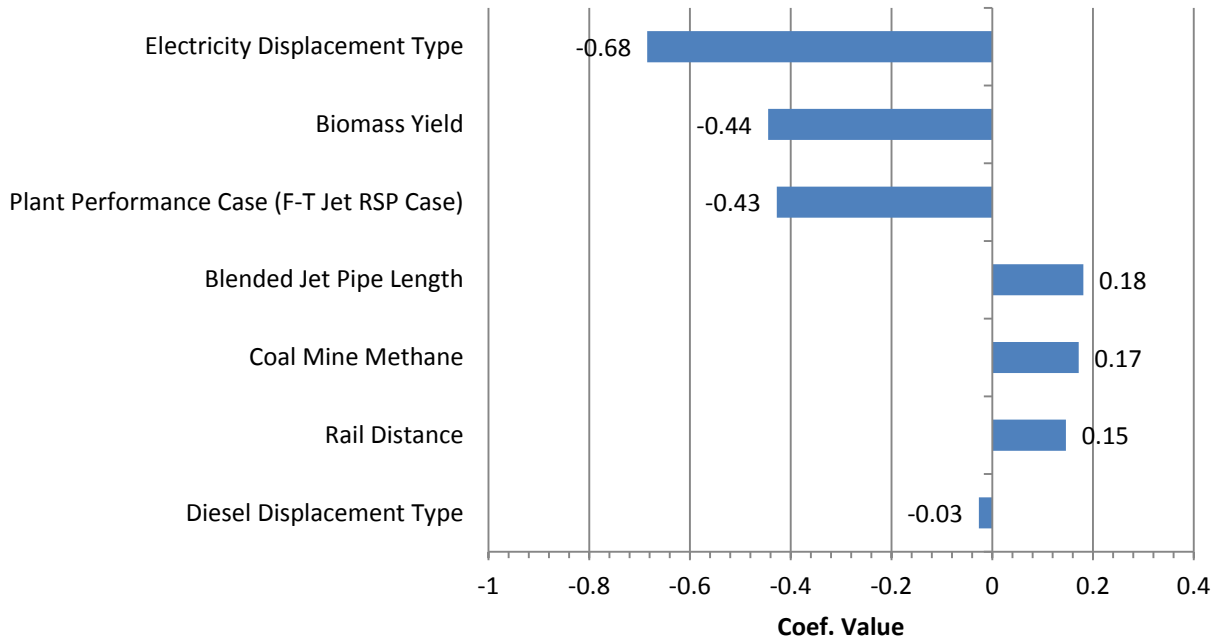
Figure 5-59: Scenario 10: CBTL, 19.2% Chipped Biomass, Validated: LC GHG Emissions Breakdowns



** Includes CO_2 Compression*
*** Includes conventional jet fuel profile*

The error bars shown in **Figure 5-59** reflect variability in model output based on the stochastic analyses (for more information, refer to Chapter 1). The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-6**. As shown, variability in emissions resulted primarily from the type of electricity displacement used. Other key contributors to variability in model output include biomass yield, and the F-T jet fuel RSP case. **Figure 5-60** summarizes the key factors contributing to variability identified in the model sensitivity analysis, for GHG emissions. Values provided in the figure show the correlation coefficient between the indicated parameter and total life cycle GHG emissions. Other important factors included the blended jet fuel pipe length, coal mine methane emissions, the rail transport distance and the diesel displacement type. Other parameters had minimal to negligible effect on life cycle GHG emissions.

Figure 5-60: Scenario 10: CBTL, 19.2% Chipped Biomass, Validated: LC GHG Emissions Sensitivity



In addition to GHG emissions, other life cycle environmental emissions and flows were also considered. **Table 5-40** provides a summary of these flows. As shown, Airplane operation is the primary source of carbon monoxide and NOx within the life cycle. Particulate matter (PM_{10}) derives primarily from the combustion of diesel under raw materials transport and product transport operations. Non-methane volatile organic carbons (NMVOCs) result from product transport, including upstream conventional jet fuel emissions, and end use. The highest levels of mercury emissions occur during energy conversion and end use. Most water consumption occurs during biomass cultivation. Note that mass units displayed for water consumption (kg/MJ jet fuel) are equivalent to volume units for water consumption (L/MJ jet fuel).

Table 5-40: Scenario 10: CBTL, 19.2% Chipped Biomass, Validated: Non-GHG Emissions

LC Stage	Carbon monoxide	NO_x	SO2	PM10	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	1.23E-04	2.48E-04	8.03E-05	3.11E-06	9.96E-06	3.99E-10	2.41E-05	5.01E+02	kg/MJ Jet Fuel
RMT	5.47E-04	4.90E-04	1.14E-04	6.22E-04	9.50E-05	4.20E-10	7.05E-06	1.88E-01	kg/MJ Jet Fuel
EC	-5.17E-04	-1.56E-03	-2.69E-03	-1.55E-04	-7.07E-04	5.31E-08	1.44E-05	-7.70E-01	kg/MJ Jet Fuel
PT	2.76E-04	4.38E-04	6.25E-04	3.28E-05	8.45E-04	5.80E-10	2.92E-06	1.08E+00	kg/MJ Jet Fuel
EU	7.72E-03	1.21E-02	5.56E-04	9.50E-07	7.72E-04	3.01E-08	7.16E-09	2.81E-02	kg/MJ Jet Fuel
Total	**8.15E-03**	**1.17E-02**	**-1.32E-03**	**5.04E-04**	**1.02E-03**	**8.45E-08**	**4.85E-05**	**5.02E+02**	**kg/MJ Jet Fuel**

5.11 Scenario 11: CBTL, 28.3 Percent Chipped Biomass and Validation

The purpose of this scenario is to evaluate potential process values, economic factors, and environmental emissions associated with the production of F-T jet fuels from a combination of 71.7 percent sub-bituminous coal and 28.3 percent chipped biomass. This scenario evaluates a 1:1 (volume) blend of F-T jet fuels and conventional U.S. average jet fuel, based on a 30-year study period. Coal feedstock is derived from the Rosebud seam in southern Montana, and is transported by train to the CBTL facility, located in the Southeastern U.S. Biomass feedstock is field-chipped Southern pine biomass, cultivated and harvested in the Southeastern U.S. and transported, via chip truck, to the CBTL facility. The F-T process employed uses a slurry-based iron catalyst using a single feed, oxygen blown Transport Reactor Integrated Gasifier (TRIG™; refer to Chapter 2 for additional discussion). Carbon dioxide is captured at the CBTL facility using a Selexol process to segregate carbon dioxide. Additional carbon dioxide is stripped from overhead gas downstream of the F-T synthesis process, using a methyldiethanolamine (MDEA) unit. Captured carbon dioxide is then routed to a purification and compression system, where it is compressed to a supercritical state. F-T jet fuel produced by the F-T facility is then conveyed to a blending facility, where it is blended with conventional jet fuel, and transported to an airport. Finally, the blended jet fuel is combusted in a jet airplane.

The following text provides a summary of process model, economic model, and environmental model results for this scenario.

5.11.1 Process Results

As discussed in Chapter 2, three Aspen Plus® model cases were run for this scenario: low RSP, expected RSP, and high RSP. Process summary results, both modeled and validated, for each of the three cases are reported in **Table 5-41**. Results obtained from the Aspen Plus® simulations are based on a 50,000 barrel per day (bpd) production rate for total F-T products (F-T jet fuel, F-T diesel, F-T naphtha, and F-T LPG) for the CBTL, 28.3 percent Chipped Biomass configuration under all three RSP cases. Fuel production breakdowns are minimally variable among the three RSP cases. For all three RSP cases, approximately 49 percent (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34 percent by volume of total products) being F-T naphtha. F-T jet fuel is produced by hydrocracking the F-T wax to a final boiling point of about 300°C. Hydrocracking also produces naphtha boiling range liquids and F-T LPG. Relatively smaller quantities of F-T diesel (10 percent of total products) and F-T LPG (7 percent of total products) are produced as a result of hydrocracking. These proportions assume that straight run F-T output would be sold as a product. Results from each of the three Aspen Plus® model cases were incorporated into the economic and environmental analyses, the results of which are displayed below. For additional information regarding the application of low, expected, and high RSP values to the stochastic analysis provided here, refer to Chapter 1.

Table 5-41: Scenario 11: CBTL, 28.3% Chipped Biomass: Process Summary

Property	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
CBTL Facility Design and Operating Data							
Plant Design Capacity	50,000	50,000	50,000	50,000	50,000	50,000	bpd
Plant Capacity Factor	85	85	90	90	92	92	%
Plant Efficiency, HHV	54	54	52	52	50	50	%
Carbon Capture Rate	88	88	89	89	90	90	%
Gasifier Modules	7	7	7	7	7	7	Count
F-T Modules	10	10	10	10	10	10	Count
CBTL Facility Inputs/Feed							
Coal Feed, Montana Rosebud, As Received	22,960	22,995	23,476	23,520	24,038	24,094	tons/ day
Biomass Feed, Southern Pine, As Received	12,161	12,179	12,131	12,153	12,421	12,450	tons/ day
Water Feed (Total Withdrawal)	14,232,793	14,302,948	14,046,752	14,127,472	13,708,218	13,797,906	gallons/day
CBTL Facility Outputs/Production							
F-T Jet Fuel Production	24,649	24,648	24,647	24,647	24,645	24,644	bpd
F-T Diesel Fuel Production	4,767	4,767	4,767	4,767	4,766	4,766	bpd
F-T Naphtha Production	16,973	16,972	16,972	16,972	16,970	16,970	bpd
F-T LPG Production	3,612	3,612	3,614	3,615	3,619	3,620	bpd
Total Liquid Product Output	50,000	50,000	50,000	50,000	50,000	50,000	bpd
Export Power	204	203	166	165	101	100	MW
CO2 Captured and Compressed	30,938	31,089	31,538	31,715	32,000	32,197	tons/ day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,297	49,297	49,295	49,294	49,290	49,288	bpd

CBTL facility fuels production capacity was fixed at 50,000 bpd for all three RSP cases. An expected capacity factor of 90 percent was included, ranging from 85 to 92 percent for low and high RSP cases, respectively. In the modeled case the overall expected plant efficiency of 52.4 percent (range of 50.2to 53.9 percent) is defined as the heating value of the liquid products (HHV basis), F-T LPG, and export power divided by the higher heating value of the input coal and biomass. In the validation case the overall expected plant efficiency is 52.3 percent (range of 50.0 to 53.8 percent) , a variation of less than 1 percent from the modeled case. In the modeled case, makeup water for the CBTL facility, as modeled in Aspen Plus®, is estimated to be approximately 14.0 million gallons per day (mgd; expected RSP case), of which 96.9 percent (13.6 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.69 bbl water/bbl F-T product, based on the expected RSP modeled case. In the validated case, makeup water for the CBTL facility is estimated to be approximately 14.1 million gallons per day (mgd; expected RSP case), of which 97.0 percent (13.7 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.73 bbl water/bbl F-T product, based on the expected RSP validated case. Here there is strong agreement between the modeled and validated case with a variation of makeup water for the CBTL facility of 0.08 million gallon per day (0.57 percent) and a normalized variation of 0.04 bbl water/bbl F-T product (0.57 percent).

Under the modeled case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 101 to 204 MW, with an expected value of 166 MW. Based on the expected RSP case, gross power production for the CBTL facility is 759 MW, including power generated from steam (527 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (244 MW), carbon dioxide compressors (93.3 MW), the Selexol unit (62.9 MW), hydrocarbon recovery/refrigeration (42.3 MW), and oxygen compression (31.7 MW). Total auxiliaries consume 593 MW, for a net power output of 166 MW under the expected RSP case.

Under the validated case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 99.6 to 203 MW, with an expected value of 165 MW. Based on the expected RSP case, gross power production for the CBTL facility is 762 MW, including power generated from steam (530 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (245 MW), carbon dioxide compressors (93.7 MW), the Selexol unit (63.2 MW), hydrocarbon recovery/refrigeration (43.1 MW), and oxygen compression (31.8 MW). Total auxiliaries consume 597 MW, for a net power output of 165 MW under the expected RSP case.

Carbon balance for both the modeled and validated case of the CBTL facility is shown in **Table 5-42**, for all three RSP cases. As shown, carbon inputs were within 0.2 percent of carbon outputs for each of the three RSP cases. Carbon dioxide produced during the production of fuels and electric power is separated from the syngas stream prior to entering the F-T unit. The Selexol unit and the MDEA unit both produce the concentrated CO_2 streams that are dehydrated and compressed to 2,200 psi for pipeline delivery and carbon management. Other flue gas streams containing CO_2 are vented to the atmosphere. These include the flue gases from the HRSG units and from the fired heaters that are utilized during the F-T process. For the expected RSP case, approximately 2 percent of total carbon (range of 1 percent for the low RSP case to 4 percent for the high RSP case) is output to slag/ash from the TRIG gasifier.

Table 5-42: Scenario 11: CBTL, 28.3% Chipped Biomass: Conversion Facility Carbon Balance

Input Flow	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
Coal Carbon	11,496	11,513	11,754	11,776	12,036	12,063	TPD
Biomass Carbon	3,715	3,721	3,706	3,713	3,795	3,803	TPD
Total Carbon Input	15,211	15,234	15,460	15,489	15,830	15,867	**TPD**
F-T Products	5,284	5,284	5,284	5,284	5,284	5,284	TPD
Slag/Ash	152	153	310	310	634	635	TPD
Stack Gas	1,012	999	962	948	908	895	TPD
Fuel Gas	276	270	251	244	222	215	TPD
WWTP	31	30	30	31	31	30	TPD
Carbon Capture, Sequestered	8,462	8,503	8,628	8,677	8,758	8,813	TPD
Total Carbon Output	**15,216**	**15,239**	**15,465**	**15,495**	**15,837**	**15,872**	**TPD**
Carbon Capture	**86.5**	**86.7**	**87.4**	**87.6**	**88.3**	**88.5**	**%**

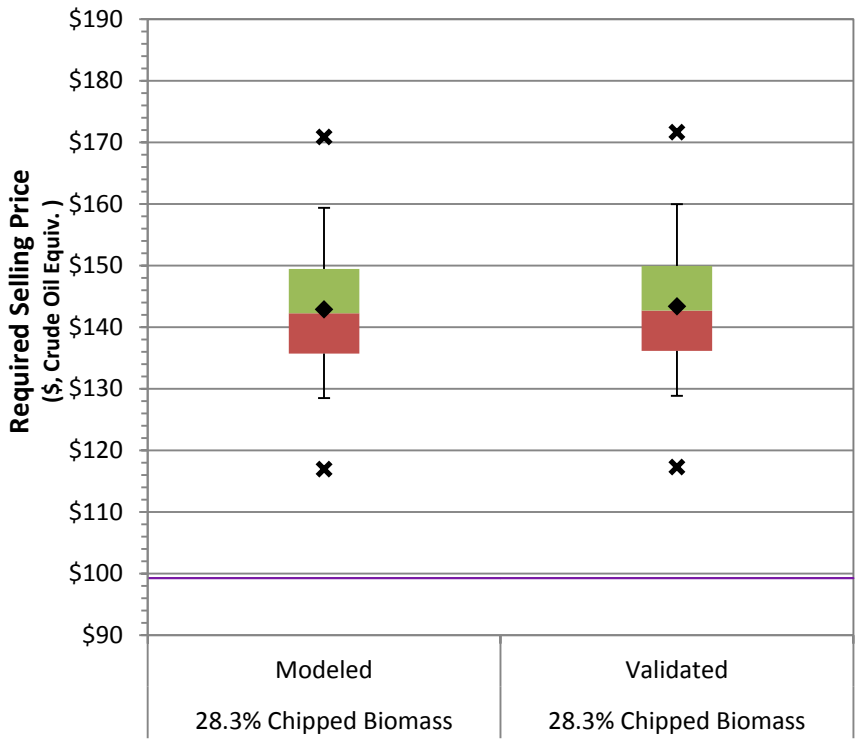
5.11.2 Economic Results

Results from the economic model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Figure 5-61 provides a summary of the estimated RSP for the F-T jet fuel produced under this scenario. As shown, RSP ranges from $136 to $149/bbl for the modeled case, with a mean value of $143/bbl, on a crude oil equivalent basis and for the variation, case the RSP ranges from $136 to $150/bbl, with a mean value of $143/bbl. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 40 economic parameters shown in **Table 1-5**. As shown, 25th and 75th percentile values are relatively close to the mean value, however, selling price distributions are characterized by long tails, with an overall range of $117 to $172/bbl, on a crude oil equivalent basis.

Cost of the F-T jet fuel product is estimated on a crude oil equivalent basis. This is defined as the RSP of the diesel product divided by a factor of 1.1433. Thus if the average world oil price were below or equal to the calculated crude oil equivalent price the CBTL plant would be economically viable. Key contributors to the variability shown for RSP results are discussed below.

Figure 5-61: Scenario 11: CBTL, 28.3% Chipped Biomass: F-T Jet Fuel RSP, Crude Oil Equivalent Basis



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel spot price value.

It is clear from **Figure 5-61** that there is minimal variation between the modeled and validated RSP results. **Table 5-43** provides a summary of the economic estimated performance of the CBTL facility under the validated case of this scenario, including the key contributing factors to the calculation of RSP. Total operating and maintenance costs represent an average of $591 million/yr. Of this amount, $339 to $369 million/yr, mean $355 million/yr (60.0 percent), results from fixed costs, while $228 to $245 million/year, mean $236 million/yr (40.0 percent) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, range from $9,085 to $9,965 million, mean $9,530 million. Coal feedstock costs for this scenario range from $271 to $283 million/yr, mean $277 million/yr. Biomass feedstock costs range from $92.4 to $100 million/yr, mean $96.3 million/yr. Total feedstock costs are approximately $218 million lower than total operating and maintenance costs, on average. Projected revenues include credits and product sales revenue. Power credit, from the sale of produced electricity, amounts to $85.6 to $96.5 million/yr, mean $87.9 million/yr, while CO_2 credit is estimated to be $341 to $405 million/yr, mean $374 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,175to $2,394 million/yr, mean $2,287 million/yr.

Required product sales prices in the validated case are also provided in **Table 5-43**. Crude oil equivalent RSP is discussed above for **Figure 5-61**. On a straight basis, RSP for F-T jet fuel was calculated to be $157 to $173/bbl, mean $166/bbl, with F-T diesel at $156 to $171/bbl, mean $164/bbl, F-T naphtha at $108 to $119/bbl, mean $114/bbl, and F-T LPG at $62.9 to $69.3/bbl, mean $66.2/bbl. The default capital charge factor (CCF) used in the analysis was 0.1872.

Table 5-43: Scenario 11: CBTL, 28.3% Chipped Biomass: Summary of Economics

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	355	294	423	339	369	$MM/yr
Variable Operating and Maintenance Cost (VOM)	236	203	281	228	245	$MM/yr
Capital: Total Overnight Cost (TOC)	9,530	8,089	11,691	9,085	9,965	$MM
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	277	254	302	271	283	$MM/yr
Biomass Cost, Southern Pine, Chips, As Received	96	79	111	92	100	$MM/yr
Biomass Cost, Southern Pine, Torrefied, As Received	0	0	0	0	0	$MM/yr
Credits and Revenue						
Power Credit	(88)	(124)	(48)	(97)	(86)	$MM/yr
Credit @ $40/ton for CO_2	(374)	(480)	(263)	(405)	(341)	$MM/yr
Annual Revenue Required	2,287	1,862	2,773	2,175	2,394	$MM/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	166	135	198	157	173	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	164	134	196	156	171	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	114	93	137	108	119	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	66	54	79	63	69	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	143	117	172	136	150	$/bbl

Figure 5-62 provides breakdowns for the cost factors in the validated case that contribute to the RSP. As shown, capital cost is the primary factor in determining RSP, and accounts for approximately 78.0 percent of total RSP, or $112/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 22.6 percent of total RSP, or $32.4bbl, while feedstock costs represent 14.3 percent of total RSP, or $20.5/bbl, on a crude oil equivalent basis. As shown, variability in total RSP is driven largely by potential variability in capital costs, and to a much lesser extent by variability in operations and maintenance and feedstock costs. The negative credits bar comprises the sale of the co-produced electricity and compressed CO_2. Electricity accounts for 19.1 percent of the total credit, while captured and compressed CO_2 accounts for 80.9 percent.

Figure 5-62: Scenario 11: CBTL, 28.3% Chipped Biomass, Validated: RSP, Crude Oil Equivalent Basis

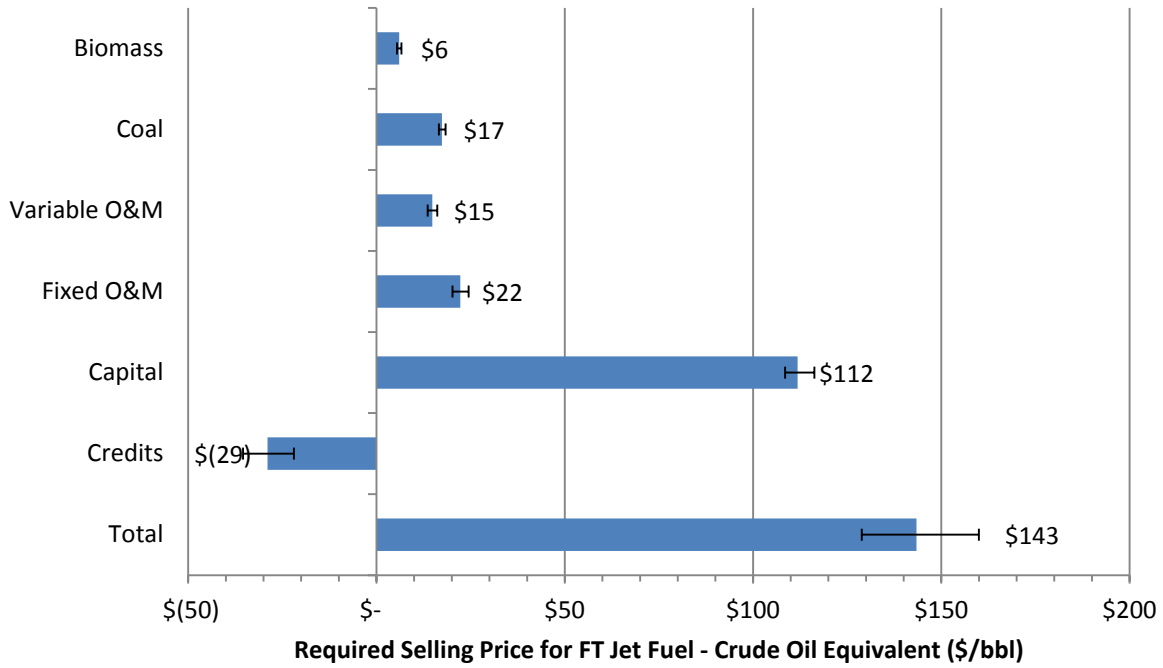
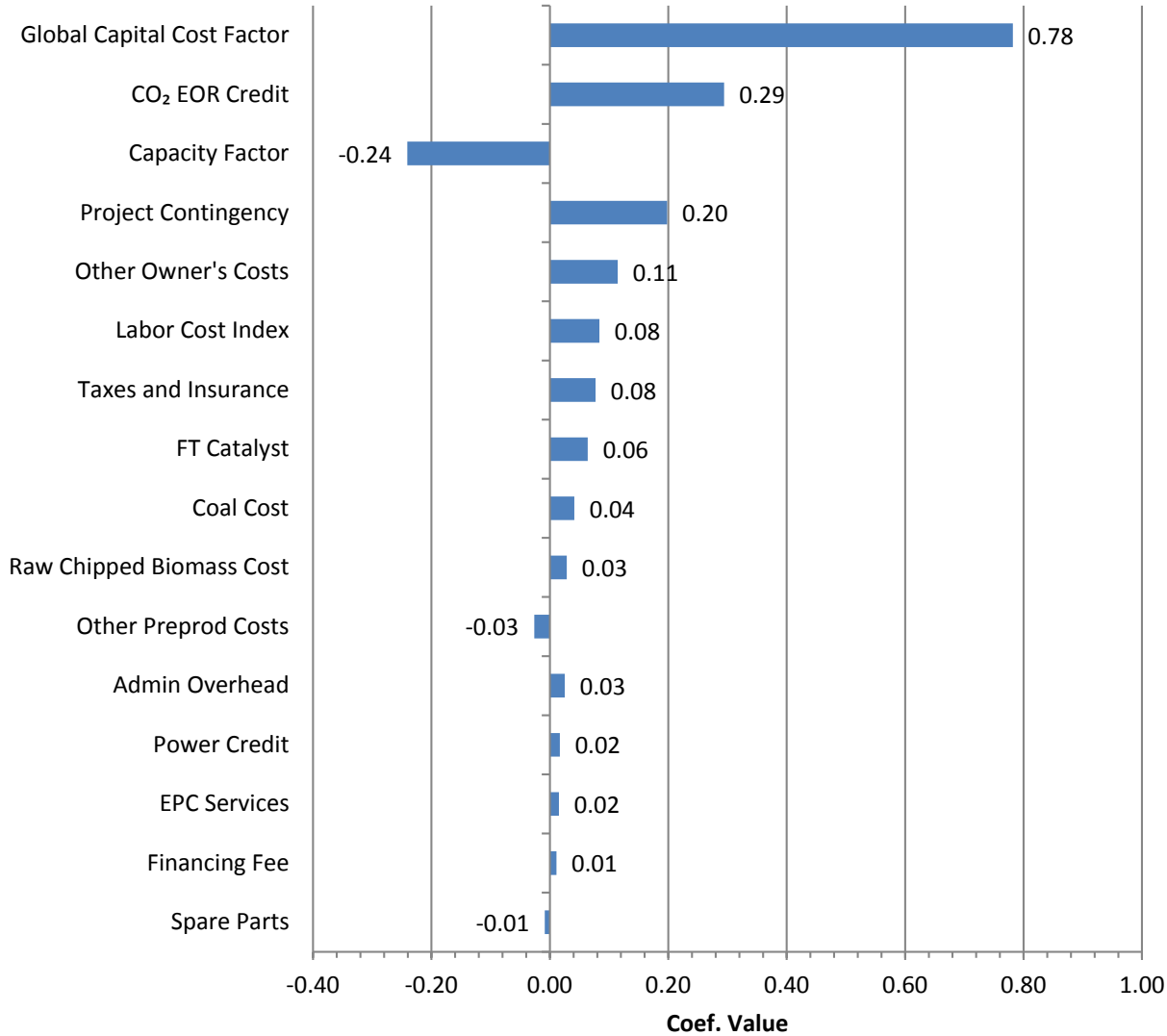


Figure 5-63 provides a summary of model sensitivity in the validated case, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.78. Other key factors that account for at least 10 percent of the observed variability in RSP include the CO_2 EOR credit, capacity factor, project contingency, and other owner's costs. Parameters that caused minimal influence on RSP included EPC services, other preproduction costs, financing fees, cost of spare parts, and others as shown.

Figure 5-63: Scenario 11: CBTL, 28.3% Chipped Biomass, Validated: Sensitivity of RSP to Modeled Variables

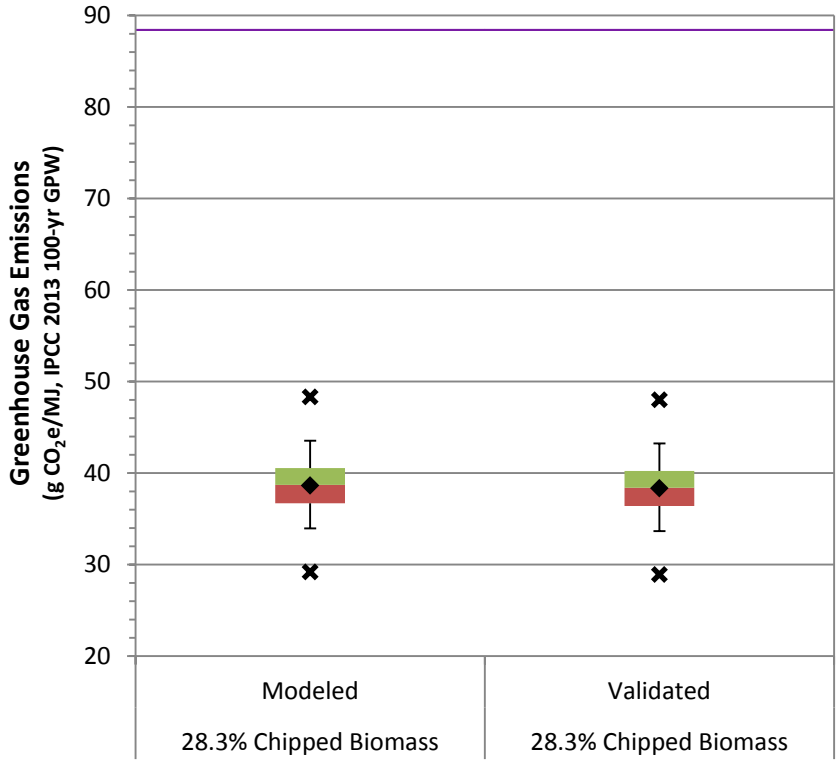


5.11.3 Environmental Results

Results from the environmental model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Results from the environmental life cycle analysis include GHG emissions and other emissions, including select criteria air pollutants, other pollutants of concern, and water consumption. **Figure 5-64** provides a summary life cycle GHG emissions for this scenario, in comparison to conventional jet fuel life cycle GHG emissions of 88.41 g CO_2e/MJ. In the modeled case the resulting range is 36.7 to 40.6 g CO_2e/MJ, mean 38.7 g CO_2e/MJ or approximately 55.8 percent less than conventional jet fuel. In the validated case the resulting range is 36.4 to 40.2 g CO_2e/MJ, mean 38.4 g CO_2e/MJ or approximately 56.1 percent less than conventional jet fuel.

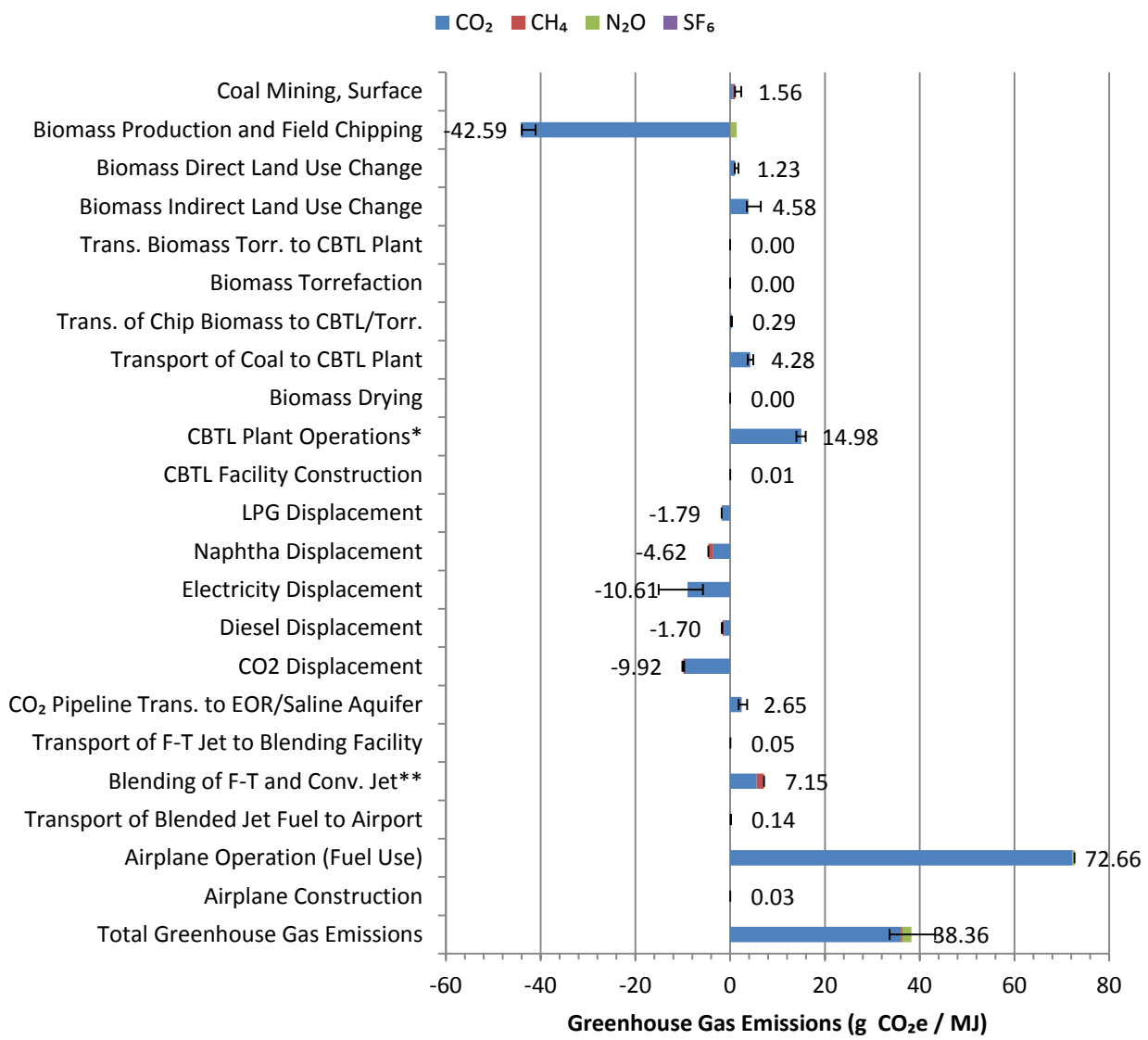
Figure 5-64: Scenario 11: CBTL, 28.3% Chipped Biomass, Validated: Summary of LC GHG Emissions



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

It is clear from **Figure 5-64** that there is minimal variation between the modeled and validated LC GHG emission results. **Figure 5-65** provides detail regarding the importance of the various LCA components in the validated case that were modeled, with respect to gross GHG emissions contributions. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 65.8 percent of gross life cycle GHG emissions. Second in importance to fuel combustion is CBTL plant operations, at 13.7 percent of gross life cycle emissions, while emissions associated with blending of F-T and conventional jet fuel represent 5.11 percent of gross life cycle emissions. The biomass indirect land use change accounts for 3.74 percent of gross life cycle GHG emissions. Emissions from the transport of coal to the CBTL plant represent approximately 3.54 percent of gross emissions. GHG emissions associated with biomass drying generate 2.18 percent of gross life cycle emissions, while pipeline transport of CO_2 and biomass direct land use change generate 0.96 percent and 0.47 percent respectively. Other contributors to gross emissions were less than 1 percent individually.

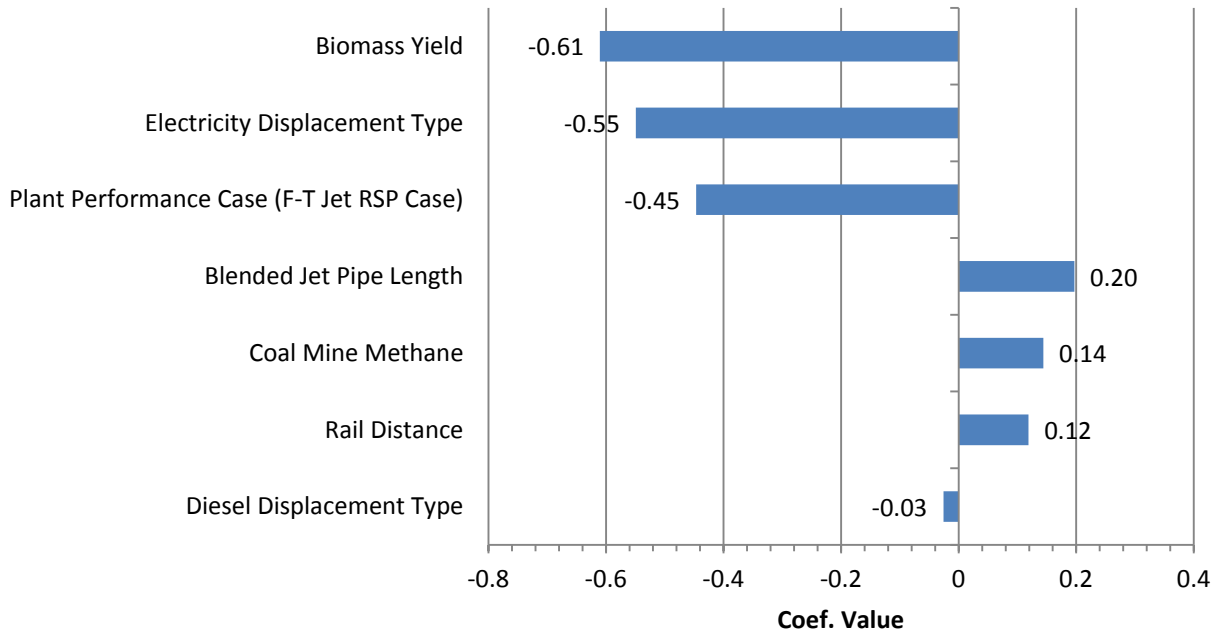
Figure 5-65: Scenario 11: CBTL, 28.3% Chipped Biomass, Validated: LC GHG Emissions Breakdowns



** Includes CO_2 Compression*
*** Includes conventional jet fuel profile*

The error bars shown in **Figure 5-65** reflect variability in model output based on the stochastic analyses (for more information, refer to Chapter 1). The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-6**. As shown, variability in emissions resulted primarily from biomass yield. Other key contributors to variability in the model are the type of electricity displacement used and the F-T jet fuel RSP case. **Figure 5-66** summarizes the key factors contributing to variability identified in the model sensitivity analysis, for GHG emissions. Values provided in the figure show the correlation coefficient between the indicated parameter and total life cycle GHG emissions. Other important factors included the blended jet fuel pipe length, the coal mine methane emissions, the rail transport distance and the diesel displacement type. Other parameters had minimal to negligible effect on life cycle GHG emissions.

Figure 5-66: Scenario 11: CBTL, 28.3% Chipped Biomass, Validated: LC GHG Emissions Sensitivity



In addition to GHG emissions, other life cycle environmental emissions and flows were also considered. **Table 5-44** provides a summary of these flows. As shown, Airplane operation is the primary source of carbon monoxide and NOx within the life cycle. Particulate matter (PM_{10}) derives primarily from the combustion of diesel under raw materials transport and product transport operations. Non-methane volatile organic carbons (NMVOCs) result from product transport, including upstream conventional jet fuel emissions, and end use. The highest levels of mercury emissions occur during energy conversion and end use. Most water consumption occurs during biomass cultivation. Note that mass units displayed for water consumption (kg/MJ jet fuel) are equivalent to volume units for water consumption (L/MJ jet fuel).

Table 5-44: Scenario 11: CBTL, 28.3% Chipped Biomass, Validated: Non-GHG Emissions

LC Stage	Carbon monoxide	NO_x	SO2	PM10	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	1.75E-04	2.73E-04	1.11E-04	3.66E-06	9.04E-06	4.36E-10	3.54E-05	7.57E+02	kg/MJ Jet Fuel
RMT	5.06E-04	4.47E-04	1.07E-04	5.66E-04	8.85E-05	4.54E-10	6.42E-06	1.82E-01	kg/MJ Jet Fuel
EC	-5.12E-04	-1.52E-03	-2.63E-03	-1.43E-04	-7.03E-04	4.76E-08	1.44E-05	-5.61E-01	kg/MJ Jet Fuel
PT	2.76E-04	4.38E-04	6.25E-04	3.28E-05	8.45E-04	5.80E-10	2.92E-06	1.08E+00	kg/MJ Jet Fuel
EU	7.72E-03	1.21E-02	5.56E-04	9.50E-07	7.72E-04	3.01E-08	7.16E-09	2.81E-02	kg/MJ Jet Fuel
Total	**8.16E-03**	**1.18E-02**	**-1.23E-03**	**4.60E-04**	**1.01E-03**	**7.92E-08**	**5.92E-05**	**7.57E+02**	**kg/MJ Jet Fuel**

5.12 Scenario 12: CBTL, 16.5 Percent Torrefied Biomass and Validation

The purpose of this scenario is to evaluate potential process values, economic factors, and environmental emissions associated with the production of F-T jet fuels from a combination of 83.5 percent sub-bituminous coal and 16.5 percent Torrefied Biomass. This scenario evaluates a 1:1 (volume) blend of F-T jet fuels and conventional U.S. average jet fuel, based on a 30-year study period. Coal feedstock is derived from the Rosebud seam in southern Montana, and is transported by train to the CBTL facility, located in the Southeastern U.S. Southern pine biomass feedstock is produced and harvested in the Southeastern U.S., field-chipped, and then transported by chip truck to a separate torrefaction facility, where the biomass is torrefied. Torrefaction increases energy density of the biomass, and greatly reduces grinding energy required, as discussed in greater detail in Chapter 4. Torrefied biomass is then transported by truck to the CBTL facility. The F-T process employed uses a slurry-based iron catalyst using a single feed, oxygen blown Transport Reactor Integrated Gasifier (TRIG™; refer to Chapter 2 for additional discussion). Carbon dioxide is captured at the CBTL facility using a Selexol process to segregate carbon dioxide. Additional carbon dioxide is stripped from overhead gas downstream of the F-T synthesis process, using a methyldiethanolamine (MDEA) unit. Captured carbon dioxide is then routed to a purification and compression system, where it is compressed to a supercritical state. F-T jet fuel produced by the F-T facility is then conveyed to a blending facility, where it is blended with conventional jet fuel, and transported to an airport. Finally, the blended jet fuel is combusted in a jet airplane.

The following text provides a summary of process model, economic model, and environmental model results for this scenario.

5.12.1 Process Results

As discussed in Chapter 2, three Aspen Plus® model cases were run for this scenario: low RSP, expected RSP, and high RSP. Process summary results, both modeled and validated, for each of the three cases are reported in **Table 5-45**. Results obtained from the Aspen Plus® simulations are based on a 50,000 barrel per day (bpd) production rate for total F-T products (F-T jet fuel, F-T diesel, F-T naphtha, and F-T LPG) for the CBTL, 16.5 percent Torrified Biomass configuration under all three RSP cases. Fuel production breakdowns are minimally variable among the three RSP cases. For all three RSP cases, approximately 49 percent (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34 percent by volume of total products) being F-T naphtha. F-T jet fuel is produced by hydrocracking the F-T wax to a final boiling point of about 300°C. Hydrocracking also produces naphtha boiling range liquids and F-T LPG. Relatively smaller quantities of F-T diesel (10 percent of total products) and F-T LPG (7 percent of total products) are produced as a result of hydrocracking. These proportions assume that straight run F-T output would be sold as a product. Results from each of the three Aspen Plus® model cases were incorporated into the economic and environmental analyses, the results of which are displayed below. For additional information regarding the application of low, expected, and high RSP values to the stochastic analysis provided here, refer to Chapter 1.

Table 5-45: Scenario 12: CBTL, 16.5% Torrefied Biomass: Process Summary

Property	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
CBTL Facility Design and Operating Data							
Plant Design Capacity	50,000	50,000	50,000	50,000	50,000	50,000	bpd
Plant Capacity Factor	85	85	90	90	92	92	%
Plant Efficiency, HHV	55	55	54	54	52	52	%
Carbon Capture Rate	88	88	89	89	90	90	%
Gasifier Modules	9	9	9	9	9	9	Count
F-T Modules	10	10	10	10	10	10	Count
CBTL Facility Inputs/Feed							
Coal Feed, Montana Rosebud, As Received	23,513	24,538	25,056	25,102	25,831	25,890	tons/ day
Biomass Feed, Southern Pine, As Received	5,318	4,499	4,482	4,490	4,511	4,521	tons/ day
Water Feed (Total Withdrawal)	14,655,377	14,818,999	14,560,878	14,639,913	14,354,612	14,442,909	gallons/day
CBTL Facility Outputs/Production							
F-T Jet Fuel Production	24,649	24,648	24,647	24,646	24,644	24,644	bpd
F-T Diesel Fuel Production	4,767	4,767	4,767	4,767	4,766	4,766	bpd
F-T Naphtha Production	16,973	16,973	16,972	16,971	16,970	16,969	bpd
F-T LPG Production	3,612	3,613	3,615	3,616	3,620	3,621	bpd
Total Liquid Product Output	50,001	50,001	50,000	50,000	50,000	50,000	bpd
Export Power	258	257	225	225	187	186	MW
CO2 Captured and Compressed	30,149	30,289	30,830	31,004	31,413	31,604	tons/ day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,297	49,297	49,294	49,293	49,288	49,287	bpd

CBTL facility fuels production capacity was fixed at 50,000 bpd for all three RSP cases. An expected capacity factor of 90 percent was included, ranging from 85 to 92 percent for low and high RSP cases, respectively. In the modeled case the overall expected plant efficiency of 53.8 percent (range of 51.8to 55.4 percent) is defined as the heating value of the liquid products (HHV basis), F-T LPG, and export power divided by the higher heating value of the input coal and biomass. In the validation case the overall expected plant efficiency is 53.7 percent (range of 51.7 to 55.3 percent) , a variation of less than1 percent from the modeled case. In the modeled case, makeup water for the CBTL facility, as modeled in Aspen Plus®, is estimated to be approximately 14.6 million gallons per day (mgd; expected RSP case), of which 96.5 percent (14.1 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.93 bbl water/bbl F-T product, based on the expected RSP modeled case. In the validated case, makeup water for the CBTL facility is estimated to be approximately 14.6 million gallons per day (mgd; expected RSP case), of which 96.6 percent (14.1 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.97 bbl water/bbl F-T product, based on the expected RSP validated case. Here there is strong agreement between the modeled and validated case with a variation of makeup water for the CBTL facility of 0.08 million gallon per day (0.54 percent) and a normalized variation of 0.04 bbl water/bbl F-T product (0.54 percent).

Under the modeled case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 187 to 258 MW, with an expected value of 225 MW. Based on the expected RSP case, gross power production for the CBTL facility is 791 MW, including power generated from steam (559 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (244 MW), carbon dioxide compressors (91.5 MW), the Selexol unit (61.5 MW), hydrocarbon recovery/refrigeration (43.5 MW), and oxygen compression (31.6 MW). Total auxiliaries consume 566 MW, for a net power output of 225 MW under the expected RSP case.

Under the validated case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 186 to 257 MW, with an expected value of 225 MW. Based on the expected RSP case, gross power production for the CBTL facility is 794 MW, including power generated from steam (562 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (245 MW), carbon dioxide compressors (91.9 MW), the Selexol unit (61.8 MW), hydrocarbon recovery/refrigeration (44.5 MW), and oxygen compression (31.7 MW). Total auxiliaries consume 570 MW, for a net power output of 225 MW under the expected RSP case.

Carbon balance for both the modeled and validated case of the CBTL facility is shown in **Table 5-46**, for all three RSP cases. As shown, carbon inputs were within 0.2 percent of carbon outputs for each of the three RSP cases. Carbon dioxide produced during the production of fuels and electric power is separated from the syngas stream prior to entering the F-T unit. The Selexol unit and the MDEA unit both produce the concentrated CO_2 streams that are dehydrated and compressed to 2,200 psi for pipeline delivery and carbon management. Other flue gas streams containing CO_2 are vented to the atmosphere. These include the flue gases from the HRSG units and from the fired heaters that are utilized during the F-T process. For the expected RSP case, approximately 2 percent of total carbon (range of 1 percent for the low RSP case to 4 percent for the high RSP case) is output to slag/ash from the TRIG gasifier.

Table 5-46: Scenario 12: CBTL, 16.5% Torrefied Biomass: Conversion Facility Carbon Balance

Input Flow	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
Coal Carbon	11,772	12,286	12,545	12,568	12,933	12,963	TPD
Biomass Carbon	3,185	2,695	2,684	2,689	2,701	2,708	TPD
Total Carbon Input	14,958	14,980	15,229	15,258	15,634	15,670	**TPD**
F-T Products	5,284	5,284	5,284	5,284	5,284	5,284	TPD
Slag/Ash	150	150	305	305	626	628	TPD
Stack Gas	986	976	939	925	888	876	TPD
Fuel Gas	266	260	241	234	213	206	TPD
WWTP	29	32	29	30	29	31	TPD
Carbon Capture, Sequestered	8,247	8,285	8,436	8,484	8,599	8,652	TPD
Total Carbon Output	**14,962**	**14,986**	**15,234**	**15,262**	**15,639**	**15,677**	**TPD**
Carbon Capture	**86.6**	**86.7**	**87.5**	**87.7**	**88.4**	**88.6**	**%**

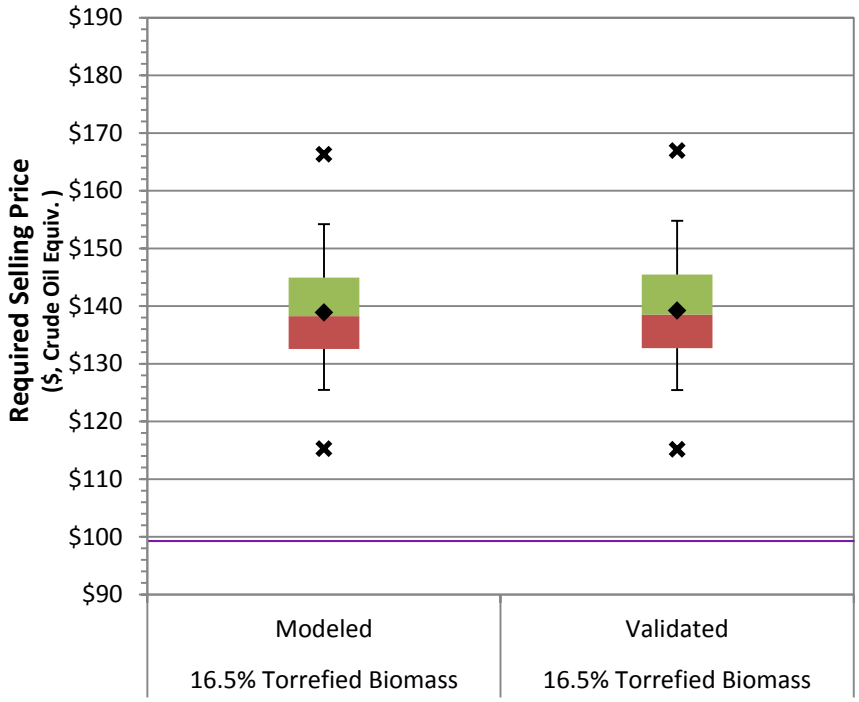
5.12.2 Economic Results

Results from the economic model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Figure 5-67 provides a summary of the estimated RSP for the F-T jet fuel produced under this scenario. As shown, RSP ranges from $133 to $145/bbl for the modeled case, with a mean value of $139/bbl, on a crude oil equivalent basis and for the variation, case the RSP ranges from $133 to $145/bbl, with a mean value of $139/bbl. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 40 economic parameters shown in **Table 1-5**. As shown, 25th and 75th percentile values are relatively close to the mean value, however, selling price distributions are characterized by long tails, with an overall range of $115 to $167/bbl, on a crude oil equivalent basis.

Cost of the F-T jet fuel product is estimated on a crude oil equivalent basis. This is defined as the RSP of the diesel product divided by a factor of 1.1433. Thus if the average world oil price were below or equal to the calculated crude oil equivalent price the CBTL plant would be economically viable. Key contributors to the variability shown for RSP results are discussed below.

Figure 5-67: Scenario 12: CBTL, 16.5% Torrefied Biomass: F-T Jet Fuel RSP, Crude Oil Equivalent Basis



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel spot price value.

It is clear from **Figure 5-67** that there is minimal variation between the modeled and validated RSP results. **Table 5-47** provides a summary of the economic estimated performance of the CBTL facility under the validated case of this scenario, including the key contributing factors to the calculation of RSP. Total operating and maintenance costs represent an average of $538 million/yr. Of this amount, $297 to $324 million/yr, mean $311 million/yr (57.9 percent), results from fixed costs, while $218 to $235 million/year, mean $227 million/yr (42.1 percent) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, range from $8,549 to $9,378 million, mean $8,974 million. Coal feedstock costs for this scenario range from $289 to $302 million/yr, mean $296 million/yr. Biomass feedstock costs range from $189 to $201 million/yr, mean $196 million/yr. Total feedstock costs are approximately $46.0 million lower than total operating and maintenance costs, on average. Projected revenues include credits and product sales revenue. Power credit, from the sale of produced electricity, amounts to $116 to $131 million/yr, mean $123 million/yr, while CO_2 credit is estimated to be $333 to $397 million/yr, mean $365 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,119 to $2,323 million/yr, mean $2,221 million/yr.

Required product sales prices in the validated case are also provided in **Table 5-47**. Crude oil equivalent RSP is discussed above for **Figure 5-67**. On a straight basis, RSP for F-T jet fuel was calculated to be $153 to $168/bbl, mean $161/bbl, with F-T diesel at $152 to $166/bbl, mean $159/bbl, F-T naphtha at $106 to $116/bbl, mean $111/bbl, and F-T LPG at $61.3 to $67.2/bbl, mean $64.3/bbl. The default capital charge factor (CCF) used in the analysis was 0.1872.

Table 5-47: Scenario 12: CBTL, 16.5% Torrefied Biomass: Summary of Economics

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	311	257	371	297	324	$MM/yr
Variable Operating and Maintenance Cost (VOM)	227	194	268	218	235	$MM/yr
Capital: Total Overnight Cost (TOC)	8,974	7,608	10,911	8,549	9,378	$MM
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	296	271	324	289	302	$MM/yr
Biomass Cost, Southern Pine, Chips, As Received	0	0	0	0	0	$MM/yr
Biomass Cost, Southern Pine, Torrefied, As Received	196	172	225	189	201	$MM/yr
Credits and Revenue						
Power Credit	(123)	(157)	(90)	(131)	(116)	$MM/yr
Credit @ $40/ton for CO_2	(365)	(471)	(258)	(397)	(333)	$MM/yr
Annual Revenue Required	2,221	1,829	2,641	2,119	2,323	$MM/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	161	133	193	153	168	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	159	132	191	152	166	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	111	92	133	106	116	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	64	53	77	61	67	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	139	115	167	133	145	$/bbl

Figure 5-68 provides breakdowns for the cost factors in the validated case that contribute to the RSP. As shown, capital cost is the primary factor in determining RSP, and accounts for approximately 75.6 percent of total RSP, or $105/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 21.2 percent of total RSP, or $29.5bbl, while feedstock costs represent 19.3 percent of total RSP, or $26.9/bbl, on a crude oil equivalent basis. As shown, variability in total RSP is driven largely by potential variability in capital costs, and to a much lesser extent by variability in operations and maintenance and feedstock costs. The negative credits bar comprises the sale of the co-produced electricity and compressed CO_2. Electricity accounts for 25.2 percent of the total credit, while captured and compressed CO_2 accounts for 74.8 percent.

Figure 5-68: Scenario 12: CBTL, 16.5% Torrefied Biomass, Validated: RSP, Crude Oil Equivalent Basis

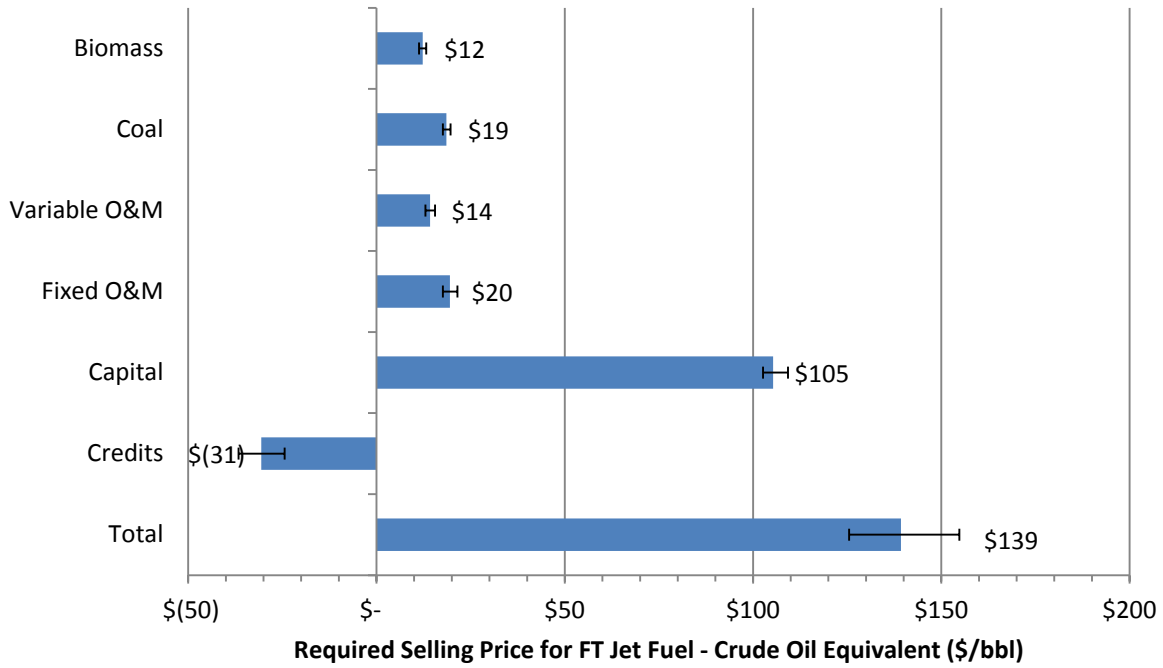
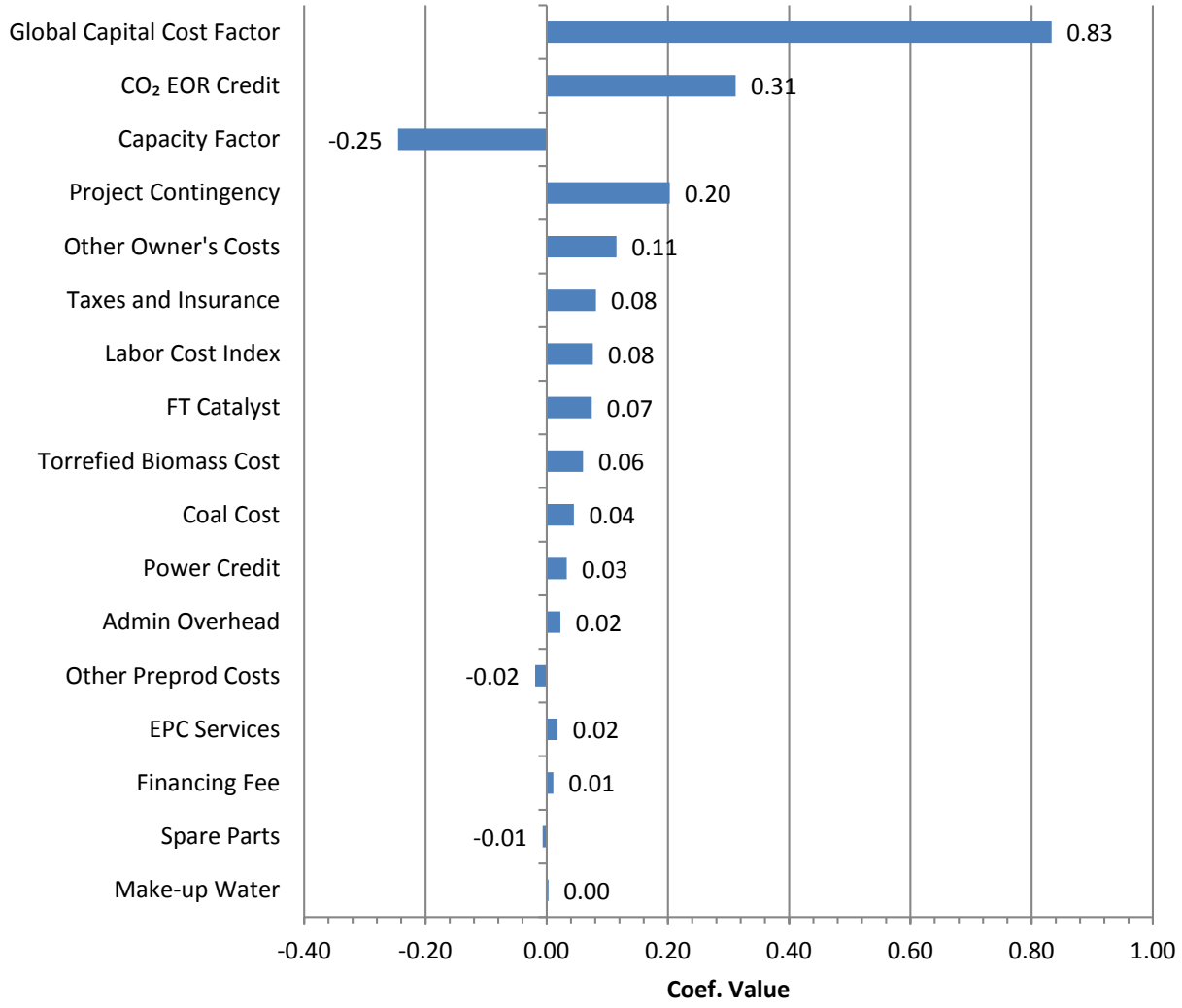


Figure 5-69 provides a summary of model sensitivity in the validated case, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.83. Other key factors that account for at least 10 percent of the observed variability in RSP include the CO_2 EOR credit, capacity factor, project contingency, and other owner's costs. Parameters that caused minimal influence on RSP included the cost of torrefied biomass, the coal cost, cost of spare parts, EPC services, power credits, and others as shown.

Figure 5-69: Scenario 12: CBTL, 16.5% Torrefied/Chipped Biomass, Validated: Sensitivity of RSP to Modeled Variables

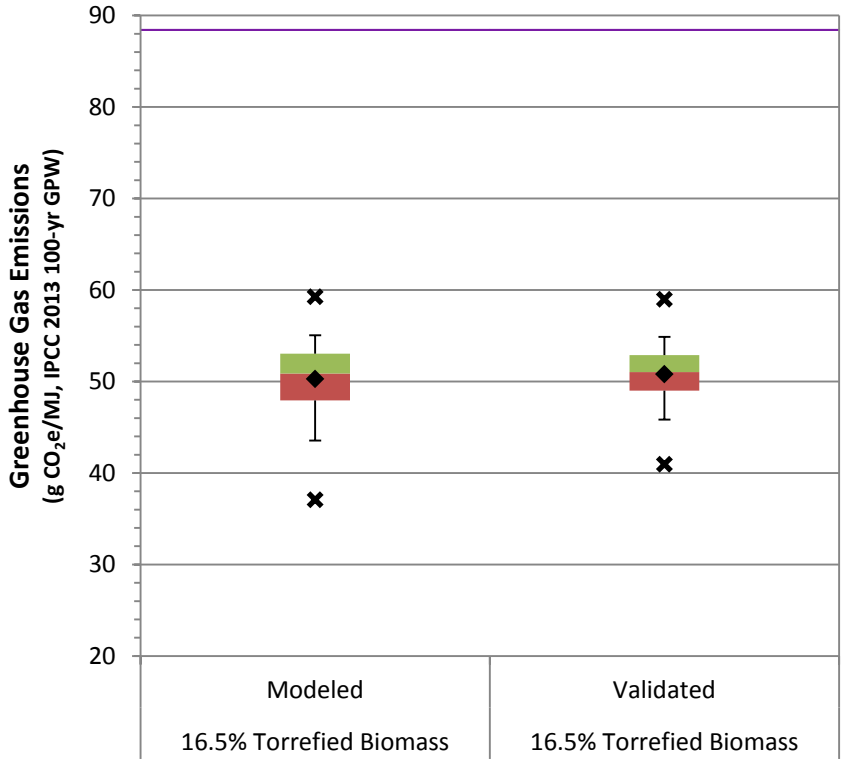


5.12.3 Environmental Results

Results from the environmental model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Results from the environmental life cycle analysis include GHG emissions and other emissions, including select criteria air pollutants, other pollutants of concern, and water consumption. **Figure 5-70** provides a summary life cycle GHG emissions for this scenario, in comparison to conventional jet fuel life cycle GHG emissions of 88.41 g CO_2e/MJ. In the modeled case the resulting range is 47.9 to 53.0 g CO_2e/MJ, mean 50.3 g CO_2e/MJ or approximately 42.5 percent less than conventional jet fuel. In the validated case the resulting range is 49.0 to 52.9 g CO_2e/MJ, mean 50.8 g CO_2e/MJ or approximately 41.9 percent less than conventional jet fuel.

