DEVELOPMENT AND APPLICATION OF A DECISION SUPPORT TOOL FOR BIOMASS CO-FIRING IN EXISTING COAL FIRED POWER PLANTS

By

Jason S. Smith

A THESIS

Submitted to
Michigan State University
in partial fulfillment of the requirements
for the degree of

Biosystems Engineering—Master of Science

2015

ABSTRACT

DEVELOPMENT AND APPLICATION OF A DECISION SUPPORT TOOL FOR BIOMASS CO-FIRING IN EXISTING COAL FIRED POWER PLANTS

By

Jason S. Smith

Biomass co-firing has the potential to be a low cost source of renewable energy that can utilize the existing infrastructure of existing coal fired power plants, while reducing the overall environmental impact of the existing systems. Though there are technical barriers to the development of co-firing systems, there is a growing need to utilize biomass resources in renewable energy production and several systems have shown the ability to do so successfully. In moving forward, project developers need tools to identify potential technical, economic or logistical issues when planning the development of such systems. The purpose of this study is to use the aggregated information regarding various combustion technologies, pre-treatment technologies and available biomass feedstocks to generate a decision support tool for energy providers that will help identify economic, environmental and social impacts of developing site specific biomass co-firing projects at existing coal fired power plants. This decision support tool will then be utilized to examine existing power plant and biomass data to generate a site specific case study in the state of Michigan.

Dedicated to my loving wife Emily and to my awesome family.
Thank you for loving me, pushing me and believing in me; even when I didn't believe in myself.
I love you all!

ACKNOWLEDGEMENTS

There are many people without whom this thesis would not be possible. Firstly, I would like to thank my advisor Dr. Steven Safferman for his guidance in every aspect of the project and for his kindness in allowing me the opportunity to pursue my Master's degree.

I would also like to thank my committee, Dr. Chris Saffron and Dr. Tim Harrigan. Their support throughout the project and valuable insight made this project the success that it is.

I would like to thank members of the development team Dr. Mike Thomas and Mr. David Binkley, without whom this project would not have been possible.

I would also like to offer a special thanks to Consumer's Energy for funding this project, and for their belief in me to carry out this work.

Last but not least, I would like to thank again my wife and family for their patience and their support throughout this journey.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1 INTRODUCTION

With renewable energy standards becoming more prevalent in the U.S. and environmental regulations resulting in the potential closure of existing coal fired power plants, energy companies are increasingly interested in finding new ways to reduce carbon emissions. In this effort, biomass co-firing is being considered as a transition option toward a low carbon or carbon free power sector (Lempp, 2013). Stand-alone biomass plants have the proven ability to produce reliable energy using a carbon neutral fuel source, but can be cost prohibitive when compared to other renewable energy options and may compete with other industry for biomass feedstock supplies (Kinney, 2012; Lempp, 2013), resulting in energy insecurity and a high Levelized Cost of Electricity (LCOE). According to the U.S Energy Information Administration (EIA), LCOE's of new biomass plant installations are expected to be $100/MWh, as compared to $72.6/MWh for wind and $42.8/MWh for geothermal (EIA, 2015).   This is due to the seasonal nature of some forms of biomass and is exacerbated by the fact that biomass resources may be dispersed without a supply chain as well established as that of coal or other competing fossil fuels. Additionally, transport efficiencies for biomass tend to be much lower than conventional fossil fuels due to poor bulk density, energy density, and high moisture content (Demirbas, 2005). Co-firing biomass and coal at exiting coal fired power plants can negate some of the aforementioned issues. An existing coal supply line and combustion system can help to buffer the system against fluxuations in biomass availability. (Williams, Pourkashanian, & Jones, 2001). When compared to dedicated biomass systems, co-fired fired operations can be quite large and take advantage of the improved efficiencies of such systems (Williams et al., 2001).   Finally, modifying existing systems is much more cost effective than building new, as capital costs can be kept low through the co-opting of existing infrastructure (Centre, 2005). This is also true of operation and maintenance costs, as existing labor and equipment can be utilized in most cases to carry out daily activities. All of these benefits can be realized with relative certainty because co-firing is a commercial ready technology as a recent review of co-firing experience identified over 100 successful co-firing field demonstrations (Baxter, 2005).

However, co-firing is not without challenges or barriers to overcome. Previous studies have noted that biomass fuel cannot be conditioned in the same manner as coal. The fibrous nature of biomass precludes it from being directly injected to size reduction technologies such as coal pulverizers. In fact, in pulverized coal systems, biomass has been shown to be problematic at blending rates greater than 3% by heat without specific pretreatment and conditioning. Additionally, high alkali contents of some biomass fuels can lead to untimely boiler corrosion and increase maintenance requirements. Coal fired power plants that sell fly ash for beneficial use also need to ensure that the addition of biomass ash does not compromise the chemical composition of saleable byproducts.

Though there are technical barriers to the development of co-firing systems, there is a growing need to utilize biomass resources in renewable energy production and several systems have shown the ability to do so successfully. In moving forward, project developers need tools to identify potential technical, economic or logistical issues when planning the development of such systems. The purpose of this study is to use the aggregated information regarding various combustion technologies, pre-treatment technologies and available biomass feedstocks to generate a decision support tool for energy providers that will help identify economic, environmental and social impacts of developing site specific biomass co-firing projects at existing coal fired power plants. This decision support tool will then be utilized to examine existing power plant and biomass data to generate a site specific case study in the state of Michigan.

2 OBJECTIVES

The objective of this thesis is to develop a decision support tool to evaluate the strategic use of biomass co-firing at existing power plants to include biomass aggregation, processing, and integration into existing infrastructure, to calibrate this tool using literature values, to verify the tool through matching logic structures to existing literature, and validate the tool through comparison with existing case studies. The tool will then be used to investigate scenarios surrounding a real coal fired power plant. Outputs to be estimated by the tool shall include:

- Cost of capital investment normalized to renewable electricity production,
- levelized cost of electricity production,
- associated reduction in net CO_2 emissions and
- energy returned on energy invested to produce biomass energy.

3 LITERATURE REVIEW

A review of previously published literature was performed in order to establish the baseline assumptions and governing equations contained within the decision support tool. First, a review of combustion technologies applied at coal fired power plants was performed in order to understand the application and limitation of biomass firing in such systems. Secondly, a review of previously established biomass co-firing methodologies was performed to determine how biomass is commonly used within the context of existing coal fired power plants. As the model is also intended to ascertain the effect of biomass pre-treatment on project feasibility, the literature review was extended to include the technical nature and use of biomass pre-treatment techniques such as drying, densification, and torrefaction. Lastly a review of existing models and case studies was performed in order to better understand the current state of the technology, and the application of technical and economic models to biomass co-firing.

3.1 Combustion Boiler Types and Methodologies

The methods of combustion most commonly used in existing coal fired power plants. Combustion methods can be divided into 3 main categories: fixed bed, pulverized fuel, and fluidized bed combustion systems. There are several variations of each and an overview of each to understand the benefits and limitations associated with using biomass in such systems are discussed in the sequential sections.

3.1.1 Pulverized Fuel Combustion

Pulverized fuel or dust combustion systems (PCs) use compressed air to feed fuel into a combustion cyclone (Van Loo & Koppejan, 2008). Because the feedstock needs to be reliably moved by compressed air, fuel quality in dust combustion needs to be constant with a maximum fuel particle size of 10-20 mm and a moisture content of no more than 20 wt% (wet basis) (Van Loo & Koppejan, 2008). Common in existing coal-fired power plants, the feedstock is pulverized prior to combustion to increase completeness of reaction before feeding into a whirling cyclone of combustion air. Feedstock in this process have the most stringent size and moisture specifications, as feedstock needs to be injected in the same manner as pulverized coal but cannot mat or bind during the feeding process. This is by far the most common form of coal boiler used in the state of Michigan. According to an analysis performed of US Energy Information Administration (EIA) databases, 99% of coal fired capacity in the state of Michigan comes from pulverized coal boilers (EIA, 2012)

3.1.2 Fixed Bed

In fixed bed system biomass is loaded onto a metal mesh or grate upon which the combustion reaction is performed. Here, air passes through a fixed bed (grate) inside of a combustion chamber. Inside where in the primary combustion chamber the drying, gasification and ignition phases of combustion are performed in the presence of excess oxygen. Heavy particles remain securely on the grate while fines and gasses are lifted and combusted in a separate zone (Van Loo & Koppejan, 2008). An annotated depiction of one such system is shown in Figure 1.

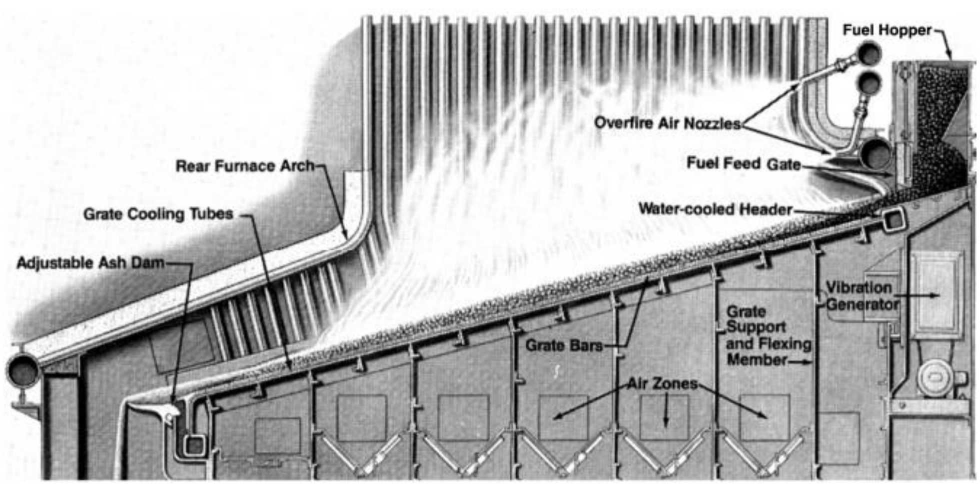


Figure 1: Cross Section of Overfeed, Water-Cooled, Vibrating Grate Boiler (EPA, 2007)

Such furnaces are designed to accommodate fuels that have a high moisture content, varying particle sizes, and high ash content (Van Loo & Koppejan, 2008). Grate furnaces come in various types which are commonly defined by grate configuration (fixed, moving, travelling, rotating and vibrating) as well as air movement patterns (underfeed, counter current, co-current and cross flow) (Van Loo & Koppejan, 2008). Fixed bed boilers are not commonly associated with direct co-firing as most large scale coal fired power plants do not currently utilize this boiler type. According to an analysis of EIA form 860 data for 2012 (EIA, 2012) less than 1% of coal fired generation capacity in Michigan comes from stoker boilers. However, these systems can be a part of more complex co-firing strategies such as in-direct co-firing. (Van Loo & Koppejan, 2008). In these systems, biomass is combusted separately but in the same plant as coal and is used to drive the same generators. This is useful where biomass cannot be directly mixed with coal due to particle size, matting, or other concerns. There is, however, a significant and often prohibitive added cost to adding a new combustion unit to an existing plant (Maciejewska, Veringa, Sanders, & Peteves, 2006).

3.1.3 Fluidized Bed

Fluidized bed combustion uses a mixture of inert material, such as sand, in suspension with the fuel particles. Compressed air is continuously fed through the bottom of the combustion bed to force the bed to fluidize, thus improving available surface are and particle interaction. (Van Loo & Koppejan, 2008). In these beds, inert material makes up roughly 90-98% of the total mixture by mass, with the fuel constituting the remainder of the mixture. The bed material provides high thermal inertia, allows for greater particle interaction (i.e. improved heat transfer) and stabilizes the combustion process. However, like pulverized fuel boilers, the fuel particle size must be consistently less than 80mm (Van Loo & Koppejan, 2008). The combustion temperature has to be kept low (800-900ºC) to prevent ash from coalescing with the inert particles and de-fluidizing the bed in a process called sintering (Van Loo & Koppejan, 2008).

3.2 Combustion Plant Configurations

Another key consideration in biomass co-firing is determining where in the coal fired power plant process biomass will be utilized. Biomass's point of insertion relative to the existing process flow is called the combustion configuration. The two most commonly used combustion configurations are direct co-firing (also known as direct mixing) and parallel co-firing.

3.2.1 Direct Co-Firing

As the name suggests, direct co-firing involves mixing the biomass and coal feedstocks at a pre-determined ratio prior to insertion into the power plant boiler. At low biomass blending rates, this configuration is the most economical and thus the most widely used. Depending on the biomass fuel characteristics, biomass specific mills may be required to ensure particle sizing and flow. Tillman et al. describes three primary methods by which direct co-firing can take place at coal fired power plant (Tillman, 2000), which are depicted in Figure 1.

The first option Tillman presents is to blend the fuel directly at the fuel pile, prior to size reduction or firing of the coal. This is logistically the simplest and least expensive option as mostly existing infrastructure is used and very little new capital investment is required. However this option can only be accomplished at low biomass blending rations, usually <5% (Tillman, 2000) due to inconsistencies between biomass and coal physical properties. The viable blending ratio is even lower for pulverized fuel boilers utilizing herbaceous or fibrous biomass; usually <3% (FEMP, 2004; Maciejewska et al., 2006). This is due to the inability of coal pulverizers to crush large quantities of biomass without biomass matting, resulting in the inhibiting of fuel flow.

The second option partially addresses this issue by utilizing separate milling of biomass. After milling, compressed air is used to insert biomass into the existing coal fired system. This can be accomplished by tapping in to the existing coal pipeline entering the burner, or through a separate injection port at the burner itself. This approach involves a higher investment but co-firing at higher ratios (up to 15% biomass by heating value) can be achieved (FEMP, 2004).

The final option is related to option 2. Here again, biomass is milled separately and through a separate injection port infused directly into the boiler. However, in this option the injection port is strategically placed so that biomass is used as a re-burn fuel to control the NOx emissions. NOx re-burn fuel systems take advantage of multi stage combustion zones inside of the boiler to limit NOx production. In this scenario, the first stage or main combustion zone would be where coal is burned. The second stage is a re-burning zone. Here excess fuels with a high volatile carbon and low nitrogen content are added to create a reducing zone. As will be discussed in later sections, biomass has the required properties for a re-burn fuel, and can be utilized in this manner

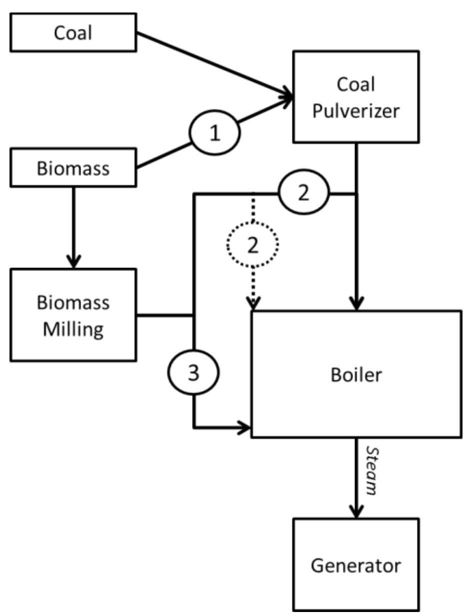


Figure 2: Direct Fire Biomass Pathways

3.2.2 Parallel Co-Firing

In parallel co-firing operations, biomass is in a parallel boiler in order to produce low grade steam. This steam is then upgraded to match the specifications of the coal boiler steam and injected into the steam cycle either at or ahead of the generator, as shown in Figure 3. Capital costs for parallel co-firing installations are significantly higher than with direct mixing due to the need to install a new boiler system and steam upgrading equipment. However, there are a number of advantages that can be realized as well according to (Van Loo & Koppejan, 2008).

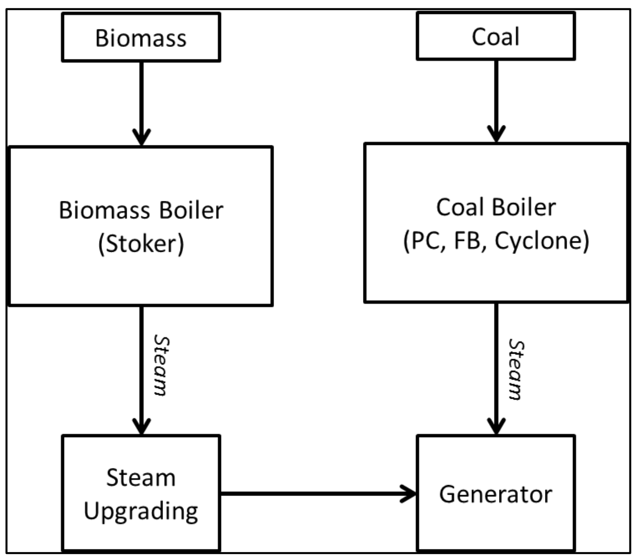


Figure 3: Generalized Parallel Co-Firing Configuration

First, different combustion methodologies can be employed for the biomass, reducing the need for biomass conditioning prior to combustion. Most coal fired power plants in the United States utilize either pulverized coal, fluidized bed or cyclone boilers (EIA, 2012). These systems have strict requirements for particle sizing prior to combustion, as seen in Table 1. Biomass boilers are generally fixed/stoker boilers that can accommodate larger particle sizes. Having a separate biomass boiler also allows for the combustion conditions to be tailored for a lower heating value fuel, improving overall system efficiency and reducing the need for pre-combustion conditioning activities such as drying.

Table 1: Biomass Sizing Requirements for Various Boiler Types (FEMP, 2004)

Existing Boiler Type	Particle Size Required (mm)
Pulverized Coal	<0.0002
Fluidized Bed	<50
Stoker	20-90

(Van Loo & Koppejan, 2008) Having a separate biomass boiler system can also be useful for fuels with high alkali and/or chlorine contents (Van Loo & Koppejan, 2008). High alkali and chlorine content biomass sources such as wheat straw can be problematic to boiler operators, as these traits can cause corrosion of conventional coal boilers, as well as harmful byproducts (such as dioxin) under conditions of incomplete combustion. As boiler conditions and materials can be tailored to the biomass in parallel co-firing, these concerns are greatly reduced.

Lastly, it is critical to note that coal and biomass ash are kept separate in parallel co-firing operations. This may be an important and deciding factor for operations that need to keep ash chemical composition within specific limits for the purpose of beneficial re-sale.

3.3 Biomass Pre-Treatments

As observed from the previous sections, the type of combustion system depends on the plant layout, and the blending ratio of biomass greatly depends on the chemical and physical conditions of the biomass delivered to the power plant. Chemical and physical conditions of the biomass depend on the inherent properties of the biomass and pre-treatment. The following subsection outlines key biomass pre-treatments that can be employed to condition biomass prior to delivery.

3.3.1 Torrefaction

Torrefaction is a thermo-chemical process conducted in an anaerobic environment, at a temperature of 200-300^{o}C. Residence times vary depending on biomass moisture content but generally are 1 hour. Because of the lack of oxygen, the biomass does not combust at these temperatures but rather decomposes during which volatiles such as carbon monoxide are given off and the solid portion of the biomass that remains as the final product. This is sometimes called char, bio-char or bio-coal. (Bergman, 2005). Combustible torrefaction gas (torgas) is also produced during the reaction, which is often combusted to help heat the torrefaction reaction. Torrefaction is a promising pre-treatment option, improving the properties of biomass, including the following (Bergman, 2005).

1. Increased specific heating value.
2. Improved water resistance (hydrophobicity).
3. Increased friability (ease of grinding).
4. Greater Uniformity.

Torrefied biomass will act more like coal as it is more brittle and is easily pulverized to a fine dust without binding. This property is known as friability and has further implications in energy consumption. The improved friability of biomass through torrefaction can reduce particle size reduction energy inputs by 70-90%, compared to non-torrefied biomass(Bergman, 2005). Furthermore, the improved hydrophobicity of the feedstock allows for easier storage, as torrefied biomass will not spoil, ferment or otherwise degrade as regular biomass will if not kept in a controlled environment.

Torrefaction is still an emerging technology, with several units in the pre-commercial development stages but few in full scale industrial operation. The resultant model makes the assumption that full scale production of a viable torrefaction product will be available in the near term.

3.3.2 Pelleting

Pelletizing is a compacting process that changes the biomass into a homogenous, high energy dense cylindrical shape with dimension of 6-8 mm diameter (Van Loo & Koppejan, 2008). At present, pellets are the form of biomass most often used in coal-fired plants for co-combustion (Bergman, 2005).

The most important role of pelleting is that it improves both the bulk density and energy density of biomass feedstocks. Low bulk density can cause a number of problems along the supply chain and within combustion operations. Such feedstocks are orders of magnitude more expensive to transport to the combustion facility. Once at the facility, feedstocks with a low energy density need to be treated differently in the combustion process. If the energy density is low, adding too much of the low energy density feedstock to the combustion reaction will lower the combustion temperature and reduce overall combustion efficiency while also releasing harmful byproducts of incomplete combustion. For this reason, non-densified feedstocks may need to be fed a lower ratio to coal, thus limiting their potential impact. (Bologa, Paur, Seifert, Woletz, & Ulbricht, 2012; Dunajski, Kruk, & Nowak, 2013; Gil et al., 2010; Svanberg, Olofsson, Flodén, & Nordin, 2013). Pellets also have the added benefit of being more uniform in size and shape than unprocessed biomass, reducing concerns of binding during feedstock handling.

The process of pelleting is defined by 5 steps; drying, milling, steam-conditioning, densification, and cooling. Drying is necessary if and only if biomass does not meet the prerequisite conditions for pelleting. Depending on the type of biomass being pelleted, initial moisture content needs to be between 8 and 12% by weight (w.b.). This is because pellet stability is a function of the friction between the pelleting apparatus and the raw material. If the material is too dry, the friction from pressing will cause material carbonization. If the biomass is too moist, residual moisture in the formed pellet will cause expansion over time. In either case, pellet stability is lost. After drying biomass is hammer milled to reduce particle size and sometimes steam conditioned to improve cohesion. The biomass is then densified and quickly cooled to increase durability. (Van Loo & Koppejan, 2008).

The primary drawback of pelleting is that it does not completely address the issue of moisture management. Although pellets are dry, they readily absorb moisture and will swell or complete disintegrate under wet conditions (Gil, 2010). Consequently, pelleted biomass still needs to be stored in a controlled environment before use in combustion.

3.3.3 Drying

Drying is the process of vaporizing moisture found in biomass. This is often performed in a controlled chamber with the aid of an external combustion reactor; however air drying can also be effective. (Van Loo & Koppejan, 2008). This process is necessary to improve overall handling and combustion efficiency. Moisture content in raw biomass can be quite high. For raw woody biomass, for instance (sometimes called greenwood), the moisture contents often exceed 50% by weight (Svoboda K., 2005). Combustion can be difficult to sustain if biomass moisture exceeds 60% wt. (Van Loo & Koppejan, 2008). Above this moisture content, support fuel is needed to sustain the reaction (Svoboda K., 2005). Thus drying plays an integral role in the combustion process. However, the need to dry needs to be balanced against the financial cost of drying. Reducing moisture content from 50% to levels lower than 10-15% has been shown to be cost prohibitive even in large installations. (Svanberg, 2013).

In addition to reduced boiler efficiency, high moisture content is also associated with biomass decomposition and associated energy loss during storage.

The following drying options are available (Gebreegziabher, Oyedun, & Hui, 2013; Svanberg et al., 2013; Werther & Ogada, 1999).

- **Open-air drying**: harvested biomass is left in the open air. The targeted resultant moisture content for woody biomass in this situation is around 30% (Van Loo & Koppejan, 2008). However, precipitation events can negate this effect. With few input costs, open air drying is the cheapest, yet least reliable drying option.
- **Mechanical dryers**: These include belt, drum, tube and fluidized bed style boilers. All driers are capable of reducing biomass to user defined moisture contents, however they require an energy

input (fossil fuel, electricity, or excess biomass). If the raw biomass source is in log or branch form, size reduction will be required ahead of the drying process.

3.4 Biomass Feedstocks

Biomass feedstocks can generally be divided into three categories; dedicated energy crops, crop residues, and feedstocks of opportunity. Dedicated energy crops, are those purposefully grown to be utilized as energy crops. These include energy grasses, short rotation poplar, and willow. Biomass residues are those feedstocks which are a byproduct of other agricultural processes such as wheat straw, corn stover and forest slash. Feedstocks of opportunity are generally defined as those which can be obtained as a waste product of a residential or industrial process such as sawdust, biosolids, and construction debris.

As shown in Table 2, the biomass and coal differ in a few key composition characteristics. Notably, as previously discussed biomass naturally has higher moisture content than most coal species, thus lowering its net calorific value. Further, biomass is generally lower in sulfur content, and has a lower C/O ratio than coal. Certain biomass residues such as straw are also known to have higher chlorine content than coal. If not properly managed, this can be corrosive to boilers. Similarly, high alkali and high ash content fuels such as switchgrass and miscanthus can cause issues with slagging if not properly managed.

Finally, the high volatile matter content when combined with ambient moisture can result in mass loss during storage if not properly managed. This mass loss can be as high as 1% per month {Srivastava, 2011 #231}. Torrefaction, and to a degree pelleting can manage this loss. For the purposes of this study, processing is assumed to be expedient and mass losses are thus considered to be negligible.

Table 2: Typical properties of different solid fuels - CEN-335- Solid biofuels, Fuel specifications and classes, March 2003

	Coal	Peat	Wood without bark	Bark	Forest residues (coniferous tree with needles)	Willow	Straw	Reed canary grass (spring harvest)
Ash content (db.)	8.5-10.9	4-7	0.4-0.5	2-3	1-3	1.1-4.0	5	6.2-7.5
Moisture content (wt%)	6-10	40-55	5-60	45-65	50-60	50-60	17-25	15-20
NCV (MJ/kg)	26-28.3	20.9-21.3	18.5-20	18.5-23	18.5-20	18.4-19.2	17.4	17.1-17.5
C, %db.	76-87	52-56	48-52	48-52	48-52	47-51	45-47	45,5-46,1
H, %db.	3.5-5	5-6.5	6.2-6.4	5.7-6.8	6-6.2	5.8-6.7	5.8-6.0	5.7-5.8
N, %db.	0.8-1.5	1-3	0.1-0.5	0.3-0.8	0.3-0.5	0.2-0.8	0.4-0.6	0.65-1.04
O, %db.	2.8-11.3	30-40	38-42	24.3-40.2	40-44	40-46	40-46	44
S, %db.	0.5-3.1	<0.05-0.3	<0.05	<0.05	<0.05	0.02-0.10	0.05-0.2	0.08-0.13
Cl, %db.	<0.1	0.02-0.06	0.01-0.03	0.01-0.03	0.01-0.04	0.01-0.05	0.14-0.97	0.09

3.5 Previous Modeling Efforts

Several models have been developed previously to describe individual components of the biomass co-firing process chain that CREDIT is attempting to describe. These studies should be divided into two distinct categories; mechanistic and techno-economic. Kinetic models attempt to describe one or a series of physical/ chemical relationships between project parameters. An example of this would be a model that describes the relationship between fuel properties and energy generation or a model that describes the relationship between fuel volatile matter and NOx emissions. Techno-economic models attempt to describe the relationship between required process technologies, process mechanics, and cost.

3.5.1 Kinetic & Mechanistic

The following kinetic or mechanistic models were investigated for use or incorporation into CREDIT.

- (Basu, 2013) and (Van Loo & Koppejan, 2008) derive stoichiometric relationships for the combustion of biomass based upon the carbon, hydrogen, nitrogen, and sulfur mass fractions of biomass and coal, the moisture content of biomass and coal, as well as the excess air ratio used by the boiler. These equations predict the rate of formation of carbon dioxide, sulfur dioxide and nitrogen compounds based upon these parameters. Both texts also offer equations for gross calorific content and net calorific content of feedstocks based on these characteristics, and methodologies to apply these values to boiler outputs. Van Loo & Koppejan 2008 also offers stoichiometric adjustments to these equations based upon the formation of incomplete combustion products.
- Based on live studies conducted Allen Fossil Plant, (Tillman, 2000) studied the relationship between co-firing rates and NOx emission reduction. In these tests, sawdust was blended into a cyclone boiler firing Utah coal as a base feed at a rate of 15% biomass by mass (7% by energy). Tillman found that NOx emissions were strongly correlated to the increase in volatile carbon content in biomass. The relationship was described as NOx = 1.554(FN) + .021(EO2) + 0.0013 (FR) + 1.46(V/FC) – 1.75. Where FN was the fuel nitrogen percentage, EO2 was the excess oxygen in flue gas, FR was the firing rate and V/FC was the volatile to fixed carbon ratio. This relationship was observed to have an R^2 value of 0.87. At the pre-described blending rates, NOx emissions were found to be reduced by 15% (mass) while the boiler system experienced no capacity loss and only minor reductions in efficiency.

3.5.2 Techno-Economic

The following techno-economic models were investigated for use or incorporation into CREDIT, and also investigated to ensure CREDIT fits a niche not previously occupied by existing models.

- Caputo et. al developed a series of equations the cost of installation of new equipment associated with biomass gasification and direct combustion based on the study of several case studies. Select values and equations from this study were used to calibrate CREDIT economic assumptions about the relative cost of processing equipment installations. (Caputo, Palumbo, Pelagagge, & Scacchia, 2005)
- COFIRE is a spreadsheet based techno-economic analysis developed in 1990 by the Energy Production Research Institute (EPRI) to assess the cost of modifications needed for various fuel blending ratios and generator sizes. Though the model itself and the calculations used in the model are not publicly available, reported model results have been used to calibrate the power plant assessment portion of CREDIT after adjusting the results to 2015 dollars.
- Batidzirai et al developed a techno-economic analysis of a biomass torrefaction reactor depot. For this model, Batizirai utilized a mass and energy balance analysis of a torrefaction reactor that utilized direct combustion of excess biomass as an energy source to size a system for economic assessment. Analysis was performed for systems ranging from 50 -500 kilo tonnes per year. Elements of the energy balance from this study, as well as the method of associating reactor yield with the moisture content observed in previous studies were adopted for CREDIT analysis of torrefaction reactions. (Batidzirai, Mignot, Schakel, Junginger, & Faaij, 2013)
- As part of its expanding effort to provide decision support tools for renewable energy generation the National Renewable Energy Laboratory developed an executable computer program called the System Advisory Model (SAM). SAM is capable of integrating online weather data, feedstock availability (per the Billion Ton Study), and other regional data to produce a

region specific techno-economic assessment for several renewable energy technologies. Installation of new dedicated biomass only combustion systems is covered by this model, but retrofitting of existing coal fired power plants is not. Functional elements of the model such as integration with existing databases have been adopted by CREDIT to improve site specific accuracy.

3.6 Co-Firing Case Studies

In addition to understanding the models developed around co-firing, it is crucial to look at the existing instances of full scale biomass co-firing technology application in order to understand how the models compare, and to understand some of the practical limitations of technology deployment. The literature provides two such kinds of study. The first is the presentation of results from full scale field operations. Though several plants have reportedly tested biomass co-firing at various levels, not all have reported their findings. This is reflected in the literature review. Additionally, other entities have conducted and reported full scale engineering feasibility studies regarding biomass co-firing. Though these may not provide field level data, they do provide a useful look at other forms of situational analysis that can be used to develop a decision support model.

3.6.1 Field Testing & Full Time Units

- Tillman, 2000 reports the results of several co-firing case studies performed between the years of 1990 and 1999 at several facilities, all conducted under the auspices of the EPRI. These facilities include the Bailly, Seward, Shawville, Allen, and Michigan City Generating stations. The results from these studies are aggregated in (Tillman, 2000). As this dataset includes several studies performed by the same author with the same methodology, they represent a good source of data for comparison. Economic and emission data from these case studies were used to validate CREDIT. In these studies, Tillman investigates the blending effects of varying biomass injection rates on NOx reduction, boiler efficiency, pulverizer energy requirements, and capital investment requirements.

- In 2003, co-firing of torrefied wood was tested in PC-plant in the Netherlands, where torrefied wood was mixed with coal at a ratio of up to 9% (energy basis). The conclusion was that a 9% torrefied biomass blend was non-problematic and that co-firing at higher ratios may even be possible (Weststeyn A., 2004).

