Plant Power: The Cost of Using Biomass for Power Generation and Potential for Decreased Greenhouse Gas Emissions

By
Amanda Dulcinea Cuellar

B.S. Chemical Engineering, B.A. Plan II Honors
The University of Texas at Austin, 2009

SUBMITTED TO THE ENGINEERING SYSTEMS DIVISION IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE DEGREE OF

MASTER OF SCIENCE IN TECHNOLOGY AND POLICY

AT THE
MASSACHUSETTS INSTITUTE OF TECHNOLOGY
June 2012

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Signature of Author: ____
Technology and Policy Program, Engineering Systems Division
May 11, 2012

Certified by: ____
Howard J. Herzog
Senior Research Engineer, MIT Energy Initiative
Thesis Supervisor

Accepted by:____
Joel P. Clark
Professor of Materials Systems and Engineering Systems
Acting Director, Technology & Policy Program

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Submitted to the Engineering Systems Division on May 11, 2012 in partial fulfillment of the requirements for the degree of Master of Science in Technology and Policy

Abstract

To date, biomass has not been a large source of power generation in the United States, despite the potential for greenhouse gas (GHG) benefits from displacing coal with carbon neutral biomass. In this thesis, the fuel cycle GHG emissions of power generation from both dedicated biomass power plants and coal power plants with biomass co-firing are quantified using a model based on Argonne National Laboratory's GREET model. The potential for negative emissions by adding a carbon capture and sequestration unit to the power plant is also analyzed. Finally an economic analysis of retrofitting existing coal plants to fire or co-fire biomass is conducted. If no land use change emissions are incurred during biomass production, co-firing as little as 5% biomass with coal can lead to a decrease in GHG emissions compared to coal alone. When a CCS unit is added to the modeled power plants, those co-firing 15% or higher biomass have negative emissions; essentially the plants capture CO_2 from the air. Nonetheless a carbon price of at least \$52 per ton CO_2 equivalent is needed to make co-firing plants economically competitive with coal plants and a price of \$71 per ton CO_2 equivalent is needed for co-firing plants with CCS.

A policy analysis concludes that the lack of political support for biomass power generation stems from the lack of benefits directly related to current policy goals (e.g., energy security), high costs, and the perception that biomass firing with coal is not a 'clean' energy source. Nonetheless, this thesis demonstrates that the potential exists for immediate greenhouse gas emissions benefits from biomass power generation and, through technology development, for a future in which biomass is less costly to convert to power. In order to capture the benefits available today from biomass and to accelerate the development of preferred biomass feedstocks, policy measures are necessary to incentivize biomass power generation. Existing state policies and proposed rules at the federal level are inconsistent and do not provide the necessary incentives for biomass power systems. Two policy measures are proposed: first, a nationwide sustainable biomass certification system and second, policy measures that promote use of biomass that meets the certification criteria. These policies will result in both a supply of sustainable biomass and an increased demand for biomass power generation.

Thesis Supervisor: Howard J. Herzog

Title: Senior Research Engineer

Acknowledgements

Writing this thesis has been a significant endeavor that I could not have completed without the support of Howard Herzog, my advisor and his assistant, Mary Gallagher. During my time at MIT Howard has taught me to be a better researcher and challenged me to always think critically about my work. I would also like to acknowledge the financial support of the MIT Carbon Sequestration Initiative, National Science Foundation Graduate Research Fellowship, and the Lemelson and de Neufville scholarships.

On a more personal note I would like to thank my parents, Jesús and Yolanda Cuéllar for their constant support and for teaching me the work ethic that has allowed me to reach my academic goals. My sisters, Victoria and Julieta, also earn my thanks for the moral support and company they have provided during my time at MIT. I would also like to thank my husband, Joseph Harbolovic. He has been my companion throughout the long hours of writing and perfecting this thesis and his support has been invaluable during my studies at MIT.

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Chapter 1. Motivation and Objectives

With growing concern about global climate change and the environmental effects of energy generation, one energy source that has come to the forefront as an alternative is biomass. Biomass has achieved prominence as an alternative energy source because it is a renewable resource and because it is considered a carbon neutral energy source. Through photosynthesis plants capture carbon dioxide from the atmosphere and store it in biological molecules. If biomass is then combusted for power generation, these molecules break down and release carbon dioxide back into the atmosphere. When biomass grows back after being harvested for power generation the plant recaptures carbon dioxide from the atmosphere causing the entire process to have net zero emissions. Although many biomass energy initiatives are focusing on converting biological molecules into liquid fuel for transport, biomass can also be converted to electric power. Converting biomass to power has the benefit of using a carbon neutral fuel to produce power, low capital costs if biomass is converted in existing power plants and can make use of varied biomass sources including cellulosic feedstocks that avoid the food versus fuel conflict. Although biomass is considered a carbon neutral energy source, the fossil fuel inputs required to cultivate, transport, process, and handle biomass as well as greenhouse gas emissions from other sources throughout these steps must be incorporated into the carbon balance of biobased fuels.

This thesis relies on original analysis to quantify and understand the fuel cycle greenhouse gas (GHG) and energy balance of biomass to power with and without carbon capture and sequestration (CCS). In addition this thesis analyzes the land limits to widespread biomass to power implementation and assesses the effects of these limitations on potential biomass to power GHG benefits. Finally this thesis quantifies the economic barriers to biomass for power production and identifies policies that could lower or remove these barriers.

1.1 Motivation

In 2009 fossil fuel combustion for electricity generation in the United States contributed 37% of all GHG emissions that year. GHG emissions from coal combustion for power generation accounted for 81% of the electricity emissions from fossil fuels. (USEPA, 2011)Therefore decreasing emissions from coal generated power would contribute significantly to any effort to decrease the US contribution to global climate change. Because biomass is considered a carbon neutral feedstock, co-firing biomass and coal has the potential to decrease GHG emissions from coal power generation. There is also a theoretical potential for negative emissions if a carbon capture and sequestration (CCS) unit is added to a biomass power plant. Because a portion of the carbon dioxide sequestered by the CCS unit was originally captured by the plant from the atmosphere, this scheme could lead to negative emissions as long as other emissions throughout the fuel cycle are not greater than the carbon sequestered.

Generating renewable power from biomass and coal co-firing has many benefits aside from the decrease in GHG emissions. In contrast to biofuel production, the combustion of biomass to generate power can use a variety of feedstocks and biological molecules including herbaceous biomass and cellulosic feedstocks. The variety of feedstocks that can be used for power generation means that with careful selection of biomass fuel and its method of cultivation, biomass to power can avoid the food versus fuel debate, which has become a serious concern for biofuels as global food prices trend upwards (Alex Evans, 2011).

Biomass can be co-fired up to a ratio of 5% in an existing coal plant with no retrofits (Bain, Overend, & Craig, 1998). Therefore biomass power generation can occur with minimal capital costs if it is burned in existing coal facilities. At higher co-firing ratios an existing coal plant would require retrofits to facilitate the feeding and storage of biomass fuel. (Bain et al., 1998) Because biomass can be co-fired in a coal facility typically used for baseload generation, biomass is a non-intermittent source of renewable electricity and avoids many of the strains placed on power systems by other renewable energy sources such as wind and solar.

Another benefit of biomass to power through combustion is that this technology has been used extensively around the world and can be rapidly deployed. The IEA Database of Biomass Cofiring initiatives lists over 200 power plants worldwide that have co-fired or fired solely biomass fuels (IEA, 2009).

Biomass is not being widely used for power generation in the US currently and is more widely converted to biofuels. In 2010 biofuel consumption (including ethanol and biodiesel) totaled 1140 trillion BTU whereas biomass generated electricity consumption totaled 440 trillion BTU. (EIA, 2011a) Although biofuels have far more complicated conversion processes than biomass to power that result in a less favorable energy balance, the added value of these fuels is much higher than for biomass to power conversion. Since coal is far cheaper than biomass per unit of energy, the primary competitive advantage of biomass fuel is its potential to decrease GHG emissions.

1.2 Objective

For the conversion of biomass to power, quantify what benefits (if any) are possible, identify the main obstacles to its implementation, and recommend policies to overcome these barriers.

1.3 Approach

In this thesis, the following approach is taken:

1. Construct a model of the fuel cycle for biomass and coal to calculate the net carbon emissions from biomass to power at different co-firing rates with coal by adapting the existing GREET model

2. Use this model to calculate the energy required throughout the biomass to power fuel cycle to determine if the entire system has a positive energy balance

3. Simulate the addition of a carbon capture and sequestration unit to a biomass to power plant co-firing coal to determine the potential for negative emissions

4. Quantify the land area required to grow the biomass to reach given negative emission targets with a biomass power plant equipped with a CCS unit

5. Create an economic model of the biomass power plant to determine what the economic barriers are to biomass to power in the United States

6. Review existing renewable energy policies and make policy recommendations that will incentivize the conversion of biomass to power in coal plants.

Chapter 2. State of Technology Overview

Biomass refers to any biologically sourced feedstock that ultimately derives from a plant source. Through photosynthesis, green plants convert solar energy to chemical energy stored in the bonds of biological molecules. This energy is released through various chemical pathways and can be used for everyday plant functions. Because plants originally sequester the carbon in biomass from the atmosphere, biomass is considered a carbon neutral energy source. (Y. Zhang, McKechnie, et al., 2010) Chemical energy in the biological molecules of plants can be released through combustion or other thermochemical processes for use in power generation. Biological processing to convert biomass to liquid fuels is another, more common, route for converting biomass to energy. Nonetheless, this thesis will focus on the biomass to power route through combustion in a boiler. Biomass combustion for power generation is a mature technology that has the potential to decrease GHG emissions from electricity generation in the near term. In addition, if a carbon capture and sequestration unit is added to a biomass power plant, then part of the carbon dioxide captured from the air by the biomass will be sequestered and possibly lead to negative carbon emissions.

Although biomass has the potential to contribute significantly to low carbon power generation, implementation of the technology has not been widespread. Worldwide dedicated firing and co-firing of biomass has been practiced at over 200 power plants with capacities as high as 4000 MW (operated by Drax Power in North Yorkshire, UK). (IEA, 2009) In the United States the EIA reported that the nameplate capacity of plants firing wood or wood derived fuel was 3498 MW. Plants using other biomass fuels (including municipal solid waste, landfill gas, sludge waste, and agricultural byproducts, among others) in the US have a nameplate capacity of 5043 MW. (EIA, 2011b) In terms of net power generation in the US, biomass made up 1.4% of power generation in 2010, as shown in Figure 1.

