NATIONAL ENERGY TECHNOLOGY LABORATORY

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

February 19, 2014

DOE/NETL-2012/1563

U.S. DEPARTMENT OF ENERGY

Disclaimer

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Final Report

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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
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
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
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

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
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

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Executive Summary

The Connecticut Center for Advanced Technology (CCAT) has received funding from the Defense Logistics Agency (DLA) Energy 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 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.*

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 and sequestration of carbon dioxide streams generated during the production of these fuels in a CTL facility.

Recently, a more novel approach to achieving compliance has been to investigate 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 – 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 six discreet F-T jet fuel production scenarios, as shown in **Table ES-1**.

Boundaries considered for the analysis of F-T jet fuels production scenarios include geographic, temporal, material, and economic. Briefly, the geographic system boundary considered 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

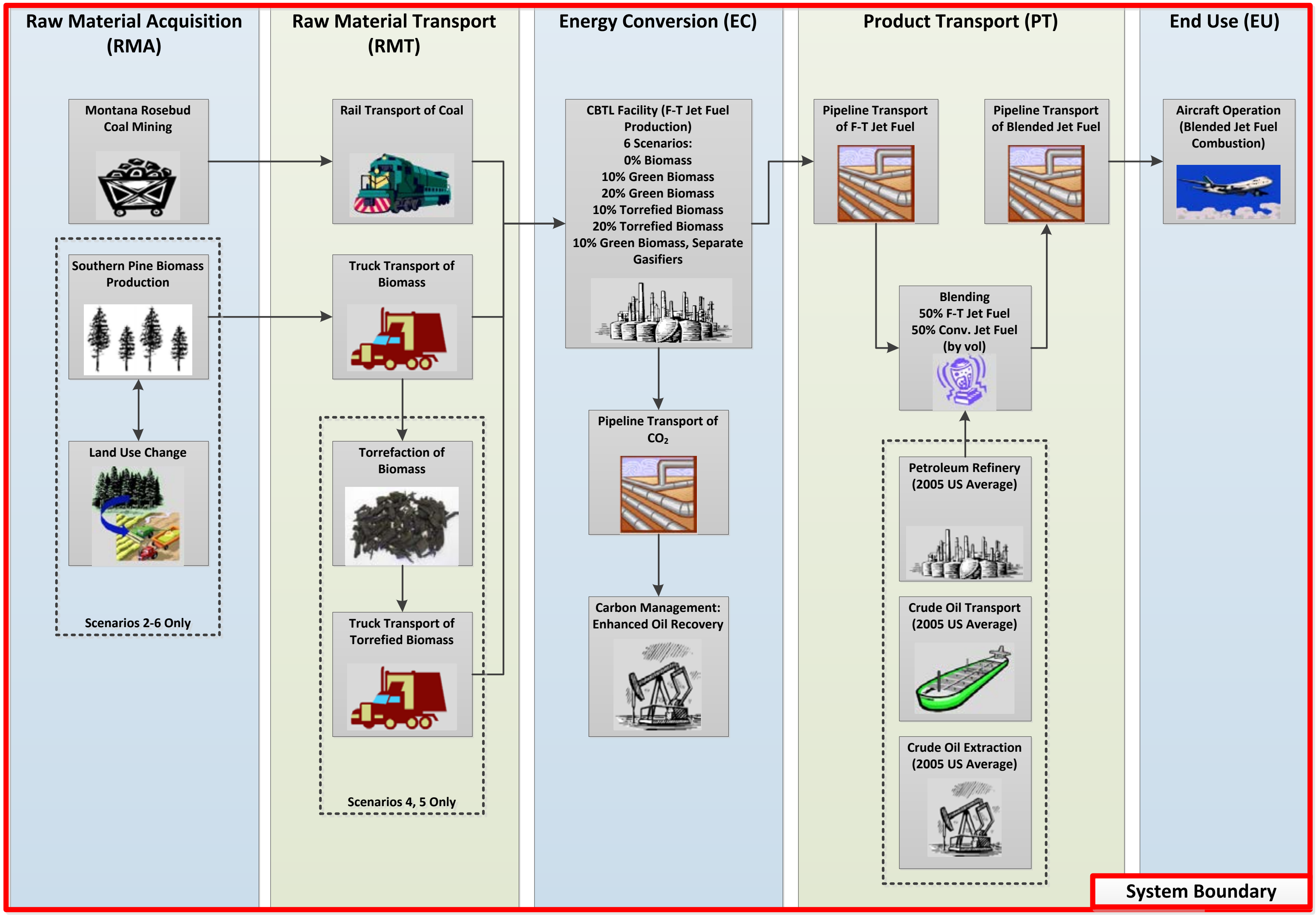
Table ES-1: Overview of Study Scenarios

<table>
<tr><th rowspan="2">Scenario Property</th><th colspan="6">Scenario Number and Name</th></tr>
<tr><th>1: CBTL, 0% Biomass</th><th>2: CBTL, 10% Biomass, Chipped</th><th>3: CBTL, 20% Biomass, Chipped</th><th>4: CBTL, 10% Biomass, Torrefied</th><th>5: CBTL, 20% Biomass, Torrefied</th><th>6: CBTL, 10% Biomass, Microchipped, Separate Gasifiers</th></tr>
<tr><td>CBTL Facility Location</td><td colspan="6">Southeastern U.S.</td></tr>
<tr><td>Biomass Type</td><td>N/A</td><td colspan="5">Short Rotation Woody Crops (Southern Yellow Pine)</td></tr>
<tr><td>Coal Type</td><td colspan="6">Montana Rosebud</td></tr>
<tr><td>Biomass Pretreatment</td><td>N/A</td><td colspan="2">Dry and Grind (from Wood Chips)</td><td colspan="2">Torrefaction</td><td>Separate Gasifier</td></tr>
<tr><td>Biomass Feed (by weight)</td><td>0%</td><td>10%</td><td>20%</td><td>10%</td><td>20%</td><td>10%</td></tr>
<tr><td>Gasifier Type</td><td colspan="5">Single Feed, Transport, O_2 Blown</td><td>Single Feed, Transport, O_2 Blown with Separate Biomass Gasifier</td></tr>
<tr><td>Liquefaction Type</td><td colspan="6">Indirect</td></tr>
<tr><td>F-T Reactor Type</td><td colspan="6">Slurry Iron Catalyst</td></tr>
<tr><td>Product Slate</td><td colspan="6">Maximize F-T Jet Fuel Production</td></tr>
<tr><td>CO_2 Capture</td><td colspan="6">Acid Gas Removal (H_2S and CO_2 – i.e., Selexol)</td></tr>
<tr><td>Default CO_2 Management</td><td colspan="6">Carbon Capture and CO_2 Enhanced Oil Recovery</td></tr>
</table>

Basin in Texas for enhanced oil recovery and long term carbon storage. 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**.

The technological/process model provides a process level evaluation of the six 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 carbon dioxide. 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.

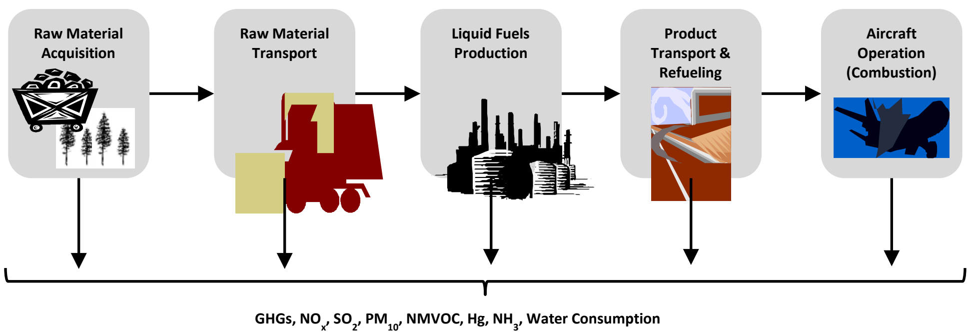
Figure ES-1: Material System Boundary for the Study



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. 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. Life cycle emissions estimates focus on life cycle GHG emissions, but other emissions were also considered, including select criteria air pollutants, other pollutants of concern, and water consumption. Life cycle emissions are evaluated and broken down according to five discreet life cycle stages, as shown in **Figure ES-2**.

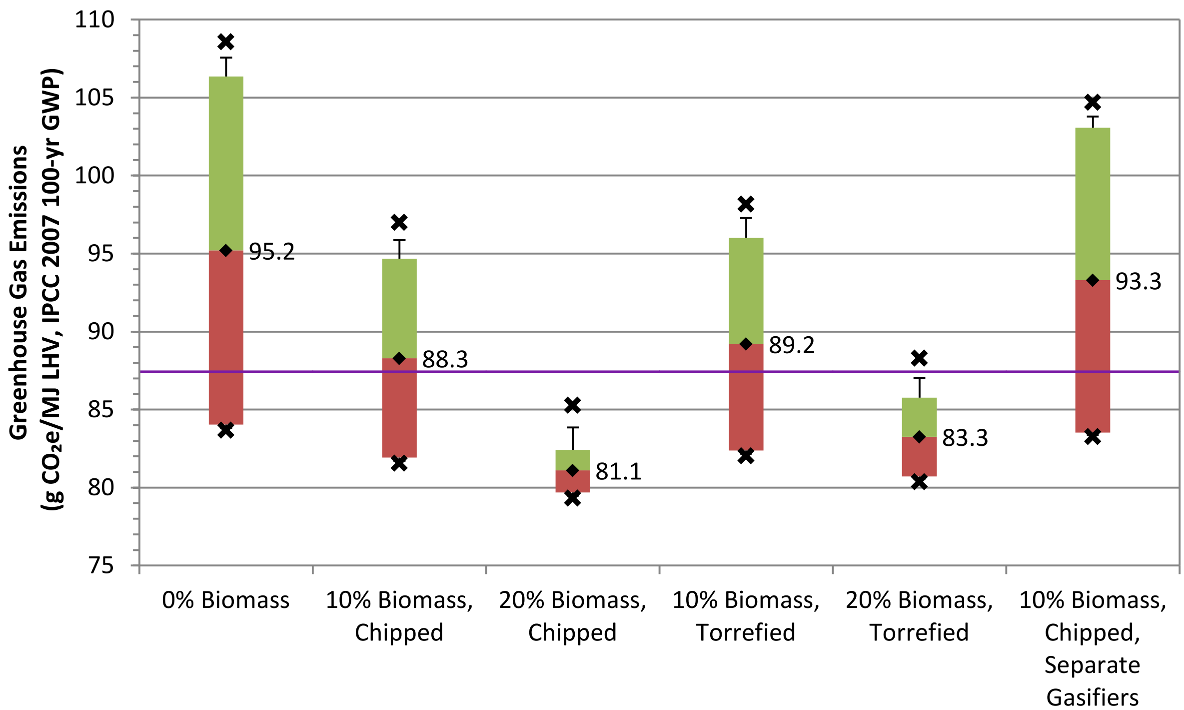
Figure ES-2: Life Cycle Stages Schematic for the Study



Results from the life cycle GHG emissions model are summarized in **Figure ES-3**, for each of the six production scenarios described previously. The solid horizontal line indicates the estimated life cycle emissions level for baseline conventional jet fuel, consistent with EISA requirements. Only one of the six scenarios, the CBTL, 20% Chipped Biomass scenario, indicated life cycle emissions that were entirely below the EISA baseline value of 87.4 g CO_2e/MJ, over the entire distribution of modeled results. Emissions from the CBTL 25th and 75th percentile results, 20% Chipped Biomass scenario ranged from 79.7 to 82.4 g CO_2e/MJ, mean value 81.1 g CO_2e/MJ.

For all other scenarios, the distribution of results lies at least partially below the EISA baseline value. As shown in **Figure ES-3**, 25th and 75th percentile results from the CBTL, 20% Torrefied Biomass scenario are entirely below the EISA baseline ranging from 80.7 to 85.8 g CO_2e/MJ, mean 83.3 g CO_2e/MJ. Only the maximum value for the distribution, 88.3 g CO_2e/MJ, strays above the EISA baseline. For the CBTL, 10% Chipped Biomass and the CBTL, 10% Torrefied Biomass scenarios, mean values are only 0.9 and 1.8 g CO_2e/MJ above the EISA baseline value respectively, with the 25th percentile range extending well below the baseline value in both cases. For the CBTL, 0% Biomass scenario and the CBTL, 10% Biomass, Microchipped, Separate Gasifiers scenario, mean values are 7.8 and 5.9 g CO_2e/MJ above the EISA baseline value, respectively. However, even for these scenarios, the EISA baseline value is still within the 25th percentile range of results. Therefore, results from this study indicate that all investigated scenarios could potentially meet EISA requirements.

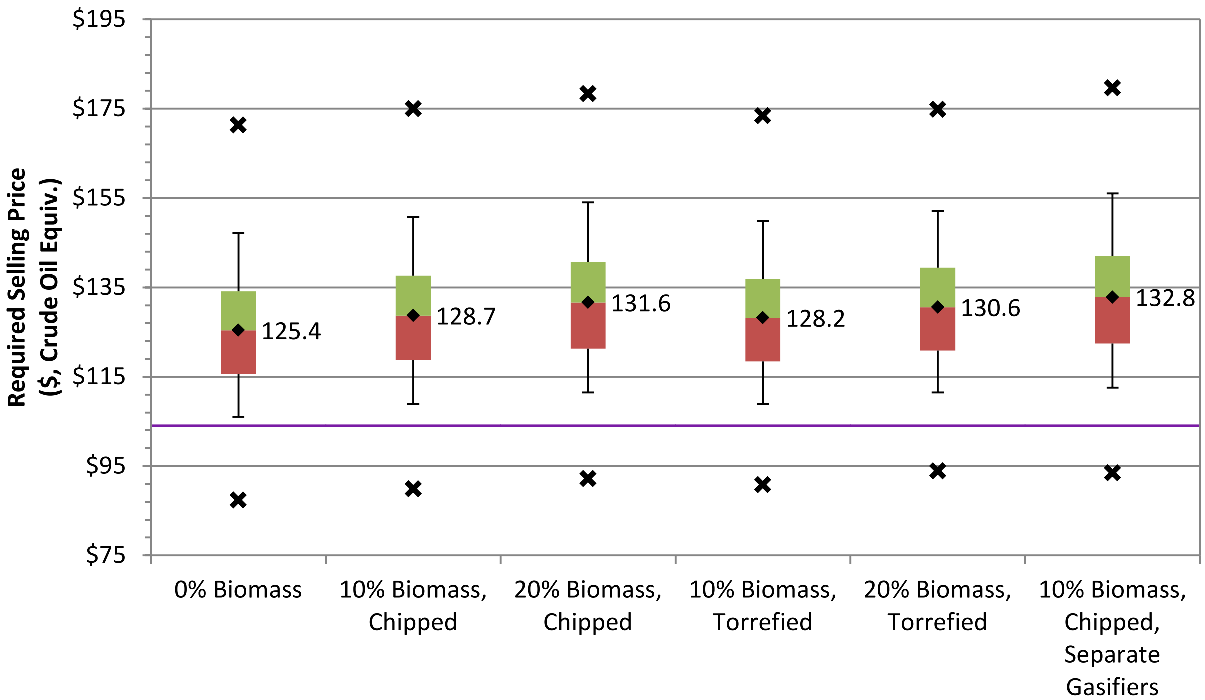
Figure ES-3: Summary of GHG Emissions derived from Combined Co-product Management, All Scenarios



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 life cycle GHG emissions values displayed in **Figure ES-3** are derived from a combined co-product management scenario. Briefly, the combined results were derived by calculating a 50/50 split between system expansion and energy allocation results. The combined co-product scheme was selected as the study default because there is otherwise no clear choice between results (from system expansion and energy allocation results), and both are equally likely to occur. The equal validity of system expansion and energy allocation has been previously document in support of life cycle analyses for alternative jet fuel production (Aviation Fuel Life Cycle Assessment Working Group, 2011). Therefore, the combined scenario presented here represents the applicable range of uncertainty when comparing life cycle GHG results among scenarios. Within this study, co-product management method is the key source of uncertainty for life cycle GHG emissions, as shown for the combined scenario (**Figure ES-3**). Uncertainty associated with the technological performance, modeled parameters, and data values are small in comparison to the uncertainty derived from co-product management method. RSP values (crude oil equivalent basis) for F-T jet fuel are summarized in **Figure ES-4**, for each of the six 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 2012; $104/bbl of crude oil (EIA, 2012b).

Figure ES-4: 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 baseline value.

As shown, 25th/75th percentile values for all six scenarios generally range between about $116/bbl and $142/bbl, with minimum/tail end distribution values reaching as low as $87/bbl for the CBTL, 0% Biomass scenario. Overall, RSP results distributions for the CBTL, 0% Biomass were the lowest of all scenarios, with 25th/75th percentile values ranging from $116 to $134/bbl, mean $125/bbl. Conversely, RSP results distributions for the CBTL, 10% Biomass, Microchipped, Separate Gasifiers scenario were consistently higher than other scenarios, ranging from $122 to $142/bbl, mean $133/bbl.

RSP results distributions for the remaining scenarios fall between RSP values for the CBTL, 0% biomass and the CBTL, 10% Biomass, Microchipped, Separate Gasifiers scenarios. Scenarios utilizing 20% biomass have generally higher RSP values than scenarios utilizing 10% biomass. For example, RSP values for the CBTL, 20% Chipped Biomass scenario range from $121 to $141/bbl, mean $132/bbl, while RSP values for the CBTL, 10% Chipped Biomass scenario range from $119 to $138/bbl, mean $129/bbl. Comparing mean values, the CBTL, 20% Chipped Biomass scenario results in a mean RSP value that is approximately $2.90/bbl higher than the CBTL, 10% Chipped Biomass scenario. Similar trends are apparent for the 10% Torrefied Biomass scenario (range $118 to $137/bbl, mean $128/bbl) and the 20% Torrefied Biomass scenario (range $121 to $139/bbl, mean $131/bbl), wherein the 20% Torrefied Biomass scenario results in a mean RSP value that is approximately $2.40 higher than the 10% Torrefied Biomass scenario.

Key conclusions and considerations with respect to study outcomes include the following:

- The CBTL, 0% Biomass CBTL facility configuration is estimated to have an overall HHV efficiency of 53.4%. A pinch analysis[1] was used in the simulations for optimal heat integration, utilization, and recovery. A minimum temperature approach of 30 °F was used for heat recovery in the bottoming cycle. Such an aggressive heat recovery is likely to result in higher overall efficiencies for a conceptual plant than would be expected for a commercially operating facility. Recovery rates differing between the conceptual model and a commercial facility is a model limitation.
- Co-gasification of woody biomass and coal in the same gasification system results in a slight lowering of the overall efficiency, in comparison to coal only and coal/torrefied biomass scenarios. This is because of the lower quality of the chipped biomass compared to coal or torrefied biomass, with respect to carbon content and heating value, and because more parasitic power is required for chipped biomass preparation.
- For the CBTL, 0% Biomass scenario, the required selling price of the jet fuel product has an estimated 25th to 75th percentile range of \$116 to \$134/bbl, mean \$125/bbl on a crude oil equivalent basis. This required selling price is above current world oil prices. For comparison, WTI spot pricing from early 2012 was \$104/bbl. However, the high required selling price of the jet fuel is greatly influenced by the high capital charge factor (0.2365[2]) used in this economic analysis. If a lower charge factor were to be used (for example using 0.1695 in place of 0.2365), the RSP of jet fuel would be reduced by approximately 20%. On a crude oil equivalent basis this would be approximately \$100/barrel – less than the current world oil price as of early 2012. As a result, plant financing criteria will be critical factors in determining the economic viability of a CBTL facility.
- 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% Biomass scenario has an estimated 25th to 75th percentile range of \$116 to \$134/bbl, mean \$125/bbl, while the CBTL, 10% Chipped Biomass scenario has a range of \$119 to \$138/bbl, mean \$129/bbl, and the CBTL, 20% Chipped Biomass scenario has an RSP range of \$121 to \$141/bbl, mean \$132/bbl. Thus, on average, use of 10% and 20% chipped biomass drive an increase in RSP of about \$3/bbl and \$6/bbl over the CBTL, 0% Biomass scenario, respectively. The elevated cost results from higher capital cost of CBTL facilities under the biomass scenarios, mostly due to costs of the biomass preparation and feeding. Another factor is the high cost of the delivered woody biomass feedstock on a dollars per MMBtu basis compared to coal.

[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, I. (2007). *Pinch Analysis and Process Integration, 2nd Edition*. U.K.: Elsevier, Ltd, Leng, W., Abbas, A., & Khalilpour, R. (2010). *Pinch Analysis for Integration of Coal-fired Power Plants with Carbon Capture*. Paper presented at the 20th European Symposium on Computer Aided Process Engineering – ESCAPE20. Retrieved from http://www.aidic.it/escape20/webpapers/558Leng.pdf.

[2] This capital charge factor is based on a 50% debt to equity ratio, a 15-year debt term, a nominal dollar cost for debt of 8% and 20% on equity, and an after tax weighted cost of capital of 13.1%.

- Based on results from the combined allocation strategy, only one of the six scenarios, the CBTL, 20% Chipped Biomass scenario, indicated life cycle emissions that were entirely below the EISA baseline value of 87.4 g CO_2e/MJ, over the entire distribution of modeled results. Emissions from the CBTL 25th and 75th percentile results, 20% Chipped Biomass scenario ranged from 79.7 to 82.4 g CO_2e/MJ, mean value 81.1 g CO_2e/MJ. For all other scenarios, the distribution of results lies partially below and partially above the EISA baseline value. However, for all scenarios, the EISA baseline value is still within the 25th percentile range of results. Therefore, results from this study indicate that all investigated scenarios could potentially meet EISA requirements based on the combined allocation method.

  With respect to life cycle GHG emissions, results indicate that the allocation method utilized is a key consideration with respect to total GHG emissions. Comparing energy allocation to system expansion, it is clear that the system expansion method results in higher life cycle GHG emissions overall, as compared to energy allocation. For example, for the CBTL, 0% Biomass scenario, total life cycle GHG emissions were found to have a 25th to 75th percentile range of 83.9 to 84.1 g CO_2e/MJ, mean 84.0 g CO_2e/MJ based on energy allocation, compared to 105.7 to 106.9 g CO_2e/MJ, mean 106.3 g CO_2e/MJ based on system expansion. Optimization of life cycle performance, including CBTL facility performance, also causes variability in life cycle GHG emissions. However, the degree of variability due to life cycle co-product management accounting procedure drives the greatest uncertainty in life cycle GHG emissions for jet fuel produced from CBTL operations.

  At present, EISA does not specify a preferred or required allocation method for the evaluation of life cycle GHG emissions for alternative jet fuel. If a select method of allocation is codified by future regulation under EISA, the U.S. EPA, or another federal entity, then the alternative jet fuel production configurations with CO_2 enhanced oil recovery as a carbon management strategy, as modeled in this study, would meet the EISA baseline when modeled with energy allocation. Conversely, only the CBTL, 20% Chipped Biomass scenario would meet or outperform the EISA baseline for jet fuel when modeled based on system expansion, using national average profiles to displace co-products. In general, improvements within the current technical and environmental modeling data uncertainty ranges will not change this conclusion.

- The biomass content contained in the CBTL facility feedstock was also a key consideration with respect to life cycle GHG emissions. As noted above, the results for the two scenarios that utilized 20% biomass to generate F-T fuels had the lowest overall life cycle GHG emissions. The scenario that utilized 0% biomass feedstock had the highest overall life cycle GHG emissions, while scenarios that utilized 10% 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.

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. When considering results based on combined allocation, conformance with EISA is a strong driver for the utilization of higher percentages of biomass, in order to produce alternative fuels that have a low carbon footprint. For example, only the scenario that utilizes 20% chipped biomass (i.e., CBTL, 20% Chipped Biomass) indicated life cycle GHG emissions that are below the EISA baseline requirement of 87.4 g CO_2e/MJ, for the entire range of reported emissions values. However, this scenario had the second highest RSP value of all scenarios, indicating a trade-off between cost and GHG emissions performance. In comparison, the CBTL, 0% Biomass scenario had the lowest overall cost range, but the highest overall range of life cycle GHG emissions. Overall, the separate gasifier scenario had relatively high cost and relatively high GHG emissions. However, the variability of the results for scenario performance, show that with careful attention to design and financial parameters that inform the life cycle GHG emissions and cost considerations, could potentially support the viability of any of the six scenarios.

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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 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.*

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 coal and biomass to liquids (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, and Boundaries

The following discussion of background for the study includes an overview of pertinent study background information, a review of the six 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. However, compliance requires aggressive capture and sequestration of carbon dioxide streams generated during the production of these fuels in a CTL facility.

Recently, a more novel approach to achieving compliance has been to investigate 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 – 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 management, can produce fuels with life cycle GHG emissions significantly less than those from conventional petroleum (NETL, 2011b).

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.

An important goal of the technological review portion of this study is to identify those operations, unique to CBTL, that are associated with uncertainty and require further research, development, and demonstration (RD&D) so that the technological risks can be lowered. The approach to identifying these uncertainties in this study is to develop conceptual designs of CBTL configurations that use combinations of coal and woody biomass to maximize production of F-T jet fuel.

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 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 RSP values for the six 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 of jet fuel. All results are expressed on the basis of this functional unit.

1.2.3 Scenarios Considered

This study models six jet fuel production scenarios, as show in **Table 1-1**. Each of the six scenarios relies on Powder River Basin Montana Rosebud subbituminous coal as a source of fossil energy, while five of the scenarios also use short rotation woody crop biomass (Southern yellow pine). 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 torrefaction for the two torrefaction scenarios. Biomass under the CBTL, 10% 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 TRIG transport gasifier. 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. 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: CBTL, 0% Biomass	2: CBTL, 10% Biomass, Chipped	3: CBTL, 20% Biomass, Chipped	4: CBTL, 10% Biomass, Torrefied	5: CBTL, 20% Biomass, Torrefied	6: CBTL, 10% Biomass, Microchipped, Separate Gasifiers
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
Biomass Feed (by weight)	0%	10%	20%	10%	20%	10%
Gasifier Type	Single Feed, Transport, O_2 Blown					Single Feed, Transport, O_2 Blown with Separate Biomass Gasifier
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)					
Default CO_2 Management	Carbon Capture and CO_2 Enhanced Oil Recovery					

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 and long term carbon storage

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.

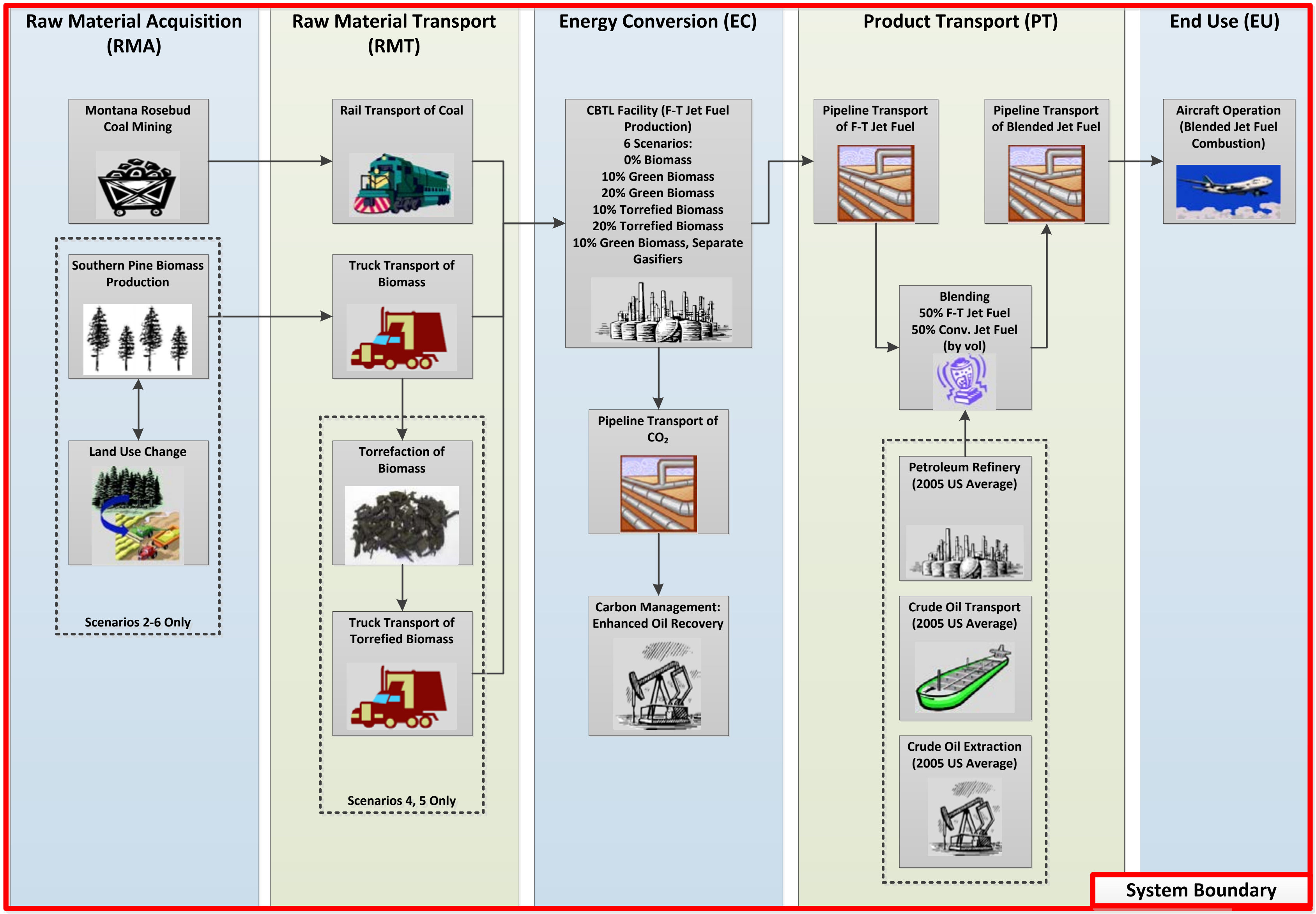
Economic System Boundary: The economic system boundary for the study includes costs and costing factors associated with the production, preparation, and transport of biomass, the delivered cost of coal, and the conversion of biomass and coal into liquid fuels. Additional considerations within the economic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

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 six 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 power, 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 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 are under development by Rentech Inc. The 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 Transport Integrated Gasification (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 in Wilsonville, Alabama since 1995.

1.3.1 Process Performance Estimates via Aspen 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.

1.4 Economic Model Overview

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. 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. 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% 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% 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. Broad scope LCAs may consider a wide array of input materials and energy, along with outputs of pollutants, products, byproducts, solid waste, and various other flows. Broad scope LCAs are appropriate for consideration of a wide array of environmental effects that could result from production of a product or product suite, with potential considerations ranging from explicit emissions to effects on the biosphere. Alternatively, focused LCAs are well suited for products or services where a decision may be made based on quantified life cycle inputs or emissions. 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. The U.S. Supreme Court found, in *Massachusetts v. US EPA*, 549 US 497 (2007), that GHGs may be considered air pollutants under the federal Clean Air Act. This finding gave the U.S. EPA authority to regulate GHG emissions within the U.S. In May, 2010, the U.S. EPA completed and issued a final rule to establish an approach to addressing GHG emissions from stationary sources, and which set GHG emissions thresholds. The final rule addresses the following GHGs: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

With respect to this study, quantification of life cycle GHG emissions focused on carbon dioxide, methane, nitrous oxide, and sulfur hexafluoride. 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.

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 1-2**, along with a brief definition.

Table 1-2: 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:

Figure 1-2: Life Cycle Stages Schematic

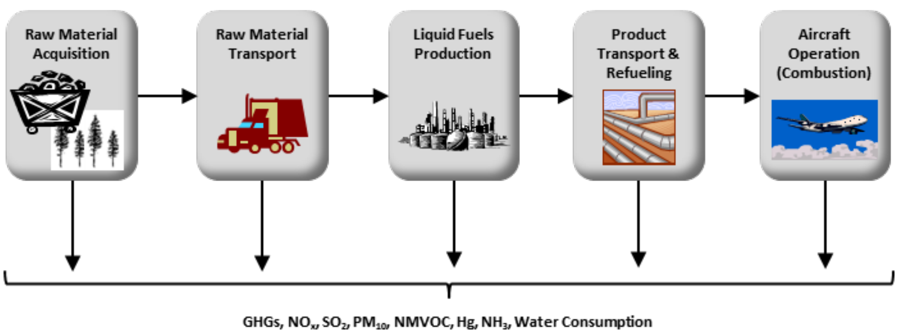


Figure Source: Adapted From (Aviation Fuel Life Cycle Assessment Working Group, 2011)

Raw Materials Acquisition (RMA): Raw materials 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 Materials Transport (RMT): Raw materials 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, carbon dioxide transport pipelines, and carbon dioxide enhanced oil recovery processes utilized in support of carbon management and eventual sequestration.

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.

Figure 1-3: Study System Boundary, System Expansion

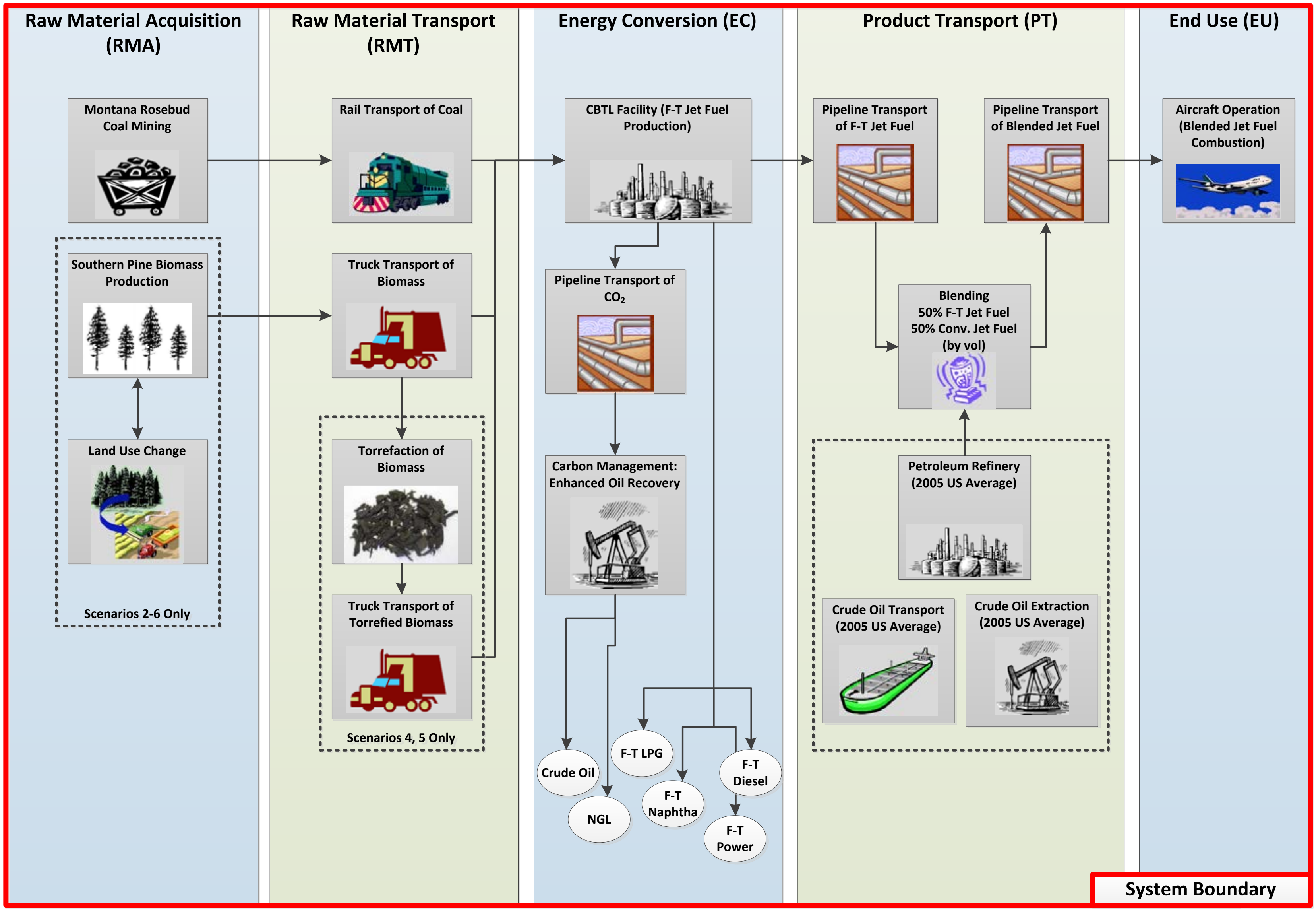
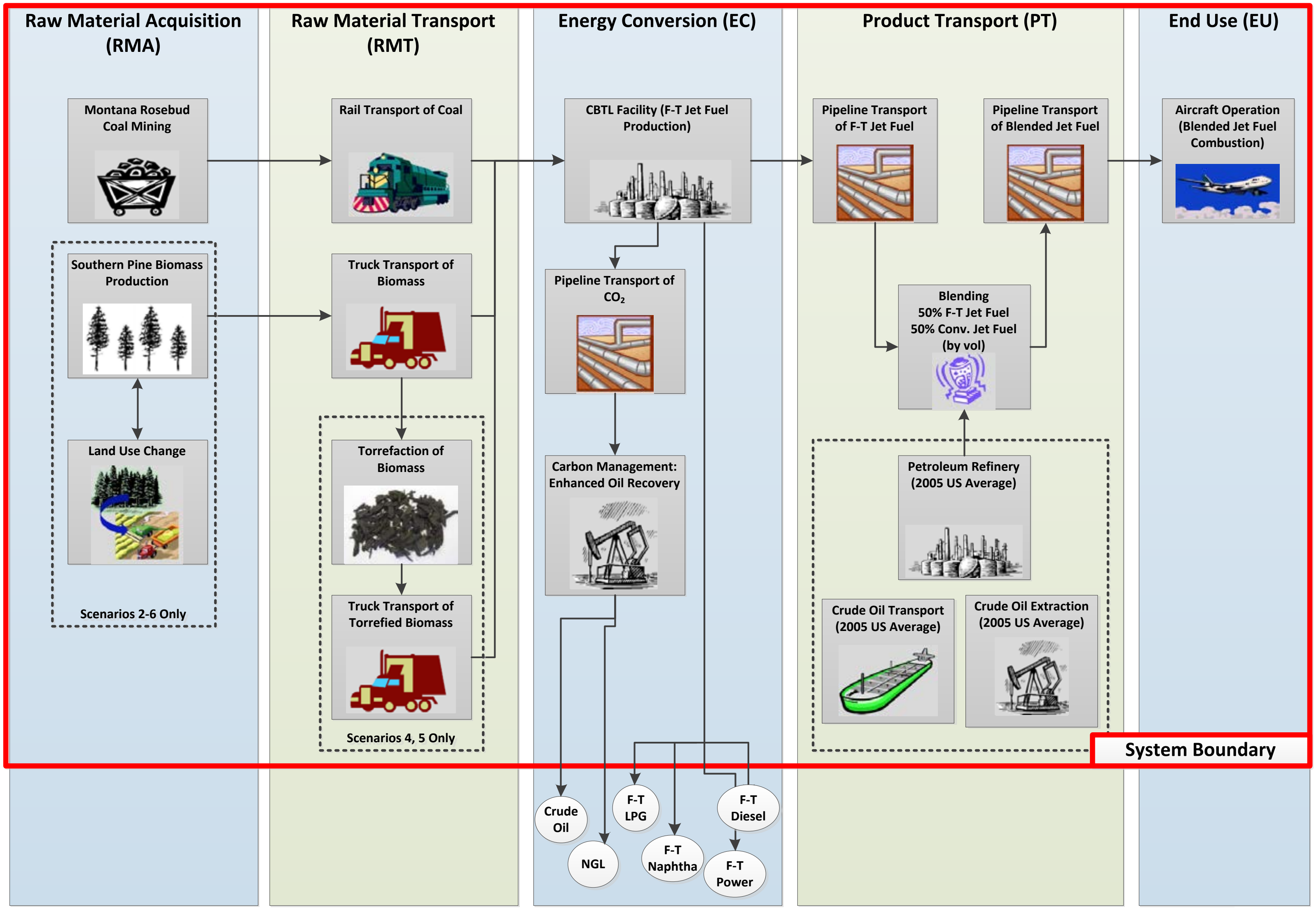


Figure 1-4: Study System Boundary, Energy Allocation



Process disaggregation is usually not feasible because most co-products are side-by-side, using the same equipment and other resources, making it impractical to apply a partitioning scheme. The remaining two co-production management methods are system expansion and allocation. These two methods are used in this analysis and are described in more detail below.

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 and EOR are included within the system boundary.

The following table (**Table 1-3**) shows the greenhouse gas displacement factors used for a model with system expansion. F-T jet fuel is the only product that exits the system. The other products (F-T diesel, F-T naphtha, LPG, electricity and crude oil) are included within the boundaries by considering the products they could potentially displace. For example, the emission of 0.75 kg of CO_2e is prevented when a kilogram of conventional diesel is displaced by F-T diesel.

Table 1-3: Example of Displacement Values Used for System Expansion

Co-product	Substitute / Displacement Product				
	Displaced Product	Value	Units	Description	Source
F-T Diesel	Conventional Diesel	0.75	kg CO_2e/ kg (2007 IPCC GWP)	2005 US average for conventional diesel fuel sold or distributed (petroleum baseline). Cradle-to-gate life cycle ending at the exit of the petroleum refinery.	NETL 2008
F-T Naphtha	Conventional Naphtha	0.56	kg CO_2e/ kg (2007 IPCC GWP)	PE International U.S. profile Naphtha at refinery	PE 2006
F-T LPG	Conventional LPG	0.84	kg CO_2e/ kg (2007 IPCC GWP)	PE International U.S. profile liquid gas LPG (70wt% propane; 30wt% butane)	PE 2006
F-T Electricity	Conventional Electricity Mix	0.19	kg CO_2e/ MJ (2007 IPCC GWP)	NETL Model of U.S. Electricity Grid Mix	NETL 2011
Crude Oil (CO_2-EOR)	US Domestic Crude Oil (2005 Average)	0.27	kg CO_2e/ kg (2007 IPCC GWP)	2005 US domestic crude oil. Cradle-to-gate life cycle profile for crude oil extraction only.	NETL 2009b
Natural Gas Liquids (CO_2-EOR)	Natural Gas Liquids	0.84	kg CO_2e/ kg (2007 IPCC GWP)	PE International U.S. profile liquid gas LPG (70wt% propane; 30wt% butane)	NETL 2010a

Co-product allocation divides environmental flows based on the physical or economic properties of the co-products. Energy-based co-production allocation is based on the relative energy contents of the co-products and, by definition, is useful when all major co-products considered in a study contain associated energy content. Mass and volume allocation divide environmental flows based on mass or volume, respectively, and are viable where co-products are measured and sold on a mass or volume basis. A drawback of volume allocation is that, unlike mass or energy, volume may not be conserved through a process (for example processing of feedstock through the CBTL facility).

Economic/market value allocation divides environmental flows based on market value. As such, a greater proportion of environmental flows would be attributed to the most valuable co-products. However, economic allocation is complicated by variability in price over time. As a result, co-product market instability could drive variability in environmental flows, even though no physical or process change has occurred.

The following table (**Table 1-4**) provides an example of a system with five co-products, the mass and energy content of each co-product, and the percent contribution of each co-product in terms of mass and energy. In this example, if F-T Jet Fuel is the functional unit, mass allocation would assign it 16.8% of the system's life cycle burdens and energy allocation would assign it 16.3% of the system's life cycle burdens. Additionally, the life cycle system boundary for energy allocation is contained in **Figure 1-4**. As shown, co-products from the CBTL facility and EOR operations are indicated outside of the study system boundary for energy allocation.

Table 1-4: Example of Co-Product Allocation Factors Based on Mass and Energy

Products*	Mass		Energy	
	Grams	% Mass Contribution	MJ LHV	% Energy Contribution
F-T Jet Fuel	11.16	16.8%	0.49	16.3%
F-T Diesel	2.19	3.3%	0.09	3.1%
F-T Naphtha	7.14	10.8%	0.31	10.5%
F-T LPG	1.27	1.9%	0.06	2.0%
F-T Electricity	N/A	N/A	0.07	2.3%
EOR Crude Oil	43.55	65.6%	1.92	64.0%
EOR Natural Gas Liquids	1.10	1.7%	0.05	1.8%
Total:	66.41	100%	2.99	100.0%

*Based on values for Scenario 2: CBTL, 10% Chipped Biomass

This analysis also generates results for a combined co-product management scheme by calculating a 50/50 split between system expansion and co-product allocation results. The combined co-product management scheme was selected as the study default because there is otherwise no clear choice between results (from system expansion and co-product allocation results), and both are equally likely to occur. A summary of stochastic analysis completed in support of the study, including stochastic analyses for the LCA, is contained in the separate discussion of the CBTL Jet Fuel model, below.