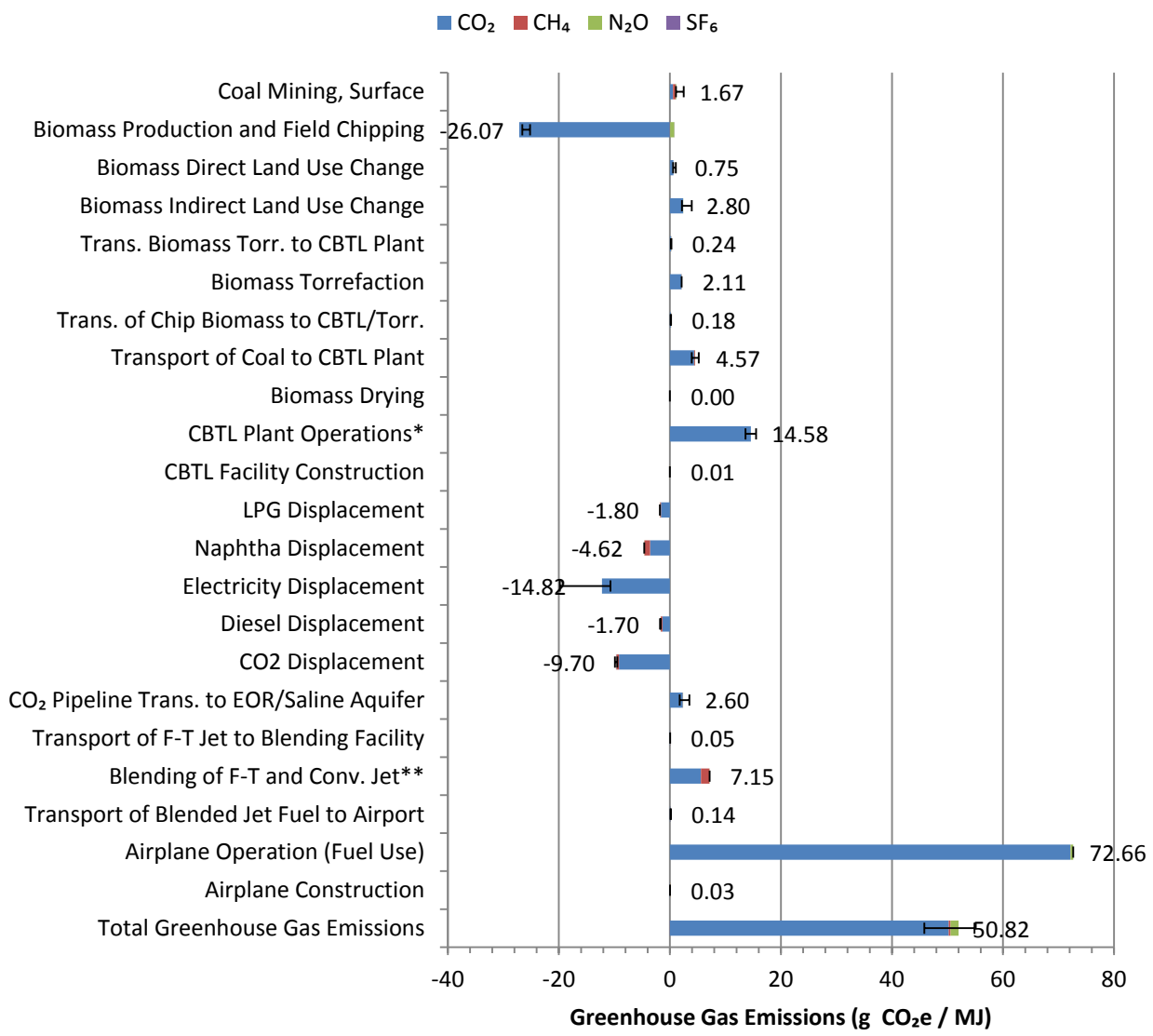
Figure 5-70: Scenario 12: CBTL, 16.5% Torrefied Biomass: Summary of LC GHG Emissions



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

It is clear from **Figure 5-70** that there is minimal variation between the modeled and validated LC GHG emission results. **Figure 5-71** provides detail regarding the importance of the various LCA components in the validated case that were modeled, with respect to gross GHG emissions contributions. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 65.9 percent of gross life cycle GHG emissions. Second in importance to fuel combustion is CBTL plant operations, at 13.3 percent of gross life cycle emissions, while emissions associated with blending of F-T and conventional jet fuel represent 5.12 percent of gross life cycle emissions. The transport of coal to the CBTL plant accounts for 4.00 percent of gross life cycle GHG emissions. Emissions from the pipeline transport of CO_2 represents approximately 2.18 percent of gross emissions. GHG emissions associated with biomass indirect land use change generate 2.13 percent of gross life cycle emissions, while the torrefaction of biomass generates 1.91 percent. Other contributors to gross emissions were less than 1 percent individually.

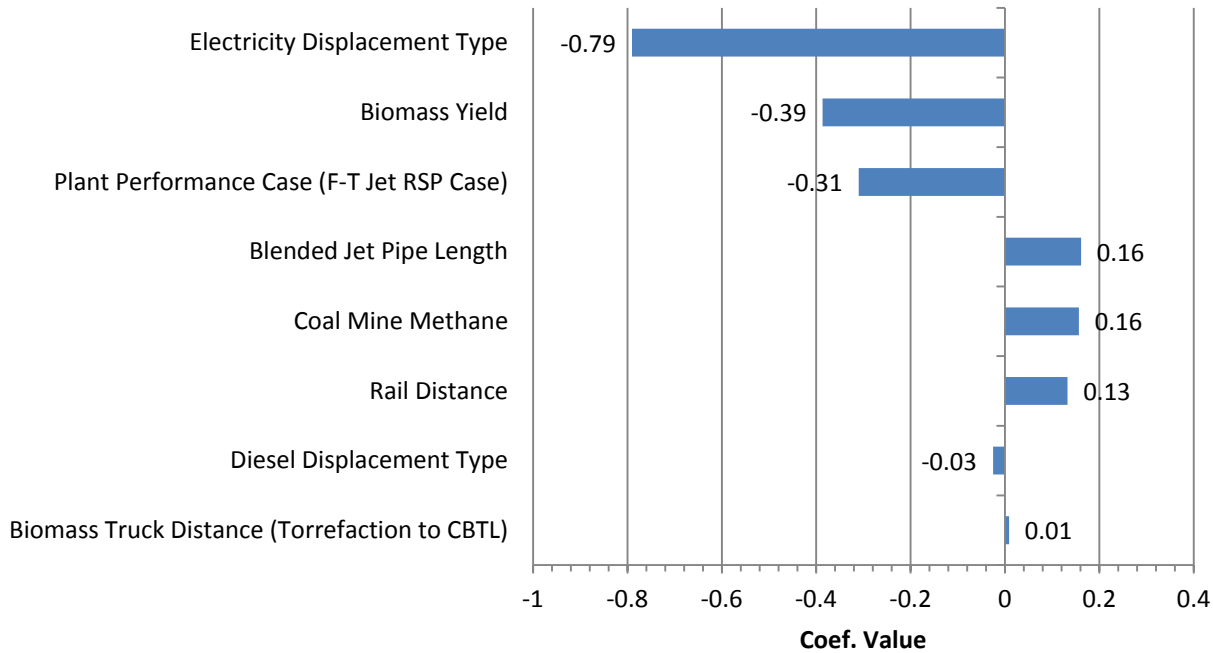
Figure 5-71: Scenario 12: CBTL, 16.5% Torrefied Biomass, Validated: LC GHG Emissions Breakdowns



** Includes CO_2 Compression*
*** Includes conventional jet fuel profile*

The error bars shown in **Figure 5-71** reflect variability in model output based on the stochastic analyses (for more information, refer to Chapter 1). The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-6.** As shown, variability in emissions resulted primarily from the type of electricity displacement used. Other key contributors to variability in model output include biomass yield, and the F-T jet fuel RSP case. **Figure 5-72** summarizes the key factors contributing to variability identified in the model sensitivity analysis, for GHG emissions. Values provided in the figure show the correlation coefficient between the indicated parameter and total life cycle GHG emissions. Other important factors included the blended jet fuel pipe length, the coal mine methane emissions, the rail transport distance, the diesel displacement type, and the biomass truck transport distance from the trorrefaction facility to the CBTL plant. Other parameters had minimal to negligible effect on life cycle GHG emissions.

Figure 5-72: Scenario 12: CBTL, 16.5% Torrefied Biomass, Validated: LC GHG Emissions Sensitivity



In addition to GHG emissions, other life cycle environmental emissions and flows were also considered. **Table 5-48** provides a summary of these flows. As shown, Airplane operation is the primary source of carbon monoxide and NOx within the life cycle. Particulate matter (PM_{10}) derives primarily from the combustion of diesel under raw materials transport and product transport operations. Non-methane volatile organic carbons (NMVOCs) result from product transport, including upstream conventional jet fuel emissions, and end use. The highest levels of mercury emissions occur during energy conversion and end use. Most water consumption occurs during biomass cultivation. Note that mass units displayed for water consumption (kg/MJ jet fuel) are equivalent to volume units for water consumption (L/MJ jet fuel).

Table 5-48: Scenario 12: CBTL, 16.5% Torrefied Biomass, Validated: Non-GHG Emissions

LC Stage	Carbon monoxide	NO_x	SO2	PM10	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	1.57E-05	1.64E-04	1.70E-05	1.67E-06	9.65E-06	2.68E-10	1.60E-06	1.42E-02	kg/MJ Jet Fuel
RMT	5.15E-04	4.72E-04	1.06E-04	6.03E-04	8.86E-05	2.91E-10	6.81E-06	1.64E-01	kg/MJ Jet Fuel
EC	-5.28E-04	-1.64E-03	-2.83E-03	-1.79E-04	-7.14E-04	4.93E-08	1.55E-05	-1.53E+00	kg/MJ Jet Fuel
PT	2.76E-04	4.38E-04	6.25E-04	3.28E-05	8.45E-04	5.80E-10	2.92E-06	1.08E+00	kg/MJ Jet Fuel
EU	7.72E-03	1.21E-02	5.56E-04	9.50E-07	7.72E-04	3.01E-08	7.16E-09	2.81E-02	kg/MJ Jet Fuel
Total	**8.00E-03**	**1.16E-02**	**-1.52E-03**	**4.59E-04**	**1.00E-03**	**8.05E-08**	**2.68E-05**	**-2.37E-01**	**kg/MJ Jet Fuel**

5.13 Scenario 13: CBTL, 19.6 Percent Torrefied Biomass and Validation

The purpose of this scenario is to evaluate potential process values, economic factors, and environmental emissions associated with the production of F-T jet fuels from a combination of 80.4 percent sub-bituminous coal and 19.6 percent Torrefied Biomass. This scenario evaluates a 1:1 (volume) blend of F-T jet fuels and conventional U.S. average jet fuel, based on a 30-year study period. Coal feedstock is derived from the Rosebud seam in southern Montana, and is transported by train to the CBTL facility, located in the Southeastern U.S. Southern pine biomass feedstock is produced and harvested in the Southeastern U.S., field-chipped, and then transported by chip truck to a separate torrefaction facility, where the biomass is torrefied. Torrefaction increases energy density of the biomass, and greatly reduces grinding energy required, as discussed in greater detail in Chapter 4. Torrefied biomass is then transported by truck to the CBTL facility. The F-T process employed uses a slurry-based iron catalyst using a single feed, oxygen blown Transport Reactor Integrated Gasifier (TRIG™; refer to Chapter 2 for additional discussion). Carbon dioxide is captured at the CBTL facility using a Selexol process to segregate carbon dioxide. Additional carbon dioxide is stripped from overhead gas downstream of the F-T synthesis process, using a methyldiethanolamine (MDEA) unit. Captured carbon dioxide is then routed to a purification and compression system, where it is compressed to a supercritical state. F-T jet fuel produced by the F-T facility is then conveyed to a blending facility, where it is blended with conventional jet fuel, and transported to an airport. Finally, the blended jet fuel is combusted in a jet airplane.

The following text provides a summary of process model, economic model, and environmental model results for this scenario.

5.13.1 Process Results

As discussed in Chapter 2, three Aspen Plus® model cases were run for this scenario: low RSP, expected RSP, and high RSP. Process summary results, both modeled and validated, for each of the three cases are reported in **Table 5-49**. Results obtained from the Aspen Plus® simulations are based on a 50,000 barrel per day (bpd) production rate for total F-T products (F-T jet fuel, F-T diesel, F-T naphtha, and F-T LPG) for the CBTL, 19.6 percent Torrified Biomass configuration under all three RSP cases. Fuel production breakdowns are minimally variable among the three RSP cases. For all three RSP cases, approximately 49 percent (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34 percent by volume of total products) being F-T naphtha. F-T jet fuel is produced by hydrocracking the F-T wax to a final boiling point of about 300°C. Hydrocracking also produces naphtha boiling range liquids and F-T LPG. Relatively smaller quantities of F-T diesel (10 percent of total products) and F-T LPG (7 percent of total products) are produced as a result of hydrocracking. These proportions assume that straight run F-T output would be sold as a product. Results from each of the three Aspen Plus® model cases were incorporated into the economic and environmental analyses, the results of which are displayed below. For additional information regarding the application of low, expected, and high RSP values to the stochastic analysis provided here, refer to Chapter 1.

Table 5-49: Scenario 13: CBTL, 19.6% Torrefied Biomass: Process Summary

Property	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
CBTL Facility Design and Operating Data							
Plant Design Capacity	50,000	50,000	50,000	50,000	50,000	50,000	bpd
Plant Capacity Factor	85	85	90	90	92	92	%
Plant Efficiency, HHV	55	55	54	54	52	52	%
Carbon Capture Rate	88	88	89	89	90	90	%
Gasifier Modules	9	9	9	9	9	9	Count
F-T Modules	10	10	10	10	10	10	Count
CBTL Facility Inputs/Feed							
Coal Feed, Montana Rosebud, As Received	23,513	23,548	24,056	24,100	24,814	24,871	tons/ day
Biomass Feed, Southern Pine, As Received	5,318	5,326	5,309	5,318	5,346	5,358	tons/ day
Water Feed (Total Withdrawal)	14,655,377	14,723,331	14,473,076	14,551,460	14,275,646	14,362,926	gallons/day
CBTL Facility Outputs/Production							
F-T Jet Fuel Production	24,649	24,648	24,647	24,646	24,644	24,644	bpd
F-T Diesel Fuel Production	4,767	4,767	4,767	4,767	4,766	4,766	bpd
F-T Naphtha Production	16,973	16,972	16,971	16,971	16,970	16,969	bpd
F-T LPG Production	3,612	3,613	3,615	3,616	3,620	3,621	bpd
Total Liquid Product Output	50,001	50,001	50,000	50,000	50,000	50,000	bpd
Export Power	258	257	226	226	189	188	MW
CO2 Captured and Compressed	30,149	30,301	30,824	30,997	31,394	31,584	tons/ day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,297	49,297	49,294	49,293	49,288	49,287	bpd

CBTL facility fuels production capacity was fixed at 50,000 bpd for all three RSP cases. An expected capacity factor of 90 percent was included, ranging from 85 to 92 percent for low and high RSP cases, respectively. In the modeled case the overall expected plant efficiency of 54.0 percent (range of 52.0 to 55.4 percent) is defined as the heating value of the liquid products (HHV basis), F-T LPG, and export power divided by the higher heating value of the input coal and biomass. In the validation case the overall expected plant efficiency is 53.9 percent (range of 51.8 to 55.4 percent) , a variation of less than 1 percent from the modeled case. In the modeled case, makeup water for the CBTL facility, as modeled in Aspen Plus®, is estimated to be approximately 13.0 million gallons per day (mgd; expected RSP case), of which 94 percent (12.2 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.2 bbl water/bbl F-T product, based on the expected RSP modeled case. In the validated case, makeup water for the CBTL facility is estimated to be approximately 14.5 million gallons per day (mgd; expected RSP case), of which 96.8 percent (14.0 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.89 bbl water/bbl F-T product, based on the expected RSP validated case. Here there is strong agreement between the modeled and validated case with a variation of makeup water for the CBTL facility of0.08 million gallon per day (0.54 percent) and a normalized variation of 0.04 bbl water/bbl F-T product (0.54 percent).

Under the modeled case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 189 to 258 MW, with an expected value of 226 MW. Based on the expected RSP case, gross power production for the CBTL facility is 791 MW, including power generated from steam (559 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (243 MW), carbon dioxide compressors (91.5 MW), the Selexol unit (61.3 MW), hydrocarbon recovery/refrigeration (43.6 MW), and oxygen compression (31.5 MW). Total auxiliaries consume 565 MW, for a net power output of 226 MW under the expected RSP case.

Under the validated case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 188 to 257 MW, with an expected value of 226 MW. Based on the expected RSP case, gross power production for the CBTL facility is 794 MW, including power generated from steam (562 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (244 MW), carbon dioxide compressors (91.9 MW), the Selexol unit (61.6 MW), hydrocarbon recovery/refrigeration (44.6 MW), and oxygen compression (31.5 MW). Total auxiliaries consume 568 MW, for a net power output of 226 MW under the expected RSP case.

Carbon balance for both the modeled and validated case of the CBTL facility is shown in **Table 5-50**, for all three RSP cases. As shown, carbon inputs were within 0.2 percent of carbon outputs for each of the three RSP cases. Carbon dioxide produced during the production of fuels and electric power is separated from the syngas stream prior to entering the F-T unit. The Selexol unit and the MDEA unit both produce the concentrated CO_2 streams that are dehydrated and compressed to 2,200 psi for pipeline delivery and carbon management. Other flue gas streams containing CO_2 are vented to the atmosphere. These include the flue gases from the HRSG units and from the fired heaters that are utilized during the F-T process. For the expected RSP case, approximately 2 percent of total carbon (range of 1 percent for the low RSP case to 4 percent for the high RSP case) is output to slag/ash from the TRIG gasifier.

Table 5-50: Scenario 13: CBTL, 19.6% Torrefied Biomass: Conversion Facility Carbon Balance

Input Flow	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
Coal Carbon	11,772	11,790	12,044	12,066	12,424	12,452	TPD
Biomass Carbon	3,185	3,190	3,179	3,185	3,201	3,209	TPD
Total Carbon Input	14,958	14,980	15,224	15,252	15,626	15,661	**TPD**
F-T Products	5,284	5,284	5,284	5,284	5,284	5,284	TPD
Slag/Ash	150	150	305	305	626	627	TPD
Stack Gas	986	972	936	922	886	873	TPD
Fuel Gas	266	259	240	233	212	205	TPD
WWTP	29	31	29	30	29	30	TPD
Carbon Capture, Sequestered	8,247	8,289	8,434	8,482	8,594	8,647	TPD
Total Carbon Output	**14,962**	**14,985**	**15,228**	**15,256**	**15,630**	**15,667**	**TPD**
Carbon Capture	**86.6**	**86.8**	**87.5**	**87.7**	**88.4**	**88.6**	**%**

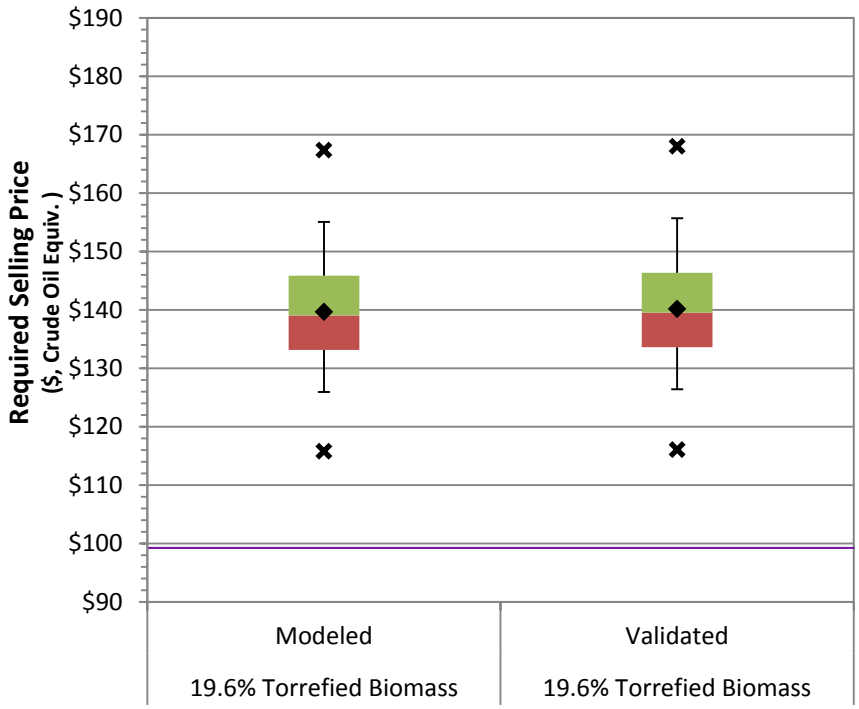
5.13.2 Economic Results

Results from the economic model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Figure 5-73 provides a summary of the estimated RSP for the F-T jet fuel produced under this scenario. As shown, RSP ranges from $133 to $146/bbl for the modeled case, with a mean value of $140/bbl, on a crude oil equivalent basis and for the variation, case the RSP ranges from $134 to $146/bbl, with a mean value of $140/bbl. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 40 economic parameters shown in **Table 1-5**. As shown, 25th and 75th percentile values are relatively close to the mean value, however, selling price distributions are characterized by long tails, with an overall range of $116to $168/bbl, on a crude oil equivalent basis.

Cost of the F-T jet fuel product is estimated on a crude oil equivalent basis. This is defined as the RSP of the diesel product divided by a factor of 1.1433. Thus if the average world oil price were below or equal to the calculated crude oil equivalent price the CBTL plant would be economically viable. Key contributors to the variability shown for RSP results are discussed below.

Figure 5-73: Scenario 13: CBTL, 19.6% Torrefied Biomass: F-T Jet Fuel RSP, Crude Oil Equivalent Basis



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel spot price value.

It is clear from **Figure 5-73** that there is minimal variation between the modeled and validated RSP results. **Table 5-51** provides a summary of the economic estimated performance of the CBTL facility under the validated case of this scenario, including the key contributing factors to the calculation of RSP. Total operating and maintenance costs represent an average of $536 million/yr. Of this amount, $296 to $322 million/yr, mean $309 million/yr (57.8 percent), results from fixed costs, while $218 to $234 million/year, mean $226 million/yr (42.2 percent) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, range from $8,515 to $9,342 million, mean $8,939 million. Coal feedstock costs for this scenario range from $278 to $290 million/yr, mean $284 million/yr. Biomass feedstock costs range from $224 to $238 million/yr, mean $232 million/yr. Total feedstock costs are approximately $19.6 million lower than total operating and maintenance costs, on average. Projected revenues include credits and product sales revenue. Power credit, from the sale of produced electricity, amounts to $117 to $131 million/yr, mean $124 million/yr, while CO_2 credit is estimated to be $333 to $397 million/yr, mean $365 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,135 to $2,338 million/yr, mean $2,236 million/yr.

Required product sales prices in the validated case are also provided in **Table 5-51**. Crude oil equivalent RSP is discussed above for **Figure 5-73**. On a straight basis, RSP for F-T jet fuel was calculated to be $154 to $169/bbl, mean $162/bbl, with F-T diesel at $153 to $167/bbl, mean $160/bbl, F-T naphtha at $106 to $117/bbl, mean $112/bbl, and F-T LPG at $61.7 to $67.6/bbl, mean $64.8/bbl. The default capital charge factor (CCF) used in the analysis was 0.1872.

Table 5-51: Scenario 13: CBTL, 19.6% Torrefied Biomass: Summary of Economics

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	309	256	369	296	322	$MM/yr
Variable Operating and Maintenance Cost (VOM)	226	193	268	218	234	$MM/yr
Capital: Total Overnight Cost (TOC)	8,939	7,582	10,873	8,515	9,342	$MM
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	284	260	312	278	290	$MM/yr
Biomass Cost, Southern Pine, Chips, As Received	0	0	0	0	0	$MM/yr
Biomass Cost, Southern Pine, Torrefied, As Received	232	203	266	224	238	$MM/yr
Credits and Revenue						
Power Credit	(124)	(157)	(91)	(131)	(117)	$MM/yr
Credit @ $40/ton for CO_2	(365)	(471)	(258)	(397)	(333)	$MM/yr
Annual Revenue Required	2,236	1,844	2,656	2,135	2,338	$MM/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	162	134	194	154	169	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	160	133	192	153	167	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	112	93	134	106	117	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	65	54	78	62	68	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	140	116	168	134	146	$/bbl

Figure 5-74 provides breakdowns for the cost factors in the validated case that contribute to the RSP. As shown, capital cost is the primary factor in determining RSP, and accounts for approximately 74.8 percent of total RSP, or $105/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 20.9 percent of total RSP, or $29.3/bbl, while feedstock costs represent 20.2 percent of total RSP, or $28.3/bbl, on a crude oil equivalent basis. As shown, variability in total RSP is driven largely by potential variability in capital costs, and to a much lesser extent by variability in operations and maintenance and feedstock costs. The negative credits bar comprises the sale of the co-produced electricity and compressed CO_2. Electricity accounts for 25.4 percent of the total credit, while captured and compressed CO_2 accounts for 74.6 percent.

Figure 5-74: Scenario 13: CBTL, 19.6% Torrefied Biomass, Validated: RSP, Crude Oil Equivalent Basis

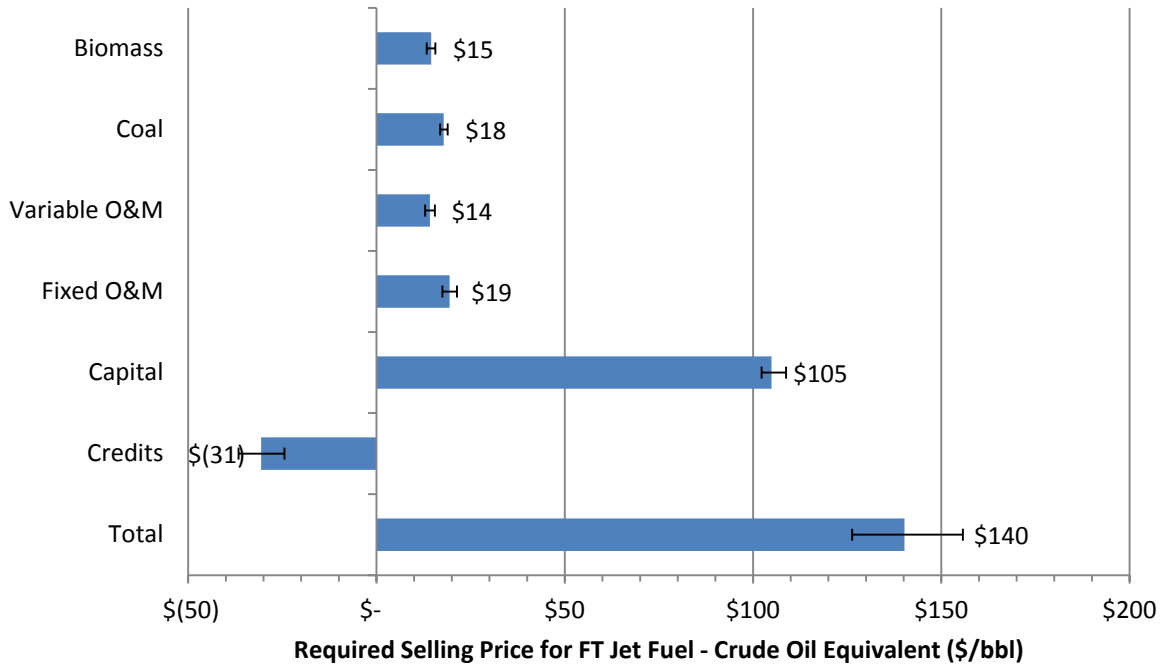
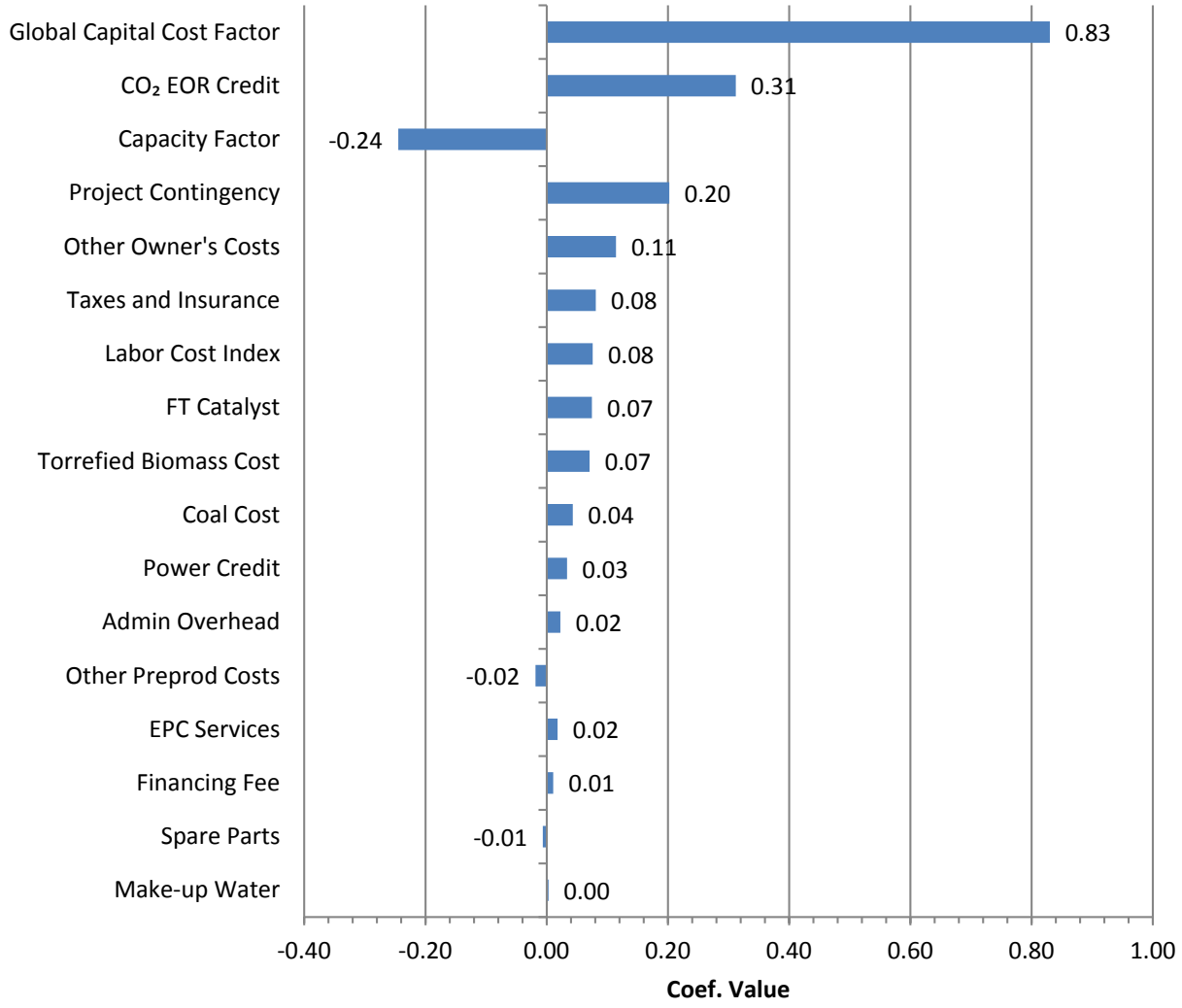


Figure 5-75 provides a summary of model sensitivity in the validated case, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.83. Other key factors that account for at least 10 percent of the observed variability in RSP include the CO_2 EOR credit, capacity factor, project contingency, and other owner's costs. Parameters that caused minimal influence on RSP include the cost of spare parts, coal cost, EPC services, other preproduction costs, and others as shown.

Figure 5-75: Scenario 13: CBTL, 19.6% Torrefied/Chipped Biomass, Validated: Sensitivity of RSP to Modeled Variables

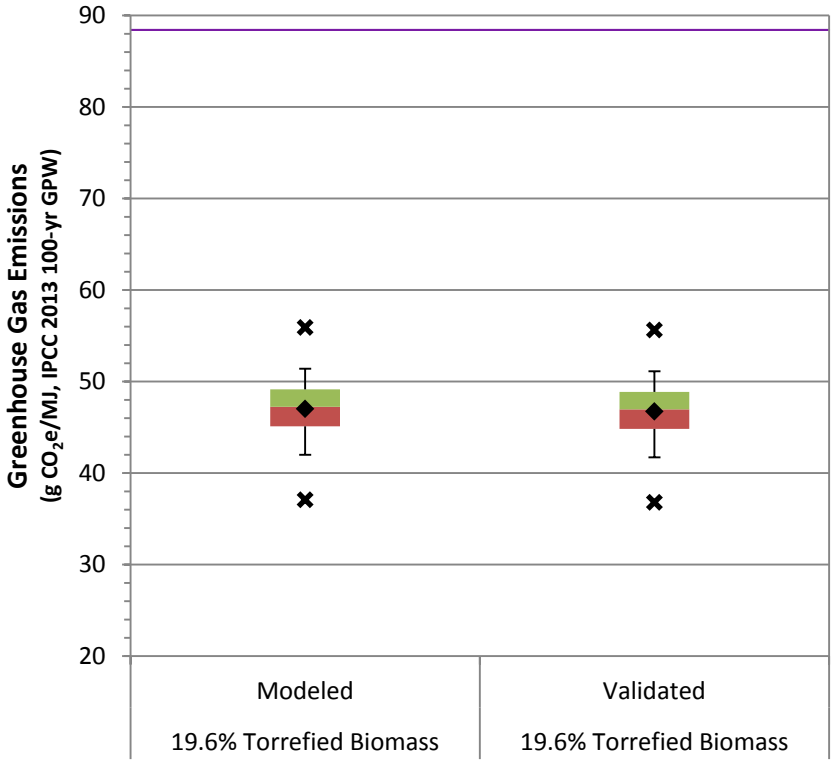


5.13.3 Environmental Results

Results from the environmental model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Results from the environmental life cycle analysis include GHG emissions and other emissions, including select criteria air pollutants, other pollutants of concern, and water consumption. **Figure 5-76** provides a summary life cycle GHG emissions for this scenario, in comparison to conventional jet fuel life cycle GHG emissions of 88.41 g CO_2e/MJ. In the modeled case the resulting range is 45.1 to 49.2 g CO_2e/MJ, mean 47.0 g CO_2e/MJ or approximately 46.2 percent less than conventional jet fuel. In the validated case the resulting range is 44.8 to 48.9 g CO_2e/MJ, mean 46.8 g CO_2e/MJ or approximately46.5 percent less than conventional jet fuel.

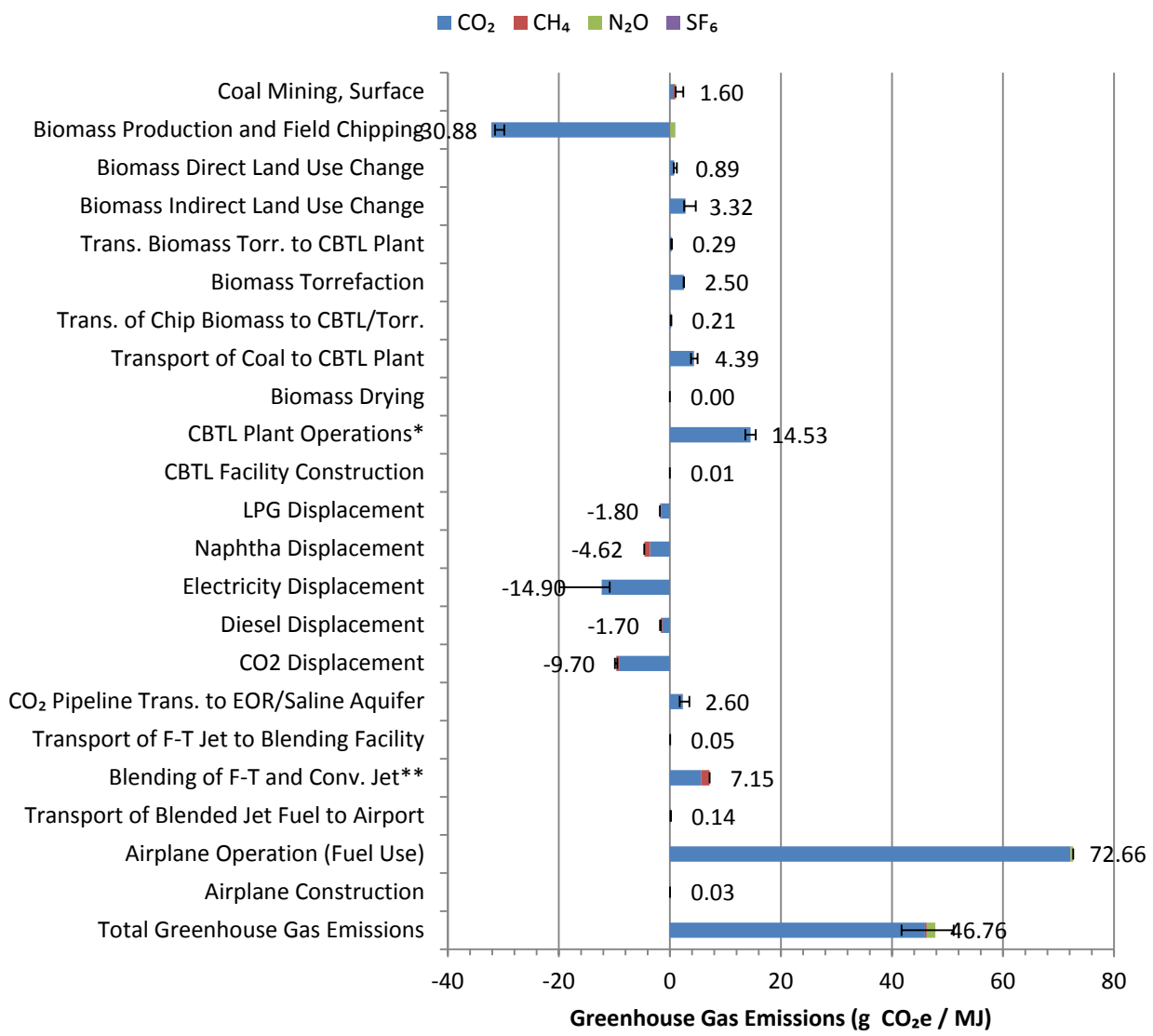
Figure 5-76: Scenario 13: CBTL, 19.6% Torrefied Biomass, Validated: Summary of LC GHG Emissions



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

It is clear from **Figure 5-76** that there is minimal variation between the modeled and validated LC GHG emission results. **Figure 5-77** provides detail regarding the importance of the various LCA components in the validated case that were modeled, with respect to gross GHG emissions contributions. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 65.4 percent of gross life cycle GHG emissions. Second in importance to fuel combustion is CBTL plant operations, at 13.2 percent of gross life cycle emissions, while emissions associated with blending of F-T and conventional jet fuel represent 5.08 percent of gross life cycle emissions. The transport of coal to the CBTL plant accounts for 3.81 percent of gross life cycle GHG emissions. Emissions from the pipeline transport of CO_2 represent approximately 2.56 percent of gross emissions. GHG emissions associated with biomass indirect land use change generate 2.25 percent of gross life cycle emissions, while the torrefaction of biomass generates 2.11 percent. Other contributors to gross emissions were less than 1 percent individually.

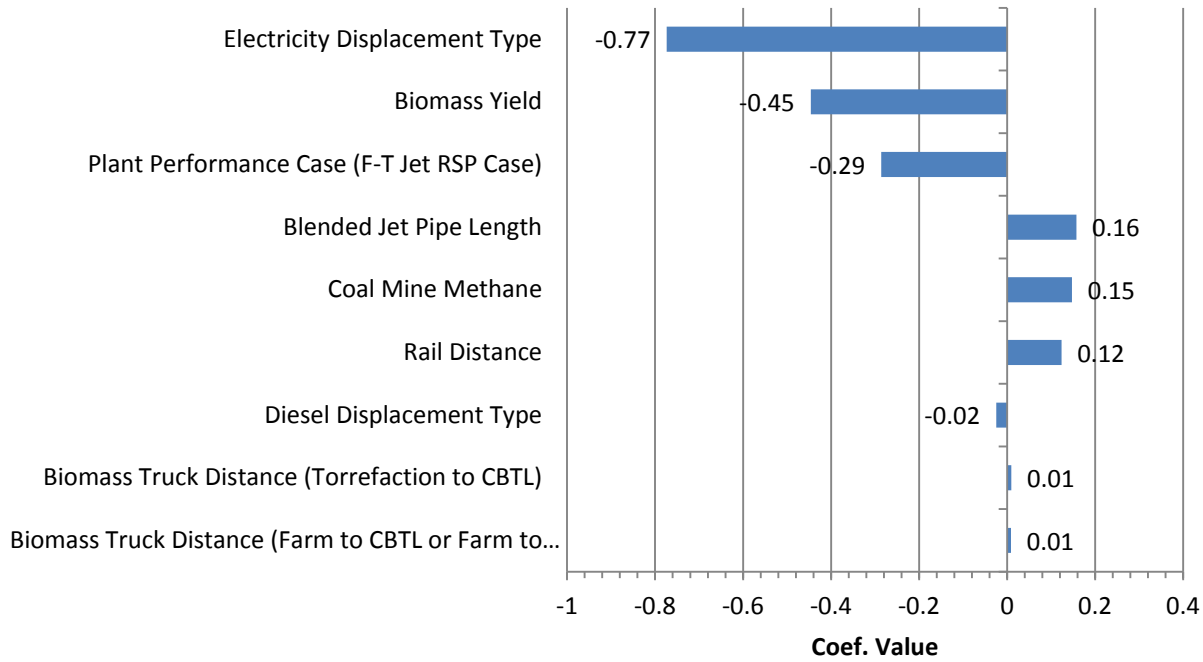
Figure 5-77: Scenario 13: CBTL, 19.6% Torrefied Biomass, Validated: LC GHG Emissions Breakdowns



** Includes CO_2 Compression*
***Includes conventional jet fuel profile*

The error bars shown in **Figure 5-77** reflect variability in model output based on the stochastic analyses (for more information, refer to Chapter 1). The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-6**. As shown, variability in emissions resulted primarily from the type of electricity displacement used. Other key contributors to variability in model output include biomass yield and the F-T jet fuel RSP case. **Figure 5-78** summarizes the key factors contributing to variability identified in the model sensitivity analysis, for GHG emissions. Values provided in the figure show the correlation coefficient between the indicated parameter and total life cycle GHG emissions. Other important factors included the blended jet fuel pipe length, coal mine methane emissions, the rail transport distance, the diesel displacement type, and the biomass trucking distances. Other parameters had minimal to negligible effect on life cycle GHG emissions.

Figure 5-78: Scenario 13: CBTL, 19.6% Torrefied Biomass, Validated: LC GHG Emissions Sensitivity



In addition to GHG emissions, other life cycle environmental emissions and flows were also considered. **Table 5-53** provides a summary of these flows. As shown, Airplane operation is the primary source of carbon monoxide and NOx within the life cycle. Particulate matter (PM_{10}) derives primarily from the combustion of diesel under raw materials transport and product transport operations. Non-methane volatile organic carbons (NMVOCs) result from product transport, including upstream conventional jet fuel emissions, and end use. The highest levels of mercury emissions occur during energy conversion and end use. Most water consumption occurs during biomass cultivation. Note that mass units displayed for water consumption (kg/MJ jet fuel) are equivalent to volume units for water consumption (L/MJ jet fuel).

Table 5-52: Scenario 13: CBTL, 19.6% Torrefied Biomass, Validated: Non-GHG Emissions

LC Stage	Carbon monoxide	NO_x	SO2	PM10	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	1.51E-05	1.57E-04	1.63E-05	1.60E-06	9.27E-06	2.58E-10	1.54E-06	1.36E-02	kg/MJ Jet Fuel
RMT	4.94E-04	4.53E-04	1.02E-04	5.79E-04	8.50E-05	2.79E-10	6.54E-06	1.57E-01	kg/MJ Jet Fuel
EC	-5.29E-04	-1.64E-03	-2.83E-03	-1.80E-04	-7.14E-04	4.66E-08	1.57E-05	-1.61E+00	kg/MJ Jet Fuel
PT	2.76E-04	4.38E-04	6.25E-04	3.28E-05	8.45E-04	5.80E-10	2.92E-06	1.08E+00	kg/MJ Jet Fuel
EU	7.72E-03	1.21E-02	5.56E-04	9.50E-07	7.72E-04	3.01E-08	7.16E-09	2.81E-02	kg/MJ Jet Fuel
Total	**7.97E-03**	**1.15E-02**	**-1.53E-03**	**4.34E-04**	**9.97E-04**	**7.78E-08**	**2.67E-05**	**-3.26E-01**	**kg/MJ Jet Fuel**

5.14 Scenario 14: CBTL, 28.3 Percent Torrefied Biomass and Validation

The purpose of this scenario is to evaluate potential process values, economic factors, and environmental emissions associated with the production of F-T jet fuels from a combination of 71.3 percent sub-bituminous coal and 28.3 percent Torrefied Biomass. This scenario evaluates a 1:1 (volume) blend of F-T jet fuels and conventional U.S. average jet fuel, based on a 30-year study period. Coal feedstock is derived from the Rosebud seam in southern Montana, and is transported by train to the CBTL facility, located in the Southeastern U.S. Southern pine biomass feedstock is produced and harvested in the Southeastern U.S., field-chipped, and then transported by chip truck to a separate torrefaction facility, where the biomass is torrefied. Torrefaction increases energy density of the biomass, and greatly reduces grinding energy required, as discussed in greater detail in Chapter 4. Torrefied biomass is then transported by truck to the CBTL facility. The F-T process employed uses a slurry-based iron catalyst using a single feed, oxygen blown Transport Reactor Integrated Gasifier (TRIG™; refer to Chapter 2 for additional discussion). Carbon dioxide is captured at the CBTL facility using a Selexol process to segregate carbon dioxide. Additional carbon dioxide is stripped from overhead gas downstream of the F-T synthesis process, using a methyldiethanolamine (MDEA) unit. Captured carbon dioxide is then routed to a purification and compression system, where it is compressed to a supercritical state. F-T jet fuel produced by the F-T facility is then conveyed to a blending facility, where it is blended with conventional jet fuel, and transported to an airport. Finally, the blended jet fuel is combusted in a jet airplane.

The following text provides a summary of process model, economic model, and environmental model results for this scenario.

5.14.1 Process Results

As discussed in Chapter 2, three Aspen Plus® model cases were run for this scenario: low RSP, expected RSP, and high RSP. Process summary results, both modeled and validated, for each of the three cases are reported in **Table 5-53**. Results obtained from the Aspen Plus® simulations are based on a 50,000 barrel per day (bpd) production rate for total F-T products (F-T jet fuel, F-T diesel, F-T naphtha, and F-T LPG) for the CBTL, 28.3 percent Torrified Biomass configuration under all three RSP cases. Fuel production breakdowns are minimally variable among the three RSP cases. For all three RSP cases, approximately 49 percent (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34 percent by volume of total products) being F-T naphtha. F-T jet fuel is produced by hydrocracking the F-T wax to a final boiling point of about 300°C. Hydrocracking also produces naphtha boiling range liquids and F-T LPG. Relatively smaller quantities of F-T diesel (10 percent of total products) and F-T LPG (7 percent of total products) are produced as a result of hydrocracking. These proportions assume that straight run F-T output would be sold as a product. Results from each of the three Aspen Plus® model cases were incorporated into the economic and environmental analyses, the results of which are displayed below. For additional information regarding the application of low, expected, and high RSP values to the stochastic analysis provided here, refer to Chapter 1.

Table 5-53: Scenario 14: CBTL, 28.3% Torrefied Biomass: Process Summary

Property	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
CBTL Facility Design and Operating Data							
Plant Design Capacity	50,000	50,000	50,000	50,000	50,000	50,000	bpd
Plant Capacity Factor	85	85	90	90	92	92	%
Plant Efficiency, HHV	56	56	54	54	52	52	%
Carbon Capture Rate	88	88	89	89	90	90	%
Gasifier Modules	9	9	9	9	9	9	Count
F-T Modules	10	10	10	10	10	10	Count
CBTL Facility Inputs/Feed							
Coal Feed, Montana Rosebud, As Received	20,773	20,804	21,280	21,319	21,987	22,037	tons/ day
Biomass Feed, Southern Pine, As Received	7,608	7,619	7,603	7,617	7,669	7,686	tons/ day
Water Feed (Total Withdrawal)	14,393,648	14,459,977	14,231,588	14,308,166	14,057,737	14,142,782	gallons/day
CBTL Facility Outputs/Production							
F-T Jet Fuel Production	24,648	24,648	24,647	24,646	24,644	24,643	bpd
F-T Diesel Fuel Production	4,767	4,767	4,767	4,767	4,766	4,766	bpd
F-T Naphtha Production	16,972	16,972	16,971	16,971	16,970	16,969	bpd
F-T LPG Production	3,613	3,613	3,616	3,617	3,621	3,622	bpd
Total Liquid Product Output	50,000	50,000	50,000	50,001	50,001	50,001	bpd
Export Power	259	258	230	229	194	193	MW
CO2 Captured and Compressed	30,187	30,338	30,810	30,981	31,346	31,532	tons/ day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,297	49,296	49,293	49,292	49,288	49,287	bpd

CBTL facility fuels production capacity was fixed at 50,000 bpd for all three RSP cases. An expected capacity factor of 90 percent was included, ranging from 85 to 92 percent for low and high RSP cases, respectively. In the modeled case the overall expected plant efficiency of 54.3 percent (range of 52.4 to 55.7 percent) is defined as the heating value of the liquid products (HHV basis), F-T LPG, and export power divided by the higher heating value of the input coal and biomass. In the validation case the overall expected plant efficiency is 54.2 percent (range of 52.2 to 55.6 percent) , a variation of less than 1 percent from the modeled case. In the modeled case, makeup water for the CBTL facility, as modeled in Aspen Plus®, is estimated to be approximately 14.2 million gallons per day (mgd; expected RSP case), of which 97.7 percent (13.9 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.78 bbl water/bbl F-T product, based on the expected RSP modeled case. In the validated case, makeup water for the CBTL facility is estimated to be approximately 14.3 million gallons per day (mgd; expected RSP case), of which 97.7 percent (14.0 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.81 bbl water/bbl F-T product, based on the expected RSP validated case. Here there is strong agreement between the modeled and validated case with a variation of makeup water for the CBTL facility of 0.08 million gallon per day (0.54 percent) and a normalized variation of 0.04 bbl water/bbl F-T product (0.54 percent).

Under the modeled case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 194 to 259 MW, with an expected value of 230 MW. Based on the expected RSP case, gross power production for the CBTL facility is 791 MW, including power generated from steam (559 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (240 MW), carbon dioxide compressors (91.4 MW), the Selexol unit (60.9 MW), hydrocarbon recovery/refrigeration (43.9 MW), and oxygen compression (31.1 MW). Total auxiliaries consume 561 MW, for a net power output of 230 MW under the expected RSP case.

Under the validated case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 193 to 258 MW, with an expected value of 229 MW. Based on the expected RSP case, gross power production for the CBTL facility is 794 MW, including power generated from steam (562 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (241 MW), carbon dioxide compressors (91.8 MW), the Selexol unit (61.2 MW), hydrocarbon recovery/refrigeration (44.9 MW), and oxygen compression (31.2 MW). Total auxiliaries consume 565 MW, for a net power output of 229 MW under the expected RSP case.

Carbon balance for both the modeled and validated case of the CBTL facility is shown in **Table 5-54**, for all three RSP cases. As shown, carbon inputs were within 0.2 percent of carbon outputs for each of the three RSP cases. Carbon dioxide produced during the production of fuels and electric power is separated from the syngas stream prior to entering the F-T unit. The Selexol unit and the MDEA unit both produce the concentrated CO_2 streams that are dehydrated and compressed to 2,200 psi for pipeline delivery and carbon management. Other flue gas streams containing CO_2 are vented to the atmosphere. These include the flue gases from the HRSG units and from the fired heaters that are utilized during the F-T process. For the expected RSP case, approximately 2 percent of total carbon (range of 1 percent for the low RSP case to 4 percent for the high RSP case) is output to slag/ash from the TRIG gasifier.

Table 5-54: Scenario 14: CBTL, 28.3% Torrefied Biomass: Conversion Facility Carbon Balance

Input Flow	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
Coal Carbon	10,401	10,416	10,655	10,674	11,009	11,033	TPD
Biomass Carbon	4,556	4,563	4,554	4,562	4,593	4,603	TPD
Total Carbon Input	14,957	14,979	15,208	15,236	15,602	15,637	**TPD**
F-T Products	5,284	5,284	5,284	5,284	5,284	5,284	TPD
Slag/Ash	150	150	305	305	625	626	TPD
Stack Gas	977	964	928	914	878	866	TPD
Fuel Gas	263	256	237	230	209	203	TPD
WWTP	31	31	30	29	31	29	TPD
Carbon Capture, Sequestered	8,257	8,299	8,431	8,479	8,581	8,633	TPD
Total Carbon Output	**14,962**	**14,984**	**15,214**	**15,241**	**15,608**	**15,641**	**TPD**
Carbon Capture	**86.7**	**86.9**	**87.6**	**87.8**	**88.5**	**88.7**	**%**

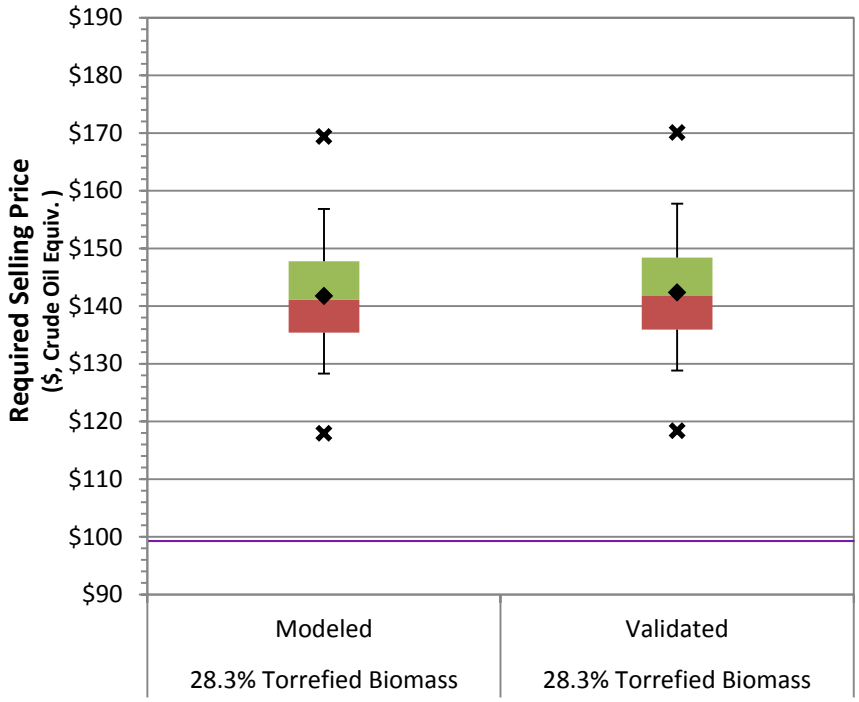
5.14.2 Economic Results

Results from the economic model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Figure 5-79 provides a summary of the estimated RSP for the F-T jet fuel produced under this scenario. As shown, RSP ranges from $135 to $148/bbl for the modeled case, with a mean value of $142/bbl, on a crude oil equivalent basis and for the variation, case the RSP ranges from $136 to $148/bbl, with a mean value of $142/bbl. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 40 economic parameters shown in **Table 1-5**. As shown, 25th and 75th percentile values are relatively close to the mean value, however, selling price distributions are characterized by long tails, with an overall range of $118 to $170/bbl, on a crude oil equivalent basis.

Cost of the F-T jet fuel product is estimated on a crude oil equivalent basis. This is defined as the RSP of the diesel product divided by a factor of 1.1433. Thus if the average world oil price were below or equal to the calculated crude oil equivalent price the CBTL plant would be economically viable. Key contributors to the variability shown for RSP results are discussed below.

Figure 5-79: Scenario 14: CBTL, 28.3% Torrefied Biomass: F-T Jet Fuel RSP, Crude Oil Equivalent Basis



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel spot price value.

It is clear from **Figure 5-79** that there is minimal variation between the modeled and validated RSP results. **Table 5-55** provides a summary of the economic estimated performance of the CBTL facility under the validated case of this scenario, including the key contributing factors to the calculation of RSP. Total operating and maintenance costs represent an average of $529 million/yr. Of this amount, $291 to $317 million/yr, mean $304 million/yr (57.6 percent), results from fixed costs, while $216 to $232 million/year, mean $224 million/yr (42.4 percent) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, range from $8,394 to $9,212 million, mean $8,812 million. Coal feedstock costs for this scenario range from $246 to $257 million/yr, mean $252 million/yr. Biomass feedstock costs range from $321 to $341 million/yr, mean $70 million/yr. Total feedstock costs are approximately $54.7 million greater than total operating and maintenance costs, on average. Projected revenues include credits and product sales revenue. Power credit, from the sale of produced electricity, amounts to $119 to $133 million/yr, mean $125 million/yr, while CO_2 credit is estimated to be $333 to $396 million/yr, mean $365 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,170 to $2,372 million/yr, mean $2,271 million/yr.

Required product sales prices in the validated case are also provided in **Table 5-55**. Crude oil equivalent RSP is discussed above for **Figure 5-79**. On a straight basis, RSP for F-T jet fuel was calculated to be $157 to $171/bbl, mean $164/bbl, with F-T diesel at $155 to $170/bbl, mean $163/bbl, F-T naphtha at $108 to $118/bbl, mean $113/bbl, and F-T LPG at $62.8 to $68.6/bbl, mean $65.8/bbl. The default capital charge factor (CCF) used in the analysis was 0.1872.

Table 5-55: Scenario 14: CBTL, 28.3% Torrefied Biomass: Summary of Economics

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	304	251	363	291	317	$MM/yr
Variable Operating and Maintenance Cost (VOM)	224	191	266	216	232	$MM/yr
Capital: Total Overnight Cost (TOC)	8,812	7,471	10,722	8,394	9,212	$MM
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	252	229	276	246	257	$MM/yr
Biomass Cost, Southern Pine, Chips, As Received	0	0	0	0	0	$MM/yr
Biomass Cost, Southern Pine, Torrefied, As Received	332	291	382	321	341	$MM/yr
Credits and Revenue						
Power Credit	(125)	(158)	(94)	(133)	(119)	$MM/yr
Credit @ $40/ton for CO_2	(365)	(470)	(258)	(396)	(333)	$MM/yr
Annual Revenue Required	2,271	1,891	2,689	2,170	2,372	$MM/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	164	137	196	157	171	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	163	135	195	155	170	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	113	94	136	108	118	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	66	55	79	63	69	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	142	118	170	136	148	$/bbl

Figure 5-80 provides breakdowns for the cost factors in the validated case that contribute to the RSP. As shown, capital cost is the primary factor in determining RSP, and accounts for approximately 72.6 percent of total RSP, or $103/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 20.3 percent of total RSP, or $29.0/bbl, while feedstock costs represent 22.4 percent of total RSP, or $32.0/bbl, on a crude oil equivalent basis. As shown, variability in total RSP is driven largely by potential variability in capital costs, and to a much lesser extent by variability in operations and maintenance and feedstock costs. The negative credits bar comprises the sale of the co-produced electricity and compressed CO_2. Electricity accounts for 25.3 percent of the total credit, while captured and compressed CO_2 accounts for 74.7 percent.

Figure 5-80: Scenario 14: CBTL, 28.3% Torrefied Biomass, Validated: RSP, Crude Oil Equivalent Basis

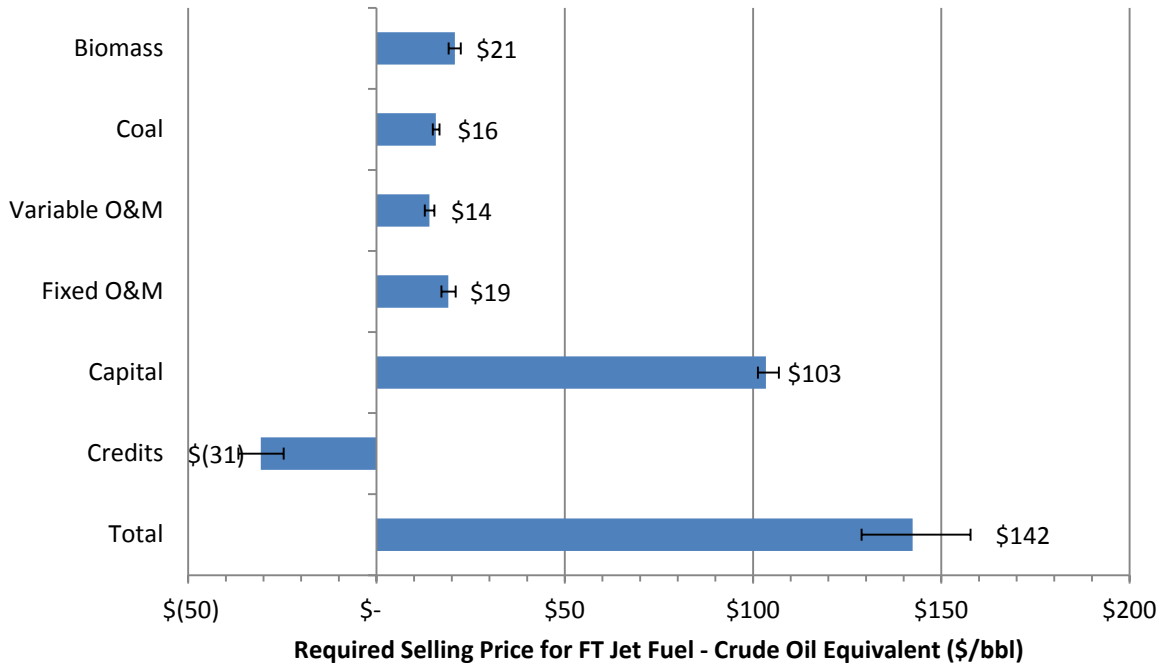
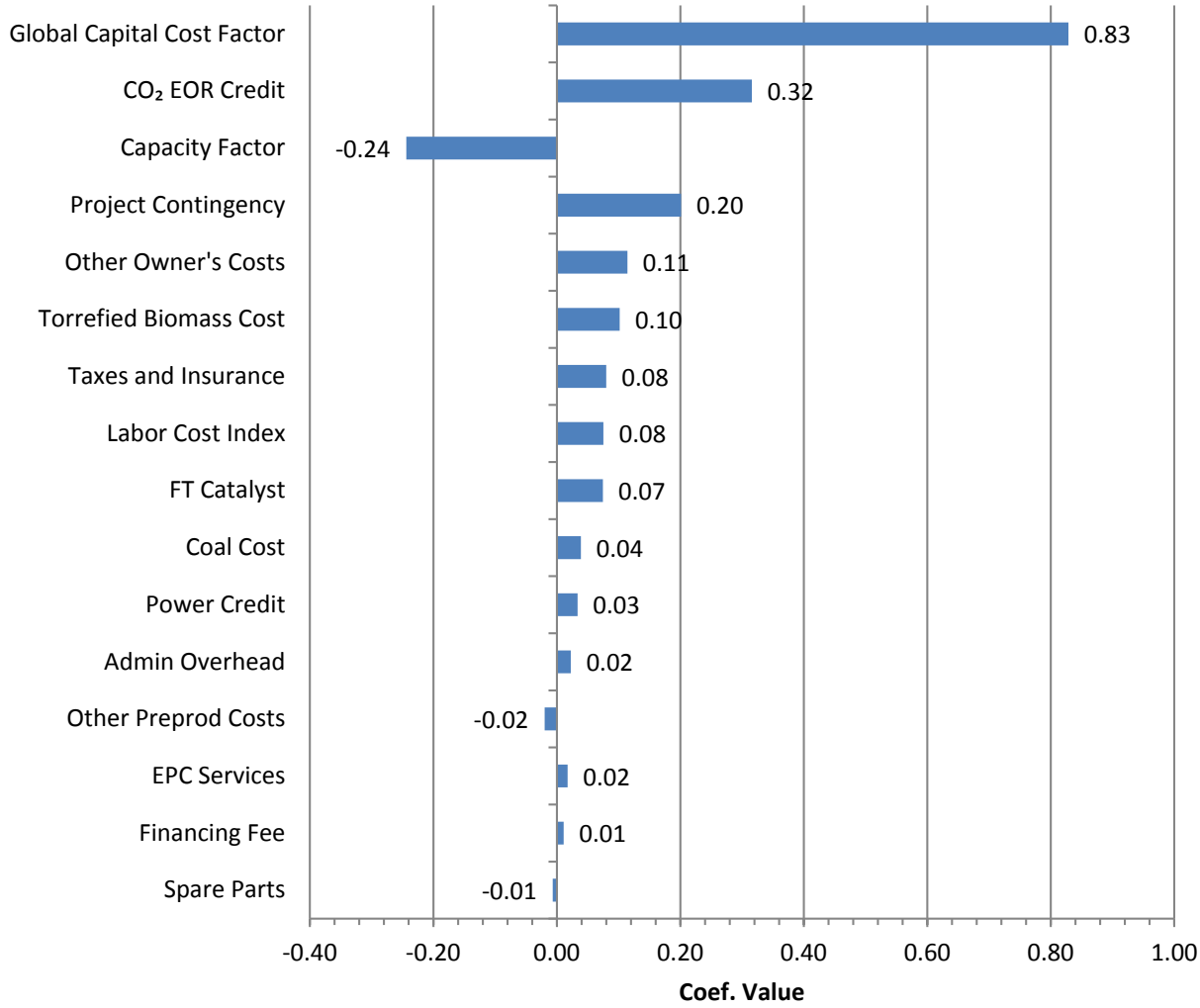


Figure 5-81 provides a summary of model sensitivity in the validated case, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.83. Other key factors that account for at least 10 percent of the observed variability in RSP include the CO_2 EOR credit, capacity factor, project contingency, and other owner's costs. Parameters that caused minimal influence on RSP included the administrative overhead costs, other preproduction costs, EPC service costs, financing fees, cost of spare costs, and others as shown.