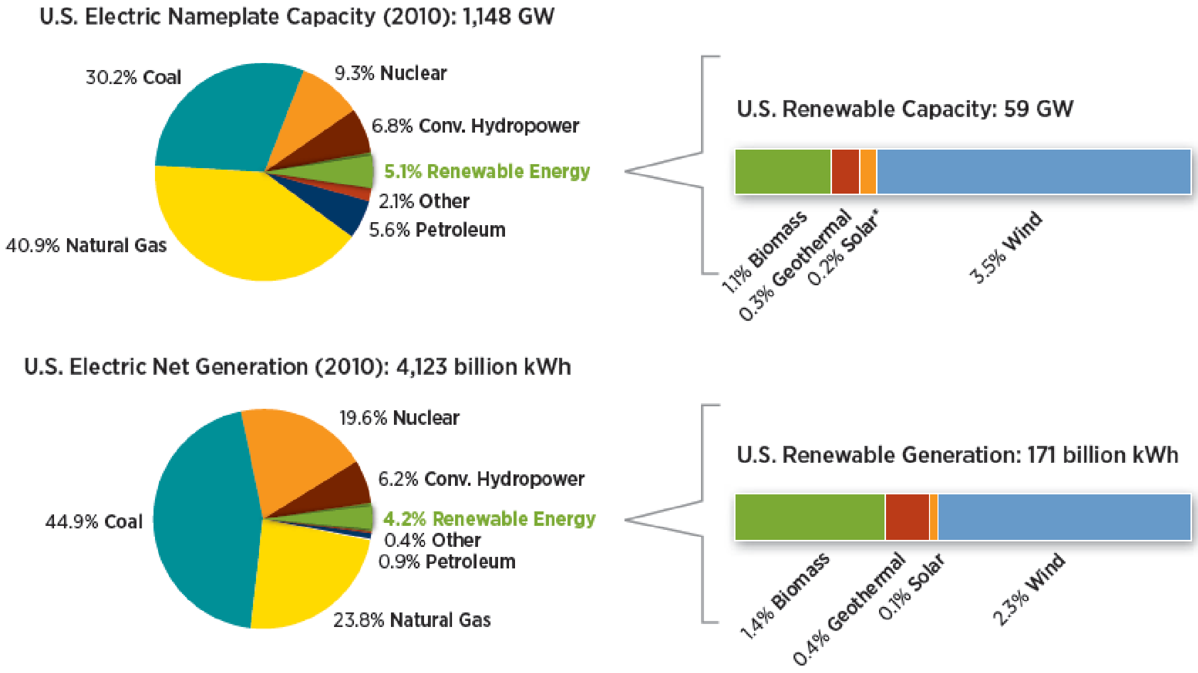

Figure 1. US nameplate capacity and net electric generation by source for 2010. (EERE, 2011)

The low penetration of biomass to power in the electric market is mostly due to economic reasons. Biomass is generally more expensive than coal, often requires retrofits to fire in an existing coal plant, and decreases the efficiency and output of a coal plant. In this chapter we will outline the state of biomass feedstocks and conversion technology as well as expand on the technical concerns when biomass is fired in an existing coal plant.

2.1 Biomass Feedstocks

Biomass can derive from two sources: dedicated energy crops or waste streams from forestry activities, agriculture, industry, or urban areas. Dedicated energy crops are produced using the same agricultural methods used for food crops; they require agricultural chemicals and heavy machinery powered by fossil fuels. Agricultural chemicals such as pesticides and fertilizers are produced from petroleum and natural gas, which incurs a carbon debt (Hoffmeister, 2000). In addition, nitrogen fertilizer applied to soil emits nitrous oxide, a potent greenhouse gas with 298 times the global warming potential of carbon dioxide (Argonne, 2011).

Waste biomass consists of the byproducts of various industries such as forestry, agriculture, woodworking, and the paper industry, among others. Agricultural waste (such as inedible stalks, leaves, and husks), forestry byproducts, or yard trimmings from an urban area are also considered waste biomass sources. (Walsh, 2004) Although waste biomass avoids many of the greenhouse gas emissions from cultivation incurred by dedicated biomass crops, only a limited amount of waste exists and the quality is often inconsistent. Gathering and transporting certain wastes, such as those from forest maintenance, can also be costly and may incur a large carbon debt.

Dedicated biomass crops

Dedicated biomass crops, if grown with minimal inputs and disruptions to the environment, can provide a reliable source of bioenergy. An environmentally sound biomass crop must require minimal energy, chemical, and labor inputs while providing an easily obtainable source of energy.

Ideally a dedicated biomass crop will make efficient use of available inputs, require minimal maintenance and have a favorable energy balance. In order to attain these criteria, plants must make efficient use of the light energy available by producing a large leaf canopy. The biomass crop must also make efficient use of water; irrigation incurs a large energy cost in agriculture. At harvest the biomass should have a low water content or be dried to ensure high conversion efficiency to energy. In addition to using water and solar energy efficiently, plants must also have high nutrient and nitrogen use efficiency. (Heaton, Clifton-Brown, Voigt, Jones, & Long, 2004) Nitrogen fertilizers are produced from natural gas (Hoffmeister, 2000) and the application of any fertilizer requires fossil fuel powered machinery. Plants make the best use of nitrogen and other nutrients when they have high internal recycling of nitrogen, maximize nutrient uptake from the soil, and use the captured nitrogen and nutrients efficiently. Biomass crops should also have little need for pest control. Similar to fertilizers, pesticides must be applied using energy intensive farm equipment and are often produced from fossil fuel sources. Biomass crops with a limited need for cultivation, such as a perennial crop that requires planting once every 10 to 20 years, minimizes the use of energy intensive agricultural machinery and thus the energy requirements of the crop. (Heaton et al., 2004)

Fast growing woody biomass, miscanthus, switchgrass, and high diversity grasses are four dedicated biomass crops that show promise for bioenergy production. In Sweden salix, or willow, is a short rotation woody biomass that is used for energy production. (Handbook, 2008) Woody crops have a high energy density, but can have high water content at harvest and require several years after planting before they can be harvested (Heaton *et al.*, 2004). The salix shoots can be harvested every 4 to 5 years whereas a study on hybrid poplars found harvesting every six years to be the most cost effective practice (Strauss and Grado, 1992). Other woody biomass crops such as alder and ash are being tested for use in energy generation as well. (Handbook, 2008)

Switchgrass is an herbaceous perennial native to the United States that shows promise as a biomass feedstock. Because switchgrass is native to the US, concerns over species invasion are diminished. In addition, switchgrass is able to produce high yields with low inputs and has been shown to improve and protect environmental quality (Sanderson et al., 1996). During growth switchgrass increases the amount of organic matter and organic carbon in the soil, thereby sequestering CO_2. (Heaton et al., 2004) Another benefit of using switchgrass as a dedicated biomass crop is that few insects or diseases attack the plant, which minimizes the amount of pesticides required. Nonetheless, switchgrass does require regular nitrogen application to maintain yields. Another benefit of switchgrass as a dedicated biomass feedstock is that it can be harvested and baled by commercially available hay equipment. (USDOE, 2011a)

Miscanthus is an herbaceous perennial, similar to switchgrass, with very favorable characteristics for an energy crop. Because miscanthus is a rhizomatous perennial it produces shoots every year that die in winter; if harvest is delayed sufficiently the miscanthus shoots dry in the field and the harvested biomass will have low water content (Heaton et al., 2004). Miscanthus also requires low pesticide and fertilizer inputs (Loo & Koppejan, 2008). The plant’s extensive root network allows it to efficiently capture nutrients from the soil. In addition to efficiently capturing nutrients, miscanthus’ root system also contributes to soil organic matter, thereby sequestering carbon in the soil during growth. Miscanthus differs from other herbaceous perennials because it can grow well in cool climates as well as more temperate climates. (Heaton et al., 2004)

Low input, high-diversity (LIHD) grassland biomass also shares many of the attributes of miscanthus and switchgrass. Such grasslands consist of a mix of perennial native grasses. In a 2006 life cycle analysis of LIHD biomass the authors found that yields of high diversity grasses were more than twice that of grassland monocultures after a decade. This study also found that LIHD grasslands used to produce fuels are carbon negative (sequestering approximately 4 Mg CO_2/ha/yr in this study) because the carbon released to harvest, process and transport the biomass is less than the amount of carbon the grasses sequester in the soil and their roots. As the name indicates, LIHD grasses can be grown with little fertilizer, irrigation, and other agricultural inputs. (Tilman *et al.*, 2006) Table 1 shows a summary of the various qualities of short rotation woody biomass, miscanthus, and high diversity grasses.

Table 1. Characteristics of Miscanthus, short rotation woody biomass, switchgrass and low-input, high-diversity grasses. (Aravindhakshan, Epplin, & Taliaferro, 2010; Fargione, Hill, Tilman, Polasky, & Hawthorne, 2008; Heaton et al., 2004; Keshwani & Cheng, 2009; Klass, 1998; McLaughlin & Adams Kszos, 2005; Pimentel & Patzek, 2005; Sanderson et al., 1996; Strauss & Grado, 1992; Venturi, Gigler, & Huisman, 1999)

Biomass source	**Energy per ha (GJ/ha/yr)**	**Harvest frequency**	**Pesticide kg/ha**	**Fertilizer kg/ha N**	**Fertilizer kg/ha P**	**Fertilizer kg/ha K**	**Moisture content at harvest, %w.b.**
Miscanthus	199.7	Annually	N/A	40-100	10-20	40-100	12-15% w.b.
Short rotation woody biomass	310*	4-6 years	5.5** (herbicide), 1.6† (fungicide)	120‡	60**	60**	50% w.b. (willow)
Low-input high-diversity grasses	68.1	Annually	2.24ˆ	--	7.4-12ˇ	--	Not available
Switchgrass	244	1-2 times/yr.	0.25 (herbicide)	50-120	50	80	Not available

* assuming yield of 16 tonnes/yr, ** during establishment, † insecticide/fungicide for maintenance, ‡maintenance, application in 3rd and 5th season, ˆglyphosphate application in first year, ˇ applied every 3 years

Waste Biomass Sources

Waste biomass sources are many and varied. They include residues from the forest and wood working industries, agriculture residues, food processing wastes, fibers, wood components of municipal solid waste, construction or demolition waste, yard trimmings, and oils from oilseed crops or industry. Although these waste streams may be plentiful, there are limitations to the actual amount of biomass that can be obtained. Collection machinery has efficiency limitations and may not be able to access remote resources. There are also environmental constraints to the amount of biomass that can be removed from fields and forests; there is a minimum amount of biomass that must be left in these areas to reduce erosion and maintain soil quality. (USDOE, 2011a) Economic constraints also limit the amount of waste biomass that can be collected, especially if the biomass is currently used for another economic activity. (Walsh, 2004)

Woody biomass is currently the preferred biomass source for electricity generation from biomass. Aside from its high heating value compared to other biomass sources, many woody biomass sources have a low ash and impurity content (See Table 1 for a comparison of wood characteristics with other fuels). Another benefit of woody biomass is its widespread harvesting and use in the wood and paper industry, which provides a centralized source of woody byproducts such as sawdust, bark, branches, and other wood portions not used in wood products. Because woody biomass from these industries is already centralized, no additional transportation cost, in terms of money, GHG emissions, or energy, need be expended if the feedstock is used in the vicinity. (EPRI, 2006)

2.2 Carbon Balance for Biomass Feedstocks

Although biomass itself is carbon neutral, the process of cultivating, harvesting and transporting biomass incurs significant carbon emissions. These fuel-cycle emissions, though, vary depending on the type of biomass analyzed, its source, and the practices used during production. In addition, the impact on land use change from dedicated energy crops (those produced solely to be converted to energy) on GHG emissions is also a major concern.

Producing an energy crop has the potential to incur two kinds of land use change (LUC). The first, direct LUC, results from changing a plot of land from its original use to energy crop cultivation. (H. Kim, Kim, & Dale, 2009) Changing the use of a given plot of land can result in greenhouse gas emissions stemming from changes in the amount of carbon sequestered by biomass above and below ground resulting from native biomass removal and decomposition (Fargione et al., 2008). The magnitude of greenhouse gas emissions produced by direct land use changes varies significantly depending on the soil chemistry, original use of the land, energy crop planted, and other considerations (H. Kim et al., 2009; Searchinger et al., 2008). An article by Fargione *et al.* published in 2008 found that the carbon debt incurred by direct LUC can outweigh the carbon benefits of biofuels when native ecosystems are converted to energy crop cultivation. In the most extreme case, converting peatland rainforest to palm oil cultivation for biodiesel, Fargione *et al.* calculate that the direct LUC carbon debt will require 423 years of biofuel use to repay. (Fargione et al., 2008) Although Fargione’s study focused on land use change that contributed GHG emissions, land use change can also produce negative emissions when vegetation that contains low carbon in above and below ground growth is substituted with one that sequesters more carbon.