3.6.2 Feasibility Studies

- The Idaho National Laboratory conducted a feasibility study to determine the cost of woody biomass co-firing at a blending rate of 20% by mass. INL utilized combustion models developed in ASPEN to calculate mass and energy balances, in conjunction with a spreadsheet based economic assessment. The INL report also utilized a version of a Monte Carlo analysis to ascertain model result distribution based upon variation across multiple parameters. This method of analysis was duplicated within the CREDIT scenario analysis and data validation process as a method to deal with the uncertainty inherent in assumption based feasibility studies.
- Srivastava et. al. investigated the cost effectiveness of biomass pre-treatment via torrefaction and pelleting in the state of Michigan. A scenario was developed investigating the production of farmed willow crops followed by torrefaction, and pelleting prior to combustion. The effects of pre-treatment and depoting were evaluated at multiple distances in order to determine the distance at which torrefaction became cost effective through the realization of transport efficiencies. Values for Michigan specific biomass generation rates as well as machinery costs were used to calibrate CREDIT. (Srivastava, Abbas, Saffron, & Pan, 2011)

- Hartmann and Kaltschmitt conducted a life cycle analysis (LCA) of a German coal fired power plant that co-fed a 10% residual wood and straw blend with coal. (Hartmann & Kaltschmitt, 1999)

4 METHODS

A spreadsheet model was developed using literature derived relationships and equations and then used to evaluate the long term cost, GHG emissions, and energy generation potential associated with co-firing biomass at exiting coal fired power plants based on analysis of publicly available data and data provided by MSU extension agents. Microsoft Excel was utilized to perform the necessary calculations and conditional relationship statements in order to ensure that the tool could be used by plant operators, policy makers, and members of the public at large without the need for specialized software.

Two biomass pre-processing routines were investigated in order to determine the logistic and economic viability of using biomass depots as a portion of the biomass co-firing lifecycle process. The calculations, methods, and assumptions contained within the spreadsheet model are outlined in the following sections.

4.1 Process Outline & Model Scope

Figure 4 illustrates the scope of the analysis. The model begins by assuming feedstock is purchased at the point of biomass generation. This is sometimes called the “farm-gate” in literature. Feedstock price and raw physical and chemical characteristics are assumed at this point from feedstock specific literature derived values. Biomass is then assumed to be transported via truck from the farm gate to an aggregation point called a biomass depot. Once at the biomass depot, biomass may be processed through milling, drying, densification or torrefaction. Figure 4 displays the two processing schematics used in later scenario analysis. After depoting, biomass is transported from the depot to the power plant either by rail or by truck.

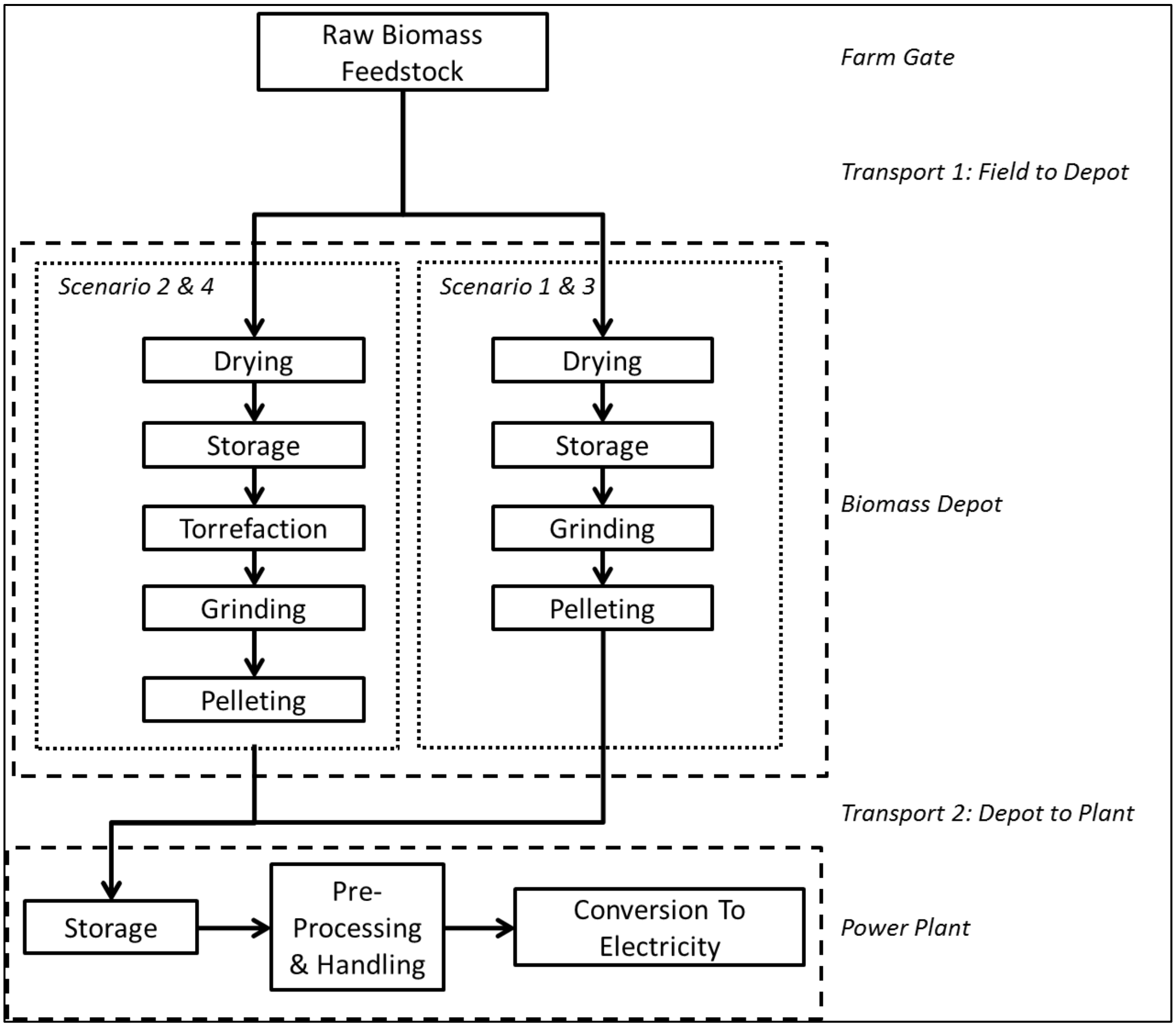


Figure 4: Process Configuration

At the power plant, biomass will be offloaded, stored, and where necessary processed to meet boiler fuel specifications. Processing activities at the power plant may include drying, milling, or incorporation into a separate boiler. Figure 5 offers a more detailed description of the incorporation routes that can be utilized at the power plant.

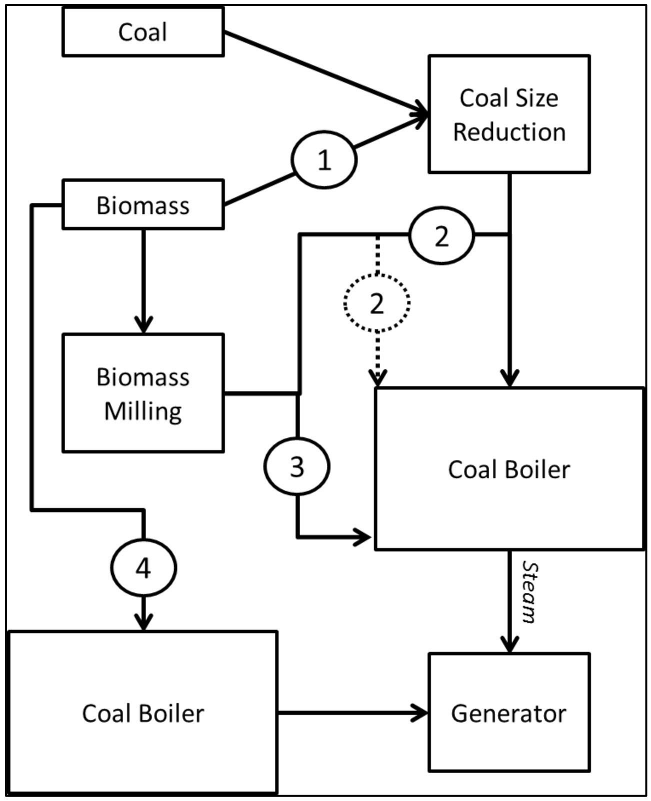


Figure 5: Biomass Incorporation Routes at Coal Fired Power Plants

4.2 Model Outline

The model that was derived from this effort was designated the Combustion of Renewable Energy Development Iterative Tool (CREDIT). CREDIT is capable of drawing upon existing databases as well as regional data relating to biomass production and land availability to generate energy production cost estimates, projected CO_2 mitigation data, as well as scenario analysis of various biomass pre-processing techniques. The logical structure derived for this task is shown in Figure 6. CREDIT leverages site data collected and aggregated by the US EIA to populate several key parameters regarding the selected site, including but not limited to boiler type, boiler capacity, boiler feeding rate, fuel type, and emission data. The tool requests that the user select which power plant and boiler is under investigation through a dropdown menu. These parameters are used as the baseline for several calculations regarding biomass requirements and capacity.

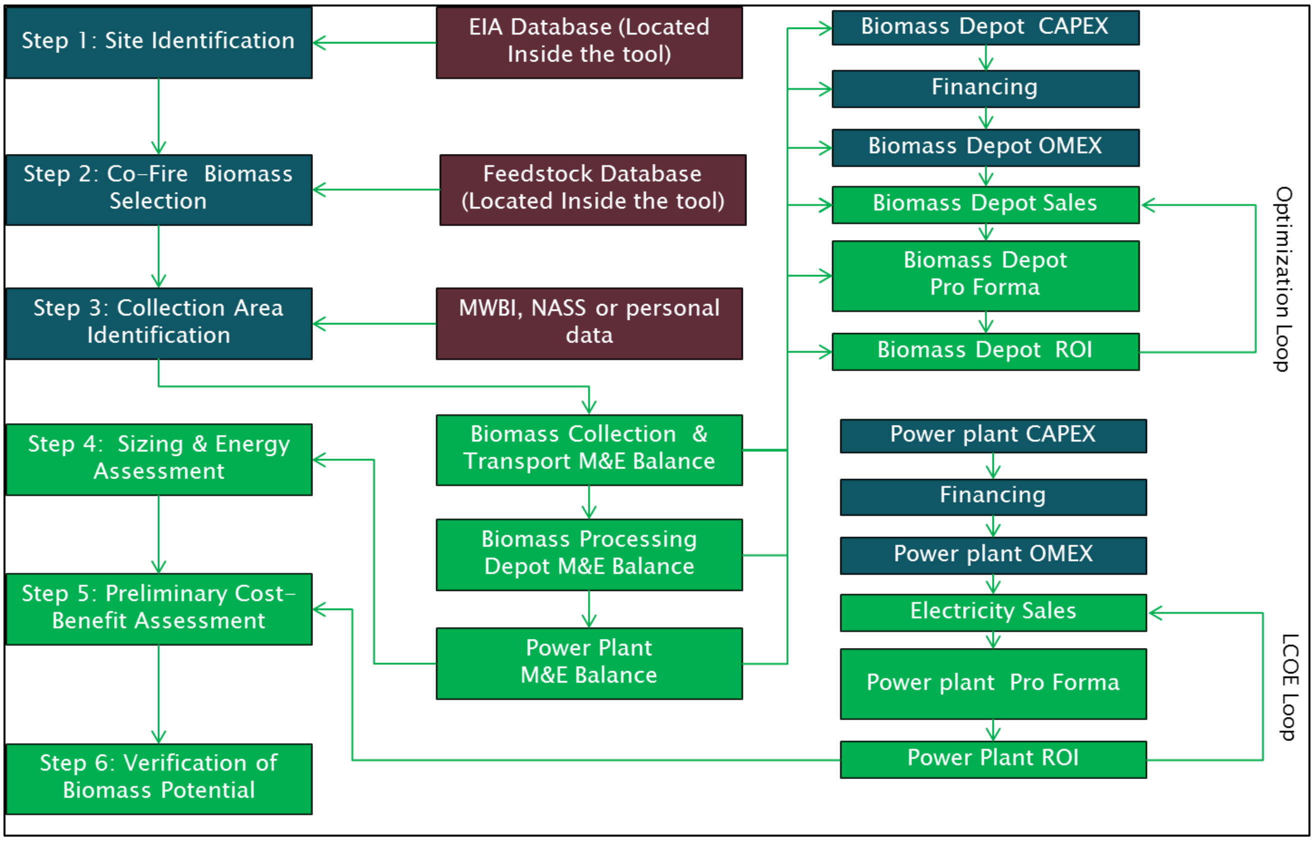


Figure 6: CREDIT data flow chart

(Blue denotes user definable areas, purple denotes databases, and green denotes calculation sheets)

After site identification, the user is prompted to identify the type of biomass that is to be co-fired from a pre-defined list of biomass sources. Table 2 lists the relevant feedstocks along with their associated chemical properties. Based on the answers given to the first 2 questions, an advised blending ratio is recommended which maximizes the amount of biomass which can be blended given the type of biomass, the boiler type and the combustion configuration (Figure 7). Users may accept this value or enter their own before calculating the amount of biomass required to meet this blending ratio.

English Units			
Power Plant Data			
General			
Power Plant/Boiler Name	J H Campbell - Boiler 2		= User Required Input
Proposed Co-Feed	Hybrid Poplar		= Editable Cell (Table value default)
Biomass Integration Configuration	Direct Mixing		= Calculation (Not Editable)
Advised Biomass Blending Rate (Energy Basis)	5%	Calculate Biomass Required (Energy Basis)	
Advised Biomass Blending Rate (Mass Basis) (Non-Preffered Option)	5%	Calculate Biomass Required (Mass Basis)	

Figure 7: CREDIT Screenshot, Biomass Blend Calculation

Users are then asked a series of questions regarding biomass collection, transportation and logistics in order to ascertain the collection area needed to achieve the desired blending ratio. Figure 8 is a screenshot from CREDIT depicting the information needed for this step. Green cells are user defined inputs, while blue cells are automated lookup values associated with user defined feedstock.

In-Field or On-Site Data		
Feedstock Type	Hybrid Poplar	
Felled or Farmed	Farmed	
Feedstock Production Rate	286,329.33	ton/yr
Feedstock Dry Matter	282,836	ton/yr
Feedstock Density	0.0086	ton/ft3
C	49.4%	%dm
H	6.0%	%dm
N	43.1%	%dm
O	0.2%	%dm
S	0.1%	%dm
Fixed Carbon	13.7%	%dm
Volatile Matter	85.1%	%dm
Ash	1.2%	%dm
Moisture	40.0%	
HHV (ar)	8,532	Btu/lb
LHV (ar)	6,825	Btu/lb
Collection Area (Total)	1,445,071	Acres
Farmland in Collection Area	32,903	Acres
Farmland Productivity	5.00	dry ton/Acre
Total AOE Productivity	286,329	dry ton/yr
In Field Drying?	Yes	
Resultant Moisture Content	30%	%

Figure 8: CREDIT Screenshot, Biomass Collection Data

Additionally, if biomass is intended to be aggregated at a depot prior to use at the coal fired power plant, the user may define what depot operations will take place including drying, torrefaction, and densification of the biomass. Figure 9 shows a screenshot of CREDIT showing the user inputs for this step.

Depot Data		
Depot Uptime	90%	(percent)
Operating Hours	7884	
Drying at Depot?	Yes	
Cost of Natural Gas	2.84	$/MMBtu
Exit Moisture Content	10%	
Thermal Efficiency	90%	
Torrefaction at Depot?	No	
Thermal Efficiency	100%	
Product Yield	90.0%	
Densification at Depot?	Yes	
Resultant Bulk Density	43.94	lb/ft3

Figure 9: CREDIT Screenshot, Biomass Depot Questionnaire

Collected data is then fed into several subroutines (each an individual excel worksheet) as is outlined by the data flow diagram in Figure 6. The calculations utilized in these sheets are detailed in the following sections. An additional critical point is the optimization loops associated with the economic analyses. Excel macros were developed to allow the user to determine the value of processed biomass feedstock exiting the biomass depot, as well as the break-even electricity sale price for the power plant. These break-even prices are optimizations that set the net present value NPV either the depot or the power plant to zero, after a return on investment of 8% is reached. The resultant values are used to calculate the levelized cost of electricity production (LCOE) for the given scenario (Figure 10).

Economic Assessment			
Power Plant Metrics	Value	Unit	General Equation
Retail Price of Electricity	$ 0.120	$/kwh	LCOE Retail Price
Simplified LCOE	$ 0.075	$/kWh	
Return on Capital Investment	8%		
NPV of Biomass Depot	$ -		Optimize Biomass Feedstock Price
NPV of Power Plant Modifications	$ 63,188,000		
	$ 75	$/ tonne (ar)	

Figure 10: CREDIT Screenshot, Electricity and Biomass Price Optimization Macros

4.3 Process Modeling

In order to achieve CREDIT's goal of determining project feasibility, it is necessary to understand the mass and energy balances associated with the individual processes involved in the model. This section outlines the governing equations and assumptions made in producing these calculations at the power plant and at the biomass depot.

4.3.1 Combustion Modeling

Combustion is a complex phenomenon involving simultaneous coupled heat and mass transfer with chemical reaction and fluid flow (Jenkins, Baxter, Miles Jr, & Miles, 1998). In order to predict the mass and energy flows associated with these reactions, it is necessary to utilize knowledge of fuel properties and how those fuel properties effect the combustion reaction. In order to produce a reasonably accurate assumption of combustion conditions that are sufficient to meet the stated aims of the decision support tool, the combustion reaction is presumed to proceed based on the basis of complete stoichiometric combustion as outlined in this section. Energy generation from the reaction is calculated based on the lower heating value of coal and biomass in accordance with the relationships developed by Basu 2013 as well as VanLoo and Koopejan 2008. (Basu, 2013; Van Loo & Koppejan, 2008).

The first step in modeling the combustion process of biomass fuel is to understand the chemical and physical composition of the fuel source. The primary methods are to perform an ultimate and proximate testing analysis of the feedstocks. Ultimate analysis is the laboratory defined elemental composition of the biomass which includes C, H, N, O, S and ash content on a percent weight basis. Proximate analysis defines the combustion characteristics of the fuel by calculating the value of gross components such as moisture content, volatile matter, fixed carbon, and ash content on a percent weight basis. Volatile matter is defined as the condensable and non-condensable vapor released when the fuel is heated, ash is defined as the inorganic solid residue left after the fuel is completely burned, and fixed carbon is defined as the remaining portion of the biomass which cannot be defined as volatile matter, moisture or ash. For the purposes of this study, ultimate and proximate analyses were derived from the Energy Centre of the Netherlands (ECN) Phyllis2 database (ECN, 2015), which aggregates ultimate and proximate analysis from internal laboratory work and literature. At present, the database has in excess of 3000 entries. The database further allows for the averaging and statistical analysis of multiple studies on similar type feedstocks. The values presented in Table 3 represent the average values established by the ECN Phyllis2 database for the given biomass fuels. This table is utilized by CREDIT as a VLOOKUP table to determine feedstock chemical composition of user defined feedstocks.

Table 3: Ultimate and Proximate Analysis Values Used for Modeling as determined by ECN's PHYLLIS Database (ECN, 2015)

	Ultimate Analysis (%dm)					Proximate Analysis (%dm)		
	C	H	S	O	N	Ash	Fixed Carbon	Volatile Matter
Hybrid Poplar	49.4%	6.0%	0.1%	43.1%	0.2%	1.2%	13.7%	85.1%
Willow Wood	49.9%	5.9%	0.1%	41.8%	0.6%	1.7%	16.1%	82.2%
WWTP Biosolids	34.0%	4.9%	1.3%	20.0%	4.7%	35.0%	11.5%	53.5%
Wheat Straw	46.0%	5.5%	0.1%	41.4%	1.7%	5.0%	0.0%	0.0%
Switchgrass-Baled	47.8%	5.8%	0.1%	35.1%	1.2%	10.1%	0.0%	0.0%
Miscanthus-Baled	44.9%	5.4%	0.1%	40.3%	0.5%	4.6%	19.5%	71.5%
Hybrid Poplar (Torrefied)	53.0%	5.5%	0.0%	37.9%	0.5%	3.1%	24.7%	72.2%
Willow Wood (Torrefied)	53.0%	5.5%	0.0%	37.9%	0.5%	3.1%	24.7%	72.2%
Hybrid Poplar (T & P)	53.0%	5.5%	0.0%	37.9%	0.5%	3.1%	24.7%	72.2%
Willow Wood (T & P)	53.0%	5.5%	0.0%	37.9%	0.5%	3.1%	24.7%	72.2%
Switchgrass - Char	50.5%	2.8%	0.1%	19.7%	1.2%	28.2%	[redacted]	[redacted]
Switchgrass- Pelleted	47.8%	5.8%	0.1%	35.1%	1.2%	10.1%	[redacted]	[redacted]

The energy generated from the combustion of coal and biomass is predicated on the net calorific value or lower heating value (LHV) of the combined biomass and coal blend. Lower heating values of coal and biomass can be ascertained through proximate and ultimate analysis of the given feedstocks. To do this, the higher heating value of the fuel (HHV), also called the gross calorific value must be calculated.

Channiwala and Parikh (Channiwala & Parikh, 2002)developed Equation 1 for the following unified correlation for HHV based on 15 existing correlations and 50 fuels, including biomass, gas, and coal.

$$HHV = 349C + 1178.3H + 100.5S - 103.4O - 15.1N - 21.1ASH \text{ kJ/kg}$$

Equation 1: Higher Heating Value of Fuels (Channiwala and Parikh 2002)

where C, H, S, O, N, and ASH are percentages of carbon, hydrogen, sulfur, oxygen, nitrogen, and ash as determined by ultimate analysis on a dry basis. Using the as received analysis proximate analysis of the feedstock in conjunction with the calculated HHV, the LHV or net calorific value can be determined using Equation 2.

$$LHV = HHV - h_g\left(\frac{9H}{100} - \frac{M}{100}\right) \text{ kj/kg}$$

Equation 2: Lower Heating Value of Fuels (Basu 2013)

where LHV, HHV, H, and M are lower heating value, higher heating value, hydrogen percentage, and moisture percentage, respectively, on an as received basis. Here, h_g is the latent heat of steam in the same units as HHV. The latent heat of vaporization when the reference temperature is 100°C is 2260 kJ/kg (Basu, 2013). Energy generation is calculated based on the LHV of constituent feedstocks because it accounts for the latent heat of vaporization of water. This is a critical factor to account for when considering biomass as a co-feedstock due to its relatively high moisture content in comparison with traditional fossil fuels.

Figure 11 outlines the generalized mass balance for a pulverized coal fired power plant. The primary inputs are the biomass, coal, and atmospheric air. Water and steam are used as a medium to deliver energy from the boiler to the turbine. In conventional operation though, water from this process is conserved and recycled in a continuous loop. For the purposes of this study, which is primarily focused on the utilization of biomass and coal, it is assumed that 100% of process water is conserved.

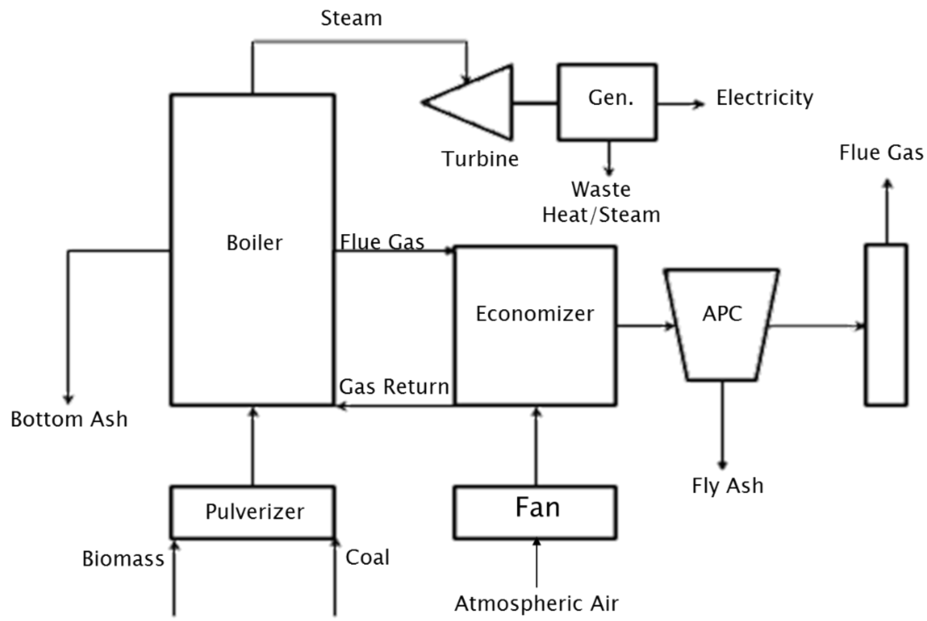


Figure 11: Generalized Mass Flow Diagram of a Coal Fired Power Plant Utilizing Co-Firing

In order to perform the mass balance in an academically appropriate format that meets the tool goal of generating supported approximations of process parameters, the CREDIT model utilizes the stoichiometric relationship of complete combustion in pulverized fuel boilers as established by Basu, 2013 and Van Loo & Koopejan, 2008.

The first calculation to be performed is the determination of the mass of dry air that will be required to combust the given fuel under ideal conditions. Assuming that dry air contains 23.16% oxygen, 76.8% nitrogen and 0.04% inert gasses by mass, Basu states that the mass of dry air required can be found using the Equation 3.

$$M_{da} = \left[0.1153C + 0.3434\left(H - \frac{O}{8}\right) + 0.043S\right] \text{ kg/kg of dry fuel}$$

Equation 3: Mass of Dry Air (Basu, 2013)

where C, H, O, and S are the mass fractions of their respective elements on a dry matter basis. In CREDIT, these values are derived from the proximate analysis values previously defined for the chosen feedstock. This value is, in turn, used to calculate the total mass of air needed to perform combustion using Equation 4.

$$M_{wa} = (1 + EAC)M_{da}(1 + X_m)$$

Equation 4: Mass of actual air required (Basu, 2013)

where EAC is the mass of excess air used in the combustion reaction and X_m is the moisture content of the boiler air. In CREDIT, EAC and X_m are determined using listed values for the boiler in question defined by the EIA boiler summary embedded in the model (EIA, 2012). The total mass of flue gas (W_c) generated can then be calculated using Equation 5.

$$W_c = M_{wa} - 0.2315M_{da} + 3.66C + 9H + N + O + 2.5S \text{ kg/kg dry fuel}$$

Equation 5: Mass of Total Flue Gas (Basu, 2013)

Using the same methodology, Basu further states that the mass of several key flue gas constituents can be calculated using Equations 6-10.

$$NO_x = N + 0.768EAC * M_{da} \text{ kg/kg dry fuel}$$

Equation 6: NOx Calculation (Basu, 2013)

$$CO_2 = 3.66C \text{ kg/kg fuel}$$

Equation 7: Carbon Dioxide produced from fixed carbon in Flue Gas (Basu, 2013)

$$H_2O = \left[9H + EAC * M_{da} * X_m + M_f + L_q * X_{mL}\right] \text{ kg/kg dry fuel}$$

Equation 8: Water Vapor in Flue Gas (Basu, 2013)

$$O_2 = [O + 0.2315M_{da}(EAC - 1)] \text{ kg/kg fuel}$$

Equation 9: Oxygen in Flue Gas (Basu, 2013)

$$SO_2 = 2S \text{ kg/kg fuel}$$

Equation 10: SO2 in Flue Gas (Basu, 2013)

Co-blending of feedstocks has the potential to result in incomplete combustion of fuel due to the reduction in boiler operating temperature, as well as the change in air injection ratios. As this model does not utilize computational fluid dynamic or advanced reaction kinetics and subsequently assumes complete combustion, it is necessary to account for this contingency in another way to accomplish the ultimate goal of CREDIT; which is to provide information to support decision making. This is accomplished through comparative examination of the process parameters required for complete combustion to the EIA defined boiler capabilities. Key amongst these parameters are excess air injection rate capacity and fuel feed rate capacity. If the stated ratings for these parameters are sufficient to support complete combustion of the proposed feedstock blend, it is assumed that complete combustion will be feasible with the budgeted modifications to the boiler. If either required parameter exceeds the boiler rating provided by the EIA, a notification is generated for the user specifying that incomplete combustion may result from the proposed project parameters.

Ash is collected in 2 primary locations; the boiler bottom (bottom ash) and particle captured from the flue gas (fly ash). Because this model assumes complete combustion of fuel, ash is calculated using Equation 11.

$$\text{Ash out} = M_{airin} + Mass_{CoalIn} + Mass_{BiomassIn} - Mass_{FlueGas}$$

Equation 11: Generalized Mass Balance

This model does not differentiate between bottom ash and fly ash generation, but, in general, bottom ash accounts for 90% of the ash total in pulverized fuel boiler systems.

4.3.2 Biomass Depot Modeling

Figure 12 displays the generalized process flow diagram associated with the biomass depot investigated in this model. By adding or subtracting process elements or pieces of equipment, it is possible to arrive at several different configurations for a biomass depot pant. For the purposes of CREDIT and this study, four basic configurations are considered based on their practicality and appearance in previous studies. These are:

1. Biomass dried, torrefied, and densified to produce a torrefied pellet (TOP)
2. Biomass dried and pelleted
3. Biomass pelleted as received
4. Biomass aggregated and stored onsite without modification (not pictured)

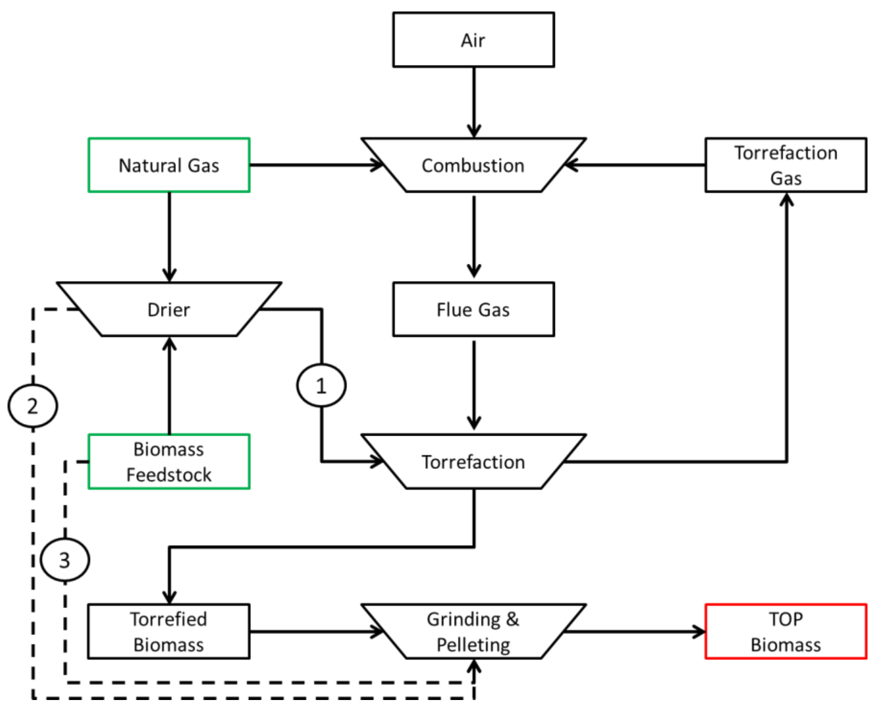


Figure 12: Biomass Depot Process Configuration

Functionally, the modeling of these configurations is accomplished through the use of "if-then" conditionals within the excel spreadsheet. Thus, as the user defines the configuration, different processes can be turned "on" or "off" by skipping the subroutines for any individual process.

4.3.3 Torrefaction

Torrefaction is a relatively complex process to model on the chemical level, as the condition of torrefied biomass is dependent upon the type of torrefier, temperature of torrefaction, duration of torrefaction, rate of oxygen infusion in to the process, and physical/chemical characteristics of the biomass being torrefied (Joshi, de Vries, Woudstra, & de Jong, 2014) (Park, Meng, Lim, Rojas, & Park, 2013). It is unlikely that the user of this decision support tool inherently knows the desired values of these parameters. Even if they are known, combinations of these parameters are not studied thoroughly enough to produce an empirical model to predict the ultimate and proximate analysis of biomass based on their manipulation.