Figure 5-81: Scenario 14: CBTL, 28.3% Torrefied/Chipped Biomass, Validated: Sensitivity of RSP to Modeled Variables

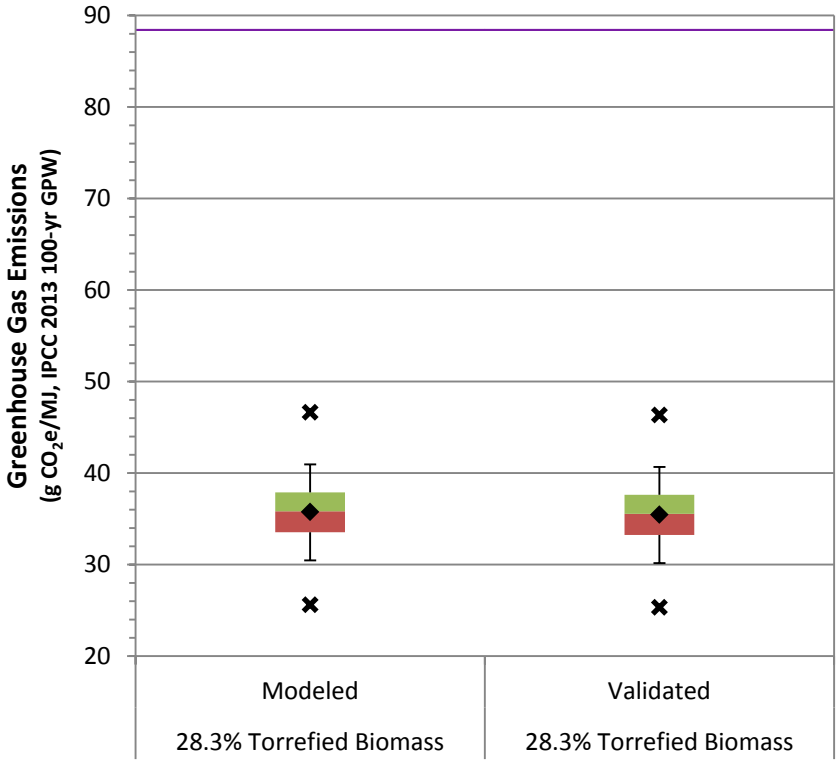


5.14.3 Environmental Results

Results from the environmental model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Results from the environmental life cycle analysis include GHG emissions and other emissions, including select criteria air pollutants, other pollutants of concern, and water consumption. **Figure 5-82** provides a summary life cycle GHG emissions for this scenario, in comparison to conventional jet fuel life cycle GHG emissions of 88.41 g CO_2e/MJ. In the modeled case the resulting range is 33.5 to 37.9 g CO_2e/MJ, mean 35.8 g CO_2e/MJ or approximately 59.1 percent less than conventional jet fuel. In the validated case the resulting range is 33.2 to 37.6 g CO_2e/MJ, 35.5 g CO_2e/MJ or approximately 59.4 percent less than conventional jet fuel.

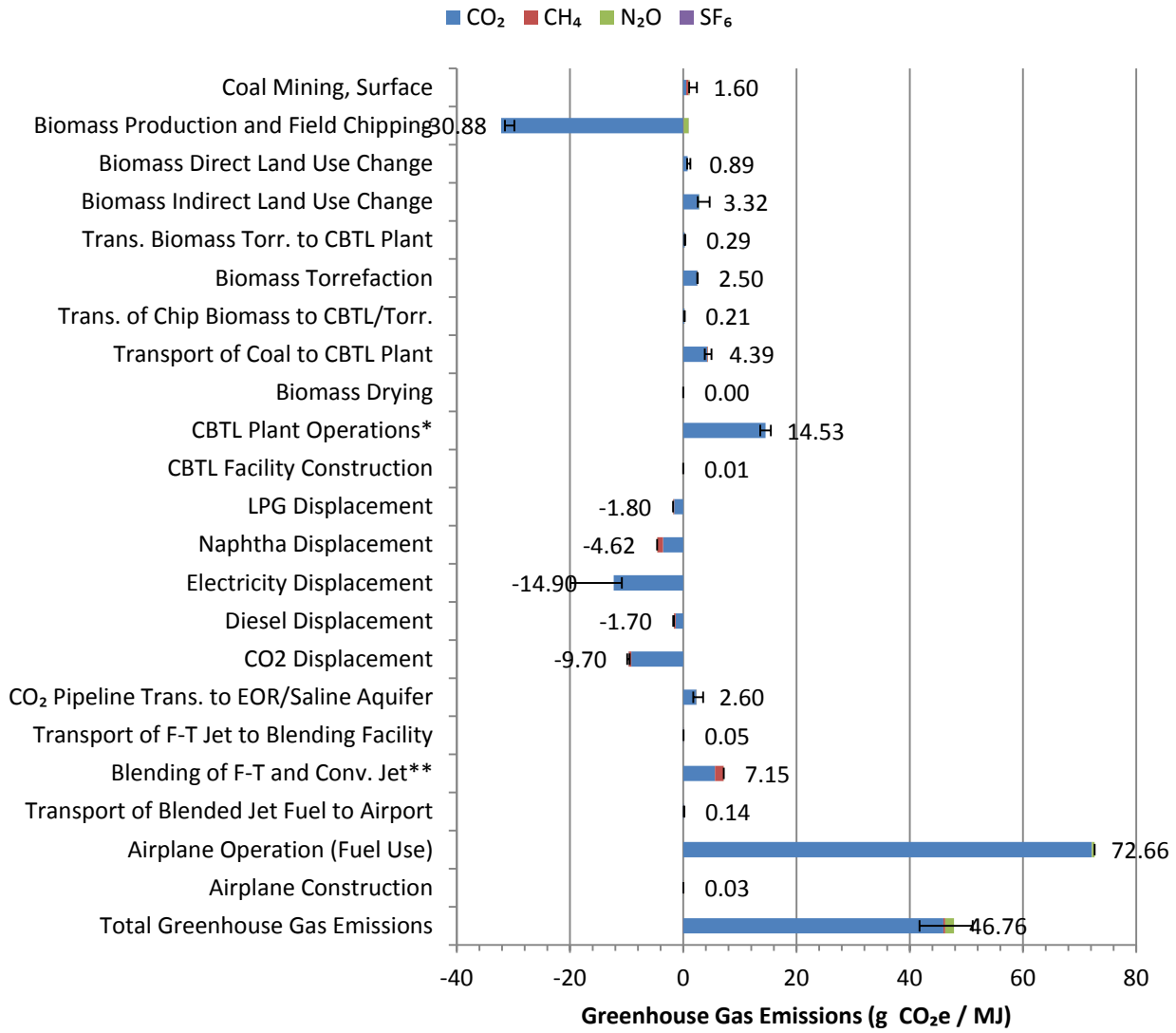
Figure 5-82: Scenario 14: CBTL, 28.3% Torrefied Biomass, Validated: Summary of LC GHG Emissions



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

It is clear from **Figure 5-82** that there is minimal variation between the modeled and validated LC GHG emission results. **Figure 5-83** provides detail regarding the importance of the various LCA components in the validated case that were modeled, with respect to gross GHG emissions contributions. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 64.0 percent of gross life cycle GHG emissions. Second in importance to fuel combustion is CBTL plant operations, at 12.8 percent of gross life cycle emissions, while emissions associated with blending of F-T and conventional jet fuel represent 4.98 percent of gross life cycle emissions. The transport of coal to the CBTL plant accounts for 3.59 percent of gross life cycle GHG emissions. Emissions from biomass indirect land use change represent approximately 3.30 percent of gross emissions. GHG emissions associated with pipeline transport of CO_2 generates 3.16 percent of gross life cycle emissions, while the torrefaction of biomass generates 2.07 percent. Other contributors to gross emissions were less than 1 percent individually.

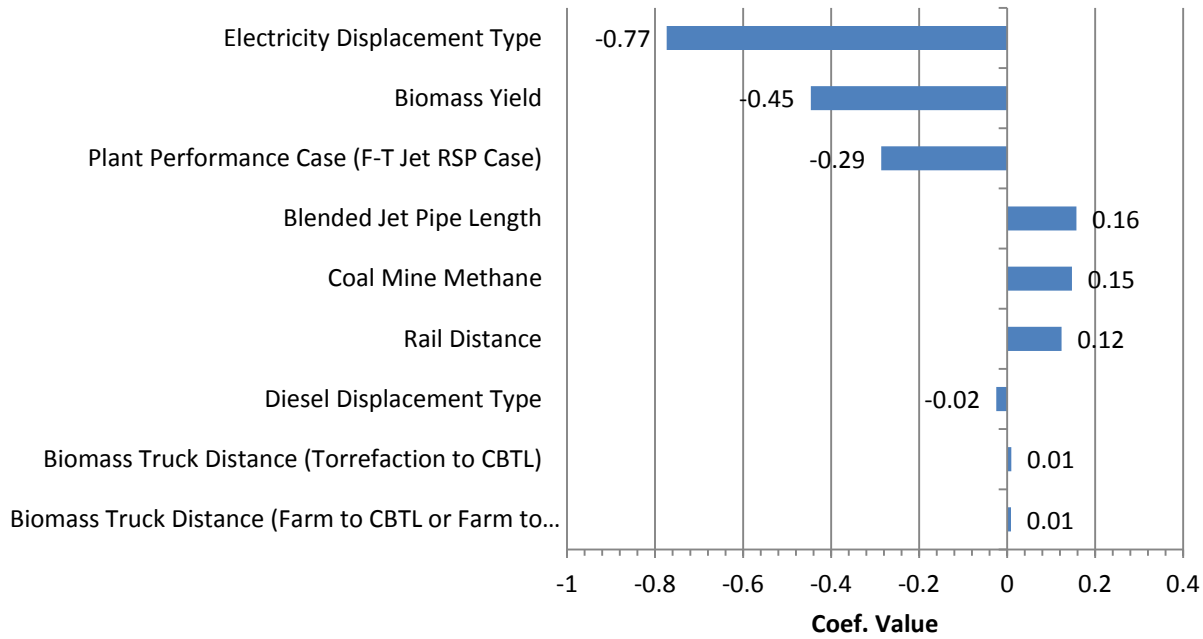
Figure 5-83: Scenario 14: CBTL, 28.3% Torrefied Biomass, Validated: LC GHG Emissions Breakdowns



** Includes CO_2 Compression*
*** Includes conventional jet fuel profile*

The error bars shown in **Figure 5-83** reflect variability in model output based on the stochastic analyses (for more information, refer to Chapter 1). The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-6**. As shown, variability in emissions resulted primarily from the type of electricity displacement used. Another key contributor to variability in model output is biomass yield. **Figure 5-84** summarizes the key factors contributing to variability identified in the model sensitivity analysis, for GHG emissions. Values provided in the figure show the correlation coefficient between the indicated parameter and total life cycle GHG emissions. Other important factors included the F-T jet fuel RSP case, the blended jet fuel pipe length coal mine methane emissions, the rail transport distance, the diesel displacement type, and the biomass truck transportation distances. Other parameters had minimal to negligible effect on life cycle GHG emissions.

Figure 5-84: Scenario 14: CBTL, 28.3% Torrefied Biomass, Validated: LC GHG Emissions Sensitivity



In addition to GHG emissions, other life cycle environmental emissions and flows were also considered. **Table 5-56** provides a summary of these flows. As shown, Airplane operation is the primary source of carbon monoxide and NOx within the life cycle. Particulate matter (PM_{10}) derives primarily from the combustion of diesel under raw materials transport and product transport operations. Non-methane volatile organic carbons (NMVOCs) result from product transport, including upstream conventional jet fuel emissions, and end use. The highest levels of mercury emissions occur during energy conversion and end use. Most water consumption occurs during biomass cultivation. Note that mass units displayed for water consumption (kg/MJ jet fuel) are equivalent to volume units for water consumption (L/MJ jet fuel).

Table 5-56: Scenario 14: CBTL, 28.3% Torrefied Biomass, Validated: Non-GHG Emissions

LC Stage	Carbon monoxide	NO_x	SO2	PM10	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	1.33E-05	1.39E-04	1.44E-05	1.42E-06	8.20E-06	2.28E-10	1.36E-06	1.21E-02	kg/MJ Jet Fuel
RMT	4.37E-04	4.01E-04	9.01E-05	5.12E-04	7.52E-05	2.47E-10	5.79E-06	1.39E-01	kg/MJ Jet Fuel
EC	-5.30E-04	-1.65E-03	-2.84E-03	-1.82E-04	-7.15E-04	3.91E-08	1.62E-05	-1.84E+00	kg/MJ Jet Fuel
PT	2.76E-04	4.38E-04	6.25E-04	3.28E-05	8.45E-04	5.80E-10	2.92E-06	1.08E+00	kg/MJ Jet Fuel
EU	7.72E-03	1.21E-02	5.56E-04	9.50E-07	7.72E-04	3.01E-08	7.16E-09	2.81E-02	kg/MJ Jet Fuel
Total	**7.91E-03**	**1.15E-02**	**-1.56E-03**	**3.65E-04**	**9.86E-04**	**7.02E-08**	**2.63E-05**	**-5.72E-01**	**kg/MJ Jet Fuel**

5.15 Scenario 15: CBTL, 11.7 Percent Pelleted Biomass and Validation

The purpose of this scenario is to evaluate potential process values, economic factors, and environmental emissions associated with the production of F-T jet fuels from a combination of 88.3 percent sub-bituminous coal and 11.7 percent pelleted biomass. This scenario evaluates a 1:1 (volume) blend of F-T jet fuels and conventional U.S. average jet fuel, based on a 30-year study period. Coal feedstock is derived from the Rosebud seam in southern Montana, and is transported by train to the CBTL facility, located in the Southeastern U.S. Biomass feedstock is field-chipped Southern pine biomass, cultivated and harvested in the Southeastern U.S. , field-chipped, and then transported by chip truck to a separate pelletization facility, where the biomass is formed into pellets. Pelleted biomass is then transported by truck to the CBTL facility. The F-T process employed uses a slurry-based iron catalyst using a single feed, oxygen blown Transport Reactor Integrated Gasifier (TRIG™; refer to Chapter 2 for additional discussion). Carbon dioxide is captured at the CBTL facility using a Selexol process to segregate carbon dioxide. Additional carbon dioxide is stripped from overhead gas downstream of the F-T synthesis process, using a methyldiethanolamine (MDEA) unit. Captured carbon dioxide is then routed to a purification and compression system, where it is compressed to a supercritical state. F-T jet fuel produced by the F-T facility is then conveyed to a blending facility, where it is blended with conventional jet fuel, and transported to an airport. Finally, the blended jet fuel is combusted in a jet airplane.

The following text provides a summary of process model, economic model, and environmental model results for this scenario.

5.15.2 Process Results

As discussed in Chapter 2, three Aspen Plus® model cases were run for this scenario: low RSP, expected RSP, and high RSP. Process summary results, both modeled and validated, for each of the three cases are reported in **Table 5-57**. Results obtained from the Aspen Plus® simulations are based on a 50,000 barrel per day (bpd) production rate for total F-T products (F-T jet fuel, F-T diesel, F-T naphtha, and F-T LPG) for the CBTL, 11.7 percent Pelleted Biomass configuration under all three RSP cases. Fuel production breakdowns are minimally variable among the three RSP cases. For all three RSP cases, approximately 49 percent (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34 percent by volume of total products) being F-T naphtha. F-T jet fuel is produced by hydrocracking the F-T wax to a final boiling point of about 300°C. Hydrocracking also produces naphtha boiling range liquids and F-T LPG. Relatively smaller quantities of F-T diesel (10 percent of total products) and F-T LPG (7 percent of total products) are produced as a result of hydrocracking. These proportions assume that straight run F-T output would be sold as a product. Results from each of the three Aspen Plus® model cases were incorporated into the economic and environmental analyses, the results of which are displayed below. For additional information regarding the application of low, expected, and high RSP values to the stochastic analysis provided here, refer to Chapter 1.

Table 5-57: Scenario 15: CBTL, 11.7% Pelleted Biomass: Process Summary

Property	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
CBTL Facility Design and Operating Data							
Plant Design Capacity	50,000	50,000	50,000	50,000	50,000	50,000	bpd
Plant Capacity Factor	85	85	90	90	92	92	%
Plant Efficiency, HHV	55	55	53	53	51	51	%
Carbon Capture Rate	88	88	89	89	90	90	%
Gasifier Modules	8	8	8	8	8	8	Count
F-T Modules	10	10	10	10	10	10	Count
CBTL Facility Inputs/Feed							
Coal Feed, Montana Rosebud, As Received	26,728	26,769	27,298	27,349	28,104	28,169	tons/ day
Biomass Feed, Southern Pine, As Received	3,286	3,291	3,274	3,280	3,291	3,298	tons/ day
Water Feed (Total Withdrawal)	15,064,488	15,135,573	14,881,770	14,963,547	14,662,766	14,755,221	gallons/day
CBTL Facility Outputs/Production							
F-T Jet Fuel Production	24,649	24,649	24,647	24,647	24,645	24,644	bpd
F-T Diesel Fuel Production	4,767	4,767	4,767	4,767	4,766	4,766	bpd
F-T Naphtha Production	16,973	16,973	16,972	16,971	16,970	16,970	bpd
F-T LPG Production	3,612	3,612	3,615	3,615	3,619	3,620	bpd
Total Liquid Product Output	50,000	50,000	50,000	50,000	50,000	50,000	bpd
Export Power	265	264	228	228	188	187	MW
CO2 Captured and Compressed	30,137	30,290	30,857	31,033	31,457	31,653	tons/ day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,298	49,297	49,294	49,293	49,289	49,288	bpd

CBTL facility fuels production capacity was fixed at 50,000 bpd for all three RSP cases. An expected capacity factor of 90 percent was included, ranging from 85 to 92 percent for low and high RSP cases, respectively. In the modeled case the overall expected plant efficiency of 53.5 percent (range of 51.5 to 55.1 percent) is defined as the heating value of the liquid products (HHV basis), F-T LPG, and export power divided by the higher heating value of the input coal and biomass. In the validation case the overall expected plant efficiency is 53.4 percent (range of 51.3 to 55.0 percent) , a variation of less than 1 percent from the modeled case. In the modeled case, makeup water for the CBTL facility, as modeled in Aspen Plus®, is estimated to be approximately 14.9 million gallons per day (mgd; expected RSP case), of which 95.9 percent (14.3 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 7.09 bbl water/bbl F-T product, based on the expected RSP modeled case. In the validated case, makeup water for the CBTL facility is estimated to be approximately 15.0 million gallons per day (mgd; expected RSP case), of which 95.9 percent (14.4 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 7.13 bbl water/bbl F-T product, based on the expected RSP validated case. Here there is strong agreement between the modeled and validated case with a variation of makeup water for the CBTL facility of 0.08 million gallon per day (0.55 percent) and a normalized variation of 0.04 bbl water/bbl F-T product (0.55 percent).

Under the modeled case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 188 to 265 MW, with an expected value of 228 MW. Based on the expected RSP case, gross power production for the CBTL facility is 794 MW, including power generated from steam (562 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (245 MW), carbon dioxide compressors (91.6 MW), the Selexol unit (60.5 MW), hydrocarbon recovery/refrigeration (42.9 MW), and oxygen compression (31.8 MW). Total auxiliaries consume 566 MW, for a net power output of 228 MW under the expected RSP case.

Under the validated case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 187 to 264 MW, with an expected value of 228 MW. Based on the expected RSP case, gross power production for the CBTL facility is 797 MW, including power generated from steam (565 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (246 MW), carbon dioxide compressors (92.0 MW), the Selexol unit (60.8 MW), hydrocarbon recovery/refrigeration (43.8 MW), and oxygen compression (31.9 MW). Total auxiliaries consume 570 MW, for a net power output of 228 MW under the expected RSP case.

Carbon balance for both the modeled and validated case of the CBTL facility is shown in **Table 5-58**, for all three RSP cases. As shown, carbon inputs were within 0.2 percent of carbon outputs for each of the three RSP cases. Carbon dioxide produced during the production of fuels and electric power is separated from the syngas stream prior to entering the F-T unit. The Selexol unit and the MDEA unit both produce the concentrated CO_2 streams that are dehydrated and compressed to 2,200 psi for pipeline delivery and carbon management. Other flue gas streams containing CO_2 are vented to the atmosphere. These include the flue gases from the HRSG units and from the fired heaters that are utilized during the F-T process. For the expected RSP case, approximately 2 percent of total carbon (range of 1 percent for the low RSP case to 4 percent for the high RSP case) is output to slag/ash from the TRIG gasifier.

Table 5-58: Scenario 15: CBTL, 11.7% Pelleted Biomass: Conversion Facility Carbon Balance

Input Flow	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
Coal Carbon	13,382	13,403	13,668	13,693	14,071	14,104	TPD
Biomass Carbon	1,004	1,005	1,000	1,002	1,005	1,008	TPD
Total Carbon Input	14,386	14,408	14,668	14,695	15,076	15,111	**TPD**
F-T Products	5,284	5,284	5,284	5,284	5,284	5,284	TPD
Slag/Ash	150	150	305	306	627	629	TPD
Stack Gas	1,001	988	951	938	902	889	TPD
Fuel Gas	272	265	246	239	218	211	TPD
WWTP	30	32	32	31	31	31	TPD
Carbon Capture, Sequestered	8,243	8,285	8,442	8,491	8,610	8,665	TPD
Total Carbon Output	**14,980**	**15,004**	**15,261**	**15,289**	**15,672**	**15,709**	**TPD**
Carbon Capture	**86.3**	**86.6**	**87.3**	**87.5**	**88.2**	**88.5**	**%**

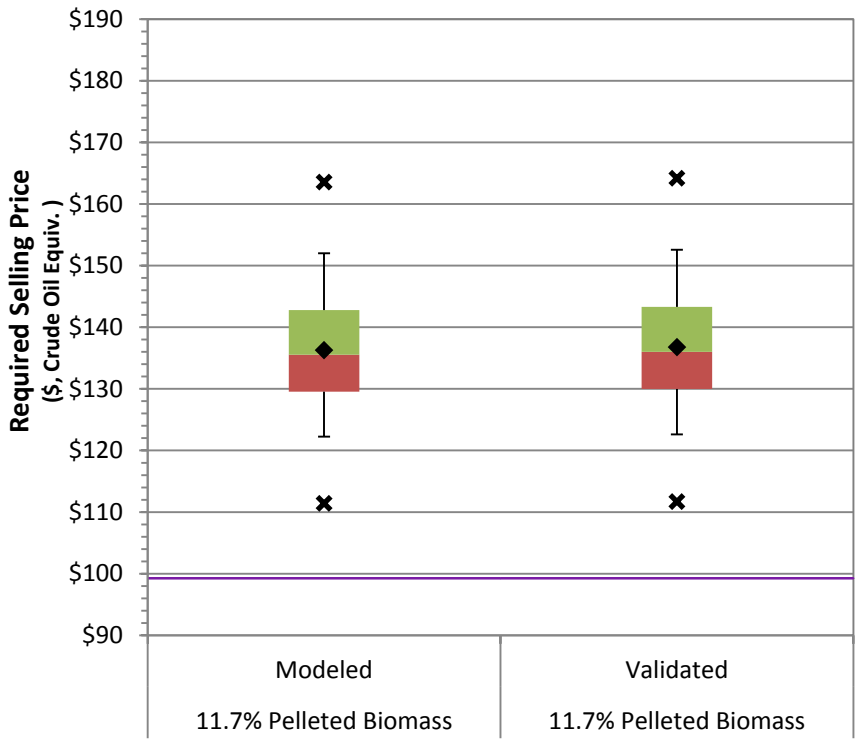
5.15.3 Economic Results

Results from the economic model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Figure 5-85 provides a summary of the estimated RSP for the F-T jet fuel produced under this scenario. As shown, RSP ranges from $130 to $143/bbl for the modeled case, with a mean value of $136/bbl, on a crude oil equivalent basis and for the variation, case the RSP ranges from $130 to $143/bbl, with a mean value of $137/bbl. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 40 economic parameters shown in **Table 1-5**. As shown, 25th and 75th percentile values are relatively close to the mean value, however, selling price distributions are characterized by long tails, with an overall range of $112 to $164/bbl, on a crude oil equivalent basis.

Cost of the F-T jet fuel product is estimated on a crude oil equivalent basis. This is defined as the RSP of the diesel product divided by a factor of 1.1433. Thus if the average world oil price were below or equal to the calculated crude oil equivalent price the CBTL plant would be economically viable. Key contributors to the variability shown for RSP results are discussed below.

Figure 5-85: Scenario 15: CBTL, 11.7% Pelleted Biomass: F-T Jet Fuel RSP, Crude Oil Equivalent Basis



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel spot price value.

It is clear from **Figure 5-85** that there is minimal variation between the modeled and validated RSP results. **Table 5-59** provides a summary of the economic estimated performance of the CBTL facility under the validated case of this scenario, including the key contributing factors to the calculation of RSP. Total operating and maintenance costs represent an average of $550 million/yr. Of this amount, $306 to $333 million/yr, mean $320 million/yr (58.2 percent), results from fixed costs, while $221 to $238 million/year, mean $230 million/yr (41.8 percent) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, range from $8,731 to $9,592 million, mean $9,168 million. Coal feedstock costs for this scenario range from $315 to $330 million/yr, mean $323 million/yr. Biomass feedstock costs range from $80.6 to $86.1 million/yr, mean $83.2 million/yr. Total feedstock costs are approximately $144 million lower than total operating and maintenance costs, on average. Projected revenues include credits and product sales revenue. Power credit, from the sale of produced electricity, amounts to $118 to $133 million/yr, mean $125 million/yr, while CO_2 credit is estimated to be $334 to $397 million/yr, mean $366 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,075 to $2,285 million/yr, mean $2,182 million/yr.

Required product sales prices in the validated case are also provided in **Table 5-59**. Crude oil equivalent RSP is discussed above for **Figure 5-85**. On a straight basis, RSP for F-T jet fuel was calculated to be $150 to $165/bbl, mean $158/bbl, with F-T diesel at $149 to $164/bbl, mean $156/bbl, F-T naphtha at $104 to $114/bbl, mean $109/bbl, and F-T LPG at $60.0 to $66.2/bbl, mean $63.2/bbl. The default capital charge factor (CCF) used in the analysis was 0.1872.

Table 5-59: Scenario 15: CBTL, 11.7% Pelleted Biomass: Summary of Economics

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	320	265	383	306	333	$MM/yr
Variable Operating and Maintenance Cost (VOM)	230	196	273	221	238	$MM/yr
Capital: Total Overnight Cost (TOC)	9,168	7,765	11,216	8,731	9,592	$MM
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	323	295	353	315	330	$MM/yr
Biomass Cost, Southern Pine, Chips, As Received	83	70	94	81	86	$MM/yr
Biomass Cost, Southern Pine, Torrefied, As Received	0	0	0	0	0	$MM/yr
Credits and Revenue						
Power Credit	(125)	(161)	(91)	(133)	(118)	$MM/yr
Credit @ $40/ton for CO_2	(366)	(472)	(258)	(397)	(334)	$MM/yr
Annual Revenue Required	2,182	1,771	2,644	2,075	2,285	$MM/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	158	129	190	150	165	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	156	128	188	149	164	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	109	89	131	104	114	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	63	52	76	60	66	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	137	112	164	130	143	$/bbl

Figure 5-86 provides breakdowns for the cost factors in the validated case that contribute to the RSP. As shown, capital cost is the primary factor in determining RSP, and accounts for approximately 78.7 percent of total RSP, or $108/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 22.0 percent of total RSP, or $30.1/bbl, while feedstock costs represent 16.3 percent of total RSP, or $22.2/bbl, on a crude oil equivalent basis. As shown, variability in total RSP is driven largely by potential variability in capital costs, and to a much lesser extent by variability in operations and maintenance and feedstock costs. The negative credits bar comprises the sale of the co-produced electricity and compressed CO_2. Electricity accounts for 25.5 percent of the total credit, while captured and compressed CO_2 accounts for 74.5 percent.

Figure 5-86: Scenario 15: CBTL, 11.7% Pelleted Biomass, Validated: RSP, Crude Oil Equivalent Basis

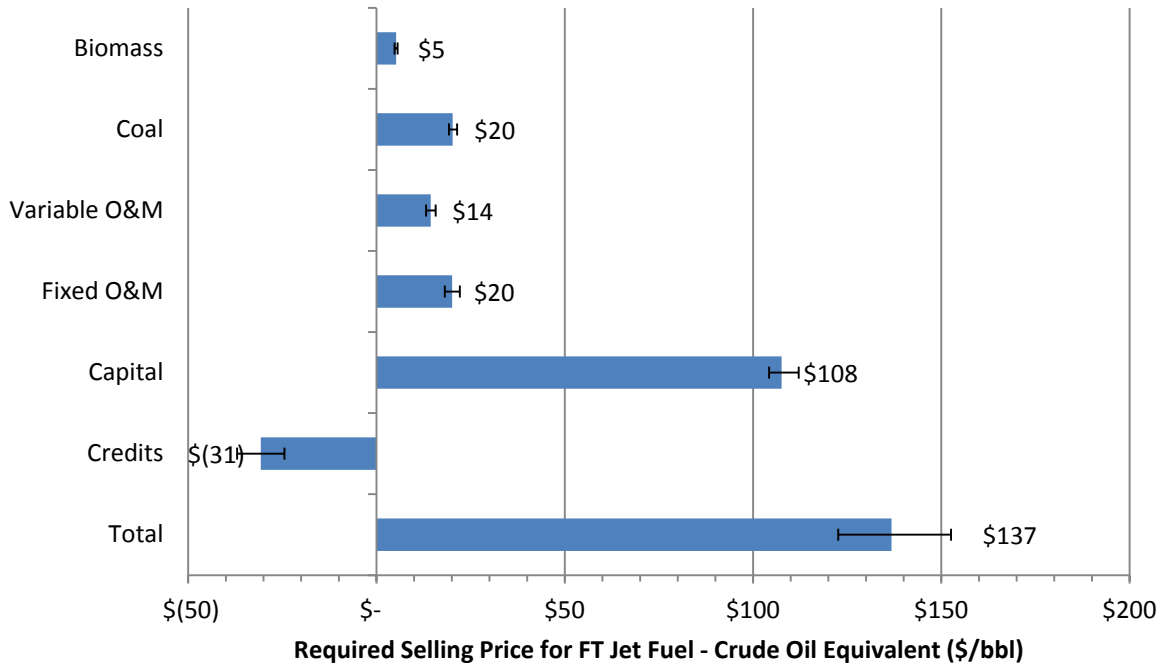
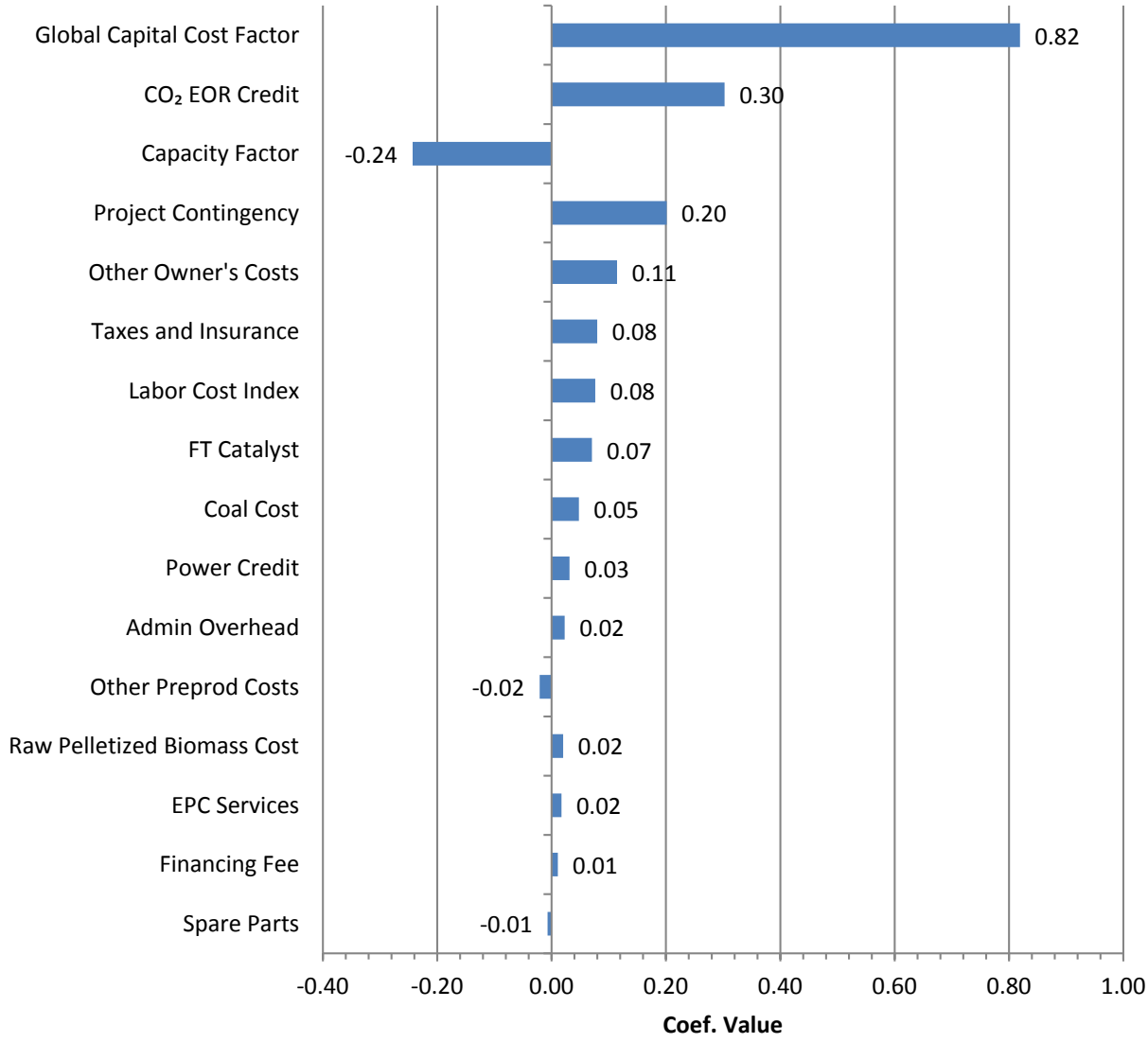


Figure 5-87 provides a summary of model sensitivity in the validated case, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.82. Other key factors that account for at least 10 percent of the observed variability in RSP include the CO_2 EOR credit, capacity factor, project contingency, and other owner's costs. Parameters that caused minimal influence on RSP included the cost of spare parts, EPC services, administrative overhead expenditures, financing fees, the cost of raw pelletized biomass, and others as shown.

Figure 5-87: Scenario 15: CBTL, 11.7% Chipped Biomass, Validated: Sensitivity of RSP to Modeled Variables

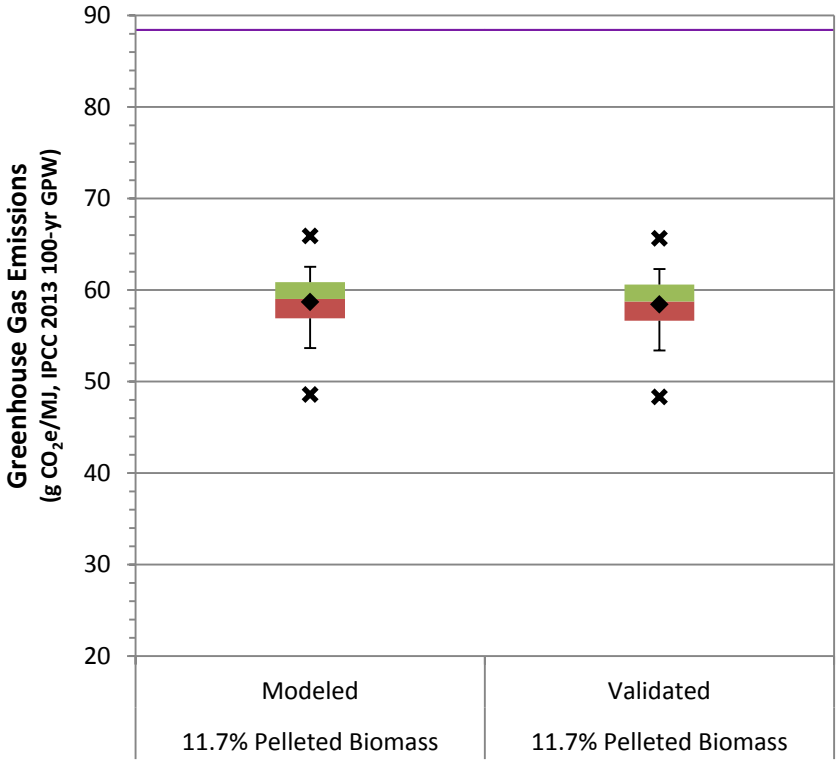


5.15.4 Environmental Results

Results from the environmental model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Results from the environmental life cycle analysis include GHG emissions and other emissions, including select criteria air pollutants, other pollutants of concern, and water consumption. **Figure 5-88** provides a summary life cycle GHG emissions for this scenario, in comparison to conventional jet fuel life cycle GHG emissions of 88.41 g CO_2e/MJ. In the modeled case the resulting range is 48.6 to 65.9 g CO_2e/MJ, mean 58.7 g CO_2e/MJ or approximately 32.8 percent less than conventional jet fuel. In the validated case the resulting range is 48.3 to 65.7 g CO_2e/MJ, mean 58.5 g CO_2e/MJ or approximately 33.1 percent less than conventional jet fuel.

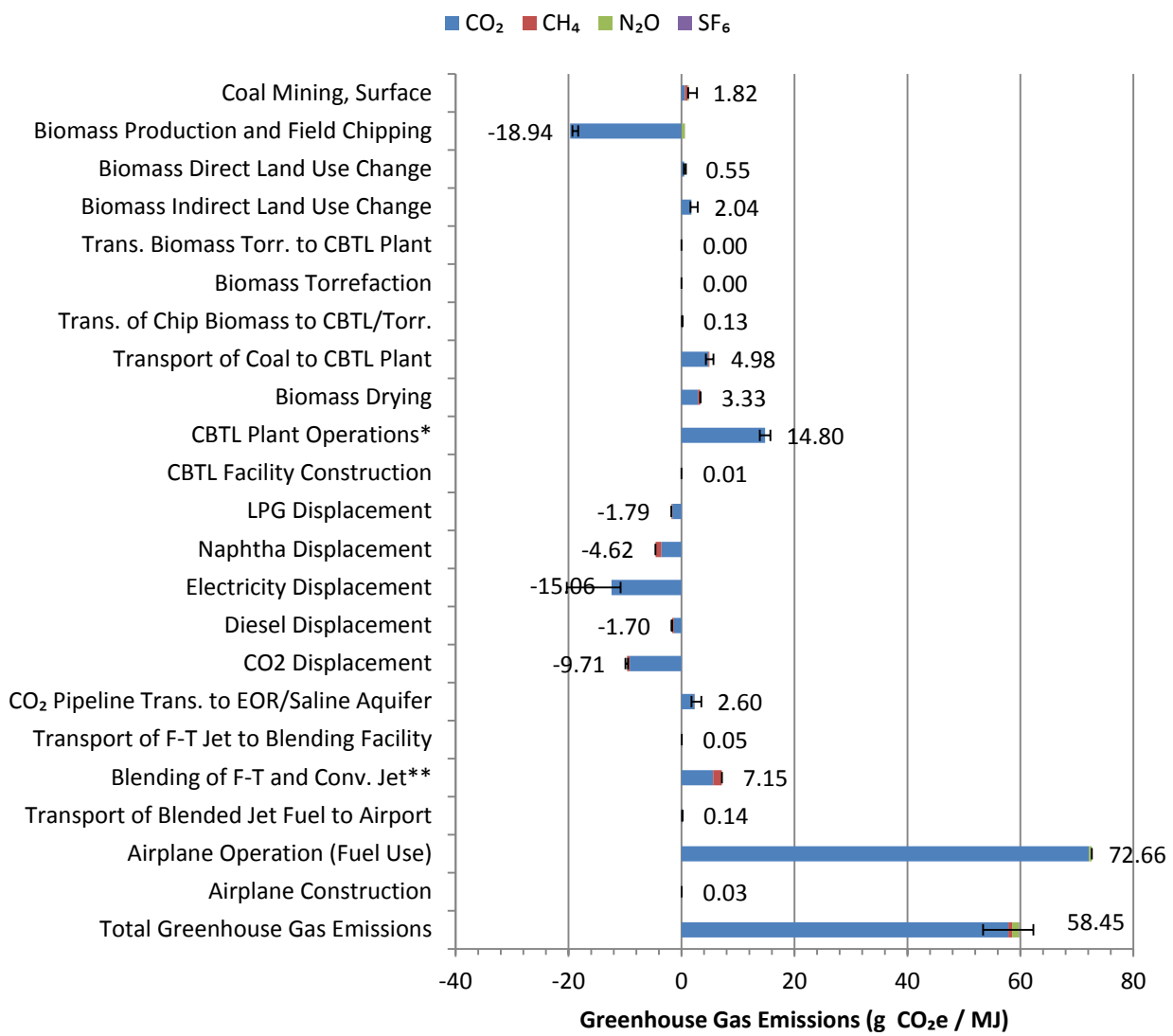
Figure 5-88: Scenario 15: CBTL, 11.7% Pelleted Biomass, Validated: Summary of LC GHG Emissions



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

It is clear from **Figure 5-88** that there is minimal variation between the modeled and validated LC GHG emission results. **Figure 5-89** provides detail regarding the importance of the various LCA components in the validated case that were modeled, with respect to gross GHG emissions contributions. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 65.4 percent of gross life cycle GHG emissions. Second in importance to fuel combustion is CBTL plant operations, at 13.4 percent of gross life cycle emissions, while emissions associated with blending of F-T and conventional jet fuel represent 5.08 percent of gross life cycle emissions. The transport of coal to the CBTL plant accounts for 4.33 percent of gross life cycle GHG emissions. Emissions from the pipeline transport of CO_2 represents approximately 2.65 percent of gross emissions. GHG emissions associated with biomass indirect land use change generate 2.12 percent of gross life cycle emissions, while biomass drying generates 1.57 percent. Other contributors to gross emissions were less than 1 percent individually.

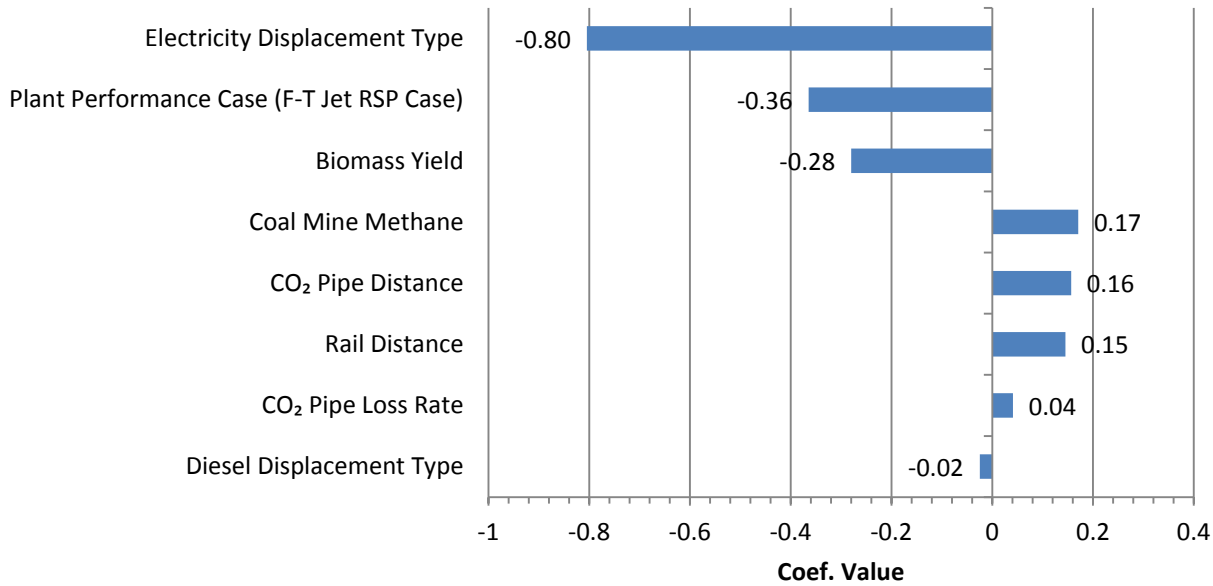
Figure 5-89: Scenario 15: CBTL, 11.7% Pelleted Biomass, Validated: LC GHG Emissions Breakdowns



** Includes CO_2 Compression*
*** Includes conventional jet fuel profile*

The error bars shown in **Figure 5-89** reflect variability in model output based on the stochastic analyses (for more information, refer to Chapter 1). The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-6**. As shown, variability in emissions resulted primarily from the type of electricity displacement used. Other key contributors to variability in model output include the F-T jet fuel RSP case and biomass yield. **Figure 5-90** summarizes the key factors contributing to variability identified in the model sensitivity analysis, for GHG emissions. Values provided in the figure show the correlation coefficient between the indicated parameter and total life cycle GHG emissions. Other important factors include coal mine methane emissions, the blended jet fuel pipe length, the rail transport distance, the CO_2 pipe loss rate, and the diesel displacement type. Other parameters had minimal to negligible effect on life cycle GHG emissions.

Figure 5-90: Scenario 15: CBTL, 11.7% Pelleted Biomass, Validated: LC GHG Emissions Sensitivity



In addition to GHG emissions, other life cycle environmental emissions and flows were also considered. **Table 5-60** provides a summary of these flows. As shown, Airplane operation is the primary source of carbon monoxide and NOx within the life cycle. Particulate matter (PM_{10}) derives primarily from the combustion of diesel under raw materials transport and product transport operations. Non-methane volatile organic carbons (NMVOCs) result from product transport, including upstream conventional jet fuel emissions, and end use. The highest levels of mercury emissions occur during energy conversion and end use. Most water consumption occurs during biomass cultivation. Note that mass units displayed for water consumption (kg/MJ jet fuel) are equivalent to volume units for water consumption (L/MJ jet fuel).

Table 5-60: Scenario 15: CBTL, 11.7% Pelleted Biomass, Validated: Non-GHG Emissions

LC Stage	Carbon monoxide	NO_x	SO2	PM10	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	8.88E-05	2.32E-04	6.08E-05	2.76E-06	1.05E-05	3.75E-10	1.69E-05	3.38E+02	kg/MJ Jet Fuel
RMT	5.72E-04	5.16E-04	1.19E-04	6.57E-04	9.89E-05	3.98E-10	7.44E-06	1.91E-01	kg/MJ Jet Fuel
EC	-4.48E-04	-1.40E-03	-2.79E-03	-1.67E-04	-5.58E-04	5.59E-08	1.43E-05	-1.12E+00	kg/MJ Jet Fuel
PT	2.76E-04	4.38E-04	6.25E-04	3.28E-05	8.45E-04	5.80E-10	2.92E-06	1.08E+00	kg/MJ Jet Fuel
EU	7.72E-03	1.21E-02	5.56E-04	9.50E-07	7.72E-04	3.01E-08	7.16E-09	2.81E-02	kg/MJ Jet Fuel
Total	**8.21E-03**	**1.19E-02**	**-1.43E-03**	**5.27E-04**	**1.17E-03**	**8.73E-08**	**4.16E-05**	**3.38E+02**	**kg/MJ Jet Fuel**

5.16 Scenario 16: CBTL, 19.2 Percent Pelleted Biomass and Validation

The purpose of this scenario is to evaluate potential process values, economic factors, and environmental emissions associated with the production of F-T jet fuels from a combination of 80.8 percent sub-bituminous coal and 19.2 percent pelleted biomass. This scenario evaluates a 1:1 (volume) blend of F-T jet fuels and conventional U.S. average jet fuel, based on a 30-year study period. Coal feedstock is derived from the Rosebud seam in southern Montana, and is transported by train to the CBTL facility, located in the Southeastern U.S. Biomass feedstock is field-chipped Southern pine biomass, cultivated and harvested in the Southeastern U.S., field-chipped, and then transported by chip truck to a separate pelletization facility, where the biomass is formed into pellets. Pelleted biomass is then transported by truck to the CBTL facility. The F-T process employed uses a slurry-based iron catalyst using a single feed, oxygen blown Transport Reactor Integrated Gasifier (TRIG™; refer to Chapter 2 for additional discussion). Carbon dioxide is captured at the CBTL facility using a Selexol process to segregate carbon dioxide. Additional carbon dioxide is stripped from overhead gas downstream of the F-T synthesis process, using a methyldiethanolamine (MDEA) unit. Captured carbon dioxide is then routed to a purification and compression system, where it is compressed to a supercritical state. F-T jet fuel produced by the F-T facility is then conveyed to a blending facility, where it is blended with conventional jet fuel, and transported to an airport. Finally, the blended jet fuel is combusted in a jet airplane.

The following text provides a summary of process model, economic model, and environmental model results for this scenario.

5.16.2 Process Results

As discussed in Chapter 2, three Aspen Plus® model cases were run for this scenario: low RSP, expected RSP, and high RSP. Process summary results, both modeled and validated, for each of the three cases are reported in **Table 5-61**. Results obtained from the Aspen Plus® simulations are based on a 50,000 barrel per day (bpd) production rate for total F-T products (F-T jet fuel, F-T diesel, F-T naphtha, and F-T LPG) for the CBTL, 19.2 percent Pelleted Biomass configuration under all three RSP cases. Fuel production breakdowns are minimally variable among the three RSP cases. For all three RSP cases, approximately 49 percent (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34 percent by volume of total products) being F-T naphtha. F-T jet fuel is produced by hydrocracking the F-T wax to a final boiling point of about 300°C. Hydrocracking also produces naphtha boiling range liquids and F-T LPG. Relatively smaller quantities of F-T diesel (10 percent of total products) and F-T LPG (7 percent of total products) are produced as a result of hydrocracking. These proportions assume that straight run F-T output would be sold as a product. Results from each of the three Aspen Plus® model cases were incorporated into the economic and environmental analyses, the results of which are displayed below. For additional information regarding the application of low, expected, and high RSP values to the stochastic analysis provided here, refer to Chapter 1.

Table 5-61: Scenario 16: CBTL, 19.2% Pelleted Biomass: Process Summary

Property	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
CBTL Facility Design and Operating Data							
Plant Design Capacity	50,000	50,000	50,000	50,000	50,000	50,000	bpd
Plant Capacity Factor	85	85	90	90	92	92	%
Plant Efficiency, HHV	55	55	54	54	52	52	%
Carbon Capture Rate	88	88	89	89	90	90	%
Gasifier Modules	7	7	7	7	7	7	Count
F-T Modules	10	10	10	10	10	10	Count
CBTL Facility Inputs/Feed							
Coal Feed, Montana Rosebud, As Received	24,662	24,700	25,208	25,255	25,977	26,037	tons/ day
Biomass Feed, Southern Pine, As Received	5,438	5,446	5,422	5,433	5,455	5,468	tons/ day
Water Feed (Total Withdrawal)	14,969,504	15,040,106	14,788,919	14,870,064	14,573,741	14,665,595	gallons/day
CBTL Facility Outputs/Production							
F-T Jet Fuel Production	24,649	24,648	24,647	24,647	24,645	24,644	bpd
F-T Diesel Fuel Production	4,767	4,767	4,767	4,767	4,766	4,766	bpd
F-T Naphtha Production	16,973	16,972	16,972	16,971	16,970	16,970	bpd
F-T LPG Production	3,612	3,612	3,615	3,615	3,619	3,620	bpd
Total Liquid Product Output	50,000	50,000	50,000	50,000	50,000	50,000	bpd
Export Power	267	266	233	232	194	193	MW
CO2 Captured and Compressed	30,173	30,325	30,845	31,021	31,411	31,606	tons/ day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,297	49,297	49,294	49,293	49,289	49,288	bpd

CBTL facility fuels production capacity was fixed at 50,000 bpd for all three RSP cases. An expected capacity factor of 90 percent was included, ranging from 85 to 92 percent for low and high RSP cases, respectively. In the modeled case the overall expected plant efficiency of 53.7 percent (range of 51.7to 55.2 percent) is defined as the heating value of the liquid products (HHV basis), F-T LPG, and export power divided by the higher heating value of the input coal and biomass. In the validation case the overall expected plant efficiency is 53.6 percent (range of 51.6to 55.1 percent) , a variation of less than 1 percent from the modeled case. In the modeled case, makeup water for the CBTL facility, as modeled in Aspen Plus®, is estimated to be approximately 14.8 million gallons per day (mgd; expected RSP case), of which 96.5 percent (14.3mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 7.04 bbl water/bbl F-T product, based on the expected RSP modeled case. In the validated case, makeup water for the CBTL facility is estimated to be approximately 14.9 million gallons per day (mgd; expected RSP case), of which 96.5 percent (14.4mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 7.08 bbl water/bbl F-T product, based on the expected RSP validated case. Here there is strong agreement between the modeled and validated case with a variation of makeup water for the CBTL facility of 0.08 million gallon per day 0.55 percent) and a normalized variation of 0.04 bbl water/bbl F-T product (0.55 percent).

Under the modeled case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 194 to 267MW, with an expected value of 233 MW. Based on the expected RSP case, gross power production for the CBTL facility is 795 MW, including power generated from steam (563 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (242 MW), carbon dioxide compressors (91.6 MW), the Selexol unit (60.3 MW), hydrocarbon recovery/refrigeration (42.7 MW), and oxygen compression (31.5 MW). Total auxiliaries consume 562 MW, for a net power output of 233 MW under the expected RSP case.

Under the validated case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 193 to 266 MW, with an expected value of 232 MW. Based on the expected RSP case, gross power production for the CBTL facility is 798 MW, including power generated from steam (566 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (243 MW), carbon dioxide compressors (92.0 MW), the Selexol unit (60.6 MW), hydrocarbon recovery/refrigeration (43.6 MW), and oxygen compression (31.5 MW). Total auxiliaries consume 566 MW, for a net power output of 232 MW under the expected RSP case.

Carbon balance for both the modeled and validated case of the CBTL facility is shown in **Table 5-62**, for all three RSP cases. As shown, carbon inputs were within 0.2 percent of carbon outputs for each of the three RSP cases. Carbon dioxide produced during the production of fuels and electric power is separated from the syngas stream prior to entering the F-T unit. The Selexol unit and the MDEA unit both produce the concentrated CO_2 streams that are dehydrated and compressed to 2,200 psi for pipeline delivery and carbon management. Other flue gas streams containing CO_2 are vented to the atmosphere. These include the flue gases from the HRSG units and from the fired heaters that are utilized during the F-T process. For the expected RSP case, approximately 2 percent of total carbon (range of 1 percent for the low RSP case to 4 percent for the high RSP case) is output to slag/ash from the TRIG gasifier.

Table 5-62: Scenario 16: CBTL, 19.2% Pelleted Biomass: Conversion Facility Carbon Balance

Input Flow	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
Coal Carbon	12,348	12,367	12,621	12,645	13,006	13,036	TPD
Biomass Carbon	1,661	1,664	1,657	1,660	1,666	1,670	TPD
Total Carbon Input	14,009	14,030	14,278	14,304	14,673	14,707	**TPD**
F-T Products	5,284	5,284	5,284	5,284	5,284	5,284	TPD
Slag/Ash	150	150	305	306	627	628	TPD
Stack Gas	999	986	949	935	899	886	TPD
Fuel Gas	272	266	247	239	219	212	TPD
WWTP	32	32	30	31	30	30	TPD
Carbon Capture, Sequestered	8,253	8,295	8,439	8,488	8,597	8,652	TPD
Total Carbon Output	**14,990**	**15,012**	**15,254**	**15,284**	**15,655**	**15,691**	**TPD**
Carbon Capture	**86.4**	**86.6**	**87.3**	**87.6**	**88.2**	**88.5**	**%**

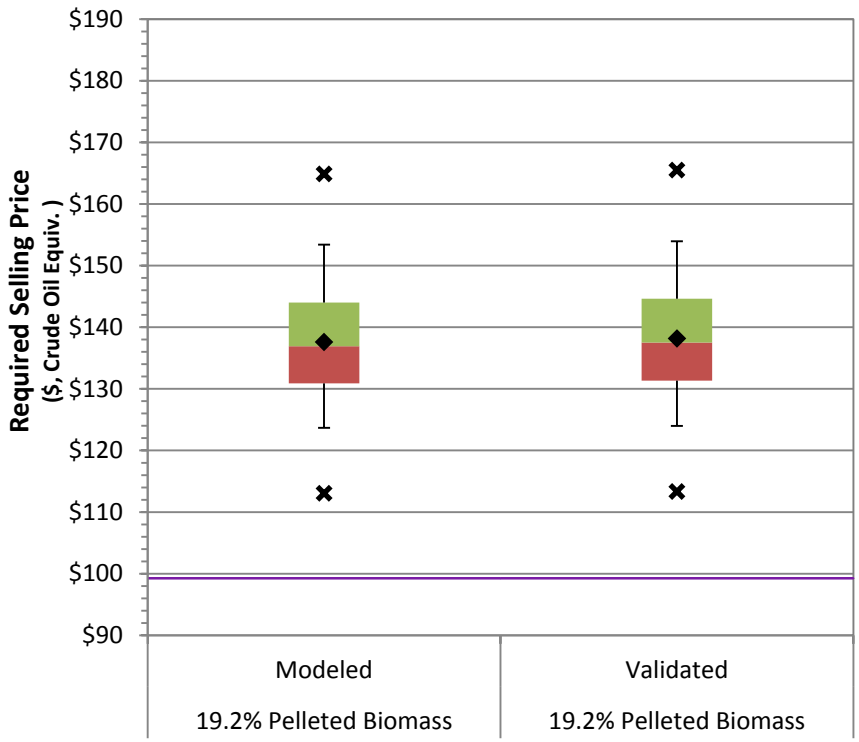
5.16.3 Economic Results

Results from the economic model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Figure 5-91 provides a summary of the estimated RSP for the F-T jet fuel produced under this scenario. As shown, RSP ranges from $131 to $144/bbl for the modeled case, with a mean value of $138/bbl, on a crude oil equivalent basis and for the variation, case the RSP ranges from $131 to $145/bbl, with a mean value of $138/bbl. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 40 economic parameters shown in **Table 1-5**. As shown, 25th and 75th percentile values are relatively close to the mean value, however, selling price distributions are characterized by long tails, with an overall range of $113 to $166/bbl, on a crude oil equivalent basis.

Cost of the F-T jet fuel product is estimated on a crude oil equivalent basis. This is defined as the RSP of the diesel product divided by a factor of 1.1433. Thus if the average world oil price were below or equal to the calculated crude oil equivalent price the CBTL plant would be economically viable. Key contributors to the variability shown for RSP results are discussed below.

Figure 5-91: Scenario 16: CBTL, 19.2% Pelleted Biomass: F-T Jet Fuel RSP, Crude Oil Equivalent Basis



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel spot price value.

It is clear from **Figure 5-91** that there is minimal variation between the modeled and validated RSP results. **Table 5-63** provides a summary of the economic estimated performance of the CBTL facility under the validated case of this scenario, including the key contributing factors to the calculation of RSP. Total operating and maintenance costs represent an average of $550 million/yr. Of this amount, $306 to $333 million/yr, mean $320 million/yr (58.3 percent), results from fixed costs, while $221 to $229 million/year, mean $172 million/yr (41.7 percent) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, range from $8,706 to $9,561million, mean $9,142 million. Coal feedstock costs for this scenario range from $291 to $304million/yr, mean $298 million/yr. Biomass feedstock costs range from $134 to $143 million/yr, mean $138 million/yr. Total feedstock costs are approximately $114 million lower than total operating and maintenance costs, on average. Projected revenues include credits and product sales revenue. Power credit, from the sale of produced electricity, amounts to $120 to $135 million/yr, mean $127 million/yr, while CO_2 credit is estimated to be $334 to $397 million/yr, mean $365 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,097 to $2,309 million/yr, mean $2,204 million/yr.

Required product sales prices in the validated case are also provided in **Table 5-63**. Crude oil equivalent RSP is discussed above for **Figure 5-91**. On a straight basis, RSP for F-T jet fuel was calculated to be $152 to $167/bbl, mean $160/bbl, with F-T diesel at $150 to $165bbl, mean $158/bbl, F-T naphtha at $105 to $115/bbl, mean $110/bbl, and F-T LPG at $60.7 to $66.8/bbl, mean $63.8/bbl. The default capital charge factor (CCF) used in the analysis was 0.1872.

Table 5-63: Scenario 16: CBTL, 19.2% Pelleted Biomass: Summary of Economics

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	320	265	383	306	333	$MM/yr
Variable Operating and Maintenance Cost (VOM)	229	196	272	221	237	$MM/yr
Capital: Total Overnight Cost (TOC)	9,142	7,745	11,199	8,706	9,561	$MM
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	298	272	326	291	304	$MM/yr
Biomass Cost, Southern Pine, Chips, As Received	138	117	156	134	143	$MM/yr
Biomass Cost, Southern Pine, Torrefied, As Received	0	0	0	0	0	$MM/yr
Credits and Revenue						
Power Credit	(127)	(162)	(94)	(135)	(120)	$MM/yr
Credit @ $40/ton for CO_2	(365)	(472)	(258)	(397)	(334)	$MM/yr
Annual Revenue Required	2,204	1,794	2,668	2,097	2,309	$MM/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	160	131	191	152	167	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	158	130	189	150	165	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	110	90	132	105	115	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	64	52	76	61	67	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	138	113	166	131	145	$/bbl

Figure 5-92 provides breakdowns for the cost factors in the validated case that contribute to the RSP. As shown, capital cost is the primary factor in determining RSP, and accounts for approximately 77.6 percent of total RSP, or $107/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 21.8 percent of total RSP, or $30.1/bbl, while feedstock costs represent 17.3 percent of total RSP, or $23.9/bbl, on a crude oil equivalent basis. As shown, variability in total RSP is driven largely by potential variability in capital costs, and to a much lesser extent by variability in operations and maintenance and feedstock costs. The negative credits bar comprises the sale of the co-produced electricity and compressed CO_2. Electricity accounts for 25.8 percent of the total credit, while captured and compressed CO_2 accounts for 74.2 percent.