The second kind of land use change, indirect LUC, occurs when a commodity crop displaced by an energy crop leads to a price increase in the commodity crop and causes land elsewhere to be cleared to grow the now high priced commodity (Searchinger *et al.*, 2008; Kim et al., 2009). Unlike direct LUC, indirect LUC is not a part of the biomass supply chain, and may even occur far from the biomass production site. Indirect land use change assumes that the effects of land use change in one area ripples throughout the world market. As demonstrated in the Searchinger *et al.* paper, though, indirect land use change depends on many factors. Depending on the elasticity of the commodity demand curve, demand for the displaced crop may even decrease with increasing prices leading to lower emissions from indirect land use change than necessary to replenish lost production (Searchinger *et al*., 2008). The greenhouse gas effects of indirect LUC are difficult to know definitively and allocating all the carbon debt incurred by indirect LUC to biomass production is a controversial practice (Kim *et al*., 2009).

In light of the substantial greenhouse gas debt incurred by land use change, biomass production should be limited to lands that already have a low level of above and below ground carbon storage and lands that are not currently used to grow crops. Depleted agricultural lands are a good candidate for biomass cultivation.

2.3 Biomass Models and Databases

Information on biomass characteristics and use for transportation has been aggregated in publicly available databases and the Argonne National Laboratory's GREET (Greenhouse gases, Regulated Emissions, and Energy use in Transportation) model. Three biomass characteristic databases are the BIOBIB database (developed and maintained by the University of Technology, Vienna, Austria), the Phyllis database (developed and maintained by the Netherlands Energy Research Foundation), and the IEA's BioBank database. The BIOBIB and Phyllis databases contain information for a variety of biomass sources including both dedicated biomass crops and wastes. The IEA's database includes information from the analysis of biomass and ash samples from installations where the biomass is used. (Loo & Koppejan, 2008)

The GREET model is a lifecycle analysis tool for conventional and renewable transportation fuels. The simulation calculates fuel-cycle (well-to-pump and pump-to-wheel) consumption of energy, emissions of greenhouse gases, and emissions of five criteria pollutants (VOCs, carbon monoxide, nitrous oxides, particulate matter 10, and sulfur oxides) for several conventional and renewable transportation fuels. (Wang, Wu, & A. Elgowainy, 2007) Electric vehicles powered by electricity produced from biomass is one of the fuel options included in the GREET model, which is relevant to this report. The GREET model has the capability to analyze energy requirements and emissions from corn, sugarcane, soybean, and cellulosic biomass sourced fuels. This model provides useful information in terms of the energy consumption, greenhouse gas emissions, and criteria emissions for the lifecycle of these biomass sources from cultivation to conversion to a biofuel. The GREET model does not, however, include information on land use change effects of biomass production. (Argonne, 2011)

2.4 Thermochemical Conversion Processes

The two more advanced technologies for large scale electricity generation from biomass are combustion of biomass with coal and combining gasification with a combined cycle turbine or single cycle gas turbine. Overall, gas turbines convert biomass to electricity more efficiently than direct combustion of biomass or biomass derived syngas coupled with steam turbines at small scales. At larger scales, combustion in a gas turbine in a combined cycle process is possible. (A. Bauen, 2004) The efficiency of biomass-integrated gasifier/gas turbine cycles (BIGCC) has been demonstrated as 37.2%, but is expected to be up to 40-45% efficient (Kheshgi, Prince, & Marland, 2000). Nonetheless, biomass gasification is not a mature technology. In contrast operational dedicated biomass combustion plants present 20-25% efficiency on a high-heating value basis (Kheshgi et al., 2000), although with pre-treatment and co-combustion with coal the efficiency will likely be closer to that of coal combustion. When co-firing coal with 3-5% biomass on a mass basis modest losses to boiler efficiency can be expected (Loo & Koppejan, 2008).

The efficiency of thermal biomass conversion systems are limited by a variety of factors. Direct limits to biomass conversion efficiency include moisture content and limits to combustion temperature for biomass fuels and are described in more detail in the following sections when applicable. Indirect limits to biomass conversion efficiency consist of parasitic losses during the cultivation, transportation, and pre-processing of biomass fuels. The energy penalty incurred by biomass cultivation and pre-processing is described in previous sections. Because of the low energy density of biomass fuels, particularly before processing, transportation of biomass can be costly both in terms of energy and economic costs. It is commonly cited that the maximum distance wood fuel can be obtained and economically transported by truck or rail is 50 miles (80 km). This limit on the radius for biomass procurement also limits the size and consequently efficiency of a biomass fueled power station. (Klass, 1998) The efficiency of small decentralized plants is limited because of economic and technology constraints (Loo & Koppejan, 2008). Co-conversion of a conventional fuel with biomass alleviates these limitations by improving the economics of a co-fired facility and increasing the economically achievable size of the power plant.

Combustion

Combustion consists of three steps: rapid oxidation of the fuel followed by energy release and the formation of carbon dioxide and water. (Loo & Koppejan, 2008) The ideal combustion fuel will have a low moisture content, small fuel particle size, and contain little ash and contaminants. High moisture content in the combustion fuel can lead to non self-sustaining combustion, cause incomplete combustion, low overall thermal efficiencies (particularly if energy is not recovered from vaporized water in the exhaust stream), high emissions, and lead to the formation of products that negatively affect system operation. Greater moisture content in the fuel also requires longer residence time of the fuel in the combustion chamber and creates a greater volume of flue gases, which requires a larger combustion chamber. Small fuel particle size increases the rate of combustion of the fuel and facilitates complete combustion. The major ash forming elements in biomass are silicone, calcium, magnesium, potassium, sodium, and phosphorus. Biomass ash content can vary widely from 0.5 (clean, woody biomass) to 12.0 (some straw and cereals) wt% on a dry basis or even greater if the fuel is contaminated with soil or other mineral impurities. Ash in the fuel at high enough temperatures will melt and accumulate on the inside of the boiler or heat exchanging surfaces, which in turn lowers the efficiency of the boiler. This process, ash slagging, can occur at temperatures ranging from 800 to 1700°C for biomass. To avoid expensive maintenance when slagging occurs, fuels with low ash content and/or a high slagging temperature are preferred. The ash slagging temperature of the fuel depends on the elements in the ash; calcium and magnesium tend to increase the ash melting temperature whereas potassium and sodium tend to decrease the slagging temperature. Other solutions are to remove ash from the bottom of the unit as molten slag during combustion, keep the temperature of combustion below the slagging temperature, or design the boiler to diminish contact of hot gases from combustion with hot surfaces. Impurities in the fuel such as chlorine, sulfur, potassium, and sodium attack heat exchanger surfaces and are the primary chemicals in corrosion mechanisms. Other impurities in biomass including volatile metals, heavy metals, and nitrogen increase harmful air emissions from the combustion process and interfere with the function of environmental control equipment. Coal ash is often recovered and sold for reuse in other products; with co-combustion the effect of biomass ash and impurities on the resale value and use of the ash must be taken into consideration. (Klass, 1998; Loo & Koppejan, 2008; L. Zhang, Xu, & Champagne, 2010)

Table 2 contains guiding values for elements in biomass fuels and ashes. Fuels within the ranges shown in Table 2 can be used in modern combustion units without negative effects. Any fuel that does not meet the guiding concentrations may still be combusted, but may require design considerations to avoid negative effects on the boiler or emissions. These guiding factors are general guidelines for fuels under consideration; the complex interactions between some of the elements in biomass fuels, various combustion configurations, operating conditions, and other factors specific to a given project may alter the elemental limits of the fuel. (Loo & Koppejan, 2008)

Table 2. Guiding concentrations for elements in biomass feedstocks along with the limiting effects of the element in combustion. (Handbook, 2008)

Element	Guiding concentration in fuel on dry basis. (wt.%)	Limiting parameter
N	<2.5	NOx emissions
Cl	<0.3	Corrosion, HCl emissions, PCDD/F emissions
S	<0.2	Corrosion, SOx emissions
Ca	15-35	Ash melting point
K	<7.0	Ash melting point, depositions, corrosion, aerosol formation
Zn	<0.08	Ash recycling, ash utilization, particulate emissions
Cd	<0.0005	Ash recycling, ash utilization, particulate emissions

Biomass pre-processing occurs before combustion to facilitate energy generation, transportation and storage. Aside from producing less problematic fuel, pre-processing also makes biomass transportation and storage easier. The lower energy density of biomass, as compared to coal, makes transportation more costly both in terms of energy and money. In addition, greater fuel handling capacity is needed when combusting biomass as it has one tenth to two fifths the energy density of coal. (Loo & Koppejan, 2008; L. Zhang, Xu, et al., 2010) The moisture in biomass can also lead to self-heating or decomposition during prolonged storage (Bridgeman, Jones, Shield, & Williams, 2008). In combustion as well as other thermo-chemical conversion processes, small particles are preferred because they mix more easily in the combustion chamber,—provide greater fuel homogeneity— which facilitates control of the process. Biomass is fibrous, which makes it difficult to break down into homogeneous, small pieces (Bridgeman et al., 2008). To address the low energy density, transportation, and large particle concerns, biomass may be dried, ground, and pelletized. Before pelletization, biomass must be dried to 10% moisture content by weight. Pellets have higher energy density than biomass and better storage characteristics. (Loo & Koppejan, 2008). Other experimental pre-processing methods exist that will produce a drier feedstock and some even produce fuel with fewer impurities that will decrease negative effects on the boiler. Co-combustion with coal is possible with biomass at any level of pre-processing. In this thesis we assume that all biomass has been dried sufficiently for combustion, but we do not evaluate biomass that has undergone any further pre-processing.

Table 3 summarizes the characteristics of several biomass fuels, preprocessed biomass feedstocks and coal. Of the minimally treated biomass feedstocks (wood chips, miscanthus, and grasses), wood chips are the most suitable for co-firing with coal because of their low moisture and ash content, and high slagging temperature, HHV, and energy density.

Table 3. Characteristics of processed biomass, minimally processed biomass, and coal. (Ausilio Bauen, Berndes, Junginger, Londo, & Vuille, 2009; P.C.A. Bergman, Boersma, Zwart, & Kiel, 2005; EPRI, 2006; Klass, 1998; Loo & Koppejan, 2008; UP, n.d.; Uslu, Faaij, & Bergman, 2008; Venturi et al., 1999; Yanik, Ebale, Kruse, Saglam, & Yüksel, 2008)

Biomass/fuel	Moisture content (wt%)	Ash content (wt% d.b.)	Slagging/ melting T (°C)	HHV (MJ/kg)	Energy density (MJ/m3)	S (mg/kg d.b.)
Wood chips	15-50	1.0-2.5	1340->1700	18.05-19.8	2800-3900	100-1000
Gasified biomass (CFB)	Process dependent	--	Fuel dependent	5-20 (MJ/Nm$^{3)}$	11-18	--
Grass	15-18	4.0-12.0	1100-1330	15.92-18.4	2740	800-7000
Torrefied biomass	1-6	Fuel dependent	Fuel dependent	20-24	18000	Fuel dependent
Coal	3.1-5.2	8.7	1010->1430	29.47-32.61	20000	10000

Co-firing of coal with biomass has been practiced at nearly 230 facilities worldwide (IEA, 2009). Most of the facilities with co-firing experience are pulverized coal boilers with a power rating of 50-700 MW_e. (IEA, 2009; Loo & Koppejan, 2008) Most co-combustion projects have operated with less than 10% biomass on a heat input basis. (Loo & Koppejan, 2008) The co-firing ratios of plants that have practice with co-combustion in the IEA's database were incomplete for the units listed, so this assertion cannot be verified with the database data. (IEA, 2009)

Gasification and single and combined cycle gas turbine combustion

Gasification converts a feedstock into syngas and a solid residue through the thermochemical conversion of the feedstock with limited oxygen supply at or above atmospheric pressure. During gasification nearly all the carbon in the feedstock is converted to a gaseous form and the remaining mass becomes an inert residue. The product gas contains carbon monoxide, hydrogen, carbon dioxide, methane and nitrogen (if air is used as an oxidizing agent) as well as impurities such as char particles, ash, tars, and oils. The solid residue is a mixture of ash and possibly unconverted carbon or char. Gasification has the benefit of converting a varied biomass feedstock to syngas, which can then be used for many applications. Syngas can be used to generate heat, electricity, chemicals or transport fuels. (A. Bauen, 2004; Kirkels & Verbong, 2011) The technology favored for biomass gasification is fluidized bed gasification because of its suitability for medium scale applications. (EPRI, 2006) Although gasification of biomass produces a high quality fuel that avoids many of the problems associated with biomass feedstocks, the technology is not mature and is not expected to be cost competitive with combustion technologies in most markets (Kirkels & Verbong, 2011).