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 six different CBTL jet fuel production scenarios. The CBTL Jet Fuel Model incorporates a stochastic analysis of modeled results, drawing on input statistical distributions for the 13 environmental and 18 economic parameters shown in **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. The user can choose from individual life cycle analysis allocation methods (energy and system expansion) or a combination of the two types. 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 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

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 six 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 13 environmental and 18 economic parameters, as shown in **Table 1-5**.

The technological/process modeling completed in support of this study included three separate Aspen process simulations for each of the six 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 six scenarios has a parameter denoted as the "CBTL Facility Operations Scenario," corresponding to each of the Aspen simulations runs. The default distribution for that parameter is modeled as a discrete distribution with probabilities of 20%, 60%, and 20% 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 for EOR.

Table 1-5: Adjustable 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	39.99 (31.99, 47.98)
Biomass Yield as harvested (kg/acre-yr)	Triangular	6,350 (2,994, 7,620)
Chip Type (0 = Conventional Chipper and 1 = Microchipper)	Uniform	0 (0, 1)
Direct Land Use (kg CO_2/kg as harvested biomass)	Triangular	0.022 (0.022, 0.022)
Indirect Land use (kg CO_2/kg as harvested biomass)	Triangular	0.083 (0.055, 0.110)
Rail Distance (mile)	Triangular	1,600 (1,280, 1,920)
Biomass Truck Distance: Farm to CBTL Facility (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	40 (20, 50)
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/km)	Triangular	2.6E-07 (1.3E-07, 3.9E-07)
Blended Jet Fuel Transport Pipeline Length (mile)	Triangular	225.0 (180, 270)
Blended Jet Fuel Transport Scenario (1 = 100% pipeline, and 0 = 60% pipeline and 40% Truck Transportation)	Uniform	1 (1, 0)
Economic		
Global Capital Cost Factor	Triangular	1.00 (0.85, 1.30)
Capacity Factor	Triangular	0.90 (0.85, 0.92)
Capital Recovery Factor	Triangular	0.24 (0.21, 0.26)
Labor Cost Index	Triangular	1.00 (0.90, 1.20)
Taxes and Insurance (Fraction of TPC)	Triangular	0.020 (0.016, 0.024)
F-T Catalyst ($/lb)	Triangular	3.00 (2.10, 3.90)
Project Contingency	Triangular	0.15 (0.10, 0.20)
Coal Cost ($/ton)	Triangular	36.26 (34.45, 38.07)
Raw Chipped Biomass Cost ($/dry ton)	Triangular	43.65 (39.29, 48.02)
Raw Microchipped Biomass Cost ($/dry ton)	Triangular	46.36 (41.72, 50.99)
Torrefied Biomass Cost ($/ton)	Triangular	134.66, (121.19, 148.13)
Other Owner's Costs (Fraction of TPC)	Triangular	0.15 (0.12, 0.18)
Power Credit ($/MWh)	Triangular	70.59 (63.53, 77.65)
CO_2-EOR Credit ($/ton)	Triangular	40 (28, 52)
Diesel: Jet Fuel Equivalent	Triangular	0.99 (0.95, 1.00)
Naphtha: Jet Fuel Equivalent	Triangular	0.69 (0.62, 0.76)
LPG: Jet Fuel Equivalent	Triangular	0.40 (0.35, 0.50)
Crude Oil Equivalent Diesel/Oil	Triangular	1.20 (1.10, 1.30)

The stochastic analysis was performed by using the @RISK Excel add-in, developed by Palisade® Corporation. The sampling procedure for the stochastic model was Latin Hypercube with a seed value. The environmental and economic parameters are shown in **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.

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.

1.7 Summary of Key Study Assumptions

Table 1-6 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.

Table 1-6: 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
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
Power Production	Gas Turbine, Heat Recovery Steam Generator
Cooling	Cooling Tower
Economic	
Biomass Chipping Method	Standard or Microchip
Delivered Biomass Cost	$22.63/ton (as delivered)
Natural Gas Cost	$4/Mcf
Electricity Cost/Value	$70.59/MWh
CBTL Facility Land Cost	$3,000/Acre
Financing Fee	2.7% of Total Plant Cost (TPC)
Other Owners Costs	15% of TPC
Montana Rosebud Coal Delivered Cost	$36.26/ton (as received)
Green Biomass Chips	$48.12/ton (dry)
Green Biomass Microchips	$51.10/ton (dry)
Torrefied Biomass Delivered Cost	$134.7/ton (as received)
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 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	700 miles
Fugitive CO_2 Loss During Transport, Utilization, and Storage	Approximately 0.6% of CO_2 input
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)

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2 Technologies and Processes

This chapter 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 and associated co-products from a combination of coal and biomass. The technologies and processes discussed here were evaluated within a series of Aspen model runs, as discussed in Chapter 1. The following text provides details regarding the modeled process, for each of the six modeled scenarios. Each Scenario section includes a written description, a CBTL facility flow diagram (**Figure 2-1**, **Figure 2-2**, **Figure 2-3**, and **Figure 2-4**) and the associated Aspen streams tables (**Table 2-1**, **Table 2-2**, **Table 2-3**, **Table 2-4**, **Table 2-5**, and **Table 2-6**).

2.1 Scenario 1: CBTL, 0% Biomass

Figure 2-1 shows the block flow schematic for the CBTL, 0% Biomass configuration where the only feedstock is Montana Rosebud coal. The coal (30,483 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% moisture down to 18% 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 carbon dioxide 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 includes CO_2, CO, H_2, light hydrocarbons, an aqueous stream containing oxygenates, naphtha, distillate, and wax.

The overhead gas is sent to a methyldiethanolamine (MDEA) unit for CO_2 removal then to a cryogenic separation unit to separate a methane-rich gas, a 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 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 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.

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

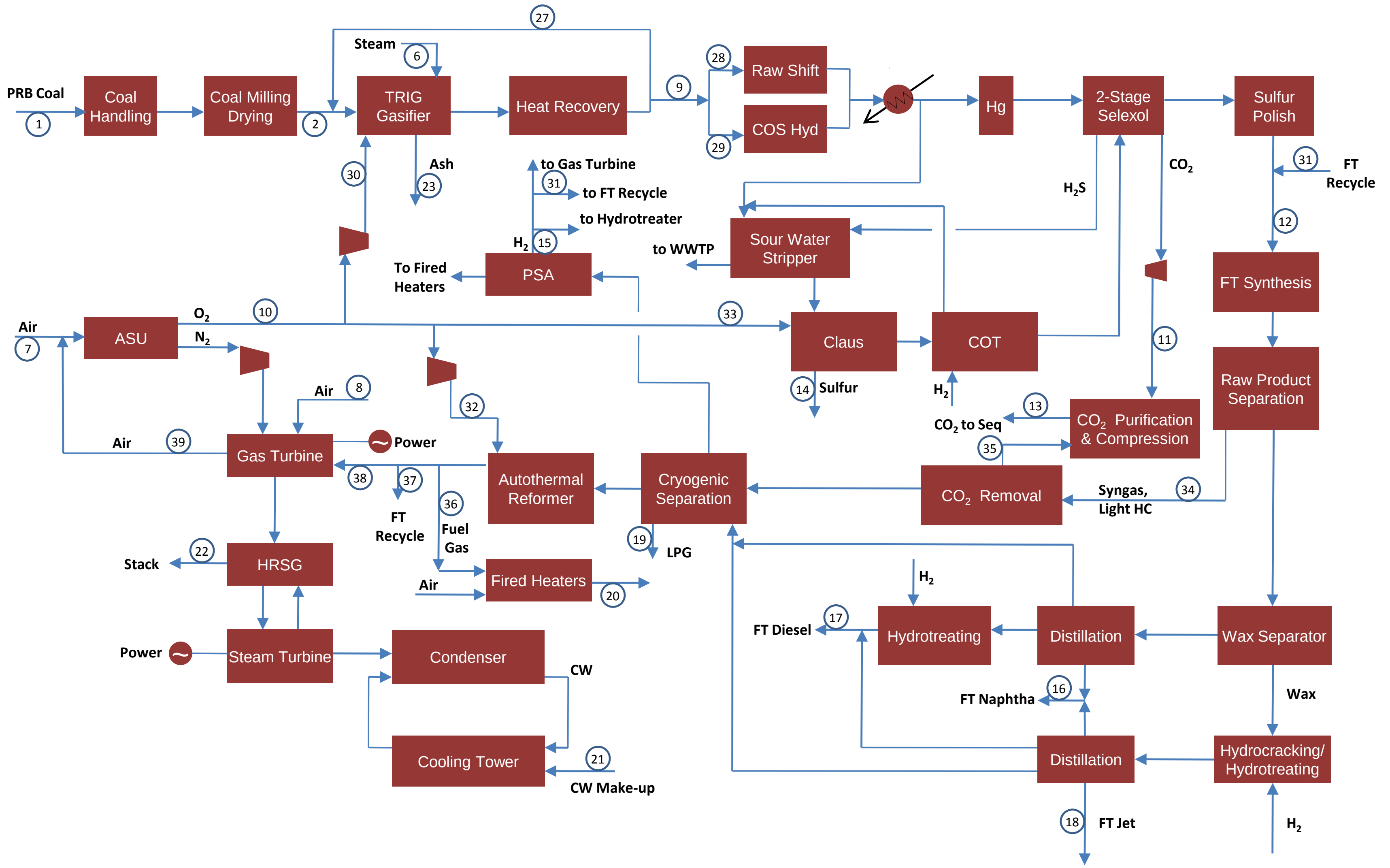


Table 2-1: CBTL, 0% Biomass: Stream Values

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	2,214.7	14.7
Mass Flow (lb/hr)	2,540,262	2,299,557	488,712	6,632,570	3,531,600	3,968,428	1,569,809	1,653,551	2,425,750	2,572,940	9,222
Mole Flow (lbmol/hr)			27,128	229,843	122,383	192,114	48,781	40,117	154,620	58,683	36
Mole Fraction											
H_2O			1.0	9.87E-03	9.87E-03	0.1397	0.0	1.42E-03	6.57E-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	5.95E-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	0.0	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)	39,503	175,107	53,580	273,563	31,236	111,863	4,497,474	4,254,830	242,663	208,865	2,035,014
Mole Flow (lbmol/hr)	19,272	1,657	252	1,288	640	3,065	249,648	150,209		10,111	98,516
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.1419	1.0	0.0976		0.1397	0.1397
Ar	1.23E-04	0.0	0.0	0.0	2.02E-05	0.0860	0.0	0.0156		7.32E-03	7.32E-03
CO_2	8.62E-09	0.0	0.0	0.0	0.0600	0.5549	0.0	0.0441		0.1274	0.1274
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0994		0.0	0.0
N_2	3.39E-04	0.0	0.0	0.0	7.89E-07	0.2172	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		0.3958	0.3958
COS	0.0	0.0	0.0	0.0	2.19E-05	4.67E-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	5.27E-06	0.0	4.78E-06		3.90E-03	3.90E-03
SO_2	0.0	0.0	0.0	0.0	0.0	3.42E-13	0.0	3.34E-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	4.35E-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	0.3372	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	H_2 to 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)	1,933,414	1,422,813	380,528	111,297	35,699	1,610,604	1,041,495	7,307
Mole Flow (lbmol/hr)	93,598	44,213	18,062	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	0.2433
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	0.5532
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	3.19E-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	0.0	0.0	0.0	0.0	0.0	0.0

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)	259,440	324,886	218,739
Mole Flow (lbmol/hr)	13,018	22,232	7,580
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	8.97E-17	6.30E-17	0.2074
N_2	0.0538	0.0379	0.7732
CO	0.3460	0.2433	0.0
COS	2.33E-13	1.64E-13	0.0
H_2	0.3647	0.5532	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	3.97E-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	3.19E-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	0.0	0.0	0.0

Refinery fired heaters for distillation and feed heating for hydrotreating and hydrocracking are heated in heaters using fuel 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.

2.2 Scenario 2: CBTL, 10% Chipped Biomass and Scenario 3: CBTL, 20% Chipped Biomass

The overall configuration for these scenarios is very similar to the CBTL, 0% 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% 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%. The moisture must be reduced to about 18% 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% 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% 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% Biomass scenario.

Figure 2-2: CBTL, 10% and 20% Chipped Biomass Plant Configurations

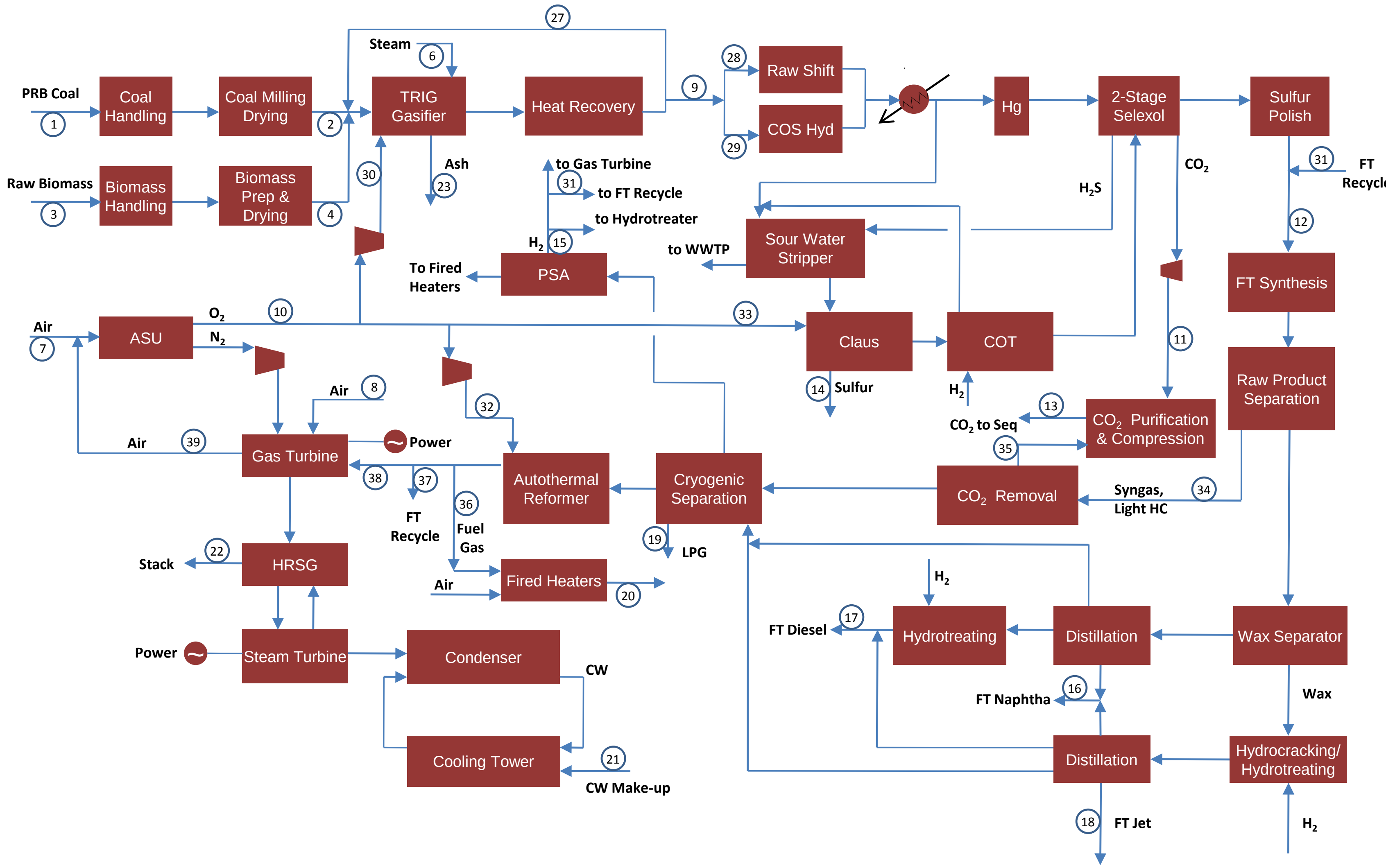


Table 2-2: CBTL, 10% Biomass, Chipped: Stream Values

PFD Name	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)	2,343,430	2,121,375	340,883	235,708	450,844	6,582,726	3,531,600	3,993,790	1,558,441	1,672,221	2,421,560
Mole Flow (lbmol/hr)					25,026	228,116	122,383	192,963	48,428	40,542	154,454
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	0.0

PFD Name	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)	2,214.7	14.7	317.0	14.7	14.7	14.7	227.1	14.7	14.7	14.7	14.7
Mass Flow (lb/hr)	2,591,612	8,546	39,502	175,107	53,580	273,562	31,235	112,042	4,417,976	4,255,042	228,088
Mole Flow (lbmol/hr)	59,108	33	19,272	1,657	252	1,288	640	3,064	245,235	150,207	
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1417	1.0	0.0976	
Ar	0.0	0.0	1.22E-04	0.0	0.0	0.0	1.99E-05	0.0854	0.0	0.0156	
CO_2	0.9926	0.0	8.63E-09	0.0	0.0	0.0	0.0600	0.5592	0.0	0.0442	
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0994	
N_2	6.42E-05	0.0	3.33E-04	0.0	0.0	0.0	7.66E-07	0.2136	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	4.34E-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	5.16E-06	0.0	4.68E-06	
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.20E-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	H_2 to 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)	210,191	2,030,329	1,963,461	1,413,958	375,433	109,821	34,662	1,606,671
Mole Flow (lbmol/hr)	10,156	98,097	94,866	43,938	17,803	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	0.0	0.0	0.0	0.0

PFD Name	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)	1,041,430	7,306	254,425	324,572	218,968
Mole Flow (lbmol/hr)	23,665	500	12,763	22,213	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	0.0	0.0	0.0	0.0

Table 2-3: CBTL, 20% Biomass, Chipped: Stream Values

PFD Name	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)	2,136,407	1,933,969	699,231	483,492	411,016	6,530,247	3,531,600	4,020,281	1,546,443	1,691,679	2,417,281
Mole Flow (lbmol/hr)					22,815	226,297	122,383	193,845	48,055	40,984	154,277
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	5.83E-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	0.0

PFD Name	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)	2,214.7	14.7	317.0	14.7	14.7	14.7	227.0	14.7	14.7	14.7	14.7
Mass Flow (lb/hr)	2,611,141	7,835	39,497	175,107	53,580	273,562	31,235	112,220	4,334,287	4,255,215	212,757
Mole Flow (lbmol/hr)	59,553	31	19,269	1,657	252	1,288	640	3,064	240,589	150,204	
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1415	1.0	0.0975	
Ar	0.0	0.0	1.21E-04	0.0	0.0	0.0	1.95E-05	0.0848	0.0	0.0155	
CO_2	0.9926	0.0	8.64E-09	0.0	0.0	0.0	0.0600	0.5638	0.0	0.0444	
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0994	
N_2	6.28E-05	0.0	3.27E-04	0.0	0.0	0.0	7.43E-07	0.2098	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	3.98E-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	5.06E-06	0.0	4.58E-06	
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.96E-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	H_2 to 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	2,025,192	1,995,088	1,404,563	370,243	108,310	33,571	1,602,719
Mole Flow (lbmol/hr)	10,202	97,648	96,197	43,646	17,540	3,366	1,043	60,969
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	7.79E-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	0.0	0.0	0.0	0.0

PFD Name	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)	1,041,430	7,305	249,329	324,232	219,084
Mole Flow (lbmol/hr)	23,665	500	12,502	22,191	7,592
Mole Fraction					
H_2O	0.0	0.0542	0.0773	0.0542	9.87E-03
Ar	0.0	0.0571	0.0814	0.0571	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	0.0517	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	3.79E-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	4.52E-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	0.0	0.0	0.0	0.0

2.3 Scenario 4: CBTL, 10% Torrefied Biomass and Scenario 5: CBTL, 20% Torrefied Biomass

The overall configuration for cases 4 and 5 is very similar to the CBTL, 10% Chipped Biomass scenario. However, in these two cases, torrefied woody biomass is used in place of the green woody biomass used in cases 2 and 3. 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 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% moisture before torrefaction and the torrefied material had a moisture content of 5.72%. 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% Chipped Biomass scenario. 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. 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% 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% 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.

Figure 2-3: Scenarios 4 and 5 Plant Configuration: CBTL, 10% and 20% Torrefied Biomass Plant Configurations

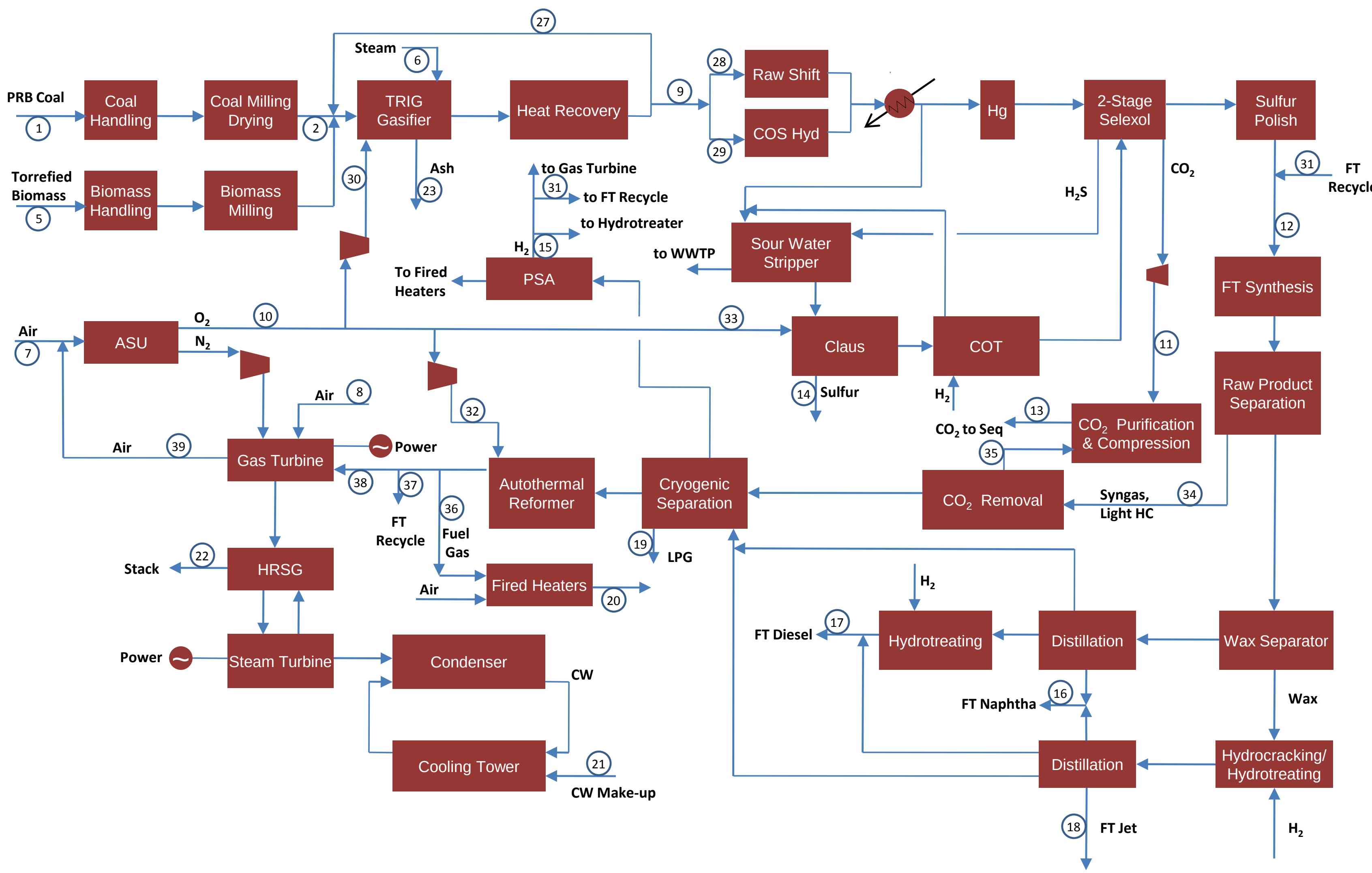


Table 2-4: CBTL, 10% Biomass, Torrefied: Stream Values

PFD Name	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	2,214.7
Mass Flow (lb/hr)	2,264,440	2,049,871	227,763	435,647	6,539,766	3,531,600	3,891,201	1,548,398	1,649,379	2,431,981	2,570,490
Mole Flow (lbmol/hr)				24,182	226,627	122,383	187,905	48,116	40,021	154,941	58,630
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	7.57E-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	0.4816	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	0.0	0.0

PFD Name	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	39,507	175,105	53,580	273,558	31,239	110,531	4,463,571	4,253,669	220,204	204,796
Mole Flow (lbmol/hr)	32	19,279	1,657	252	1,288	640	3,032	247,766	150,223		9,890
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.1454	1.0	0.0978		0.1301
Ar	0.0	1.22E-04	0.0	0.0	0.0	2.04E-05	0.0865	0.0	0.0155		7.35E-03
CO_2	0.0	8.61E-09	0.0	0.0	0.0	0.0601	0.5544	0.0	0.0437		0.1234
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0995		0.0
N_2	0.0	3.30E-04	0.0	0.0	0.0	7.81E-07	0.2137	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	4.29E-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	5.52E-06	0.0	4.93E-06		3.76E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	3.01E-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	H_2 to 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)	2,365,756	1,525,445	1,398,123	393,913	116,093	34,181	1,615,755	1,042,988
Mole Flow (lbmol/hr)	114,242	73,663	43,446	18,843	3,608	1,062	61,540	23,700
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	0.1098	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	1.98E-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	6.22E-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	0.0	0.0	0.0	0.0	0.0

PFD Name	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)	7,245	273,057	320,841	218,095
Mole Flow (lbmol/hr)	500	13,809	22,143	7,558
Mole Fraction				
H_2O	0.0549	0.0782	0.0549	9.87E-03
Ar	0.0573	0.0815	0.0573	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	0.2431	0.3460	0.2431	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	8.49E-14	6.83E-14	0.0
ISOBU-01	4.19E-19	5.98E-19	4.19E-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	0.0	0.0	0.0	0.0

Table 2-5: CBTL, 20% Biomass, Torrefied: Stream Values

PFD Name	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	2,214.7
Mass Flow (lb/hr)	1,993,916	1,804,980	451,245	383,602	6,449,756	3,531,600	3,815,336	1,527,665	1,645,665	2,438,833	2,568,583
Mole Flow (lbmol/hr)				21,293	223,508	122,383	183,740	47,471	39,936	155,289	58,590
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	7.59E-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	9.90E-15	0.0
ISOBU-01				0.0	0.0	0.0	0.0	0.0	0.0	7.40E-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	0.0	0.0

PFD Name	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	39,510	175,104	53,580	273,557	31,243	109,159	4,422,247	4,252,058	198,179	200,809
Mole Flow (lbmol/hr)	28	19,286	1,657	252	1,288	640	2,997	245,472	150,223		9,671
Mole Fraction											
H_2O	0.0	0.0	0.0	0.0	0.0	0.0	0.1490	1.0	0.0980		0.1205
Ar	0.0	1.22E-04	0.0	0.0	0.0	2.07E-05	0.0872	0.0	0.0154		7.39E-03
CO_2	0.0	8.59E-09	0.0	0.0	0.0	0.0601	0.5535	0.0	0.0432		0.1191
O_2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0995		0.0
N_2	0.0	3.21E-04	0.0	0.0	0.0	7.74E-07	0.2103	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	3.90E-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	5.78E-06	0.0	5.09E-06		3.62E-03
SO_2	0.0	0.0	0.0	0.0	0.0	0.0	2.62E-13	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	H_2 to 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)	2,752,041	1,063,295	1,373,686	408,240	121,272	32,706	1,621,465	1,044,542
Mole Flow (lbmol/hr)	132,533	51,206	42,687	19,687	3,768	1,016	61,825	23,736
Mole Fraction								
H_2O	0.1205	0.1205	0.0	0.0588	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	5.99E-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	0.4239	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	0.3460	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	7.81E-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	0.0	0.0	0.0	0.0	0.0

PFD Name	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	287,635	316,736	217,617
Mole Flow (lbmol/hr)	500	14,662	22,052	7,541
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	0.0	0.0	0.0	0.0

2.4 Scenario 6: CBTL, 10% 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 atmosphere.

Both processes are under development by Rentech Inc. The 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 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 this must be compressed so that this syngas can be combined with the high pressure syngas coming from the TRIG coal gasification process.

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

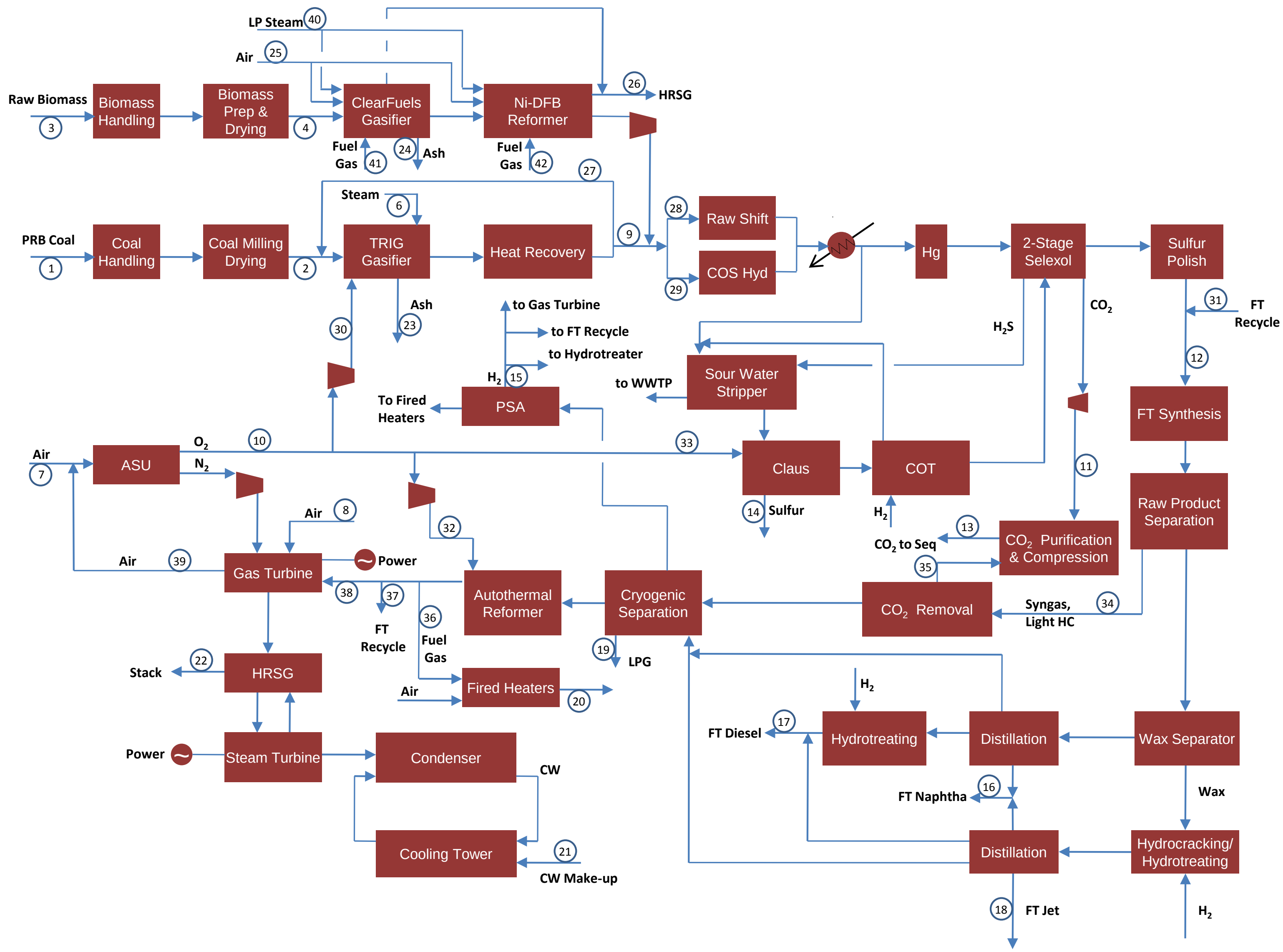


Table 2-6: CBTL, 10% Biomass, Microchipped, Separate Gasifiers: Stream Values

PFD Name	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)	2,387,684	2,161,437	360,028	240,160	459,358	6,234,290	3,531,600	3,730,058	1,480,709	1,581,373	2,302,115
Mole Flow (lbmol/hr)					25,498	216,041	122,383	180,574	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	9.23E-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	5.28E-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	2.96E-08
SO_2					0.0	0.0	0.0	0.0	0.0	0.0	0.0
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	2.65E-11
C_2H_6					0.0	0.0	0.0	0.0	0.0	0.0	4.81E-12
C_3H_6					0.0	0.0	0.0	0.0	0.0	0.0	3.14E-15
C_3H_8					0.0	0.0	0.0	0.0	0.0	0.0	1.05E-16
ISOBU-01					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	5.19E-19
1-BUT-01					0.0	0.0	0.0	0.0	0.0	0.0	1.67E-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	0.0

PFD Name	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)	2,214.7	14.7	317.0	14.7	14.7	14.7	224.4	14.7	14.7	14.7	14.7
Mass Flow (lb/hr)	2,450,112	8,750	39,606	175,138	53,588	273,610	31,164	276,219	4,522,057	5,294,804	228,087
Mole Flow (lbmol/hr)	55,886	34	19,342	1,657	252	1,288	638	9,772	251,012	185,197	
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	7.01E-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	

PFD Name	CF Ash	Air	Stack	Syngas Recycle	Syngas to WGS	Syngas to COS	O_2 to Gasifier	H_2 to 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	1,067.9	294.1	500.0	500.0	268.0	87.3	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	816,725	1,021,872	196,327	1,685,527	2,044,531	1,337,353	132,579	108,366	34,991	1,503,682
Mole Flow (lbmol/hr)		28,303	35,160	9,504	81,597	98,977	41,558	5,536	3,367	1,087	58,571
Mole Fraction											
H_2O		9.87E-03	0.1595	0.1397	0.1397	0.1397	0.0	1.47E-03	0.0	0.0	0.0
Ar		9.25E-03	0.0214	7.32E-03	7.32E-03	7.32E-03	0.0318	9.15E-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	1.44E-18	0.9504	0.9504	0.0
N_2		0.7732	0.6430	5.50E-03	5.50E-03	5.50E-03	0.0178	3.60E-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	5.62E-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	8.08E-07	0.0	0.0	7.64E-08
SO_2		0.0	6.10E-13	0.0	0.0	0.0	0.0	7.50E-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	7.22E-10	0.0	0.0	1.47E-03
C_2H_6		0.0	0.0	0.0	0.0	0.0	0.0	1.31E-10	0.0	0.0	4.58E-04
C_3H_6		0.0	0.0	0.0	0.0	0.0	0.0	8.56E-14	0.0	0.0	1.26E-03
C_3H_8		0.0	0.0	0.0	0.0	0.0	0.0	2.87E-15	0.0	0.0	4.02E-04
ISOBU-01		0.0	0.0	0.0	0.0	0.0	0.0	2.44E-20	0.0	0.0	0.0
N-BUT-01		0.0	0.0	0.0	0.0	0.0	0.0	1.41E-17	0.0	0.0	3.49E-04
1-BUT-01		0.0	0.0	0.0	0.0	0.0	0.0	4.55E-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	0.0	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	51,232	1,955	334,927	228,150	24,324	173,393	31,753
Mole Flow (lbmol/hr)	22,733	3,317	104	21,687	7,906	1,350	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	0.2957	0.3695	0.2957	0.0	0.0	0.4008	0.2957
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	0.0	0.0	0.0	0.0	0.0	0.0	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, 2012a). 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, 2012a). 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% of the delivered cost (EIA, 2012a). 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.

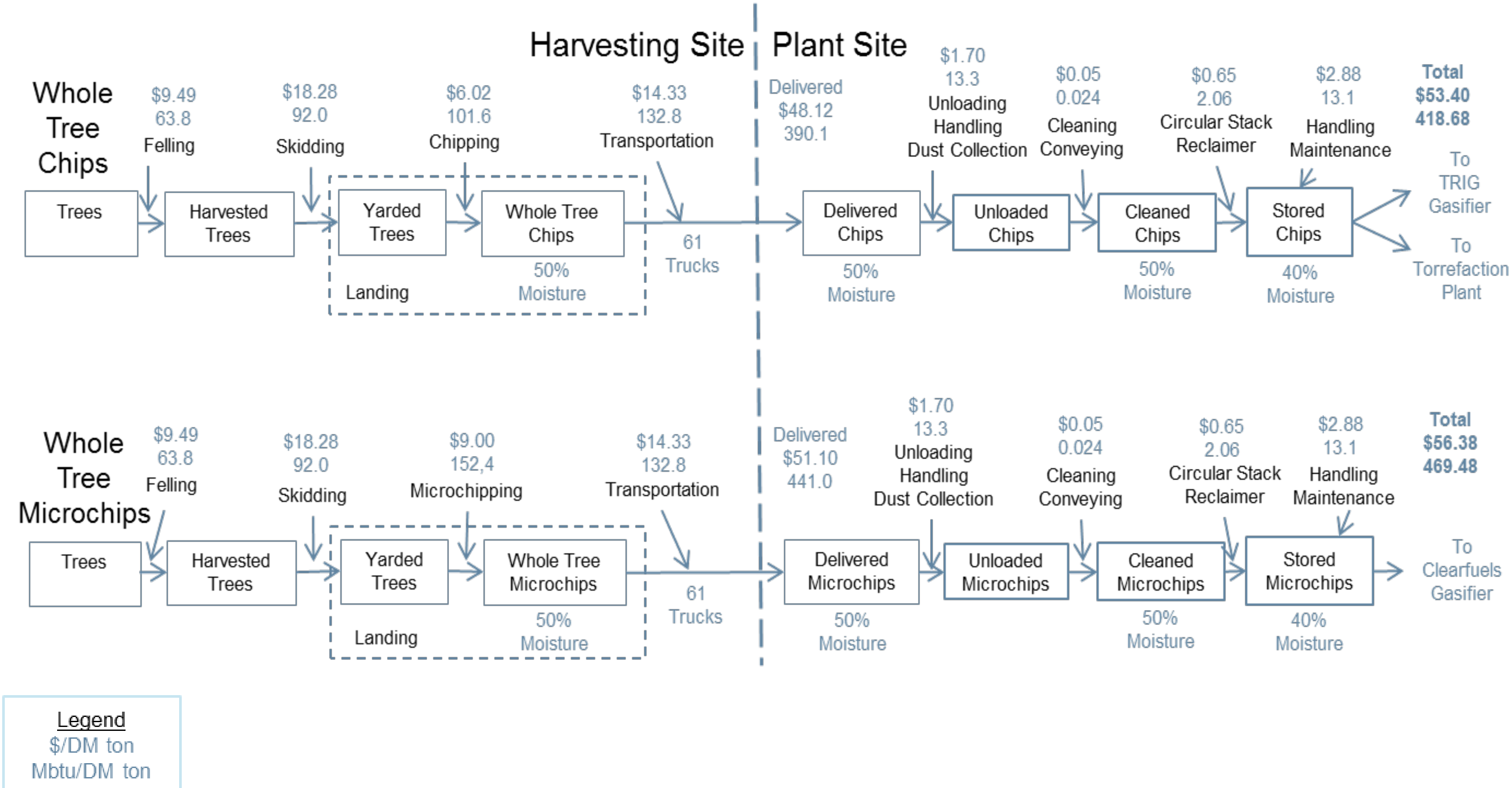
3.1.1.2 Biomass Feedstock

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% 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% 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% 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.

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 (Scenarios 2 and 3) 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 (Scenarios 4 and 5), 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
Chipped Wood	34.8
Coal	71

Source: (J. Kiel, 2011a).

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% for a total BEC estimate of $136 MM. Adding 10% home office and 15% 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 Recovery Factor	0.2365	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% 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 Rentech Inc. (Wright & Ibsen, 2012) 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 0.2365. **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.

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.

The method used to determine total capital requirement is as follows: the bare erected cost (BEC) estimates for each of the conceptual plants under Scenarios 1-6, 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% 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% 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)	48.12	3.69
Green Woody Biomass Microchips (Dry)	51.10	3.92
Torrefied Woody Biomass (As Received)	134.66	6.51

Table 3-6: By-Product Value

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

By-product credits include any sales of electric power to the grid. No credit is taken for the sale of elemental sulfur. Because it is assumed that the captured carbon dioxide will be used for CO_2 enhanced oil recovery operations, an expected value of $40/ton is assumed for the carbon dioxide captured. 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 Required Selling Price Estimates for Products

The key measure of the economic viability of the CBTL facilities under each of the six 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 recovery factor or Capital Charge Factor. The default capital recovery factor used in this financial analysis is 0.2365 (Nexant, 2008).

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.

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. Assuming that this ratio is valid then dividing the RSP by 1.2 will give an estimate of the crude oil equivalent (COE) price.

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 materials acquisition (RMA), raw materials 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 Materials Acquisition

Raw materials 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

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.

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 39-40 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 (5 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. Torrefaction (discussed in greater detail below) provides an alternative to grinding, 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

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 nominal 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

[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.

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% 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)

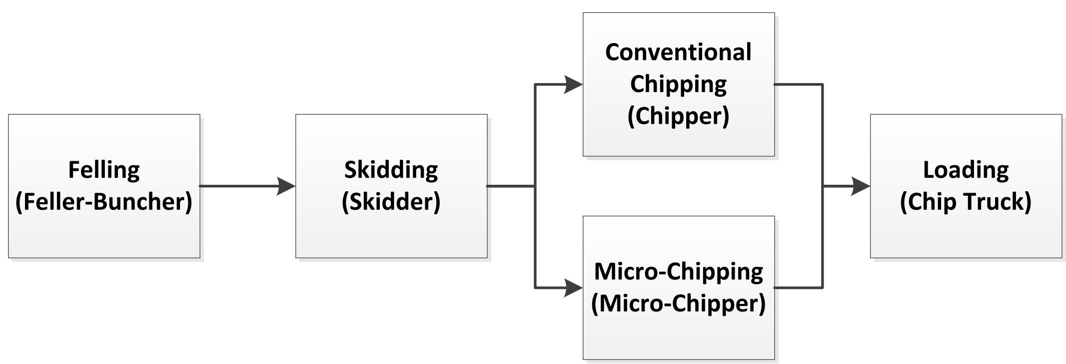
Water use was also considered. Water is supplied to the plantings via a combination of rainfall and irrigation water, with the irrigation water assumed to be a 1:1 mix of surface water and groundwater. Herein, irrigation water is assumed to be used supplemental to rainfall in order to minimize water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

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% of all cropland and pasture lost during direct land use would be replaced at a

[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.

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 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.

4.2.2.1 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.

4.2.2.2 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^{o}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% by mass of the gas stream - even when the biomass is dried to zero or near-zero moisture content. Typically, about 5 to 10% 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.