As such, a more practical approach was employed by CREDIT whereby the entrance and exit conditions of the biomass into the torrefaction unit are set as user defined givens and the physical and energy requirements for the process are back-calculated using the mass balance of the reaction as defined in Equation 12.

$$m_{raw\ \ biomass} = m_{torgas} + m_{torrefied\ biomass}$$

Equation 12: Torrefaction Mass Balance

where m_x is the mass of the respective mass flow component. The mass and moisture content of the biomass stream is defined by the previous steps, however, the torgas/torrefied biomass ratio is relatively difficult to determine theoretically as it relies on variables such as torrefier type, operation temperature, residence time, and feedstock composition. These variables, in turn, are specifically chosen by plant operators in order to achieve specific properties of torrefied biomass. Thus, in order to model this reaction, a number of assumptions are made. For the purposes of this study, it was assumed that the torrefaction plant would produce torrefied biomass at a yield rate consistent with previous studies defined by Table 4 as shown in Equations 14 and 15.

$$Y_{mass}(\%) = \left(\frac{m_{torrefiedbiomass}}{m_{rawbiomass}}\right)_{daf} * 100$$

Equation 13: Torrefaction Mass Yield

$$Y_{energy}(\%) = \left(\frac{LHV_{torrefiedbiomass}}{LHV_{rawbiomass}}\right)_{daf} * 100$$

Equation 14: Torrefaction Energy Yield

Using the values listed in Table 4, in combination with the yield rates defined in Equations 14 and 15, it is possible to determine the mass yields of both torrefied biomass and the torrefaction gas.

Table 4: Torrefaction Yield and Efficiency Relation to Moisture Content (Batidzirai et al., 2013)

Moisture Content	Model Values (torrefaction plant)		Theoretical Values (Torrefaction Plant)	
	Thermal Efficiency (%)	Feedstock to Product Ratio	Thermal Efficiency (%)	Feedstock to Product Ratio
20%	96.4	1.59	98.0	1.35
30%	95.4	1.84	97.6	1.70
35%	94.8	1.99	97.3	1.88
40%	93.8	2.18	96.9	2.11
45%	92.7	2.41	96.3	2.35
50%	91.0	2.72	95.6	2.67
55%	88.6	3.11	95.0	3.08

Using the process stream masses, along with associated LHVs of the constituent components, it is possible to calculate the thermal energy required to perform the torrefaction reaction using Equation 16.

$$E_{torr} = \frac{\left(m_{torrefied\ biomass} * LHV_{torr} - m_{dried\ biomass} * LHV_{dry}\right) + m_{torgas} * LHV_{torgas}}{\eta_{torr}}$$

Equation 15: Torrefaction Energy Balance (Batidzirai et al 2013)

where n_{torr} is the thermal efficiency of the torrefaction reactor as defined in Table 4 and E_{torr} is the required energy input for torrefaction. In CREDIT, it is assumed that E_{torr} will be supplied through the combustion of natural gas.

4.4 Financial Modeling

One of the key aspects of the model was to determine the financial viability of proposed projects. In order to accomplish this, CREDIT estimates capital costs and operating costs for the proposed depot system and coal fired power plant. The methods and assumptions relating financial considerations are found in this section.

4.4.1 Power Plant Capital Costs

Power plant capital costs will vary greatly depending upon the selected biomass type, biomass blending rates, and energy incorporation strategy (direct vs. indirect combustion). This is due to the different types of infrastructure that will be required based upon these factors. In general, these infrastructure needs can be broken down into 5 categories; capital costs of boiler/generator modifications (CI_{mod}) biomass storage costs (CI_{BS}), biomass handling equipment (CI_{BH}) biomass conditioning equipment (CI_{CD}), and boiler construction (CI_{BC}) . For example, if a power plant with a PC boiler is to co-fire chipped wood with a moisture content of 30% at a blending ratio of 10%, by energy value, the biomass must first be dried and pulverized separately from coal because the PC system cannot incorporate more than 3% biomass directly into the coal pulverizer due to concerns of product matting (FEMP, 2004). Conversely, a parallel fired system would not need such conditioning equipment as the boiler would be built to handle the biomass. However, a separate cost would be assessed for the construction of the new boiler. Both systems would require separate biomass storage and handling systems. Thus, the capital costs for the direct fired system would be $CI_{mod} + CI_{BS} + CI_{BH} + CI_{BC}$, whereas the costs for the parallel fired system would be $CI_{BC} + CI_{BS} + CI_{BH.}$ This logic leads to several permutations of system capital cost requirements which are outlined by the logic diagram found in Figure 13.

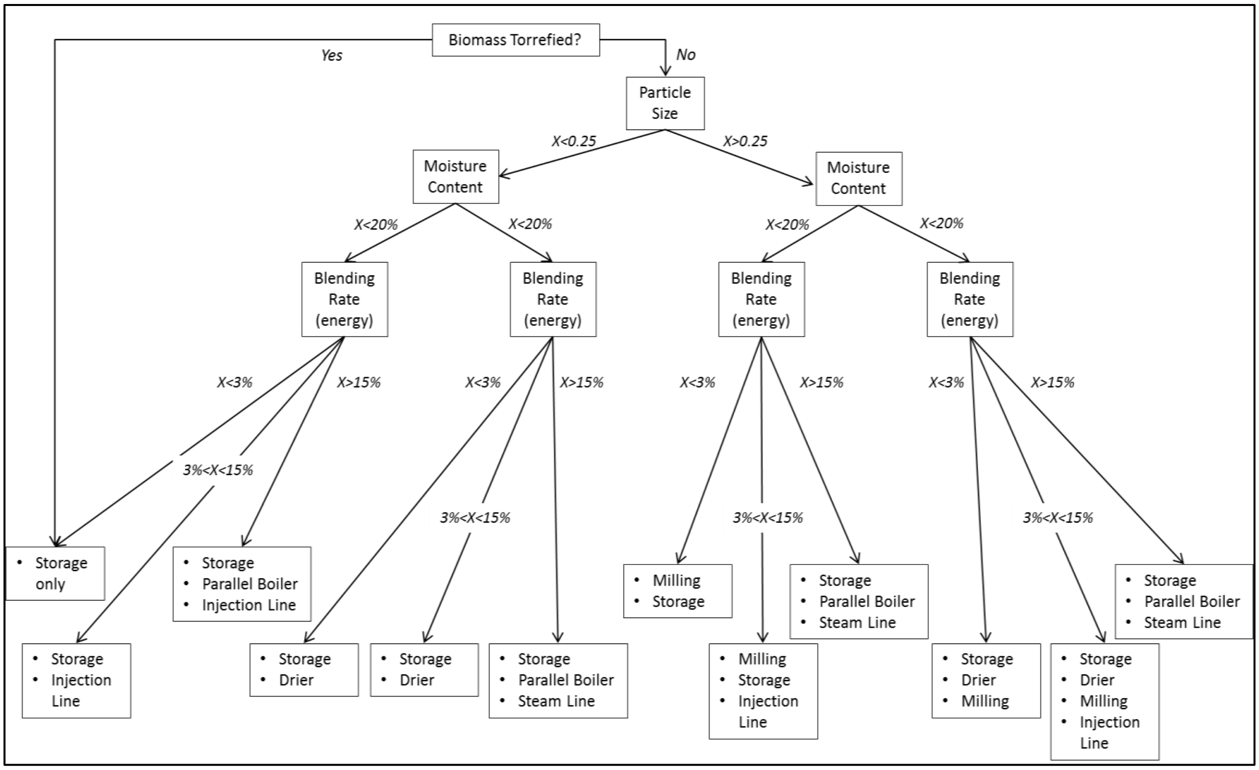


Figure 13: Pulverized Coal Equipment Decision Tree

Functionally, these permutations are handled within CREDIT through the use of “if-then” conditional statements associated with user inputs regarding biomass type, pre-conditioning, and plant setup.

The capital costs associated with the aforementioned infrastructure categories were calculated by scaling the costs of known existing operations using a power scaling equation of the general form, as shown in Equation 20.

$$\frac{Costs_{size2}}{Costs_{size1}} = \left(\frac{Size_2}{Size1}\right)^{\alpha}$$

Equation 16: power scaling equation

where “size 1” is the size and/or capacity of the reference system,” size 2” is the size/capacity of the proposed system, and alpha is a scaling factor ranging from 0-1. Alpha values as well as reference pricing is readily available within existing literature. For power plant costs, CREDIT utilizes the reference costs and alpha values established by (De & Assadi, 2009) as well as (Caputo et al., 2005). This is a common methodology deployed in techno-economic analyses of complex systems where finding pricing of individual components for every conceivable size is impractical. Equations 17-21 illustrate these relationships in reference to the previously defined capital cost categories.

$$CI_{mod} = 50 * \frac{M_{bm} * LHV_{bm}}{\left(M_{coal,i} - \Delta M_{coal}\right) * LHV_{coal}} * TC_n$$

Equation 17: Boiler Modification Costs (Caputo et al., 2005; De & Assadi, 2009)

$$CI_{BS} = \left[136{,}578 * \frac{M_{bm} * LHV_{bm}}{\left(M_{coal,i} - \Delta M_{coal}\right) * LHV_{coal}} * TC_n\right]^{0.5575}$$

Equation 18: Biomass Storage (Caputo et al., 2005; De & Assadi, 2009)

$$CI_{BH} = \left[55{,}780 * \frac{M_{bm} * LHV_{bm}}{\left(M_{coal,i} - \Delta M_{coal}\right) * LHV_{coal}} * TC_n\right]^{0.9554}$$

Equation 19: Biomass Handling Equipment (Caputo et al., 2005; De & Assadi, 2009)

$$CI_{CD} = \left[13{,}646 * \frac{M_{bm} * LHV_{bm}}{\left(M_{coal,i} - \Delta M_{coal}\right) * LHV_{coal}} * TC_n\right]^{0.5575}$$

Equation 20: Biomass Conditioning Equipment (Caputo et al., 2005; De & Assadi, 2009)

4.4.2 Power Plant Operation and Maintenance Costs

Maintenance and labor costs were estimated at eight percent of total capital costs annually (Batidzirai et al., 2013). Additionally, replacement of the drier and biomass handling units was assumed to be required in year 10. The cost of replacement was assumed to be equivalent to the purchase prices assessed in year 0.

The summation of O&M costs were escalated by 1.5 percent each year through year 20 to account for inflation and the real value of money. This approach follows the practice of the American Society of Agricultural and Biological Engineers (Binkley, 2010)

4.4.3 Biomass Depot Capital and Maintenance Costs

Depot capital costs were determined by applying the power scaling method defined in Section 3.5.1. to individual components of the biomass depot process flow. As with the power plant, not all capital investments were necessary for each scenario. In this case, the required equipment is not determined by a logic flow structure but rather by user defined inputs. If the user specifies that the product reaching the power plant is torrefied and pelleted, a torrefier and a palletization system are added to the capital costs. The reference costs and capacities of individual components associated with this project are derived from the literature (Srivastava et al., 2011).

4.4.4 Biomass Depot Operation and Maintenance Costs

Maintenance and labor costs were estimated at eight percent of total capital costs annually (Batidzirai et al., 2013). Additionally, replacement equipment for the torrefaction reactor, drier, and pelletization unit was assumed to be required in year 10 and was valued at the cost estimated by CREDIT in the investment cost module.

Additionally, feedstock costs, electricity costs, and natural gas costs were calculated to scale with the plant. Electricity prices and natural gas prices are user defined values in the model. For the purposes of this study, these utility costs were set to May 2015 values as determined by the US EIA for the state of Michigan. The summation of O&M costs were escalated by 1.5 percent each year through year 20 to account for inflation and the real value of money. This approach follows the practice of the American Society of Agricultural and Biological Engineers (Binkley, 2010).

4.4.5 Net Present Value (NPV)

A 20 year pro-forma analysis was produced based on the capital and operating costs for the economic analysis portion of CREDIT. The resulting NPV indicated whether the power plant investment generates a positive or negative return on investment. In general, a positive NPV indicates that the project should be considered and a negative NPV indicated the opposite.

The pro-forma and subsequent NPV calculation were based on projected electricity sale revenues and cost flows tracked within CREDIT. The retail price of electricity was indexed to the real industrial price of electricity provided by the EIA.

All scenarios analyzed in this study were assumed to be financed entirely by loans at an interest rate of 7% over the 20 year useful life of the project. Grants funds considered within CREDIT as a revenue realized in year 0. A salvage value was added to the cash flows in year 20 and any value that exceeded the remaining depreciation balance was valued as a capital gain.

The net present value of the power-plant capital investment was calculated by Equation 21 derived by Binkley et al, 2015,

$$NPV_t = \sum_{t=1}^{U} Y_o - \frac{[(H_t + X_t + K_t - (E_t + I_t + L_{t-1})) \times (1 - Q_t)] + G_t + D_t(Q_t) - P_t}{(1+r)^t} + \frac{S_U}{(1+r)^U}$$

Equation 21: Net Present Value Calculation (Binkley et al., 2015)

where :

NPV_t =	The net present value in year i
H_t =	Electricity sales revenue
X_t =	Taxable grant funding
K_t =	Value of carbon credits
E_t =	Operational expenditures including repairs, labor, and insurance.
I_t =	Loan interest
L_{t-1} =	Carryover losses

Q_t = Marginal tax rate
G_t = Grant funding
D_t = depreciation of equipment
P_t = loan principal
Y_o = initial cash investment
S_U = Equipment salvage value at project's end
r = Opportunity cost of capital
U = Project useful life

4.4.6 Levelized Cost of Electricity (LCOE)

In order to determine the levelized cost of electricity, a goal seek routine was added to the model to determine the saleable price of electricity such that the power plant NPV is equal to 0 after 20 years. The effective equation for this optimization takes the general form:

$$LCOE = \frac{CAPEX + \sum_{i=1}^{N} \frac{OPEX_i}{(1+r)^i}}{\sum_{I=1}^{N} \frac{e_i}{(1+r)^i}}$$

Equation 22: Generalized LCOE Equation

Where N is the project lifetime in years, CAPEX is the capital expenditure made in year zero, OPEX is the sum of all operational expenditures in year i, r is the opportunity cost of capital investment, and e is the specific energy yield of the power plant in kWh for year i.

4.4.7 Energy Returned on Energy Invested

Another key metric assessed by this model is energy returned on energy invested (EROEI), Equation 22.

$$EROEI = \frac{Usable\ Acquired\ Energy}{Energy\ Expended}$$

Equation 23: Generalized EROEI Equation

Energy return on investment is a ratio of the useful energy obtained (electricity or combined heat and power) versus the energy invested in a system (i.e. transport fuel, feedstock processing, and feedstock handling). A non-fractional value denotes a viable project, whereas a fractional EROEI means the project is an energy sink. EROEI in this study is used to eliminate potential projects that may be financially viable, and theoretically meet renewable energy generation requirements, but in actuality require more energy to operate than they produce. It is also possible to compare the EROEI of this project with the EROEI of similar energy technologies such as those listed in Table 5.

Table 5: EROEI for Common Fuels (Murphy & Hall, 2010)

EROI	Fuel
1.3	Biodiesel
3.0	Bitumen tar sands
80.0	Coal
1.3	Ethanol corn
5.0	Ethanol sugarcane
100.0	Hydro
35.0	Oil imports 1990
18.0	Oil imports 2005
12.0	Oil imports 2007
20.0	Oil production
10.0	Natural gas 2005
10.0	Nuclear (with diffusion enrichment)
50-75	Nuclear (with centrifuge enrichment)
6.8	Photovoltaic
5.0	Shale oil
1.6	Solar collector
1.9	Solar flat plate
18.0	Wind

4.5 Statistical Methods

In biological systems there is inherently high variation and uncertainty with material properties and kinetics. For this model, these uncertainties are most clearly manifested in the variation of biomass chemical composition and production rates (or yield). As outlined in the previous chapter, biomass physical and chemical composition plays a key role in determining the energy potential of the biomass, reaction kinetics of the combustion reaction, and combustion products. Similarly, when determining the amount of biomass available to a depot or a power plant, it is critical to understand the crop yield.

However, the yield can vary greatly from year to year and region to region. Consequently, itis important to understand the natural variation associated with these key biological components. Data gathering activities are outlined in this section.

4.5.1 Fuel Variation

Fuel data was collected from both the NREL biomass feedstock database and the ECN Phyllis2 biomass feedstock database. Both are web based databases that catalogue the results of internal and published analyses of biomass feedstocks. A simple statistical analysis was performed on this data to determine variation between samples. Table 5 provides a sample of this analysis for switchgrass. . A complete list of feedstock tables is available in the appendix.

Table 6: Sample Fuel Properties Variation - Switchgrass

Fuel Properties	Unit	Min	Max	Median	Mean	Std dev		Samples
Proximate Analysis								
Moisture content	wt% (ar)	8.2	15.0	11.9	11.7	2.8	24%	5
Ash content	wt% (dry)	1.9	10.1	6.3	6.3	1.4	22%	34
Volatile matter	wt% (daf)	72.9	86.9	84.3	83.2	4.5	5%	8
Fixed carbon	wt% (daf)	13.1	27.1	15.8	16.8	4.5	27%	8
Ultimate Analysis								
Carbon	wt% (daf)	45.2	53.2	50.6	49.4	2.5	5%	13
Hydrogen	wt% (daf)	5.6	6.5	6.1	6.1	0.4	6%	13
Nitrogen	wt% (daf)	0.4	1.3	0.6	0.6	0.2	28%	30
Sulphur	wt% (daf)	0.0	0.2	0.1	0.1	0.1	45%	13
Oxygen	wt% (daf)	39.0	48.6	43.7	44.0	2.9	7%	13
Total (with halides)	wt% (daf)	0.0	101.8	0.6	38.7	49.3	127%	34
Calorific Values								
Net calorific value (LHV)	MJ/kg (daf)	16.9	18.9	17.7	17.8	0.7	4%	12
Gross calorific value (HHV)	MJ/kg (daf)	18.3	20.2	18.9	19.2	0.7	4%	12
HHVMilne	MJ/kg (daf)	16.9	21.6	19.5	19.5	1.2	6%	13
Halides								
Chlorine (Cl)	mg/kg (daf)	370	5249	1062	1952	1943	1	5
Major elements								
Potassium (K)	mg/kg (dry)	3400	3400	3400	3400	0	0	1
Sodium (Na)	mg/kg (dry)	33	33	33	33	0	0	1

The results from these analyses were used to derive the anticipated distributions of biomass composition, which were in turn used for iterations of the Monte Carlo analysis discussed in the next section.

4.5.2 Biomass Yield Variation

In order to account for the uncertainty associated with biomass yield, regional data was procured from active field studies in the investigated study area. MSU Extension Educators have managed 4 field plots within Isabella county since 2009. Table 7 displays the summary of field test results for the mature switchgrass crop harvested in 2014 (Pennington, 2015). Though the sample size is not large, it is the best representative sample available for region specific production rates of switchgrass. As with the biomass chemical analysis, variations noted in these studies can be incorporated into the Monte Carlo analysis described in the next section.

Table 7: 2014 MSU Field Plot Data for Isabella County - Yield and Dry Matter

	% Dry Matter	Yield (dry lb/acre)
Mean	59.5%	7.73
Standard Error	0.5%	0.21
Median	59.7%	7.64
Standard Deviation	1.0%	0.41
Sample Variance	0.0%	0.17
Range	2.3%	0.96
Minimum	58.1%	7.35
Maximum	60.4%	8.32
Count	4	4

Figure 14 displays the average annual yield for the 4 test plots represented in Table 7. As can be seen, the plot increases yield over time. This is common among perennial grass energy crops, as full maturity does not occur until year 4 or 5 of establishment. This natural variation will also need to be incorporated into any analysis of feedstock production potential.

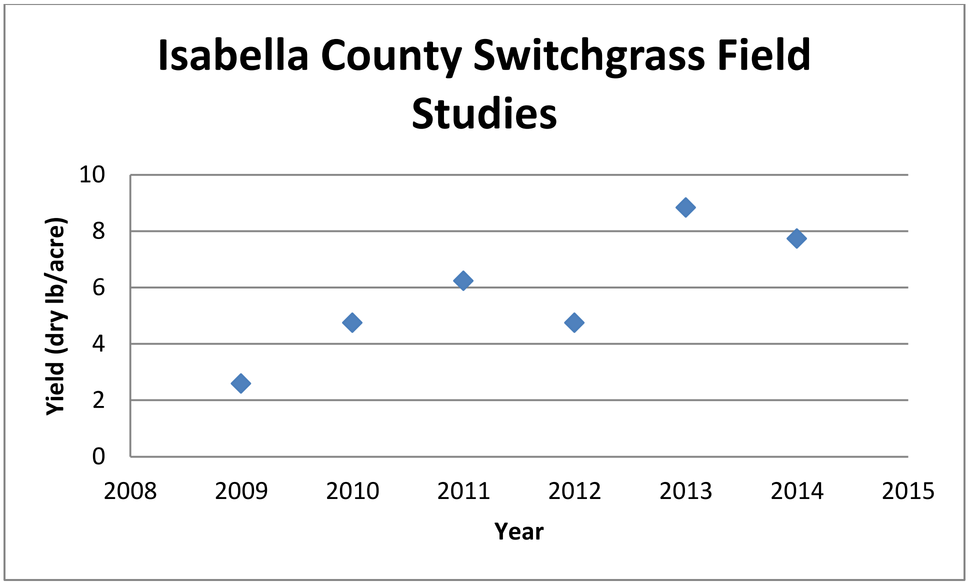


Figure 14: Isabella County Switchgrass Annual Yield

4.5.3 Monte Carlo Analysis

For models with multiple parameters with ranges of variability it is helpful to visualize possible distributions through a Monte Carlo simulation analysis. Monte Carlo analysis is used to simulate random variation in sets of related variables. In order to run a Monte Carlo analysis, a range of potential values must be established for each studied variable. In the case of this study, the range for the investigated input parameters was determined by values found in the literature. Where a suitable range of values were not available, a range of ±20% from the default value was assumed. The Monte Carlo analysis then selects one value randomly from the given ranges for each parameter. The new set of input values generated from this activity is then used to calculate a result from the model under investigation. The process of randomizing variables over a range and re-running the model and recording the results is repeated until outcome distributions can be used to predict the result within a pre-determined error range (O'Donnel, Hickner, & Barna, 2002). Monte Carlo methods can be particularly useful to help ascertain the risk associated with a model that relies on a large number of independent variables such as CREDIT.

For the purposes of this study, 16 input variables were defined for investigation with the range of values shown in Table 8. A Monte Carlo simulation was performed for a 1000 iterations of the random variable assignment using an excel macro embedded within CREDIT. The value of 1000 iterations was selected through operator attempts to reduce error while keeping model runtime low (<1 hr.). Results from the analysis were subsequently tested for normality of distribution and used to calculate confidence intervals for CREDIT results. Outputs investigated were NPV of the Power Plant, plant-gate feedstock pricing, and cost of CO_2 mitigation.

Table 8: Sample of Distribution Parameters for Monte Carlo Analysis

	Default	Min	Max
Feedstock Production (kg/hectare/yr.)	1,120,622	896,498	1,344,746
Raw Biomass Moisture Content (% w.b.)	20%	10%	40%
Biomass LHV (kJ/kg)	18,780	18,240	19,510
Market Electricity Price ($/kWh)	$ 0.12	$ 0.08	$ 0.14
Farmgate Feedstock Price ($/dt)	$ 0.05	$ 0.04	$ 0.05
Natural Gas Price ($/MJ)	$ 0.003	$ 0.002	$ 0.003
Specific Transportation Cost ($/km)	$ 2.25	$ 1.80	$ 2.70
Plant O&M Cost ($/kW installed capacity)	$ 47.60	$ 38.08	$ 57.12
Boiler Modifications ($ @ ref case)	$ 6,813	$ 5,450	$ 8,176
Plant Storage ($ @ ref case)	$ 862,221	$ 689,777	$ 1,034,665
Plant Handling ($ @ ref case)	$ 1,311,789	$ 1,049,431	$ 1,574,146
Plant Conditioning ($ @ ref case)	$ 86,148	$ 68,918	$ 103,377
Depot O&M Costs (% of capital costs)	8%	6%	10%
Depot Cap Costs	$ 7,129,364	$ 5,703,491	$ 8,555,236
Boiler Efficiency (Thermal)	90%	80%	99%
Torrefier Efficiency (Thermal)	90%	80%	99%
Drier Efficiency (Thermal)	90%	80%	99%

5 RESULTS AND DISCUSSION

The methods outlined in the previous section were applied to generate an excel based decision support tool for the co-firing of biomass in coal fired power plants. This section details the results of the verification and validation activities applied to the decision support tool, as well as the results of four scenario analyses that were conducted for a Michigan coal fired power plant using CREDIT.

5.1 Model Verification and Validation

As with all decision support tools, CREDIT is an approximate imitation of a real world situation. As such, it is the intent of CREDIT to produce reasonable approximations of economic and environmental impacts that would be realized by implementing co-firing of biomass at existing coal fired power plants. The extent to which all models and decision support tools can accomplish this is governed by model verification and validation.

According to Robert Sargent, "verification of a model is the process of confirming it is correctly implemented with respect to the conceptual model" (i.e. it matches specifications and assumptions deemed acceptable for the given purpose of application) (Sargent, 2011). Verification for CREDIT development has taken place iteratively throughout the development process by consulting with experts in the fields of economics, combustion, biomass harvesting, and biomass harvesting. It is further verified via the logical structure that was developed through the literature review and represented in the logic flow diagrams Figure 15 displays a sample logic diagram for depicting the required equipment for various biomass conditions at a pulverized coal plant.

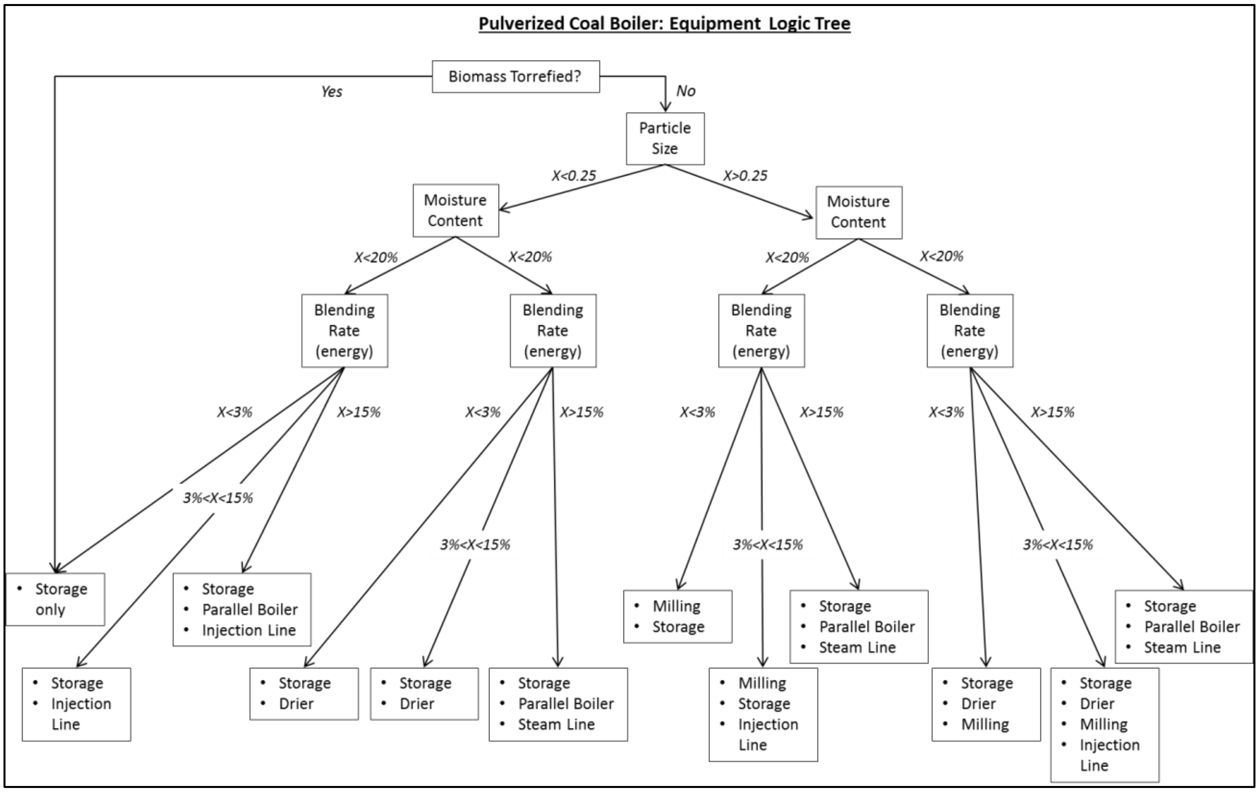


Figure 15: Pulverized Coal Co-Firing Equipment Configuration Logic Tree

The model has further been verified through cross comparing model parameters with literature values such as feedstock composition, production rates, equipment efficiency, equipment cost and others to determine reasonable ranges of potential values. These values have in-turn been incorporated into the Monte Carlo simulations already outlined in order to determine a reasonable margin of error for predicted results.

Validation of the model is defined as any activity that checks the accuracy of the model's representation of the real system (Sargent, 2011). For many models, it is possible and highly preferable to accomplish this through direct experimental testing of the model. However, it is difficult to fully validate CREDIT based on direct experimentation. Even one iteration of direct testing could cost several million dollars, many years, and would take the full cooperation of multiple entities. A feasible alternative is to run CREDIT with inputs from documented case studies and compare the predictive results against the findings in the case study. This method has been used by other decision support tool developers in published literature (Binkley, 2010). There are some drawbacks. First, it is improbable that published case studies will supply all of the same required parameters and outputs by the model being tested. Thus it may be necessary to make standard assumptions for parameters not provided in the case study. Further, definitions of key terms and calculations may differ between case studies, thus making their results hard to compare. To combat this issue, case studies used for comparison were derived from a single entity (Tillman, 1997) in order to assure case study methods, calculations and terminology were standardized to the degree practicable. Finally, it can be difficult to compare results across time and geographic location. To minimize this, studies for comparison were selected only from the United States and economic values were adjusted to reflect 2015 U.S. dollars.

Despite these limitations it is important to note that Sargent (Sargent, 2011) further states that, "a model should be verified and validated to the degree needed for the model's intended purpose or application." Given that, it is not the intent of CREDIT to have 100% accurate predictive power but rather to produce reasonable approximations of economic and environmental impacts that would be realized by implementing co-firing of biomass at existing coal fired power plants, sufficiently well to determine whether or not further study and investment in the scenario is warranted.

5.1.1 Comparison to known scenarios

For this this analysis, four case conducted by Tillman, T.A. (Tillman, 1997) were selected for comparison. The results are displayed in Tables 9 and 10. Note that a few modifications were made to CREDIT in order to accurately track the EPRI cases. First, the EPRI studies were conducted in 1997 thus a cost conversion factor of 1.49 was applied to bring values to 2015 dollars. Secondly, the EPRI studies all assume a SO_2 credit of $80/ton. This was applied to CREDIT specifically for the purposes of this comparison, though it is largely irrelevant to current studies as 2015 SO_2 credits were traded at

$0.11/ton. Lastly, Tillman does not include the avoided cost of coal as a factor in his levelized cost of power calculation. CREDIT was adjusted for these studies to account for this in comparison, but it is not true of CREDIT as a whole. Results are presented in the Figures and Tables below.