The syngas product from gasification can be combusted in an engine, gas turbine, or a boiler. Biomass gasification units encounter similar economies of scale limitations as other biomass conversion facilities and are generally limited to units with generating capacity of less than 50 MW_e. Co-firing in coal plants with gasified biomass fuel eliminates the scale limitations and is a more economical option for biomass gasification. Co-gasification of biomass and coal is also a possibility without compromising the unit's operation as long as small quantities of biomass relative to coal are used and the biomass ash has a low quantity of alkalis (sodium and potassium). Although biomass gasification is an effective pre-processing option for biomass, few commercial biomass gasifiers exist, in part because of the high cost of technology development and implementation (Kirkels & Verbong, 2011).

Gasified biomass can be combusted using two different gas turbine technologies. The gas can be combusted in a single cycle gas turbine, or in a combined cycle plant. Combined cycle plants have the benefit of high conversion efficiencies. A combined cycle plant first combusts gas in a gas turbine and then recovers heat from the exhaust gas to produce steam that powers a steam turbine to generate more electricity. Combined cycle plants can reach conversion efficiencies of 43%. (Campbell, Mcmullan, & Williams, 2000) The single cycle gas turbine simply combusts the gas in the turbine and does not recover heat from the exhaust gas in secondary steam turbines. Although processing and combustion at an integrated gasification combined cycle power plant presents the advantage of high conversion efficiency, such operations exist at a commercial scale of 30-200 MW_e. Because biomass is a dispersed resource, transportation of high volumes of biomass would result in high feedstock costs particularly at higher co-firing ratios. (Kirkels & Verbong, 2011)

Experimental Technology: Torrefaction

Torrefaction is a promising technology for producing a biomass based fuel similar to coal that would avoid many of the problems associated with biomass combustion in a power plant. Nonetheless, torrefaction is a technology in development, and does not yet occur on a commercial scale. (Uslu et al., 2008)

Torrefaction is a thermochemical process (i.e., a mild pyrolysis) that converts dried biomass into char and torrefaction gas. During torrefaction, the biomass is heated to 200°C-300°C under atmospheric pressure and in the absence of oxygen. (Uslu et al., 2008) The char product can be combusted in a power plant and has many advantageous characteristics that make it superior to raw biomass. Torrefaction char is low in moisture and even hydrophobic due to the destruction of hydroxyl groups that diminishes the product's capacity to bond with water (Bridgeman et al., 2008; Uslu et al., 2008). The product is 70% of the biomass feedstock weight and contains 90% of the energy in the original feedstock. (Uslu et al., 2008) In addition the torrefied product is porous and loses much of its mechanical strength, making it easier to grind into smaller particles. If the torrefied biomass is made into pellets, these can approach the energy density of coal. Coal has an energy density of approximately 20 GJ/m^3 whereas pelletized torrefied biomass has an energy density of 18 GJ/m^3. (Uslu et al., 2008) With properties now approaching those of coal, torrefied biomass no longer requires separate handling units and facilities (Bridgeman et al., 2008).

Torrefied biomass generally has a low level of contaminants, moisture, and is easily pulverized, making it a biomass fuel very similar to coal. Therefore co-combustion of coal with torrefied biomass does not have the negative effects on the boiler function or overall power plant efficiency that non-torrefied biomass does. Likewise gasified biomass, through sufficient clean-up, will cause no negative effects on the boiler function when co-fired with coal.

2.5 Carbon Capture and Sequestration

Because the carbon contained in biomass has been captured from the atmosphere by the original plant, capturing and sequestering carbon dioxide from biomass co-combustion with coal can result in net negative carbon emissions. Carbon capture can occur before or after combustion depending on the pre-treatment and combustion method used. Another carbon capture strategy is to combust the fuel in nearly pure oxygen, thus producing a high concentration of CO_2 in the flue gas. (Herzog *et al.*, 2009) In this thesis we will focus on post-combustion carbon capture technologies because they can be used with existing coal fired power plants.

Post-combustion capture

Post combustion capture is compatible with existing power plants, making it a favorable choice for near-term carbon capture. Implementation of post-combustion capture does not require substantial changes to existing combustion technology. (Herzog, Meldon, & Hatton, 2009)

Flue gas exiting a coal-fired power plant is at approximately one atmosphere of pressure and contains 10-15% carbon dioxide (Herzog et al., 2009). The low pressure of the gas stream and low CO_2 content limits the technologies available for post-combustion capture. All operating carbon capture plants to date rely on a chemical absorption process using monoethanolamine (MEA) based solvents. The capture system works by first chemically absorbing the CO_2 into the solvent in the absorber. Then, the carbon loaded solvent is contacted with steam in the stripper to reverse the reaction and release the CO_2. Finally, the steam/CO_2 stream is cooled to condense the water and leave a concentrated carbon dioxide stream that can be compressed for transportation and sequestered. (Herzog et al., 2009)

A major challenge for absorption capture is the parasitic load incurred by the capture system on the power plant. For a supercritical pulverized coal power plant the capture and compression system decreases the overall thermal efficiency of the plant by 24%. To recuperate the energy lost to the capture system, 30% more fuel must be combusted. Because of the high cost of the parasitic load, a main goal for researchers of absorption capture is to develop solvents with high rates of CO_2 absorption, which require smaller equipment and less energy from the power plant. (Herzog et al., 2009)

Ecofys and IEAGHG in a 2011 study state that post combustion capture using chemical absorption is the most likely technology to be used when retrofitting an existing power plant with CCS. This study also states that these units (post combustion, chemical absorption) are expected to be compatible with biomass firing and co-firing. Chemical absorption plants do require that the flue gas be cleaned of impurities such as acid gases and particulate matter. Because a biomass firing plant has not yet been fitted with a CCS unit, the extent to which biomass burning plants would need more or less emissions control technology to avoid fouling the chemical absorbent is not known. The main effect of biomass combustion on a CCS unit is expected to be a higher flue gas volume, due to moisture in the fuel, which produces a more dilute CO_2 stream exiting the power plant. (IEAGHG & ECOFYS, 2011)

Pre-combustion capture

Pre-combustion capture is only possible if gasification is used as a pre-treatment method. During the water-gas shift reaction of gasification, carbon monoxide is reacted with steam to produce carbon dioxide and hydrogen. At this point in the process, the carbon dioxide can be separated and sequestered. (Herzog et al., 2009) Though pre-combustion capture is less expensive than post-combustion carbon capture (Herzog et al., 2009), the overall cost of IGCC is higher than for pulverized coal (a technology that can be used with post-combustion capture). Few commercial biomass gasifiers exist (Kirkels & Verbong, 2011). Therefore pre-combustion capture from biomass would also require construction of gasification plants and the infrastructure for carbon capture and sequestration.

Oxy-combustion capture

Oxy-combustion takes a different approach to carbon capture; rather than separating carbon dioxide from nitrogen and nitrogen compounds, the oxy-combustion approach eliminates nitrogen from the process entirely by combusting the fuel in 95% or higher oxygen. After combustion, the flue gas stream still requires removal of contaminants, but the extent of clean-up is minimized. Oxygen production on-site is the most expensive component of an oxy-combustion plant and would result in high capital costs. (Herzog et al., 2009)

Biochar carbon capture

Biochar production from biomass and subsequent burial to sequester the carbon in the char is another method for capturing a portion of the carbon in biomass. This method requires sacrificing some of the energy potential of the feedstock by burying the carbon rich biochar. Biochar is a byproduct of pyrolysis. (Roberts, Gloy, Joseph, Scott, & Lehmann, 2010) Although energy generation from the gaseous product of pyrolysis is possible, maximizing biochar production minimizes energy generation from the process (Verheijen, Jeffery, Bastos, van der Velde, & Diafas, 2010).

Although the research is not yet conclusive, most reports estimate that biochar can remain stable in soil for hundreds to thousands of years, meaning that the carbon in biochar can be sequesterd by burying it or mixing it in with soil (Lehmann, 2007; Verheijen et al., 2010). Although pyrolysis and the process of biochar production is well understood, there are still many unknowns regarding the effects of mixing biochar into soils, the rate of decomposition to carbon dioxide, the biochar loading capacity of soil, the carbon negativity of biochar sequestration, and environmental effects of this sequestration method (Verheijen et al., 2010).

There is some evidence that biochar application can improve soils and lead to greater plant productivity. Nonetheless, biochar is currently an experimental technology being implemented at start-up ventures. Large scale commercial biochar plants do not exist yet. (Verheijen et al., 2010)

Chapter 3. Biomass Fuel Cycle Emissions and Energy Model

Biomass has the potential to be a carbon neutral feedstock for power generation. Although burning biomass to generate electricity releases carbon dioxide, when biomass grows back after being harvested for power generation the plant recaptures carbon from the atmosphere causing the entire process to have net zero emissions. Nonetheless, the fossil fuel inputs required to cultivate, transport, process, and handle biomass as well as greenhouse gas emissions from other sources throughout these steps disrupt the carbon balance of biobased fuels. Therefore analyzing the extent of greenhouse gas emissions from biomass procurement and comparing it to that of conventional fuels is necessary to gauge the real climate effects of bioelectricity. Figure 2 shows greenhouse gas (GHG) flows for the biomass to electricity system.

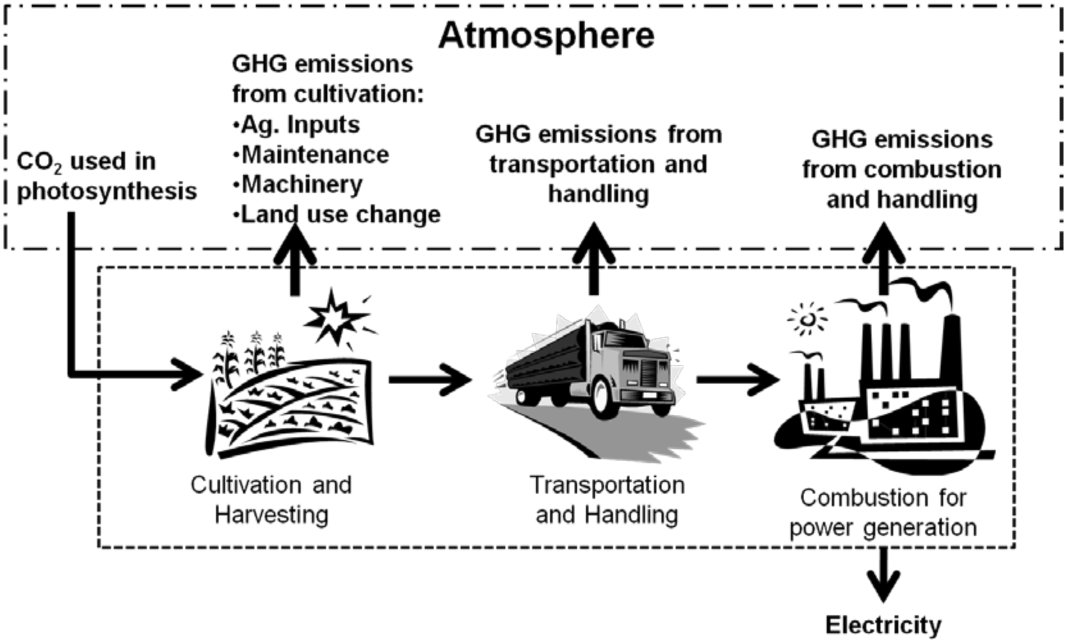
Atmosphere
CO₂ used in photosynthesis
GHG emissions from cultivation:
•Ag. Inputs
•Maintenance
•Machinery
•Land use change
GHG emissions from transportation and handling
GHG emissions from combustion and handling
Cultivation and Harvesting
Transportation and Handling
Combustion for power generation
Electricity

Figure 2. Basic GHG flows in biomass to electricity system.