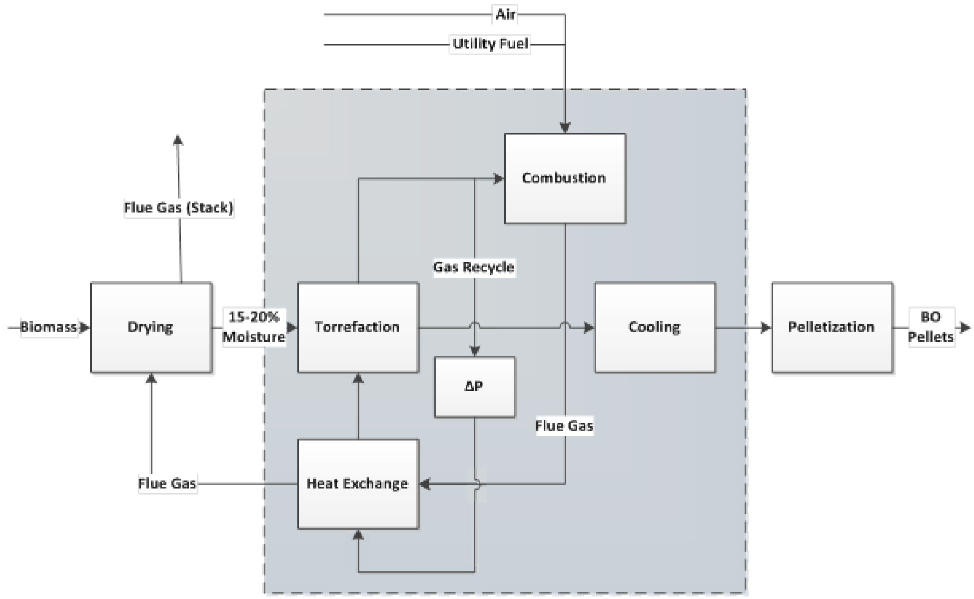
Figure 4-2 shows the schematic of the directly heated torrefaction system assumed for this study. This system is under development by ECN of the Netherlands (Bergman, Boersma, Zwart, & Kiel, 2005). In this system some or most of the necessary heat for drying and torrefaction comes from the combustion 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% moisture prior to being fed to the torrefaction step. Torrefaction is accomplished in the directly heated moving bed torrefaction chamber at a temperature of 536^{o}F (280^{o}C). 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% the value of the dry feed to the torrefaction reactor for woodcuttings and demolition wood, respectively (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% 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^{o}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^{o}C for 17.5 minutes (Bergman, Boersma, Kiel, Prins, & Ptasinski, 2005; 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, carbon dioxide transport pipelines, and CO_2 enhanced oil recovery.

4.3.1 CBTL Facility

All of the six 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.

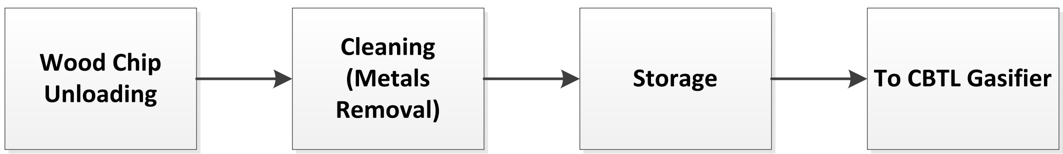
4.3.1.2.1 Feedstock Handling at the CBTL Facility

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 trucks arriving at the CBTL facility or torrefaction plant site. 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% 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% 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 (Scenarios 2 and 3 Only)

Under Scenario 2, CBTL, 10% Chipped Biomass and Scenario 3: CBTL, 20% 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 (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 (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%. 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.

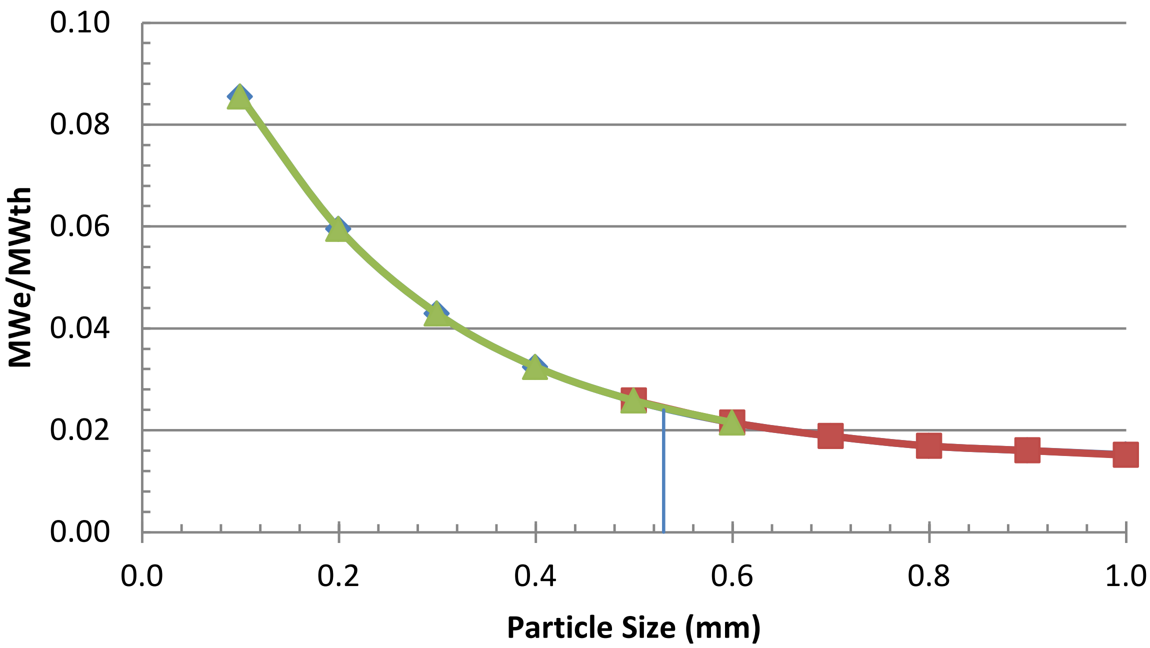
Finally, the influence of the torrefaction operating conditions (residence time and temperature) was found to be limited. Variations in torrefaction time and temperature did not have a very pronounced impact on the grinding energy. Most of the torrefied data on the plots were bunched together at the low end of the grinding energy curves (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 (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: (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 modeling for the six 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 700 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% 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. Wildboz (2007) assumes that leakage rate will be similar to that of natural gas in pipeline transport, and assumes a leakage rate of 0.026% per 1000 km of transport distance. This value is assumed for this study.

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. Approximately 96% of this total, or 5.55E-06 kg CO_2/kg CO_2-km transported, results from CO_2 venting during pigging operations. The remaining 4%, or 2.60E-07 kg CO_2/kg CO_2-km transported, results from fugitive pipeline leakage.

Catastrophic events, including leakage of large volumes of CO_2 from CO_2 transport pipelines, are excluded from this study.

4.3.3 Carbon Dioxide Enhanced Oil Recovery

Carbon dioxide enhanced oil recovery (CO_2-EOR) encompasses oil extraction activities using carbon dioxide injection, combined with a water alternating gas (WAG) injection strategy, and underground storage of injected carbon dioxide. The study assumes that CO_2-EOR would occur in the Permian Basin of Texas, where CO_2-EOR is currently being employed, based on natural sources of extracted carbon dioxide that are piped to the region. During the CO_2-EOR process, carbon dioxide is injected into an oil-bearing formation. This reduces the viscosity of the crude oil, allowing a greater fraction of the total oil-in-place to be recovered, than could be recovered using conventional techniques. The system is then flushed with water (i.e., water alternating gas process) to drive formation oil away from injection wells and towards extraction wells. Some fraction of carbon dioxide that is injected is later recovered, along with crude oil, water, natural gas, and minor components. The carbon dioxide is separated and then subsequently re-injected in support of continued oil extraction. Over time, the injected carbon dioxide remains within the oil bearing formation, and is eventually sequestered therein. Carbon dioxide is delivered from the CBTL facility via the carbon dioxide transport pipeline to the CO_2-EOR site. CO_2-EOR operations result in the production of crude oil and natural gas liquids as products.

The analysis considered within this study considers all phases of CO_2-EOR including: site preparation and construction, CO_2-EOR flooding operation, well abandonment, and post-closure monitoring of CO_2 storage. The data sources and analyses presented here are based largely on prior life cycle modeling for EOR activities (Aviation Fuel Life Cycle Assessment Working Group, 2011).

4.3.3.1 Construction

The CO_2-EOR facilities considered within this study include infrastructure required for CO_2 transport, CO_2 injection, product/CO_2 production and transport, and product/CO_2 processing, including processing of both liquid and gaseous fluid streams. Because the process is presumed to occur within the Permian Basin on oil fields that were previously extracted using primary and secondary oil recovery techniques, it is assumed that several needed components are pre-existing. Specifically, the following facilities are presumed to be pre-existing with respect to CO_2-EOR site construction: water tanks, crude oil tanks, EOR pattern (injection and production wells), produced fluid collection lines, and water distribution lines. Implementation of CO_2-EOR would, however, require the construction/installation of new equipment. Required facilities include new CO_2 distribution lines, a gas processing facility, CO_2 compressors, excess brine disposal wells, and tank battery vapor recovery units. While EOR pattern wells are pre-existing, it is assumed that they will require extensive workover prior to initiation of CO_2-EOR activities on site, and also periodically throughout operations.

4.3.3.2 Operation

Enhanced oil recovery, also termed tertiary oil recovery, includes the extraction of oil from formation oil that cannot be meaningfully extracted by primary production and secondary recovery (i.e., water flood extraction). In the CO_2-EOR process, CO_2 is injected into the oil containing formation under pressure. Above a minimum miscibility pressure, CO_2 flooding enhances miscibility of the oil contained in the formation. Herein, under sufficient pressure, CO_2 and formation oil become mutually soluble, resulting in a lower overall viscosity than the pre-injection crude oil. Reduced viscosity supports increased mobility, which facilitates extraction. In the West Texas Permian Basin,

CO_2 floods are injected in sequence with water: following completion of the CO_2 flood, water injection drives the miscible CO_2/oil phase towards extraction wells. This water alternating gas EOR process supports incremental extraction of oil with each gas/water flood cycle.

Several direct and indirect sources for GHG emissions are considered for the CO_2-EOR process. These result from the upstream profile of energy and material feedstocks and energy products associated with CO_2-EOR. These potential sources of emissions can be grouped into three general categories of activities: produced gas stream processing, produced liquid stream processing, and WAG injection into the oil-bearing formation.

Electric powered pumps are assumed to be used for all processes on site that require pumps, including recovery of mixed CO_2-crude oil products from the formation, injection of brine used for the water alternating gas injection into the formation, and injection of excess produced water that is disposed of through deep well injection. Electricity use from these processes is quantified. The incoming CO_2 stream is assumed to arrive at the CO_2-EOR site at a pressure of 2,000 psig. In order to enable injection in support of CO_2-EOR, it is necessary to boost total CO_2 pressure to 2,200 psig. This is accomplished by an electric motor-driven compressor prior to injection. Electricity requirements are calculated based on average flow rates of each stream. Upstream emissions associated with production of electricity utilized at the CO_2-EOR site are estimated based on the average electricity grid profile for the U.S.

Gas Processing

Along with crude oil, gas is produced by the CO_2-EOR process. This gas contains a combination of CO_2, water vapor, and hydrocarbon gas. In order to minimize GHG emissions, enable the recycling of CO_2 back into the formation, and strip usable products from the gas stream, a series of gas processing steps are implemented. Gas processing operations include dehydration of bulk produced gas, separation of CO_2 from produced oil-associated hydrocarbon gas, and recompression of separated $CO_{2.}$ Following recompression, the CO_2 is then re-injected into the subsurface, to facilitate additional crude extraction. Stripped hydrocarbon volatiles include natural gas and natural gas liquids (NGL), which are saleable products, though they are commonly used on site. Removing hydrocarbon volatiles also reduces the pressure at which the recycled CO_2 stream becomes miscible with oil within the formation, which reduces compression and formation working pressure requirements. The separation process for CO_2 and hydrocarbon volatiles is assumed to be carried out using the Ryan-Holmes process, which is a cryogenic separation process used for some CO_2-EOR operations. The process separates natural gas and NGLs from the CO_2 using column fractionation that takes advantages of distinct condensation points for these gases.

Electricity use in support of gas processing is required for cooling (via compression of refrigerant) used for the Ryan-Holmes process separation column, and for compression of isolated CO_2 to support recycling and reinjection back into the oil-bearing formation. Separated volatile hydrocarbons are used for onsite requirements including at the fuel gas processing plant, while remaining product is delivered to a pipeline as saleable product. NGLs are collected in a storage tank, which is transported offsite by truck as saleable product.

Requirements for fuel on site (natural gas and diesel), and associated combustion emissions, were estimated for the natural gas processing plant including gas fired turbines, diesel backup generator, natural gas oil heater, and natural gas fired compression engines. Fugitive emissions from plant valves and fittings were estimated based on EPA AP-42 fugitive loss factors.

Produced Liquids Processing

Processing of extracted liquids involves the use of a tank battery – essentially a collection of fluid flow lines, processing equipment, and storage tanks – used to process and store produced liquids. A single tank battery serves one or more oil producing wells, and serves as an intermediary process between liquid products (including oil and produced water) and pipeline transport of product oil. Extracted liquids pass through a liquid/liquid separator tank that separates oil from water. The separated oil fraction is then thermally treated in a natural gas fired heater/treater. This breaks up any remaining water/oil emulsions. From that point, the separated oil and water are transferred to separate storage tanks. Here oil is stored temporarily until it is transferred to a pipeline for sale, while produced water (brine) is pumped for reinjection in the CO_2-EOR or WAG process. Alternatively, excess produced water (brine) is pumped to a separate injection well for deep well disposal. Deep well disposal of excess produced water is common within the Permian Basin and other areas with suitable deep formations.

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% 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).

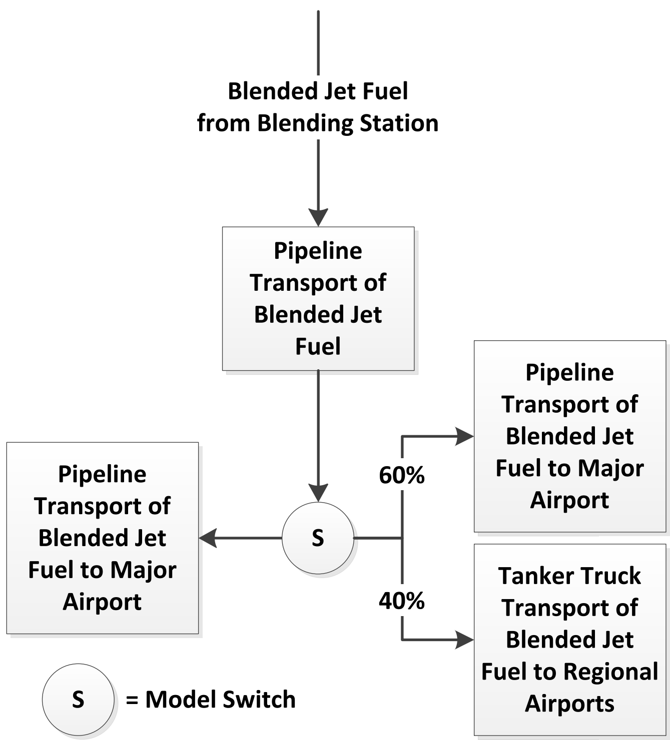
4.4.2 F-T Jet Fuel / Conventional Petroleum Jet Fuel Blending

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% 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% Pipeline Transport to Major Airport and 40% 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% of the blended product to the single major airport located 160 miles distant; and (3) tanker truck transport operations that ship 40% 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% 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% 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. Because the product suite and coal feed rates vary by scenario, mercury emissions rates also varied by scenario, ranging from 2.35E-08 kg/kg blended jet fuel for the CBTL, 20% Torrefied Biomass scenario, to 2.99E-08 kg/kg jet blended fuel for CBTL, 0% Biomass scenario. 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 six scenarios modeled in support of this study. Results from the analytical/process evaluation, economic evaluation, and life cycle analysis are presented, for each scenario.

5.1 Scenario 1: CBTL, 0% 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 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. Carbon dioxide is then transported along a pipeline to carbon dioxide based utilization and storage, supporting an enhanced oil recovery process. 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 model cases were run for this scenario: low required selling price (RSP), expected RSP, and high RSP. Process summary results 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% 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% (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34% 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% of total products) and F-T LPG (7% 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 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
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	53.8	53.4	52.2	%
CBTL Facility Inputs/Feed				
Coal Feed, Montana Rosebud, As Received	30,485	30,483	30,877	tons/day
Biomass Feed, Southern Pine, As Received	0	0	0	tons/day
Water Feed (Total Withdrawal)	14,211,738	13,706,376	13,261,426	gallons/day
CBTL Facility Outputs/Production				
F-T Jet Fuel Production	24,649	24,647	24,645	bpd
F-T Diesel Fuel Production	4,767.0	4,766.7	4,766.2	bpd
F-T Naphtha Production	16,972.8	16,971.6	16,969.9	bpd
F-T LPG Production	3,612	3,615	3,619	bpd
Total Liquid Product Output	50,000	50,000	50,000	bpd
Export Power	259	232	199	MW
CO_2 Captured and Compressed	31,112	30,875	30,780	tons/day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,298	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% was included, ranging from 85 to 92% for low and high RSP cases, respectively. The overall expected plant efficiency of 53.4% (range of 52.2 to 53.8%) 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. Makeup water for the CBTL facility, as modeled in Aspen Plus®, is estimated to be approximately 13.7 million gallons per day (mgd; expected RSP case), of which 94% (12.9 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.5 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 199 to 259 MW, with an expected value of 232 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 (92 MW), the Selexol unit (52 MW), hydrocarbon recovery/refrigeration (43 MW), and oxygen compression (32 MW). Total auxiliaries consume 562 MW, for a net power output of 232 MW under the expected RSP case.

Carbon balance for the CBTL facility is shown in **Table 5-2**, for all three RSP cases. As shown, carbon inputs were within 0.2% 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
Coal Carbon	15,263	15,262	15,459	TPD
Biomass Carbon	0	0	0	TPD
Total Carbon Input	**15,263**	**15,262**	**15,459**	**TPD**
F-T Products	5,284	5,284	5,284	TPD
Slag/Ash	153	305	618	TPD
Stack Gas	1,019	955	892	TPD
Fuel Gas	273	245	214	TPD
Waste Water Treatment Plant (WWTP)	0	0	0	TPD
Carbon Capture, Sequestered	8,509	8,447	8,425	TPD
Total Carbon Output	**15,238**	**15,237**	**15,434**	**TPD**
Carbon Capture	**87.9%**	**88.6%**	**89.5%**	**%**

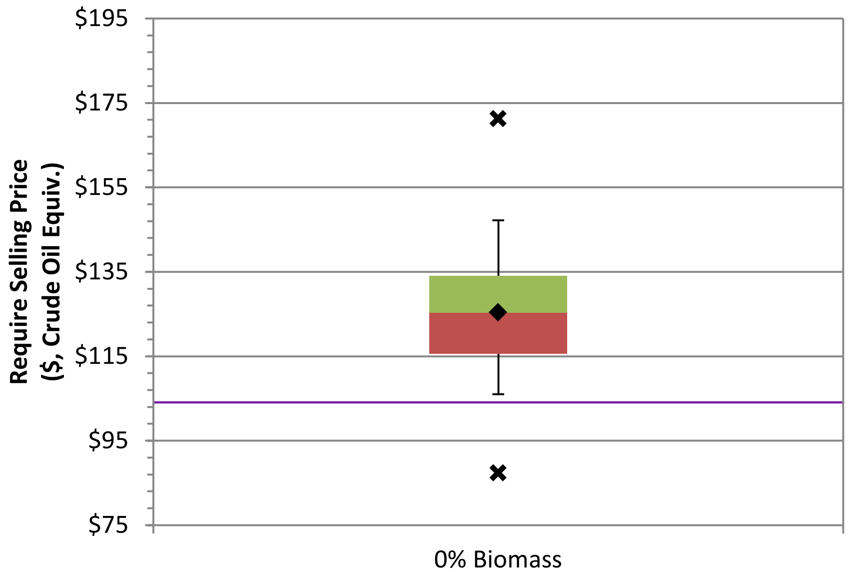
5.1.2 Economic Results

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% 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 \$116 to \$134/bbl, with a mean value of \$125/bbl, on a crude oil equivalent basis. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 18 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 \$88 to \$182/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 1.2. 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 baseline value.

Table 5-3 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 $442 million/yr. Of this amount, $261 to $286 million/yr, mean $274 million/yr (62%), results from fixed costs, while $160 to $175 million/year, mean $168 million/yr (38%) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, ranging from $7,132 to $8,118 million, mean $7,645 million. Feedstock costs for this scenario are limited to coal cost, which range from $353 to $367 million/yr, mean value of $360 million/yr. No biomass costs are incurred, and feedstock costs are approximately $82 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 $124 to $132 million/yr, mean $128 million/yr, while CO_2 credit is estimated to be $332 to $396 million/yr, mean $364 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $1,970 to $2,255 million/yr, mean $2,118 million/yr.

Required product sales prices 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 $142 to $163/bbl, mean $153/bbl, with F-T diesel at $140 to $160/bbl, mean $150/bbl, F-T naphtha at $98 to $113/bbl, mean $106/bbl, and F-T LPG at $58 to $69/bbl, mean $64/bbl. The default capital charge factor (CCF) used in the analysis was 0.2365. This CCF results from a 50% debt to equity ratio, a 15 year debt term, a nominal dollar cost for debt of 8% and 20% on equity, and an after tax weighted cost of capital of 13.1%.

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

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	274	218	342	261	286	$Million/yr
Variable Operating and Maintenance Cost (VOM)	168	138	203	160	175	$Million/yr
Capital: Total Overnight Cost (TOC)	7,645	6,035	9,813	7,132	8,118	$Million
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	360	329	389	353	367	$Million/yr
Biomass Cost, Southern Pine, Chips, As Received	0	0	0	0	0	$Million/yr
Biomass Cost, Southern Pine, Torrefied, As Received	0	0	0	0	0	$Million/yr
Credits and Revenue						
Power Credit	128	111	144	124	132	$Million/yr
Credit @ $40/ton for CO_2	364	249	475	332	396	$Million/yr
Annual Revenue Required	2,118	1,577	2,852	1,970	2,255	$Million/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	153	113	209	142	163	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	150	112	207	140	160	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	106	77	146	98	113	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	64	43	102	58	69	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	125	88	182	116	134	$/bbl

Figure 5-2 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 69% of total RSP, or $86.9/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 17% of total RSP, or $21.3/bbl, while feedstock costs represent 14% of total RSP, or $17.3/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.

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

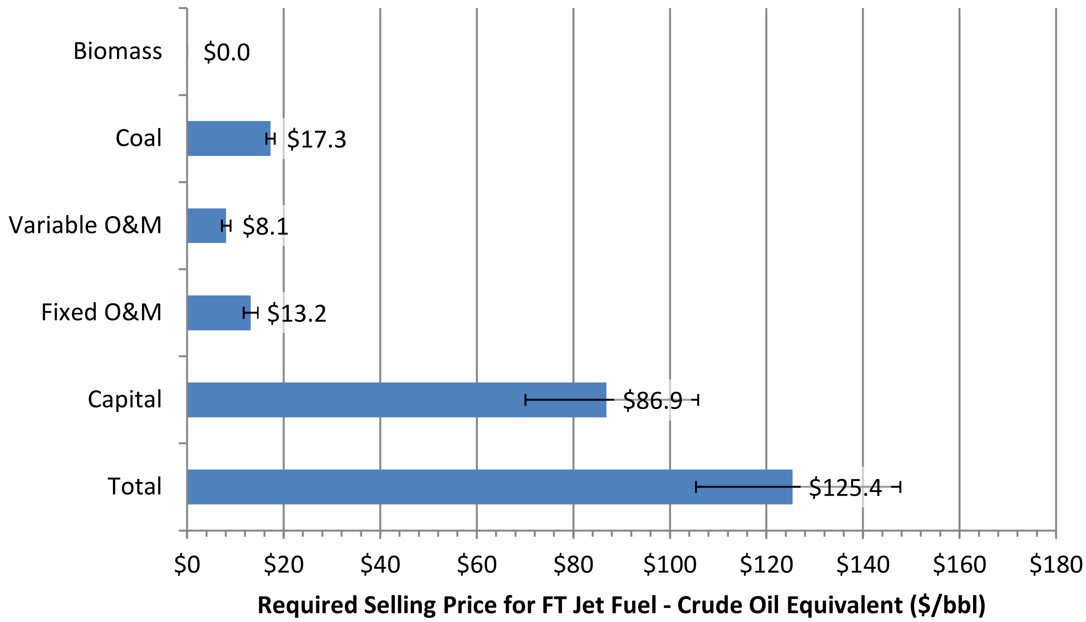
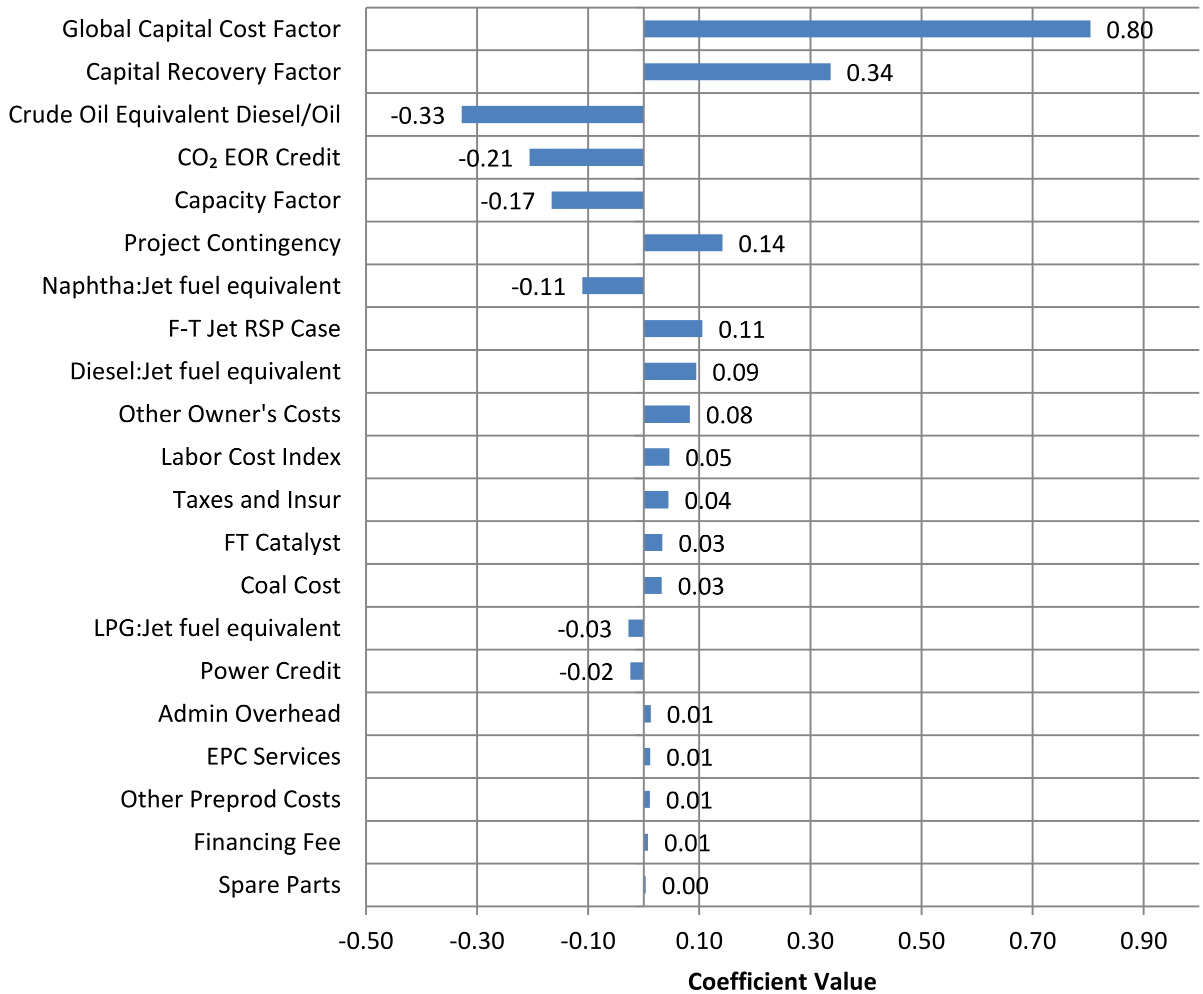


Figure 5-3 provides a summary of model sensitivity, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.8, such that variability in global capital cost factor can explain approximately 64% of total variability in RSP output. Other key factors that account for at least 10% of the observed variability in RSP include capital recovery factor and crude oil equivalent diesel/oil. Parameters that caused minimal influence on RSP included administrative overhead, power credit, F-T catalyst cost, LPG:jet fuel equivalent, and coal cost.

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



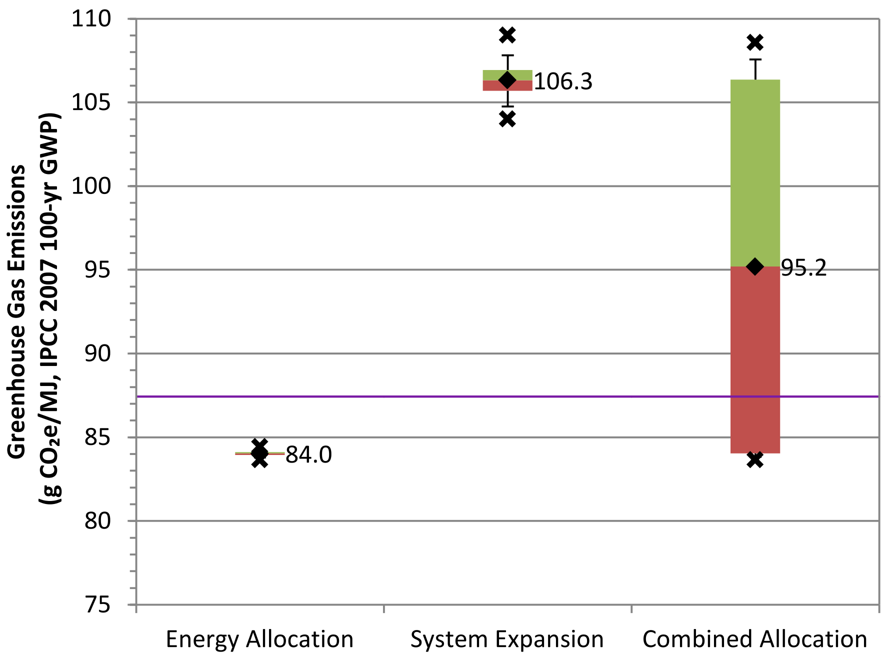
5.1.3 Environmental Results

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% 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 5-4** provides a summary life cycle GHG emissions for this scenario, in comparison to conventional jet fuel life cycle GHG emissions of 87.4 g CO_2e/MJ. As discussed in Chapter 1, two discreet allocation procedures were performed: energy allocation and system expansion. These were then combined to produce an average value as shown for the combined allocation result.

Allocation procedure is a key consideration with respect to whether or not life cycle GHG emissions for this scenario exceed life cycle emissions compared to conventional jet fuel. Anticipated GHG emissions of 25th and 75th percentile results for energy allocation range from 83.9 to 84.1g CO_2e/MJ, mean 84.0 g CO_2e/MJ, or approximately 3.9% less than conventional jet fuel (based on mean value). However, when the same scenario is considered using system expansion, the resulting range is 105.7 to 106.9 g CO_2e/MJ, mean 106.3 g CO_2e/MJ, or approximately 22% greater than conventional jet fuel. Combined allocation closely reflects the overall range of energy allocation and system expansion, ranging from 84.0 to 106 g CO_2e/MJ, mean 95.2 g CO_2e/MJ, or approximately 8.9% greater than conventional jet fuel (based on mean value). Variability of results from system expansion is greater than that for energy allocation.

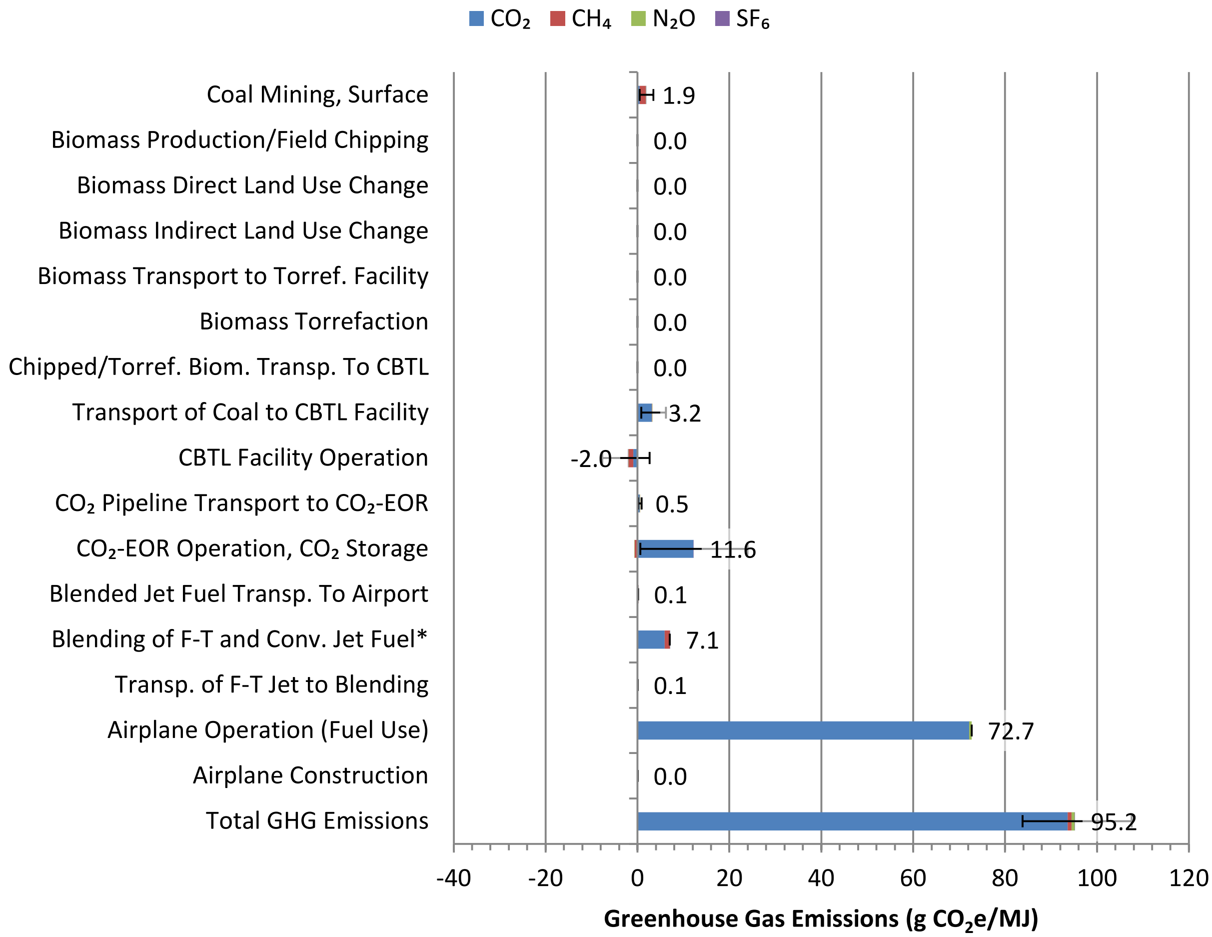
Figure 5-4: Scenario 1: CBTL, 0% Biomass: Summary of LC GHG Emissions



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.

Figure 5-5 provides detail regarding the importance of the various LCA components that were modeled, with respect to total GHG emissions contributions. Breakdowns are presented for combined allocation only. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 76% of total life cycle GHG emissions. Second in importance to fuel combustion are upstream emissions associated with enhanced oil recovery and CO_2 storage, which represent 12% of total life cycle emissions, while the production of conventional jet fuel accounts for 7.5% of total life cycle GHG emissions. Emissions from the transport of coal to the CBTL facility represent approximately 3.4% of total emissions. CBTL facility emissions are indicated as negative due to the displacement of conventional fuels having higher upstream CO_2 emissions, while coal mining accounted for approximately 1.9% of total life cycle emissions. Other contributors to total emissions were less than 1% individually.

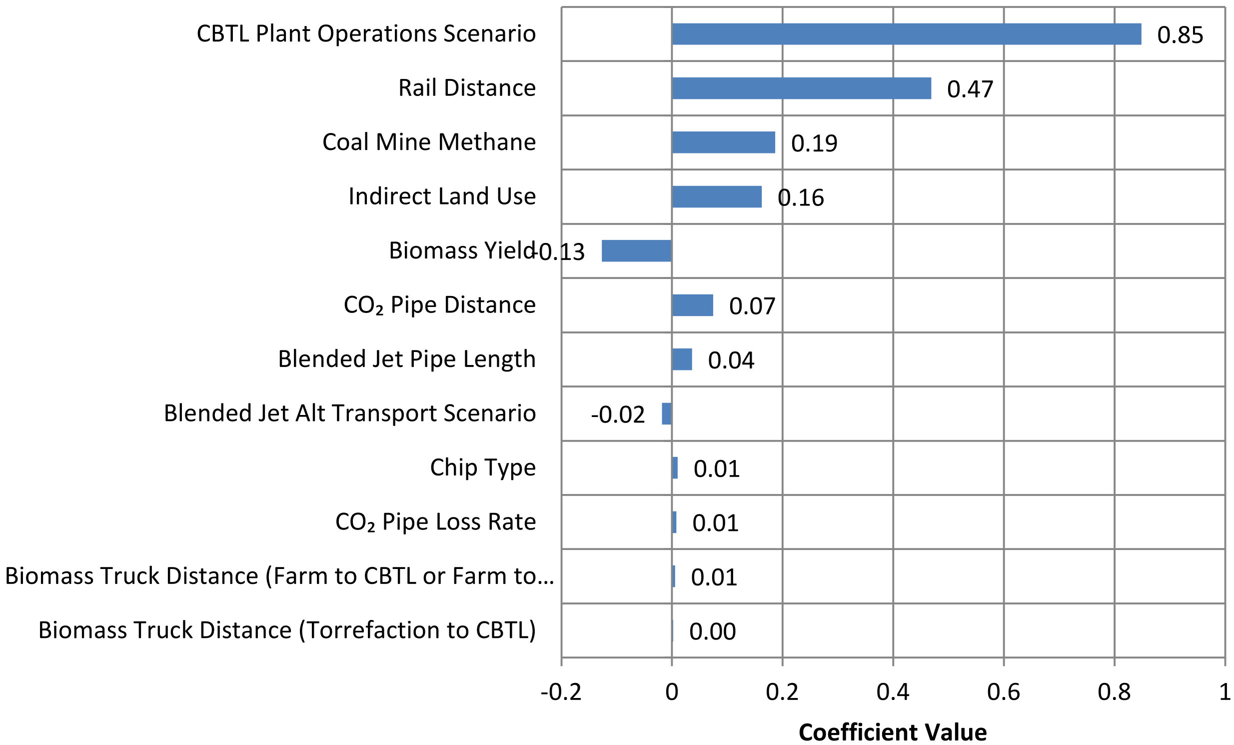
Figure 5-5: Scenario 1: CBTL, 0% Biomass: LC GHG Emissions Breakdowns, Combined Allocation



** 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), based on combined allocation. The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-5**, distinct from co-product management scheme. As shown, variability in emissions resulted primarily from CO_2-EOR operation and carbon dioxide storage. Other key contributors to variability in model output include CBTL facility operation, and transport of coal to the CBTL facility. Other modeled processes contributed minimally to the overall variability in model results**. 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. CBTL plant operations scenario refers to the low and high RSP technical cases considered in the analysis, as discussed in Chapter 2. Excluding co-product management scheme, this parameter was found to have the greatest effect on life cycle emissions, such that variability in CBTL facility operations can explain approximately 71% of total variability in GHG emissions caused by sensitivity to environmental parameters. Other important factors included rail transport distance for coal, and coal mine methane emissions. CO_2 pipeline loss rate, blended jet fuel transport method, and blended jet fuel transport pipeline length had negligible effects on model output.

Figure 5-6: Scenario 1: CBTL, 0% Biomass: 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, for energy allocation only. 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. 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: Non-GHG Emissions, Energy Allocation

LC Stage	Carbon monoxide	NOx	SO_2	PM_{10}	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	6.92E-07	3.63E-07	1.28E-07	4.36E-09	5.05E-08	1.15E-12	2.69E-08	-1.97E-04	kg/MJ Jet Fuel
RMT	2.49E-06	2.13E-06	5.94E-07	2.76E-06	4.07E-07	5.27E-13	3.13E-08	4.32E-04	kg/MJ Jet Fuel
EC	5.08E-08	2.56E-08	1.99E-08	7.94E-09	1.04E-10	1.51E-10	8.17E-08	2.95E-02	kg/MJ Jet Fuel
PT	6.53E-06	9.52E-06	1.78E-05	1.75E-07	2.00E-05	1.53E-11	8.03E-08	2.21E-02	kg/MJ Jet Fuel
EU	1.78E-04	2.79E-04	1.29E-05	6.04E-08	1.77E-05	6.89E-10	1.33E-10	6.08E-05	kg/MJ Jet Fuel
Total	**1.87E-04**	**2.91E-04**	**3.14E-05**	**3.01E-06**	**3.82E-05**	**8.57E-10**	**2.20E-07**	**5.20E-02**	**kg/MJ Jet Fuel**

5.2 Scenario 2: CBTL, 10% 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% sub-bituminous coal and 10% 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. Carbon dioxide is then transported along a pipeline to carbon dioxide based utilization and storage, supporting an enhanced oil recovery process. 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.

5.2.2 Process Results

As discussed in Chapter 2, three Aspen model cases were run for this scenario: low required selling price (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% 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% (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34% 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% of total products) and F-T LPG (7% 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 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	53.6	53.1	51.4	%
CBTL Facility Inputs/Feed				
Coal Feed, Montana Rosebud, As Received	28,056	28,121	28,481	tons/day
Biomass Feed, Southern Pine, As Received	4,183	4,091	4,143	tons/day
Water Feed (Total Withdrawal)	13,834,179	13,365,582	12,910,594	gallons/day
CBTL Facility Outputs/Production				
F-T Jet Fuel Production	24,649	24,647	24,645	bpd
F-T Diesel Fuel Production	4,767.0	4,766.8	4,766.4	bpd
F-T Naphtha Production	16,972.7	16,971.8	16,970.1	bpd
F-T LPG Production	3,612	3,615	3,619	bpd
Total Liquid Product Output	50,000	50,000	50,001	bpd
Export Power	241	214	149	MW
CO_2 Captured and Compressed	31,324	31,099	30,998	tons/day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,298	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% was included, ranging from 85 to 92% for low and high RSP cases, respectively. The overall expected plant efficiency of 53.1% (range of 51.4 to 53.6%) 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 13.4 million gallons per day (mgd; expected RSP case), of which 94% (12.6 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.4 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 149 to 241 MW, with an expected value of 214 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 MW), the Selexol unit (53 MW), hydrocarbon recovery/refrigeration (43 MW), and oxygen compression (32 MW). Total auxiliaries consume 568 MW, for a net power output of 214 MW 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% 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% of total carbon (range of 1% for the low RSP case to 4% 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	14,047	14,080	14,260	TPD
Biomass Carbon	1278	1250	1266	TPD
Total Carbon Input	**15,325**	**15,329**	**15,525**	**TPD**
F-T Products	5,284	5,284	5,284	TPD
Slag/Ash	153	307	621	TPD
Stack Gas	1,020	958	894	TPD
Fuel Gas	275	247	216	TPD
WWTP	0	0	0	TPD
Carbon Capture, Sequestered	8,567	8,508	8,485	TPD
Total Carbon Output	**15,299**	**15,304**	**15,500**	**TPD**
Carbon Capture	**87.9%**	**88.7%**	**89.5%**	**%**

5.2.3 Economic Results

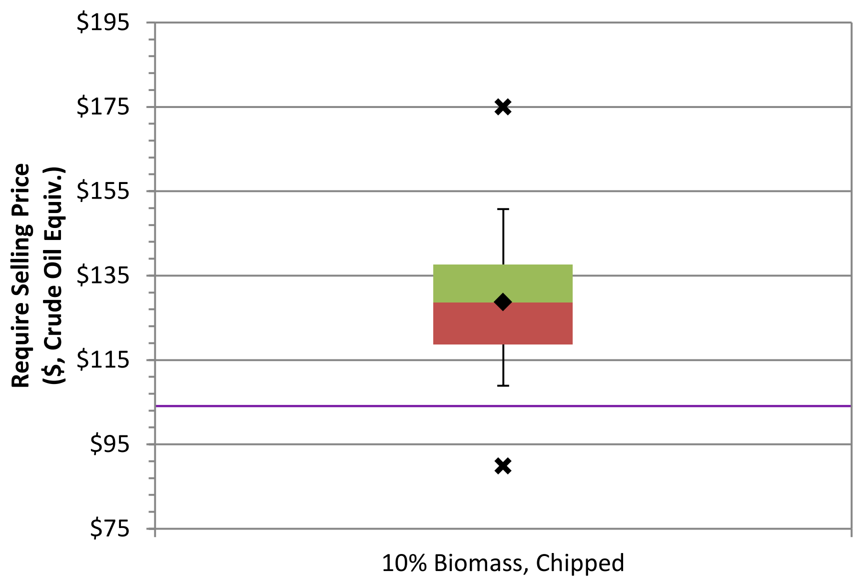
Results from the economic model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50% 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 \$119 to \$138/bbl, with a mean value of \$129/bbl, on a crude oil equivalent basis. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 18 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 $90 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 1.2. 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 baseline 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 $445 million/yr. Of this amount, $271 to $297 million/yr, mean $285 million/yr (63%), results from fixed costs, while $162 to $178 million/year, mean $170 million/yr (37%) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, range from $7,245 to $8,254 million, mean $7,771 million. Coal feedstock costs for this scenario range from $326 to $338 million/yr, mean $332 million/yr. Biomass feedstock costs range from $33 to $35 million/yr, mean $29 million/yr. Total feedstock costs are approximately $94 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 $114 to $121 million/yr, mean $118 million/yr, while CO_2 credit is estimated to be $334 to $399 million/yr, mean $367 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,021 to $2,314 million/yr, mean $2,174 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 $146 to $168/bbl, mean $157/bbl, with F-T diesel at $143 to $164/bbl, mean $154/bbl, F-T naphtha at $100 to

$116/bbl, mean $109/bbl, and F-T LPG at $60 to $71/bbl, mean $66/bbl. The default capital charge factor (CCF) used in the analysis was 0.2365. This CCF results from a 50% debt to equity ratio, a 15 year debt term, a nominal dollar cost for debt of 8% and 20% on equity, and an after tax weighted cost of capital of 13.1%.