Table 9: EPRI Base Cases: Pretax Cost of Power from Cofiring In PC Boilers (Biomass Cofiring Guidelines - 2015 Dollars)

Parameter	EPRI Case			
	1	2	3	4
Technology	PC	PC	PC	PC
Biomass Fuel	Wood (unspecified)	Wood (unspecified)	Wood (unspecified)	Wood (unspecified)
Boiler Capacity (MW)	200	500	50	150
Cofiring %, Mass	5	5	20	15
Cofiring %, Heat	2.2	2.2	8.7	6.3
Coal Type	Eastern Bituminous	Western Bituminous	Eastern Bituminous	Eastern Bituminous
Capacity Factor	0.75	0.75	0.75	0.75
Net Station Heat Rate on Coal (MJ/kWh)	11.08	10.02	11.61	10.55
Capital Cost for Cofiring System ($/kW)	$ 49.00	$ 74.50	$ 342.70	$ 260.75
Biomass Cost ($/10^6 Btu)	$ 1.27	$ 1.49	$ 1.27	$ 1.27
Biomass Cost ($/GJ)	$ 1.20	$ 1.41	$ 1.20	$ 1.20
Biomass Cos ($/kg dry)	$ 0.04	$ 0.05	$ 0.04	$ 0.04
Capacity Co-fired on Biomass (MW)	4.5	11.2	4.3	9.4
Pretax Levelized Cost of Power ($/kWh)	$ 0.02	$ 0.02	$ 0.03	$ 0.03

Table 10: CREDIT Model Outputs for Selected EPRI Cases

Parameter	CREDIT Case			
	1	2	3	4
Technology	PC	PC	PC	PC
Biomass Fuel	Poplar (40% moisture)	Poplar (40% moisture)	Poplar (40% moisture)	Poplar (40% moisture)
Boiler Capacity (MW)	200	500	50	150
Cofiring %, Mass	5	5	20	15
Cofiring %, Heat	2.0	2	8.9	6.5
Coal Type	Eastern Bituminous	Western Bituminous	Eastern Bituminous	Eastern Bituminous
Capacity Factor	0.75	0.75	0.75	0.75
Net Station Heat Rate on Coal (MJ/kWh)	11.08	10.02	11.61	10.55
Capital Cost for Cofiring System ($/kW)	$ 141.00	$ 112.00	$ 301.00	$ 235.00
Biomass Cost ($/$10^6$ Btu)	$ 1.27	$ 1.49	$ 1.27	$ 1.27
Biomass Cost ($/GJ)	$ 1.20	$ 1.41	$ 1.20	$ 1.20
Biomass Cos ($/kg dry)	$ 0.04	$ 0.05	$ 0.04	$ 0.04
Capacity Co-fired on Biomass (MW)	4.0	10	4.45	9.75
Pretax Levelized Cost of Power ($/kWh)	$ 0.02	$ 0.02	$ 0.04	$ 0.03

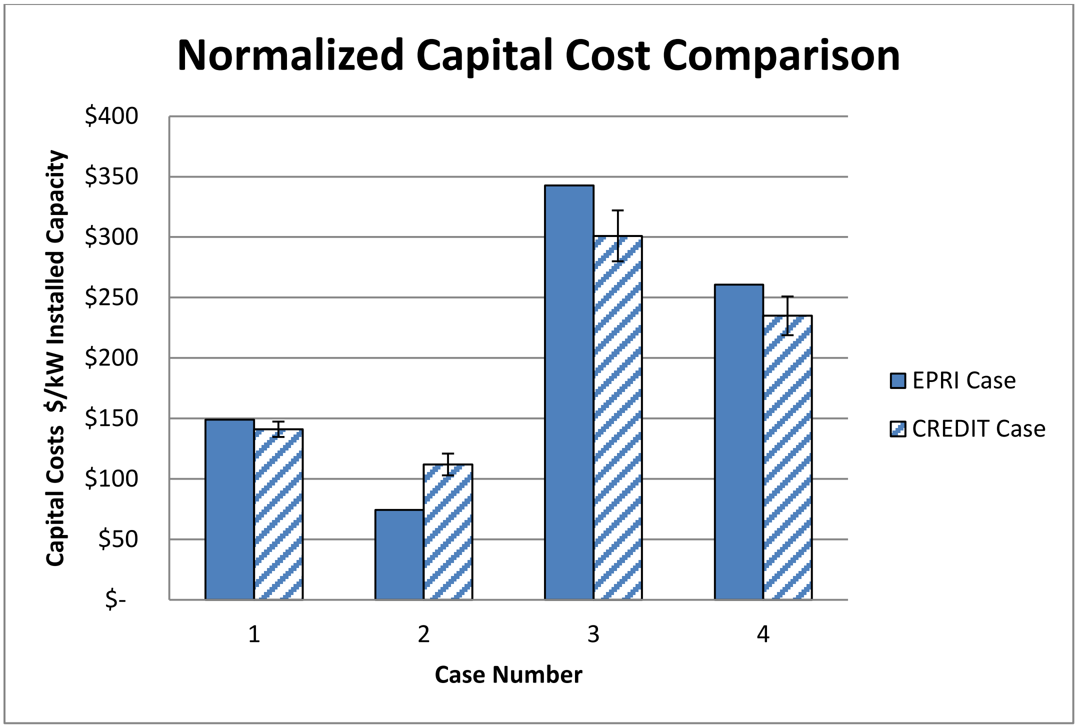


Figure 16: Normalized Capital Cost Comparison Between EPRI and CREDIT Cases. Error Bars Reflect One Standard Deviation as Determined by Monte Carlo Analysis

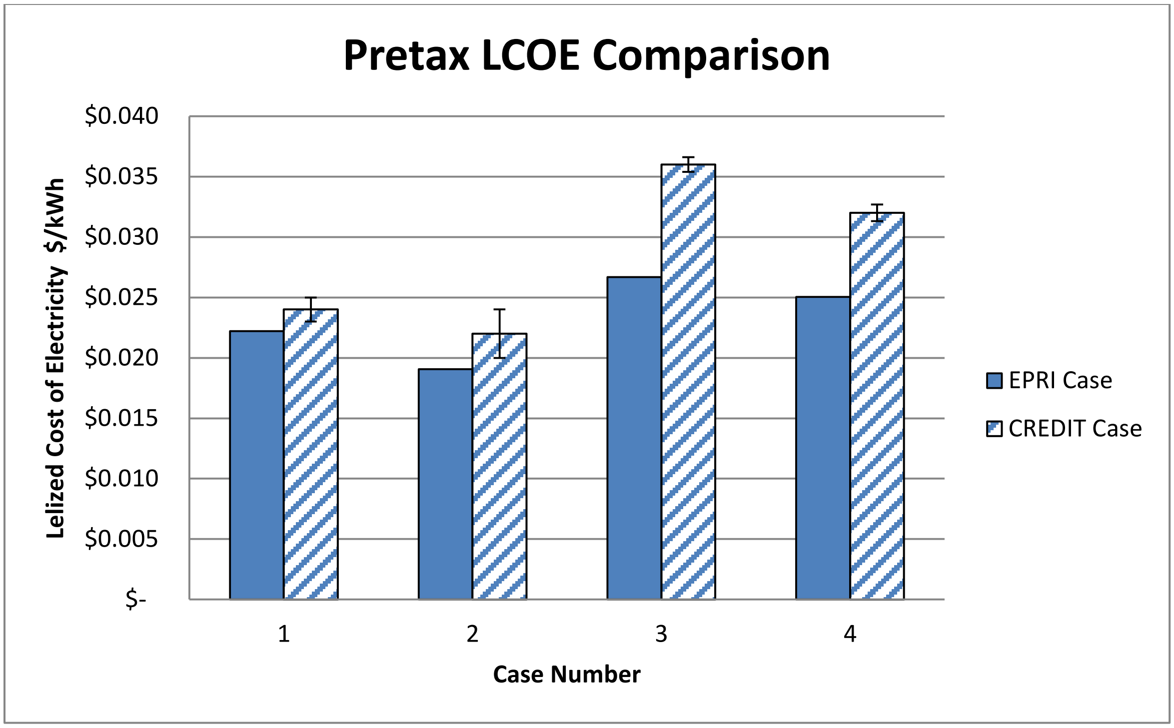


Figure 17: Levelized Cost of Electricity Comparison Between EPRI and CREDIT Cases. Error Bars Reflect One Standard Deviation as Determined by Monte Carlo Analysis

5.1.2 Validation Results and Limitations

The model is moderately sensitive to capital cost input requirements at the power plant. As observed when compared with existing case studies, it can be insufficient to assume that any particular piece of equipment needed in the process chain has a "one size fits all" cost. CREDIT is capable of determining the cost of individual equipment components based on throughput capacity, however, other site specific factors can have a significant impact on overall pricing of the equipment. These factors include, but are not limited to, space constraints, age of existing infrastructure, and plant layout. Any or all of these factors can increase the total project cost. For instance, in EPRI case 2, the estimated normalized capital cost for the plant redesign was $112/kWh whereas the observed capital cost was $75/kWh installed, making CREDIT's estimate overly conservative. Using the same modeling techniques, it was observed in case 3 that the predicted normalized capital cost of project implementation was $301/kW for the

CREDIT case and $341/kW for EPRI, thus making CREDIT's output under-conservative. This was due to case 2 having certain pre-processing infrastructure already on site (dryer, screeners) and case 3 needing additional engineering work to put a direct injection line into the boiler from a greater than average distance.

In short, it can be observed that high levels of variation in costing exist due to the nature of highly case-specific conditions found at each power plant. CREDIT is capable of adjusting to these variations if sufficient background data is present. This level of predictive power is consistent with the intent of the model, which is to support project decision making by iteratively assessing project outcomes depending upon the degree of information available to the user.

5.2 Scenario Setup

In order to utilize the resulting model, four scenarios surrounding the J.H. Campbell power plant were investigated. These scenarios involve the use of unused or marginal farmland derived from a 4 county area north of J.H. Campbell to produce dedicated energy crops for co-firing. In the analysis, the crops are assumed to be aggregated at a processing depot prior to shipment to the power plant.

5.2.1 J.H. Campbell Power Plant

The Campbell power plant complex is located on a 2,000-acre site along the Lake Michigan shoreline near West Olive, Michigan (Figure 18). Originally commissioned in 1962, it houses three pulverized coal tangentially fired boiler units that feed a 906MW steam turbine (Figure 19). The system uses a blend of bituminous and sub-bituminous coal and does not presently co-fire with biomass or supplement combustion reactions with natural gas or petroleum (EIA, 2012).

Figure 18: J.H. Campbell Power Plant (Courtesy of Consumers Energy)

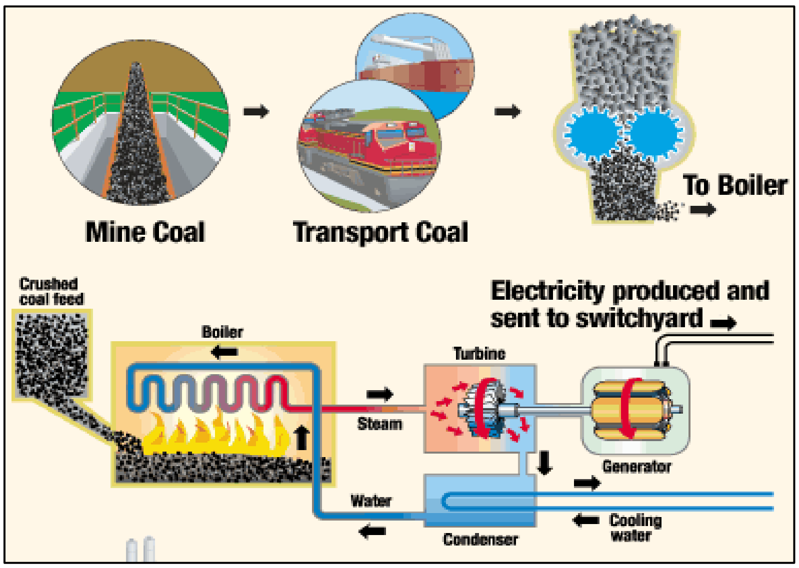


Figure 19: J.H. Campbell Power Plant Generalized Process Flow Diagram (courtesy of Consumers Energy)

5.2.2 Feedstock Collection

Michigan is home to several types of biomass that can be readily purchased for negotiable prices such as forest slash, pulpwood and C & D debris. These can easily be run solely through the power plant portion of the model by inputting biomass quantities, physical characteristics, and price in order to determine desired blending ratios, energy outputs, CO_2 reductions, and financial outputs. However, in order to display the full capabilities of CREDIT, the proposed scenario will involve the harvest and collection of farmed woody biomass from local sources.

In order to conduct this preliminary analysis, land availability data was gathered from the national agricultural statistics service for 4 viable counties in Michigan that represent a sample collection area for harvested woody biomass. These are: Isabella, Osceola, Mecosta, and Clare counties (Table 11).

Table 11: 2012 NASS Field Data – Derived from (NASS, 2012)

County	Total Landmass (Acres)	Total Farmed Land (Acres)	Idle Farmland (Acres)
Isabella	366,704	135,682	9,576
Osceola	362,256	53,638	6,362
Mecosta	355,090	71,606	4,701
Clare	361,021	25,356	2,597

Idle farmland is defined as land that was once used for crop production that is not presently in a crop rotation, forested, or used for pastureland. Assuming that a viable biomass processing plant would be able to draw from 80% of land that is presently idle, and 5% of currently cultivated land, it is calculated that 32,900 acres would be available for biomass energy crop production. As no value was found in the literature stating how much land conversion can be expected for a given scenario, these values were produced as educated guesses of the author. In order to account for the high degree of uncertainty in this value, a large range of ±30% was applied to this value in the Monte Carlo analysis.

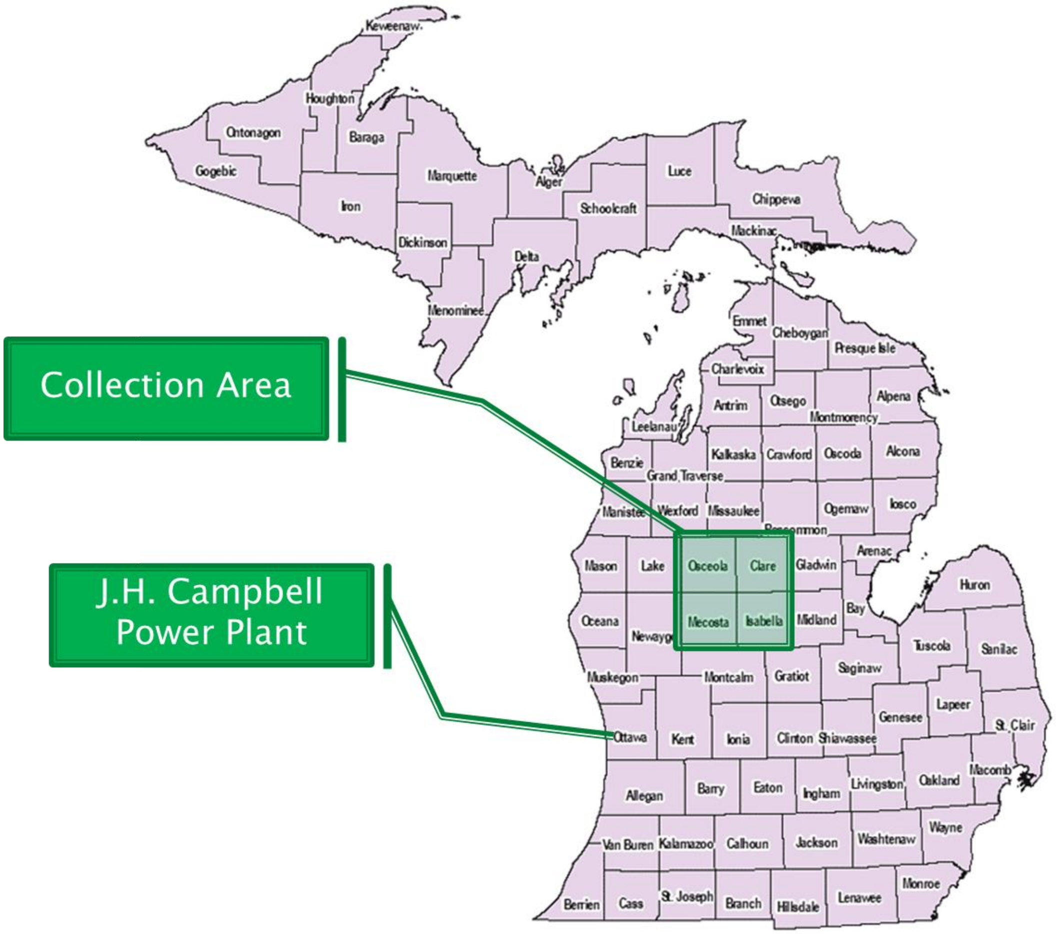


Figure 20: Study Collection Area

5.2.3 Biomass Production Capability:

The aforementioned 4 county region was selected for 2 reasons. First, it has a sufficient amount of idle farmland to produce a relevant quantity of biomass energy, while its centroid is roughly 100 miles from the power plant. This is critical as it will allow for comparison with studies performed in other states that routinely set their observations at round distances such as 100, 200, or 300 miles.

More importantly, the MSU research team has relevant field data relating to feedstock production rates in this area. Specifically, MSU extension has been performing field trials on switchgrass production in Isabella county since 2009. The accumulation of this data will allow for region-specific assumptions about biomass growth and production rates. These rates follow.

- Poplar (5 dt/acre) (Srivastava et al., 2011)
- Switchgrass (7.73 dt/acre, MSU field trials in Isabella county)

Given the total area of interest (total area of the 4 aforementioned counties), the total area of tillable land, and production rates of each crop, it is possible to calculate the distribution density of biomass in the collection area using the generalized formula:

$$DD_{biomass} = \frac{Land_{cultivated} * Yield_{biomass}}{Land_{total}}$$

Equation 24: Biomass Distribution Density Equation

Using the distribution density of biomass it is possible to estimate the total distance traveled by collection vehicles in order to aggregate biomass at the biomass depot using the following equation from (De & Assadi, 2009).

$$Distance\ Traveled = \frac{4}{3} * \frac{M_{biomss}}{\pi\ * DD_{biomass}}^{0.5} * \frac{\mathrm{M_{biomass}}}{\mathrm{VC}}$$

Equation 25: Farm-Gate to Biomass Depot Distance Traveled Equation (De & Assadi, 2009)

Where $M_{biomass}$ is the total mass of biomass being transported in tonnes (wet basis), $DD_{biomass}$ is the previously calculated distribution density in tonnes/km^2/yr, and VC is the vehicle capacity of transport vehicles in tonnes.

Using these values, and average transport distance of 80 km was calculated for switchgrass and an average distance of 81 km was calculated for poplar.

5.3 Scenario Analysis

Figure 21 displays the relative differences in processes that will be assessed across all scenarios. For the purposes of this study, the in-field operations are estimated based on the works of previous studies and field trials conducted by other researchers at MSU. CREDIT is designed to process information from farm-gate to energy generation. However, data from other sources regarding planting, cultivation, and harvest were used by this study in order to better calculate the energy return on investment realized by these 4 scenarios.

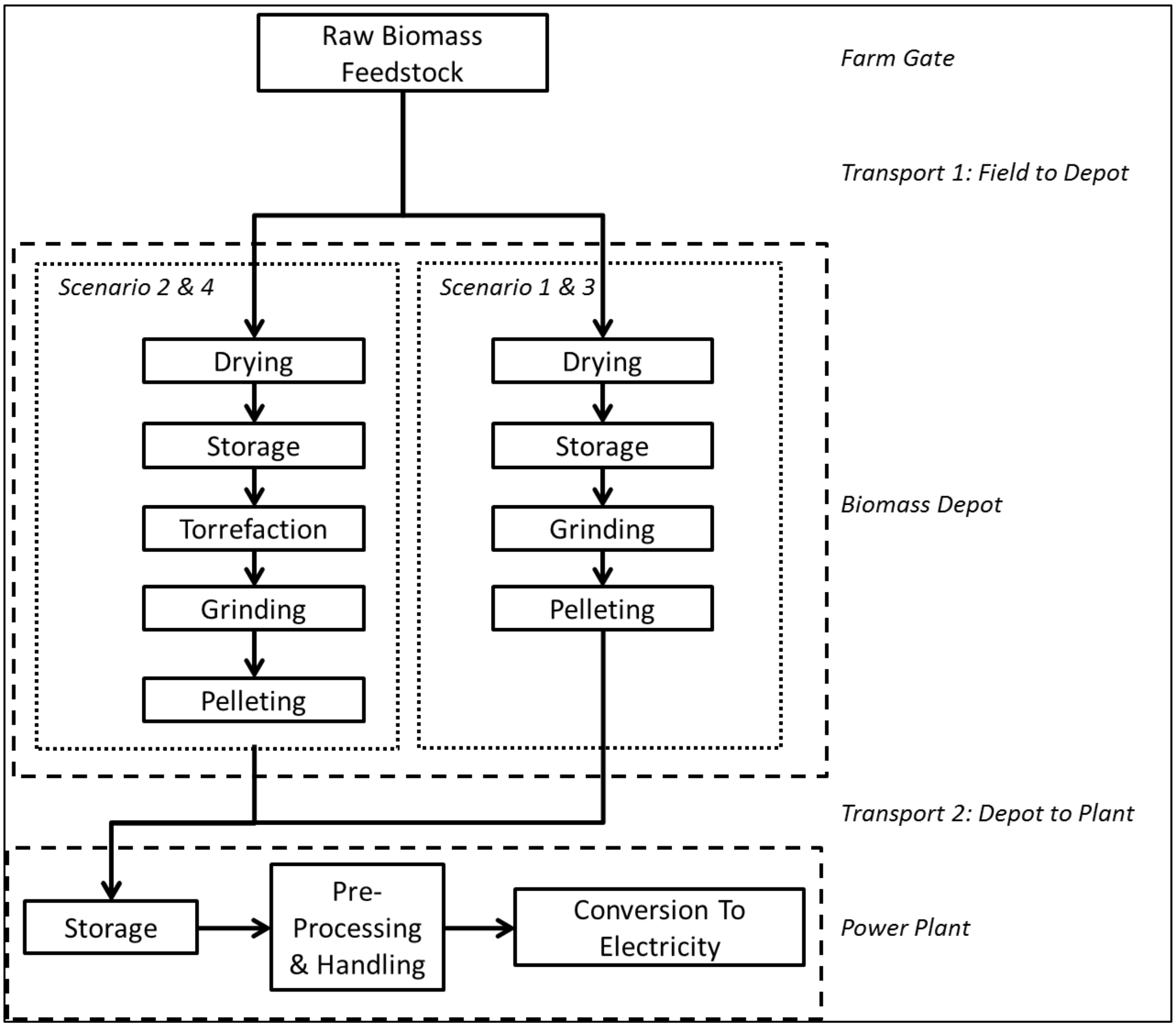


Figure 21: Scenario Outline

5.4 Scenario 1 – Pelleted Poplar

In the first investigated scenario plantation grown and chipped poplar is delivered to a biomass depot located 100 mile from the J.H. Campbell power plant. The biomass is assumed to be purchased from the individual farms at a price of $41.60 per dry ton of biomass ($0.056 per kg) (Srivastava et al., 2011), and transported via a 40 ton (36.3 tonne) capacity chip van to the centralized processing depot. At the processing depot, the chipped biomass is dried to a moisture content of 10% and stored on site. At need, the biomass is then hammer milled, pelleted, and placed in storage once again before being transported to the power plant. Once at the power plant, the pelleted biomass is unloaded and stored separately from the coal (thus necessitating the addition of offloading equipment and storage silos. The pelleted biomass is blended with the coal at a rate of 5% by energy value. As suggested in the literature (Nussbaumer, 2003), pulverized coal boilers receiving >3% biomass by energy content will likely require a separate injection system for the biomass, due to its incompatibility with grinding equipment. This necessitates that a hammer mill be procured capable of reducing the pellets to a particle size of <0.25 micro meters.

5.4.1 Energy Assessment

Energy return on investment analysis for scenario 1 was performed in accordance with the process flow outlined in Figure 6. Results are shown in Table 12. In-field operations cultivation , including planting and harvesting, were derived from literature values established (Dillen, Djomo, Al Afas, Vanbeveren, & Ceulemans, 2013) based on a 16 year study of poplar harvest on marginal cropland. The values reported were scaled to the production level of this scenario assuming linear growth. Uncertainties related to this method are captured in the Monte Carlo analysis.

Transport from farm to depot and depot to farm are assumed to be performed by a 40 ton chip van. Energy values on a MJ/tonne/km were derived from the literature (Anon, 2010) and applied to the calculated transport distances for both aggregation and final shipping of the biomass feedstock.

Electricity values for equipment were scaled based on equipment loading of previously derived literature values and natural gas requirements were calculated based on the energy needs of both the drier and torrefaction systems as detailed in Equation 16.

The large and positive EROI predicted by this model suggests that this project is highly viable from an energy accounting standpoint. This is expected due to the fact that the biomass is lightly processed using these techniques when compared to other energy sources.

Table 12: EROI Accounting for Scenario 1

	LHV	
	MMBTUs/yr	GJ/yr
In-Field Operations	190,341	200,821
Transport (Farm to Depot)	63,885	67,402
Depot		
Natural Gas for Drying (Depot)	308,119	325,083
Natural Gas for Torrefaction (Depot)	-	-
Electricity for Drying (Depot)	6,806	7,181
Electricity for Torrefaction (Depot)	-	-
Electricity for Grinding (Depot)	9,037	9,535
Electricity for Pelleting (Depot)	25,826	27,248
Transport (Depot to Power Plant)	203,868	215,092
Energy Return on Energy Invested (EROEI)	5	5

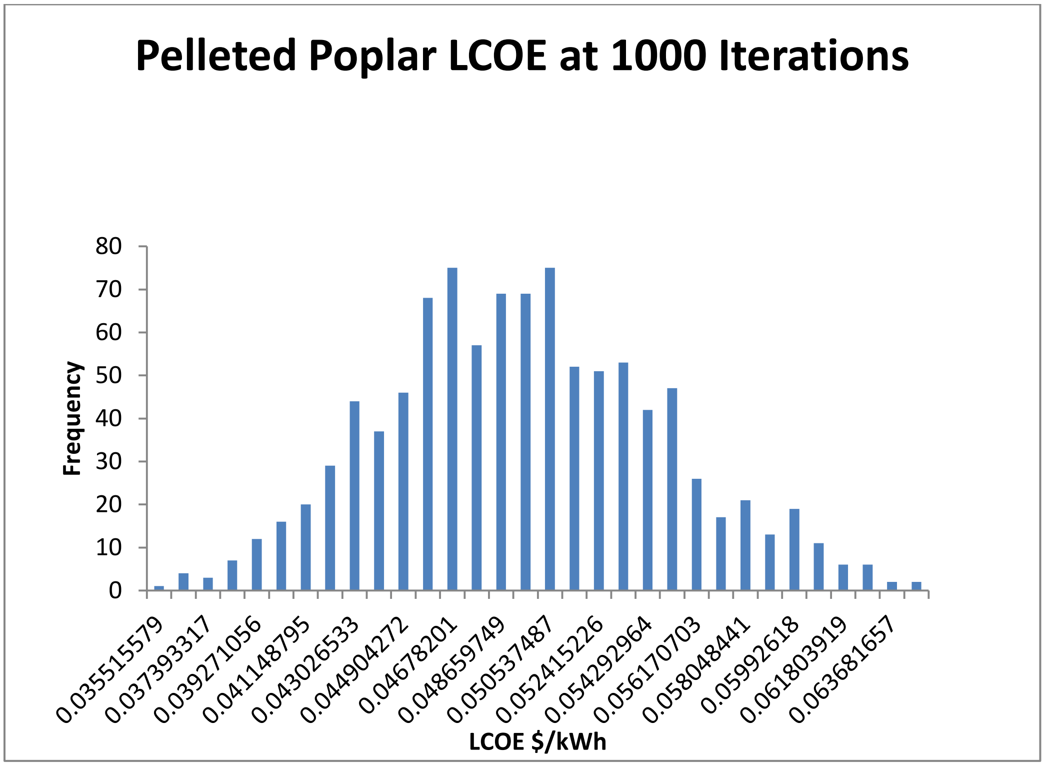


Figure 22: Pelleted Poplar Monte Carlo Analysis

5.4.2 Economic Assessment

The results of the economic modeling activities for scenario 1 are detailed in Table 13. The primary metric derived from the economic assessment is the levelized cost of electricity or LCOE. This is the price at which the power plant could produce electricity and return a net present value of $0 assuming a required return on capital investment. For this scenario a return of 8% was specified. This yielded a LCOE of $0.0486. Monte Carlo analysis of this scenario at 1000 iterations, found the LCOE to be fairly normally distributed (Kurtosis = -0.3, Skewness =0 .1) with a standard deviation of $0.005.

The LCOE of $0.0486 is a favorable metric as new installations of other renewable energy sources such as wind and solar typically range from 10-20 cents per kWh. New biomass installations for 2015 are projected to be approximately 10 cents per kWh.

Table 13: Scenario 1 Economic Summary

Power Plant Metrics	Value	Unit
Retail Price of Electricity	$0.120	$/kwh
Simplified LCOE	$0.0486	$/kWh
Return on Capital Investment	8%	
NPV of Biomass Depot	$-	
NPV of Power Plant Modifications	$168,205,000	
Plant-Gate Feedstock Cost	$91	$/tonne (ar)
	$101	$/tonne (dry)
Relative Capital Costs	$95	$/kW Capacity
Additional Ash Disposal	$-	

In this analysis, one of the single largest contributors to LCOE was the cost of delivered biomass. Power plant upgrades can initially be costly but become trivial once amortized over the 20 year lifespan, in comparison with operating expenses.

Interestingly, when the cost of processing biomass is investigated, it is found that the single highest cost at the processing depot is also the purchase of raw feedstock (Figure 23).

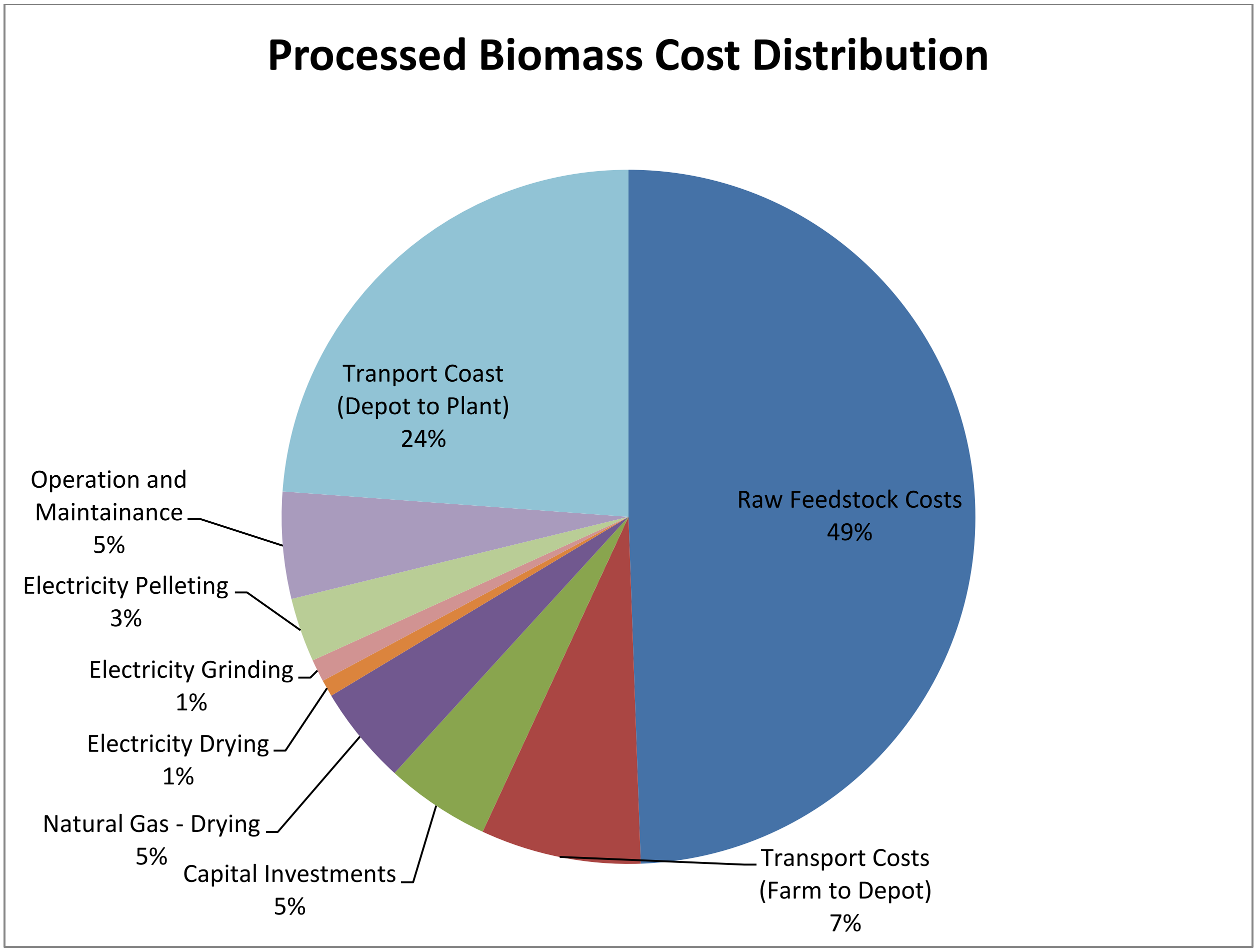


Figure 23: Cost distribution of biomass processing for scenario 1

5.4.3 Emissions Analysis

Emissions analyses were performed for both coal only and with the co-firing scenarios. Results are presented in terms of emissions reductions in Table 14. Negative values reflect a net reduction in air emissions.