The first step in the system outlined in Figure 2 is the cultivation of a biomass crop. Depending on the crop the amount of fertilizer, pesticides, irrigation, and crop maintenance will vary. All of these inputs require energy and result in GHG emissions. Machinery for crop maintenance and harvesting also requires energy to produce as well as to operate and generates GHG emissions throughout its lifecycle. After harvesting the biomass must be transported to either a pre-processing facility or its point of use. The combustion of fossil fuel to transport biomass to its point of use results in the consumption of energy and production of GHG emissions. The last step in the biomass to power scenario is handling and combustion at the power plant. Handling biomass at the power plant can require separate equipment to feed the biomass into the boiler because of the lower energy density of biomass compared to coal (Mann & Spath, 2001). Mann and Spath (2001) note that at 5% co-firing the biomass can be mixed in with coal on the conveyor leading into the boiler. At higher co-firing ratios, though, an additional biomass conveyor is needed to feed biomass into the boiler. (Mann & Spath, 2001) Additional handling steps require energy to build and operate and produce GHG emissions throughout their lifecycle. Ideally complete combustion of a hydrocarbon results in water and carbon dioxide. In reality, though, combustion of biomass and coal also produces small amounts of methane and nitrous oxide, which have several times the global warming potential of carbon dioxide.

This chapter describes the methodology and results for a model created to approximate the energy and emissions from bioelectricity generation from three feedstocks: farmed trees, switchgrass and forest residue. The model simulates combustion of the biomass feedstock with coal at varying co-firing ratios in an existing power plant. Data from the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model developed by Argonne National Laboratory as well as data and methodology from the literature were used to construct this model. Although the model looks at the fuel cycle of biomass and coal, it does not account for carbon contributions from direct or indirect land use change (see Section 2.2). It also does not account for the embedded energy of the equipment needed for a biomass to power plant (generally very small compared to the lifetime direct emissions). More details of how the emissions and energy contribution of the biomass and coal fuel cycle were calculated are outlined below.

3.1 Literature Sourced Data and Methodology

In terms of the steps shown in Figure 2 and described above, the GREET model contains data needed to evaluate emissions and energy use in all three steps. In the agricultural inputs step GREET contains estimates for the energy and emissions from producing and transporting fertilizers and pesticides as well as the emissions from the volatization of fertilizers in soil, which produces nitrous oxide. Forest residue, though, does not require cultivation since it is collected from logging operations as available. GREET also contains information on the amount of energy and emissions resulting from crop maintenance and harvesting. In the emissions and energy estimate for the fossil fuel used in agricultural inputs, the GREET model includes the impact of the fuel production lifecycle. GREET, however, does not include an estimate for the energy and emissions from the production of equipment used in agriculture such as tractors or combines. The basic information necessary to calculate the energy and emissions contribution of producing this equipment is contained in GREET, though the factors needed to calculate the quantity of farming equipment used throughout cultivation is only given for corn and corn stover.

Total emissions are calculated in terms of carbon dioxide equivalents. As mentioned above GHG emissions from biomass cultivation include carbon dioxide (CO_2), nitrous oxide (N_2O), and methane (CH_4). All emissions are multiplied by their global warming potential (which converts any GHG emission into the equivalent carbon dioxide emissions that would have the same global warming effect as the GHG in question) and add all emissions. The global warming potentials used in this study apply over 100 years of the GHG's residence in the atmosphere and are summarized in Table 4.

Table 4. Global warming potential of greenhouse gases relative to CO_2. (Barker et al., 2007)

Greenhouse Gas	Global warming potential relative to CO_2
CO_2	1
CH_4	25
N_2O	298

Although coal is not cultivated like biomass is, coal does have to be mined and cleaned. GREET includes an estimate of emissions and energy consumption for the mining and cleaning of coal. Table 5 shows a summary of the total energy and emissions of methane, nitrous oxide and carbon dioxide for each feedstock for cultivation, mining (in the case of coal), and transportation to point of use as reported in GREET.

Table 5. Summary of emissions and total energy from the agricultural and transportation step of biomass and coal production (Argonne, 2011)

Fuel	Total Energy (BTU/dry ton)	CH_4 (g/dry ton)	N_2O (g/dry ton)	CO_2 (g/dry ton)
Farmed trees	540,328	74.8	1.9	41,894
Switchgrass	620,704	186.7	11.9	43,260
Forest residue	617,901	66.3	0.9	48,532
Coal	412,922	41.0	0.6	33,458

The transportation step includes lifecycle energy use and emissions for the fuel used to transport biomass to the point of combustion. GREET uses a fixed value for the distance and therefore energy used to transport biomass to its point of use as well as a fixed mode of transportation for biomass. For coal, GREET assumes that 10% of coal is transported on a barge over 330 miles and the other 90% of coal is transported by train over 440 miles. The biomass transportation model does not account for the longer transportation distance for the biomass required by a larger facility (given a constant yield of biomass per cropping area, a larger facility will require more biomass and therefore more cropping area for its feedstock, which will result in a longer transport distance from more distant fields). GREET also does not include the manufacture of transportation vehicles in the lifecycle analysis of this step. Table 6 contains the transportation distance and mode assumed for biomass feedstocks in GREET as well as the energy consumption and emissions per ton or million BTU transported.

Table 6. Transportation distance and mode of transportation used in the GREET model (Argonne, 2011)**.**

Fuel	Transportation Distance (miles)	Transportation mode	Energy Consumption: Btu/ton of fuel transported	Total Emissions: grams/million Btu of fuel transported
Farmed trees	40	Truck	145,517	11,939
Switchgrass	40	Truck	103,075	8,457
Forest residue	75	Truck	272,845	22,235
Coal (10%)	330	Barge	191,273	15,715
Coal (90%)	440	Train		

GREET also provides emissions data for combustion of biomass in a utility boiler. The GREET model accounts for methane, nitrous oxide and carbon dioxide emissions from combustion. These values are summarized in Table 7.

Table 7. Emissions values for biomass and coal combusted in utility boilers. (Argonne, 2011)

Fuel	**CH_4 (g/mmBTU fuel burned)**	**N_2O (g/mmBTU fuel burned)**	**CO_2 (g/mmBTU fuel burned)**
Farmed trees	3.6	10.4	97,001
Switchgrass	3.6	10.4	90,794
Forest residue	3.6	10.3	121,275
Coal	1.1	1.0	102,660

Table 8 contains the fuel characteristics used in this model and obtained from the GREET model. Throughout this model the higher heating value is used in all calculations.

Table 8. Fuel characteristics (Argonne, 2011).

Fuel	**LHV (million BTU/ton)**	**HHV (million BTU/ton)**
Coal	20	21
Bituminous coal	22	23
Farmed trees	17	18
Switchgrass	15	16
Forest residue	13	14

As was mentioned before, handling biomass at the power plant can require separate equipment for storing and feeding the biomass into the boiler depending on the co-firing ratio of the plant (Mann & Spath, 2001). Since this equipment is required only because of biomass co-firing, energy and emissions associated with its manufacture (also that of the raw materials used in its manufacture), installation at the power plant, and operation should be included in the bioelectricity fuel cycle. GREET does not contain data for the power plant adaptations necessary to co-combust biomass and these figures are not given in the Mann and Spath publication. Therefore they are not included in this model.

The addition of biomass to a coal fired power plant will decrease the efficiency and capacity of the plant. At zero percent co-firing the plant size and efficiency are at their maximum. As the co-firing rate increases, the effect of moisture in the fuel, as well as limits on operating conditions imposed by the biomass, cause the plant efficiency to decrease. In this study we account for the efficiency and output by interpolating from values used in the Mann and Spath report. Mann and Spath analyze three power plant scenarios in an average American coal plant (no details were given on the type of plant modeled): no co-firing, 5% co-firing, and 15% co-firing. In their study, Mann and Spath rely on data from power plants that have co-fired biomass to determine how plant efficiency and capacity will be affected by the two co-firing scenarios. (Mann & Spath, 2001) Data from the Mann and Spath report is given in Table 9.

Table 9. Power plant capacity and efficiency at different amounts of biomass co-firing as reported in Mann and Spath. (Mann & Spath, 2001)

% co-fire (heat input)	Plant capacity (MW)	Plant efficiency (%)
0%	360	32.0%
5%	354	31.5%
15%	350	31.1%

Estimates for the efficiency of dedicated biomass power plants vary. The US Department of Energy's Energy Efficiency and Renewable Energy office (EERE) reports that the technology exists to attain efficiencies over 40% for dedicated biomass plants, but that most existing plants operate at efficiencies closer to 20% (EERE, 2005). The International Energy Agency (IEA) reports that dedicated biomass power plants operate at an efficiency about 10 percentage points lower than a coal only plant. In addition the IEA reports that dedicated biomass plants typically are about 30% efficient depending on the size of the plant. (IEA, 2007) Other literature sources state that a biomass fired power plant will operate at 20% to 25% efficiency (Loo & Koppejan, 2008). For this study it is assumed that dedicated biomass power plants operate at 30% efficiency.

3.2 Model Description and Methodology

Using the lifecycle steps described previously, a model was developed to calculate energy requirements and emissions from a power plant co-firing biomass with the characteristics given in Table 10 for three power plant capacities (100MW, 150MW, and 200MW).

Table 10. Characteristics of the power plant scenarios modeled in this analysis.

Percent Co-firing	Plant Efficiency	Facility size (MW)	Facility size (MW)	Facility size (MW)
0%	40.0%	100.0	150.0	200.0
5%	39.5%	98.8	148.1	197.5
10%	39.2%	98.0	147.0	196.0
15%	39.1%	97.8	146.6	195.5
20%	39.0%	97.5	146.3	195.0
100%	30.0%	75.0	112.5	150.0

As discussed above, the efficiency and capacity of a power plant decreases as the co-firing ratio of biomass increases. To calculate the efficiency values (for co-firing at 5% to 15%) in Table 10, we used a second degree polynomial fit to the data points given by Mann and Spath (see Table 9) to calculate values for percent biomass firing. The equation obtained from the fit is shown as (Eq. 1.

$$\text{eff drop} = -0.4 * (\text{co - fire ratio})^2 + 0.12(\text{co - fire ratio}) \qquad \text{(Eq. 1)}$$

Figure 3 shows graphically the data points used and the polynomial fit obtained.

