Logistics, Costs, and GHG Impacts of Utility-Scale Cofiring with 20% Biomass

Idaho National Laboratory is operated by Battelle Energy Alliance, LLC for the United States Department of Energy under contract DE-AC07-05ID14517.

Pacific Northwest National Laboratory is operated by Battelle for the United States Department of Energy under contract DE-AC05-76RL01830.

Technical Report
INL/EXT-12-25252
PNNL-23492
June 2013

Prepared for the U.S. Department of Energy Bioenergy Technologies Office
Under DOE Idaho Operations Office Contract DE-AC07-05ID14517

Logistics, Costs, and GHG Impacts of Utility-Scale Cofiring with 20% Biomass

June 2013

Idaho National Laboratory
Idaho Falls, Idaho 83415
http://www.inl.gov

Contributors:
Richard Boardman
Kara Cafferty
Corrie Nichol
Erin Searcy
Tyler Westover
Rick Wood

Pacific Northwest National Laboratory
Richland, Washington 99352
http://www.pnnl.gov

Contributors:
Mark Bearden,
James Cabe
Corinne Drennan
Susanne Jones
Jonathan Male
George Muntean
Lesley Snowden-Swan
Sarah Widder

Prepared for the
U.S. Department of Energy
Bioenergy Technology Office
Under DOE Idaho Operations Office
Contract DE-AC07-05ID14517

(This page is intentionally left blank)

EXECUTIVE SUMMARY

This report presents the results of an evaluation of utility-scale biomass cofiring in large pulverized coal power plants. The purpose of this evaluation is to assess the cost and greenhouse gas reduction benefits of substituting relatively high volumes of biomass in coal. Two scenarios for cofiring up to 20% biomass with coal (on a lower heating value basis) are presented; (1) woody biomass in central Alabama where Southern Pine is currently produced for the wood products and paper industries, and (2) purpose-grown switchgrass in the Ohio River Valley. These examples are representative of regions where renewable biomass growth rates are high in correspondence with major U.S. heartland power production. While these scenarios may provide a realistic reference for comparing the relative benefits of using a high volume of biomass for power production, this evaluation is not intended to be an analysis of policies concerning renewable portfolio standards or the optimal use of biomass for energy production in the U.S.

Four major elements comprise the assessment of economic and environmental impacts of cofiring high volumes of biomass to produce dispatchable electricity for the grid:

1. Biomass supply system logistics and feedstock preprocessing engineering: The objective of this analysis is to correlate the cost of biomass with supply system variables in order to minimize the cost of delivering biomass in a form compatible with existing coal plant infrastructure. The overall biomass feedstock costs are a sum of the cost of raw feedstock, as provided by producers at various distances from the power plant, with the cost of conversion into a uniform format that is compatible with the existing coal-feed systems and boiler operations. A centralized collection and treatment system is also considered and compared to collection and processing at distributed supply depots as a function of the biomass draw distance from the power plants. The pretreatment operations evaluated include torrefaction to increase the heating value of the biomass while also converting it to a brittle material that can be ground with the coal. Leaching is also evaluated, as applied to switchgrass to remove deleterious alkaline and chloride salts that may foul boiler heat transfer tubes and interfere with flue gas cleanup operations.

2. Power plant simulations to determine the Levelized Cost of Electricity (LCOE): A detailed Aspen Plus® process model is presented and used to determine the effects of cofiring on the cost of electricity and pollutant discharge rates for each of the coal-fired power plants selected for this evaluation. The power plant models predict the boiler performance and emissions rates for each of the cases. The results are used to estimate LCOE based on a simplified financial model that accounts for capital expenses, fuel costs, operation costs, and electricity revenues. LCOE estimates provide a useful figure of merit to compare with other renewable electricity generation options. These estimates do not account for factors such as dispatchability in real electrical power markets, where the price of electricity varies with demand and regulatory requirements.

3. Life cycle greenhouse gas (GHG) emissions estimation: Life cycle analysis (LCA) of GHG emissions is presented. Emissions for coal mining and biomass cultivation are based on studies from the literature, while emissions related to feedstock harvesting, handling, processing, and combustion at the power plant are derived from the modeling presented in the two elements above.

4. Comparison with wind- and solar-generated electricity and natural gas repowering options: The biomass cofiring cases are compared to other renewable electricity generation alternatives as well as natural gas repowering of a specific Ohio coal-fired power plant. This comparison provides insight into the potential value proposition of biomass cofiring relative to other options. LCOE calculations for natural gas assume a steady cost of fuel at 2012 market prices. [Note: By the time this report was

completed natural gas prices for the electricity market has risen from approximately $3.50 to approximately $4.50 per million Btu (MMBtu).]

The basis for selecting a cofiring rate of 20% biomass centers on the assumption that this level of substitution for coal can be accomplished when providing a biomass feedstock that is compatible with the existing power plant coal conveyors, grinders, pneumatic feed lines/injectors, and burner arrangements. Untreated biomass is does not pulverize effectively with coal. Torrefaction is one method of improving the milling and grinding characteristics of biomass. Although additional work is needed to confirm this assumption, preliminary measurement of the grindability of torrefied biomass and coal indicate wood and switchgrass can be pulverized in existing coal milling operations. Higher percentages of biomass cofiring may also be possible, but are not considered in this assessment.

Details about the feedstock logistics and cost models, power plant model development and validation, LCOE and LCA calculations, and a comparison with a similar cofiring study completed by the National Energy Technology Laboratory (NETL) are provided in Appendices to the report. The main body provides a summary of the key assumptions, modeling results, and general observations. Some key outcomes of the simulation predictions are tabulated here.

Scenario	**Biomass for 20% Cofire** (dry ton/yr)	**Lowest Biomass Supply Cost** ($/MMBtu)	**Optimum System & Draw Radius** (miles)	**LCOE** ($/MWh**)**	**LCA** (gCO$_2$-eq/kWh)
Alabama 3 power plants 5,860 MWe	Southern Pine 4,365,000	ca 4	distributed depot 300	Coal- 30.3 Cofire- 34.4	Coal- 1,033 Cofire- 868
Ohio 3 power plants 5,215 MWe	switchgrass in 2030 3,885,000	ca 10	centralized system 125	Coal- 27.9 Cofire- 43.2	Coal- 968 Cofire- 835
20% wind addition to Alabama coal-only portfolio	N/A	N/A	N/A	wind/coal mix 39.9	not determined
10% solar addition to Alabama coal-only portfolio	N/A	N/A	N/A	solar/coal mix 49.8	not determined
Natural Gas Retrofit§	N/A	N/A	N/A	43.5	675
Natural Gas Repower with NGCC	N/A	N/A	N/A	40.2	488

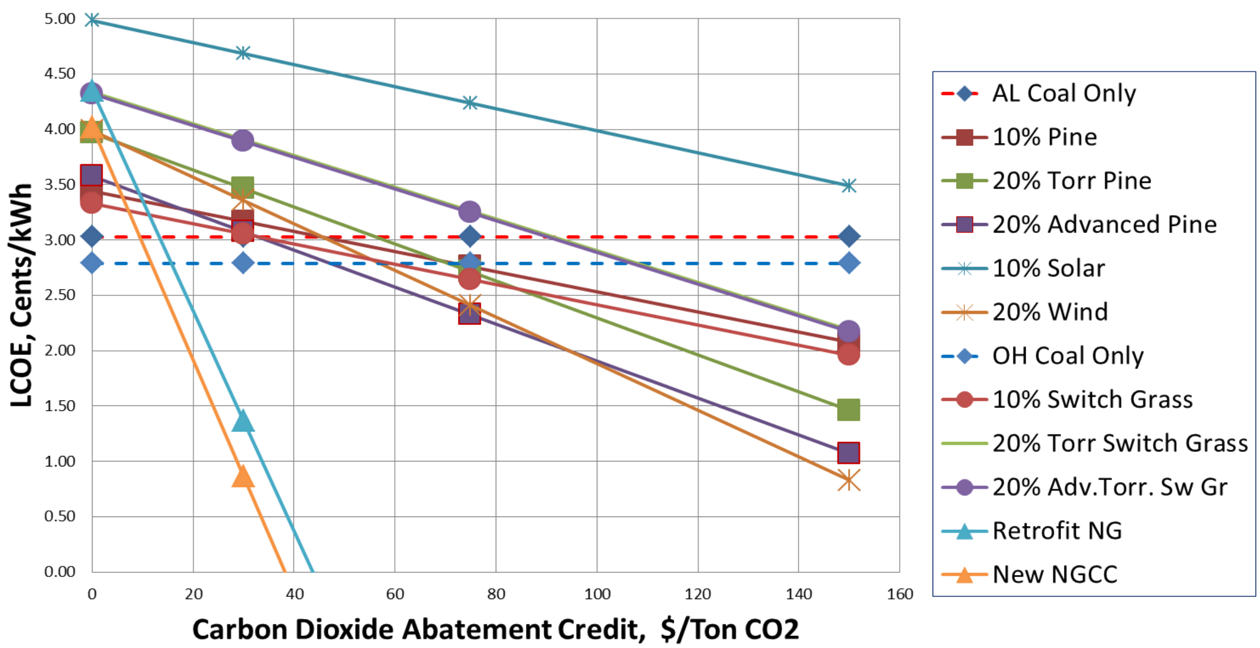
§ Based on Integrated Environmental Control Model

The relatively high cost of switchgrass reflects the higher production and preprocessing costs associated with this feedstock. An advance distributed depot biomass collection and processing system is optimum for the Alabama woody biomass scenario. A centralized biomass collection and processing system is marginally better than a distributed depot supply system for the Ohio switchgrass scenario. The benefits of a uniform feedstock based on a blend of biomass sources may reduce the fuel costs predicted in this study. An evaluation of feed source blending could be evaluated could be completed using the tools and approach developed for this assessment.

Cofiring 20% biomass results in life-cycle CO_2 emissions reductions of 16% for the Alabama coal-only case and 14% for the Ohio coal-only case. Based on the average of these results, if 20% of the coal combusted in 2010 had been replaced with biomass, CO_2 emissions could have been reduced by roughly 350 million metric tons, or about 6% of net annual GHG emissions. This would have required approximately 225 million tons of dry biomass. Such an ambitious fuel substitution would require development of a biomass feedstock production and supply system tantamount to coal. This material would need to meet stringent specifications to ensure reliable conveyance to boiler burners, efficient combustion, and no adverse impact on heat-transfer surfaces and flue gas cleanup operations.

Natural gas fuel switching with coal results in life-cycle CO_2 emissions of 30%, while replacement of the coal plant with NGCC provides a 50% reduction relative to the Ohio coal-only power plant. The main impediment to retrofitting or repowering with natural gas is the high capital cost associated with either option. Wind and solar power additions also require a large capital project. Biomass cofiring, on the other hand, may commence without a significant retrofit to the coal plant when the feedstock is processed to resemble coal.

A plot of LCOE trends for each of the options versus an assumed credit for reducing CO_2 reveals the relative advantage of the various options. For example, cofiring 20% biomass in Alabama would be economically beneficial when a CO_2 abatement credit of \$45/ton-CO_2 or higher is offered. This is the point where the adjusted LCOE crosses the Alabama coal-only horizontal trend line. In other words, the credit for offsetting CO_2 emissions must be at least \$45/ton-CO_2 to justify fuel switching in that case. In the case of cofiring switchgrass in Ohio Power Plants, 10% cofiring provides a competitive LCOE option when the CO_2 abatement credit exceeds \$60/ton-CO_2. Similarly, the intersection of the various trend lines reveals the relative value among the options evaluated in this study.



Comparative LCOE for 10% and 20% biomass cofiring cases with:

- *Alabama (AL) and Ohio (OH) baseline coal-only (horizontal trend lines)*

- *20% wind with coal-only power plants in Alabama*
- *10% solar with coal-only power plants in Alabama*
- *Retrofit of the Ohio Muskingum River Plant with natural gas(NG)burners*
- *Conversion of the Ohio Muskingum River Plant infrastructure to NGCC*

Finally, the results of this study are consistent with the results of the NETL cofiring study in regard to the increase in cost of electricity and associated GHG reduction benefits of biomass cofiring. However, combustion trials need to be undertaken in utility-scale power plants to confirm the technical performance of the processed biomass performance in existing coal plant feed systems and to observe the impacts on boiler heat rate and flue gas cleanup operations. This scale of testing is beyond the scope of this study.

TABLE OF CONTENTS

FIGURES

TABLES

Acronyms and Abbreviations

AAEA	American Agricultural Economics Association
ASABE	American Society of Agricultural and Biological Engineers
ASAE	American Society of Agricultural Engineers
BETO	Bioenergy Technology Office
BLM	Biomass Logistics Model
BNSF	Burlington Northern Santa Fe (Railway)
BT2	U.S. Billion-Ton Study Update (Oak Ridge National Laboratory)
Btu	British thermal unit
CAPEX	capital expenditure
CDM	clean development mechanism
CEN	(European Committee for Standardization)
COE	cost of electricity
DM	dry matter
DOE	U.S. Department of Energy
EERE	Energy Efficiency and Renewable Energy (DOE Office of)
EIA	Energy Information Administration (DOE)
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator
FGD	flue gas desulfurization
GHG	greenhouse gas
GTSC	gas turbine simple cycle
HHV	higher heating value
ID	induced draft
IECM	Integrated Environmental Control Model
INL	Idaho National Laboratory
IPCC	Intergovernmental Panel on Climate Change
KDF	Knowledge Discovery Framework
kWh	kilowatt hours
LCA	life cycle analysis
LC-GHG	life-cycle greenhouse gas
LCOE	levelized cost of energy or electricity
sLCOE	simplified levelized cost of electricity
LHV	lower heating value
LNB	low NOx burner
MMBtu	million British thermal units

MW	megawatt
MWh	megawatt hour
NASS	National Association of Suggestion Systems
NETL	National Energy Technology Laboratory
NG	natural gas
NGCC	natural gas combined cycle
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
OPEX	operating expenditure
ORNL	Oak Ridge National Laboratory
PDU	process demonstration unit
PFI	Pellet Fuels Institute
PGE	Portland General Electric
PNNL	Pacific Northwest National Laboratory
PRB	Powder River Basin
R&D	research and development
R&M	repair and maintenance
REC	Renewable Energy Credit
RPS	renewable portfolio standard
RTTS	Reconfigurable Thermal Treatment System
SCR	selective catalytic reduction
TEA	technical and economic analysis
THC	total hydrocarbons
USDA	United States Department of Agriculture
UN	United Nations
$US	United States dollars

1.0 INTRODUCTION

1.1 Background

Implementation of biomass for electricity generation is often driven by environmental considerations (UN 1998; UN 2011). Compared with coal, biomass is inherently lower in sulfur content, resulting in lower sulfurous gas emissions. Some studies indicate that biomass cofiring with coal also results in lower emissions of nitrogen oxides (NOx) during electricity generation[1]. Numerous analyses of national and global potential for biomass availability, environmental impacts of bioenergy development, and technologies for biomass conversion to electricity have been documented over the last 30 years (LaTourrette et al. 2011). Fewer public resources exist for the tactical, localized considerations of biomass and coal cofiring operations related to biomass feedstock logistics and preprocessing technologies for use of biomass in existing infrastructure. Even less information exists on the feasibility of cofiring more than 10% biomass; the required feedstock logistics and pre-processing; the potential profitability of high-volume cofiring; and the potential greenhouse gas (GHG) impacts.

This evaluation is not intended to be an analysis of changes to existing policy. A complete comparison of the benefits of biomass conversion to large-scale electrical power is beyond the scope of this study. This study is intended to provide quantitative data on the logistical requirements and cost/benefit changes that would occur if cofiring biomass with coal at levels of up to 20 percent (LHV) biomass in typical utility-scale power plants. The work is presented as utility-scale case studies representative of the U.S. electricity infrastructure under scenarios for woody and herbaceous biomass cofiring. This study also identifies the requirements for large quantities of biomass, its conversion into a format that is compatible with the existing coal-feed systems and changes to cost and GHG levels. Maximizing use of existing power plant infrastructure avoids expensive retrofit of the power plant feed systems and burners.

General conclusions are offered in the main document along with data gaps that still exist for industries considering high-volume cofiring applications. Details of the technical approaches, modeling, and assumptions are then provided in a set of related appendices. Experimental support of technical approaches is also detailed in the appendices.

1.2 Scope of the Study

Four major elements comprise the assessment of economic and environmental impacts of cofiring high volumes of biomass to produce dispatchable electricity for the grid:

1. <u>Biomass supply system logistics and feedstock preprocessing engineering</u>: The objective of this analysis is to correlate the cost of biomass with supply system variables in order to minimize the cost of delivering biomass in a form compatible with existing coal plant infrastructure. The overall biomass feedstock costs are a sum of the cost of raw feedstock, as provided by producers at various distances from the power plant, with the cost of conversion into a uniform format that is compatible with the existing coal-feed systems and boiler operations. A centralized collection and treatment system is also considered and compared to collection and processing at distributed supply depots as a function of the biomass draw distance from the power plants. The pretreatment operations evaluated include torrefaction to increase the heating value of the biomass while also converting it to a brittle material that can be ground with the coal. Leaching is also evaluated, as applied to switchgrass to

[1] Biopower life cycle analyses indicate certain farming/fertilizer practices result in higher net emissions of nitrous oxide emissions (LaTourrette et al. 2011). Life-cycle analyses of various farming practices are beyond the scope of this study.

remove deleterious alkaline and chloride salts that may foul boiler heat transfer tubes and interfere with flue gas cleanup operations.

2. Power plant simulations to determine the levelized cost of electricity (LCOE): A detailed Aspen Plus® process model is presented and used to determine the effects of cofiring on the cost of electricity and pollutant discharge rates for each of the coal-fired power plants selected for this evaluation. The power plant models predict the boiler performance and emissions rates for each of the cases. The results are used to estimate LCOE based on a simplified financial model that accounts for capital expenses, fuel costs, operation costs, and electricity revenues.

3. Life cycle greenhouse gas (GHG) emissions estimation: Life cycle analysis (LCA) of GHG emissions is presented. Emissions for coal mining and biomass cultivation are based on studies from the literature, while emissions related to feedstock harvesting, handling, processing, and combustion at the power plant are derived from the modeling presented in the two elements above.

4. Comparison with wind- and solar-generated electricity and natural gas repowering options: The biomass cofiring cases are compared to other renewable electricity generation alternatives as well as natural gas repowering of a specific Ohio coal-fired power plant. This comparison provides insight into the potential value proposition of biomass cofiring relative to other options. LCOE calculations for natural gas assume a steady cost of fuel at 2012 market prices.

Much of this study focuses on the ability to successfully execute high-volume biomass cofiring without modification to the existing utility infrastructure. However, challenges associated with increasing the cofiring ratio to 20% (energy content basis) are substantial. This report provides an initial assessment of the critical logistical challenges of high-volume cofiring in existing infrastructure by evaluating the impact of torrefaction, pretreatment, and densification to pellets as a preprocessing technology combination. Some biomass materials, especially herbaceous materials, may also require leaching to reduce soluble alkaline salts that may foul boiler tubes in the furnace. Pretreatment operations combined with depot supply systems may enable biomass materials to be produced as a commodity feedstock. Theoretically, this commodity produced “on-specification” may then serve as a direct coal replacement.

The remainder of this study focuses on determining the LCOE and LCA associated with cofiring scenarios for Southern Pine (woody) and switchgrass (herbaceous) feedstocks. The scenarios include preprocessing at the power plant, and preprocessing at a distributed number of depots (“advanced” strategies).

1.3 Cofiring Biomass with Coal: Technical Challenges

Many biomass feedstock sources are available for cofiring. These materials can be recovered to varying degrees based on the feedstock supply-system operations that are implemented to precondition the biomass to render it more suitable for cofiring.

Biomass has a lower energy density than coal; therefore, when cofired in a pulverized coal boiler in sufficient quantities, it can derate the performance of the boiler, which can reduce the total power output of the boiler and the overall capacity of a power plant. Biomass can be upgraded via heat treatments (e.g., torrefaction) to increase its energy density; however, this increase in energy density is achieved at a cost of biomass, and the economic cost of boiler derating must be considered against the economic costs of collecting, transporting, and processing additional biomass.

Biomass also has undesirable ash properties. It is more apt to agglomerate and adhere to boiler furnace walls and heat exchanger tubes, potentially causing fouling and losses in boiler performance. Further, elements commonly found in biomass ash can lead to corrosion problems and affect the ability of a power utility to sell the ash collected from coal boilers for other uses (e.g., the production of Portland cement).

Raw biomass is typically incompatible with the grinders in pulverized coal plants. Figure 1~~Figure 1~~ shows potential biomass insertion points in a coal plant. The analyses in this report focus on inserting biomass at insertion point Number 1, based on biomass pretreatment and torrefaction operations. Insertion and locations Number 2 and Number 3 require retrofit of the existing plant feed lines and/or pulverized-feed burner designs.

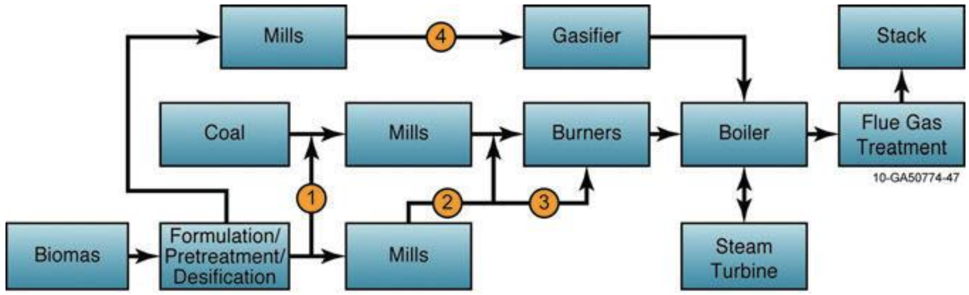


Figure 1. Potential biomass cofiring insertion points (Tumuluru et al. 2012).

1.4 Overview of Study Scenarios

For the scenarios considered for this study, the biomass feedstock was selected to reflect materials commonly grown in a given region of the country. In addition, it was desirable to see the cost impact on plants that currently fire different coals. Another consideration was to select regions for which biomass harvesting and collection strategies and costs have been sufficiently vetted, to improve confidence in the analyses. Cofiring scenarios were selected for large utility-scale power plants in central Alabama and the Ohio River Valley. These locations are representative of the concentrated coal-fired power-generation regions co-located with substantial biomass production capacity and thus provide an optimistic test for early entry of biomass cofiring on a scale that can begin to impact total GHG emissions.

These locations were analyzed as two separate scenarios according to the predominant type of biomass produced in the area. Four separate cases were evaluated for each of these scenarios. The first case analyzed a baseline considering only the combustion of coal. The second case analyzed cofiring with 10% raw biomass. This was selected as the highest raw biomass cofiring ratio (energy basis) achievable without substantially impacting boiler performance. The third case analyzed torrefied biomass, enabling a 20% cofiring ratio without impacting boiler performance. For this case, the biomass preprocessing and torrefaction were considered to be done at a central location near the power plant site where is can be conveyed to the coal holding silos. The fourth case analyzed for each scenario was 20% cofiring, where torrefaction and other preprocessing were accomplished at distributed depots. A third scenario analyzed two cases where coal was replaced with natural gas, enabling a comparison between the Levelized Cost of Electricity (LCOE) effects of biomass cofiring versus natural gas conversion.

Table 1. Summary of Representative Cofiring Analysis Cases[a]

Scenario	Description	Case	Fuel Percentages (LHV) Coal	So. Pine	Switch-grass	Natural Gas	Torr.	Leaching	Depot
Alabama	James H. Miller Jr. Units 1-4 and E. C. Gaston Unit 5[b]	1	100						
		2	90	10					
		3	80	20			X		
		4	80	20			X		X
Ohio	General James M. Gavin Units 1 & 2 and Muskingum River Unit 5[c]	5	100						
		6	90		10				
		7	80		20		X	X	
		8	80		20		X	X	X
Natural Gas	Muskingum River Unit 5 conversion to natural gas	9				100			
	Muskingum River Unit 5 repowered with NGCC	10				100			

[a] Representative cases were independently selected for this study and do not reflect the opinions or plans of any commercial utility, power plant operator, or feedstock supplier.

[b] The Alabama case assumes local and regional Southern Loblolly Pine is grown to meet the demand required for five large coal-fired units in the Southeast. The analysis considers supply to four 670-MW units at the James H. Miller Jr. Electric Generating Plant and the largest unit of the E. C. Gaston plant. The five units have a combined summer power-generation capacity of more than 3,000 MW, which is about 30% of the total coal-fired power-generation capacity in Alabama. A comparison between cofiring raw and torrefied biomass with both regional Appalachian bituminous coal (fired at E. C. Gaston) and Wyoming Powder River Basin (PRB) subbituminous coal is also given.

[c] The Ohio River Valley scenario is based on purpose-grown switchgrass cofired raw or torrefied with Appalachian Pittsburgh #8 bituminous coal at the Muskingum River plant (1,529 MW, or approximately 7% of the total power generated in Ohio). The General James M Gavin plant with two 1,320-MW units receives the bulk of the herbaceous biomass cofiring with a mixture of Pittsburgh #8 and PRB.

1.5 Technical Approach

This study draws on measured data, experimental operations, and process-modeling tools to determine (1) the cost of conditioned biomass feedstock delivered to the power plant yard, (2) LCOE based on plant performance and including retrofit of an existing pulverized-coal/air-entrained boiler power plant, and (3) cost/benefit of GHG emissions abated based on the net change in LCOE that accounts for CO_2 abatement credits. Each step in the analysis in this report leverages ongoing DOE Bioenergy Technology Office (BETO) support projects, where:

- Biomass samples representative of actual biomass sources are collected using realistic harvest and supply practices and material and energy balance data are established for the equipment used in these operations
- Feedstock composition, heating values, and physical properties are measured and incorporated into an electronically searchable database
- Material and energy balance data of pretreatment operations (i.e., drying, torrefaction, and pelleting) are obtained from generic pilot plant operations and a process deployment unit (PDU) configured to represent feedstock processing and densification

- Pilot plant and PDU data are used to calibrate mechanistic process models that simulate commercial-scale plants of these unit operations
- The Knowledge Discovery Framework (KDF) tool is used to determine the amount, condition, and cost of feedstock from the field that is available as a function of distance from the plant- based on the Oak Ridge National Laboratory (ORNL) Billion-Ton Study Update database
- A flexible, dynamic supply-chain logistic model representing the various supply-chain options, including depots that produce a uniform commodity meeting biopower specifications, is used to compute the cost of feedstock delivered to the power plant yard
- A cofiring power plant model is used to predict boiler performance and electrical output
- LCOE and GHG emissions are calculated using life-cycle assessment (LCA) and economic pro forma computational tools.

The combined techno-enviro-economic analysis (TEA) is illustrated in Figure 2. The sensitivity of biomass feedstock price at the plant gate was determined as a function of collection distance and torrefaction/densification at either distributed collection depots or on the power plant site. Physical property data for the feedstocks of interests was extracted from the BETO database. Feedstock processing and preparation costs were predicted using the BETO Biomass Logistics Model (BLM). These models were calibrated with laboratory and bench-scale testing equipment.

Computation of LCOE and GHG emissions drew on conversion process modeling and test experience of the PNNL coal combustion and conversion team. Predictions accounted for effects of biomass combustion on the boiler heating rate, and hence power production efficiency.

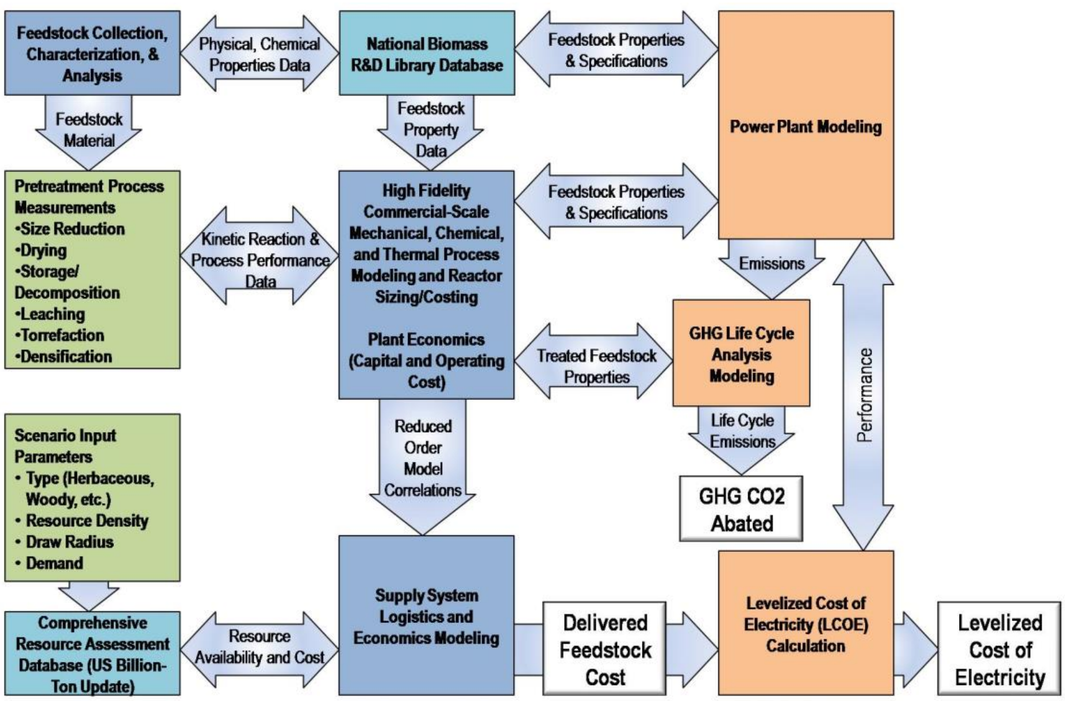


Figure 2. Data Acquisition and Modeling Steps Leading to a Scenario-Specific Feedstock Costs, LCOE, and life-cycle GHG emissions.

(This page is intentionally left blank)

2.0 BIOMASS FEEDSTOCK SUPPLY AND PREPROCESSING

2.1 Objectives and Assumptions

Two major barriers to cofiring biomass in large quantities at any power plant presents are reliable collection of a large supply of biomass from local sources and conversion of this biomass to a stable material that can be blended with the coal prior to insertion into the power plant. The dynamics and risk in biomass fuel supply are major barriers to implementing cofiring. This report assumes that the demand for large amounts of biomass will create a feedstock production market similar to the pulp and paper industry. Therefore, the cost of the feedstock is assumed to be a function of competition among suppliers and the unit operations that are associated with collection and delivery and pretreatment operations such as grinding, drying, torrefaction, and densification. The technical approach outlined in Section 1.5 was applied to determine the costs of producing and supplying biomass that meets stability, heating value, ash content, and grindability characteristics similar to coal.

The key assumption to this assessment is the production of a biomass fuel that can directly substitute for coal at the power plant in-feed point. In this manner, a major capital improvement project can be avoided. Under this assumption, the impact of cofiring on LCOE is computed through the cost difference of biomass versus coal feedstock, plant operating costs, and credits that may be applied for reducing GHG emissions.

2.2 Biomass Logistics Model

In partnership with DOE and others, Idaho National Laboratory (INL) developed a Biomass Logistics Model (BLM) to model the supply logistics. BLM is a system dynamics model built in the PowerSim™ Suite that can be used to calculate the delivered cost of a given biomass feedstock for a number of harvesting, collection, preprocessing, transportation, and storage options. This model was used to simulate the supply chain for the various cases evaluated in this study.

The BLM incorporates a reduced-order torrefaction model calibrated using a more detailed mechanistic torrefaction model and verified in actual torrefaction experiments at INL. Torrefaction is a preconversion thermal treatment that processes biomass at atmospheric pressure in the absence of oxygen at temperatures between 200 and 300°C (Usla et al. 2008). Torrefaction can be used to convert raw biomass into a high-energy-density, hydrophobic, compactable, grindable, solid with a lower oxygen-to-carbon ratio that more closely resembles coal when combusted in a power plant. More technical information on torrefaction can be found in Tumuluru et al. (2010b).

Biomass cofiring poses challenges for retrofit of existing boilers, primarily because of feeding and ash characteristics. Coal from feed silos is generally fed to bowl mills that are swept by a portion of the preheated combustion air. This technique has several advantages for the power plant firing coal and a potential disadvantage when cofiring with biomass. Partially dried biomass can conceptually be added to the coal feed to the bowl mills when the ratio of biomass to coal is low. Previous cofiring testing in utility boilers suggests up to 10% raw biomass can be combined with coal.

2.3 Feedstock Logistics Overview

This section covers the modeling of supply systems to deliver biomass to the feedstock infeed system (“throat”) of the power plant. This cost was modeled using the BLM’s supply system costs that are based on a methodology adapted from two widely accepted agricultural equipment engineering-economic costing methodologies presented by the American Society of Agricultural and Biological Engineers (ASABE) and the American Agricultural Economics Association (AAEA). More detail on these calculations can be found in Appendix A. Note, however, that the purchase cost of biomass, referred to as farm gate price and landing price for herbaceous biomass and woody biomass, respectively, are estimated using tools developed by (DOE 2011a). When the total biomass cost is reported at the feed insertion point in this report, it is the sum of the purchase cost of biomass at the landing or farm gate plus preprocessing and transportation costs.

For the conventional scenarios analyzed in this paper, INL developed conventional designs for the model herbaceous feedstock (Hess et al. 2009) and model woody feedstock (Searcy and Hess 2010) used (Figure 3). The advanced scenarios modeled in this paper also followed those described in Hess et al. (2009) and Searcy and Hess (2010) (illustrated in Figure 4).

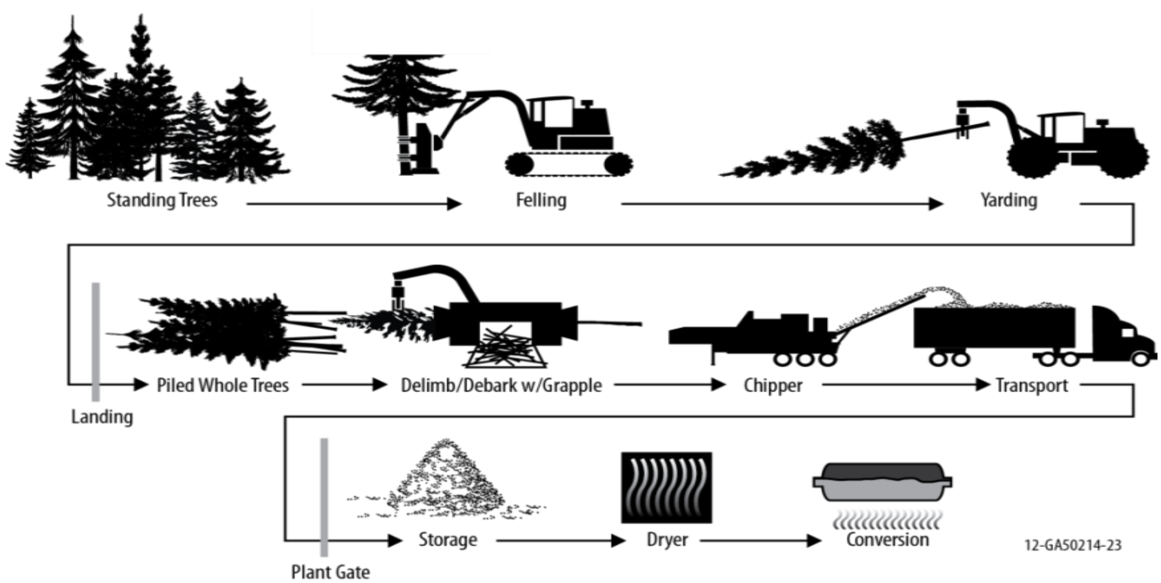


Figure 3. Conventional woody biomass feedstock supply-system scenario.

2.3.1 Woody Feedstock Logistics Scenarios

A conventional woody biomass feedstock supply chain was assumed for the scenario of cofiring 10% woody biomass with 90%. Details of the specific machinery modeled for the processes of each unit operation included in the model can be found in Appendix A. The majority of cofiring applications to date have been limited to approximately 10% biomass to avoid derating of the boiler because of the lower heat and higher moisture content of the biomass compared to coal. In addition, woody biomass has high costs associated with chipping or size reduction. Furthermore, woody limbs and trimmings have low density, which increases transportation and storage costs.

The advanced woody biomass feedstock supply chains were developed to overcome or mitigate these challenges to increase the biomass-to-coal cofiring ratio to 20%. For the first advanced woody scenario, a torrefaction operation was added inside the plant gate. For the second advanced woody scenario, torrefaction and densification were done at a preprocessing depot. All operations prior to the material arriving at the plant were the same as in the conventional woody design. Details can be found in Appendix B, Woody Feedstock Logistics Scenarios.

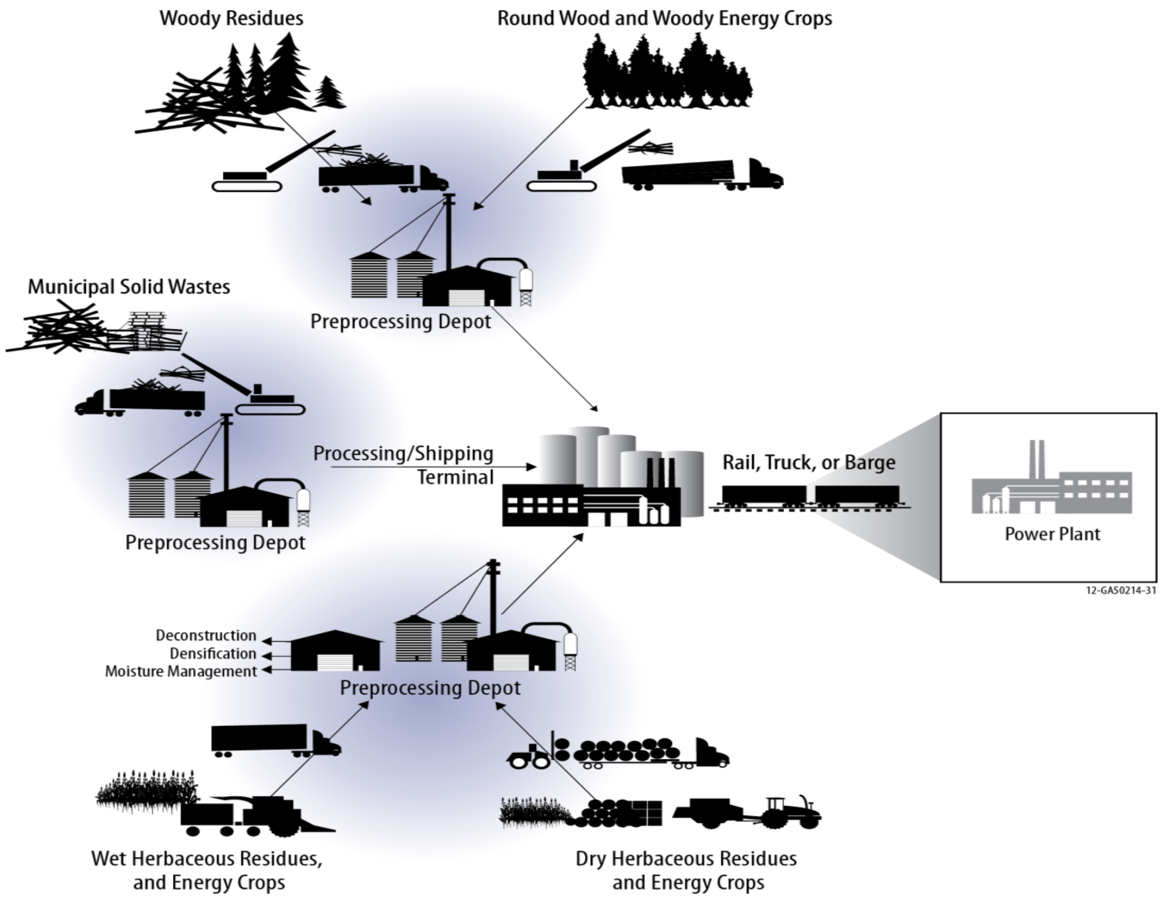


Figure 4. Advanced Uniform feedstock supply system design.

2.3.2 Herbaceous Feedstock Logistics Scenarios

In general, the overall series of operations included for the herbaceous cases were the same as those discussed for the woody supply. Details can be found in Appendix C, Herbaceous Feedstock Logistics Scenarios. One notable exception in the advanced cases where higher cofiring rates are desired is the need to include a leaching step for herbaceous material. Leaching is a process of soaking biomass in water and/or other solvents to dissolve undesired salts that can cause slagging, fouling, and even corrosion in conventional boilers. Leaching necessitates the addition of a dewatering step in this design.

2.3.3 Torrefaction for Advanced Scenarios

The advanced cases studies utilize torrefaction to improve the physical properties of biomass. Torrefaction produces a material with energy density and grindability properties similar to coal, making it possible to use the power plant's grinding and particle classifier mills to grind the torrefied wood chips and coal into micro-size participles that are easily entrained by the primary air stream that feed to the burner registers. In addition, torrefaction produces a relatively hydrophobic product, resulting in better long-term storage properties. The centralized advance cases assume a large torrefaction unit is built and operated at power plant feedstock staging pile. The advanced deport cases assume a distribution of smaller torrefaction units are used to process the biomass feedstock before it is transported to the power plant.

The advanced depot designs provide the opportunity to format and blend biomass into a consistent, stable, infrastructure-compatible, flowable material early in the supply chain. In the advanced woody depot design, the depot contains infrastructure to torrefy and densify woody biomass. Based on a previous technical review (Tumuluru et al. 2010a), it was determined that a pelletization process best meets the needs for this analysis. Because advanced biomass feedstock supply systems use biomass preprocessing depots, more cost-efficient transportation modes (e.g., rail and barge) can be used.

Experimental data supporting the feedstock torrefaction, densification, and grinding/entrainment assumptions invoked in this study are presented in Appendix D, Feedstock Pretreatment Experimental Support Studies.

2.3.4 Feedstock Logistics Results – Woody and Herbaceous

To minimize the cost of supplying biomass to the power plant, it is desirable to minimize the shipping distance between the biomass supply and the power plant. In many cases, it may be difficult to accomplish this objective. Figure 5 shows the logistics cost (minus grower payment) of woody feedstock as a function of total shipping distance. The benefit of the depot concept is readily apparent when longer shipping distances are required.

Figure 6 shows the logistics cost (minus grower payment) of herbaceous feedstock as a function of total shipping distance. For this analysis, it was assumed that the biomass must be brought to a total energy density of 10,000 Btu/lb in order to avoid derating boiler performance.

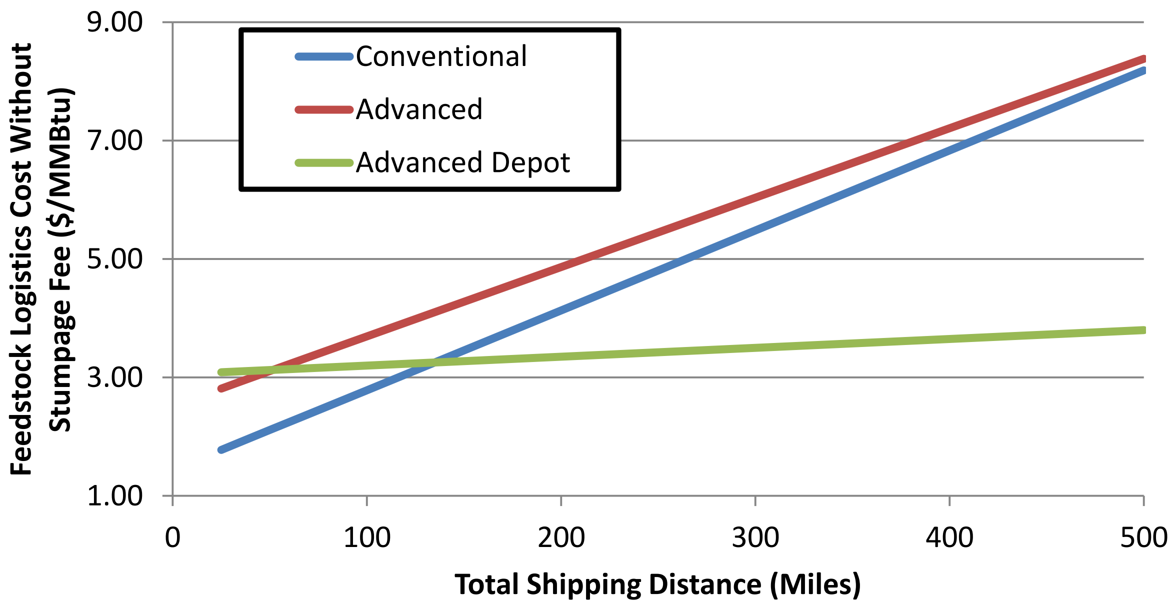


Figure 5: Logistics Cost Comparison for the Woody Scenarios on an Energy-Delivered Basis

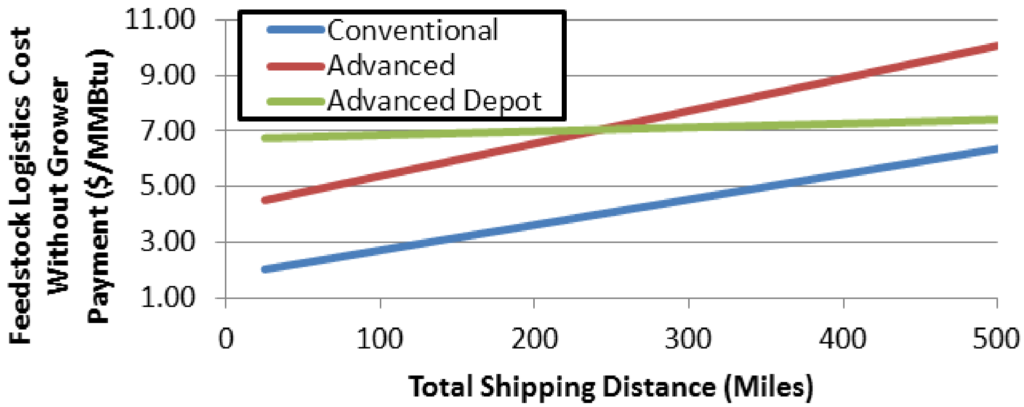


Figure 6. Logistics cost comparison for the herbaceous scenarios on an energy-delivered basis.

2.4 Biomass Supply System Sensitivities – Draw Radius and Biomass Availability

Data collected from the ORNL Billion-Ton Biomass Update (BT2) Data Explorer (DOE, 2011a) were combined with the logistics costs discussed in the above sections to account for the region-specific feedstock supply market conditions. The total biomass consumed was calculated to provide a percentage (on an energy basis) of the total fuel consumed by the power producer, which was converted to tons of biomass required.

2.4.1 Alabama Case for Woody Biomass Scenarios

For the initial analysis, the James H. Miller plant is considered as the only plant drawing biomass from the surrounding region. The BT2 Data Explorer allows county-level resolution of available woody biomass, and biomass from counties within a given radius of the plant that were aggregated to estimate the necessary grower payment to supply the required amounts of biomass. This analysis is summarized in Table 2~~Table 2~~. Note that for the smallest radius (25 mi), the BT2 Data Explorer indicates that an insufficient amount of biomass will be available at <$200/dry ton to cofire at either the 10 or 20% level. In other words, the BT2 Data Explorer KDF tool does not predict woody biomass available at a cost of greater than $200/dry ton.

Table 2. Estimated grower payment for woody biomass in Alabama to supply the James H. Miller plant with 10 and 20% biomass feedstock.

	Radius (mi)	10%	20%
Total biomass required (dry ton/yr)		**1,025,000**	**2,049,000**
Estimated grower payment at the landing	25	(a)	(a)
	50	$80–90	$120–130
	100	$30	$70–80
	250	$10–20	$10–20
	500	$10	$10

[a] Insufficient biomass within 25 mi predicted at <$200 by the BT2 Data Explorer.

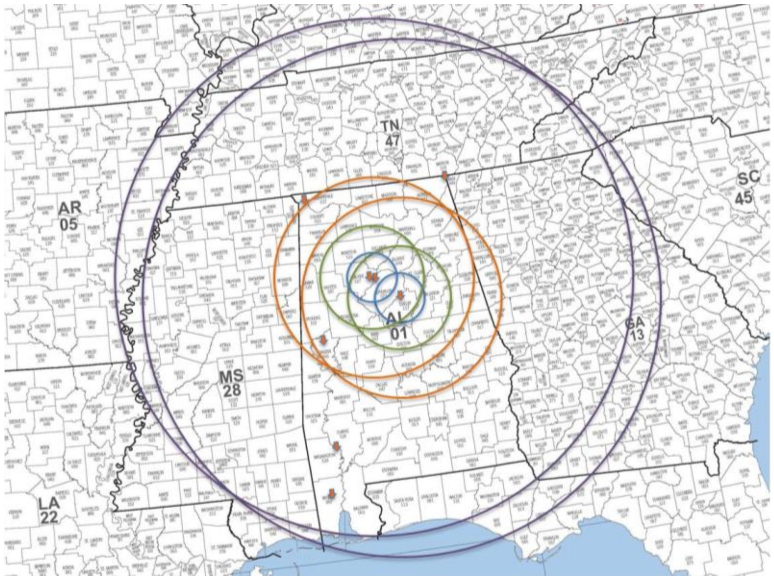


Figure 7. Overlapping draw areas for E. C. Gaston and Gorgas, and James H. Miller plants (blue at 25 mi, green at 50 mi, orange at 100 mi, and purple at 250 mi).