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)	285	227	357	271	297	$Million/yr
Variable Operating and Maintenance Cost (VOM)	170	140	205	162	178	$Million/yr
Capital: Total Overnight Cost (TOC)	7,771	6,123	10,067	7,245	8,254	$Million
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	332	359	304	326	338	$Million/yr
Biomass Cost, Southern Pine, Chips, As Received	29	40	29	33	35	$Million/yr
Biomass Cost, Southern Pine, Torrefied, As Received	0	0	0	0	0	$Million/yr
Credits and Revenue						
Power Credit	118	103	133	114	121	$Million/yr
Credit @ $40/ton for CO_2	367	250	478	334	399	$Million/yr
Annual Revenue Required	2,174	1,622	2,915	2,021	2,314	$Million/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	157	116	214	146	168	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	154	115	212	143	164	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	109	79	151	100	116	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	66	44	104	60	71	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	129	90	186	119	138	$/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 69% of total RSP, or $89.0/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 17% of total RSP, or $22.0/bbl, while feedstock costs represent 14% of total RSP, or $17.8/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.

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

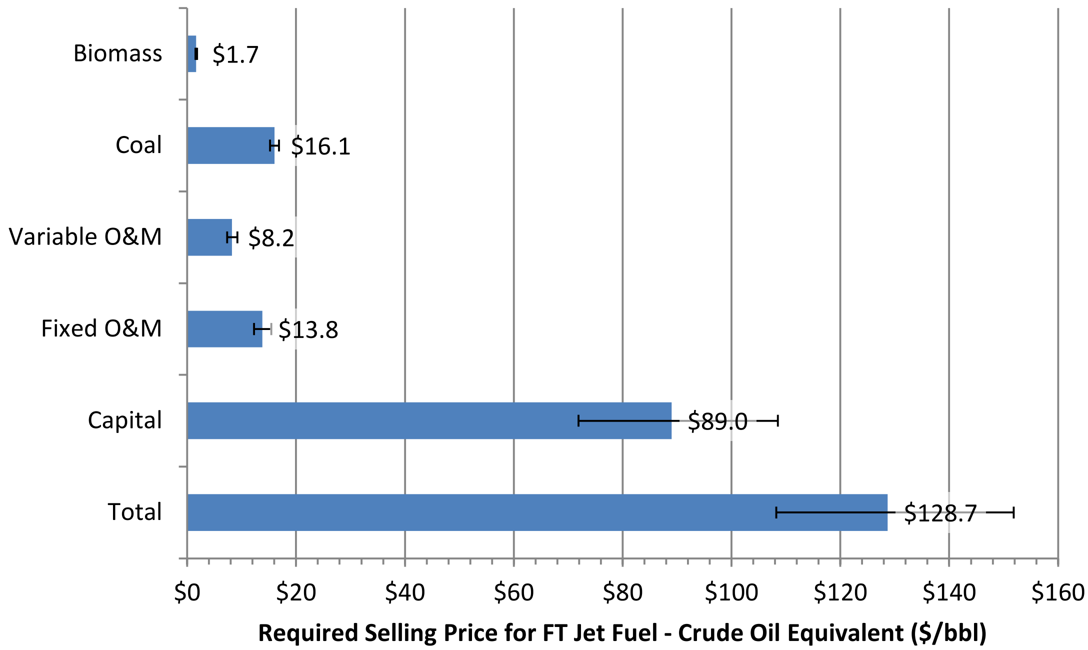
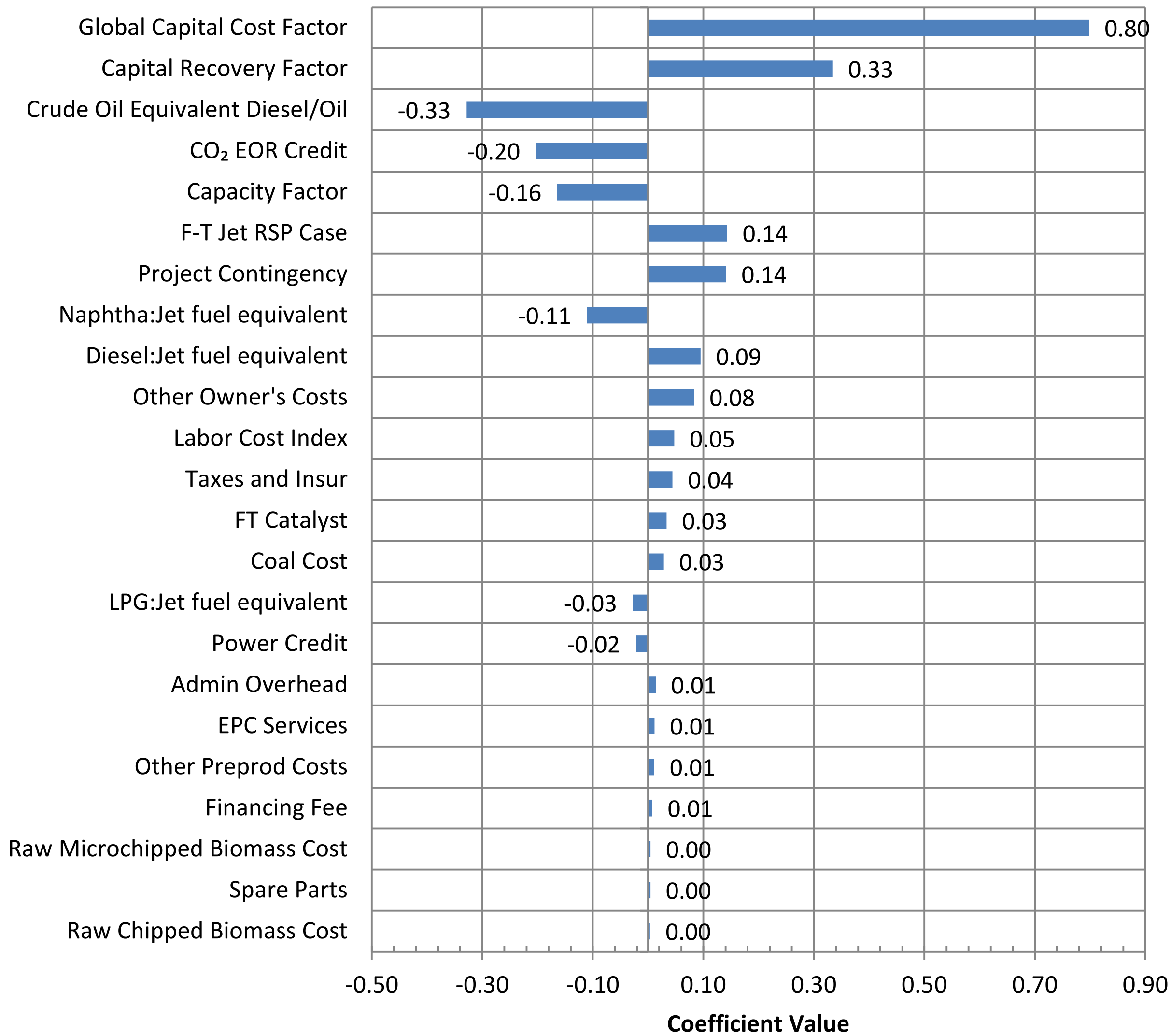


Figure 5-9 provides a summary of model sensitivity, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.8, such that variability in global capital cost factor can explain approximately 64% of total variability in RSP output. Other key factors that account for at least 10% of the observed variability in RSP include capital recovery factor and crude oil equivalent diesel/oil. Parameters that caused minimal influence on RSP included raw chipped biomass cost, spare parts, financing fee, administrative overhead, F-T catalyst cost, taxes and insurance, and others as shown.

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



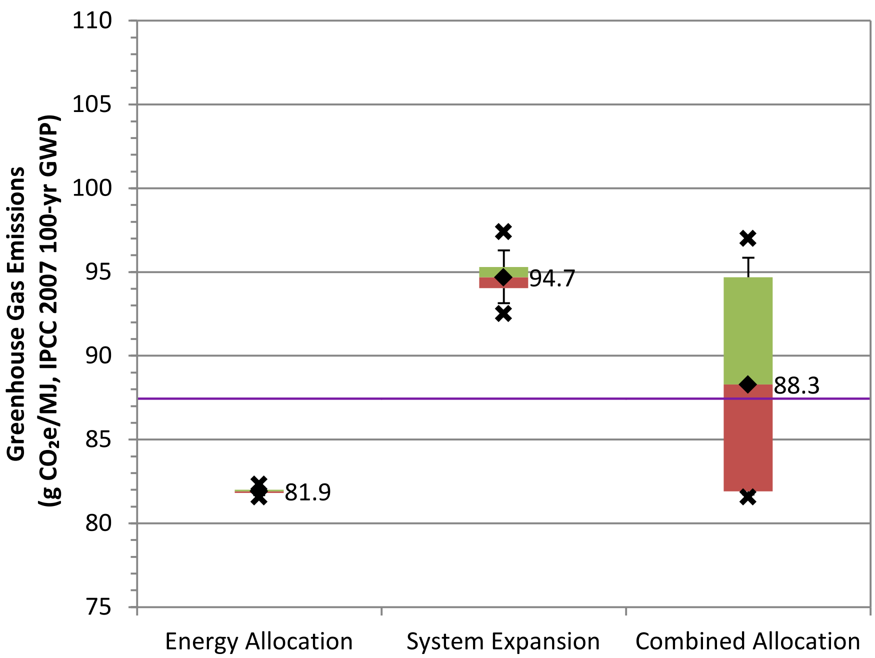
5.2.4 Environmental Results

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% 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 87.4 g CO_2e/MJ. As discussed in Chapter 1, two discreet allocation procedures were performed: energy allocation and system expansion. These were then combined to produce an average value as shown for the combined allocation result.

Allocation procedure is a key consideration with respect to whether or not life cycle GHG emissions for this scenario exceed life cycle emissions compared to conventional jet fuel. Anticipated GHG emissions of 25th and 75th percentile results for energy allocation range from 81.8 to 82.0g CO_2e/MJ, mean 81.9 g CO_2e/MJ, or approximately 6.3% less than conventional jet fuel (based on mean value). However, when the same scenario is considered using system expansion, the resulting range is 94.1 to 95.3 g CO_2e/MJ, mean 94.7 g CO_2e/MJ, or approximately 8.3% greater than conventional jet fuel. Combined allocation closely reflects the overall range of energy allocation and system expansion, ranging from 81.9 to 94.7 g CO_2e/MJ, mean 88.3 g CO_2e/MJ, or approximately 1.0% greater than conventional jet fuel (based on mean value). Variability of results from system expansion is greater than that for energy allocation.

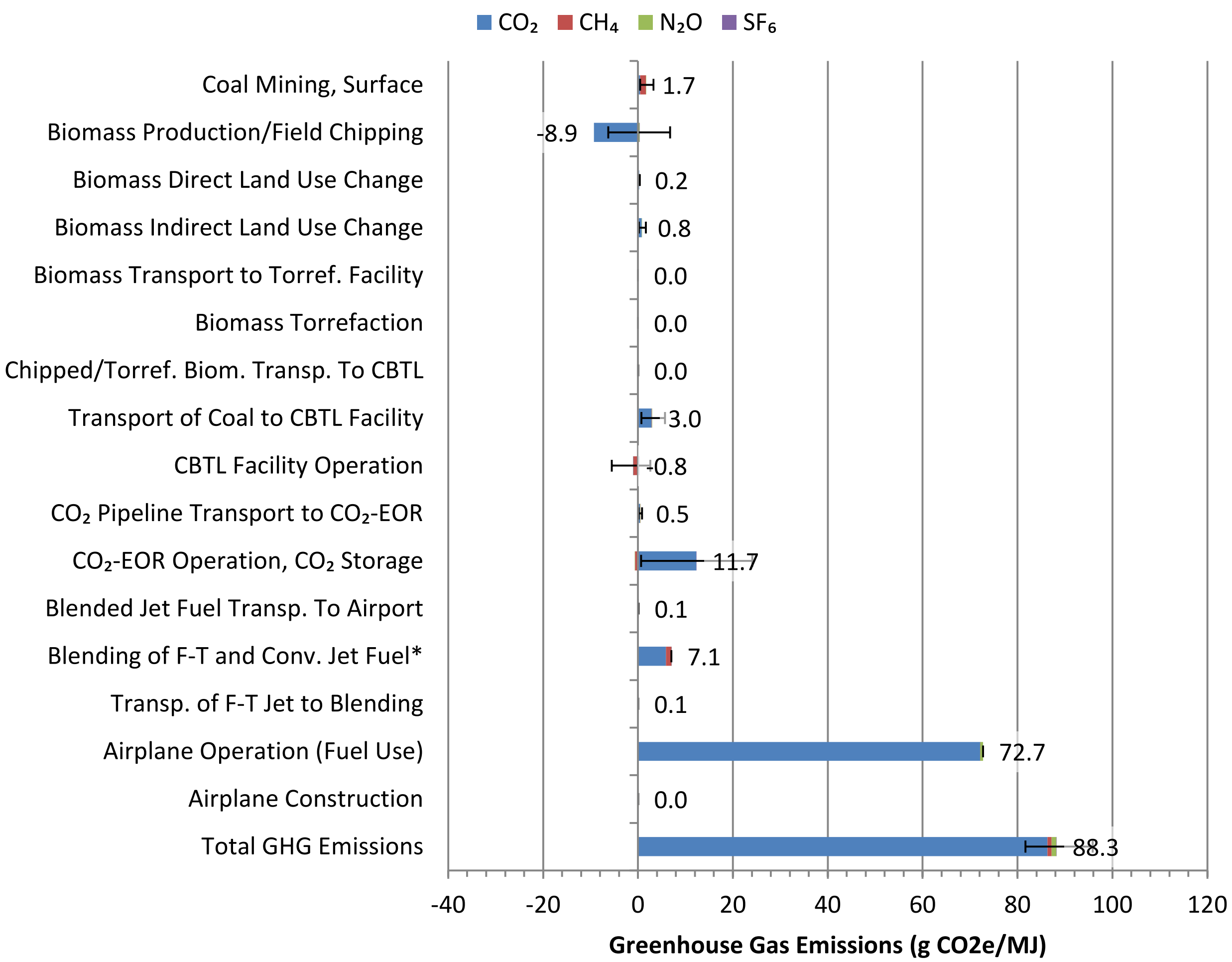
Figure 5-10: Scenario 2: CBTL, 10% Chipped Biomass: Summary of LC GHG Emissions



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 total GHG emissions contributions. Breakdowns are presented for combined allocation only. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 82% of total life cycle GHG emissions. Second in importance to fuel combustion are upstream emissions associated with CO_2 enhanced oil recovery, which represent 13% of total life cycle emissions, while carbon dioxide uptake associated with biomass production represented -10% of total life cycle emissions. The production of conventional jet fuel accounts for 8.0% of total life cycle GHG emissions. Emissions from the transport of coal to the CBTL facility represent approximately 3.4% of total emissions. CBTL facility emissions are indicated as negative due to the displacement of conventional fuels having higher upstream CO_2 emissions, while coal mining accounted for approximately 1.9% of total life cycle emissions. Other contributors to total emissions were less than 1% individually.

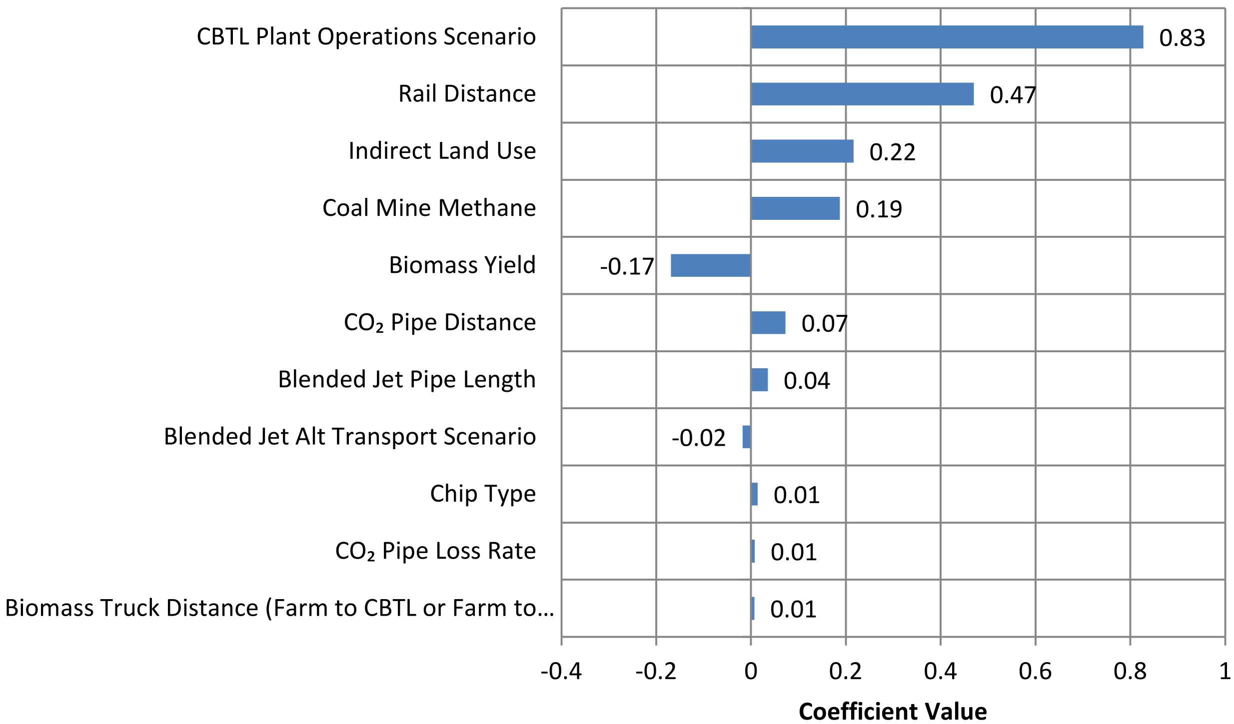
Figure 5-11: Scenario 2: CBTL, 10% Chipped Biomass: LC GHG Emissions Breakdowns, Combined Allocation



** 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), based on combined allocation. The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-5**, distinct from co-product management scheme. As shown, variability in emissions resulted primarily from CO_2-EOR operation and biomass production. Other key contributors to variability in model output include CBTL facility operation, and transport of coal to the CBTL facility. Other modeled processes contributed minimally to the overall variability in model results. **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. CBTL plant operations scenario refers to the low and high RSP technical cases considered in the analysis, as discussed in Chapter 2. Excluding co-product management scheme, this parameter was found to have the greatest effect on life cycle emissions, such that variability in CBTL facility operations can explain approximately 69% of total variability in GHG emissions caused by sensitivity to environmental parameters. Other important factors included rail transport distance for coal, indirect land use, coal mine methane emissions, and biomass yield. 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, for energy allocation only. 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, Energy Allocation

LC Stage	Carbon monoxide	NOx	SO_2	PM_{10}	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	8.84E-07	5.08E-07	2.77E-07	5.83E-09	2.58E-05	1.34E-12	7.71E-08	1.17E+00	kg/MJ Jet Fuel
RMT	2.31E-06	1.97E-06	5.62E-07	2.54E-06	3.82E-07	5.69E-13	2.89E-08	4.19E-04	kg/MJ Jet Fuel
EC	1.72E-07	3.74E-07	2.26E-08	8.36E-09	6.72E-07	1.51E-10	8.14E-08	2.95E-02	kg/MJ Jet Fuel
PT	6.53E-06	9.52E-06	1.78E-05	1.75E-07	2.00E-05	1.53E-11	8.03E-08	2.21E-02	kg/MJ Jet Fuel
EU	1.78E-04	2.79E-04	1.29E-05	6.04E-08	1.77E-05	6.89E-10	1.33E-10	6.08E-05	kg/MJ Jet Fuel
Total	**1.88E-04**	**2.91E-04**	**3.15E-05**	**2.79E-06**	**6.45E-05**	**8.57E-10**	**2.68E-07**	**1.22E+00**	**kg/MJ Jet Fuel**

5.3 Scenario 3: CBTL, 20% 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% sub-bituminous coal and 20% 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. Carbon dioxide is then transported along a pipeline to carbon dioxide based utilization and storage, supporting an enhanced oil recovery process. 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 model cases were run for this scenario: low required selling price (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% 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% (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34% 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% of total products) and F-T LPG (7% 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 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	53.3	52.8	51.4	%
CBTL Facility Inputs/Feed				
Coal Feed, Montana Rosebud, As Received	25,515	25,637	25,960	tons/day
Biomass Feed, Southern Pine, As Received	8,559	8,390	8,496	tons/day
Water Feed (Total Withdrawal)	13,419,622	13,007,225	12,540,963	gallons/day
CBTL Facility Outputs/Production				
F-T Jet Fuel Production	24,649	24,647	24,644	bpd
F-T Diesel Fuel Production	4,766.9	4,766.8	4,766.3	bpd
F-T Naphtha Production	16,972.7	16,971.8	16,969.9	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	220	194	144	MW
CO_2 Captured and Compressed	31,548	31,334	31,223	tons/day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,298	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% was included, ranging from 85 to 92% for low and high RSP cases, respectively. The overall expected plant efficiency of 52.8% (range of 51.4 to 53.3%) 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 13.0 million gallons per day (mgd; expected RSP case), of which 94% (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 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 144 to 220 MW, with an expected value of 194 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 MW), the Selexol unit (52 MW), hydrocarbon recovery/refrigeration (43 MW), and oxygen compression (32 MW). Total auxiliaries consume 557 MW, for a net power output of 194 MW 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% 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% of total carbon (range of 1% for the low RSP case to 4% 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	12,775	12,836	12,998	TPD
Biomass Carbon	2615	2563	2596	TPD
Total Carbon Input	**15,390**	**15,399**	**15,594**	**TPD**
F-T Products	5,284	5,284	5,284	TPD
Slag/Ash	154	308	624	TPD
Stack Gas	1,021	960	896	TPD
Fuel Gas	276	249	218	TPD
WWTP	0	0	0	TPD
Carbon Capture, Sequestered	8,628	8,572	8,546	TPD
Total Carbon Output	**15,364**	**15,373**	**15,568**	**TPD**
Carbon Capture	**88.0%**	**88.7%**	**89.6%**	**%**

5.3.2 Economic Results

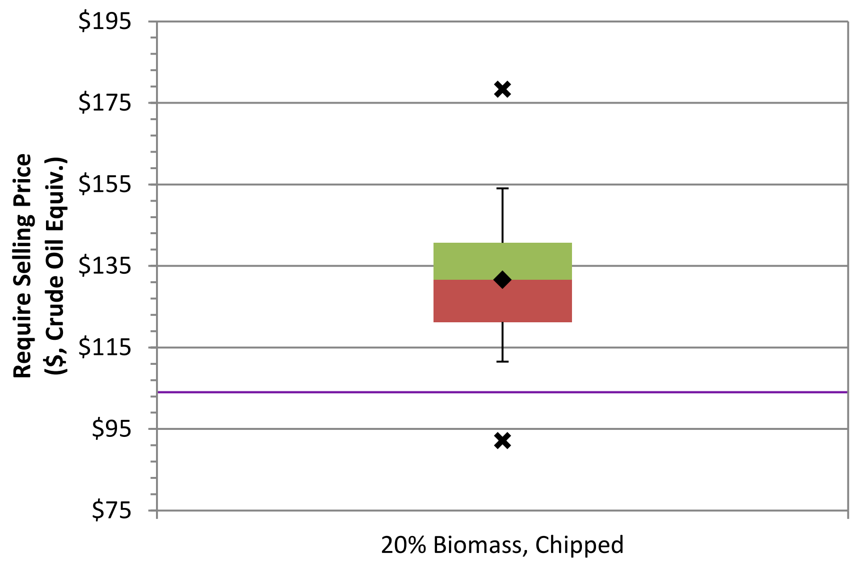
Results from the economic model are reported as a range of values, reflecting the distribution of results based on the stochastic analyses. To reflect the stochastic analysis incorporated into the model, the following discussion focuses on reporting of the study mean (average) values, as well as the middle 50% 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 $122 to $141/bbl, with a mean value of $132/bbl, on a crude oil equivalent basis. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 18 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 $93 to $190/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 1.2. 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 baseline 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 $467 million/yr. Of this amount, $281 to $307 million/yr, mean $295 million/yr (63%), results from fixed costs, while $164 to $179 million/year, mean $172 million/yr (37%) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, range from $7,335 to $8,353 million, mean $7,867 million. Coal feedstock costs for this scenario range from $297 to $308 million/yr, mean $302 million/yr. Biomass feedstock costs range from $67 to $73 million/yr, mean $70 million/yr. Total feedstock costs are approximately $95 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 $101 million/yr, mean $107 million/yr, while CO_2 credit is estimated to be $337 to $402 million/yr, mean $370 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,068 to $2,364 million/yr, mean $2,224 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 $150 to $171/bbl, mean $161/bbl, with F-T diesel at $146 to $168/bbl, mean $158/bbl, F-T naphtha at $103 to $119/bbl, mean $111/bbl, and F-T LPG at $61 to $71/bbl, mean $67/bbl. The default capital charge factor (CCF) used in the analysis was 0.2365. This CCF results from a 50% debt to equity ratio, a 15 year debt term, a nominal dollar cost for debt of 8% and 20% on equity, and an after tax weighted cost of capital of 13.1%.

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)	295	236	370	281	307	$Million/yr
Variable Operating and Maintenance Cost (VOM)	172	142	207	164	179	$Million/yr
Capital: Total Overnight Cost (TOC)	7,867	6,183	10,245	7,335	8,353	$Million
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	302	277	327	297	308	$Million/yr
Biomass Cost, Southern Pine, Chips, As Received	70	60	82	67	73	$Million/yr
Biomass Cost, Southern Pine, Torrefied, As Received	0	0	0	0	0	$Million/yr
Credits and Revenue						
Power Credit	107	93	120	103	110	$Million/yr
Credit @ $40/ton for CO_2	370	252	482	337	402	$Million/yr
Annual Revenue Required	2,224	1,663	2,973	2,068	2,364	$Million/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	161	119	218	150	171	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	158	117	216	146	168	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	111	80	155	103	119	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	67	45	106	61	72	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	132	93	190	122	141	$/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 69% of total RSP, or $90.7/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 17% of total RSP, or $22.8/bbl, while feedstock costs represent 14% of total RSP, or $18.1/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.

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

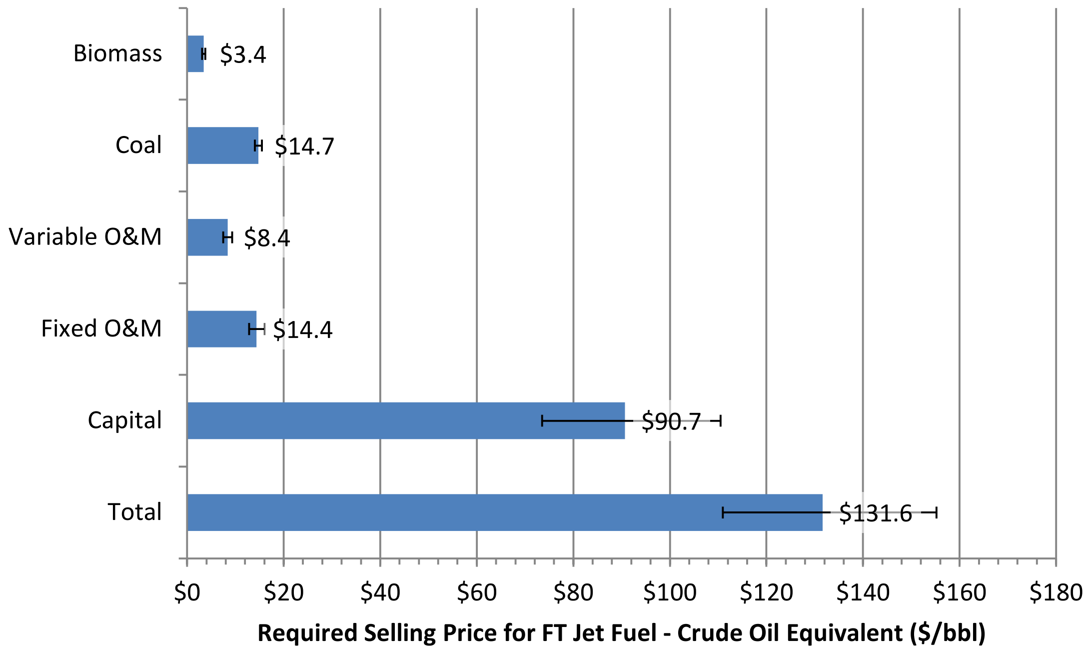
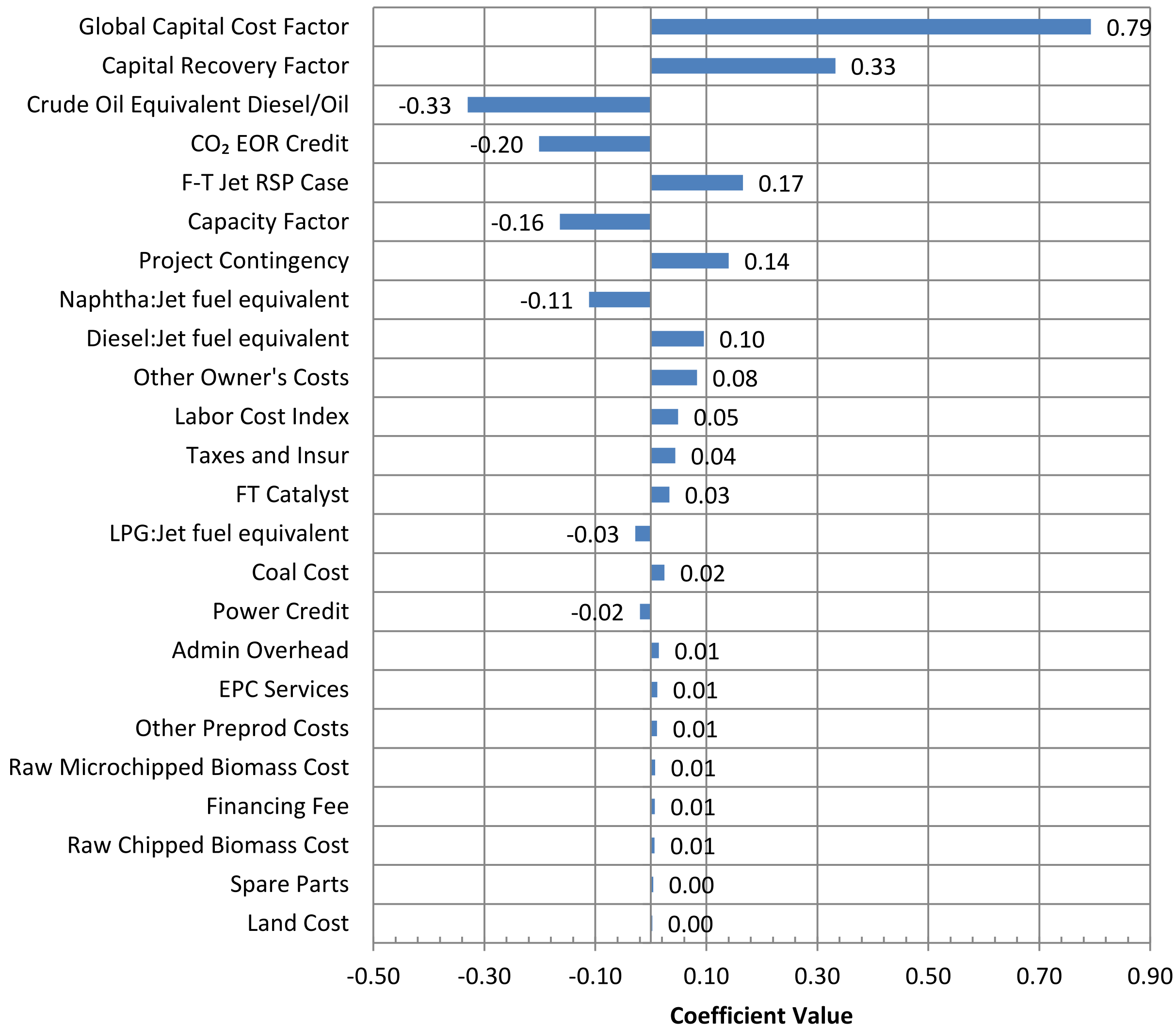


Figure 5-15 provides a summary of model sensitivity, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.79, such that variability in global capital cost factor can explain approximately 62% of total variability in RSP output. Other key factors that account for at least 10% of the observed variability in RSP include capital recovery factor and crude oil equivalent diesel/oil. Parameters that caused minimal influence on RSP included land cost, raw chipped biomass cost, administrative overhead, F-T catalyst cost, coal cost, and others as shown.

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



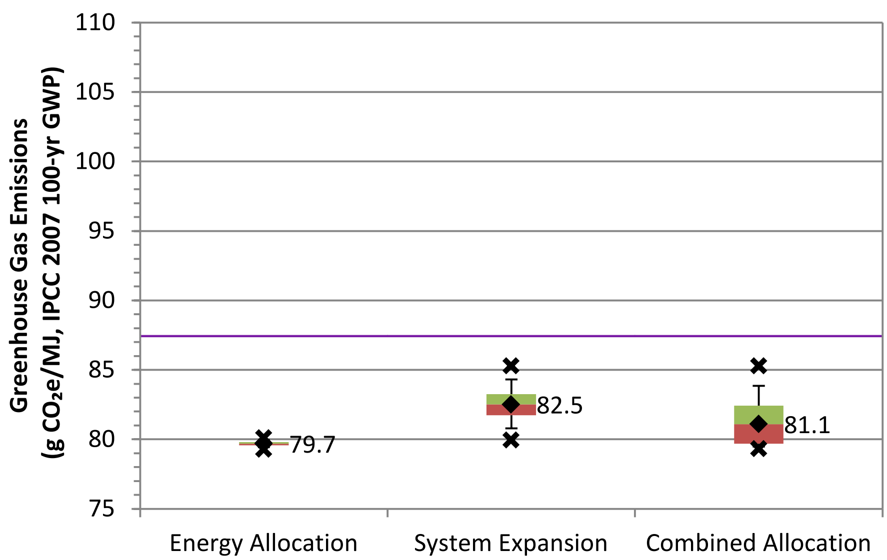
5.3.3 Environmental Results

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% 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 87.4 g CO_2e/MJ. As discussed in Chapter 1, two discreet allocation procedures were performed: energy allocation and system expansion. These were then combined to produce an average value as shown for the combined allocation result.

Allocation procedure is a key consideration with respect to whether or not life cycle GHG emissions for this scenario exceed life cycle emissions compared to conventional jet fuel. Anticipated GHG emissions of 25th and 75th percentile results for energy allocation range from 79.6 to 79.8 g CO_2e/MJ, mean 79.7 g CO_2e/MJ, or approximately 8.8% less than conventional jet fuel (based on mean value). However, when the same scenario is considered using system expansion, the resulting range is 81.8 to 83.2 g CO_2e/MJ, mean 82.5 g CO_2e/MJ, or approximately 5.6% less than conventional jet fuel. Combined allocation closely reflects the overall range of energy allocation and system expansion, ranging from 79.7 to 82.4 g CO_2e/MJ, mean 81.1 g CO_2e/MJ, or approximately 7.2% less than conventional jet fuel (based on mean value). Variability of results from system expansion is greater than that for energy allocation.

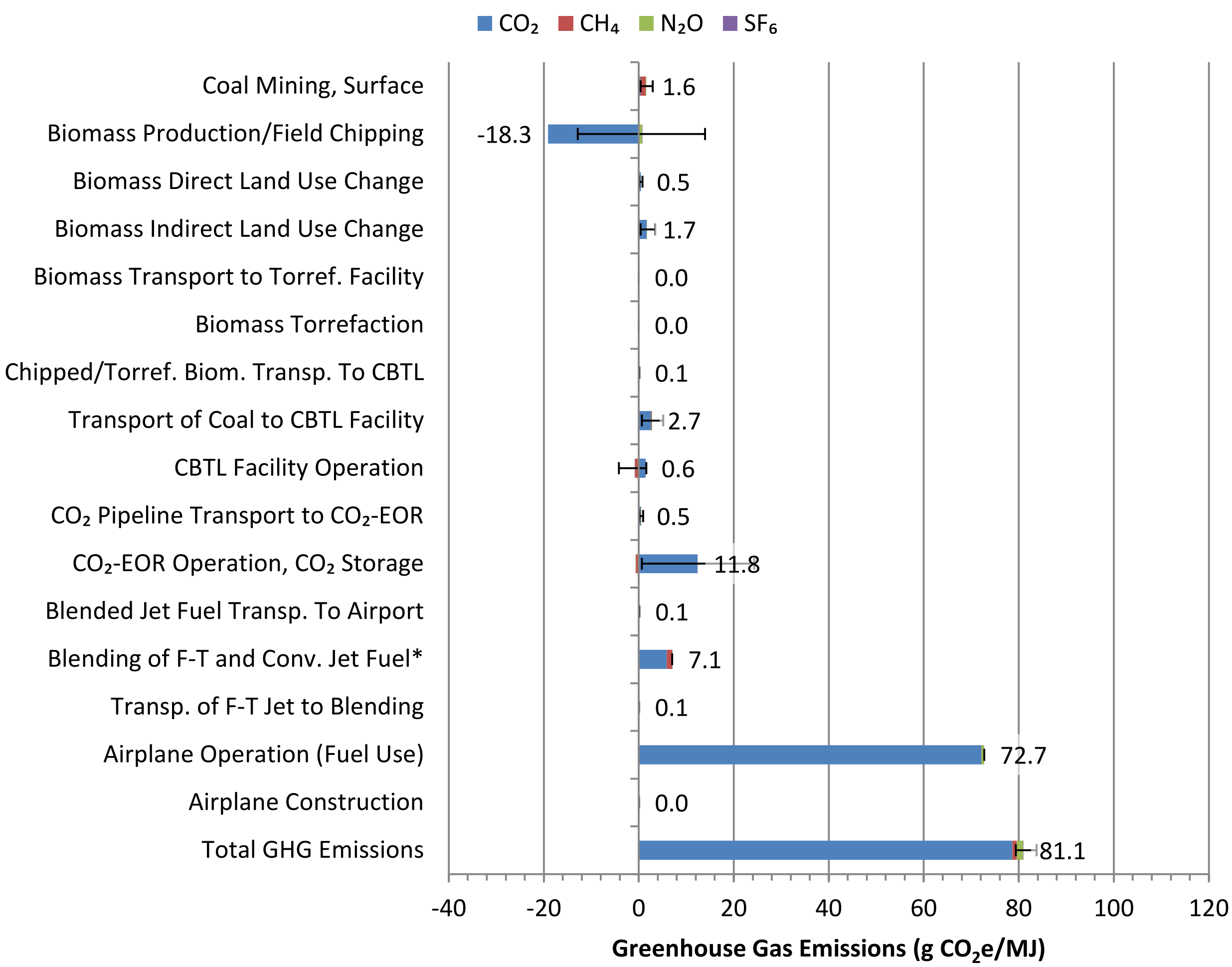
Figure 5-16: Scenario 3: CBTL, 20% Chipped Biomass: Summary of LC GHG Emissions



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 total GHG emissions contributions. Breakdowns are presented for combined allocation only. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 90% of total life cycle GHG emissions. Second in importance to fuel combustion is carbon dioxide uptake associated with biomass production, at -23% of total life cycle emissions, while emissions associated with CO_2 enhanced oil recovery represent 15% of total life cycle emissions. The production of conventional jet fuel accounts for 8.8% of total life cycle GHG emissions. Emissions from the transport of coal to the CBTL facility represent approximately 3.3% of total emissions. GHG emissions associated with indirect land use change generate 2.1% of total life cycle emissions, while coal mining generates 2.0%. Other contributors to total emissions were less than 1% individually.