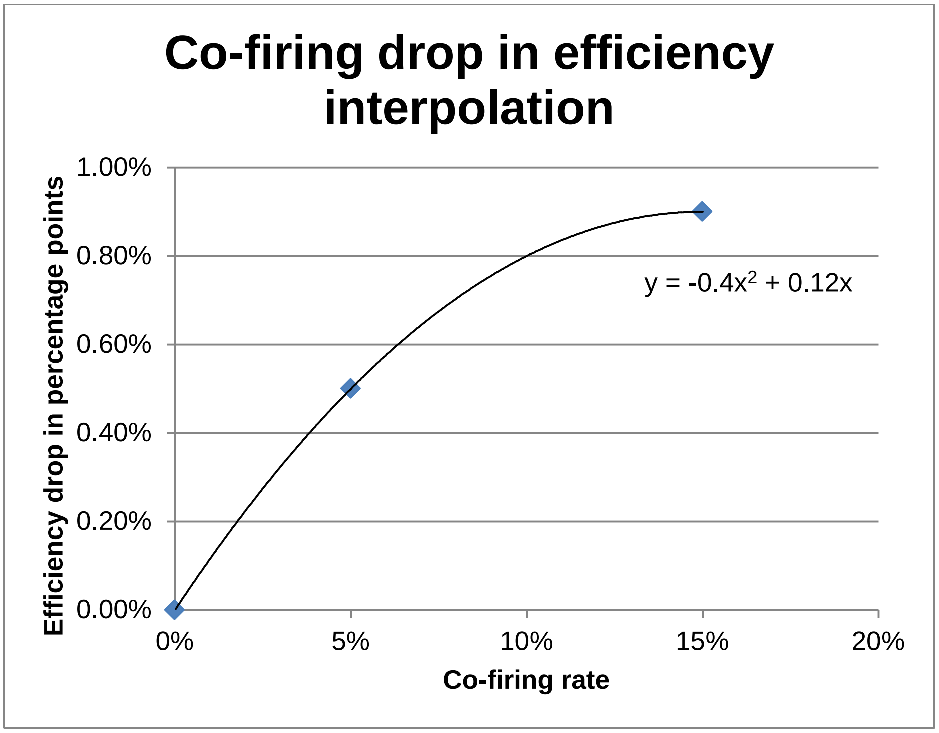

Figure 3. Co-firing drop in efficiency interpolation.

The resulting efficiency drop calculated using Equation 1 is shown in Table 11. The change in efficiency is not extrapolated to 100% biomass fired combustion. As mentioned above, the change in efficiency for a dedicated biomass plant was obtained from the literature.

For 20% co-firing, though, the equation shown in Figure 3 decreases. Given that the drop in efficiency should increase as the co-firing ratio increases, we cannot use Equation 1 to extrapolate the change in efficiency for 20% co-firing. W linear extrapolation using the slope of the polynomial at 15% co-firing cannot be used to find the drop in efficiency because at this point the slope is zero. Therefore a linear fit to the drop in efficiency at 10% and 15% is used to extrapolate to 20% co-firing using the point slope formula. The results of the interpolation and extrapolation are shown in Table 11.

Table 11. Results of the interpolation and extrapolation to determine the efficiency drop from the co-firing ratios modeled in this analysis.

Co-firing rate	Drop in efficiency (% points)
0%	0.0%
5%	0.5%
10%	0.8%
15%	0.9%
20%	1.0%

The drop in plant capacity noted by Spath and Mann is the result of the drop in efficiency of the plant; therefore drop in plant capacity is calculated directly from the drop in efficiency values summarized in Table 11. Equation 2 is used to calculate the new capacity of the coal fired power plant when it co-fires biomass.

$$P_e = P_{e,orig}\left(\frac{n_{biomass}}{n_{orig}}\right) \qquad \text{(Eq. 2)}$$

In Equation 2 the capacity of the power plant with biomass combustion is equal to the original capacity of the plant times the ratio of biomass efficiency to the original efficiency of the plant (at 100% coal combustion). The drop in capacity of the biomass co-fired and fired power plant is used for when regularizing the model's results per kWh of electricity generated. The capacities calculated using Equation 2 are summarized in Table 10.

For the fuel cycle emissions and energy analysis he power plant size, co-firing ratio, fuel heat rate, and heat rate (efficiency) of the plant are used to determine the mass of biomass and coal that is required for each power plant scenario and biomass feedstock. Equation 3 was used to calculate the mass of biomass and coal (for coal the percent of coal co-fired with biomass is used in Equation 3 and vice versa when calculating the mass of biomass) required in each co-firing scenario. For this analysis the capacity factor used is 80%.

$$\frac{\text{t. biomass}}{\text{year}} = \text{power plant size} * \%\ \text{co-fire} * \text{capacity factor} * 8760\ \text{hrs/yr} * \text{heat rate} * \left[\text{HHV}_{\text{biomass}}\right]^{-1} \qquad \text{(Eq. 3)}$$

The mass of each feedstock calculated using Equation 3 was then combined with fuel cycle emissions and energy factors for each feedstock (shown in Table 5, Table 6, and Table 7) to calculate the total energy and emissions from each scenario. The fuel cycle emissions and energy factors include contributions from the steps shown in Figure 2 and described above. In the combustion step the mass of carbon, in the form of carbon dioxide, contained in the combusted biomass is subtracted from the total GHG emissions from biomass combustion because it is assumed that regrowing the feed biomass will capture the same amount of carbon in the original plant from the atmosphere (in the form of carbon dioxide). Although there is a time lag between the time the biomass is combusted (releases carbon dioxide into the atmosphere) and the time when the biomass has grown enough to recapture all carbon dioxide from the atmosphere, this model accounts for the net emissions of the process over its lifetime and does not include a temporal component. Through this calculation the total energy and emissions that would result from one year of operating a co-firing plant was estimated as described in each scenario.

3.3 Results

The calculations described above confirm that co-firing coal with biomass decreases greenhouse gas emissions when compared with coal fired power. Figure 4 illustrates the emissions rate results for different co-firing ratios; the emission rates are the same for all scenarios modeled because of simplifying assumptions in the model.

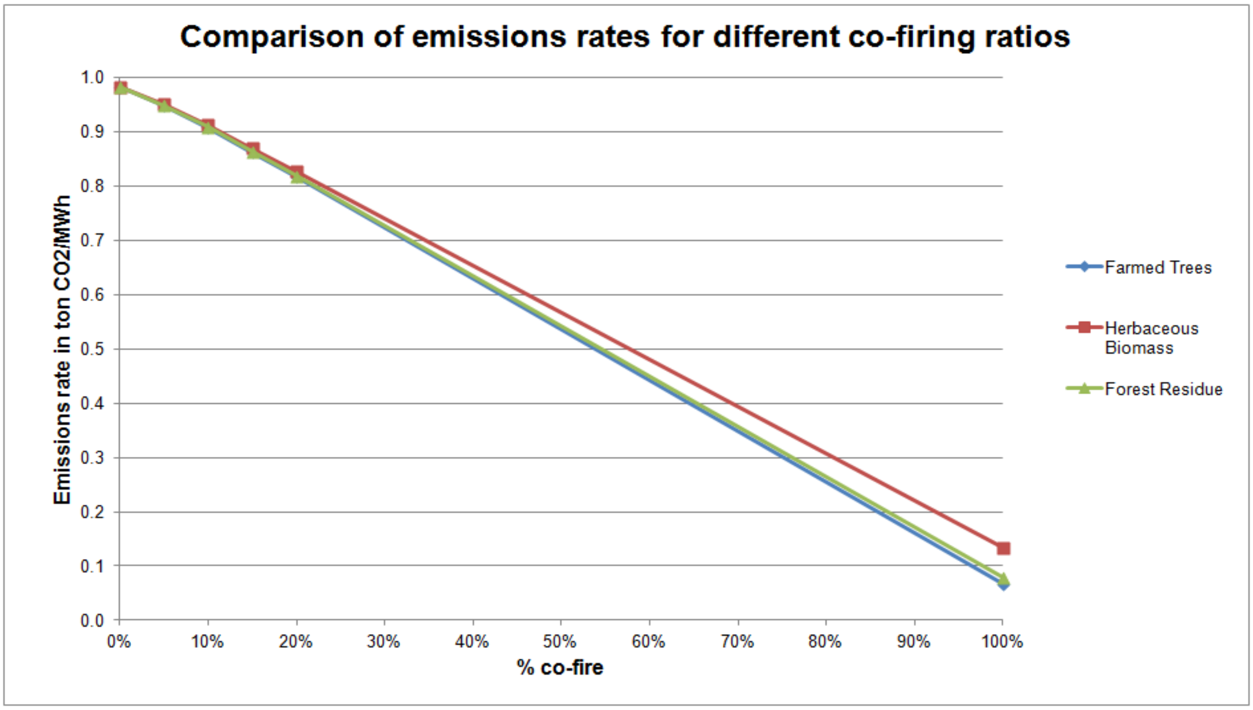

Figure 4. Emissions rate for different feedstocks decreases as the co-firing ratio increases for all three biomass sources analyzed.

Although Figure 4 is specifically for a 100 MW plant (the plant will have 100 MW capacity at 0% co-fire and decreasing output as the co-firing ratio increases), the emissions rate for each feedstock is the same regardless of the plant size. This outcome is the result of simplifying assumptions made in the model.

Although all biomass sources analyzed have a higher upstream emissions (including all steps required to procure the feedstock before it is burned) rate per kWh, total GHG emissions for the biomass to electricity lifecycle considering carbon uptake by biomass regrowth is lower than for coal. Biomass net combustion emissions (including the carbon absorbed by biomass regrowth) are much lower than combustion emissions from coal, which more than compensates for the higher upstream emissions of biomass. Emissions from coal, farmed trees, switchgrass and forest residue are shown in Table 12. Net combustion emissions is the regrowth emissions rate (which is a negative value) added to the sum of biomass and coal upstream emissions added to combustion emissions.

Table 12. Comparison of lifecycle, combustion, and net combustion emissions rates for coal and biomass.

Fuel	% co-fire	Biomass upstream emissions rate (g/kWh)	Coal upstream emissions rate (g/kWh)	Combustion emissions rate (g/kWh)	Regrowth emissions rate (g/kWh)	Net combustion emissions rate (g/kWh)	% of coal firing emissions
Coal	100%	0	14.4	878.5	0	892.9	100.0%
Farmed trees	5%	1.1	13.8	888.4	-42.0	861.3	96.5%
	10%	2.2	13.2	894.0	-84.7	824.7	92.4%
	15%	3.3	12.5	895.1	-127.4	783.4	87.7%
	20%	4.4	11.8	896.2	-170.3	742.0	83.1%
	100%	28.5	0.0	1139.7	-1107.2	61.0	6.8%
Switch-grass	5%	1.2	13.8	887.9	-39.4	863.6	96.7%
	10%	2.4	13.2	893.0	-79.3	829.3	92.9%
	15%	3.6	12.5	893.6	-119.3	790.4	88.5%
	20%	4.9	11.8	894.1	-159.5	751.3	84.1%
	100%	31.6	0.0	1126.2	-1036.4	121.4	13.6%
Forest residue	5%	1.5	13.8	898.9	-52.6	861.7	96.5%
	10%	3.1	13.2	915.1	-105.9	825.5	92.5%
	15%	4.7	12.5	926.8	-159.3	784.7	87.9%
	20%	6.2	11.8	938.6	-212.9	743.7	83.3%
	100%	40.5	0.0	1415.2	-1383.8	71.9	8.1%

The rate of emissions shown in Table 12 does not vary among the power plant capacities modeled because of the assumptions in this analysis. Overall Table 12 shows that the negative emissions from plant regrowth can have a significant effect on total emissions and results in a drop in emissions even at low co-firing ratios (5%).