For the second analysis, three power producers are considered. Figure 7 illustrates the overlapping draw areas for E. C. Gaston (1,862 MW), James H. Miller (2,751 MW), and Gorgas (1,247 MW). Gorgas and James H. Miller are so closely located that the draw areas for these plants (upper circles in Figure 7) are basically the same as a single plant. This results in a higher demand that drives up the supplier costs as shown in Table 3~~Table 3~~.

Table 3. Estimated Grower Payment for Woody Biomass in Alabama to Supply the James H. Miller, E. C. Gaston, and Gorgas Plants with 10 and 20% Biomass Feedstock.

	Radius (mi)	**10%**	**20%**
Total biomass required (dry ton/yr)		2,183,000	4,365,000
Estimated grower payment at the landing:	50	$110–120	(a)
	100	$70–80	$100
	250	$10–20	$20–30
	500	~$10	$10–20

(a) Insufficient biomass predicted at <$200 by the BT2 Data Explorer.

2.4.2 Summary of Specific Alabama Woody Cases

A comparison of the supply-demand cost estimate response is plotted in Figure 8. This graph was prepared by performing a linear interpolation between amounts projected at discrete dollar values from the BT2 Data Explorer KDF. The supplier cost reaches an asymptote at a draw distance of about 250 miles.

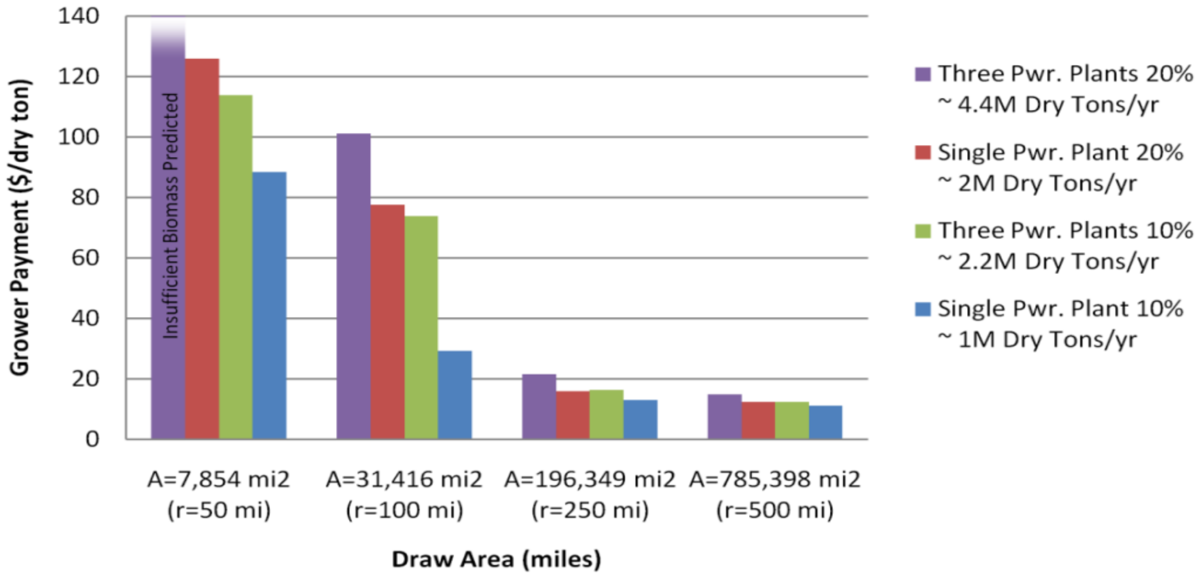


Figure 8. Landing price for woody biomass versus draw radius in Alabama.

Although the optimal draw radius to minimize both the supplier price and the logistical cost of handling and transporting the biomass has not been explicitly calculated, based on the logistics analysis presented in Appendix B, the cost to move biomass from the farm gate or landing to the feed system of the power plant can be combined with the landing price analysis from the BT2 data to illustrate the tradeoffs between the logistics cost to move biomass from longer distances to the plant, and the changes in landing prices that result from competition for resources in a small area. Figure 9 shows the result of this analysis on an energy-delivered basis. For a small draw radius, the landing price dominates the total delivered biomass cost, and the influence of higher mass loss in the cases that include torrefaction is more evident when the landing price is high. As the draw radius is widened and the landing price decreases, transportation costs begin to dominate the overall cost.

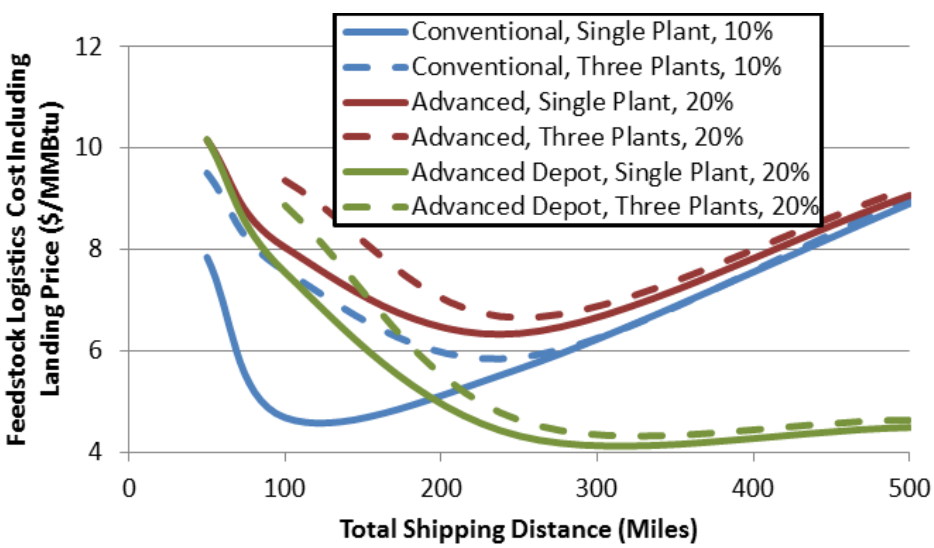


Figure 9. Total delivered woody biomass cost including landing price.

2.4.3 Ohio River Valley Scenario for Herbaceous Biomass

The biomass required for cofiring in the Ohio scenario is calculated based on the same assumptions listed for the woody case, however, because woody biomass can currently be purchased (owing to an existing industry to provide woody biomass for pulp and paper mills) and herbaceous biomass cannot, projections in the U.S. Billion-Ton Study Update (DOE 2011a) and the supporting data available in the KDF conservative baseline yield for the years 2020 and 2030 were used to predict feedstock production and grower payments costs.

For the single plant analysis, the Muskingum River plant is considered as the only plant drawing biomass from the surrounding region. Data from the BT2 Data Explorer were extracted for projected available herbaceous biomass (perennial grasses such as switchgrass) farm gate prices, and those counties in each circle were aggregated to get an estimate of the necessary grower price at the farm gate to supply the required biomass for cofiring. This analysis is summarized in Table 4~~Table 4~~ for both the 2020 and 2030 predictions of the BT2 data.

Table 4. Estimated grower payment for herbaceous biomass in Ohio to supply the Muskingum River plant with biomass feedstock for 10 and 20% cofiring.

	Radius (mi)	2020		2030	
		10%	**20%**	**10%**	**20%**
Total biomass required (dry ton/yr)		567,000	1,139,000	570,000	1,139,000
Estimated grower payment at the farm gate	25	(a)	(a)	(a)	(a)
	50	\$50–55	\$80	\$45–50	\$45–50
	100	\$45–50	\$50–55	\$40–45	\$45–50
	250	\$45–50	\$45–50	\$40–45	\$40–45

(a) Insufficient biomass predicted at <\$80 by the BT2 Data Explorer.

An analysis similar to the single case was conducted on the combined draw areas for the three power plants. For the analysis with three power consumers, Muskingum River (1,529 MW), General James M. Gavin (2,600 MW), and Kyger Creek (1,086MW) were considered. General James M. Gavin and Kyger Creek are so closely located that the draw areas for these plants are practically the same. Figure 10 illustrates the overlapping draw areas. The estimated farm gate prices are summarized in Table 5~~Table 5~~. The BT2 Data Explorer KDF tool does not predict amounts of biomass above a farm-gate price of \$80/dry ton.

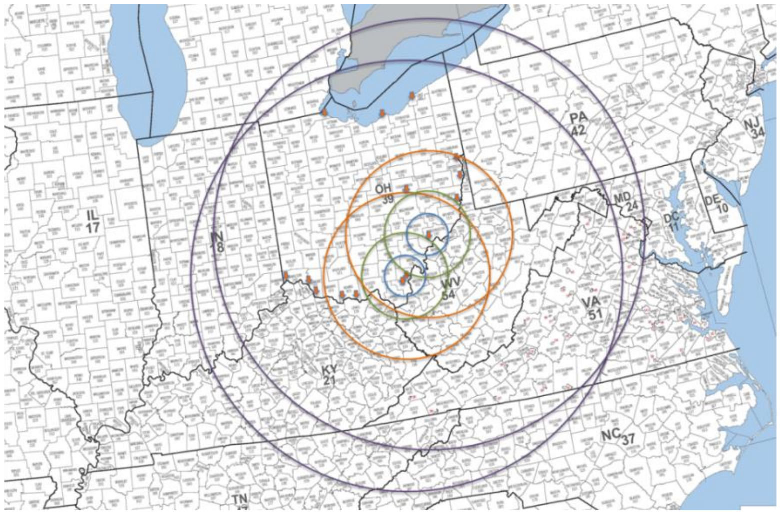


Figure 10. Overlapping draw areas for Muskingum River, General James M. Gavin, and Kyger Creek plants (U.S. Census Bureau 2010).

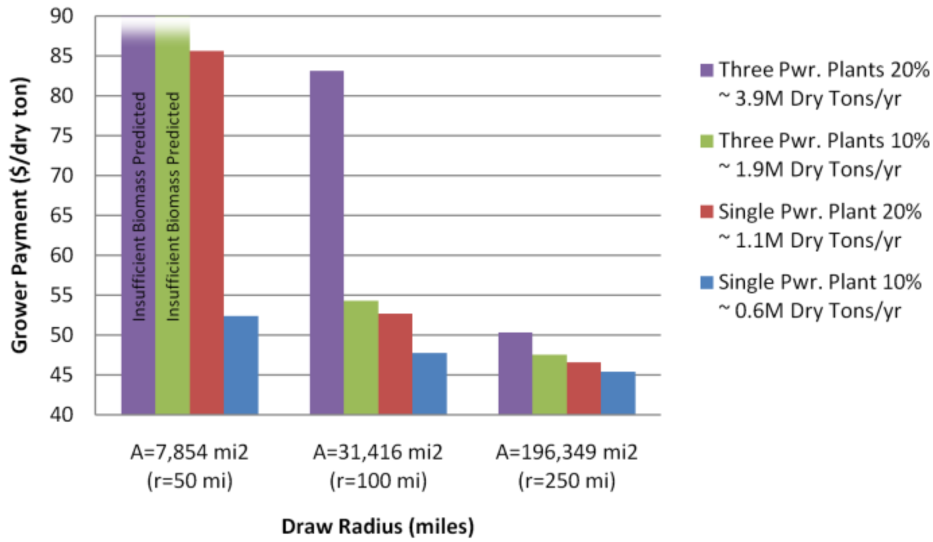
Table 5. Estimated grower payment for herbaceous biomass to supply the Muskingum River, General James M. Gavin, and Kyger Creek plants with 10 and 20% biomass feedstock.

		2020		**2030**	
	Radius (mi)	**10%**	**20%**	**10%**	**20%**
Total biomass required (dry ton/yr)		1,942,000	3,885,000	1,942,000	3,885,000
Estimated grower payment at the farm gate	25	(a)	(a)	(a)	(a)
	50	(a)	(a)	$50–55	(a)
	100	$50–55	$75–80	$45–50	$50–55
	250	$45–50	$50–55	$40–45	$45–50

(a) Insufficient biomass predicted at <$80 by the BT2 Data Explorer.

2.4.4 Summary of Specific Ohio Switchgrass Cases

Figure 11 illustrates the farm-gate price decreases as the draw radius increases. All of the cases exhibit a minimal farm gate price at the 250-mi radius. However, the higher demand cases do not radically change the projected farm gate prices for the 2030 projections.



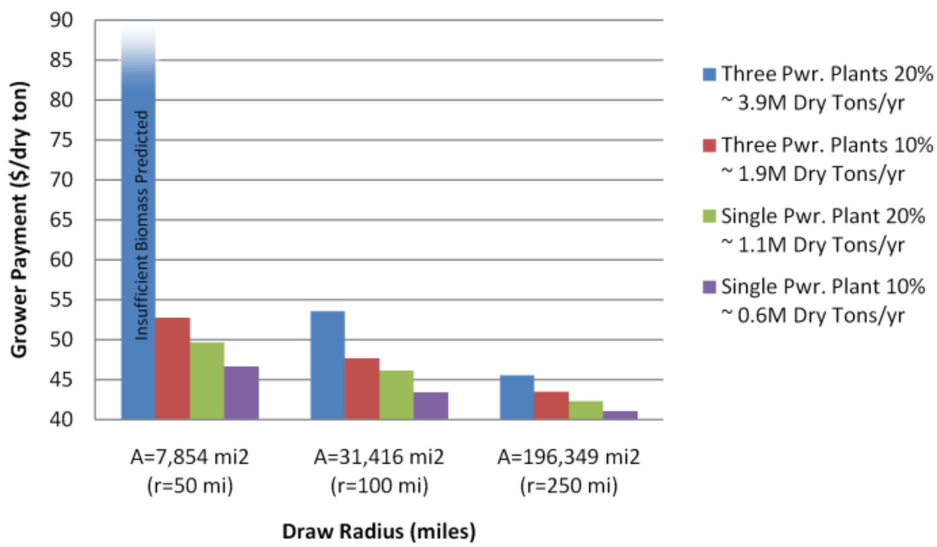


Figure 11. Grower payment price for herbaceous biomass versus draw radius in Ohio for 2020 (above) and 2030 (below) predictions.

Figure 12 shows the combined farm-gate price analysis for 2020. The sharp increase in cost for the advanced cases is attributed to the substantial mass loss due to the extent of torrefaction required to upgrade the biomass energy content to avoid derating the performance of the boiler at higher cofiring percentages. A more specific case-by-case analysis based on individual boilers and acceptable fuel property ranges could show that this level of torrefaction may not be necessary.

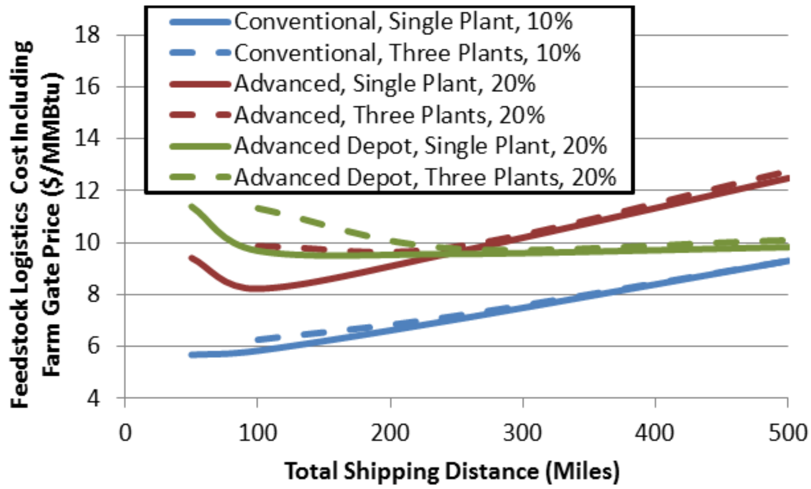


Figure 12. Total delivered herbaceous biomass cost including grower payment in 2030.

(This page is intentionally left blank)

3.0 ELECTRICITY GENERATION

3.1 Objectives and Assumptions

In order to determine the effects of cofiring on the cost of electricity and pollutant discharge rates, a detailed Aspen Plus® process model (hereafter referred to as the Aspen model) was developed for each of the coal-fired power plants selected for this evaluation. Model formulation and verification details are described in Appendix E, Power Plant Models. This study assumes the biomass feed is compatible with the existing coal feed system after passing through the formulation and pretreatments steps outlined in Section 2.0. It is assumed that the biomass is mixed with the coal that is feed to the primary coal milling feed silos. A general overview of pulverized coal fired power plants coal storage and feeding operations is described in Appendix E.

The power plant models calculate the coal and biomass feedrates for the associated electrical power generation cases. These data are then used to calculate the LCOE for each of the cases, respectively. Appendix F, discusses the calculation method and assumptions invoked for LCOE calculations. The emissions rates provided by the custom plant models are in turn combined with coal and biomass production and delivery emissions data to compute the life-cycle greenhouse gas (GHG) emissions. Appendix G, GHG Life-Cycle Analysis, discusses the methodology and assumptions applied for these calculations.

3.2 Power Plant Modeling

Power plant model development and validation was accomplished in four steps:

Step 1. An Aspen model was developed for a 400 MWe reference pulverized coal plant representing the average size and unit operations of pulverized coal-fired power plants in the United States. This model was calibrated (or tuned) using plant performance data presented in the National Energy Technology Laboratory report, Baseline for Fossil Energy Plants, Case 9 (NETL 2007), and with data generated by the Integrated Environmental Control Model (version 6.2.4), available over the Internet (Berkenpas et al. 2009). The reference coal plant burns western subbituminous coal with low-NOx Burners (LNB) and does not have a FGD unit, which is consistent with about one-half of the coal plants of its size. Cold-side electrostatic precipitators (ESP) are commonly used to control particulate matter.

Step 2. The baseline Aspen Model developed in Step 1 was adapted to the Alabama and Ohio power plants selected for this case study. The custom Aspen models reflect the emissions controls and steam production systems for the respective plants as summarized in Table 6. Specifically, flue-gas desulfurization (FGD) units and selective catalytic reactors (SCR) NOx abatement units were added to reflect the actual plant operations. The models were tuned using data extracted from the Energy Information Administration data sheets reports for each plant. The models were also validated by comparing the Aspen Model results to Case 11 of the NETL Baseline for Fossil Energy Plants.

Step 3. Biomass cofiring cases were simulated using the custom Aspen models developed in Step 2. The results of these cases were validated with IECM model results.

Step 4. The Integrated Environmental Control Model was used to assess a natural-gas fired boiler retrofit at the Muskingum River plant. Additionally, an Aspen model for a new gas/combined cycle plant at Muskingum River plant site was developed to compare to the retrofit case.

Table 6: Power Plant Model Features (from EIA Data)

Aspen Models	Plants	Coal Rank	NOx Control	Particulate Control	FGD	Steam Quality
Reference Coal	400 MW_e Plant	Subbituminous	LNB	Cold-Side ESP		Sub-Critical
Alabama Scenario	James H. Miller, Jr.	Powder River Basin Subbituminous	LNB/SCR	Hot-Side ESP	Wet-Limestone	Sub-Critical
	Gorgas	Powder River Basin Subbituminous	LNB/SCR	Cold-Side ESP	Wet Limestone	Super-Critical
	E. C. Gaston	Alabama Bituminous	LNB/SCR	Hot-Side ESP	Wet-Limestone	Super-Critical
Ohio Scenario	Muskingum River	Pittsburg #8 Bituminous	LNB/SCR	Cold-Side ESP	No scrubbers	Super-Critical
	Kyger Creek	Blend: Pittsburg #8 / Powder River Basin Subbituminous	SCR	Cold-Side ESP	Wet-Limestone	Sub-Critical
	General James M. Gavin	Blend: Pittsburg #8 / Powder River Basin Subbituminous	LNB/SCR	Cold-Side ESP	Mg-Enhanced	Super-Critical

3.2.1 Reference Power Plant Model Data

EIA data from Form 860 (required to be completed by each permitted power plant in the United States) were filtered to determine the weighted average unit size, age, coal type, steam cycle, and environmental equipment for a representative coal-fired power plant (EIA, 2012a, EIA 2012b). The data were first filtered for nameplate capacities greater than 10 MW and built after 1970 (40 years old or less). The average coal plant size at the time of this screening is 412 MWe, with a start date of 1983. The resulting 524 generators were further filtered for coal type. The most common coal type by weight is subbituminous.

Table 7. Criteria for selecting representative coal plant type and scale.

Coal Plant Parameter	
Plant capacity	300–500 MW (412 MWe on average)
No. of plants in this general category	39
Coal Type	**Western Subbituminous**
Breakdown Within Category	**No. of Plants**
Subcritical steam cycle	21
NO_X burners	22
No FGD	14
Cold side electrostatic precipitator	13

Based on the power plant data reduction, an Aspen model was developed for a reference plant using western subbituminous coal in a water wall boiler producing steam for a subcritical single reheat steam cycle as described in Appendix E. Coal is delivered to the boilers through hot-air-swept pulverizers and flue gas energy is recovered with a rotary combustion air heater. NO_X emissions are controlled with low NO_X burners, and particulates are removed with a cold-side ESP. This model agrees well with values reported in the EIA database and was tuned to reproduce the values obtained in Case 9 of the NETL Cost and Performance Baseline for Fossil Energy Plants, and with the Integrated Environmental Control Model (version 6.2.4.). The Aspen cases were also validated against the IECM model as shown in Appendix E. Net plant efficiencies of approximately 35-37 percent are consistent with the Aspen model results for a 400 MWe plant firing either coal and combinations of coal with pine chips and coal with terrified pine.

3.2.2 Alabama and Ohio Power Plant Models

For this evaluation, a custom model was developed for the power plants identified in Table 6 by modifying the reference Aspen model. For woody biomass cofiring in Alabama, a representative model was developed for Unit 4 (one of four identical units) of the James H. Miller plant and Unit 5 of the E.C. Gaston plant. For herbaceous feedstock cofiring in Ohio, a representative model was developed for Muskingum River Unit 5 and General James M. Gavin Unit 2 (one of two identical units). A simplified wet limestone FGD unit operation was added for the models of the Alabama plants, while a magnesium-enhanced lime unit operation was added to the General James M. Gavin plant model. A supercritical steam cycle upgrade was added for the E. C. Gaston, Muskingum River, and General James M. Gavin plants. Inputs to the units included annual average temperature, pressure, and relative humidity relative to the site locations of each of the plants.

Compared to the EIA record data, the custom power plant models predict 5 to 10 percent lower heat rates as shown in Table 8. However, a the heat rate for a simulation of Case 11 of the NETL Baseline for Fossil Energy Plants was predicted within 0.1 percent. Hence, the Aspen models for this evaluation appear to be conservative for the respective plants.

The coal-only models were modified to predict the impact of biomass cofiring with 10 percent (lower heating value) raw material and with 20 percent addition (lower heating value) torrefied material. In this manner, the overall heating value was maintained close to the baseline coal-only cases listed in Table 8.

Table 8. Comparison of Aspen model results with EIA data and NETL Case 11.

Simulation Heat Rate (Btu/kWh)	James H. Miller	E. C. Gaston	Muskingum River	General James M. Gavin	NETL Case 11	Simulation to Match NETL
EIA data coal only	10,239	9,822	9,820	9,944		
Coal only	9,755	9,273	8,844	9,466	8,721	8,727
10% biomass	9,775	9,357	8,934	9,548		
20% torr biomass	9,693	9,330	8,849	9,449		

3.2.3 Natural Gas Repower

An Aspen model was developed for a natural gas repowering project at Muskingum River Unit 5. This case assumed a plant efficiency of 33.56 percent and a coal energy content equivalency of 10,927 Btu/lb (LHV). A separate natural-gas/combined cycle plant was modeled for a unit replacement at the Muskingum plant that would utilize as much of the equipment possible at the plant to repower to a NGCC configuration.

3.3 Levelized Cost of Electricity

The simplified LCOE (sLCOE) calculation method outlined in Appendix F, Levelized Cost of Electricity, was applied for this assessment. Key among the sLCOE assumptions is the retrofit of an existing, fully-depreciated pulverized coal plant. The present evaluation also assumes that the biomass will be added to the coal in-feed to the coal grinder hold silos. The cost of transport and mechanized delivery of the biomass to his insertion point is included in the cost of biomass. Hence the incremental cost of cofiring biomass is seen as an operating expense that includes the pretreatment operations in the following general expression (see Appendix F for additional details):

sLCOE = {(overnight capital cost * capital recovery factor (CRF) + fixed operation and maintenance [O&M] cost)/(8760 * capacity factor)} + (fuel cost * heat rate) + variable O&M cost

i. Overnight capital cost is the estimated total project cost measured in dollars per installed kilowatt ($/kW). Values for biomass, wind, and solar were obtained from EIA (2010e).
ii. For the capital recover factor, a project life of 20 years and the U.S. government discount rate of 4% for new projects were chosen.
iii. Fixed O&M costs in dollars per kilowatt-year ($/kW-yr) and variable O&M costs in dollars per kilowatt-hour ($/kWh). Specific values are tabulated in Appendix F.
iv. The capacity factor for biomass is assumed to be the same as the coal plant capacity factor, or 85.6 percent of installed capacity average on-line operation. Solar and wind capacity factors were taken from EIA data as previously explained (EIA 2010e).
v. Coal cost data were taken from EIA (2010f).
vi. Biomass fuel costs are calculated from the analysis supporting this study (Section 2).
vii. Solar and wind have zero fuel cost.
viii. Heat rate for the coal firing and coal and biomass cofiring is determined directly from the Aspen models.

ix. Variable O&M costs are shown in Table 39 of EIA (2010e).

The results of these analyses for the generalized 400-MWcoal-fired power plant are summarized in Appendix F, Levelized Cost of Electricity. For the natural gas retrofit and NGCC project, a capital expense is required for equipment upgrades or replacement, respectively. No cost for decommissioning of the coal unit was included in the NGCC replacement of the coal power plant unit. Similarly, a wind or solar power generation addition to the utility portfolio require a capital project and must account for the real-time capacity factors which may require the base load power plants to cycle in order to dispatch electricity to compensate for wind and solar variability. The present evaluation has not addressed the complications that may result for adding non-dispatchable wind and solar energy to the system. The sLCOE costs only account for the capacity factors associated with these renewable options.

The results for the case-specific Alabama and Ohio sLCOE calculations are summarized in Table 9 along with Coal & Solar and Coal & Wind examples. Figure 13 provides a graphic comparison of the prediction results plotted against a progressive credit that may be applied for avoiding CO_2 (or GHG) emissions.

Table 9. LCOE Summary for Scenarios 1, 2, and 3.

	Alabama Scenario						Ohio Scenario					
	Coal	10% cofire	20% cofire central process	20% cofire depot system	Coal & Solar	Coal & Wind	Coal	10% cofire	20% cofire central process	20% cofire depot system	Retrofit NG	New NGCC
Biomass/renewable fraction (%)	0	10	20	20	10	20	0	10	20	20	0	0
Period (years)	20	20	20	20	20	20	20	20	20	20	20	20
Discount rate (%)	4	4	4	4	4	4	4	4	4	4	4	4
Capital recovery factor[a]	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074
Capital cost \$/kW[b]	0	213	213	213	4697	2409	0	213	213	213	250	750
Capacity factor (%)[c]	85.60	85.60	85.60	85.60	18.77	29.87	85.60	85.60	85.60	85.60	87.00	87.00
Fixed O&M (\$/kW)	29.31	32.24	32.24	32.24	25.73	27.73	29.31	32.24	32.24	32.24	25	14.22
Variable O&M (\$/kW-yr)	0.00	0.006	0.006	0.006	0	0	0.00	0.006	0.006	0.006	0.0004	0.0039
Heat rate (Btu/kWh)	9,642	9,675	9,606	9,606	-	-	9,658	9,687	9,627	9,627	9,355	6,815
Fuel cost (\$/MMBtu)[d]	2.24	6.13	6.75	4.72	0	0	1.99	7.19	9.65	9.57	4.00	4.00
sLCOE (¢/kWh)	0	7.17	7.72	5.77	22.58	7.83	0	8.20	10.53	0	4.35	0
Composite price 3,000,000 MWh/yr[e]	3.03	3.44	3.97	3.58	4.98	3.99	2.79	3.33	4.34	4.32	4.35	4.02
Composite price with -\$30/ton CO_2abatement	3.03	3.17	3.47	3.08	4.68	3.36	2.79	3.06	3.91	3.89	1.37	0.86
Composite price with -\$75/ton CO_2abatement	3.03	2.76	2.71	2.32	4.24	2.41	2.79	2.64	3.26	3.25	-3.11	-3.87
Composite price with -\$150/ton CO_2abatement	3.03	2.08	1.46	1.07	3.49	0.83	2.79	1.96	2.19	2.17	-10.58	-11.77

(a) CRF = {i(1+i)^n}/{[(1+i)^n]-1} where i= discount rate
(b) From EIA (2010d)
(c) Coal from sLCOE calculator, Wind & Solar calculated from Average EIA Form 923 for 2010
(d) Coal price from EIA Form 923 for 2010
(e) Composite price = Coal sLCOE * (1-renewable frac) + Renewable sLCOE * renewable frac

A plot of LCOE trends for each of the options versus an assumed credit for reducing CO_2 reveals the relative advantage of the various options (Figure 13). For example, cofiring 20% biomass in Alabama would be economically beneficial when a CO_2 abatement credit of \$45/ton-CO_2 or higher is offered. This is the point where the adjusted LCOE crosses the Alabama coal-only horizontal trend line. In other words, the credit for offsetting CO_2 emissions must be at least \$45/ton-CO_2 to justify fuel switching. In the case of cofiring switchgrass in Ohio Power Plants, 10% cofiring provides a competitive LCOE option when the CO_2 abatement credit exceeds \$60/ton-CO_2. Similarly, the intersection of the various trend lines reveals the relative value among the options evaluated in this study.

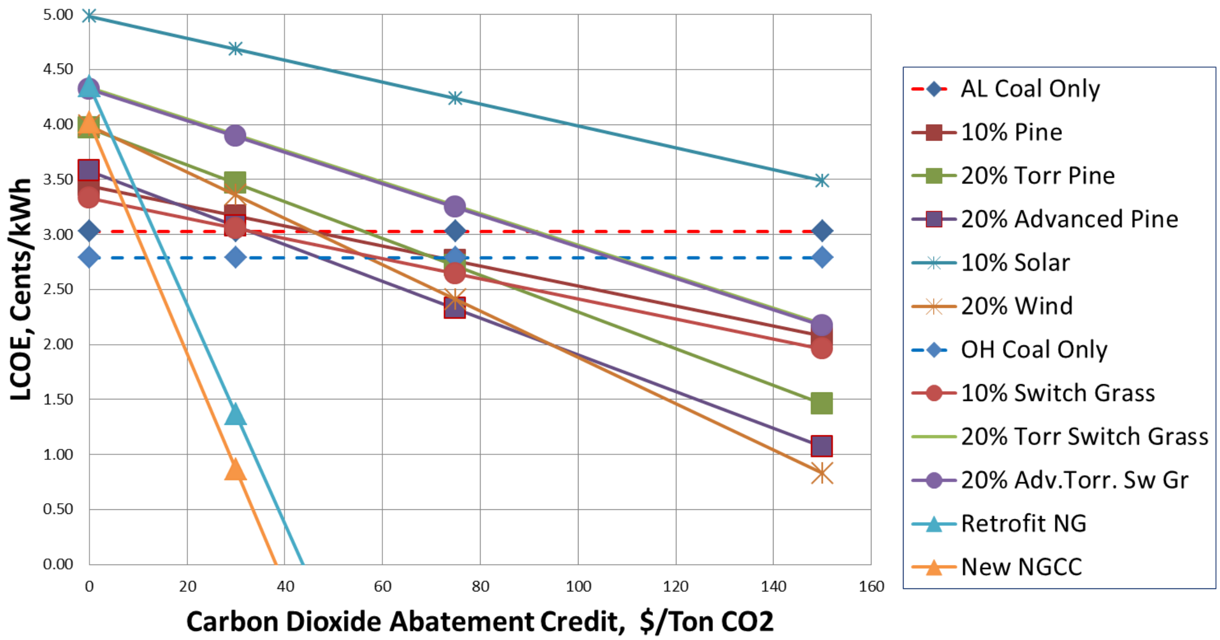


Figure 13. Alabama pine, Ohio switchgrass, solar, wind, and natural gas LCOE vs. CO_2 abatement credit.

The LCOE trend associated with natural gas retrofit or replacement with NGCC indicate a CO_2 abatement credit of only $10-15/ton would favor these options, assuming the price of natural gas remains constant for the life of the project. However, this analysis does not account for any loss of revenue during a plant conversion outage to retrofit an existing plant with gas burner technology.

3.4 GHG Modeling Methodology

A life-cycle analysis (LCA) is a widely adopted approach for evaluating and comparing the environmental consequences of energy options. Because biomass is a renewable feedstock that absorbs carbon as it grows, its combustion is generally viewed as carbon neutral. As such, utilities and policymakers are considering cofiring existing coal plants to curb GHG emissions from power generation.

LCAs of GHG emissions were conducted for the Alabama woody biomass and Ohio switchgrass cofiring scenarios, according to the steps described in detail in Appendix G, Greenhouse Gas Emissions Modeling. The goal of these analyses was to provide an initial estimate of GHG reductions associated with cofiring scenarios relative to the 100% coal baseline and to help identify the major drivers affecting GHG emissions for the various options. Cumulative GHG emissions were determined for the power production life cycle, beginning with resource extraction/cultivation through fuel combustion and generation of electricity product at the plant. A third scenario examined the comparative GHG reductions associated with retrofitting or repowering an existing coal plant to use natural gas. The GHG results were subsequently used to trend the CO_2 abatement benefits presented in previous section for LCOE.

While the combustion of biomass is viewed as carbon neutral, many other sources of GHG emissions in the fuel-supply chain must be considered. These include emissions from fertilizer use and biomass cultivation, harvesting, transportation, and any additional preprocessing required (e.g., drying, densifying, or torrefaction). Each of these steps may include fossil fuel consumption and energy use that can offset some projected GHG reductions associated with cofiring biomass. The amount of inputs and preprocessing required will vary by the type of biomass feedstock, so each biomass source will have a different impact on the overall carbon balance.

Figure 14 and Figure 15 illustrate the study boundaries and primary processes involved in the power production life cycle for the coal, cofiring, and natural gas scenarios. Biogenic carbon was not tracked in this analysis, only fossil carbon (i.e., it was assumed that CO_2 uptake during biomass growth is equal to that emitted during combustion in the power plant). Further, direct and indirect land-use change impacts and transmission losses that occur during delivery of power to the final user were not included in the analysis.

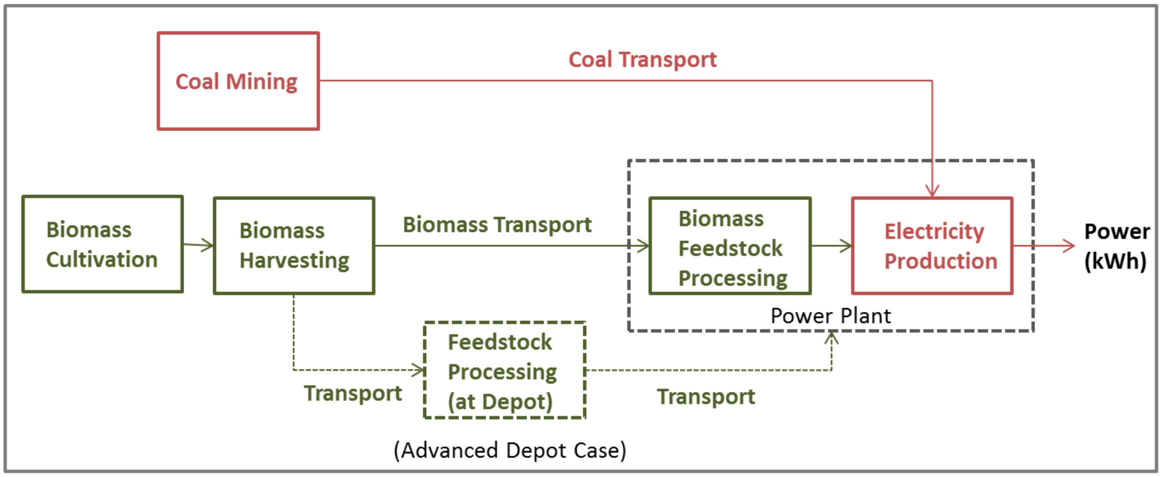


Figure 14. Primary life-cycle stages for the coal and cofiring power, Scenarios 1 and 2.

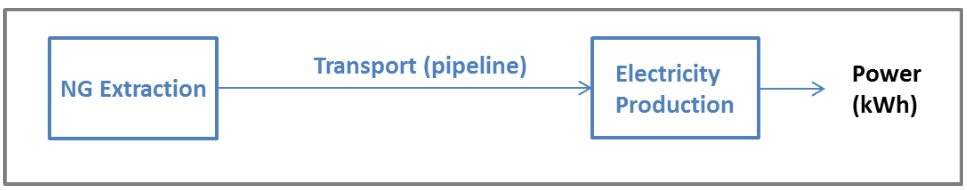


Figure 15. Primary life-cycle stages for the natural gas power, Scenario 3.

Assumptions for energy consumption and emissions during coal mining and woody and switchgrass biomass feedstock cultivation were taken from the literature. Studies from the literature were chosen based on the quality and thoroughness of their data and their applicability to the study scenario. Energy consumption for the feedstock logistics steps presented in Appendices A, B, and C were used to calculate emissions associated with biomass harvesting, transportation, and preprocessing. Results from the Aspen model were used to calculate emissions for the electricity production stage.

The goal of this work is to provide initial estimates and identify the major drivers affecting GHG emissions for the various scenarios, in particular for cofiring torrefied material. This analysis is based partially on data from the open literature and therefore, further refinement of assumptions is necessary to more accurately represent life cycle inventories for key processes affecting GHG emissions. Among the most significant assumptions affecting GHG emissions are additional energy for torrefaction, biomass drying energy, and cultivation and harvesting intensities for Southern Pine and switchgrass. Additional sensitivity and uncertainty analyses around these key parameters are necessary to enable a better understanding of tradeoffs involved in biomass cofiring. These analyses would be greatly assisted by additional experimental data.

Figure 16 shows life cycle emissions for all of the power scenarios and cases analyzed. This analysis indicates that 10% cofiring has the potential to reduce GHG emissions from the 100% coal power baseline by 8.3% for Southern Pine and 8.6% for switchgrass. Cofiring with 20% biomass has the potential to reduce emissions by 15.9% for Southern Pine and 13.7% for switchgrass. Coal combustion is the primary source of life cycle emissions for the cofiring cases, constituting an average of 96 and 92% for the 10% and 20% cofiring cases, respectively. Within the biomass supply chain portion of the life cycle, cultivation and processing at the plant (or depot) are the largest contributors to GHG emissions. Biomass transportation is a minor contributor but will be an increasing influence with higher cofiring ratios. Implementing the advanced depot feedstock logistics system does not significantly impact net GHG emissions. Retrofitting existing boilers at a coal plant to accommodate natural gas could reduce emissions by 30% while repowering to NGCC could result in emissions reductions of 50%.

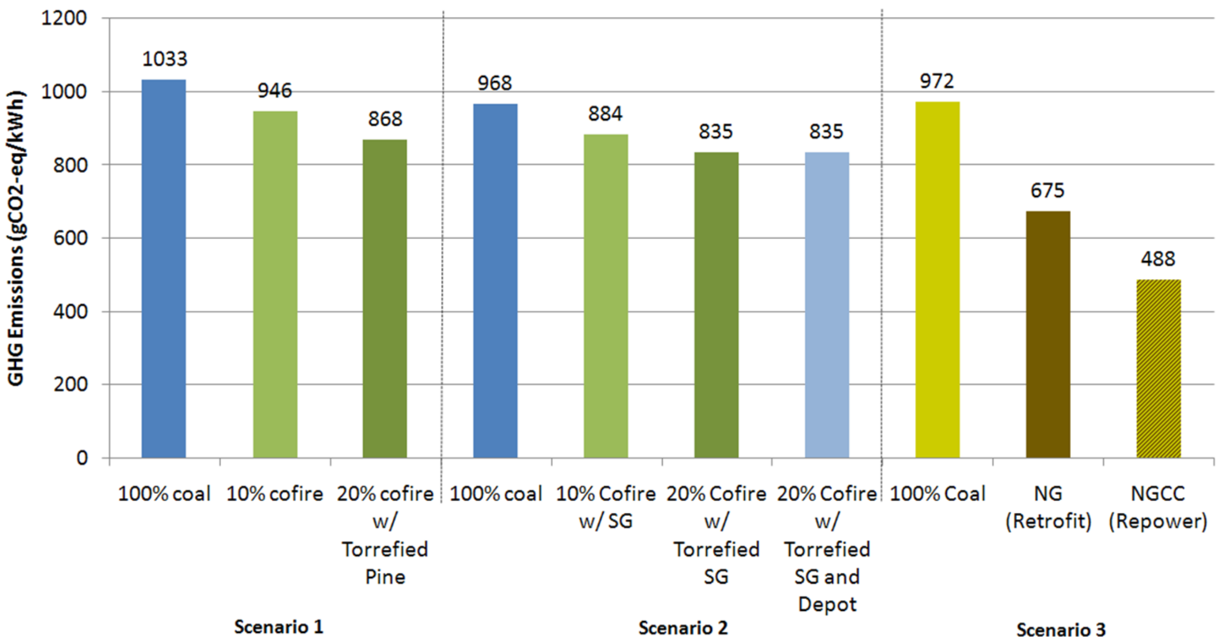
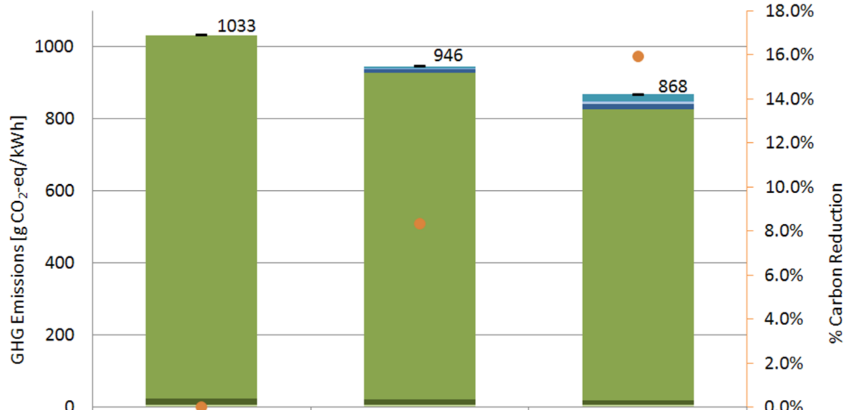


Figure 16. Comparison of life-cycle GHG emissions for Scenario 1 (Alabama coal/wood cofiring); Scenario 2 (Ohio coal/switchgrass cofiring) and Scenario 3 (Average U.S. Coal and Ohio natural gas retrofit & repowering).

3.4.1 Scenario 1: Alabama Plant – Southern Pine

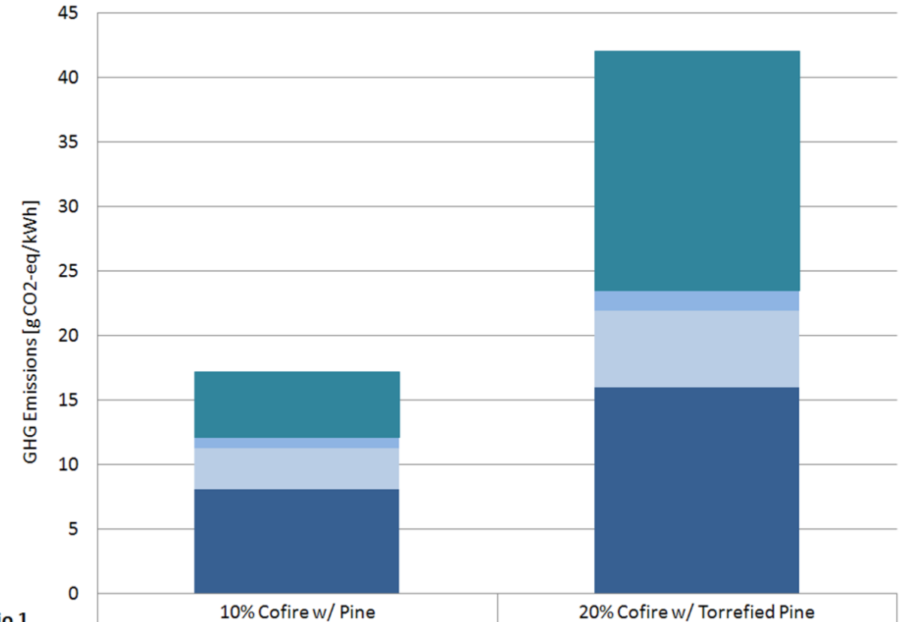
This scenario is modeled after the James H. Miller and E. C. Gaston plants in Alabama. The calculated weighted average plant efficiency and coal energy content assumed for the analysis is 33.24% and 8992 Btu/lb (LHV), respectively. Figure 17 shows the estimated net GHG emissions for Scenario 1, 100% coal, 10% biomass cofiring, and 20% biomass cofiring cases. Net GHG emissions for coal power are estimated at 1,033 g CO_2-eq/kWh. Coal combustion emissions in the electricity production stage are overwhelmingly the largest contributor in the life cycle, constituting 98% of overall GHG emissions, or 1,010 g CO_2-eq/kWh. This estimate is consistent with other estimates of the carbon intensity of coal combustion, which range from 852 g CO_2-eq/kWh (Bauer 2008) to 1,136 g CO_2-eq/kWh (Ortiz et al. 2011). Rail transportation of coal contributes only 1.5% of the total coal power life cycle emissions. A weighted average is used for PRB (1,000 mi) and Alabama coal (300 mi) travel distances. Increasing transportation distance to a maximum of 2,000 mile for PRB coal and 500 mile for Alabama coal results in transportation emissions of 30.6 g CO_2-eq/kWh, still only 3% of the net GHG emissions. This indicates that coal transportation distance is a relatively minor contributor in the power life cycle.

As shown in Figure 17, the life cycle GHG emissions estimate for the 10% cofire case is 946 g CO_2-eq/kWh, an 8.3% reduction from the coal baseline. The total contribution of the biomass lifecycle to overall GHG emissions is 17.2 g CO_2-eq/kWh, or 2% of the total GHG emissions. Figure 18 details biomass contributions to greenhouse gas emissions. Biomass cultivation makes up approximately 45% of the total biomass cofiring contribution, which consists of application of fertilizer and herbicides; leaf litter, which falls on the ground during the harvesting process and decomposes (as N_2O); and diesel emissions associated with tilling. Significant variability exists in GHG emission estimates associated with biomass cultivation, stemming from differing assumptions for fertilizer use, farming practices, and soil conditions (Heath and Mann 2011). Changes in these assumptions would impact the carbon intensity of biomass and the overall carbon reduction possible with cofiring. Biomass processing consists of drying and handling at the plant and contributes 30% to the total biomass cofiring portion of the power life cycle.



Scenario 1	100% coal	10% Cofire w/ Pine	20% Cofire w/ Torrefied Pine
Biomass Processing		5.0	18.5
Biomass Transportation		0.9	1.6
Biomass Harvesting		3.2	5.9
Biomass Cultivation		8.1	16.0
Coal Electricity Production	1009.8	908.8	807.9
Coal Transportation	15.4	13.9	12.3
Coal Mining	7.3	6.6	5.8
Total	1033	946	868
% Carbon Reductions	0.0%	8.3%	15.9%

Figure 17. Net GHG emissions and percent carbon reduction for 100% coal, 10% woody/90% coal cofiring, and 20% torrefied/80% coal for Scenario 1 – Alabama power plant with southern pine.



Scenario 1	10% Cofire w/ Pine	20% Cofire w/ Torrefied Pine
Biomass Processing	5.0	18.5
Biomass Transportation	0.9	1.6
Biomass Harvesting	3.2	5.9
Biomass Cultivation	8.1	16.0

Figure 18. GHG emissions from the cultivating, harvesting, transport, and in-plant processing of southern pine for the Scenario 1 cofiring cases.

A plot the GHG emissions estimate for the 20% torrefied wood cofire case is shown in Figure 19. The calculated rate of 868 g CO_2-eq/kWh gives a15.9% reduction from the 100% coal case. The cultivation, harvesting, and transportation stages for the 20% case are naturally about twice those for the 10% case. The feedstock processing stage, however, is more than double that of the 10% case because of the extra energy required for torrefaction compared to just drying the wood chips. However, the increase in GHG emissions due to mass loss during torrefaction is offset by the increased heating value of torrefied wood compared to raw wood chips.