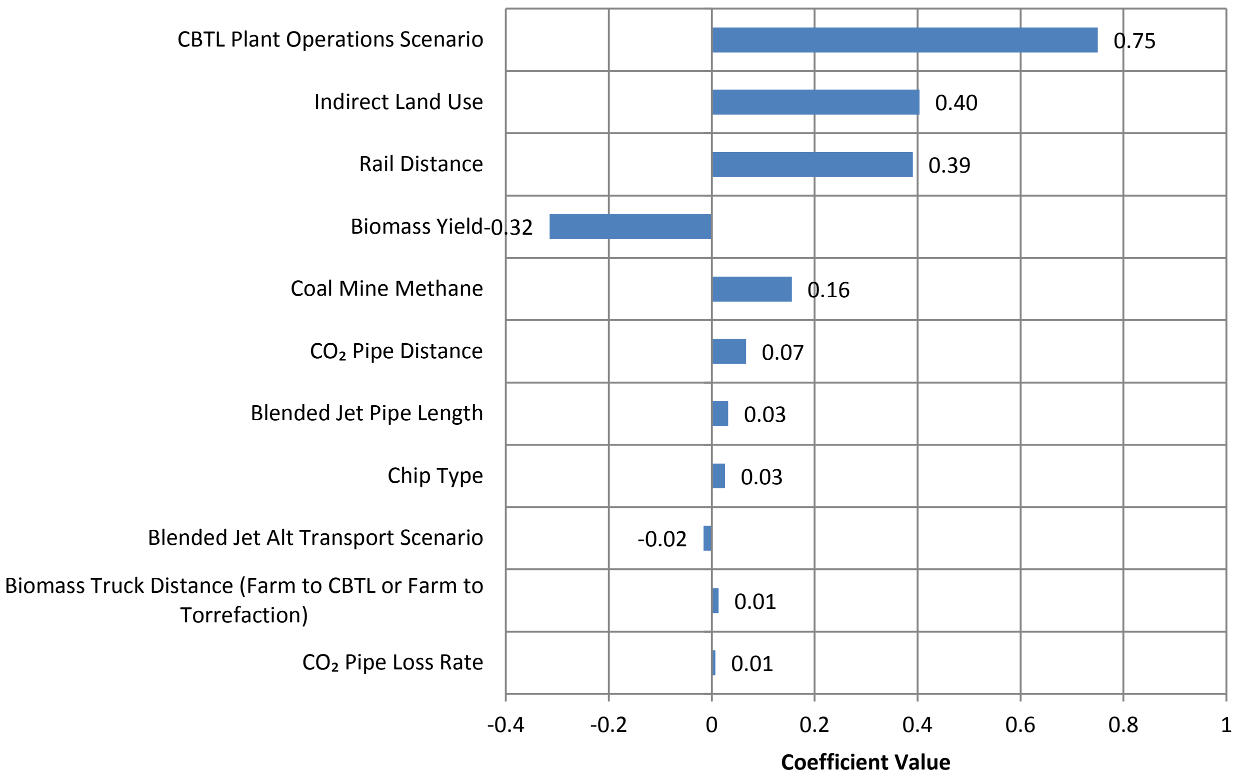
Figure 5-17: Scenario 3: CBTL, 20% Chipped Biomass: LC GHG Emissions Breakdowns, Combined Allocation



** 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), based on combined allocation. The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-5**, distinct from co-product management scheme. As shown, variability in emissions resulted primarily from CO_2-EOR operation and biomass production. Other key contributors to variability in model output include CBTL facility operation, transport of coal to the CBTL facility, and indirect land use change associated with biomass production. Other modeled processes contributed minimally to the overall variability in model results. **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. CBTL plant operations scenario refers to the low and high RSP technical cases considered in the analysis, as discussed in Chapter 2. Excluding co-product management scheme, this parameter was found to have the greatest effect on life cycle emissions, such that variability in CBTL facility operations can explain approximately 58% of total variability in GHG emissions caused by sensitivity to environmental parameters. Other important factors included indirect land use, rail transport distance for coal, biomass yield, and coal mine methane emissions. 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, for energy allocation only. 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 5-12: Scenario 3: CBTL, 20% Chipped Biomass: Non-GHG Emissions, Energy Allocation

LC Stage	Carbon monoxide	NOx	SO_2	PM_{10}	NMVOC	Hg (+II)	Ammonia	Water Consumption	Units
RMA	1.08E-06	6.60E-07	4.33E-07	7.37E-09	5.27E-05	1.53E-12	1.30E-07	2.39E+00	kg/MJ Jet Fuel
RMT	2.13E-06	1.79E-06	5.28E-07	2.31E-06	3.57E-07	6.13E-13	2.63E-08	4.06E-04	kg/MJ Jet Fuel
EC	2.98E-07	7.38E-07	2.55E-08	8.80E-09	1.37E-06	1.51E-10	8.12E-08	2.95E-02	kg/MJ Jet Fuel
PT	6.53E-06	9.52E-06	1.78E-05	1.75E-07	2.00E-05	1.53E-11	8.03E-08	2.21E-02	kg/MJ Jet Fuel
EU	1.78E-04	2.79E-04	1.29E-05	6.04E-08	1.77E-05	6.89E-10	1.33E-10	6.08E-05	kg/MJ Jet Fuel
Total	**1.88E-04**	**2.92E-04**	**3.17E-05**	**2.56E-06**	**9.21E-05**	**8.57E-10**	**3.18E-07**	**2.44E+00**	**kg/MJ Jet Fuel**

5.4 Scenario 4: CBTL, 10% 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% sub-bituminous coal and 10% 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. Carbon dioxide is then transported along a pipeline to carbon dioxide based utilization and storage, supporting an enhanced oil recovery process. 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 model cases were run for this scenario: low required selling price (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% 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% (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34% 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% of total products) and F-T LPG (7% 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 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% Torr. 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	54.2	53.8	52.5	%
CBTL Facility Inputs/Feed				
Coal Feed, Montana Rosebud, As Received	27,072	27,173	27,623	tons/day
Biomass Feed, Torrefied Southern Pine, As Received	2790	2733	2712	tons/day
Water Feed (Total Withdrawal)	13,936,321	13,452,070	13,042,347	gallons/day
CBTL Facility Outputs/Production				
F-T Jet Fuel Production	24,649	24,647	24,644	bpd
F-T Diesel Fuel Production	4,766.9	4,766.7	4,766.4	bpd
F-T Naphtha Production	16,972.6	16,971.4	16,969.9	bpd
F-T LPG Production	3,612	3,615	3,620	bpd
Total Liquid Product Output	50,000	50,000	50,001	bpd
Export Power	255	234	204	MW
CO_2 Captured and Compressed	31,020	30,846	30,798	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% was included, ranging from 85 to 92% for low and high RSP cases, respectively. The overall expected plant efficiency of 53.8% (range of 52.5 to 54.2%) 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 13.5 million gallons per day (mgd; expected RSP case), of which 94% (12.6 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.4 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 204 to 255 MW, with an expected value of 233 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 (92 MW), the Selexol unit (52 MW), hydrocarbon recovery/refrigeration (43 MW), and oxygen compression (32 MW). Total auxiliaries consume 557 MW, for a net power output of 234 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% of total carbon (range of 1% for the low RSP case to 4% for the high RSP case) is output to slag/ash from the TRIG gasifier.

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

Input Flow	Low RSP Case	Expected RSP Case	High RSP Case	Units
Coal Carbon	13,554	13,605	13,830	TPD
Biomass Carbon	1,672	1,637	1,625	TPD
Total Carbon Input	**15,226**	**15,242**	**15,455**	**TPD**
F-T Products	5,284	5,284	5,284	TPD
Slag/Ash	152	305	618	TPD
Stack Gas	1,009	946	884	TPD
Fuel Gas	271	242	212	TPD
WWTP	26	26	26	TPD
Carbon Capture, Sequestered	8,484	8,440	8,431	TPD
Total Carbon Output	**15,226**	**15,243**	**15,455**	**TPD**
Carbon Capture	**88.0%**	**88.7%**	**89.6%**	**%**

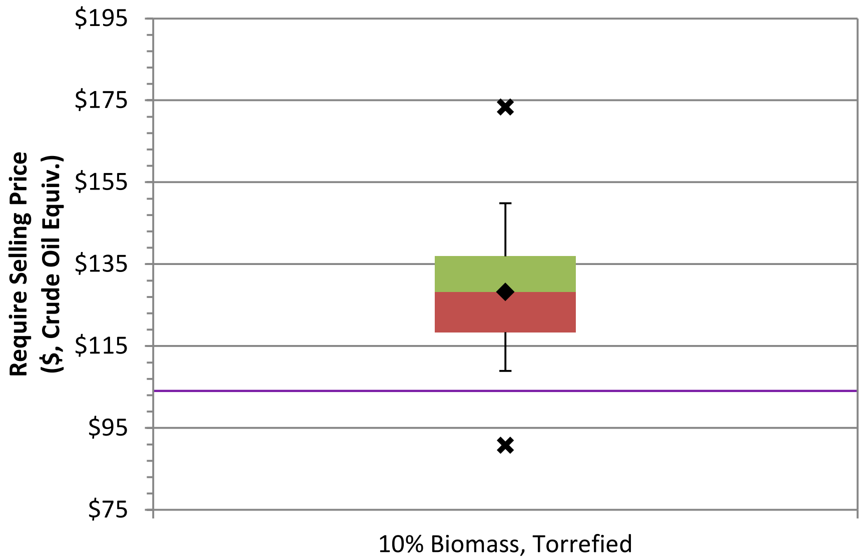
5.4.2 Economic Results

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% 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 $119 to $137/bbl, with a mean value of $128/bbl, on a crude oil equivalent basis. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 18 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 $91 to $185/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 1.2. 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% Torr. 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 baseline 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 $435 million/yr. Of this amount, $257 to $281 million/yr, mean $269 million/yr (62%), results from fixed costs, while $159 to $174 million/year, mean $166 million/yr (38%) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, ranging from $7,031 to $8,002 million, mean $7,538 million. Coal feedstock costs for this scenario range from $315 to $327 million/yr, mean $321 million/yr. Biomass feedstock costs range from $115 to $123 million/yr, mean $119 million/yr. Total feedstock costs are approximately $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 $125 to $133 million/yr, mean $129 million/yr, while CO_2 credit is estimated to be $331 to $395 million/yr, mean $364 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,019 to $2,301 million/yr, mean $2,166 million/yr.

Required product sales prices are also provided in **Table 5-15**. 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 $146 to $167/bbl, mean $157/bbl, with F-T diesel at $143 to $163/bbl, mean $154/bbl, F-T naphtha at $100 to $115/bbl, mean $108/bbl, and F-T LPG at $60 to $70/bbl, mean $65/bbl. The default capital charge factor (CCF) used in the analysis was 0.2365. This CCF results from a 50% debt to equity ratio, a 15 year debt term, a nominal dollar cost for debt of 8% and 20% on equity, and an after tax weighted cost of capital of 13.1%.

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

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	269	214	337	257	281	$Million/yr
Variable Operating and Maintenance Cost (VOM)	166	137	201	159	174	$Million/yr
Capital: Total Overnight Cost (TOC)	7,538	5,957	9,665	7,031	8,002	$Million
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	321	294	348	315	327	$Million/yr
Biomass Cost, Southern Pine, Chips, As Received	-	-	-	-	-	$Million/yr
Biomass Cost, Southern Pine, Torrefied, As Received	119	103	136	115	123	$Million/yr
Credits and Revenue						
Power Credit	129	112	145	125	133	$Million/yr
Credit @ $40/ton for CO_2	364	248	475	331	395	$Million/yr
Annual Revenue Required	2,166	1,638	2,885	2,019	2,301	$Million/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	157	117	212	146	167	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	154	115	211	143	163	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	108	79	148	100	115	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	65	44	103	60	70	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	128	91	185	119	137	$/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 67% of total RSP, or $86.0/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 16% of total RSP, or $21.0/bbl, while feedstock costs represent 17% of total RSP, or $21.3/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.

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

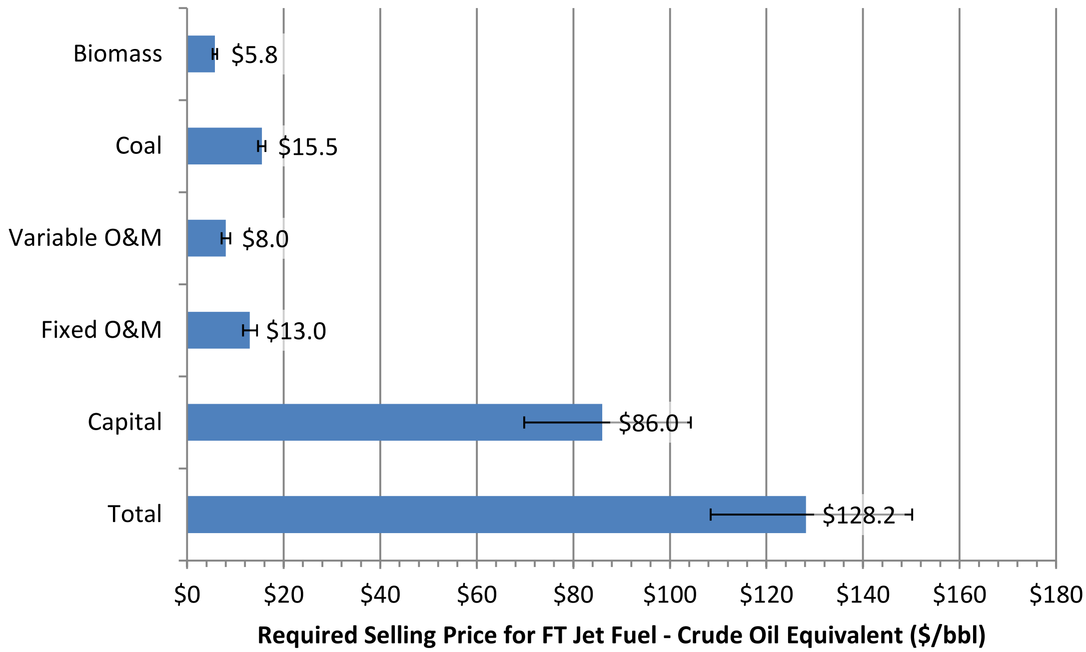
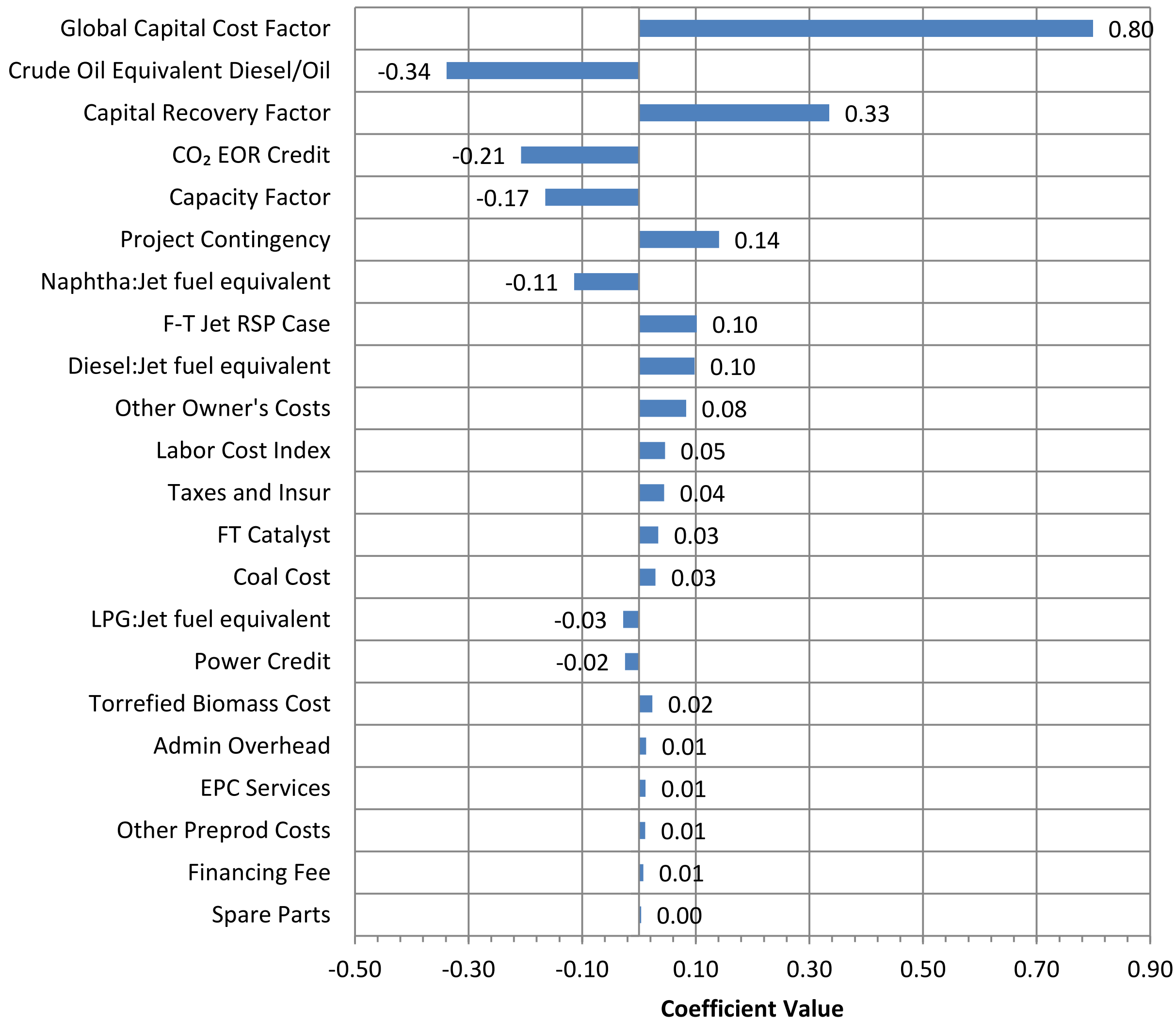


Figure 5-21 provides a summary of model sensitivity, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.8, such that variability in global capital cost factor can explain approximately 64% of total variability in RSP output. Other key factors that account for at least 10% of the observed variability in RSP include capital recovery factor and crude oil equivalent diesel/oil. Parameters that caused minimal influence on RSP included spare parts, financing fees, administrative overhead, torrefied biomass cost, F-T catalyst, and others as shown.

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



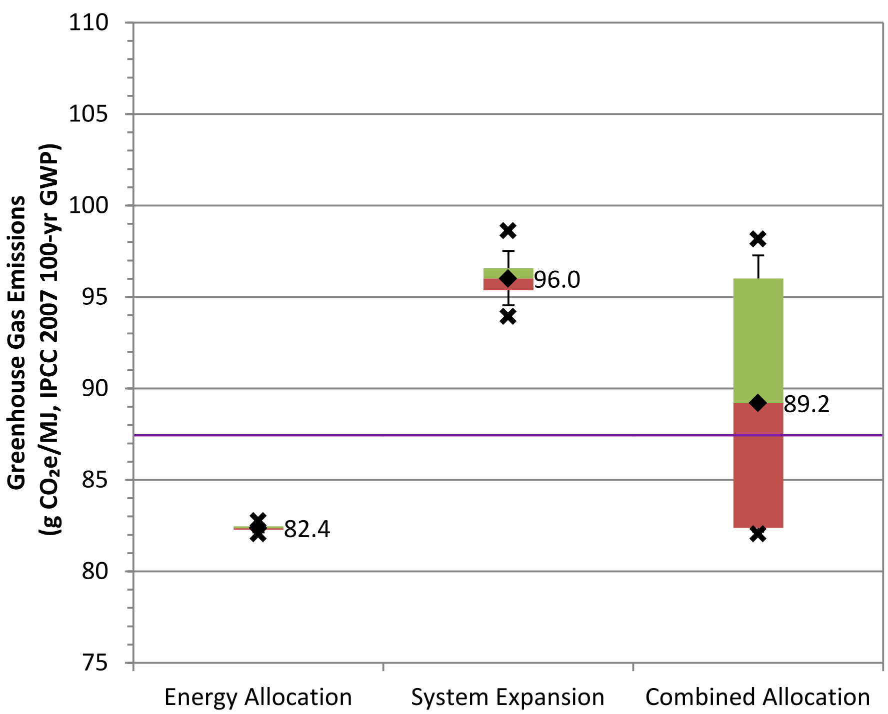
5.4.3 Environmental Results

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% 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 87.4 g CO_2e/MJ. As discussed in Chapter 1, two discreet allocation procedures were performed: energy allocation and system expansion. These were then combined to produce an average value as shown for the combined allocation result.

Allocation procedure is a key consideration with respect to whether or not life cycle GHG emissions for this scenario exceed life cycle emissions compared to conventional jet fuel. Anticipated GHG emissions of 25th and 75th percentile results for energy allocation range from 82.3 to 82.5 g CO_2e/MJ, mean 82.4 g CO_2e/MJ, or approximately 5.8% less than conventional jet fuel (based on mean value). However, when the same scenario is considered using system expansion, the resulting range is 95.4 to 96.6 g CO_2e/MJ, mean 96.0 g CO_2e/MJ, or approximately 9.8% greater than conventional jet fuel. Combined allocation closely reflects the overall range of energy allocation and system expansion, ranging from 82.4 to 96.0 g CO_2e/MJ, mean 89.2 g CO_2e/MJ, or approximately 2.0% greater than conventional jet fuel (based on mean value). Variability of results from system expansion is greater than that for energy allocation.

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

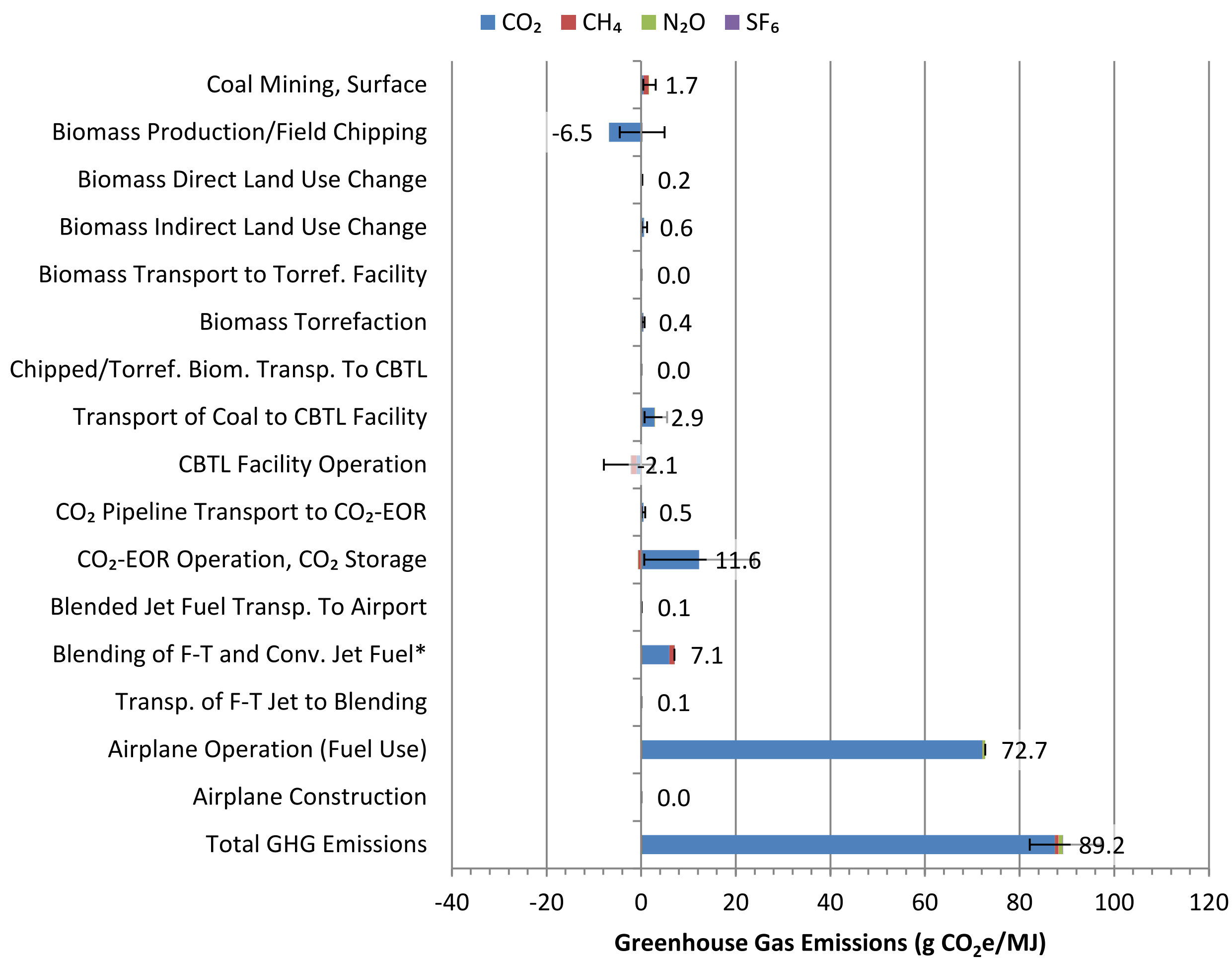


Key: Black diamonds = mean (average); green bars = 75th percentile; red bars = 25th percentile; point where green and red bars meet = 50th percentile (median); whiskers = 5th and 95th percentile; small "x" marks = minimum and maximum; solid purple line = conventional jet fuel baseline value.

Figure 5-23 provides detail regarding the importance of the various LCA components that were modeled, with respect to total GHG emissions contributions. Breakdowns are presented for combined allocation only. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 82% of total life cycle GHG emissions. Second in importance to fuel combustion are upstream emissions associated with CO_2 enhanced oil recovery, which represent 13% of total life cycle emissions, while carbon dioxide uptake associated with biomass production represented -7.3% of total life cycle emissions. The production of conventional jet fuel accounts for 8.0% of total life cycle GHG emissions. Emissions from the transport of coal to the CBTL facility represent approximately 3.3% of total emissions. CBTL facility emissions are indicated as negative due to the displacement of conventional fuels having higher upstream CO_2

emissions, while coal mining accounted for approximately 1.9% of total life cycle emissions. Other contributors to total emissions were less than 1% individually.

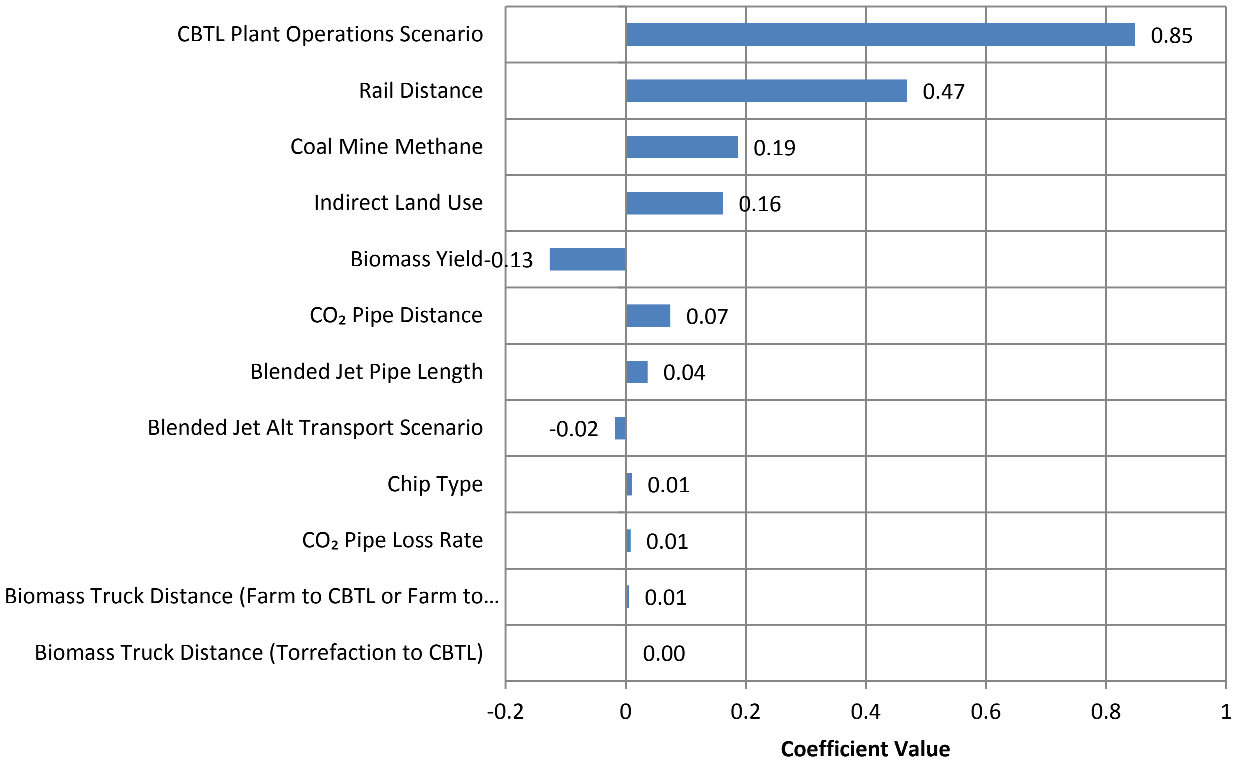
Figure 5-23: Scenario 4: CBTL, 10% Torr. Biomass: LC GHG Emissions Breakdowns, Combined Allocation



** 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 1-5**, distinct from co-product management scheme. As shown, variability in emissions resulted primarily from CO_2-EOR operation, biomass production, and CBTL facility operation. Other key contributors to variability in model output include transport of coal to the CBTL facility. Other modeled processes contributed minimally to the overall variability in model results. **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. CBTL plant operations scenario refers to the low and high RSP technical cases considered in the analysis, as discussed in Chapter 2. Excluding co-product management scheme, this parameter was found to have the greatest effect on life cycle emissions, such that variability in CBTL facility operations can explain approximately 72% of total variability in GHG emissions caused by sensitivity to environmental parameters. Other important factors included rail transport distance for coal, coal mine methane emissions, indirect land use, and biomass yield. Other parameters had minimal to negligible effect on life cycle GHG emissions.

Figure 5-24: Scenario 4: CBTL, 10% Torr. 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, for energy allocation only. 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 5-16: Scenario 4: CBTL, 10% Torr. Biomass: Non-GHG Emissions, Energy Allocation

LC Stage	Carbon monoxide	NOx	SO_2	PM_{10}	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	7.97E-07	4.51E-07	2.31E-07	5.22E-09	1.88E-05	1.23E-12	6.22E-08	8.53E-01	kg/MJ Jet Fuel
RMT	2.40E-06	2.02E-06	5.67E-07	2.46E-06	3.75E-07	2.00E-11	2.92E-08	4.24E-04	kg/MJ Jet Fuel
EC	5.08E-08	2.56E-08	1.99E-08	7.94E-09	1.04E-10	1.51E-10	8.17E-08	2.95E-02	kg/MJ Jet Fuel
PT	6.53E-06	9.52E-06	1.78E-05	1.75E-07	2.00E-05	1.53E-11	8.03E-08	2.21E-02	kg/MJ Jet Fuel
EU	1.78E-04	2.79E-04	1.29E-05	6.04E-08	1.77E-05	6.89E-10	1.33E-10	6.08E-05	kg/MJ Jet Fuel
Total	**1.87E-04**	**2.91E-04**	**3.15E-05**	**2.71E-06**	**5.69E-05**	**8.77E-10**	**2.54E-07**	**9.06E-01**	**kg/MJ Jet Fuel**

5.5 Scenario 5: CBTL, 20% 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% sub-bituminous coal and 20% 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. Carbon dioxide is then transported along a pipeline to carbon dioxide based utilization and storage, supporting an enhanced oil recovery process. 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 model cases were run for this scenario: low required selling price (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% 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% (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34% 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% of total products) and F-T LPG (7% 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 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% Torr. 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	54.6	54.2	52.9	%
CBTL Facility Inputs/Feed				
Coal Feed, Montana Rosebud, As Received	23,750	23,927	24,407	tons/day
Biomass Feed, Torrefied Southern Pine, As Received	5509	5414	5392	tons/day
Water Feed (Total Withdrawal)	13,612,267	13,180,065	12,828,063	gallons/day
CBTL Facility Outputs/Production				
F-T Jet Fuel Production	24,649	24,647	24,644	bpd
F-T Diesel Fuel Production	4,766.9	4,766.7	4,766.3	bpd
F-T Naphtha Production	16,972.6	16,971.5	16,969.6	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	237	208	MW
CO_2 Captured and Compressed	30,940	30,823	30,817	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% was included, ranging from 85 to 92% for low and high RSP cases, respectively. The overall expected plant efficiency of 54.2% (range of 52.9 to 54.6%) 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 13.1 million gallons per day (mgd; expected RSP case), of which 94% (12.4 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.3 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 208 to 257 MW, with an expected value of 237 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 (92 MW), the Selexol unit (52 MW), hydrocarbon recovery/refrigeration (44 MW), and oxygen compression (31 MW). Total auxiliaries consume 553 MW, for a net power output of 237 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% of total carbon (range of 1% for the low RSP case to 4% 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	11,891	11,980	12,220	TPD
Biomass Carbon	3,300	3,243	3,229	TPD
Total Carbon Input	**15,191**	**15,223**	**15,449**	**TPD**
F-T Products	5,284	5,284	5,284	TPD
Slag/Ash	152	304	618	TPD
Stack Gas	998	936	877	TPD
Fuel Gas	268	239	209	TPD
WWTP	26	26	26	TPD
Carbon Capture, Sequestered	8,463	8,434	8,437	TPD
Total Carbon Output	**15,191**	**15,223**	**15,450**	**TPD**
Carbon Capture	**87.9**	**88.6**	**89.5**	**%**

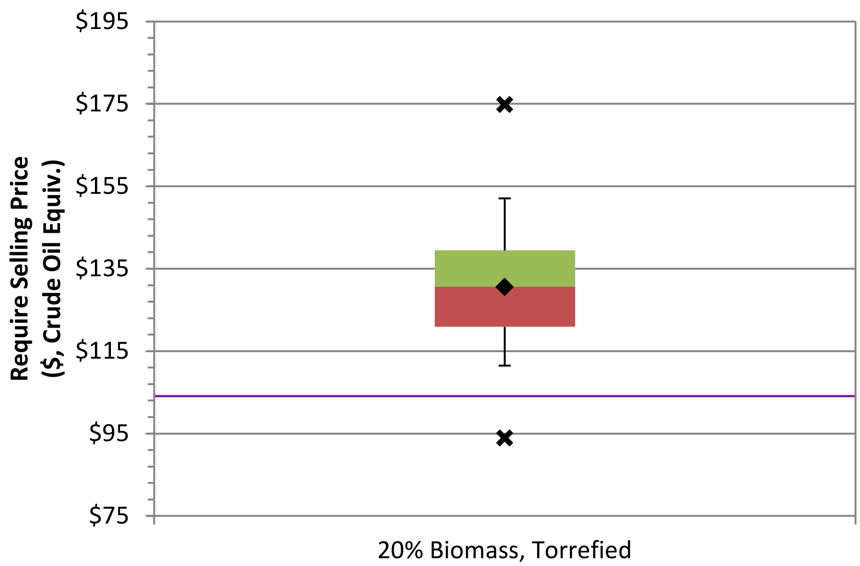
5.5.2 Economic Results

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% 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 \$121 to \$139/bbl, with a mean value of \$131/bbl, on a crude oil equivalent basis. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 18 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 \$94 to \$187/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 1.2. 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% Torr. 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 baseline 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 \$428 million/yr. Of this amount, \$252 to \$275 million/yr, mean \$264 million/yr (62%), results from fixed costs, while \$157 to \$171 million/year, mean \$164 million/yr (38%) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, ranging from \$6,909 to \$7,856 million, mean \$7,401 million. Coal feedstock costs for this scenario range from \$277 to \$288 million/yr, mean \$283 million/yr. Biomass feedstock costs range from \$230 to \$245 million/yr, mean \$237 million/yr. Total feedstock costs are approximately \$92 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 \$125 to \$133 million/yr, mean \$129 million/yr, while CO_2 credit is estimated to be \$331 to \$395 million/yr, mean \$364 million/yr, based on a rate of \$40/ton. Considering these credits, annual revenue required totals \$2,061 to \$2,338 million/yr, mean \$2,206 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 $149 to $169/bbl, mean $160/bbl, with F-T diesel at $146 to $166/bbl, mean $156/bbl, F-T naphtha at $102 to $117/bbl, mean $101/bbl, and F-T LPG at $61 to $71/bbl, mean $67/bbl. The default capital charge factor (CCF) used in the analysis was 0.2365. This CCF results from a 50% debt to equity ratio, a 15 year debt term, a nominal dollar cost for debt of 8% and 20% on equity, and an after tax weighted cost of capital of 13.1%.

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

Property	Mean Value	Min	Max	25th Percen-tile	75th Percen-tile	Units ($2007)
Fixed Operating and Maintenance Cost (FOM)	264	210	331	252	275	$Million/yr
Variable Operating and Maintenance Cost (VOM)	164	135	197	157	171	$Million/yr
Capital: Total Overnight Cost (TOC)	7,401	5,831	9,522	6,909	7,856	$Million
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	283	258	307	277	288	$Million/yr
Biomass Cost, Southern Pine, Chips, As Received	-	-	-	-	-	$Million/yr
Biomass Cost, Southern Pine, Torrefied, As Received	237	206	268	230	245	$Million/yr
Credits and Revenue						
Power Credit	129	112	145	125	133	$Million/yr
Credit @ $40/ton for CO_2	364	248	475	331	395	$Million/yr
Annual Revenue Required	2,206	1,694	2,908	2,061	2,338	$Million/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	160	120	215	149	169	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	156	118	213	146	166	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	110	81	149	102	117	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	67	46	104	61	71	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	131	94	187	121	139	$/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 65% of total RSP, or $84.7/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 16% of total RSP, or $20.7/bbl, while feedstock costs represent 19% of total RSP, or $25.2/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.

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

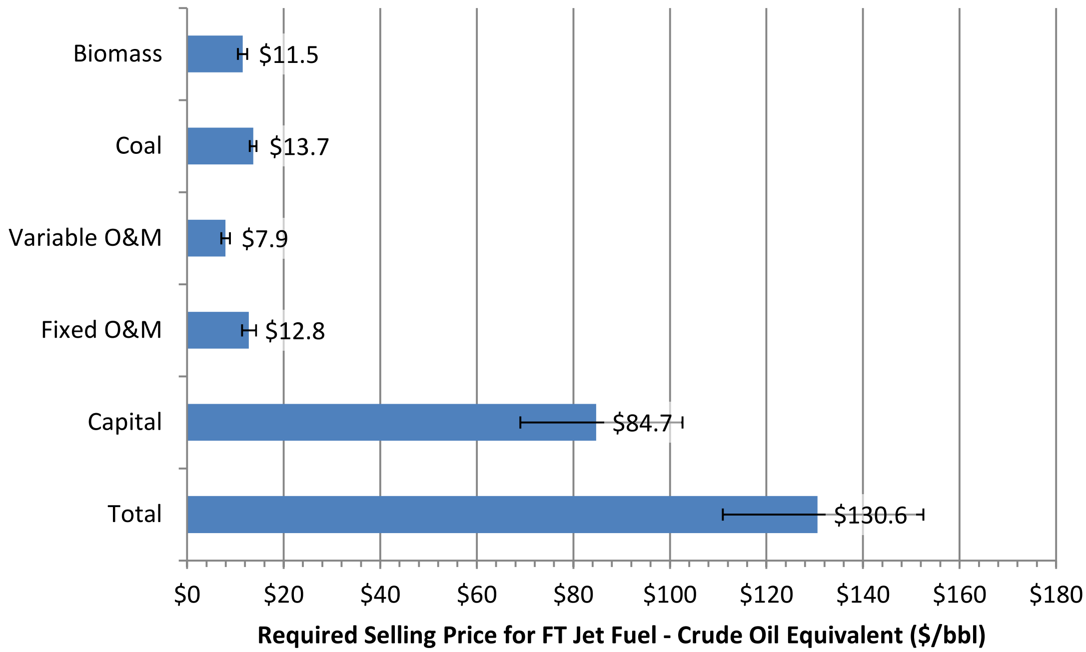
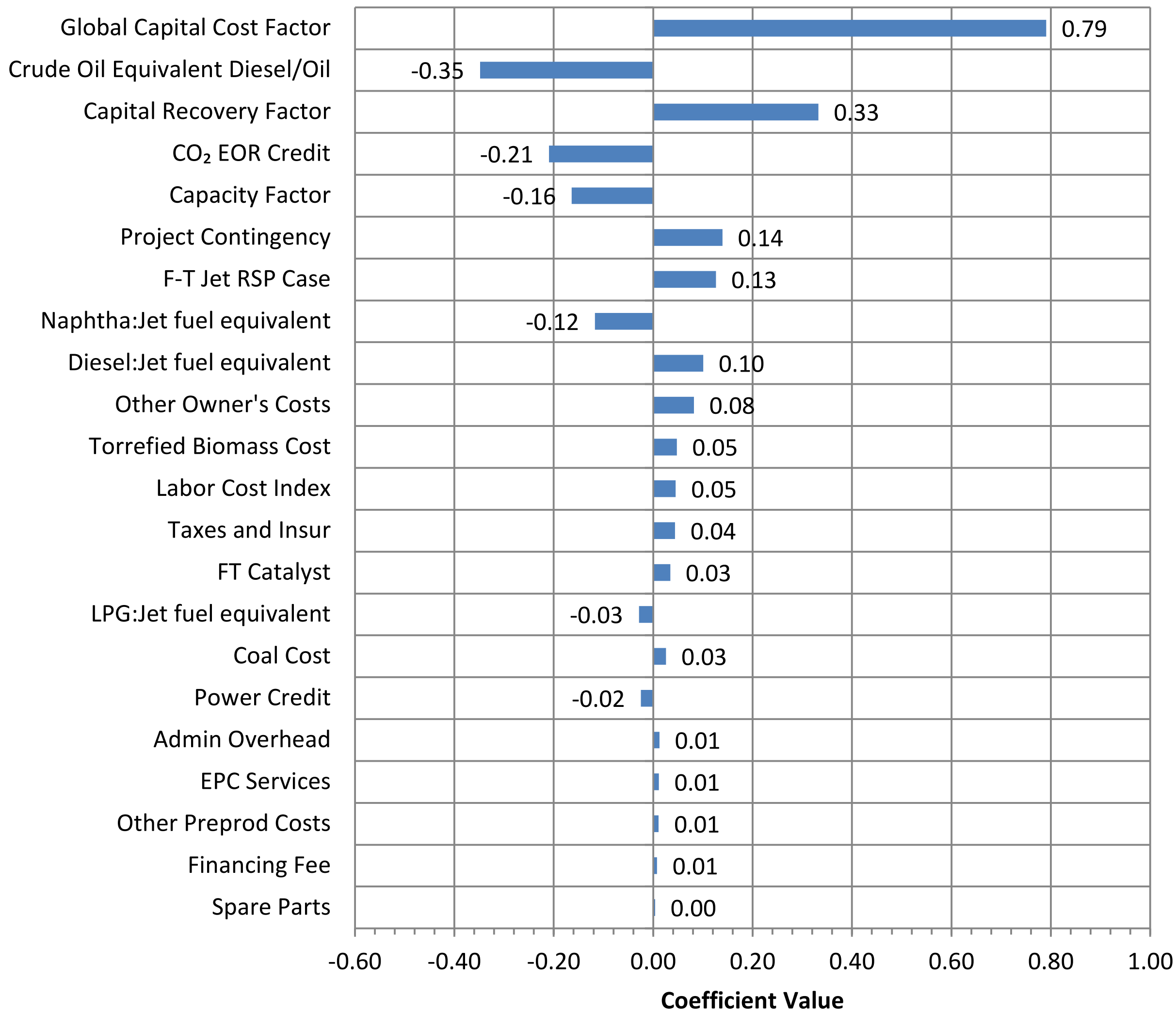


Figure 5-27 provides a summary of model sensitivity, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.79, such that variability in global capital cost factor can explain approximately 62% of total variability in RSP output. Other key factors that account for at least 10% of the observed variability in RSP include capital recovery factor and crude oil equivalent diesel/oil. Parameters that caused minimal influence on RSP included spare parts, financing fees, administrative overhead, power credit, F-T catalyst, coal cost, and others as shown.

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



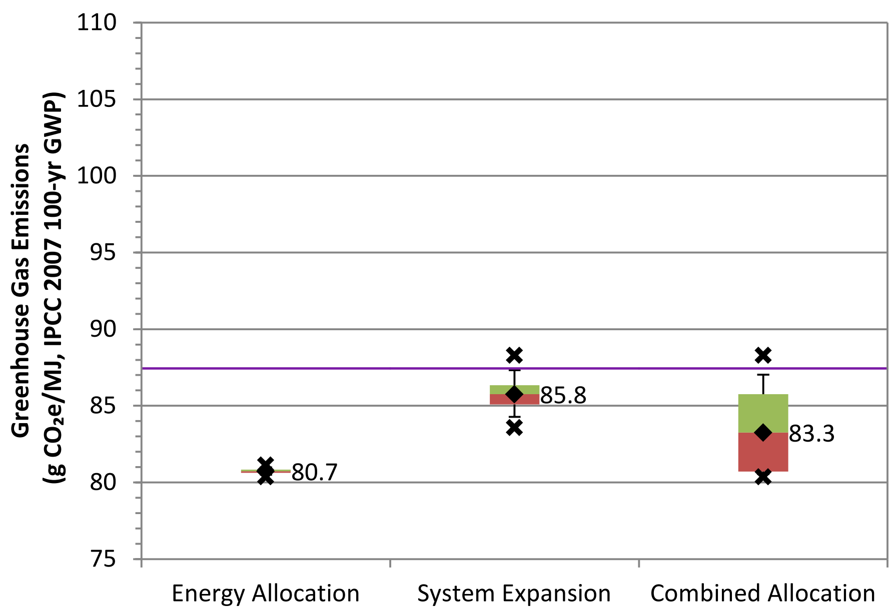
5.5.3 Environmental Results

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% 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 87.4 g CO_2e/MJ. As discussed in Chapter 1, two discreet allocation procedures were performed: energy allocation and system expansion. These were then combined to produce an average value as shown for the combined allocation result.

Allocation procedure is a key consideration with respect to whether or not life cycle GHG emissions for this scenario exceed life cycle emissions compared to conventional jet fuel. Anticipated GHG emissions of 25th and 75th percentile results for energy allocation range from 80.6 to 80.8 g CO_2e/MJ, mean 80.7 g CO_2e/MJ, or approximately 7.6% less than conventional jet fuel (based on mean value). However, when the same scenario is considered using system expansion, the resulting range is 85.1 to 86.3 g CO_2e/MJ, mean 85.8 g CO_2e/MJ, or approximately 1.9% less than conventional jet fuel. Combined allocation closely reflects the overall range of energy allocation and system expansion, ranging from 80.7 to 85.8 g CO_2e/MJ, mean 83.3 g CO_2e/MJ, or approximately 4.7% less than conventional jet fuel (based on mean value). Variability of results from system expansion is greater than that for energy allocation.