In this analysis we also calculated the amount of energy required to produce the fuel consumed in each scenario modeled. Energy use for the power generation lifecycle increases with increasing co-firing ratios, as shown in Table 13 (in the column 'Thermal energy to produce feedstocks'). To put the energy consumption in perspective we calculated the ratio of thermal energy out (the energy contained in the feedstock in each scenario) to the energy in (the energy required to produce the feedstock for each scenario). The results of these calculations are shown in Table 13.

Table 13. Results of fuel cycle energy analysis given as the ratio of thermal energy out (energy contained in the feedstock for each scenario) to energy in (thermal energy required to produce the feedstock) for each co-firing scenario.

Fuel	% co-fire	Feedstock thermal energy (BTU/kWh)	Thermal energy required to produce feedstocks (BTU/kWh)	Ratio of thermal energy out:energy in
Coal	100%	6824	137	49.9
Farmed trees	5%	6911	142	48.6
	10%	6964	147	47.4
	15%	6981	151	46.3
	20%	6999	155	45.2
	100%	9099	278	32.8
Herbaceous biomass	5%	6911	145	47.6
	10%	6964	153	45.4
	15%	6981	161	43.5
	20%	6999	168	41.7
	100%	9099	362	25.1
Forest residue	5%	6911	147	47.1
	10%	6964	156	44.7
	15%	6981	165	42.4
	20%	6999	173	40.4
	100%	9099	397	22.9

Although biomass co-combustion and combustion can produce significant reductions in GHG emissions, the system's ratio of thermal energy out to energy in decreases significantly when firing 100% biomass. Nonetheless, the ratio of energy output to energy input is much more favorable than for biofuels, which some studies have claimed to be less than one (Pimentel & Patzek, 2005) or slightly above one (Felix & Tilley, 2009).

3.4 Model Verification

To verify the results from the model they were compared to findings from a 2004 NREL report by Mann and Spath. A 2001 study by the same authors also analyzes the biomass to power lifecycle, but does not present results that can be compared to this study. The Mann and Spath 2004 article quantifies the energy and GHG emissions associated with different levels of biomass co-firing. Their lifecycle boundaries are similar to those used in this model except that they include the energy and emissions from power plant retrofits in their analysis. Mann and Spath use waste biomass as the feedstock in their study and count the emissions that would have resulted from landfilling this biomass waste as negative emissions in the biomass/coal lifecycle. The Mann and Spath results allow for the landfilling carbon credit to be separated from the fuel cycle results, which was done in the summary shown in Table 14.

Table 14. Summary of the emissions results from Mann and Spath (2004) and from this study (GREET adaptation). (Pamela L Spath & Mann, 2004)

Study	% co-fire (heat input)	Plant Capacity (MW)	Power plant efficiency (%)	Gross CO_2 eq. emissions (g/kWh)	% difference from this study	Biomass used
Mann and Spath, 2004	0%	600		847	-5%	Urban waste biomass
	15%	600		908	-4%	
	100%	600		1217	-16%	
GREET Adaptation	0%	200	40.00%	892.9		Forest Residue
	5%	198	39.50%	914.3		
	10%	196	39.20%	931.4		
	15%	196	39.10%	944.0		
	20%	195	39.00%	956.6		
	100%	150	30.00%	1455.8		

For this comparison the forest residue biomass category is used because it is most similar to the two waste categories studied by Mann and Spath. Waste feedstocks do not have a cultivation step and only include energy and emissions from collection and transportation in their lifecycle. The comparison in Table 14 shows that in the 2004 Mann and Spath study (which does not include negative emissions), the emissions per kWh of electricity produced increases as the co-firing ratio increases, following the same trend exhibited in this analysis. The Mann and Spath 2004 study does not include much detail beyond that shown in Table 14, therefore a detailed comparison of the fuel cycle steps analyzed in their study and this one cannot be completed. (Pamela L Spath & Mann, 2004) The similarity between the results from this analysis and the results from the Mann and Spath 2004 study verify this analysis. The difference between these analyses is 5% at most for all co-firing ratios and 16% for the 100% biomass scenario.

3.5 Conclusion

The model presented in this chapter successfully quantifies the fuel cycle energy inputs for three biomass feedstocks as well as the emissions from their production and combustion. The results of this analysis confirm that biomass co-combustion with coal can decrease overall emissions from electricity generation (when there are no land use change emissions) and produces more energy than is consumed during the fuel cycle, which is a point of contention for domestic ethanol and biodiesel production. The disagreement over the net energy from biofuel production is partly rooted in a disagreement over the limits to the biofuel lifecycle analysis. Even in studies that use boundaries similar to those presented in this analysis the ratio of energy out to energy in for biofuels is, at its maximum, approximately 2.25 (Shapouri, Duffield, & Wang, 2002). Biomass combustion for electricity generation presents a far more favorable energy ratio than biofuels, while resulting in a decrease in GHG emissions when compared to coal combustion.

Although this analysis produced useful insights into the effects of biomass co-firing in terms of energy use and GHG emissions, there are many improvements needed to provide more accurate results. In particular transportation energy and emissions should be re-calculated to reflect the increased transportation distance associated with higher levels of co-combustion. Future iterations of this analysis should also include the energy and emissions from retrofits to existing power plants for co-firing. Energy requirements and emissions should also be calculated for dedicated equipment used for biomass cultivation, harvesting, and transport. The contribution of this equipment to overall energy and emissions should be amortized over the lifetime of the equipment and would therefore require a dynamic model of a biomass co-firing system over time. In this model the effect of land use change emissions are not calculated. As mentioned previously, land use change emissions depend on several variables that are unique to the biomass and growing conditions. Because land use change emissions vary over time (they can even become negative with proper land management), they should also be analyzed using a dynamic model.

Contributions to lifecycle energy use and emissions from the above mentioned processes may be mitigated through a well-designed co-firing system. A biomass feedstock with minimal input and maintenance requirements will minimize energy and emissions from cultivation. Likewise, maximizing the efficiency of the co-fired power plant while minimizing the travel distance of biomass will minimize the overall contribution of transportation and biomass cultivation to total energy use and GHG emissions. Land use change effects will be minimized if biomass does not displace crops or a carbon storing ecosystem.

Chapter 4. Biomass with CCS Fuel Cycle Emissions Model

Adding carbon capture and sequestration to a power plant firing or co-firing biomass creates a permanent sink for a portion of the atmospheric carbon emitted when biomass is combusted. Therefore coupling biomass to power with a carbon capture and sequestration (CCS) unit has the potential to result in negative GHG emissions. A schematic of the basic carbon emissions and sinks is shown in Figure 5.

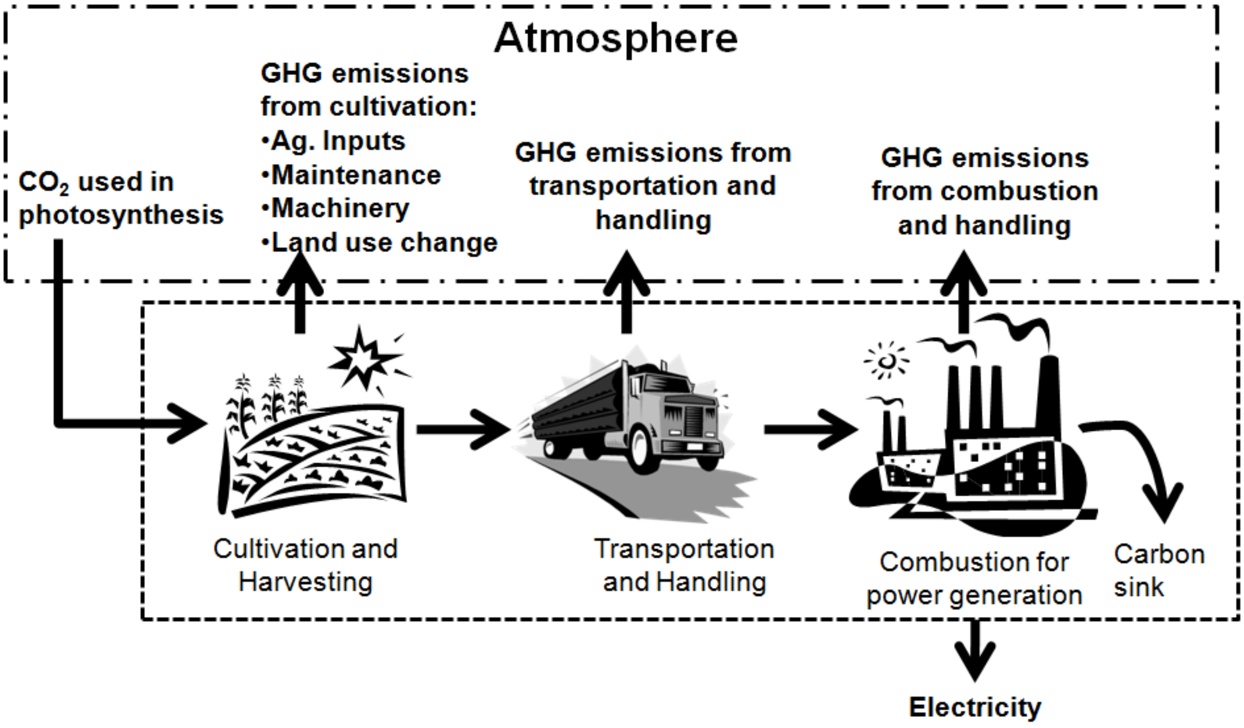
Atmosphere
GHG emissions from cultivation:
•Ag. Inputs
•Maintenance
•Machinery
•Land use change
GHG emissions from transportation and handling
GHG emissions from combustion and handling
CO_2 used in photosynthesis
Cultivation and Harvesting
Transportation and Handling
Combustion for power generation
Carbon sink
Electricity

Figure 5. Schematic of biomass to power carbon emissions and sinks with carbon capture and sequestration.

This system, though, will still have emissions from the cultivation and transportation of biomass to the power plant. Carbon emissions from the biomass with CCS system shown in Figure 5 can be positive if more emissions are produced throughout the lifecycle of the biomass and power plant operation than are sequestered in the carbon sink. In this chapter the GREET model adaptation presented in the previous chapter is adjusted to quantify the emissions from a biomass with CCS (BECCS) power plant. All of the methodology and assumptions described in Chapter 3 still hold in the present analysis. The rest of this chapter will detail the CCS particular adaptations made to the model and contextualize the results in terms of the land area needed to grow biomass to offset a given amount of GHG emissions.

4.1 Methodology

The GREET model adaptation described in the previous chapter is used for this analysis with adjustments to account for the effects of adding a CCS unit to the power plant. Table 15 shows the adjusted efficiency values used for this scenario. Adding a CCS unit to a pulverized coal plant decreases its efficiency by approximately 10.75 percentage points (NETL, 2010), which is reflected in the efficiency values in Table 15.

Table 15. Summary of the six scenarios modeled for the biomass to power with CCS scenario.

Percent Biomass Co-firing	Plant Efficiency	Facility size (MW)	Facility size (MW)	Facility size (MW)
0%	29.3%	73.3	109.9	146.5
5%	28.8%	72.0	108.0	144.0
10%	28.5%	71.3	106.9	142.5
15%	28.4%	71.0	106.5	142.0
20%	28.3%	70.8	106.1	141.5
100%	19.3%	48.3	72.4	96.5

This analysis models combustion of biomass and coal in a power plant with a CCS unit capable of capturing 90% of carbon dioxide in the flue gas. Net emissions from the entire system were calculated using Equation 4.

$$\text{net emissions} = 10\%(C_{CO_2}) + C_{GHG} + L_{coal} + L_{biomass} - S_{plant} \qquad \text{(Eq. 4)}$$

In Equation 4 C_{CO_2} represents the total carbon dioxide emissions from combustion, C_{GHG} represents other GHG emissions from combustion besides carbon dioxide expressed in global warming potential, L_{coal} are the coal fuel cycle emissions, $L_{biomass}$ represents biomass fuel cycle emissions, and S_{plant} represents the carbon the biomass regrowth captures from the atmosphere.