The feedstock processing stage of the biomass portion of the lifecycle is 44% of the total for the 20% cofiring case, while only 29% of the total for the 10% cofiring case. Drying and torrefaction of wood chips is assumed to require 2029 MBtu/DM ton of energy using natural gas (see Appendix B). This is lower than a value found in the literature, 4,300 MBtu/ton (Tabata et al. 2011). This difference could be due to the local and specific feedstock assumptions made in the literature study or differing equipment assumptions. With torrefaction energy having such a significant impact on the biomass portion of the life cycle, a sensitivity analysis was conducted around this factor. Figure 20 shows the impact of torrefaction energy on percent carbon reduction from the 100% coal baseline for this scenario. This value includes both direct combustion emissions and indirect emissions associated with production and distribution of natural gas. In summary, GHG reductions decrease linearly as torrefaction energy increases, with all reductions being negated completely at 20 MMBtu/DM ton.

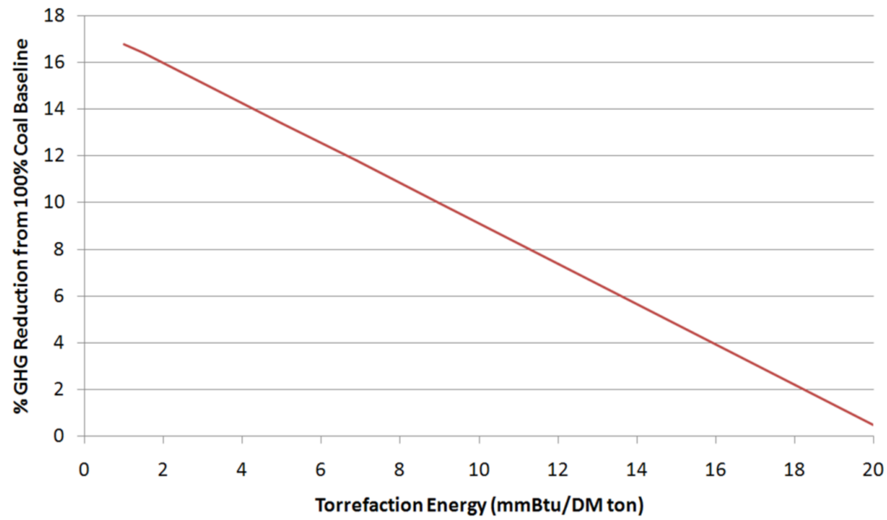


Figure 19. Impact of energy required for torrefaction of biomass on carbon reductions from the 100% coal baseline for 20% torrefied/80% coal cofiring (Scenario 1).

The life-cycle GHG contributions of transporting biomass distances ranging from 25 to 500 mile vary from 0.8 to 16 g/kWh (Table 10). Thus, the GHG emissions of the biomass supply chain can contribute up to 28% of the overall GHG emissions for the 500 mile case. However, the net relative contribution is under 2 percent for the net GHG emissions. Therefore, it is not a significant factor at these cofiring ratios, even at the extreme case of 500 mi. As the cofiring ratio increases, biomass transportation assumptions will naturally have a greater impact on the overall GHG estimates.

Table 10. GHG emissions at 25, 50, 100, 250, and 500-mi transportation distances.

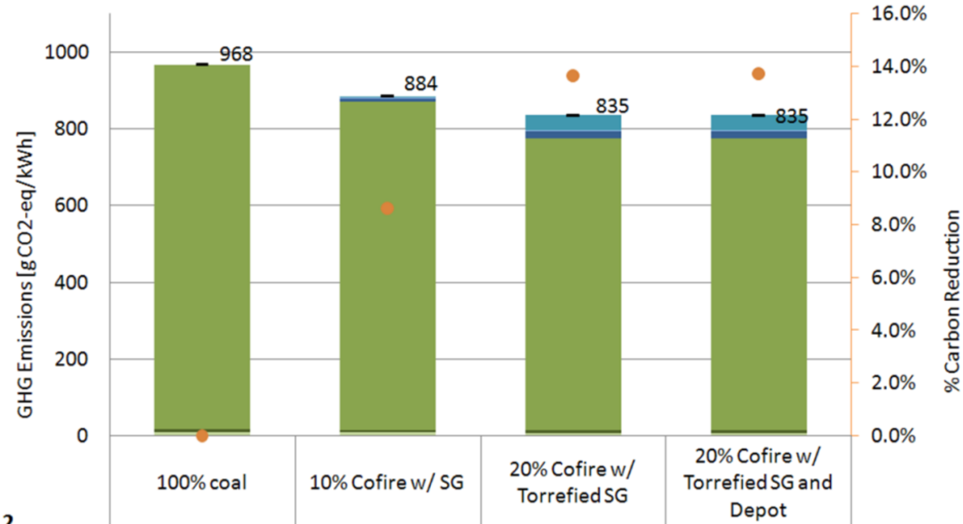
	25 mi	50 mi	100 mi	250 mi	500 mi
GHG emissions, g CO_2-eq/kWh	0.8	1.6	3.2	4.8	16.0
Percent biomass portion of GHG emissions	1.9	3.8	7.3	10.6	28.4
Percent contribution of net cofire GHG emissions	0.09	0.18	0.37	0.55	1.8

3.4.2 Scenario 2: Ohio Plant – Switchgrass

This scenario is modeled after the Muskingum River and General James M. Gavin plants in Ohio. The calculated weighted average plant efficiency and coal energy content assumed for the analysis are 34.33% and 11,116 Btu/lb (LHV), respectively. Figure 20 plots the estimated net GHG emissions for the cases included in Scenario 2 for 100% coal and cofiring of switchgrass. In addition to the 10% cofiring and 20% cofiring cases, an additional case was evaluated using the advanced herbaceous depot feedstock logistics scenario to explore the impact of torrefaction on transportation emissions. The net GHG emissions estimate for 100% coal power is 968 g CO_2-eq/kWh. This result is about 6% lower than Scenario 1 which is attributed to the plant higher efficiency and coal heat content applicable to the case.

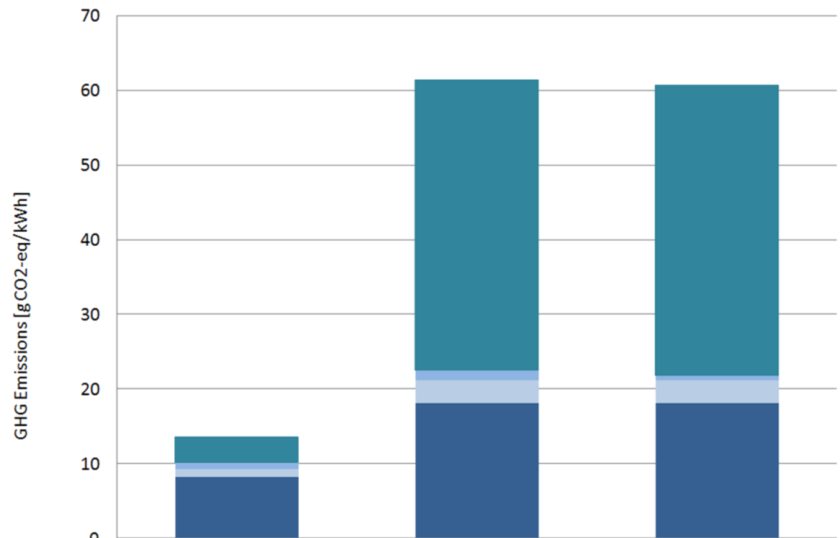
Cofiring switchgrass gives similar reductions as in the woody biomass cases of Scenario 1. Coal combustion emissions make up the majority of the life cycle, constituting 98%, 97%, and 91% of the total for the 100% coal, 10% cofiring, and 20% cofiring cases, respectively. The 10% cofire case results in 8.6% lower GHG emissions, and the 20% torrefied case results in 13.7% lower GHG emissions.

Figure 21 shows the break out of the contribution from the switchgrass biomass supply chain. The 20% cofiring reductions for switchgrass are less than with woody biomass. This is attributed to the higher energy required for switchgrass grinding, leaching, torrefaction, and densification. Although the transportation emissions are reduced by a significant proportion for the depot case, it does not have a significant impact on overall GHG emissions because this stage is a minor contributor to the overall lifecycle GHG emissions compared to coal combustion emissions.



Scenario 2	100% coal	10% Cofire w/ SG	20% Cofire w/ Torrefied SG	20% Cofire w/ Torrefied SG and Depot
Biomass Processing		3.4	38.9	38.9
Biomass Transportation		0.8	1.3	0.6
Biomass Harvesting		1.0	3.0	3.1
Biomass Cultivation		8.3	18.2	18.2
Coal Electricity Production	951.0	855.9	760.8	760.8
Coal Transportation	7.6	6.8	6.1	6.1
Coal Mining	9.1	8.2	7.3	7.3
Total	968	884	835	835
% Carbon Reductions	0.0%	8.6%	13.7%	13.7%

Figure 20. Net GHG Emissions and percent carbon reduction for 100% coal, 10% woody/90% coal cofiring, and 20% torrefied/80% coal for Scenario 2 – Ohio Power Plant with switchgrass.



Scenario 2	10% Cofire w/ SG	20% Cofire w/ Torrefied SG	20% Cofire w/ Torrefied SG and Depot
Biomass In-Plant Processing	3.4	38.9	38.9
Biomass Transportation	0.8	1.3	0.6
Biomass Harvesting	1.0	3.0	3.1
Biomass Cultivation	8.3	18.2	18.2

Figure 21. GHG emissions from the cultivating, harvesting, transport, and in-plant processing of switchgrass for the Scenario 2 cofiring cases.

(This page is intentionally left blank)

4.0 CONCLUDING REMARKS AND DATA GAPS

This study evaluates the possible benefits of utility-scale biomass cofiring in the United States with a comparison to solar and wind electrical power generation as well as retrofitting a coal-fired unit with natural gas burners or a new natural gas/combined cycle plant. In 2010, net GHG emitted in the United States was equivalent to 6,821.8 million metric tons CO_2, up 3.2% from 2009, and up 10.5% since 1990 (EPA 2011). Coal-fired power generation accounted for 1,827 million metric tons. Intuitively, substituting renewable biomass for coal could reduce lifecycle CO_2 emissions in the power sector. If just 20% of the coal combusted in 2010 had been replaced with biomass, CO_2 emissions could have been reduced by roughly 350 million metric tons, or about 6% of net annual GHG emissions. This would have required approximately 225 million tons of dry biomass. Such an ambitious fuel substitution would require development of a biomass feedstock production and supply system tantamount to coal. This material would need to meet stringent specifications to ensure reliable conveyance to boiler burners, efficient combustion, and no adverse impact on heat-transfer surfaces and flue gas cleanup operations.

Cofiring scenarios were considered for large utility-scale power plants in central Alabama and the Ohio River Valley. These locations are representative of the concentrated coal-fired power-generation regions and thus provide an optimistic test for early entry of biomass cofiring biomass on a scale that can begin to impact total GHG emissions.

For the Alabama scenario, it was assumed that local and regional Southern Pine can be grown to meet the demand required to substitute up to 20% (lower heating value) of the coal used in as many as three coal-fired plants. The analysis modeled the James H. Miller, Jr, Plant (with four 670-MW boilers beginning operation between 1978 and 1991, and currently burning PRB coal and retrofitted with FGD units between 2009 and 2011) and E. C. Gaston Unit 5 (firing local Alabama bituminous coal and retrofitted in 2010 with a FGD unit). The five boilers have a combined nominal capacity of 3,522 MW, representing 11% of Alabama power generation.

For the Ohio scenario, it was assumed that purpose-grown switchgrass can be produced to replace up to 20% (lower heating value) of the coal fired in two 1,300-MW units of the General James M. Gavin plant (currently burning a blend of Pittsburgh #8 and PRB coal) along with Muskingum River Unit 5 (a 1968 vintage 640-MW station burning Pittsburgh #8). The General James M. Gavin boilers are equipped with FGD while the Muskingum River boiler has no FGD and does not comply with current regulations. The 3,225-MWe output of these plants represents 10% of the total power generation in Ohio. Instead of installing an FGD, the Muskingum River unit is also considering conversion to gas or repowering with a NGCC. Hence, a comparison of these two options was evaluated in this study.

A significant barrier to increasing biomass use for power generation is the high cost of feedstock based on both supply and logistical challenges. This work focused on producing a feedstock compatible with the feed systems of existing plants. Based on previous cofiring trails sponsored by the DOE and individual utilities, at least 10% biomass can possibly be blended with ground coal prior to being pulverized in the existing coal milling and particle entrainment feed line. For higher cofiring rates, it was assumed that torrefaction would be necessary to improve biomass grindability in the existing roller or ball mills of most plants. This study also assumed that herbaceous materials would require leaching to reduce soluble alkaline salts that may foul boiler tubes in the furnace. When used in conjunction with a depot concept, pretreatment operations could enable biomass to be produced as a commodity that could serve as a near drop-in replacement for coal in many power plants. The possibility of feeding as much as 20% biomass with coal through the existing feeder systems was partially confirmed through feedstock pretreatment and grinding studies supporting this work. However, only a field trial in a representative feed system will allay the technical risk of cofeeding such a large mass of biomass.

A standard method for technical, economical, and environmental assessments of cofiring in utility-scale boilers was developed to model feedstock delivery through a system of distributed depots versus centralized collection and pretreatment operations at the power plant or a near-by location. The analysis demonstrates that a wide collection distance is necessary to control supplier costs that may result for high demand when millions of tons of biomass feedstock (about 8 million tons per year for the combined cases studied in this report) to minimize the costs of biomass feedstock. A tradeoff between grower payments (at the tree landing for Southern Pine or the farm gate for switchgrass, respectively) and shipping costs results in a mathematical cost function that can be minimized by performing a systems analysis. For three Alabama plants producing 3,522 MWe, an advance depot concept using distributed torrefaction and densification, and that extends 300 miles from the power plants, provides the least cost woody material (ca $4/MMBtu) for 20% cofiring with coal. For herbaceous switchgrass supply in vicinity of three Ohio power plants producing 3,255 MWe, a centralized biomass treatment option with biomass collection extending only 100 miles from the power plant center results in the lowest cost material (ca $10/MMBtu). The higher cost of switchgrass versus woody feedstock is attributed to higher production, collection, and pretreatment costs.

From a business viewpoint, the LCOE evaluation indicates 20% cofiring woody biomass in Alabama co-firing provides the best overall economic gain when a CO_2 abatement credit of $45/ton-$CO_2$ is offered. In the case of cofiring switchgrass in Ohio Power Plants, 10% cofiring provides the most competitive LCOE option when the CO_2 abatement credit offer exceeds $60/ton-$CO_2$. Additionally, the data reveal that the woody biomass cofiring LCOE lower than wind power generation up to a CO_2 abatement credit of approximately $85/ton-$CO_2$. Solar power generation was not found to be cost-competitive up to a CO_2 abatement credit of $200/tonCO-$_2$. Additionally, this analysis does not include the impacts of wind and solar power generation variability.

Either a natural gas retrofit of the Muskingum River Plant in Ohio, or its replacement with NGCC are cost competitive with a coal-only fired operation when a CO_2 abatement credit of only $10-15/ton-$CO_2$ is offered, assuming the price of natural gas remains constant for the life of the project. However, this analysis does not account for any loss of revenue during a plant conversion outage to retrofit an existing plant with gas burner technology.

The LCA for the cases evaluated in this study demonstrates cofiring can have immediate positive lifecycle benefits, particularly for cases based on an advanced depot concept. The current LCA of GHG for switchgrass grown in vicinity of Ohio power plants is relatively more positive than the recent NETL study for a plant located in Indiana as shown in Appendix H, Comparison of Results with NETL Cofiring Study. This underscores the need to evaluate specific biomass supply-chain and coal-related contributions to lifecycle emissions. A sensitivity study is recommended to better understand key GHG emissions factors associated with a variety of regional biomass growth and production techniques. This study should especially quantify the GHG emissions associated with torrefaction of various biomass forms.

This study does not address risks associated with potential negative impacts on burner flame chemistry, boiler fouling, or flue gas cleanup equipment. Cofiring has been shown to have minor impacts on pollutant formation and cleanup equipment; however, ash deposition may either decrease or increase depending on conditions. Although the fusion temperatures of coal and biomass ash and ash mixtures have been measured by many sources, the complex mechanisms of mineral aerosol formation and deposition in an actual boiler are dependent on several phenomena (e.g., mixture-fraction chemical compositions, conversion reactions, transport processes, and surface impaction mechanisms at actual boiler conditions). Because biomass may contain uniquely different elemental compositions, parametric testing of situation-specific biomass/coal blends should be performed in a full-scale boiler, or using a representative pilot plant with boiler tube materials maintained at realistic conditions. A single well-designed study could help understand specific flame and ash behavior phenomena and gas cleanup impacts. Such a study could simultaneously investigate metallic and ceramic corrosion potential with cofiring.

In consideration of the negative impacts of relatively high amounts of chorine and alkali metals in some biomass, the mechanisms of ash leaching, demonstration of leaching technology, and the costs associated with leaching need to be better understood. This study relies on preliminary data provided by leaching tests for select crops. Therefore, additional parametric study of leaching for many varieties of biomass will help establish the cost benefits of this preconditioning step.

In closing, this study is intended to provide quantitative data on the logistical requirements and cost/benefit changes that would occur if co-firing biomass with coal at levels of up to 20 percent (LHV) biomass in typical utility-scale power plants. This study also identifies the requirements for large quantities of biomass, its conversion into a format that is compatible with the existing coal-feed systems and changes to cost and GHG levels that would occur. Maximizing use of existing power plant infrastructure avoids expensive retrofit of the power plant feed systems and burners. This evaluation is not intended to be an analysis of changes to existing policy. A complete comparison of the benefits of biomass conversion to large-scale electrical power is beyond the scope of this study.

(This page is intentionally left blank)

5.0 ACKNOWLEDGEMENTS

In addition to the cast of authors and experimental analysts contributing to this report, technical input and project steering was provided by Elliott Levine, Bioenergy Technology Office (BETO) Technical Lead for this activity. This report was preceded by a national biopower workshop organized under his direction, which provided incentive to complete this study focusing on utility-scale biomass cofiring.

Technical reviews of the data input, modeling results, and draft reports were completed by the Electrical Power Research Institute, select electrical power utilities, invited biomass conversion research professors, and BETO subject matter experts and external program advisors.

Pacific General Electric provided bulk amounts of purpose-grown *Arundo Donax* for the laboratory leach tests and pilot plant torrefaction and densification tests that are summarized in Appendix D, Experimental Support Studies. Arrangements and encouragement of the PGE project lead for biopower, Jaison Moody, were key to this industrial interaction.

Under a Cooperative Research and Development Agreement, the Electric Power Research Institute provided data on biomass leaching and commercial torrefaction plant design details, performance parameters, and capital cost estimates. This information was incorporated into the Biomass Logistics Model to complete leaching and torrefaction cost estimates for the scenarios of this assessment.

Finally, the efforts of technical editors Leslie Ovard and Marsha Bodily are recognized.

(This page is intentionally left blank)

6.0 REFERENCES

ASABE – American Society of Agricultural and Biological Engineers. 2006. *Agricultural Machinery Management Data*. ASAE D497.5, St. Joseph, MI.

ASME – American Society of Mechanical Engineers. 1980. “Wells Street Power Station.” *ASME Milwaukee: History & Heritage*. Accessed March 20, 2012, at http://sections.asme.org/milwaukee/history/4-pulverizedcoal.html. [membership access required]

Berkenpas MB, et al. 2009. *IECM User Manual*. Final Report to U.S. Department of Energy’s National Energy Technology Center (DOE/NETL) from Carnegie Mellon University, Pittsburgh, Pennsylvania.

DOE – U.S. Department of Energy. 2002. *Biopower Factsheet: Biomass Cofiring: A Renewable Alternative for Utilities*. DOE/GO-102000-1055. Available at http://www.nrel.gov/docs/fy00osti/28009.pdf.

DOE – U.S. Department of Energy. 2011a. *U.S. Billion-Ton Update*: *Biomass Supply for a Bioenergy and Bioproducts Industry*. ORNL/TM-2011/224, RD Perlack and BJ Stokes (Leads), Oak Ridge National Laboratory, Oak Ridge, Tennessee.

DOE – U.S. Department of Energy. 2011b. *Biomass Multi-Year Program Plan: November 2011*. U.S. Department of Energy, Energy Efficiency and Renewable Energy, Washington, D.C. Available at http://www1.eere.energy.gov/biomass/pdfs/mypp_november_2011.pdf.

DOE – U.S. Department of Energy. 2012. “Billion-Ton Update (BT2) Data Explorer.” *Bioenergy Knowledge Discovery Framework (Bioenergy KDF)*.Available at https://www.bioenergykdf.net/.

EcoInvent Database. 2011. Version 2.2, Swiss Center for Life Cycle Inventories, Hamburg, Germany.

El-Wakill MM. 1984. Powerplant Technology. McGraw-Hill, New York, pp. 79–171.

EIA – Energy Information Administration. 2008. Office of Oil & Gas, Natural Gas Division, Transportation Information Systems.

EIA – Energy Information Administration. 2009. *Annual Energy Review 2008*. DOE/EIA-0384(2008), Office of Energy Markets and End Use, Washington, D.C. Available at http://www.eia.gov/FTPROOT/multifuel/038408.pdf.

EIA – Energy Information Administration. 2010a. *Annual Energy Outlook 2010*. Office of Integrated Analysis and Forecasting, U.S. Department of Energy, Washington, D.C.

EIA – Energy Information Administration. 2010b. Table 1.2, “Summary Statistics for the United States, 2001-2011.” In *Electric Power Annual 2010*. Accessed March 29, 2012 at http://www.eia.gov/electricity/annual/.

EIA – Energy Information Administration.2010c. “Power Plant Operations Report 2010, Form EIA-923.”Available athttp://www.eia.gov/cneaf/electricity/.

EIA – Energy Information Administration. 2010d. *Updated Capital Cost Estimates for Electricity Generation Plants*. Energy Information Administration, U.S. Department of Energy, Washington, D.C.

EIA – Energy Information Administration. 2010e. *Updated Capital Costs for Renewable Resources*. Energy Information Administration, U.S. Department of Energy, Washington, D.C.

EIA – Energy Information Administration. 2010f. *Annual Coal Report*. Energy Information Administration, U.S. Department of Energy, Washington, D.C.

EIA – Energy Information Administration. 2011. *Today in Energy, August 2, 2011*. Available at http://205.254.135.7/todayinenergy/detail.cfm?id=2470 (Accessed March 29, 2012).

EIA - Energy Information Administration. 2012. *Annual Energy Outlook 2012 Early Release Overview*. DOE/EIA-0383ER.U.S.

EIA – Energy Information Administration. 2012a. *State Electricity Profiles 2010*. Office of Electricity, Renewables, and Uranium Statistics, U.S. Department of Energy, Washington, D.C.

EIA – Energy Information Administration. 2012b. *Electricity: Analysis and Projections*. Available at http://www.eia.gov/cneaf/electricity/page/eia860.html.

EPA – Environmental Protection Agency. 2011. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009*. EPA430-R-11-005, Washington, D.C. Available at: http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2011-Complete_Report.pdf.

Hess JR, KL Kenney, LP Ovard, EM Searcy, and CT Wright. 2009. Uniform-Format Solid Feedstock Supply System: A Commodity-Scale Design to Produce an Infrastructure-Compatible Bulk Solid from Lignocellulosic Biomass. INL/EXT-08-17527, Idaho National Laboratory, Idaho Falls, Idaho. Available at www.inl.gov/bioenergy/uniform-feedstock.

NETL – National Energy Technology Laboratory. 2007. *Cost and Performance Baseline for Fossil Energy Plants*. DOE/NETL-2007-1281, Volume 1, Revision 1, U.S. Department of Energy: Washington, DC. Available at: http://www.netl.doe.gov/energy-analyses/pubs/BitBase_FinRep_2007.pdf.

NETL – National Energy Technology Laboratory. 2008. *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels*. DOE/NETL-2009/1346, Office of Systems, Analyses and Planning, U.S. Department of Energy: Washington, DC. Available at http://www.netl.doe.gov/energy-analyses/pubs/NETL%20LCA%20Petroleum-based%20Fuels%20Nov%202008.pdf.

Searcy E and JR Hess. 2010. Uniform-Format Feedstock Supply System Design Reports: A Commodity-Scale Design to Produce an Infrastructure-Compatible Biocrude from Lignocellulosic Biomass. INL/EXT-10-20372, Bioenergy Program, Idaho National Laboratory, Idaho Falls, Idaho.

Tumuluru JS, CT Wright, KL Kenney, and JR Hess. 2010a. *A Review on Biomass Densification Technologies for Energy Application*. INL/EXT-10-18420, Idaho National Laboratory, Idaho Falls, Idaho.

Tumuluru JS, S Sokhansanj, CT Wright, and R Boardman. 2010b.*Biomass Torrefaction Process Review and Moving Bed Torrefaction System Model Development*. INL/EXT-10-19569, Idaho National Laboratory, Idaho Falls, Idaho, and Oak Ridge National Laboratory, Oak Ridge, Tennessee.

Tumuluru JS, JR Hess, RD Boardman, CT Wright, and TL Westover. 2012. "Formulation, Pretreatment, and Densification Options to Improve Biomass Specifications for Co-Firing High Percentages with Coal." *Industrial Biotechnology* 8(3):113–132.

UN – United Nations. 1998. *Kyoto Protocol to the United Nations Framework Convention on Climate Change*. Available at http://unfccc.int/resource/docs/convkp/kpeng.pdf.

UN – United Nations. 2011. *Clean Development Mechanism (CDM) Methodology Booklet*. Unite Nations Convention on Climate Change. Available at https://cdm.unfccc.int/methodologies/index.html.

Uslu A, APC Faaij, and PCA Bergman. 2008. "Pre-Treatment Technologies and Their Effect on International Bioenergy Supply Chain Logistics: Techno-Economic Evaluation of Torrefaction, Fast Pyrolysis, and Pelletisation." *Energy* 33(8):1206–1223.

7.0 APPENDICES

(This page is intentionally left blank)

Appendix A

Feedstock Logistics Models

A.1 Feedstock Logistics Economic Analysis Methodology

BLMs supply systems costs using a methodology adapted from two widely accepted agricultural equipment engineering-economic costing methodologies presented by the American Society of Agricultural and Biological Engineers (ASABE) and the American Agricultural Economics Association (AAEA). For the most part, the two methodologies use the same equations and machinery data; however, the AAEA method incorporates several cost factors that the ASABE method does not. These methods were reviewed and compared by Turhollow and Sokhansanj (2007), who compiled a recommended standard costing methodology for biomass. While the ASABE and AAEA methods apply specifically to agricultural machinery, Turhollow and Sokhansanj (2007) extend the methodology to include buildings, shelters, and transportation and handling equipment associated with biomass supply and logistics.

The cost methodology described by Turhollow and Sokhansanj (2007) is incorporated as a two-step process into the BLM and includes the calculation of machinery cost (represented in $/hr or $/ton) and machinery performance (generally represented in $/ton). Model development is an iterative process, so model inputs are continuously updated. The costs and performance parameters are taken from the February 2012 version of the model and are represented in 2012 U.S. dollars.

A.2 Equipment and Buildings Costs

Cost calculations for equipment, buildings, and other handling and processing equipment generally follow the methodology described by Turhollow and Sokhansanj (2007). These costs are categorized as ownership costs represented in $/yr (fixed costs) and operating costs represented in $/hr (variable costs).The annual usage (hr) for machinery cost was calculated based on the harvest window, machine capacity, and number of machines. The ownership costs ($/yr) were divided by the annual use (hr) to provide an hourly ownership cost. The ownership cost ($/hr) and operating cost ($/hr) were then summed to provide a total hourly machinery cost. Ownership and operating costs for these designs included in the economic analyses are as follows:

- ownership costs

  annual depreciation

  interest on the value of the machinery and equipment

  property taxes on equipment

  insurance

  housing (e.g., equipment shed)

  salvage value

- operating costs

  repair and maintenance

  fuel (diesel an electricity)

  materials (e.g., baling twine and bale wrap)

  labor.

All costs are based on values obtained for a particular year. For example, the cost of a harvesting machine may be based on a vendor quote obtained in 2005, while the cost of diesel fuel for this equipment may be based on fuel prices in 2008. To normalize costs to a common cost basis, so that analyses can be performed for years other than those in which the costs were obtained, and to avoid the need to update costs annually, a method was developed to allow backcasting to previous years and forecasting to future years. For cost items in which a cost database exists with current and historical costs recorded on at least an annual basis, this database is integrated with the feedstock cost model. For current year and backcasting analysis, the database is simply indexed to the appropriate cost year. For forecasting, the values in the database are regressed to a simple equation for extrapolating to future years. Cost databases are included for estimating fuel prices, labor rates, and land rent values. These databases are generated from data provided by the EIA, the U.S. Department of Labor – Bureau of Labor Statistics, and the U.S. Department of Agriculture National Agricultural Statistics Service (USDA-NASS).

A representative cost index is used to estimate the backcasted and forecasted costs for items (e.g., capital costs or repair and maintenance costs) for which historical cost records do not exist. The USDA-NASS publishes monthly Prices Paid by Farmers indices that represent the average costs of inputs purchased by farmers and ranchers to produce agricultural commodities and a relative measure of historical costs. The Machinery Index is used for machinery list prices, the ASABE repair and maintenance factors are used for machinery repair and maintenance costs, and the ASABE salvage factors are used for machinery salvage values. These USDA-NASS indices are used for all equipment used in the feedstock supply-system analysis, including harvest and collection equipment (e.g., fellers, skidders, balers, and tractors), loaders and transportation-related vehicles, grinders, and storage-related equipment and structures. The Chemical Engineering Plant Cost Index is used for plant handling, queuing, and storage equipment such as conveyors and storage bins.

A.3 Equipment Performance

Biomass costs are calculated after the machine has performed a function on the product or on the land; these costs are a function of machinery performance, and are expressed in $/ton, $/item, or $/ac (e.g., mowing a field in $/ac, baling in $/bale, and grinding the biomass in $/ton). The operating characteristics of the machines, including speed, efficiency, width of operation, and/or throughput, are needed to calculate these costs. Machine speed, capacity, or throughput are rarely provided by the manufacturer because of the variability attributed to factors like operator skill level, field conditions, feedstock type and conditions, and equipment conditions (e.g., how well it has been maintained). Consequently, equipment performance can be difficult to identify.

Several sources of equipment performance data are used in the cost analyses described in this report. In some cases, the capacity is determined from time-in-motion tests, and in other cases it is determined from typical agricultural machinery speeds published in American Society of Agricultural Engineers (ASAE) D497.5 (ASABE 2006) or from data provided by expert operators (e.g., custom harvest operators).

A.4 Biomass Cost

Ownership and operating costs are calculated for all processing machinery, transportation and handling equipment, and storage and queuing infrastructure throughout the supply chain. These costs are summed to provide an hourly usage cost ($/hr) for machinery and a yearly usage cost ($/yr) for infrastructure. The hourly costs ($/hr) are then divided by the machine capacity (ton/hr), and the yearly costs are divided by the annual tons processed to give a cost per ton for each operation. The feedstock cost is determined by summing the machine cost per ton for each piece of equipment used in the supply-system analysis. Finally, the total annual costs are determined by summing the operating costs ($/ton) for each piece of equipment and multiplying the sum by the total annual tonnage (800,000 tons) processed by this equipment.

The total capital investment is determined by multiplying the number of equipment units by the equipment purchase price for each piece of equipment used in the supply-system analysis. This analysis does not take into account important factors like land usage and local competition for resources. Because of this, the analysis has been conducted including the logistics costs of harvesting and collection for woody and herbaceous biomass, and preprocessing at the landing for woody biomass.

The purchase cost of biomass, referred to as farm gate price and landing price for herbaceous biomass and woody biomass, respectively, are generated from the *Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry* (DOE 2011a). This analysis includes logistics cost for harvest and collection and the preprocessing at the landing for woody biomass, including an economic model to account for market forces. When the total biomass cost is reported at the plant gate in this report, it is the sum of the purchase cost of biomass reported in the *Billion-Ton Update* and the logistics costs from the landing or farm gate to the power plant. The logistics cost is modeled as indicated above with the BLM and the logistics costs of harvest, collection, and woody preprocessing costs (already included in the farm gate price, or landing price)are then subtracted to avoid double counting.

A.5 Energy-Use Analysis

Energy consumption is of particular importance in analyzing feedstock supply-system designs. Energy consumption throughout supply-chain unit operations is calculated based on the fuel or electricity consumed by the equipment involved.

Diesel fuel consumption estimates are based on actual consumption estimates from equipment specifications or from manufacturer/dealer quotes, when available.

A.6 Sensitivity Analysis

Sensitivity analyses were conducted for each design scenario using the PowerSim® sensitivity analysis tool. PowerSim® takes a systems approach to modeling based on positive and negative feedback and accumulations and flows. Variables within the model are assigned probability distributions and ranges determined from research and documentation. For each sensitivity run, a value is randomly selected for each variable from each probability distribution and computed as one scenario of the model. This process is repeated thousands of times and the results are collected. A statistical analysis provides the confidence interval, mean, and standard deviation for the overall sensitivity analysis.

The parameters included in the sensitivity analysis vary between design scenarios because the model input is different for each scenario. The parameters generally include:

- feedstock variables

  biomass yield

  biomass removal limit

- harvest and collection variables

  harvest window

  field losses (harvest efficiency)

  machine field speed/capacity

  machine field efficiency

  biomass moisture at harvest (e.g., standing tree moisture)

  biomass bulk density (e.g., tree pile or chip density)

  distance to landing

- storage variables

  dry matter loss in storage

  machine (e.g., loader) capacity

- preprocessing variables

  machine capacity

  biomass moisture

- handling and transportation variables

  transport distance/winding factor

  transporter speed

  loader/unloader capacity

- plant receiving variables

  receiving (hr/day)

  feedstock inventory

  feedstock bulk density.

A range (including a minimum and maximum value), most likely value, and probability distribution were identified for each selected input variable. A triangular distribution was used to describe the probability distribution of most input variables and is appropriate because of the small amount of data available. A Latin hypercube analysis was chosen as a variable selection criterion for each sensitivity run.

A.7 Appendix A References

ASABE – American Society of Agricultural and Biological Engineers. 2006. *Agricultural Machinery Management Data*. ASAE D497.5, St. Joseph, MI.

ASME – American Society of Mechanical Engineers. 1980. "Wells Street Power Station." *ASME Milwaukee: History & Heritage*. Accessed March 20, 2012, at http://sections.asme.org/milwaukee/history/4-pulverizedcoal.html. [membership access required]

DOE – U.S. Department of Energy. 2011a. *U.S. Billion-Ton Update*: *Biomass Supply for a Bioenergy and Bioproducts Industry*. ORNL/TM-2011/224, RD Perlack and BJ Stokes (Leads), Oak Ridge National Laboratory, Oak Ridge, Tennessee.

Turhollow AF, S Sokhansanj (2007) Costs of harvesting, storing in a large pile, and transporting corn stover in a wet form. Appl Eng Agric 23(4):439–448.

Appendix B

Woody Feedstock Logistics Scenarios

B.1 Conventional Woody Feedstock Logistics–10% Pine/90% Coal

A conventional woody biomass feedstock supply chain was assumed for the scenario of cofiring 10% woody biomass with 90% coal (Searcy and Hess 2010). Conventional biomass feedstock supply-system designs are constructed using technologies that (a) are adaptable to existing local feedstock resources and biomass infrastructures;(b) represent feedstock supply-system technologies, costs, and logistics; and(c) are achievable today for supplying biomass feedstocks to power plants. A conventional woody biomass design that supplies Southern Pine pulpwood to the power plant on spec., namely a 5-cmdebarked woodchip at 10% moisture content with an ash content of <1% was modeled (i.e., the same as the "Low-Ash/Low-Moisture Conventional" scenario presented in Searcy and Hess [2010]). Although this feedstock is available to meet smaller quantity demands, an expanding bioenergy industry will require a broader biomass feedstock source; therefore, advanced designs include more resources and a modified design to accommodate these resources (Searcy and Hess 2010). Figure B.1 shows the process flow for the conventional woody biomass feedstock supply system. The yellow rectangles represent individual modeled processes, green ovals represent changes in format intermediates, and white rectangles represent alternate processes that were not modeled. Operations occurring at the landing and power plant are shown in grey squares.

In the conventional woody design, trees are harvested and then transpirationally dried prior to collection. The dried trees are delimbed and debarked, then ejected into a chip van for transport to the power plant. When received at the power plant, the chips are cleaned, dried, and fed into the modeled conversion process of combustion.

Several key feedstock format and machinery attributes have been identified that influence the processes within the supply system. From a cost, performance, and logistics perspective, each attribute becomes an input and/or constraint on the supply system that must be considered to design a viable supply-system capable of meeting the needs of a power plant. Within each unit operation section of this report, the modeled attributes of all biomass material intermediates (hereafter referred to as format intermediates) are identified, and variances in those attributes are discussed to provide a better understanding of how supply-system performance is, or may be, affected by feedstock format intermediate attributes. Details of the specific machinery modeled for the processes of each unit operation included in the model can be found in Searcy and Hess (2010).

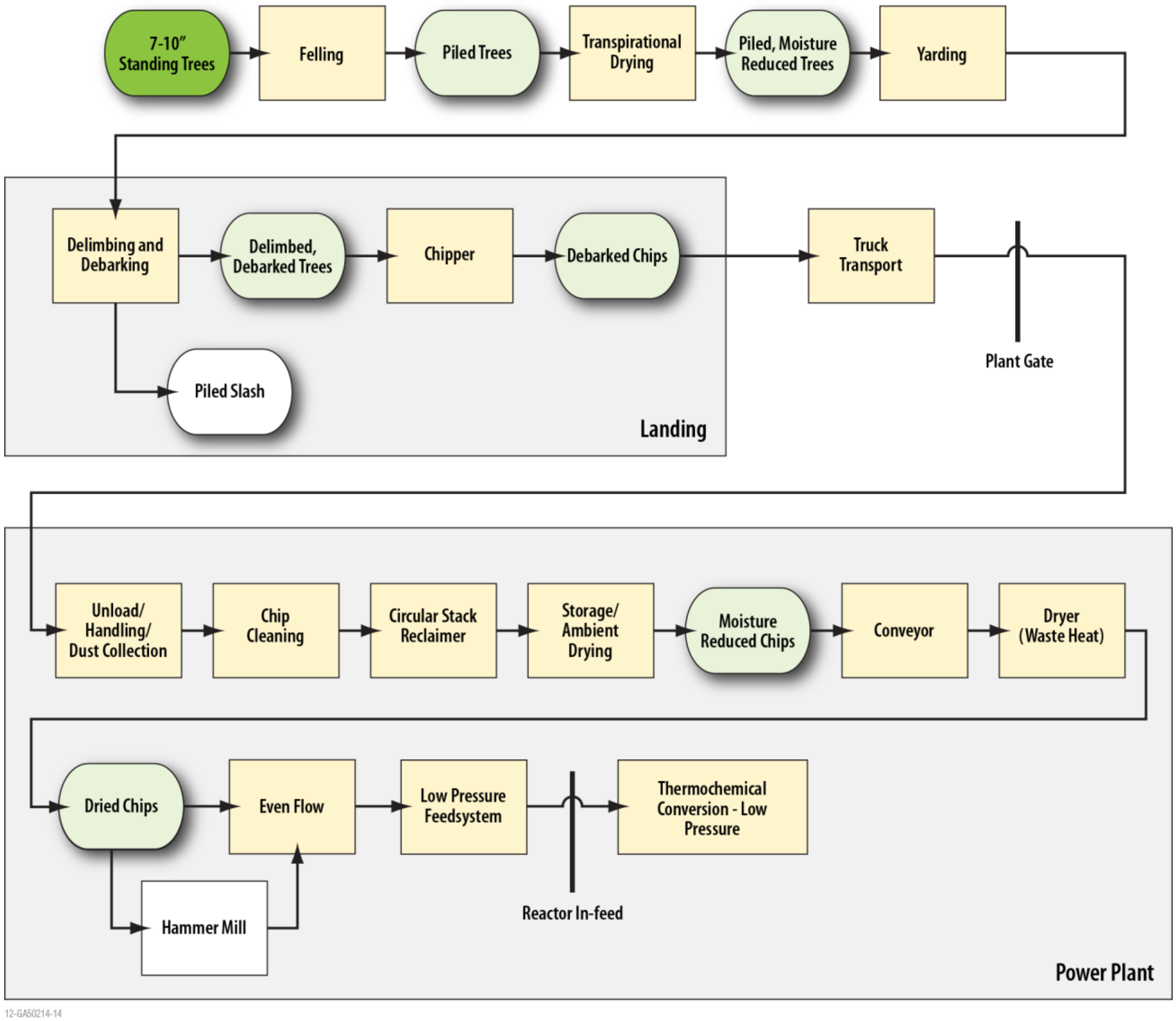


Figure B.1. Order of unit operations in the conventional woody biomass feedstock supply system

The feedstock system modeled here is designed to supply a power plant with 180,000 dry matter (DM) tons of biomass annually on a year-round biomass delivery schedule. This supply corresponds to the amount needed to cofire a 400-MW power plant at 10 % (based on energy content).

In many cases, it is clear that the performance of one supply-system process is significantly impacted by the performance of another. As such, both the individual unit operations report sections and the overall integrated supply-system design are concluded with an integrated summary analysis of cost, performance, and logistics based on stated format, intermediate attributes, and equipment operational assumptions.

Major design assumptions and costs are summarized in the following sections. A more detailed description is given in Searcy and Hess (2010).

B.1.1 Feedstock Harvest and Collection

Harvest and collection encompasses all processes associated with moving the biomass from the location of production, in this case the tree stand, to the queuing location, as shown in Figure B.2.The green ovals represent format intermediates and yellow rectangles represent individual modeled processes. Although the modeled feedstock is Southern Pine pulpwood, the same harvesting and collection equipment may be used for harvesting various whole trees. Processes, equipment, and associated costs may vary significantly from one feedstock to another.

Figure B.2. Conventional woody harvest and collection supply logistics processes and format intermediates.

A breakdown of the costs associated with each piece of equipment used in the harvest and collection operation identifies significant cost components that are valuable for making individual comparisons and recognizing areas of research potential, as shown in Table B.1. These costs are reported in terms of DM tons entering each process, and expressed in 2012 $/DM ton unless otherwise noted. Total operation cost is the sum of ownership and operating cost (Searcy and Hess 2010).The total harvest and collection cost for pulpwood sized trees is $18.28/ton. A large portion of the costs are operating costs, which include labor and fuel costs. Because each tree has to be harvested individually, harvesting is a labor-intensive operation.

Table B.1. Static model costs for major harvest and collection equipment in the conventional woody scenario.

	Felling		Skidding	
Equipment	Tracked Carrier with a Rotary-Head Feller Buncher	Transpirational Drying	Medium Grapple Skidder (wheeled)	Total Cost per DM Ton for Harvest and Collection
Installed equipment quantities (No. of machines)	12	N/A	11	23
Installed capital ($/DM ton/yr)	17.60	N/A	10.66	28.26
Ownership costs	*5.73*	*N/A*	*1.59*	*7.33*
Operating costs	*3.44*	*N/A*	*7.51*	*10.95*
Labor	1.13	N/A	1.50	2.63
Non-labor[a]	1.79	N/A	2.39	4.18
R&M	0.52	N/A	3.62	4.14
Energy use (MBtu/DM ton)	89.7	N/A	83.8	173.5

(a) Sum of fuel and material cost.

B.1.2 In-Field Preprocessing

The transport and handling costs of moving whole trees are greatly reduced by comminution at the landing prior to transport because the packing density is greatly increased. The branches and/or bark can be removed prior to comminution using a stroke-boom delimber or iron gate for larger trees, a flail chain, or other techniques. A flail shredder is modeled in the conventional design.

This in-field process brings the biomass to the landing and piles it by a skidder. The skidder feeds the material through a flail shredder, which removes the branches, tops, and much of the bark (the bark is high in ash content and may be contaminated with dirt). The delimbed trees are loaded into a chipper (the chips have a lower moisture content because of the transpirational drying; however, approximately 35%, wet basis, of the transported mass is water). The chipped material is then loaded into a chip van for transport to the power plant. This process is shown in Figure B.3. The green ovals represent format intermediates and yellow rectangles represent processes modeled in this report.

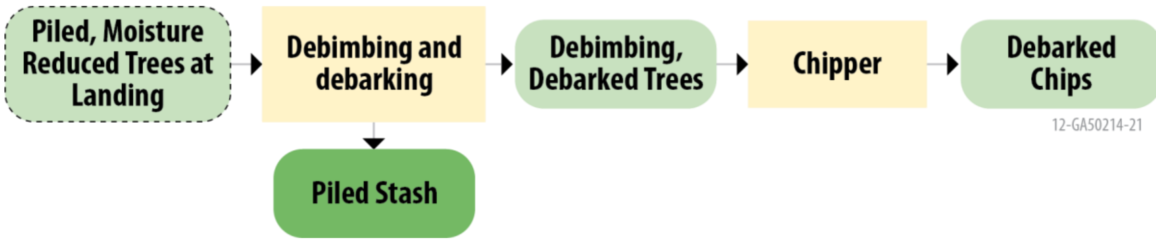


Figure B.3. Preprocessing supply logistic processes and format intermediates for the conventional woody design.

A breakdown of the costs associated with each piece of equipment used in the preprocessing unit operation identifies significant cost components that are valuable for making individual comparisons and identifying areas of research potential as shown in Table B.2. These costs are reported in terms of DM tons entering each process and expressed in 2012 $/DM ton unless otherwise noted. Total operation cost is the sum of ownership, operating, and DM loss cost (Searcy and Hess 2010).The total preprocessing cost for pulpwood sized trees is $12.66/DM ton. The preprocessing operation consumes very high amounts of diesel fuel to run the flail and the chipper (reflected in the energy consumption of the flail and chipper).

Table B.2. Static model costs for major preprocessing equipment in the conventional woody scenario.

	Delimbing and Debarking	Chipper	Total Cost per DM Ton for Preprocessing
Installed equipment quantity (No. of machines)	7	7	14
Installed capital ($/DM ton/yr)	2.55	3.76	6.31
Ownership costs	*0.45*	*1.61*	*2.06*
Operating costs	*6.00*	*4.60*	*10.60*
Labor	1.15	1.15	2.30
Non-labor	4.86	3.46	8.32
Energy use (MBtu/DM ton)	116.39	105.81	222.51

B.1.3 Transportation

Transport and delivery are key elements of forest activities, and the way they are organized has implications for the production system as a whole (Hubbard et al. 2007). After comminution, debarked chips are ejected into the back of a chip van and transported via truck to the power plant as shown in Figure B.4.The green ovals represent biomass format intermediates and yellow rectangles represent processes modeled in this report. Increased bulk density resulting from the chipping process greatly enhances the economics of transportation and handling.

Figure B.4. Transportation supply logistic processes and biomass format intermediates for the conventional woody design.

Trucks transport most forestry products and harvesting material. About 90 % of the pulpwood delivered to U.S. mills in 2005 arrived by truck (Hubbard et al. 2007). A breakdown of the costs associated with each piece of equipment used in the transportation operation identifies significant cost components that are valuable for making individual comparisons and identifying areas potential research, as shown in Table B.3. These costs are reported in terms of DM tons entering each process and expressed in 2012 $/DM ton. Transportation costs reported in Table B.3 are reported for a distance of 50 mi; however, costs were also calculated for distances of 25, 100, 250, and 500 mi. Total operation cost is the sum of ownership, operating, and DM loss cost (Searcy and Hess 2010).The total transportation cost for pulpwood sized trees is $11.52/DM ton.

Table B.3. Static model costs for major transportation equipment in the conventional woody scenario.

	Chip Van	Total Cost per DM Ton for Transportation
Quantity of equipment (No. of machines)	13 trucks	13 trucks
Installed capital ($/DM ton/yr)	11.65	11.65
Ownership costs	*1.81*	*1.81*
Operating costs	*9.71*	*9.71*
Labor	5.12	5.12
Non-labor	4.28	4.28
R&M	0.31	0.31
Energy use (MBtu/DM ton)	140.4	140.4

B.1.4 In-Plant Handling and Processing

Once at the power plant, chips are unloaded into a hopper using a truck tipper, cleaned to remove metal pieces and dirt, and conveyed using a circular stack reclaimer. A dryer is used to reduce moisture from 30 to 12% weight basis. During in-plant handling and processing, the format of the material remains a chip, as shown in Figure B.5. The green ovals represent biomass format intermediates and the yellow rectangles represent processes modeled in this report.