Figure 5-92: Scenario 16: CBTL, 19.2% Pelleted Biomass, Validated: RSP, Crude Oil Equivalent Basis

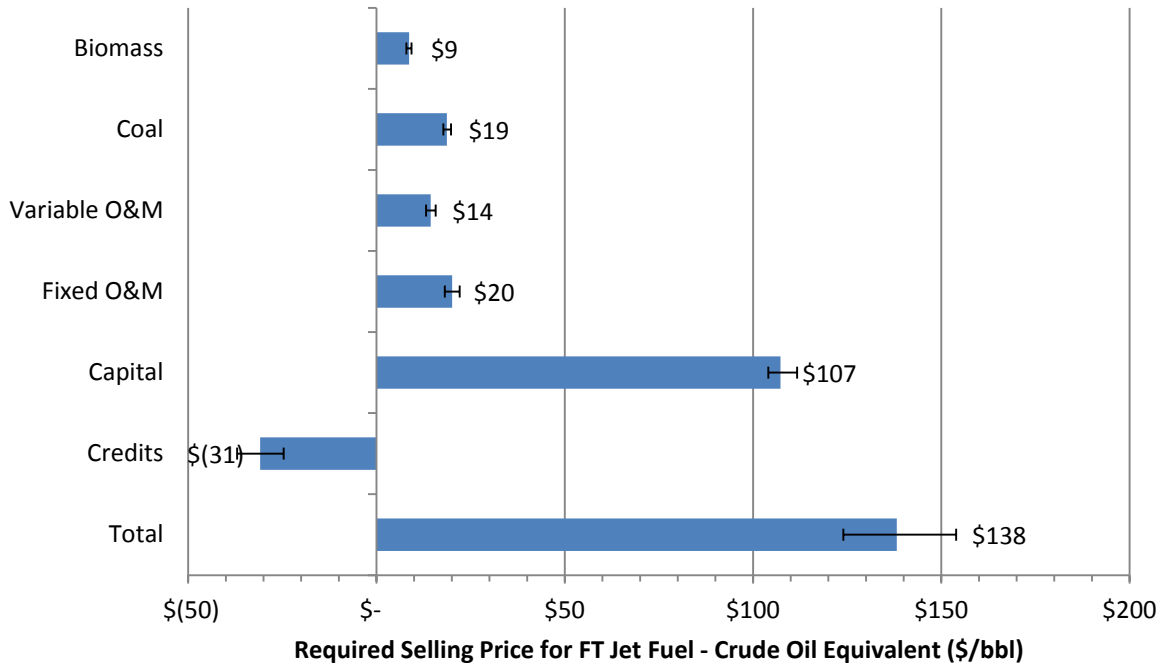
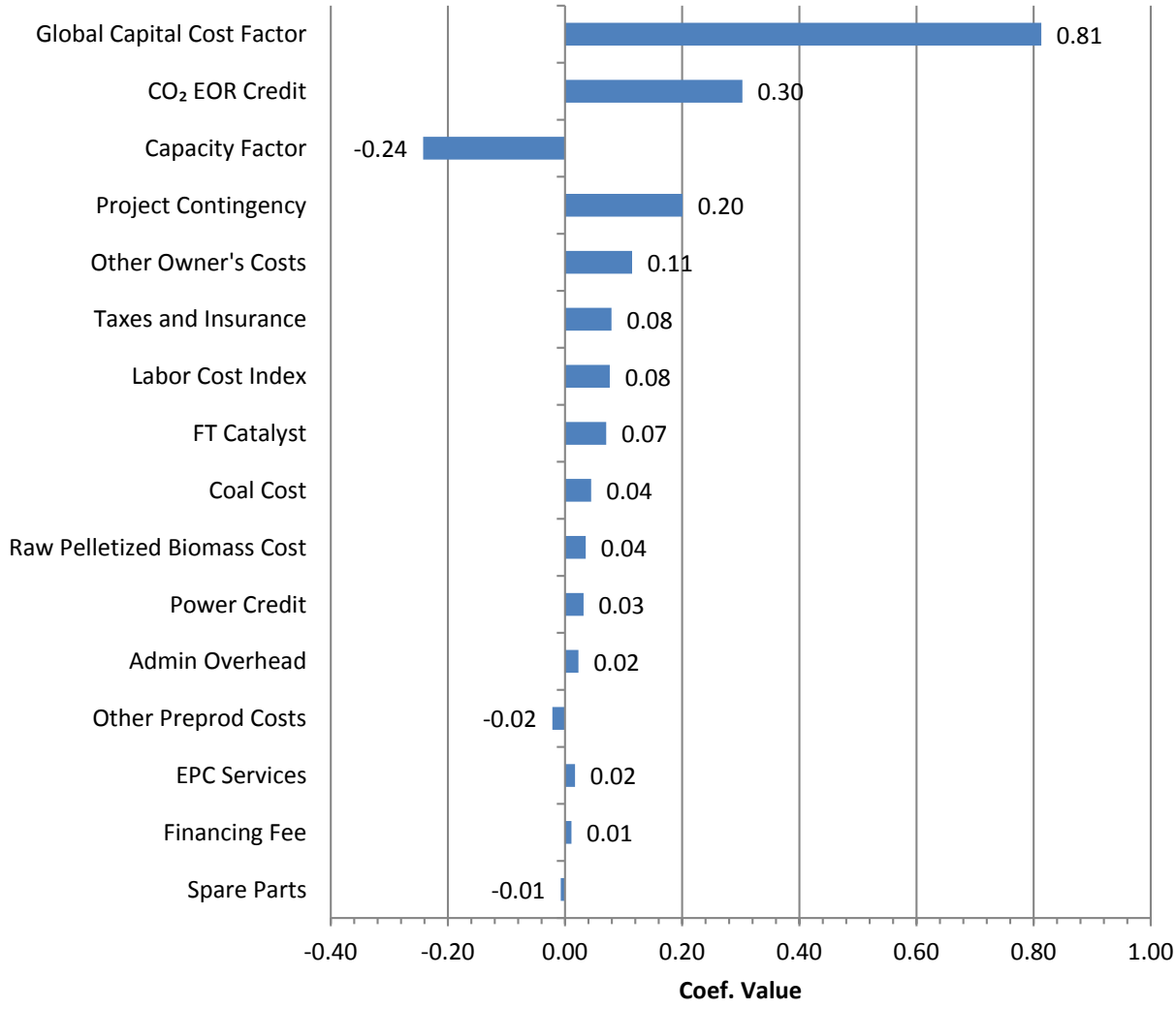


Figure 5-93 provides a summary of model sensitivity in the validated case, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.82. Other key factors that account for at least 10 percent of the observed variability in RSP include the CO_2 EOR credit, capacity factor, project contingency and other owner's costs. Parameters that caused minimal influence on RSP included EPC services, administrative overhead expenditures, financing fees, the cost of spare parts, and others as shown.

Figure 5-93: Scenario 16: CBTL, 19.2% Chipped Biomass, Validated: Sensitivity of RSP to Modeled Variables

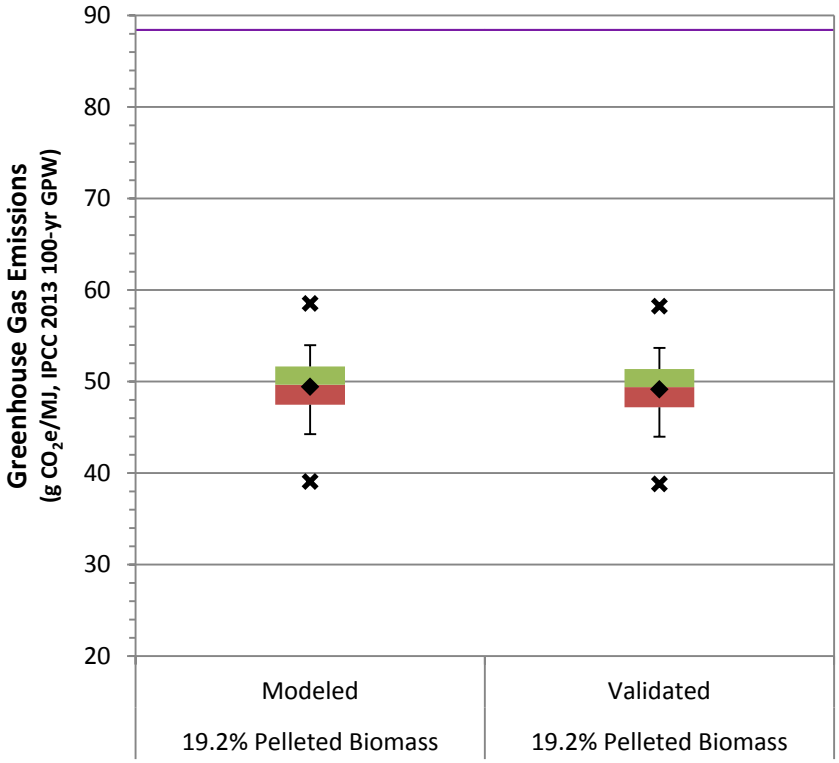


5.16.4 Environmental Results

Results from the environmental model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Results from the environmental life cycle analysis include GHG emissions and other emissions, including select criteria air pollutants, other pollutants of concern, and water consumption. **Figure 5-94** provides a summary life cycle GHG emissions for this scenario, in comparison to conventional jet fuel life cycle GHG emissions of 88.41 g CO_2e/MJ. In the modeled case the resulting range is 39.1 to 58.5 g CO_2e/MJ, mean 49.5 g CO_2e/MJ or approximately 43.4 percent less than conventional jet fuel. In the validated case the resulting range is 38.8 to 58.3 g CO_2e/MJ, mean 49.2 g CO_2e/MJ or approximately 43.7 percent less than conventional jet fuel.

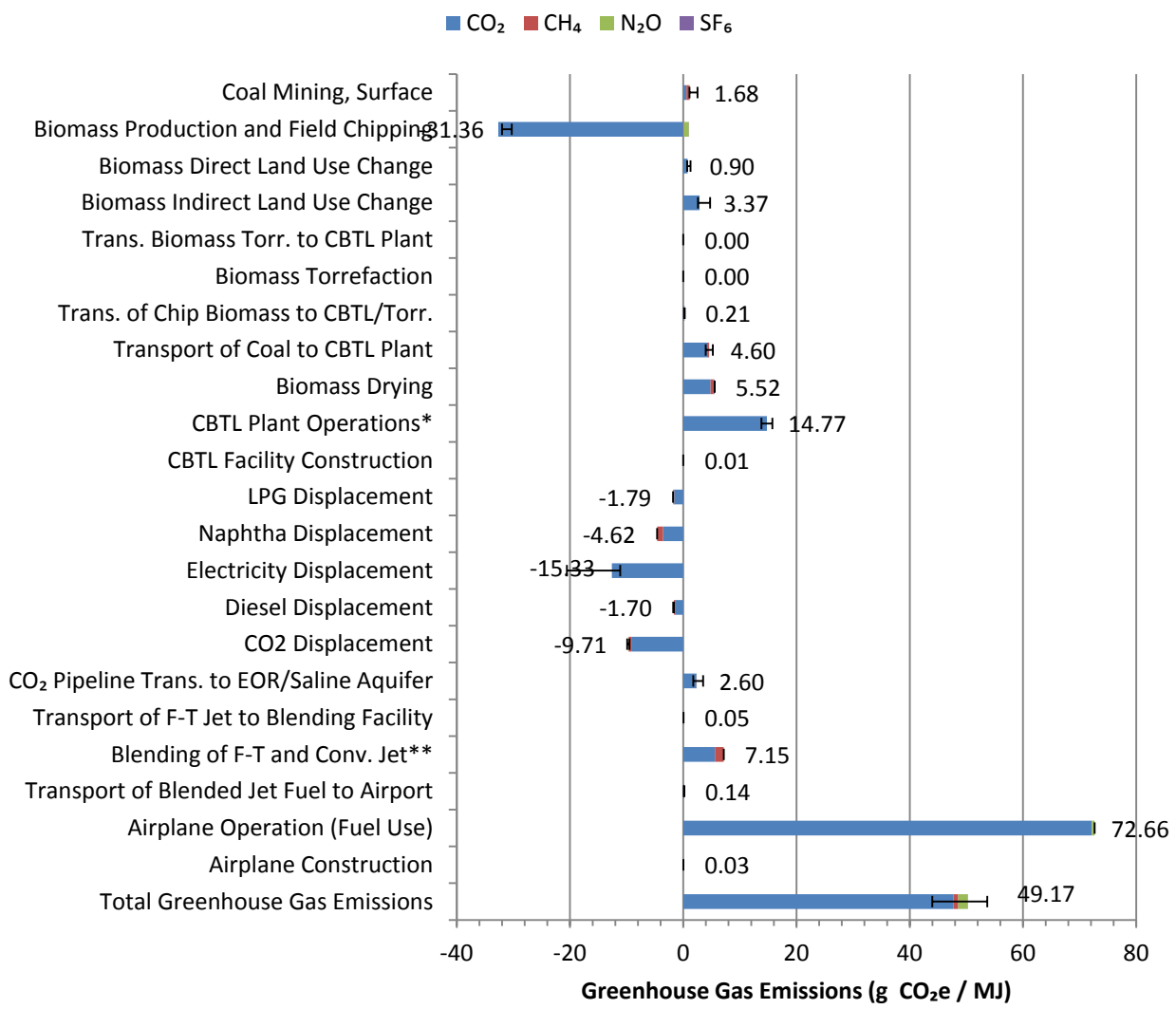
Figure 5-94: Scenario 16: CBTL, 19.2% Pelleted Biomass, Validated: Summary of LC GHG Emissions



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

It is clear from **Figure 5-94** that there is minimal variation between the modeled and validated LC GHG emission results. **Figure 5-95** provides detail regarding the importance of the various LCA components in the validated case that were modeled, with respect to gross GHG emissions contributions. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 63.5 percent of gross life cycle GHG emissions. Second in importance to fuel combustion is CBTL plant operations, at 13.0 percent of gross life cycle emissions, while emissions associated with blending of F-T and conventional jet fuel represent 4.93 percent of gross life cycle emissions. The transport of coal to the CBTL plant accounts for 4.25 percent of gross life cycle GHG emissions. Emissions from biomass indirect land use change represent approximately 3.87 percent of gross emissions. GHG emissions associated with pipeline transport of CO_2 generates 2.52 percent of gross life cycle emissions, while biomass drying generates 2.05 percent. Other contributors to gross emissions were less than 1 percent individually.

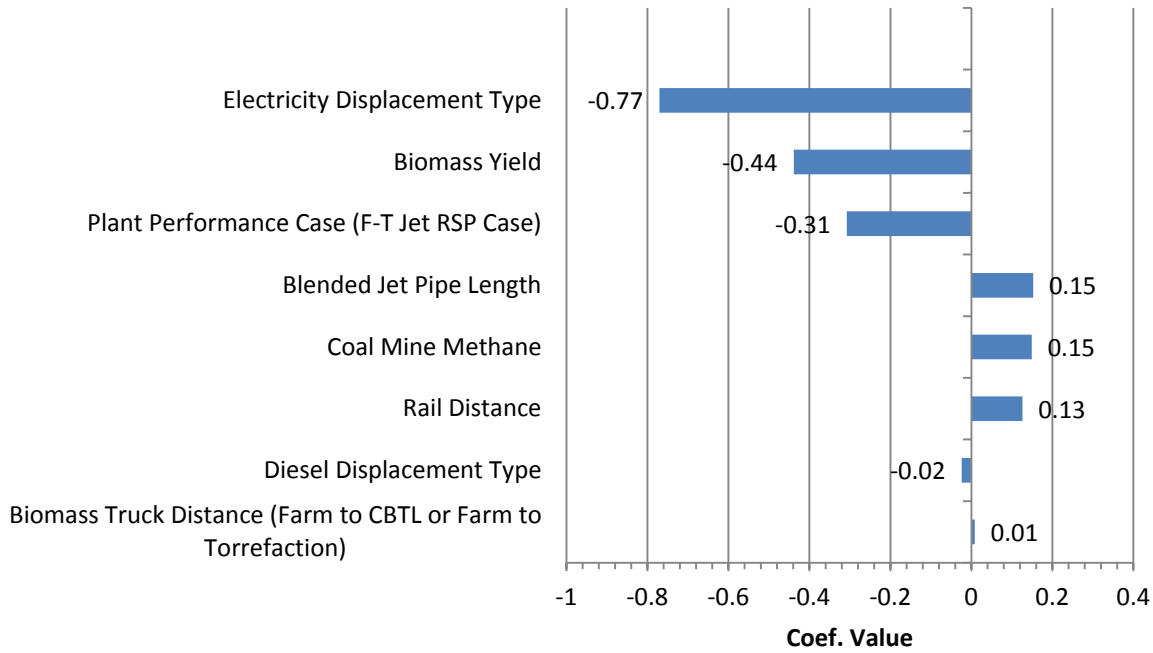
Figure 5-95: Scenario 16: CBTL, 19.2% Pelleted Biomass, Validated: LC GHG Emissions Breakdowns



** Includes CO_2 Compression*
*** Includes conventional jet fuel profile*

The error bars shown in **Figure 5-95** reflect variability in model output based on the stochastic analyses (for more information, refer to Chapter 1). The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-6**. As shown, variability in emissions resulted primarily from the type of electricity displacement used. Other key contributors to variability in model output include biomass yield, and the F-T jet fuel RSP case. **Figure 5-96** summarizes the key factors contributing to variability identified in the model sensitivity analysis, for GHG emissions. Values provided in the figure show the correlation coefficient between the indicated parameter and total life cycle GHG emissions. Other important factors included the CO_2 pipe length, the coal mine methane emissions, the rail transport distance, the diesel displacement type, the biomass truck transportation distance from farm, and the biomass chip type. Other parameters had minimal to negligible effect on life cycle GHG emissions.

Figure 5-96: Scenario 16: CBTL, 19.2% Pelleted Biomass, Validated: LC GHG Emissions Sensitivity



In addition to GHG emissions, other life cycle environmental emissions and flows were also considered. **Table 5-64** provides a summary of these flows. As shown, Airplane operation is the primary source of carbon monoxide and NOx within the life cycle. Particulate matter (PM_{10}) derives primarily from the combustion of diesel under raw materials transport and product transport operations. Non-methane volatile organic carbons (NMVOCs) result from product transport, including upstream conventional jet fuel emissions, and end use. The highest levels of mercury emissions occur during energy conversion and end use. Most water consumption occurs during biomass cultivation. Note that mass units displayed for water consumption (kg/MJ jet fuel) are equivalent to volume units for water consumption (L/MJ jet fuel).

Table 5-64: Scenario 16: CBTL, 19.2% Pelleted Biomass, Validated: Non-GHG Emissions

LC Stage	Carbon monoxide	NO_x	SO2	PM10	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	1.34E-04	2.53E-04	8.71E-05	3.23E-06	9.71E-06	4.06E-10	2.67E-05	5.59E+02	kg/MJ Jet Fuel
RMT	5.36E-04	4.79E-04	1.12E-04	6.07E-04	9.31E-05	4.27E-10	6.88E-06	1.86E-01	kg/MJ Jet Fuel
EC	-3.96E-04	-1.25E-03	-2.78E-03	-1.60E-04	-4.56E-04	5.07E-08	1.42E-05	-1.09E+00	kg/MJ Jet Fuel
PT	2.76E-04	4.38E-04	6.25E-04	3.28E-05	8.45E-04	5.80E-10	2.92E-06	1.08E+00	kg/MJ Jet Fuel
EU	7.72E-03	1.21E-02	5.56E-04	9.50E-07	7.72E-04	3.01E-08	7.16E-09	2.81E-02	kg/MJ Jet Fuel
Total	**8.27E-03**	**1.21E-02**	**-1.39E-03**	**4.84E-04**	**1.26E-03**	**8.21E-08**	**5.07E-05**	**5.59E+02**	**kg/MJ Jet Fuel**

5.17 Scenario 17: CBTL, 28.3 Percent Pelleted Biomass and Validation

The purpose of this scenario is to evaluate potential process values, economic factors, and environmental emissions associated with the production of F-T jet fuels from a combination of 71.7 percent sub-bituminous coal and 28.3 percent pelleted biomass. This scenario evaluates a 1:1 (volume) blend of F-T jet fuels and conventional U.S. average jet fuel, based on a 30-year study period. Coal feedstock is derived from the Rosebud seam in southern Montana, and is transported by train to the CBTL facility, located in the Southeastern U.S. Biomass feedstock is field-chipped Southern pine biomass, cultivated and harvested in the Southeastern U.S., field-chipped, and then transported by chip truck to a separate pelletization facility, where the biomass is formed into pellets. Pelleted biomass is then transported by truck to the CBTL facility. The F-T process employed uses a slurry-based iron catalyst using a single feed, oxygen blown Transport Reactor Integrated Gasifier (TRIG™; refer to Chapter 2 for additional discussion). Carbon dioxide is captured at the CBTL facility using a Selexol process to segregate carbon dioxide. Additional carbon dioxide is stripped from overhead gas downstream of the F-T synthesis process, using a methyldiethanolamine (MDEA) unit. Captured carbon dioxide is then routed to a purification and compression system, where it is compressed to a supercritical state. F-T jet fuel produced by the F-T facility is then conveyed to a blending facility, where it is blended with conventional jet fuel, and transported to an airport. Finally, the blended jet fuel is combusted in a jet airplane.

The following text provides a summary of process model, economic model, and environmental model results for this scenario.

5.17.2 Process Results

As discussed in Chapter 2, three Aspen Plus® model cases were run for this scenario: low RSP, expected RSP, and high RSP. Process summary results, both modeled and validated, for each of the three cases are reported in **Table 5-65**. Results obtained from the Aspen Plus® simulations are based on a 50,000 barrel per day (bpd) production rate for total F-T products (F-T jet fuel, F-T diesel, F-T naphtha, and F-T LPG) for the CBTL, 28.3 percent Pelleted Biomass configuration under all three RSP cases. Fuel production breakdowns are minimally variable among the three RSP cases. For all three RSP cases, approximately 49 percent (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34 percent by volume of total products) being F-T naphtha. F-T jet fuel is produced by hydrocracking the F-T wax to a final boiling point of about 300°C. Hydrocracking also produces naphtha boiling range liquids and F-T LPG. Relatively smaller quantities of F-T diesel (10 percent of total products) and F-T LPG (7 percent of total products) are produced as a result of hydrocracking. These proportions assume that straight run F-T output would be sold as a product. Results from each of the three Aspen Plus® model cases were incorporated into the economic and environmental analyses, the results of which are displayed below. For additional information regarding the application of low, expected, and high RSP values to the stochastic analysis provided here, refer to Chapter 1.

Table 5-65: Scenario 17: CBTL, 28.3% Pelleted Biomass: Process Summary

Property	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
CBTL Facility Design and Operating Data							
Plant Design Capacity	50,000	50,000	50,000	50,000	50,000	50,000	bpd
Plant Capacity Factor	85	85	90	90	92	92	%
Plant Efficiency, HHV	55	55	54	54	52	52	%
Carbon Capture Rate	88	88	89	89	90	90	%
Gasifier Modules	7	7	7	7	7	7	Count
F-T Modules	10	10	10	10	10	10	Count
CBTL Facility Inputs/Feed							
Coal Feed, Montana Rosebud, As Received	22,109	22,142	22,620	22,664	23,338	23,392	tons/ day
Biomass Feed, Southern Pine, As Received	8,097	8,109	8,082	8,098	8,140	8,159	tons/ day
Water Feed (Total Withdrawal)	14,852,419	14,922,469	14,664,345	14,746,273	14,463,409	14,554,788	gallons/day
CBTL Facility Outputs/Production							
F-T Jet Fuel Production	24,649	24,648	24,647	24,647	24,644	24,644	bpd
F-T Diesel Fuel Production	4,767	4,767	4,767	4,767	4,766	4,766	bpd
F-T Naphtha Production	16,973	16,972	16,972	16,971	16,970	16,970	bpd
F-T LPG Production	3,612	3,612	3,615	3,616	3,619	3,620	bpd
Total Liquid Product Output	50,000	50,000	50,000	50,000	50,000	50,000	bpd
Export Power	269	268	239	238	201	200	MW
CO2 Captured and Compressed	30,217	30,370	30,829	31,009	31,353	31,548	tons/ day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,297	49,297	49,294	49,293	49,289	49,288	bpd

CBTL facility fuels production capacity was fixed at 50,000 bpd for all three RSP cases. An expected capacity factor of 90 percent was included, ranging from 85 to 92 percent for low and high RSP cases, respectively. In the modeled case the overall expected plant efficiency of 53.9 percent (range of 52.0to 55.3 percent) is defined as the heating value of the liquid products (HHV basis), F-T LPG, and export power divided by the higher heating value of the input coal and biomass. In the validation case the overall expected plant efficiency is 53.8 percent (range of 51.9 to 55.2 percent) , a variation of less than 1 percent from the modeled case. In the modeled case, makeup water for the CBTL facility, as modeled in Aspen Plus®, is estimated to be approximately 14.7 million gallons per day (mgd; expected RSP case), of which 97.3 percent (14.3 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.98 bbl water/bbl F-T product, based on the expected RSP modeled case. In the validated case, makeup water for the CBTL facility is estimated to be approximately 14.7 million gallons per day (mgd; expected RSP case), of which 97.3 percent (14.4 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 7.02 bbl water/bbl F-T product, based on the expected RSP validated case. Here there is strong agreement between the modeled and validated case with a variation of makeup water for the CBTL facility of 0.08 million gallon per day (0.56 percent) and a normalized variation of 0.04 bbl water/bbl F-T product (0.56 percent).

Under the modeled case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 201 to 269 MW, with an expected value of 239 MW. Based on the expected RSP case, gross power production for the CBTL facility is 796 MW, including power generated from steam (564 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (238 MW), carbon dioxide compressors (91.5 MW), the Selexol unit (60.0 MW), hydrocarbon recovery/refrigeration (42.5 MW), and oxygen compression (31.0 MW). Total auxiliaries consume 558 MW, for a net power output of 239 MW under the expected RSP case.

Under the validated case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 200 to 268 MW, with an expected value of 238 MW. Based on the expected RSP case, gross power production for the CBTL facility is 799 MW, including power generated from steam (567 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (240 MW), carbon dioxide compressors (91.9 MW), the Selexol unit (60.3 MW), hydrocarbon recovery/refrigeration (43.4 MW), and oxygen compression (31.1 MW). Total auxiliaries consume 562 MW, for a net power output of 238 MW under the expected RSP case.

Carbon balance for both the modeled and validated case of the CBTL facility is shown in **Table 5-66**, for all three RSP cases. As shown, carbon inputs were within 0.2 percent of carbon outputs for each of the three RSP cases. Carbon dioxide produced during the production of fuels and electric power is separated from the syngas stream prior to entering the F-T unit. The Selexol unit and the MDEA unit both produce the concentrated CO_2 streams that are dehydrated and compressed to 2,200 psi for pipeline delivery and carbon management. Other flue gas streams containing CO_2 are vented to the atmosphere. These include the flue gases from the HRSG units and from the fired heaters that are utilized during the F-T process. For the expected RSP case, approximately 2 percent of total carbon (range of 1 percent for the low RSP case to 4 percent for the high RSP case) is output to slag/ash from the TRIG gasifier.

Table 5-66: Scenario 17: CBTL, 28.3% Pelleted Biomass: Conversion Facility Carbon Balance

Input Flow	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
Coal Carbon	11,069	11,086	11,325	11,347	11,685	11,712	TPD
Biomass Carbon	2,474	2,477	2,469	2,474	2,487	2,493	TPD
Total Carbon Input	13,543	13,563	13,794	13,821	14,172	14,205	**TPD**
F-T Products	5,284	5,284	5,284	5,284	5,284	5,284	TPD
Slag/Ash	150	150	305	306	626	627	TPD
Stack Gas	996	983	946	932	895	882	TPD
Fuel Gas	273	266	247	240	219	212	TPD
WWTP	31	33	31	30	31	31	TPD
Carbon Capture, Sequestered	8,265	8,307	8,435	8,485	8,582	8,636	TPD
Total Carbon Output	**14,999**	**15,023**	**15,248**	**15,277**	**15,636**	**15,673**	**TPD**
Carbon Capture	**86.4**	**86.6**	**87.3**	**87.6**	**88.2**	**88.5**	**%**

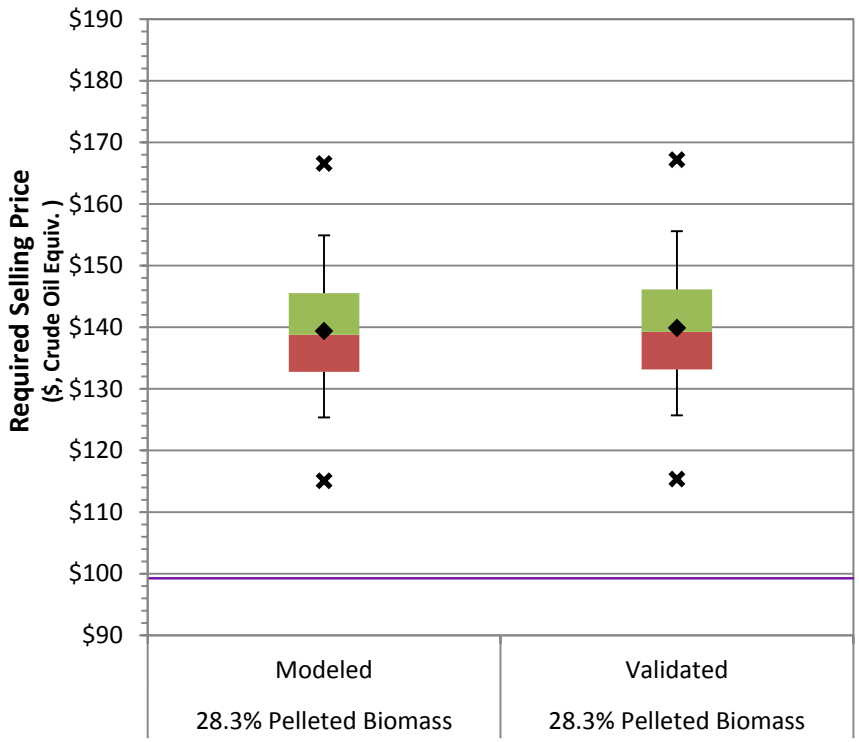
5.17.3 Economic Results

Results from the economic model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Figure 5-97 provides a summary of the estimated RSP for the F-T jet fuel produced under this scenario. As shown, RSP ranges from $133 to $146/bbl for the modeled case, with a mean value of $139/bbl, on a crude oil equivalent basis and for the variation, case the RSP ranges from $133 to $146/bbl, with a mean value of $140/bbl. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 40 economic parameters shown in **Table 1-5**. As shown, 25th and 75th percentile values are relatively close to the mean value, however, selling price distributions are characterized by long tails, with an overall range of $115 to $167/bbl, on a crude oil equivalent basis.

Cost of the F-T jet fuel product is estimated on a crude oil equivalent basis. This is defined as the RSP of the diesel product divided by a factor of 1.1433. Thus if the average world oil price were below or equal to the calculated crude oil equivalent price the CBTL plant would be economically viable. Key contributors to the variability shown for RSP results are discussed below.

Figure 5-97: Scenario 17: CBTL, 28.3% Pelleted Biomass: F-T Jet Fuel RSP, Crude Oil Equivalent Basis



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel spot price value.

It is clear from **Figure 5-97** that there is minimal variation between the modeled and validated RSP results. **Table 5-67** provides a summary of the economic estimated performance of the CBTL facility under the validated case of this scenario, including the key contributing factors to the calculation of RSP. Total operating and maintenance costs represent an average of $549 million/yr. Of this amount, $306 to $333 million/yr, mean $320 million/yr (58.3 percent), results from fixed costs, while $220 to $237 million/year, mean $229 million/yr (41.7 percent) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, range from $8,679 to $9,524 million, mean $9,108 million. Coal feedstock costs for this scenario range from $261 to $273 million/yr, mean $267 million/yr. Biomass feedstock costs range from $199 to $212 million/yr, mean $205 million/yr. Total feedstock costs are approximately $75.9 million lower than total operating and maintenance costs, on average. Projected revenues include credits and product sales revenue. Power credit, from the sale of produced electricity, amounts to $123 to $138 million/yr, mean $130 million/yr, while CO_2 credit is estimated to be $334 to $396 million/yr, mean $365 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,126to $2,334 million/yr, mean $2,231 million/yr.

Required product sales prices in the validated case are also provided in **Table 5-67**. Crude oil equivalent RSP is discussed above for **Figure 5-97**. On a straight basis, RSP for F-T jet fuel was calculated to be $154 to $169/bbl, mean $162/bbl, with F-T diesel at $152 to $167/bbl, mean $160/bbl, F-T naphtha at $106 to $116/bbl, mean $111/bbl, and F-T LPG at $61.5 to $67.5/bbl, mean $64.6/bbl. The default capital charge factor (CCF) used in the analysis was 0.1872.

Table 5-67: Scenario 17: CBTL, 28.3% Pelleted Biomass: Summary of Economics

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	320	264	382	306	333	$MM/yr
Variable Operating and Maintenance Cost (VOM)	229	196	272	220	237	$MM/yr
Capital: Total Overnight Cost (TOC)	9,108	7,723	11,148	8,679	9,524	$MM
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	267	244	293	261	273	$MM/yr
Biomass Cost, Southern Pine, Chips, As Received	205	174	232	199	212	$MM/yr
Biomass Cost, Southern Pine, Torrefied, As Received	0	0	0	0	0	$MM/yr
Credits and Revenue						
Power Credit	(130)	(164)	(97)	(138)	(123)	$MM/yr
Credit @ $40/ton for CO_2	(365)	(471)	(258)	(396)	(334)	$MM/yr
Annual Revenue Required	2,231	1,823	2,692	2,126	2,334	$MM/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	162	133	193	154	169	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	160	132	191	152	167	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	111	92	133	106	116	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	65	53	77	62	68	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	140	115	167	133	146	$/bbl

Figure 5-98 provides breakdowns for the cost factors in the validated case that contribute to the RSP. As shown, capital cost is the primary factor in determining RSP, and accounts for approximately 76.4 percent of total RSP, or $107/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 21.5 percent of total RSP, or $30.1bbl, while feedstock costs represent 18.5 percent of total RSP, or $25.9/bbl, on a crude oil equivalent basis. As shown, variability in total RSP is driven largely by potential variability in capital costs, and to a much lesser extent by variability in operations and maintenance and feedstock costs. The negative credits bar comprises the sale of the co-produced electricity and compressed CO_2. Electricity accounts for 26.3 percent of the total credit, while captured and compressed CO_2 accounts for 73.7 percent.

Figure 5-98: Scenario 17: CBTL, 28.3% Pelleted Biomass, Validated: RSP, Crude Oil Equivalent Basis

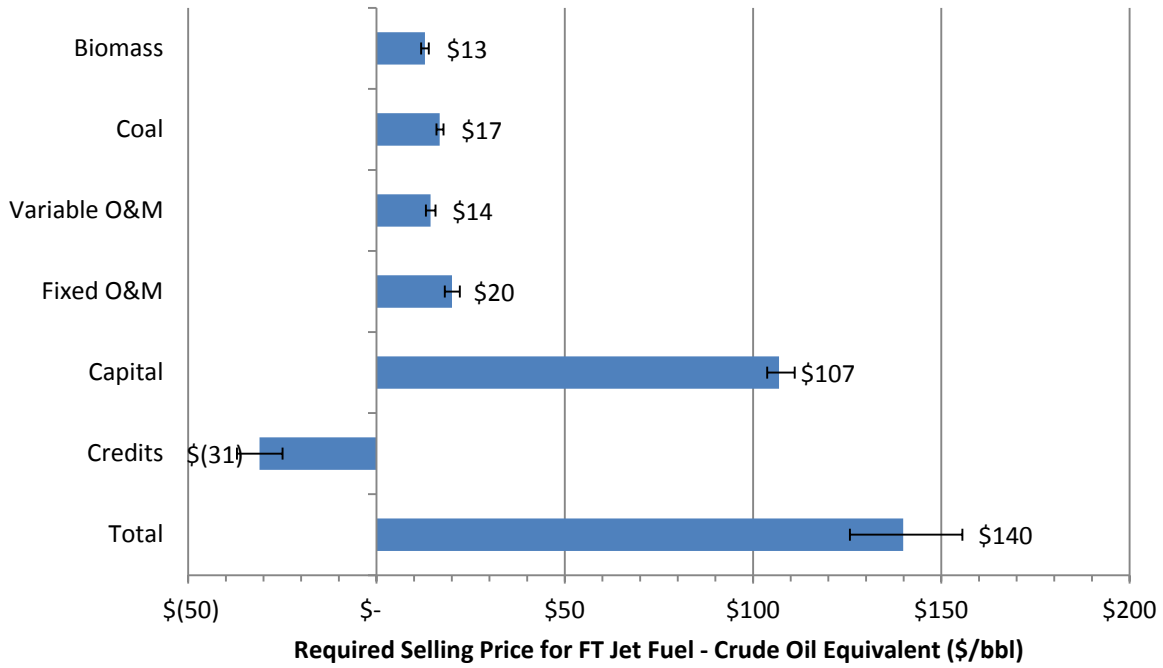
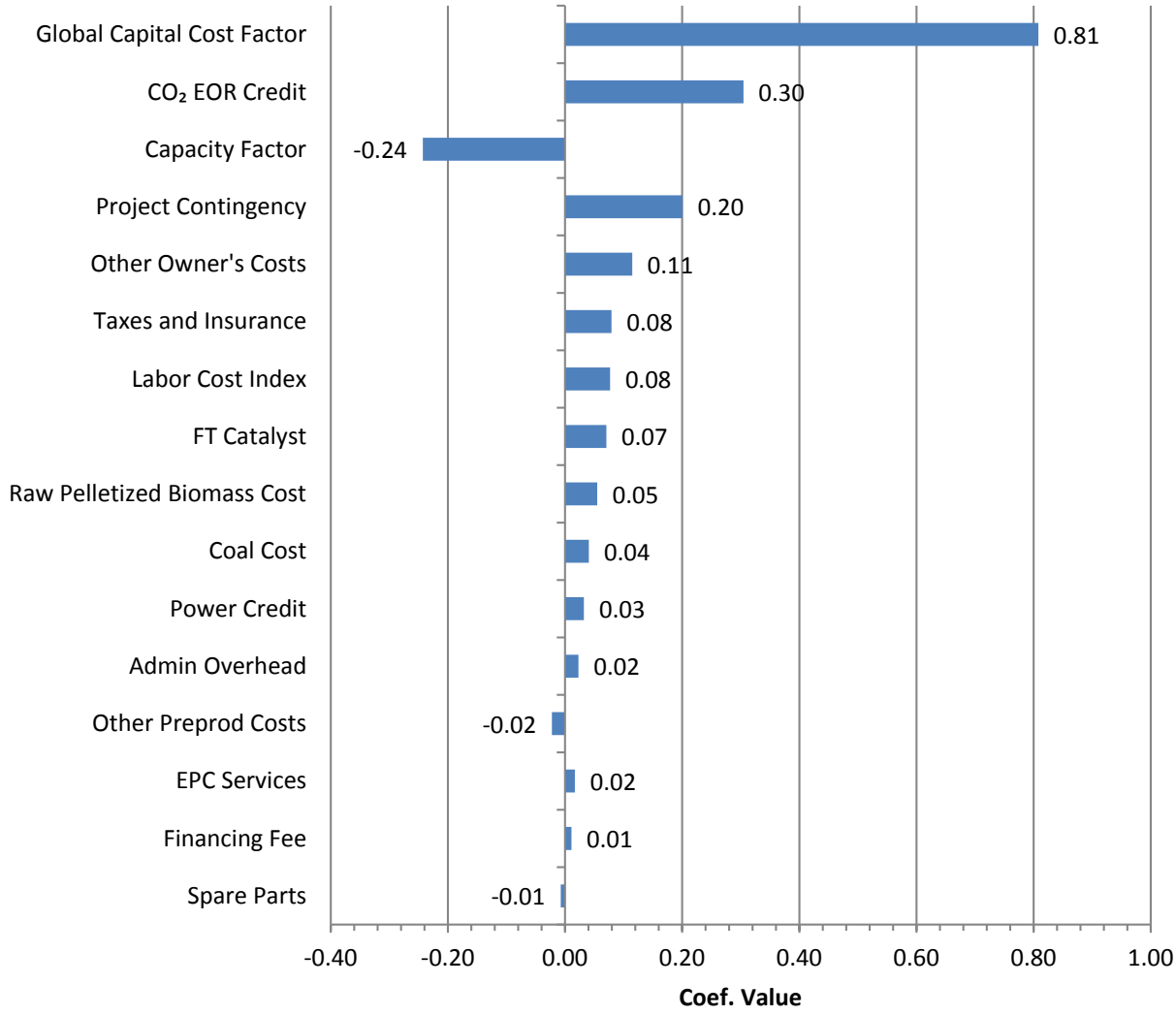


Figure 5-99 provides a summary of model sensitivity in the validated case, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.81. Other key factors that account for at least 10 percent of the observed variability in RSP include the CO_2 EOR credit, capacity factor, project contingency, and other owner's costs. Parameters that caused minimal influence on RSP included EPC services, other preproduction costs, financing fees, cost of spare parts, and others as shown.

Figure 5-99: Scenario 17: CBTL, 28.3% Chipped Biomass, Validated: Sensitivity of RSP to Modeled Variables

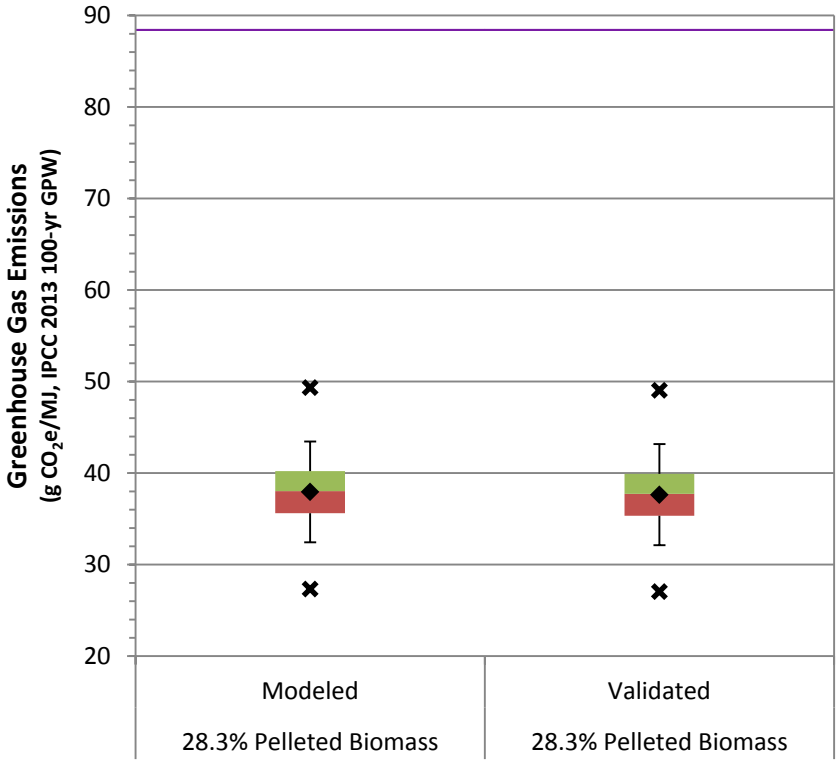


5.17.4 Environmental Results

Results from the environmental model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Results from the environmental life cycle analysis include GHG emissions and other emissions, including select criteria air pollutants, other pollutants of concern, and water consumption. **Figure 5-100** provides a summary life cycle GHG emissions for this scenario, in comparison to conventional jet fuel life cycle GHG emissions of 88.41 g CO_2e/MJ. In the modeled case the resulting range is 27.3 to 49.4 g CO_2e/MJ, mean 38.0 g CO_2e/MJ or approximately 56.6 percent less than conventional jet fuel. In the validated case the resulting range is 27.1 to 49.0 g CO_2e/MJ, mean 37.6 g CO_2e/MJ or approximately 56.9 percent less than conventional jet fuel.

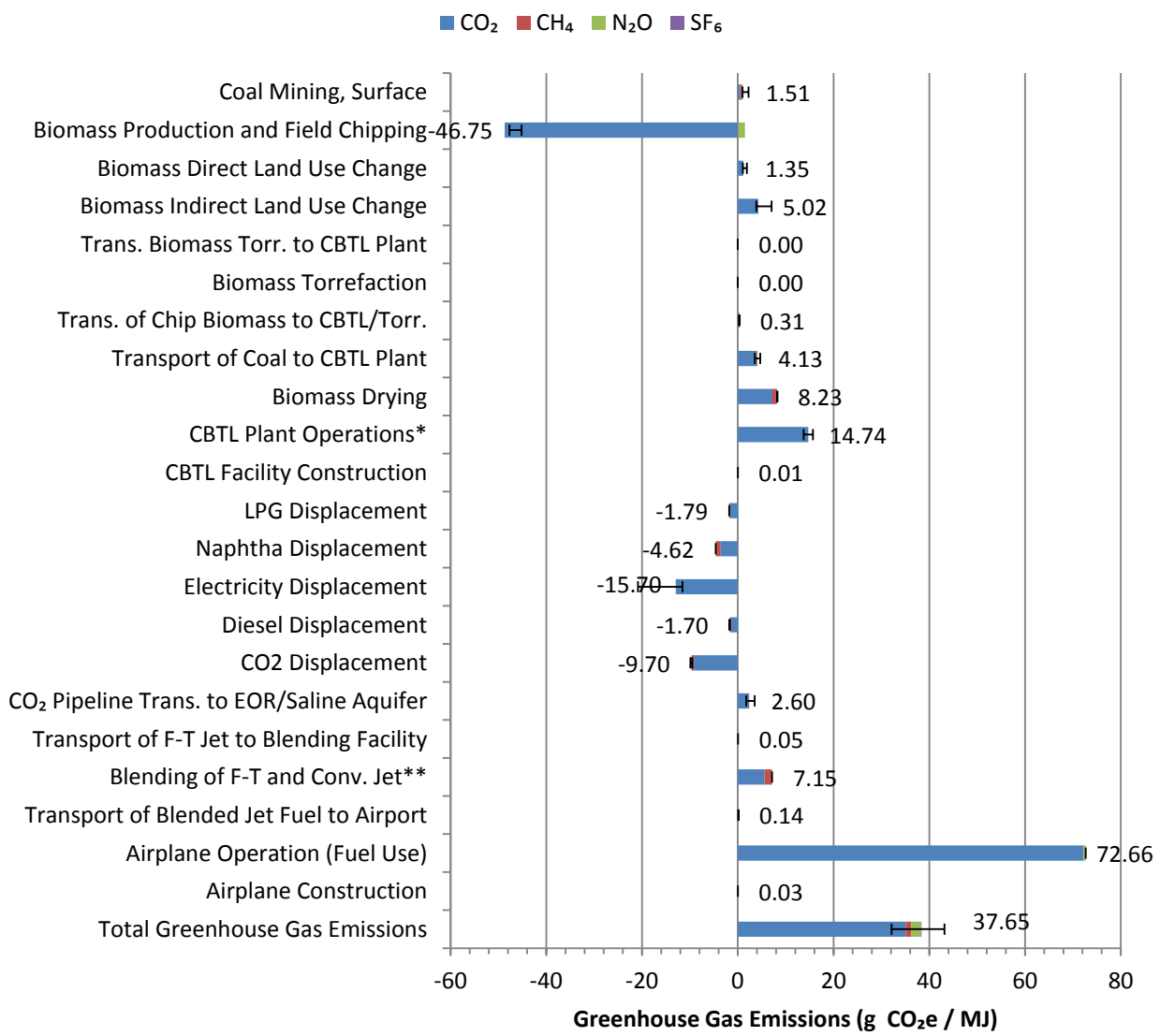
Figure 5-100: Scenario 17: CBTL, 28.3% Pelleted Biomass, Validated: Summary of LC GHG Emissions



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

It is clear from **Figure 5-100** that there is minimal variation between the modeled and validated LC GHG emission results. **Figure 5-101** provides detail regarding the importance of the various LCA components in the validated case that were modeled, with respect to gross GHG emissions contributions. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 61.2 percent of gross life cycle GHG emissions. Second in importance to fuel combustion is CBTL plant operations, at 12.5 percent of gross life cycle emissions, while emissions associated with blending of F-T and conventional jet fuel represent 6.11 percent of gross life cycle emissions. The biomass indirect land use change accounts for 4.75 percent of gross life cycle GHG emissions. Emissions from the transport of coal to the CBTL plant represent approximately 3.63 percent of gross emissions. GHG emissions associated with biomass drying generate 3.35 percent of gross life cycle emissions, while pipeline transport of CO_2 and biomass direct land use change generate 1.98 percent and 0.98 percent respectively. Other contributors to gross emissions were less than 1 percent individually.

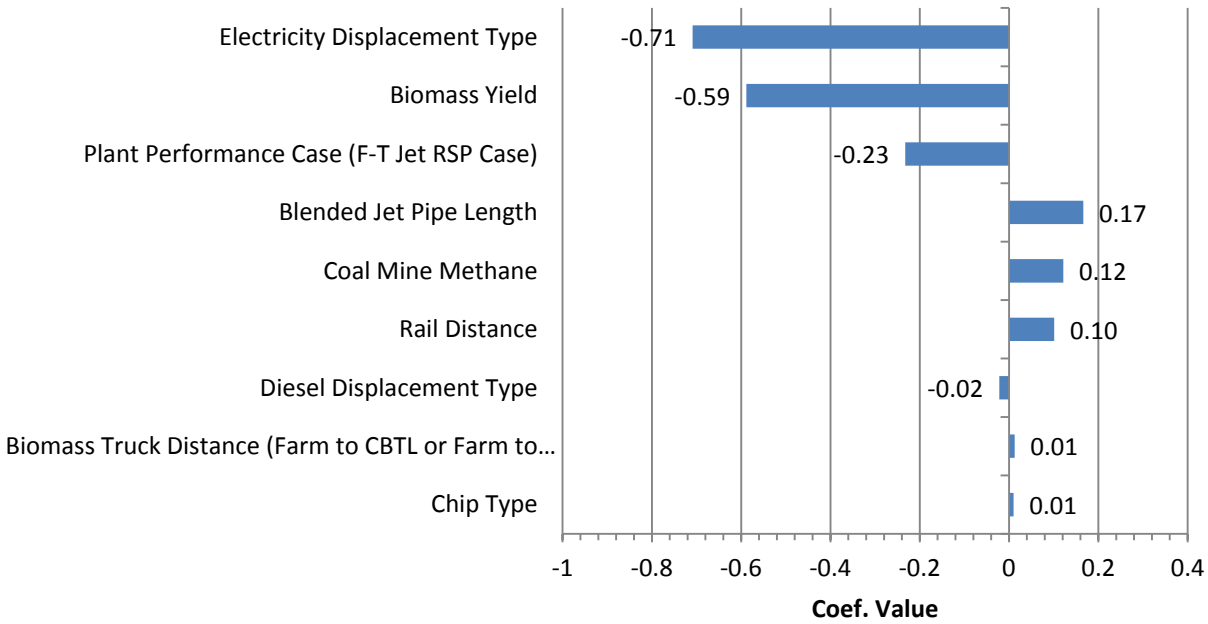
Figure 5-101: Scenario 17: CBTL, 28.3% Pelleted Biomass, Validated: LC GHG Emissions Breakdowns



** Includes CO_2 Compression*
*** Includes conventional jet fuel profile*

The error bars shown in **Figure 5-101** reflect variability in model output based on the stochastic analyses (for more information, refer to Chapter 1). The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-6**. As shown, variability in emissions resulted primarily from biomass yield and the type of electricity displacement used. Another key contributor to variability in model is the biomass yield. **Figure 5-102** summarizes the key factors contributing to variability identified in the model sensitivity analysis, for GHG emissions. Values provided in the figure show the correlation coefficient between the indicated parameter and total life cycle GHG emissions. Other important factors included the F-T jet fuel RSP case, the CO_2 pipe length, the coal mine methane emissions, the rail transport distance, the diesel displacement type, the biomass transport distance from farm, and the biomass chip type. Other parameters had minimal to negligible effect on life cycle GHG emissions.

Figure 5-102: Scenario 17: CBTL, 28.3% Pelleted Biomass, Validated: LC GHG Emissions Sensitivity



In addition to GHG emissions, other life cycle environmental emissions and flows were also considered. **Table 5-68** provides a summary of these flows. As shown, Airplane operation is the primary source of carbon monoxide and NOx within the life cycle. Particulate matter (PM_{10}) derives primarily from the combustion of diesel under raw materials transport and product transport operations. Non-methane volatile organic carbons (NMVOCs) result from product transport, including upstream conventional jet fuel emissions, and end use. The highest levels of mercury emissions occur during energy conversion and end use. Most water consumption occurs during biomass cultivation. Note that mass units displayed for water consumption (kg/MJ jet fuel) are equivalent to volume units for water consumption (L/MJ jet fuel).

Table 5-68: Scenario 17: CBTL, 28.3% Pelleted Biomass, Validated: Non-GHG Emissions

LC Stage	Carbon monoxide	NO_x	SO2	PM10	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	1.91E-04	2.80E-04	1.20E-04	3.81E-06	8.72E-06	4.46E-10	3.88E-05	8.33E+02	kg/MJ Jet Fuel
RMT	4.91E-04	4.32E-04	1.04E-04	5.45E-04	8.60E-05	4.63E-10	6.19E-06	1.79E-01	kg/MJ Jet Fuel
EC	-3.32E-04	-1.06E-03	-2.76E-03	-1.52E-04	-3.30E-04	4.42E-08	1.41E-05	-1.08E+00	kg/MJ Jet Fuel
PT	2.76E-04	4.38E-04	6.25E-04	3.28E-05	8.45E-04	5.80E-10	2.92E-06	1.08E+00	kg/MJ Jet Fuel
EU	7.72E-03	1.21E-02	5.56E-04	9.50E-07	7.72E-04	3.01E-08	7.16E-09	2.81E-02	kg/MJ Jet Fuel
Total	**8.34E-03**	**1.22E-02**	**-1.35E-03**	**4.31E-04**	**1.38E-03**	**7.58E-08**	**6.20E-05**	**8.34E+02**	**kg/MJ Jet Fuel**

5.18 Scenario 18: CBTL, 16.5 Percent Torrefied and Pelleted Biomass and Validation

The purpose of this scenario is to evaluate potential process values, economic factors, and environmental emissions associated with the production of F-T jet fuels from a combination of 83.5 percent sub-bituminous coal and 16.5 percent Torrefied Biomass. This scenario evaluates a 1:1 (volume) blend of F-T jet fuels and conventional U.S. average jet fuel, based on a 30-year study period. Coal feedstock is derived from the Rosebud seam in southern Montana, and is transported by train to the CBTL facility, located in the Southeastern U.S. Southern pine biomass feedstock is produced and harvested in the Southeastern U.S., field-chipped, and then transported by chip truck to a separate torrefaction/pelletization facility, where the biomass is torrefied and formed into pellets. Torrefaction increases energy density of the biomass, and greatly reduces grinding energy required, as discussed in greater detail in Chapter 4. Torrefied/pelletized biomass is then transported by truck to the CBTL facility. The F-T process employed uses a slurry-based iron catalyst using a single feed, oxygen blown Transport Reactor Integrated Gasifier (TRIG™; refer to Chapter 2 for additional discussion). Carbon dioxide is captured at the CBTL facility using a Selexol process to segregate carbon dioxide. Additional carbon dioxide is stripped from overhead gas downstream of the F-T synthesis process, using a methyldiethanolamine (MDEA) unit. Captured carbon dioxide is then routed to a purification and compression system, where it is compressed to a supercritical state. F-T jet fuel produced by the F-T facility is then conveyed to a blending facility, where it is blended with conventional jet fuel, and transported to an airport. Finally, the blended jet fuel is combusted in a jet airplane.

The following text provides a summary of process model, economic model, and environmental model results for this scenario.

5.18.2 Process Results

As discussed in Chapter 2, three Aspen Plus® model cases were run for this scenario: low RSP, expected RSP, and high RSP. Process summary results, both modeled and validated, for each of the three cases are reported in **Table 5-69**. Results obtained from the Aspen Plus® simulations are based on a 50,000 barrel per day (bpd) production rate for total F-T products (F-T jet fuel, F-T diesel, F-T naphtha, and F-T LPG) for the CBTL, 16.5 percent Torrified/Pelleted Biomass configuration under all three RSP cases. Fuel production breakdowns are minimally variable among the three RSP cases. For all three RSP cases, approximately 49 percent (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34 percent by volume of total products) being F-T naphtha. F-T jet fuel is produced by hydrocracking the F-T wax to a final boiling point of about 300°C. Hydrocracking also produces naphtha boiling range liquids and F-T LPG. Relatively smaller quantities of F-T diesel (10 percent of total products) and F-T LPG (7 percent of total products) are produced as a result of hydrocracking. These proportions assume that straight run F-T output would be sold as a product. Results from each of the three Aspen Plus® model cases were incorporated into the economic and environmental analyses, the results of which are displayed below. For additional information regarding the application of low, expected, and high RSP values to the stochastic analysis provided here, refer to Chapter 1.

Table 5-69: Scenario 18: CBTL, 16.5% Torrefied/Pelleted Biomass: Process Summary

Property	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
CBTL Facility Design and Operating Data							
Plant Design Capacity	50,000	50,000	50,000	50,000	50,000	50,000	bpd
Plant Capacity Factor	85	85	90	90	92	92	%
Plant Efficiency, HHV	56	55	54	54	52	52	%
Carbon Capture Rate	88	88	89	89	90	90	%
Gasifier Modules	9	9	9	9	9	9	Count
F-T Modules	10	10	10	10	10	10	Count
CBTL Facility Inputs/Feed							
Coal Feed, Montana Rosebud, As Received	24,542	24,579	25,098	25,145	25,872	25,932	tons/ day
Biomass Feed, Southern Pine, As Received	4,500	4,507	4,490	4,498	4,518	4,528	tons/ day
Water Feed (Total Withdrawal)	14,602,274	14,670,841	14,417,410	14,496,559	14,214,486	14,503,625	gallons/day
CBTL Facility Outputs/Production							
F-T Jet Fuel Production	24,649	24,648	24,647	24,647	24,644	24,644	bpd
F-T Diesel Fuel Production	4,767	4,767	4,767	4,767	4,766	4,766	bpd
F-T Naphtha Production	16,973	16,972	16,971	16,971	16,970	16,969	bpd
F-T LPG Production	3,612	3,613	3,615	3,616	3,620	3,621	bpd
Total Liquid Product Output	50,000	50,001	50,000	50,001	50,001	50,001	bpd
Export Power	267	266	235	234	196	195	MW
CO2 Captured and Compressed	29,602	29,756	30,306	30,480	30,892	31,082	tons/ day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,297	49,297	49,294	49,293	49,289	49,287	bpd

CBTL facility fuels production capacity was fixed at 50,000 bpd for all three RSP cases. An expected capacity factor of 90 percent was included, ranging from 85 to 92 percent for low and high RSP cases, respectively. In the modeled case the overall expected plant efficiency of 54.1 percent (range of 52.1to 55.6 percent) is defined as the heating value of the liquid products (HHV basis), F-T LPG, and export power divided by the higher heating value of the input coal and biomass. In the validation case the overall expected plant efficiency is 54.0 percent (range of 51.9 to 55.5 percent) , a variation of less than1 percent from the modeled case. In the modeled case, makeup water for the CBTL facility, as modeled in Aspen Plus®, is estimated to be approximately 14.4 million gallons per day (mgd; expected RSP case), of which 96.5 percent (13.9 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.87 bbl water/bbl F-T product, based on the expected RSP modeled case. In the validated case, makeup water for the CBTL facility is estimated to be approximately 14.5 million gallons per day (mgd; expected RSP case), of which 96.5 percent (14.0 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.90 bbl water/bbl F-T product, based on the expected RSP validated case. Here there is strong agreement between the modeled and validated case with a variation of makeup water for the CBTL facility of 0.08 million gallon per day (0.55 percent) and a normalized variation of 0.04 bbl water/bbl F-T product (0.55 percent).

Under the modeled case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 196 to 267 MW, with an expected value of 235 MW. Based on the expected RSP case, gross power production for the CBTL facility is 790 MW, including power generated from steam (558 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (237 MW), carbon dioxide compressors (90.2 MW), the Selexol unit (59.5 MW), hydrocarbon recovery/refrigeration (43.4 MW), and oxygen compression (30.7 MW). Total auxiliaries consume 555 MW, for a net power output of 235 MW under the expected RSP case.

Under the validated case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 195 to 266 MW, with an expected value of 234 MW. Based on the expected RSP case, gross power production for the CBTL facility is 793 MW, including power generated from steam (561 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (238 MW), carbon dioxide compressors (90.6 MW), the Selexol unit (59.8 MW), hydrocarbon recovery/refrigeration (44.4 MW), and oxygen compression (30.8 MW). Total auxiliaries consume 559 MW, for a net power output of 234 MW under the expected RSP case.

Carbon balance for both the modeled and validated case of the CBTL facility is shown in **Table 5-70**, for all three RSP cases. As shown, carbon inputs were within 0.2 percent of carbon outputs for each of the three RSP cases. Carbon dioxide produced during the production of fuels and electric power is separated from the syngas stream prior to entering the F-T unit. The Selexol unit and the MDEA unit both produce the concentrated CO_2 streams that are dehydrated and compressed to 2,200 psi for pipeline delivery and carbon management. Other flue gas streams containing CO_2 are vented to the atmosphere. These include the flue gases from the HRSG units and from the fired heaters that are utilized during the F-T process. For the expected RSP case, approximately 2 percent of total carbon (range of 1 percent for the low RSP case to 4 percent for the high RSP case) is output to slag/ash from the TRIG gasifier.

Table 5-70: Scenario 18: CBTL, 16.5% Torrefied/Pelleted Biomass: Conversion Facility Carbon Balance

Input Flow	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
Coal Carbon	12,288	12,306	12,566	12,590	12,954	12,984	TPD
Biomass Carbon	2,695	2,699	2,689	2,694	2,706	2,712	TPD
Total Carbon Input	14,983	15,005	15,255	15,284	15,659	15,696	**TPD**
F-T Products	5,284	5,284	5,284	5,284	5,284	5,284	TPD
Slag/Ash	148	148	302	302	620	621	TPD
Stack Gas	982	968	932	919	882	870	TPD
Fuel Gas	267	260	240	233	212	206	TPD
WWTP	31	31	31	32	30	30	TPD
Carbon Capture, Sequestered	8,097	8,140	8,292	8,341	8,457	8,510	TPD
Total Carbon Output	**14,808**	**14,831**	**15,081**	**15,110**	**15,486**	**15,521**	**TPD**
Carbon Capture	**86.4**	**86.6**	**87.3**	**87.6**	**88.3**	**88.5**	**%**

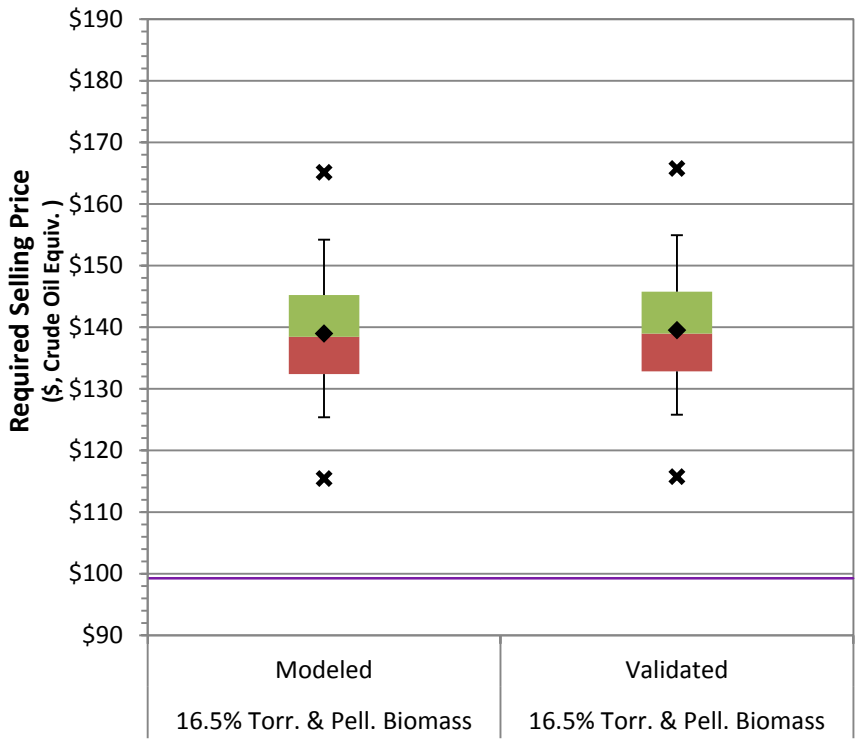
5.18.3 Economic Results

Results from the economic model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Figure 5-103 provides a summary of the estimated RSP for the F-T jet fuel produced under this scenario. As shown, RSP ranges from $132 to $145/bbl for the modeled case, with a mean value of $139/bbl, on a crude oil equivalent basis and for the variation, case the RSP ranges from $133 to $146/bbl, with a mean value of $140/bbl. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 40 economic parameters shown in **Table 1-5**. As shown, 25th and 75th percentile values are relatively close to the mean value, however, selling price distributions are characterized by long tails, with an overall range of $116 to $166/bbl, on a crude oil equivalent basis.