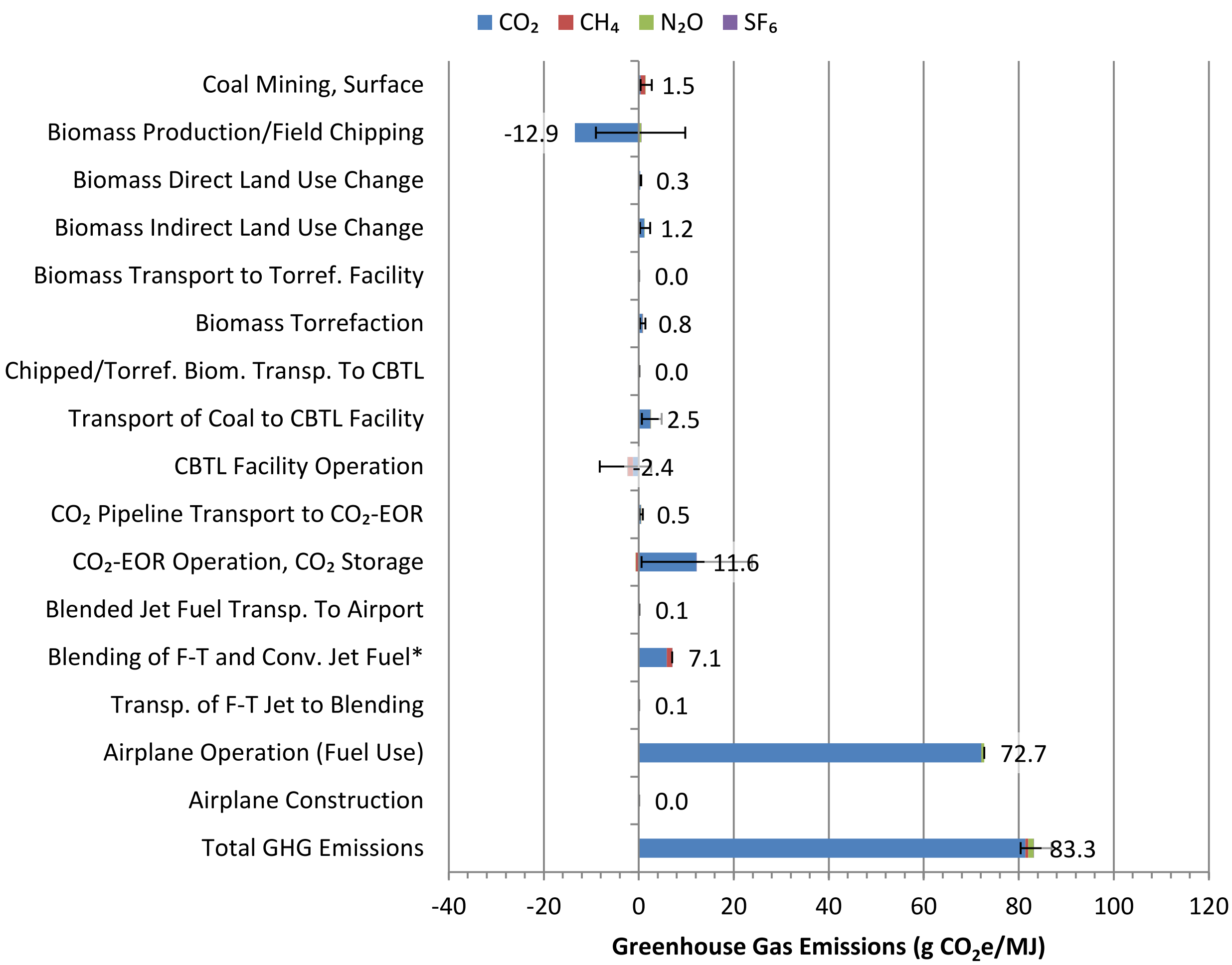
Figure 5-28: Scenario 5: CBTL, 20% Torr. Biomass: Summary of LC GHG Emissions



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 total GHG emissions contributions. Breakdowns are presented for combined allocation only. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 87% of total life cycle GHG emissions. Second in importance to fuel combustion is carbon dioxide uptake associated with biomass production, at -16% of total life cycle emissions, while emissions associated with CO_2 enhanced oil recovery represent 14% of total life cycle emissions. The production of conventional jet fuel accounts for 8.5% of total life cycle GHG emissions. Emissions from the transport of coal to the CBTL facility represent approximately 3.0% of total emissions. GHG emissions associated with indirect land use change generate 1.4% of total life cycle emissions, while coal mining generates 1.8%. Other contributors to total emissions were less than 1% individually.

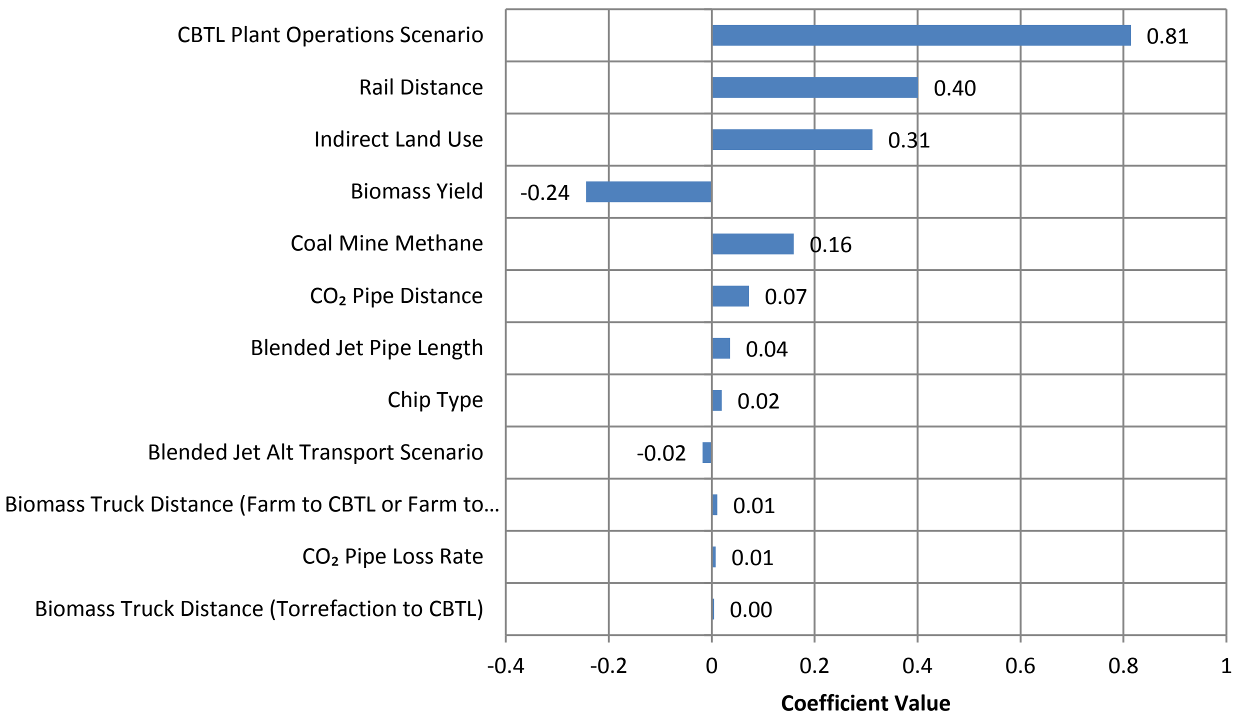
Figure 5-29: Scenario 5: CBTL, 20% Torr. Biomass: LC GHG Emissions Breakdowns, Combined Allocation



** 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), based on combined allocation. The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-5**, distinct from co-product management scheme. As shown, variability in emissions resulted primarily from CO_2-EOR operation and biomass production. Other key contributors to variability in model output include CBTL facility operation and transport of coal to the CBTL facility. Other modeled processes contributed minimally to the overall variability in model results. **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. CBTL plant operations scenario refers to the low and high RSP technical cases considered in the analysis, as discussed in Chapter 2. Excluding co-product management scheme, this parameter was found to have the greatest effect on life cycle emissions, such that variability in CBTL facility operations can explain approximately 66% of total variability in GHG emissions caused by sensitivity to environmental parameters. Other important factors included rail transport distance for coal, indirect land use, biomass yield, and coal mine methane emissions. Other parameters had minimal to negligible effect on life cycle GHG emissions.

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



In addition to GHG emissions, other life cycle environmental emissions and flows were also considered. **Table 5-17** provides a summary of these flows, for energy allocation only. 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 5-20: Scenario 5: CBTL, 20% Torr. Biomass: Non-GHG Emissions, Energy Allocation

LC Stage	Carbon monoxide	NOx	SO_2	PM_{10}	NMVOC	Hg (+II)	Ammonia	Water Consump-tion	Units
RMA	9.00E-07	5.37E-07	3.31E-07	6.06E-09	3.73E-05	1.30E-12	9.68E-08	1.69E+00	kg/MJ Jet Fuel
RMT	2.31E-06	1.92E-06	5.41E-07	2.17E-06	3.44E-07	3.91E-11	2.71E-08	4.17E-04	kg/MJ Jet Fuel
EC	5.08E-08	2.56E-08	1.98E-08	7.93E-09	1.04E-10	1.51E-10	8.17E-08	2.96E-02	kg/MJ Jet Fuel
PT	6.53E-06	9.52E-06	1.78E-05	1.75E-07	2.00E-05	1.53E-11	8.03E-08	2.21E-02	kg/MJ Jet Fuel
EU	1.78E-04	2.79E-04	1.29E-05	6.04E-08	1.77E-05	6.89E-10	1.33E-10	6.08E-05	kg/MJ Jet Fuel
Total	**1.87E-04**	**2.91E-04**	**3.16E-05**	**2.42E-06**	**7.53E-05**	**8.96E-10**	**2.86E-07**	**1.74E+00**	**kg/MJ Jet Fuel**

5.6 Scenario 6: CBTL, 10% 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% sub-bituminous coal and 10% 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. 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. Carbon dioxide is then transported along a pipeline to carbon dioxide based utilization and storage, supporting an enhanced oil recovery process. 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 model cases were run for this scenario: low required selling price (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% 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% (by volume) of the total F-T products is F-T jet fuel, with most of the remaining (34% 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% of total products) and F-T LPG (7% 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 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	52.1	51.9	50.5	%
CBTL Facility Inputs/Feed				
Coal Feed, Montana Rosebud, As Received	28,543	28,652	29,299	tons/day
Biomass Feed, Southern Pine, As Received	4255	4320	4464	tons/day
Water Feed (Total Withdrawal)	14,194,721	13,745,584	13,603,873	gallons/day
CBTL Facility Outputs/Production				
F-T Jet Fuel Production	24,651	24,652	24,649	bpd
F-T Diesel Fuel Production	4,767.1	4,767.5	4,767.0	bpd
F-T Naphtha Production	16,973.9	16,974.8	16,972.9	bpd
F-T LPG Production	3,609	3,606	3,611	bpd
Total Liquid Product Output	50,000	50,000	50,000	bpd
Export Power	205	206	196	MW
CO_2 Captured and Compressed	29,755	29,401	29,884	tons/day
Jet Fuel Delivered to Airport (50/50 by vol. blend)	49,301	49,304	49,298	bpd

CBTL facility fuels production capacity was fixed at 50,000 bpd for all three modeled cases. An expected capacity factor of 90% was included, ranging from 85 to 92% for low and high RSP cases, respectively. The overall expected plant efficiency of 51.9% (range of 50.5 to 52.1%) 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 13.7 million gallons per day (mgd; expected RSP case), of which 94% (12.9 mgd) is used for cooling tower make-up. Normalized to fuels production, water use for the CBTL facility is approximately 6.5 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 196 to 206 MW, with an expected value of 206 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 (89 MW), the Selexol unit (51 MW), hydrocarbon recovery/refrigeration (38 MW), and oxygen compression (31 MW). Total auxiliaries consume 559 MW, for a net power output of 206 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% 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% of total carbon (range of 1% for the low RSP case to 4% 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	14,291	14,346	14,670	TPD
Biomass Carbon	1,300	1,320	1,364	TPD
Total Carbon Input	**15,591**	**15,665**	**16,034**	**TPD**
F-T Products	5,284	5,284	5,284	TPD
Slag/Ash	168	312	613	TPD
Stack Gas	1,809	1,830	1,771	TPD
Fuel Gas	168	171	160	TPD
WWTP	0	0	0	TPD
Carbon Capture, Sequestered	8,138	8,044	8,181	TPD
Total Carbon Output	**15,567**	**15,641**	**16,010**	**TPD**
Carbon Capture	**81.3%**	**81.0%**	**82.1%**	**%**

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% 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 \$123 to \$142/bbl, with a mean value of \$133/bbl, on a crude oil equivalent basis. Ranges are based on stochastic analysis completed in support of the economic analysis, based on the 18 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 \$94 to \$191/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 1.2. 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% 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 baseline 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 \$463 million/yr. Of this amount, \$277 to \$303 million/yr, mean \$291 million/yr (63%), results from fixed costs, while \$164 to \$180 million/year, mean \$172 million/yr (37%) results from variable costs. Total overnight capital costs (TOC), defined as the sum of Total Plant Cost (TPC) and Owner's Cost, ranging from \$7,363 to \$8,399 million, mean \$7,902 million. Coal feedstock costs for this scenario range from \$332 to \$345 million/yr, mean \$339 million/yr. Biomass feedstock costs range from \$34 to \$37 million/yr, mean \$36 million/yr. Total feedstock costs are approximately \$88 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 $110 to $118 million/yr, mean $114 million/yr, while CO_2 credit is estimated to be $318 to $379 million/yr, mean $349 million/yr, based on a rate of $40/ton. Considering these credits, annual revenue required totals $2,087 to $2,385 million/yr, mean $2,244 million/yr.

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)	291	232	368	277	303	$Million/yr
Variable Operating and Maintenance Cost (VOM)	172	142	208	164	180	$Million/yr
Capital: Total Overnight Cost (TOC)	7,902	6,175	10,369	7,363	8,399	$Million
Feedstock Costs						
Coal Cost, Montana Rosebud, As Received	339	310	369	332	345	$Million/yr
Biomass Cost, Southern Pine, Chips, As Received	36	30	42	34	37	$Million/yr
Biomass Cost, Southern Pine, Torrefied, As Received	-	-	-	-	-	$Million/yr
Credits and Revenue						
Power Credit	114	99	128	110	118	$Million/yr
Credit @ $40/ton for CO_2	349	237	459	318	379	$Million/yr
Annual Revenue Required	2,244	1,687	2,991	2,087	2,385	$Million/yr
Product Selling Price						
Required Selling Price per Barrel of F-T Jet (RSP F-T Jet)	162	121	219	151	173	$/bbl
Required Selling Price per Barrel of F-T Diesel (RSP F-T Diesel)	159	119	217	148	170	$/bbl
Required Selling Price per Barrel of F-T Naphtha (RSP F-T Naphtha)	112	82	157	104	120	$/bbl
Required Selling Price per Barrel of F-T LPG (RSP F-T LPG)	68	46	107	62	73	$/bbl
Crude Oil Equivalent Selling Price of F-T Jet (COE)	133	94	191	123	142	$/bbl

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 $151 to $173/bbl, mean $162/bbl, with F-T diesel at $148 to $170/bbl, mean $159/bbl, F-T naphtha at $104 to $120/bbl, mean $112/bbl, and F-T LPG at $62 to $73/bbl, mean $68/bbl. The default capital charge factor (CCF) used in the analysis was 0.2365. This CCF results from a 50% debt to equity ratio, a 15 year debt term, a nominal dollar cost for debt of 8% and 20% on equity, and an after tax weighted cost of capital of 13.1%.

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 69% of total RSP, or $91.7/bbl, crude oil equivalent basis. Total operating and maintenance costs represent 17% of total

RSP, or $22.7/bbl, while feedstock costs represent 14% of total RSP, or $18.4/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.

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

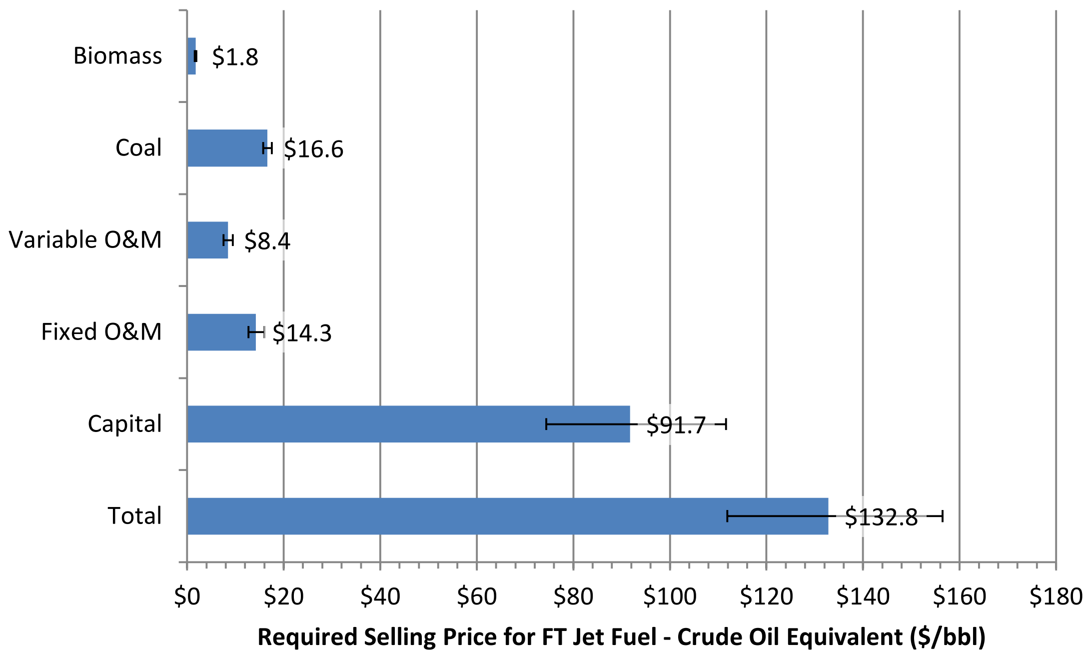
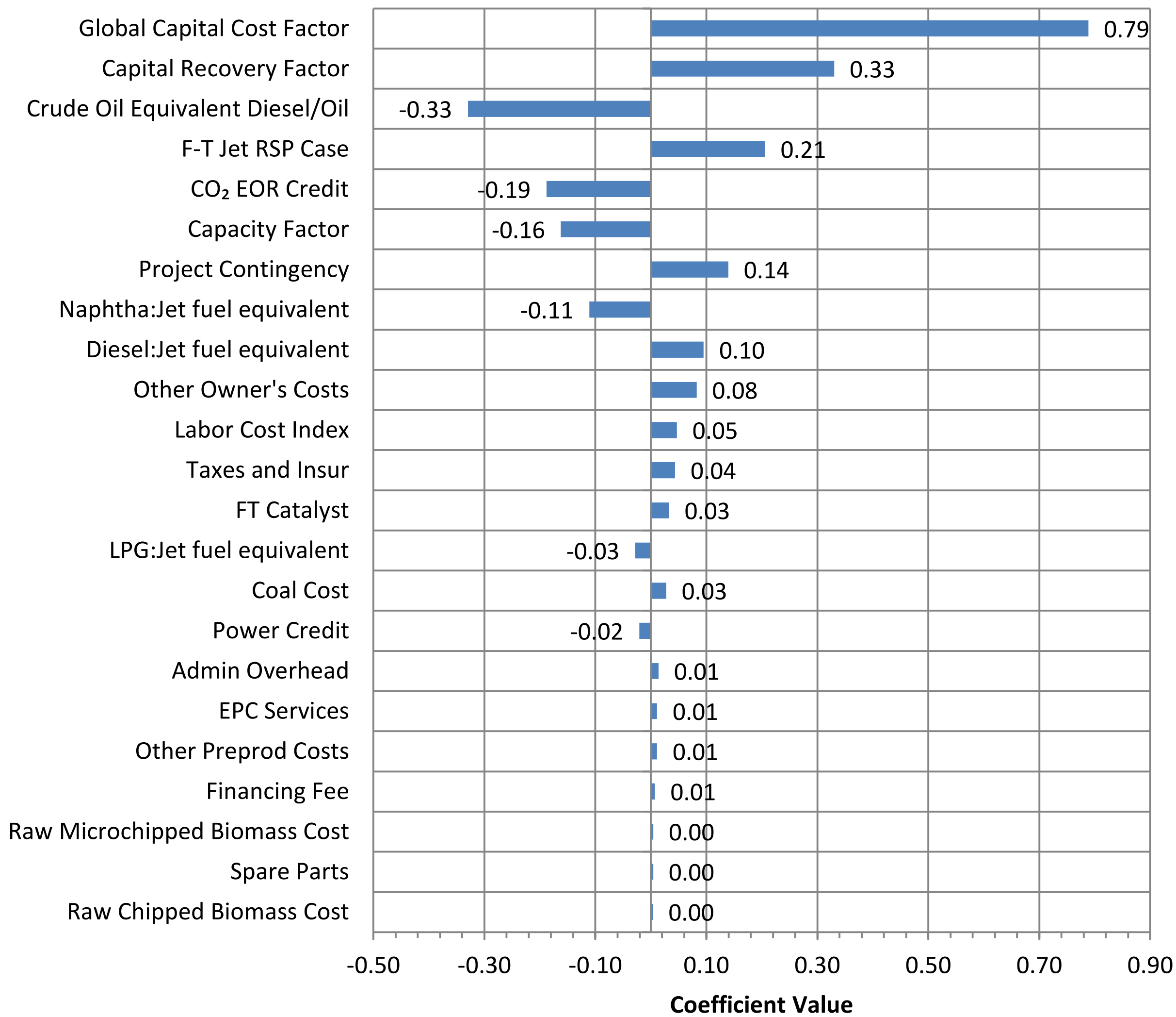


Figure 5-33 provides a summary of model sensitivity, based on correlation coefficient outputs from the stochastic analysis. Values provided in the figure show the correlation coefficient between the indicated parameter and total RSP. Variability in the global capital cost factor was determined to be the primary driver of variability in RSP, with a correlation coefficient of 0.79, such that variability in global capital cost factor can explain approximately 62% of total variability in RSP output. Other key factors that account for at least 10% of the observed variability in RSP include capital recovery factor and crude oil equivalent diesel/oil. Parameters that caused minimal influence on RSP included raw chipped microchipped biomass cost, spare parts, administrative overhead, power credit, F-T catalyst, coal cost, and others as shown.

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



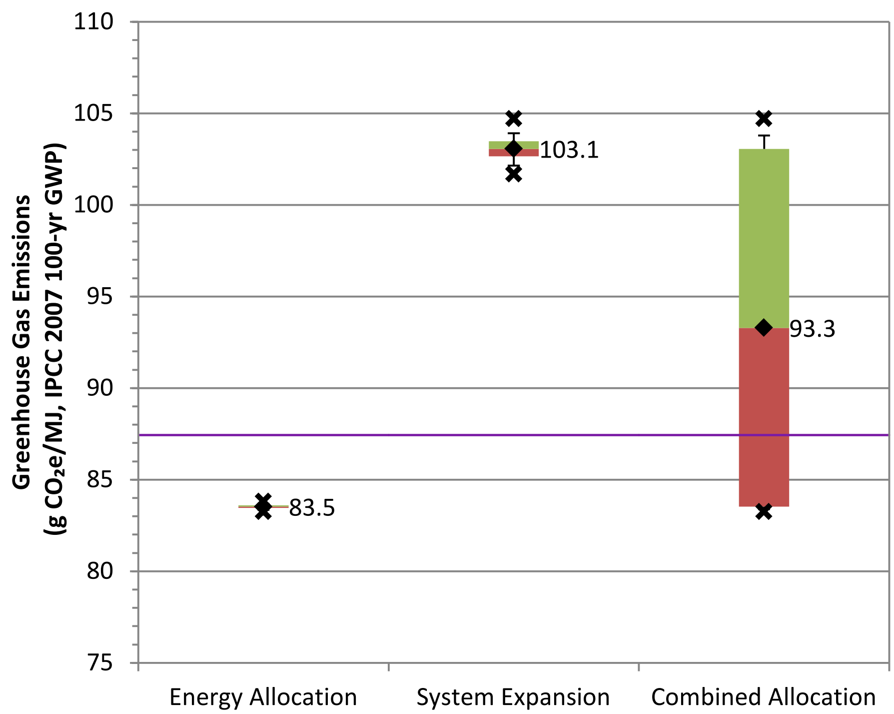
5.6.3 Environmental Results

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% 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 87.4 g CO_2e/MJ. As discussed in Chapter 1, two discreet allocation procedures were performed: energy allocation and system expansion. These were then combined to produce an average value as shown for the combined allocation result.

Allocation procedure is a key consideration with respect to whether or not life cycle GHG emissions for this scenario exceed life cycle emissions compared to conventional jet fuel. Anticipated GHG emissions of 25th and 75th percentile results for energy allocation range from 83.5 to 83.6 g CO_2e/MJ, mean 83.5 g CO_2e/MJ, or approximately 4.4% less than conventional jet fuel (based on mean value). However, when the same scenario is considered using system expansion, the resulting range is 102.6 to 103.5 g CO_2e/MJ, mean 103.1 g CO_2e/MJ, or approximately 17.9% greater than conventional jet fuel. Combined allocation closely reflects the overall range of energy allocation and system expansion, ranging from 83.5 to103 g CO_2e/MJ, mean 93.3 g CO_2e/MJ, or approximately 6.7% greater than conventional jet fuel (based on mean value). Variability of results from system expansion is greater than that for energy allocation.

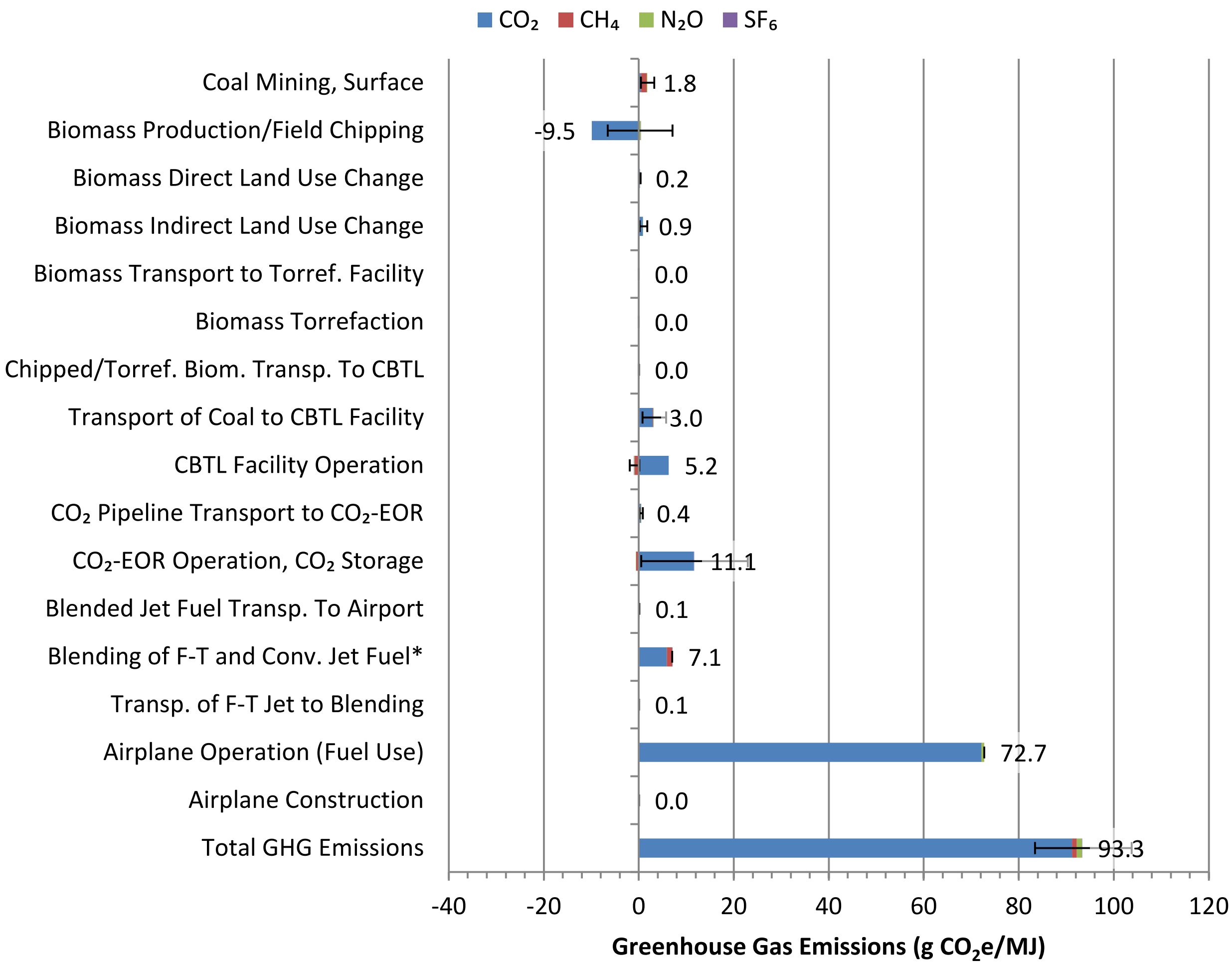
Figure 5-34: Scenario 6: CBTL, 10% Biomass, Microchipped, Sep. Gasifiers: Summary of LC GHG Emissions



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 total GHG emissions contributions. Breakdowns are presented for combined allocation only. Airplane operation, that is, combustion of blended jet fuel in a jet airplane, is the primary source of GHG emissions, representing 78% of total life cycle GHG emissions. Second in importance to fuel combustion are upstream emissions associated with CO_2 enhanced oil recovery, which represent 12% of total life cycle emissions, while carbon dioxide uptake associated with biomass production represented -10% of total life cycle emissions. The production of conventional jet fuel accounts for 7.6% of total life cycle GHG emissions. Emissions from the CBTL facility represent 5.6% of total life cycle emissions, while transport of coal to the CBTL facility represents approximately 3.2% of total emissions. Coal mining accounted for approximately 1.9% of total life cycle emissions, while indirect land use contributed 1.0% of total. Other contributors to total emissions were less than 1% individually.

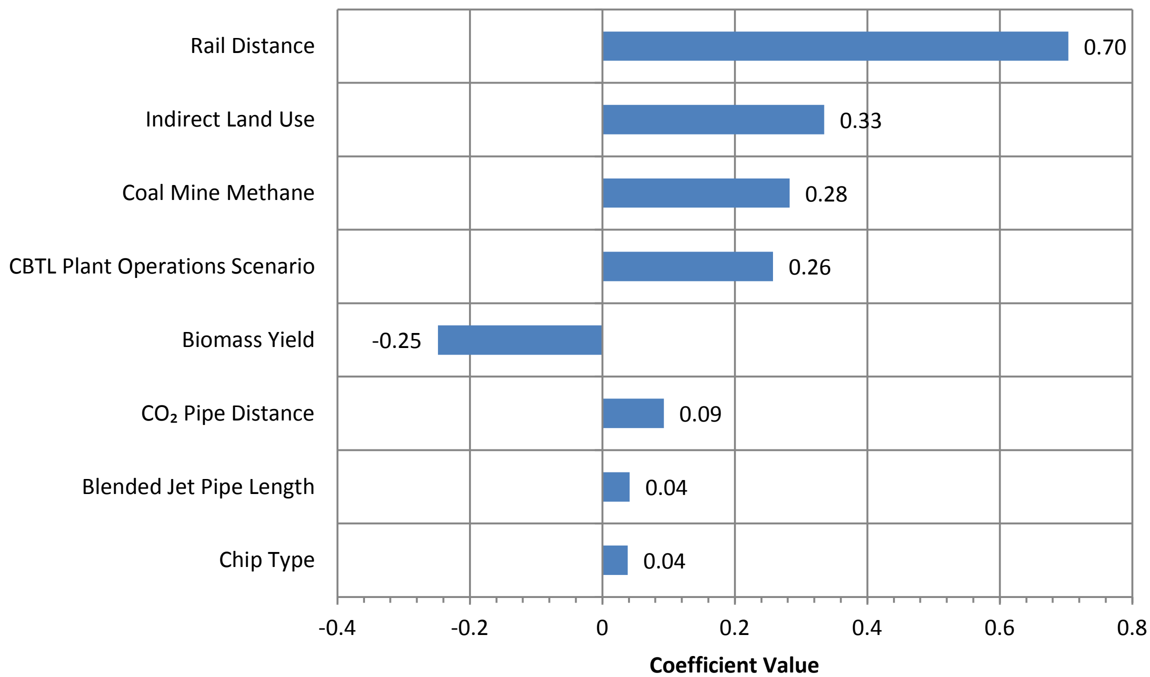
Figure 5-35: Scenario 6: CBTL, 10% Biomass, Microchipped, Sep. Gasifiers: LC GHG Emissions Breakdowns, Combined Allocation



** 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), based on combined allocation. The variability shown reflects model output sensitivity to the environmental parameters contained in **Table 1-5**, distinct from co-product management scheme. As shown, variability in emissions resulted primarily from CO_2-EOR operation and biomass production. Other key contributors to variability in model output include CBTL facility operation and transport of coal to the CBTL facility. Other modeled processes contributed minimally to the overall variability in model results. **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. CBTL plant operations scenario refers to the low and high RSP technical cases considered in the analysis, as discussed in Chapter 2. Excluding co-product management scheme, rail distance was found to have the greatest effect on life cycle emissions, such that variability in CBTL facility operations can explain approximately 70% of total variability in GHG emissions caused by sensitivity to environmental parameters.

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 5-24** provides a summary of these flows, for energy allocation only. 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, Energy Allocation

LC Stage	Carbon monoxide	NOx	SO_2	PM_{10}	NMVOC	Hg (+II)	Ammonia	Water Consumption	Units
RMA	9.44E-07	5.44E-07	2.99E-07	6.24E-09	2.83E-05	1.42E-12	8.35E-08	1.28E+00	kg/MJ Jet Fuel
RMT	2.44E-06	2.08E-06	5.95E-07	2.69E-06	4.05E-07	6.05E-13	3.06E-08	4.45E-04	kg/MJ Jet Fuel
EC	1.83E-07	4.08E-07	2.27E-08	8.31E-09	7.36E-07	1.57E-10	8.46E-08	3.06E-02	kg/MJ Jet Fuel
PT	6.53E-06	9.52E-06	1.78E-05	1.75E-07	2.00E-05	1.53E-11	8.03E-08	2.21E-02	kg/MJ Jet Fuel
EU	1.78E-04	2.79E-04	1.29E-05	6.04E-08	1.77E-05	6.89E-10	1.33E-10	6.08E-05	kg/MJ Jet Fuel
Total	**1.88E-04**	**2.91E-04**	**3.16E-05**	**2.94E-06**	**6.71E-05**	**8.63E-10**	**2.79E-07**	**1.34E+00**	**kg/MJ Jet Fuel**

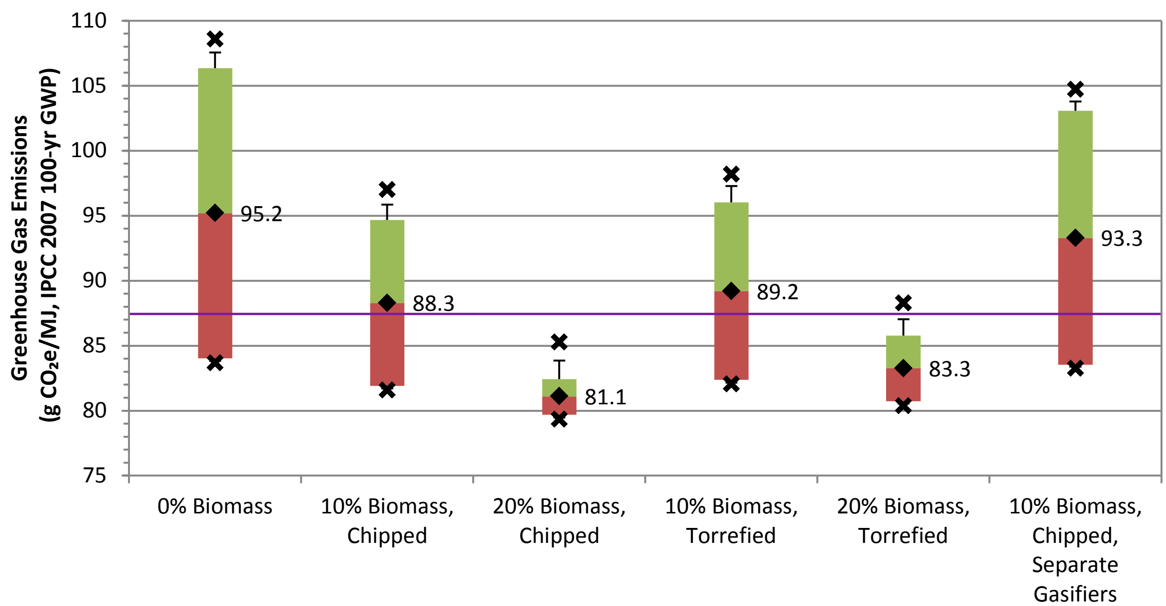
5.7 Comparison of All Scenarios

The following text provides a summary comparison of the modeled results for cost and life cycle GHG emissions associated with each of the six 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% of the distribution for key economic parameters, that is, the 25th and 75th percentile results.

Life cycle GHG emissions from a 1:1 (volume) blend of F-T jet fuel and conventional jet fuel are summarized in **Figure 5-37**, for each of the six production scenarios described previously, based on the results for combined allocation. The solid horizontal line indicates the estimated life cycle emissions level for baseline conventional jet fuel, consistent with EISA requirements. Only one of the six scenarios, the CBTL, 20% Chipped Biomass scenario, indicated life cycle emissions that were entirely below the EISA baseline value of 87.4 g CO_2e/MJ, over the entire distribution of modeled results. Emissions from the CBTL, 20% Torrefied Biomass scenario ranged from 79.7 to 82.4 g CO_2e/MJ, mean value 81.1 g CO_2e/MJ.

For all other scenarios, the distribution of results lies at least partially below the EISA baseline value. As shown in **Figure 5-37**, 25th and 75th percentile results from the CBTL, 20% Torrefied Biomass scenario are entirely below the EISA baseline ranging from 80.7 to 85.8 g CO_2e/MJ, mean 83.3 g CO_2e/MJ. Only the maximum value for the distribution, 88.3 g CO_2e/MJ, strays above the EISA baseline. For the CBTL, 10% Chipped Biomass and the CBTL, 10% Torrefied Biomass scenarios, mean values are only 0.87 and 1.79 g CO_2e/MJ above the EISA baseline value, with the 25th percentile range extending well below the baseline value. For the CBTL, 0% Biomass scenario and the CBTL, 10% Biomass, Microchipped, Separate Gasifiers scenario, mean values are 7.8 and 5.8 g CO_2e/MJ above the EISA baseline value, respectively. However, even for these scenarios, the EISA baseline value is still within the 25th percentile range of results. Therefore, results from this study indicate that all investigated scenarios could potentially meet EISA requirements. However, especially for the CBTL, 0% Biomass scenario and the CBTL, 10% Biomass, Microchipped, Separate Gasifiers scenario, careful attention to design and financial parameters may be warranted, especially with respect to CO_2 enhanced oil recovery and biomass production (where applicable), in order to minimize life cycle emissions.

Figure 5-37: 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.

Life cycle GHG emissions results underscore the importance of biomass carbon uptake 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 15% reduction in life cycle GHG emissions, from a mean value of 95.2 g CO_2e/MJ to 81.1 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 13% reduction in life cycle GHG emissions, to a mean value of 83.3 g CO_2e/MJ for the latter scenario. 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 93.3 g CO_2e/MJ, based on a 10% rate of biomass co-feeding. This represents a 2.0% 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 5.7% over and above the dual gasifiers scenario.

RSP values (crude oil equivalent basis) for F-T jet fuel are summarized in **Figure 5-38**, for each of the six 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 2012 (EIA, 2012b).

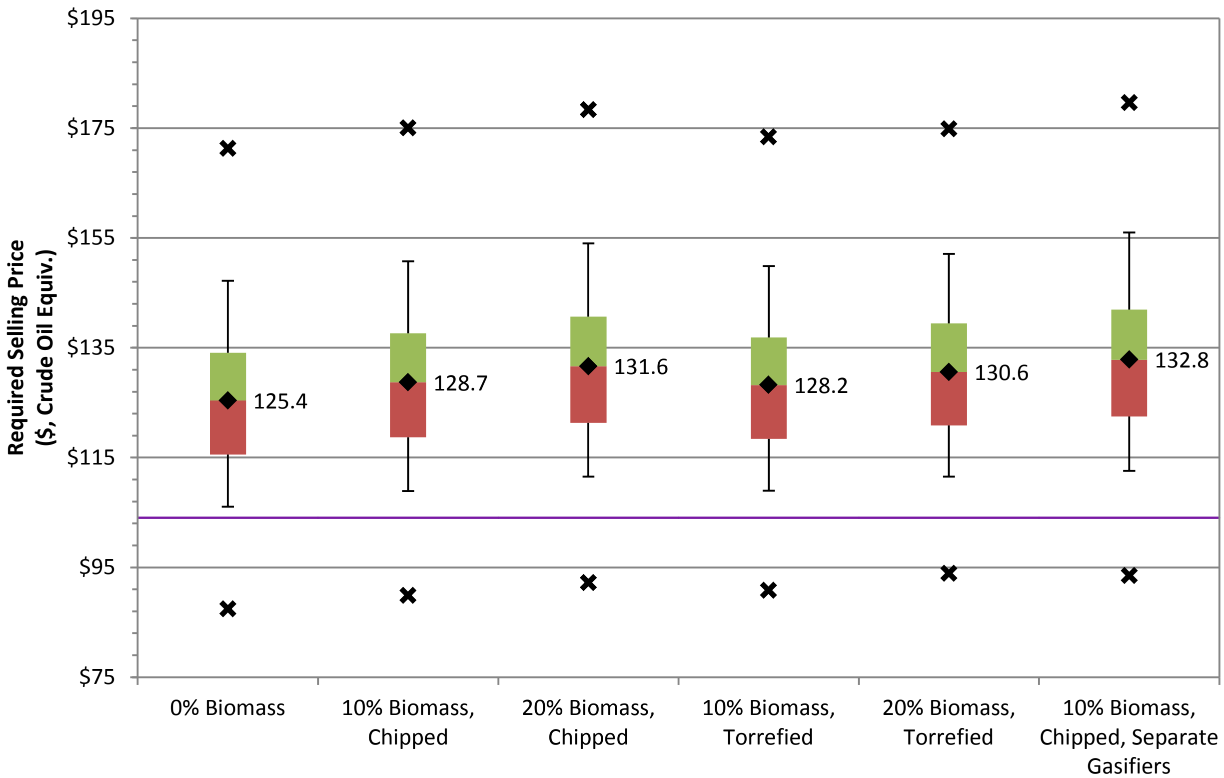
As shown, 25th percentile/75th percentile values for all six scenarios generally range between about \$116/bbl and \$142.bbl, with minimum/tail end distribution values reaching as low as \$87.4/bbl for the CBTL, 0% Biomass scenario. Overall, RSP results distributions for the CBTL, 0% biomass were the lowest of all scenarios, with 25th/75th percentile values ranging from \$116 to \$134/bbl, mean \$125/bbl. Conversely, RSP results distributions for the CBTL, 10% Biomass, Microchipped, Separate Gasifiers scenario were consistently higher than other scenarios, ranging from \$122 to \$142/bbl, mean \$133/bbl.

RSP results distributions for the remaining scenarios fall between RSP values for the CBTL, 0% Biomass and the CBTL, 10% Biomass, Microchipped, Separate Gasifiers scenarios. Scenarios utilizing 20% biomass have generally higher RSP values than scenarios utilizing 10% biomass. For example, RSP values for the CBTL, 20% Chipped Biomass scenario range from \$121 to \$141/bbl, mean \$132/bbl, while RSP values for the CBTL, 10% Chipped Biomass scenario range from \$119 to \$138/bbl, mean \$129/bbl. Comparing mean values, the CBTL, 20% Chipped Biomass scenario results in a mean RSP value that is approximately \$2.90/bbl higher than the CBTL, 10% Chipped Biomass scenario. Similar trends are apparent for the 10% Torrefied Biomass scenario (range \$118 to \$137/bbl, mean \$128/bbl) and the 20% Torrefied Biomass scenario (range \$121 to \$139/bbl, mean \$131/bbl), wherein the 20% Torrefied Biomass scenario results in a mean RSP value that is approximately \$2.40 higher than the 10% Torrefied Biomass scenario.