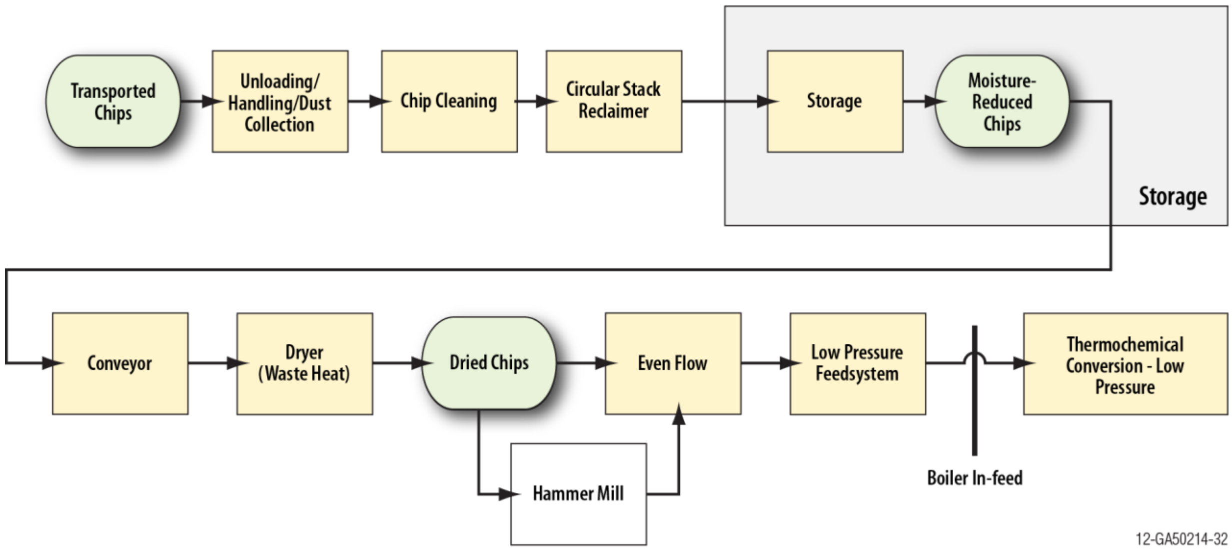


Figure B.5. In-plant handling and processing supply logistic processes and biomass format intermediates for the conventional woody design.

A breakdown of the costs associated with each piece of equipment used in the in-plant handling and preprocessing operation identifies significant cost components that are valuable for making individual comparisons and identifying areas for potential research. These costs are reported in Table B.4 in terms of DM tons entering each process. Costs are expressed in 2012 $/DM ton. Total operation cost is the sum of ownership, operating, and DM loss cost. The total in-plant handling and preprocessing cost for pulpwood sized trees is $15.09/DM ton.

Table B.4. Static model costs for major in-plant handling and preprocessing equipment in the conventional woody scenario.

Equipment	Unloading/Handling/ Dust Collection/ Cleaning Scale, Truck Tipper and Hopper, Dust Collection, Moisture Meter, Electro Magnet, Circular Stack Reclaimer	Dryer	Total Cost per DM Ton for In-Plant Handling and Processing
Quantity of equipment (No. of machines)	18	1	19
Installed capital ($/DM ton/yr)	17.14	33.97	51.12
Ownership costs	*2.34*	*3.25*	*5.58*
Operating costs	*1.75*	*7.75*	*9.50*
Labor	0.63	1.00	1.63
Non-labor	0.70	6.74	7.44
R&M	0.43	0.00	0.43
Energy use (MBtu/DM ton)	42.2	893.2	935.4

B.1.5 Storage

Storage encompasses all processes associated with piling, pile turning, and ambient drying of the woody biomass. It also includes costs associated with storage site preparation (e.g., construction of an asphalt pad, silo, or other storage structure). The conventional design includes storage on an asphalt pad. The storage operation for the conventional woody scenario is summarized in Figure B.6.The green ovals represent format intermediates and yellow rectangles represent individual modeled processes.

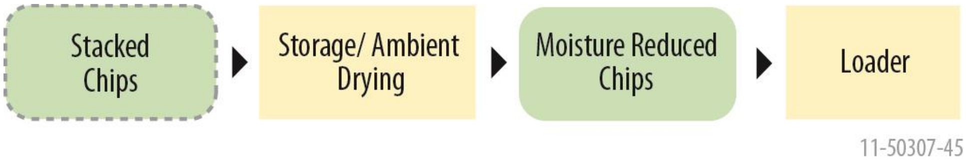


Figure B.6. Conventional woody storage supply logistics processes and format intermediates.

In the conventional woody scenario, material is queued at the refinery with a 7-day supply. If necessary, longer storage (up to 1 month) could be incorporated into the system. The DM losses during storage are estimated to be 2%, which are from a combination of mechanical losses (from moving the material around using loader) and biological losses as shown in Table B.5. Cleaned chips are piled and ambient-dried to reduce moisture content from 35 to 30%. Because the conventional woody design scenario assumes an open-air storage environment, no additional storage structures are constructed. A variety of alternate storage options are discussed in Searcy and Hess (2010).

Costs associated with the storage operation in the conventional woody design include an asphalt pad and a loader to move material around the yard, as shown in Table B.5. Costs are expressed in 2012 $US/DM ton. Total operation cost is the sum of ownership, operating, and DM loss cost (Searcy and Hess 2010).The loader is the only component of storage that incurs an operating cost; it is also the source of some DM loss (unrecovered material).

The total storage cost for cleaned pulpwood chips is $2.05/DM ton. Long-term storage is uncommon in operations that handle comminuted woody biomass.

Table B.5. Static model costs for storage equipment in the conventional woody scenario.

Equipment	Storage	Front-End Loader	Asphalt Pad	Total Cost per DM Ton for Storage
Quantity of equipment (No. of machines)	N/A	1	1	2
Installed capital ($/DM ton/yr)	N/A	0.77	2.39	3.15
Ownership costs	*N/A*	*0.15*	*0.38*	*0.53*
Operating costs	*N/A*	*0.49*	*0.00*	*0.49*
Labor	N/A	0.19	0.00	0.19
Non-labor	N/A	0.25	0.00	0.25
R&M	N/A	0.04	0.00	0.04
DM loss costs	*1.03*	*0.00*	*0.00*	*1.03*
Energy use (MBtu/DM ton)	N/A	8.9	N/A	8.9

B.1.6 Total Conventional Woody Logistics Cost

Costs associated with the conventional woody design are shown in Table B.6, where costs are expressed in 2012 $US/DM ton. The total logistics cost for a shipping distance of 50 mi, minus grower payment, for cleaned pulpwood chips is $66.50/DM ton, which is the sum of ownership, operating, and DM loss costs.

The total logistics cost expressed in 2012 $US/DM ton, not including stumpage fee, for shipping distances of 25, 50, 100, 250, and 500 mi are $61.92, $66.50, $77.57, $103.00, and $148.79, respectively.

Table B.6. Static model costs for the conventional woody scenario.

Equipment	Harvesting and Collection	In-Field Preprocess ing	Transpor-tation	In-Plant Handling and Processing	Storage	Total Logistics Cost
Installed capital ($/DM ton/yr)	28.26	11.13	11.65	51.12	3.15	105.31
Ownership costs	*7.33*	*2.98*	*1.81*	*5.58*	*0.53*	*18.22*
Operating costs	*10.95*	*16.61*	*9.71*	*9.50*	*0.49*	*47.25*
Labor	2.63	3.04	5.12	1.63	0.19	12.61
Non-labor	4.18	8.26	4.28	7.44	0.25	24.41
R&M	4.14	5.29	0.31	0.43	0.04	10.21
DM loss costs	*0.00*	*0.00*	*0.00*	0.00	*1.03*	*1.03*
Energy use (MBtu/DM ton)	173.5	285.5	140.4	935.4	8.9	1543.7

B.1.7 Sensitivity Analysis

Sensitivity analysis affecting total costs ($/DM ton) was conducted to gain insight into the uncertainty associated with specific assumptions within the cost calculations. Monte Carlo sampling methods and triangular probability distributions were used to generate values for the variables chosen for this sensitivity analysis. Table B.7 lists the variables used in the sensitivity analysis and their triangular distribution parameters.

While total costs were reported earlier in this report, the actual cost value can vary greatly. The histogram in Figure B.7 illustrates the results of the sensitivity analysis by displaying the variability within actual total cost caused by variations in the chosen variables within their respective probability distributions. Ranges were developed through 1,000 Monte Carlo samplings so the probability of the actual cost being outside the specified ranges is possible but of low probability. A total cost of 66.50$/DM ton was reported earlier for the conventional woody scenario for a shipping distance of 50 mi, but, the cost can range from $61.98 to $77.09/DM ton with an average cost of $68.96/DM ton.

Table B.7. Variables used in the sensitivity analysis and their triangular distribution parameters.

Variable	Minimum	Maximum	Peak
Electricity price ($/kWh)	0.04	0.12	0.06
Natural gas price ($/MMBtu)	6.35	14.93	10.00
Off- road diesel price ($/gal)	2.94	3.31	3.46
Semi load time (min)	25.50	34.50	30.00
Semi speed (mph)	42.50	57.50	50.00
Haul distance (mi)	0.10	0.45	0.30
Transport DM loss (%)	0.00	1.00	0.01
Storage DM loss (%)	0.00	4.00	2.00
Handling DM loss (%)	0.00	0.50	0.01
Loader capacity (%)	0.75	1.50	1.00
Chipper efficiency (%)	50.00	80.00	75.00
Chipper capacity (tons/hr)	42.50	55.00	50.00
Dryer efficiency (%)	76.50	93.50	85.00
Dyer capacity (tons/hr)	99.00	121.00	110.00
Tipper capacity (%)	0.85	1.15	1.00
Roadsider efficiency (%)	50.00	71.50	60.00
Harvesting efficiency (%)	50.00	80.00	60.00
Labor harvesting/collection (%)	0.75	1.50	1.00
Labor preprocessing (%)	0.75	1.50	1.00
Labor transit (%)	0.75	1.50	1.00
Labor storage (%)	0.75	1.50	1.00
Labor handling (%)	0.75	1.50	1.00

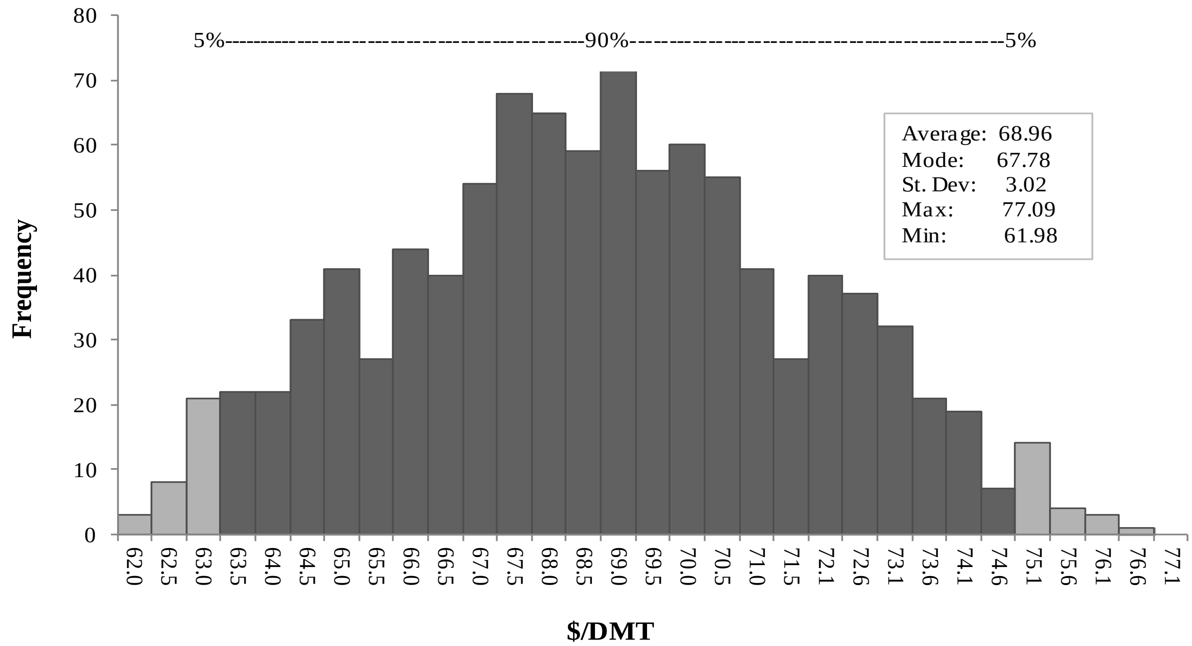


Figure B.7. Conventional Woody Feedstock Supply Scenario Sensitivity Histogram

B.2 Advanced Woody Feedstock Logistics – 20% Pine/80% Coal with Torrefaction

As previously discussed, the majority of cofiring applications to date have been limited to approximately 10% biomass/90% coal to avoid derating of the boiler because of the lower heat and higher moisture content of the biomass compared to coal. In addition, woody biomass has high costs associated with chipping or size reduction and woody limbs and trimmings have low density, which increases transportation and storage costs. These challenges must be overcome or mitigated to increase the biomass-to-coal cofiring ratio to 20%. This section introduces technologies (e.g., torrefaction) that modify woody material into a format that more closely resembles coal to make it possible to increase the cofiring ratio. Torrefaction increases the energy density of the material, improves its stability and storability, and decreases the energy required for size reduction and/or grinding.

Further, this section discusses logistical challenges associated with increasing the cofiring ratio. Nearly all facilities that accept biomass do so by the truckload from resources less than 100 mi away—this means receiving and processing hundreds of truckloads of material each day. Increasing the cofiring ratio not only complicates logistics at the plant, but greatly changes the supply of material to the plant, making it necessary in many cases to gather resources from distances of 200 mi or more. Because long-distance shipping of unprocessed woody biomass by truck is not economical, the material must be densified to decrease shipping costs. This section discusses densification strategies and introduces the advanced woody design concept.

Material in the advanced woody design is handled identically to the conventional woody scenario, but a torrefaction step is added after drying. The torrefied material is then pulverized and fed into the power plant process. The advanced woody scenario increases the portion of biomass cofiring to 20%. The feedstock system modeled here is designed to supply a power plant with 330,000 DM tons of biomass annually on a year-round biomass delivery schedule. This supply corresponds to the amount needed to cofire a 400-MW power plant at 20%. Incorporating torrefaction inside the plant gate has advantages for conversion in-feed, and avoids a costly volumetric densification step required to transport torrefied biomass.

For the first advanced woody scenario, a torrefaction operation is added inside the plant gate as shown in Figure B.8. Yellow rectangles represent individual modeled processes, green ovals represent changes in format intermediates, and white rectangles represent alternate processes that were not modeled. All operations prior to the material arriving at the plant are the same as in the conventional woody design.

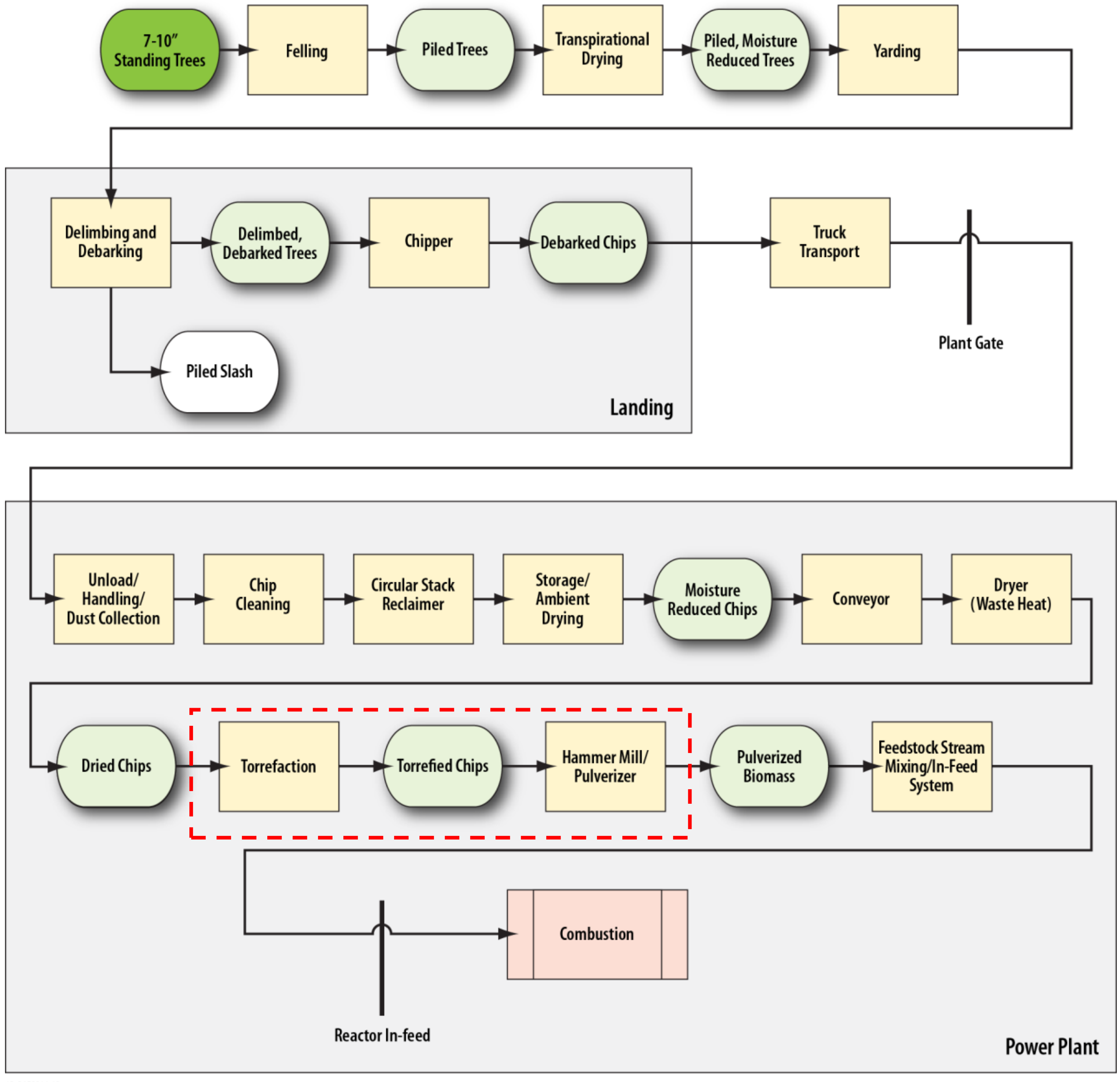


Figure B.8. Order of unit operations in the advanced woody biomass feedstock supply system, where the torrefaction operation is located inside the plant gate.

B.2.1 Impact of Torrefaction on Material Properties

Torrefaction significantly changes the physical properties of biomass (e.g., reducing moisture content of the pre-dried biomass from 10 to <6%) (Lipinsky et al. 2002).Typically, the moisture content of the torrefied biomass ranges between 1 and 6% on a weight basis, depending on the conditions of torrefaction

(Bergman and Kiel 2005).[1]INL was able to produce a torrefied pine with a moisture content of only 0.79%. DM loss during INL testing was 12%.

Biomass is highly fibrous and tenacious in nature because fibers form links between particles, making it difficult to handle the raw, ground samples. Torrefaction causes a breakdown of the hemicellulose matrix and depolymerization of the cellulose, which decreases the fiber length (Bergman et al. 2005; Bergman and Kiel 2005), causing it to lose its mechanical strength and making it easier to grind and pulverize (Arias et al. 2008). The reduction in power consumption for grinding biomass ranges from 70 to 90%, based on the conditions under which the material is torrefied (Bergman and Kiel 2005). Mill capacity also increases by a factor 7.5 to 15. The size reduction characteristics of torrefied biomass are very similar to coal. In addition, torrefaction produces a relatively more hydrophobic product by reduction of hydroxide (OH) groups through desorption of water and lowering the biomass capacity to form hydrogen bonds (Pastorova et al. 1993).

Variability in feedstock quality (i.e., due to types of raw materials, tree species, climatic and seasonal variations, storage conditions, and time) significantly influences the quality of pellets produced (Lehtikangas 1999). However, torrefying the biomass before pelletization produces uniform feedstock with consistent quality. Studies indicate that the pressure required for densification following torrefaction can be reduced by a factor of two when material is densified at a temperature of 225°C and the energy consumption during densification is reduced by a factor of two compared to raw biomass pelletization using a pellet mill (Lipinsky et al. 2002; Reed and Bryant 1978; Koukios 1993; Bergman et al. 2005). The pellets produced also have a higher mechanical strength, typically 1.5 to 2 times greater, than conventional pellets. Biomass loses relatively more oxygen and hydrogen than carbon during torrefaction, which in turn increases the calorific value of the product (Uslu et al. 2008).

In the scenario considered for this study, torrefaction occurs inside the plant gate. Torrefied wood chips are fed directly to the hammer mill/pulverizer. If a scenario were considered that included offsite torrefaction, a product volumetric densification step would be required because torrefaction decreases the bulk volumetric density of the wood, leading to stability concerns.

B.2.2 Pulverization

Pulverization is used in coal-fired power plants to size the coal for introduction into the burners. Because torrefaction produces a material with properties similar to coal, traditional pulverization equipment can also be used to prepare torrefied wood chips for introduction into the burners. Prior to torrefaction, wood is chipped to a size of about 2-cm thick. Coal is typically crushed to 1.9 cm prior to pulverization, so the size of the torrefied wood product matches well with typical crushed coal.

There are three types of pulverizers used in the coal industry: low-speed mills (e.g., ball and tube mills); medium speed mills (e.g., the bowl mill, the ring and ball mill, and the vertical roller mill); and high speed impact mills (e.g., the roll wheel coal pulverizer shown in Figure B.9). Low- and medium-speed mills are typically selected for subbituminous to anthracite coals, while high-speed mills are used primarily for brown coal.

---

[1]Moisture in the biomass can be held in varying degrees of bonding; easily-removed water is referred to as free water and more tightly-retained water referred to as bound water.

Figure B.9. Roll Wheel Coal Pulverizer at a Modern Utility Power Station (B&W 2005)

The importance of pulverization in power production underscores the need to optimize pulverizer performance for torrefied wood. Similarly, the broad industry expertise with coal pulverization highlights the benefit of torrefying woody biomass feedstocks—the properties are much more similar to coal than for wood that has not been torrefied.

Power plants typically specify a pulverizer feed size of 70% passing through a 200-mesh screen (74 microns) and 99% passing through a 50-mesh screen (297 microns). Maintaining these specifications is important to controlling fuel/air velocities to the burners and ensuring complete combustion of the fuel before entering the superheater section of the boiler.

Many modern pulverizers are designed to accommodate moisture levels of up to 40% in the feedstock, so they can also provide some drying functionality. However, to handle high inlet moisture feeds, the primary air temperature must be increased. Feeds with greater than 40% moisture could potentially be pulverized, but the associated high primary air temperatures require special structural materials, increasing the chance of pulverizer fires (B&W 2005). The 40% moisture limit typically applies to coal, while biomass moisture limits may be lower because of the difference in reactivity of biomass as compared to that of coal.

B.2.3 Total Advanced Woody System Cost

Costs associated with the advanced woody design are shown in Table B.8, where costs are expressed in 2012 $US/DM ton. The total logistics cost for a shipping distance of 50 mi, minus grower payment, for cleaned pulpwood torrefied chips is $92.83/DM ton, which is the sum of ownership, operating, and dry matter DM loss costs (Searcy and Hess 2010).The total logistics costs expressed in 2012 $US/DM ton, minus grower payment, for shipping distances of 25, 50, 100, 250, and 500 mi are $87.58, $92.83, $103.20, $134.31, and $186.25, respectively.

Table B.8. Static model costs for the advanced woody scenario.

Equipment	Harvesting and Collection	In-Field Preprocessing	Transportation	In-Plant Handling and Processing	Storage	Total Logistics Cost
Installed capital ($/DM ton/yr)	30.78	12.14	11.24	142.55	3.12	199.82
Ownership costs	*7.24*	*2.96*	*1.76*	*14.23*	*0.50*	*26.70*
Operating costs	*10.95*	*16.61*	*9.71*	*16.67*	*0.49*	*54.42*
Labor	2.63	3.04	5.12	2.07	0.19	13.05
Non-labor	4.18	8.26	4.28	14.29	0.26	31.27
R&M	4.14	5.29	0.31	0.29	0.04	10.07
DM loss costs	*0.00*	*0.00*	*0.00*	10.69	*1.02*	*11.72*
Energy use (MBtu/ DM ton)	196.9	324.0	140.4	2029.3	10.1	2700.6

B.2.4 Sensitivity Analysis

A total cost of $92.83/DM ton was reported for the advanced scenario for a total shipping distance of 50 mi; however, based on a sensitivity analysis the actual value can range from $78.19 to $93.89/DM ton with an average of $85.85/DM ton, as shown in Figure B.10.

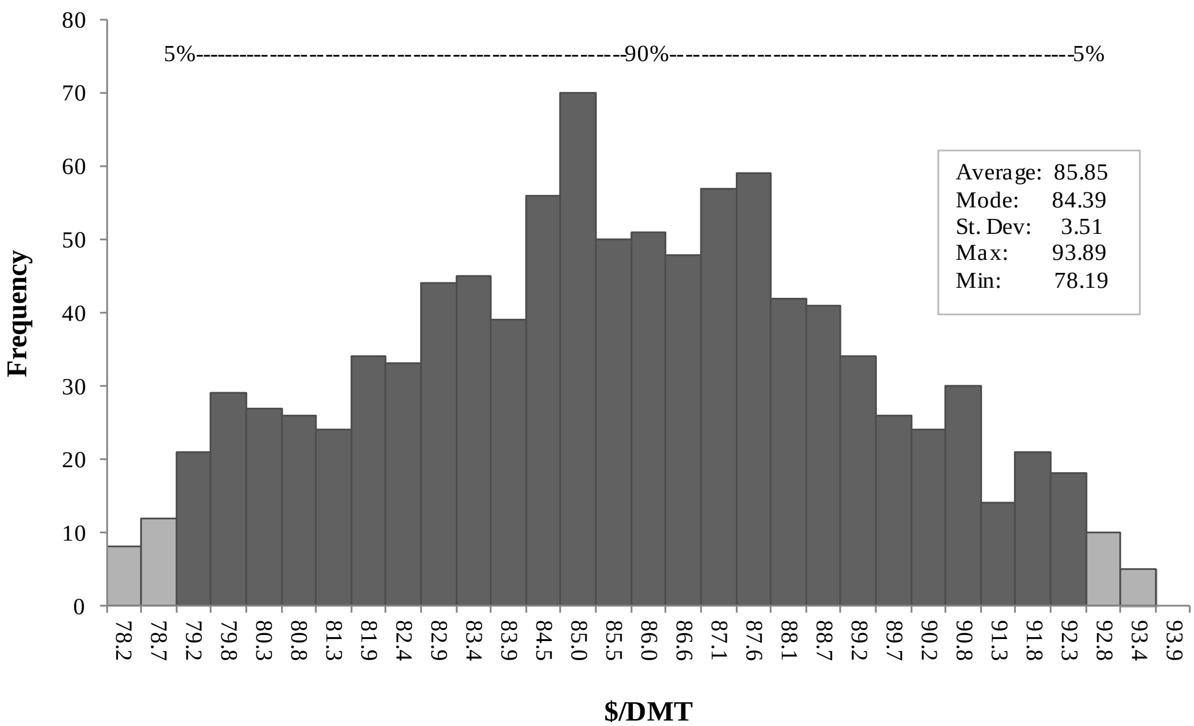


Figure B.10. Advanced woody feedstock supply scenario sensitivity histogram.

B.3 Advanced Woody Depot Feedstock Logistics – 20% Pine/ 80% Coal with Densification and Torrefaction

For the second advanced woody scenario, the advanced woody depot design, torrefaction is moved away from the plant gate, and occurs in a biomass processing depot. Woody biomass resources are sent to a local biomass processing depot where the biomass is torrefied and densified prior to transport as shown in Figure B.11. The feedstock system modeled here is designed to supply a power plant with 330,000 DM tons of biomass annually on a year-round biomass delivery schedule. This supply corresponds to the amount needed to cofire a 400-MW power plant at 20%. The yellow rectangles in Figure B.11 represent individual modeled processes, green ovals represent changes in format intermediates, and white rectangles represent alternate processes that were not modeled. Harvest and collection, in-field processing, and transportation to the depot are the same as in the conventional woody design.

B.3.1 Biomass Processing Depot

A key feature of advanced designs is the integration of a biomass processing depot. The depot provides the opportunity to format biomass into a consistent, stable, infrastructure-compatible, flowable material early in the supply chain, increasing supply-chain efficiency downstream. The depot enables feedstock blending, which can enhance conversion performance. In the advanced woody depot design, the depot contains infrastructure to torrefy and densify woody biomass such that it can be safely and economically transported to the power plant. The advanced system concept is further developed in Hess et al. (2009) and Searcy and Hess (2010). The maximum depot capacity used in this analysis is 14.29 ton/hr, which would require three depots to support a 20% cofiring scenario for a 400-MW plant.

B.3.2 Densification

Densification is required in the advanced woody depot design to increase the density of the biomass for transport, but also to stabilize the torrefied biomass and decrease the risk of spontaneous combustion. Conventional processes for biomass densification can be classified into baling, pelletization, extrusion, and briquetting, which are carried out using a bailer, pelletizer, screw press, piston, or a roller press respectively. Pelletization and briquetting are the most common processes used for biomass densification of solid fuel applications. The advanced woody depot design incorporates pelletization as a densification technology. These high-pressure compaction technologies, also called binderless technologies, are usually carried out using either a screw press or a piston press (Sokhansanj et al. 2005). In a screw press, the biomass is extruded continuously through a heated, tapered die. The briquette quality and production process of a screw press are superior to piston press technology. However, comparing wear of parts in a piston press (e.g., ram and die) to wear observed in a screw press shows that the screw press parts require more maintenance. The central hole incorporated into the densified logs produced by a screw press helps achieve uniform and efficient combustion, and the resulting logs can be carbonized more quickly because of better heat transfer.

Many researchers have worked on the densification of herbaceous and woody biomass using pellet mills and screw/piston presses (Tabil and Sokhansanj 1996a, 1996b; Ndiema et al. 2002; Adapa et al. 2002, 2003; Li and Liu 2000; Mani et al. 2006; Tumuluru et al. 2010a). Low raw densities for herbaceous and woody biomass limit their application in energy production, and require densification prior to cost-effective use in energy applications. Densification helps reduce technical limitations associated with storage, loading, and transportation.

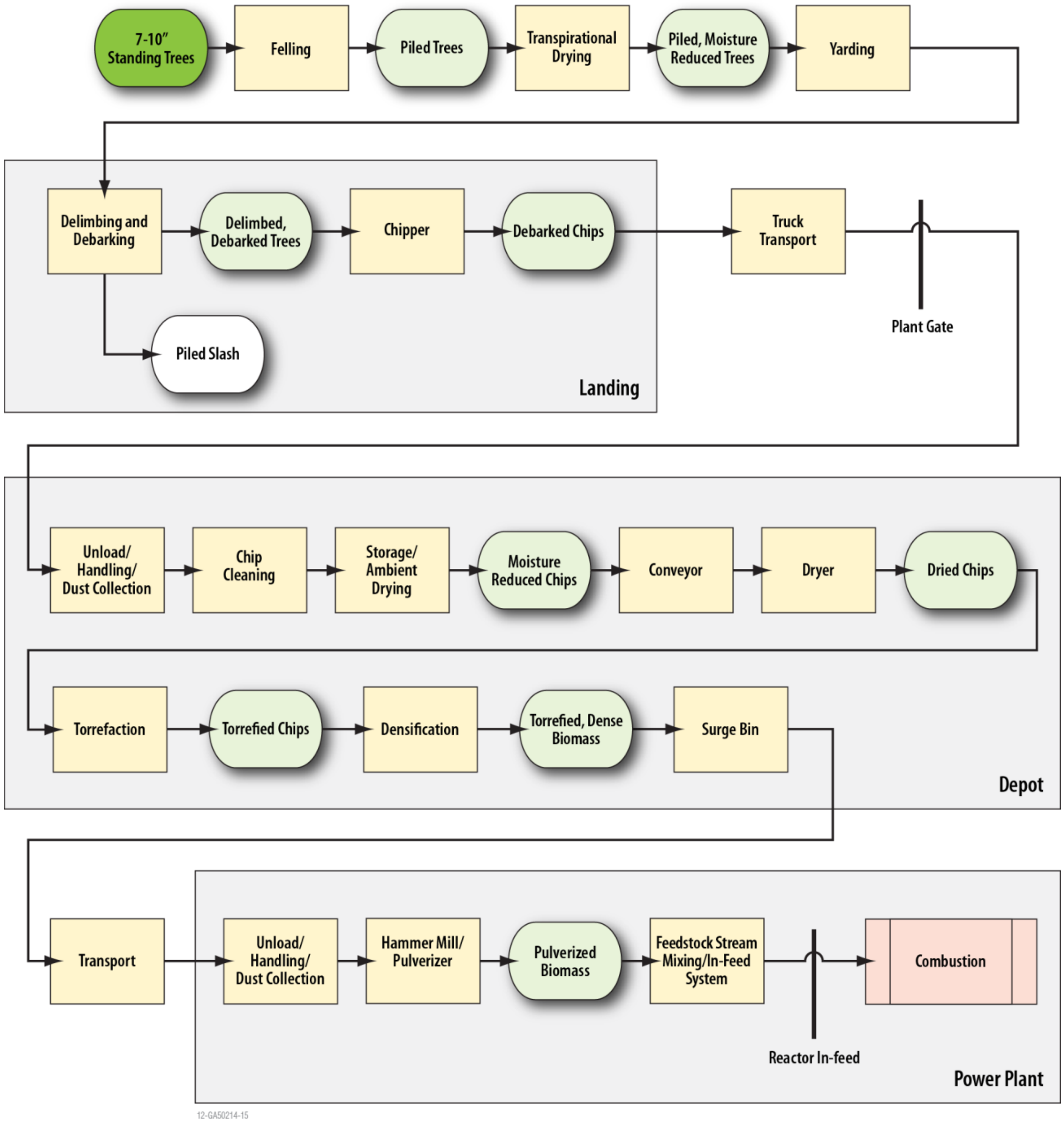


Figure B.11. Order of unit operations in the advanced woody depot feedstock supply system.

A study was conducted to review select biomass processing options, including densification technologies and specific energy consumption, biomass pretreatment methods, densification process modeling, and optimization (Tumuluru et al. 2010a).Two widely used technologies for producing a densified biomass, the pellet mill and the briquette press, were compared. A briquette press is more flexible in terms of feedstock variables, where higher moisture content and larger particles are acceptable for making good quality briquettes. Among the different densification systems, the screw press (involving both compression and pushing) consumes the most energy because it not only compresses but also shears and mixes the material; a pellet mill or cubing machine consumes the least, depending on the material processed. Pretreatment technologies (i.e., preheating, grinding, steam explosion, and torrefaction) can help to reduce specific energy consumption during densification and improve binding characteristics.

The degree of binding during densification is important to accomplishing loading, unloading, and other material transfer activities without the material breaking into smaller pieces. The degree of binding is dependent on the specific biomass material and the amount of lignin that exists in the material. The binding behavior can be improved by preheating biomass to temperatures of 100 to 130°Cto soften the lignin content and by adjusting the moisture to around 10 to 12%. Adjustment of the percentage of fine- to medium-size particles in the biomass mix also helps improve the degree of binding. Natural or commercial binders, such as protein or lignosulphonates can also be added. The quality of densified biomass for both domestic and international markets is evaluated using CEN (European Standard) or PFI (United States Standard).

Both process and material parameters affect the densification process. Process variables include temperature, pressure, retention (or hold) time, relaxation time, and die geometry and speed. Material variables include moisture content, particle size and shape, particle size distribution, and biomass chemical composition (e.g., starch, protein, fat, and lignocelluloses content) (Tumuluru et al. 2010a).

Table B.9 shows depot equipment specifications for the advanced woody depot design. Table shows the cost summary for the depot in the advanced woody depot scenario. Costs are expressed in 2012 $US/DM ton. Total operation cost is the sum of ownership, operating, and DM loss.

Table B.9. Equipment performance parameters for the advanced woody depot scenario

	Receiving/ Handling	Storage	Dryer	Torrefaction	Densification	Surge Bin
Equipment rated capacity (ton/hr)	100	120	110	20	20	100
Operational efficiency (percent)	100	100	100	100	100	100
DM loss (percent)	0	2	0	11.88	0	0
Operational window:						
Hr/day	24	24	14	14	14	14
Day/yr	350	350	300	300	300	300

Table B.10. Static model costs for depot equipment in the advanced woody depot scenario.

	Receiving/Handling	Storage	Dryer	Torrefaction	Densification	Surge Bin
Quantity of equipment (No. of machines)	varies	1	3	3	3	3
Installed capital ($/DM ton/yr)	10.45	3.12	39.78	65.72	2.75	0.75
Ownership costs	1.57	0.50	3.51	6.28	1.28	0.06
Operating costs	0.78	0.49	11.54	3.42	4.07	0.01
Labor	0.00	0.19	1.64	1.64	1.25	0.00
Non-labor	0.47	0.25	9.90	1.78	1.04	0.01
R&M	0.30	0.04	0.00	0.00	1.79	0.00
DM loss costs	0.00	0.90	0.00	9.38	0.00	0.00
Energy use (MBtu/DM ton)	27.9	10.1	1488.6	235.1	54.0	0.3

B.3.3 High-Capacity Transportation (Rail)

Much of the biomass resource required to meet long-term biopower demand is inaccessible using current biomass supply systems because of unfavorable economics, which are partly due to high transportation costs. However, the economics of transporting densified biomass using high-capacity transport systems, such as rail, are not well understood.

Advanced biomass feedstock supply systems use biomass processing depots to shift the preprocessing operations away from the power plant to earlier in the supply chain, which decreases the high costs associated with transportation, handing, and storage. Because of the increase in bulk density, material stability, and flowability of biomass, more cost-efficient transportation modes (e.g., rail and barge)will be used. Figure B.12 illustrates the cost associated with transportation of biomass over specific distances. The depot cases in this study use rail transportation between the depots and the power plant as a means to reduce the delivered cost of biomass.

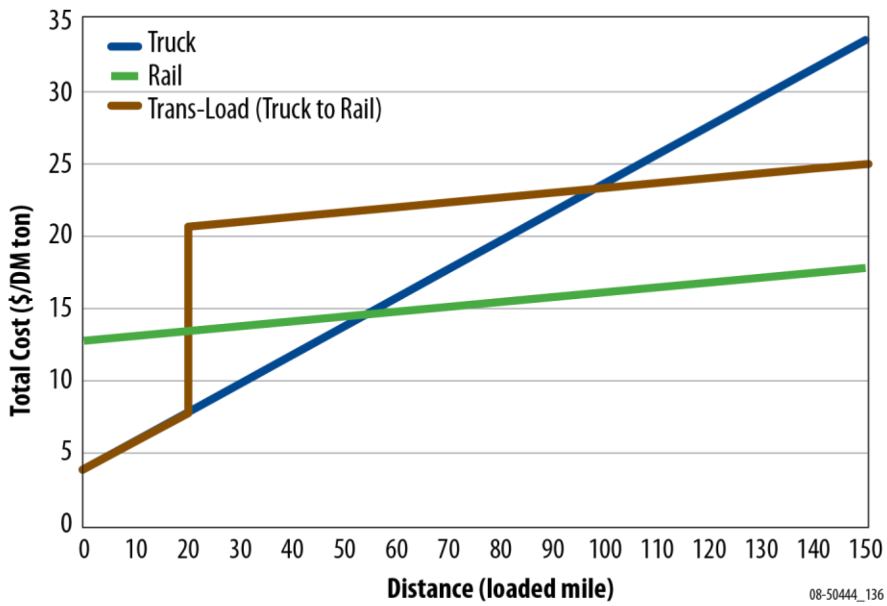


Figure B.12. Transportation cost comparison for truck, trans-load(truck to rail), and rail (Hess et al. 2009).

B.3.4 Total Advanced Woody System Cost

Costs associated with the advanced woody depot design are shown in Table B.11, where costs are expressed in 2012 $US/DM ton. The total logistics cost for a shipping distance of 50 mi, minus grower payment, for cleaned pulpwood torrefied chips is $93.13/DM ton, which is the sum of ownership, operating, and DM loss costs(Searcy and Hess 2010).

The total logistics cost expressed in 2012 $US/DM ton, minus grower payment, for shipping distances of 25, 50, 100, 250, and 500 mi are $92.47, $93.13, $94.46, $98.44, and $105.07, respectively.

Table B.11. Static model costs for the advanced woody depot scenario.

Equipment	Harvesting and Collection	In-Field Preprocessing	Transportation	Depot Handling/ Processing	Storage	Power Plant Handling	Total Logistics Cost
Installed capital ($/DM ton/yr)	30.78	12.14	6.36	119.45	3.12	0.58	172.42
Ownership costs	*7.24*	*2.96*	*0.90*	*12.70*	*0.50*	*0.08*	*24.39*
Operating costs	*10.95*	*16.61*	*10.51*	*19.82*	*0.49*	*0.10*	*58.47*
Labor	2.63	3.04	2.81	4.53	0.19	0.00	13.20
Non-labor	4.18	8.26	7.48	13.20	0.25	0.09	33.46
R&M	4.14	5.29	0.21	2.09	0.04	0.01	11.78
DM loss costs	*0.00*	*0.00*	*0.00*	*9.38*	*0.90*	*0.00*	*10.28*
Energy use (MBtu/ DM ton)	196.9	324.0	42.1	1805.9	10.1	5.1	2384.1

B.3.5 Sensitivity Analysis

A total cost of $93.13/DM ton was reported earlier for the advanced depot scenario for a total shipping distance of 50 mi; however, based on a sensitivity analysis, actual costs range can range from $92.88 and $109.95/DM ton, with an average of $100.81/DM ton as shown in Figure B.13.

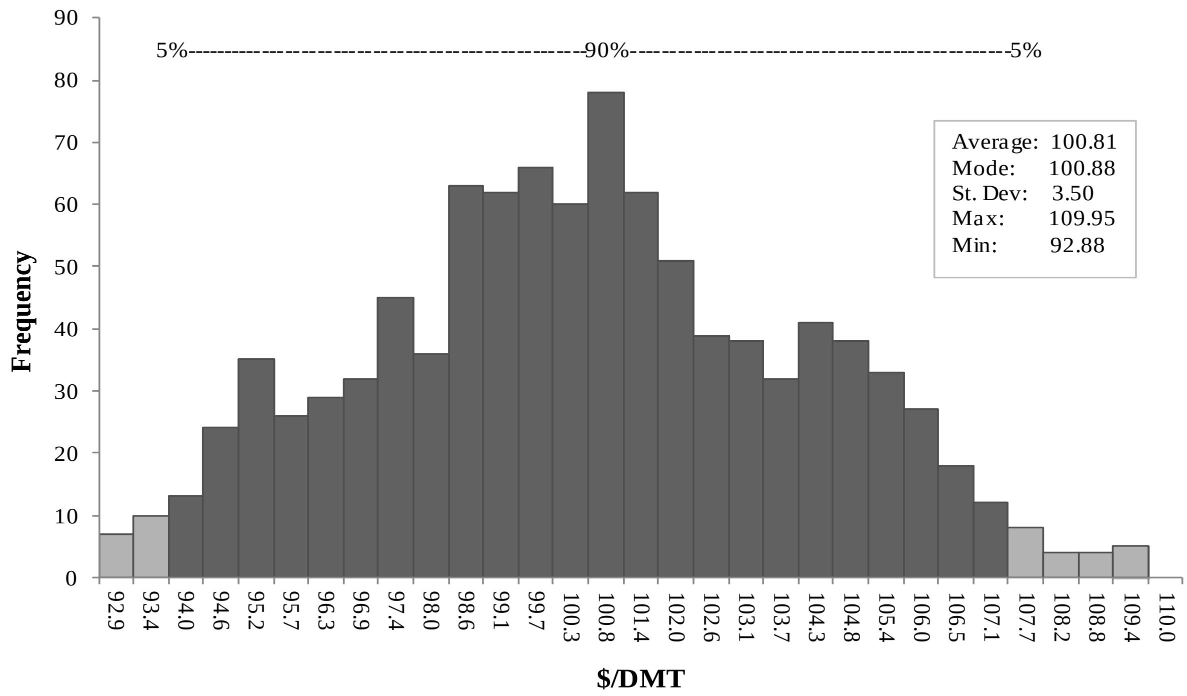


Figure B.13. Advanced depot woody feedstock supply scenario sensitivity histogram.

B.4 Woody Feedstock Logistics Comparison

To minimize the cost of supplying biomass to the power plant, it is desirable to minimize the total shipping distance between the biomass supply and the power plant. In many cases, it may be difficult to accomplish this objective. Existing power plants that wish to cofire biomass may have little control over the suitability and/or availability of the land immediately around the power plant for growing and harvesting biomass. Hence, the distance required to ship biomass to the power plant will be plant-specific. Figure B.14 shows the logistics cost (minus grower payment) of woody feedstock as a function of total shipping distance. In these cases, the conventional case uses less biomass than the advanced and advanced depot cases. Because of this, the cost curves are different as different economies of scale, transportation, and preprocessing are modeled in the analysis. The conventional case always outperforms the advanced case, regardless of the shipping distance considered. This is because the form of the biomass and the required shipping distance in these cases are identical. The advanced depot case, however, outperforms the conventional case when shipping distances exceed 175 mi, primarily due to savings obtained by using rail transportation between the depot and the power plant.

In Figure B.15, the increased energy density of the torrefied product is considered. From these results, it can be seen that the advanced depot scenario outperforms the conventional case when shipping distances exceed only 80 mi. Another observation is that for short shipping distances, the cost of biomass is around \$5/MMBtu, but as the shipping distance increases the cost can quickly rise above \$6/MMBtu for all but the depot scenario. The benefit of the depot concept is readily apparent where longer shipping distances are required.

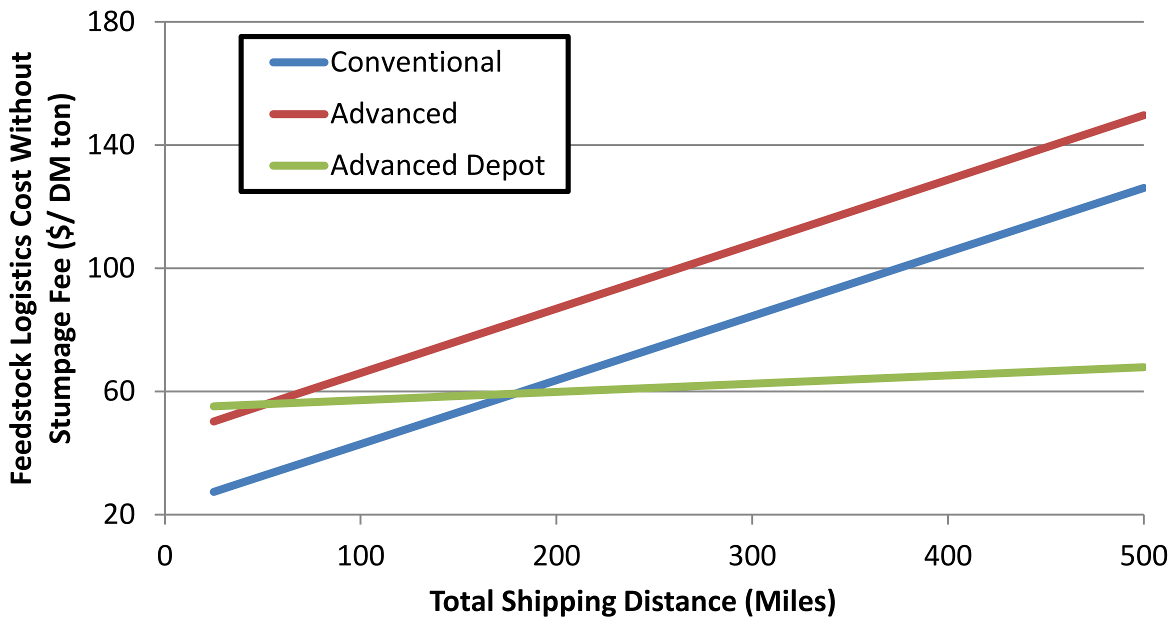


Figure B.14. Logistics cost comparison for the woody scenarios on a mass-delivered basis.