Cost of the F-T jet fuel product is estimated on a crude oil equivalent basis. This is defined as the RSP of the diesel product divided by a factor of 1.1433. Thus if the average world oil price were below or equal to the calculated crude oil equivalent price the CBTL plant would be economically viable. Key contributors to the variability shown for RSP results are discussed below.

Figure 5-103: Scenario 18: CBTL, 16.5% Torrefied/Pelleted Biomass: F-T Jet Fuel RSP, Crude Oil Equivalent Basis



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel spot price value.

It is clear from **Figure 5-103** that there is minimal variation between the modeled and validated RSP results. **Table 5-71** provides a summary of the economic estimated performance of the CBTL facility under the validated case of this scenario, including the key contributing factors to the calculation of RSP. Total operating and maintenance costs represent an average of $537 million/yr. Of this amount, $297 to $323 million/yr, mean $311 million/yr (57.9 percent), results from fixed costs, while $217 to $234 million/year, mean $226 million/yr (42.1 percent) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, range from $8,516 to $9,341 million, mean $8,939 million. Coal feedstock costs for this scenario range from $290 to $303 million/yr, mean $297 million/yr. Biomass feedstock costs range from $199 to $213 million/yr, mean $206 million/yr. Total feedstock costs are approximately $34.4 million lower than total operating and maintenance costs, on average. Projected revenues include credits and product sales revenue. Power credit, from the sale of produced electricity, amounts to $121 to $136 million/yr, mean $128 million/yr, while CO_2 credit is estimated to be $328 to $390 million/yr, mean $359 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,122 to $2,325 million/yr, mean $2,225 million/yr.

Required product sales prices in the validated case are also provided in **Table 5-71**. Crude oil equivalent RSP is discussed above for **Figure 5-103**. On a straight basis, RSP for F-T jet fuel was calculated to be $153 to $168/bbl, mean $161/bbl, with F-T diesel at $152 to $167/bbl, mean $160/bbl, F-T naphtha at $106 to $116/bbl, mean $111/bbl, and F-T LPG at $61.4 to $67.3/bbl, mean $64.5/bbl. The default capital charge factor (CCF) used in the analysis was 0.1872.

Table 5-71: Scenario 18: CBTL, 16.5% Torrefied/Pelleted Biomass: Summary of Economics

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	311	257	371	297	323	$MM/yr
Variable Operating and Maintenance Cost (VOM)	226	193	268	217	234	$MM/yr
Capital: Total Overnight Cost (TOC)	8,939	7,570	10,885	8,516	9,341	$MM
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	297	271	325	290	303	$MM/yr
Biomass Cost, Southern Pine, Chips, As Received	0	0	0	0	0	$MM/yr
Biomass Cost, Southern Pine, Torrefied, As Received	206	174	232	199	213	$MM/yr
Credits and Revenue						
Power Credit	(128)	(162)	(95)	(136)	(121)	$MM/yr
Credit @ $40/ton for CO_2	(359)	(464)	(253)	(390)	(328)	$MM/yr
Annual Revenue Required	2,225	1,827	2,653	2,122	2,325	$MM/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	161	134	191	153	168	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	160	132	190	152	167	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	111	92	132	106	116	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	64	53	77	61	67	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	140	116	166	133	146	$/bbl

Figure 5-104 provides breakdowns for the cost factors in the validated case that contribute to the RSP. As shown, capital cost is the primary factor in determining RSP, and accounts for approximately 75.2 percent of total RSP, or $105/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 21.1 percent of total RSP, or $29.4bbl, while feedstock costs represent 19.7 percent of total RSP, or $27.5/bbl, on a crude oil equivalent basis. As shown, variability in total RSP is driven largely by potential variability in capital costs, and to a much lesser extent by variability in operations and maintenance and feedstock costs. The negative credits bar comprises the sale of the co-produced electricity and compressed CO_2. Electricity accounts for 26.3 percent of the total credit, while captured and compressed CO_2 accounts for 73.7 percent.

Figure 5-104: Scenario 18: CBTL, 16.5% Torrefied/Pelleted Biomass, Validated: RSP, Crude Oil Equivalent Basis

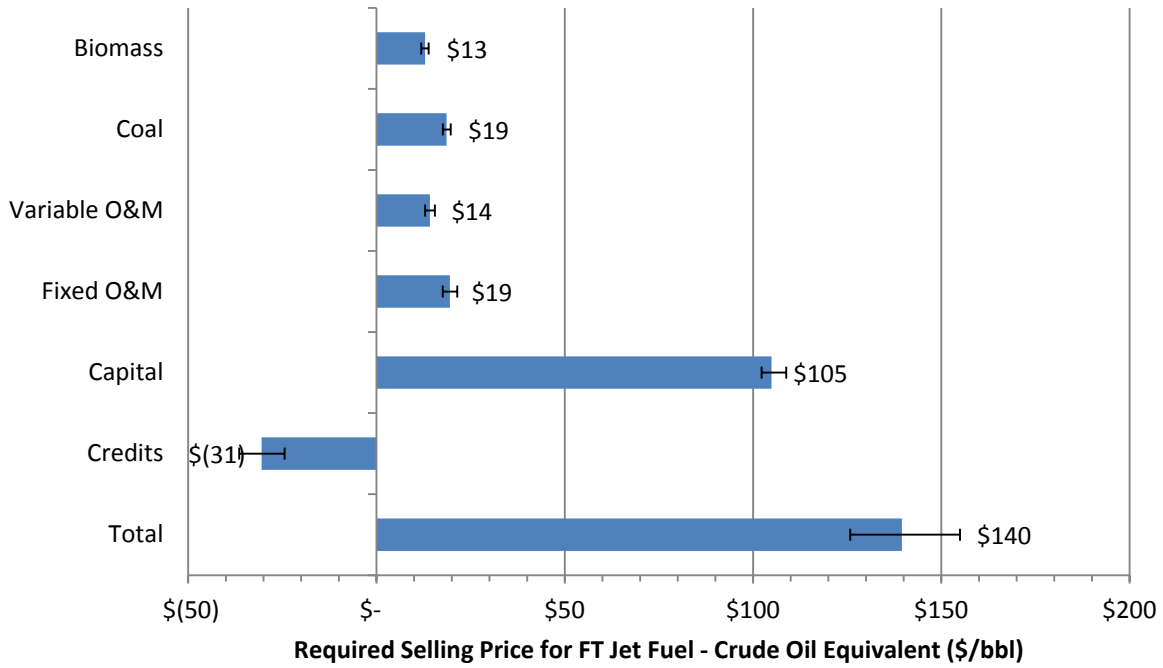
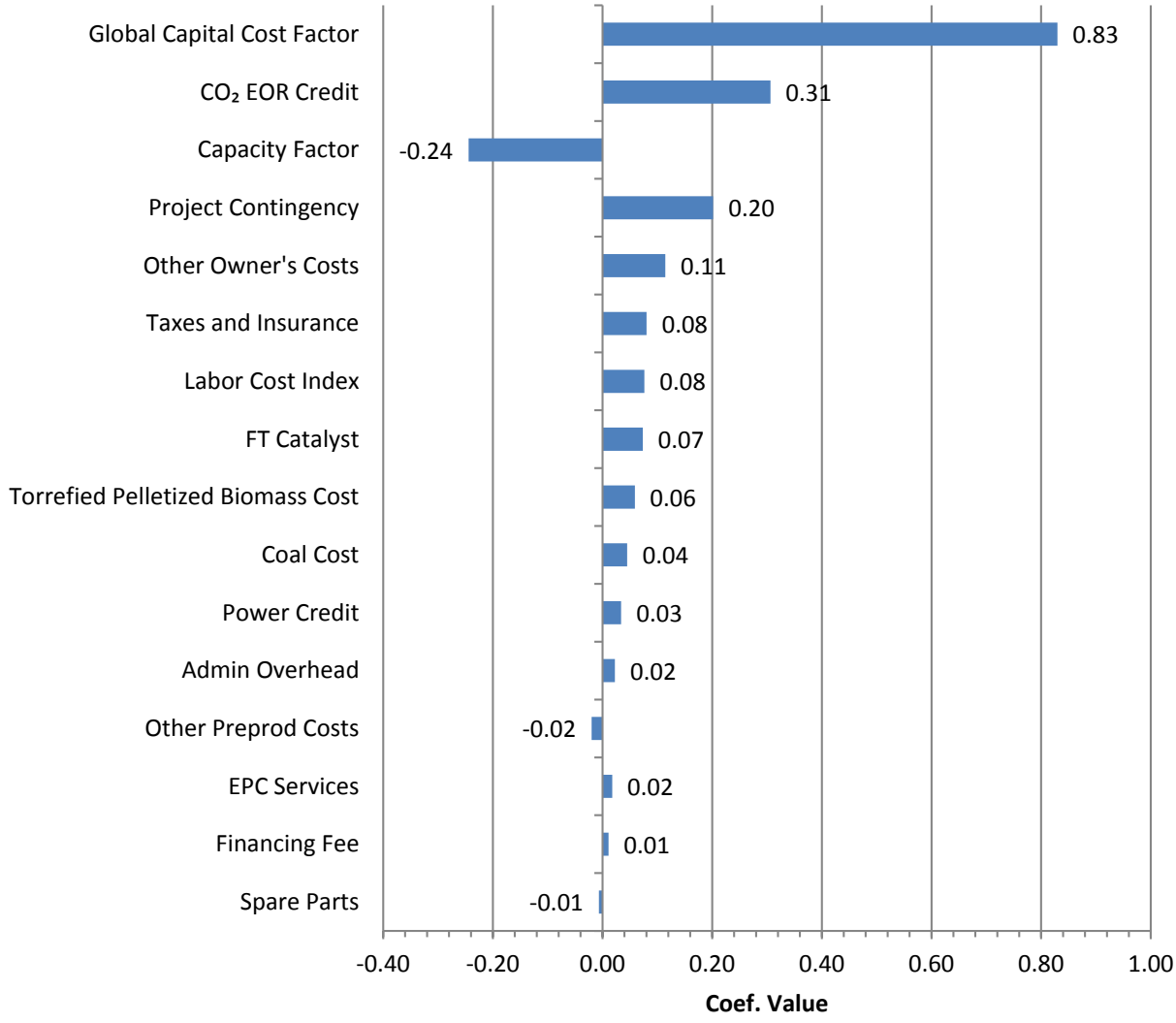


Figure 5-105 provides a summary of model sensitivity in the validated case, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.83. Other key factors that account for at least 10 percent of the observed variability in RSP include the CO_2 EOR credit, capacity factor, project contingency, and other owner's costs. Parameters that caused minimal influence on RSP included the cost of spare parts, financing fees, power credit, EPC services, power credits, and others as shown.

Figure 5-105: Scenario 18: CBTL, 16.5% Torrefied/Chipped Biomass, Validated: Sensitivity of RSP to Modeled Variables

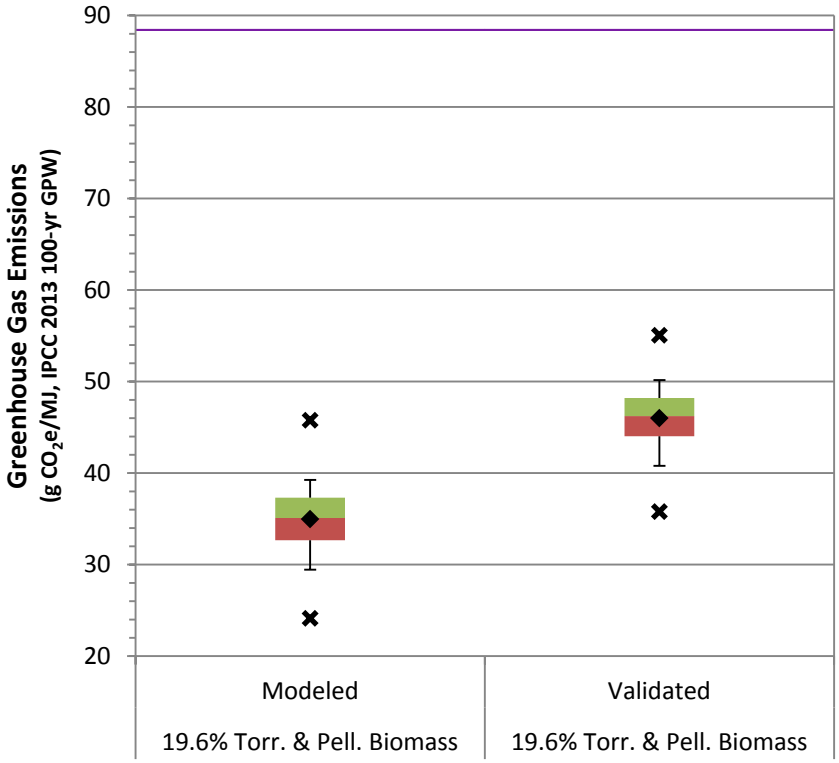


5.18.4 Environmental Results

Results from the environmental model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Results from the environmental life cycle analysis include GHG emissions and other emissions, including select criteria air pollutants, other pollutants of concern, and water consumption. **Figure 5-106** provides a summary life cycle GHG emissions for this scenario, in comparison to conventional jet fuel life cycle GHG emissions of 88.41 g CO_2e/MJ. In the modeled case the resulting range is 40.4 to 58.8 g CO_2e/MJ, mean 50.5 g CO_2e/MJ or approximately 42.2 percent less than conventional jet fuel. In the validated case the resulting range is 40.1 to 58.5 g CO_2e/MJ, mean 50.2 g CO_2e/MJ or approximately 42.6 percent less than conventional jet fuel.

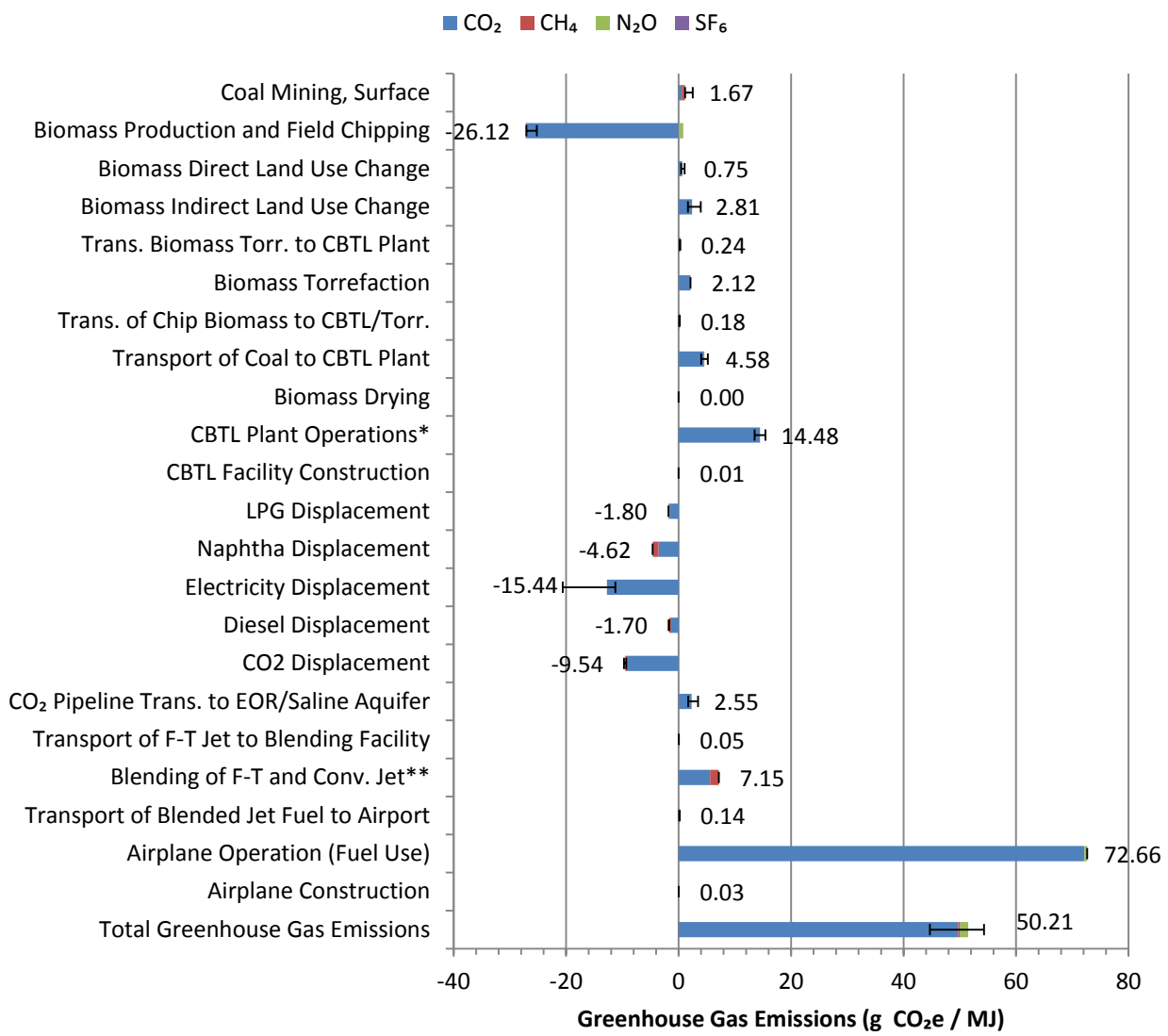
Figure 5-106: Scenario 18: CBTL, 16.5% Torrefied/Pelleted Biomass: Summary of LC GHG Emissions



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

It is clear from **Figure 5-106** that there is minimal variation between the modeled and validated LC GHG emission results. **Figure 5-107** provides detail regarding the importance of the various LCA components in the validated case that were modeled, with respect to gross GHG emissions contributions. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 65.9 percent of gross life cycle GHG emissions. Second in importance to fuel combustion is CBTL plant operations, at 13.2 percent of gross life cycle emissions, while emissions associated with blending of F-T and conventional jet fuel represent 5.12 percent of gross life cycle emissions. The transport of coal to the CBTL plant accounts for 4.01 percent of gross life cycle GHG emissions. Emissions from the pipeline transport of CO_2 represents approximately 2.18 percent of gross emissions. GHG emissions associated with biomass indirect land use change generate 2.09 percent of gross life cycle emissions, while the torrefaction of biomass generates 1.92 percent. Other contributors to gross emissions were less than 1 percent individually.

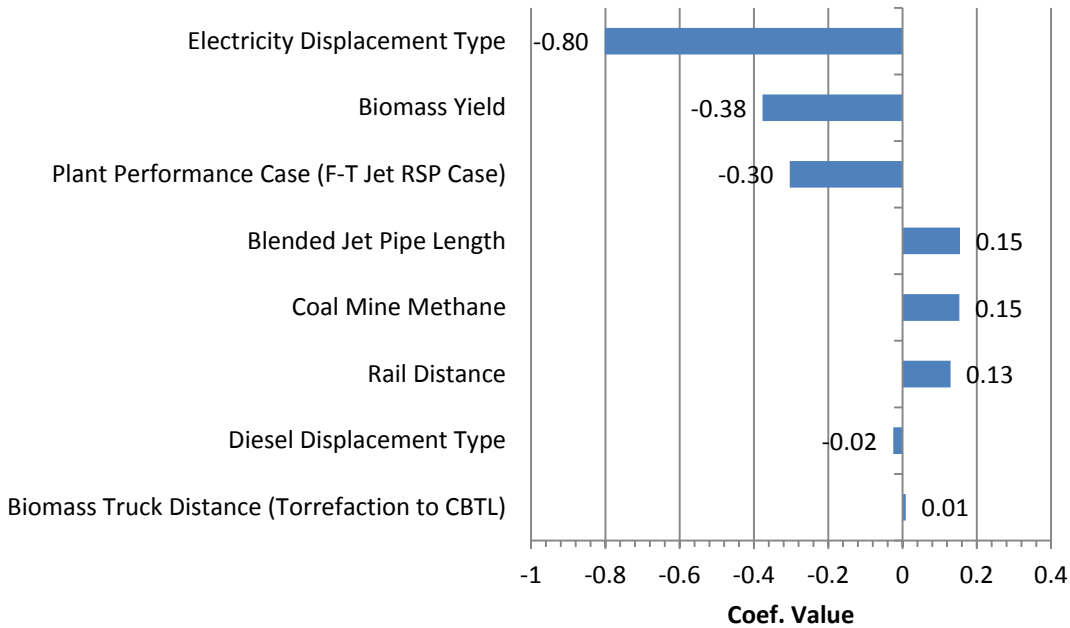
Figure 5-107: Scenario 18: CBTL, 16.5% Torrefied/Pelleted Biomass, Validated: LC GHG Emissions Breakdowns



** Includes CO_2 Compression*
*** Includes conventional jet fuel profile*

The error bars shown in **Figure 5-107** reflect variability in model output based on the stochastic analyses (for more information, refer to Chapter 1). The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-6.** As shown, variability in emissions resulted primarily from the type of electricity displacement used. Other key contributors to variability in model output include biomass yield, and the F-T jet fuel RSP case. **Figure 5-108** summarizes the key factors contributing to variability identified in the model sensitivity analysis, for GHG emissions. Values provided in the figure show the correlation coefficient between the indicated parameter and total life cycle GHG emissions. Other important factors included the CO_2 pipe length, the coal mine methane emissions, the rail transport distance, the diesel displacement type, and the biomass truck transport distance from the torrefaction facility to the CBTL plant. Other parameters had minimal to negligible effect on life cycle GHG emissions.

Figure 5-108: Scenario 18: CBTL, 16.5% Torrefied/Pelleted Biomass, Validated: LC GHG Emissions Sensitivity



In addition to GHG emissions, other life cycle environmental emissions and flows were also considered. **Table 5-72** provides a summary of these flows. As shown, Airplane operation is the primary source of carbon monoxide and NOx within the life cycle. Particulate matter (PM_{10}) derives primarily from the combustion of diesel under raw materials transport and product transport operations. Non-methane volatile organic carbons (NMVOCs) result from product transport, including upstream conventional jet fuel emissions, and end use. The highest levels of mercury emissions occur during energy conversion and end use. Most water consumption occurs during biomass cultivation. Note that mass units displayed for water consumption (kg/MJ jet fuel) are equivalent to volume units for water consumption (L/MJ jet fuel).

Table 5-72: Scenario 18: CBTL, 16.5% Torrefied/Pelleted Biomass, Validated: Non-GHG Emissions

LC Stage	Carbon monoxide	NO_x	SO2	PM10	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	1.57E-05	1.64E-04	1.70E-05	1.67E-06	9.67E-06	2.69E-10	1.61E-06	1.42E-02	kg/MJ Jet Fuel
RMT	5.16E-04	4.73E-04	1.06E-04	6.04E-04	8.87E-05	2.92E-10	6.83E-06	1.64E-01	kg/MJ Jet Fuel
EC	-5.30E-04	-1.65E-03	-2.84E-03	-1.85E-04	-7.15E-04	4.91E-08	1.53E-05	-1.77E+00	kg/MJ Jet Fuel
PT	2.76E-04	4.38E-04	6.25E-04	3.28E-05	8.45E-04	5.80E-10	2.92E-06	1.08E+00	kg/MJ Jet Fuel
EU	7.72E-03	1.21E-02	5.56E-04	9.50E-07	7.72E-04	3.01E-08	7.16E-09	2.81E-02	kg/MJ Jet Fuel
Total	**7.99E-03**	**1.16E-02**	**-1.54E-03**	**4.54E-04**	**1.00E-03**	**8.03E-08**	**2.67E-05**	**-4.75E-01**	**kg/MJ Jet Fuel**

5.19 Scenario 19: CBTL, 19.6 Percent Torrefied and Pelleted Biomass and Validation

The purpose of this scenario is to evaluate potential process values, economic factors, and environmental emissions associated with the production of F-T jet fuels from a combination of 80.4 percent sub-bituminous coal and 19.6 percent Torrefied Biomass. This scenario evaluates a 1:1 (volume) blend of F-T jet fuels and conventional U.S. average jet fuel, based on a 30-year study period. Coal feedstock is derived from the Rosebud seam in southern Montana, and is transported by train to the CBTL facility, located in the Southeastern U.S. Southern pine biomass feedstock is produced and harvested in the Southeastern U.S., field-chipped, and then transported by chip truck to a separate torrefaction/pelletization facility, where the biomass is torrefied and formed into pellets. Torrefaction increases energy density of the biomass, and greatly reduces grinding energy required, as discussed in greater detail in Chapter 4. Torrefied/pelletized biomass is then transported by truck to the CBTL facility. The F-T process employed uses a slurry-based iron catalyst using a single feed, oxygen blown Transport Reactor Integrated Gasifier (TRIG™; refer to Chapter 2 for additional discussion). Carbon dioxide is captured at the CBTL facility using a Selexol process to segregate carbon dioxide. Additional carbon dioxide is stripped from overhead gas downstream of the F-T synthesis process, using a methyldiethanolamine (MDEA) unit. Captured carbon dioxide is then routed to a purification and compression system, where it is compressed to a supercritical state. F-T jet fuel produced by the F-T facility is then conveyed to a blending facility, where it is blended with conventional jet fuel, and transported to an airport. Finally, the blended jet fuel is combusted in a jet airplane.

The following text provides a summary of process model, economic model, and environmental model results for this scenario.

5.19.2 Process Results

As discussed in Chapter 2, three Aspen Plus® model cases were run for this scenario: low RSP, expected RSP, and high RSP. Process summary results, both modeled and validated, for each of the three cases are reported in **Table 5-73**. Results obtained from the Aspen Plus® simulations are based on a 50,000 barrel per day (bpd) production rate for total F-T products (F-T jet fuel, F-T diesel, F-T naphtha, and F-T LPG) for the CBTL, 19.6 percent Torrified/Pelleted Biomass configuration under all three RSP cases. Fuel production breakdowns are minimally variable among the three RSP cases. For all three RSP cases, approximately 49 percent (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34 percent by volume of total products) being F-T naphtha. F-T jet fuel is produced by hydrocracking the F-T wax to a final boiling point of about 300°C. Hydrocracking also produces naphtha boiling range liquids and F-T LPG. Relatively smaller quantities of F-T diesel (10 percent of total products) and F-T LPG (7 percent of total products) are produced as a result of hydrocracking. These proportions assume that straight run F-T output would be sold as a product. Results from each of the three Aspen Plus® model cases were incorporated into the economic and environmental analyses, the results of which are displayed below. For additional information regarding the application of low, expected, and high RSP values to the stochastic analysis provided here, refer to Chapter 1.

Table 5-73: Scenario 19: CBTL, 19.6% Torrefied/Pelleted Biomass: Process Summary

Property	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
CBTL Facility Design and Operating Data							
Plant Design Capacity	50,000	50,000	50,000	50,000	50,000	50,000	bpd
Plant Capacity Factor	85	85	90	90	92	92	%
Plant Efficiency, HHV	56	56	54	54	52	52	%
Carbon Capture Rate	88	88	89	89	90	90	%
Gasifier Modules	9	9	9	9	9	9	Count
F-T Modules	10	10	10	10	10	10	Count
CBTL Facility Inputs/Feed							
Coal Feed, Montana Rosebud, As Received	23,559	23,595	24,104	24,149	24,862	24,919	tons/ day
Biomass Feed, Southern Pine, As Received	5,329	5,337	5,319	5,329	5,356	5,368	tons/ day
Water Feed (Total Withdrawal)	14,480,225	14,548,248	14,303,570	14,381,977	14,109,955	14,197,371	gallons/day
CBTL Facility Outputs/Production							
F-T Jet Fuel Production	24,649	24,648	24,647	24,646	24,644	24,643	bpd
F-T Diesel Fuel Production	4,767	4,767	4,767	4,767	4,766	4,766	bpd
F-T Naphtha Production	16,973	16,972	16,971	16,971	16,970	16,969	bpd
F-T LPG Production	3,612	3,613	3,615	3,616	3,620	3,621	bpd
Total Liquid Product Output	50,000	50,000	50,000	50,000	50,000	50,000	bpd
Export Power	269	268	238	237	200	199	MW
CO2 Captured and Compressed	29,518	29,670	30,204	30,377	30,777	30,966	tons/ day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,297	49,296	49,294	49,293	49,288	49,287	bpd

CBTL facility fuels production capacity was fixed at 50,000 bpd for all three RSP cases. An expected capacity factor of 90 percent was included, ranging from 85 to 92 percent for low and high RSP cases, respectively. In the modeled case the overall expected plant efficiency of 54.2 percent (range of 52.2 to 55.7 percent) is defined as the heating value of the liquid products (HHV basis), F-T LPG, and export power divided by the higher heating value of the input coal and biomass. In the validation case the overall expected plant efficiency is 54.1 percent (range of 52.1 to 55.6 percent) , a variation of less than 1 percent from the modeled case. In the modeled case, makeup water for the CBTL facility, as modeled in Aspen Plus®, is estimated to be approximately 13.0 million gallons per day (mgd; expected RSP case), of which 94 percent (12.2 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.2 bbl water/bbl F-T product, based on the expected RSP modeled case. In the validated case, makeup water for the CBTL facility is estimated to be approximately 14.3 million gallons per day (mgd; expected RSP case), of which 96.8 percent (13.8 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.81 bbl water/bbl F-T product, based on the expected RSP validated case. Here there is strong agreement between the modeled and validated case with a variation of makeup water for the CBTL facility of0.08 million gallon per day (0.55 percent) and a normalized variation of 0.04 bbl water/bbl F-T product (0.55 percent).

Under the modeled case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 200 to 269 MW, with an expected value of 238 MW. Based on the expected RSP case, gross power production for the CBTL facility is 789 MW, including power generated from steam (557 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (235 MW), carbon dioxide compressors (89.9 MW), the Selexol unit (59.0 MW), hydrocarbon recovery/refrigeration (43.5 MW), and oxygen compression (30.4 MW). Total auxiliaries consume 552 MW, for a net power output of 238 MW under the expected RSP case.

Under the validated case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 199 to 268 MW, with an expected value of 237 MW. Based on the expected RSP case, gross power production for the CBTL facility is 792 MW, including power generated from steam (560 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (236 MW), carbon dioxide compressors (90.3 MW), the Selexol unit (59.2 MW), hydrocarbon recovery/refrigeration (44.5 MW), and oxygen compression (30.5 MW). Total auxiliaries consume 555 MW, for a net power output of 237 MW under the expected RSP case.

Carbon balance for both the modeled and validated case of the CBTL facility is shown in **Table 5-74**, for all three RSP cases. As shown, carbon inputs were within 0.2 percent of carbon outputs for each of the three RSP cases. Carbon dioxide produced during the production of fuels and electric power is separated from the syngas stream prior to entering the F-T unit. The Selexol unit and the MDEA unit both produce the concentrated CO_2 streams that are dehydrated and compressed to 2,200 psi for pipeline delivery and carbon management. Other flue gas streams containing CO_2 are vented to the atmosphere. These include the flue gases from the HRSG units and from the fired heaters that are utilized during the F-T process. For the expected RSP case, approximately 2 percent of total carbon (range of 1 percent for the low RSP case to 4 percent for the high RSP case) is output to slag/ash from the TRIG gasifier.

Table 5-74: Scenario 19: CBTL, 19.6% Torrefied/Pelleted Biomass: Conversion Facility Carbon Balance

Input Flow	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
Coal Carbon	11,796	11,813	12,068	12,091	12,448	12,476	TPD
Biomass Carbon	3,192	3,196	3,186	3,192	3,208	3,215	TPD
Total Carbon Input	14,987	15,010	15,254	15,282	15,655	15,691	**TPD**
F-T Products	5,284	5,284	5,284	5,284	5,284	5,284	TPD
Slag/Ash	148	148	301	302	618	620	TPD
Stack Gas	978	964	928	914	878	866	TPD
Fuel Gas	266	259	239	232	211	205	TPD
WWTP	30	31	30	31	31	29	TPD
Carbon Capture, Sequestered	8,074	8,116	8,265	8,313	8,425	8,478	TPD
Total Carbon Output	**14,779**	**14,802**	**15,047**	**15,076**	**15,448**	**15,482**	**TPD**
Carbon Capture	**86.4**	**86.6**	**87.3**	**87.6**	**88.3**	**88.5**	**%**

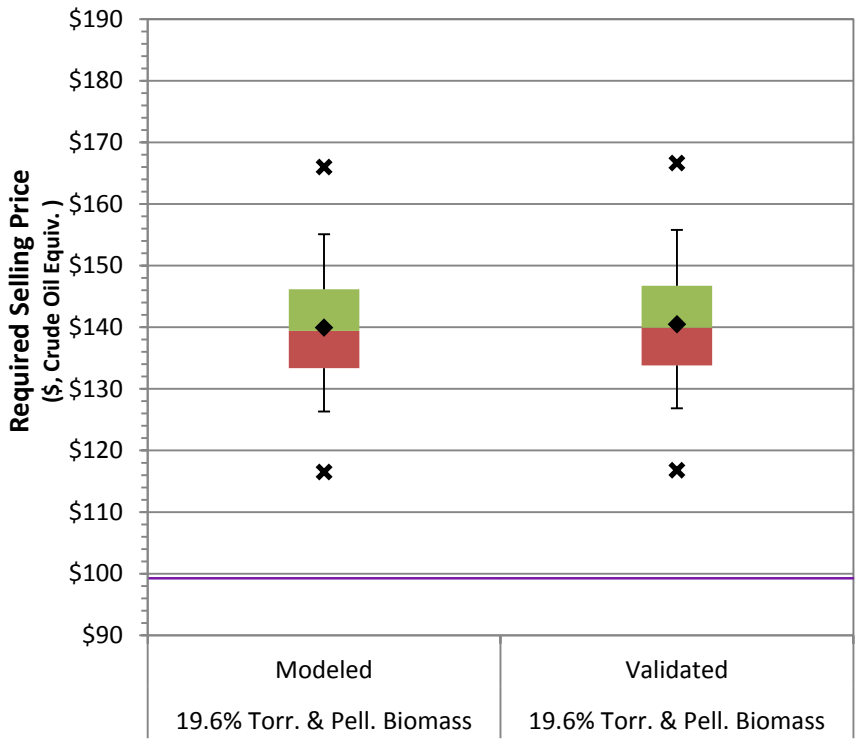
5.19.3 Economic Results

Results from the economic model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Figure 5-109 provides a summary of the estimated RSP for the F-T jet fuel produced under this scenario. As shown, RSP ranges from $133 to $146/bbl for the modeled case, with a mean value of $140/bbl, on a crude oil equivalent basis and for the variation, case the RSP ranges from $134 to $147/bbl, with a mean value of $141/bbl. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 40 economic parameters shown in **Table 1-5**. As shown, 25th and 75th percentile values are relatively close to the mean value, however, selling price distributions are characterized by long tails, with an overall range of $117to $167/bbl, on a crude oil equivalent basis.

Cost of the F-T jet fuel product is estimated on a crude oil equivalent basis. This is defined as the RSP of the diesel product divided by a factor of 1.1433. Thus if the average world oil price were below or equal to the calculated crude oil equivalent price the CBTL plant would be economically viable. Key contributors to the variability shown for RSP results are discussed below.

Figure 5-109: Scenario 19: CBTL, 19.6% Torrefied/Pelleted Biomass: F-T Jet Fuel RSP, Crude Oil Equivalent Basis



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel spot price value.

It is clear from **Figure 5-109** that there is minimal variation between the modeled and validated RSP results. **Table 5-75** provides a summary of the economic estimated performance of the CBTL facility under the validated case of this scenario, including the key contributing factors to the calculation of RSP. Total operating and maintenance costs represent an average of $534 million/yr. Of this amount, $295 to $321 million/yr, mean $309 million/yr (57.8 percent), results from fixed costs, while $217 to $233 million/year, mean $225 million/yr (42.2 percent) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, range from $8,475 to $9,300 million, mean $8,898 million. Coal feedstock costs for this scenario range from $278 to $291 million/yr, mean $285 million/yr. Biomass feedstock costs range from $235 to $252 million/yr, mean $244 million/yr. Total feedstock costs are approximately $5.67 million lower than total operating and maintenance costs, on average. Projected revenues include credits and product sales revenue. Power credit, from the sale of produced electricity, amounts to $123 to $138 million/yr, mean $130 million/yr, while CO_2 credit is estimated to be $327 to $389 million/yr, mean $358 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,137 to $2,340 million/yr, mean $2,241 million/yr.

Required product sales prices in the validated case are also provided in **Table 5-75**. Crude oil equivalent RSP is discussed above for **Figure 5-109**. On a straight basis, RSP for F-T jet fuel was calculated to be $155 to $169/bbl, mean $162/bbl, with F-T diesel at $153 to $168/bbl, mean $161/bbl, F-T naphtha at $107 to $117/bbl, mean $112/bbl, and F-T LPG at $61.8 to $67.8/bbl, mean $64.9/bbl. The default capital charge factor (CCF) used in the analysis was 0.1872.

Table 5-75: Scenario 19: CBTL, 19.6% Torrefied/Pelleted Biomass: Summary of Economics

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	309	255	368	295	321	$MM/yr
Variable Operating and Maintenance Cost (VOM)	225	192	267	217	233	$MM/yr
Capital: Total Overnight Cost (TOC)	8,898	7,539	10,833	8,475	9,300	$MM
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	285	260	312	278	291	$MM/yr
Biomass Cost, Southern Pine, Chips, As Received	0	0	0	0	0	$MM/yr
Biomass Cost, Southern Pine, Torrefied, As Received	244	206	275	235	252	$MM/yr
Credits and Revenue						
Power Credit	(130)	(164)	(96)	(138)	(123)	$MM/yr
Credit @ $40/ton for CO_2	(358)	(462)	(252)	(389)	(327)	$MM/yr
Annual Revenue Required	2,241	1,842	2,664	2,137	2,340	$MM/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	162	135	192	155	169	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	161	134	191	153	168	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	112	93	133	107	117	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	65	54	77	62	68	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	141	117	167	134	147	$/bbl

Figure 5-110 provides breakdowns for the cost factors in the validated case that contribute to the RSP. As shown, capital cost is the primary factor in determining RSP, and accounts for approximately 74.3 percent of total RSP, or $104/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 20.8 percent of total RSP, or $29.3/bbl, while feedstock costs represent 20.6 percent of total RSP, or $29.0/bbl, on a crude oil equivalent basis. As shown, variability in total RSP is driven largely by potential variability in capital costs, and to a much lesser extent by variability in operations and maintenance and feedstock costs. The negative credits bar comprises the sale of the co-produced electricity and compressed CO_2. Electricity accounts for 26.7 percent of the total credit, while captured and compressed CO_2 accounts for 73.3 percent.

Figure 5-110: Scenario 19: CBTL, 19.6% Torrefied/Pelleted Biomass, Validated: RSP, Crude Oil Equivalent Basis

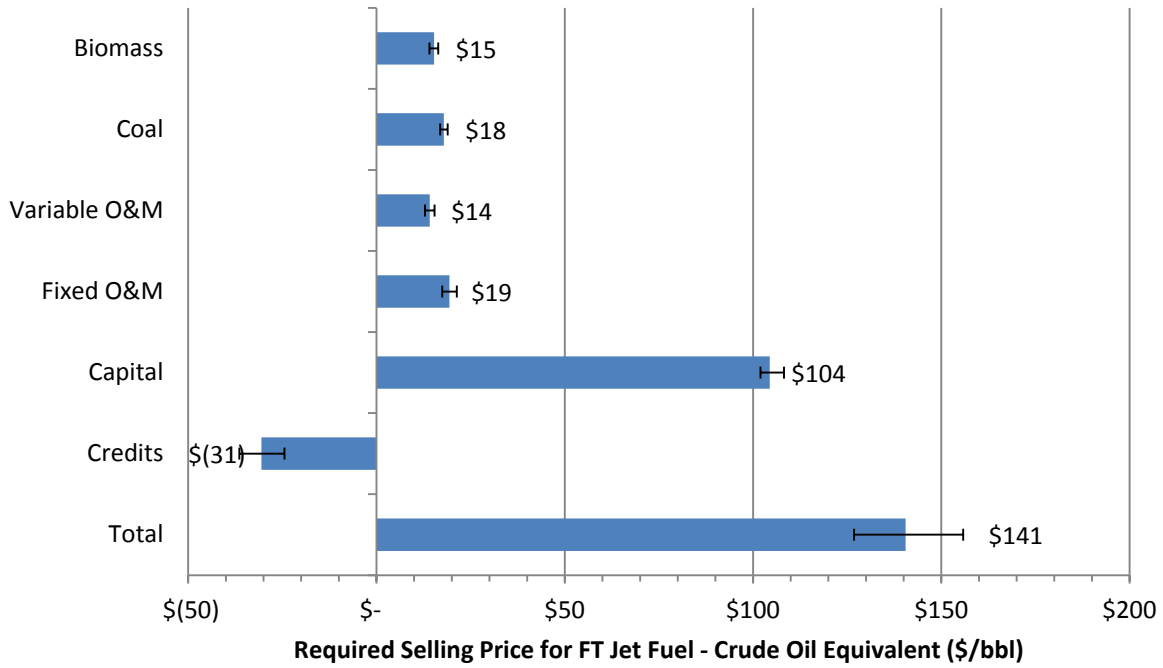
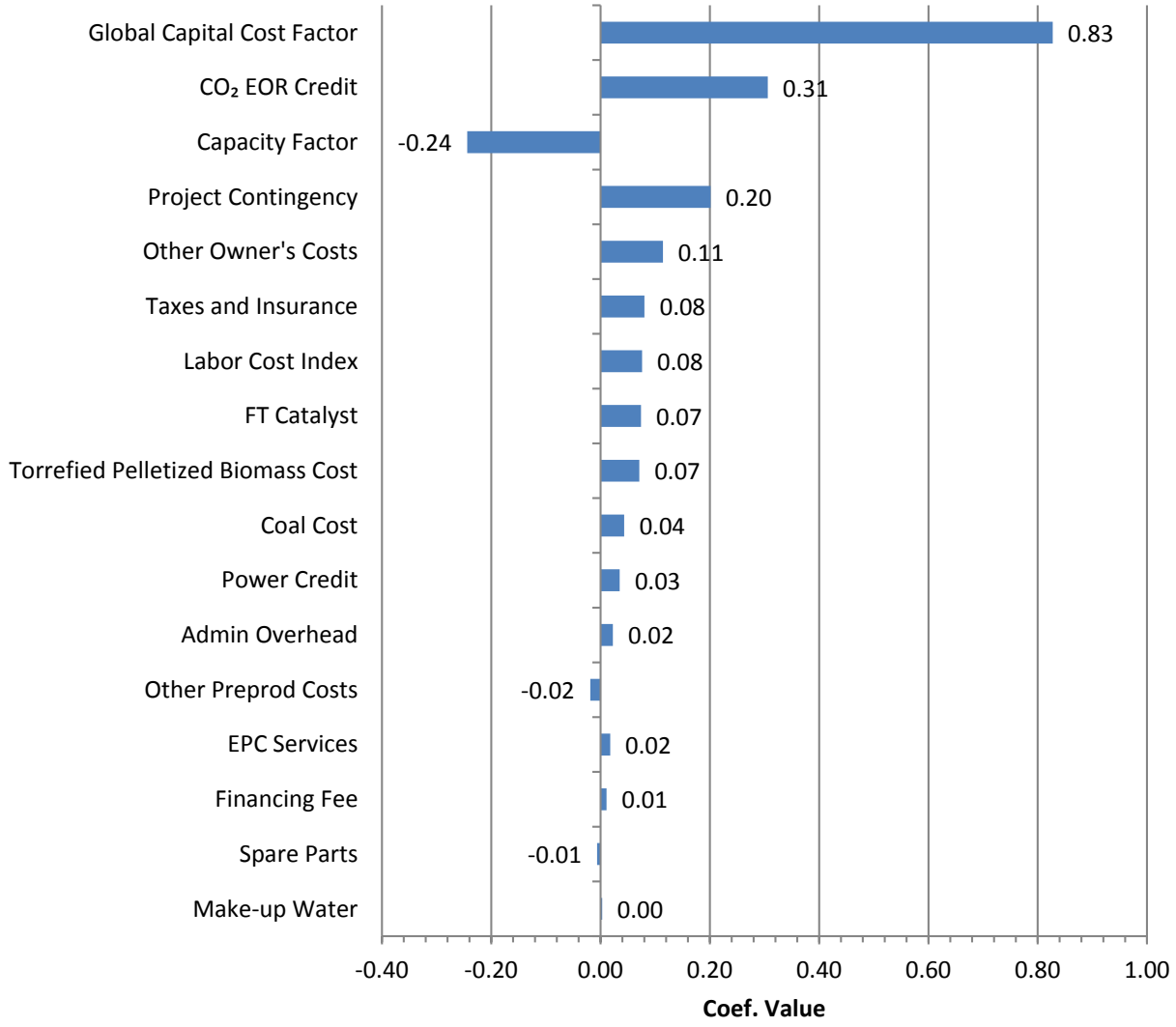


Figure 5-111 provides a summary of model sensitivity in the validated case, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.83. Other key factors that account for at least 10 percent of the observed variability in RSP include the CO_2 EOR credit, capacity factor, project contingency, and other owner's costs. Parameters that caused minimal influence on RSP include the cost of spare parts, financing fees, EPC service costs, other preproduction costs, and others as shown.

Figure 5-111: Scenario 19: CBTL, 19.6% Torrefied/Chipped Biomass, Validated: Sensitivity of RSP to Modeled Variables

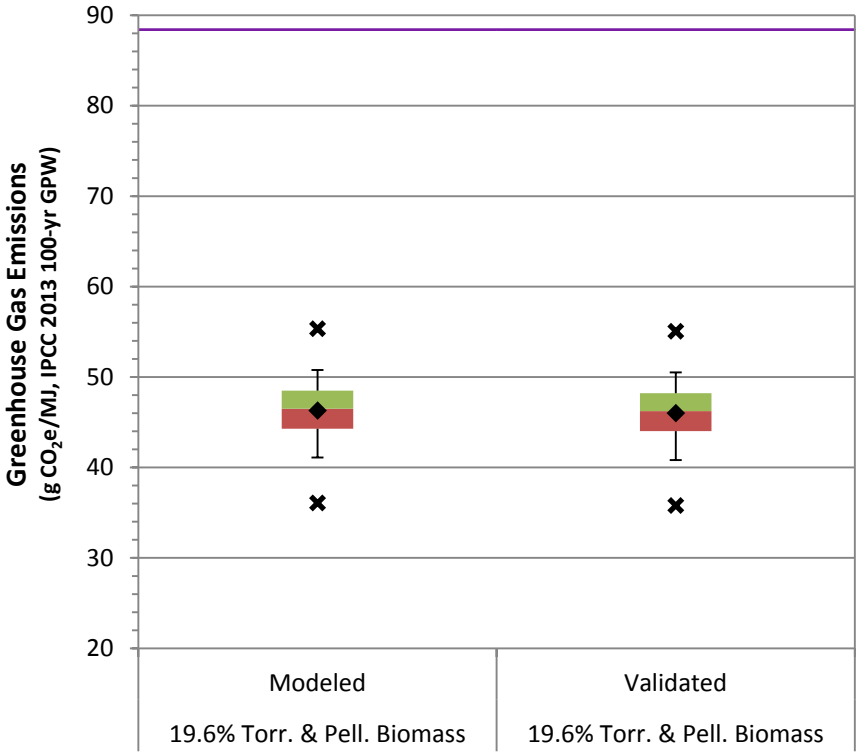


5.19.4 Environmental Results

Results from the environmental model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Results from the environmental life cycle analysis include GHG emissions and other emissions, including select criteria air pollutants, other pollutants of concern, and water consumption. **Figure 5-112** provides a summary life cycle GHG emissions for this scenario, in comparison to conventional jet fuel life cycle GHG emissions of 88.41 g CO_2e/MJ. In the modeled case the resulting range is 36.1 to 55.3 g CO_2e/MJ, mean 46.3 g CO_2e/MJ or approximately 47.0 percent less than conventional jet fuel. In the validated case the resulting range is 35.8 to 55.1 g CO_2e/MJ, mean 46.0 g CO_2e/MJ or approximately47.3 percent less than conventional jet fuel.

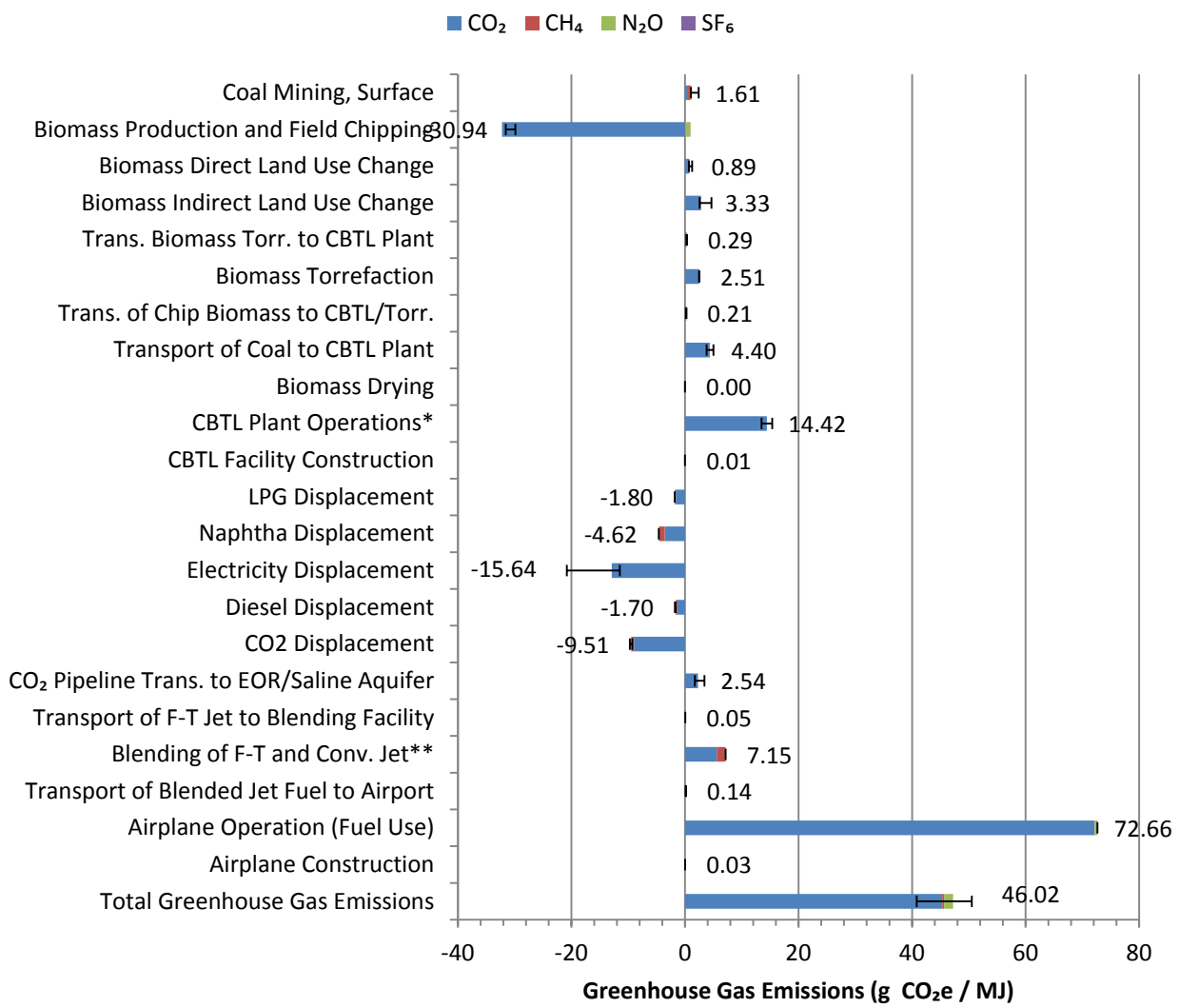
Figure 5-112: Scenario 19: CBTL, 19.6% Torrefied/Pelleted Biomass, Validated: Summary of LC GHG Emissions



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

It is clear from **Figure 5-112** that there is minimal variation between the modeled and validated LC GHG emission results. **Figure 5-113** provides detail regarding the importance of the various LCA components in the validated case that were modeled, with respect to gross GHG emissions contributions. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 65.5 percent of gross life cycle GHG emissions. Second in importance to fuel combustion is CBTL plant operations, at 13.1 percent of gross life cycle emissions, while emissions associated with blending of F-T and conventional jet fuel represent 5.08 percent of gross life cycle emissions. The transport of coal to the CBTL plant accounts for 3.82 percent of gross life cycle GHG emissions. Emissions from the pipeline transport of CO_2 represent approximately 2.57 percent of gross emissions. GHG emissions associated with biomass indirect land use change generate 2.26 percent of gross life cycle emissions, while the torrefaction of biomass generates 2.07 percent. Other contributors to gross emissions were less than 1 percent individually.

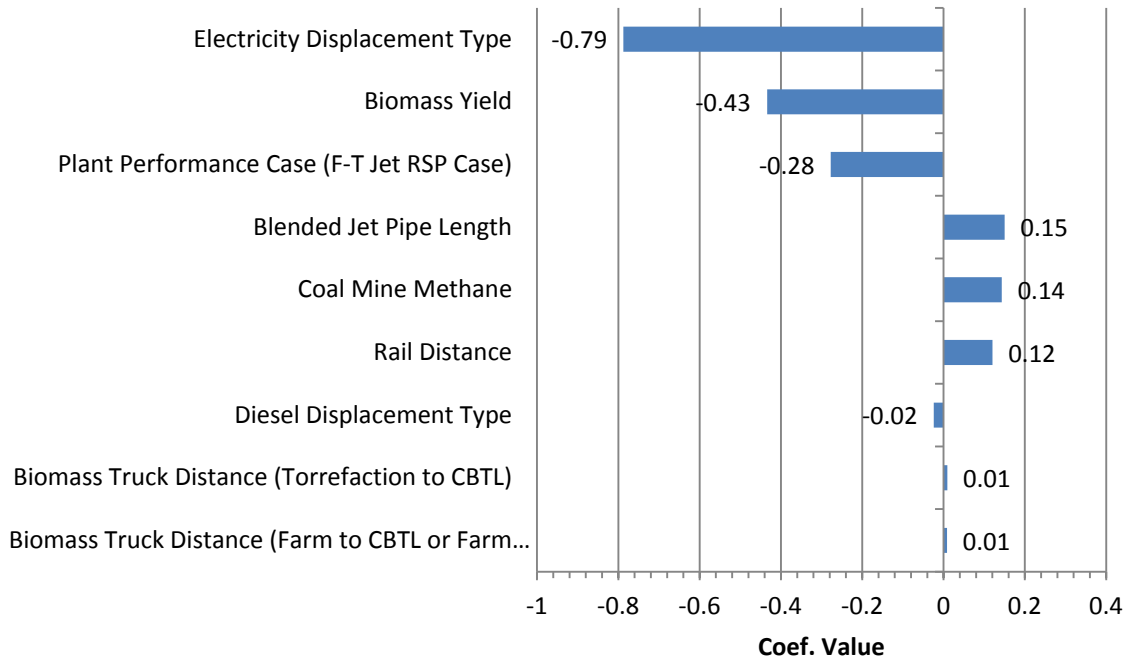
Figure 5-113: Scenario 19: CBTL, 19.6% Torrefied/Pelleted Biomass, Validated: LC GHG Emissions Breakdowns



** Includes CO_2 Compression*
***Includes conventional jet fuel profile*

The error bars shown in **Figure 5-113** reflect variability in model output based on the stochastic analyses (for more information, refer to Chapter 1). The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-6**. As shown, variability in emissions resulted primarily from the type of electricity displacement used. Other key contributors to variability in model output include biomass yield and the F-T jet fuel RSP case. **Figure 5-114** summarizes the key factors contributing to variability identified in the model sensitivity analysis, for GHG emissions. Values provided in the figure show the correlation coefficient between the indicated parameter and total life cycle GHG emissions. Other important factors included the blended jet fuel pipe length, the coal mine methane emissions, the rail transport distance, and the biomass truck transportation distances. Other parameters had minimal to negligible effect on life cycle GHG emissions.

Figure 5-114: Scenario 19: CBTL, 19.6% Torrefied/Pelleted Biomass, Validated: LC GHG Emissions Sensitivity



In addition to GHG emissions, other life cycle environmental emissions and flows were also considered. **Table 5-76** provides a summary of these flows. As shown, Airplane operation is the primary source of carbon monoxide and NOx within the life cycle. Particulate matter (PM_{10}) derives primarily from the combustion of diesel under raw materials transport and product transport operations. Non-methane volatile organic carbons (NMVOCs) result from product transport, including upstream conventional jet fuel emissions, and end use. The highest levels of mercury emissions occur during energy conversion and end use. Most water consumption occurs during biomass cultivation. Note that mass units displayed for water consumption (kg/MJ jet fuel) are equivalent to volume units for water consumption (L/MJ jet fuel).

Table 5-76: Scenario 19: CBTL, 19.6% Torrefied/Pelleted Biomass, Validated: Non-GHG Emissions

LC Stage	Carbon monoxide	NO_x	SO2	PM10	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	1.54E-05	1.61E-04	1.66E-05	1.64E-06	9.45E-06	2.63E-10	1.57E-06	1.39E-02	kg/MJ Jet Fuel
RMT	5.04E-04	4.62E-04	1.04E-04	5.90E-04	8.67E-05	2.85E-10	6.67E-06	1.60E-01	kg/MJ Jet Fuel
EC	-5.40E-04	-1.71E-03	-2.94E-03	-2.05E-04	-7.21E-04	4.63E-08	4.33E-06	-2.32E+00	kg/MJ Jet Fuel
PT	2.76E-04	4.38E-04	6.25E-04	3.28E-05	8.45E-04	5.80E-10	2.92E-06	1.08E+00	kg/MJ Jet Fuel
EU	7.72E-03	1.21E-02	5.56E-04	9.50E-07	7.72E-04	3.01E-08	7.16E-09	2.81E-02	kg/MJ Jet Fuel
Total	**7.97E-03**	**1.15E-02**	**-1.64E-03**	**4.21E-04**	**9.92E-04**	**7.75E-08**	**1.55E-05**	**-1.03E+00**	**kg/MJ Jet Fuel**

5.20 Scenario 20: CBTL, 28.3 Percent Torrefied and Pelleted Biomass and Validation

The purpose of this scenario is to evaluate potential process values, economic factors, and environmental emissions associated with the production of F-T jet fuels from a combination of 71.3 percent sub-bituminous coal and 28.3 percent Torrefied Biomass. This scenario evaluates a 1:1 (volume) blend of F-T jet fuels and conventional U.S. average jet fuel, based on a 30-year study period. Coal feedstock is derived from the Rosebud seam in southern Montana, and is transported by train to the CBTL facility, located in the Southeastern U.S. Southern pine biomass feedstock is produced and harvested in the Southeastern U.S., field-chipped, and then transported by chip truck to a separate torrefaction/pelletization facility, where the biomass is torrefied and formed into pellets. Torrefaction increases energy density of the biomass, and greatly reduces grinding energy required, as discussed in greater detail in Chapter 4. Torrefied/pelletized biomass is then transported by truck to the CBTL facility. The F-T process employed uses a slurry-based iron catalyst using a single feed, oxygen blown Transport Reactor Integrated Gasifier (TRIG™; refer to Chapter 2 for additional discussion). Carbon dioxide is captured at the CBTL facility using a Selexol process to segregate carbon dioxide. Additional carbon dioxide is stripped from overhead gas downstream of the F-T synthesis process, using a methyldiethanolamine (MDEA) unit. Captured carbon dioxide is then routed to a purification and compression system, where it is compressed to a supercritical state. F-T jet fuel produced by the F-T facility is then conveyed to a blending facility, where it is blended with conventional jet fuel, and transported to an airport. Finally, the blended jet fuel is combusted in a jet airplane.

The following text provides a summary of process model, economic model, and environmental model results for this scenario.

5.20.2 Process Results

As discussed in Chapter 2, three Aspen Plus® model cases were run for this scenario: low RSP, expected RSP, and high RSP. Process summary results, both modeled and validated, for each of the three cases are reported in **Table 5-77**. Results obtained from the Aspen Plus® simulations are based on a 50,000 barrel per day (bpd) production rate for total F-T products (F-T jet fuel, F-T diesel, F-T naphtha, and F-T LPG) for the CBTL, 28.3 percent Torrified/Pelleted Biomass configuration under all three RSP cases. Fuel production breakdowns are minimally variable among the three RSP cases. For all three RSP cases, approximately 49 percent (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34 percent by volume of total products) being F-T naphtha. F-T jet fuel is produced by hydrocracking the F-T wax to a final boiling point of about 300°C. Hydrocracking also produces naphtha boiling range liquids and F-T LPG. Relatively smaller quantities of F-T diesel (10 percent of total products) and F-T LPG (7 percent of total products) are produced as a result of hydrocracking. These proportions assume that straight run F-T output would be sold as a product. Results from each of the three Aspen Plus® model cases were incorporated into the economic and environmental analyses, the results of which are displayed below. For additional information regarding the application of low, expected, and high RSP values to the stochastic analysis provided here, refer to Chapter 1.

Table 5-77: Scenario 20: CBTL, 28.3% Torrefied/Pelleted Biomass: Process Summary

Property	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
CBTL Facility Design and Operating Data							
Plant Design Capacity	50,000	50,000	50,000	50,000	50,000	50,000	bpd
Plant Capacity Factor	85	85	90	90	92	92	%
Plant Efficiency, HHV	56	56	55	55	53	53	%
Carbon Capture Rate	88	88	89	89	90	90	%
Gasifier Modules	14	14	14	14	14	14	Count
F-T Modules	10	10	10	10	10	10	Count
CBTL Facility Inputs/Feed							
Coal Feed, Montana Rosebud, As Received	20,833	20,864	21,343	21,382	22,049	22,099	tons/ day
Biomass Feed, Southern Pine, As Received	7,630	7,641	7,626	7,640	7,691	7,708	tons/ day
Water Feed (Total Withdrawal)	14,144,429	14,211,048	13,990,534	14,067,148	13,822,406	13,907,459	gallons/day
CBTL Facility Outputs/Production							
F-T Jet Fuel Production	24,648	24,648	24,647	24,646	24,644	24,643	bpd
F-T Diesel Fuel Production	4,767	4,767	4,767	4,767	4,766	4,766	bpd
F-T Naphtha Production	16,972	16,972	16,971	16,971	16,970	16,969	bpd
F-T LPG Production	3,613	3,613	3,616	3,617	3,621	3,622	bpd
Total Liquid Product Output	50,000	50,000	50,001	50,000	50,001	50,000	bpd
Export Power	275	274	246	245	187	209	MW
CO2 Captured and Compressed	29,287	29,440	29,925	30,096	30,464	30,648	tons/ day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,296	49,296	49,293	49,292	49,288	49,286	bpd

CBTL facility fuels production capacity was fixed at 50,000 bpd for all three RSP cases. An expected capacity factor of 90 percent was included, ranging from 85 to 92 percent for low and high RSP cases, respectively. In the modeled case the overall expected plant efficiency of 54.7 percent (range of 52.7 to 56.1 percent) is defined as the heating value of the liquid products (HHV basis), F-T LPG, and export power divided by the higher heating value of the input coal and biomass. In the validation case the overall expected plant efficiency is 54.6 percent (range of 52.6 to 56.0 percent) , a variation of less than 1 percent from the modeled case. In the modeled case, makeup water for the CBTL facility, as modeled in Aspen Plus®, is estimated to be approximately 14.0 million gallons per day (mgd; expected RSP case), of which 97.6 percent (13.7 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.66 bbl water/bbl F-T product, based on the expected RSP modeled case. In the validated case, makeup water for the CBTL facility is estimated to be approximately 14.1 million gallons per day (mgd; expected RSP case), of which 97.7 percent (13.7 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.70 bbl water/bbl F-T product, based on the expected RSP validated case. Here there is strong agreement between the modeled and validated case with a variation of makeup water for the CBTL facility of 0.08 million gallon per day (0.54 percent) and a normalized variation of 0.04 bbl water/bbl F-T product (0.54 percent).