Table 14: Scenario 1 Emissions Analysis

Power Plant Summary	Change in Emission	Unit	Notes
Delta CO_2 (Co-Fire - Base Case)	(15,211)	kg/hr	Gross
	(1,929)	tonne/yr	
	(44,961)	kg/hr	Net (Assuming Biomass is Carbon Neutral)
	(5,703)	tonne/yr	
Delta SO_2 (Co-Fire - Base Case)	(216)	kg/hr	
	(27)	tonne/yr	

As expected, blending of biomass with coal resulted in a net reduction in both carbon dioxide and sulfur dioxide emissions. Carbon emissions were reduced both on a gross basis and a net basis. The gross basis values presented is a straight subtraction of CO_2 emissions expectations between the base case of only coal being fired in the boiler systems, and the scenario under investigation. The net basis assumes that any carbon introduced to the system by biomass is a carbon neutral source of energy as defined by (Hartmann & Kaltschmitt, 1999). This value then is the CO_2 avoided by the replacement of coal.

5.5 Scenario 2 – TOP Poplar

In the second scenario, plantation grown and chipped poplar is delivered to a biomass depot located 100 mile from the J.H. Campbell power plant. The biomass is assumed to be purchased from the individual farms at a price of $41.60 per dry ton of biomass ($0.056 per kg) (Srivastava et al., 2011), and transported via a 40 ton (36.3 tonne) capacity chip van to the centralized processing depot. At the processing depot, the chipped biomass is dried to a moisture content of 10% and stored on site. At need, the biomass is then torrefied at 25^{0}C. The torrefaction reaction makes use of natural gas and the produced torrefaction gas to heat the reactor as shown in Figure12. Torrefied biomass is then hammer milled, pelleted, cooled, and placed in storage once again before being transported to the power plant. Once at the power plant, the TOP biomass is unloaded and stored separately from the coal (thus necessitating the addition of offloading equipment and storage silos). Sources vary on whether or not torrefied biomass can be stored with coal due to its similar hydrophobicity. However, CREDIT's base assumption is that separate storage will be required. TOP biomass is blended with the coal at a rate of 5% by energy value. Due to torrefied wood's similarity to coal in friability, it can be safely assumed that at this blending ratio, TOP biomass can be directly mixed with the coal prior to pulverization. Unlike scenario 1, this means the system will not need additional handling equipment, a hammer mill, or a separate boiler injection port. This greatly reduces overall capital costs and project footprint at the power plant site.

5.5.1 Energy Assessment

Energy return on investment analysis for scenario 1 was performed in accordance with the process flow outlined in Figure 6. The results of the energy accounting are found in Table 15. In-field operations cultivation (including planting) and harvest were derived from literature as discussed for scenario 1. Uncertainties related to this method in addition to other uncertainties are captured in the Monte Carlo analysis. Transport from farm to depot and depot to power plant are assumed to occur in the same manner as scenario 1.

Electricity values for equipment were scaled based on equipment loading of previously derived literature values, and natural gas requirements were calculated based on the energy needs of both the drier and torrefaction systems as detailed in Equation 16.

For this scenario CREDIT calculates an anticipated EROI of approximately 6. Though not large, the EROI is non-fractional and thus represents a viable project. However, as Figure 24 shows, the EROI distribution over the Monte Carlo analysis is scattered and not normally distributed (Kurtosis >1). As such uncertainty is relatively high over the range of calculated EROI values. Though this is not ideal and it should be noted that all EROI values over the range are non-fractional and thus represent a valid project.

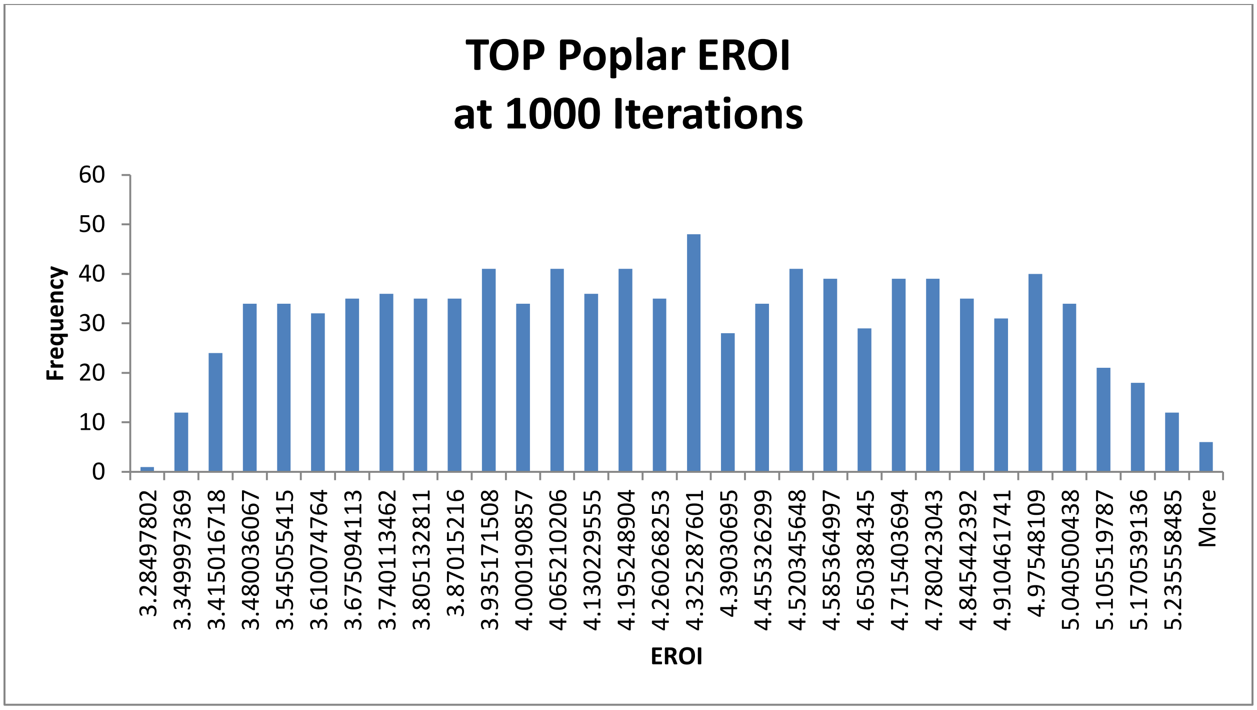


Figure 24: Monte Carlo Histogram - Scenario 2 EROI

Table 15: Scenario 2 Energy Assessment

	LHV	
	MMBTUs/yr	GJ/yr
In-Field Operations	186,345	196,604
Transport (Farm to Depot)	61,885	65,292
Depot		
Natural Gas for Drying (Depot)	301,650	318,258
Natural Gas for Torrefaction (Depot)	108,345	114,310
Electricity for Drying (Depot)	6,720	7,090
Electricity for Torrefaction (Depot)	16,246	17,140
Electricity for Grinding (Depot)	8,344	8,804
Electricity for Pelleting (Depot)	23,937	25,255
Transport (Depot to Power Plant)	179,614	189,502
Energy Return on Energy Invested (EROEI)	4	4

5.5.2 Economic Assessment

The results of the economic modeling activities for scenario 2 are detailed in Table 16. The primary metric derived from the economic assessment is the levelized cost of electricity or LCOE is the same as used in scenario 1: a net present value of $0 and a return of 8%. This yielded a LCOE of $0.076. Monte Carlo analysis of this scenario at 1000 iterations, found the LCOE to be fairly normally distributed (Kurtosis = -0.01, Skewness = -0.38) with a standard deviation of $0.007.

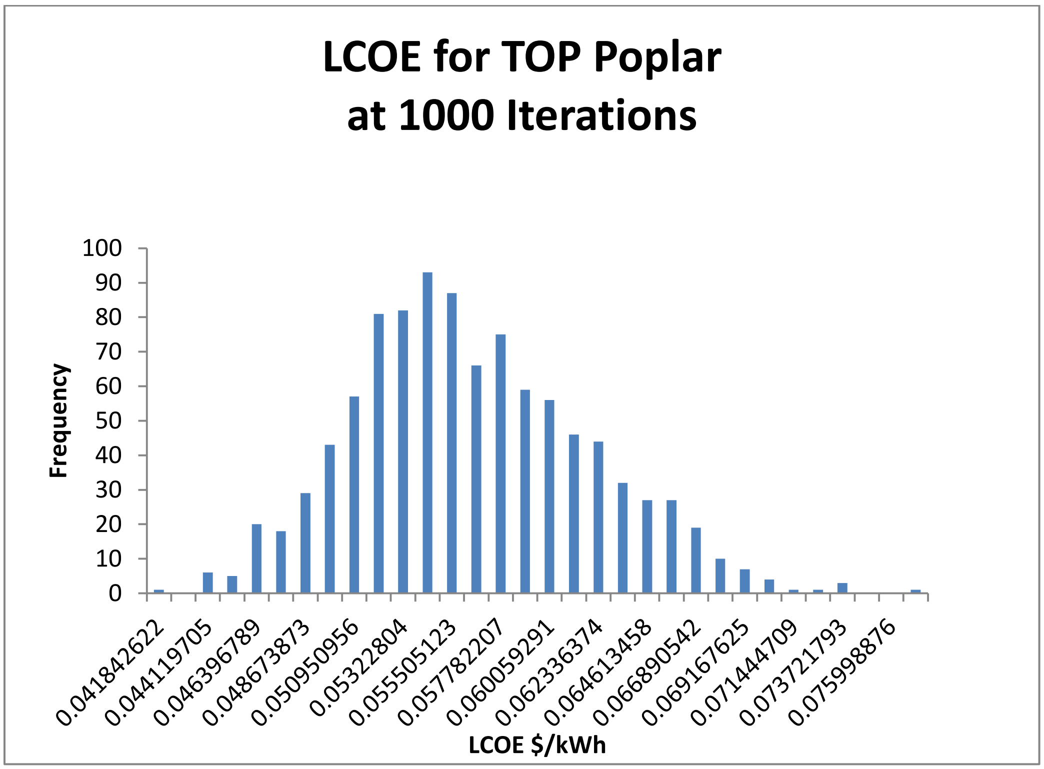


Figure 25: Monte Carlo Histogram - Scenario 2 LCOE

Though higher than its sister scenario (Scenario 1), the LCOE of $0.056 is a favorable metric as new installations of other renewable energy sources such as wind and solar typically range from 10-20 cents per kWh with new biomass installations for 2015 are projected to be approximately 10 cents per kWh. As with Scenario 1, this is largely due to the fact that this scenario takes advantage of in-place infrastructure whereas other projects largely need to build new. In terms of capital cost at the power plant, Scenario 2 shows a clear advantage over Scenario 1. The similarity of TOP biomass to coal greatly reduces the need for capital investment in new handling, processing, and injection equipment (Bergman, 2005; Van Loo & Koppejan, 2008). This is reflected in the low relative capital costs ($32/kWh capacity vs. $97/kWh for Scenario 1).

Table 16: Scenario 2 Economic Summary

Power Plant Metrics	Value		Unit
Retail Price of Electricity	$	0.120	$/kwh
Simplified LCOE	$	0.056	$/kWh
Return on Capital Investment	8%		
NPV of Biomass Depot	$	-	
NPV of Power Plant Modifications	$	154,342,000	
Plant-Gate Feedstock Cost	$	130	$/tonne (ar)
	$	134	$/tonne (dry)
Relative Capital Costs	$	32	$/kW Capacity

As with Scenario 1 the single largest contributor to LCOE was the cost of delivered biomass. In Scenario 2 as the cost of delivered biomass reaches $130 per tonne (ar) due to the increased processing costs of torrefaction. Torrefaction scenarios may win out over pelleting alone where distances are long or where biomass characteristics are prohibitive to use in coal fired power plants without extreme modifications. However, in this case the benefits do not outweigh the costs according to CREDIT.

As with Scenario 1, when the cost of processing biomass was investigated. The single highest cost at the processing depot is also the purchase of raw feedstock, though the ratio of feedstock costs to total costs is not as high. Operation and maintenance costs as well as capital investments are greatly increased in this scenario, due to the presence of the torrefaction reactor and its supporting systems (Figure 26).

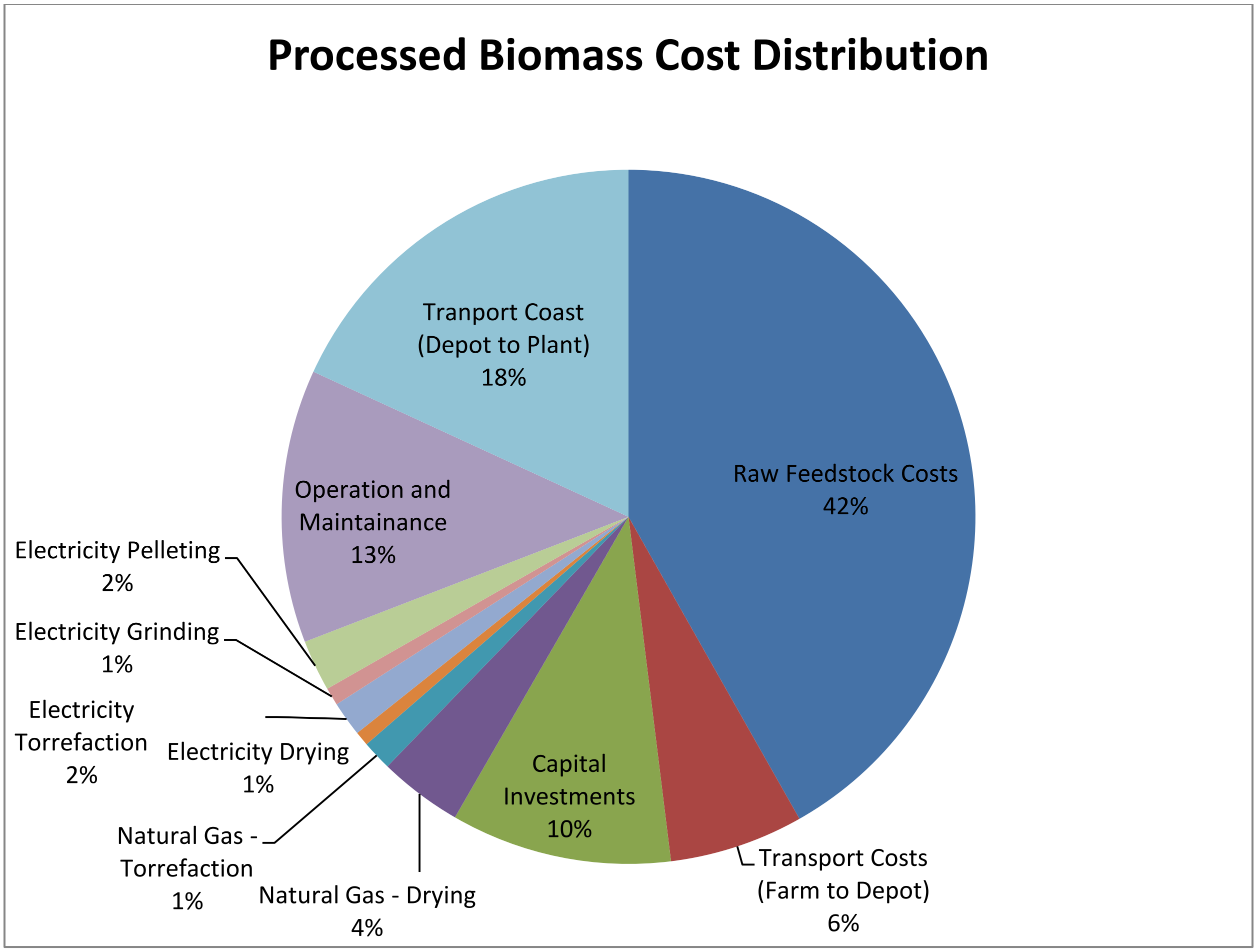


Figure 26: Scenario 2 Processes Biomass Cost Distribution

5.5.3 Emissions Analysis

Emissions analyses were performed for both the base case (coal only) along with the co-firing scenario.

The comparative results are presented in terms of emissions reductions in Table 17.

Table 17: Scenario 2 Emissions Analysis

Power Plant Summary	Change in Emission	Unit	Notes
Delta CO2 (Co-Fire - Base Case)	44,280	kg/hr	Gross
	12,400	tonne/yr	
	1,573	kg/hr	Net (Assuming Biomass is Carbon Neutral)
	(45,230)	tonne/yr	
Delta SO2 (Co-Fire - Base Case)	(5,737)	kg/hr	
	(122)	tonne/yr	

As expected, blending of torrefied biomass with coal resulted in a net reduction in sulfur dioxide emissions. Carbon emissions were increased on a gross basis but decreased on a net basis. This change from scenario 1 is attributed to the change in chemical composition of the biomass after torrefaction. During the torrefaction process, the ratio of carbon to oxygen is increased, and in this case resulted in a gross increase in carbon dioxide releases. Because this value is directly correlated to coal displacement, and each scenario displaces the same amount of coal, net CO_2 reductions are similar across all scenarios.

5.6 Scenario 3 – Pelleted Switchgrass

In this scenario farm grown and baled switchgrass is delivered to a biomass depot located 100 miles from the J.H. Campbell power plant. The biomass is assumed to be purchased from the individual farms at a price of $82.23 per wet ton of biomass ($0.091 per kg) (Anon, 2008), and transported via a 20 ton (18.1 tonne) capacity flatbed trailer to the centralized processing depot. At the processing depot, the switchgrass is de-baled, dried to a moisture content of 10% hammer milled, pelleted, and placed in storage before being transported to the power plant. Once at the power plant, the pelleted biomass is unloaded and stored separately from the coal (thus necessitating the addition of offloading equipment and storage silos). The pelleted biomass is blended with the coal at a rate of 5% by energy value. As suggested in the literature (Nussbaumer, 2003), pulverized coal boilers receiving >3% biomass by energy content will likely require a separate injection system for the biomass, due to its incompatibility with grinding equipment. This necessitates that a hammer mill be procured capable of reducing the pellets to a particle size of <0.25 inches (6.3 mm).

5.6.1 Energy Assessment

Energy return on investment analysis for scenario 3 was performed in accordance with the process flow outlined in Figure 6. The results of the energy accounting are found in Table 18. In-field operations cultivation, including planting and harvesting, were derived from literature values established in the literature (Anon, 2008). The values reported ISU were scaled to the production level of this scenario assuming linear growth. Uncertainties related to this and other data collection methods are captured in the Monte Carlo analysis presented in Figure27.

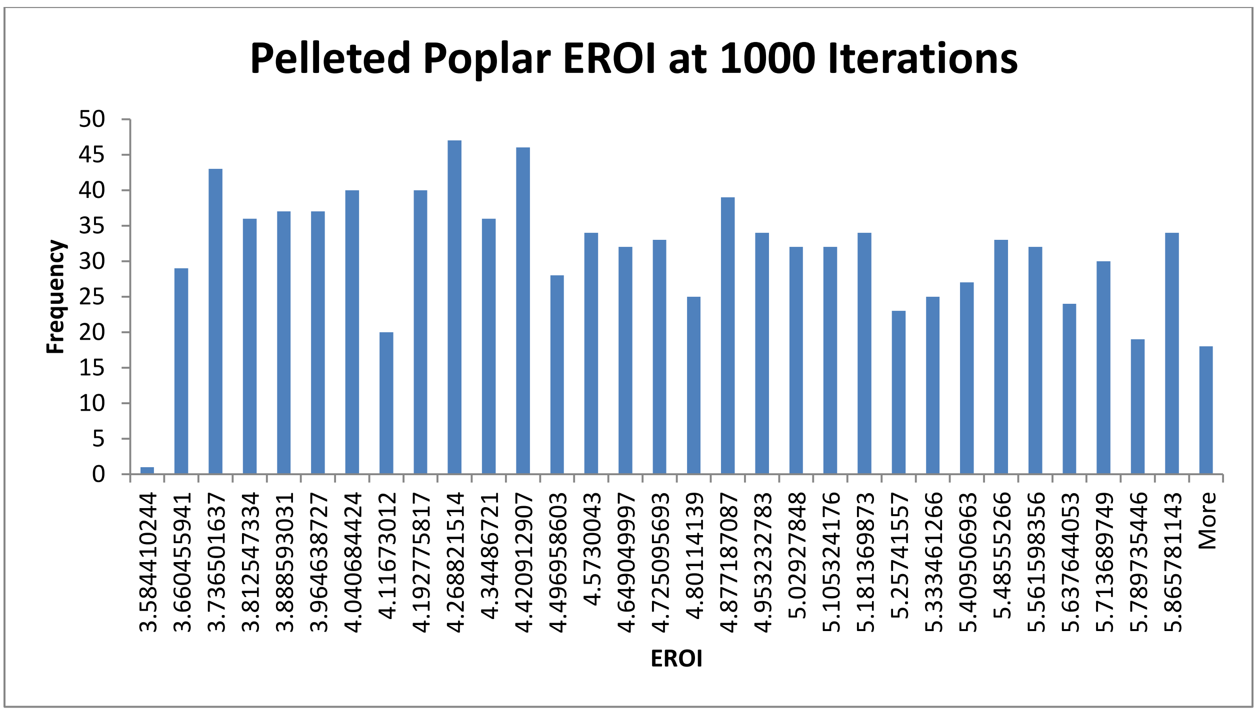


Figure 27: Monte Carlo Histogram for Scenario 3 EROI

Transport from the depot to the power plant is assumed to be performed by a 20 ton chip van. Energy values on a MJ/tonne/km were derived from the literature (Anon, 2010) and applied to the calculated transport distances for both aggregation and final shipping of the biomass feedstock.

Electricity values for equipment were scaled based on equipment loading of previously derived literature values and natural gas requirements were calculated based on the energy needs of both the drier and torrefaction systems as detailed in Equation 16.

The positive large and positive EROI predicted by this model suggests that this project is highly viable from an energy accounting standpoint (Table 18). This is expected due to the fact that the biomass is lightly processed using these techniques when compared to other energy sources.

Table 18: Scenario 3 Energy Accounting

	LHV	
	MMBTUs/yr	GJ/yr
In-Field Operations	193,642	204,303
Transport (Farm to Depot)	65,557	69,166
Depot		
Natural Gas for Drying (Depot)	313,462	330,720
Natural Gas for Torrefaction (Depot)	-	-
Electricity for Drying (Depot)	6,877	7,255
Electricity for Torrefaction (Depot)	-	-
Electricity for Grinding (Depot)	9,135	9,638
Electricity for Pelleting (Depot)	26,094	27,531
Transport (Depot to Power Plant)	207,384	218,802
Energy Return on Energy Invested (EROEI)	5	5

5.6.2 Economic Assessment

The results of the economic modeling activities for scenario 3 are detailed in Table 19. The primary metric derived from the economic assessment is the levelized cost of electricity or LCOE. For this scenario a return of 8% was specified. This yielded a LCOE of $0.065. Monte Carlo analysis of this scenario at 1000 iterations, found the LCOE to be fairly normally distributed (Kurtosis = -0.4, Skewness = 0.2) with a standard deviation of $0.008 (Figure 28).

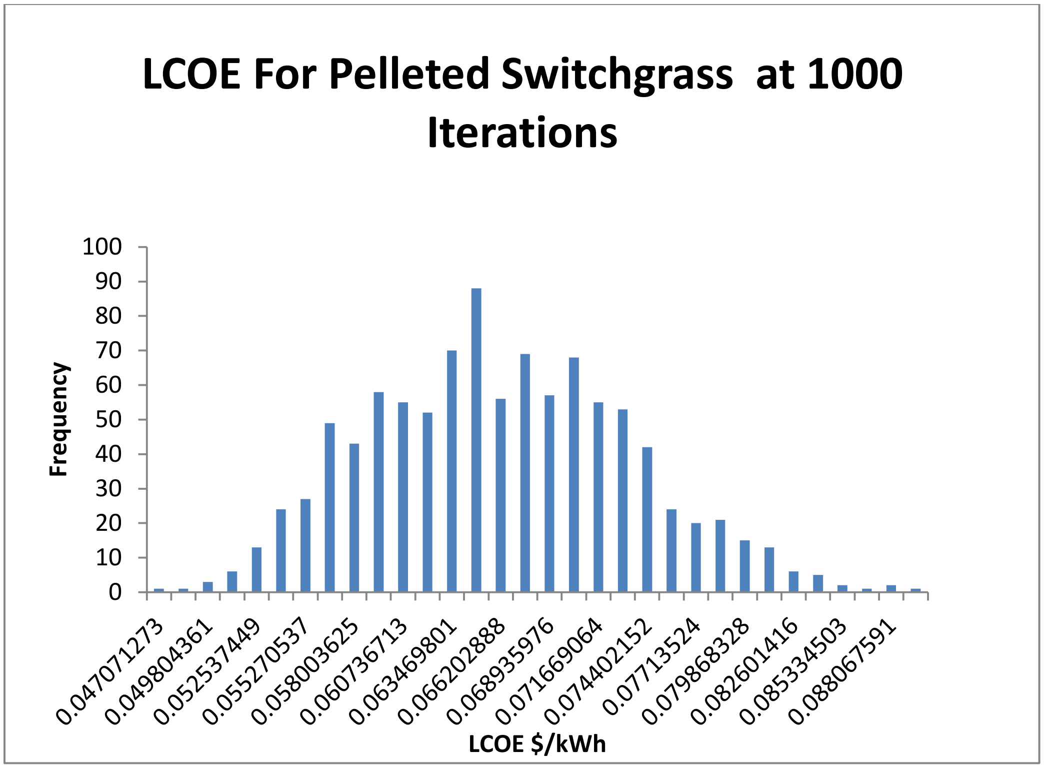


Figure 28: Scenario 3 Monte Carlo Histogram for LCOE

The LCOE of $0.065 is a favorable metric for power providers searching for renewable energy capacity as new installations of other renewable energy sources such as wind and solar typically range from 10-20 cents per kWh (Table 19). This is somewhat higher than the cost of poplar due primarily to the relatively high price of raw feedstock.

Table 19: Scenario 3 Economic Assessment

Power Plant Metrics	Value		Unit
Retail Price of Electricity	$	0.120	$/kwh
Simplified LCOE	$	0.0651	$/kWh
Return on Capital Investment	8%		
NPV of Biomass Depot	$	-	
NPV of Power Plant Modifications	$	$129,774,000	
Plant-Gate Feedstock Cost	$	115	$/tonne (ar)
	$	128	$/tonne (dry)
Relative Capital Costs	$	95	$/kW Capacity

As with the previous scenarios the single largest contributor to LCOE was the cost of delivered biomass. Power plant upgrades can initially be costly in this scenario ($95/kW of installed capacity), but once amortized over the 20 year lifespan of the project, they become trivial in comparison with operating expenses.

The cost of delivered feedstock is also the single highest contributor of cost to biomass processors as well, as seen in Figure 28.

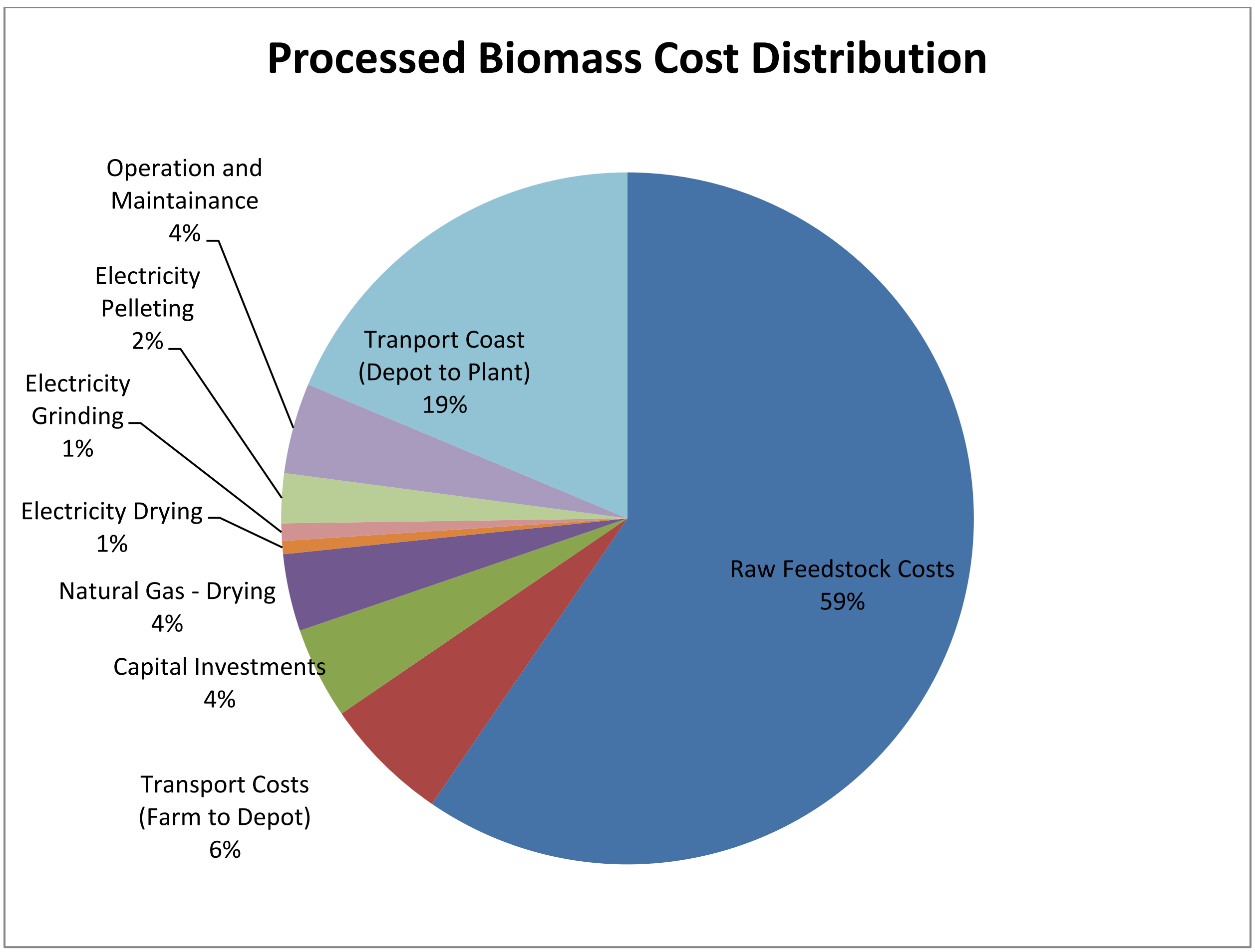


Figure 28: Scenario 3 Biomass Depot Processing Cost Distribution

5.6.3 Emissions Analysis

Emissions analyses were performed for both the base case (coal only) along with the co-firing scenario. The comparative results are presented in terms of emissions reductions in Table 20.

Table 20: Scenario 3 Emissions Report

<table>
<tr><th>Power Plant Summary</th><th>Change in Emission</th><th>Unit</th><th>Notes</th></tr>
<tr><td rowspan="4">Delta CO2
(Co-Fire - Base Case)</td><td>(20,700)</td><td>kg/hr</td><td rowspan="2">Gross</td></tr>
<tr><td>(2,626)</td><td>tonne/yr</td></tr>
<tr><td>(45,230)</td><td>kg/hr</td><td rowspan="2">Net (Assuming Biomass is Carbon Neutral)</td></tr>
<tr><td>(5,737)</td><td>tonne/yr</td></tr>
<tr><td rowspan="2">Delta SO2
(Co-Fire - Base Case)</td><td>(209)</td><td>kg/hr</td><td></td></tr>
<tr><td>(27)</td><td>tonne/yr</td><td></td></tr>
</table>

As expected, blending of biomass with coal resulted in a net reduction in both carbon dioxide and sulfur dioxide emissions. Carbon emissions were reduced both on a gross basis and a net basis. Because this value is directly correlated to coal displacement, and each scenario displaces the same amount of coal, net CO_2 reductions are similar across all scenarios.