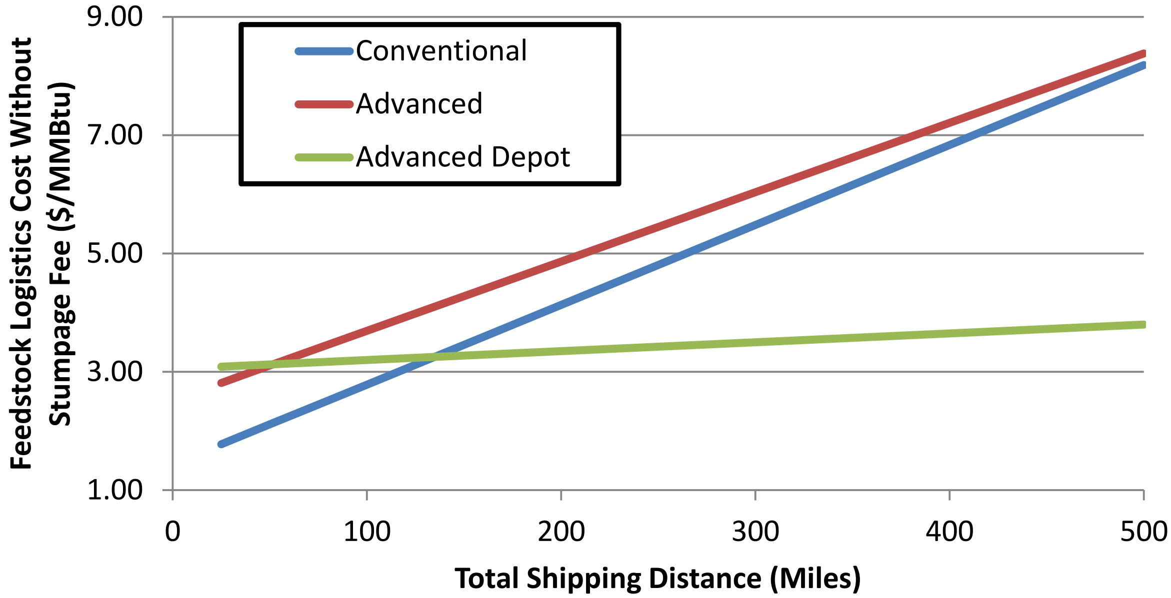


Figure B.15. Logistics cost comparison for the woody scenarios on an energy-delivered basis.

B.5 Appendix B References

Adapa PK, J Bucko, LG Tabil, G Schoenau, and S Sokhansanj. 2002. "Pelleting Characteristics of Fractionated Sun Cure and Dehydrated Alfalfa Grinds." *ASAE/CSAE North-Central Intersectional Meeting*, Saskatoon, Saskatchewan, Canada, September 27–28, 2002.

Arias BR, CG Pevida, JD Fermoso, MG Plaza, FG Rubiera, and JJ Pis Martinez. 2008. "Influence of Torrefaction on the Grindability and Reactivity of Woody Biomass," *Fuel Processing Technology*, 89:2, pp. 169–175

B&W – Babcock and Wilcox Company. 2005. *Steam: Its Generation and Use, 41st Ed.* Barberton, Ohio.

Bergman PCA and JHA Kiel. 2005. "Torrefaction for Biomass Upgrading." Published at *14th European Biomass Conference & Exhibition*, Paris, France, October 17–21, 2005.

Bergman PCA, AR Boersma, JHA Kiel, MJ Prins, KJ Ptasinski, and FJJG Janssen.2005. *Torrefied Biomass for Entrained-flow Gasification of Biomass*. Report ECN-C—05-067, Petten, The Netherlands: Energy Research Centre of the Netherlands. Available at http://alexandria.tue.nl/repository/books/638046.pdf

Hubbard WL, C Biles, and MS Ashton. 2007. *Sustainable Forestry for Bioenergy and Bio-Based Products: Trainers Curriculum Notebook*. Southern Forest Research Partnership, Inc., Athens, Georgia.

Koukios EG. 1993. "Progress in Thermochemical, Solid-State Refining of Biofuels – From Research to Commercialization." In *Advances in Thermochemical Biomass Conversion,* AV Bridgwater (ed.), Springer Netherlands, pp. 1678–1692.

Lehtikangas P. 1999. *Quality Properties of Fuel Pellets from Forest Biomass*. Licentiate Thesis, University of Agricultural Sciences, Uppsala, Sweden.

Li Y and H Liu. 2000. "High-Pressure Densification of Wood Residues to Form an Upgraded Fuel." *Biomass Bioenergy* 19(3):177–186.

Lipinsky ES, JR Arcate, and TB Reed. 2002. "Enhanced Wood Fuels via Torrefaction." *Fuel Chemistry Division Preprints* 47(1):408–410.

Mani S, LG Tabil, and S Sokhansanj. 2006. "Specific Energy Requirement for Compacting Corn Stover." *Bioresource Technology* 97(12):1420–1426.

Ndiema CKW, PN Manga, and CR Ruttoh. 2002. "Influence of Die Pressure on Relaxation Characteristics of Briquetted Biomass." *Energy Conversion and Management* 43(16):2157–2161.

Ortiz DS, AE Curtright, C Samaras, A Litovitz, and N Burger. 2011. *Near-Term Opportunities for Integrating Biomass into the U.S. Electrical Supply: Technical Considerations*. RAND Corporation, Santa Monica, California.

Pastorova I, PW Arisz, and JJ Boon. 1993. "Preservation of D-Glucose Oligosaccharides in Cellulose Chars." *Carbohydrate Research* 248:151–165.

Reed T and B Bryant. 1978. *Densified Biomass: A New Form of Solid Fuel*. Prepared for Office of Energy Technology, U.S. Department of Energy by Solar Energy Research Institute, Division of Solar Technology, Golden, Colorado.

Searcy E and JR Hess. 2010. Uniform-Format Feedstock Supply System Design Reports: A Commodity-Scale Design to Produce an Infrastructure-Compatible Biocrude from Lignocellulosic Biomass. INL/EXT-10-20372, Bioenergy Program, Idaho National Laboratory, Idaho Falls, Idaho.

Sokhansanj S, S Mani, X Bi, P Zaini, & LG Tabil. 2005. "Binderless pelletization of biomass." *ASAE Annual International Meeting*, Tampa Convention Centre, Tampa, Florida; July 17-20, Paper Number 056061, 2950 Niles Road, St. Joseph, MI 49085-9659 USA.

Tabil LG and S Sokhansanj. 1996a. "Compression and Compaction Behavior of Alfalfa Grinds, Part 1: Compression Behavior." *Powder Handling Process* 8:17–23.

Tumuluru JS, CT Wright, KL Kenney, and JR Hess. 2010a. *A Review on Biomass Densification Technologies for Energy Application*. INL/EXT-10-18420, Idaho National Laboratory, Idaho Falls, Idaho.

Tumuluru JS, S Sokhansanj, CT Wright, and R Boardman. 2010b.*Biomass Torrefaction Process Review and Moving Bed Torrefaction System Model Development*. INL/EXT-10-19569, Idaho National Laboratory, Idaho Falls, Idaho, and Oak Ridge National Laboratory, Oak Ridge, Tennessee.

Tumuluru JS, JR Hess, RD Boardman, CT Wright, and TL Westover. 2012. "Formulation, Pretreatment, and Densification Options to Improve Biomass Specifications for Co-Firing High Percentages with Coal." *Industrial Biotechnology* 8(3):113–132.

Uslu A, APC Faaij, and PCA Bergman. 2008. "Pre-Treatment Technologies and Their Effect on International Bioenergy Supply Chain Logistics: Techno-Economic Evaluation of Torrefaction, Fast Pyrolysis, and Pelletisation." *Energy* 33(8):1206–1223.

Appendix C

Herbaceous Feedstock Logistics Scenario

C.1 Methodology for Herbaceous Biomass Cases

In the herbaceous biopower cases discussed in this section, herbaceous biomass is collected with conventional harvest and bale handling equipment at similar costs and logistics. This equipment is used for the first-generation collection and handling of herbaceous biomass and preprocessing technologies are located inside the power plant gate. The cases summarized and shown below follow this model of material collection and preprocessing, which limits the use of herbaceous biomass to those areas in the direct vicinity of the power plant. The logistics of collecting and moving herbaceous biomass, along with the total price of biomass from the producer, sets the cost of biomass within some radius of the power plant. In cases where multiple power plants compete for the same resources in an overlapping area, the price of biomass will also be subject to the forces of competition in that area. As biomass consumption in an area increases, growers will be able to invest in larger collection, storage, and transportation systems to allow greater production capacity.

C.2 Conventional Herbaceous Feedstock Logistics – 10% Switchgrass/90% Coal

A conventional herbaceous biomass feedstock supply chain will be used to supply biomass for the scenario of cofiring 10% herbaceous biomass with 90% coal (Hess et al. 2009). Switchgrass is the feedstock chosen for the herbaceous case. A primary objective for the conventional biomass feedstock supply-system design is to select technologies adaptable to existing local feedstock resources and biomass infrastructures. Conventional designs represent feedstock supply-system technologies, costs, and logistics that are achievable today for supplying biomass feedstocks to power plants. This section outlines a conventional herbaceous biomass design that supplies on-spec biomass to the power plant. Figure C.1 shows the process flow for the conventional herbaceous biomass feedstock supply system. Yellow rectangles represent individual modeled processes, green ovals represent changes in format intermediates, and white rectangles represent alternate processes that were not modeled. Operations occurring at the power plant are shown in the outlined square (Hess et al. 2009).

In the conventional herbaceous design, herbaceous biomass is harvested when dry; baled, stacked, and stored in the field (covered with tarps, as needed); and then transported to the power plant as needed.

Several key feedstock format and machinery attributes have been identified that influence the processes within the supply system. From a cost, performance, and logistics perspective, each attribute becomes an input and/or constraint on the supply system that must be considered to design a viable supply-system capable of meeting the needs of a power plant. The modeled attributes of all biomass material intermediates (referred to as format intermediates) are identified, and variances in those attributes are discussed to provide a better understanding of how supply-system performance is, or may be, affected by feedstock format intermediate attributes. Details of the specific machinery modeled for the processes of each unit operation can be found in Hess et al. (2009).

The feedstock system modeled here is designed to supply a power plant with 400,000 DM tons of biomass annually on a year-round biomass delivery schedule. This supply corresponds to the amount needed to cofire a 400-MW power plant at 10%.

In many cases, it is clear that the performance of one supply-system process is significantly impacted by the performance of another. As such, both the individual unit operations report sections and the overall integrated supply-system design are concluded with an integrated summary analysis of cost, performance, and logistics based on stated format, intermediate attributes, and equipment operational assumptions.

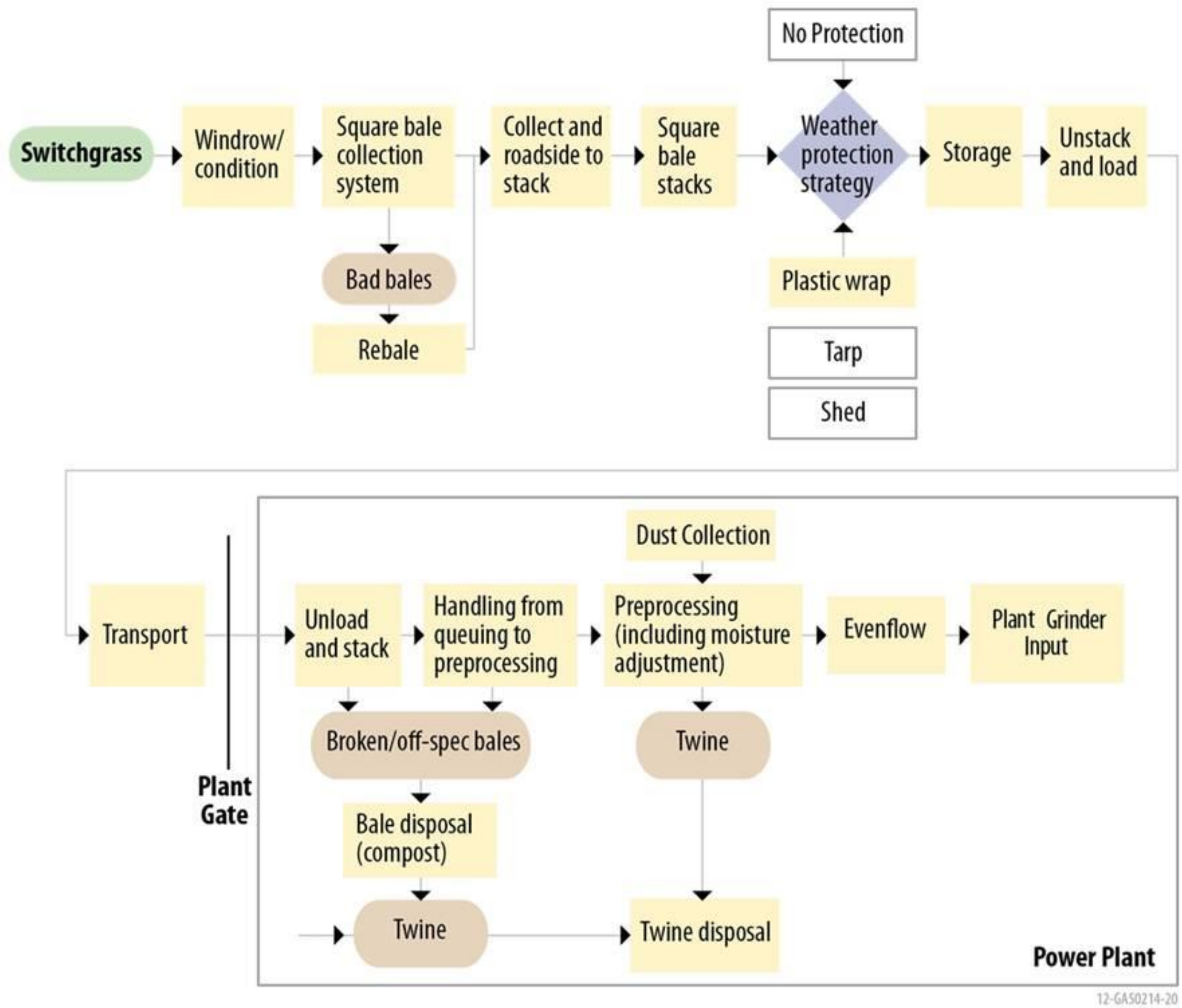


Figure C.1. Order of unit operations in the conventional herbaceous biomass feedstock supply system.

C.2.1 Feedstock Harvest and Collection

Harvest and collection encompasses all processes associated with moving the biomass from the location of production, in this case the field, to the queuing location (i.e., the square bale stacks) as shown in Figure C.2. For baled switchgrass, the queuing is typically the field-side storage location. Harvest and collection processes include cutting, gathering, densifying, and transporting the material to the field-side storage location. The yellow boxes in Figure C.2 identify the specific processes being performed. However, depending on a number of variables, the specific processes, equipment, and associated costs may vary significantly from one feedstock to another. Many of the variables that impact the selection of processes and equipment are based on the feedstock, location, and the biomass material format changes between process operations. The green ovals in Figure C.2 identify the feedstock and its format as it moves from one process to the next within the supply system.

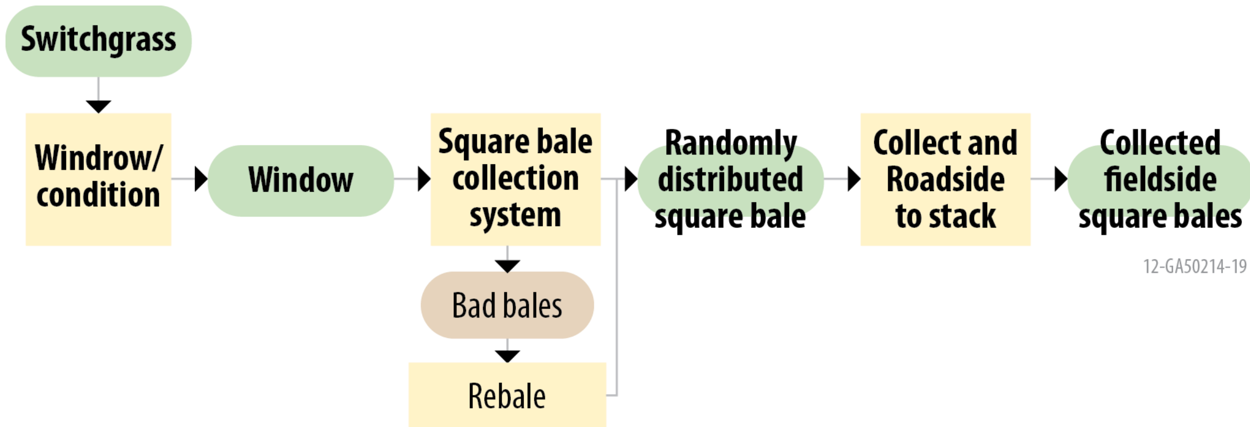


Figure C.2. Conventional bale harvest and collection supply logistics processes and format intermediates.

A breakdown of the costs associated with each piece of equipment used in the harvest and collection operation identifies significant cost components that are valuable for making individual comparisons and recognizing areas of research potential. These costs are reported in Table C.1 in terms of DM tons entering each process, respectively. Costs are expressed in 2012 $/DM ton, unless otherwise noted. Total operation cost is the sum of ownership and operating cost (Hess et al. 2009).The total harvest and collection cost of switchgrass from this analysis is $15.73/DM ton.

Table C.1. Static model costs for major harvest and collection equipment in the conventional switchgrass case.

	Condition and Windrow	Bailing	Collect and Roadside	
Equipment	Self-Propelled Windrower with Disc Headers	275 hp Tractor and Large Square Bailer	Self-Propelled Stacker	Total Cost per DM Ton for Harvest and Collection
Installed equipment quantities (No. of machines)	64	84	41	
Installed capital ($/DM ton/yr)	9.40	25.03	7.59	42.03
Ownership costs	1.33	3.06	1.10	5.50
Operating costs[a]	2.23	6.67	1.34	10.23
Energy use (MBtu/DM ton)	38.58	61.86	31.67	132.11

(a) Sum of fuel and material cost.

C.2.2 Conventional Bale Storage

Because harvest of herbaceous crops is seasonal, it is necessary to store the material until it is needed by the power plant. Storage encompasses all the processes associated with stacking and protecting the biomass from weather or other environmental conditions. This process is shown in Figure C.3. In the conventional bale design, storage does not include biomass material stabilization (drying or ensiling) because stabilization of the biomass material occurs with the field-drying process in the harvest and collection operation, and the stack moisture has already been reduced to ~12%. The conventional bale storage design employs technologies and methods to protect the bales from both mechanical and biological losses; however, the model assumes a 5 % physical loss, or shrink, during storage.

The storage configuration for the conventional bale design is on-farm stacks of bales located field-side or near field-side. Several options can be used to protect stacks of bales from weather damage, including under-shed storage, tarping, or wrapping in plastic as shown in Figure C.3. In Figure 4.20, green ovals in represent format intermediates, yellow rectangles represent processes modeled in this report, white rectangles represent processes not modeled in this report, and grey diamonds represent multiple process options. For the purposes of this analysis, material is stored field-side with plastic wrap until needed at the power plant.

Table C.2 summarizes the cost of field storage of switchgrass. Costs are expressed in 2012 $/DM ton unless otherwise noted. The total storage cost from this analysis is $4.26/DM ton, including ownership, operating, and DM loss cost (Hess et al. 2009).

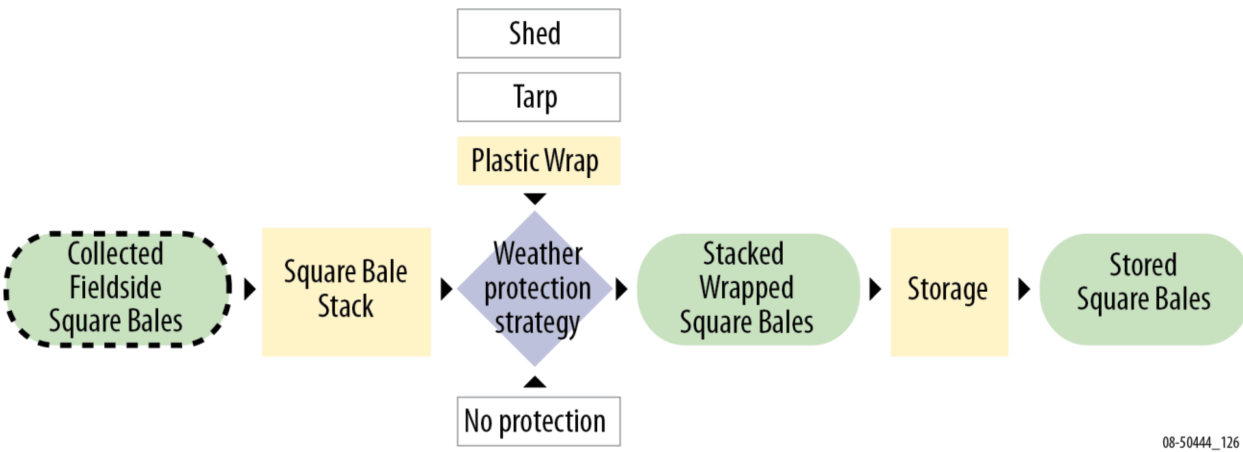


Figure C.3. Storage supply logistic processes and format intermediates.

Table C.2. Static model costs for major storage equipment in the conventional switchgrass case.

	Stacking Loader	Weather Protection Wrapper	Storage at Power Plant (Loader)	Total Cost per DM Ton for Storage
Installed equipment quantity (No. of machines)	33	209	2	
Installed capital ($/DM ton/yr)	3.05	2.41	0.27	5.73
Ownership costs	*0.44*	*0.84*	*0.15*	*1.43*
Operating costs	*0.81*		*0.87*	*1.69*
DM loss costs		*1.14*		*1.14*
Energy use (MBtu/DM ton)	11.61		10.92	22.53

C.2.3 Transportation

The conventional bale transportation and handling operation centers on the movement of baled material from long-term field-side storage to shorter-term bale-yard storage at the power plant. These processes involve the use of self-propelled loaders and semi-tractor trailers as shown in Figure C.4, where green ovals represent format intermediates, tan ovals represent potential waste streams, yellow rectangles represent processes modeled in this report, white rectangles represent processes not modeled in this report, and grey diamonds represent decision points.

Transportation and handling costs, shown in Table C.3, are directly impacted by the relatively low bulk density of the baled feedstock—typically around 6 to 10 lb/ft^3 when dry. This relatively low bulk density format makes it difficult to load enough bales on a truck to reach the gross vehicle weight limit required for optimizing delivery systems. The total transportation cost for a shipping distance of 50 mi is $10.85/DM ton; however, costs were also calculated for distances of 25, 100, 250, and 500 mi. Total operation cost is the sum of ownership, operating, and DM loss cost (Hess et al. 2009).

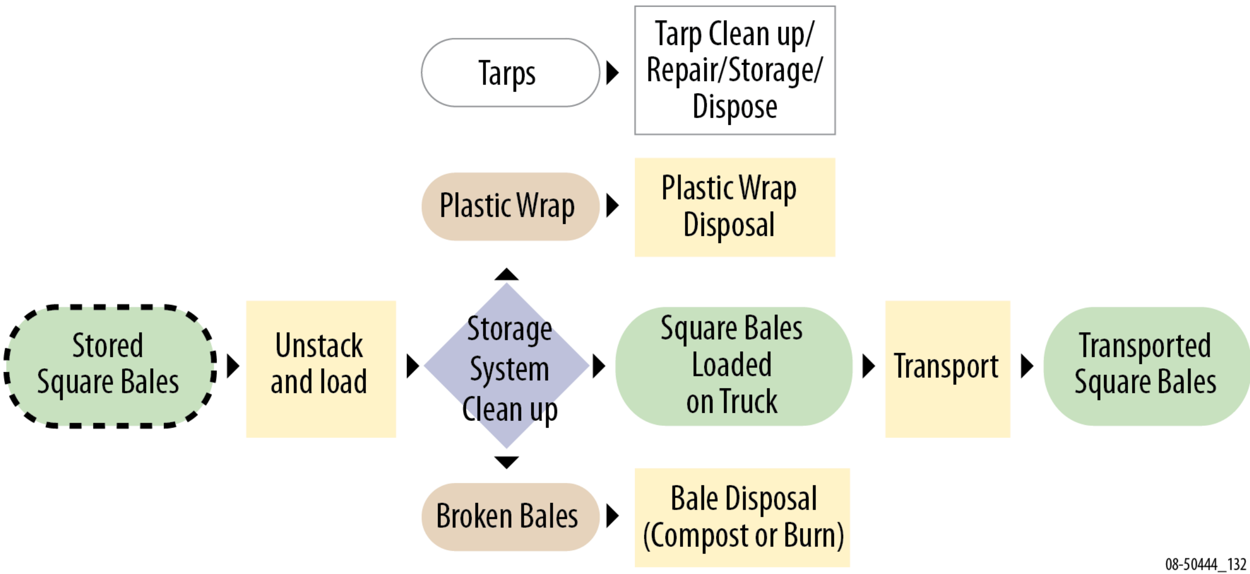


Figure C.4. Transportation and handling supply logistic processes and format intermediates.

Table C.3. Static model costs for major transport transportation and handling equipment in the conventional bale – corn stover and switchgrass scenarios assuming 50-mi transportation.

Equipment	Unstack/Unwrap, Load, and Cleanup Loader	Transport 3-Axle Day Cab with 53-ft Flat Bed Trailer	Unloader	Total Cost per DM Ton for Transportation
Quantity of equipment (No. of machines)	5	32	5	
Installed capital ($/DM ton/yr)	0.46	6.34	0.46	7.27
Ownership costs	*0.16*	*1.04*	*0.16*	*1.35*
Operating costs	*1.03*	*7.45*	*1.03*	*9.50*
Energy use (MBtu/DM ton)	12.40	99.37	12.40	124.18

C.2.4 Conventional Bale Receiving, Handling and Preprocessing

Power plant receiving and preprocessing encompasses all processes associated with weighing and unloading incoming trucks, moving baled feedstock into short term storage (queuing), moving bales from queuing into the preprocessing system for grinding, and feeding the ground feedstock into the power plant as shown in Figure C.5. Green ovals represent biomass format intermediates, tan ovals represent potential waste streams, yellow rectangles represent processes modeled in this report, and white rectangles represent processes not modeled in this report. Blue, pink, and red rectangles represent different conversion processes. The primary objective of the conventional bale supply logistics system is to get the biomass from the field to the power plant. Bale sorting will be used for biomass quality control.

The conventional bale preprocessing design requirement is to simply shred the bale, sufficiently reducing the biomass size to move the material through the feed system and into the boiler. Multistage fractional milling preprocessing systems that produce biomass particles and particle size distributions to optimize material handling and conversion are not modeled in the conventional bale design. In reality, such a simplified preprocessing system may not be adequate for direct injection of biomass into the boiler feed system; additional or alternate preprocessing systems may be required for the boiler feed system to function properly. Future analysis will focus on the ability to co-feed raw biomass in a conventional coal boiler; subsequent sections of this report include modeling based on torrefied and leached switchgrass.

Costs for major in-plant handling and preprocessing equipment in the conventional herbaceous switchgrass scenario are expressed in 2012 $/DM ton as shown in Table C.4. Total operation cost is the sum of ownership, operating, and DM loss cost. The total in-plant handling and preprocessing cost for switchgrass is $15.48/DM ton.

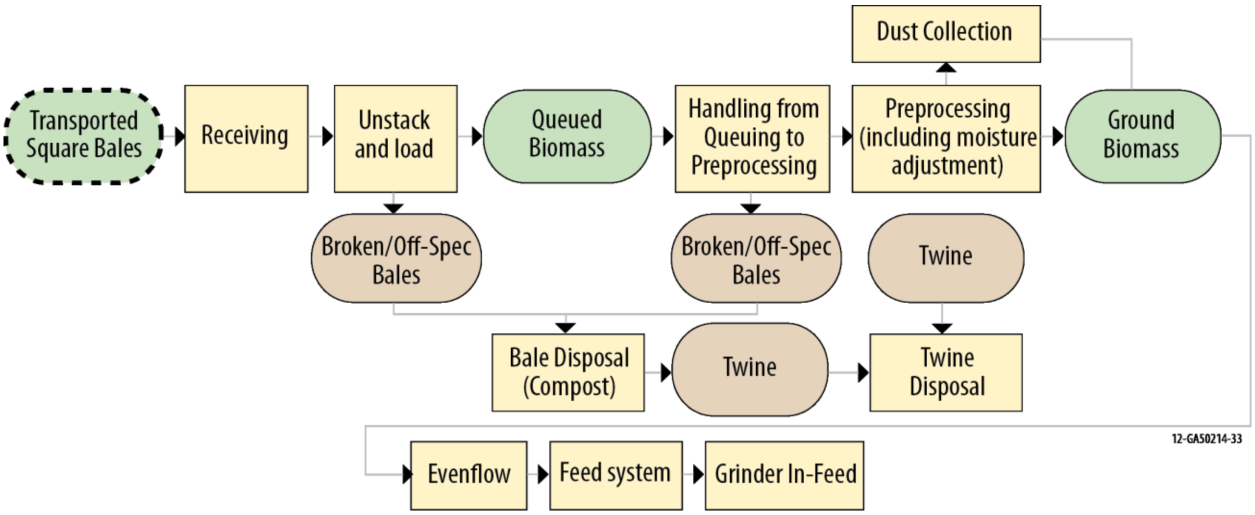


Figure C.5. Receiving and preprocessing supply logistic processes and biomass format intermediates.

Table C.4. Static model costs for major in-plant handling and preprocessing equipment in the conventional herbaceous switchgrass scenario.

Equipment	Power Plant Handling (Conveyors)	Power Plant Preprocessing (Grinding, Conveying, Dust Collection)	Total Cost per DM Ton for Receiving and Handling
Quantity of equipment (No. of machines)	4	98	
Installed capital ($/DM ton/yr)	0.40	10.90	11.30
Ownership costs	*0.04*	*3.28*	*3.32*
Operating costs	*0.05*	*12.10*	*12.15*
Energy use (MBtu/DM ton)	2.73	266.24	268.97

C.2.5 Total Conventional Bale Switchgrass Logistics Cost

A summary of costs associated with supply logistics for the conventional bale switchgrass case are listed in Table C.5.Costs are expressed in 2012 $US/DM ton. The total logistics cost for a shipping distance of 50 mi, minus grower payment, for switchgrass is $46.31/DM ton, which is the sum of ownership, operating, and dry matter loss costs.

The total logistics cost expressed in 2012 $US/DM ton, minus grower payment, for shipping distances of 25, 50, 100, 250, and 500 mi are $43.24, $46.31, $52.45, $70.88, and $101.63, respectively.

Table C.5. Static model costs for conventional bale switchgrass.

Equipment	Harvesting and Collection	Storage	Transportation	In-Plant Handling and Processing	Total Logistics Cost
Installed capital ($/DM ton/yr)	42.03	5.73	7.27	11.30	66.32
Ownership costs	*5.50*	*1.43*	*1.35*	*3.32*	*11.60*
Operating costs	*10.23*	*1.69*	*9.50*	*12.15*	*33.57*
DM loss costs	*0*	*1.14*	*0*	0	*1.14*

Energy use (MBtu/DM ton)	132.11	22.53	124.18	268.97	547.78

C.2.6 Sensitivity Analysis

A sensitivity analysis was conducted on the above analyses to illustrate the sensitivity of the projected prices to variations in the input parameters for the model. Monte Carlo sampling methods and triangular probability distributions were used for the values chosen for the input parameters summarized in Table C.6.

The histogram in Figure C.6 illustrates the variation possible in the total cost reported previously. This sensitivity follows the same methodology detailed in Hess et al. (2009). A total cost of \$46.31/DM ton was reported earlier for the conventional herbaceous scenario for a shipping distance of 50 mi; however, the actual value can range from \$41.16to \$52.01/DM ton with an average cost of \$46.20/DM ton.

Table C.6. Variables used in the sensitivity analysis and their triangular distribution parameters.

Variable	Minimum	Maximum	Peak
Electricity price ($/kWh)	0.04	0.12	0.06
Natural gas price ($/MMBtu)	6.35	14.93	10.00
Off-road diesel price ($/gal)	2.94	3.31	3.46
Semi load time (min)	25.50	34.50	30.00
Semi speed (mph)	42.50	57.50	50.00
Haul distance (mi)	0.10	0.45	0.30
Transport DM loss (%)	0.00	1.00	0.01
Storage DM loss (%)	0.00	4.00	2.00
Handling DM loss (%)	0.00	0.50	0.01
Loader capacity (%)	0.75	1.50	1.00
Chipper efficiency (%)	50.00	80.00	75.00
Chipper capacity (tons/hr)	42.50	55.00	50.00
Dryer efficiency (%)	76.50	93.50	85.00
Dyer capacity (tons/hr)	99.00	121.00	110.00
Tipper capacity (%)	0.85	1.15	1.00
Roadsider efficiency (%)	50.00	71.50	60.00
Harvesting efficiency (%)	50.00	80.00	60.00
Labor harvesting/collection (%)	0.75	1.50	1.00
Labor preprocessing (%)	0.75	1.50	1.00
Labor transit (%)	0.75	1.50	1.00
Labor storage (%)	0.75	1.50	1.00
Labor handling (%)	0.75	1.50	1.00

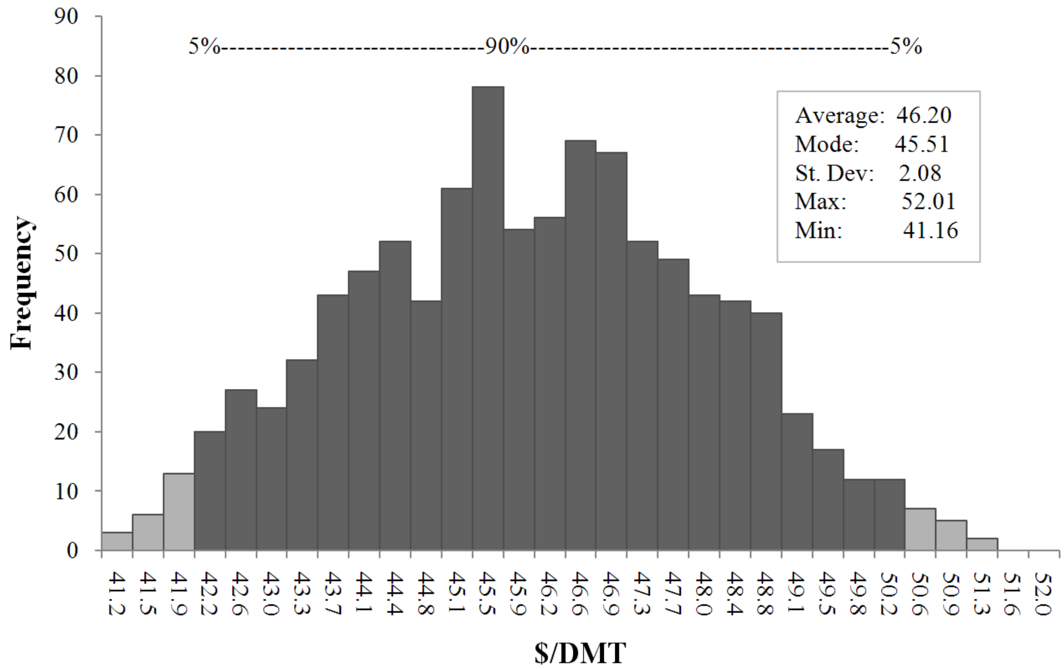


Figure C.6. Total conventional bale switchgrass supply-system design cost distribution histogram from risk analysis.

C.3 Advanced Herbaceous Feedstock Logistics – 20% Switchgrass/ 80% Coal with Leaching, Torrefaction, and Densification

C.3.1 Introduction

Herbaceous biomass in general, and switchgrass in this case, have higher ash content and lower bulk density than other feed materials—much lower than coal. This presents challenges with corrosion, fouling, and slagging in a standard coal boiler when cofire rates are increased past a nominal point, necessitating the additional preprocessing of herbaceous biomass. Additional preprocessing steps that enable increased cofiring rates include leaching and torrefaction.

This section discusses the modeling and effect on cost when torrefaction and leaching are included inside the power plant gate. In addition, the cofiring ratio is increased from 10% in the conventional case to 20% for this case. The supply system is unchanged with the exception of the addition of these steps in the process as illustrated in Figure C.7, where yellow rectangles represent individual modeled processes, green ovals represent changes in format intermediates, and white rectangles represent alternate processes that were not modeled.

Leaching and dewatering are included in this design. The dewatering process is assumed to produce mechanically pressed material at about 20% moisture. This material is then suitable to feed directly into the torrefaction system. The feedstock system modeled here is designed to supply a power plant with 800,000 DM tons of biomass annually on a year-round biomass delivery schedule. This supply corresponds to the amount needed to cofire a 400-MW power plant at 20%.

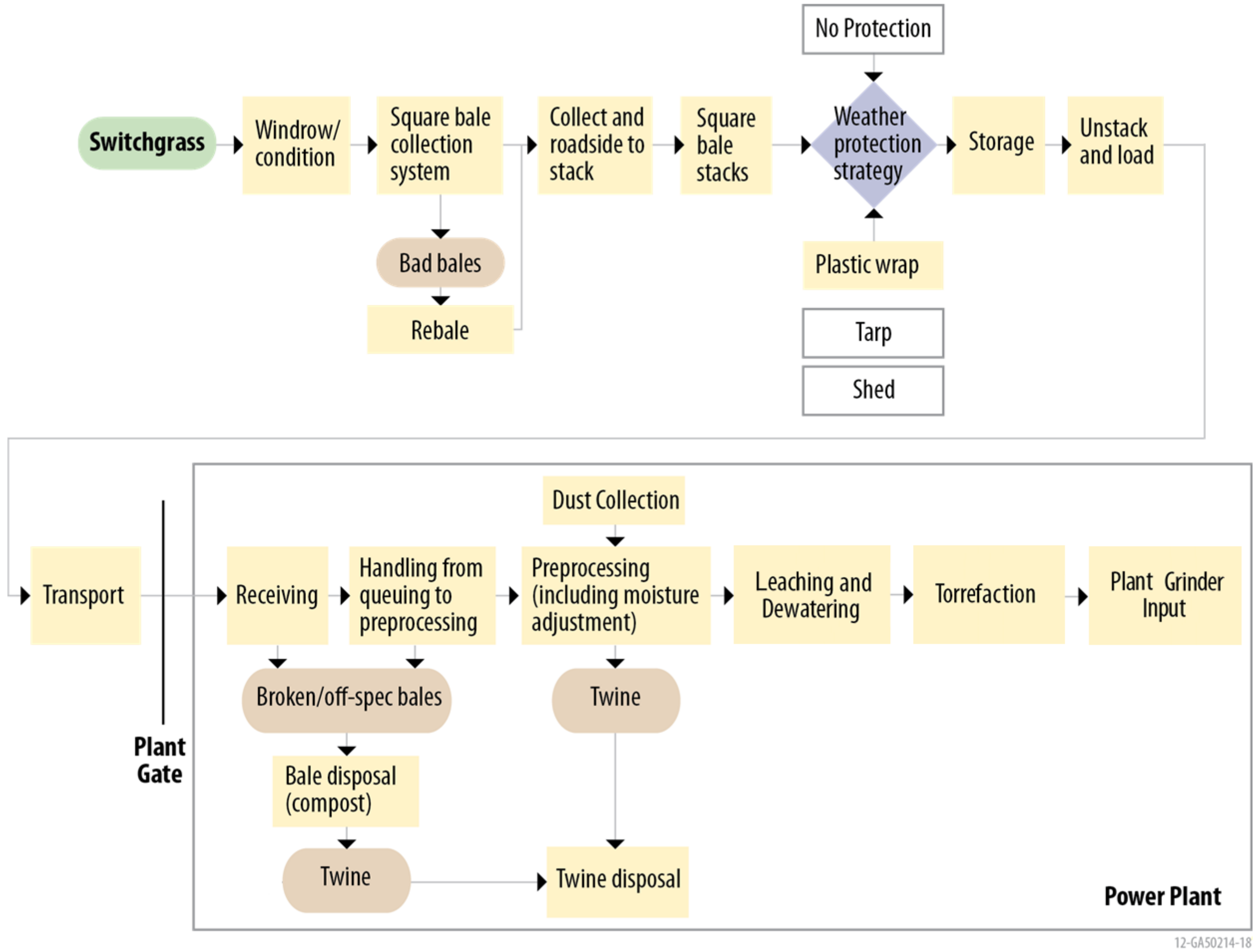


Figure C.7. Order of unit operations in the advanced herbaceous biomass feedstock supply system with addition of torrefaction and leaching steps.

C.3.2 Leaching and Torrefaction

Leaching is the process of soaking biomass in water and/or other solvents to dissolve undesired inorganic compounds. This process is necessary in the production of power from biomass with higher levels of inorganic compounds, which, at best, leads to higher ash when burned in a coal boiler and can cause slagging, fouling, and even corrosion in conventional boilers. Furthermore, torrefaction increases the relative concentration of inorganics in biomass due to the lower volatility of inorganic species.

As previously discussed, torrefaction produces a material much more coal-like in terms of grindability and energy density. Preliminary experimentation has shown that the mass yield for torrefied herbaceous feed material with the required energy density will be lower than for woody feedstock. INL is investigating the optimal torrefaction parameters for biomass.

The unit operations for leaching and torrefaction, along with the cost are summarized in Table C.7.Costs are expressed in 2012 $US/DM ton. Total operation cost is the sum of ownership, operating, and DM loss cost.

Table C.7. Static model costs for the cost projections for the leaching operation in the advanced herbaceous design.

Equipment	Leaching Baths	Torrefaction
Installed capital ($/DM ton/yr)	37.13	49.21
Ownership costs	*2.74*	*4.46*
Operating costs	*6.15*	*0.23*
DM loss costs		*41.86*
Energy use (MBtu/DM ton)	194.35	1654.93

C.3.3 Total Advanced Herbaceous Switchgrass System Cost

A summary of costs associated with supply logistics for the advanced switchgrass case are listed in Table C.8.Costs are expressed in 2012 $US/DM ton. The total logistics cost for a shipping distance of 50 mi, minus grower payment is $104.46/DM ton, which is the sum of ownership, operating, and DM loss costs (Hess et al. 2009).

The total logistics cost expressed in 2012 $US/DM ton, minus grower payment, for shipping distances of 25, 50, 100, 250, and 500 mi are $99.07, $104.46, $115.21, $147.55, and $201.45, respectively.

Table C.8. Static model costs for the advanced herbaceous switchgrass scenario.

Equipment	Harvesting and Collection	Storage	Transportation	In-Plant Handling and Processing	Total Logistics Cost
Installed capital ($/DM ton/yr)	76.30	10.34	7.27	105.90	199.80
Ownership costs	*5.50*	*1.43*	*1.35*	*11.69*	*19.97*
Operating costs	*10.23*	*1.67*	*9.50*	*20.09*	*41.50*
DM loss costs	*0*	*1.14*	*0*	41.86	*42.99*
Energy use (MBtu/DM ton)	239.32	40.81	124.18	707.19	1111.50

C.3.4 Sensitivity Analysis

A total cost of $104.46/DM ton was reported for the advanced scenario, but based on sensitivity analysis the actual value can range from $95.26 to $113.66/DM ton with an average of $104.42/DM ton, as shown in Figure C.8.

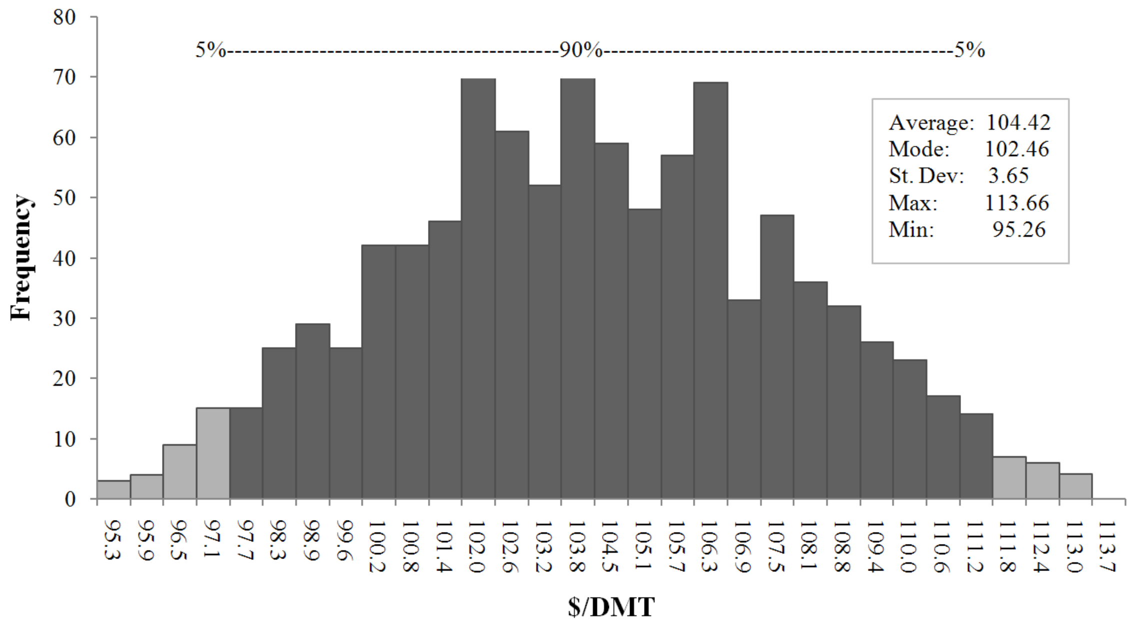


Figure C.8.Advanced herbaceous feedstock supply scenario sensitivity histogram.

C.4 Advanced Herbaceous Depot Feedstock Logistics – 20% Switchgrass/80% Coal with Leaching, Torrefaction, and Densification

The second advanced herbaceous scenario analyzed includes a depot where biomass is locally preprocessed to improve transportation logistics. Switchgrass is brought to the local depot where it is ground, leached and dewatered, and torrefied prior to shipping to the power plant. Other operations are identical to the conventional herbaceous case discussed above.

The flow of material through this scenario is illustrated in Figure C.9, where yellow rectangles represent individual modeled processes, green ovals represent changes in format intermediates, and white rectangles represent alternate processes that were not modeled.

C.4.1 Biomass Processing Depot

The advanced biomass processing depot design includes a biomass preprocessing depot that enables the material to be ground and densified close to the field and put into a format that is free flowing, less prone to deterioration, and has higher bulk density to reduce subsequent transportation costs. The depot also enables feedstock blending, which can enhance conversion performance or be used to provide a more consistent product. The design in the advanced herbaceous depot design contains infrastructure to torrefy and densify switchgrass such that it can be safely and economically transported to the power plant. The advanced system concept is detailed in Hess et al. (2009) and Searcy and Hess (2010). The maximum depot capacity used in this analysis is 15.08 ton/hr, which would require 11 depots to support a 20% cofiring scenario for a 400-MW plant.

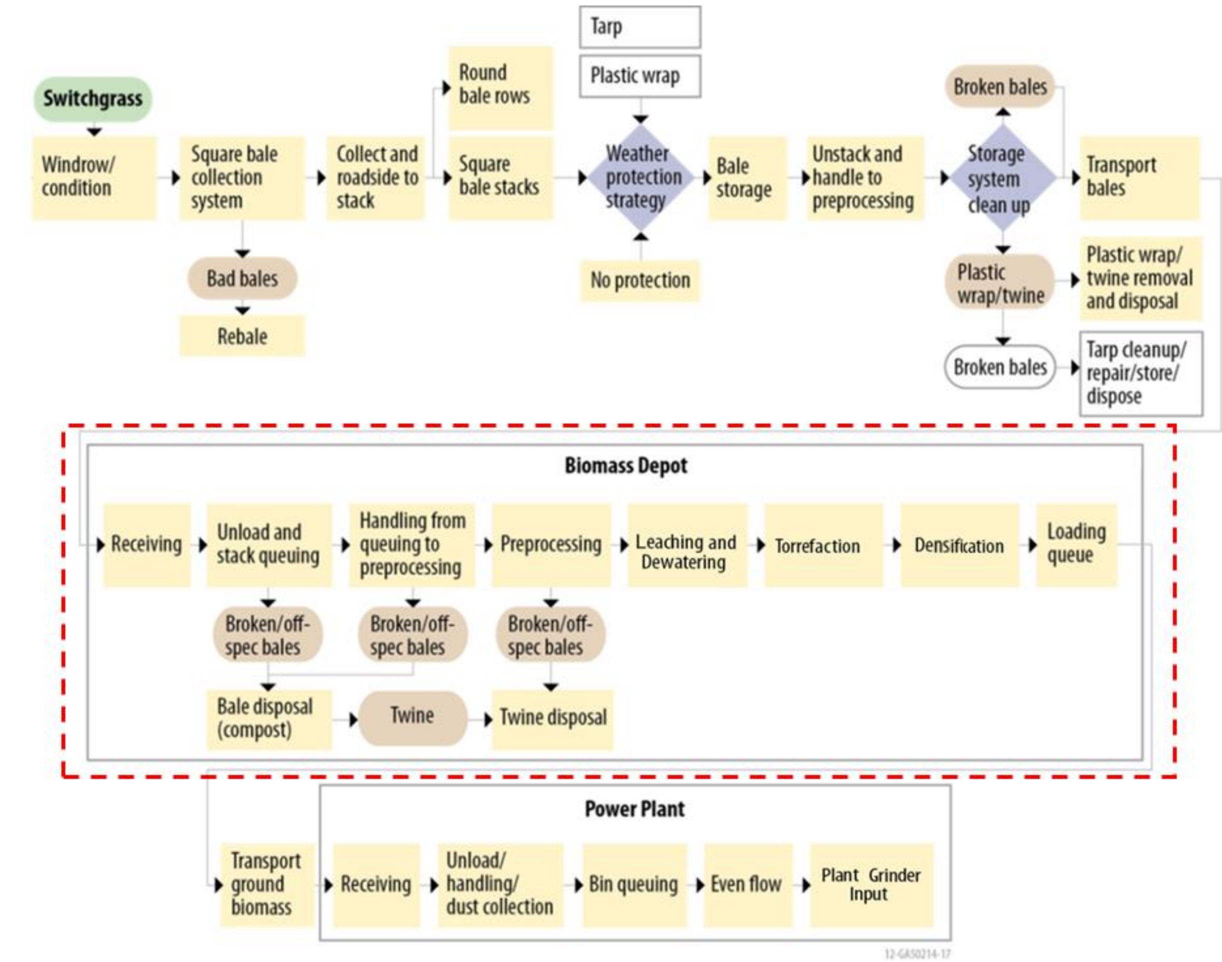


Figure C.9. Order and location of operations in the advanced herbaceous depot feedstock supply system.