Under the modeled case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 187 to 275 MW, with an expected value of 246 MW. Based on the expected RSP case, gross power production for the CBTL facility is 789 MW, including power generated from steam (557 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (228 MW), carbon dioxide compressors (89.2 MW), the Selexol unit (57.5 MW), hydrocarbon recovery/refrigeration (43.7 MW), and oxygen compression (29.6 MW). Total auxiliaries consume 543 MW, for a net power output of 246 MW under the expected RSP case.

Under the validated case of this scenario, the CBTL facility generates all required parasitic power needs and produces net export power for sale. Net power production rate varied according to RSP case, ranging from 209 to 274 MW, with an expected value of 245 MW. Based on the expected RSP case, gross power production for the CBTL facility is 792 MW, including power generated from steam (560 MW) and gas turbines (232 MW). Power is consumed within the CBTL facility by a suite of auxiliary loads. Major auxiliary loads include air separation (230 MW), carbon dioxide compressors (89.6 MW), the Selexol unit (57.8 MW), hydrocarbon recovery/refrigeration (44.7 MW), and oxygen compression (29.7 MW). Total auxiliaries consume 547 MW, for a net power output of 245 MW under the expected RSP case.

Carbon balance for both the modeled and validated case of the CBTL facility is shown in **Table 5-78**, for all three RSP cases. As shown, carbon inputs were within 0.2 percent of carbon outputs for each of the three RSP cases. Carbon dioxide produced during the production of fuels and electric power is separated from the syngas stream prior to entering the F-T unit. The Selexol unit and the MDEA unit both produce the concentrated CO_2 streams that are dehydrated and compressed to 2,200 psi for pipeline delivery and carbon management. Other flue gas streams containing CO_2 are vented to the atmosphere. These include the flue gases from the HRSG units and from the fired heaters that are utilized during the F-T process. For the expected RSP case, approximately 2 percent of total carbon (range of 1 percent for the low RSP case to 4 percent for the high RSP case) is output to slag/ash from the TRIG gasifier.

Table 5-78: Scenario 20: CBTL, 28.3% Torrefied/Pelleted Biomass: Conversion Facility Carbon Balance

Input Flow	Low RSP Case		Expected RSP Case		High RSP Case		Units
	Modeled	Validated	Modeled	Validated	Modeled	Validated	
Coal Carbon	10,431	10,446	10,686	10,706	11,040	11,065	TPD
Biomass Carbon	4,569	4,576	4,567	4,575	4,606	4,616	TPD
Total Carbon Input	15,000	15,023	15,253	15,281	15,645	15,681	**TPD**
F-T Products	5,284	5,284	5,284	5,284	5,284	5,284	TPD
Slag/Ash	147	147	299	300	614	616	TPD
Stack Gas	965	951	915	902	867	856	TPD
Fuel Gas	262	256	236	229	208	202	TPD
WWTP	32	30	31	30	31	30	TPD
Carbon Capture, Sequestered	8,012	8,054	8,189	8,237	8,341	8,392	TPD
Total Carbon Output	**14,702**	**14,722**	**14,955**	**14,982**	**15,345**	**15,380**	**TPD**
Carbon Capture	**86.4**	**86.7**	**87.4**	**87.6**	**88.3**	**88.5**	**%**

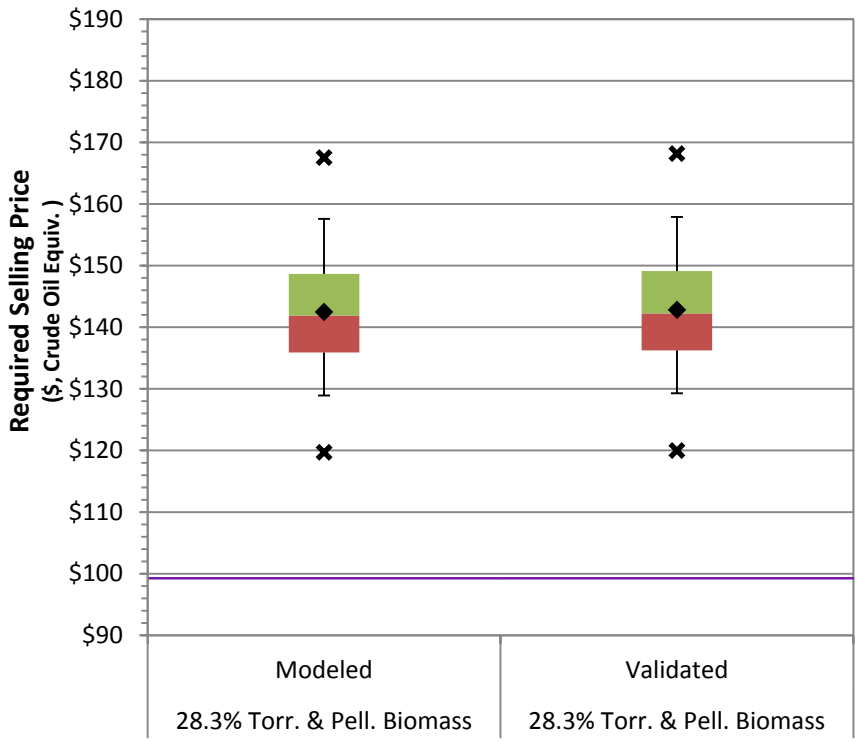
5.20.3 Economic Results

Results from the economic model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Figure 5-115 provides a summary of the estimated RSP for the F-T jet fuel produced under this scenario. As shown, RSP ranges from $136 to $149/bbl for the modeled case, with a mean value of $143/bbl, on a crude oil equivalent basis and for the variation, case the RSP ranges from $136 to $149/bbl, with a mean value of $143/bbl. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 40 economic parameters shown in **Table 1-5**. As shown, 25th and 75th percentile values are relatively close to the mean value, however, selling price distributions are characterized by long tails, with an overall range of $120 to $168/bbl, on a crude oil equivalent basis.

Cost of the F-T jet fuel product is estimated on a crude oil equivalent basis. This is defined as the RSP of the diesel product divided by a factor of 1.1433. Thus if the average world oil price were below or equal to the calculated crude oil equivalent price the CBTL plant would be economically viable. Key contributors to the variability shown for RSP results are discussed below.

Figure 5-115: Scenario 20: CBTL, 28.3% Torrefied/Pelleted Biomass: F-T Jet Fuel RSP, Crude Oil Equivalent Basis



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel spot price value.

It is clear from **Figure 5-115** that there is minimal variation between the modeled and validated RSP results. **Table 5-79** provides a summary of the economic estimated performance of the CBTL facility under the validated case of this scenario, including the key contributing factors to the calculation of RSP. Total operating and maintenance costs represent an average of $527 million/yr. Of this amount, $290 to $316 million/yr, mean $304 million/yr (57.7 percent), results from fixed costs, while $215 to $231 million/year, mean $223 million/yr (42.3 percent) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, range from $8,340 to $9,151 million, mean $8,752 million. Coal feedstock costs for this scenario range from $246 to $258 million/yr, mean $252 million/yr. Biomass feedstock costs range from $338 to $361 million/yr, mean $70 million/yr. Total feedstock costs are approximately $74.9 million greater than total operating and maintenance costs, on average. Projected revenues include credits and product sales revenue. Power credit, from the sale of produced electricity, amounts to $127 to $142 million/yr, mean $134 million/yr, while CO_2 credit is estimated to be $324 to $385 million/yr, mean $355 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,175 to $2,376 million/yr, mean $2,278 million/yr.

Required product sales prices in the validated case are also provided in **Table 5-79**. Crude oil equivalent RSP is discussed above for **Figure 5-115**. On a straight basis, RSP for F-T jet fuel was calculated to be $157 to $172/bbl, mean $165/bbl, with F-T diesel at $156 to $171/bbl, mean $163/bbl, F-T naphtha at $109 to $119/bbl, mean $114/bbl, and F-T LPG at $62.9 to $68.9/bbl, mean $66.0/bbl. The default capital charge factor (CCF) used in the analysis was 0.1872.

Table 5-79: Scenario 20: CBTL, 28.3% Torrefied/Pelleted Biomass: Summary of Economics

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	304	251	362	290	316	$MM/yr
Variable Operating and Maintenance Cost (VOM)	223	190	264	215	231	$MM/yr
Capital: Total Overnight Cost (TOC)	8,752	7,410	10,658	8,340	9,151	$MM
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	252	230	277	246	258	$MM/yr
Biomass Cost, Southern Pine, Chips, As Received	0	0	0	0	0	$MM/yr
Biomass Cost, Southern Pine, Torrefied, As Received	349	295	395	338	361	$MM/yr
Credits and Revenue						
Power Credit	(134)	(167)	(102)	(142)	(127)	$MM/yr
Credit @ $40/ton for CO_2	(355)	(457)	(250)	(385)	(324)	$MM/yr
Annual Revenue Required	2,278	1,886	2,689	2,175	2,376	$MM/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	165	139	194	157	172	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	163	137	192	156	171	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	114	96	134	109	119	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	66	55	78	63	69	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	143	120	168	136	149	$/bbl

Figure 5-116 provides breakdowns for the cost factors in the validated case that contribute to the RSP. As shown, capital cost is the primary factor in determining RSP, and accounts for approximately 71.9 percent of total RSP, or $103/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 20.2 percent of total RSP, or $28.9/bbl, while feedstock costs represent 23.1 percent of total RSP, or $33.0/bbl, on a crude oil equivalent basis. As shown, variability in total RSP is driven largely by potential variability in capital costs, and to a much lesser extent by variability in operations and maintenance and feedstock costs. The negative credits bar comprises the sale of the co-produced electricity and compressed CO_2. Electricity accounts for 27.4 percent of the total credit, while captured and compressed CO_2 accounts for 72.6 percent.

Figure 5-116: Scenario 20: CBTL, 28.3% Torrefied/Pelleted Biomass, Validated: RSP, Crude Oil Equivalent Basis

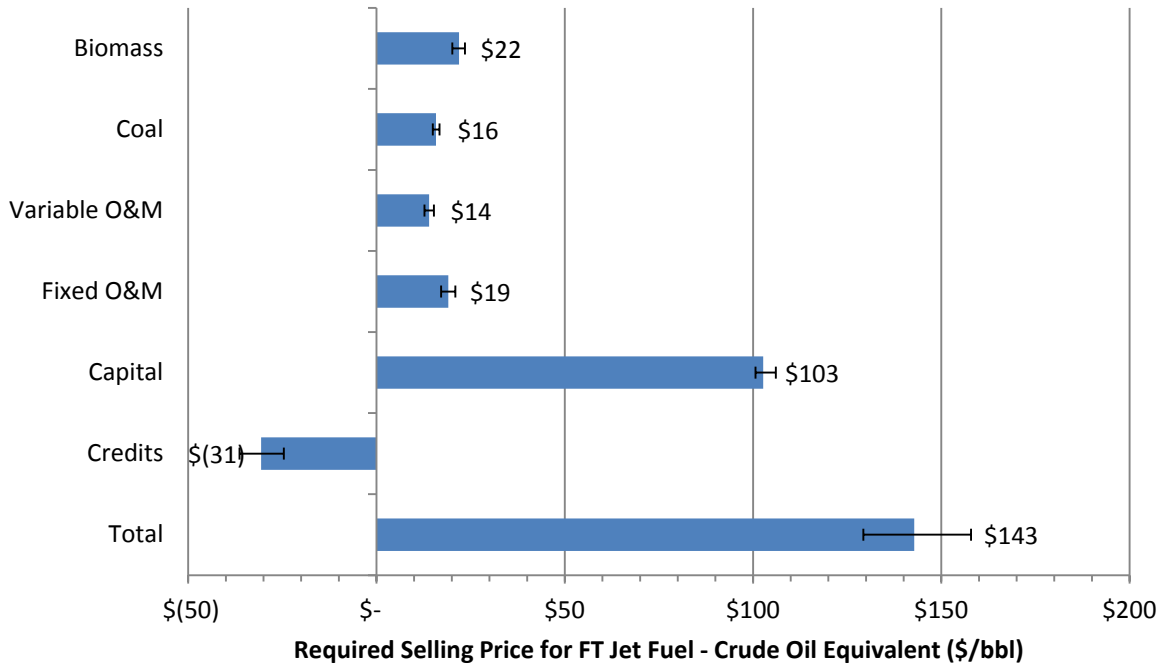
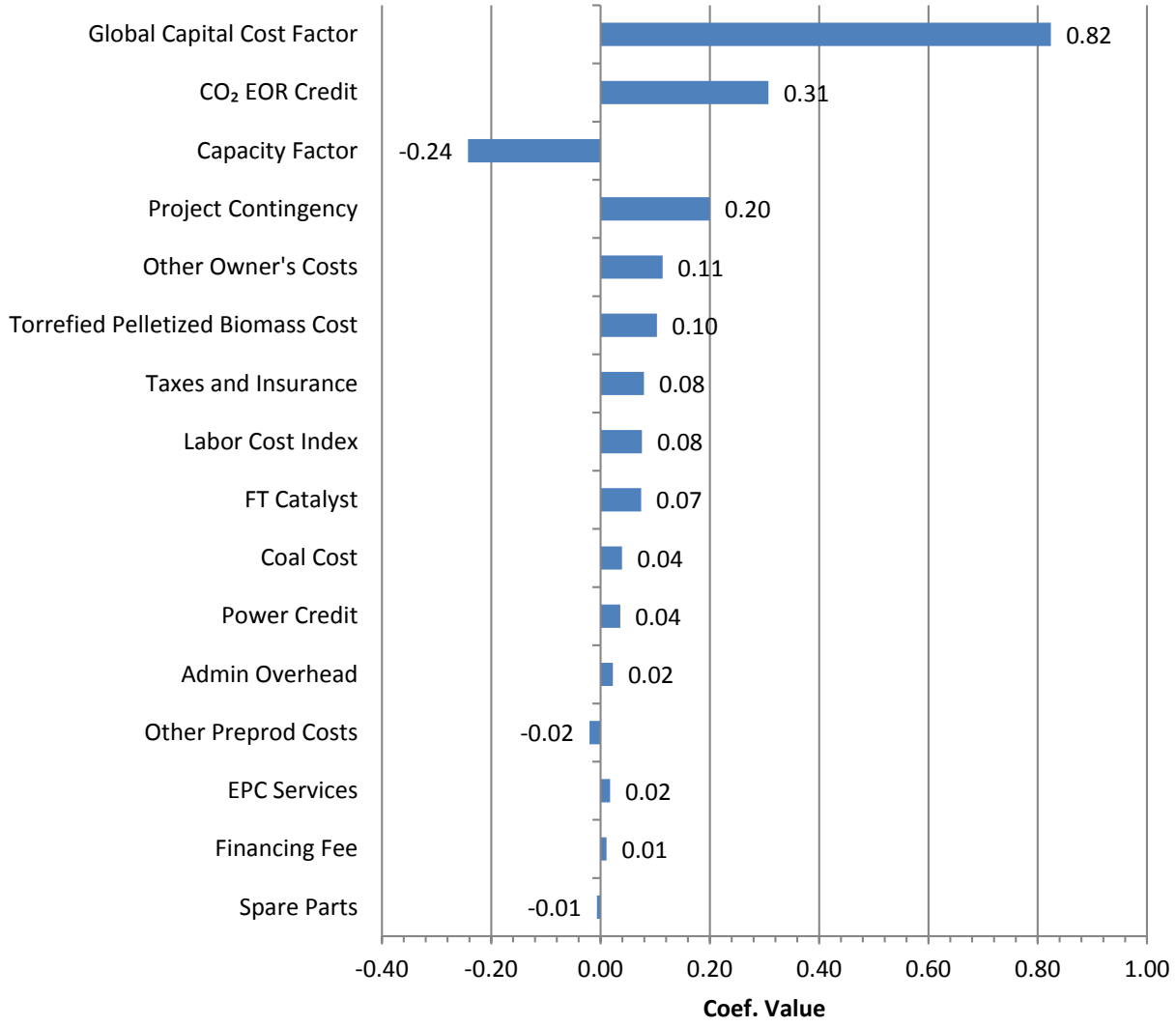


Figure 5-117 provides a summary of model sensitivity in the validated case, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.82. Other key factors that account for at least 10 percent of the observed variability in RSP include the CO_2 EOR credit, capacity factor, project contingency, other owner's costs, and cost of torrefied and pelletized biomass. Parameters that caused minimal influence on RSP included the cost of spare parts, financing fees. EPC service costs, other preproduction costs, and others as shown.

Figure 5-117: Scenario 20: CBTL, 28.3% Torrefied/Chipped Biomass, Validated: Sensitivity of RSP to Modeled Variables

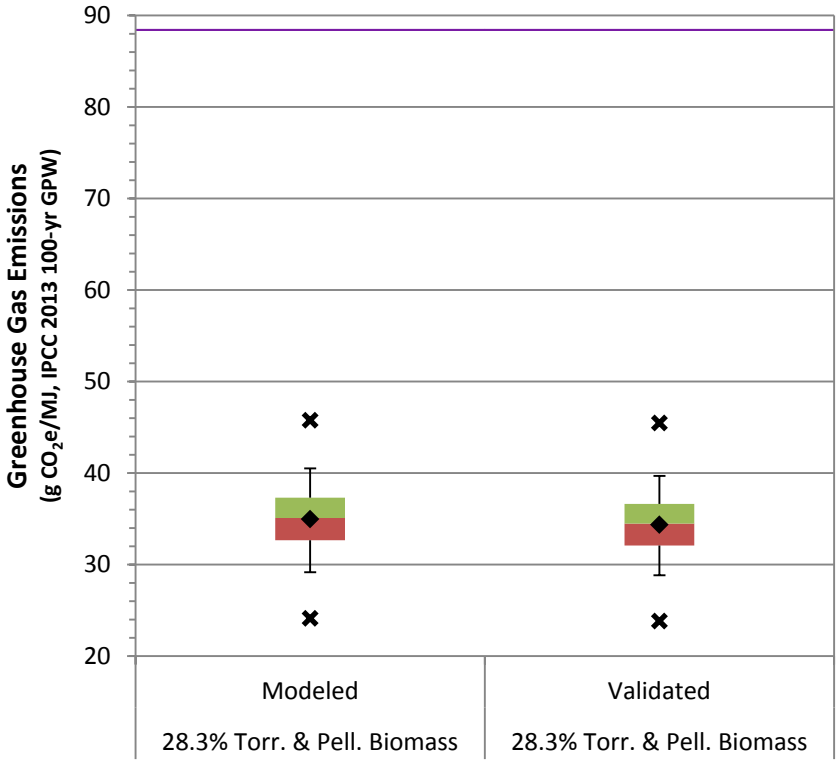


5.20.4 Environmental Results

Results from the environmental model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Results from the environmental life cycle analysis include GHG emissions and other emissions, including select criteria air pollutants, other pollutants of concern, and water consumption. **Figure 5-118** provides a summary life cycle GHG emissions for this scenario, in comparison to conventional jet fuel life cycle GHG emissions of 88.41 g CO_2e/MJ. In the modeled case the resulting range is 32.7 to 37.3 g CO_2e/MJ, mean 35.0 g CO_2e/MJ or approximately 60.0 percent less than conventional jet fuel. In the validated case the resulting range is 32.1 to 36.6 g CO_2e/MJ, 34.4 g CO_2e/MJ or approximately 60.7 percent less than conventional jet fuel.

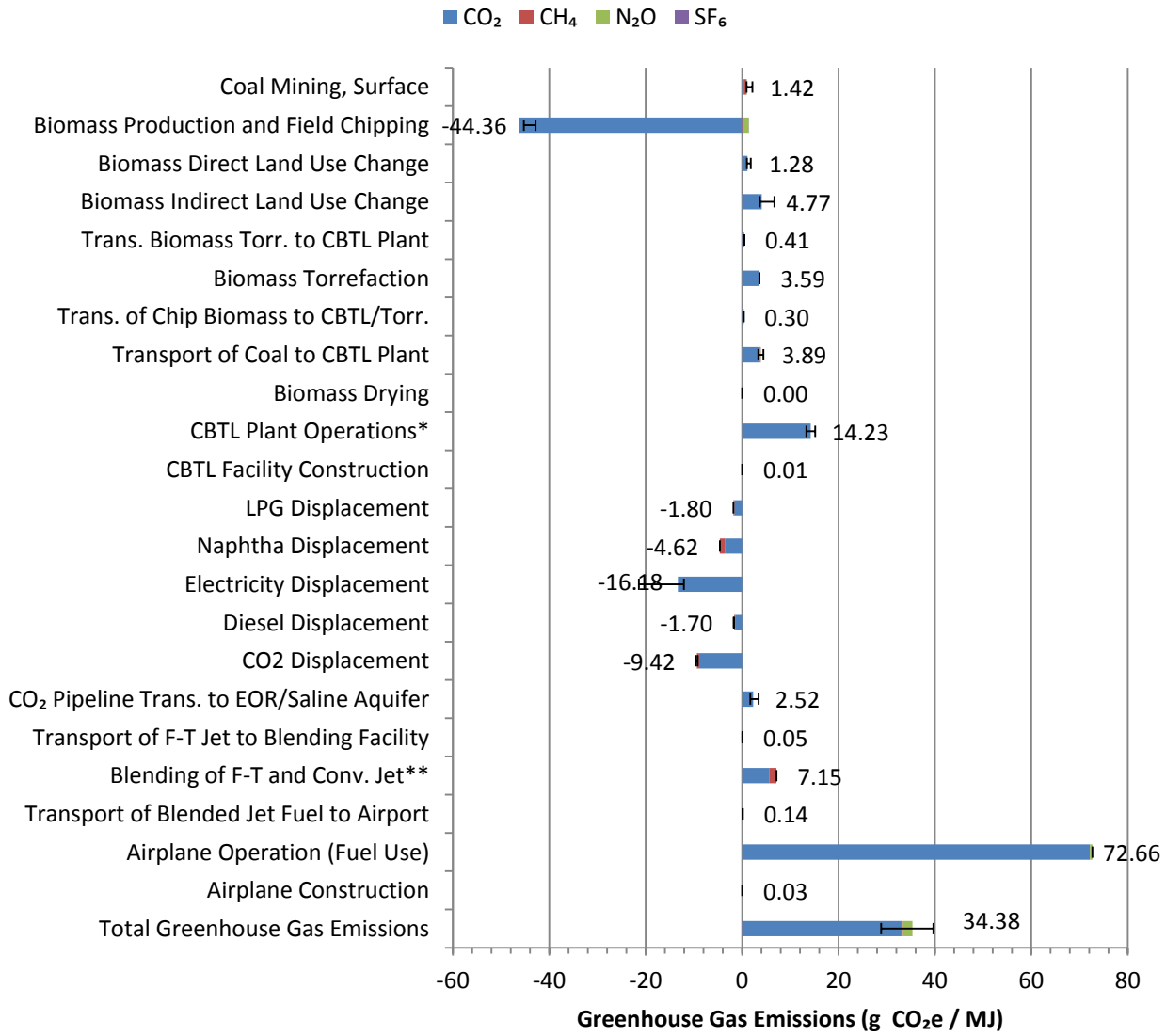
Figure 5-118: Scenario 20: CBTL, 28.3% Torrefied/Pelleted Biomass, Validated: Summary of LC GHG Emissions



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

It is clear from **Figure 5-118** that there is minimal variation between the modeled and validated LC GHG emission results. **Figure 5-119** provides detail regarding the importance of the various LCA components in the validated case that were modeled, with respect to gross GHG emissions contributions. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 64.2 percent of gross life cycle GHG emissions. Second in importance to fuel combustion is CBTL plant operations, at 12.6 percent of gross life cycle emissions, while emissions associated with blending of F-T and conventional jet fuel represent 4.98 percent of gross life cycle emissions. The transport of coal to the CBTL plant accounts for 3.61 percent of gross life cycle GHG emissions. Emissions from biomass indirect land use change represent approximately 3.32 percent of gross emissions. GHG emissions associated with pipeline transport of CO_2 generates 3.17 percent of gross life cycle emissions, while the torrefaction of biomass generates 2.01 percent. Other contributors to gross emissions were less than 1 percent individually.

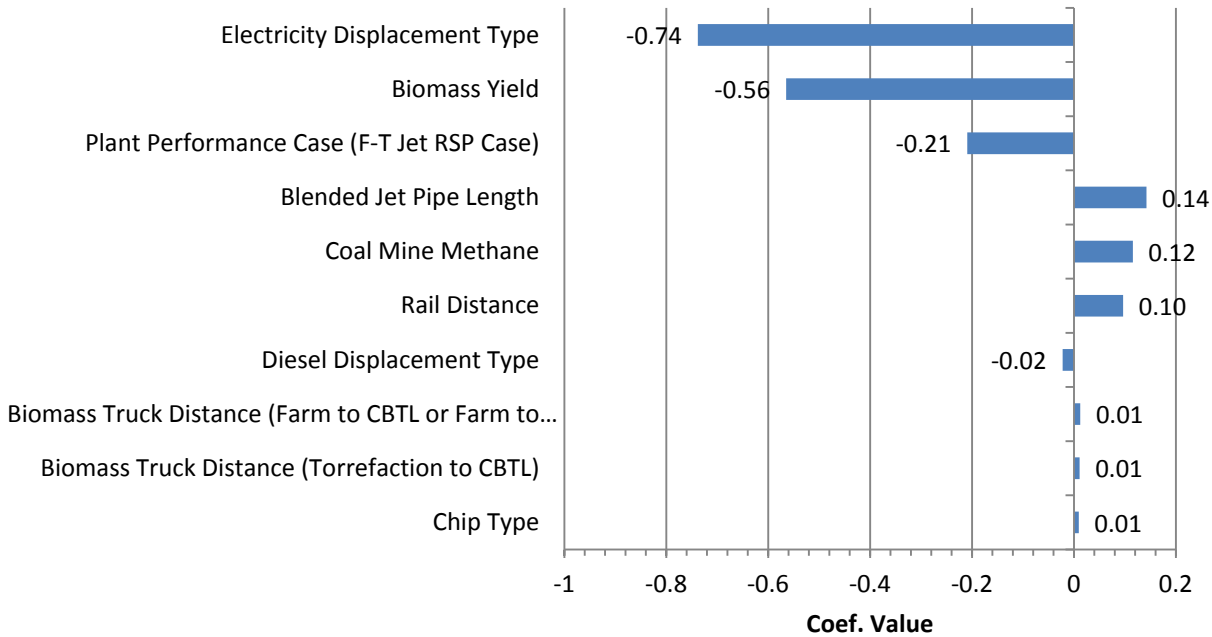
Figure 5-119: Scenario 20: CBTL, 28.3% Torrefied/Pelleted Biomass, Validated: LC GHG Emissions Breakdowns



** Includes CO_2 Compression*
*** Includes conventional jet fuel profile*

The error bars shown in **Figure 5-119** reflect variability in model output based on the stochastic analyses (for more information, refer to Chapter 1). The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-6**. As shown, variability in emissions resulted primarily from the type of electricity displacement used. Another key contributor to variability in model output is biomass yield. **Figure 5-120** summarizes the key factors contributing to variability identified in the model sensitivity analysis, for GHG emissions. Values provided in the figure show the correlation coefficient between the indicated parameter and total life cycle GHG emissions. Other important factors included the F-T jet fuel RSP case, the blended jet fuel pipe length, the coal mine methane emissions, the rail transport distance, the diesel displacement type, the biomass truck transportation distances, and the biomass chip type. Other parameters had minimal to negligible effect on life cycle GHG emissions.

Figure 5-120: Scenario 20: CBTL, 28.3% Torrefied/Pelleted Biomass, Validated: LC GHG Emissions Sensitivity



In addition to GHG emissions, other life cycle environmental emissions and flows were also considered. **Table 5-80** provides a summary of these flows. As shown, Airplane operation is the primary source of carbon monoxide and NOx within the life cycle. Particulate matter (PM_{10}) derives primarily from the combustion of diesel under raw materials transport and product transport operations. Non-methane volatile organic carbons (NMVOCs) result from product transport, including upstream conventional jet fuel emissions, and end use. The highest levels of mercury emissions occur during energy conversion and end use. Most water consumption occurs during biomass cultivation. Note that mass units displayed for water consumption (kg/MJ jet fuel) are equivalent to volume units for water consumption (L/MJ jet fuel).

Table 5-80: Scenario 20: CBTL, 28.3% Torrefied/Pelleted Biomass, Validated: Non-GHG Emissions

LC Stage	Carbon monoxide	NO_x	SO2	PM10	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	1.48E-05	1.54E-04	1.60E-05	1.57E-06	9.07E-06	2.52E-10	1.51E-06	1.33E-02	kg/MJ Jet Fuel
RMT	4.84E-04	4.44E-04	9.98E-05	5.67E-04	8.32E-05	2.74E-10	6.41E-06	1.54E-01	kg/MJ Jet Fuel
EC	-5.40E-04	-1.71E-03	-2.94E-03	-2.06E-04	-7.21E-04	4.36E-08	4.48E-06	-2.43E+00	kg/MJ Jet Fuel
PT	2.76E-04	4.38E-04	6.25E-04	3.28E-05	8.45E-04	5.80E-10	2.92E-06	1.08E+00	kg/MJ Jet Fuel
EU	7.72E-03	1.21E-02	5.56E-04	9.50E-07	7.72E-04	3.01E-08	7.16E-09	2.81E-02	kg/MJ Jet Fuel
Total	**7.95E-03**	**1.15E-02**	**-1.65E-03**	**3.96E-04**	**9.88E-04**	**7.48E-08**	**1.53E-05**	**-1.15E+00**	**kg/MJ Jet Fuel**

5.21 Comparison of All Scenarios

The following text provides a summary comparison of the modeled results for cost and life cycle GHG emissions associated with each of the 20 scenarios considered in support of this study. Summary results are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the discussion below focuses on reporting of the study mean (average) values, as well as the middle 50 percent of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

RSP values (crude oil equivalent basis) for F-T jet fuel are summarized in **Figure 5-121**, for each of the 20 production scenarios described previously. Here, the solid horizontal line does not indicate a baseline value or requirement. There are no baseline EISA requirements with respect to fuel cost. Instead, the solid horizontal line provides a simple comparison point, and represents spot pricing for crude oil from early 2014 scaled to 2011 dollars (EIA, 2014).

The default economic assumptions for this analysis are based on a commercial fuels application (NETL, 2011d). For that application, the percent of capital financed by debt is 50 percent and the interest rate on debt is 8 percent. Alternatively, under a loan guarantee scenario, the percent of capital financed by debt increases to 60 percent and the interest rate decreases to 4.56 percent (NETL, 2009). Both scenarios are based on an IRROE of 20 percent, an effective tax rate of 38 percent, with a 20-year declining balance depreciation schedule, and no investment tax credit (NETL, 2011c). The commercial fuels financial structure results in a capital charge factor of 0.1872, while the loan guarantee structure yields a capital charge factor of 0.1591

The average values for all 20 scenarios ranges between about $133/bbl and $146 bbl, with minimum/tail end distribution values reaching as low as $109/bbl for the CBTL, 0 percent Biomass scenario. Overall, RSP results distributions for the CBTL, 0 percent biomass were the lowest of all scenarios, with 25th/75th percentile values ranging from $127 to $141/bbl, mean $134/bbl. Conversely, RSP results distributions for the CBTL, 10 percent Biomass, Microchipped, Separate Gasifiers scenario were consistently higher than other scenarios, ranging from $139 to $153/bbl, mean $146/bbl.

RSP results distributions for the remaining scenarios fall between RSP values for the CBTL, 0 percent Biomass and the CBTL, 10 percent Biomass, Microchipped, Separate Gasifiers scenarios. Scenarios utilizing a higher percentage of biomass generally have a greater RSP. For example, RSP values for the CBTL, 30 percent Chipped Biomass scenario range from $136 to $150/bbl, mean $143/bbl, while RSP values for the CBTL, 20 percent Chipped Biomass scenario range from $133 to $147/bbl, mean $140/bbl, and RSP values for the CBTL, 10 percent Chipped Biomass scenario range from $130 to $144/bbl, mean $137/bbl. Comparing mean values, the CBTL, 30 percent Chipped Biomass scenario results in a mean RSP value that is approximately $3.29/bbl higher than the CBTL, 20 percent Chipped Biomass scenario and $6.27/bbl higher than the CBTL, 10 percent Chipped Biomass scenario. Similar trends are apparent for the 30 percent Torrefied Biomass scenario (range $136 to $148/bbl, mean $142/bbl), the 20 percent Torrefied Biomass scenario (range $133 to $146/bbl, mean $140/bbl) and the 10 percent Torrefied Biomass scenario (range $130 to $143/bbl, mean $137/bbl), wherein the 30 percent Torrefied Biomass scenario results in a mean RSP value that is approximately $2.65 higher than the 20 percent Torrefied Biomass scenario and $5.31 higher than the 10 percent Torrefied Biomass scenario. These trends are also observed in the pelleted and torrefied/pelleted scenarios with 28.3 percent Pelleted Biomass $3.10/bbl greater than 11.7 percent Pelleted Biomass and 28.3 percent Pelleted/Torrefied Biomass $3.52/bbl greater than 16.5 percent Pelleted/Torrefied Biomass.

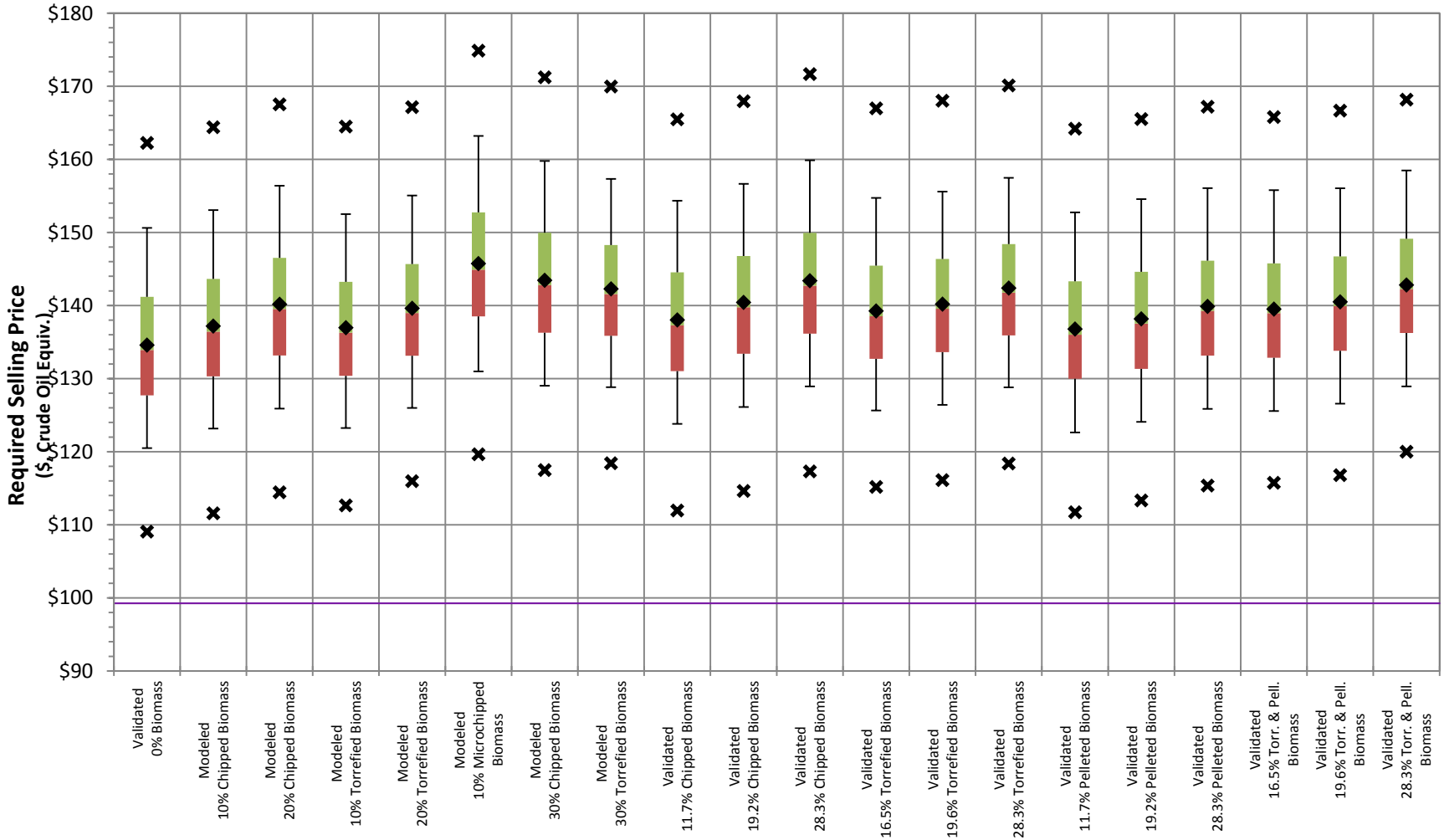
In contrast to life cycle GHG emissions, use of torrefied biomass may result in a slight net decrease in RSP, in comparison to chipped biomass. For example, based on mean values of $143/bbl for the CBTL, 30 percent Chipped Biomass scenario and $142/bbl for the CBTL, 30 percent Torrefied Biomass scenario, torrefaction results in a total cost savings of about one dollars per barrel. Similarly, for the 10 percent biomass scenarios, comparing mean values of $137/bbl for chipped biomass to $137/bbl for torrefied biomass also results in a total cost savings of about a dollar per barrel. Note, however, that based on the observed range of RSP results for torrefaction and biomass grinding, under real world scenarios, cost savings associated with torrefaction versus grinding may not be differentiable.

There are two sets of three scenarios that examine the difference in biomass preparation, focusing on either chipped or pelletized biomass (11.7, 19.2, and 28.3 percent biomass). There is a slight reduction in the expected RSP when shifting from chipped to pelleted biomass in those scenarios, though the uncertainty bars generally overlap. Pelleted biomass is more expensive than chipped biomass due to the additional processing requirements upstream of the facility. However, because the pelleted biomass arrives at the plant with less moisture, the parasitic drying requirements are lower, which increases the overall efficiency of the plant and leads to the production of more export power than in the chipped cases. Additionally, there is a small reduction in the capital cost associated with biomass preparation/handling equipment and the gasifiers. The difference in the expected RSP values for the chipped and pelleted cases increases as the percentage of biomass in the feed increases.

The cost disparity between use of a single gasifier and dual gasifiers is somewhat more pronounced. Based on a comparison of mean values, RSP for the CBTL, 10 percent Biomass, Microchipped, Separate Gasifiers scenario is $8.55/bbl greater than the CBTL, 10 percent Chipped Biomass scenario, and $8.77/bbl greater than the CBTL, 10 percent Torrefied Biomass scenario. However, based on the observed range of RSP results, there remains considerable overlap among these (and all) scenarios.

Under the financial structure for a loan guarantee scenario (capital charge factor = 0.1591), the RSP results for the scenarios range from $96/bbl to $116/bbl based on the 25th percentile/75th percentile values. These results are 4% lower to 17% higher than current crude oil prices. The mean values for each of the scenarios decreases by approximately $33/bbl or a 23.5% reduction. For example, the mean for the 100% coal scenario decreases to $101/bbl. These differences illustrate the importance of the financing structure.

Figure 5-121: All Scenarios: F-T Jet Fuel, RSP, Crude Oil Equivalent Basis



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel spot price value.

Life cycle GHG emissions from a 1:1 (volume) blend of F-T jet fuel and conventional jet fuel are summarized in **Figure 5-122**, for each of the 20 production scenarios described previously. The solid horizontal line indicates the estimated life cycle emissions level for baseline conventional jet fuel, consistent with EISA requirements. All of the 20 scenarios indicated life cycle emissions that were entirely below the EISA baseline value of 88.41 g CO_2e/MJ, over the entire distribution of modeled results.

When considering all of the scenarios in this study, the 25th and 75th percentiles of the GHG emissions range from 74.9 to 31.3 g CO_2e/MJ. In the CBTL, 0% Biomass scenario, the GHG emissions were 13.5 g CO_2e/MJ below the baseline, a 15.3 percent reduction, and in the CBTL, 30% Torrefied Biomass scenario, the GHG emissions are 57.1 g CO_2e/MJ below the baseline, a 64.6 percent reduction. Therefore, results from this study indicate that all investigated scenarios would likely meet EISA requirements.

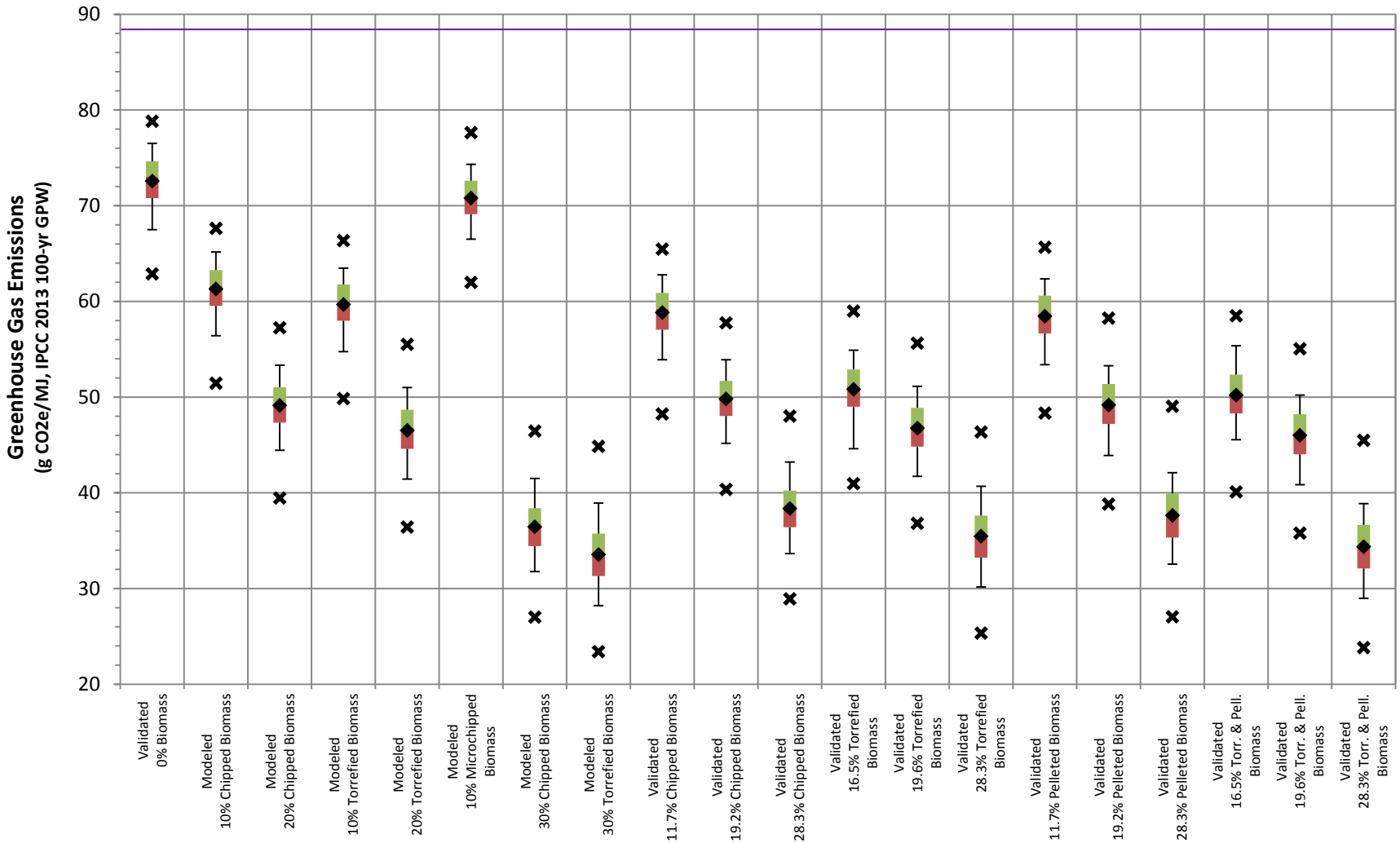
Life cycle GHG emissions results underscore the importance of biological carbon sequestration during Southern pine production, and its effect on the overall life cycle emissions from jet fuel. Note that here, mean values alone are discussed in order to facilitate comparison among scenarios. Comparing the CBTL, 0 percent Biomass scenario to the CBTL, 20 percent Chipped Biomass scenario indicates that a 20 percent increase in biomass results in a 32.5 percent reduction in life cycle GHG emissions, from a mean value of 72.8 g CO_2e/MJ to 49.1 g CO_2e/MJ. The use of torrefied biomass provides a similar level of GHG emissions reduction. Comparing the CBTL, 0 percent Biomass scenario to the CBTL, 20 percent Biomass, Torrefied scenario indicates that the latter provides a 36.1 percent reduction in life cycle GHG emissions, to a mean value of 46.5 g CO_2e/MJ for the latter scenario. Similar trends are also observed in the pelleted/torrefied cases. Finally, incorporation of biomass provides a lesser degree of GHG emissions benefit for the separate gasifiers scenario. Life cycle GHG emissions from that scenario average 70.8 g CO_2e/MJ, based on a 10 percent rate of biomass co-feeding. This represents a 2.78 percent reduction in life cycle emissions in comparison to the CBTL, 0 percent Biomass scenario. Reliance on a single coal plus biomass gasifier, as modeled for the other 10 percent biomass scenarios, results in an additional net reduction in GHG emissions of up to 15.8 percent over and above the dual gasifiers scenario.

There are two sets of three scenarios that examine the difference in biomass preparation, focusing on either chipped or pelletized biomass (11.7, 19.2, and 28.3 percent biomass). Given the range of uncertainty associated with the results, there is no statistically significant difference between chipped and pelletized biomass.

As shown by **Figure 5-122**, the all of the scenarios have long tails below the 25th percentile. This is primarily driven by the uncertainty in the type of electricity that is displaced by the power produced from the F-T facility. As shown in **Table 1-4**, there is a substantial difference between the expected (2010 U.S. grid mix) and high (fleet coal) displacement values. The difference is much less significant between the expected and low (EIA 2035 grid mix) values, explaining the smaller tails above the 75th percentile

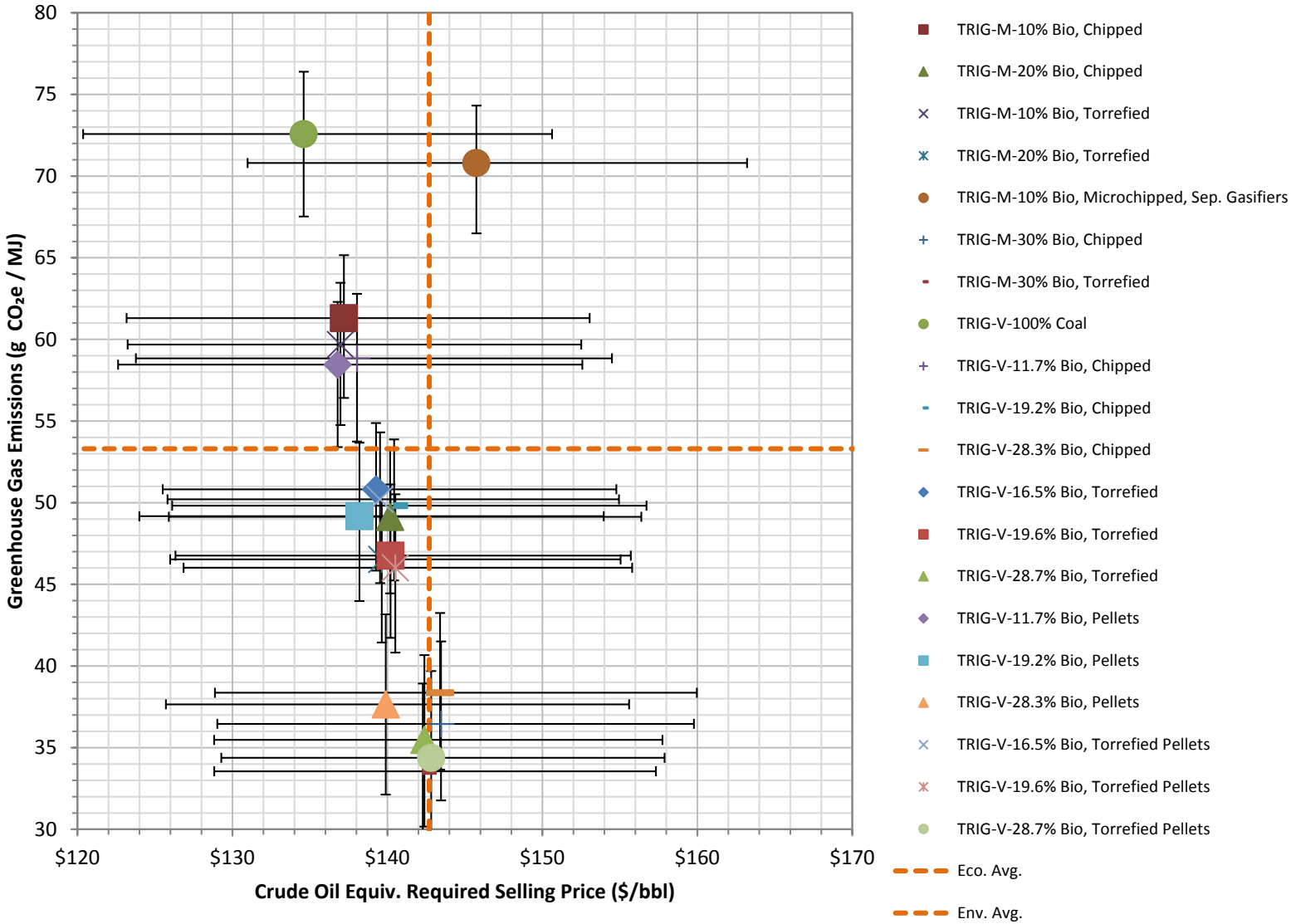
Figure 5-87 combines the LC GHG emissions and RSP values into a single chart. The points represent the mean, while the uncertainty bars span the 5th to 95th percentiles. The lower left quadrant of the figure represents the lowest cost and lowest LC GHG emissions. The CBTL, 0 percent biomass scenario, has the lowest RSP, but highest GHG emissions, while the 30 percent torrefied scenario has the lowest GHG emissions and third highest RSP.

Figure 5-122: All Scenarios: Summary of LC GHG Emissions



Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

Figure 5-123: Combined F-T Jet Fuel RSP and LC GHG Emissions



6 Conclusions and Recommendations

The following text provides: (1) a summary of conclusions regarding the technical, economic, and life cycle analyses conducted for this study; (2) provides a summary of technological development considerations for research and development; and (3) identifies the most competitive options for the production of F-T jet fuels.

6.1 Technical, Economic, and Life Cycle Environmental Conclusions

The following conclusions have resulted from the technical, economic, and life cycle environmental analysis of the 20 F-T jet fuel production scenarios considered in this study.

- The CBTL, 0 percent Biomass CBTL facility configuration is estimated to have an overall HHV efficiency of 53.2 percent. A very aggressive pinch analysis[1] was used in the simulations for optimal heat integration, utilization, and recovery. This procedure is likely to result in higher overall efficiencies for a conceptual plant than would be expected for a commercially operating facility. The CBTL facility processes 30,500 tons per day of Montana Rosebud subbituminous coal to produce 50,000 barrels per day of products, of which jet fuel constitutes about 49 percent by volume. The average required selling price of the jet fuel product for the 20 scenarios has an estimated 25th to 75th percentile range of $133 to $146/bbl on a crude oil equivalent basis. This required selling price is above current world oil prices. For comparison, WTI spot pricing from early 2014 scaled to 2011 dollars was $99.24/bbl.
- Co-gasification of chipped and coal in the same gasification system results in a slight lowering of the overall efficiency, in comparison to coal only, coal/pelleted biomass and, coal/torrefied biomass scenarios. This is because of the lower quality of the chipped biomass compared to coal, pelleted, or torrefied biomass, with respect to carbon content, moisture content, and heating value, and because more parasitic power is required for chipped biomass preparation.
- The Total Overnight Cost (TOC) for the configurations evaluated in this study range from $7.4 to $12 billion spanning the range of uncertainty in all of the economic parameters considered.
- Higher percentages of biomass utilized in the gasification process results in increased overall RSP. For example, the RSP of the jet fuel product for the CBTL, 0 percent Biomass scenario has an estimated 25th to 75th percentile range of $127 to $140/bbl, mean $134/bbl, while the CBTL, 10 percent Chipped Biomass scenario has a range of $130 to $144/bbl, mean $137/bbl, and the CBTL, 20 percent Chipped Biomass scenario has an RSP range of $133 to $147/bbl, mean $140/bbl. Thus, on average, use of 10 percent and 20 percent chipped biomass drive an increase in RSP of about $3/bbl and $6/bbl over the CBTL, 0 percent Biomass scenario, respectively. The elevated cost results from the higher capital cost of the CBTL facilities under the biomass scenarios, mostly because of the costs of the biomass

[1] Pinch analysis is an algorithm that was used in support of optimization for the modeled heat exchanger network. The analysis is used to reduce energy consumption of a process by first setting a feasible energy consumption target, then optimizing plant systems to attempt to meet those targets. CBTL facility systems included in the pinch analysis include the heat recovery systems, energy supply methods, and process operating conditions (Kemp, 2007; Leng, et al., 2010).

preparation and feeding. Another factor is the high cost of the delivered woody biomass feedstock to the plant on a dollars per MMBtu basis compared to coal.

- The use of torrefied biomass may result in a slight net decrease in RSP, in comparison to chipped biomass. For example, based on mean values of $143/bbl for the CBTL, 30 percent Chipped Biomass scenario and $142/bbl for the CBTL, 30 percent Torrefied Biomass scenario, torrefaction results in a total cost savings of about one dollars per barrel. Similarly, for the 10 percent biomass scenarios, comparing mean values of $137/bbl for chipped biomass to $137/bbl for torrefied biomass also results in a total cost savings of about a dollar per barrel. Note, however, that based on the observed range of RSP results for torrefaction and biomass grinding, under real world scenarios, cost savings associated with torrefaction versus grinding may not be differentiable.
- The RSP of the jet fuel product for the separate gasifier scenario is higher compared to the other scenarios that consider chipped or torrefied biomass at a 10 percent feed rate. The 25th to 75th percentile RSP range for the separate gasifiers scenario is $138 to $152/bbl, mean $146/bbl, compared to $130 to $144/bbl, mean $137/bbl for the 10 percent Chipped Biomass scenario, and $130 to $143/bbl, mean $137/bbl for the 10 percent Torrefied Biomass scenario. This is due to the higher capital cost for the CBTL facility under the separate gasification scenario. The additional costs for the ClearFuels® and DFB systems are not compensated for by the lower cost of the TRIG coal gasification system that now processes less feed material. The BEC of the ClearFuels®/DFB combination would have to be reduced by 44 percent to give the same RSP of jet fuel obtained for the other 10 percent biomass scenarios.
- There are two sets of three scenarios that examine the difference in biomass preparation, focusing on either chipped or pelletized biomass (11.7, 19.2, and 28.3 percent biomass). There is a slight reduction in the expected RSP when shifting from chipped to pelleted biomass in those scenarios, though the uncertainty bars generally overlap. Pelleted biomass is more expensive than chipped biomass due to the additional processing requirements upstream of the facility. However, because the pelleted biomass arrives at the plant with less moisture, the parasitic drying requirements are lower, which increases the overall efficiency of the plant and leads to the production of more export power than in the chipped cases. Additionally, there is a small reduction in the capital cost associated with biomass preparation/handling equipment and the gasifiers. The difference in the expected RSP values for the chipped and pelleted cases increases as the percentage of biomass in the feed increases.
- Under the financial structure for a loan guarantee scenario (capital charge factor = 0.1591), the RSP results for the scenarios range from $96/bbl to $116/bbl based on the 25th percentile/75th percentile values. These results are 4% lower to 17% higher than current crude oil prices. The mean values for each of the scenarios decreases by approximately $33/bbl or a 23.5% reduction. For example, the mean for the 100% coal scenario decreases to $101/bbl. These differences illustrate the importance of the financing structure.
- All of the 20 scenarios indicated life cycle emissions that were entirely below the EISA baseline value of 88.41 g CO_2e/MJ, over the entire distribution of modeled results.
- For all scenarios, the mean total GHG emissions predicted by this study produced is 72.83 g CO_2e/MJ in the case of CBTL, 0% Biomass ,15.58 g CO_2e/MJ below the baseline or an 17.6% reduction and 33.52 g CO_2e/MJ in the case of CBTL, 30% Torrefied Biomass, 54.89 g

CO_2e/MJ below the baseline or a 62.1% reduction. Therefore, results from this study indicate that all investigated scenarios would likely meet EISA requirements.

- There is a linear relationship between the percentage of biomass that is fed to the CBTL facility and the resulting life cycle GHG emissions. The exact percentage reduction differs depending on the biomass preparation methods, but for each 10% increase in the amount of biomass fed, there is roughly a 15% decrease in life cycle GHG emissions.
- Life cycle GHG emissions results underscore the importance of biological carbon sequestration during Southern pine production, and its effect on the overall life cycle emissions from jet fuel. Note that here, mean values alone are discussed in order to facilitate comparison among scenarios. Comparing the CBTL, 0% Biomass scenario to the CBTL, 20% Chipped Biomass scenario indicates that a 20% increase in biomass results in a 32.6% reduction in life cycle GHG emissions, from a mean value of 72.8 g CO_2e/MJ to 49.1 g CO_2e/MJ. The use of torrefied biomass provides a similar level of GHG emissions reduction, although the rate of emission reduction is dampened slightly due to the additional energy requirements of the torrefaction process. Thus, comparing the CBTL, 0% Biomass scenario to the CBTL, 20% Biomass, Torrefied scenario indicates that the latter provides a 36.1% reduction in life cycle GHG emissions, to a mean value of 46.5 g CO_2e/MJ for the latter scenario.
- A similar comparison cannot be directly drawn for the pelleted and pelleted/torrefied scenarios because of the inconsistencies in percent biomass, though similar trends are observed. Finally, incorporation of biomass provides a lesser degree of GHG emissions benefit for the separate gasifiers scenario. Life cycle GHG emissions from that scenario average 70.8 g CO_2e/MJ, based on a 10% rate of biomass co-feeding. This represents a 2.76% reduction in life cycle emissions in comparison to the CBTL, 0% Biomass scenario. Reliance on a single coal plus biomass gasifier, as modeled for the other 10% biomass scenarios, results in an additional net reduction in GHG emissions of up to 13.4% over and above the dual gasifiers scenario.
- The biomass content contained in the CBTL facility feedstock was also a key consideration with respect to life cycle GHG emissions. The results for the scenarios that utilized 30 percent biomass to generate F-T fuels had the lowest overall life cycle GHG emissions. The scenario that utilized 0 percent biomass feedstock had the highest overall life cycle GHG emissions, while scenarios that utilized 10 and 20 percent biomass feedstock had intermediary life cycle GHG emissions values. Incorporating biomass reduces life cycle GHG emissions because total carbon emissions are partially offset by the uptake of atmospheric carbon during biomass cultivation. Even considering GHG emissions associated with land use change that results from the cultivation of Southern pine biomass, utilization of biomass still results in a net reduction in life cycle GHG emissions, in comparison to the coal-only scenario.
- In the CBTL, 10 percent Biomass, Microchipped, Separate Gasifiers scenario, the chipped biomass is gasified in a separate gasification system from the coal. Because the ClearFuels® gasification and the Dual Fluid Bed reformer require significant fuel gas for heating and because this system operates at essentially atmospheric pressure, the overall efficiency of this configuration is lower than any of the other configurations. This configuration has 63.6 percent higher direct GHG emissions from the CBTL facility is because the combustion emissions from fuel gas required to heat the ClearFuels® gasifier and the DFB reformer are vented to atmosphere. With respect to life cycle GHG emissions, the separate gasifiers

scenario results in comparatively higher life cycle GHG emissions than the other biomass scenarios considered, but on average still shows a net benefit over the CBTL, 0 percent Biomass scenario. The separate gasifiers scenario results in a 25th to 75th percentile range in life cycle GHG emissions of 69.2 to 72.6 g CO_2e/MJ, mean 70.8 g CO_2e/MJ, while the CBTL, 0 percent biomass scenario results in a range of 71.1 to 74.8 g CO_2e/MJ.

- There are two sets of three scenarios that examine the difference in biomass preparation, focusing on either chipped or pelletized biomass (11.7, 19.2, and 28.3 percent biomass). Given the range of uncertainty associated with the results, there is no statistically significant difference between chipped and pelletized biomass.
- The validation results were compared to the modeled results for all thirteen scenarios listed above. Overall, the agreement was very good. The average deviation in calculated process outputs was less than 1.5 percent for every case. For the pelletized biomass cases, the average deviation was less than 1.1 percent. The torrefied biomass cases were slightly closer in agreement than the biomass cases. The most significant deviation was in the syngas H_2:CO ratio. In the validation cases, this ratio was approximately 4 percent lower for the biomass cases and from 4-14 percent lower for the torrefied biomass cases. The impact of this was to require a slight increase in capital equipment cost for the validation cases resulting in a slight increase in the estimated RSP of jet fuel averaging about 0.55 $/bbl. For more information on the validation procedure, see Appendix C.

6.2 Technological Development Considerations

In the process of conducting the process modeling analysis of the 20 CBTL facility configurations it was necessary to make various assumptions for both process performance and equipment costs. Most of the operational equipment in the plants are commercially available technologies and the costs and performance are known with a fairly high degree of confidence. However there are several operations that were analyzed in this report that are outside of current commercial practice and a few technologies that have not been proven at commercial scale. It is in these areas that additional research, development, and demonstration (RD&D) need to be conducted so that the degree of confidence both in performance and costs can be improved.

The following areas are identified as requiring additional RD&D.

- ***TRIG gasification***: The test campaigns with pelletized and torrefied biomass demonstrated the technical feasibility of co-firing the TRIG gasifier with mixtures of PRB coal and biomass. However, the experimental runs were at much lower pressure than what is expected for commercial operation, raising the possibility that the syngas methane content will be high, adversely impacting the performance of the Fischer-Tropsch reactor and overall plant efficiency. It is recommended that a sensitivity analysis be performed on the systems model to quantify the impact of elevated syngas methane content on plant performance and economics. If sufficient data is available, the existing chemistry model should be modified to include a kinetic model for methane production to predict the expected syngas methane for commercial operation. It was assumed in this analysis that the heat recovery system on the gasifier would act as a steam superheater. This should be confirmed ideally at commercial scale. Also gasifier operation at pressures higher than 400 psi should be demonstrated. Better estimates of gasifier capital costs should also be made.
- ***Woody biomass preparation***: The fine grinding assumptions made in this analysis for the raw biomass cases are outside the range of commercial practice. For commercial pulp wood chips

size reduction to chips is readily accomplished by a variety of commercially proven chippers. However reducing the size of the wood to particle sizes in the rage of 200 to 400 microns is not commercially practiced. The data on energy consumption versus particle size used in this current analysis was taken from small scale grinding equipment that may not be representative of energy requirements from large scale equipment. Therefore grinding tests should be conducted on various woody biomass samples on larger than bench scale equipment, if possible, to determine the optimum type of mill needed and to quantify the actual grinding energy required. Determination of the potential costs and throughputs of the grinding mills should also be determined.