5.7 Scenario 4 – TOP Switchgrass

In this scenario, farm grown and baled switchgrass is delivered to a biomass depot located 100 mile from the J.H. Campbell power plant. The biomass is assumed to be purchased from the individual farms at a price of $82.23 per wet ton of biomass ($0.091 per kg) (Anon, 2008) and transported via a 20 ton (18.1 tonne) capacity flatbed trailer to the centralized processing depot. At the processing depot, the switchgrass is de-baled, dried to a moisture content of 10%, hammer milled, pelleted, and placed in storage before being transported to the power plant. Once at the power plant, the pelleted biomass is unloaded and stored separately from the coal (thus necessitating the addition of offloading equipment and storage silos).

Once at the power plant, the TOP biomass is unloaded and stored separately from the coal (thus necessitating the addition of offloading equipment and storage silos). Sources vary on whether or not torrefied biomass can be stored with coal due to its similar hydrophobicity. However, CREDIT's base assumption is that separate storage will be required. The TOP biomass is blended with the coal at a rate of 5% by energy value. Due to torrefied wood's similarity to coal in friability, it can be safely assumed that at this blending ratio, TOP biomass can be directly mixed with the coal prior to pulverization. Unlike scenario 3, this means the system will not need additional handling equipment, a hammer mill, or a separate boiler injection port. This greatly reduces overall capital costs and project footprint at the power plant site.

5.7.1 Energy Assessment

Energy return on investment analysis for scenario 4 was performed in accordance with the process flow outlined in Figure 6. The results of the energy accounting are found in Table 21. In-field operations cultivation, including planting and harvesting, were derived from literature values established in the literature (Anon, 2008) . The values reported were scaled to the production level of this scenario assuming linear growth.

Table 21: Scenario 4 Energy Accounting

	LHV	
	MMBTUs/yr	GJ/yr
In-Field Operations	214,938	226,771
Transport (Farm to Depot)	76,660	80,881
Depot		
Natural Gas for Drying (Depot)	347,935	367,091
Natural Gas for Torrefaction (Depot)	-	-
Electricity for Drying (Depot)	7,321	7,724
Electricity for Torrefaction (Depot)	17,699	18,673
Electricity for Grinding (Depot)	9,130	9,632
Electricity for Pelleting (Depot)	26,078	27,514
Transport (Depot to Power Plant)	207,189	218,596
Energy Return on Energy Invested (EROEI)	4	4

5.7.2 Economic Assessment

The results of the economic modeling activities for scenario 4 are detailed in Table 21. The primary metric derived from the economic assessment is the levelized cost of electricity or LCOE where a return of 8% was specified. This yielded a LCOE of $0.088. Monte Carlo analysis of this scenario at 1000 iterations found the LCOE to be fairly normally distributed (Kurtosis = -0.01, Skewness = 0.2) with a standard deviation of $0.009 (Figure 29).

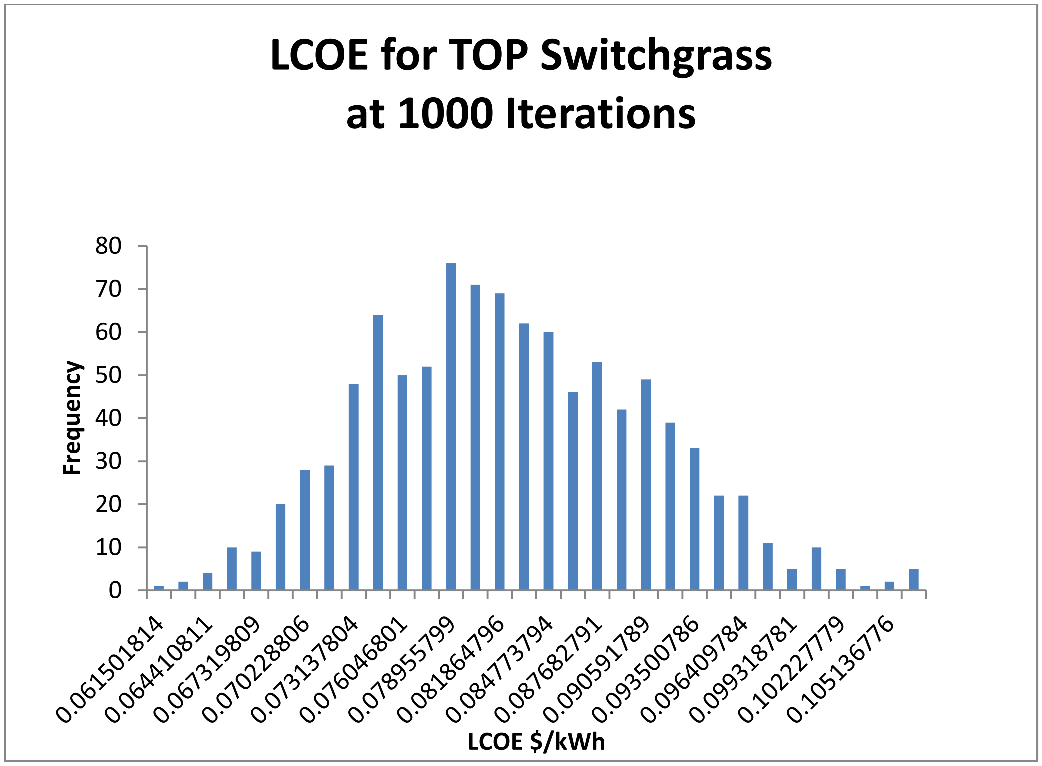


Figure 29: LCOE of TOP Switchgrass Monte Carlo Histogram

Though higher than scenario 3 that did not use torrefaction the LCOE of $0.082 is still cost competitive with other renewable energy. In terms of capital cost at the power plant, scenario 4 shows a clear advantage over scenario 3. The similarity of TOP biomass to coal greatly reduces the need for capital investment in new handling, processing, and injection equipment. (Bergman, 2005; Van Loo & Koppejan, 2008). This is reflected in the low relative capital costs ($32/kWh capacity vs. $97/kWh for scenario 1).

Table 22: Scenario 4 Financial Summary

Power Plant Metrics	Value		Unit
Retail Price of Electricity	$	0.120	$/kwh
Simplified LCOE	$	0.0817	$/kWh
Return on Capital Investment	8%		
NPV of Biomass Depot	$	-	
NPV of Power Plant Modifications	$	91,331,000	
Plant-Gate Feedstock Cost	$	153	$/tonne (ar)
	$	158	$/tonne (dry)
Relative Capital Costs	$	32	$/kW Capacity

As with scenario 2, raw biomass feedstock is still the largest cost at the depot. However, capital costs and O &M associated with torrefaction begin to play a much stronger roll, cumulatively accounting for 44% of the cost of processed biomass (Figure 30).

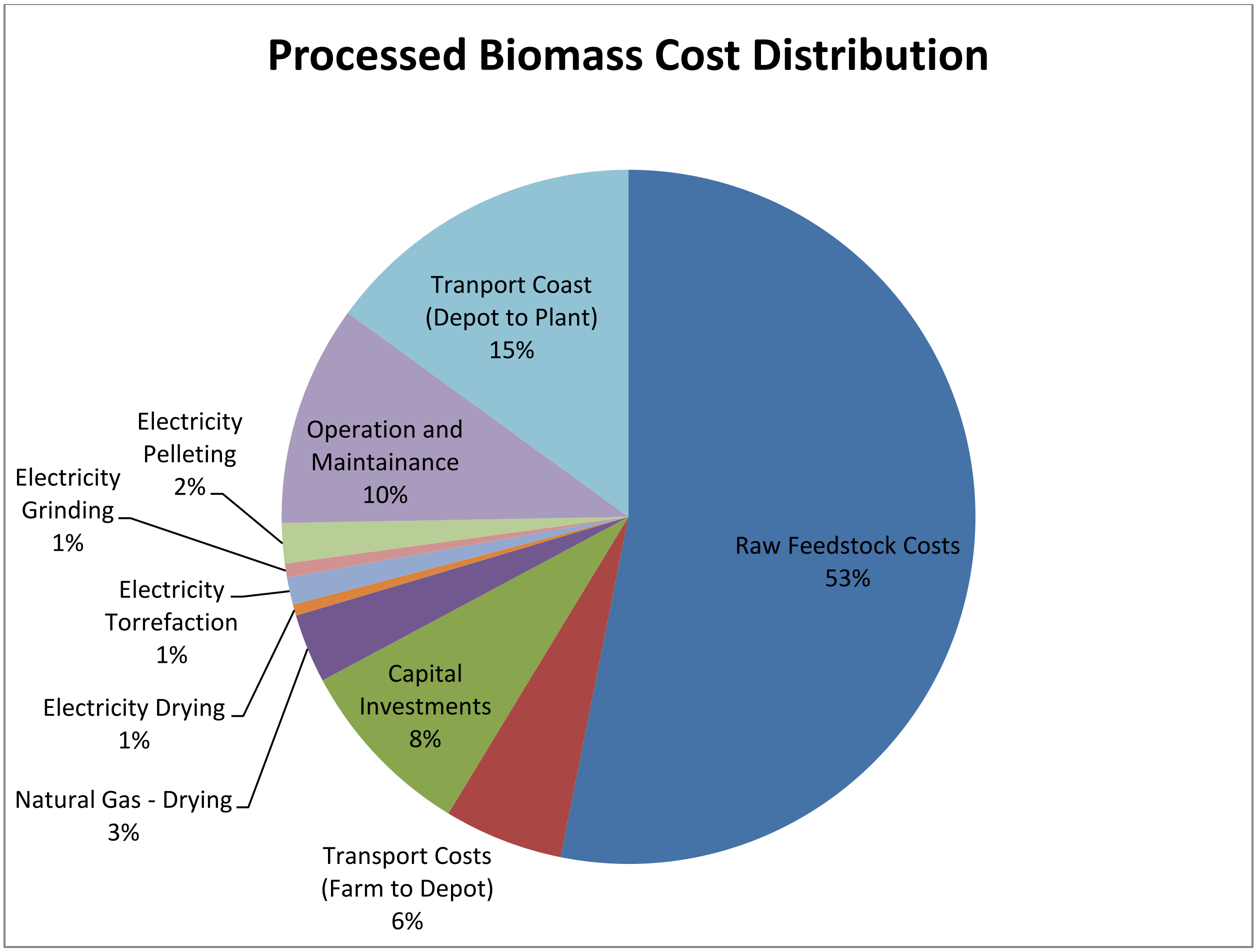


Figure 30: Scenario 4 Processed Biomass Cost Distribution

5.7.3 Emissions Analysis

Emissions analyses were performed for both the base case (coal only) along with the co-firing scenario.

The comparative results are presented in terms of emissions reductions in Table 23.

Table 23: Scenario 4 Emissions Report

Power Plant Summary	Change in Emission	Unit	Notes
Delta CO2 (Co-Fire - Base Case)	12,847	kg/hr	Gross
	1,629	tonne/yr	
	(45,230)	kg/hr	Net (Assuming Biomass is Carbon Neutral)
	(5,737)	tonne/yr	
Delta SO2 (Co-Fire - Base Case)	(79)	kg/hr	
	(10)	tonne/yr	

As expected, blending of torrefied biomass with coal resulted in a net reduction in sulfur dioxide emissions. Carbon emissions were increased on a gross basis but decreased on a net basis. This change from scenario 3 is attributed to the change in chemical composition of the biomass after torrefaction. During the torrefaction process, the ratio of carbon to oxygen is increased, and in this case resulted in a gross increase in carbon dioxide releases. The gross basis values presented is a straight subtraction of CO_2 emissions expectations between the base case of only coal being fired in the boiler systems, and the scenario under investigation. The net basis assumes that any carbon introduced to the system by biomass is a carbon neutral source of energy as defined by (Hartmann & Kaltschmitt, 1999). Because this value is directly correlated to coal displacement, and each scenario displaces the same amount of coal, net CO_2 reductions are similar across all scenarios.

5.8 Comparison of Results

At a distance of 100 miles, it is observed that pelleting is the superior biomass pre-treatment in terms of cost efficiency. This is largely due to the lower costs of biomass processing. In short, it has a higher plant-gate cost but improved shipping costs and a reduced capital requirement as compared to other alternatives. At a distance of 100 miles, however, this difference is not enough for it to economically outperform less intensive processing techniques. Nor were the additional capital upgrades required for the pelleted biomass scenarios sufficiently large to outweigh the higher plant-gate price of torrefied biomass over the course of a 20 year lifespan.

However, all scenarios are found to be cost competitive with projected energy production costs. Table 23 contains the model outputs alongside the EIA's projection of LCOEs for various energy technologies in 2020. All are in the upper half of available option and are more cost effective than solar PV and solar thermal technologies, and under the right conditions, is competitive with wind. This is largely due to this scenario's ability to utilize existing infrastructure to reduce capital costs. Stand-alone biomass is projected to be greater than $100/MWh. Important to note are a few differences in assumptions made by CREDIT and the EIA. Critically, CREDIT assumes a more conservative required return on capital investment of 8% as opposed to the EIA's assumption of 6.1% for all listed technologies. This further emphasizes the competitiveness of the studied scenarios.

Table 24: EIA LCOE Projections for 2020 (EIA, 2015)In combination with study ouputs.

Plant type	$/MWh
Geothermal	47.8
Pelletized Poplar	48.6
TOP Poplar	55.6
Pelletized Switchgrass	65.1
NG: Advanced Combined Cycle	72.6
Wind	73.6
NG: Conventional Combined Cycle	75.2
TOP Switchgrass	81.7
Hydro	83.5
Conventional Coal	95.1
Advanced Nuclear	95.2
New Stand-Alone Biomass	100.0
NG: Advanced CC with CCS	100.2
NG: Advanced Combustion Turbine	113.5
IGCC (Integrated Coal-Gasification Combined Cycle)	115.7
Solar PV	125.3
NG: Conventional Combustion Turbine	141.5
Wind-Offshore	196.9
Solar Thermal	239.7

6 CONCLUSIONS

CREDIT has been shown to produce approximations of energy production and economic costs that are consistent with those of a decision support tool based on comparisons to exiting case studies. When used to analyze a scenario surrounding the J.H. Campbell power plant in western Michigan, wherein biomass from a four county region 100 miles from the power plant was trucked to the facility, CREDIT returned positive NPV's for the power plant, while maintaining a positive EROI and an LCOE that was lower than many other renewable energy options. At a blending rate of 5% biomass by energy value and a biomass transport distance of 100 miles, it was determined that pelletized poplar was the most economical of all studied options at $48.6/MW, followed by pelletized switchgrass, TOP poplar, and TOP switchgrass with LCOE values of 55.6, 65.1, and 81.7 dollars per MWh, respectively. Given the assumptions and parameters of this study, it appears that at a distance of 100 miles, poplar is preferable to switchgrass as a feedstock and pelleting is preferable to torrefaction as a pre-treatment from an economic perspective.

These pricing results indicate that biomass co-firing is a highly competitive option for renewable energy generation. Among options investigated by the US EIA only geothermal is competitive with pelleted poplar in terms of LCOE, while pelleted switchgrass and TOP poplar appear to be on-par with the cost of wind energy. This is logical, as co-firing utilizes existing infrastructure to reduce overall project costs in the near-term and energy companies should investigate to meet renewable energy portfolios.

Project financing is heavily influenced by the cost of raw biomass feedstock. Across all scenario investigations, the expense to purchase feedstock was the largest cost factor over a 20 year pro-forma analysis, accounting for between 40 and 80% of lifetime project costs at the energy depot and between 65-95% of costs at the power plant. As switchgrass is assumed to be nearly twice as expensive as poplar on a per/energy unit basis, the end price of switchgrass derived bioenergy is understandably high in comparison to poplar.

Similarly, under these conditions, it was observed that TOP biomass was less cost efficient than dried and pelleted biomass. This is due to its increased plant-gate cost and the economic model's sensitivity to plant-gate costs. There are some conditions made by the scenario analysis that may shift this value as well as the sensitivity to plant-gate feedstock costs. First, a blending rate of 5% biomass by energy value was selected to correspond with the availability of biomass in the study region. Biomass blending at higher rates will require increased capital costs for the pelleted biomass scenarios, but little to no increase for the torrefied scenarios due to the relative change in infrastructure needed. Further, a 20 year project life was selected for this project, thus allowing capital costs to amortize and account for less of the total project cost. If the project were to decrease in length, this would increase the model's sensitivity to capital costs. This would in-turn begin to favor a feedstock like TOP biomass that has a higher feedstock cost but a lower capital cost. This fact will be particularly important when investigating scenarios for coal power plants with a limited life expectancy.

Finally, the dependence of project success on feedstock cost denotes the need to locate the lowest cost feedstocks possible. These are sometimes referred to in literature as "feedstocks of opportunity" (Tillman, 2000). Such feedstocks might include construction and demolition debris, mill wastes, forest residues and industrial paper wastes. Such feedstocks may provide a valuable source of energy while being provided at low or no cost to the energy producer.

Due to the sensitivity of the results with respect to feedstock, future work should expand upon the tool's ability to assess feedstock availability and optimized conditioning routines. The predictive power of biomass energy availability in Michigan would be greatly enhanced through integration with GIS-based biomass availability assessments. Efforts such as the Michigan Forest Biomass Inventory

(Michigan Tech), the Michigan Waste Biomass Inventory to Support Renewable Energy (Michigan State University) and National Ag Statistics Services field statistics, would provide data for understanding how much biomass energy is available on a state or national level for biomass co-firing. For the scenario analyses in this study, the NASS survey of unused farmland was utilized to estimate the potential availability of cropland for purpose grown energy crops, but given the ability to integrate existing databases, one might just as easily run several simulations based on the availability of forest residues, construction debris, and waste biomass. Further, this could be automated in order to produce mapped results of biomass co-firing energy potential in Michigan and beyond.

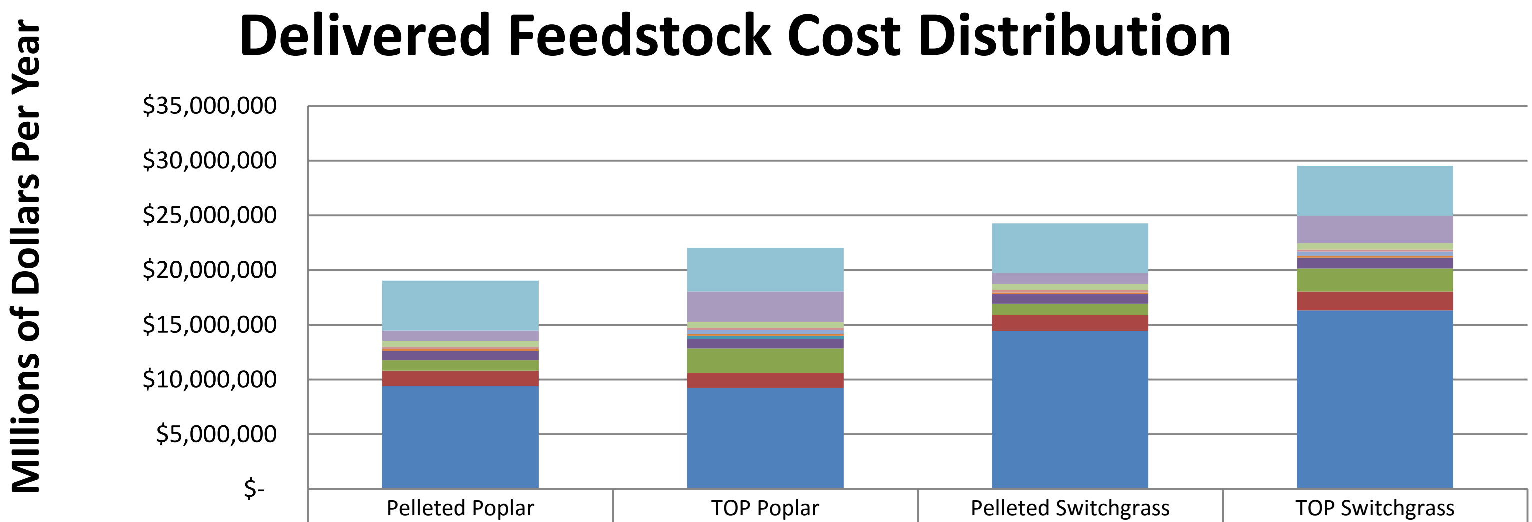
Upon integration with existing GIS databases, it may be useful to develop and implement biomass aggregation and pre-treatment optimization sub-routines. These calculations would theoretically allow users to identify the optimum number of biomass collection points as well as the optimum structure of biomass pre-treatment activities based on feedstock type, power plant configuration, distance to the power plant, and biomass blending rates for a given GIS defined collection area. Optimization calculations would be performed with relation to economic performance and environmental considerations. Optimization calculations would provide a useful baseline for the development of biomass supply chain activities, in keeping with the goal of delivering feedstock in the most efficient manner possible.

Lessons learned from the development of this tool could also be used to generate a companion tool for the integration of biomass co-firing at natural gas plants. Increasingly, new energy needs are being met by the installation of natural gas plants in Michigan. Through the use of gasification or through parallel combustion (depending on the configuration of the natural gas plant), it is technically feasible to integrate biomass into natural gas based power plants. Future developments in Michigan’s energy portfolio may warrant such a study and to-date no known decision support tools have been created for this task.

The work completed in this study may also have relevance for public policy. Reduction of baseline greenhouse gas emissions through the production of renewable energy remains a topic of discussion in State and American politics. Integration of this tool with existing databases may allow future works to investigate cost-benefit analyses associated with the utilization of co-firing and the creation of biomass based infrastructure, the implementation of which could have implications for energy portfolio diversification and energy security.

APPENDICES

Appendix A – Supplemental Results Charts



	Pelleted Poplar	TOP Poplar	Pelleted Switchgrass	TOP Switchgrass
Transport Costs (Depot to Plant)	$4,534,001	$3,994,584	$4,534,001	$4,607,854
Operation and Maintainance	$944,853	$2,803,461	$1,032,618	$2,468,975
Electricity Pelleting	$567,670	$526,153	$567,670	$573,204
Electricity Grinding	$198,636	$183,411	$198,636	$200,670
Electricity Torrefaction	$-	$357,088	$-	$389,020
Electricity Drying	$149,604	$147,711	$149,604	$160,920
Natural Gas - Torrefaction	$-	$307,701	$-	$-
Natural Gas - Drying	$875,059	$856,687	$875,059	$988,137
Capital Investments	$927,424	$2,267,676	$1,045,250	$2,112,703
Transport Costs (Farm to Depot)	$1,420,790	$1,376,309	$1,420,790	$1,704,913
Raw Feedstock Costs	$9,403,986	$9,206,552	$14,456,636	$16,324,770

Figure 31: Delivered Feedstock Cost Distribution

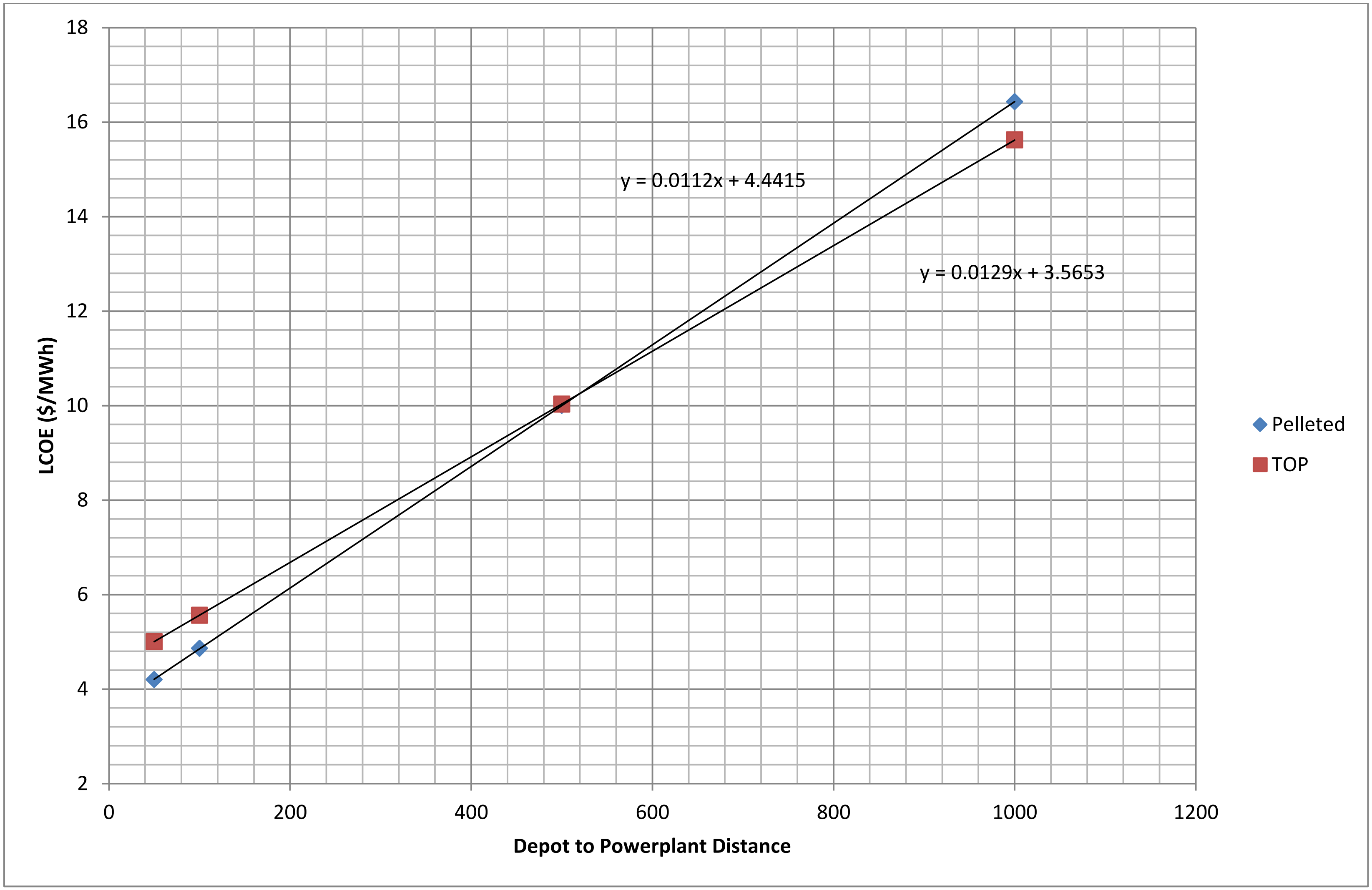


Figure 32: Poplar LCOE Sensitivity to Depot Distance from Power Plant

Table 25: Scenario 1 Monte Carlo Statistics

	EROEI	LCOE	NPV	$/tonne ar	Cost of Processed Biomass as Received	Cost of Processed Biomass Per Dry Matter	Effective Price of Elect. ($/kWh installed)
Mean	4.789	0.049	168191324.000	71.032	90.971	101.079	95.815
Standard Error	0.021	0.000	408183.933	0.181	0.204	0.227	0.242
Median	4.785	0.049	168907000.000	71.221	90.754	100.838	95.953
Mode	#N/A	#N/A	169058000.000	#N/A	#N/A	#N/A	#N/A
Standard Deviation	0.680	0.005	12907909.314	5.715	6.452	7.169	7.664
Sample Variance	0.462	0.000	166614122855878.000	32.658	41.626	51.391	58.744
Kurtosis	-1.195	-0.234	-0.264	-0.620	-0.453	-0.453	-0.709
Skewness	0.052	0.190	-0.173	0.033	0.081	0.081	-0.020
Range	2.387	0.029	69819000.000	28.687	35.026	38.918	36.451
Minimum	3.639	0.036	131249000.000	57.092	73.266	81.406	76.622
Maximum	6.026	0.065	201068000.000	85.779	108.292	120.324	113.073
Sum	4789.355	49.045	168191324000.000	71032.319	90970.806	101078.674	95815.259
Count	1000.000	1000.000	1000.000	1000.000	1000.000	1000.000	1000.000
Confidence Level(95.0%)	0.042	0.000	800996.255	0.355	0.400	0.445	0.476

Table 26: Scenario 2 Monte Carlo Statistics

	EROEI	LCOE	NPV	$/tonne ar	Cost of Processed Biomass as Received	Cost of Processed Biomass Per Dry Matter	Effective Price of Elect. ($/kWh installed)
Mean	4.251	0.056	153659001.000	110.252	130.058	134.081	31.666
Standard Error	0.016	0.000	423299.036	0.210	0.230	0.237	0.115
Median	4.246	0.055	155103000.000	110.379	130.162	134.188	31.508
Mode	#N/A	#N/A	171462000.000	#N/A	#N/A	#N/A	#N/A
Standard Deviation	0.518	0.005	13385890.855	6.649	7.268	7.493	3.623
Sample Variance	0.269	0.000	179182073974975.000	44.210	52.825	56.143	13.127
Kurtosis	-1.100	-0.040	-0.032	-0.563	-0.391	-0.391	-1.154
Skewness	0.030	0.382	-0.367	0.061	0.035	0.035	0.066
Range	2.016	0.035	85114000.000	32.010	38.057	39.234	12.911
Minimum	3.285	0.042	102309000.000	94.066	111.262	114.703	25.399
Maximum	5.301	0.077	187423000.000	126.076	149.319	153.937	38.310
Sum	4251.219	55.860	153659001000.000	110252.113	130058.242	134080.662	31666.133
Count	1000.000	1000.000	1000.000	1000.000	1000.000	1000.000	1000.000
Confidence Level(95.0%)	0.032	0.000	830657.249	0.413	0.451	0.465	0.225

Table 27: Scenario 3 Monte Carlo Statistics

	EROEI	LCOE	NPV	$/tonne ar	Cost of Processed Biomass as Received	Cost of Processed Biomass Per Dry Matter	Effective Price of Elect. ($/kWh installed)
Mean	4.681	0.065	128,732,781.000	95.460	115.282	128.091	96.109
Standard Error	0.021	0.000	556,463.377	0.262	0.279	0.310	0.241
Median	4.633	0.065	129,379,500.000	95.262	114.913	127.681	96.587
Mode	#N/A	#N/A	110,014,000.000	#N/A	#N/A	#N/A	#N/A
Standard Deviation	0.665	0.007	17,596,917.055	8.273	8.814	9.794	7.633
Sample Variance	0.442	0.000	309,651,489,834,867.000	68.437	77.690	95.914	58.260
Kurtosis	(1.146)	(0.321)	(0.334)	(0.857)	(0.737)	(0.737)	(0.785)
Skewness	0.156	0.207	(0.194)	0.056	0.109	0.109	(0.133)
Range	2.357	0.042	102,008,000.000	38.522	43.727	48.585	34.746
Minimum	3.584	0.047	71,105,000.000	77.172	95.445	106.050	77.954
Maximum	5.942	0.089	173,113,000.000	115.694	139.172	154.635	112.700
Sum	4,680.579	65.487	128,732,781,000.000	95,459.724	115,282.228	128,091.364	96,109.230
Count	1,000.000	1,000.000	1,000.000	1,000.000	1,000.000	1,000.000	1,000.000
Confidence Level(95.0%)	0.041	0.000	1,091,971.156	0.513	0.547	0.608	0.474

Table 28: Scenario 4 Monte Carlo Statistics

	EROEI	LCOE	NPV	$/tonne ar	Cost of Processed Biomass as Received	Cost of Processed Biomass Per Dry Matter	Effective Price of Elect. ($/kWh installed)
Mean	4.256	0.082	91127563.000	133.056	153.010	157.742	31.979
Standard Error	0.019	0.000	629170.501	0.307	0.324	0.334	0.115
Median	4.187	0.081	92369500.000	132.868	152.870	157.598	32.075
Mode	#N/A	#N/A	96289000.000	#N/A	#N/A	#N/A	#N/A
Standard Deviation	0.615	0.008	19896118.184	9.714	10.250	10.568	3.650
Sample Variance	0.378	0.000	395855518798822.000	94.370	105.072	111.672	13.320
Kurtosis	-1.184	-0.294	-0.294	-0.650	-0.491	-0.491	-1.195
Skewness	0.189	0.247	-0.240	0.076	0.055	0.055	-0.042
Range	2.153	0.045	108886000.000	48.633	54.637	56.327	12.921
Minimum	3.234	0.062	31166000.000	110.167	127.547	131.491	25.460
Maximum	5.387	0.107	140052000.000	158.800	182.183	187.818	38.381
Sum	4256.059	81.746	91127563000.000	133055.565	153009.626	157741.882	31978.823
Count	1000.000	1000.000	1000.000	1000.000	1000.000	1000.000	1000.000
Confidence Level(95.0%)	0.038	0.001	1234647.359	0.603	0.636	0.656	0.226