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 \$129/bbl for the CBTL, 10% Chipped Biomass scenario and \$128/bbl for the CBTL, 10% Torrefied Biomass scenario, torrefaction results in a total cost savings of about a dollar per barrel. Similarly, for the 20% biomass scenarios, comparing mean values of \$132/bbl for chipped biomass to \$131/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 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% Biomass, Microchipped, Separate Gasifiers scenario is \$4.10/bbl greater than the CBTL, 10% Chipped Biomass scenario, and \$4.60/bbl greater than the CBTL, 10% Torrefied Biomass scenario. However, based on the observed range of RSP results, there remains considerable overlap among these (and all) scenarios.

Figure 5-38: 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 baseline value.

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 six F-T jet fuel production scenarios considered in this study.

- The CBTL, 0% Biomass CBTL facility configuration is estimated to have an overall HHV efficiency of 53.4%. 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% by volume. The unallocated GHG emissions from the CBTL facility under this scenario are estimated to be 4.08 g CO_2e/MJ (LHV) of products. The required selling price of the jet fuel product has an estimated 25th to 75th percentile range of \$116 to \$134/bbl, mean \$125/bbl on a crude oil equivalent basis. This required selling price is above current world oil prices. For comparison, WTI spot pricing from early 2012 was \$104/bbl. However, the high required selling price of the jet fuel is greatly influenced by the high capital charge factor (0.2365[2]) used in this economic analysis. If a lower charge factor were to be used (for example using 0.1695 in place of 0.2365), the RSP of jet fuel would be reduced by approximately 20%. On a crude oil equivalent basis this would be approximately \$100/barrel – less than the current world oil price as of early 2012. As a result, plant financing criteria will be critical factors in determining the economic viability of a CBTL facility.
- Co-gasification of chipped biomass and coal in the same gasification system results in a slight lowering of the overall efficiency, in comparison to coal only and coal/torrefied biomass scenarios. This is because of the lower quality of the chipped biomass compared to coal or torrefied biomass, with respect to carbon content and heating value, and because more parasitic power is required for chipped biomass preparation.
- 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% Biomass scenario has an estimated 25th to 75th percentile range of \$116 to \$134/bbl, mean \$125/bbl, while the CBTL,

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[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, I. (2007). *Pinch Analysis and Process Integration, 2nd Edition*. U.K.: Elsevier, Ltd, Leng, W., Abbas, A., & Khalilpour, R. (2010). *Pinch Analysis for Integration of Coal-fired Power Plants with Carbon Capture*. Paper presented at the 20th European Symposium on Computer Aided Process Engineering – ESCAPE20. Retrieved from http://www.aidic.it/escape20/webpapers/558Leng.pdf.

[2] This capital charge factor is based on a 50% debt to equity ratio, a 15-year debt term, a nominal dollar cost for debt of 8% and 20% on equity, and an after tax weighted cost of capital of 13.1%.

10% Chipped Biomass scenario has a range of \$119 to \$138/bbl, mean \$129/bbl, and the CBTL, 20% Chipped Biomass scenario has an RSP range of \$121 to \$141/bbl, mean \$132/bbl. Thus, on average, use of 10% and 20% chipped biomass drive an increase in RSP of about \$3/bbl and \$6/bbl over the CBTL, 0% 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.

- RSP for scenarios using torrefied biomass is slightly lower than for scenarios using chipped biomass plus grinding. For example, the RSP for the CBTL, 10% Torrefied Biomass scenario has a 25th to 75th percentile range of \$119 to \$137/bbl, mean \$128/bbl, while the RSP for the CBTL, 10% Chipped Biomass scenario has a range of \$119 to \$138/bbl, mean \$129/bbl (based on crude oil equivalent). Similarly, for the CBTL, 20% Torrefied Biomass scenario, the RSP range is \$121 to \$139/bbl, mean \$131/bbl, compared to \$121 to \$141/bbl, mean \$132/bbl for the CBTL, 20% Chipped Biomass scenario (based on crude oil equivalent). Thus, although the cost of the torrefied feedstock is considerably higher than for the chipped biomass, the higher quality of the torrefied material and the lower processing costs compensate for this higher feed cost, and may result in a slight reduction in RSP value for torrefied biomass, as compared to chipped biomass.

- 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% feed rate. The 25th to 75th percentile RSP range for the separate gasifiers scenario is \$123 to \$142/bbl, mean \$133/bbl, compared to \$119 to \$138/bbl, mean \$129/bbl for the 10% Chipped Biomass scenario, and \$119 to \$137/bbl, mean \$128/bbl for the 10% 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% to give the same RSP of jet fuel obtained for the other 10% biomass scenarios.

- Based on results from the combined allocation strategy, only one of the six scenarios, the CBTL, 20% Chipped Biomass scenario, indicated life cycle emissions that were entirely below the EISA baseline value of 87.4 g CO_2e/MJ, over the entire distribution of modeled results. Emissions from the CBTL, 20% Chipped Biomass scenario ranged from 79.7 to 82.4 g CO_2e/MJ, mean value 85.3 g CO_2e/MJ.

  For all other scenarios, the distribution of results lies at least partially below the EISA baseline value. The 25th and 75th percentile results from the CBTL, 20% Torrefied Biomass scenario are entirely below the EISA baseline ranging from 80.7 to 85.8 g CO_2e/MJ, mean 83.3 g CO_2e/MJ. Only the maximum value for the distribution, 88.3 g CO_2e/MJ, is above the EISA baseline. For the CBTL, 10% Chipped Biomass and the CBTL, 10% Torrefied Biomass scenarios, mean values are only 0.87 and 1.79 g CO_2e/MJ above the EISA baseline value, with the 25th percentile range extending well below the baseline value. For the CBTL, 0% Biomass scenario and the CBTL, 10% Biomass, Microchipped, Separate Gasifiers scenario, mean values are 7.8 and 5.9 g CO_2e/MJ above the EISA baseline value, respectively. However, even for these scenarios, the EISA baseline value is still within the 25th percentile range of results. Therefore, results from this study indicate that all investigated scenarios could potentially meet EISA requirements based on combined allocation.

With respect to life cycle GHG emissions, results indicate that the allocation method utilized is a key consideration with respect to total GHG emissions. Comparing energy allocation to system expansion, for the scenarios modeled within this study, it is clear that the system expansion method results in higher life cycle GHG emissions overall, as compared to energy allocation. For example, for the CBTL, 0% Biomass scenario, total life cycle GHG emissions were found to have a 25th to 75th percentile range of 83.9 to 84.1 g CO_2e/MJ, mean 84.0 g CO_2e/MJ based on energy allocation, compared to 105.7 to 106.9 g CO_2e/MJ, mean 106.3 g CO_2e/MJ based on system expansion. Optimization of life cycle performance, including CBTL facility performance, also causes variability in life cycle GHG emissions. However, the degree of variability due to life cycle co-product management accounting procedure drives the greatest uncertainty in life cycle GHG emissions for jet fuel produced from coal and biomass to liquids (CBTL) operations.

At present, EISA does not specify a preferred or required allocation method for the evaluation of life cycle GHG emissions for alternative jet fuel. If a select method of allocation is codified by future regulation under EISA, the U.S. EPA, or another federal entity, then the alternative jet fuel production configurations with CO_2 enhanced oil recovery as a carbon management strategy, as modeled in this study, would meet the EISA baseline when modeled with energy allocation. Conversely, only the CBTL, 20% Chipped Biomass scenario would meet or outperform the EISA baseline for jet fuel when modeled based on system expansion, using national average profiles to displace co-products. In general, improvements within the current technical and environmental modeling data uncertainty ranges will not change this conclusion.

- 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 two scenarios that utilized 20% biomass to generate F-T fuels had the lowest overall life cycle GHG emissions. The scenario that utilized 0% biomass feedstock had the highest overall life cycle GHG emissions, while scenarios that utilized 10% 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% 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. Especially significant is the much higher GHG emissions from this configuration (6.75 g CO_2e/MJ (LHV) versus about 4.08 g CO_2e/MJ (LHV) of product under the CBTL, 0% Biomass scenario). This 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% Biomass scenario. Based on combined allocation, the separate gasifiers scenario results in a 25th to 75th percentile range in life cycle GHG emissions of 83.5 to 103 g CO_2e/MJ, mean

93.3 g CO_2e/MJ, while the CBTL, 0% biomass scenario results in a range of 84.0 to 106 g CO_2e/MJ.

6.2 Technological Development Considerations

In the process of conducting the process modeling analysis of the six CBTL facility configurations it was necessary to make various assumptions for both process performance and equipment costs. Many of the operational equipment in the plants are commercially available technology 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 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***: more testing is needed on the pilot unit at Wilsonville and at the smaller units at the Energy & Environmental Research Center to confirm performance for coal/biomass co-gasification. This should include investigations of woody biomass feeding requirements with respect to average particle sizes and optimum moisture content. Testing at different pressures and temperatures should be attempted with various feed ratios of coal to biomass. Synthesis gas composition should be monitored to assess hydrogen to carbon monoxide ratio, methane content, overall carbon conversion, and tar content. 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 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. 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. 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. Tests should also be conducted on co-grinding coal and 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. 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. When considering results based on combined allocation, EISA is a strong driver for the utilization of higher percentages of biomass, in order to produce alternative fuels that have a low carbon footprint. For example, only the scenario that utilizes 20% chipped biomass (i.e., CBTL, 20% Chipped Biomass) indicated life cycle GHG emissions that are below the EISA baseline requirement of 87.4 g CO_2e/MJ, for the entire range of reported emissions values. However, this scenario had the second highest RSP value of all scenarios, indicating a trade-off between cost and GHG emissions performance. In comparison, the CBTL, 0% Biomass scenario had the lowest overall cost range, but the highest overall range of life cycle GHG emissions. Overall, the separate gasifiers scenario had relatively high cost and relatively high GHG emissions. However, as discussed previously, variability in scenario performance, based on results from the stochastic analyses considered, could potentially support the viability of any of the six 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 and 2007

IPCC GWP Factor	Vintage	20 Year	100 Year	500 Year
CO_2	2007	1	1	1
CH_4	2007	72	25	7.6
N_2O	2007	289	298	153
SF_6	2007	16300	22800	32600
CO_2	2001	1	1	1
CH_4	2001	62	23	7
N_2O	2001	275	296	156
SF_6	2001	15100	22200	32400

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/ft^3
F-T Naphtha	0.706	kg/L	44.1	lb/ft^3
F-T Diesel	0.770	kg/L	48.0	lb/ft^3
F-T Jet Fuel	0.760	kg/L	47.4	lb/ft^3
Blended Jet Fuel	0.805	kg/L	50.3	lb/ ft^3
Conventional Petroleum Jet Fuel	0.782	kg/L	48.9	lb/ ft^3
EOR Crude Oil	0.873	kg/L	54.6	lb/ft^3
EOR Natural Gas Liquids	0.650	kg/L	40.6	lb/ft^3

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 six scenarios in the main body of the report, except in alternate units of lb CO_2e/MMBtu LHV and lb CO_2e/bbl. Results are provided based on reporting for combined (A), energy (B) and system expansion (C) allocation, and are contained in the following tables.

Table B-1A: CBTL, 0% Biomass – Combined Allocation

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	**1.09E+00**	**3.02E+00**	**2.99E-01**	**1.36E-05**	**4.41E+00**	**5.76E+00**	**1.59E+01**	**1.58E+00**	**7.20E-05**	**2.33E+01**
Coal Mining, Surface	1.09E+00	3.02E+00	2.99E-01	1.36E-05	4.41E+00	5.76E+00	1.59E+01	1.58E+00	7.20E-05	2.33E+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	**7.27E+00**	**2.08E-01**	**5.31E-02**	**3.62E-07**	**7.53E+00**	**3.84E+01**	**1.10E+00**	**2.80E-01**	**1.91E-06**	**3.97E+01**
Biomass Transp. to Torref. Facility	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 Biomass 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
Transport of Coal to CBTL Plant	7.27E+00	2.08E-01	5.31E-02	3.62E-07	7.53E+00	3.84E+01	1.10E+00	2.80E-01	1.91E-06	3.97E+01
Energy Conversion Facility	**2.73E+01**	**-3.92E+00**	**-1.39E-01**	**3.56E-02**	**2.33E+01**	**1.44E+02**	**-2.07E+01**	**-7.33E-01**	**1.88E-01**	**1.23E+02**
Plant Operations (inc. CO_2 Compression)	-2.08E+00	-2.50E+00	-1.07E-01	-2.40E-04	-4.69E+00	-1.10E+01	-1.32E+01	-5.64E-01	-1.26E-03	-2.47E+01
CO_2 Transport to CO_2-EOR Operation	1.07E+00	1.28E-03	8.01E-04	0.00E+00	1.07E+00	5.63E+00	6.73E-03	4.23E-03	0.00E+00	5.64E+00
CO_2-EOR Operation & CO_2 Storage	2.84E+01	-1.42E+00	-3.29E-02	3.58E-02	2.69E+01	1.50E+02	-7.50E+00	-1.74E-01	1.89E-01	1.42E+02
Product Transport	**1.41E+01**	**2.68E+00**	**8.68E-02**	**1.98E-03**	**1.69E+01**	**7.45E+01**	**1.41E+01**	**4.58E-01**	**1.05E-02**	**8.91E+01**
Transp. of Blended J-F to Airport	2.98E-01	2.15E-02	1.60E-03	1.32E-03	3.22E-01	1.57E+00	1.13E-01	8.44E-03	6.98E-03	1.70E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.37E+01	2.65E+00	8.45E-02	6.89E-05	1.64E+01	7.22E+01	1.40E+01	4.46E-01	3.63E-04	8.66E+01
Transport of F-T Jet to Blending Facility	1.34E-01	9.60E-03	7.25E-04	5.90E-04	1.45E-01	7.06E-01	5.07E-02	3.83E-03	3.11E-03	7.63E-01
End Use	**1.68E+02**	**3.10E-02**	**1.31E+00**	**1.92E-07**	**1.69E+02**	**8.86E+02**	**1.63E-01**	**6.94E+00**	**1.01E-06**	**8.93E+02**
Airplane Operation (Fuel Use)	1.68E+02	2.76E-02	1.31E+00	0.00E+00	1.69E+02	8.86E+02	1.45E-01	6.94E+00	0.00E+00	8.93E+02
Airplane Construction	8.28E-02	3.40E-03	4.27E-04	1.92E-07	8.66E-02	4.37E-01	1.79E-02	2.26E-03	1.01E-06	4.57E-01
Total	**2.18E+02**	**2.01E+00**	**1.61E+00**	**3.76E-02**	**2.21E+02**	**1.15E+03**	**1.06E+01**	**8.52E+00**	**1.98E-01**	**1.17E+03**

Table B-1B: CBTL, 0% Biomass – Energy Allocation

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	**3.07E-01**	**7.04E-03**	**5.01E-08**	**7.74E+02**	**1.24E+00**	**1.62E+00**	**3.72E-02**	**2.65E-07**	**4.09E+03**	**6.54E+00**
Coal Mining, Surface	3.07E-01	7.04E-03	5.01E-08	7.74E+02	1.24E+00	1.62E+00	3.72E-02	2.65E-07	4.09E+03	6.54E+00
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	**2.04E+00**	**1.25E-03**	**1.33E-09**	**5.32E+01**	**2.12E+00**	**1.08E+01**	**6.60E-03**	**7.03E-09**	**2.81E+02**	**1.12E+01**
Biomass Transp. to Torref. Facility	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 Biomass 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
Transport of Coal to CBTL Plant	2.04E+00	1.25E-03	1.33E-09	5.32E+01	2.12E+00	1.08E+01	6.60E-03	7.03E-09	2.81E+02	1.12E+01
Energy Conversion Facility	**5.99E+00**	**2.12E-05**	**2.74E-08**	**4.15E-01**	**5.99E+00**	**3.16E+01**	**1.12E-04**	**1.44E-07**	**2.19E+00**	**3.16E+01**
Plant Operations (inc. CO_2 Compression)	5.69E+00	2.28E-06	2.74E-08	8.80E-02	5.69E+00	3.00E+01	1.20E-05	1.44E-07	4.64E-01	3.00E+01
CO_2 Transport to CO_2-EOR Operation	3.00E-01	1.89E-05	0.00E+00	3.27E-01	3.00E-01	1.58E+00	9.97E-05	0.00E+00	1.73E+00	1.58E+00
CO_2-EOR Operation & CO_2 Storage	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
Product Transport	**1.41E+01**	**7.28E-03**	**2.59E-05**	**2.44E+03**	**1.69E+01**	**7.45E+01**	**3.84E-02**	**1.37E-04**	**1.29E+04**	**8.91E+01**
Transp. of Blended J-F to Airport	2.98E-01	1.34E-04	1.73E-05	1.96E+01	3.22E-01	1.57E+00	7.08E-04	9.12E-05	1.03E+02	1.70E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.37E+01	7.09E-03	9.00E-07	2.41E+03	1.64E+01	7.22E+01	3.74E-02	4.75E-06	1.27E+04	8.66E+01
Transport of F-T Jet to Blending Facility	1.34E-01	6.08E-05	7.71E-06	8.75E+00	1.45E-01	7.06E-01	3.21E-04	4.07E-05	4.62E+01	7.63E-01
End Use	**1.68E+02**	**1.10E-01**	**2.50E-09**	**2.82E+01**	**1.69E+02**	**8.86E+02**	**5.82E-01**	**1.32E-08**	**1.49E+02**	**8.93E+02**
Airplane Operation (Fuel Use)	1.68E+02	1.10E-01	0.00E+00	2.51E+01	1.69E+02	8.86E+02	5.82E-01	0.00E+00	1.33E+02	8.93E+02
Airplane Construction	8.28E-02	3.58E-05	2.50E-09	3.10E+00	8.66E-02	4.37E-01	1.89E-04	1.32E-08	1.64E+01	4.57E-01
Total	**1.90E+02**	**1.26E-01**	**2.60E-05**	**3.30E+03**	**1.95E+02**	**1.00E+03**	**6.64E-01**	**1.37E-04**	**1.74E+04**	**1.03E+03**

Table B-1C: CBTL, 0% Biomass – System Expansion

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	**1.88E+00**	**4.31E-02**	**3.07E-07**	**4.74E+03**	**7.58E+00**	**9.90E+00**	**2.27E-01**	**1.62E-06**	**2.50E+04**	**4.00E+01**
Coal Mining, Surface	1.88E+00	4.31E-02	3.07E-07	4.74E+03	7.58E+00	9.90E+00	2.27E-01	1.62E-06	2.50E+04	4.00E+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	**1.25E+01**	**7.65E-03**	**8.14E-09**	**3.26E+02**	**1.29E+01**	**6.59E+01**	**4.04E-02**	**4.30E-08**	**1.72E+03**	**6.83E+01**
Biomass Transp. to Torref. Facility	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 Biomass 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
Transport of Coal to CBTL Plant	1.25E+01	7.65E-03	8.14E-09	3.26E+02	1.29E+01	6.59E+01	4.04E-02	4.30E-08	1.72E+03	6.83E+01
Energy Conversion Facility	**4.87E+01**	**-2.33E-02**	**9.29E-04**	**-7.15E+03**	**4.06E+01**	**2.57E+02**	**-1.23E-01**	**4.91E-03**	**-3.78E+04**	**2.15E+02**
Plant Operations (inc. CO_2 Compression)	-9.84E+00	-1.79E-02	-6.29E-06	-4.57E+03	-1.51E+01	-5.20E+01	-9.46E-02	-3.32E-05	-2.41E+04	-7.95E+01
CO_2 Transport to CO_2-EOR Operation	1.83E+00	1.16E-04	0.00E+00	2.00E+00	1.84E+00	9.67E+00	6.10E-04	0.00E+00	1.06E+01	9.69E+00
CO_2-EOR Operation & CO_2 Storage	5.67E+01	-5.52E-03	9.36E-04	-2.59E+03	5.39E+01	2.99E+02	-2.91E-02	4.94E-03	-1.37E+04	2.84E+02
Product Transport	**1.41E+01**	**7.28E-03**	**2.59E-05**	**2.44E+03**	**1.69E+01**	**7.45E+01**	**3.84E-02**	**1.37E-04**	**1.29E+04**	**8.91E+01**
Transp. of Blended J-F to Airport	2.98E-01	1.34E-04	1.73E-05	1.96E+01	3.22E-01	1.57E+00	7.08E-04	9.12E-05	1.03E+02	1.70E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.37E+01	7.09E-03	9.00E-07	2.41E+03	1.64E+01	7.22E+01	3.74E-02	4.75E-06	1.27E+04	8.66E+01
Transport of F-T Jet to Blending Facility	1.34E-01	6.08E-05	7.71E-06	8.75E+00	1.45E-01	7.06E-01	3.21E-04	4.07E-05	4.62E+01	7.63E-01
End Use	**1.68E+02**	**1.10E-01**	**2.50E-09**	**2.82E+01**	**1.69E+02**	**8.86E+02**	**5.82E-01**	**1.32E-08**	**1.49E+02**	**8.93E+02**
Airplane Operation (Fuel Use)	1.68E+02	1.10E-01	0.00E+00	2.51E+01	1.69E+02	8.86E+02	5.82E-01	0.00E+00	1.33E+02	8.93E+02
Airplane Construction	8.28E-02	3.58E-05	2.50E-09	3.10E+00	8.66E-02	4.37E-01	1.89E-04	1.32E-08	1.64E+01	4.57E-01
Total	**2.45E+02**	**1.45E-01**	**9.56E-04**	**3.77E+02**	**2.47E+02**	**1.29E+03**	**7.65E-01**	**5.04E-03**	**1.99E+03**	**1.31E+03**

Table B-2A: CBTL, 10% Chipped Green Biomass – Combined Allocation

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	**-1.82E+01**	**8.76E-02**	**1.95E-06**	**2.57E+03**	**-1.44E+01**	**-9.63E+01**	**4.62E-01**	**1.03E-05**	**1.36E+04**	**-7.59E+01**
Coal Mining, Surface	1.01E+00	2.31E-02	1.64E-07	2.54E+03	4.07E+00	5.31E+00	1.22E-01	8.68E-07	1.34E+04	2.15E+01
Biomass Production and Field Chipping	-2.17E+01	6.27E-02	1.79E-06	2.92E+01	-2.09E+01	-1.14E+02	3.31E-01	9.44E-06	1.54E+02	-1.10E+02
Biomass Direct Land Use Change	5.15E-01	0.00E+00	0.00E+00	0.00E+00	5.15E-01	2.72E+00	0.00E+00	0.00E+00	0.00E+00	2.72E+00
Biomass Indirect Land Use Change	1.90E+00	1.74E-03	0.00E+00	0.00E+00	1.92E+00	1.00E+01	9.16E-03	0.00E+00	0.00E+00	1.01E+01
Raw Material Transport	**6.77E+00**	**4.15E-03**	**4.66E-09**	**1.79E+02**	**7.01E+00**	**3.57E+01**	**2.19E-02**	**2.46E-08**	**9.45E+02**	**3.70E+01**
Biomass Transp. to Torref. Facility	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 Biomass to CBTL Plant	6.75E-02	4.13E-05	2.87E-10	4.34E+00	7.28E-02	3.57E-01	2.18E-04	1.52E-09	2.29E+01	3.84E-01
Transport of Coal to CBTL Plant	6.70E+00	4.10E-03	4.37E-09	1.75E+02	6.94E+00	3.54E+01	2.17E-02	2.31E-08	9.22E+02	3.66E+01
Energy Conversion Facility	**3.02E+01**	**-1.10E-02**	**4.69E-04**	**-3.29E+03**	**2.65E+01**	**1.59E+02**	**-5.79E-02**	**2.47E-03**	**-1.74E+04**	**1.40E+02**
Plant Operations (inc. CO_2 Compression)	5.34E-01	-8.25E-03	-2.72E-06	-1.99E+03	-1.75E+00	2.82E+00	-4.36E-02	-1.43E-05	-1.05E+04	-9.22E+00
CO_2 Transport to CO_2-EOR Operation	1.07E+00	6.77E-05	0.00E+00	1.17E+00	1.08E+00	5.67E+00	3.57E-04	0.00E+00	6.18E+00	5.68E+00
CO_2-EOR Operation & CO_2 Storage	2.86E+01	-2.78E-03	4.71E-04	-1.30E+03	2.71E+01	1.51E+02	-1.47E-02	2.49E-03	-6.89E+03	1.43E+02
Product Transport	**1.41E+01**	**7.28E-03**	**2.59E-05**	**2.44E+03**	**1.69E+01**	**7.45E+01**	**3.84E-02**	**1.37E-04**	**1.29E+04**	**8.91E+01**
Transp. of Blended J-F to Airport	2.98E-01	1.34E-04	1.73E-05	1.96E+01	3.22E-01	1.57E+00	7.08E-04	9.12E-05	1.03E+02	1.70E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.37E+01	7.09E-03	9.00E-07	2.41E+03	1.64E+01	7.22E+01	3.74E-02	4.75E-06	1.27E+04	8.66E+01
Transport of F-T Jet to Blending Facility	1.34E-01	6.08E-05	7.71E-06	8.75E+00	1.45E-01	7.06E-01	3.21E-04	4.07E-05	4.62E+01	7.63E-01
End Use	**1.68E+02**	**1.10E-01**	**2.50E-09**	**2.82E+01**	**1.69E+02**	**8.86E+02**	**5.82E-01**	**1.32E-08**	**1.49E+02**	**8.93E+02**
Airplane Operation (Fuel Use)	1.68E+02	1.10E-01	0.00E+00	2.51E+01	1.69E+02	8.86E+02	5.82E-01	0.00E+00	1.33E+02	8.93E+02
Airplane Construction	8.28E-02	3.58E-05	2.50E-09	3.10E+00	8.66E-02	4.37E-01	1.89E-04	1.32E-08	1.64E+01	4.57E-01
Total	**2.01E+02**	**1.98E-01**	**4.96E-04**	**1.92E+03**	**2.05E+02**	**1.06E+03**	**1.05E+00**	**2.62E-03**	**1.02E+04**	**1.08E+03**

Table B-2B: CBTL, 10% Chipped Green Biomass – Energy Allocation

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	**-5.11E+00**	**2.46E-02**	**5.47E-07**	**7.20E+02**	**-4.03E+00**	**-2.70E+01**	**1.30E-01**	**2.89E-06**	**3.80E+03**	**-2.13E+01**
Coal Mining, Surface	2.82E-01	6.48E-03	4.61E-08	7.12E+02	1.14E+00	1.49E+00	3.42E-02	2.43E-07	3.76E+03	6.02E+00
Biomass Production and Field Chipping	-6.07E+00	1.76E-02	5.01E-07	8.18E+00	-5.85E+00	-3.21E+01	9.28E-02	2.65E-06	4.32E+01	-3.09E+01
Biomass Direct Land Use Change	1.44E-01	0.00E+00	0.00E+00	0.00E+00	1.44E-01	7.62E-01	0.00E+00	0.00E+00	0.00E+00	7.62E-01
Biomass Indirect Land Use Change	5.33E-01	4.87E-04	0.00E+00	0.00E+00	5.39E-01	2.81E+00	2.57E-03	0.00E+00	0.00E+00	2.84E+00
Raw Material Transport	**1.90E+00**	**1.16E-03**	**1.31E-09**	**5.02E+01**	**1.97E+00**	**1.00E+01**	**6.13E-03**	**6.89E-09**	**2.65E+02**	**1.04E+01**
Biomass Transp. to Torref. Facility	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 Biomass to CBTL Plant	1.89E-02	1.16E-05	8.06E-11	1.22E+00	2.04E-02	9.99E-02	6.11E-05	4.25E-10	6.43E+00	1.08E-01
Transport of Coal to CBTL Plant	1.88E+00	1.15E-03	1.22E-09	4.90E+01	1.95E+00	9.92E+00	6.07E-03	6.46E-09	2.58E+02	1.03E+01
Energy Conversion Facility	**6.37E+00**	**8.17E-05**	**7.32E-08**	**5.87E+01**	**6.43E+00**	**3.36E+01**	**4.31E-04**	**3.86E-07**	**3.10E+02**	**3.39E+01**
Plant Operations (inc. CO_2 Compression)	6.06E+00	6.27E-05	7.32E-08	5.84E+01	6.13E+00	3.20E+01	3.31E-04	3.86E-07	3.08E+02	3.23E+01
CO_2 Transport to CO_2-EOR Operation	3.01E-01	1.90E-05	0.00E+00	3.28E-01	3.02E-01	1.59E+00	1.00E-04	0.00E+00	1.73E+00	1.59E+00
CO_2-EOR Operation & CO_2 Storage	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
Product Transport	**1.41E+01**	**7.28E-03**	**2.59E-05**	**2.44E+03**	**1.69E+01**	**7.45E+01**	**3.84E-02**	**1.37E-04**	**1.29E+04**	**8.91E+01**
Transp. of Blended J-F to Airport	2.98E-01	1.34E-04	1.73E-05	1.96E+01	3.22E-01	1.57E+00	7.08E-04	9.12E-05	1.03E+02	1.70E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.37E+01	7.09E-03	9.00E-07	2.41E+03	1.64E+01	7.22E+01	3.74E-02	4.75E-06	1.27E+04	8.66E+01
Transport of F-T Jet to Blending Facility	1.34E-01	6.08E-05	7.71E-06	8.75E+00	1.45E-01	7.06E-01	3.21E-04	4.07E-05	4.62E+01	7.63E-01
End Use	**1.68E+02**	**1.10E-01**	**2.50E-09**	**2.82E+01**	**1.69E+02**	**8.86E+02**	**5.82E-01**	**1.32E-08**	**1.49E+02**	**8.93E+02**
Airplane Operation (Fuel Use)	1.68E+02	1.10E-01	0.00E+00	2.51E+01	1.69E+02	8.86E+02	5.82E-01	0.00E+00	1.33E+02	8.93E+02
Airplane Construction	8.28E-02	3.58E-05	2.50E-09	3.10E+00	8.66E-02	4.37E-01	1.89E-04	1.32E-08	1.64E+01	4.57E-01
Total	**1.85E+02**	**1.43E-01**	**2.65E-05**	**3.30E+03**	**1.90E+02**	**9.77E+02**	**7.57E-01**	**1.40E-04**	**1.74E+04**	**1.01E+03**

Table B-2C: CBTL, 10% Chipped Green Biomass – System Expansion

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	**-3.14E+01**	**1.51E-01**	**3.36E-06**	**4.42E+03**	**-2.47E+01**	**-1.66E+02**	**7.95E-01**	**1.77E-05**	**2.33E+04**	**-1.31E+02**
Coal Mining, Surface	1.73E+00	3.98E-02	2.83E-07	4.37E+03	6.99E+00	9.14E+00	2.10E-01	1.49E-06	2.31E+04	3.69E+01
Biomass Production and Field Chipping	-3.73E+01	1.08E-01	3.07E-06	5.02E+01	-3.59E+01	-1.97E+02	5.69E-01	1.62E-05	2.65E+02	-1.90E+02
Biomass Direct Land Use Change	8.85E-01	0.00E+00	0.00E+00	0.00E+00	8.85E-01	4.67E+00	0.00E+00	0.00E+00	0.00E+00	4.67E+00
Biomass Indirect Land Use Change	3.27E+00	2.99E-03	0.00E+00	0.00E+00	3.30E+00	1.72E+01	1.58E-02	0.00E+00	0.00E+00	1.74E+01
Raw Material Transport	**1.16E+01**	**7.13E-03**	**8.01E-09**	**3.08E+02**	**1.21E+01**	**6.14E+01**	**3.76E-02**	**4.23E-08**	**1.63E+03**	**6.37E+01**
Biomass Transp. to Torref. Facility	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 Biomass to CBTL Plant	1.16E-01	7.11E-05	4.94E-10	7.47E+00	1.25E-01	6.13E-01	3.75E-04	2.61E-09	3.94E+01	6.61E-01
Transport of Coal to CBTL Plant	1.15E+01	7.06E-03	7.51E-09	3.00E+02	1.19E+01	6.08E+01	3.73E-02	3.97E-08	1.59E+03	6.30E+01
Energy Conversion Facility	**5.40E+01**	**-2.20E-02**	**9.37E-04**	**-6.65E+03**	**4.65E+01**	**2.85E+02**	**-1.16E-01**	**4.95E-03**	**-3.51E+04**	**2.45E+02**
Plant Operations (inc. CO_2 Compression)	-5.00E+00	-1.66E-02	-5.51E-06	-4.04E+03	-9.62E+00	-2.64E+01	-8.75E-02	-2.91E-05	-2.13E+04	-5.08E+01
CO_2 Transport to CO_2-EOR Operation	1.85E+00	1.16E-04	0.00E+00	2.01E+00	1.85E+00	9.74E+00	6.14E-04	0.00E+00	1.06E+01	9.76E+00
CO_2-EOR Operation & CO_2 Storage	5.71E+01	-5.56E-03	9.43E-04	-2.61E+03	5.43E+01	3.01E+02	-2.93E-02	4.97E-03	-1.38E+04	2.86E+02
Product Transport	**1.41E+01**	**7.28E-03**	**2.59E-05**	**2.44E+03**	**1.69E+01**	**7.45E+01**	**3.84E-02**	**1.37E-04**	**1.29E+04**	**8.91E+01**
Transp. of Blended J-F to Airport	2.98E-01	1.34E-04	1.73E-05	1.96E+01	3.22E-01	1.57E+00	7.08E-04	9.12E-05	1.03E+02	1.70E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.37E+01	7.09E-03	9.00E-07	2.41E+03	1.64E+01	7.22E+01	3.74E-02	4.75E-06	1.27E+04	8.66E+01
Transport of F-T Jet to Blending Facility	1.34E-01	6.08E-05	7.71E-06	8.75E+00	1.45E-01	7.06E-01	3.21E-04	4.07E-05	4.62E+01	7.63E-01
End Use	**1.68E+02**	**1.10E-01**	**2.50E-09**	**2.82E+01**	**1.69E+02**	**8.86E+02**	**5.82E-01**	**1.32E-08**	**1.49E+02**	**8.93E+02**
Airplane Operation (Fuel Use)	1.68E+02	1.10E-01	0.00E+00	2.51E+01	1.69E+02	8.86E+02	5.82E-01	0.00E+00	1.33E+02	8.93E+02
Airplane Construction	8.28E-02	3.58E-05	2.50E-09	3.10E+00	8.66E-02	4.37E-01	1.89E-04	1.32E-08	1.64E+01	4.57E-01
Total	**2.16E+02**	**2.53E-01**	**9.66E-04**	**5.50E+02**	**2.20E+02**	**1.14E+03**	**1.34E+00**	**5.10E-03**	**2.90E+03**	**1.16E+03**

Table B-3A: CBTL, 20% Chipped Green Biomass – Combined Allocation

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	**-3.86E+01**	**1.53E-01**	**3.82E-06**	**2.37E+03**	**-3.41E+01**	**-2.03E+02**	**8.09E-01**	**2.01E-05**	**1.25E+04**	**-1.80E+02**
Coal Mining, Surface	9.17E-01	2.11E-02	1.50E-07	2.31E+03	3.71E+00	4.84E+00	1.11E-01	7.91E-07	1.22E+04	1.96E+01
Biomass Production and Field Chipping	-4.44E+01	1.29E-01	3.67E-06	5.98E+01	-4.28E+01	-2.34E+02	6.79E-01	1.93E-05	3.16E+02	-2.26E+02
Biomass Direct Land Use Change	1.06E+00	0.00E+00	0.00E+00	0.00E+00	1.06E+00	5.57E+00	0.00E+00	0.00E+00	0.00E+00	5.57E+00
Biomass Indirect Land Use Change	3.90E+00	3.56E-03	0.00E+00	0.00E+00	3.94E+00	2.06E+01	1.88E-02	0.00E+00	0.00E+00	2.08E+01
Raw Material Transport	**6.25E+00**	**3.82E-03**	**4.57E-09**	**1.68E+02**	**6.48E+00**	**3.30E+01**	**2.02E-02**	**2.41E-08**	**8.87E+02**	**3.42E+01**
Biomass Transp. to Torref. Facility	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 Biomass to CBTL Plant	1.38E-01	8.47E-05	5.89E-10	8.90E+00	1.49E-01	7.31E-01	4.47E-04	3.11E-09	4.70E+01	7.88E-01
Transport of Coal to CBTL Plant	6.11E+00	3.74E-03	3.98E-09	1.59E+02	6.33E+00	3.22E+01	1.97E-02	2.10E-08	8.40E+02	3.34E+01
Energy Conversion Facility	**3.32E+01**	**-1.02E-02**	**4.73E-04**	**-2.99E+03**	**2.98E+01**	**1.75E+02**	**-5.39E-02**	**2.49E-03**	**-1.58E+04**	**1.58E+02**
Plant Operations (inc. CO_2 Compression)	3.35E+00	-7.49E-03	-2.27E-06	-1.68E+03	1.42E+00	1.77E+01	-3.95E-02	-1.20E-05	-8.85E+03	7.51E+00
CO_2 Transport to CO_2-EOR Operation	1.08E+00	6.82E-05	0.00E+00	1.18E+00	1.08E+00	5.71E+00	3.60E-04	0.00E+00	6.23E+00	5.72E+00
CO_2-EOR Operation & CO_2 Storage	2.88E+01	-2.80E-03	4.75E-04	-1.31E+03	2.73E+01	1.52E+02	-1.48E-02	2.51E-03	-6.94E+03	1.44E+02
Product Transport	**1.41E+01**	**7.28E-03**	**2.59E-05**	**2.44E+03**	**1.69E+01**	**7.45E+01**	**3.84E-02**	**1.37E-04**	**1.29E+04**	**8.91E+01**
Transp. of Blended J-F to Airport	2.98E-01	1.34E-04	1.73E-05	1.96E+01	3.22E-01	1.57E+00	7.08E-04	9.12E-05	1.03E+02	1.70E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.37E+01	7.09E-03	9.00E-07	2.41E+03	1.64E+01	7.22E+01	3.74E-02	4.75E-06	1.27E+04	8.66E+01
Transport of F-T Jet to Blending Facility	1.34E-01	6.08E-05	7.71E-06	8.75E+00	1.45E-01	7.06E-01	3.21E-04	4.07E-05	4.62E+01	7.63E-01
End Use	**1.68E+02**	**1.10E-01**	**2.50E-09**	**2.82E+01**	**1.69E+02**	**8.86E+02**	**5.82E-01**	**1.32E-08**	**1.49E+02**	**8.93E+02**
Airplane Operation (Fuel Use)	1.68E+02	1.10E-01	0.00E+00	2.51E+01	1.69E+02	8.86E+02	5.82E-01	0.00E+00	1.33E+02	8.93E+02
Airplane Construction	8.28E-02	3.58E-05	2.50E-09	3.10E+00	8.66E-02	4.37E-01	1.89E-04	1.32E-08	1.64E+01	4.57E-01
Total	**1.83E+02**	**2.64E-01**	**5.02E-04**	**2.02E+03**	**1.88E+02**	**9.65E+02**	**1.40E+00**	**2.65E-03**	**1.07E+04**	**9.94E+02**

Table B-3B: CBTL, 20% Chipped Green Biomass – Energy Allocation

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	**-1.08E+01**	**4.29E-02**	**1.07E-06**	**6.64E+02**	**-9.54E+00**	**-5.69E+01**	**2.26E-01**	**5.63E-06**	**3.50E+03**	**-5.04E+01**
Coal Mining, Surface	2.57E-01	5.89E-03	4.19E-08	6.47E+02	1.04E+00	1.35E+00	3.11E-02	2.21E-07	3.42E+03	5.47E+00
Biomass Production and Field Chipping	-1.24E+01	3.60E-02	1.03E-06	1.67E+01	-1.20E+01	-6.56E+01	1.90E-01	5.41E-06	8.83E+01	-6.32E+01
Biomass Direct Land Use Change	2.95E-01	0.00E+00	0.00E+00	0.00E+00	2.95E-01	1.56E+00	0.00E+00	0.00E+00	0.00E+00	1.56E+00
Biomass Indirect Land Use Change	1.09E+00	9.96E-04	0.00E+00	0.00E+00	1.10E+00	5.75E+00	5.25E-03	0.00E+00	0.00E+00	5.81E+00
Raw Material Transport	**1.75E+00**	**1.07E-03**	**1.28E-09**	**4.70E+01**	**1.81E+00**	**9.22E+00**	**5.65E-03**	**6.75E-09**	**2.48E+02**	**9.56E+00**
Biomass Transp. to Torref. Facility	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 Biomass to CBTL Plant	3.87E-02	2.37E-05	1.65E-10	2.49E+00	4.17E-02	2.04E-01	1.25E-04	8.70E-10	1.31E+01	2.20E-01
Transport of Coal to CBTL Plant	1.71E+00	1.05E-03	1.11E-09	4.45E+01	1.77E+00	9.01E+00	5.52E-03	5.88E-09	2.35E+02	9.34E+00
Energy Conversion Facility	**6.76E+00**	**1.45E-04**	**1.21E-07**	**1.20E+02**	**6.89E+00**	**3.57E+01**	**7.65E-04**	**6.39E-07**	**6.32E+02**	**3.64E+01**
Plant Operations (inc. CO_2 Compression)	6.46E+00	1.26E-04	1.21E-07	1.19E+02	6.59E+00	3.41E+01	6.64E-04	6.39E-07	6.30E+02	3.48E+01
CO_2 Transport to CO_2-EOR Operation	3.02E-01	1.91E-05	0.00E+00	3.30E-01	3.03E-01	1.60E+00	1.01E-04	0.00E+00	1.74E+00	1.60E+00
CO_2-EOR Operation & CO_2 Storage	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
Product Transport	**1.41E+01**	**7.28E-03**	**2.59E-05**	**2.44E+03**	**1.69E+01**	**7.45E+01**	**3.84E-02**	**1.37E-04**	**1.29E+04**	**8.91E+01**
Transp. of Blended J-F to Airport	2.98E-01	1.34E-04	1.73E-05	1.96E+01	3.22E-01	1.57E+00	7.08E-04	9.12E-05	1.03E+02	1.70E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.37E+01	7.09E-03	9.00E-07	2.41E+03	1.64E+01	7.22E+01	3.74E-02	4.75E-06	1.27E+04	8.66E+01
Transport of F-T Jet to Blending Facility	1.34E-01	6.08E-05	7.71E-06	8.75E+00	1.45E-01	7.06E-01	3.21E-04	4.07E-05	4.62E+01	7.63E-01
End Use	**1.68E+02**	**1.10E-01**	**2.50E-09**	**2.82E+01**	**1.69E+02**	**8.86E+02**	**5.82E-01**	**1.32E-08**	**1.49E+02**	**8.93E+02**
Airplane Operation (Fuel Use)	1.68E+02	1.10E-01	0.00E+00	2.51E+01	1.69E+02	8.86E+02	5.82E-01	0.00E+00	1.33E+02	8.93E+02
Airplane Construction	8.28E-02	3.58E-05	2.50E-09	3.10E+00	8.66E-02	4.37E-01	1.89E-04	1.32E-08	1.64E+01	4.57E-01
Total	**1.80E+02**	**1.62E-01**	**2.71E-05**	**3.30E+03**	**1.85E+02**	**9.49E+02**	**8.53E-01**	**1.43E-04**	**1.74E+04**	**9.78E+02**