C.4.2 Densification

Densification is described in detail in previous sections. Modeled costs of the depot equipment including densification are summarized in Table C.9.Costs are expressed in 2012 $US/DM ton. Total operation cost is the sum of ownership, operating, and DM loss cost.

Table C.9. Static model costs for depot equipment in the advanced herbaceous depot scenario.

	Leaching/Dewatering	Torrefaction	Densification
Quantity of equipment (No. of machines)	11	11	11
Installed capital ($/DM ton/yr)	37.13	79.49	4.16
Ownership costs	2.74	7.21	2.44
Operating costs	6.15	13.98	8.09
Energy use(MBtu/DM ton)	194.35	1654.93	116.61

C.4.3 High-Capacity Transportation (Rail)

Leached, torrefied, densified switchgrass transportation to the power plant is modeled using transportation modalities similar to the woody advanced depot case discussed previously.

C.4.4 Total Advanced Herbaceous System Cost: Switchgrass

Costs associated with the advanced herbaceous depot design are shown in Table C.10.Costs are expressed in 2012 $US/DM ton. The total logistics cost for a shipping distance of 50 mi (i.e., 15 mi from the field to the depot by truck, and 35 mi from the depot to the power plant by rail), minus grower payment, for torrefied, densified switchgrass is $140.96/DM ton, which is the sum of ownership, operating, and DM loss costs.

The total logistics cost expressed in 2012 $US/DM ton, minus grower payment, for shipping distances of 25, 50, 100, 250, and 500 mi are $140.32, $140.96, $142.23, $146.06, and $152.44, respectively.

Table C.10. Static model costs for the advanced herbaceous depot scenario.

Equipment	Harvesting and Collection	Storage	Depot Handling/ Processing	Transpor-tation	Power Plant Handling	Total Logistics Cost
Installed capital ($/DM ton/yr)	76.30	17.65	138.64	4.69	3.75	241.03
Ownership costs	*5.50*	*2.07*	*16.16*	*0.86*	*0.53*	*25.12*
Operating costs	*10.23*	*1.72*	*40.20*	*11.66*	*0.71*	*64.52*
DM loss costs	*0*	*1.14*	*50.18*	*0*	*0*	*51.32*
Energy use (MBtu/DM ton)	239.32	44.45	2425.39	54.62	36.66	2800.43

C.4.5 Sensitivity Analysis

A total cost of $140.96/DM ton was reported for the advanced herbaceous depot scenario, but based on sensitivity analysis the actual value can range from $139.36 to $144.01/DM ton with an average of $141.47/DM ton, as shown in Figure C.10.

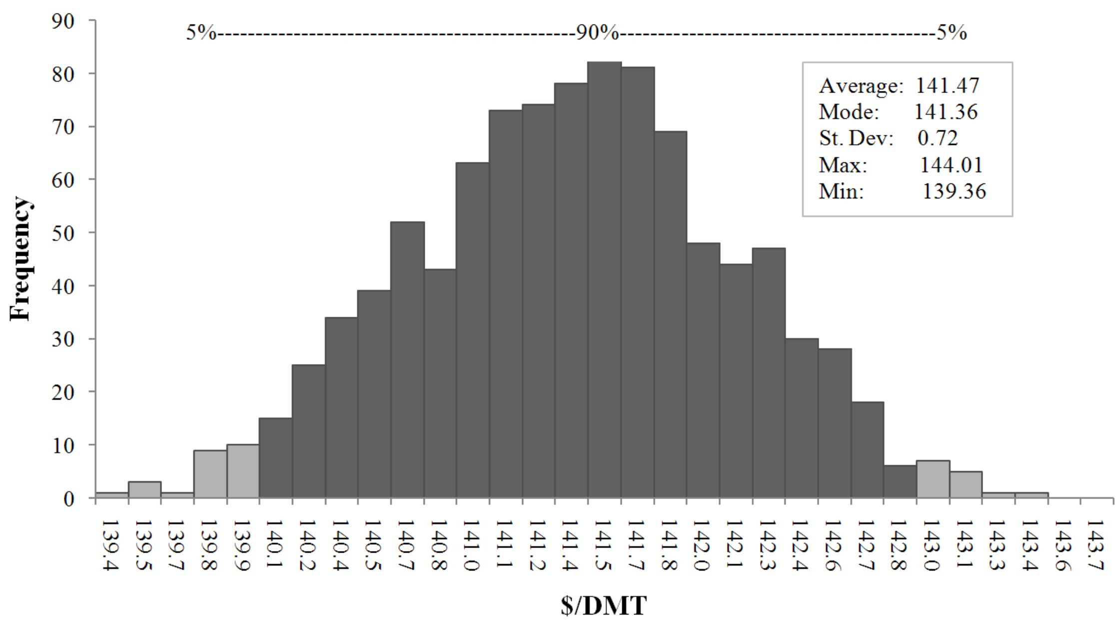


Figure C.10. Advanced depot herbaceous feedstock supply scenario sensitivity histogram.

C.5 Herbaceous Feedstock Logistics Comparison

Figure C.11 shows the logistics cost (minus grower payment) of herbaceous feedstock as a function of total shipping distance. The conventional case always outperforms the advanced case and the advanced depot case, regardless of the shipping distance considered. This is primarily due to the increased cost associated with torrefaction of biomass due largely to the lower starting energy density of this feedstock, i.e., more mass is lost in upgrading. For this analysis, it was assumed that the biomass must be brought to a total energy density of 10,000 Btu/lb in order to operate the boiler without derating. In Figure C.12, the increased energy density of the torrefied product is considered. From these results, it can be seen that the conventional scenario outperforms both advanced scenarios for cofiring with less than 10% biomass. If the cofiring rate is increased to 20% or higher, it may become necessary to torrefy the biomass to increase its energy density to be comparable with coal (to avoid boiler derating), and in these cases, the advanced scenario outperforms the advanced depot scenario up to a shipping distance of just under 250 mi.

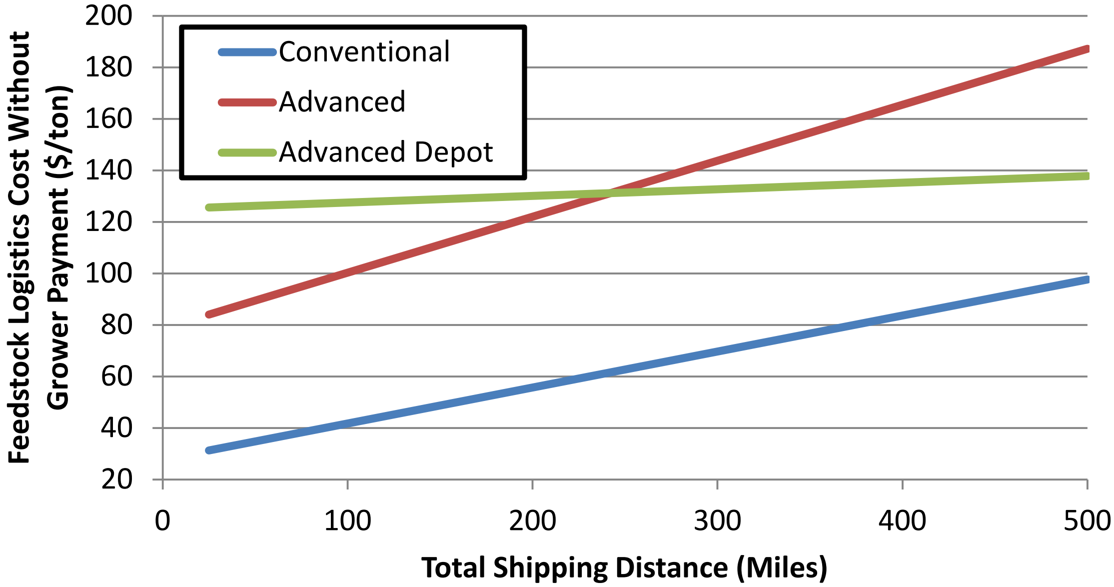


Figure C.11. Logistics cost comparison for the herbaceous scenarios on a mass delivered basis.

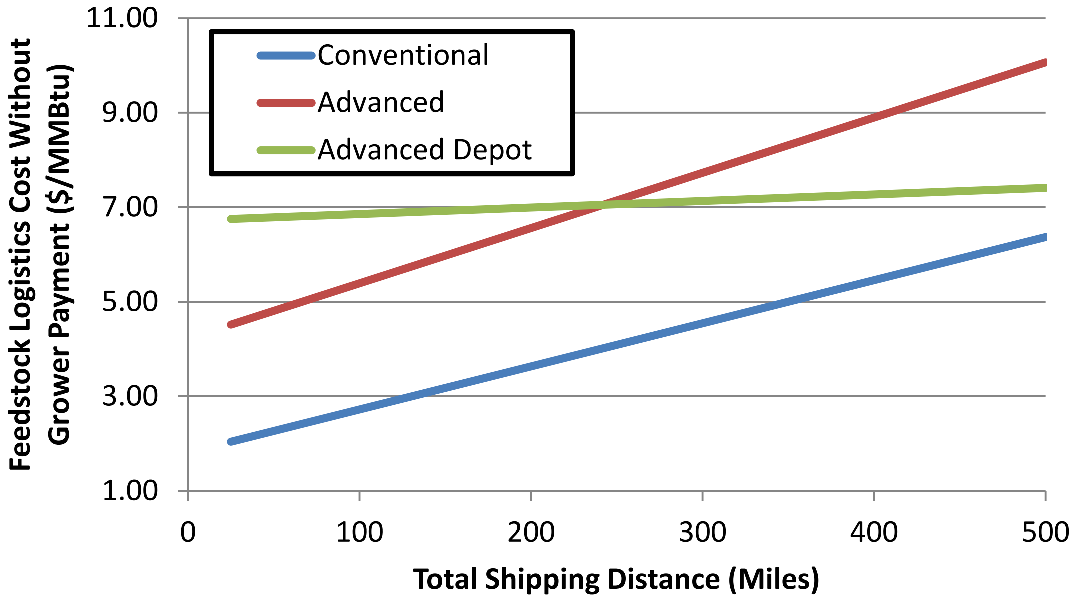


Figure C.12. Logistics cost comparison for the herbaceous scenarios on an energy-delivered basis

C.6 Appendix C References

Hess JR, KL Kenney, LP Ovard, EM Searcy, and CT Wright. 2009. Uniform-Format Solid Feedstock Supply System: A Commodity-Scale Design to Produce an Infrastructure-Compatible Bulk Solid from Lignocellulosic Biomass. INL/EXT-08-17527, Idaho National Laboratory, Idaho Falls, Idaho. Available at www.inl.gov/bioenergy/uniform-feedstock.

Searcy E and JR Hess. 2010. Uniform-Format Feedstock Supply System Design Reports: A Commodity-Scale Design to Produce an Infrastructure-Compatible Biocrude from Lignocellulosic Biomass. INL/EXT-10-20372, Bioenergy Program, Idaho National Laboratory, Idaho Falls, Idaho.

(This page is intentionally left blank)

.

Appendix D

Experimental Support Studies

D.1 Biomass Preprocessing and Co-Milling

This appendix contains testing results conducted at the Idaho National Laboratory (INL) on the preprocessing operations modeled in this report, along with results of grinding tests conducted with biomass and coal in an impact ball mill. This information is provided to support the modeling assumptions and processes presented earlier in this report introduction.

Biopower is defined as the production of power directly from the combustion of biomass. This method of producing power from a renewable source provides a viable technology in the near term for displacing coal and other fossil fuels for power production. In the long term, it enables the development of an infrastructure for the production and delivery of a commodity feedstock material of sufficient consistency and quality that it can be adopted for other end uses, including the production of liquid fuels.

The objective of this work is to provide the technical data needed to confirm representative agriculture, woody, and energy crops could be inserted with the established conveyance, grinding, and transport lines in an existing power plant. This report considers the material properties and processing steps necessary to render biomass compatible with conventional coal-fired boilers in a cofiring scenario. This has many implications in regards to the specifications the biomass material must meet. The following specific areas are considered for this report:

- Energy content
- Ash composition
- Material grindability
- Air-entrained material flowability.

D.1.1 Energy Content

The energy content of biomass is typically significantly lower than coal, and depending on the biomass type, can vary significantly. For cofiring with coal, this energy content can limit the amount of material cofired without reducing the performance and efficiency of the boiler. These properties can also pose a challenge to the boiler feed systems, which are designed for the energy density of coal and must feed a larger solid fraction to achieve burner stoichiometry.

D.1.2 Ash Composition

Problematic properties of biomass can include a higher overall ash content. Biomass may also produce ash that is more corrosive and more prone to agglomeration and adhesion on boiler tubes (reducing the efficiency and performance of the boiler).

D.1.3 Grindability

Coal tends to be brittle and fracture readily. In pulverized coal power plants, it is typically ground in ball mills or other pulverizers wherein the grinding modality is optimized for brittle materials. Biomass typically does not grind well under these conditions and must therefore be treated if it is to be cofed with coal into existing power plant grinding and feed systems.

Raw biomass also exhibits substantially different grinding behavior than coal. Raw biomass typically requires a vastly different grinding modality to reduce it to an optimal particle size. This can include cutting and chopping, as well as hammer milling to achieve appropriate particle size distributions for combustion.

D.1.4 Air Entrainment and Flowability

In coal-fired boilers, pulverized coal is entrained in air flowing through the grinder, and ultimately into the boiler where it is burned. If biomass is to be cofired with coal, it must perform similarly in the feed systems of coal boilers. This includes demonstrating that the material will entrain in air and not settle in delivery tubes.

Three possibilities exist for the combustion of biomass in a pulverized coal boiler. First, the biomass can be handled separately from the coal (i.e., size reduction, feed tube transportation to dedicated burners, and combustion) in specific zones within the boiler. Second, the biomass can be size reduced and inserted with the coal into the coal feed tubes, where it is co-combusted with the coal in the boiler. The third option, which is the most attractive to a boiler owner, is to render the biomass in a format that can be fed with coal directly into the grinding apparatus and is then completely compatible with coal in the boiler. It is expected that the analysis of these options will demonstrate that it is possible to economically produce material that is compatible with coal and can be fed as described in the third option.

This report summarizes testing conducted at INL to determine the cost and effectiveness of new technologies (e.g., leaching, torrefaction, and densification) to render biomass more compatible with coal boilers and at the lowest cost possible.

D.2 Work Summary

For this report, the following biomass types were tested: (1) pine, (2) switchgrass, (3) corn stover, (4) *Arundo donax*, and (5) leached *Arundo donax*. All materials were first ground and dried.

Each type of material was torrefied to two levels (i.e., 230 and 270°C). During torrefaction, data were collected, including analyzing the gas composition released during torrefaction, and overall mass yield of the torrefaction process.

Switchgrass was used as a test case to determine the optimal levels of binder additives (two binders were tested) to produce a suitable pellet. Samples of each material at each torrefaction temperature were pelleted. Pelletization energy was recorded for each material.

Pellets were then dried and sifted to remove fines and tested in a pellet durability tester. Pellet bulk density was also tested.

Pellets were then subjected to an “impact ball mill” grinding test. These tests include 100% coal, 80/20 coal/biomass, and 100% biomass. The resulting particle size distribution was recorded as a measure of the ability to grind and entrain the material in the flow and delivery apparatus of a coal boiler.

Material properties were analyzed to determine the heating value and ash composition of each sample.

D.3 Results

Test results are summarized in the following sections. Each section contains a brief description of the testing or operation and the results obtained during the processing.

D.3.1 Torrefaction

Material was torrefied in the INL Reconfigurable Thermal Treatment System (RTTS) (Figure D.1~~Figure D.1~~). This system enables the controlled torrefaction of biomass as it moves through a reactor column. Temperature and residence time is controlled to obtain the desired level of thermal treatment.

During torrefaction, data were collected to enable characterization of the process parameters. The data collected included the temperature within the reactor vessel, gas composition released during torrefaction, and overall mass yield of the torrefaction process. These data are presented in Table D.1~~Table D.1~~.

Table D.2 reports values from three separate gas analyzers. Analyzer one returns values for O_2, CO, CO_2, and H_2. Analyzer two reports total hydrocarbons (THC), and analyzer three reports CO and CH_4. Note that two analyzers report CO and that reported values vary slightly. This reflects the sensitivity ranges of the analyzers; analyzer three is less sensitive at the lower ranges and therefore less accurate.

During torrefaction, the mass yield of the process at each temperature was captured (Table D.2~~Table D.2~~). The mass of material inserted into the torrefier was measured, as was the mass exiting (the mass of torrefied material). The waste value accounts for several waste streams captured as a result of torrefaction. Waste was collected from the process in the form of condensed liquids, some tars, and some solid particulate captured in the filters and left in the chamber of the torrefier. This was all summed and recorded. The total mass loss represents mass that was unaccounted for. This mass exited the torrefier in the form of light volatiles and gases that were vented from the process. The solid yield was calculated by dividing the mass out by the mass in.

For the processing of herbaceous biomass, it was found that the inclusion of steel balls assisted in flow and mixing in the torrefaction reactor. For one run (switchgrass at 270°C), some steel balls were not separated out of the output stream and the mass reflects the presence of some of these processing aids, resulting in inaccurate mass output measurements.

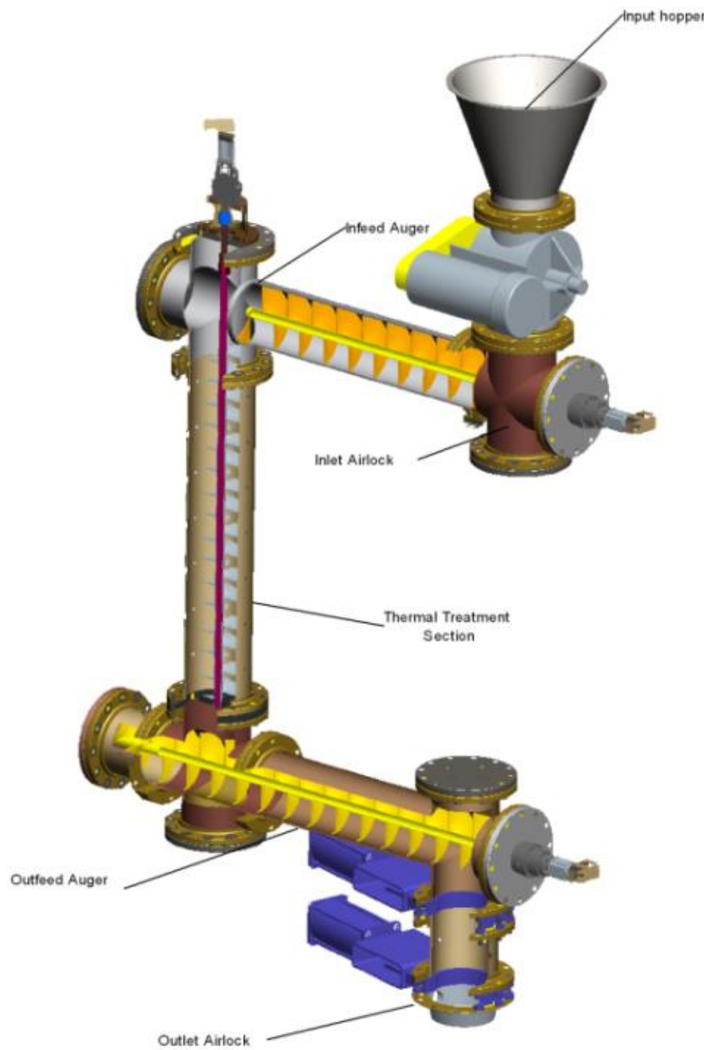


Figure D.1. INL Reconfigurable Thermal Treatment System (RTTS).

Table D.1. Gas analyzer data collected during torrefaction.

Material	Target Temp.	Temp. (°C)		O_2 percent		CO percent		CO_2 percent		H_2 percent		THC ppm		CO percent		CH_4 percent	
		Avg	St. Dev.	Avg	St. Dev.	Avg	St. Dev.	Avg	St. Dev.	Avg	St. Dev.	Avg	St. Dev.	Avg	St. Dev.	Avg	St. Dev.
Switchgrass[a]	180	176.2	1.725	0.46	0.067	0.27	0.018	1.23	0.048	[b]	[b]	1831	212.7	0.071	0.0136	0.009	0.0020
Switchgrass[a]	230	212.5	2.203	0.74	0.047	2.14	0.267	5.93	0.330	[b]	[b]	[b]	[b]	2.031	0.7664	0.117	0.0248
Switchgrass	270	285.0	20.665	0.39	0.213	0.86	0.096	1.55	0.123	0.16	0.036	2959	955.1	0.645	0.2279	0.028	0.0086
Southern Pine	180	178.0	0.000	2.46	0.140	0.03	0.004	1.89	0.033	[b]	[b]	1272	60.3	[b]	[b]	0.039	0.0045
Southern Pine	230	216.7	0.683	5.16	0.140	0.16	0.001	3.07	0.149	[b]	[b]	802	129.3	0.005	0.0058	0.021	0.0007
Southern Pine	270	261.7	3.204	1.79	0.462	2.64	0.640	14.46	0.433	0.86	0.336	5986	1584.3	2.066	0.6197	0.128	0.0563
Arundo donax	180	195.5	5.665	4.73	8.232	2.15	1.583	5.36	3.541	[b]	[b]	5259	3091.8	1.736	1.1832	0.037	0.0159
Arundo donax	270	291.2	8.902	1.06	0.021	1.06	0.072	2.08	0.175	[b]	[b]	5037	745.7	0.853	0.1238	0.045	0.0103
Leached *Arundo donax*[c]	230	239.9	0.458	0.18	0.029	4.59	0.028	10.31	0.087	[b]	[b]	9679	297.9	3.924	0.0220	0.060	0.0047
Leached *Arundo donax*[c]	270	283.6	1.284	0.01	0.014	11.38	1.178	19.27	1.157	[b]	[b]	9918	219.4	9.908	0.2673	0.435	0.1117
Corn Stover	180	--	--	11.84	1.268	0.20	0.002	0.45	0.043	[b]	[b]	326	26.0	0.115	0.0054	0.006	0.0008

(a) These data rely on a small data set due to the limited data available at steady state.
(b) Below detectible limits.
(c) This material torrefied in a different reactor due to the smaller amounts available.

** Samples of Arundo donax provided by PGE (Moody, 2012) and EPRI (Cerezo, 2012)*

Table D.2. Mass balance for the torrefaction process.

Material	Target Temp.	Mass Balance (kg)				Solid Yield (%)
		Mass In	Mass Out	Total Waste	Mass Loss	
Switchgrass	180	653.52	555.35	36	62.17	85
Switchgrass	230	266.84	213.08	22.06	31.7	80
Switchgrass[(a)]	270	65.08	63.08[(a)]	0[(a)]	2[(a)]	[(a)]
Southern Pine	180	1023.35	1004.55	12.9	5.9	98
Southern Pine	230	742.31	718.13	19.7	4.48	97
Southern Pine	270	466.07	343.98	34.24	87.85	74
Arundo donax	180	575.13	503.955	6.04	65.135	88
Arundo donax	270	138.83	117.62	5.89	15.32	85
Leached *Arundo donax*	230	3.7	2.635	0.3	0.765	71
Leached *Arundo donax*	270	3.17	2.04	0.55	0.58	64
(a) Steel ball processing aids inadvertently included in mass output measurement.						

** Samples of Arundo donax provided by PGE (Moody, 2012) and EPRI (Cerezo, 2012)*

D.3.2 Binder Additive

Torrefied material is difficult to pelletize. The torrefaction process drives off light volatile compounds in the biomass and increases the glass transition temperature of the remaining lignin in the material, which plays a key role in the formation of durable pellets. Materials at each of the torrefaction levels were tested with and without binder additives to determine the ability to produce a densified feedstock pellet to improve the transportation logistics of torrefied biomass.

For this test, two binders were used. Both binders were soy oil based and one contained a lignin additive to improve binder effectiveness. To enable another point of comparison, some of the samples were tested with raw material as a binder. For these tests, torrefied material was mixed with a small quantity of raw material (of the same type), and pellets were made. These tests were restricted to less than 10% by mass of raw material so as to not counteract the benefits attained during torrefaction. For the materials tested, a mass fraction of roughly 8% was used, as it appeared to provide the most benefit to pellet production and did not improve significantly at higher mass fractions.

Torrefied feedstock material was first tested without binders to determine the required pellet energy and relative pellet durability. Binders were then added to some of the torrefied material at a level expected to be a mid-range weight percentage of binder material, and the material was pelletized. The pellets were observed during operations, and the amount of binder was adjusted accordingly. The optimal binder amount was then used for subsequent testing. Those results are presented in the following section.

D.3.3 Pelleting and Tests

Using the CME Pellet Mill, the ability to form good pellets and the energy required for pellet formation were recorded. Some of the materials tested presented significant challenges to form good pellets. It is worth noting that the pellet-forming die was not optimized for any particular material and the production of pellets with material-specific dies may enable the formation of more consistent pellets. The results presented here form the basis of a relative comparison between the pellet quality and durability of the materials tested.

After completion of pelleting work, pellets were dried and sifted to remove fines. The resulting pellets were tested in a pellet durability tester, which tumbles the pellets for a given time. Then, the mass of pellets is compared to the mass of fines generated. This ratio is recorded as the pellet durability.

Pellet bulk density was determined by placing a known mass of pellets into a known geometry circular container. The pellets are leveled, and the height of the pellets in the container is measured, and a bulk density is then calculated.

Table D.3~~Table D.3~~ contains a large amount of data, and trends in the data are not immediately apparent. For example, the densification energy does not seem to follow any specific trend as the torrefaction temperature is increased.

After testing as described above, correlation coefficients were calculated to statistically quantify the effect of various binders and other parameters on pellet production. Correlation coefficients near zero indicate no correlation, and correlations near an absolute value of 1 indicate exact correlation between input parameter and output result. Correlation coefficients are summarized Table D.4~~Table D.4~~.

Table D.3~~Table D.3~~demonstrates that the correlations that exist are often small, and some are of no statistical significance (e.g., the addition of binders had no real effect on the pelleting process yield). The value of many of the other correlation coefficients is small, demonstrating only a small correlation between the parameters analyzed and indicating that other factors had an effect on the output parameter variation.

Some interesting trends can be identified based on these data. For instance, as biomass torrefaction temperature is increased, the energy to densify the biomass slightly increases (as would be expected based on previous work where densification of torrefied biomass is more difficult). In conjunction, as the level of binder increases, the densification energy slightly decreases (a benefit of the binders is reduced densification energy).

Surprisingly, the statistical analysis demonstrates that overall, the addition tested binders reduced the overall pellet durability. This is where the strongest interactions are noted when individual binders are selected for analysis.

Table D.3. Densification testing results.

Material	Torr. (°C)	Binder		Pellet Yield (%)	Bulk Dens. (g/cm^3)	Pellet Durability		Dens. En. (kWh)	Energy Consumed per Pellets Produced
		Type	(Wt%)			Avg.	St. Dev.		
Southern Pine	0		0	23.9	0.1346	0.8470	0.0231	0.1310	0.3613
Southern Pine	230		0	21.1	0.3307	0.8716	0.0102	1.2300	5.5395
Southern Pine	270	GG1	1	16.9	0.3984	0.4872	0.0215	0.6700	0.6678
Southern Pine	270	GG2	4	38.3	0.4128	0.5518	0.0120	1.1500	1.1226
Southern Pine	270	Raw	8	26.3	0.3808	0.7911	0.0065	0.9600	1.5805
Southern Pine	270		0	46.5	0.4156	0.7896	0.0137	1.4800	1.2867
Corn stover	0		0	76.5	0.4233	0.8688	0.0143	0.7100	0.4332
Corn stover	230		0	6.9	0.2090	0.3339	0.0113	0.8250	5.2953
Corn stover	230	GG1	1	40.8	0.3987	0.6044	0.0138	1.0700	1.0536
Corn stover	270		0	34.3	0.4806	0.7441	0.0665	1.1100	1.6082
Corn stover	270	GG1	2	36.9	0.4291	0.3415	0.0108	0.6800	0.9001
Corn stover	270	GG2	2	41.5	0.4318	0.3297	0.0167	0.6200	0.7279
Switchgrass	0		0	76.9	0.3977	0.9165	0.0063	0.7500	0.3903
Switchgrass	230		0	40.3	0.5669	0.8435	0.0151	1.7800	1.9685
Switchgrass	230	GG1	1	73.5	0.5707	0.9096	0.0078	1.2300	0.7345
Switchgrass	270		0	16.7	0.3041	0.5333	0.0179	0.7600	2.0440
Switchgrass	270	GG1	1	16.9	0.2962	0.3437	0.0136	0.6700	1.6363
Switchgrass	270	GG1	2	20.0	0.3147	0.3449	0.0216	0.7000	1.4402
Switchgrass	270	GG1	4	32.0	0.3203	0.3119	0.0211	0.6800	0.8299
Switchgrass	270	GG2	2	22.6	0.3133	0.3963	0.0164	0.6900	1.2945
Arundo donax	0		0	39.1	0.3556	0.6926	0.0208	0.5200	0.5101
Arundo donax	230		0	15.9	0.2761	0.3996	0.0196	0.6100	1.5076
Arundo donax	230	GG1	1	44.6	0.4489	0.4009	0.0052	0.5000	0.4612
Arundo donax	230	GG2	1	30.3	0.3630	0.2066	0.0110	0.4000	0.5306
Arundo donax	230	Raw	8	41.8	0.2837	0.5436	0.0207	0.7300	0.6984
Arundo donax	270		0	33.2	0.3912	0.3031	0.0171	0.3800	0.4602
Arundo donax	270	GG1	2	28.4	0.3942	0.1133	0.0137	0.3700	0.5873
Arundo donax	270	GG2	2	41.5	0.3917	0.2023	0.0250	0.4900	0.4514
Arundo donax	270	Raw	8	48.2	0.3614	0.4140	0.0203	0.5300	0.4774
Leached *Arundo donax*	0		0	75.6	0.4027	0.8858	0.0273	0.4600	0.3280
Leached *Arundo donax*	230		0	40.8	0.3903	0.5866	0.0131	0.7400	0.7744
Leached *Arundo donax*	270		0	46.5	0.5025	0.5581	0.0111	0.3700	0.5771
Leached *Arundo donax*	270	GG2	2	37.2	0.5035	0.4808	0.0154	0.5500	1.0267

** Samples of Arundo donax provided by PGE (Moody, 2012) and EPRI (Cerezo, 2012)*

Table D.4. Correlation coefficients for various input/output parameters.

Input Parameter	Output Parameter	Correlation Coefficient
Torrefaction Temperature	Densification Energy/Pellets Produced	0.2308
Overall Binder Performance	Pellet Durability	-0.1948
	Pelleting Process Yield	-0.0380
	Densification Energy/Pellets Produced	-0.1578
Binder 1	Pellet Durability	-0.5661
Binder 2		-0.4604
Raw Biomass		-0.1960
Binder 1	Pellet Bulk Density	-0.0303
Binder 2		0.1438
Raw Biomass		-0.1225
Binder 1	Pelleting Process Yield	-0.1140
Binder 2		-0.0274
Raw Biomass		0.0182
Binder 1	Densification Energy/Pellets Produced	-0.2159
Binder 2		-0.1986
Raw Biomass		-0.1776

D.3.4 Impact Ball Milling

Because the grinding modality in a typical coal-fired boiler relies on impact, such as for a ball mill, the pellets produced in the testing outlined above were subjected to a similar laboratory-scale test.

A bituminous coal sample was first ground in the impact ball mill to a mean particle size of approximately 90 micron. The parameters required to mill the coal to this level were then used to grind samples of biomass pellets and biomass/coal mixtures.

Particle size testing was performed on each sample using a Camsizer™ digital image processing system. For each material tested, the theoretical sieve size was calculated for which a volume percentage of the total sample passes through the sieve. Three volume percentages of material were specified for reporting: 50%, 16%, and 84%. In addition to particle size quantification, the Camsizer™ was also programmed to report the sphericity and aspect ratio of the particles in each test. A lower value for the aspect ratio indicates more elongated particles. A factor for 1/sphericity increasing from unity designates a particle with a corrugated/irregular surface. The resulting particle size distribution was measured for each sample ground, and the results are presented in Table D.5~~Table D.5~~ and Table D.6~~Table D.6~~.

Samples of each biomass material were also characterized and the particle size is recorded in Table D.6 and Table D.6~~Table D.6~~. This characterization was conducted to investigate effect of pelletizing and subsequent re-grinding biomass on particle size. It was expected that the final particle size distribution of the raw biomass samples after pelleting and re-grinding would be similar to the particle size distribution of the biomass prior to pelleting. This test demonstrated that the particle size distribution for raw pelleted and re-ground biomass ranges from roughly 2/3 to 1/2 the size for the raw unprocessed biomass. The torrefied biomass, in comparison, has a substantially reduced particle size, typically around 1/3 the preprocessed biomass size distribution. This is consistent with published results which demonstrate an increase in friability and grinding efficiency for torrefied biomass. The resulting material is more brittle, and performs more like coal upon grinding in this impact ball mill type grinder.

Table D.5. Particle size results for southern pine and corn stover.

Material	Torr. (°C)	Binder		Sieve Size at Which Cum.% Material Passes Through (mm)			1/Sphericity	Aspect Ratio	Notes
		Type	(Wt%)	50%	16%	84%			
Coal	0			0.098	0.051	0.278	1.357	0.674	
Southern Pine[(a)]	0			1.197	0.481	2.186	1.835	0.423	Some fibers
Southern Pine	0			0.542	0.116	2.152	2.475	0.528	Some whole pellets
Southern Pine[(a)]	230			0.779	0.153	1.966	1.883	0.460	Some fibers
Southern Pine	230			0.380	0.099	2.196	2.288	0.539	Some whole pellets
Southern Pine[(a)]	270			0.528	0.125	1.500	1.585	0.477	
Southern Pine	270			0.218	0.064	1.971	1.757	0.590	
Southern Pine	270	Raw	8	0.207	0.068	0.865	1.761	0.584	
Southern Pine	270	GG1	4	2.105	0.812	4.338	1.855	0.644	Moderate agglomeration
Southern Pine	270	GG2	4	1.832	0.755	3.884	1.712	0.658	
90/10 Coal/S.P.	0			0.093	0.050	0.240	3.077	0.543	
80/20 Coal/S.P.	230			0.109	0.054	0.839	1.527	0.608	
80/20 Coal/S.P.	270			0.107	0.052	1.618	1.534	0.629	
Corn stover[(a)]	0			0.742	0.247	1.905	2.188	0.454	Some fibers
Corn stover	0			0.455	0.098	3.171	2.278	0.534	Some whole pellets
Corn stover[(a)]	230			0.377	0.146	0.942	1.901	0.492	Some fibers
Corn stover	230			0.136	0.056	1.533	1.776	0.572	
Corn stover	230	GG1	1	1.210	0.272	3.657	2.410	0.581	Minor agglomeration
Corn stover[(a)]	270			0.259	0.088	0.836	1.721	0.527	
Corn stover	270			0.239	0.067	6.278	2.370	0.565	
Corn stover	270	GG1	2	0.718	0.193	2.841	1.818	0.632	
Corn stover	270	GG2	2	0.714	0.146	3.393	1.916	0.625	Minor agglomeration

(a) These samples were not pelletized before characterization.

Table D.6. Particle size results for Switchgrass and *Arundo Donax*.

Material	Torr. (°C)	Binder		Sieve Size at Which Cum.% Material Passes Through (mm)			1/Sphericity	Aspect Ratio	Notes
		Type	(Wt%)	50%	16%	84%			
Switchgrass[(a)]	0			0.975	0.278	3.838	6.667	0.359	Some fibers
Switchgrass	0			0.638	0.139	3.389	2.660	0.543	Some whole pellets
Switchgrass[(a)]	230			0.442	0.144	1.475	2.618	0.402	Some fibers
Switchgrass	230			0.194	0.070	0.603	1.751	0.583	
Switchgrass	230	GG1	1	1.001	0.180	4.939	2.519	0.578	
Switchgrass[(a)]	270			0.620	0.173	2.061	2.841	0.412	Some fibers
Switchgrass	270			0.544	0.085	5.070	2.315	0.573	
Switchgrass	270	GG1	1	1.220	0.175	5.912	2.545	0.554	Minor agglomeration
Switchgrass	270	GG1	2	0.923	0.129	4.186	2.137	0.589	Minor agglomeration
Switchgrass	270	GG1	4	1.793	0.521	4.330	1.919	0.633	Minor agglomeration
Switchgrass	270	GG2	2	1.089	0.273	3.153	1.931	0.625	Minor agglomeration
Arundo donax[(a)]	0			0.459	0.117	1.307	2.037	0.403	Some fibers
Arundo donax	0			0.258	0.080	1.275	1.953	0.554	
Arundo donax[(a)]	230			0.344	0.112	1.091	1.957	0.427	Some fibers
Arundo donax	230			0.293	0.074	4.139	2.257	0.563	
Arundo donax	230	Raw	8	0.474	0.095	4.578	2.370	0.559	
Arundo donax	230	GG1	1	0.861	0.167	3.356	2.198	0.604	
Arundo donax	230	GG2	1	0.868	0.185	3.234	2.128	0.606	Minor agglomeration
Arundo donax[(a)]	270			0.364	0.103	1.152	1.821	0.452	Some fibers
Arundo donax	270			0.227	0.066	3.470	1.957	0.580	
Arundo donax	270	Raw	8	0.228	0.072	2.199	1.689	0.606	
Arundo donax	270	GG1	2	0.798	0.286	2.236	1.799	0.635	Moderate agglomeration
Arundo donax	270	GG2	2	1.165	0.322	3.331	1.898	0.630	Minor agglomeration
Leached A.D. [(a)]	0			0.680	0.243	1.984	2.475	0.426	Some fibers
Leached A.D.	0			0.233	0.084	0.677	1.869	0.534	Some fibers
Leached A.D.	230			0.175	0.061	2.324	1.799	0.585	
Leached A.D.	270			0.104	0.049	2.332	1.531	0.619	
Leached A.D.	270	GG1	2	0.484	0.084	2.831	1.825	0.621	

(a) These samples were not pelletized before characterization.

** Samples of Arundo donax provided by PGE (Moody, 2012) and EPRI (Cerezo, 2012)*

Because the goal of this research is to produce a biomass material with properties that render it completely compatible with coal in a coal-fired boiler, some grinding tests were conducted with biomass and coal mixes. These tests are shown in Table D.5~~Table D.5~~. Previous work has suggested that a cofiring ratio of up to 10% raw biomass can be accomplished without derating the boiler and ratios of as much as 20% or more can be accomplished if the biomass has been torrefied to increase its energy density. Three tests were conducted where biomass was milled with coal: one with 10% (by mass) of biomass, one with

20% Southern Pine torrefied at 230°C, and one with 20% Southern Pine torrefied at 270°C. The results demonstrate that the mean particle sizes of each test are near the target of 90 micron. The largest variation is demonstrated in the screen size to pass 84% of the ground material. For the raw sample, this is near the coal sample at 0.240 mm, but higher mix ratios with torrefied biomass demonstrate substantially larger screen sizes necessary to pass 84% of the material. Further replications of this testing, including the performance of co-milling with herbaceous biomass are suggested to better characterize the grinding performance of other biomass types when milled with coal. Also, given the milling action of a coal pulverizer, wherein particles are transported out of the mill when the correct particle size is achieved, and larger particles continue to be ground, future investigations will consider the tendency of biomass particles to accumulate in a coal pulverizer, possibly reducing its efficiency and throughput.

Table D.5~~Table D.5~~ and Table D.6~~Table D.6~~ also demonstrate that the mean particle size for the untreated biomass samples (without binder) is larger for the 270°C torrefied biomass than for the 230°C torrefied biomass. It has been noted that electrostatic forces between sufficiently small particles can cause some agglomeration, even in the absence of binders (which tend to exacerbate the tendency of the biomass to agglomerate). Future work will focus on the utilization of a physical screen-type size characterization method, which may be more able to mechanically break up the agglomerations, resulting in a more accurate particle size distribution.

For all biomass samples, the average particle size was larger than the 98 micron coal sample. A few samples came close to this average size: corn stover and switchgrass torrefied at 230°C and pelletized without a binder. The blends of coal and Southern Pine were also very close to the average particle size of the coal sample alone; however, the sieve size at which 84% of the material was able to pass through was somewhat larger than for coal alone. Because biomass tends to be significantly more reactive than coal, it is reasonable to assume that these particle sizes will result in favorable combustion properties, although further testing is required to verify this assumption.

Using raw biomass as the binder for pelletization seemed to result in the least change in particle size properties compared to pelletizing a given material without a binder. In all cases, the use of binder 1 (GG1) and binder 2 (GG2) resulted in an increase in the average particle size. In fact, all samples that exhibited minor to moderate agglomeration were pelletized using one of these binders. Testing with switchgrass also indicated that using more binder results in a larger average particle size and potentially increases the tendency for agglomeration of the milled material.

In all cases, the average particle size of the torrefied biomass was similar to, or smaller than, non-torrefied biomass. For Southern Pine and *Arundo donax*, increasing the torrefaction temperature from 230 to 270°C resulted in a somewhat smaller average particle size. The opposite effect was observed when increasing the torrefaction temperature for corn stover and switchgrass.

Note that for some of the biomass samples, the biomass particles tended to agglomerate and form larger particles, resulting in a larger apparent particle size distribution. This is illustrated in the photographs obtained from the Camsizer™ (Figure D.2~~Figure D.2~~).

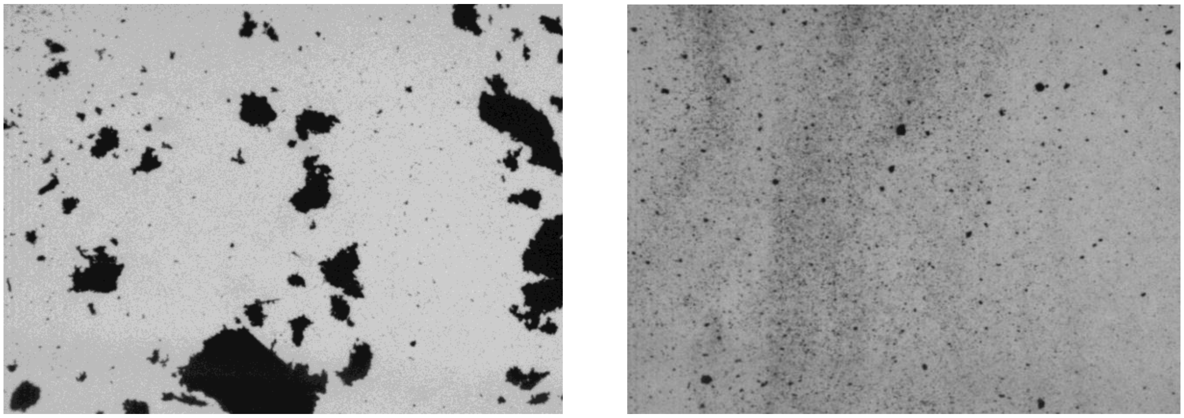


Figure D.2. Camsizer™ Images Showing Agglomeration of *Arundo Donax* (270°C torrefaction, 2 % GG1 binder) (left image) Compared to Coal (right image).

Figure D.3~~Figure D.3~~ shows two types of biomass with higher percentages of binder additives. The effect illustrated in Figure D.2~~Figure D.2~~ as seen by the Camsizer™ are also apparent in the photographs, where the material is clearly seen to form larger agglomerates which the optical sizing process is unable to distinguish or dissociate into fundamental particle sizes. It is expected that a sufficiently turbulent flow feed system would cause these agglomerated particles to dissociate, but again, more testing is required to confirm this assumption. Given that binder materials had little positive effect on the formation and durability of pellets, a more suitable binder material must be identified.

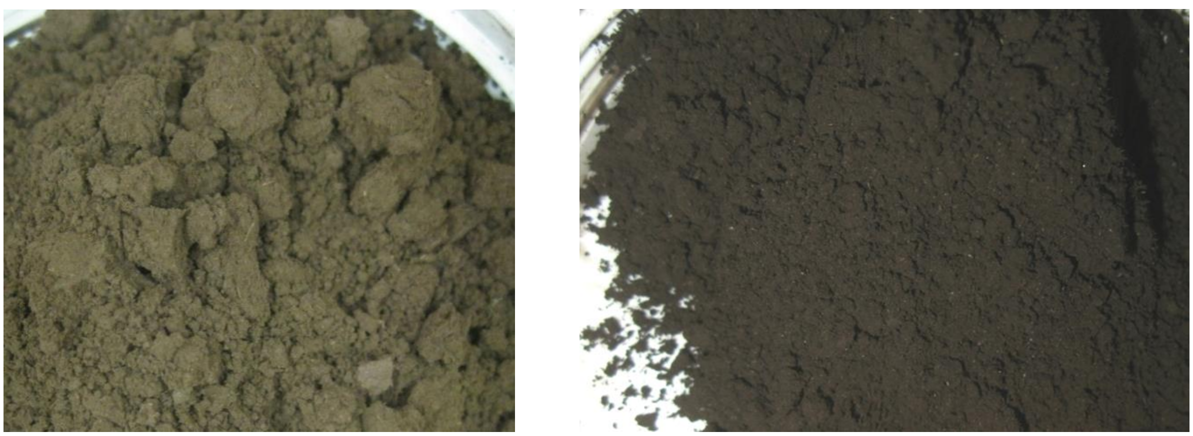


Figure D.3. Photographs of 270° torrefied southern pine with 4% binder (left), and 270° torrefied *Arundo Donax* with 2% binder (right).

For some samples, particularly those not torrefied, some pellets made it through the milling process virtually intact (see Figure D.4~~Figure D.4~~). Of the biomass types tested, only *Arundo donax* did not exhibit this effect.

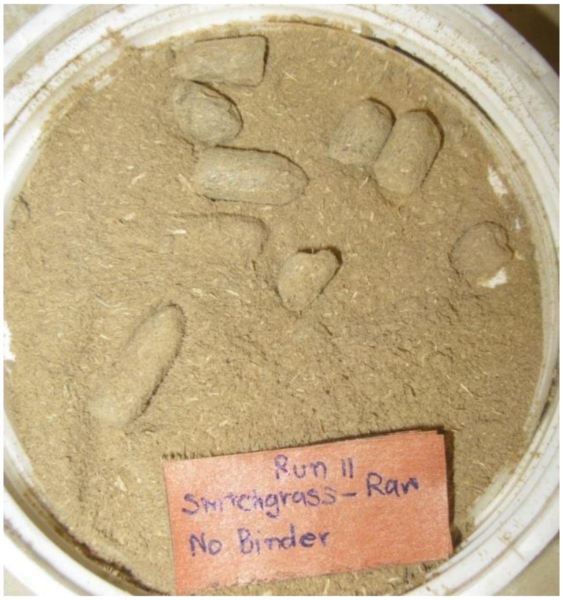


Figure D.4. Switchgrass sample showing that some pellets remained intact after the milling process.

These results show that significant work remains to improve preprocessing techniques to achieve the desired particle size properties for biomass materials being ground in coal grinders. In addition, flow-loop and fluidization testing are recommended to determine the optimal biomass properties to allow pulverization and feeding in existing coal-fired power plant systems. Future work will also consider the optimal biomass particle size at a given pretreatment condition for combustion, which will inform the decisions about what percentage of biomass cofiring can be achieved without retrofit of an existing coal boiler.

D.3.5 Suitability for Use in a Coal Boiler

To determine the suitability of firing a specific biomass in a given coal boiler design, combustion testing in a representative boiler will likely be required. However, it is possible to perform an initial screening of material based on defined specifications for the fuel. In 2010, the Electric Power Research Institute (EPRI) drafted a preliminary specification for pelletized, torrefied biomass based on experience with coal boilers. This specification was updated by EPRI in 2012 (INL – EPRI private communications).The testing and analyses performed by INL allow a comparison of results to a subset of these specifications, as shown in Table D.7~~Table D.7~~.

Woody biomass easily met the 20 wt% ash requirement, as did all of the tested herbaceous biomass types. For *Arundo donax*, leaching was shown to reduce ash content by a few percent. A higher torrefaction temperature resulted in higher ash content of the finished fuel due to increased mass loss of volatile material during torrefaction. It may be possible to reduce ash content in the herbaceous biomass types further by modifying the leaching process.