- ***Torrefaction of woody biomass***: Although there are some commercial enterprises worldwide (especially in Europe) where biomass torrefaction is practiced, this is essentially a developing technology particularly in the U.S. It is unlikely that any useful information could be obtained from any of limited number of commercial torrefaction operations operating or under development in the U.S., though data could be obtained from equipment manufactures. In this current analysis data on torrefaction was acquired mostly from small scale equipment and it was not possible to obtain experimental data and overall material balances for Southern pine wood. Assumptions were made for the energy content of the volatiles and torrefied product yield for the modeled cases. Additional R&D is needed using various torrefaction reactor types to determine experimentally the torrefaction conditions (temperature and residence time) the torrefied product yield and the analysis and heating values of the volatiles. This data should then be used to develop a complete mass and energy balance for the integrated process from chipped biomass to torrefied product. The characteristics of the torrefied product should also be determined especially ultimate analysis and energy use and mill requirements for grinding the torrefied biomass and pelletized torrefied biomass. Tests should also be conducted on co-grinding coal and torrefied biomass, including pelletized torrefied biomass.
- ***ClearFuels® gasification and Dual Fluid Bed reforming***: although the concept of the ClearFuels® gasifier has been in development for several years it has not been demonstrated at commercial scale. In this analysis, simulation data from Rentech Inc. was used as far as possible to develop the mass and energy balances around both ClearFuels® and the DFB that were used to analyze the separate gasifier scenario. The Rentech demonstration plant is no longer in operation and currently there are no other facilities operating with a similar configuration so there is no means to validate this scenario against actual operational conditions. As a result there is considerable uncertainty concerning the performance of both ClearFuels® and DFB. Rentech Inc. has recently installed a pilot scale gasifier at their facility in Colorado and testing of this system should be conducted with various biomass samples to determine the performance of the system. Performance testing should include the biomass to steam ratios, residence times, biomass feed characteristics, operating temperature, determination of indirect heat duties, biomass conversion, tar yield, and synthesis gas composition. For the DFB testing should include steam to syngas feed ratio and extent of reforming of tars and light hydrocarbons.
- ***Cryogenic gas separations and refrigeration:*** because of the methane content of the TRIG synthesis gas it was necessary to include autothermal reforming and cryogenic gas separation in the conceptual designs. Although practiced at Sasol in South Africa, there is uncertainty concerning the refrigeration duty and the capital costs of these units. If possible better assessments for this equipment should be obtained.

6.3 Most Competitive Options

The most competitive options considered in this study were determined based on consideration of a combination of cost (RSP) and potential for meeting the requirements of EISA. All of the cases are below the baseline requirements of EISA and additions of biomass result in an even larger reduction. The CBTL, 0 percent Biomass scenario had the lowest overall cost with a mean RSP of $134/bbl, but the highest overall rlife cycle GHG emissions at mean value of 72.8 g CO_2e/MJ, which was still 17.6 percent lower than the baseline requirement of 88.41 g CO_2e/MJ. Conversely, the 30 percent torrefied biomass scenario had an RSP of $142/bbl, but had the lowest life cycle GHG emissions at 33.5 g CO_2e/MJ. As discussed previously, variability in scenario performance, based on results from the stochastic analyses considered, could potentially support the viability of any of the 20 scenarios, given careful attention to design and financial parameters that inform life cycle GHG emissions and cost considerations.

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Appendix A: Units and Conversion Factors

This appendix provides relevant unit information and conversion factors that were utilized within this study, or that may be useful for further analysis or evaluation of study results.

Table A-1: Mass, Distance, Area, Volume, and Energy Conversion Factors

Category	Input			Output	
	Value	Units		Value	Units
Mass	1	lb	=	0.454	kg
	1	short ton	=	0.907	tonne
Distance	1	mile	=	1.609	km
	1	foot	=	0.305	m
Area	1	ft^2	=	0.093	m^2
	1	acre	=	43,560	ft^2
Volume	1	gallon	=	3.785	L
	1	bbl	=	42	gallons
	1	ft^3	=	28.320	L
	1	ft^3	=	7.482	gallons
	1	ft^3	=	0.178	bbl
Energy	1	Btu	=	1,055.056	J
	1	MJ	=	947.817	Btu
	1	kWh	=	3,412.142	Btu
	1	MWh	=	3600	MJ

Table A-2: IPCC Global Warming Potential (GWP) Factors, 2001, 2007 and 2013

IPCC GWP Factor	Vintage	20 Year	100 Year	500 Year
CO_2	2013	1	1	N/A
CH_4	2013	85	30	N/A
N_2O	2013	264	265	N/A
SF_6	2013	17,500	23,500	N/A
CO_2	2007	1	1	1
CH_4	2007	72	25	7.6
N_2O	2007	289	298	153
SF_6	2007	16,300	22,800	32,600
CO_2	2001	1	1	1
CH_4	2001	62	23	7
N_2O	2001	275	296	156
SF_6	2001	15,100	22,200	32,400

Table A-3: Energy Density of Feedstocks and Products

Feed or Product Stream	Energy Density (LHV) (SI Units)		Energy Density (LHV) (English Units)	
Montana Rosebud Coal*	19.19	MJ/kg	8,252	Btu/lb
Southern Pine**	9.72	MJ/kg	4,178	Btu/lb
Torrefied Southern Pine***	21.40	MJ/kg	9,203	Btu/lb
EOR Crude Oil	44.10	MJ/kg	18,960	Btu/lb
EOR Natural Gas Liquids	48.80	MJ/kg	20,980	Btu/lb
F-T LPG	46.00	MJ/kg	19,775	Btu/lb
F-T Naphtha	43.98	MJ/kg	18,908	Btu/lb
F-T Diesel	43.06	MJ/kg	18,512	Btu/lb
F-T Jet Fuel	43.81	MJ/kg	18,835	Btu/lb
Blended Jet Fuel	43.51	MJ/kg	18,704	Btu/lb
Conventional Petroleum Jet Fuel	43.20	MJ/kg	18,573	Btu/lb

*LHV reported for as received Montana Rosebud Coal with a moisture content of 25.77%
**LHV reported for as received Southern Pine with a moisture content of 43.3%
***LHV reported for as received Torrefied Southern Pine with a moisture content of 5.72%

Table A-4: Physical Density of Products

Product Stream	Density (SI Units)		Density (English Units)	
F-T LPG	0.592	kg/L	36.9	lb/ft³
F-T Naphtha	0.706	kg/L	44.1	lb/ft³
F-T Diesel	0.770	kg/L	48.0	lb/ft³
F-T Jet Fuel	0.760	kg/L	47.4	lb/ft³
Blended Jet Fuel	0.782	kg/L	48.9	lb/ ft³
Conventional Petroleum Jet Fuel	0.805	kg/L	50.3	lb/ ft³
EOR Crude Oil	0.873	kg/L	54.6	lb/ft³
EOR Natural Gas Liquids	0.650	kg/L	40.6	lb/ft³

Appendix B: Life Cycle Environmental Results in Alternate Units

This appendix provides a summary of life cycle environmental results as reported for each of the 20 scenarios, modeled and validated, in the main body of the report, except in alternate units of lb CO_2e/MMBtu LHV and lb CO_2e/bbl.

Table B-1: CBTL, 0% Biomass

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**1.55E+00**	**1.30E+00**	**4.30E-01**	**1.17E-03**	**4.72E+00**	**7.93E+00**	**6.68E+00**	**2.21E+00**	**5.98E-03**	**2.42E+01**
Coal Mining, Surface	1.55E+00	1.30E+00	4.30E-01	1.17E-03	4.72E+00	7.93E+00	6.68E+00	2.21E+00	5.98E-03	2.42E+01
Biomass Production and Field Chipping	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biomass Direct Land Use Change	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biomass Indirect Land Use Change	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Raw Material Transport	**1.24E+01**	**4.36E-01**	**8.06E-02**	**1.93E-08**	**1.29E+01**	**6.35E+01**	**2.24E+00**	**4.13E-01**	**9.88E-08**	**6.62E+01**
Torref. Biomass Transp. to CBTL Plant	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biomass Torrefaction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Transport of Coal to CBTL Plant	1.24E+01	4.36E-01	8.06E-02	1.93E-08	1.29E+01	6.35E+01	2.24E+00	4.13E-01	9.88E-08	6.62E+01
Energy Conversion Facility	**-2.40E+01**	**-4.40E+00**	**-1.57E-01**	**-8.65E-02**	**-3.44E+01**	**-1.23E+02**	**-2.26E+01**	**-8.05E-01**	**-4.44E-01**	**-1.76E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.51E+01	5.90E-04	1.46E-04	1.33E-05	3.51E+01	1.80E+02	3.03E-03	7.48E-04	6.80E-05	1.80E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.45E+01	-4.47E+00	-1.89E-01	-8.65E-02	-7.55E+01	-3.31E+02	-2.29E+01	-9.69E-01	-4.44E-01	-3.87E+02
CO_2 Transport to CO_2-EOR Operation	5.38E+00	6.83E-02	3.18E-02	0.00E+00	6.00E+00	2.76E+01	3.51E-01	1.63E-01	0.00E+00	3.08E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**1.71E+02**	**9.14E-01**	**1.60E+00**	**-8.33E-02**	**1.69E+02**	**8.78E+02**	**4.69E+00**	**8.19E+00**	**-4.27E-01**	**8.69E+02**

Table B-2: CBTL, 10% Chipped Biomass

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-2.93E+01**	**1.27E+00**	**1.39E+00**	**1.67E-03**	**-2.45E+01**	**-1.50E+02**	**6.52E+00**	**7.13E+00**	**8.59E-03**	**-1.26E+02**
Coal Mining, Surface	1.43E+00	1.20E+00	3.97E-01	1.07E-03	4.35E+00	7.32E+00	6.16E+00	2.04E+00	5.51E-03	2.23E+01
Biomass Production and Field Chipping	-3.46E+01	7.06E-02	9.63E-01	6.00E-04	-3.34E+01	-1.78E+02	3.62E-01	4.94E+00	3.08E-03	-1.71E+02
Biomass Direct Land Use Change	8.23E-01	0.00E+00	0.00E+00	0.00E+00	9.62E-01	4.22E+00	0.00E+00	0.00E+00	0.00E+00	4.94E+00
Biomass Indirect Land Use Change	3.04E+00	0.00E+00	2.94E-02	0.00E+00	3.59E+00	1.56E+01	0.00E+00	1.51E-01	0.00E+00	1.84E+01
Raw Material Transport	**1.16E+01**	**4.11E-01**	**7.59E-02**	**1.81E-08**	**1.21E+01**	**5.97E+01**	**2.11E+00**	**3.89E-01**	**9.31E-08**	**6.22E+01**
Torref. Biomass Transp. to CBTL Plant	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biomass Torrefaction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	2.30E-01	9.29E-03	1.54E-03	3.73E-10	2.24E-01	1.18E+00	4.77E-02	7.88E-03	1.91E-09	1.15E+00
Transport of Coal to CBTL Plant	1.14E+01	4.02E-01	7.43E-02	1.78E-08	1.19E+01	5.85E+01	2.06E+00	3.81E-01	9.12E-08	6.11E+01
Energy Conversion Facility	**-2.16E+01**	**-4.41E+00**	**-1.57E-01**	**-8.71E-02**	**-3.12E+01**	**-1.11E+02**	**-2.26E+01**	**-8.08E-01**	**-4.47E-01**	**-1.60E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.53E+01	5.90E-04	1.46E-04	1.33E-05	3.52E+01	1.81E+02	3.03E-03	7.48E-04	6.80E-05	1.81E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.23E+01	-4.48E+00	-1.90E-01	-8.71E-02	-7.25E+01	-3.20E+02	-2.30E+01	-9.73E-01	-4.47E-01	-3.72E+02
CO_2 Transport to CO_2-EOR Operation	5.42E+00	6.88E-02	3.20E-02	0.00E+00	6.04E+00	2.78E+01	3.53E-01	1.64E-01	0.00E+00	3.10E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**1.42E+02**	**8.52E-01**	**2.55E+00**	**-8.34E-02**	**1.43E+02**	**7.29E+02**	**4.37E+00**	**1.31E+01**	**-4.28E-01**	**7.32E+02**

Table B-3: CBTL, 20% Chipped Biomass

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-6.18E+01**	**1.24E+00**	**2.40E+00**	**2.21E-03**	**-5.51E+01**	**-3.17E+02**	**6.36E+00**	**1.23E+01**	**1.13E-02**	**-2.83E+02**
Coal Mining, Surface	1.30E+00	1.10E+00	3.62E-01	9.80E-04	3.97E+00	6.67E+00	5.62E+00	1.86E+00	5.03E-03	2.04E+01
Biomass Production and Field Chipping	-7.10E+01	1.45E-01	1.97E+00	1.23E-03	-6.84E+01	-3.64E+02	7.43E-01	1.01E+01	6.32E-03	-3.51E+02
Biomass Direct Land Use Change	1.69E+00	0.00E+00	0.00E+00	0.00E+00	1.97E+00	8.67E+00	0.00E+00	0.00E+00	0.00E+00	1.01E+01
Biomass Indirect Land Use Change	6.23E+00	0.00E+00	6.04E-02	0.00E+00	7.35E+00	3.20E+01	0.00E+00	3.10E-01	0.00E+00	3.77E+01
Raw Material Transport	**1.09E+01**	**3.85E-01**	**7.09E-02**	**1.70E-08**	**1.13E+01**	**5.58E+01**	**1.98E+00**	**3.64E-01**	**8.71E-08**	**5.80E+01**
Torref. Biomass Transp. to CBTL Plant	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biomass Torrefaction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	4.71E-01	1.91E-02	3.15E-03	7.65E-10	4.60E-01	2.42E+00	9.78E-02	1.62E-02	3.92E-09	2.36E+00
Transport of Coal to CBTL Plant	1.04E+01	3.66E-01	6.78E-02	1.62E-08	1.08E+01	5.34E+01	1.88E+00	3.48E-01	8.31E-08	5.56E+01
Energy Conversion Facility	**-1.91E+01**	**-4.42E+00**	**-1.58E-01**	**-8.78E-02**	**-2.80E+01**	**-9.78E+01**	**-2.27E+01**	**-8.10E-01**	**-4.50E-01**	**-1.44E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.54E+01	5.90E-04	1.46E-04	1.33E-05	3.53E+01	1.82E+02	3.03E-03	7.48E-04	6.80E-05	1.81E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-5.99E+01	-4.49E+00	-1.90E-01	-8.78E-02	-6.95E+01	-3.07E+02	-2.30E+01	-9.77E-01	-4.50E-01	-3.56E+02
CO_2 Transport to CO_2-EOR Operation	5.46E+00	6.93E-02	3.23E-02	0.00E+00	6.09E+00	2.80E+01	3.56E-01	1.66E-01	0.00E+00	3.12E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**1.11E+02**	**7.87E-01**	**3.55E+00**	**-8.35E-02**	**1.14E+02**	**5.71E+02**	**4.04E+00**	**1.82E+01**	**-4.29E-01**	**5.86E+02**

Table B-4: CBTL, 10% Torrefied Biomass

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-3.28E+01**	**1.24E+00**	**1.49E+00**	**1.71E-03**	**-2.77E+01**	**-1.68E+02**	**6.36E+00**	**7.62E+00**	**8.75E-03**	**-1.42E+02**
Coal Mining, Surface	1.38E+00	1.16E+00	3.84E-01	1.04E-03	4.21E+00	7.07E+00	5.95E+00	1.97E+00	5.33E-03	2.16E+01
Biomass Production and Field Chipping	-3.84E+01	7.85E-02	1.07E+00	6.67E-04	-3.69E+01	-1.97E+02	4.03E-01	5.49E+00	3.42E-03	-1.89E+02
Biomass Direct Land Use Change	9.15E-01	0.00E+00	0.00E+00	0.00E+00	1.06E+00	4.69E+00	0.00E+00	0.00E+00	0.00E+00	5.46E+00
Biomass Indirect Land Use Change	3.38E+00	0.00E+00	3.27E-02	0.00E+00	3.97E+00	1.73E+01	0.00E+00	1.68E-01	0.00E+00	2.04E+01
Raw Material Transport	**1.46E+01**	**4.20E-01**	**8.21E-02**	**6.89E-04**	**1.51E+01**	**7.48E+01**	**2.16E+00**	**4.21E-01**	**3.54E-03**	**7.74E+01**
Torref. Biomass Transp. to CBTL Plant	3.28E-01	1.30E-02	2.18E-03	5.37E-10	3.44E-01	1.68E+00	6.65E-02	1.12E-02	2.76E-09	1.76E+00
Biomass Torrefaction	2.97E+00	8.36E-03	6.35E-03	6.89E-04	2.99E+00	1.52E+01	4.29E-02	3.26E-02	3.54E-03	1.53E+01
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	2.55E-01	1.03E-02	1.71E-03	4.14E-10	2.48E-01	1.31E+00	5.29E-02	8.76E-03	2.13E-09	1.27E+00
Transport of Coal to CBTL Plant	1.10E+01	3.88E-01	7.18E-02	1.72E-08	1.15E+01	5.66E+01	1.99E+00	3.68E-01	8.81E-08	5.90E+01
Energy Conversion Facility	**-2.44E+01**	**-4.40E+00**	**-1.57E-01**	**-8.64E-02**	**-3.47E+01**	**-1.25E+02**	**-2.26E+01**	**-8.05E-01**	**-4.43E-01**	**-1.78E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.48E+01	5.90E-04	1.46E-04	1.33E-05	3.47E+01	1.78E+02	3.03E-03	7.48E-04	6.80E-05	1.78E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.46E+01	-4.47E+00	-1.89E-01	-8.64E-02	-7.55E+01	-3.31E+02	-2.29E+01	-9.69E-01	-4.43E-01	-3.87E+02
CO_2 Transport to CO_2-EOR Operation	5.38E+00	6.83E-02	3.18E-02	0.00E+00	5.99E+00	2.76E+01	3.50E-01	1.63E-01	0.00E+00	3.08E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**1.39E+02**	**8.36E-01**	**2.65E+00**	**-8.20E-02**	**1.39E+02**	**7.11E+02**	**4.29E+00**	**1.36E+01**	**-4.21E-01**	**7.12E+02**

Table B-5: CBTL, 20% Torrefied Biomass

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-6.65E+01**	**1.18E+00**	**2.52E+00**	**2.24E-03**	**-5.95E+01**	**-3.41E+02**	**6.04E+00**	**1.29E+01**	**1.15E-02**	**-3.05E+02**
Coal Mining, Surface	1.21E+00	1.02E+00	3.38E-01	9.15E-04	3.71E+00	6.23E+00	5.24E+00	1.73E+00	4.69E-03	1.90E+01
Biomass Production and Field Chipping	-7.62E+01	1.55E-01	2.12E+00	1.32E-03	-7.31E+01	-3.91E+02	7.98E-01	1.09E+01	6.78E-03	-3.75E+02
Biomass Direct Land Use Change	1.81E+00	0.00E+00	0.00E+00	0.00E+00	2.11E+00	9.30E+00	0.00E+00	0.00E+00	0.00E+00	1.08E+01
Biomass Indirect Land Use Change	6.69E+00	0.00E+00	6.48E-02	0.00E+00	7.86E+00	3.43E+01	0.00E+00	3.32E-01	0.00E+00	4.03E+01
Raw Material Transport	**1.67E+01**	**4.05E-01**	**8.35E-02**	**1.37E-03**	**1.72E+01**	**8.59E+01**	**2.08E+00**	**4.29E-01**	**7.01E-03**	**8.84E+01**
Torref. Biomass Transp. to CBTL Plant	6.50E-01	2.57E-02	4.32E-03	1.06E-09	6.81E-01	3.33E+00	1.32E-01	2.22E-02	5.46E-09	3.49E+00
Biomass Torrefaction	5.88E+00	1.66E-02	1.26E-02	1.37E-03	5.92E+00	3.02E+01	8.50E-02	6.46E-02	7.01E-03	3.04E+01
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	5.06E-01	2.04E-02	3.38E-03	8.21E-10	4.91E-01	2.60E+00	1.05E-01	1.74E-02	4.21E-09	2.52E+00
Transport of Coal to CBTL Plant	9.71E+00	3.42E-01	6.32E-02	1.51E-08	1.01E+01	4.98E+01	1.75E+00	3.24E-01	7.76E-08	5.20E+01
Energy Conversion Facility	**-2.53E+01**	**-4.40E+00**	**-1.57E-01**	**-8.63E-02**	**-3.57E+01**	**-1.30E+02**	**-2.26E+01**	**-8.05E-01**	**-4.43E-01**	**-1.83E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.44E+01	5.90E-04	1.46E-04	1.33E-05	3.44E+01	1.76E+02	3.03E-03	7.48E-04	6.80E-05	1.76E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.50E+01	-4.47E+00	-1.89E-01	-8.64E-02	-7.61E+01	-3.34E+02	-2.29E+01	-9.68E-01	-4.43E-01	-3.90E+02
CO_2 Transport to CO_2-EOR Operation	5.37E+00	6.82E-02	3.18E-02	0.00E+00	5.99E+00	2.76E+01	3.50E-01	1.63E-01	0.00E+00	3.07E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**1.06E+02**	**7.59E-01**	**3.69E+00**	**-8.07E-02**	**1.08E+02**	**5.45E+02**	**3.90E+00**	**1.89E+01**	**-4.14E-01**	**5.55E+02**

Table B-6: CBTL, 10% Biomass, Microchipped, Sep. Gasifiers

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-3.10E+01**	**1.30E+00**	**1.45E+00**	**1.73E-03**	**-2.59E+01**	**-1.59E+02**	**6.66E+00**	**7.45E+00**	**8.87E-03**	**-1.33E+02**
Coal Mining, Surface	1.45E+00	1.22E+00	4.04E-01	1.09E-03	4.44E+00	7.46E+00	6.28E+00	2.07E+00	5.62E-03	2.28E+01
Biomass Production and Field Chipping	-3.65E+01	7.46E-02	1.02E+00	6.34E-04	-3.51E+01	-1.87E+02	3.83E-01	5.22E+00	3.25E-03	-1.80E+02
Biomass Direct Land Use Change	8.69E-01	0.00E+00	0.00E+00	0.00E+00	1.01E+00	4.46E+00	0.00E+00	0.00E+00	0.00E+00	5.20E+00
Biomass Indirect Land Use Change	3.21E+00	0.00E+00	3.11E-02	0.00E+00	3.78E+00	1.65E+01	0.00E+00	1.59E-01	0.00E+00	1.94E+01
Raw Material Transport	**1.19E+01**	**4.19E-01**	**7.73E-02**	**1.85E-08**	**1.24E+01**	**6.09E+01**	**2.15E+00**	**3.97E-01**	**9.49E-08**	**6.35E+01**
Torref. Biomass Transp. to CBTL Plant	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biomass Torrefaction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	2.43E-01	9.81E-03	1.62E-03	3.94E-10	2.36E-01	1.25E+00	5.03E-02	8.33E-03	2.02E-09	1.21E+00
Transport of Coal to CBTL Plant	1.16E+01	4.09E-01	7.57E-02	1.81E-08	1.21E+01	5.96E+01	2.10E+00	3.88E-01	9.29E-08	6.23E+01
Energy Conversion Facility	**3.09E+00**	**-4.36E+00**	**-1.54E-01**	**-8.27E-02**	**-7.95E+00**	**1.59E+01**	**-2.24E+01**	**-7.89E-01**	**-4.24E-01**	**-4.08E+01**
Plant Construction & Operations (inc. CO_2 Compression)	5.83E+01	5.90E-04	1.46E-04	1.33E-05	5.75E+01	2.99E+02	3.03E-03	7.48E-04	6.80E-05	2.95E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.03E+01	-4.42E+00	-1.84E-01	-8.27E-02	-7.12E+01	-3.10E+02	-2.27E+01	-9.46E-01	-4.24E-01	-3.65E+02
CO_2 Transport to CO_2-EOR Operation	5.14E+00	6.53E-02	3.04E-02	0.00E+00	5.76E+00	2.64E+01	3.35E-01	1.56E-01	0.00E+00	2.95E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**1.65E+02**	**9.37E-01**	**2.62E+00**	**-7.89E-02**	**1.65E+02**	**8.48E+02**	**4.81E+00**	**1.34E+01**	**-4.05E-01**	**8.45E+02**

Table B-7: CBTL, 30% Chipped Biomass

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-9.59E+01**	**1.21E+00**	**3.46E+00**	**2.77E-03**	**-8.74E+01**	**-4.92E+02**	**6.19E+00**	**1.77E+01**	**1.42E-02**	**-4.48E+02**
Coal Mining, Surface	1.17E+00	9.83E-01	3.25E-01	8.80E-04	3.56E+00	5.99E+00	5.05E+00	1.67E+00	4.51E-03	1.83E+01
Biomass Production and Field Chipping	-1.09E+02	2.23E-01	3.04E+00	1.90E-03	-1.05E+02	-5.61E+02	1.14E+00	1.56E+01	9.72E-03	-5.40E+02
Biomass Direct Land Use Change	2.60E+00	0.00E+00	0.00E+00	0.00E+00	3.04E+00	1.33E+01	0.00E+00	0.00E+00	0.00E+00	1.56E+01
Biomass Indirect Land Use Change	9.60E+00	0.00E+00	9.29E-02	0.00E+00	1.13E+01	4.92E+01	0.00E+00	4.77E-01	0.00E+00	5.80E+01
Raw Material Transport	**1.01E+01**	**3.58E-01**	**6.57E-02**	**1.57E-08**	**1.04E+01**	**5.16E+01**	**1.84E+00**	**3.37E-01**	**8.07E-08**	**5.36E+01**
Torref. Biomass Transp. to CBTL Plant	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biomass Torrefaction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	7.26E-01	2.93E-02	4.85E-03	1.18E-09	7.07E-01	3.72E+00	1.50E-01	2.49E-02	6.04E-09	3.63E+00
Transport of Coal to CBTL Plant	9.34E+00	3.29E-01	6.08E-02	1.45E-08	9.73E+00	4.79E+01	1.69E+00	3.12E-01	7.46E-08	4.99E+01
Energy Conversion Facility	**-1.65E+01**	**-4.43E+00**	**-1.59E-01**	**-8.88E-02**	**-2.44E+01**	**-8.45E+01**	**-2.27E+01**	**-8.15E-01**	**-4.56E-01**	**-1.25E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.55E+01	5.90E-04	1.46E-04	1.33E-05	3.55E+01	1.82E+02	3.03E-03	7.48E-04	6.80E-05	1.82E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-5.75E+01	-4.50E+00	-1.92E-01	-8.88E-02	-6.60E+01	-2.95E+02	-2.31E+01	-9.83E-01	-4.56E-01	-3.39E+02
CO_2 Transport to CO_2-EOR Operation	5.52E+00	7.02E-02	3.27E-02	0.00E+00	6.15E+00	2.83E+01	3.60E-01	1.68E-01	0.00E+00	3.15E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**7.90E+01**	**7.15E-01**	**4.61E+00**	**-8.40E-02**	**8.48E+01**	**4.05E+02**	**3.67E+00**	**2.36E+01**	**-4.31E-01**	**4.35E+02**

Table B-8: CBTL, 30% Torrefied Biomass

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-9.95E+01**	**1.12E+00**	**3.54E+00**	**2.76E-03**	**-9.07E+01**	**-5.11E+02**	**5.73E+00**	**1.82E+01**	**1.41E-02**	**-4.65E+02**
Coal Mining, Surface	1.05E+00	8.86E-01	2.93E-01	7.93E-04	3.21E+00	5.40E+00	4.55E+00	1.50E+00	4.07E-03	1.65E+01
Biomass Production and Field Chipping	-1.13E+02	2.31E-01	3.15E+00	1.96E-03	-1.09E+02	-5.81E+02	1.19E+00	1.62E+01	1.01E-02	-5.58E+02
Biomass Direct Land Use Change	2.69E+00	0.00E+00	0.00E+00	0.00E+00	3.14E+00	1.38E+01	0.00E+00	0.00E+00	0.00E+00	1.61E+01
Biomass Indirect Land Use Change	9.94E+00	0.00E+00	9.63E-02	0.00E+00	1.17E+01	5.10E+01	0.00E+00	4.94E-01	0.00E+00	5.99E+01
Raw Material Transport	**1.89E+01**	**3.90E-01**	**8.50E-02**	**2.03E-03**	**1.93E+01**	**9.68E+01**	**2.00E+00**	**4.36E-01**	**1.04E-02**	**9.92E+01**
Torref. Biomass Transp. to CBTL Plant	9.65E-01	3.82E-02	6.42E-03	1.58E-09	1.01E+00	4.95E+00	1.96E-01	3.29E-02	8.12E-09	5.19E+00
Biomass Torrefaction	8.74E+00	2.46E-02	1.87E-02	2.03E-03	8.80E+00	4.48E+01	1.26E-01	9.60E-02	1.04E-02	4.52E+01
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	7.52E-01	3.04E-02	5.03E-03	1.22E-09	7.30E-01	3.86E+00	1.56E-01	2.58E-02	6.26E-09	3.75E+00
Transport of Coal to CBTL Plant	8.42E+00	2.97E-01	5.48E-02	1.31E-08	8.78E+00	4.32E+01	1.52E+00	2.81E-01	6.73E-08	4.51E+01
Energy Conversion Facility	**-2.62E+01**	**-4.40E+00**	**-1.57E-01**	**-8.66E-02**	**-3.68E+01**	**-1.34E+02**	**-2.26E+01**	**-8.06E-01**	**-4.44E-01**	**-1.89E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.40E+01	5.90E-04	1.46E-04	1.33E-05	3.40E+01	1.74E+02	3.03E-03	7.48E-04	6.80E-05	1.74E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.56E+01	-4.47E+00	-1.89E-01	-8.66E-02	-7.68E+01	-3.37E+02	-2.30E+01	-9.70E-01	-4.45E-01	-3.94E+02
CO_2 Transport to CO_2-EOR Operation	5.39E+00	6.84E-02	3.19E-02	0.00E+00	6.00E+00	2.76E+01	3.51E-01	1.63E-01	0.00E+00	3.08E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**7.44E+01**	**6.81E-01**	**4.71E+00**	**-7.98E-02**	**7.80E+01**	**3.82E+02**	**3.49E+00**	**2.42E+01**	**-4.09E-01**	**4.00E+02**

Table B-9: CBTL, 11.7% Chipped Biomass

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-3.47E+01**	**1.27E+00**	**1.56E+00**	**1.76E-03**	**-2.96E+01**	**-1.78E+02**	**6.50E+00**	**7.99E+00**	**9.05E-03**	**-1.52E+02**
Coal Mining, Surface	1.41E+00	1.18E+00	3.91E-01	1.06E-03	4.29E+00	7.21E+00	6.07E+00	2.01E+00	5.43E-03	2.20E+01
Biomass Production and Field Chipping	-4.07E+01	8.30E-02	1.13E+00	7.05E-04	-3.92E+01	-2.09E+02	4.26E-01	5.80E+00	3.62E-03	-2.01E+02
Biomass Direct Land Use Change	9.67E-01	0.00E+00	0.00E+00	0.00E+00	1.13E+00	4.96E+00	0.00E+00	0.00E+00	0.00E+00	5.80E+00
Biomass Indirect Land Use Change	3.57E+00	0.00E+00	3.46E-02	0.00E+00	4.21E+00	1.83E+01	0.00E+00	1.77E-01	0.00E+00	2.16E+01
Raw Material Transport	**1.15E+01**	**4.07E-01**	**7.50E-02**	**1.79E-08**	**1.20E+01**	**5.91E+01**	**2.09E+00**	**3.85E-01**	**9.21E-08**	**6.15E+01**
Torref. Biomass Transp. to CBTL Plant	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biomass Torrefaction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	2.70E-01	1.09E-02	1.81E-03	4.38E-10	2.63E-01	1.39E+00	5.60E-02	9.26E-03	2.25E-09	1.35E+00
Transport of Coal to CBTL Plant	1.12E+01	3.96E-01	7.32E-02	1.75E-08	1.17E+01	5.77E+01	2.03E+00	3.76E-01	8.98E-08	6.02E+01
Energy Conversion Facility	**-2.12E+01**	**-4.41E+00**	**-1.58E-01**	**-8.76E-02**	**-3.07E+01**	**-1.09E+02**	**-2.26E+01**	**-8.09E-01**	**-4.49E-01**	**-1.57E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.53E+01	5.90E-04	1.46E-04	1.33E-05	3.53E+01	1.81E+02	3.03E-03	7.48E-04	6.80E-05	1.81E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.20E+01	-4.48E+00	-1.90E-01	-8.76E-02	-7.20E+01	-3.18E+02	-2.30E+01	-9.75E-01	-4.49E-01	-3.69E+02
CO_2 Transport to CO_2-EOR Operation	5.45E+00	6.92E-02	3.22E-02	0.00E+00	6.06E+00	2.79E+01	3.55E-01	1.65E-01	0.00E+00	3.11E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**1.37E+02**	**8.37E-01**	**2.72E+00**	**-8.37E-02**	**1.38E+02**	**7.02E+02**	**4.30E+00**	**1.39E+01**	**-4.30E-01**	**7.07E+02**

Table B-10: CBTL, 19.2% Chipped Biomass

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-5.91E+01**	**1.24E+00**	**2.31E+00**	**2.17E-03**	**-5.26E+01**	**-3.03E+02**	**6.37E+00**	**1.19E+01**	**1.11E-02**	**-2.70E+02**
Coal Mining, Surface	1.31E+00	1.10E+00	3.65E-01	9.88E-04	4.00E+00	6.72E+00	5.66E+00	1.87E+00	5.07E-03	2.05E+01
Biomass Production and Field Chipping	-6.80E+01	1.39E-01	1.89E+00	1.18E-03	-6.55E+01	-3.49E+02	7.12E-01	9.71E+00	6.05E-03	-3.36E+02
Biomass Direct Land Use Change	1.62E+00	0.00E+00	0.00E+00	0.00E+00	1.89E+00	8.30E+00	0.00E+00	0.00E+00	0.00E+00	9.70E+00
Biomass Indirect Land Use Change	5.97E+00	0.00E+00	5.78E-02	0.00E+00	7.04E+00	3.06E+01	0.00E+00	2.97E-01	0.00E+00	3.61E+01
Raw Material Transport	**1.09E+01**	**3.88E-01**	**7.13E-02**	**1.71E-08**	**1.14E+01**	**5.61E+01**	**1.99E+00**	**3.66E-01**	**8.75E-08**	**5.83E+01**
Torref. Biomass Transp. to CBTL Plant	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biomass Torrefaction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	4.52E-01	1.83E-02	3.02E-03	7.33E-10	4.40E-01	2.32E+00	9.37E-02	1.55E-02	3.76E-09	2.26E+00
Transport of Coal to CBTL Plant	1.05E+01	3.69E-01	6.83E-02	1.63E-08	1.09E+01	5.38E+01	1.89E+00	3.50E-01	8.38E-08	5.61E+01
Energy Conversion Facility	**-1.93E+01**	**-4.42E+00**	**-1.58E-01**	**-8.81E-02**	**-2.82E+01**	**-9.92E+01**	**-2.27E+01**	**-8.11E-01**	**-4.52E-01**	**-1.45E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.54E+01	5.90E-04	1.46E-04	1.33E-05	3.53E+01	1.82E+02	3.03E-03	7.48E-04	6.80E-05	1.81E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.02E+01	-4.49E+00	-1.91E-01	-8.81E-02	-6.96E+01	-3.09E+02	-2.30E+01	-9.78E-01	-4.52E-01	-3.57E+02
CO_2 Transport to CO_2-EOR Operation	5.48E+00	6.96E-02	3.24E-02	0.00E+00	6.10E+00	2.81E+01	3.57E-01	1.66E-01	0.00E+00	3.13E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**1.14E+02**	**7.88E-01**	**3.47E+00**	**-8.38E-02**	**1.17E+02**	**5.84E+02**	**4.05E+00**	**1.78E+01**	**-4.30E-01**	**5.99E+02**

Table B-11: CBTL, 28.3% Chipped Biomass

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-9.00E+01**	**1.21E+00**	**3.27E+00**	**2.68E-03**	**-8.18E+01**	**-4.62E+02**	**6.22E+00**	**1.68E+01**	**1.37E-02**	**-4.19E+02**
Coal Mining, Surface	1.19E+00	1.00E+00	3.31E-01	8.97E-04	3.63E+00	6.11E+00	5.14E+00	1.70E+00	4.60E-03	1.86E+01
Biomass Production and Field Chipping	-1.03E+02	2.09E-01	2.85E+00	1.78E-03	-9.89E+01	-5.27E+02	1.07E+00	1.46E+01	9.13E-03	-5.07E+02
Biomass Direct Land Use Change	2.44E+00	0.00E+00	0.00E+00	0.00E+00	2.85E+00	1.25E+01	0.00E+00	0.00E+00	0.00E+00	1.46E+01
Biomass Indirect Land Use Change	9.01E+00	0.00E+00	8.73E-02	0.00E+00	1.06E+01	4.62E+01	0.00E+00	4.48E-01	0.00E+00	5.45E+01
Raw Material Transport	**1.02E+01**	**3.63E-01**	**6.66E-02**	**1.59E-08**	**1.06E+01**	**5.24E+01**	**1.86E+00**	**3.42E-01**	**8.18E-08**	**5.43E+01**
Torref. Biomass Transp. to CBTL Plant	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biomass Torrefaction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	6.82E-01	2.75E-02	4.56E-03	1.11E-09	6.64E-01	3.50E+00	1.41E-01	2.34E-02	5.67E-09	3.41E+00
Transport of Coal to CBTL Plant	9.52E+00	3.36E-01	6.20E-02	1.48E-08	9.93E+00	4.89E+01	1.72E+00	3.18E-01	7.61E-08	5.09E+01
Energy Conversion Facility	**-1.69E+01**	**-4.43E+00**	**-1.59E-01**	**-8.87E-02**	**-2.50E+01**	**-8.68E+01**	**-2.27E+01**	**-8.14E-01**	**-4.55E-01**	**-1.28E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.55E+01	5.90E-04	1.46E-04	1.33E-05	3.54E+01	1.82E+02	3.03E-03	7.48E-04	6.80E-05	1.82E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-5.79E+01	-4.50E+00	-1.91E-01	-8.87E-02	-6.66E+01	-2.97E+02	-2.31E+01	-9.82E-01	-4.55E-01	-3.42E+02
CO_2 Transport to CO_2-EOR Operation	5.52E+00	7.01E-02	3.26E-02	0.00E+00	6.14E+00	2.83E+01	3.59E-01	1.67E-01	0.00E+00	3.15E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**8.46E+01**	**7.27E-01**	**4.42E+00**	**-8.40E-02**	**8.99E+01**	**4.34E+02**	**3.73E+00**	**2.27E+01**	**-4.31E-01**	**4.61E+02**

Table B-12: CBTL, 16.5% Torrefied Biomass

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-5.47E+01**	**1.20E+00**	**2.16E+00**	**2.05E-03**	**-5.03E+01**	**-2.81E+02**	**6.15E+00**	**1.11E+01**	**1.05E-02**	**-2.58E+02**
Coal Mining, Surface	1.27E+00	1.07E+00	3.54E-01	9.58E-04	3.85E+00	6.52E+00	5.49E+00	1.81E+00	4.91E-03	1.98E+01
Biomass Production and Field Chipping	-6.30E+01	1.29E-01	1.75E+00	1.09E-03	-6.28E+01	-3.23E+02	6.60E-01	9.00E+00	5.61E-03	-3.22E+02
Biomass Direct Land Use Change	1.50E+00	0.00E+00	0.00E+00	0.00E+00	1.81E+00	7.70E+00	0.00E+00	0.00E+00	0.00E+00	9.29E+00
Biomass Indirect Land Use Change	5.54E+00	0.00E+00	5.36E-02	0.00E+00	6.75E+00	2.84E+01	0.00E+00	2.75E-01	0.00E+00	3.46E+01
Raw Material Transport	**1.60E+01**	**4.10E-01**	**8.30E-02**	**1.13E-03**	**1.66E+01**	**8.20E+01**	**2.10E+00**	**4.26E-01**	**5.80E-03**	**8.52E+01**
Torref. Biomass Transp. to CBTL Plant	5.38E-01	2.12E-02	3.57E-03	8.81E-10	5.84E-01	2.76E+00	1.09E-01	1.83E-02	4.52E-09	3.00E+00
Biomass Torrefaction	4.87E+00	1.37E-02	1.04E-02	1.13E-03	5.08E+00	2.50E+01	7.04E-02	5.35E-02	5.80E-03	2.61E+01
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	4.19E-01	1.69E-02	2.80E-03	6.80E-10	4.22E-01	2.15E+00	8.68E-02	1.44E-02	3.49E-09	2.16E+00
Transport of Coal to CBTL Plant	1.02E+01	3.58E-01	6.62E-02	1.58E-08	1.05E+01	5.22E+01	1.84E+00	3.40E-01	8.12E-08	5.40E+01
Energy Conversion Facility	**-2.50E+01**	**-4.41E+00**	**-1.57E-01**	**-8.67E-02**	**-3.54E+01**	**-1.28E+02**	**-2.26E+01**	**-8.06E-01**	**-4.45E-01**	**-1.82E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.45E+01	5.90E-04	1.46E-04	1.33E-05	3.45E+01	1.77E+02	3.03E-03	7.48E-04	6.80E-05	1.77E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.50E+01	-4.47E+00	-1.89E-01	-8.67E-02	-7.59E+01	-3.33E+02	-2.30E+01	-9.70E-01	-4.45E-01	-3.89E+02
CO_2 Transport to CO_2-EOR Operation	5.39E+00	6.85E-02	3.19E-02	0.00E+00	6.00E+00	2.77E+01	3.51E-01	1.64E-01	0.00E+00	3.08E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**1.18E+02**	**7.82E-01**	**3.33E+00**	**-8.15E-02**	**1.17E+02**	**6.03E+02**	**4.01E+00**	**1.71E+01**	**-4.18E-01**	**6.00E+02**

Table B-13: CBTL, 19.6% Torrefied Biomass

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-6.51E+01**	**1.18E+00**	**2.48E+00**	**2.21E-03**	**-5.82E+01**	**-3.34E+02**	**6.05E+00**	**1.27E+01**	**1.14E-02**	**-2.99E+02**
Coal Mining, Surface	1.22E+00	1.03E+00	3.40E-01	9.19E-04	3.73E+00	6.26E+00	5.27E+00	1.74E+00	4.72E-03	1.91E+01
Biomass Production and Field Chipping	-7.47E+01	1.52E-01	2.08E+00	1.30E-03	-7.17E+01	-3.83E+02	7.82E-01	1.07E+01	6.64E-03	-3.68E+02
Biomass Direct Land Use Change	1.78E+00	0.00E+00	0.00E+00	0.00E+00	2.07E+00	9.12E+00	0.00E+00	0.00E+00	0.00E+00	1.06E+01
Biomass Indirect Land Use Change	6.56E+00	0.00E+00	6.35E-02	0.00E+00	7.71E+00	3.36E+01	0.00E+00	3.26E-01	0.00E+00	3.95E+01
Raw Material Transport	**1.67E+01**	**4.05E-01**	**8.35E-02**	**1.34E-03**	**1.71E+01**	**8.55E+01**	**2.08E+00**	**4.28E-01**	**6.87E-03**	**8.79E+01**
Torref. Biomass Transp. to CBTL Plant	6.37E-01	2.52E-02	4.23E-03	1.04E-09	6.67E-01	3.27E+00	1.29E-01	2.17E-02	5.36E-09	3.42E+00
Biomass Torrefaction	5.77E+00	1.62E-02	1.23E-02	1.34E-03	5.81E+00	2.96E+01	8.33E-02	6.33E-02	6.87E-03	2.98E+01
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	4.96E-01	2.00E-02	3.32E-03	8.05E-10	4.82E-01	2.54E+00	1.03E-01	1.70E-02	4.13E-09	2.47E+00
Transport of Coal to CBTL Plant	9.76E+00	3.44E-01	6.36E-02	1.52E-08	1.02E+01	5.01E+01	1.76E+00	3.26E-01	7.80E-08	5.23E+01
Energy Conversion Facility	**-2.53E+01**	**-4.40E+00**	**-1.57E-01**	**-8.67E-02**	**-3.57E+01**	**-1.30E+02**	**-2.26E+01**	**-8.06E-01**	**-4.45E-01**	**-1.83E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.44E+01	5.90E-04	1.46E-04	1.33E-05	3.44E+01	1.77E+02	3.03E-03	7.48E-04	6.80E-05	1.76E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.51E+01	-4.47E+00	-1.89E-01	-8.67E-02	-7.61E+01	-3.34E+02	-2.30E+01	-9.70E-01	-4.45E-01	-3.90E+02
CO_2 Transport to CO_2-EOR Operation	5.39E+00	6.85E-02	3.19E-02	0.00E+00	6.00E+00	2.77E+01	3.51E-01	1.64E-01	0.00E+00	3.08E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**1.08E+02**	**7.59E-01**	**3.65E+00**	**-8.11E-02**	**1.09E+02**	**5.52E+02**	**3.89E+00**	**1.87E+01**	**-4.16E-01**	**5.61E+02**

Table B-14: CBTL, 28.3% Torrefied Biomass

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-9.39E+01**	**1.13E+00**	**3.37E+00**	**2.67E-03**	**-8.54E+01**	**-4.82E+02**	**5.78E+00**	**1.73E+01**	**1.37E-02**	**-4.38E+02**
Coal Mining, Surface	1.08E+00	9.09E-01	3.00E-01	8.13E-04	3.30E+00	5.54E+00	4.66E+00	1.54E+00	4.17E-03	1.69E+01
Biomass Production and Field Chipping	-1.07E+02	2.18E-01	2.98E+00	1.85E-03	-1.03E+02	-5.49E+02	1.12E+00	1.53E+01	9.52E-03	-5.27E+02
Biomass Direct Land Use Change	2.54E+00	0.00E+00	0.00E+00	0.00E+00	2.96E+00	1.31E+01	0.00E+00	0.00E+00	0.00E+00	1.52E+01
Biomass Indirect Land Use Change	9.39E+00	0.00E+00	9.10E-02	0.00E+00	1.10E+01	4.82E+01	0.00E+00	4.67E-01	0.00E+00	5.66E+01
Raw Material Transport	**1.85E+01**	**3.92E-01**	**8.47E-02**	**1.92E-03**	**1.90E+01**	**9.50E+01**	**2.01E+00**	**4.35E-01**	**9.84E-03**	**9.73E+01**
Torref. Biomass Transp. to CBTL Plant	9.12E-01	3.60E-02	6.06E-03	1.50E-09	9.56E-01	4.68E+00	1.85E-01	3.11E-02	7.67E-09	4.90E+00
Biomass Torrefaction	8.26E+00	2.33E-02	1.77E-02	1.92E-03	8.32E+00	4.24E+01	1.19E-01	9.07E-02	9.84E-03	4.27E+01
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	7.10E-01	2.87E-02	4.75E-03	1.15E-09	6.90E-01	3.64E+00	1.47E-01	2.44E-02	5.91E-09	3.54E+00
Transport of Coal to CBTL Plant	8.63E+00	3.04E-01	5.62E-02	1.34E-08	9.01E+00	4.43E+01	1.56E+00	2.89E-01	6.90E-08	4.62E+01
Energy Conversion Facility	**-2.61E+01**	**-4.40E+00**	**-1.57E-01**	**-8.66E-02**	**-3.65E+01**	**-1.34E+02**	**-2.26E+01**	**-8.06E-01**	**-4.44E-01**	**-1.87E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.41E+01	5.90E-04	1.46E-04	1.33E-05	3.41E+01	1.75E+02	3.03E-03	7.48E-04	6.80E-05	1.75E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.55E+01	-4.47E+00	-1.89E-01	-8.66E-02	-7.66E+01	-3.36E+02	-2.30E+01	-9.70E-01	-4.45E-01	-3.93E+02
CO_2 Transport to CO_2-EOR Operation	5.39E+00	6.84E-02	3.19E-02	0.00E+00	6.00E+00	2.76E+01	3.51E-01	1.63E-01	0.00E+00	3.08E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**7.98E+01**	**6.93E-01**	**4.54E+00**	**-8.00E-02**	**8.32E+01**	**4.09E+02**	**3.56E+00**	**2.33E+01**	**-4.10E-01**	**4.27E+02**

Table B-15: CBTL, 0% Biomass, Validated

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**1.55E+00**	**1.30E+00**	**4.31E-01**	**1.17E-03**	**4.73E+00**	**7.95E+00**	**6.69E+00**	**2.21E+00**	**5.99E-03**	**2.43E+01**
Coal Mining, Surface	1.55E+00	1.30E+00	4.31E-01	1.17E-03	4.73E+00	7.95E+00	6.69E+00	2.21E+00	5.99E-03	2.43E+01
Biomass Production and Field Chipping	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biomass Direct Land Use Change	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biomass Indirect Land Use Change	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Raw Material Transport	**1.24E+01**	**4.37E-01**	**8.07E-02**	**1.93E-08**	**1.29E+01**	**6.36E+01**	**2.24E+00**	**4.14E-01**	**9.90E-08**	**6.63E+01**
Torref. Biomass Transp. to CBTL Plant	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biomass Torrefaction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Transport of Coal to CBTL Plant	1.24E+01	4.37E-01	8.07E-02	1.93E-08	1.29E+01	6.36E+01	2.24E+00	4.14E-01	9.90E-08	6.63E+01
Energy Conversion Facility	**-2.47E+01**	**-4.41E+00**	**-1.58E-01**	**-8.73E-02**	**-3.50E+01**	**-1.27E+02**	**-2.26E+01**	**-8.09E-01**	**-4.48E-01**	**-1.80E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.45E+01	5.90E-04	1.46E-04	1.33E-05	3.45E+01	1.77E+02	3.03E-03	7.48E-04	6.80E-05	1.77E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.47E+01	-4.48E+00	-1.90E-01	-8.73E-02	-7.56E+01	-3.32E+02	-2.30E+01	-9.74E-01	-4.48E-01	-3.88E+02
CO_2 Transport to CO_2-EOR Operation	5.43E+00	6.90E-02	3.21E-02	0.00E+00	6.05E+00	2.79E+01	3.54E-01	1.65E-01	0.00E+00	3.10E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**1.71E+02**	**9.08E-01**	**1.60E+00**	**-8.41E-02**	**1.69E+02**	**8.75E+02**	**4.66E+00**	**8.20E+00**	**-4.32E-01**	**8.66E+02**

Table B-16: CBTL, 11.7% Chipped Biomass, Validated

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-3.48E+01**	**1.27E+00**	**1.56E+00**	**1.77E-03**	**-2.96E+01**	**-1.78E+02**	**6.51E+00**	**8.00E+00**	**9.07E-03**	**-1.52E+02**
Coal Mining, Surface	1.41E+00	1.19E+00	3.92E-01	1.06E-03	4.30E+00	7.22E+00	6.08E+00	2.01E+00	5.44E-03	2.20E+01
Biomass Production and Field Chipping	-4.07E+01	8.32E-02	1.13E+00	7.06E-04	-3.93E+01	-2.09E+02	4.27E-01	5.81E+00	3.62E-03	-2.02E+02
Biomass Direct Land Use Change	9.69E-01	0.00E+00	0.00E+00	0.00E+00	1.13E+00	4.97E+00	0.00E+00	0.00E+00	0.00E+00	5.81E+00
Biomass Indirect Land Use Change	3.58E+00	0.00E+00	3.46E-02	0.00E+00	4.22E+00	1.84E+01	0.00E+00	1.78E-01	0.00E+00	2.17E+01
Raw Material Transport	**1.15E+01**	**4.08E-01**	**7.52E-02**	**1.80E-08**	**1.20E+01**	**5.92E+01**	**2.09E+00**	**3.86E-01**	**9.23E-08**	**6.16E+01**
Torref. Biomass Transp. to CBTL Plant	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biomass Torrefaction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	2.71E-01	1.09E-02	1.81E-03	4.39E-10	2.64E-01	1.39E+00	5.61E-02	9.28E-03	2.25E-09	1.35E+00
Transport of Coal to CBTL Plant	1.13E+01	3.97E-01	7.34E-02	1.75E-08	1.17E+01	5.78E+01	2.04E+00	3.76E-01	9.00E-08	6.03E+01
Energy Conversion Facility	**-2.18E+01**	**-4.42E+00**	**-1.58E-01**	**-8.81E-02**	**-3.17E+01**	**-1.12E+02**	**-2.27E+01**	**-8.12E-01**	**-4.52E-01**	**-1.62E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.47E+01	5.90E-04	1.46E-04	1.33E-05	3.47E+01	1.78E+02	3.03E-03	7.48E-04	6.80E-05	1.78E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.20E+01	-4.49E+00	-1.91E-01	-8.81E-02	-7.24E+01	-3.18E+02	-2.30E+01	-9.78E-01	-4.52E-01	-3.72E+02
CO_2 Transport to CO_2-EOR Operation	5.48E+00	6.96E-02	3.24E-02	0.00E+00	6.10E+00	2.81E+01	3.57E-01	1.66E-01	0.00E+00	3.13E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**1.36E+02**	**8.35E-01**	**2.72E+00**	**-8.42E-02**	**1.37E+02**	**6.99E+02**	**4.28E+00**	**1.40E+01**	**-4.32E-01**	**7.02E+02**

Table B-17: CBTL, 19.2% Chipped Biomass, Validated

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-5.92E+01**	**1.24E+00**	**2.32E+00**	**2.17E-03**	**-5.27E+01**	**-3.04E+02**	**6.39E+00**	**1.19E+01**	**1.11E-02**	**-2.70E+02**
Coal Mining, Surface	1.31E+00	1.11E+00	3.65E-01	9.90E-04	4.01E+00	6.74E+00	5.67E+00	1.87E+00	5.08E-03	2.06E+01
Biomass Production and Field Chipping	-6.81E+01	1.39E-01	1.90E+00	1.18E-03	-6.57E+01	-3.50E+02	7.13E-01	9.72E+00	6.06E-03	-3.37E+02
Biomass Direct Land Use Change	1.62E+00	0.00E+00	0.00E+00	0.00E+00	1.89E+00	8.32E+00	0.00E+00	0.00E+00	0.00E+00	9.72E+00
Biomass Indirect Land Use Change	5.98E+00	0.00E+00	5.79E-02	0.00E+00	7.06E+00	3.07E+01	0.00E+00	2.97E-01	0.00E+00	3.62E+01
Raw Material Transport	**1.10E+01**	**3.88E-01**	**7.15E-02**	**1.71E-08**	**1.14E+01**	**5.62E+01**	**1.99E+00**	**3.67E-01**	**8.77E-08**	**5.84E+01**
Torref. Biomass Transp. to CBTL Plant	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biomass Torrefaction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	4.52E-01	1.83E-02	3.03E-03	7.34E-10	4.41E-01	2.32E+00	9.38E-02	1.55E-02	3.77E-09	2.26E+00
Transport of Coal to CBTL Plant	1.05E+01	3.70E-01	6.84E-02	1.64E-08	1.10E+01	5.39E+01	1.90E+00	3.51E-01	8.39E-08	5.62E+01
Energy Conversion Facility	**-1.99E+01**	**-4.43E+00**	**-1.59E-01**	**-8.86E-02**	**-2.89E+01**	**-1.02E+02**	**-2.27E+01**	**-8.14E-01**	**-4.54E-01**	**-1.49E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.48E+01	5.90E-04	1.46E-04	1.33E-05	3.48E+01	1.78E+02	3.03E-03	7.48E-04	6.80E-05	1.78E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.02E+01	-4.50E+00	-1.91E-01	-8.86E-02	-6.98E+01	-3.09E+02	-2.31E+01	-9.81E-01	-4.54E-01	-3.58E+02
CO_2 Transport to CO_2-EOR Operation	5.51E+00	7.00E-02	3.26E-02	0.00E+00	6.13E+00	2.83E+01	3.59E-01	1.67E-01	0.00E+00	3.15E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**1.13E+02**	**7.86E-01**	**3.47E+00**	**-8.43E-02**	**1.16E+02**	**5.80E+02**	**4.03E+00**	**1.78E+01**	**-4.33E-01**	**5.95E+02**

Table B-18: CBTL, 28.3% Chipped Biomass, Validated

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-9.01E+01**	**1.21E+00**	**3.28E+00**	**2.68E-03**	**-8.19E+01**	**-4.63E+02**	**6.23E+00**	**1.68E+01**	**1.38E-02**	**-4.20E+02**
Coal Mining, Surface	1.19E+00	1.00E+00	3.32E-01	8.99E-04	3.64E+00	6.12E+00	5.15E+00	1.70E+00	4.61E-03	1.87E+01
Biomass Production and Field Chipping	-1.03E+02	2.10E-01	2.86E+00	1.78E-03	-9.91E+01	-5.27E+02	1.08E+00	1.47E+01	9.15E-03	-5.08E+02
Biomass Direct Land Use Change	2.45E+00	0.00E+00	0.00E+00	0.00E+00	2.86E+00	1.26E+01	0.00E+00	0.00E+00	0.00E+00	1.47E+01
Biomass Indirect Land Use Change	9.03E+00	0.00E+00	8.74E-02	0.00E+00	1.06E+01	4.63E+01	0.00E+00	4.49E-01	0.00E+00	5.46E+01
Raw Material Transport	**1.02E+01**	**3.64E-01**	**6.67E-02**	**1.60E-08**	**1.06E+01**	**5.25E+01**	**1.87E+00**	**3.42E-01**	**8.19E-08**	**5.44E+01**
Torref. Biomass Transp. to CBTL Plant	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biomass Torrefaction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	6.83E-01	2.76E-02	4.57E-03	1.11E-09	6.66E-01	3.50E+00	1.42E-01	2.34E-02	5.69E-09	3.42E+00
Transport of Coal to CBTL Plant	9.54E+00	3.36E-01	6.22E-02	1.49E-08	9.94E+00	4.90E+01	1.72E+00	3.19E-01	7.63E-08	5.10E+01
Energy Conversion Facility	**-1.75E+01**	**-4.43E+00**	**-1.59E-01**	**-8.92E-02**	**-2.56E+01**	**-9.00E+01**	**-2.27E+01**	**-8.16E-01**	**-4.58E-01**	**-1.31E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.49E+01	5.90E-04	1.46E-04	1.33E-05	3.49E+01	1.79E+02	3.03E-03	7.48E-04	6.80E-05	1.79E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-5.80E+01	-4.50E+00	-1.92E-01	-8.92E-02	-6.66E+01	-2.97E+02	-2.31E+01	-9.85E-01	-4.58E-01	-3.42E+02
CO_2 Transport to CO_2-EOR Operation	5.55E+00	7.04E-02	3.28E-02	0.00E+00	6.18E+00	2.85E+01	3.61E-01	1.68E-01	0.00E+00	3.17E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**8.38E+01**	**7.24E-01**	**4.43E+00**	**-8.45E-02**	**8.92E+01**	**4.30E+02**	**3.71E+00**	**2.27E+01**	**-4.33E-01**	**4.58E+02**

Table B-19: CBTL, 16.5% Torrefied Biomass, Validated

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-5.48E+01**	**1.20E+00**	**2.17E+00**	**2.05E-03**	**-4.85E+01**	**-2.81E+02**	**6.16E+00**	**1.11E+01**	**1.05E-02**	**-2.49E+02**
Coal Mining, Surface	1.27E+00	1.07E+00	3.54E-01	9.60E-04	3.89E+00	6.53E+00	5.50E+00	1.82E+00	4.92E-03	1.99E+01
Biomass Production and Field Chipping	-6.32E+01	1.29E-01	1.76E+00	1.10E-03	-6.06E+01	-3.24E+02	6.61E-01	9.02E+00	5.62E-03	-3.11E+02
Biomass Direct Land Use Change	1.50E+00	0.00E+00	0.00E+00	0.00E+00	1.75E+00	7.71E+00	0.00E+00	0.00E+00	0.00E+00	8.97E+00
Biomass Indirect Land Use Change	5.55E+00	0.00E+00	5.37E-02	0.00E+00	6.52E+00	2.85E+01	0.00E+00	2.76E-01	0.00E+00	3.34E+01
Raw Material Transport	**1.60E+01**	**4.11E-01**	**8.32E-02**	**1.13E-03**	**1.65E+01**	**8.22E+01**	**2.11E+00**	**4.27E-01**	**5.81E-03**	**8.47E+01**
Torref. Biomass Transp. to CBTL Plant	5.39E-01	2.13E-02	3.58E-03	8.83E-10	5.65E-01	2.76E+00	1.09E-01	1.84E-02	4.53E-09	2.90E+00
Biomass Torrefaction	4.88E+00	1.37E-02	1.04E-02	1.13E-03	4.91E+00	2.50E+01	7.05E-02	5.36E-02	5.81E-03	2.52E+01
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	4.19E-01	1.70E-02	2.80E-03	6.81E-10	4.08E-01	2.15E+00	8.70E-02	1.44E-02	3.49E-09	2.09E+00
Transport of Coal to CBTL Plant	1.02E+01	3.59E-01	6.64E-02	1.59E-08	1.06E+01	5.23E+01	1.84E+00	3.40E-01	8.14E-08	5.45E+01
Energy Conversion Facility	**-2.56E+01**	**-4.41E+00**	**-1.57E-01**	**-8.72E-02**	**-3.60E+01**	**-1.32E+02**	**-2.26E+01**	**-8.08E-01**	**-4.47E-01**	**-1.84E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.39E+01	5.90E-04	1.46E-04	1.33E-05	3.39E+01	1.74E+02	3.03E-03	7.48E-04	6.80E-05	1.74E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.50E+01	-4.48E+00	-1.90E-01	-8.72E-02	-7.59E+01	-3.33E+02	-2.30E+01	-9.73E-01	-4.47E-01	-3.90E+02
CO_2 Transport to CO_2-EOR Operation	5.42E+00	6.89E-02	3.21E-02	0.00E+00	6.04E+00	2.78E+01	3.53E-01	1.65E-01	0.00E+00	3.10E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**1.17E+02**	**7.80E-01**	**3.33E+00**	**-8.20E-02**	**1.18E+02**	**5.99E+02**	**4.00E+00**	**1.71E+01**	**-4.20E-01**	**6.06E+02**

Table B-20: CBTL, 19.6% Torrefied Biomass, Validated

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-6.52E+01**	**1.18E+00**	**2.49E+00**	**2.22E-03**	**-5.83E+01**	**-3.35E+02**	**6.07E+00**	**1.27E+01**	**1.14E-02**	**-2.99E+02**
Coal Mining, Surface	1.22E+00	1.03E+00	3.40E-01	9.21E-04	3.73E+00	6.27E+00	5.28E+00	1.75E+00	4.73E-03	1.92E+01
Biomass Production and Field Chipping	-7.48E+01	1.53E-01	2.08E+00	1.30E-03	-7.18E+01	-3.84E+02	7.83E-01	1.07E+01	6.66E-03	-3.69E+02
Biomass Direct Land Use Change	1.78E+00	0.00E+00	0.00E+00	0.00E+00	2.07E+00	9.13E+00	0.00E+00	0.00E+00	0.00E+00	1.06E+01
Biomass Indirect Land Use Change	6.57E+00	0.00E+00	6.36E-02	0.00E+00	7.72E+00	3.37E+01	0.00E+00	3.26E-01	0.00E+00	3.96E+01
Raw Material Transport	**1.67E+01**	**4.06E-01**	**8.36E-02**	**1.34E-03**	**1.72E+01**	**8.56E+01**	**2.08E+00**	**4.29E-01**	**6.88E-03**	**8.81E+01**
Torref. Biomass Transp. to CBTL Plant	6.38E-01	2.52E-02	4.24E-03	1.05E-09	6.69E-01	3.27E+00	1.29E-01	2.18E-02	5.37E-09	3.43E+00
Biomass Torrefaction	5.78E+00	1.63E-02	1.24E-02	1.34E-03	5.82E+00	2.96E+01	8.35E-02	6.34E-02	6.88E-03	2.98E+01
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	4.97E-01	2.01E-02	3.32E-03	8.06E-10	4.83E-01	2.55E+00	1.03E-01	1.70E-02	4.14E-09	2.48E+00
Transport of Coal to CBTL Plant	9.78E+00	3.44E-01	6.37E-02	1.52E-08	1.02E+01	5.02E+01	1.77E+00	3.27E-01	7.81E-08	5.24E+01
Energy Conversion Facility	**-2.59E+01**	**-4.41E+00**	**-1.57E-01**	**-8.72E-02**	**-3.63E+01**	**-1.33E+02**	**-2.26E+01**	**-8.08E-01**	**-4.47E-01**	**-1.86E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.38E+01	5.90E-04	1.46E-04	1.33E-05	3.38E+01	1.73E+02	3.03E-03	7.48E-04	6.80E-05	1.73E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.51E+01	-4.48E+00	-1.90E-01	-8.72E-02	-7.61E+01	-3.34E+02	-2.30E+01	-9.73E-01	-4.47E-01	-3.90E+02
CO_2 Transport to CO_2-EOR Operation	5.42E+00	6.89E-02	3.21E-02	0.00E+00	6.04E+00	2.78E+01	3.53E-01	1.64E-01	0.00E+00	3.10E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**1.07E+02**	**7.56E-01**	**3.65E+00**	**-8.16E-02**	**1.09E+02**	**5.48E+02**	**3.88E+00**	**1.87E+01**	**-4.18E-01**	**5.58E+02**