Table B-3C: CBTL, 20% Chipped Green Biomass – System Expansion

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	**-6.63E+01**	**2.64E-01**	**6.56E-06**	**4.09E+03**	**-5.87E+01**	**-3.50E+02**	**1.39E+00**	**3.46E-05**	**2.16E+04**	**-3.10E+02**
Coal Mining, Surface	1.58E+00	3.62E-02	2.58E-07	3.98E+03	6.38E+00	8.33E+00	1.91E-01	1.36E-06	2.10E+04	3.37E+01
Biomass Production and Field Chipping	-7.64E+01	2.21E-01	6.31E-06	1.03E+02	-7.37E+01	-4.03E+02	1.17E+00	3.33E-05	5.43E+02	-3.89E+02
Biomass Direct Land Use Change	1.82E+00	0.00E+00	0.00E+00	0.00E+00	1.82E+00	9.59E+00	0.00E+00	0.00E+00	0.00E+00	9.59E+00
Biomass Indirect Land Use Change	6.70E+00	6.12E-03	0.00E+00	0.00E+00	6.78E+00	3.54E+01	3.23E-02	0.00E+00	0.00E+00	3.58E+01
Raw Material Transport	**1.07E+01**	**6.58E-03**	**7.86E-09**	**2.89E+02**	**1.11E+01**	**5.67E+01**	**3.47E-02**	**4.15E-08**	**1.53E+03**	**5.88E+01**
Biomass Transp. to Torref. Facility	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 Biomass to CBTL Plant	2.38E-01	1.46E-04	1.01E-09	1.53E+01	2.57E-01	1.26E+00	7.69E-04	5.35E-09	8.09E+01	1.36E+00
Transport of Coal to CBTL Plant	1.05E+01	6.43E-03	6.85E-09	2.74E+02	1.09E+01	5.55E+01	3.40E-02	3.61E-08	1.45E+03	5.74E+01
Energy Conversion Facility	**5.97E+01**	**-2.06E-02**	**9.45E-04**	**-6.10E+03**	**5.28E+01**	**3.15E+02**	**-1.09E-01**	**4.99E-03**	**-3.22E+04**	**2.79E+02**
Plant Operations (inc. CO_2 Compression)	2.48E-01	-1.51E-02	-4.66E-06	-3.47E+03	-3.74E+00	1.31E+00	-7.97E-02	-2.46E-05	-1.83E+04	-1.97E+01
CO_2 Transport to CO_2-EOR Operation	1.86E+00	1.17E-04	0.00E+00	2.03E+00	1.86E+00	9.82E+00	6.19E-04	0.00E+00	1.07E+01	9.84E+00
CO_2-EOR Operation & CO_2 Storage	5.75E+01	-5.60E-03	9.50E-04	-2.63E+03	5.47E+01	3.04E+02	-2.96E-02	5.01E-03	-1.39E+04	2.89E+02
Product Transport	**1.41E+01**	**7.28E-03**	**2.59E-05**	**2.44E+03**	**1.69E+01**	**7.45E+01**	**3.84E-02**	**1.37E-04**	**1.29E+04**	**8.91E+01**
Transp. of Blended J-F to Airport	2.98E-01	1.34E-04	1.73E-05	1.96E+01	3.22E-01	1.57E+00	7.08E-04	9.12E-05	1.03E+02	1.70E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.37E+01	7.09E-03	9.00E-07	2.41E+03	1.64E+01	7.22E+01	3.74E-02	4.75E-06	1.27E+04	8.66E+01
Transport of F-T Jet to Blending Facility	1.34E-01	6.08E-05	7.71E-06	8.75E+00	1.45E-01	7.06E-01	3.21E-04	4.07E-05	4.62E+01	7.63E-01
End Use	**1.68E+02**	**1.10E-01**	**2.50E-09**	**2.82E+01**	**1.69E+02**	**8.86E+02**	**5.82E-01**	**1.32E-08**	**1.49E+02**	**8.93E+02**
Airplane Operation (Fuel Use)	1.68E+02	1.10E-01	0.00E+00	2.51E+01	1.69E+02	8.86E+02	5.82E-01	0.00E+00	1.33E+02	8.93E+02
Airplane Construction	8.28E-02	3.58E-05	2.50E-09	3.10E+00	8.66E-02	4.37E-01	1.89E-04	1.32E-08	1.64E+01	4.57E-01
Total	**1.86E+02**	**3.67E-01**	**9.77E-04**	**7.43E+02**	**1.91E+02**	**9.82E+02**	**1.94E+00**	**5.16E-03**	**3.92E+03**	**1.01E+03**

Table B-4A: CBTL, 10% Torrefied Biomass – Combined Allocation

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	**-1.30E+01**	**6.93E-02**	**1.46E-06**	**2.48E+03**	**-9.50E+00**	**-6.88E+01**	**3.66E-01**	**7.71E-06**	**1.31E+04**	**-5.01E+01**
Coal Mining, Surface	9.73E-01	2.23E-02	1.59E-07	2.46E+03	3.93E+00	5.14E+00	1.18E-01	8.39E-07	1.30E+04	2.08E+01
Biomass Production and Field Chipping	-1.58E+01	4.57E-02	1.30E-06	2.12E+01	-1.52E+01	-8.32E+01	2.41E-01	6.87E-06	1.12E+02	-8.02E+01
Biomass Direct Land Use Change	3.75E-01	0.00E+00	0.00E+00	0.00E+00	3.75E-01	1.98E+00	0.00E+00	0.00E+00	0.00E+00	1.98E+00
Biomass Indirect Land Use Change	1.38E+00	1.26E-03	0.00E+00	0.00E+00	1.40E+00	7.30E+00	6.67E-03	0.00E+00	0.00E+00	7.38E+00
Raw Material Transport	**7.49E+00**	**4.21E-03**	**2.70E-06**	**1.78E+02**	**7.73E+00**	**3.95E+01**	**2.22E-02**	**1.42E-05**	**9.41E+02**	**4.08E+01**
Biomass Transp. to Torref. Facility	3.96E-02	2.39E-05	1.63E-10	3.09E+00	4.33E-02	2.09E-01	1.26E-04	8.59E-10	1.63E+01	2.29E-01
Biomass Torrefaction	9.21E-01	1.86E-04	2.69E-06	3.14E+00	9.27E-01	4.86E+00	9.84E-04	1.42E-05	1.66E+01	4.89E+00
Transport of Biomass to CBTL Plant	4.92E-02	3.01E-05	2.09E-10	3.16E+00	5.30E-02	2.60E-01	1.59E-04	1.10E-09	1.67E+01	2.80E-01
Transport of Coal to CBTL Plant	6.48E+00	3.97E-03	4.22E-09	1.69E+02	6.71E+00	3.42E+01	2.09E-02	2.23E-08	8.91E+02	3.54E+01
Energy Conversion Facility	**2.70E+01**	**-1.17E-02**	**4.64E-04**	**-3.58E+03**	**2.30E+01**	**1.42E+02**	**-6.17E-02**	**2.45E-03**	**-1.89E+04**	**1.21E+02**
Plant Operations (inc. CO_2 Compression)	-2.40E+00	-9.00E-03	-3.16E-06	-2.29E+03	-5.02E+00	-1.27E+01	-4.75E-02	-1.67E-05	-1.21E+04	-2.65E+01
CO_2 Transport to CO_2-EOR Operation	1.07E+00	6.72E-05	0.00E+00	1.16E+00	1.07E+00	5.62E+00	3.55E-04	0.00E+00	6.13E+00	5.63E+00
CO_2-EOR Operation & CO_2 Storage	2.83E+01	-2.76E-03	4.67E-04	-1.29E+03	2.69E+01	1.50E+02	-1.46E-02	2.47E-03	-6.83E+03	1.42E+02
Product Transport	**1.41E+01**	**7.28E-03**	**2.59E-05**	**2.44E+03**	**1.69E+01**	**7.45E+01**	**3.84E-02**	**1.37E-04**	**1.29E+04**	**8.91E+01**
Transp. of Blended J-F to Airport	2.98E-01	1.34E-04	1.73E-05	1.96E+01	3.22E-01	1.57E+00	7.08E-04	9.12E-05	1.03E+02	1.70E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.37E+01	7.09E-03	9.00E-07	2.41E+03	1.64E+01	7.22E+01	3.74E-02	4.75E-06	1.27E+04	8.66E+01
Transport of F-T Jet to Blending Facility	1.34E-01	6.08E-05	7.71E-06	8.75E+00	1.45E-01	7.06E-01	3.21E-04	4.07E-05	4.62E+01	7.63E-01
End Use	**1.68E+02**	**1.10E-01**	**2.50E-09**	**2.82E+01**	**1.69E+02**	**8.86E+02**	**5.82E-01**	**1.32E-08**	**1.49E+02**	**8.93E+02**
Airplane Operation (Fuel Use)	1.68E+02	1.10E-01	0.00E+00	2.51E+01	1.69E+02	8.86E+02	5.82E-01	0.00E+00	1.33E+02	8.93E+02
Airplane Construction	8.28E-02	3.58E-05	2.50E-09	3.10E+00	8.66E-02	4.37E-01	1.89E-04	1.32E-08	1.64E+01	4.57E-01
Total	**2.03E+02**	**1.79E-01**	**4.94E-04**	**1.54E+03**	**2.07E+02**	**1.07E+03**	**9.47E-01**	**2.61E-03**	**8.14E+03**	**1.09E+03**

Table B-4B: CBTL, 10% Torrefied Biomass – Energy Allocation

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	**-3.67E+00**	**1.95E-02**	**4.11E-07**	**6.96E+02**	**-2.67E+00**	**-1.93E+01**	**1.03E-01**	**2.17E-06**	**3.67E+03**	**-1.41E+01**
Coal Mining, Surface	2.74E-01	6.28E-03	4.47E-08	6.90E+02	1.11E+00	1.44E+00	3.32E-02	2.36E-07	3.64E+03	5.83E+00
Biomass Production and Field Chipping	-4.43E+00	1.28E-02	3.66E-07	5.97E+00	-4.27E+00	-2.34E+01	6.78E-02	1.93E-06	3.15E+01	-2.26E+01
Biomass Direct Land Use Change	1.05E-01	0.00E+00	0.00E+00	0.00E+00	1.05E-01	5.56E-01	0.00E+00	0.00E+00	0.00E+00	5.56E-01
Biomass Indirect Land Use Change	3.89E-01	3.55E-04	0.00E+00	0.00E+00	3.93E-01	2.05E+00	1.88E-03	0.00E+00	0.00E+00	2.07E+00
Raw Material Transport	**2.10E+00**	**1.18E-03**	**7.59E-07**	**5.01E+01**	**2.17E+00**	**1.11E+01**	**6.24E-03**	**4.00E-06**	**2.65E+02**	**1.15E+01**
Biomass Transp. to Torref. Facility	1.11E-02	6.73E-06	4.57E-11	8.68E-01	1.22E-02	5.88E-02	3.55E-05	2.41E-10	4.58E+00	6.42E-02
Biomass Torrefaction	2.59E-01	5.24E-05	7.57E-07	8.83E-01	2.61E-01	1.37E+00	2.77E-04	4.00E-06	4.66E+00	1.38E+00
Transport of Biomass to CBTL Plant	1.38E-02	8.46E-06	5.88E-11	8.89E-01	1.49E-02	7.30E-02	4.46E-05	3.10E-10	4.69E+00	7.86E-02
Transport of Coal to CBTL Plant	1.82E+00	1.12E-03	1.19E-09	4.75E+01	1.89E+00	9.61E+00	5.89E-03	6.27E-09	2.51E+02	9.96E+00
Energy Conversion Facility	**5.93E+00**	**2.12E-05**	**2.74E-08**	**4.15E-01**	**5.93E+00**	**3.13E+01**	**1.12E-04**	**1.44E-07**	**2.19E+00**	**3.13E+01**
Plant Operations (inc. CO_2 Compression)	5.63E+00	2.28E-06	2.74E-08	8.80E-02	5.63E+00	2.97E+01	1.20E-05	1.44E-07	4.64E-01	2.97E+01
CO_2 Transport to CO_2-EOR Operation	2.99E-01	1.89E-05	0.00E+00	3.27E-01	3.00E-01	1.58E+00	9.97E-05	0.00E+00	1.72E+00	1.58E+00
CO_2-EOR Operation & CO_2 Storage	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
Product Transport	**1.41E+01**	**7.28E-03**	**2.59E-05**	**2.44E+03**	**1.69E+01**	**7.45E+01**	**3.84E-02**	**1.37E-04**	**1.29E+04**	**8.91E+01**
Transp. of Blended J-F to Airport	2.98E-01	1.34E-04	1.73E-05	1.96E+01	3.22E-01	1.57E+00	7.08E-04	9.12E-05	1.03E+02	1.70E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.37E+01	7.09E-03	9.00E-07	2.41E+03	1.64E+01	7.22E+01	3.74E-02	4.75E-06	1.27E+04	8.66E+01
Transport of F-T Jet to Blending Facility	1.34E-01	6.08E-05	7.71E-06	8.75E+00	1.45E-01	7.06E-01	3.21E-04	4.07E-05	4.62E+01	7.63E-01
End Use	**1.68E+02**	**1.10E-01**	**2.50E-09**	**2.82E+01**	**1.69E+02**	**8.86E+02**	**5.82E-01**	**1.32E-08**	**1.49E+02**	**8.93E+02**
Airplane Operation (Fuel Use)	1.68E+02	1.10E-01	0.00E+00	2.51E+01	1.69E+02	8.86E+02	5.82E-01	0.00E+00	1.33E+02	8.93E+02
Airplane Construction	8.28E-02	3.58E-05	2.50E-09	3.10E+00	8.66E-02	4.37E-01	1.89E-04	1.32E-08	1.64E+01	4.57E-01
Total	**1.86E+02**	**1.38E-01**	**2.71E-05**	**3.22E+03**	**1.92E+02**	**9.84E+02**	**7.30E-01**	**1.43E-04**	**1.70E+04**	**1.01E+03**

Table B-4C: CBTL, 10% Torrefied Biomass – System Expansion

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	**-2.24E+01**	**1.19E-01**	**2.51E-06**	**4.26E+03**	**-1.63E+01**	**-1.18E+02**	**6.28E-01**	**1.33E-05**	**2.25E+04**	**-8.62E+01**
Coal Mining, Surface	1.67E+00	3.84E-02	2.73E-07	4.22E+03	6.76E+00	8.83E+00	2.03E-01	1.44E-06	2.23E+04	3.57E+01
Biomass Production and Field Chipping	-2.71E+01	7.85E-02	2.24E-06	3.65E+01	-2.61E+01	-1.43E+02	4.14E-01	1.18E-05	1.93E+02	-1.38E+02
Biomass Direct Land Use Change	6.44E-01	0.00E+00	0.00E+00	0.00E+00	6.44E-01	3.40E+00	0.00E+00	0.00E+00	0.00E+00	3.40E+00
Biomass Indirect Land Use Change	2.38E+00	2.17E-03	0.00E+00	0.00E+00	2.40E+00	1.25E+01	1.15E-02	0.00E+00	0.00E+00	1.27E+01
Raw Material Transport	**1.29E+01**	**7.23E-03**	**4.64E-06**	**3.06E+02**	**1.33E+01**	**6.79E+01**	**3.82E-02**	**2.45E-05**	**1.62E+03**	**7.02E+01**
Biomass Transp. to Torref. Facility	6.81E-02	4.12E-05	2.80E-10	5.31E+00	7.44E-02	3.60E-01	2.17E-04	1.48E-09	2.80E+01	3.93E-01
Biomass Torrefaction	1.58E+00	3.21E-04	4.63E-06	5.40E+00	1.59E+00	8.36E+00	1.69E-03	2.44E-05	2.85E+01	8.41E+00
Transport of Biomass to CBTL Plant	8.45E-02	5.17E-05	3.60E-10	5.43E+00	9.11E-02	4.46E-01	2.73E-04	1.90E-09	2.87E+01	4.81E-01
Transport of Coal to CBTL Plant	1.11E+01	6.82E-03	7.26E-09	2.90E+02	1.15E+01	5.88E+01	3.60E-02	3.83E-08	1.53E+03	6.09E+01
Energy Conversion Facility	**4.81E+01**	**-2.34E-02**	**9.29E-04**	**-7.16E+03**	**4.00E+01**	**2.54E+02**	**-1.24E-01**	**4.90E-03**	**-3.78E+04**	**2.11E+02**
Plant Operations (inc. CO_2 Compression)	-1.04E+01	-1.80E-02	-6.35E-06	-4.58E+03	-1.57E+01	-5.51E+01	-9.50E-02	-3.35E-05	-2.42E+04	-8.27E+01
CO_2 Transport to CO_2-EOR Operation	1.83E+00	1.15E-04	0.00E+00	2.00E+00	1.83E+00	9.67E+00	6.09E-04	0.00E+00	1.05E+01	9.68E+00
CO_2-EOR Operation & CO_2 Storage	5.67E+01	-5.51E-03	9.35E-04	-2.59E+03	5.38E+01	2.99E+02	-2.91E-02	4.93E-03	-1.37E+04	2.84E+02
Product Transport	**1.41E+01**	**7.28E-03**	**2.59E-05**	**2.44E+03**	**1.69E+01**	**7.45E+01**	**3.84E-02**	**1.37E-04**	**1.29E+04**	**8.91E+01**
Transp. of Blended J-F to Airport	2.98E-01	1.34E-04	1.73E-05	1.96E+01	3.22E-01	1.57E+00	7.08E-04	9.12E-05	1.03E+02	1.70E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.37E+01	7.09E-03	9.00E-07	2.41E+03	1.64E+01	7.22E+01	3.74E-02	4.75E-06	1.27E+04	8.66E+01
Transport of F-T Jet to Blending Facility	1.34E-01	6.08E-05	7.71E-06	8.75E+00	1.45E-01	7.06E-01	3.21E-04	4.07E-05	4.62E+01	7.63E-01
End Use	**1.68E+02**	**1.10E-01**	**2.50E-09**	**2.82E+01**	**1.69E+02**	**8.86E+02**	**5.82E-01**	**1.32E-08**	**1.49E+02**	**8.93E+02**
Airplane Operation (Fuel Use)	1.68E+02	1.10E-01	0.00E+00	2.51E+01	1.69E+02	8.86E+02	5.82E-01	0.00E+00	1.33E+02	8.93E+02
Airplane Construction	8.28E-02	3.58E-05	2.50E-09	3.10E+00	8.66E-02	4.37E-01	1.89E-04	1.32E-08	1.64E+01	4.57E-01
Total	**2.21E+02**	**2.20E-01**	**9.62E-04**	**-1.31E+02**	**2.23E+02**	**1.16E+03**	**1.16E+00**	**5.08E-03**	**-6.92E+02**	**1.18E+03**

Table B-5A: CBTL, 20% Torrefied Biomass – Combined Allocation

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	**-2.69E+01**	**1.13E-01**	**2.72E-06**	**2.20E+03**	**-2.31E+01**	**-1.42E+02**	**5.95E-01**	**1.43E-05**	**1.16E+04**	**-1.22E+02**
Coal Mining, Surface	8.57E-01	1.97E-02	1.40E-07	2.16E+03	3.46E+00	4.52E+00	1.04E-01	7.39E-07	1.14E+04	1.83E+01
Biomass Production and Field Chipping	-3.12E+01	9.05E-02	2.58E-06	4.21E+01	-3.01E+01	-1.65E+02	4.77E-01	1.36E-05	2.22E+02	-1.59E+02
Biomass Direct Land Use Change	7.43E-01	0.00E+00	0.00E+00	0.00E+00	7.43E-01	3.92E+00	0.00E+00	0.00E+00	0.00E+00	3.92E+00
Biomass Indirect Land Use Change	2.74E+00	2.50E-03	0.00E+00	0.00E+00	2.77E+00	1.45E+01	1.32E-02	0.00E+00	0.00E+00	1.46E+01
Raw Material Transport	**7.71E+00**	**3.97E-03**	**5.34E-06**	**1.67E+02**	**7.94E+00**	**4.07E+01**	**2.10E-02**	**2.82E-05**	**8.83E+02**	**4.19E+01**
Biomass Transp. to Torref. Facility	7.85E-02	4.74E-05	3.22E-10	6.12E+00	8.58E-02	4.14E-01	2.50E-04	1.70E-09	3.23E+01	4.53E-01
Biomass Torrefaction	1.82E+00	3.69E-04	5.34E-06	6.22E+00	1.84E+00	9.63E+00	1.95E-03	2.82E-05	3.28E+01	9.69E+00
Transport of Biomass to CBTL Plant	9.74E-02	5.96E-05	4.14E-10	6.26E+00	1.05E-01	5.14E-01	3.15E-04	2.19E-09	3.31E+01	5.54E-01
Transport of Coal to CBTL Plant	5.70E+00	3.49E-03	3.72E-09	1.49E+02	5.91E+00	3.01E+01	1.84E-02	1.96E-08	7.85E+02	3.12E+01
Energy Conversion Facility	**2.65E+01**	**-1.18E-02**	**4.64E-04**	**-3.60E+03**	**2.25E+01**	**1.40E+02**	**-6.22E-02**	**2.45E-03**	**-1.90E+04**	**1.19E+02**
Plant Operations (inc. CO_2 Compression)	-2.86E+00	-9.10E-03	-3.21E-06	-2.31E+03	-5.50E+00	-1.51E+01	-4.80E-02	-1.70E-05	-1.22E+04	-2.90E+01
CO_2 Transport to CO_2-EOR Operation	1.06E+00	6.71E-05	0.00E+00	1.16E+00	1.07E+00	5.62E+00	3.54E-04	0.00E+00	6.13E+00	5.63E+00
CO_2-EOR Operation & CO_2 Storage	2.83E+01	-2.76E-03	4.67E-04	-1.29E+03	2.69E+01	1.49E+02	-1.45E-02	2.47E-03	-6.82E+03	1.42E+02
Product Transport	**1.41E+01**	**7.28E-03**	**2.59E-05**	**2.44E+03**	**1.69E+01**	**7.45E+01**	**3.84E-02**	**1.37E-04**	**1.29E+04**	**8.91E+01**
Transp. of Blended J-F to Airport	2.98E-01	1.34E-04	1.73E-05	1.96E+01	3.22E-01	1.57E+00	7.08E-04	9.12E-05	1.03E+02	1.70E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.37E+01	7.09E-03	9.00E-07	2.41E+03	1.64E+01	7.22E+01	3.74E-02	4.75E-06	1.27E+04	8.66E+01
Transport of F-T Jet to Blending Facility	1.34E-01	6.08E-05	7.71E-06	8.75E+00	1.45E-01	7.06E-01	3.21E-04	4.07E-05	4.62E+01	7.63E-01
End Use	**1.68E+02**	**1.10E-01**	**2.50E-09**	**2.82E+01**	**1.69E+02**	**8.86E+02**	**5.82E-01**	**1.32E-08**	**1.49E+02**	**8.93E+02**
Airplane Operation (Fuel Use)	1.68E+02	1.10E-01	0.00E+00	2.51E+01	1.69E+02	8.86E+02	5.82E-01	0.00E+00	1.33E+02	8.93E+02
Airplane Construction	8.28E-02	3.58E-05	2.50E-09	3.10E+00	8.66E-02	4.37E-01	1.89E-04	1.32E-08	1.64E+01	4.57E-01
Total	**1.89E+02**	**2.22E-01**	**4.98E-04**	**1.24E+03**	**1.93E+02**	**9.99E+02**	**1.17E+00**	**2.63E-03**	**6.57E+03**	**1.02E+03**

Table B-5B: CBTL, 20% Torrefied Biomass – Energy Allocation

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	**-7.56E+00**	**3.17E-02**	**7.64E-07**	**6.20E+02**	**-6.51E+00**	**-3.99E+01**	**1.67E-01**	**4.03E-06**	**3.27E+03**	**-3.43E+01**
Coal Mining, Surface	2.41E-01	5.53E-03	3.94E-08	6.08E+02	9.73E-01	1.27E+00	2.92E-02	2.08E-07	3.21E+03	5.14E+00
Biomass Production and Field Chipping	-8.78E+00	2.54E-02	7.25E-07	1.18E+01	-8.47E+00	-4.64E+01	1.34E-01	3.83E-06	6.25E+01	-4.47E+01
Biomass Direct Land Use Change	2.09E-01	0.00E+00	0.00E+00	0.00E+00	2.09E-01	1.10E+00	0.00E+00	0.00E+00	0.00E+00	1.10E+00
Biomass Indirect Land Use Change	7.70E-01	7.04E-04	0.00E+00	0.00E+00	7.79E-01	4.07E+00	3.72E-03	0.00E+00	0.00E+00	4.11E+00
Raw Material Transport	**2.17E+00**	**1.12E-03**	**1.50E-06**	**4.70E+01**	**2.23E+00**	**1.14E+01**	**5.89E-03**	**7.93E-06**	**2.48E+02**	**1.18E+01**
Biomass Transp. to Torref. Facility	2.21E-02	1.33E-05	9.06E-11	1.72E+00	2.41E-02	1.16E-01	7.04E-05	4.78E-10	9.07E+00	1.27E-01
Biomass Torrefaction	5.13E-01	1.04E-04	1.50E-06	1.75E+00	5.16E-01	2.71E+00	5.48E-04	7.92E-06	9.23E+00	2.72E+00
Transport of Biomass to CBTL Plant	2.74E-02	1.68E-05	1.17E-10	1.76E+00	2.95E-02	1.45E-01	8.84E-05	6.15E-10	9.29E+00	1.56E-01
Transport of Coal to CBTL Plant	1.60E+00	9.82E-04	1.05E-09	4.18E+01	1.66E+00	8.46E+00	5.18E-03	5.52E-09	2.21E+02	8.77E+00
Energy Conversion Facility	**5.87E+00**	**2.11E-05**	**2.74E-08**	**4.14E-01**	**5.87E+00**	**3.10E+01**	**1.12E-04**	**1.44E-07**	**2.19E+00**	**3.10E+01**
Plant Operations (inc. CO_2 Compression)	5.57E+00	2.28E-06	2.74E-08	8.80E-02	5.57E+00	2.94E+01	1.20E-05	1.44E-07	4.64E-01	2.94E+01
CO_2 Transport to CO_2-EOR Operation	2.99E-01	1.89E-05	0.00E+00	3.26E-01	3.00E-01	1.58E+00	9.96E-05	0.00E+00	1.72E+00	1.58E+00
CO_2-EOR Operation & CO_2 Storage	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
Product Transport	**1.41E+01**	**7.28E-03**	**2.59E-05**	**2.44E+03**	**1.69E+01**	**7.45E+01**	**3.84E-02**	**1.37E-04**	**1.29E+04**	**8.91E+01**
Transp. of Blended J-F to Airport	2.98E-01	1.34E-04	1.73E-05	1.96E+01	3.22E-01	1.57E+00	7.08E-04	9.12E-05	1.03E+02	1.70E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.37E+01	7.09E-03	9.00E-07	2.41E+03	1.64E+01	7.22E+01	3.74E-02	4.75E-06	1.27E+04	8.66E+01
Transport of F-T Jet to Blending Facility	1.34E-01	6.08E-05	7.71E-06	8.75E+00	1.45E-01	7.06E-01	3.21E-04	4.07E-05	4.62E+01	7.63E-01
End Use	**1.68E+02**	**1.10E-01**	**2.50E-09**	**2.82E+01**	**1.69E+02**	**8.86E+02**	**5.82E-01**	**1.32E-08**	**1.49E+02**	**8.93E+02**
Airplane Operation (Fuel Use)	1.68E+02	1.10E-01	0.00E+00	2.51E+01	1.69E+02	8.86E+02	5.82E-01	0.00E+00	1.33E+02	8.93E+02
Airplane Construction	8.28E-02	3.58E-05	2.50E-09	3.10E+00	8.66E-02	4.37E-01	1.89E-04	1.32E-08	1.64E+01	4.57E-01
Total	**1.82E+02**	**1.50E-01**	**2.82E-05**	**3.14E+03**	**1.88E+02**	**9.63E+02**	**7.94E-01**	**1.49E-04**	**1.66E+04**	**9.91E+02**

Table B-5C: CBTL, 20% Torrefied Biomass – System Expansion

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	**-4.62E+01**	**1.94E-01**	**4.67E-06**	**3.79E+03**	**-3.98E+01**	**-2.44E+02**	**1.02E+00**	**2.47E-05**	**2.00E+04**	**-2.10E+02**
Coal Mining, Surface	1.47E+00	3.38E-02	2.41E-07	3.72E+03	5.95E+00	7.77E+00	1.79E-01	1.27E-06	1.96E+04	3.14E+01
Biomass Production and Field Chipping	-5.37E+01	1.56E-01	4.43E-06	7.24E+01	-5.18E+01	-2.83E+02	8.21E-01	2.34E-05	3.82E+02	-2.73E+02
Biomass Direct Land Use Change	1.28E+00	0.00E+00	0.00E+00	0.00E+00	1.28E+00	6.74E+00	0.00E+00	0.00E+00	0.00E+00	6.74E+00
Biomass Indirect Land Use Change	4.71E+00	4.30E-03	0.00E+00	0.00E+00	4.76E+00	2.49E+01	2.27E-02	0.00E+00	0.00E+00	2.51E+01
Raw Material Transport	**1.32E+01**	**6.82E-03**	**9.18E-06**	**2.88E+02**	**1.36E+01**	**6.99E+01**	**3.60E-02**	**4.85E-05**	**1.52E+03**	**7.20E+01**
Biomass Transp. to Torref. Facility	1.35E-01	8.16E-05	5.54E-10	1.05E+01	1.47E-01	7.12E-01	4.30E-04	2.92E-09	5.55E+01	7.78E-01
Biomass Torrefaction	3.14E+00	6.35E-04	9.18E-06	1.07E+01	3.16E+00	1.66E+01	3.35E-03	4.84E-05	5.64E+01	1.67E+01
Transport of Biomass to CBTL Plant	1.67E-01	1.02E-04	7.12E-10	1.08E+01	1.80E-01	8.84E-01	5.41E-04	3.76E-09	5.68E+01	9.53E-01
Transport of Coal to CBTL Plant	9.81E+00	6.01E-03	6.39E-09	2.56E+02	1.02E+01	5.18E+01	3.17E-02	3.37E-08	1.35E+03	5.36E+01
Energy Conversion Facility	**4.71E+01**	**-2.36E-02**	**9.28E-04**	**-7.19E+03**	**3.90E+01**	**2.49E+02**	**-1.25E-01**	**4.90E-03**	**-3.80E+04**	**2.06E+02**
Plant Operations (inc. CO_2 Compression)	-1.13E+01	-1.82E-02	-6.46E-06	-4.61E+03	-1.66E+01	-5.96E+01	-9.61E-02	-3.41E-05	-2.43E+04	-8.75E+01
CO_2 Transport to CO_2-EOR Operation	1.83E+00	1.15E-04	0.00E+00	2.00E+00	1.83E+00	9.66E+00	6.09E-04	0.00E+00	1.05E+01	9.68E+00
CO_2-EOR Operation & CO_2 Storage	5.66E+01	-5.51E-03	9.34E-04	-2.59E+03	5.38E+01	2.99E+02	-2.91E-02	4.93E-03	-1.36E+04	2.84E+02
Product Transport	**1.41E+01**	**7.28E-03**	**2.59E-05**	**2.44E+03**	**1.69E+01**	**7.45E+01**	**3.84E-02**	**1.37E-04**	**1.29E+04**	**8.91E+01**
Transp. of Blended J-F to Airport	2.98E-01	1.34E-04	1.73E-05	1.96E+01	3.22E-01	1.57E+00	7.08E-04	9.12E-05	1.03E+02	1.70E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.37E+01	7.09E-03	9.00E-07	2.41E+03	1.64E+01	7.22E+01	3.74E-02	4.75E-06	1.27E+04	8.66E+01
Transport of F-T Jet to Blending Facility	1.34E-01	6.08E-05	7.71E-06	8.75E+00	1.45E-01	7.06E-01	3.21E-04	4.07E-05	4.62E+01	7.63E-01
End Use	**1.68E+02**	**1.10E-01**	**2.50E-09**	**2.82E+01**	**1.69E+02**	**8.86E+02**	**5.82E-01**	**1.32E-08**	**1.49E+02**	**8.93E+02**
Airplane Operation (Fuel Use)	1.68E+02	1.10E-01	0.00E+00	2.51E+01	1.69E+02	8.86E+02	5.82E-01	0.00E+00	1.33E+02	8.93E+02
Airplane Construction	8.28E-02	3.58E-05	2.50E-09	3.10E+00	8.66E-02	4.37E-01	1.89E-04	1.32E-08	1.64E+01	4.57E-01
Total	**1.96E+02**	**2.94E-01**	**9.67E-04**	**-6.48E+02**	**1.99E+02**	**1.04E+03**	**1.55E+00**	**5.11E-03**	**-3.42E+03**	**1.05E+03**

Table B-6A: CBTL, 10% Chipped Green Biomass, Separate Gasifiers – Combined Allocation

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	**-1.94E+01**	**9.21E-02**	**2.07E-06**	**2.63E+03**	**-1.54E+01**	**-1.02E+02**	**4.86E-01**	**1.09E-05**	**1.39E+04**	**-8.14E+01**
Coal Mining, Surface	1.03E+00	2.37E-02	1.68E-07	2.60E+03	4.17E+00	5.44E+00	1.25E-01	8.89E-07	1.37E+04	2.20E+01
Biomass Production and Field Chipping	-2.30E+01	6.66E-02	1.90E-06	3.10E+01	-2.22E+01	-1.21E+02	3.51E-01	1.00E-05	1.64E+02	-1.17E+02
Biomass Direct Land Use Change	5.47E-01	0.00E+00	0.00E+00	0.00E+00	5.47E-01	2.89E+00	0.00E+00	0.00E+00	0.00E+00	2.89E+00
Biomass Indirect Land Use Change	2.02E+00	1.84E-03	0.00E+00	0.00E+00	2.04E+00	1.06E+01	9.73E-03	0.00E+00	0.00E+00	1.08E+01
Raw Material Transport	**6.94E+00**	**4.25E-03**	**4.78E-09**	**1.84E+02**	**7.19E+00**	**3.66E+01**	**2.24E-02**	**2.52E-08**	**9.69E+02**	**3.79E+01**
Biomass Transp. to Torref. Facility	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 Biomass to CBTL Plant	7.17E-02	4.39E-05	3.05E-10	4.61E+00	7.73E-02	3.78E-01	2.32E-04	1.61E-09	2.43E+01	4.08E-01
Transport of Coal to CBTL Plant	6.86E+00	4.20E-03	4.47E-09	1.79E+02	7.11E+00	3.62E+01	2.22E-02	2.36E-08	9.44E+02	3.75E+01
Energy Conversion Facility	**4.27E+01**	**-1.06E-02**	**4.43E-04**	**-3.18E+03**	**3.91E+01**	**2.25E+02**	**-5.60E-02**	**2.34E-03**	**-1.68E+04**	**2.06E+02**
Plant Operations (inc. CO_2 Compression)	1.47E+01	-8.05E-03	-2.61E-06	-1.94E+03	1.24E+01	7.74E+01	-4.25E-02	-1.38E-05	-1.03E+04	6.57E+01
CO_2 Transport to CO_2-EOR Operation	1.02E+00	6.43E-05	0.00E+00	1.11E+00	1.02E+00	5.38E+00	3.40E-04	0.00E+00	5.87E+00	5.39E+00
CO_2-EOR Operation & CO_2 Storage	2.70E+01	-2.63E-03	4.45E-04	-1.23E+03	2.56E+01	1.42E+02	-1.39E-02	2.35E-03	-6.51E+03	1.35E+02
Product Transport	**1.41E+01**	**7.28E-03**	**2.59E-05**	**2.44E+03**	**1.69E+01**	**7.45E+01**	**3.84E-02**	**1.37E-04**	**1.29E+04**	**8.91E+01**
Transp. of Blended J-F to Airport	2.98E-01	1.34E-04	1.73E-05	1.96E+01	3.22E-01	1.57E+00	7.08E-04	9.12E-05	1.03E+02	1.70E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.37E+01	7.09E-03	9.00E-07	2.41E+03	1.64E+01	7.22E+01	3.74E-02	4.75E-06	1.27E+04	8.66E+01
Transport of F-T Jet to Blending Facility	1.34E-01	6.08E-05	7.71E-06	8.75E+00	1.45E-01	7.06E-01	3.21E-04	4.07E-05	4.62E+01	7.63E-01
End Use	**1.68E+02**	**1.10E-01**	**2.50E-09**	**2.82E+01**	**1.69E+02**	**8.86E+02**	**5.82E-01**	**1.32E-08**	**1.49E+02**	**8.93E+02**
Airplane Operation (Fuel Use)	1.68E+02	1.10E-01	0.00E+00	2.51E+01	1.69E+02	8.86E+02	5.82E-01	0.00E+00	1.33E+02	8.93E+02
Airplane Construction	8.28E-02	3.58E-05	2.50E-09	3.10E+00	8.66E-02	4.37E-01	1.89E-04	1.32E-08	1.64E+01	4.57E-01
Total	**2.12E+02**	**2.03E-01**	**4.71E-04**	**2.11E+03**	**2.17E+02**	**1.12E+03**	**1.07E+00**	**2.48E-03**	**1.11E+04**	**1.15E+03**

Table B-6B: CBTL, 10% Chipped Green Biomass, Separate Gasifiers – Energy Allocation

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	**-5.62E+00**	**2.67E-02**	**5.98E-07**	**7.62E+02**	**-4.46E+00**	**-2.97E+01**	**1.41E-01**	**3.16E-06**	**4.02E+03**	**-2.36E+01**
Coal Mining, Surface	2.98E-01	6.85E-03	4.88E-08	7.53E+02	1.21E+00	1.58E+00	3.62E-02	2.57E-07	3.98E+03	6.37E+00
Biomass Production and Field Chipping	-6.66E+00	1.93E-02	5.50E-07	8.97E+00	-6.42E+00	-3.51E+01	1.02E-01	2.90E-06	4.73E+01	-3.39E+01
Biomass Direct Land Use Change	1.58E-01	0.00E+00	0.00E+00	0.00E+00	1.58E-01	8.35E-01	0.00E+00	0.00E+00	0.00E+00	8.35E-01
Biomass Indirect Land Use Change	5.84E-01	5.34E-04	0.00E+00	0.00E+00	5.90E-01	3.08E+00	2.82E-03	0.00E+00	0.00E+00	3.12E+00
Raw Material Transport	**2.01E+00**	**1.23E-03**	**1.38E-09**	**5.31E+01**	**2.08E+00**	**1.06E+01**	**6.49E-03**	**7.30E-09**	**2.80E+02**	**1.10E+01**
Biomass Transp. to Torref. Facility	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 Biomass to CBTL Plant	2.08E-02	1.27E-05	8.83E-11	1.33E+00	2.24E-02	1.10E-01	6.70E-05	4.66E-10	7.05E+00	1.18E-01
Transport of Coal to CBTL Plant	1.99E+00	1.22E-03	1.30E-09	5.18E+01	2.06E+00	1.05E+01	6.42E-03	6.84E-09	2.73E+02	1.09E+01
Energy Conversion Facility	**1.05E+01**	**8.72E-05**	**7.87E-08**	**6.43E+01**	**1.06E+01**	**5.55E+01**	**4.61E-04**	**4.15E-07**	**3.40E+02**	**5.59E+01**
Plant Operations (inc. CO_2 Compression)	1.02E+01	6.86E-05	7.87E-08	6.40E+01	1.03E+01	5.39E+01	3.62E-04	4.15E-07	3.38E+02	5.43E+01
CO_2 Transport to CO_2-EOR Operation	2.95E-01	1.86E-05	0.00E+00	3.22E-01	2.96E-01	1.56E+00	9.83E-05	0.00E+00	1.70E+00	1.56E+00
CO_2-EOR Operation & CO_2 Storage	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
Product Transport	**1.41E+01**	**7.28E-03**	**2.59E-05**	**2.44E+03**	**1.69E+01**	**7.45E+01**	**3.84E-02**	**1.37E-04**	**1.29E+04**	**8.91E+01**
Transp. of Blended J-F to Airport	2.98E-01	1.34E-04	1.73E-05	1.96E+01	3.22E-01	1.57E+00	7.08E-04	9.12E-05	1.03E+02	1.70E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.37E+01	7.09E-03	9.00E-07	2.41E+03	1.64E+01	7.22E+01	3.74E-02	4.75E-06	1.27E+04	8.66E+01
Transport of F-T Jet to Blending Facility	1.34E-01	6.08E-05	7.71E-06	8.75E+00	1.45E-01	7.06E-01	3.21E-04	4.07E-05	4.62E+01	7.63E-01
End Use	**1.68E+02**	**1.10E-01**	**2.50E-09**	**2.82E+01**	**1.69E+02**	**8.86E+02**	**5.82E-01**	**1.32E-08**	**1.49E+02**	**8.93E+02**
Airplane Operation (Fuel Use)	1.68E+02	1.10E-01	0.00E+00	2.51E+01	1.69E+02	8.86E+02	5.82E-01	0.00E+00	1.33E+02	8.93E+02
Airplane Construction	8.28E-02	3.58E-05	2.50E-09	3.10E+00	8.66E-02	4.37E-01	1.89E-04	1.32E-08	1.64E+01	4.57E-01
Total	**1.89E+02**	**1.46E-01**	**2.66E-05**	**3.35E+03**	**1.94E+02**	**9.97E+02**	**7.68E-01**	**1.40E-04**	**1.77E+04**	**1.03E+03**

Table B-6C: CBTL, 10% Chipped Green Biomass, Separate Gasifiers – System Expansion

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	**-3.32E+01**	**1.58E-01**	**3.53E-06**	**4.50E+03**	**-2.64E+01**	**-1.75E+02**	**8.32E-01**	**1.87E-05**	**2.38E+04**	**-1.39E+02**
Coal Mining, Surface	1.76E+00	4.05E-02	2.88E-07	4.45E+03	7.13E+00	9.31E+00	2.14E-01	1.52E-06	2.35E+04	3.76E+01
Biomass Production and Field Chipping	-3.93E+01	1.14E-01	3.25E-06	5.30E+01	-3.79E+01	-2.08E+02	6.01E-01	1.71E-05	2.80E+02	-2.00E+02
Biomass Direct Land Use Change	9.35E-01	0.00E+00	0.00E+00	0.00E+00	9.35E-01	4.94E+00	0.00E+00	0.00E+00	0.00E+00	4.94E+00
Biomass Indirect Land Use Change	3.45E+00	3.15E-03	0.00E+00	0.00E+00	3.49E+00	1.82E+01	1.66E-02	0.00E+00	0.00E+00	1.84E+01
Raw Material Transport	**1.19E+01**	**7.27E-03**	**8.17E-09**	**3.14E+02**	**1.23E+01**	**6.26E+01**	**3.83E-02**	**4.31E-08**	**1.66E+03**	**6.49E+01**
Biomass Transp. to Torref. Facility	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 Biomass to CBTL Plant	1.23E-01	7.50E-05	5.22E-10	7.89E+00	1.32E-01	6.47E-01	3.96E-04	2.75E-09	4.16E+01	6.98E-01
Transport of Coal to CBTL Plant	1.17E+01	7.19E-03	7.65E-09	3.06E+02	1.22E+01	6.20E+01	3.79E-02	4.04E-08	1.62E+03	6.42E+01
Energy Conversion Facility	**7.49E+01**	**-2.13E-02**	**8.86E-04**	**-6.42E+03**	**6.76E+01**	**3.95E+02**	**-1.13E-01**	**4.67E-03**	**-3.39E+04**	**3.57E+02**
Plant Operations (inc. CO_2 Compression)	1.91E+01	-1.62E-02	-5.30E-06	-3.95E+03	1.46E+01	1.01E+02	-8.54E-02	-2.80E-05	-2.09E+04	7.70E+01
CO_2 Transport to CO_2-EOR Operation	1.74E+00	1.10E-04	0.00E+00	1.90E+00	1.75E+00	9.21E+00	5.81E-04	0.00E+00	1.00E+01	9.23E+00
CO_2-EOR Operation & CO_2 Storage	5.40E+01	-5.25E-03	8.91E-04	-2.47E+03	5.13E+01	2.85E+02	-2.77E-02	4.70E-03	-1.30E+04	2.71E+02
Product Transport	**1.41E+01**	**7.28E-03**	**2.59E-05**	**2.44E+03**	**1.69E+01**	**7.45E+01**	**3.84E-02**	**1.37E-04**	**1.29E+04**	**8.91E+01**
Transp. of Blended J-F to Airport	2.98E-01	1.34E-04	1.73E-05	1.96E+01	3.22E-01	1.57E+00	7.08E-04	9.12E-05	1.03E+02	1.70E+00
Blending of F-T and Conv. Jet (includes Conv. Jet Fuel Profile)	1.37E+01	7.09E-03	9.00E-07	2.41E+03	1.64E+01	7.22E+01	3.74E-02	4.75E-06	1.27E+04	8.66E+01
Transport of F-T Jet to Blending Facility	1.34E-01	6.08E-05	7.71E-06	8.75E+00	1.45E-01	7.06E-01	3.21E-04	4.07E-05	4.62E+01	7.63E-01
End Use	**1.68E+02**	**1.10E-01**	**2.50E-09**	**2.82E+01**	**1.69E+02**	**8.86E+02**	**5.82E-01**	**1.32E-08**	**1.49E+02**	**8.93E+02**
Airplane Operation (Fuel Use)	1.68E+02	1.10E-01	0.00E+00	2.51E+01	1.69E+02	8.86E+02	5.82E-01	0.00E+00	1.33E+02	8.93E+02
Airplane Construction	8.28E-02	3.58E-05	2.50E-09	3.10E+00	8.66E-02	4.37E-01	1.89E-04	1.32E-08	1.64E+01	4.57E-01
Total	**2.36E+02**	**2.61E-01**	**9.15E-04**	**8.68E+02**	**2.40E+02**	**1.24E+03**	**1.38E+00**	**4.83E-03**	**4.58E+03**	**1.26E+03**