Table D.7. Suitability of resulting biomass properties for direct fire in a coal boiler.

Material	Torr	Binder		Ash	Volatile Matter	HHV	Bulk Density	Energy Density	Mechanical Durability	N	S	Cl	Na + K
	°C	Type	wt%	wt%, dry	wt% , dry	Btu/lb, daf	lb/ft^3	kBtu/ft^3	% intact	wt% , dry	wt% , dry	wt% , dry	ppm, dry
Proposed EPRI Specification:			<2[(a)]	< 20	> 60	8,500–12,000	45–55	400–700	85.0–97.5	<1	<0.6	<0.03	<4,000
Southern Pine	0			2.40	86.02	8,935	8.41	75	84.7	0.462	0.007	0.15	3,435
Southern Pine	230			2.88	84.81	8,981	20.65	185	87.2	0.474	0.014		
Southern Pine	270			0.91	78.25	9,406	25.95	244	79.0	0.521	0.013		
Southern Pine	270	Raw	8	0.82	79.41	9,545	23.78	227	79.1	0.525	0.011		
Southern Pine	270	GG1	4	0.81	79.90	9,844	24.87	245	48.7	0.511	0.011		
Southern Pine	270	GG2	4	0.94	78.50	10,008	25.77	258	55.2	0.512	0.031		
Corn stover	0			6.51	80.32	8,385	26.43	222	86.9	0.804	0.042		
Corn stover	230			6.99	77.40	8,648	13.05	113	33.4	0.866	0.041		
Corn stover	230	GG1	1	7.79	77.78	8,823	24.89	220	60.4	0.829	0.050		
Corn stover	270			13.32	52.98	10,859	30.00	326	74.4	1.151	0.061		
Corn stover	270	GG1	2	12.76	54.74	11,018	26.79	295	34.1	1.139	0.034		
Corn stover	270	GG2	2	12.96	55.00	11,080	26.96	299	33.0	1.125	0.062		
Switchgrass	0			5.42	81.81	8,169	24.83	203	91.7	0.958	0.065		
Switchgrass	230			6.40	77.63	9,016	35.39	319	84.4	0.838	0.085		
Switchgrass	230	GG1	1	5.69	78.67	8,943	35.63	319	91.0	0.899	0.072		
Switchgrass	270			9.25	70.51	9,839	18.98	187	53.3	1.047	0.098		
Switchgrass	270	GG1	1	7.67	71.06	9,791	18.49	181	34.4	1.113	0.088		
Switchgrass	270	GG1	2	7.76	71.51	9,850	19.64	193	34.5	1.119	0.088		
Switchgrass	270	GG1	4	7.45	72.80	9,854	20.00	197	31.2	1.122	0.087		
Switchgrass	270	GG2	2	7.78	71.47	9,836	19.56	192	39.6	1.115	0.068		
Arundo donax	0			12.96	75.01	8,473	22.20	188	69.3	2.010	0.306	5.05	25,483
Arundo donax	230			13.59	70.40	9,107	17.24	157	40.0	2.199	0.286		
Arundo donax	230	Raw	8	13.96	71.23	9,188	17.71	163	54.4	2.392	0.318		
Arundo donax	230	GG1	1	17.80	61.37	10,131	28.03	284	40.1	2.300	0.325		
Arundo donax	230	GG2	1	17.39	61.59	10,001	22.66	227	20.7	2.327	0.294		
Arundo donax	270			16.59	57.47	10,294	24.42	251	30.3	2.589	0.330		
Arundo donax	270	Raw	8	17.36	58.93	10,084	22.56	228	41.4	2.578	0.366		
Arundo donax	270	GG1	2	16.60	59.07	10,597	24.61	261	11.3	2.442	0.294	5.26	34,305
Arundo donax	270	GG2	2	17.79	59.44	10,595	24.45	259	20.2	2.460	0.332	4.83	33,199
Leached A.D.	0			8.76	79.21	8,408	25.14	211	88.6	1.731	0.159	0.73	5,204
Leached A.D.	230			11.90	71.95	9,510	24.37	232	58.7	1.878	0.124		
Leached A.D.	270			18.40	48.62	11,802	31.37	370	55.8	2.408	0.126		
Leached A.D.	270	GG2	2	16.01	55.95	11,508	31.43	362	48.1	2.194	0.129		

Red values indicate that the material does not meet the specification proposed by EPRI.
(a) This specification applies only to binders that differ from the biomass material.

** Samples of Arundo donax provided by PGE (Moody, 2012) and EPRI (Cerezo, 2012)*

The minimum specification for volatile matter is 60 wt% . The purpose of this specification is to ensure that combustion occurs early enough in the specified sections of the boiler. This specification was met for most of the biomass tested. However, for corn stover and *Arundo donax*, torrefaction at 270°C resulted in volatile matter content below this specification. Combustion testing is needed to ensure that this specification is properly framed. Biomass is typically much more reactive than coal, and the extent to which this has an effect on the combustion of biomass with coal should be characterized. This will allow a better understanding of the importance of this specification, and the level at which it should be set, to ensure desired combustion properties.

The heating value specification of 8,500 to 12,000 Btu/lb (higher heat volume [HHV], dry, ash-free basis) is established to ensure that biomass fed to the boiler closely matches that of coal to enable cofiring without de-rating the boiler. In every material tested, torrefaction was able to improve the heat content of the biomass to achieve this specification.

Bulk density of the torrefied pellets is important to ensure seamless transport and feeding of material in systems that were originally designed for coal. Unfortunately, the bulk density for all pellets tested fell well below the lower specification of 45 lb/ft^3. Hence, flow and feed testing of these materials will be required to determine if they can be transported, stored, and fed with existing coal plant equipment. Because of the low bulk density of the pellets, the energy density specification was also not met for all materials tested.

None of the pellets produced met the minimum specification for mechanical durability of 95 % intact. In fact, other than raw biomass, the binders selected resulted in less durable pellets. Hence, additional research and testing is required to improve pellet durability via the inclusion of other types of biomass binders.

A maximum nitrogen content of 1 wt% is specified to limit NO_X emissions during combustion (i.e., fuel NO_X). All of the Southern Pine, and some of the agricultural residues met this specification and the leached *Arundo donax* came close to meeting this specification. Further, nitrogen bound in the biomass does not appear to be volatile, as it increases as the torrefaction temperature is increased. Combustion testing is recommended to determine the fate of nitrogen bound in the biomass. Results of such testing may allow the specification to be relaxed.

All materials tested met the maximum sulfur specification of 0.6 wt%. As shown in the results of these tests, leaching of *Arundo donax* is capable of reducing the sulfur content.

Chlorine content is an important fuel specification, as excessive chlorine can contribute to accelerated corrosion within the boiler. None of the biomass materials tested met the required maximum chlorine specification of 0.03 wt%. For these analyses, only Southern Pine and *Arundo donax* were tested. The decision to limit these tests was based largely on previous experience which had demonstrated that this sample of *Arundo donax* was particularly high in inorganics, and it was desirable to characterize this, in conjunction with the leaching experiment to demonstrate the potential capabilities of a leaching operation. In addition, Southern Pine was tested to demonstrate the comparison of *Arundo donax* to a baseline material.

Excessive sodium and potassium content in the fuel can cause fouling in the boiler; hence, a maximum specification of 4,000 ppm has been proposed. While Southern Pine was able to achieve this specification, *Arundo donax* was not. However, leaching was very effective at reducing alkali content in the biomass. With further development of the leaching process, it may be possible to achieve the alkali specification for *Arundo donax*.

While the data presented is not exhaustive (e.g., only one leaching process was tested and only small samples of select biomass types were included) general trends do emerge from the data.

First, as biomass (of whatever type) is torrefied, it is possible to increase the energy density significantly. Judicious selection of torrefaction process parameters can increase the energy content to the level of some types of coal.

Second, leaching can significantly improve biomass properties, particularly in reducing the presence of chlorine, sodium, potassium, and overall ash content. Further research and testing should focus on optimizing the harvest and collection practices to minimize initial ash content (i.e., the inclusion of dirt contamination in the initial collection of biomass), optimizing leaching process parameters (including the leachate), and testing other herbaceous sources of biomass.

Third, future research should focus on the development and testing of the specifications against which the biomass has been compared. This would enable a more complete understanding of the specific requirements that a biomass type must achieve to be well suited for cofiring. This may require some boiler-specific testing and modeling to determine the performance of these materials in specific cases.

D.4 Conclusions

This analysis demonstrated the potential for the correct combination of preprocesses to render biomass compatible for cofiring in pulverized coal boilers. This work has focused on demonstrating the series of preprocessing operations necessary to enable biomass to be used as a drop-in fuel for pulverized coal boilers. However, more research should be conducted to definitively determine the processes necessary to render biomass compatible with coal. These areas of research include further work in the selection and testing of binder materials, appropriate torrefaction procedures for biomass not tested here, leaching process parameters, and coal boiler specifications and tests.

This testing also demonstrated several types of biomass that may represent a best path forward for initial biopower development. These include woody biomass (e.g., Southern Pine) and many herbaceous biomass types, perhaps combined with a leaching process. The development of a biomass feedstock based on these materials could enable rapid realization of necessary specifications and would enable subsequent development to enable the upgrading of lower-grade feedstock materials.

D.5 Reconfigurable Thermal Treatment System

Torrefaction is a preconversion thermal treatment that processes biomass at atmospheric pressure in the absence of oxygen at temperatures between 200 and 300°C (Usla et al. 2008). Raw biomass contains appreciable amounts of oxygen, nitrogen, sulfur, chlorine, fluorine, and alkali and alkaline earth metals that can deposit in the combustion system and downstream, making the system thermally unstable. Biomass is almost entirely converted to volatile matter, which can produce tars and oils that can be problematic in conventional coal combustion equipment. Torrefaction can be used to convert raw biomass into a high-energy-density, hydrophobic, compactable, grindable, solid with a lower oxygen-to-carbon ratio that more closely resembles coal when combusted in a power plant. More technical information on torrefaction can be found in Tumuluru et al. (2010b).

One challenge with torrefaction is scale-up of the equipment. Current industrial-scale torrefier designs range in capacity from <5 to~20 ton/hr. Hence, to supply 20% of the energy requirement for a 400-MW plant, anywhere from 3 to 12+ torrefaction trains would be required. While this may be reasonable given the scenario considered in this study, it would be challenging to implement on a large-scale scenario (e.g., supplying 100% of the energy requirement for a 400-MW plant). Such a scenario would likely require a depot concept or a higher-capacity torrefaction train. Other torrefaction challenges related to the state of maturity of the technology include fuel flexibility, emissions, process validation, product validation, product standardization, economic optimization, and financing (Kleinschmidt 2011).

INL was motivated by these challenges to design and construct the Reconfigurable Thermal Treatment System (RTTS) (Figure D.5). The RTTS can be reconfigured and adapted as necessary to investigate torrefaction methods and parameters for torrefaction of a variety of biomass types and material formats.

The RTTS meters material into the system via the inlet airlock. Material is then moved horizontally by the in-feed auger until it drops into the reactor thermal treatment section. Both the inlet airlock and in-feed auger are tied to an automatic fill system that maintains the system level just below the upper tee section.

As the material progresses down the reactor section, it is brought up to the desired process temperature, and that temperature is maintained until the material exits at the bottom. Material removal and residence time are controlled by the speed of the out-feed auger. This section also provides cooling of the material prior to exit via the outlet airlock.

Material in the reactor section can be agitated or stirred as needed to maintain consistency. The agitation mechanisms can be removed as needed to facilitate non-flowing materials. The different configurations allow for local material movement horizontally (inward or outward) and vertically (upward or downward) relative to the flow.

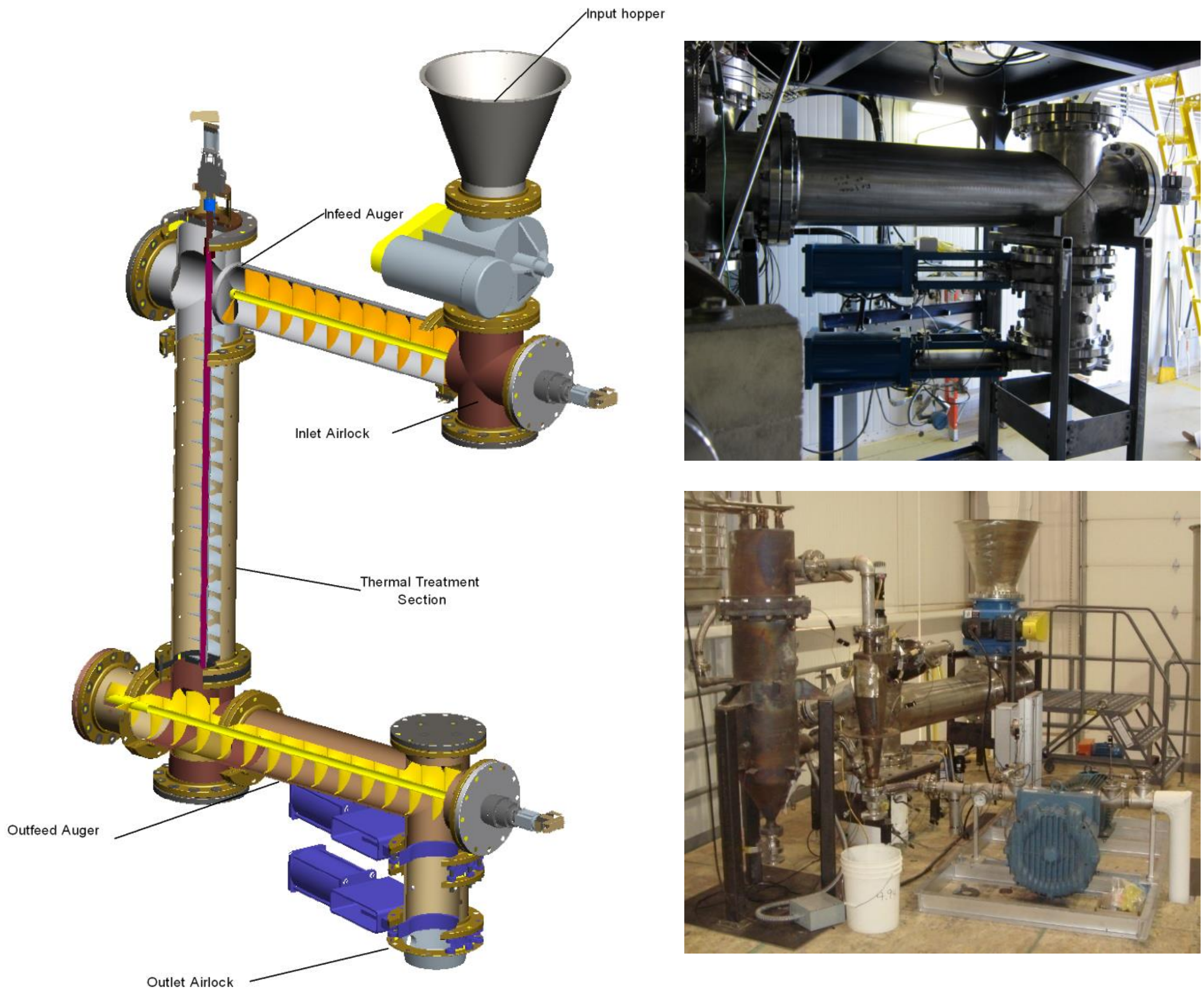


Figure D.5. RTTS schematic and photographs.

A torrefaction Module for the BLM toolset, based on the Process Flowsheet shown in Figure D.6 is calibrated with the RTTS results for a given feedstock. Southern Pine and switchgrass were torrefied to provide data to tune the torrefaction process model. In turn, this model was used to estimate the heat balance and energy requirements for a full-scale torrefaction facility.

For the current study, Southern Pine and switchgrass were torrefied in the RTTS at a temperature of 230°C and a residence time of 20 minutes. Product properties and mass loss data from this run were input into the torrefaction model to calculate the torrefaction fuel requirement, and then total biomass cost for the woody and herbaceous scenarios, including torrefaction, were calculated using the BLM.

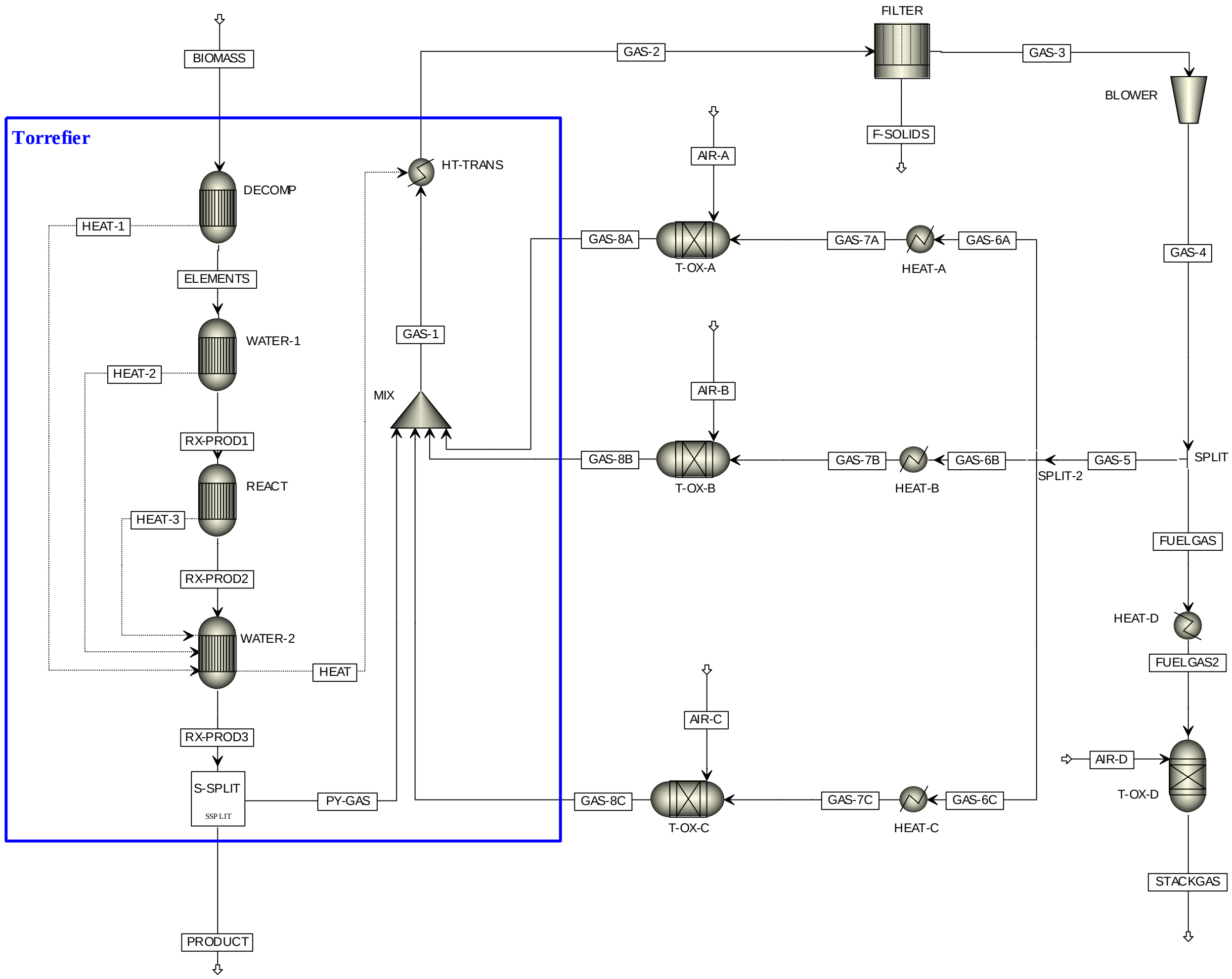


Figure D.6. Torrefaction process model diagram from the BLM.

D.6 Cofeeding Coal and Biomass in Pulverized Coal Systems

Biomass cofiring poses challenges for retrofit of existing boilers, primarily because of feeding and ash characteristics. A substantial amount of commercial experience has been gained and documented (Middlekamp 2011; Ortiz et al. 2011; NREL1998), but is not discussed in this report.

Coal from feed silos is generally fed to bowl mills that are swept by a portion of the preheated combustion air. This technique has several advantages for the power plant firing coal and a potential disadvantage when cofiring with biomass.

The flow of heated air over the bowl mill entrains coal particles ground to a sufficiently small size to burn completely in the boiler. Larger particles do not entrain and remain on the mill bowl or are removed from the gas stream by separator blades above the mill bowl and fall back to the bowl for additional grinding.

The hot air flowing through the mills partially dries the entrained coal particles as they are pneumatically conveyed to the burners. The dried particles heat, devolatilize, and ignite more readily than non-dried particles when they are carried through the burner into the flame and radiant furnace box.

The hot-air-swept coal mills provide a consistent size and energy distribution to a plurality of burners in the furnace with a minimum of equipment and controls. For power plants of the size of the representative plant (400 MW), four to six mills are expected. Mills require periodic maintenance to replace worn crushing surfaces; thus at any given time, one or more mills may be down for maintenance.

Partially dried biomass can conceptually be added to the coal feed to the bowl mills. However, additional testing is required to determine whether simple cofeed is the best solution for cofiring. Biomass ignites more readily than coal because of its higher volatile content. Fuel ignition in the mill or burner piping prior to delivery to the furnace is undesirable from a safety and operating standpoint. In addition, biomass has different aerodynamic and grinding characteristics.

Conversely, torrefied biomass behaves much more like coal. It may be stored in outdoor piles as typically done at coal power plant and has similar grinding and ignition properties as coal. Thus minimal modifications are expected for plants adding torrefied biomass to the fuel mix. As shown in Table D.8, adding torrefied wood to PRB coal actually increases the higher heating value (HHV) and lower heating value (LHV) of the blend due to the low moisture and ash contents of the torrefied material.

Table D.8. Coal and biomass elemental analysis.

Fuel Composition	Black Thunder	Southern Yellow Pine	Torrefied Yellow Pine	Black Thunder w/10% Pine	Black Thunder w/20% Torrefied Yellow Pine
Moisture (wt%)	25.92	12	0.79	24.32	21.18
Dry elemental (wt%)					
Ash	7.84	0.20	0.47	6.96	6.45
Carbon, C	68.26	47.20	52.57	65.85	65.30
Hydrogen, H	4.94	6.60	5.99	5.13	5.14
Nitrogen, N	0.76	0.20	0.45	0.69	0.70
Chlorine, Cl	0.000	0.00	0.00	0.00	0.00
Sulfur, S	0.40	0.00	0.006	0.36	0.33
Oxygen, O	17.79	45.80	40.51	21.01	22.08
HHV (Btu/lb) (as received)	8,718	7,380	9,458	8,564	8,858
LHV (calc) (as received)	7,406	7,193	8,886	8,266	8,497

D.7 Appendix D References

Cerezo, L., 2012. Electric Power Research Institute, Personal Communications

Moody, J., 2012, Portland General Electric, Personal Communications

Kleinschmidt CP. 2011. "Overview of International Developments in Torrefaction." Published at the *3rd Central European Biomass Conference (CEBC)*, Graz, Austria, January 28, 2011.

Middelkamp J. 2011. "Challenges Facing Expansion and Future of Cofiring: Will Cofiring Survive the Battle of the Renewables?" *IEA Clean Coal Centre: 1st International Workshop on Cofiring Biomass with Coal*, Yorkshire, United Kingdom, January 25–26, 2011.

NREL – National Renewable Energy Laboratory. 1998. *International and Domestic Market Opportunities for Biomass Power Volumes I and II*. NREL/SR-570-25492, National Renewable Energy Laboratory, Golden, Colorado.

Ortiz DS, AE Curtright, C Samaras, A Litovitz, and N Burger. 2011. *Near-Term Opportunities for Integrating Biomass into the U.S. Electrical Supply: Technical Considerations*. RAND Corporation, Santa Monica, California.

Tumuluru JS, S Sokhansanj, CT Wright, and R Boardman. 2010b.*Biomass Torrefaction Process Review and Moving Bed Torrefaction System Model Development*. INL/EXT-10-19569, Idaho National Laboratory, Idaho Falls, Idaho, and Oak Ridge National Laboratory, Oak Ridge, Tennessee.

Uslu A, APC Faaij, and PCA Bergman. 2008. "Pre-Treatment Technologies and Their Effect on International Bioenergy Supply Chain Logistics: Techno-Economic Evaluation of Torrefaction, Fast Pyrolysis, and Pelletisation." *Energy* 33(8):1206–1223

Appendix E

Power Plant Models

E.1 Power Plant Modeling Overview

The following sections summarize the major optional units modeled using the Aspen Plus® Power Plant Model. Heat rate (feed fuel energy required to produce a kilowatt-hour of electricity), pump and fan power requirements, water use, and flue gas cleanup performance predictions are determined from input coal composition and quantity based on empirical data for combustion efficiency and fly ash carryover.

Recirculating cooling water from a cooling tower is assumed for condensing the turbine exhaust steam. The assumptions for the 100% coal power plant are based on NETL Reference Case 9 (NETL 2007) with modifications. The net power production is adjusted to 400 MW and PRB coal with no FGD is substituted for Illinois No. 6 coal with limestone FGD.A sketch of the representative plant is shown in Figure E.1.

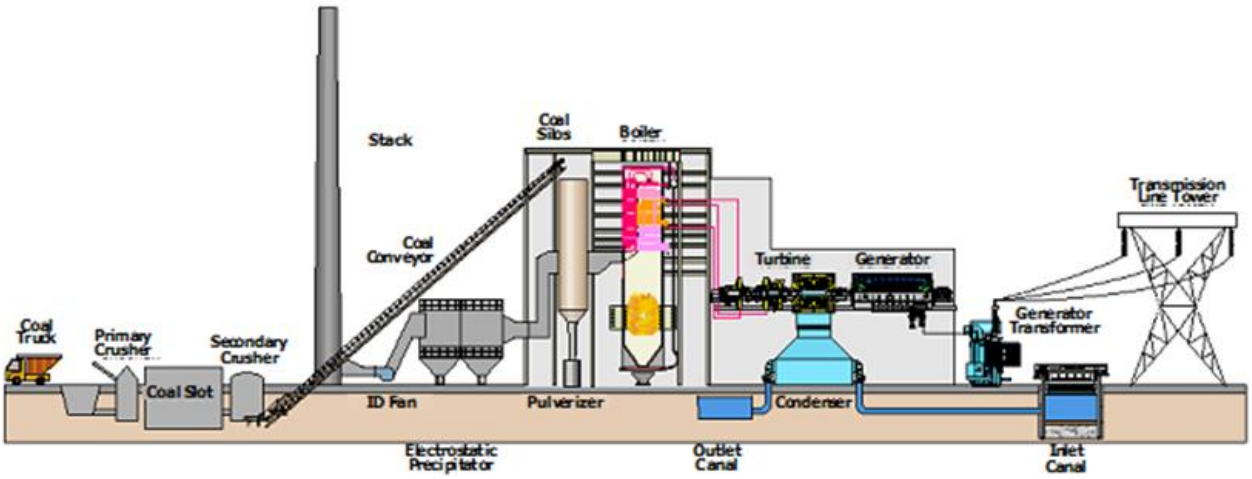


Figure E.1. Representative power plant sketch.

Two sets of power plant models were developed in this study. First, the 100% coal analysis is based on a nominal 400-MW plant, a scale determined from nonproprietary data available from EIA (2012a) and Excel workbooks that contain specific information about existing and planned generators and associated environmental equipment. These data are submitted by coal-fired electric generators via U.S. file Forms 860 and 923 reported to the EIA annually, accounting for all electric generators of combined nameplate capacity of ≥10 MW. Following the initial model, a set of models for the specific Alabama and Ohio power plants were produced and validated as described below.

If the power plant is adjacent to the coal mine supplying fuel to the plant, truck or conveyor delivery is typically used; otherwise train or barge delivery is more common. An Aspen Plus® model was built with this configuration. The primary submodels for the simulation are as follows:

- *Coal Preparation*. A crushing and drying model to determine the pulverization power requirement. (This model was validated with information from Alstom.)
- *Boiler*. A combustion model to determine the air composition and excess air required to burn the specified coal, generate flue gas of the correct composition, and determine the energy available for steam generation. International Organization for Standardization conditions for ambient air temperature, pressure, and relative humidity are assumed. Biomass and coal are assumed to mix and burn to an average specified carbon content in the ash.

- *Air Heater, ESP*. Hot flue gas exiting the boiler is cross-exchanged with the incoming combustion air to a temperature (normally 150 to 175°C) that is above the acid gas dew point. Particulate in the cooled flue gas is removed by an ESP.
- *Steam Cycle*. Power is generated by delivering superheated steam from the boiler through a subcritical steam cycle with a single reheat.
- *Cooling Tower*. A counter flow mechanical draft cooling tower is used to condense the steam turbine exhaust.

The overall model structure is shown in Figure E.2. Each major block contains the collection of unit operations that represents the actual power plant unit operation. The steam cycle is shown as an example of one block that has been expanded.

Input to the model is facilitated with an Excel calculator sheet linked to the simulation. Entries provide parameters such as the power production target, feed coal selection, and ambient conditions.

The Aspen Plus® Power Plant Model was validated against the Integrated Environmental Control Model (IECM), version 6.2.4, available over the Internet. This model was developed for the analysis of environmental control options including CO_2 capture and sequestration. Results are shown in the performance of the two models in Figure E.3

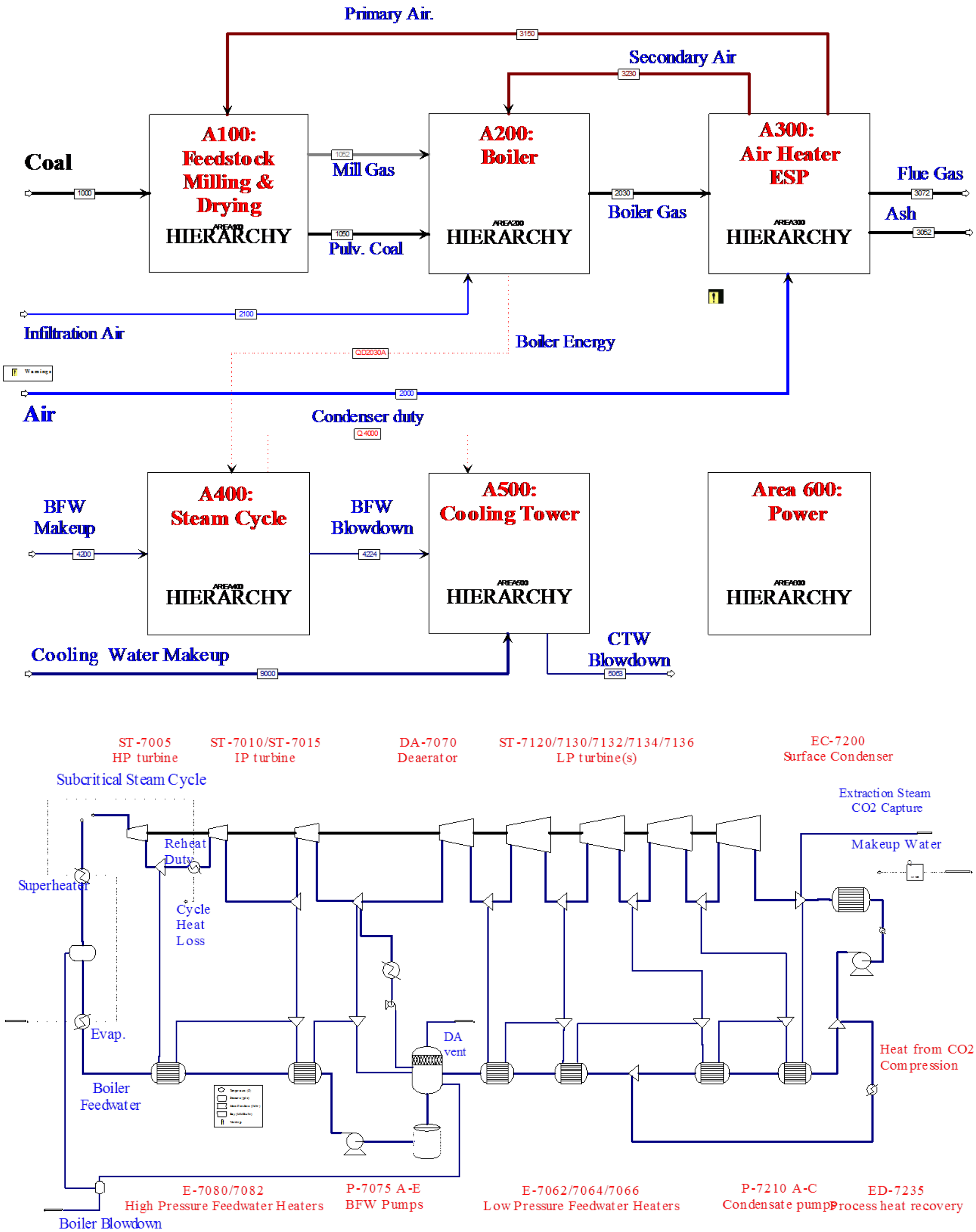


Figure E.2. Aspen Plus® power plant simulation structure with subcritical steam cycle hierarchy contents.

User Input								
Calculation								
Dependent values								
Solver or Goal Seek								

Power production & miscellaneous parameters

Key	Net Power Production Target			Heat Loss	2%		Steam Cycle	Subcritical
Constant	400,000	kW					Efficiency	34%
	Initial Coal Estimate		lower/upper limits				Boiler Eff	85%
Initial Input	396,197	lb/hrAR	396,197					
	Initial Air Estimate							
Initial Input	3,135,602	lb/hr Air						

AREA100 Fuel Handling

Coal and solid fuels are converted to elemental composition

Coal Name

PRB1	**Proximate**	Dry wt%)	**Ultimate**	(Dry wt%)	**Sulfur**		Hardgrove Index	
	Moisture	27.30	Ash	6.20	Pyritic	0.01		60
	Fixed Carbon	49.65	C	70.50	Sulfate	0.01	Mill outlet Temperature	
	Volatile Matter	44.15	H	4.80	Organic	0.28		161
	Ash	6.20	N	0.90	Total	0.29		
	Total dry	100.00	Cl	0.01				
	Sulfur	0.21	S	0.29				
	Btu/lb HHV	12,105	O	17.30				
	J/kg HHV	28,136,327	Total	100.00				
	lb/MMBtu	82.61						
	C	H	N	Cl	S	O		
	12.0107	1.00794	14.00674	35.4527	32.066	15.9994		

Note equations valid to 11,000 meters - ISO conditions - 59°F, 0 feet elevation and 60% relative humidity

Site Air						Standard Conditions for English System		
Design Temp (°F)	Design Elevation (ft)	Design Relative Humidity	Design Pressure			SCF/Mole	60.00	°F
59	0	60%	14.696			379.43	14.70	psia
59.0			14.696					
59			14.696					
Dry Air	MW	Mole %	14.696					
N2	28.01	78.0860%						
O2	32.00	20.9470%						
Ar	39.95	0.9340%						
CO2	44.01	0.0330%						
avg MW	28.9650	100.00%						
Temp (F)/(K)	Elev. (ft)/(m)	Press. (Pa)/psia	R. Humidity					
59	0	101,325	60%	H2OMolFr.				
288.2	0	14.6959	0.25	0.0101				
Design Conditions	P (millibar)	1013.25						
			SatVP					
	MW	Mole%	Weight %	Aspen inputs				
H2O	18.02	1.01%	0.0062982	19,749		Wet bulb is determined by goal seek		
N2	28.01	77.30%	0.7504504	2,353,113		from design T, dewpoint T, elevation		
O2	32.00	20.74%	0.2299527	721,040	Wet bulb T°F	Wet bulb T°C		
Ar	39.95	0.92%	0.0128004	40,137	51.58	10.9	0.0005	
CO2	44.01	0.03%	0.0004982	1,562			This cell is set to 0 by goal seek	
Total	28.8545	100.000%	100.00%	3,135,601	0.00634	Absolute Humidity - lb/lb dry air		
	0.07618	Design density (lb/ft^3)			45.1	Dewpoint °F		

Figure E.3. Partial view of excel simulation and input.

Table E.1. Aspen Plus® power plant model validation with IECM.

	NETL Case 9 Baseline	Coal Fired 400 MW Representative Plant		Biomass Cofired - Pine chips - 12% moisture supplied at @ 10% LHV of 400 MW Plant		Biomass Cofired Torrefied Pine supplied at 20% LHV of 400 MW Plant	
(Power in kW)	NETL Case 9	IECM 6.2.4 BlckThndr	AspenV7.3-V2 BlckThndr	IECM 6.2.4 BlckThndrPine10	AspenV7.3V9 BlckThndrPine10	IECM 6.2.4 BlckThndrTorr20	AspenV7.3V2 BlckThndrTorr20
Gross Power (Note 1)	582,600	425,000	428,344	425,200	428,367	424,800	428,080
Coal handling	450						
Pulverization	2,970		1,392		1,433		1,350
Ash Hanfling	570						
Fans, FD, ID, Primary	7,540		7,302		7,285		7,095
ESP	70	1,041		1,026		1,011	
Balance of plant	2,000	17,930		18,160		17,750	
Hot Side SCR	50	N/A					
Steam Turbine Aux	400						
BFW Pumps	(Note 2)		9,690		9,691		9,685
CTW Supply	530						
CTW Pumps & Fans (Note 2)	7970	5,992	9,958	5,995	9,958	5,990	9,956
Sorbent Handling	950	N/A	N/A	N/A	N/A	N/A	N/A
Wet FGD	3,180	N/A	N/A	N/A	N/A	N/A	N/A
Transformer Losses (Note 4)	1,830						
Net Power	550,020	400,037	400,001	400,000	400,000	400,049	399,994
Total Parasitic Power	28,510	24,963	28,342	25,181	28,367	24,751	28,086
Gross Power	578,530	425,000	428,344	425,181	428,367	424,800	428,080
Total Solid Feed	437,378	443,000	448,045	451,200	454,277	433,200	432,683
Coal Feed (lb/hr) (Note 5)	437,378	443,000	448,045	399,357	402,081	351,455	351,036
Biomass Type	N/A	N/A	N/A	Yellow Pine	Yellow Pine	Torrefied Pine	Torrefied Pine
Biomass Feed	N/A	N/A	N/A	51,843	52,196	81,745	81,647
Ash	42,411	25792	29,220	23,872	27,055	22,052	24,919
Total Fuel CO2 (lb/hr)		0	818,309	823,000	819,601	817,000	806,683
CO2 From Biomass (lb/hr)		N/A	N/A	79,337	79,009	155,393	153,431
Stack Flue Gas Flow ft^3/Min	1,595,233		1,241,653	1,279,000	1,241,139	1,257,000	1,205,026
Water Makeup		1,863,200	1,765,583	1,774,200	1,741,282	1,772,400	1,740,478
Stack T (°F)	358	300	302	300	303	300	301
Net Plant Efficiency	36.8%	35.34%	34.94%	35.33	34.89%	35.57	35.17%
				Note 5	Note 5	Note 6	Note 6

Notes:

1. NETL Case 9 feeds Illinois 6 coal; has a net output of 550 MW; is configured with an FGD unit and baghouse - it is shown to ensure all aspects of plant parasitic power are accounted for
2. Steam turbine drives for boiler feedwater pumps in NETL Case
3. A hyperbolic tower is assumed for IECM model - recommended for large plants in high humidity areas from 3-5 X more expensive than mechanical draft
Mechanical draft assumed for representative plant
Black & Veatch, Drbal, LF, ed. et.al.; Power Plant Engineering; 1996; P.325.
4. Transformer loss ~ 0.35% of generation calculated
5. Biomass is supplied for 10% of the boiler LHV requirement as 12% moisture pine chips (wt% 11.49)
6. Biomass is supplied for 20% of the LHV as torrified pine (230°C) (wt% 18.66)

E.2 Power Plant Reference Data

Data for the power plants used in this study extracted from EIA 2010a, EIA 2010b. Power plant data for the Alabama and Ohio plants are listed in Table E.2 through Table E.8. This information was used as the basis for the specific scenario power plant models.

Table E.2. Alabama Power Plant EIA Data

Alabama Power Plants

Plant Data — Source: EIA Forms 860, 923; 2010 from EIA.gov

Plant	Unit	Capacity MW	Operational Year	Primary Fuel	Steam Cycle	NOx Control	Particulate Control	SOx Control	SOx Sorbent
Gorgas	6	103	1951	BIT	Sub	LN	EK		
Gorgas	7	104	1952	BIT	Sub	LN	EK		
Gorgas	8	161	1956	BIT	Sub	LN	EW	SP	LS
Gorgas	9	170	1958	BIT	Sub	LN	EW	SP	LS
Gorgas	10	703	1972	BIT	Super	LN/OV/SCR	EW	SP	LS
E C Gaston	1	254	1960	BIT	Sub	LN/OV	EW		
E C Gaston	2	256	1960	BIT	Sub	LN	EW/BP		
E C Gaston	3	254	1961	BIT	Sub	LN	EW/BP		
E C Gaston	4	256	1961	BIT	Sub	LN	EW		
E C Gaston	5	842	1974	BIT	Super	LN/OV/SCR	EH	BR	LS
James H Miller Jr	1	673	1978	SUB	Sub	LN/SCR	EC	SP	LS
James H Miller Jr	2	665	1985	SUB	Sub	LN/SCR	EC	SP	LS
James H Miller Jr	3	669	1989	SUB	Sub	LN/SCR	EK	SP	LS
James H Miller Jr	4	669	1991	SUB	Sub	LN/SCR	EK	SP	LS

Primary Fuel - BIT = Bituminous coal; SUB = Subbituminous coal
Steam Cycle - Sub = Subcritical (<3000 psia); Super = Supercritical (>3400 psia)
NOx Control - LN = Low NOx burner, OV = Overfire Air; SR = SCR = Selective Catalytic Reduction

Particulate Control

- EC Electrostatic precipitator, cold side, with flue gas conditioning
- EH Electrostatic precipitator, hot side, with flue gas conditioning
- EK Electrostatic precipitator, cold side, without flue gas conditioning
- EW Electrostatic precipitator, hot side, without flue gas conditioning
- BP Baghouse, pulse

SOx Control

- BR Jet Bubbling Reactor
- SP Spray type
- SP-TR Spray Tray type

SOx Sorbent

- LS Limestone
- LIMO Magnesium emhanced lime

Table E.3. Alabama Power Plants Environmental Performance Data

Plant Data — Source: EIA Forms 860, 923; 2010 from EIA.gov

Plant	Unit	NOx lb/MMBtu	Particulate Efficiency	SOx Removal
Gorgas	6		99.7	
Gorgas	7		99.7	
Gorgas	8		99.7	98.5
Gorgas	9		99.7	98.5
Gorgas	10	0.07	99.7	98.5
E C Gaston	1	0.395	99.0	
E C Gaston	2	0.395	99.8	
E C Gaston	3	0.4	99.8	
E C Gaston	4	0.4	99.0	
E C Gaston	5	0.089	99.0	98.5
James H Miller Jr	1	0.105	99.4	98.6
James H Miller Jr	2	0.07	99.4	98.6
James H Miller Jr	3	0.074	99.7	98.6
James H Miller Jr	4	0.072	99.7	98.6

Table E.4. Ohio Power Plant EIA Data

Ohio Power Plants

Plant Data — Source: EIA Forms 860, 923; 2010 from EIA.gov

Plant	Unit	Capacity MW	Operational Year	Primary Fuel	Steam Cycle	NOx Control	Particulate Control	SOx Control	SOx Sorbent
Kyger Creek	1	200	1955	BIT/SUB	Sub	OV/SR	EC	2 jet bubbling reactors for plant	LS
Kyger Creek	2	198	1955	BIT/SUB	Sub	OV/SR	EC		
Kyger Creek	3	198	1955	BIT/SUB	Sub	OV/SR	EC		
Kyger Creek	4	198	1955	BIT/SUB	Sub	OV/SR	EC		
Kyger Creek	5	198	1955	BIT/SUB	Sub	OV/SR	EC		
Muskingum River	1	190	1953	BIT	Sub	OV	EK	No Scubbers	
Muskingum River	2	190	1954	BIT	Sub	OV	EK		
Muskingum River	3	205	1957	BIT	Sub	LN/OV	EK		
Muskingum River	4	205	1958	BIT	Sub	LN/OV	EK		
Muskingum River	5	585	1968	BIT	Super	LN/OV/SCR	EK		
General James M Gavin	1	1320	1974	BIT/SUB	Super	LN/OR/SR	EK	SP-TR	LIMO
General James M Gavin	2	1320	1975	BIT/SUB	Super	LN/OR/SR	EK	SP-TR	LIMO

Primary Fuel - BIT = Bituminous coal; SUB = Subbituminous coal
Steam Cycle - Sub = Subcritical (<3000 psia); Super = Supercritical (>3400 psia)
NOx Control - LN = Low NOx burner, OV = Overfire Air; SR = SCR = Selective Catalytic Reduction

Particulate Control

EC	Electrostatic precipitator, cold side, with flue gas conditioning
EH	Electrostatic precipitator, hot side, with flue gas conditioning
EK	Electrostatic precipitator, cold side, without flue gas conditioning
EW	Electrostatic precipitator, hot side, without flue gas conditioning
BP	Baghouse, pulse

SOx Control

BR	Jet Bubbling Reactor
SP	Spray type
SP-TR	Spray Tray type

SOx Sorbent

LS	Limestone
LIMO	Magnesium emhanced lime

Table E.5. Ohio Power Plant Environmental Performance Data

Plant Data — Source: EIA Forms 860, 923; 2010 from EIA.gov

Plant	Unit	NOx lb/MMBtu	Particulate Efficiency	SOx Removal
Kyger Creek	1	0.147	99.4	98
Kyger Creek	2	0.147	99.4	98
Kyger Creek	3	0.147	99.4	98
Kyger Creek	4	0.147	99.4	98
Kyger Creek	5	0.147	99.4	98
Muskingum River	1	0.556	99.5	0
Muskingum River	2	0.527	99.5	0
Muskingum River	3	0.491	98.5	0
Muskingum River	4	0.462	98.5	0
Muskingum River	5	0.057	99.5	0
General James M Gavin	1	0.074	99.7	95
General James M Gavin	2	0.079	99.7	95

Table E.6. Power Plant Estimated Fuel Usage Summary

Estimated Fuel Analysis

Fuel	Coal Only					
Power Plant	**Gorgas**	**E.C. Gaston**	**Miller**	**Muskingum River**	**Kyger Creek**	**Gen James M Gavin**
Coal or Coal Biomass Blend	AL Bit	AL Bit	PBR	App Bit	App/PRB	App/PRB
Cofiring %	0	0	0	0	0	0
Cofiring % Basis	N/A	N/A	N/A	N/A	N/A	N/A
Wt% of Biomass in Fuel	0	0	0	0	0	0
As Received (AR)						
Total Moisture	2.60	3.10	27.60	6.80	18.09	11.17
Ash	12.30	12.60	5.18	10.18	7.57	9.23
Carbon	67.54	68.11	50.44	68.94	60.98	64.71
Hydrogen	4.65	4.58	3.51	4.76	4.14	4.73
Nitrogen	1.47	1.50	0.68	1.35	1.19	1.30
Sulfur	1.22	1.67	0.29	2.04	1.71	3.10
Oxygen	10.21	8.44	12.29	5.95	6.31	5.76
Total	100.00	100.00	100.00	100.00	100.00	100.00
HHV (Btu/lb)	11,966	12,114	8,763	12,477	10,105	11,475
LHV (Btu/lb)	11,512	11,662	8,154	11,971	9,538	10,927
Dry Basis						
Ash	12.63	13.01	7.16	10.92	9.25	10.39
Carbon, C	69.34	70.29	69.67	73.97	74.45	72.84
Hydrogen, H	4.77	4.73	4.85	5.11	5.06	5.33
Nitrogen, N	1.51	1.55	0.94	1.45	1.46	1.46
Sulfur, S	1.26	1.72	0.40	2.19	2.08	3.48
Oxygen, O	10.49	8.71	16.98	6.38	7.71	6.49
Total Dry	100.00	100.00	100.00	100.00	100.00	100.00
HHV (Btu/lb)	12,285	12,502	12,103	13,388	12,336	12,918
LHV (Btu/lb)	11,819	12,035	11,262	12,845	11,644	12,300

Table E.7. Alabama Power Plant Biomass Properties Summary

Fuel	Alabama Plants					
	Gorgas		E.C. Gaston		James Miller	
Power Plant	Pine Chips	Torrefied Pine	Pine Chips	Torrefied Pine	Pine Chips	Torrefied Pine
Coal or Coal Biomass Blend	Blend	Blend	Blend	Blend	Blend	Blend
Cofiring %	10%	20%	10%	20%	10%	20%
Cofiring % Basis	LHV	LHV	LHV	LHV	LHV	LHV
Wt% of Biomass in Fuel	16.2%	26.3%	16.1%	26.1%	11.9%	19.9%
As Received (AR)						
Total Moisture	4.55	2.49	4.11	2.13	25.74	22.27
Ash	10.43	9.47	10.19	9.26	4.70	4.53
Carbon	64.32	64.72	64.63	64.99	49.74	51.50
Hydrogen	4.52	4.68	4.31	4.48	3.76	3.95
Nitrogen	1.25	1.21	1.24	1.20	0.63	0.66
Sulfur	1.37	1.24	1.01	0.91	0.26	0.25
Oxygen	13.56	16.18	14.51	17.02	15.16	16.84
Total	100.00	100.00	100.00	100.00	99.99	99.99
HHV (Btu/lb)	11,346	11,240	11,228	11,136	8,598	8,767
LHV (Btu/lb)	10,882	10,782	10,788	10,700	7,985	8,171
Dry Basis						
Ash	10.93	9.72	10.63	9.46	6.33	5.83
Carbon, C	67.38	66.38	67.40	66.40	66.98	66.26
Hydrogen, H	4.74	4.80	4.49	4.58	5.06	5.08
Nitrogen, N	1.31	1.24	1.29	1.23	0.85	0.84
Sulfur, S	1.44	1.27	1.06	0.93	0.35	0.32
Oxygen, O	14.20	16.60	15.13	17.40	20.41	21.66
Total Dry	100.00	100.00	100.00	100.00	99.99	99.99
HHV (Btu/lb)	11,834	11,544	11,658	11,391	11,661	11,457
LHV (Btu/lb)	11,397	11,101	11,243	10,967	11,192	10,987

Table E.8. Ohio Power Plant Biomass Properties Summary

	Ohio Plants					
Fuel	**Muskingum**		**Kyger Creek**		**James Gavin**	
Power Plant	**Switchgrass**	**Torrefied Switchgrass**	**Switchgrass**	**Torrefied Switchgrass**	**Switchgrass**	**Torrefied Switchgrass**
Coal or Coal Biomass Blend	Blend	Blend	Blend	Blend	Blend	Blend
Cofiring %	10.00%	20.00%	10.00%	20.00%	10.00%	20.00%
Cofiring % Basis	LHV	LHV	LHV	LHV	LHV	LHV
Wt% of Biomass in Fuel	18.04%	27.00%	15.43%	23.47%	17.86%	26.77%
As Received (AR)						
Total Moisture	8.64	5.69	15.87	12.62	10.60	7.47
Ash	9.39	10.72	6.78	8.05	8.27	9.67
Carbon	63.76	66.05	56.44	59.03	61.40	63.89
Hydrogen	4.47	4.11	3.96	3.73	5.05	4.67
Nitrogen	1.23	1.42	0.97	1.14	1.09	1.29
Sulfur	1.60	1.49	1.71	1.62	2.50	2.33
Oxygen	10.89	10.51	14.26	13.80	11.07	10.69
Total	99.98	100.00	99.98	100.00	99.98	100.00
HHV (Btu/lb)	11,327	11,486	9,850	10,122	11,309	11,479
LHV (Btu/lb)	10,827	11,049	9,320	9,647	10,735	10,973
Dry Basis						
Ash	10.27	11.37	8.06	9.22	9.25	10.45
Carbon, C	69.79	70.04	67.08	67.55	68.68	69.04
Hydrogen, H	4.90	4.36	4.71	4.26	5.65	5.04
Nitrogen, N	1.35	1.51	1.15	1.31	1.22	1.39
Sulfur, S	1.75	1.58	2.03	1.86	2.80	2.51
Oxygen, O	11.92	11.14	16.95	15.80	12.38	11.56
Total Dry	99.98	100.00	99.98	100.00	99.98	100.00
HHV (Btu/lb)	12,398	12,180	11,708	11,583	12,650	12,406
LHV (Btu/lb)	11,948	11,778	11,272	11,189	12,130	11,942

E.3 Appendix E References

EIA – Energy Information Administration. 2010a. *Annual Energy Outlook 2010*. Office of Integrated Analysis and Forecasting, U.S. Department of Energy, Washington, D.C.