Appendix B – Economic Assumptions

Table 29: Variable Cost Assumptions

	Default	Min	Max	Source
Market Electricity Price ($/kWh)	0.12	0.08	0.14	EIA 2014
Switchgrass Farmgate Feedstock Price ($/dt)	0.05	0.04	0.05	ISU 2014
Poplar Farmgate Feestock Price ($/dt)	0.05	0.04	0.05	Saffron and Chai 2011
Natural Gas Price ($/MJ)	0.003	0.002	0.003	EIA 2014
Specific Transportation Cost ($/km)	2.25	1.80	2.70	Svanberg 2013
Plant O&M Cost ($/kW installed capacity)	47.60	38.08	57.12	Caputo 2009
Depot O&M Costs (% of capital costs)	8%	6%	10%	Batizdiari 2013
Excavation	4%	4%	4%	Caputo 2009
Engineering	12%	12%	12%	Caputo 2009
Contingency	5%	5%	5%	Binkley 2015
Financing				
APR	7%	7%	7%	Binkley 2015
Loan (% of total capital costs)	80%	80%	80%	Binkley 2015
Grant Funding (% of total capital costs)	10%	10%	10%	Binkley 2015
Cash on Hand (% of total capital costs)	10%	10%	10%	Binkley 2015

Table 30: Capital Cost Assumptions

	Base Size	Scaling Factor	Base Cost	Min Cost	Max Cost	Source(s)
Dryer Cost	4,535 (kg/hr)	0.65	$440,000	$352,000	$528,000	(Batidzirai et al., 2013)
Torrefier Cost	1,000 (kg/hr)	0.60	$2,027,391	$5,148,800	$7,723,200	(Batidzirai et al., 2013)
Grinding Cost	4,898 (kg/hr)	0.65	$193,622	$154,898	$232,346	(Srivastava et al., 2011)
Cooling Cost	4,535 (kg/hr)	0.60	$29,970	$23,976	$35,964	(Srivastava et al., 2011)
Peripheral Equipment Cost	4,898 (kg/hr)	0.60	$1,152,000	$921,600	$1,382,400	(Srivastava et al., 2011)
Pelleting Equipment	2,721 (kg/hr)	0.61	$438,000	$350,400	$525,600	(Srivastava et al., 2011)
Building Cost Factor	1 (sq meter)	1	$900.00	$700.00	$800.00	(Srivastava et al., 2011)
Storage Cost	1 (cu meter)	1	$13.50	$13.00	$14.00	(Srivastava et al., 2011)
Boiler Modifications	1000 (kg/hr)	0.6	$61	$49	$73	(Caputo et al., 2005; De & Assadi, 2009)
Plant Storage	1000 (kg/hr)	0.6	$166,625	$133,300	$199,950	(Caputo et al., 2005; De & Assadi, 2009)
Plant Handling	1000 (kg/hr)	0.6	$68,052	$54,441	$81,662	(Caputo et al., 2005; De & Assadi, 2009)
Plant Conditioning	1000 (kg/hr)	0.6	$16,648	$13,318	$19,978	(Caputo et al., 2005; De & Assadi, 2009)

Table 31: Depreciation Schedule for Equipment and Buildings

	Depreciation Rate		
	Farm Machinery and Equipment 7 year MACRS	Machinery 10 Year MACRS	Building 20 Year MACRS
Year 1	**10.71%**	**7.50%**	**3.750%**
Year 2	**19.13%**	**13.88%**	**7.219%**
Year 3	**15.03%**	**11.79%**	**6.677%**
Year 4	**12.25%**	**10.02%**	**6.177%**
Year 5	**12.25%**	**8.74%**	**5.713%**
Year 6	**12.25%**	**8.74%**	**5.285%**
Year 7	**12.25%**	**8.74%**	**4.888%**
Year 8	**6.13%**	**8.74%**	**4.522%**
Year 9		**8.74%**	**4.462%**
Year 10		**8.74%**	**4.461%**
Year 11		**4.37%**	**4.462%**
Year 12			**4.461%**
Year 13			**4.462%**
Year 14			**4.461%**
Year 15			**4.462%**
Year 16			**4.461%**
Year 17			**4.462%**
Year 18			**4.461%**
Year 19			**4.462%**
Year 20			**4.461%**
Year 21			**2.231%**

Appendix C – Parameter Look-Up Table Values

Table 32: Miscanthus Fuel Properties (PHYLLIS2, ECN)

	Unit	Minimum	Maximum	Median	Mean	Std dev		Samples
Miscanthus Fuel Properties								
Proximate Analysis								
Moisture content	wt% (ar)	7.3	49	42	36.47	11.6	32%	37
Ash content	wt% (dry)	1.5	7.46	3.2	3.74	1.41	38%	39
Volatile matter	wt% (daf)	73.87	94.27	89.55	85.9	10.68	12%	3
Fixed carbon	wt% (daf)	5.73	26.13	10.45	14.1	10.68	76%	3
Ultimate Analysis								
Carbon	wt% (daf)	46.73	51.97	49.8	49.63	1.1	2%	47
Hydrogen	wt% (daf)	5	6.48	5.67	5.63	0.33	6%	47
Nitrogen	wt% (daf)	0.1	1.83	0.49	0.54	0.29	54%	47
Sulphur	wt% (daf)	0.02	0.21	0.06	0.06	0.04	63%	45
Oxygen	wt% (daf)	40.06	46.78	43.64	43.81	1.48	3%	47
Total (with halides)	wt% (daf)	92.86	101.66	100	99.88	1.07	1%	47
Calorific Values								
Net calorific value (LHV)	MJ/kg (daf)	15.59	20.97	18.53	18.55	0.64	3%	46
Gross calorific value (HHV)	MJ/kg (daf)	17	22.2	19.77	19.77	0.63	3%	46
HHVMilne	MJ/kg (daf)	18.47	20.16	19.28	19.32	0.35	2%	39
Chemical Analyses								
Halides								
Chlorine (Cl)	mg/kg (daf)	200	3 955.9	2 000.0	2 149.1	1 070.5	50%	45
Fluorine (F)	mg/kg (daf)	27.8	29	28.4	28.4	0.9	3%	2

Table 33: Wheat Straw Fuel Properties (PHYLLIS2, ECN)

		Unit	Minimum	Maximum	Median	Mean	Std dev		Samples
Wheat Straw - Fuel Properties									
Proximate Analysis									
	Moisture content	wt% (ar)	0	17.41	9.74	10.24	4.09	40%	23
	Ash content	wt% (dry)	1.3	13.5	6.45	6.44	2.72	42%	48
	Volatile matter	wt% (daf)	78.04	84.53	81.58	81.5	1.84	2%	19
	Ash content at 550°C	wt% (dry)	4.71	10.32	8.02	7.77	2.31	30%	4
	Ash content at 815°C	wt% (dry)	7.75	9.81	7.9	8.49	1.15	14%	3
	Fixed carbon	wt% (daf)	15.47	21.96	18.42	18.5	1.84	10%	19
Ultimate Analysis									
	Carbon	wt% (daf)	46.35	52.6	49.04	48.86	1.37	3%	38
	Hydrogen	wt% (daf)	3.2	6.39	5.96	5.87	0.52	9%	38
	Nitrogen	wt% (daf)	0.29	2.08	0.61	0.72	0.38	53%	40
	Sulphur	wt% (daf)	0.03	0.46	0.12	0.15	0.09	62%	36
	Oxygen	wt% (daf)	39.42	47.92	43.73	44.08	1.64	4%	38
	Total (with halides)	wt% (daf)	0	101.6	100	73.13	44.75	61%	52
Calorific Values									
	Net calorific value (LHV)	MJ/kg (daf)	15.2	20.49	18.21	18.11	1.07	6%	36
	Gross calorific value (HHV)	MJ/kg (daf)	16.63	21.74	19.42	19.35	1.03	5%	34
	HHVMilne	MJ/kg (daf)	15.18	20.54	19.01	18.96	0.91	5%	38
Chemical Analyses									
Halides									
	Chlorine (Cl)	mg/kg (daf)	207.1	22 775.0	2 793.7	4 335.7	5 221.3	120%	32
	Bromine (Br)	mg/kg (daf)	10.8	32.3	15.5	19.6	11.3	58%	3
	Fluorine (F)	mg/kg (daf)	7.2	7.7	7.4	7.4	0.4	5%	2

Table 34: Willow Fuel Properties (PHYLLIS2, ECN)

	Unit	Minimum	Maximum	Median	Mean	Std dev		Samples
Willow Fuel Properties								
Proximate Analysis								
Moisture content	wt% (ar)	10.23	50.1	11.3	25.25	19.82	78%	5
Ash content	wt% (dry)	0.45	4.59	1.6	2.18	1.55	71%	7
Volatile matter	wt% (daf)	80.29	86.05	83.2	83.19	2.67	3%	4
Ash content at 550°C	wt% (dry)	1.3	1.8	1.55	1.55	0.35	23%	2
Fixed carbon	wt% (daf)	13.95	19.71	16.8	16.81	2.67	16%	4
Ultimate Analysis								
Carbon	wt% (daf)	45.29	51	50.54	49.62	2.18	4%	6
Hydrogen	wt% (daf)	5.78	6.74	6	6.11	0.34	6%	6
Nitrogen	wt% (daf)	0.1	1.12	0.54	0.54	0.39	72%	6
Sulphur	wt% (daf)	0.03	0.1	0.05	0.05	0.03	54%	5
Oxygen	wt% (daf)	41.64	46.76	42.9	43.57	1.99	5%	5
Total (with halides)	wt% (daf)	0	100	98.07	61.75	48.25	78%	9
Calorific Values								
Net calorific value (LHV)	MJ/kg (daf)	17.53	19.12	18.18	18.27	0.58	3%	6
Gross calorific value (HHV)	MJ/kg (daf)	18.86	20.59	19.46	19.61	0.64	3%	6
HHVMilne	MJ/kg (daf)	17.43	20.93	20.06	19.59	1.32	7%	5
Chemical Analyses								
Halides								
Chlorine (Cl)	mg/kg (daf)	101.3	337.1	219.2	219.2	166.7	76%	2
Fluorine (F)	mg/kg (daf)	10.1	10.1	10.1	10.1	0	0%	1

Table 35: Poplar Fuel Properties (PHYLLIS2, ECN)

	Unit	Minimum	Maximum	Median	Mean	Std dev		Samples
Poplar Fuel Properties								
Proximate Analysis								
Moisture content	wt% (ar)	4.8	15	9.9	9.9	7.21	73%	2
Ash content	wt% (dry)	0.4	2.28	1.1	1.13	0.63	56%	13
Volatile matter	wt% (daf)	71.76	86.12	83.43	80.44	7.64	9%	3
Fixed carbon	wt% (daf)	13.88	28.24	16.57	19.56	7.64	39%	3
Ultimate Analysis								
Carbon	wt% (daf)	48.3	51.98	49.7	49.91	1.18	2%	10
Hydrogen	wt% (daf)	5.8	6.34	6.08	6.09	0.16	3%	10
Nitrogen	wt% (daf)	0.1	0.48	0.21	0.26	0.15	58%	8
Sulphur	wt% (daf)	0.01	0.05	0.05	0.04	0.02	53%	7
Oxygen	wt% (daf)	41.72	45.8	43.96	43.73	1.23	3%	10
Total (with halides)	wt% (daf)	0	100	100	76.91	43.85	57%	13
Calorific Values								
Net calorific value (LHV)	MJ/kg (daf)	18.24	19.51	18.78	18.78	0.49	3%	9
Gross calorific value (HHV)	MJ/kg (daf)	19.55	20.89	20.11	20.11	0.52	3%	9
HHVMilne	MJ/kg (daf)	18.62	21.06	19.68	19.77	0.77	4%	10
Chemical Analyses								
Halides								
Chlorine (Cl)	mg/kg (daf)	101.2	1 013.5	122.3	413.5	459.6	111%	6

Table 36: Switchgrass Fuel Properties (PHYLLIS2, ECN)

	Unit	Minimum	Maximum	Median	Mean	Std dev		Samples
Switchgrass Fuel Properties								
Proximate Analysis								
Moisture content	wt% (ar)	8.16	15	11.9	11.72	2.78	0.24	5
Ash content	wt% (dry)	1.9	10.11	6.25	6.3	1.38	0.22	34
Volatile matter	wt% (daf)	72.91	86.91	84.25	83.23	4.46	0.05	8
Fixed carbon	wt% (daf)	13.09	27.09	15.75	16.77	4.46	0.27	8
Ultimate Analysis								
Carbon	wt% (daf)	45.19	53.16	50.63	49.43	2.46	0.05	13
Hydrogen	wt% (daf)	5.64	6.53	6.13	6.13	0.35	0.06	13
Nitrogen	wt% (daf)	0.4	1.3	0.59	0.64	0.18	0.28	30
Sulphur	wt% (daf)	0	0.21	0.13	0.12	0.06	0.45	13
Oxygen	wt% (daf)	39.01	48.64	43.72	43.97	2.89	0.07	13
Total (with halides)	wt% (daf)	0	101.78	0.61	38.7	49.32	1.27	34
Calorific Values								
Net calorific value (LHV)	MJ/kg (daf)	16.86	18.9	17.66	17.82	0.69	0.04	12
Gross calorific value (HHV)	MJ/kg (daf)	18.29	20.22	18.94	19.16	0.7	0.04	12
HHVMilne	MJ/kg (daf)	16.91	21.62	19.47	19.51	1.22	0.06	13
Chemical Analyses								
Halides								
Chlorine (Cl)	mg/kg (daf)	370.3	5 249.9	1 062.7	1 952.3	1 943.6	1	5
Major elements								
Potassium (K)	mg/kg (dry)	3 400.0	3 400.0	3 400.0	3 400.0	0	0	1
Sodium (Na)	mg/kg (dry)	33	33	33	33	0	0	1

Table 37: Coal Proximate and Ultimate Analysis (PHYLLIS2, ECN)

	Proximate Analysis (wt % ar)				Ultimate Analysis (wt % moisture & ash free)					
	Fixed Carbon	Volatile Matter	Moisture	Ash	C	H	O	N	S	Net Heating Value (MJ/kg)
Select a Value										
Anthracite	81.8	7.7	4.5	6	91.8	3.6	2.5	1.4	0.7	36.2
Bituminous	54.9	35.6	5.3	4.2	82.8	5.1	10.1	1.4	0.6	36.1
Sub-Bituminous	43.6	34.7	10.5	11.2	76.4	5.6	14.9	1.7	1.4	31.8
Lignite	27.8	24.9	36.9	10.4	71	4.3	23.2	1.1	0.4	26.7

Table 38: Transportation Conditions

	Vehichle Capacity - Mass (kg)	Volume (m3)	Source	kg/m3	lb/ft3	condition
Hybrid Poplar - Chipped	36,280	139	NREL	275		chipped
Willow Wood - Chipped	36,280	139	NREL	275		chipped
Hybrid Poplar - Pelleted	36,280	139	NREL	625		pelleted
Willow Wood - Pelleted	36,280	139	NREL	625		pelleted
Wheat Straw - Baled	15,419		NREL			Baled
Switchgrass-Baled	15,419		NREL			Baled
Miscanthus-Baled	15,419		NREL			Baled
Straw- Pelleted	36,280	139	NREL	625		pelleted
Switchgrass- Pelleted	36,280	139	NREL	625		pelleted
Miscanthus-Pelleted	36,280	139	NREL	625		pelleted
Hybrid Poplar (Torrefied)	36,280	139	NREL	240		Torrefied
Willow Wood (Torrefied)	36,280	139	NREL	240		Torrefied
Hybrid Poplar (T & P)	36,280	139	NREL	800		TOP
Willow Wood (T & P)	36,280	139	NREL	800		TOP

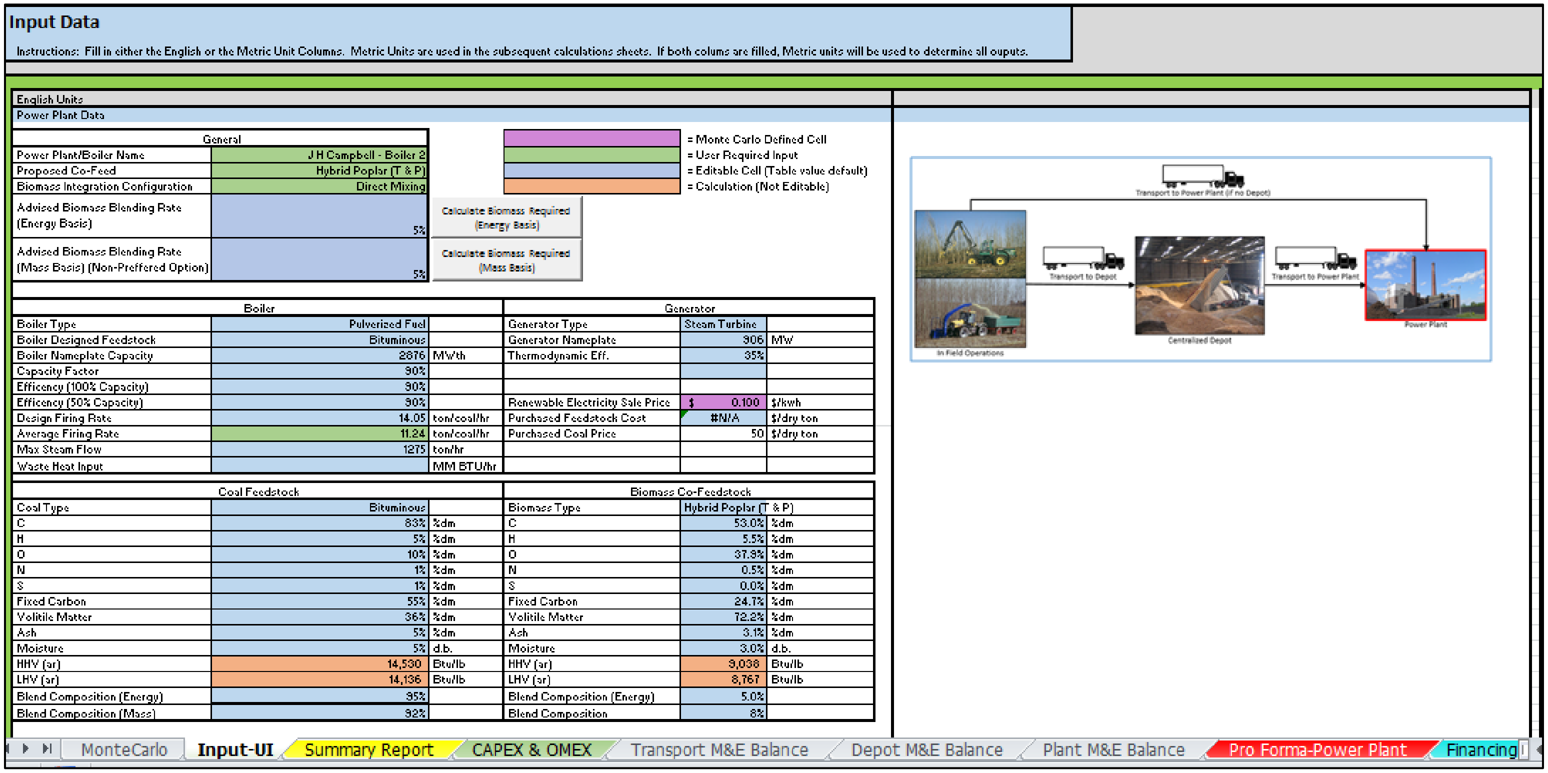
Table 39: Coal Fired Powerplant Data - 1

Utility Name	Plant Code	Plant Name	City	Lat	Long	Feeding Mechanism	Max Steam Flow (Thousand Pounds per Hour)	Coal Fire Steam Flow (0.1 Tons per Hour)	Efficiency 100% Load	Efficiency 50% Load
Consumers Energy Co	1695	B C Cobb - Boiler 4	Muskegon	43.258768	-86.242268	Pulverized Fuel	**1,050.0**	**62.6**	**0.9**	**0.9**
Consumers Energy Co	1695	B C Cobb - Boiler 5	Muskegon	43.258768	-86.242268	Pulverized Fuel	**1,050.0**	**62.6**	**0.9**	**0.9**
Consumers Energy Co	1702	Dan E Karn - Boiler 1	Essexville	43.644996	-83.840074	Pulverized Fuel	**1,750.0**	**105.5**	**0.9**	**0.9**
Consumers Energy Co	1702	Dan E Karn - Boiler 2	Essexville	43.644996	-83.840074	Pulverized Fuel	**1,750.0**	**108.4**	**0.9**	**0.9**
Consumers Energy Co	1710	J H Campbell - Boiler 2	West Olive	42.910296	-86.20074	Pulverized Fuel	**2,550.0**	**140.5**	**0.9**	**0.9**
Consumers Energy Co	1720	J C Weadock - Boiler 7	Essexville	43.639927	-83.844712	Pulverized Fuel	**1,050.0**	**63.0**	**0.9**	**0.9**
Consumers Energy Co	1720	J C Weadock - Boiler 8	Essexville	43.639927	-83.844712	Pulverized Fuel	**1,050.0**	**63.0**	**0.9**	**0.9**
Consumers Energy Co	1723	J R Whiting - Boiler 1	Erie	41.792114	-83.44948	Pulverized Fuel	**690.0**	**44.3**	**0.9**	**0.9**
Consumers Energy Co	1723	J R Whiting - Boiler 2	Erie	41.792114	-83.44948	Pulverized Fuel	**690.0**	**44.3**	**0.9**	**0.9**
Consumers Energy Co	1723	J R Whiting - Boiler 3	Erie	41.792114	-83.44948	Pulverized Fuel	**850.0**	**53.9**	**0.9**	**0.9**

Table 40: Coal Fired Power Plant Data - 2

Utility Name	Plant Code	Plant/Boiler Name	Standard Particulate Rate	Max Steam Flow (Thousand Pounds per Hour)	Coal Fire Steam Flow (0.1 Tons per Hour)	Petroleum Fire Steam Flow (0.1 Barresl per Hour)	Gas Fire Steam Flow (0.1 Tons per Hour)	Primary Fuel 1	Primary Fuel 2	Air Flow 100% Load (Cubic Feet per Minute)	Wet Dry Bottom	Fly Ash Reinjection
Consumers Energy Co	1695	B C Cobb - Boiler 4	0.180	1,050.0	62.6	0.0	0.0	BIT	SUB	370,000	D	N
Consumers Energy Co	1695	B C Cobb - Boiler 5	0.180	1,050.0	62.6	0.0	0.0	BIT	SUB	370,000	D	N
Consumers Energy Co	1702	Dan E Karn - Boiler 1	0.160	1,750.0	105.5	0.0	0.0	BIT	SUB	650,000	D	N
Consumers Energy Co	1702	Dan E Karn - Boiler 2	0.160	1,750.0	108.4	0.0	0.0	BIT	SUB	650,000	D	N
Consumers Energy Co	1710	J H Campbell - Boiler 2	0.150	2,550.0	140.5	0.0	0.0	BIT	SUB	850,000	D	N
Consumers Energy Co	1720	J C Weadock - Boiler 7	0.180	1,050.0	63.0	0.0	0.0	BIT	SUB	340,000	D	N
Consumers Energy Co	1720	J C Weadock - Boiler 8	0.180	1,050.0	63.0	0.0	0.0	BIT	SUB	340,000	D	N
Consumers Energy Co	1723	J R Whiting -Boiler 1	0.200	690.0	44.3	0.0	0.0	BIT	SUB	260,000	D	N
Consumers Energy Co	1723	J R Whiting -Boiler 2	0.200	690.0	44.3	0.0	0.0	BIT	SUB	260,000	D	N
Consumers Energy Co	1723	J R Whiting - Boiler 3	0.190	850.0	53.9	0.0	0.0	BIT	SUB	320,000	D	N

Appendix D - Screenshots



Input Data

Instructions: Fill in either the English or the Metric Unit Columns. Metric Units are used in the subsequent calculations sheets. If both colums are filled, Metric units will be used to determine all ouputs.

English Units

Power Plant Data

General	
Power Plant/Boiler Name	J H Campbell - Boiler 2
Proposed Co-Feed	Hybrid Poplar (T & P)
Biomass Integration Configuration	Direct Mixing
Advised Biomass Blending Rate (Energy Basis)	5%
Advised Biomass Blending Rate (Mass Basis) (Non-Preffered Option)	5%

Calculate Biomass Required (Energy Basis)

Calculate Biomass Required (Mass Basis)

= Monte Carlo Defined Cell

= User Required Input

= Editable Cell (Table value default)

= Calculation (Not Editable)

Boiler			Generator		
Boiler Type	Pulverized Fuel		Generator Type	Steam Turbine	
Boiler Designed Feedstock	Bituminous		Generator Nameplate	906	MW
Boiler Nameplate Capacity	2876	MWth	Thermodynamic Eff.	35%	
Capacity Factor	90%				
Efficency (100% Capacity)	90%				
Efficency (50% Capacity)	90%		Renewable Electricity Sale Price	$ 0.100	$/kwh
Design Firing Rate	14.05	ton/coal/hr	Purchased Feedstock Cost	#N/A	$/dry ton
Average Firing Rate	11.24	ton/coal/hr	Purchased Coal Price	50	$/dry ton
Max Steam Flow	1275	ton/hr			
Waste Heat Input		MM BTU/hr			

Coal Feedstock			Biomass Co-Feedstock		
Coal Type	Bituminous		Biomass Type	Hybrid Poplar (T & P)	
C	83%	%dm	C	53.0%	%dm
H	5%	%dm	H	5.5%	%dm
O	10%	%dm	O	37.9%	%dm
N	1%	%dm	N	0.5%	%dm
S	1%	%dm	S	0.0%	%dm
Fixed Carbon	55%	%dm	Fixed Carbon	24.7%	%dm
Volitile Matter	36%	%dm	Volitile Matter	72.2%	%dm
Ash	5%	%dm	Ash	3.1%	%dm
Moisture	5%	d.b.	Moisture	3.0%	d.b.
HHV (ar)	14,530	Btu/lb	HHV (ar)	9,038	Btu/lb
LHV (ar)	14,136	Btu/lb	LHV (ar)	8,767	Btu/lb
Blend Composition (Energy)	95%		Blend Composition (Energy)	5.0%	
Blend Composition (Mass)	92%		Blend Composition	8%	

MonteCarlo | Input-UI | Summary Report | CAPEX & OMEX | Transport M&E Balance | Depot M&E Balance | Plant M&E Balance | Pro Forma-Power Plant | Financing

Figure 33: User Input Screen Capture

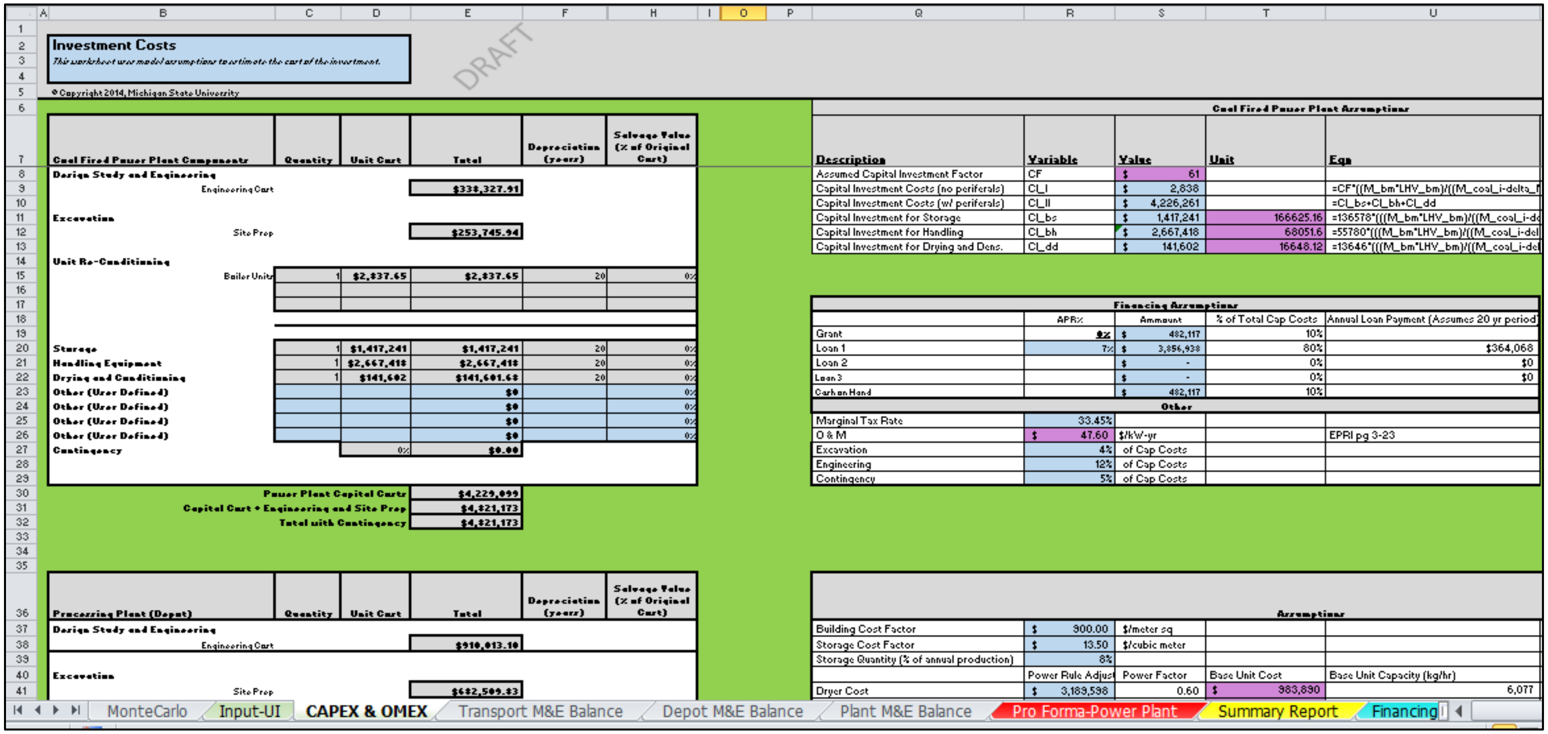
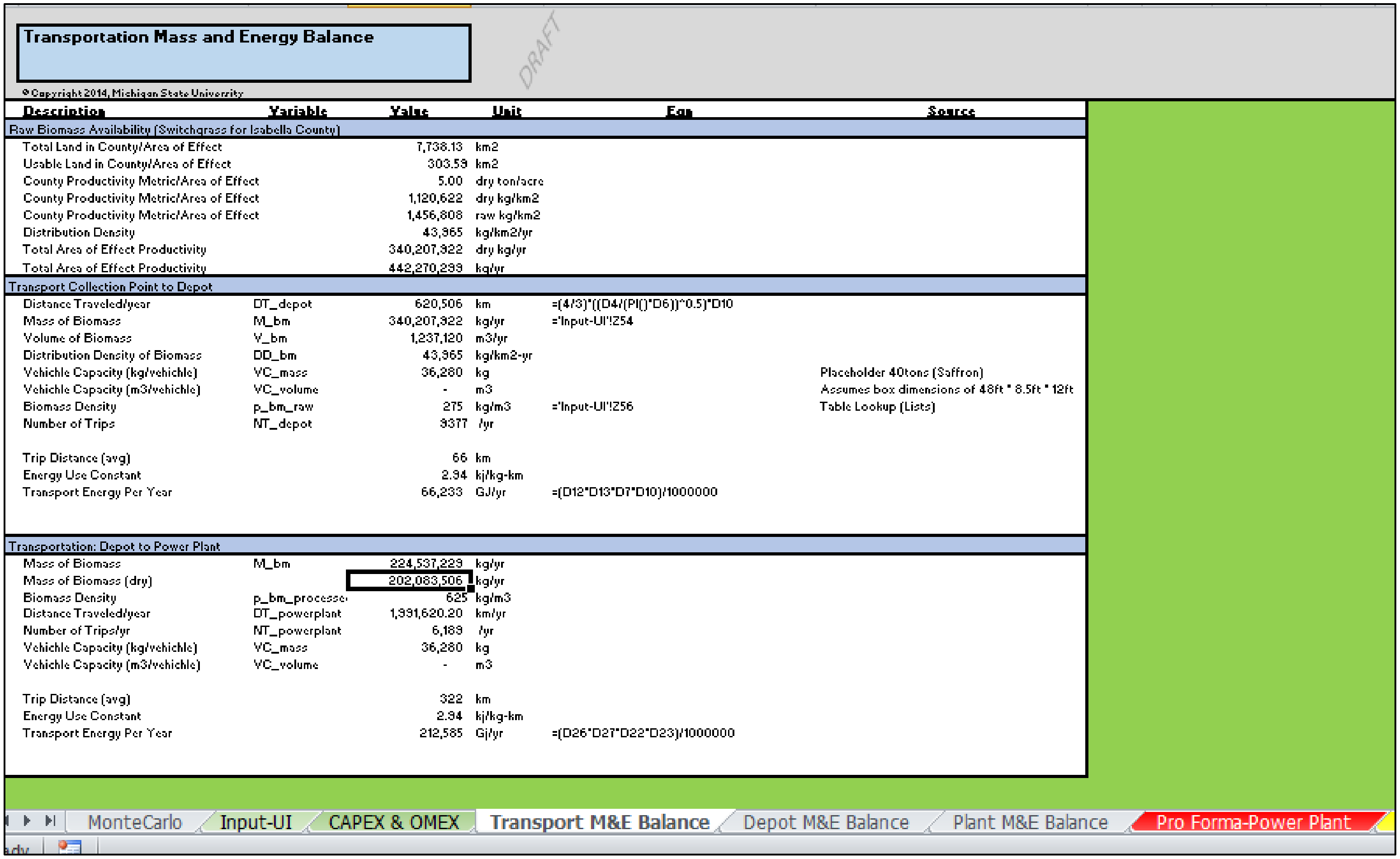