Table B-21: CBTL, 28.3% Torrefied Biomass, Validated

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-9.41E+01**	**1.13E+00**	**3.37E+00**	**2.67E-03**	**-8.56E+01**	**-4.83E+02**	**5.79E+00**	**1.73E+01**	**1.37E-02**	**-4.39E+02**
Coal Mining, Surface	1.08E+00	9.11E-01	3.01E-01	8.15E-04	3.30E+00	5.55E+00	4.67E+00	1.54E+00	4.18E-03	1.69E+01
Biomass Production and Field Chipping	-1.07E+02	2.19E-01	2.98E+00	1.86E-03	-1.03E+02	-5.50E+02	1.12E+00	1.53E+01	9.53E-03	-5.28E+02
Biomass Direct Land Use Change	2.55E+00	0.00E+00	0.00E+00	0.00E+00	2.97E+00	1.31E+01	0.00E+00	0.00E+00	0.00E+00	1.52E+01
Biomass Indirect Land Use Change	9.41E+00	0.00E+00	9.11E-02	0.00E+00	1.11E+01	4.83E+01	0.00E+00	4.68E-01	0.00E+00	5.67E+01
Raw Material Transport	**1.85E+01**	**3.93E-01**	**8.49E-02**	**1.92E-03**	**1.90E+01**	**9.52E+01**	**2.02E+00**	**4.36E-01**	**9.86E-03**	**9.75E+01**
Torref. Biomass Transp. to CBTL Plant	9.14E-01	3.61E-02	6.08E-03	1.50E-09	9.58E-01	4.69E+00	1.85E-01	3.12E-02	7.68E-09	4.91E+00
Biomass Torrefaction	8.27E+00	2.33E-02	1.77E-02	1.92E-03	8.33E+00	4.24E+01	1.20E-01	9.09E-02	9.86E-03	4.27E+01
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	7.12E-01	2.88E-02	4.76E-03	1.15E-09	6.91E-01	3.65E+00	1.48E-01	2.44E-02	5.93E-09	3.55E+00
Transport of Coal to CBTL Plant	8.65E+00	3.05E-01	5.64E-02	1.35E-08	9.03E+00	4.44E+01	1.56E+00	2.89E-01	6.91E-08	4.63E+01
Energy Conversion Facility	**-2.67E+01**	**-4.41E+00**	**-1.57E-01**	**-8.71E-02**	**-3.71E+01**	**-1.37E+02**	**-2.26E+01**	**-8.08E-01**	**-4.47E-01**	**-1.90E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.35E+01	5.90E-04	1.46E-04	1.33E-05	3.35E+01	1.72E+02	3.03E-03	7.48E-04	6.80E-05	1.72E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.56E+01	-4.48E+00	-1.90E-01	-8.71E-02	-7.66E+01	-3.36E+02	-2.30E+01	-9.73E-01	-4.47E-01	-3.93E+02
CO_2 Transport to CO_2-EOR Operation	5.42E+00	6.88E-02	3.20E-02	0.00E+00	6.03E+00	2.78E+01	3.53E-01	1.64E-01	0.00E+00	3.10E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**7.91E+01**	**6.91E-01**	**4.54E+00**	**-8.05E-02**	**8.25E+01**	**4.06E+02**	**3.54E+00**	**2.33E+01**	**-4.13E-01**	**4.23E+02**

Table B-22: CBTL, 11.7% Pelleted Biomass

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-3.93E+01**	**1.26E+00**	**1.70E+00**	**1.84E-03**	**-3.37E+01**	**-2.02E+02**	**6.46E+00**	**8.71E+00**	**9.43E-03**	**-1.73E+02**
Coal Mining, Surface	1.38E+00	1.17E+00	3.85E-01	1.04E-03	4.23E+00	7.10E+00	5.98E+00	1.98E+00	5.35E-03	2.17E+01
Biomass Production and Field Chipping	-4.58E+01	9.35E-02	1.27E+00	7.94E-04	-4.40E+01	-2.35E+02	4.80E-01	6.54E+00	4.07E-03	-2.26E+02
Biomass Direct Land Use Change	1.09E+00	0.00E+00	0.00E+00	0.00E+00	1.27E+00	5.59E+00	0.00E+00	0.00E+00	0.00E+00	6.51E+00
Biomass Indirect Land Use Change	4.02E+00	0.00E+00	3.89E-02	0.00E+00	4.73E+00	2.06E+01	0.00E+00	2.00E-01	0.00E+00	2.42E+01
Raw Material Transport	**1.14E+01**	**4.02E-01**	**7.42E-02**	**1.77E-08**	**1.19E+01**	**5.84E+01**	**2.06E+00**	**3.81E-01**	**9.10E-08**	**6.08E+01**
Torref. Biomass Transp. to CBTL Plant	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biomass Torrefaction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	3.04E-01	1.23E-02	2.03E-03	4.94E-10	2.95E-01	1.56E+00	6.31E-02	1.04E-02	2.53E-09	1.52E+00
Transport of Coal to CBTL Plant	1.11E+01	3.90E-01	7.22E-02	1.73E-08	1.16E+01	5.68E+01	2.00E+00	3.70E-01	8.85E-08	5.93E+01
Energy Conversion Facility	**-2.49E+01**	**-4.41E+00**	**-1.57E-01**	**-8.68E-02**	**-3.54E+01**	**-1.28E+02**	**-2.26E+01**	**-8.06E-01**	**-4.45E-01**	**-1.82E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.50E+01	5.90E-04	1.46E-04	1.33E-05	3.50E+01	1.80E+02	3.03E-03	7.48E-04	6.80E-05	1.80E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.53E+01	-4.47E+00	-1.89E-01	-8.68E-02	-7.65E+01	-3.35E+02	-2.30E+01	-9.71E-01	-4.45E-01	-3.92E+02
CO_2 Transport to CO_2-EOR Operation	5.40E+00	6.85E-02	3.19E-02	0.00E+00	6.01E+00	2.77E+01	3.52E-01	1.64E-01	0.00E+00	3.08E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**1.28E+02**	**8.35E-01**	**2.86E+00**	**-8.29E-02**	**1.29E+02**	**6.59E+02**	**4.28E+00**	**1.47E+01**	**-4.25E-01**	**6.61E+02**

Table B-23: CBTL, 19.2% Pelleted Biomass

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-6.61E+01**	**1.23E+00**	**2.53E+00**	**2.28E-03**	**-5.90E+01**	**-3.39E+02**	**6.32E+00**	**1.30E+01**	**1.17E-02**	**-3.03E+02**
Coal Mining, Surface	1.28E+00	1.08E+00	3.56E-01	9.64E-04	3.90E+00	6.56E+00	5.52E+00	1.83E+00	4.94E-03	2.00E+01
Biomass Production and Field Chipping	-7.58E+01	1.55E-01	2.11E+00	1.32E-03	-7.28E+01	-3.89E+02	7.94E-01	1.08E+01	6.75E-03	-3.74E+02
Biomass Direct Land Use Change	1.80E+00	0.00E+00	0.00E+00	0.00E+00	2.10E+00	9.26E+00	0.00E+00	0.00E+00	0.00E+00	1.08E+01
Biomass Indirect Land Use Change	6.66E+00	0.00E+00	6.45E-02	0.00E+00	7.83E+00	3.42E+01	0.00E+00	3.31E-01	0.00E+00	4.02E+01
Raw Material Transport	**1.07E+01**	**3.81E-01**	**7.00E-02**	**1.67E-08**	**1.12E+01**	**5.51E+01**	**1.95E+00**	**3.59E-01**	**8.59E-08**	**5.73E+01**
Torref. Biomass Transp. to CBTL Plant	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biomass Torrefaction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	5.04E-01	2.04E-02	3.37E-03	8.17E-10	4.89E-01	2.58E+00	1.04E-01	1.73E-02	4.19E-09	2.51E+00
Transport of Coal to CBTL Plant	1.02E+01	3.60E-01	6.66E-02	1.59E-08	1.07E+01	5.25E+01	1.85E+00	3.42E-01	8.17E-08	5.48E+01
Energy Conversion Facility	**-2.55E+01**	**-4.41E+00**	**-1.57E-01**	**-8.67E-02**	**-3.61E+01**	**-1.31E+02**	**-2.26E+01**	**-8.06E-01**	**-4.45E-01**	**-1.85E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.50E+01	5.90E-04	1.46E-04	1.33E-05	3.50E+01	1.79E+02	3.03E-03	7.48E-04	6.80E-05	1.79E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.59E+01	-4.47E+00	-1.89E-01	-8.67E-02	-7.71E+01	-3.38E+02	-2.30E+01	-9.71E-01	-4.45E-01	-3.96E+02
CO_2 Transport to CO_2-EOR Operation	5.39E+00	6.85E-02	3.19E-02	0.00E+00	6.01E+00	2.77E+01	3.52E-01	1.64E-01	0.00E+00	3.08E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**1.00E+02**	**7.85E-01**	**3.69E+00**	**-8.24E-02**	**1.02E+02**	**5.15E+02**	**4.03E+00**	**1.89E+01**	**-4.23E-01**	**5.24E+02**

Table B-24: CBTL, 28.3% Pelleted Biomass

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-9.93E+01**	**1.20E+00**	**3.56E+00**	**2.82E-03**	**-9.02E+01**	**-5.09E+02**	**6.14E+00**	**1.83E+01**	**1.45E-02**	**-4.63E+02**
Coal Mining, Surface	1.15E+00	9.66E-01	3.19E-01	8.65E-04	3.50E+00	5.89E+00	4.96E+00	1.64E+00	4.44E-03	1.80E+01
Biomass Production and Field Chipping	-1.13E+02	2.31E-01	3.14E+00	1.96E-03	-1.09E+02	-5.80E+02	1.18E+00	1.61E+01	1.01E-02	-5.57E+02
Biomass Direct Land Use Change	2.69E+00	0.00E+00	0.00E+00	0.00E+00	3.13E+00	1.38E+01	0.00E+00	0.00E+00	0.00E+00	1.61E+01
Biomass Indirect Land Use Change	9.93E+00	0.00E+00	9.61E-02	0.00E+00	1.17E+01	5.09E+01	0.00E+00	4.93E-01	0.00E+00	5.98E+01
Raw Material Transport	**9.93E+00**	**3.54E-01**	**6.48E-02**	**1.55E-08**	**1.03E+01**	**5.09E+01**	**1.81E+00**	**3.32E-01**	**7.96E-08**	**5.29E+01**
Torref. Biomass Transp. to CBTL Plant	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biomass Torrefaction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	7.51E-01	3.03E-02	5.02E-03	1.22E-09	7.29E-01	3.85E+00	1.56E-01	2.58E-02	6.25E-09	3.74E+00
Transport of Coal to CBTL Plant	9.18E+00	3.23E-01	5.98E-02	1.43E-08	9.58E+00	4.71E+01	1.66E+00	3.07E-01	7.33E-08	4.91E+01
Energy Conversion Facility	**-2.63E+01**	**-4.40E+00**	**-1.57E-01**	**-8.67E-02**	**-3.70E+01**	**-1.35E+02**	**-2.26E+01**	**-8.06E-01**	**-4.45E-01**	**-1.90E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.49E+01	5.90E-04	1.46E-04	1.33E-05	3.49E+01	1.79E+02	3.03E-03	7.48E-04	6.80E-05	1.79E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.66E+01	-4.47E+00	-1.89E-01	-8.67E-02	-7.79E+01	-3.42E+02	-2.30E+01	-9.70E-01	-4.45E-01	-4.00E+02
CO_2 Transport to CO_2-EOR Operation	5.39E+00	6.85E-02	3.19E-02	0.00E+00	6.01E+00	2.77E+01	3.51E-01	1.64E-01	0.00E+00	3.08E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**6.56E+01**	**7.24E-01**	**4.71E+00**	**-8.18E-02**	**6.92E+01**	**3.37E+02**	**3.71E+00**	**2.42E+01**	**-4.20E-01**	**3.55E+02**

Table B-25: CBTL, 16.5% Torrefied/Pelleted Biomass

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-5.48E+01**	**1.20E+00**	**2.16E+00**	**2.05E-03**	**-4.85E+01**	**-2.81E+02**	**6.16E+00**	**1.11E+01**	**1.05E-02**	**-2.49E+02**
Coal Mining, Surface	1.27E+00	1.07E+00	3.54E-01	9.59E-04	3.89E+00	6.53E+00	5.50E+00	1.82E+00	4.92E-03	1.99E+01
Biomass Production and Field Chipping	-6.32E+01	1.29E-01	1.76E+00	1.10E-03	-6.06E+01	-3.24E+02	6.61E-01	9.01E+00	5.62E-03	-3.11E+02
Biomass Direct Land Use Change	1.50E+00	0.00E+00	0.00E+00	0.00E+00	1.75E+00	7.71E+00	0.00E+00	0.00E+00	0.00E+00	8.97E+00
Biomass Indirect Land Use Change	5.55E+00	0.00E+00	5.37E-02	0.00E+00	6.52E+00	2.85E+01	0.00E+00	2.76E-01	0.00E+00	3.34E+01
Raw Material Transport	**1.60E+01**	**4.11E-01**	**8.32E-02**	**1.13E-03**	**1.65E+01**	**8.22E+01**	**2.11E+00**	**4.27E-01**	**5.81E-03**	**8.47E+01**
Torref. Biomass Transp. to CBTL Plant	5.39E-01	2.13E-02	3.58E-03	8.83E-10	5.64E-01	2.76E+00	1.09E-01	1.84E-02	4.53E-09	2.90E+00
Biomass Torrefaction	4.88E+00	1.37E-02	1.04E-02	1.13E-03	4.91E+00	2.50E+01	7.05E-02	5.36E-02	5.81E-03	2.52E+01
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	4.19E-01	1.70E-02	2.80E-03	6.81E-10	4.07E-01	2.15E+00	8.70E-02	1.44E-02	3.49E-09	2.09E+00
Transport of Coal to CBTL Plant	1.02E+01	3.59E-01	6.63E-02	1.59E-08	1.06E+01	5.22E+01	1.84E+00	3.40E-01	8.14E-08	5.45E+01
Energy Conversion Facility	**-2.62E+01**	**-4.39E+00**	**-1.56E-01**	**-8.52E-02**	**-3.68E+01**	**-1.34E+02**	**-2.25E+01**	**-8.00E-01**	**-4.37E-01**	**-1.89E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.43E+01	5.90E-04	1.46E-04	1.33E-05	3.43E+01	1.76E+02	3.03E-03	7.48E-04	6.80E-05	1.76E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.58E+01	-4.46E+00	-1.87E-01	-8.52E-02	-7.70E+01	-3.37E+02	-2.29E+01	-9.62E-01	-4.37E-01	-3.95E+02
CO_2 Transport to CO_2-EOR Operation	5.30E+00	6.73E-02	3.13E-02	0.00E+00	5.90E+00	2.72E+01	3.45E-01	1.61E-01	0.00E+00	3.03E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**1.16E+02**	**8.02E-01**	**3.34E+00**	**-8.00E-02**	**1.17E+02**	**5.97E+02**	**4.11E+00**	**1.71E+01**	**-4.10E-01**	**6.02E+02**

Table B-26: CBTL, 19.6% Torrefied/Pelleted Biomass

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-6.53E+01**	**1.18E+00**	**2.49E+00**	**2.22E-03**	**-5.83E+01**	**-3.35E+02**	**6.07E+00**	**1.28E+01**	**1.14E-02**	**-2.99E+02**
Coal Mining, Surface	1.22E+00	1.03E+00	3.40E-01	9.21E-04	3.73E+00	6.27E+00	5.28E+00	1.75E+00	4.73E-03	1.92E+01
Biomass Production and Field Chipping	-7.48E+01	1.53E-01	2.08E+00	1.30E-03	-7.18E+01	-3.84E+02	7.84E-01	1.07E+01	6.66E-03	-3.69E+02
Biomass Direct Land Use Change	1.78E+00	0.00E+00	0.00E+00	0.00E+00	2.07E+00	9.13E+00	0.00E+00	0.00E+00	0.00E+00	1.06E+01
Biomass Indirect Land Use Change	6.57E+00	0.00E+00	6.36E-02	0.00E+00	7.72E+00	3.37E+01	0.00E+00	3.26E-01	0.00E+00	3.96E+01
Raw Material Transport	**1.67E+01**	**4.06E-01**	**8.36E-02**	**1.34E-03**	**1.72E+01**	**8.56E+01**	**2.08E+00**	**4.29E-01**	**6.88E-03**	**8.81E+01**
Torref. Biomass Transp. to CBTL Plant	6.38E-01	2.52E-02	4.24E-03	1.05E-09	6.69E-01	3.27E+00	1.29E-01	2.18E-02	5.37E-09	3.43E+00
Biomass Torrefaction	5.78E+00	1.63E-02	1.24E-02	1.34E-03	5.82E+00	2.96E+01	8.35E-02	6.35E-02	6.88E-03	2.98E+01
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	4.97E-01	2.01E-02	3.32E-03	8.06E-10	4.83E-01	2.55E+00	1.03E-01	1.70E-02	4.14E-09	2.48E+00
Transport of Coal to CBTL Plant	9.78E+00	3.45E-01	6.37E-02	1.52E-08	1.02E+01	5.02E+01	1.77E+00	3.27E-01	7.82E-08	5.24E+01
Energy Conversion Facility	**-2.66E+01**	**-4.39E+00**	**-1.56E-01**	**-8.49E-02**	**-3.73E+01**	**-1.37E+02**	**-2.25E+01**	**-7.99E-01**	**-4.36E-01**	**-1.91E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.41E+01	5.90E-04	1.46E-04	1.33E-05	3.41E+01	1.75E+02	3.03E-03	7.48E-04	6.80E-05	1.75E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.61E+01	-4.45E+00	-1.87E-01	-8.49E-02	-7.73E+01	-3.39E+02	-2.28E+01	-9.60E-01	-4.36E-01	-3.97E+02
CO_2 Transport to CO_2-EOR Operation	5.28E+00	6.71E-02	3.12E-02	0.00E+00	5.88E+00	2.71E+01	3.44E-01	1.60E-01	0.00E+00	3.02E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**1.06E+02**	**7.81E-01**	**3.66E+00**	**-7.93E-02**	**1.08E+02**	**5.44E+02**	**4.01E+00**	**1.88E+01**	**-4.07E-01**	**5.53E+02**

Table B-27: CBTL, 28.3% Torrefied/Pelleted Biomass

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-9.42E+01**	**1.13E+00**	**3.38E+00**	**2.68E-03**	**-8.56E+01**	**-4.83E+02**	**5.80E+00**	**1.73E+01**	**1.37E-02**	**-4.39E+02**
Coal Mining, Surface	1.08E+00	9.12E-01	3.01E-01	8.16E-04	3.31E+00	5.55E+00	4.68E+00	1.55E+00	4.19E-03	1.70E+01
Biomass Production and Field Chipping	-1.07E+02	2.19E-01	2.98E+00	1.86E-03	-1.03E+02	-5.50E+02	1.12E+00	1.53E+01	9.54E-03	-5.28E+02
Biomass Direct Land Use Change	2.55E+00	0.00E+00	0.00E+00	0.00E+00	2.97E+00	1.31E+01	0.00E+00	0.00E+00	0.00E+00	1.52E+01
Biomass Indirect Land Use Change	9.42E+00	0.00E+00	9.12E-02	0.00E+00	1.11E+01	4.83E+01	0.00E+00	4.68E-01	0.00E+00	5.68E+01
Raw Material Transport	**1.86E+01**	**3.93E-01**	**8.50E-02**	**1.92E-03**	**1.90E+01**	**9.53E+01**	**2.02E+00**	**4.36E-01**	**9.87E-03**	**9.76E+01**
Torref. Biomass Transp. to CBTL Plant	9.15E-01	3.62E-02	6.08E-03	1.50E-09	9.59E-01	4.69E+00	1.85E-01	3.12E-02	7.69E-09	4.92E+00
Biomass Torrefaction	8.28E+00	2.33E-02	1.77E-02	1.92E-03	8.34E+00	4.25E+01	1.20E-01	9.10E-02	9.87E-03	4.28E+01
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	7.12E-01	2.88E-02	4.76E-03	1.16E-09	6.92E-01	3.65E+00	1.48E-01	2.44E-02	5.93E-09	3.55E+00
Transport of Coal to CBTL Plant	8.66E+00	3.05E-01	5.64E-02	1.35E-08	9.04E+00	4.44E+01	1.57E+00	2.89E-01	6.92E-08	4.64E+01
Energy Conversion Facility	**-2.80E+01**	**-4.38E+00**	**-1.55E-01**	**-8.41E-02**	**-3.82E+01**	**-1.44E+02**	**-2.25E+01**	**-7.96E-01**	**-4.32E-01**	**-1.96E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.37E+01	5.90E-04	1.46E-04	1.33E-05	3.37E+01	1.73E+02	3.03E-03	7.48E-04	6.80E-05	1.73E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.69E+01	-4.44E+00	-1.86E-01	-8.42E-02	-7.77E+01	-3.43E+02	-2.28E+01	-9.55E-01	-4.32E-01	-3.99E+02
CO_2 Transport to CO_2-EOR Operation	5.23E+00	6.65E-02	3.10E-02	0.00E+00	5.83E+00	2.69E+01	3.41E-01	1.59E-01	0.00E+00	2.99E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**7.76E+01**	**7.26E-01**	**4.55E+00**	**-7.75E-02**	**8.14E+01**	**3.98E+02**	**3.72E+00**	**2.33E+01**	**-3.98E-01**	**4.17E+02**

Table B-28: CBTL, 11.7% Pelleted Biomass, Validated

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-3.94E+01**	**1.26E+00**	**1.70E+00**	**1.84E-03**	**-3.38E+01**	**-2.02E+02**	**6.47E+00**	**8.73E+00**	**9.45E-03**	**-1.73E+02**
Coal Mining, Surface	1.39E+00	1.17E+00	3.86E-01	1.05E-03	4.24E+00	7.12E+00	5.99E+00	1.98E+00	5.36E-03	2.17E+01
Biomass Production and Field Chipping	-4.59E+01	9.37E-02	1.28E+00	7.96E-04	-4.40E+01	-2.35E+02	4.80E-01	6.55E+00	4.08E-03	-2.26E+02
Biomass Direct Land Use Change	1.09E+00	0.00E+00	0.00E+00	0.00E+00	1.27E+00	5.60E+00	0.00E+00	0.00E+00	0.00E+00	6.52E+00
Biomass Indirect Land Use Change	4.03E+00	0.00E+00	3.90E-02	0.00E+00	4.73E+00	2.07E+01	0.00E+00	2.00E-01	0.00E+00	2.43E+01
Raw Material Transport	**1.14E+01**	**4.03E-01**	**7.43E-02**	**1.78E-08**	**1.19E+01**	**5.85E+01**	**2.07E+00**	**3.81E-01**	**9.12E-08**	**6.09E+01**
Torref. Biomass Transp. to CBTL Plant	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biomass Torrefaction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	3.05E-01	1.23E-02	2.04E-03	4.94E-10	2.96E-01	1.56E+00	6.32E-02	1.05E-02	2.54E-09	1.52E+00
Transport of Coal to CBTL Plant	1.11E+01	3.91E-01	7.23E-02	1.73E-08	1.16E+01	5.69E+01	2.01E+00	3.71E-01	8.87E-08	5.94E+01
Energy Conversion Facility	**-2.55E+01**	**-4.41E+00**	**-1.58E-01**	**-8.73E-02**	**-3.60E+01**	**-1.31E+02**	**-2.26E+01**	**-8.08E-01**	**-4.48E-01**	**-1.85E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.44E+01	5.90E-04	1.46E-04	1.33E-05	3.44E+01	1.77E+02	3.03E-03	7.48E-04	6.80E-05	1.77E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.54E+01	-4.48E+00	-1.90E-01	-8.73E-02	-7.65E+01	-3.36E+02	-2.30E+01	-9.74E-01	-4.48E-01	-3.92E+02
CO_2 Transport to CO_2-EOR Operation	5.43E+00	6.89E-02	3.21E-02	0.00E+00	6.04E+00	2.78E+01	3.54E-01	1.65E-01	0.00E+00	3.10E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**1.28E+02**	**8.32E-01**	**2.86E+00**	**-8.34E-02**	**1.28E+02**	**6.56E+02**	**4.27E+00**	**1.47E+01**	**-4.28E-01**	**6.58E+02**

Table B-29: CBTL, 19.2% Pelleted Biomass, Validated

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-6.62E+01**	**1.23E+00**	**2.53E+00**	**2.28E-03**	**-5.91E+01**	**-3.40E+02**	**6.33E+00**	**1.30E+01**	**1.17E-02**	**-3.03E+02**
Coal Mining, Surface	1.28E+00	1.08E+00	3.57E-01	9.65E-04	3.91E+00	6.57E+00	5.53E+00	1.83E+00	4.95E-03	2.01E+01
Biomass Production and Field Chipping	-7.60E+01	1.55E-01	2.11E+00	1.32E-03	-7.29E+01	-3.90E+02	7.96E-01	1.08E+01	6.76E-03	-3.74E+02
Biomass Direct Land Use Change	1.81E+00	0.00E+00	0.00E+00	0.00E+00	2.10E+00	9.28E+00	0.00E+00	0.00E+00	0.00E+00	1.08E+01
Biomass Indirect Land Use Change	6.67E+00	0.00E+00	6.46E-02	0.00E+00	7.84E+00	3.42E+01	0.00E+00	3.32E-01	0.00E+00	4.02E+01
Raw Material Transport	**1.08E+01**	**3.81E-01**	**7.01E-02**	**1.68E-08**	**1.12E+01**	**5.52E+01**	**1.96E+00**	**3.60E-01**	**8.61E-08**	**5.74E+01**
Torref. Biomass Transp. to CBTL Plant	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biomass Torrefaction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	5.05E-01	2.04E-02	3.37E-03	8.19E-10	4.90E-01	2.59E+00	1.05E-01	1.73E-02	4.20E-09	2.52E+00
Transport of Coal to CBTL Plant	1.02E+01	3.61E-01	6.68E-02	1.60E-08	1.07E+01	5.26E+01	1.85E+00	3.42E-01	8.19E-08	5.49E+01
Energy Conversion Facility	**-2.61E+01**	**-4.41E+00**	**-1.58E-01**	**-8.72E-02**	**-3.67E+01**	**-1.34E+02**	**-2.26E+01**	**-8.08E-01**	**-4.48E-01**	**-1.88E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.44E+01	5.90E-04	1.46E-04	1.33E-05	3.44E+01	1.76E+02	3.03E-03	7.48E-04	6.80E-05	1.76E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.59E+01	-4.48E+00	-1.90E-01	-8.72E-02	-7.71E+01	-3.38E+02	-2.30E+01	-9.74E-01	-4.48E-01	-3.96E+02
CO_2 Transport to CO_2-EOR Operation	5.43E+00	6.89E-02	3.21E-02	0.00E+00	6.04E+00	2.78E+01	3.54E-01	1.65E-01	0.00E+00	3.10E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**9.97E+01**	**7.83E-01**	**3.69E+00**	**-8.29E-02**	**1.02E+02**	**5.11E+02**	**4.02E+00**	**1.89E+01**	**-4.25E-01**	**5.21E+02**

Table B-30: CBTL, 28.3% Pelleted Biomass, Validated

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-9.95E+01**	**1.20E+00**	**3.57E+00**	**2.83E-03**	**-9.04E+01**	**-5.10E+02**	**6.15E+00**	**1.83E+01**	**1.45E-02**	**-4.64E+02**
Coal Mining, Surface	1.15E+00	9.68E-01	3.20E-01	8.66E-04	3.51E+00	5.90E+00	4.97E+00	1.64E+00	4.44E-03	1.80E+01
Biomass Production and Field Chipping	-1.13E+02	2.31E-01	3.15E+00	1.96E-03	-1.09E+02	-5.81E+02	1.19E+00	1.62E+01	1.01E-02	-5.58E+02
Biomass Direct Land Use Change	2.69E+00	0.00E+00	0.00E+00	0.00E+00	3.14E+00	1.38E+01	0.00E+00	0.00E+00	0.00E+00	1.61E+01
Biomass Indirect Land Use Change	9.95E+00	0.00E+00	9.63E-02	0.00E+00	1.17E+01	5.10E+01	0.00E+00	4.94E-01	0.00E+00	6.00E+01
Raw Material Transport	**9.95E+00**	**3.54E-01**	**6.49E-02**	**1.55E-08**	**1.03E+01**	**5.10E+01**	**1.82E+00**	**3.33E-01**	**7.98E-08**	**5.30E+01**
Torref. Biomass Transp. to CBTL Plant	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Biomass Torrefaction	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	7.52E-01	3.04E-02	5.03E-03	1.22E-09	7.31E-01	3.86E+00	1.56E-01	2.58E-02	6.26E-09	3.75E+00
Transport of Coal to CBTL Plant	9.20E+00	3.24E-01	5.99E-02	1.43E-08	9.60E+00	4.72E+01	1.66E+00	3.07E-01	7.35E-08	4.92E+01
Energy Conversion Facility	**-2.70E+01**	**-4.41E+00**	**-1.57E-01**	**-8.72E-02**	**-3.76E+01**	**-1.38E+02**	**-2.26E+01**	**-8.08E-01**	**-4.47E-01**	**-1.93E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.43E+01	5.90E-04	1.46E-04	1.33E-05	3.43E+01	1.76E+02	3.03E-03	7.48E-04	6.80E-05	1.76E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.67E+01	-4.48E+00	-1.90E-01	-8.72E-02	-7.80E+01	-3.42E+02	-2.30E+01	-9.73E-01	-4.47E-01	-4.00E+02
CO_2 Transport to CO_2-EOR Operation	5.42E+00	6.89E-02	3.21E-02	0.00E+00	6.04E+00	2.78E+01	3.53E-01	1.65E-01	0.00E+00	3.10E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**6.48E+01**	**7.21E-01**	**4.72E+00**	**-8.23E-02**	**6.84E+01**	**3.33E+02**	**3.70E+00**	**2.42E+01**	**-4.22E-01**	**3.51E+02**

Table B-31: CBTL, 16.5% Torrefied/Pelleted Biomass, Validated

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-5.49E+01**	**1.20E+00**	**2.17E+00**	**2.06E-03**	**-4.86E+01**	**-2.82E+02**	**6.17E+00**	**1.11E+01**	**1.06E-02**	**-2.49E+02**
Coal Mining, Surface	1.28E+00	1.07E+00	3.55E-01	9.61E-04	3.89E+00	6.54E+00	5.51E+00	1.82E+00	4.93E-03	2.00E+01
Biomass Production and Field Chipping	-6.33E+01	1.29E-01	1.76E+00	1.10E-03	-6.07E+01	-3.25E+02	6.63E-01	9.03E+00	5.63E-03	-3.12E+02
Biomass Direct Land Use Change	1.51E+00	0.00E+00	0.00E+00	0.00E+00	1.75E+00	7.72E+00	0.00E+00	0.00E+00	0.00E+00	8.99E+00
Biomass Indirect Land Use Change	5.56E+00	0.00E+00	5.38E-02	0.00E+00	6.53E+00	2.85E+01	0.00E+00	2.76E-01	0.00E+00	3.35E+01
Raw Material Transport	**1.60E+01**	**4.11E-01**	**8.33E-02**	**1.13E-03**	**1.65E+01**	**8.23E+01**	**2.11E+00**	**4.27E-01**	**5.82E-03**	**8.49E+01**
Torref. Biomass Transp. to CBTL Plant	5.40E-01	2.13E-02	3.59E-03	8.84E-10	5.66E-01	2.77E+00	1.09E-01	1.84E-02	4.54E-09	2.90E+00
Biomass Torrefaction	4.89E+00	1.38E-02	1.05E-02	1.13E-03	4.92E+00	2.51E+01	7.06E-02	5.37E-02	5.82E-03	2.52E+01
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	4.20E-01	1.70E-02	2.81E-03	6.82E-10	4.08E-01	2.16E+00	8.71E-02	1.44E-02	3.50E-09	2.09E+00
Transport of Coal to CBTL Plant	1.02E+01	3.59E-01	6.65E-02	1.59E-08	1.06E+01	5.23E+01	1.84E+00	3.41E-01	8.15E-08	5.46E+01
Energy Conversion Facility	**-2.68E+01**	**-4.39E+00**	**-1.56E-01**	**-8.57E-02**	**-3.73E+01**	**-1.37E+02**	**-2.25E+01**	**-8.02E-01**	**-4.40E-01**	**-1.92E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.37E+01	5.90E-04	1.46E-04	1.33E-05	3.37E+01	1.73E+02	3.03E-03	7.48E-04	6.80E-05	1.73E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.58E+01	-4.46E+00	-1.88E-01	-8.57E-02	-7.70E+01	-3.38E+02	-2.29E+01	-9.64E-01	-4.40E-01	-3.95E+02
CO_2 Transport to CO_2-EOR Operation	5.33E+00	6.77E-02	3.15E-02	0.00E+00	5.94E+00	2.74E+01	3.47E-01	1.62E-01	0.00E+00	3.05E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**1.16E+02**	**7.99E-01**	**3.34E+00**	**-8.05E-02**	**1.17E+02**	**5.93E+02**	**4.10E+00**	**1.71E+01**	**-4.13E-01**	**5.99E+02**

Table B-32: CBTL, 19.6% Torrefied/Pelleted Biomass, Validated

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-6.54E+01**	**1.18E+00**	**2.49E+00**	**2.22E-03**	**-5.84E+01**	**-3.35E+02**	**6.08E+00**	**1.28E+01**	**1.14E-02**	**-3.00E+02**
Coal Mining, Surface	1.23E+00	1.03E+00	3.41E-01	9.23E-04	3.74E+00	6.28E+00	5.29E+00	1.75E+00	4.74E-03	1.92E+01
Biomass Production and Field Chipping	-7.50E+01	1.53E-01	2.09E+00	1.30E-03	-7.20E+01	-3.85E+02	7.85E-01	1.07E+01	6.67E-03	-3.69E+02
Biomass Direct Land Use Change	1.78E+00	0.00E+00	0.00E+00	0.00E+00	2.08E+00	9.15E+00	0.00E+00	0.00E+00	0.00E+00	1.07E+01
Biomass Indirect Land Use Change	6.58E+00	0.00E+00	6.38E-02	0.00E+00	7.74E+00	3.38E+01	0.00E+00	3.27E-01	0.00E+00	3.97E+01
Raw Material Transport	**1.67E+01**	**4.07E-01**	**8.38E-02**	**1.34E-03**	**1.72E+01**	**8.58E+01**	**2.09E+00**	**4.30E-01**	**6.90E-03**	**8.83E+01**
Torref. Biomass Transp. to CBTL Plant	6.39E-01	2.53E-02	4.25E-03	1.05E-09	6.70E-01	3.28E+00	1.30E-01	2.18E-02	5.38E-09	3.44E+00
Biomass Torrefaction	5.79E+00	1.63E-02	1.24E-02	1.34E-03	5.83E+00	2.97E+01	8.37E-02	6.36E-02	6.90E-03	2.99E+01
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	4.98E-01	2.01E-02	3.33E-03	8.08E-10	4.84E-01	2.55E+00	1.03E-01	1.71E-02	4.15E-09	2.48E+00
Transport of Coal to CBTL Plant	9.80E+00	3.45E-01	6.38E-02	1.53E-08	1.02E+01	5.03E+01	1.77E+00	3.27E-01	7.83E-08	5.25E+01
Energy Conversion Facility	**-2.73E+01**	**-4.39E+00**	**-1.56E-01**	**-8.54E-02**	**-3.79E+01**	**-1.40E+02**	**-2.25E+01**	**-8.01E-01**	**-4.38E-01**	**-1.94E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.35E+01	5.90E-04	1.46E-04	1.33E-05	3.36E+01	1.72E+02	3.03E-03	7.48E-04	6.80E-05	1.72E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.61E+01	-4.46E+00	-1.88E-01	-8.54E-02	-7.74E+01	-3.39E+02	-2.29E+01	-9.63E-01	-4.38E-01	-3.97E+02
CO_2 Transport to CO_2-EOR Operation	5.31E+00	6.75E-02	3.14E-02	0.00E+00	5.92E+00	2.73E+01	3.46E-01	1.61E-01	0.00E+00	3.04E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**1.05E+02**	**7.79E-01**	**3.66E+00**	**-7.98E-02**	**1.07E+02**	**5.41E+02**	**4.00E+00**	**1.88E+01**	**-4.09E-01**	**5.49E+02**

Table B-33: CBTL, 28.3% Torrefied/Pelleted Biomass, Validated

LC Stage or Substage	GHG Emissions (lb CO_2e/MMBtu LHV) (2007 100-year GWP)					GHG Emissions (lb CO_2e/bbl) (2007 100-year GWP)				
	CO_2	CH_4	N_2O	SF_6	Total	CO_2	CH_4	N_2O	SF_6	Total
Raw Material Acquisition	**-9.44E+01**	**1.13E+00**	**3.38E+00**	**2.68E-03**	**-8.58E+01**	**-4.84E+02**	**5.81E+00**	**1.74E+01**	**1.38E-02**	**-4.40E+02**
Coal Mining, Surface	1.08E+00	9.13E-01	3.02E-01	8.17E-04	3.31E+00	5.56E+00	4.69E+00	1.55E+00	4.19E-03	1.70E+01
Biomass Production and Field Chipping	-1.07E+02	2.19E-01	2.99E+00	1.86E-03	-1.03E+02	-5.51E+02	1.13E+00	1.53E+01	9.56E-03	-5.29E+02
Biomass Direct Land Use Change	2.56E+00	0.00E+00	0.00E+00	0.00E+00	2.98E+00	1.31E+01	0.00E+00	0.00E+00	0.00E+00	1.53E+01
Biomass Indirect Land Use Change	9.44E+00	0.00E+00	9.14E-02	0.00E+00	1.11E+01	4.84E+01	0.00E+00	4.69E-01	0.00E+00	5.69E+01
Raw Material Transport	**1.86E+01**	**3.94E-01**	**8.51E-02**	**1.93E-03**	**1.91E+01**	**9.54E+01**	**2.02E+00**	**4.37E-01**	**9.89E-03**	**9.78E+01**
Torref. Biomass Transp. to CBTL Plant	9.17E-01	3.62E-02	6.09E-03	1.50E-09	9.61E-01	4.70E+00	1.86E-01	3.13E-02	7.71E-09	4.93E+00
Biomass Torrefaction	8.30E+00	2.34E-02	1.78E-02	1.93E-03	8.36E+00	4.26E+01	1.20E-01	9.11E-02	9.89E-03	4.29E+01
Transport of Chipped Biomass to Torrf. Facility or CBTL Plant	7.14E-01	2.88E-02	4.77E-03	1.16E-09	6.93E-01	3.66E+00	1.48E-01	2.45E-02	5.94E-09	3.56E+00
Transport of Coal to CBTL Plant	8.68E+00	3.06E-01	5.65E-02	1.35E-08	9.05E+00	4.45E+01	1.57E+00	2.90E-01	6.93E-08	4.65E+01
Energy Conversion Facility	**-2.86E+01**	**-4.38E+00**	**-1.55E-01**	**-8.46E-02**	**-3.94E+01**	**-1.47E+02**	**-2.25E+01**	**-7.98E-01**	**-4.34E-01**	**-2.02E+02**
Plant Construction & Operations (inc. CO_2 Compression)	3.31E+01	5.90E-04	1.46E-04	1.33E-05	3.31E+01	1.70E+02	3.03E-03	7.48E-04	6.80E-05	1.70E+02
Co-product Displacement (CO_2, Naptha, LPG, Diesel, Electricity)	-6.70E+01	-4.45E+00	-1.87E-01	-8.46E-02	-7.84E+01	-3.44E+02	-2.28E+01	-9.58E-01	-4.34E-01	-4.02E+02
CO_2 Transport to CO_2-EOR Operation	5.26E+00	6.69E-02	3.11E-02	0.00E+00	5.86E+00	2.70E+01	3.43E-01	1.60E-01	0.00E+00	3.01E+01
Product Transport	**1.34E+01**	**3.54E+00**	**7.45E-02**	**2.04E-03**	**1.71E+01**	**6.89E+01**	**1.82E+01**	**3.82E-01**	**1.05E-02**	**8.76E+01**
Transp. of Blended J-F to Airport	2.65E-01	1.58E-02	1.32E-03	1.36E-03	3.17E-01	1.36E+00	8.10E-02	6.79E-03	7.00E-03	1.63E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.30E+01	3.52E+00	7.26E-02	7.06E-05	1.66E+01	6.69E+01	1.81E+01	3.72E-01	3.62E-04	8.53E+01
Transport of F-T Jet to Blending Facility	1.19E-01	7.07E-03	6.00E-04	6.09E-04	1.28E-01	6.12E-01	3.63E-02	3.08E-03	3.12E-03	6.54E-01
End Use	**1.68E+02**	**3.72E-02**	**1.17E+00**	**1.25E-10**	**1.69E+02**	**8.61E+02**	**1.91E-01**	**6.00E+00**	**6.42E-10**	**8.67E+02**
Airplane Operation (Fuel Use)	1.68E+02	3.31E-02	1.17E+00	0.00E+00	1.69E+02	8.61E+02	1.70E-01	5.99E+00	0.00E+00	8.67E+02
Airplane Construction	6.43E-02	4.12E-03	2.61E-04	1.25E-10	6.87E-02	3.30E-01	2.12E-02	1.34E-03	6.42E-10	3.52E-01
Total	**7.69E+01**	**7.23E-01**	**4.56E+00**	**-7.80E-02**	**8.00E+01**	**3.95E+02**	**3.71E+00**	**2.34E+01**	**-4.00E-01**	**4.10E+02**

Appendix C: Detailed Description of Validation Method

Experimental data from a series of 14 runs (or steady state periods) involving the NCCC gasifier was used to develop a generalized Aspen Plus® model of the NCCC gasifier. Compositions and physical properties of these fuel feedstocks are presented in **Table C-1** below.

Table C-1: Fuel properties

	PRB Coal	Torrified Biomass	Raw Biomass
Proximate Analysis, dry basis (wt%)			
Fixed Carbon	35.07	30.02	21.69
Volatile Matter	56.16	68.15	77.05
Ash	8.77	1.83	1.26
Total	100.00	100.00	100.00
Ultimate Analysis, dry basis (wt%)			
Ash	8.77	1.83	1.26
Carbon	69.07	60.06	51.71
Hydrogen	4.60	5.52	6.05
Nitrogen	1.18	0.30	0.02
Chlorine	0.00	0.00	0.00
Sulfur	0.29	0.01	0.06
Oxygen	16.09	32.28	40.92
Total	100.00	100.00	100.00
Heat of Combustion, dry basis			
Btu/lb	11,888	10,098	8,609
Moisture Content, as fed (wt%)			
Moisture	18.00	7.82	7.98

For all 14 test runs, the flowrates of solid fuel, air, oxygen, and steam were reported. Gasifier temperature, pressure, carbon conversion, syngas flowrate, and syngas composition were also reported for each run. For each of the test runs, the flowrate of ash was calculated assuming 100 percent ash recovery and containing only unreacted carbon. The flowrate of transport nitrogen was calculated by difference for each run so that the total feed stream mass flowrates were equal to the total of product stream mass flowrates.

The runs were grouped into eight different cases based on the feedstocks. Case 1 used coal only and consisted of an average of the data for R08-01 steady state period 37 and R08-02 steady state period 38. Case 2 used approximately 16.5 percent torrefied biomass and consisted of the average of data from R08-03 steady state periods 39 and 40. Case 3 used approximately 19.6 percent torrefied biomass and consisted of the average of data from R08-04 steady state periods 41 and 42. Case 4

used approximately 28.3 percent torrefied biomass and consisted of the data from R08-05 steady state period 43. Case 5 was coal only and consisted of the data from R08-06 steady state period 44. Case 6 used approximately 11.7 percent raw biomass and consisted of the data from R08-07 steady state period 45. Case 7 used approximately 19.2 percent raw biomass and consisted of the data from R08-08 steady state period 46. Case 8 used approximately 28.3 percent raw biomass and consisted of the data from R08-09 steady state period 47.

From this provided information, a set of chemical equilibrium reaction temperature approaches was developed for each case to calculate raw syngas compositions that best matched the reported syngas compositions.

The equilibrium reaction temperature approaches relate to the water gas shift reaction

$$H_2O + CO = CO_2 + H_2$$

and the methanation reaction

$$3H_2 + CO = CH_4 + H_2O$$

which are the primary chemical reactions in the gasifier that determine the relative amounts of CH_4, CO, CO_2, H_2O and H_2 in the syngas product.

The “best match” was considered to be identical ratios of CH_4:H_2 and CO_2:CO in both the calculated syngas and reported syngas stream. By energy balance, the gasifier heat loss for each case was calculated based on the calculated syngas composition and feed stream flowrates. **Table C-3** displays the reported feed stream flowrates, gasifier temperatures, and carbon conversions for each of the eight cases. The observed syngas compositions are compared against the calculated compositions for each case in **Table C-3**. Also reported in **Table C-3** is the calculated heat loss for each of the eight cases, expressed both in terms of MMBtu/hr and as a percentage of fuel heating value. All observed values in **Table C-3** are shown in black font, and calculated values are shown in blue.

While the observed and calculated syngas compositions in **Table C-3** agree reasonably well for all cases, there is significant variation in the calculated temperature approaches between each of the cases – particularly with respect to the shift reaction. For a given gasifier configuration, those temperature approaches might be expected to be similar for all cases.

The calculated values of **Table C-3** were re-calculated, in **Table C-4**, using uniform temperature approaches for the eight cases for the shift and methanation reactions. The observed and calculated compositions of syngas might still be considered to agree reasonably well when using the uniform temperature approaches. However, there is considerable variation in heat loss between cases; heat loss would be expected to remain relatively constant among cases.

Syngas compositions were again re-calculated in **Table C-5**. In this calculation, temperature was set to 1,700 °F, carbon conversion was set to 98.2 percent, and heat loss was set to 4 percent of fuel heating value in all cases. Still with reasonable agreement with reported syngas compositions in each case, the gasifier model parameters used in the calculation of **Table C-5** are proposed for future modeling of this gasifier at the given operating conditions. Those parameters are summarized in **Table C-2** below.

Table C-2: Proposed Gasifier Modeling Parameters

Gasifier Parameter	Value
Temperature (°F)	1,700
Carbon Conversion	98.2
Shift Reaction Temperature Approach	25 °F
Methanation Reaction Temperature Approach	-470 °F
Heat Loss (% of fuel heating value)	4.0

Table C-3: Comparison of Reported vs. Calculated Syngas Compositions

	Case 1		Case 2		Case 3		Case 4		Case 5		Case 6		Case 7		Case 8	
Coal Flow (lb/hr)	3,607		3,302		3,259		3,201		3,400		3,552		3,386		2,784	
Torr. Biomass Flow (lb/hr)	0		652		795		1,288		0		0		0		0	
Raw Biomass Flow (lb/hr)	0		0		0		0		0		472		835		1,100	
N_2 Addition (lb/hr)	6,419		9,143		7,502		7,447		5,432		7,612		8,365		7,677	
N_2:Solids ratio	1.78		2.31		1.85		1.66		1.60		1.89		1.98		1.98	
Air Addition (lb/hr)	2,982		3,216		3,251		3,224		3,007		3,013		3,121		3,064	
Air:Solids ratio	0.827		0.813		0.802		0.718		0.884		0.749		0.739		0.789	
Oxygen Flow (lb/hr)	2,260		2,395		2,379		2,544		2,293		2,371		2,357		2,231	
Steam Flow (lb/hr)	4,331		4,558		4,515		4,583		4,399		4,519		4,485		4,594	
Gasifier Temperature (°F)	1,707		1,699		1,698		1,699		1,696		1,701		1,708		1,692	
Carbon Conversion (%)	98.3		98.2		98.4		98.2		98.0		98.5		98.0		98.2	
Temp Approach Shift Rxn	156.8		-11.3		-13.3		37.6		245.0		48.0		29.3		145.2	
Temp Approach Meth Rxn	-469.7		-476.8		-464.1		-460.8		-480.0		-477.6		-489.4		-508.6	
Heat Loss (MMBtu/hr)	2.36		1.68		2.15		2.30		3.69		1.85		1.45		1.91	
Heat Loss (% of Fuel HV)	6.71		4.39		5.49		5.32		11.13		4.82		3.66		5.33	
Syngas Mole Fractions	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd
H_2	11.7	10.8	10.8	10.4	12.0	11.4	12.9	11.8	11.5	9.9	11.2	10.9	11.0	10.8	10.4	9.4
CO	7.4	7.6	6.4	6.3	7.4	7.1	8.6	8.1	7.1	7.1	7.2	7.1	7.2	7.0	6.5	6.2
CH_4	1.3	1.2	1.4	1.3	1.6	1.5	2.0	1.8	1.3	1.1	1.6	1.6	1.7	1.7	1.8	1.6
CO_2	11.6	12.0	11.9	11.8	13.0	12.5	13.4	12.7	12.5	12.5	12.4	12.2	12.3	12.0	12.4	11.8
N_2	36.8	38.8	41.6	44.2	38.8	40.4	36.2	38.9	39.3	36.5	38.2	40.4	37.4	42.0	37.6	41.1
H_2O	31.2	29.5	27.8	25.9	27.2	27.0	26.8	26.6	28.3	32.9	29.3	27.7	30.3	26.6	31.3	29.8
Total	100.0	99.9	99.9	99.9	100.0	99.9	99.9	99.9	100.0	100.0	99.9	99.9	99.9	100.1	99.9	99.9

Table C-4: Comparison of Syngas Compositions using Uniform Temperature Approaches

	Case 1		Case 2		Case 3		Case 4		Case 5		Case 6		Case 7		Case 8	
Coal Flow (lb/hr)	3,607		3,302		3,259		3,201		3,400		3,552		3,386		2,784	
Torr. Biomass Flow (lb/hr)	0		652		795		1,288		0		0		0		0	
Raw Biomass Flow (lb/hr)	0		0		0		0		0		472		835		1,100	
N_2 Addition (lb/hr)	6,419		9,143		7,502		7,447		5,432		7,612		8,365		7,677	
N_2:Solids ratio	1.78		2.31		1.85		1.66		1.60		1.89		1.98		1.98	
Air Addition (lb/hr)	2,982		3,216		3,251		3,224		3,007		3,013		3,121		3,064	
Air:Solids ratio	0.827		0.813		0.802		0.718		0.884		0.749		0.739		0.789	
Oxygen Flow (lb/hr)	2,260		2,395		2,379		2,544		2,293		2,371		2,357		2,231	
Steam Flow (lb/hr)	4,331		4,558		4,515		4,583		4,399		4,519		4,485		4,594	
Gasifier Temperature (°F)	1,707		1,699		1,698		1,699		1,696		1,701		1,708		1,692	
Carbon Conversion (%)	98.3		98.2		98.4		98.2		98.0		98.5		98.0		98.2	
Temp Approach Shift Rxn	25		25		25		25		25		25		25		25	
Temp Approach Meth Rxn	-470		-470		-470		-470		-470		-470		-470		-470	
Heat Loss (MMBtu/hr)	2.47		1.25		1.81		1.75		3.77		1.24		0.28		0.37	
Heat Loss (% of Fuel HV)	7.02		3.27		4.62		4.05		11.37		3.23		0.71		1.03	
Syngas Mole Fractions	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd
H_2	11.7	11.2	10.8	10.6	12.0	11.2	12.9	11.7	11.5	10.7	11.2	11.4	11.0	11.6	10.4	11.1
CO	7.4	7.0	6.4	6.7	7.4	7.3	8.6	8.1	7.1	6.3	7.2	7.4	7.2	7.8	6.5	6.9
CH_4	1.3	1.3	1.4	1.3	1.6	1.7	2.0	2.1	1.3	1.1	1.6	1.7	1.7	1.7	1.8	1.7
CO_2	11.6	12.6	11.9	11.5	13.0	12.3	13.4	12.7	12.5	13.3	12.4	12.2	12.3	11.7	12.4	12.0
N_2	36.8	38.9	41.6	44.2	38.8	40.5	36.2	39.1	39.3	36.5	38.2	40.4	37.4	42.0	37.6	41.0
H_2O	31.2	29.0	27.8	25.7	27.2	26.9	26.8	26.2	28.3	32.0	29.3	26.9	30.3	25.2	31.3	27.3
Total	100.0	100.0	99.9	100.0	100.0	99.9	99.9	99.9	100.0	99.9	99.9	100.0	99.9	100.0	99.9	100.0

Table C-5: Comparison of Syngas Compositions using Uniform Gasifier Parameters

	Case 1		Case 2		Case 3		Case 4		Case 5		Case 6		Case 7		Case 8	
Coal Flow (lb/hr)	3,607		3,302		3,259		3,201		3,400		3,552		3,386		2,784	
Torr. Biomass Flow (lb/hr)	0		652		795		1,288		0		0		0		0	
Raw Biomass Flow (lb/hr)	0		0		0		0		0		472		835		1,100	
N_2 Addition (lb/hr)	6,419		9,143		7,502		7,447		5,432		7,612		8,365		7,677	
N_2:Solids ratio	1.78		2.31		1.85		1.66		1.60		1.89		1.98		1.98	
Air Addition (lb/hr)	2,982		3,216		3,251		3,224		3,007		3,013		3,121		3,064	
Air:Solids ratio	0.827		0.813		0.802		0.718		0.884		0.749		0.739		0.789	
Oxygen Flow (lb/hr)	2,260		2,395		2,379		2,544		2,293		2,371		2,357		2,231	
Steam Flow (lb/hr)	4,331		4,558		4,515		4,583		4,399		4,519		4,485		4,594	
Gasifier Temperature (°F)	1,700		1,700		1,700		1,700		1,700		1,700		1,700		1,700	
Carbon Conversion (%)	98.2		98.2		98.2		98.2		98.2		98.2		98.2		98.2	
Temp Approach Shift Rxn	25		25		25		25		25		25		25		25	
Temp Approach Meth Rxn	-470		-470		-470		-470		-470		-470		-470		-470	
Heat Loss (MMBtu/hr)	1.41		1.53		1.57		1.73		1.33		1.53		1.59		1.43	
Heat Loss (% of Fuel HV)	4.00		4.00		4.00		4.00		4.00		4.00		4.00		4.00	
Syngas Mole Fractions	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd
H_2	11.7	11.6	10.8	10.5	12.0	11.4	12.9	11.8	11.5	11.9	11.2	11.3	11.0	11.0	10.4	10.9
CO	7.4	7.1	6.4	6.6	7.4	7.3	8.6	8.0	7.1	6.9	7.2	7.1	7.2	7.1	6.5	6.4
CH_4	1.3	1.6	1.4	1.2	1.6	1.7	2.0	2.1	1.3	1.6	1.6	1.6	1.7	1.5	1.8	1.2
CO_2	11.6	12.2	11.9	11.5	13.0	12.2	13.4	12.6	12.5	12.4	12.4	12.1	12.3	12.0	12.4	11.9
N_2	36.8	39.1	41.6	44.1	38.8	40.5	36.2	39.1	39.3	36.8	38.2	40.4	37.4	41.9	37.6	40.8
H_2O	31.2	28.3	27.8	26.0	27.2	26.9	26.8	26.3	28.3	30.3	29.3	27.4	30.3	26.5	31.3	28.8
Total	100.0	99.9	99.9	99.9	100.0	100.0	99.9	99.9	100.0	99.9	99.9	99.9	99.9	100.0	99.9	100.0

Additional modeling parameters that remain to be determined include:

1. Ratio of transport nitrogen flowrate to solids flowrate
2. Ratio of air flowrate to solids flowrate
3. Ratio of steam flowrate to solids flowrate

These parameters can be adjusted as needed to meet design objectives of the raw syngas. For example, the ratio of transport nitrogen to solids flow is likely determined by flowability of the solids. The flowrate of air can be adjusted to achieve a desired nitrogen concentration in the syngas or volumetric flowrate of syngas; the flowrate of oxygen is then determined by energy balance. Simultaneously, the flowrate of steam to the gasifier can be adjusted to achieve a target concentration or ratio of CO and CO_2.

As a final step of the validation, the validated model using the parameters from Table C-2 was used to calculate syngas compositions for each of the 14 individual steady state periods provided. The observed syngas compositions are compared against the calculated compositions for each test case in Table C-6 and Table C-7.

Table C-6: Comparison of Reported vs. Calculated Syngas Compositions

	Period 34		Period 35		Period 36		Period 37		Period 38		Period 39		Period 40	
Gasifier Temperature (°F)	1,700		1,691		1,694		1,702		1,711		1,699		1,700	
Gasifier Pressure (psig)	202		202		202		160		160		165		165	
Temp Approach Shift Rxn	25.8		285.5		17.5		200.4		93.8		98.1		-71.2	
Temp Approach Meth Rxn	-446.9		-439.0		-438.7		-492.9		-472.6		-504.4		-471.0	
Syngas Mole Fractions	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd
H_2	6.7	6.7	6.9	6.9	6.9	6.9	10.6	10.6	12.7	12.7	9.9	9.9	11.8	11.8
CO	9.0	9.0	9.2	9.2	9.0	9.0	6.7	6.7	8.0	8.0	5.8	5.8	7.1	7.1
CH_4	1.0	1.0	1.1	1.1	1.0	1.0	1.2	1.2	1.4	1.4	1.2	1.2	1.5	1.5
CO_2	8.5	8.5	8.8	8.8	8.9	8.9	10.6	10.6	12.7	12.7	10.9	10.9	13.0	13.0
N_2	65.4	65.4	64.3	64.3	64.2	64.3	40.7	40.7	33.1	33.1	42.8	42.8	40.3	40.3
Ar	0.4	0.4	0.4	0.4	0.4	0.4	0	0	0	0	0	0	0	0
H_2O	9.0	9.0	9.3	9.3	9.5	9.5	30.3	30.3	32.1	32.1	29.3	29.3	26.4	26.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.1	100.0	100.0	100.0	99.9	100.0	100.1

Table C-6: Comparison of Reported vs. Calculated Syngas Compositions (continued)

	Period 41		Period 42		Period 43		Period 44		Period 45		Period 46		Period 47	
Gasifier Temperature (°F)	1,701		1,696		1,699		1,696		1,701		1,708		1,692	
Gasifier Pressure (psig)	165		165		165		165		165		165		165	
Temp Approach Shift Rxn	-60.2		-43.9		-15.7		18.1		63.9		100.4		100.5	
Temp Approach Meth Rxn	-469.9		-467.6		-460.5		-467.1		-488.5		-505.6		-509.9	
Syngas Mole Fractions	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd
H_2	12.1	12.1	12.0	12.1	12.9	12.9	11.5	11.5	11.3	11.3	11.0	11.0	10.4	10.4
CO	7.4	7.4	7.4	7.3	8.6	8.6	7.1	7.1	7.2	7.2	7.2	7.2	6.5	6.5
CH_4	1.6	1.6	1.6	1.6	2.0	2.0	1.3	1.3	1.6	1.6	1.7	1.7	1.8	1.8
CO_2	13.2	13.2	12.9	13.0	13.4	13.4	12.5	12.5	12.4	12.4	12.4	12.4	12.5	12.5
N_2	38.8	38.8	38.8	38.8	36.2	36.2	39.3	39.3	38.2	38.2	37.5	37.5	37.6	37.6
Ar	0	0	0	0	0	0	0	0	0	0	0	0	0	0
H_2O	26.9	26.9	27.4	27.3	26.8	26.8	28.3	28.3	29.3	29.3	30.3	30.3	31.3	31.3
Total	100.0	100.0	100.0	100.1	100.0	99.9	100.0	100.0	100.0	100.0	100.0	100.1	100.0	100.1

Table C-7: Comparison of Syngas Compositions using Uniform Temperature Approaches

	Period 34		Period 35		Period 36		Period 37		Period 38		Period 39		Period 40	
Gasifier Temperature (°F)	1,700		1,691		1,694		1,702		1,711		1,699		1,700	
Gasifier Pressure (psig)	202		202		202		160		160		165		165	
Temp Approach Shift Rxn	25		25		25		25		25		25		25	
Temp Approach Meth Rxn	-470		-470		-470		-470		-470		-470		-470	
Syngas Mole Fractions	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd
H_2	6.7	6.3	6.9	6.4	6.9	6.4	10.6	11.6	12.7	13.0	9.9	10.9	11.8	11.5
CO	9.0	8.7	9.2	8.7	9.0	8.6	6.7	6.3	8.0	7.7	5.8	5.9	7.1	7.6
CH_4	1.0	1.2	1.1	1.4	1.0	1.3	1.2	1.0	1.4	1.4	1.2	0.9	1.5	1.4
CO_2	8.5	8.7	8.8	9.1	8.9	9.2	10.6	11.1	12.7	13.0	10.9	11.0	13.0	12.5
N_2	65.4	65.6	64.3	64.7	64.2	64.6	40.7	40.5	33.1	33.1	42.8	42.6	40.3	40.2
Ar	0.4	0.4	0.4	0.4	0.4	0.4	0	0	0	0	0	0	0	0
H_2O	9.0	9.0	9.3	9.4	9.5	9.6	30.3	29.4	32.1	31.8	29.3	28.7	26.4	26.8
Total	100.0	99.9	100.0	100.1	100.0	100.1	100.0	99.9	100.0	100.0	100.0	100.0	100.0	100.0

Table C-7: Comparison of Syngas Compositions using Uniform Temperature Approaches (continued)

	Period 41		Period 42		Period 43		Period 44		Period 45		Period 46		Period 47	
Gasifier Temperature (°F)	1,701		1,696		1,699		1,696		1,701		1,708		1,692	
Gasifier Pressure (psig)	165		165		165		165		165		165		165	
Temp Approach Shift Rxn	25		25		25		25		25		25		25	
Temp Approach Meth Rxn	-470		-470		-470		-470		-470		-470		-470	
Syngas Mole Fractions	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd	Obsv'd	Calc'd
H_2	12.1	11.8	12.0	11.7	12.9	12.5	11.5	11.4	11.3	11.9	11.0	12.2	10.4	11.7
CO	7.4	7.9	7.4	7.6	8.6	8.7	7.1	7.1	7.2	7.3	7.2	7.4	6.5	6.7
CH_4	1.6	1.6	1.6	1.6	2.0	2.1	1.3	1.3	1.6	1.4	1.7	1.3	1.8	1.4
CO_2	13.2	12.8	12.9	12.7	13.4	13.3	12.5	12.5	12.4	12.4	12.4	12.4	12.5	12.5
N_2	38.8	38.8	38.8	38.8	36.2	36.3	39.3	39.3	38.2	38.1	37.5	37.2	37.6	37.2
Ar	0	0	0	0	0	0	0	0	0	0	0	0	0	0
H_2O	26.9	27.3	27.4	27.6	26.8	27.1	28.3	28.4	29.3	28.9	30.3	29.5	31.3	30.5
Total	100.0	100.2	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

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