EIA – Energy Information Administration. 2010b. Table 1.2, "Summary Statistics for the United States, 2001-2011." In *Electric Power Annual 2010*.Accessed March 29, 2012 at http://www.eia.gov/electricity/annual/.

EIA – Energy Information Administration.2010c. "Power Plant Operations Report 2010, Form EIA-923."Available athttp://www.eia.gov/cneaf/electricity/.

EIA – Energy Information Administration. 2010d. *Updated Capital Cost Estimates for Electricity Generation Plants*. Energy Information Administration, U.S. Department of Energy, Washington, D.C.

EIA – Energy Information Administration. 2010e. *Updated Capital Costs for Renewable Resources*. Energy Information Administration, U.S. Department of Energy, Washington, D.C.

EIA – Energy Information Administration. 2010f. *Annual Coal Report*. Energy Information Administration, U.S. Department of Energy, Washington, D.C.

EIA – Energy Information Administration. 2012a. *State Electricity Profiles 2010*. Office of Electricity, Renewables, and Uranium Statistics, U.S. Department of Energy, Washington, D.C.

NETL – National Energy Technology Laboratory. 2007. *Cost and Performance Baseline for Fossil Energy Plants*. DOE/NETL-2007-1281, Volume 1, Revision 1, U.S. Department of Energy: Washington, DC. Available at: http://www.netl.doe.gov/energy-analyses/pubs/BitBase_FinRep_2007.pdf.

Skone TJ, J Littlefield, R Eckard, G Cooney, R Wallace, and J Marriott. 2012. *Role of Alternative Energy Sources: Pulverized Coal and Biomass Cofiring Technology Assessment*. DOE/NETL-2012/1537, National Energy Technology Laboratory, Pittsburgh, PA.

Appendix F

Levelized Cost of Electricity

Three models were considered for modeling the LCOE for the scenarios examined in this report. The first model was developed to represent a generic 400-MW coal plant. This hypothetical coal plant is the average size of coal plants in the United States, burns western subbituminous coal, and does not have a FGD unit, which is consistent with about one-half of the coal plants of its size. Two other models were developed which model-specific power-generation facilities. Customized models were developed for each particular case, including the specific coal type and emissions-control equipment.

F.1 Baseline Model Validation

A simplified LCOE (sLCOE) model (Skone et al. 2012) is used to compare biomass cofiring to wind and solar options. In this model, the following assumptions are made:

- A utility grid is supplied with a nominal 400 MW from coal or coal and a renewable resource.

  The renewable source is one of biomass or wind or solar.

- The representative coal plant—an existing, fully depreciated pulverized coal plant—is capable of supplying 3,000,000 MWh/yr (85.6 % availability).

  Biomass is assumed to have the same availability as the coal-fired plant, as it will be cofired in the coal plant.

  Solar availability (18.77%) and wind availability (29.28%) are calculated from EIA Form 923 data—which are tabulated below in Table F.1and Table F.2.

  When solar or wind is unavailable, the coal and biomass-fired plant operates at full load (400 MW).

  When solar or wind is available, the coal plant will reduce output down to 400 MW minus the solar or wind nameplate, such that 400 MW is always supplied.

- Two cases are examined as shown in Table F.1.

  Pulverized coal producing 2,700,000 MWh/yr and dried pine chips, solar, or wind producing 300,000 MWh/yr.

  Pulverized coal producing 2,400,000 MWh/yr and torrefied pine, solar, or wind producing 600,000 MWh/yr.

LCOE models are used to calculate the price to produce electricity. The electricity must be sold for the LCOE price or more for the producer to avoid losing money on the power production. The sLCOE model is adequate for cases where specific site details and the project financial structure are not known, and is calculated as follows:

sLCOE = {(overnight capital cost * capital recovery factor (CRF) + fixed operation and maintenance [O&M] cost)/(8760 * capacity factor)} + (fuel cost * heat rate) + variable O&M cost

This equation is examined term by term:

- Overnight capital cost is the estimated total project cost measured in dollars per installed kilowatt ($/kW). Values for biomass, wind, and solar are obtained from EIA (2010e) and shown in Table F.2.
- A CRF = {i(1 + i)^n} / {[(1 + i)^n]-1}is determined from specifying the project life and an interest rate (discount rate). This factor is dependent on many circumstances of financing. A project life of 20 years and the U.S. government discount rate of 4 % for new projects were chosen.

- Fixed O&M costs in dollars per kilowatt-year ($/kW-yr) and variable O&M costs in dollars per kilowatt-hour ($/kWh). These values are shown in Table F.2, along with overnight capital costs from EIA (2010e).
- The capacity factor for biomass is assumed the same as the coal plant capacity factor. Solar and wind capacity factors are calculated from EIA data as previously explained (EIA 2010e).
- Coal cost is taken from EIA (2010f) as the U.S. average for the electric power sector, and is shown in Table F.3.
- Biomass fuel costs are calculated for dried Southern Pine and torrefied pine using the Biomass Logistic Model.
- Solar and wind have zero fuel cost.
- Heat rate for the coal firing and coal and biomass cofiring is determined directly from the Aspen Plus Power Plant Model. The calculated heat rates agree with IECM estimations.
- Variable O&M costs taken from EIA (2010e).

Table F.1. Renewable power production scenarios.

Case 1 - Southern yellow pine biomass

Renewable Fraction	10%			
Coal Fired Nameplate (MW)	400			
Scenario	100% PRB Coal	90% Coal 10% Biomass	90% Coal 10% Solar	90% Coal 10% Wind
Coal Reliability (Note 1)	85.62%	85.6%	85.6%	85.6%
Renewable Reliability (Notes 2-3)		85.6%	18.8%	29.3%
Renewable Nameplate (MW)	400	40	182.5	117.0
MWH/yr - Coal	3,000,000	2,700,000	2,700,000	2,700,000
MWH/yr - Renewable		300,000	300,000	300,000
Total MWH/yr	3,000,000	3,000,000	3,000,000	3,000,000

Case 2 - Torrefied Southern yellow pine

Renewable Fraction	20%			
Coal Fired Nameplate (MW)	400			
Scenario	100% PRB Coal	80% Coal 20% Biomass	80% Coal 20% Solar	80% Coal 20% Wind
Coal Reliability (Note 1)	85.62%	85.6%	85.6%	85.6%
Renewable Reliability (Notes 2-3)		85.6%	18.8%	29.3%
Renewable Nameplate (MW)	400	80	364.9	233.9
MWH/yr - Coal	3,000,000	2,400,000	2,400,000	2,400,000
MWH/yr - Renewable		600,000	600,000	600,000
Total MWH/yr	3,000,000	3,000,000	3,000,000	3,000,000

Note 1 Source: http://www.nrel.gov/analysis/tech_cap_factor.html
Note 2 Biomass is assumed not to affect reliability but does increase fixed & variable maint. cost
Note 3 Reliability factors aka capacity factors is the fraction of time the generator produces nameplate capacity or is available to produce nameplate capacity
Obtained from EIAForm 923 - 2010

Table F.2.Capital and Operating Costs (EIA 2010e)

Technology	Online Year	Size (MW)	Lead Time (yrs)	Base Overnight Cost (2009$/kW)	Project Contingency Factor	Technical Optimism Factor	Total Overnight Cost (2009$/kW)	Variable O&M Cost (2009$/kW)	Fixed O&M Cost (2009$/kW)
New scrubbed coal	2014	1300	4	2,625	1.07	1	2,809	4.2	29.31
Wind	2011	100	3	2,251	1.07	1	2,409	0	27.73
Wind offshore	2014	400	4	4,404	1.10	1.25	6,056	0	86.98
Solar thermal	2013	100	3	4,333	1.07	1	4,636	0	63.23
Solar photovoltaic	2012	150	2	4,474	1.05	1	4,697	0	25.73
Biomass cofire	2014	400	3	203	1.05	1	213	5.25	32.24

Assumptions:
Base Overnight Cost is average of range for "Representative Coal Plant."
Cofire is 15 % of capacity.
Torrefied biomass is a 25 % premium to coal.
Cofire fixed O&M is 10 % greater than coal fixed O&M.

Table F.3. 2010 U.S. Average Coal Price (EIA 2010f)

Report No: DOE/EIA-0584 (2010)
Data For: 2010
Report Released: November 2011
Next Release Date: November 2012
Table 34.

Mass Weighted Average Price of Coal Delivered to End Use to End Use Sector by Census Division and State, 2010, 2009 (Dollars per Short Ton)

Census Division and State	**2010 Electric Power Sector**
U.S. Total	**44.27**
minimum	16.60
maximum	142.59

The results of these analyses for the generalized 400-MWcoal-fired power plant are summarized in Table F.4, showing the LCOE for each case. The total cost of biomass used in these analyses was the minimum determined in Appendices A, B and C of this report, considering both the farm gate price and shipping distance. For this and the subsequent analyses, the life cycle GHG emissions presented in Appendix G were used in conjunction with the biomass cost modeling to determine the effect an assumed CO_2 abatement credit would have on the total cost of electricity as compared to the current coal baseline.

Table F.4. The sLCOE Results for Reference Plant Coal Only and Coal with Renewables, Both with and Without Carbon Abatement Credits.

	Coal Only 400 MW	Coal and 10 % Dried Southern Pine Chips	Coal and 10 % Solar Photovoltaic	Coal and 10 % Wind	Coal and 20 % Torrefied So. Pine	Coal and 20 % Adv. Torrefied So. Pine	Coal and 20 % Solar Photovoltaic	Coal and 20 % Wind
Period (years)	20	20	20	20	20	20	20	20
Discount rate (%)	4	4	4	4	4	4	4	4
Capital recovery factor[(a)]	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074
Renewable capital cost \$/kW[(b)]	-	213	4,697	2,409	213	213	4,697	2,409
Capacity factor(%)[(c)]	85.60	85.60	18.80	29.90	85.60	85.60	18.80	29.90
Fixed O&M (\$/kW-yr)	29.31	32.24	25.73	27.73	32.24	32.24	25.73	27.73
Variable O&M (\$/kWh)	0.0048	0.006	0	0	0.006	0.006	0	0
Heat rate (Btu/kWh)	9,771	9,785	8,794	8,794	9,707	9,707	7,817	7,817
Coal or renewable fuel cost (\$/MMBtu)	2.54	6.9	0	0	8.23	6.2	0	0
sLCOE (¢/kWh) (renewable only)	3.35	7.99	22.58	7.83	9.23	7.26	22.58	7.83
Composite price 3,000,000 MWh/yr (coal & renewable)	3.35	3.82	5.28	3.80	4.53	4.13	7.20	4.25
Composite price with – \$30/ton CO_2abatement	3.35	3.55	4.98	3.48	4.03	3.64	6.60	3.61
Composite price with – \$75/ton CO_2abatement	3.35	3.16	4.53	3.01	3.29	2.89	5.70	2.66
Composite price with – \$150/ton CO_2abatement	3.35	2.49	3.77	2.21	2.05	1.65	4.20	1.07

(a) CRF = {i(1+i)^n}/{[(1+i)^n]-1} where i= discount rate
(b) From EIA (2010d)
(c) Coal from sLCOE calculator, Wind & Solar calculated from Average EIA Form 923 for 2010

For the case of cofiring 10 % dried pine, the LCOE of 3.82 ¢/kWh is approximately equal to the cost for the 10 % wind (3.80 ¢/kWh) and significantly lower than the cost for 10 % solar (5.28 ¢/kWh).For the 20 % cofiring scenarios, the LCOE for the advanced torrefied pine (4.13 ¢/kWh) is slightly lower compared to 20 % wind (4.25 ¢/kWh), and significantly more than20 % lower than 20 % solar (7.20 ¢/kWh).

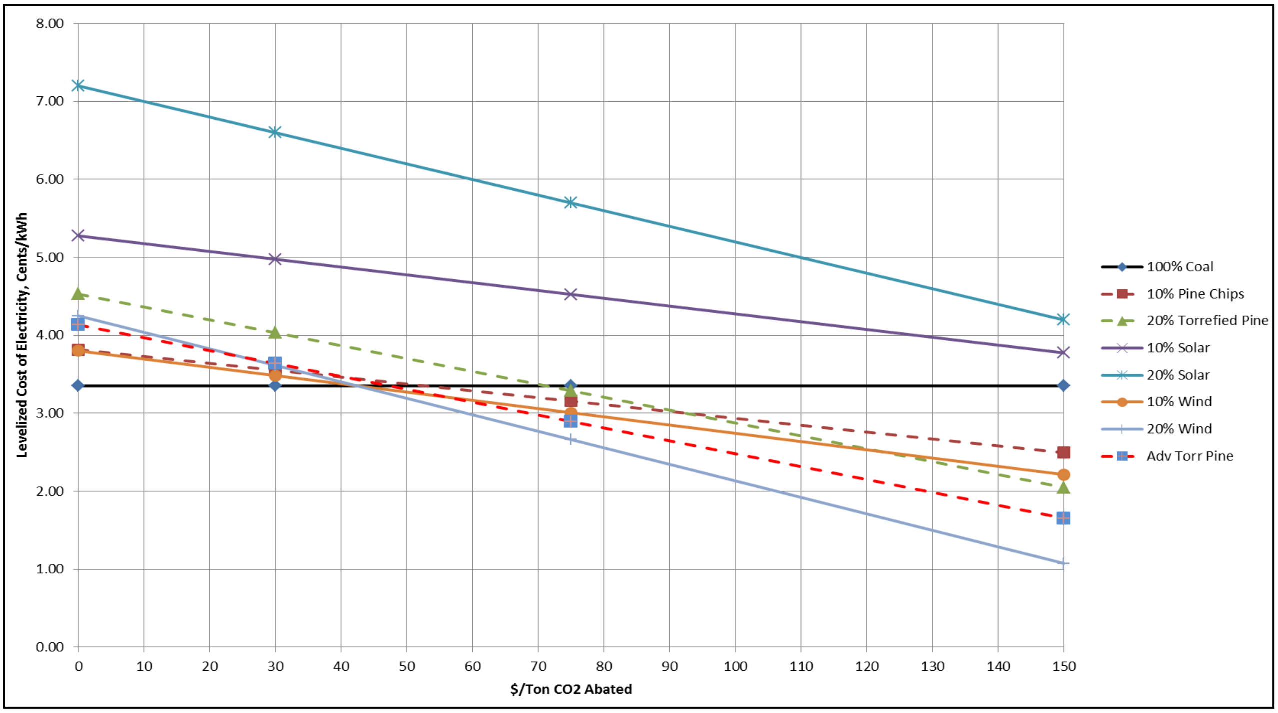


Figure F.1. 400 MW Coal Plant with Biomass, Wind, and Solar LCOE and $/ton CO_2Abatement Credit

F.2 Appendix F References

EIA – Energy Information Administration. 2010e. *Updated Capital Costs for Renewable Resources*. Energy Information Administration, U.S. Department of Energy, Washington, D.C.

EIA – Energy Information Administration. 2010f. *Annual Coal Report*. Energy Information Administration, U.S. Department of Energy, Washington, D.C.

Skone TJ, J Littlefield, R Eckard, G Cooney, R Wallace, and J Marriott. 2012. *Role of Alternative Energy Sources: Pulverized Coal and Biomass Cofiring Technology Assessment*. DOE/NETL-2012/1537, National Energy Technology Laboratory, Pittsburgh, PA.

(This page intentionally left blank)

Appendix G

GHG Modeling Assumptions

G.1 Coal Mining

Mining emissions result primarily from diesel emissions from mining equipment and methane (CH_4) emissions from the mine. Scenario 1assumesa weighted average of subbituminous coal from the coal mine near Gillette, Wyoming in the PRB (BNSF Railway 2010) and bituminous coal from a range of mines in Alabama. The mines selected are representative of the coal mines that provided coal for the James H. Millerand E. C. Gaston power plants in 2010 (EIA 2012).Scenario 2 assumes coal properties from Pittsburgh #8 and PRB coal, representative of coal used by the Muskingum River and General James M Gavin power plant. Coal from the PRB, bituminous coal mines in Alabama, and Midwest coal mines producing Pittsburgh #8 are all primarily surface mined (i.e., excavators, drills, bulldozers, shovels, and trucks are used to remove and transport overburden and coal. Therefore, emissions estimates representative of surface mining were used in this analysis. Primary sources for the coal GHG estimate include Spath and Mann (1999),Ortiz et al (2011), and ICF International (2008).Mining has a minor impact on the overall GHG emissions, contributing less than 1% to the total (Spath et al. 1999). It has been shown that a 50% change in emissions due to mining only yields a 2% change in the LCA result (Spath et al. 1999). The estimate for GHG emissions associated with surface mining of coal is based on a smaller mine than the coal mines referenced in this analysis; however, the emissions should be similar on a normalized basis. The estimate for mining emissions includes CH_4emissions from the mine which occur as part of normal mining activity. The magnitude of CH_4emissions associated with mining activity is dependent on the CH_4 content of each specific coal seam. The CH_4 content for PRB is the lowest at 242 ft^3/ton of coal and highest for Alabama coal, 445 ft^3/ton; Pittsburgh #8 coal has a CH_4 content of 340 ft^3/ton (Di Pietro et al. 2010). This translates to 1.28, 2.83, and 1.83 g of CH_4 released for every kg coal received for PRB, Alabama bituminous, and Pittsburgh #8, respectively (Spath et al. 1999).

After mining, coal is processed prior to pulverizing and combustion. The preparation requirements vary for the different types of coal, based on the impurities. PRB is relatively pure and is prepared for transportation by removing large impurities (e.g., rocks) and crushing the coal into appropriately sized pieces (ICF International 2008). Thus, energy requirements and associated GHG emissions necessary to process PRB coal are very small, but were included in the analysis. In general, bituminous coal requires jig washing, which involves suspending coal in a pulsating flow of water to separate heavier impurities, followed by dewatering using vibrating screens and centrifuges (Spath et al. 1999). The energy requirements for jig washing, as well as the water requirements and waste generation, contribute to overall GHG emissions. Coal preparation for the Alabama bituminous and Pittsburgh #8 scenarios were both assumed to require jig washing, which contributes 0.06 g CO_2-eq/kWh and 0.07 g CO_2-eq/kWh, respectively, to the overall GHG emissions.

G.2 Coal Transportation

Once mined and processed, coal must be transported, primarily by rail, to the power plant. Scenario 1 assumes a weighted average of 1,000 mi for PRB coals and 300 mi for Alabama coal. For Alabama coal, it is assumed that approximately half the coal consumed by the power plant arrives at the plant by rail and half is delivered by barge. While 300 mi overestimates the transportation distance from the major coal mines in Alabama to the coal plants in Alabama, a larger number is used to represent the fact that not all coal fired in these plants comes from Alabama mines. Scenario 2 assumes a weighted average of 500 mi travel distance for Pittsburgh #8 by rail from coal mines in south-central Illinois to the plant location in central Ohio and PRB (from Wyoming). This analysis does not account for the trip transportation of rail cars, as it is likely that empty rail cars will not be directly returned to the coal plant. Emissions stemming from locomotive operation are assigned an emissions factor of 20.7 g CO_2-eq/metric ton-km. This emissions factor is based on a diesel carbon intensity of 95.0 kg CO_2-eq/MMBtu LHV (NETL 2008), an energy density of 5.512 MMBtu/bbl (NETL 2008), and a fleet average fuel efficiency of 413 ton-miles/gallon for rail transport (Kruse et al. 2009). The GHG emissions associated with barge transportation are 14.8 g CO_2-eq/metric ton-km, about 28% less than the emissions from rail transportation (Ortiz et al. 2011). These emissions factors are based on the same diesel carbon intensity and energy density assumed above and a fleet average fuel efficiency of 576-ton-miles/gallon for barge transport (Kruse et al. 2009).The required mass of coal was calculated based on the energy content of the coal and the plant efficiency.

G.3 Biomass Cultivation

G.3.1 Southern Pine

Because Southern Pine is a dedicated energy crop, emissions resulting from the establishment of seedlings and growth of the crop must be accounted for in the LCA. After each harvest, some nutrient inputs are typically required to maintain soil quality and fertility. Application of nitrogen-rich fertilizer causes emission of nitrous oxide (N_2O), which is a potent GHG with a 100-year global warming potential of 298 times that of CO_2 (Solomon et al. 2007). In additions, herbicide application is required to control pests in a monoculture environment. While herbicides themselves do not pose a GHG risk, application of herbicide requires diesel-powered farm equipment, which contributes to the overall GHG emissions of the biomass cultivation process. As energy and emissions data for cultivation of Southern Pine crops is very limited, farming inputs are assumed similar to short rotation coppice (e.g., willow or poplar). Southern Pine is assumed to be grown in 8-year rotations on marginal land at a density of 700 trees/ac, which produces approximately 2.5 DM tons/ac/yr (Searcy and Hess 2010). This is somewhat lower than the average yield for willow, which has been reported as approximately 6.1 DM tons/ac/yr, with a range of 4.5 to 15.2 depending on harvesting practices (Keoleian and Volk 2005; Woods et al. 2006). Emissions associated with fertilizer, diesel use, leaf litter, and other agricultural inputs for willow production (Heller et al.2004; Keoleian and Volk 2005) are used in the analysis. A fertilizer application rate of 40.5 kg N/ac once every 3 years is assumed (Abrahamson et al. 2002; Adegbidi et al.2003). Although rotation cycles are different for willow and pine (3 years versus 8 years, respectively), it is assumed that fertilizer needs averaged on a yearly basis are similar. Diesel emissions associated with tilling are estimated from information given in Heller et al. (2004). This analysis does not account for changes in soil carbon balance associated with direct or indirect land-use change. This quantity is ignored because specific calculation of the impact of direct or indirect land-use changes is controversial, can be very site-specific, and is highly dependent on previous and current agriculture practices (Cherubini 2011a, 2011b, 2011c, 2011d, 2011e). However, it is anticipated that land-use change would yield a beneficial carbon reduction in this case because short rotation crops can be grown on marginal agricultural land, therefore increasing soil quality, landscape diversity, and soil carbon content (Keoleian and Volk 2005).

G.3.2 Switchgrass

Similar to the Southern Pine case, GHG emissions from the cultivation of switchgrass stem from machinery operation and chemical inputs for establishment and growth of the plants. The biomass yield resulting from cultivation is assumed to be 4.05 DM ton/ac (Hess et al. 2009). Assumptions and calculated emissions from Qin et al. (2006) are used for the switchgrass cultivation stage of the life cycle. Emissions from cultivation include those resulting from operation of diesel-powered machines and from the production and application of lime, fertilizer, and herbicide. Application of lime and nitrogen fertilizer results in direct emissions of CO_2 and N_2O, respectively. Again, carbon emissions (or credits) resulting from direct or indirect land-use change effects are not included in the analysis.

G.4 Biomass Harvesting and Collection

Biomass harvest and collection for Southern Pine generally consists of felling and gathering trees in the field and bringing them to the landing (see Appendix B). Primary GHG impacts arise from the use of diesel equipment and trucks to cut, bundle, and move timber to prepare it for processing. After being felled, trees are typically left in the field to dry from 50 to 35% moisture content. Leaving trees to dry in the field reduces transportation energy consumption and the amount of drying that must occur at the plant prior to combustion (Searcy and Hess 2010). The harvested trees must then be debarked and chipped. Energy requirements for each of these steps are given in Section 4.3 of this report. Diesel fuel is assumed to have a carbon intensity of 95 kg CO_2-eq/MMBtu diesel (NETL 2008).

Harvest and collection of switchgrass consists of windrowing (cutting), baling, stacking, and storage of the biomass field-side. Switchgrass is assumed to dry in the field to 12% moisture content before it was baled. Energy requirements for each of the harvesting and collection steps are given in Section 4.4.

G.5 Biomass Transportation

Biomass is assumed to be transported to the power plant by diesel truck and trailer for the conventional and advanced feedstock logistics cases (see Appendix B). Wood chips and switchgrass are assumed to travel 50 mi (80.5 km) by diesel truck (Searcy and Hess 2010). An advanced logistics (depot) case was also analyzed for Scenario 2 (20% cofiring of torrefied switchgrass), which assumes that switchgrass is transported by truck 15 mi(24.1 km) to the depot and the torrefied pellets are then transported 35 mi(56.3 km) by rail. Energy consumption for biomass transportation is given in Sections 4.3 and 4.4.The impact of biomass transportation distance on overall GHG emissions is also explored for Scenario 1. Transportation distances of 25, 50, 100, 250, and 500 mi (40.2, 80.5, 160.9, 402.3, and 804.7 km, respectively) were used in this sensitivity analysis, with the 50-mi(80.5 km) transportation distance being carried forward in subsequent calculations.

G.6 Biomass Processing and Torrefaction

For the woody cofiring cases, wood chips are received, cleaned, and dried from 35 to 12% moisture content at the plant in a kiln drier which consumes 0.893 MMBtu of energy per DM ton of biomass (see Section 4.3.1.4). The drying energy is supplied by natural gas. For the switchgrass cases, bales are received and the grass is ground prior to co feeding to the bowl mill. Energy requirements for handling and preprocessing of switchgrass are given in Section 4.4.2.4.

Torrefaction cases in each scenario assume torrefaction occurs at the power plant. In addition, for Scenario 2 (switchgrass cofiring), an advanced logistics case, where preprocessing occurs at a depot at a centralized location (see Appendix B), was analyzed to investigate the impact of transporting densified biomass on GHG emissions. Primary assumptions regarding the torrefaction process and material properties for Southern Pine and switchgrass are listed in Table G.1.

Table G.1. Primary assumptions for the torrefaction process and material properties in the advanced biomass logistics cases.

	Southern Pine	Switchgrass
Mass yield	88%	65%
Energy content[a] (HHV)	8,488 Btu/lb	8,527 Btu/lb
Moisture content	0.79%	2.7%
Energy usage	2,029 MBtu/DM ton[b]	1,849 MBtu/DM ton[c]

(a) LHV basis for torrefied biomass, calculated in simulations from biomass composition.
(b) Drying and torrefaction energy combined from Sections 4.3 and 4.4.
(c) Includes both torrefaction and leaching.

The energy required to torrefy biomass is assumed to come from natural gas, which has a carbon intensity of 0.07 kg CO_2-eq/MJ (USLCI Database 2012; EcoInvent Database 2011).

G.7 Electricity Production

This phase of the life cycle includes emissions related to processing and combustion of the energy source (i.e., coal, biomass, and natural gas) at the plant, along with additional auxiliary energy inputs used to operate the plant. Also included in the GHG emissions from electricity production are lifecycle emissions related to plant construction, decommissioning, and waste disposal, although these are a minor contribution. Section 2 presented detailed information on power plant specifications and physical coal properties used for each scenario. Power plants modeled for Scenario 1 include the James H. Miller. and E. C. Gaston plants in Alabama.. Power plants modeled for Scenario 2 include the General James M Gavin and Muskingum River plants in Ohio. Scenario 3 is based on the Muskingum River power plant location. The James H. Miller, E. C. Gaston, and General James M. Gavin plants are each equipped with an FGD unit, which uses lime and limestone to capture SO_2 in combustion emissions. This process results in additional GHG emissions associated with raw materials mining, transportation, and waste disposal necessary for the FGD process. PRB is low in sulfur content (0.46 weight percent dry basis); therefore CO_2 emissions from FGD are relatively low compared to the cases using bituminous coals. Alabama bituminous coal was assumed to contain 1.46% sulfur by weight (dry basis) and Pittsburgh #8 coal was assumed to contain 2.19% by weight (dry basis). The Muskingum River plant is not currently equipped with a FGD unit and the natural gas cases do not include FGD.

As-received biomass was assumed cofed to the bowl mill (see Section 2.2) and then air-entrained into the boiler as 10% of the feed on an energy (LHV) basis. It is assumed that grinding biomass (i.e., wood chips, torrefied wood pellets, switchgrass, and torrefied switchgrass pellets) is feasible and that no additional grinding power beyond that required for coal is required for cofeeding biomass. Therefore, the plant efficiency and heat rate are assumed equal to that of the 100% coal plant (De and Assadi 2009). However, practical application may require additional auxiliary energy consumption for pulverization or unique feed equipment for cofeeding raw (untorrefied) biomass (Tillman 2000). Emissions associated with power plant construction and decommissioning are assumed to have a small impact, less than 0.2% to the overall life-cycle emissions of the plant (Spath et al. 1999; Marx et al. 2011;Pehnt and Henkel 2009).In this analysis, the amount of coal required reduces linearly with increasing cofire for an LHV energy basis; thus coal life cycle GHG emissions are expected to be reduced by 10% and 20% from the baseline case in each scenario. Combustion of biomass is also assumed to be carbon neutral (i.e., balanced by uptake of carbon during growth) and does not contribute to overall life cycle GHG emissions. Therefore, only fossil carbon emissions from coal combustion are accounted for in the electricity generation stage.

G.8 Appendix G References

Abrahamson LP, TA Volk, RF Kopp, EH White, and JL Ballard. 2002. *Willow Bioenergy Producer's Handbook (revised)*. State University of New York College of Environmental Science and Forestry, Syracuse, New York.

BNSF Railway. 2010. *Guide to Coal Mines: Mines Served by BNSF Railway.* Coal Business Unit, BNSF Railway, Fort Worth, Texas. Available at http://www.bnsf.com/customers/pdf/mineguide.pdf#page=8.

Cherubini F., Strømman A.H., Hertwich E. (2011a), Climate impact of CO2 emissions from bioenergy: effect of management practices of boreal forests, *Ecological modeling*, 223: 59-66.

Cherubini F., Peters G., Berntsen T., Strømman A.H., Hertwich E. (2011b), CO2 emissions from biomass combustion for bioenergy: atmospheric decay and contribution to global warming, *Global Change Biology Bioenergy*, 3: 416-426.

Cherubini F. and Strømman A.H. (2011c), Chemicals from lignocellulosic biomass: opportunities, perspectives and potentials of biorefinery systems, *Biofuels, Bioproducts and Biorefining*, 5: 548-561.

Cherubini F., Strømman A.H., Ulgiati S. (2011d), Environmental impacts of biorefinery products: influence of allocation methods on final results, *Resources Conservation and Recycling*, 55: 1070-1077.

Cherubini F. and Strømman A.H. (2011e), Life Cycle Assessment of bioenergy systems: State of the art and future challenges, *Bioresource Technology*, 102: 437-451.

De S and M Assandi. 2009. "Impact of Cofiring Biomass with Coal in Power Plants – A Techno-Economic Assessment." *Biomass and Bioenergy* 33(2):283–293.

EcoInvent Database. 2011. Version 2.2, Swiss Center for Life Cycle Inventories, Hamburg, Germany.

EIA - Energy Information Administration. 2012. *Annual Energy Outlook 2012 Early Release Overview*. DOE/EIA-0383ER.U.S.

Heller MC, GA Keoleian, MK Mann, and TA Volk. 2004. "Life Cycle Energy and Environmental Benefits of Generating Electricity from Willow Biomass." *Renewable Energy* 29(7):1023–1042.

Hess JR, KL Kenney, LP Ovard, EM Searcy, and CT Wright. 2009. Uniform-Format Solid Feedstock Supply System: A Commodity-Scale Design to Produce an Infrastructure-Compatible Bulk Solid from Lignocellulosic Biomass. INL/EXT-08-17527, Idaho National Laboratory, Idaho Falls, Idaho. Available at www.inl.gov/bioenergy/uniform-feedstock.

ICF International. 2008. *Life Cycle Carbon and Emissions Analysis*. Report prepared for Jordan Cove Energy Project, L.P., ICF International, Fairfax, VA. Available at: http://www.jordancoveenergy.com/pdf/JCEP_Task_4_Final_070908.pdf.

Keoleian GA and TA Volk. 2005. "Renewable Energy from Willow Biomass Crops: Life Cycle Energy, Environmental and Economic Performance." *Critical Reviews in Plant Sciences* 24(5–6):385–406.

Kruse J, A Protopapas, L Olson, and D Bierling. 2009. *A Modal Comparison of Domestic Freight Transportation Effects on the General Public*. Prepared for the U.S. Department of Transportation Maritime Administration and National Waterways Foundation by the Center for Ports and Waterways, Texas Transportation Institute, Houston, Texas. Available at http://www.americanwaterways.com/press_room/news_releases/NWFSTudy.pdf.

Marx J, A Schreiber, P Zapp, M Haines, JF Hake, and J Gale. 2011. "Environmental Evaluation of CCS using Life Cycle Assessment – A Synthesis Report." *Energy Procedia* 4:2448–2456.

NETL – National Energy Technology Laboratory. 2007. *Cost and Performance Baseline for Fossil Energy Plants*. DOE/NETL-2007-1281, Volume 1, Revision 1, U.S. Department of Energy: Washington, DC. Available at: http://www.netl.doe.gov/energy-analyses/pubs/BitBase_FinRep_2007.pdf.

NETL – National Energy Technology Laboratory. 2008. *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels*. DOE/NETL-2009/1346, Office of Systems, Analyses and Planning, U.S. Department of Energy: Washington, DC. Available at http://www.netl.doe.gov/energy-analyses/pubs/NETL%20LCA%20Petroleum-based%20Fuels%20Nov%202008.pdf.

Ortiz DS, AE Curtright, C Samaras, A Litovitz, and N Burger. 2011. *Near-Term Opportunities for Integrating Biomass into the U.S. Electrical Supply: Technical Considerations*. RAND Corporation, Santa Monica, California.

Pehnt M and J Henkel. 2009. "Life Cycle Assessment of Carbon Dioxide Capture and Storage from Lignite Power Plants." *International Journal of Greenhouse Gas Control* 3(1):49–66.

Qin XY, PV Bhave, and KA Prather (2006), Comparison of two methods for obtaining quantitative mass concentrations from aerosol time-of-flight mass spectrometry measurements, *Anal. Chem.*, 78 (17), 6169-6178.

Qin XY, and KA Prather (2006), Impact of biomass emissions on particle chemistry during the California Regional Particulate Air Quality Study, *International Journal of Mass Spectrometry*, 258 (1-3), 142-150.

Skone TJ, J Littlefield, R Eckard, G Cooney, R Wallace, and J Marriott. 2012. *Role of Alternative Energy Sources: Pulverized Coal and Biomass Cofiring Technology Assessment*. DOE/NETL-2012/1537, National Energy Technology Laboratory, Pittsburgh, PA.

Searcy E and JR Hess. 2010. Uniform-Format Feedstock Supply System Design Reports: A Commodity-Scale Design to Produce an Infrastructure-Compatible Biocrude from Lignocellulosic Biomass. INL/EXT-10-20372, Bioenergy Program, Idaho National Laboratory, Idaho Falls, Idaho.

Solomon S, D Qin, M Manning, RB Alley, T Berntsen, NL Bindoff, Z Chen, A Chidthaisong, JM Gregory, GC Hegerl, M Heimann, B Hewitson, BJ Hoskins, F Joos, J Jouzel, V Kattsov, U Lohmann, T Matsuno, M Molina, N Nicholls, J Overpeck, G Raga, V Ramaswamy, J Ren, M Rusticucci, R Somerville, TF Stocker, P Whetton, RA Wood, and D Wratt. 2007. "Technical Summary." In *Climate Change 2007: The Physical Science Basis*. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, S Solomon, D Qin, M Manning, Z Chen, M Marquis, KB Averyt, M Tignor, and HL Miller (eds.), Cambridge University Press, Cambridge, United Kingdom and New York, New York, USA.

Spath PL and MK Mann. 2000. *Life Cycle Assessment of a Natural Gas Combined-Cycle Power Generation System*. TP-570-27715, National Renewable Energy Laboratory, Golden, Colorado.

Spath PL, MK Mann, and DR Kerr. 1999. *Life Cycle Assessment of Coal-Fired Power Production*. TP-570-25119, National Renewable Energy Laboratory, Golden, Colorado.

Tillman DA. 2000. "Biomass Cofiring: The Technology, the Experience, the Combustion Consequences." *Biomass and Bioenergy* 19(6):365–384.

USLCI – U.S. Life-Cycle Inventory. 2012. Database v1.1, National Renewable Energy Technology Laboratory. Available at https://www.lcacommons.gov/nrel/search.

Uslu A, APC Faaij, and PCA Bergman. 2008. "Pre-Treatment Technologies and Their Effect on International Bioenergy Supply Chain Logistics: Techno-Economic Evaluation of Torrefaction, Fast Pyrolysis, and Pelletisation." *Energy* 33(8):1206–1223.

(This page intentionally left blank)

Appendix H

Comparison of Results with NETL Cofiring Studies

H.1 Scenario Similarities

This appendix contains a brief comparison of results from this study to results published by the National Energy Technology Laboratory (NETL) in DOE/NETL-2012/1537 (Skone et al. 2012). Key inputs and results are summarized in Table H.1~~Table H.1~~ and levelized cost of electricity (LCOE) results are presented graphically in Figure H.1~~Figure H.1~~.

The current study evaluates two specific locations: Alabama (for Southern Pine co-firing) and Ohio(for switchgrass co-firing). The NETL study evaluates a generic location somewhere in Illinois or Indiana. The scale of the current study which target site-specific plants that are much larger (i.e., 3,000 and 4,169 MW) compared to the NETL study (i.e., 550 MW). One potential impact of the scale difference would be on the price paid for the biomass feedstock, which would be dependent on availability, pretreatment, and delivery assumptions. It should be noted that the costs for similar feedstocks are similar – $68.71/ton DM for chipped pine in this study vs. $69.80/ton DM for chipped Hybrid Poplar in the NETL study. This equates to a difference of less than 2%.

At first glance, the LCOE for the coal-only cases seem to be reasonably comparable; costs in the current study (i.e., 3.03 and 2.79¢/kWh) are slightly lower than in the NETL study (3.09¢/kWh). This result is expected for a larger plant running a mixture of a less-expensive subbituminous coal. However, some notable differences are apparent in the ratio of fuel costs to operating costs. The operating costs in the NETL study are 61 % higher than in the current study and the fuel costs are appreciably less in the NETL study. These differences likely reflect differences in the underlying assumptions for coal type and coal costs for the two studies. Based on operating records, the current study assumes inexpensive Power River Basin coal is blended with native bituminous coals near Alabama and Ohio. The NETL study is based on Illinois coal.

A comparison between LCOE for 10 % chipped pine (current study) and 10 % chipped poplar (NETL study) shows that the projected fuel costs for pine increases by 0.37¢/kWh, while the fuel costs for chipped poplar increases by 0.56¢/kWh over the baseline coal case. This difference is not intuitive given the estimated price for wood differs by less than 2%.

The capital expenditure (CAPEX)costs for the 10 % pine cofiring case (current study) and the Hybrid Poplar case (NETL study) differ by a wide margin. The NETL study uses existing costs for a greenfield coal plant and adjusts those costs upwards by 10 % for biomass service. The current study bases costs primarily on biomass-specific vendor quotes currently in the Idaho National Laboratory biomass logistics model database. It may be beneficial to balance the study assumptions for a future cofiring sensitivity analysis.

Greenhouse gas (GHG) reductions for cofiring are consistent between the Southern Pine (current study) and forest residue (NETL study). However, NETL GHG results for hybrid popular are less favorable due to the energy required for feedstock growth, land transformation to plantation style production, and the use of fertilizer.

Table H.1. Comparison of Study Results to DOE/NETL-2012/1537

	Alabama Scenario (Current Study)			**Ohio 2 (Current Study)**			**DOE/NETL-2012/1537**		
	Coal	**10% wood cofire**	**20% cofire**	**Coal**	**10% Cofire**	**20% Cofire**	**Coal**	**10% cofire**	**10% cofire**
Plant Specifications									
Rated capacity (MW)	3,000			4,169			550		
Location	Alabama			Ohio			Illinois or Indiana Not Specified		
Coal type	84.1% Appalachian bituminous; 15.9% subbituminous			24.6% Pittsburgh No. 8 bituminous; 75.4% subbituminous			100% Illinois #6		
Capacity factor (%)	85.6	85.6	85.6	85.6	85.6	85.6	85.0	85.0	85.0
Biomass Feed Assumptions									
Biomass type	n/a	Pine	Pine	n/a	Switchgrass	Switchgrass	n/a	Hybrid poplar	Forest residue
Pretreatment	n/a	Chipping only	Torrefaction	n/a	Baling only	Leaching + torrefaction	n/a	Chipping only	Chipping only
% cofiring (energy basis)	0.0	10.0	20.0	0.0	10.0	20.0	0.0	10.0	10.0
Cost Analysis									
Biomass cost ($/dry ton)	n/a	68.71	113.33	n/a	112.96	185.82	n/a	69.80	28.28
LCOE (¢/kWh)	3.03	3.44	3.58	2.79	3.33	4.32	3.09	4.04	3.51
CAPEX (¢/kWh)	0.00	0.02	0.04	0.00	0.02	0.04	0.00	0.35	0.35
Operating expenditure (OPEX) (¢/kWh)	0.87	0.89	0.90	0.87	0.89	0.90	1.40	1.44	1.44
Fuel (¢/kWh)	2.16	2.53	2.63	1.92	2.42	3.38	1.70	2.26	1.73
GHG Reduction (%)	n/a	8.4	16.0	n/a	8.7	13.7	n/a	1.0	6.6

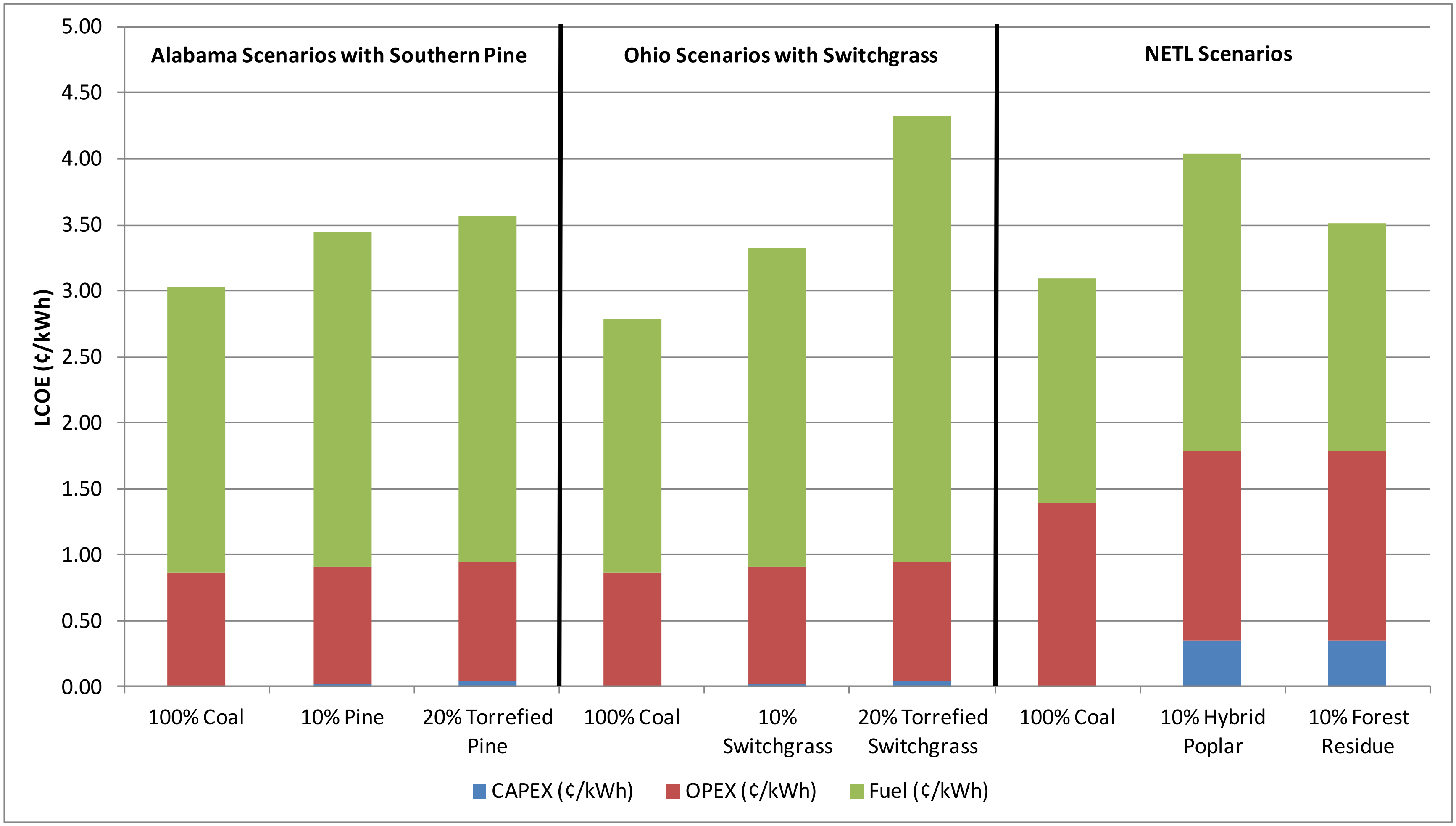


Figure H.1. Comparison of Study LCOE Results to DOE/NETL-2012/1537

In summary, the two studies show benefits of cofiring biomass, especially forest and agriculture residues in existing power plants. Plant retrofits to host the new feedstock are neither complicated nor cost exorbitant.

H.2 Appendix H References

Skone TJ, J Littlefield, R Eckard, G Cooney, R Wallace, and J Marriott. 2012. *Role of Alternative Energy Sources: Pulverized Coal and Biomass Cofiring Technology Assessment*.

DOE/NETL-2012/1537, National Energy Technology Laboratory, Pittsburgh, PA.