Figure 34: Investment Cost Screen Capture



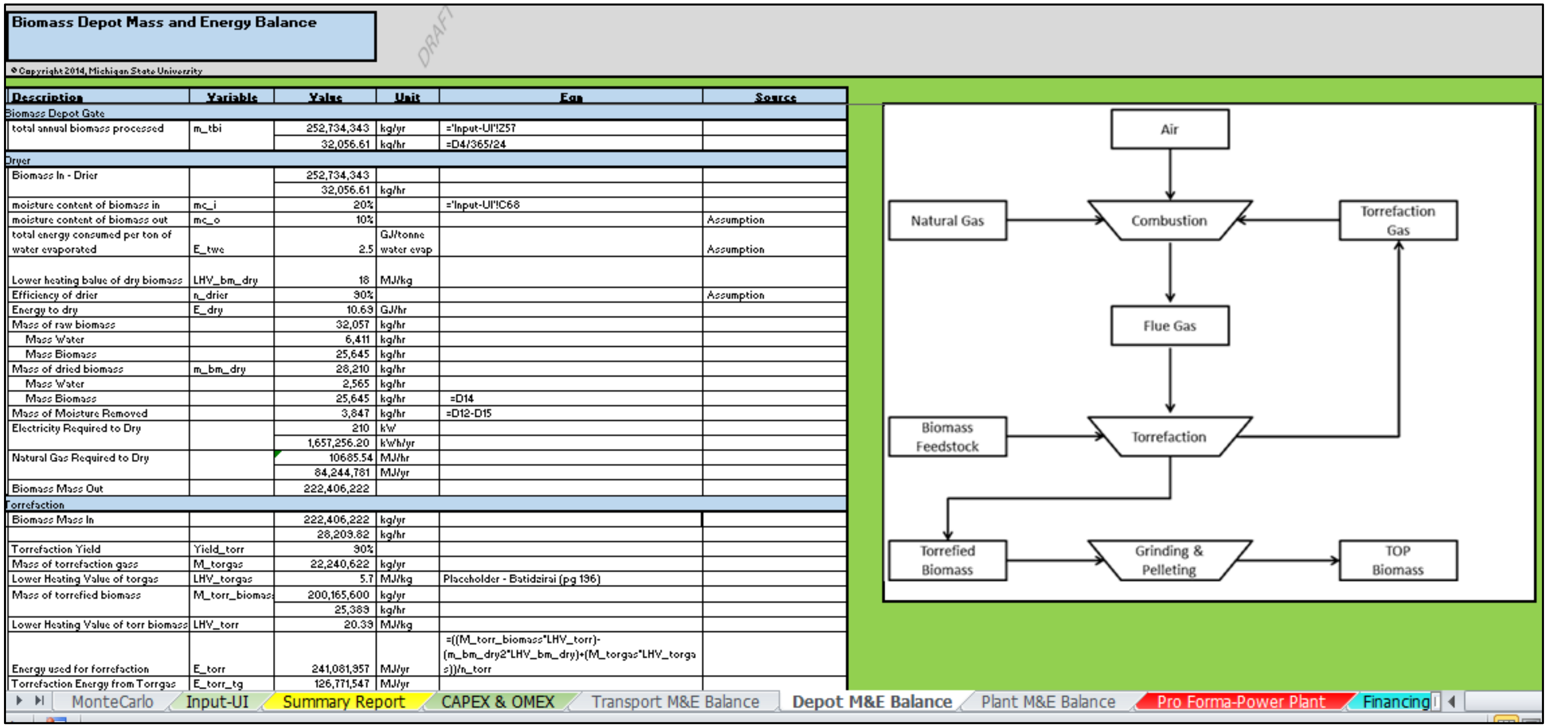
Transportation Mass and Energy Balance

DRAFT

© Copyright 2014, Michigan State University

Description	Variable	Value	Unit	Eqn	Source
Raw Biomass Availability (Switchgrass for Isabella County)					
Total Land in County/Area of Effect		7,738.13	km2		
Usable Land in County/Area of Effect		303.59	km2		
County Productivity Metric/Area of Effect		5.00	dry ton/acre		
County Productivity Metric/Area of Effect		1,120,622	dry kg/km2		
County Productivity Metric/Area of Effect		1,456,808	raw kg/km2		
Distribution Density		43,965	kg/km2/yr		
Total Area of Effect Productivity		340,207,922	dry kg/yr		
Total Area of Effect Productivity		442,270,299	kg/yr		
Transport Collection Point to Depot					
Distance Traveled/year	DT_depot	620,506	km	=(4/3)*((D4/(PI()*D6))^0.5)*D10	
Mass of Biomass	M_bm	340,207,922	kg/yr	='Input-UI'!Z54	
Volume of Biomass	V_bm	1,237,120	m3/yr		
Distribution Density of Biomass	DD_bm	43,965	kg/km2-yr		
Vehichle Capacity (kg/vehichle)	VC_mass	36,280	kg		Placeholder 40tons (Saffron)
Vehichle Capacity (m3/vehichle)	VC_volume	-	m3		Assumes box dimensions of 48ft * 8.5ft * 12ft
Biomass Density	p_bm_raw	275	kg/m3	='Input-UI'!Z56	Table Lookup (Lists)
Number of Trips	NT_depot	9377	/yr		
Trip Distance (avg)		66	km		
Energy Use Constant		2.94	kj/kg-km		
Transport Energy Per Year		66,233	GJ/yr	=(D12*D13*D7*D10)/1000000	
Transportation: Depot to Power Plant					
Mass of Biomass	M_bm	224,537,229	kg/yr		
Mass of Biomass (dry)		202,083,506	kg/yr		
Biomass Density	p_bm_processe	625	kg/m3		
Distance Traveled/year	DT_powerplant	1,991,620.20	km/yr		
Number of Trips/yr	NT_powerplant	6,169	/yr		
Vehichle Capacity (kg/vehichle)	VC_mass	36,280	kg		
Vehichle Capacity (m3/vehichle)	VC_volume	-	m3		
Trip Distance (avg)		322	km		
Energy Use Constant		2.94	kj/kg-km		
Transport Energy Per Year		212,585	Gj/yr	=(D26*D27*D22*D23)/1000000	

Figure 35: Transportation Mass and Energy Balance Screenshot

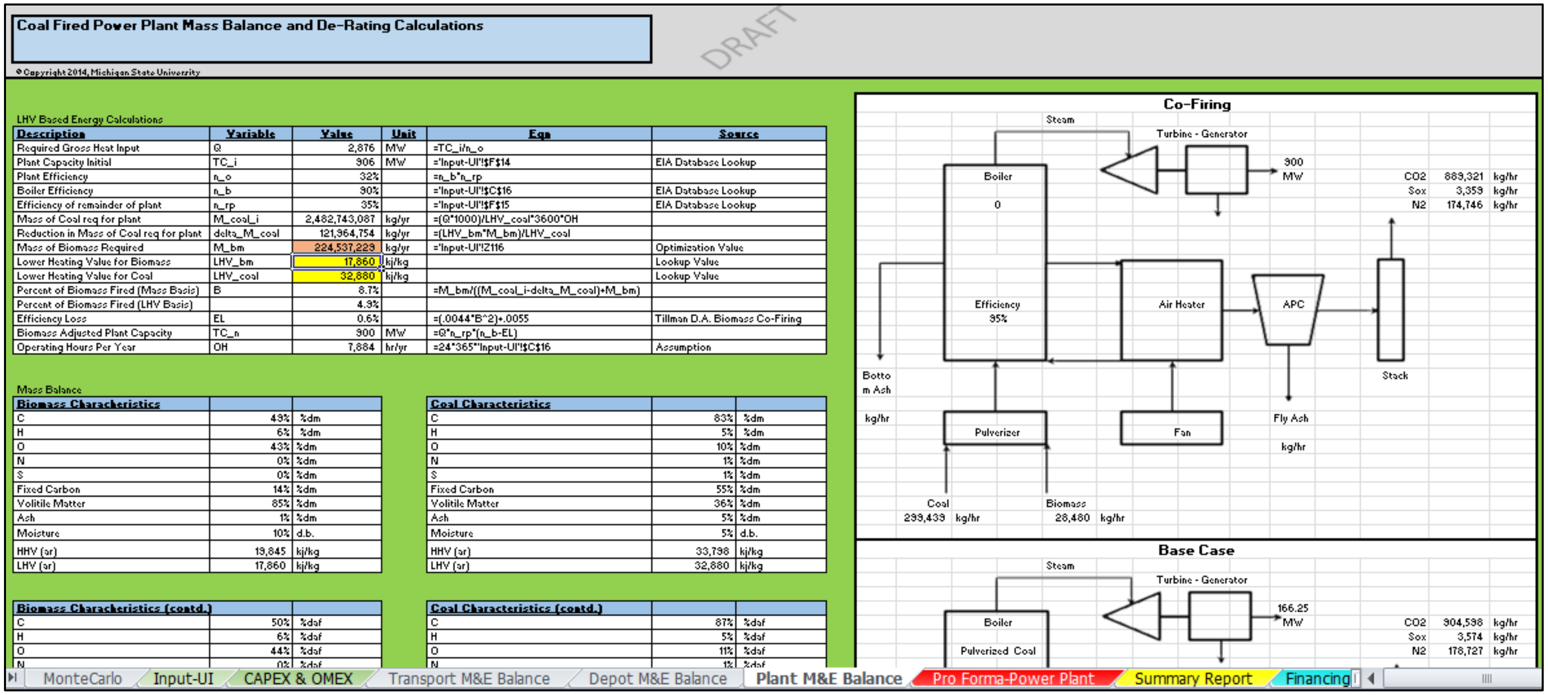


Biomass Depot Mass and Energy Balance

© Copyright 2014, Michigan State University

Description	Variable	Value	Unit	Eqn	Source
Biomass Depot Gate					
total annual biomass processed	m_tbi	252,734,343	kg/yr	='Input-UI'!Z57	
		32,056.61	kg/hr	=D4/365/24	
Dryer					
Biomass In - Drier		252,734,343			
		32,056.61	kg/hr		
moisture content of biomass in	mc_i	20%		='Input-UI'!C68	
moisture content of biomass out	mc_o	10%			Assumption
total energy consumed per ton of water evaporated	E_twe	2.5	GJ/tonne water evap		Assumption
Lower heating balue of dry biomass	LHV_bm_dry	18	MJ/kg		
Efficiency of drier	n_drier	90%			Assumption
Energy to dry	E_dry	10.69	GJ/hr		
Mass of raw biomass		32,057	kg/hr		
Mass Water		6,411	kg/hr		
Mass Biomass		25,645	kg/hr		
Mass of dried biomass	m_bm_dry	28,210	kg/hr		
Mass Water		2,565	kg/hr		
Mass Biomass		25,645	kg/hr	=D14	
Mass of Moisture Removed		3,847	kg/hr	=D12-D15	
Electricity Required to Dry		210	kW		
		1,657,256.20	kWh/yr		
Natural Gas Required to Dry		10685.54	MJ/hr		
		84,244,781	MJ/yr		
Biomass Mass Out		222,406,222			
Torrefaction					
Biomass Mass In		222,406,222	kg/yr		
		28,209.82	kg/hr		
Torrefaction Yield	Yield_torr	90%			
Mass of torrefaction gass	M_torgas	22,240,622	kg/yr		
Lower Heating Value of torgas	LHV_torgas	5.7	MJ/kg	Placeholder - Batidzirai (pg 196)	
Mass of torrefied biomass	M_torr_biomass	200,165,600	kg/yr		
		25,389	kg/hr		
Lower Heating Value of torr biomass	LHV_torr	20.39	MJ/kg		
Energy used for forrefaction	E_torr	241,081,957	MJ/yr	=((M_torr_biomass*LHV_torr)-(m_bm_dry2*LHV_bm_dry)+(M_torgas*LHV_torgas))/n_torr	
Torrefaction Energy from Torrgas	E_torr_tg	126,771,547	MJ/yr		

Figure 36: Biomass Depot Mass and Energy Balance Screenshot



Coal Fired Power Plant Mass Balance and De-Rating Calculations

DRAFT

LHV Based Energy Calculations

Description	Variable	Value	Unit	Eqn	Source
Required Gross Heat Input	Q	2,876	MW	=TC_i/n_o	
Plant Capacity Initial	TC_i	906	MW	='Input-UI'!$F$14	EIA Database Lookup
Plant Efficiency	n_o	32%		=n_b*n_rp	
Boiler Efficiency	n_b	90%		='Input-UI'!$C$16	EIA Database Lookup
Efficiency of remainder of plant	n_rp	35%		='Input-UI'!$F$15	EIA Database Lookup
Mass of Coal req for plant	M_coal_i	2,482,743,087	kg/yr	=(Q*1000)/LHV_coal*3600*OH	
Reduction in Mass of Coal req for plant	delta_M_coal	121,964,754	kg/yr	=(LHV_bm*M_bm)/LHV_coal	
Mass of Biomass Required	M_bm	224,537,229	kg/yr	='Input-UI'!Z116	Optimization Value
Lower Heating Value for Biomass	LHV_bm	17,860	kj/kg		Lookup Value
Lower Heating Value for Coal	LHV_coal	32,880	kj/kg		Lookup Value
Percent of Biomass Fired (Mass Basis)	B	8.7%		=M_bm/((M_coal_i-delta_M_coal)+M_bm)	
Percent of Biomass Fired (LHV Basis)		4.9%			
Efficiency Loss	EL	0.6%		=(.0044*B^2)+.0055	Tillman D.A. Biomass Co-Firing
Biomass Adjusted Plant Capacity	TC_n	900	MW	=Q*n_rp*(n_b-EL)	
Operating Hours Per Year	OH	7,884	hr/yr	=24*365*'Input-UI'!$C$16	Assumption

Mass Balance

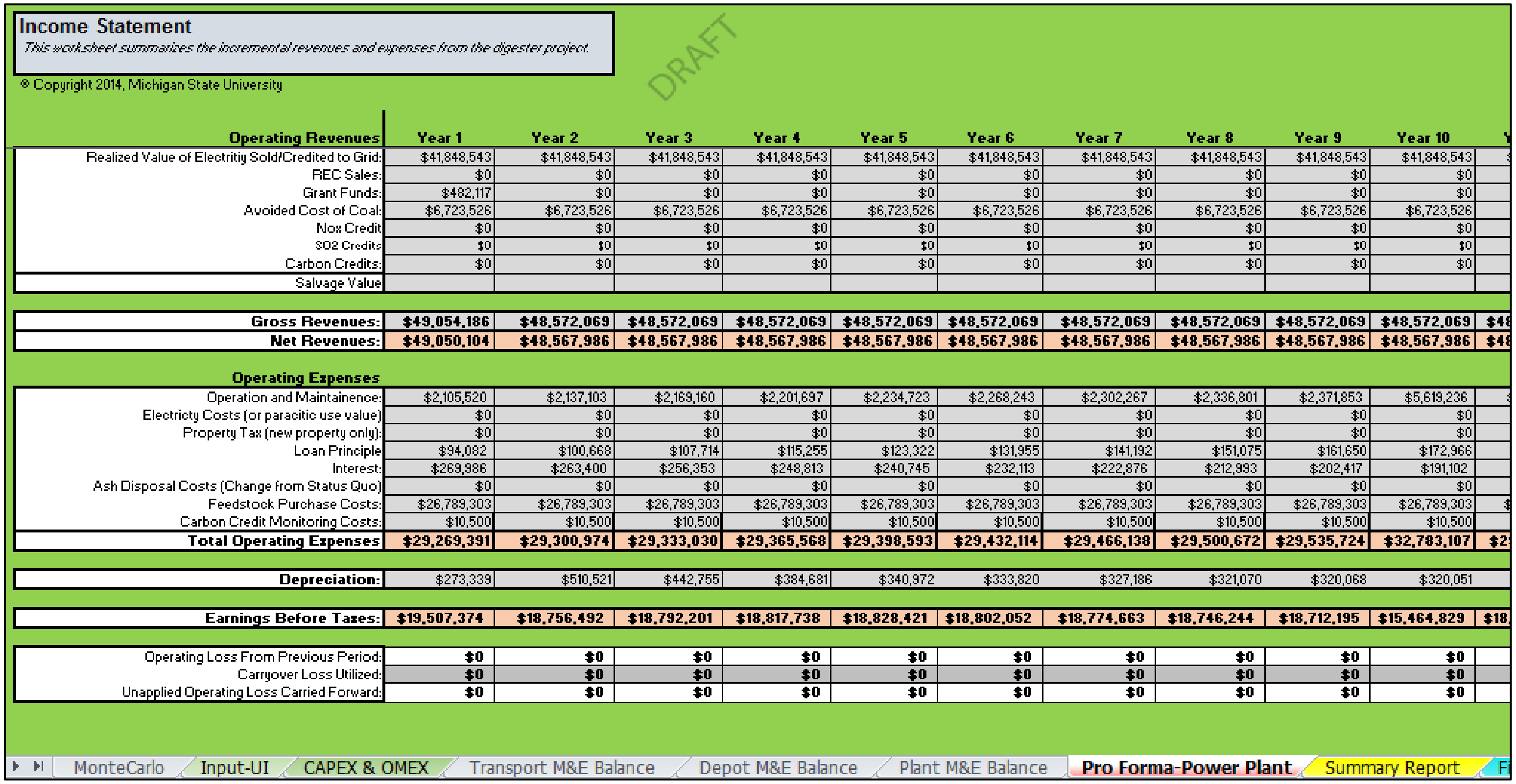
Biomass Characteristics		
C	49%	%dm
H	6%	%dm
O	43%	%dm
N	0%	%dm
S	0%	%dm
Fixed Carbon	14%	%dm
Volitile Matter	85%	%dm
Ash	1%	%dm
Moisture	10%	d.b.
HHV (ar)	19,845	kj/kg
LHV (ar)	17,860	kj/kg

Coal Characteristics		
C	83%	%dm
H	5%	%dm
O	10%	%dm
N	1%	%dm
S	1%	%dm
Fixed Carbon	55%	%dm
Volitile Matter	36%	%dm
Ash	5%	%dm
Moisture	5%	d.b.
HHV (ar)	33,798	kj/kg
LHV (ar)	32,880	kj/kg

Biomass Characteristics (contd.)		
C	50%	%daf
H	6%	%daf
O	44%	%daf
N	0%	%daf

Coal Characteristics (contd.)		
C	87%	%daf
H	5%	%daf
O	11%	%daf
N	1%	%daf

Figure 37: Co-Firing Mass and Energy Balance Screenshot



Income Statement

This worksheet summarizes the incremental revenues and expenses from the digester project.

® Copyright 2014, Michigan State University

DRAFT

Operating Revenues	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Realized Value of Electritiy Sold/Credited to Grid:	$41,848,543	$41,848,543	$41,848,543	$41,848,543	$41,848,543	$41,848,543	$41,848,543	$41,848,543	$41,848,543	$41,848,543
REC Sales:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Grant Funds:	$482,117	$0	$0	$0	$0	$0	$0	$0	$0	$0
Avoided Cost of Coal:	$6,723,526	$6,723,526	$6,723,526	$6,723,526	$6,723,526	$6,723,526	$6,723,526	$6,723,526	$6,723,526	$6,723,526
Nox Credit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SO2 Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Carbon Credits:	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Salvage Value										
Gross Revenues:	**$49,054,186**	**$48,572,069**	**$48,572,069**	**$48,572,069**	**$48,572,069**	**$48,572,069**	**$48,572,069**	**$48,572,069**	**$48,572,069**	**$48,572,069**
Net Revenues:	**$49,050,104**	**$48,567,986**	**$48,567,986**	**$48,567,986**	**$48,567,986**	**$48,567,986**	**$48,567,986**	**$48,567,986**	**$48,567,986**	**$48,567,986**
Operating Expenses										
Operation and Maintainence:	$2,105,520	$2,137,103	$2,169,160	$2,201,697	$2,234,723	$2,268,243	$2,302,267	$2,336,801	$2,371,853	$5,619,236
Electricty Costs (or paracitic use value)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Property Tax (new property only):	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Loan Principle	$94,082	$100,668	$107,714	$115,255	$123,322	$131,955	$141,192	$151,075	$161,650	$172,966
Interest:	$269,986	$263,400	$256,353	$248,813	$240,745	$232,113	$222,876	$212,993	$202,417	$191,102
Ash Disposal Costs (Change from Status Quo)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Feedstock Purchase Costs:	$26,789,303	$26,789,303	$26,789,303	$26,789,303	$26,789,303	$26,789,303	$26,789,303	$26,789,303	$26,789,303	$26,789,303
Carbon Credit Monitoring Costs:	$10,500	$10,500	$10,500	$10,500	$10,500	$10,500	$10,500	$10,500	$10,500	$10,500
Total Operating Expenses	**$29,269,391**	**$29,300,974**	**$29,333,030**	**$29,365,568**	**$29,398,593**	**$29,432,114**	**$29,466,138**	**$29,500,672**	**$29,535,724**	**$32,783,107**
Depreciation:	$273,339	$510,521	$442,755	$384,681	$340,972	$333,820	$327,186	$321,070	$320,068	$320,051
Earnings Before Taxes:	**$19,507,374**	**$18,756,492**	**$18,792,201**	**$18,817,738**	**$18,828,421**	**$18,802,052**	**$18,774,663**	**$18,746,244**	**$18,712,195**	**$15,464,829**
Operating Loss From Previous Period:	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Carryover Loss Utilized:	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Unapplied Operating Loss Carried Forward:	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**

MonteCarlo | Input-UI | CAPEX & OMEX | Transport M&E Balance | Depot M&E Balance | Plant M&E Balance | Pro Forma-Power Plant | Summary Report

Figure 38: Pro-Forma Screenshot

BIBLIOGRAPHY

BIBLIOGRAPHY

Anon. (2008). Estimated Costs for Production Storage and Transportation of Switchgrass. In I. S. Extension (Ed.), *Ag Decision Maker* (pp. 8). www.estension.iastate.edu/agdm: Iowa State University Extension.

Anon. (2010). FreightTransportation Values (Trucks and Trains). In P. C. o. G. C. Change (Ed.), *Climate Tech Book* (pp. 11). Pew Center on Global Climate Change.

Basu, P. (2013). Biomass gasification, pyrolysis, and torrefaction: practical design and theory. Boston; Amsterdam: Elsevier/AP.

Batidzirai, B., Mignot, A., Schakel, W., Junginger, H., & Faaij, A. (2013). Biomass torrefaction technology: Techno-economic status and future prospects. *ENERGY, 62*, 196-214.

Bergman, P. C. A. (2005). Torrefaction for biomass co-firing in existing coal-fired power stations. *Biocoal*.

Binkley, D. (2010). The economics of an anaerobic digestion under different electricity purchase agreements: Michigan State University.

Binkley, D., Safferman, S., Dong, Y., Smith, J. S., Tekesin, O., & Vincent, A. (2015). Anaerobic Digestion Development Iterative Tool to Evaluate Blended Feedstocks. *Water research, Under Review*.

Bologa, A., Paur, H.-R., Seifert, H., Woletz, K., & Ulbricht, T. (2012). Fine particle generation, evolution and control by small biomass combustion. *Management of Environmental Quality: An International Journal, 23*(1), 36-55. doi: 10.1108/14777831211191584

Caputo, A. C., Palumbo, M., Pelagagge, P. M., & Scacchia, F. (2005). Economics of biomass energy utilization in combustion and gasification plants: effects of logistic variables. *Biomass and Bioenergy, 28*(1), 35-51.

Centre, I. C. C. (2005). Fuels for Biomass Co-Firing.

Channiwala, S., & Parikh, P. (2002). A unified correlation for estimating HHV of solid, liquid and gaseous fuels. *Fuel, 81*(8), 1051-1063.

De, S., & Assadi, M. (2009). Impact of cofiring biomass with coal in power plants–A techno-economic assessment. *Biomass and Bioenergy, 33*(2), 283-293.

Demirbas, A. (2005). Potential applications of renewable energy sources, biomass combustion problems in boiler power systems and combustion related environmental issues. *Progress in Energy and Combustion Science, 31*(2), 171-192. doi: http://dx.doi.org/10.1016/j.pecs.2005.02.002

Dillen, S. Y., Djomo, S. N., Al Afas, N., Vanbeveren, S., & Ceulemans, R. (2013). Biomass yield and energy balance of a short-rotation poplar coppice with multiple clones on degraded land during 16 years. *Biomass and Bioenergy, 56*, 157-165. doi: http://dx.doi.org/10.1016/j.biombioe.2013.04.019

Dunajski, L., Kruk, W., & Nowak, W. (2013). Preventing circulating fluidised bed agglomeration and deposition during biomass combustion. *Archives of Thermodynamics, 34*(1), 3. doi: 10.2478/aoter-2013-0001

ECN. (2015). *Phyllis2 - Database for Biomass and Waste*. Retrieved from: https://www.ecn.nl/phyllis2

EIA. (2012). Form EIA-860 detailed data Available from USA Energy Information Administration Retrieved 7/20/2014, from US Energy Information Administration http://www.eia.gov/electricity/data/eia860/

EIA. (2015, 4/14/2015). Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015. *Annual Energy Outlook 2015.* Retrieved 6/20/2015, 2015, from http://www.eia.gov/forecasts/aeo/electricity_generation.cfm

EPA. (2007). Biomass Combined Heat and Power Catalog of Technologies. Retrieved 11/25/2014, 2014, from http://www.epa.gov/chp/documents/biomass_chp_catalog.pdf

FEMP. (2004). *Biomass Cofiring in Coal-Fired Boilers*. (DOE/EE-0288). US Department of Energy Retrieved from http://www.nrel.gov/docs/fy04osti/33811.pdf.

Gebreegziabher, T., Oyedun, A. O., & Hui, C. W. (2013). Optimum biomass drying for combustion - A modeling approach. *ENERGY, 53*, 67-73. doi: 10.1016/j.energy.2013.03.004

Gil, M. V., Oulego, P., Casal, M. D., Pevida, C., Pis, J. J., & Rubiera, F. (2010). Mechanical durability and combustion characteristics of pellets from biomass blends. *Bioresource technology, 101*(22), 8859-8867. doi: 10.1016/j.biortech.2010.06.062

Hartmann, D., & Kaltschmitt, M. (1999). Electricity generation from solid biomass via co-combustion with coal - Energy and emission balances from a German case study. *BIOMASS & BIOENERGY, 16*(6), 397-406.

Jenkins, B. M., Baxter, L. L., Miles Jr, T. R., & Miles, T. R. (1998). Combustion properties of biomass. *Fuel Processing Technology, 54*(1–3), 17-46. doi: http://dx.doi.org/10.1016/S0378-3820(97)00059-3

Joshi, Y., de Vries, H., Woudstra, T., & de Jong, W. (2014). Torrefaction: Unit Operation Modelling and Process Simulation. *Applied Thermal Engineering*. doi: 10.1016/j.applthermaleng.2013.12.059

Kinney, S.-A. (2012). Wood Bioenergy and Natural Gas Prices. *Forest 2 Market.* Retrieved 2-12-15, 2015, from http://www.forest2market.com/blog/Wood-Bioenergy-and-Natural-Gas-Prices

Lempp, P. (2013). Biomass Co-Firing: Technology Brief. from http://www.irena.org/DocumentDownloads/Publications/IRENA-ETSAP%20Tech%20Brief%20E21%20Biomass%20Co-firing.pdf

Maciejewska, A., Veringa, H., Sanders, J., & Peteves, S. (2006). Co-firing of biomass with coal: constraints and role of biomass pre-treatment. *DG JRC Institute for Energy*.

Murphy, D. J., & Hall, C. A. (2010). Year in review—EROI or energy return on (energy) invested. *Annals of the New York Academy of Sciences, 1185*(1), 102-118.

NASS. (2012). *Farms, Land in Farms, Value of Land and Buildings, and Land Use: 2012 and 2017*. Retrieved from: http://www.agcensus.usda.gov/Publications/2012/Full_Report/Volume_1,_Chapter_2_County_Level/Michigan/st26_2_008_008.pdf

Nussbaumer, T. (2003). Combustion and co-combustion of biomass: fundamentals, technologies, and primary measures for emission reduction. *Energy & Fuels, 17*(6), 1510-1521.

O'Donnel, B., Hickner, M., & Barna, B. (2002). Economic Risk Analysis Using Analytical and Monte Carlo Techniques. Retrieved 6/15/2015, 2015, from http://ufdcimages.uflib.ufl.edu/AA/00/00/03/83/00154/AA00000383_00154_00094.pdf

Park, J., Meng, J. J., Lim, K. H., Rojas, O. J., & Park, S. (2013). Transformation of lignocellulosic biomass during torrefaction. *Journal of Analytical and Applied Pyrolysis, 100*, 199-206. doi: 10.1016/j.jaap.2012.12.024

Pennington, D. (2015). [MSU Extension Field Plot Summaries].

Sargent, R. G. (2011). *Verification and Validation of Simulation Models.* Paper presented at the Winter Simulation Conference.

Srivastava, A., Abbas, D., Saffron, C., & Pan, F. (2011). Economic Analysis of Woody Biomass Supply Chain Logistics for Biofuel Produciton in Michigan (pp. 60): Department of Biosystems and Agricultural Engineering - Michigan State University.

Svanberg, M., Olofsson, I., Flodén, J., & Nordin, A. (2013). Analysing biomass torrefaction supply chain costs. *Bioresource technology, 142*, 287-296. doi: 10.1016/j.biortech.2013.05.048

Tillman, D. A. (1997). Biomass Cofiring Guidelines (pp. 61): EPRI.

Tillman, D. A. (2000). Biomass cofiring: the technology, the experience, the combustion consequences. *Biomass and Bioenergy, 19*(6), 365-384. doi: 10.1016/S0961-9534(00)00049-0

Van Loo, S., & Koppejan, J. (2008). *The handbook of biomass combustion and co-firing*. Sterling, VA; London: Earthscan.

Werther, J., & Ogada, T. (1999). Sewage sludge combustion. *Progress in Energy and Combustion Science, 25*(1), 55-116. doi: 10.1016/S0360-1285(98)00020-3

Weststeyn A., E. E. B. (2004). First Torrefied Wood Successfully Co-Fired.

Williams, A., Pourkashanian, M., & Jones, J. M. (2001). Combustion of pulverised coal and biomass. *Progress in Energy and Combustion Science, 27*(6), 587-610. doi: 10.1016/S0360-1285(01)00004-1