Adding a CCS unit to a power plant decreases the plant output by approximately 25%. (Herzog et al., 2009) In this analysis the emissions from new generation capacity to replace the loss in capacity due to CCS is not included in the model, in part because the replacement of capacity lost to CCS is decided by macroeconomic effects and may not result in a direct increase in capacity. Nonetheless this is an important point to consider as added capacity will affect the carbon balance of the co-firing and CCS system.

This analysis does not account for the emissions from carbon transport and storage. While relevant to the biomass and CCS power generation system, the GHG emissions are assumed to be small from the transport and storage system.

4.2 Results

The simulation shows that only three co-firing ratios (15%, 20% and 100% biomass firing on a heat basis) have the potential for negative net emissions from all feedstocks. These scenarios are summarized in Table 16.

Table 16. Net emissions from biomass co-firing in tons CO_2 equivalent per ton of biomass feed with and without CCS.

Co-firing ratio	g CO_2 equivalent emissions/kWh					
	Farmed Trees	w/ CCS	Switchgrass	w/ CCS	Forest residue	w/ CCS
0%	892.9	143.0	892.9	143.0	892.9	143.0
5%	861.3	89.6	863.6	93.1	861.7	77.3
10%	824.7	34.2	829.3	41.2	825.5	9.2
15%	783.4	-22.3	790.4	-11.7	784.7	-59.9
20%	742.0	-79.2	751.3	-65.0	743.7	-129.5
100%	61.0	-1448.6	121.4	-1344.8	71.9	-1817.9

The grams of CO_2 equivalent emissions sequestered per kilowatt hour are the same for all three power plant sizes simulated in this analysis for each biomass type. This result stems from simplifying assumptions made in the model.

Table 16 shows that if the goal of a biomass and CCS coal co-firing power plant is to capture carbon dioxide from the atmosphere, power plants need to co-fire 15% or more biomass (farmed trees, switchgrass, or forest residue) on a heat basis. These results also show that forest residue has the most negative emissions followed by farmed trees and switchgrass, in that order. This analysis suggests some routes for maximizing negative emissions from biomass coupled with CCS.

4.3 Land Area Requirements

This section puts the negative emissions from biomass co-combustion coupled with CCS in context by calculating the land area of biomass crops necessary to offset a given amount of emissions, in particular emissions from aviation. In addition this section includes a verification of the results from this study and a calculation of the land area necessary to reach DOE biomass co-firing goals.

For this analysis a range of typical yields for farmed trees and switchgrass is used to determine what land area would be needed to offset carbon emissions from aviation and to provide a given quantity of biomass. The biomass crop yield values used in this analysis are summarized in Table 17.

Table 17. Yields for farmed trees and switchgrass (Aravindhakshan et al., 2010; Klass, 1998; Strauss & Grado, 1992; Venturi et al., 1999)

Fuel	Maximum yield (t/ha/yr)	Minimum yield (t/ha/yr)
Farmed trees	22	15
Switchgrass	23	10

Forest residues are not included in Table 17 because they are the woody byproducts of commercial operations and include the slash left on site after logging, non-merchantable parts of the tree (including stems, stumps, foliage, and damaged trees), and residues from lumber production (including bark and wood). Since commercial forestry is a finite industry, using yield values to calculate the area of forestry activities needed to offset a given CO_2 emitting activity does not make sense. Therefore this analysis will rely on results from inventories of forest residues to calculate the amount of CO_2 emissions that could be offset if all wasted residues were used for power generation. (Klass, 1998) The forest residue calculation is shown later in this chapter.

Land area to offset aviation emissions of GHGs

Aviation was chosen as the sector for comparison in this study because of the difficulty in formulating a renewable alternative to aviation fuels and because of the growing contribution of this sector to GHG emissions worldwide (currently at 2-3% of anthropogenic emissions and expected to grow by approximately 4.7% year on year).(Blakey, Rye, & Wilson, 2011) Data for the emissions for aviation activities in the US were obtained from the EPA. Data for emissions from aviation in 2009 are shown in Table 18 below.

Table 18. GHG emissions from aircraft in the US in 2009. (Note: These values do not include international bunker fuel use in aviation) (USEPA, 2011)

Aircraft category	Emissions in million t CO_2 eq./yr
Commercial aviation	123
Military aircraft	15.5
General aviation aircraft	16.6

The negative emission results $\left(\frac{t_{biomass}}{t_{neg.emissions}}\right)$ shown in Table 16 (adjusted to represent mass of biomass per mass of negative emissions) were coupled with the biomass yield $(y_{biomass})$ range given in Table 17 to find the area of biomass cultivation necessary ($A_{biomass}$) to offset a given amount of CO_2 emissions per year $\left(\frac{t_{CO_2}}{yr}\right)$ using Equation 5.

$$A_{biomass} = \left(\frac{t_{CO_2}}{yr}\right)\left(\frac{t_{biomass}}{t_{neg.emissions}}\right)(y_{biomass})^{-1} \qquad \text{(Eq. 5)}$$

Using Equation 5 and the data shown above the land area necessary to offset the three categories of aviation emissions was calculated. Results of this analysis are summarized in Table 19.

Table 19. Land area planted with biomass required to offset carbon emissions from three aviation categories.

Biomass source	% co-firing	Min. land to offset commercial aviation (sq. mi)	Max. land to offset commercial aviation (sq. mi)	Min. land to offset military aircraft (sq. mi)	Max. land to offset military aircraft (sq. mi)	Min. land to offset general aviation (sq. mi)	Max. land to offset general aviation (sq. mi)
Farmed trees	15%	89261	130916	11298	16570	12099	17745
	20%	33636	49333	4257	6244	4559	6687
	100%	13478	19768	1706	2502	1827	2679
Switch-grass	15%	184626	424640	23368	53747	25026	57559
	20%	44512	102378	5634	12958	6034	13877
	100%	15777	36287	1997	4593	2139	4919

Table 20 shows the area of land used for crops and other agricultural uses in the United States in 2007 and the area of three states to put the results in Table 19 in perspective.

Table 20. Area used for various agriculture practices in the US in 2007 and state land area. (USCB, 2011; USDA, 2011)

	Land area (sq. mi)
US total land area	3,537,438
Cropland	635,039
Woodland	117,342
Pastureland	638,800
Conservation practices	60,230
State land area (sq. mi)	
Texas	261,797
California	155,959
Massachusetts	7,840

Land used for conservation practices may include farmland or wetlands under conservation. The results in Table 19 coupled with the values in Table 20 show that offsetting commercial aviation emissions by co-firing 20% switchgrass requires an enormous amount of cropland (an area between one quarter and two thirds the land area of the State of California) and is not a wise policy to pursue. Farmed trees co-fired at 20% with coal would also require a significant amount of land area (about 32% the area of the State of California at most) and may not be a feasible goal. The US Department of Energy (DOE) in their multi-year program plan for biomass has stated the goal of developing technologies to enable at least 20% co-firing with coal by 2014. (USDOE, 2011b) With 20% co-firing of biomass the US would have to dedicate 5% to 8% of cropland to tree farming to offset emissions from commercial aviation. This proposal would require a study of the effects throughout the agriculture system of such a change in land use. Firing exclusively biomass requires the least amount of land to offset each aviation category, but may be costly to implement in existing power plants.

Result Verification

As verification of the simulation shown in this chapter the results from the land area analysis presented here are compared to an analysis previously done by Ranjan (2010) on the land area of switchgrass needed to achieve 1Gt of negative emissions. Ranjan uses the case of a 500 MW dedicated biomass IGCC plant operating at 22% efficiency. Using the same goal of offsetting 1Gt of carbon dioxide emissions, this analysis found that the land requirement for growing switchgrass ranges from 130,000 (when yields are

23 t/ha/yr) to 300,000 (when yields are 10 t/ha/yr) square miles. Ranjan calculated the necessary land area as 200,000 square miles when switchgrass yields are 12 tons/ha/yr and 99,500 square miles when yields are 24.5 t/ha/yr; these results are slightly lower than the land areas calculated in our study. Despite these differences, Ranjan's results are consistent with our findings.

Evaluation of DOE co-firing targets

In 2010 utilities in the US generated 1847 terawatt hours from coal consuming 1046 million tons of coal (EIA, 2011b). If 20% of all coal generation in the US were replaced with biomass on a heat basis, which would be in line with the DOE's stated goal, the land area needed and amount of carbon offsets are given in Table 21.

Table 21. Tons of biomass, land area, and negative emissions from substituting 20% of utility fired coal with biomass (by heat).

Million tons of farmed trees needed	244
Min. farmed tree land area (sq. mi.)	42740
Max. farmed tree land area (sq. mi.)	62686
Million tons of herbaceous biomass needed	277
Min. switchgrass land area (sq. mi.)	46445
Max. switchgrass land area (sq. mi.)	106822
Negative emissions farmed trees (million tons CO_2 eq.)	-156
Negative emissions from switchgrass (million tons CO_2 eq.)	-128

Table 21 shows that with 20% co-firing in existing coal utilities with CCS the negative emissions possible could offset emissions from commercial aviation if switchgrass is used and emissions from all aviation sectors if farmed trees are used. This scheme would also require about 7% to 17% of US cropland to grow enough switchgrass or farmed trees for 20% co-firing in the US.

Potential offsets from forest residue

Given the finite amount of forest residue produced annually, the emissions offset possible from co-firing the available residues was calculated. The 2010 Billion Ton Study (USDOE, 2011a) estimates that current logging residue in the US totals approximately 93 million dry tons annually. Approximately 68 million dry tons of this biomass is logging residue (which corresponds to the forest residue category in this study). To ensure the sustainability of logging activities 30% of residue should be left behind on the forest floor; this leaves about 48 million dry tons of forest residue for conversion to power. Table 22 summarizes the carbon emissions that can be offset by combusting all available forest residue at the three co-firing ratios (15%, 20% and 100%) that yield negative emissions. The results in Table 22 were the same at all plant capacities (100, 150 and 200 MW) reviewed in this study since the assumption is that all biomass residues will be converted to electricity at a given rate of co-firing and that the emissions rate is constant across co-firing ratios at different plant sizes. Therefore the results shown in Table 22 hold for all plant sizes simulated. It is important to note that the results in Table 22 assume that the biomass is co-fired in as many plants as are necessary to use all available forest residue at the given co-firing ratio. Therefore, at 15% co-firing, 85% of the fuel in the power plant is coal, while at 20% co-firing, only 80% of the fuel is coal. The latter case uses less coal per unit of biomass, so more offsets are available.

Table 22. Carbon offsets possible from 48 million dry tons of forest residues.

Percent co-firing	Carbon offsets possible from forest residues (million tons CO_2 eq.)
15%	24.7
20%	39.8
100%	76.3

At 100% co-firing the negative emissions from forest residues would account for 62% of the carbon emissions from commercial airlines. Co-firing at 20% will offset emissions from both general and military aircraft.

4.4 Discussion

The model presented here allowed for the calculation of the change in emissions for a power plant co-fired with coal and biomass with the addition of a carbon capture and sequestration unit. The CCS unit results in a significant decrease in emissions from a co-fired power plant and in negative emissions for co-firing ratios of 15% and greater for all feedstocks analyzed. Despite the significant decrease in emissions possible from co-firing biomass and coal in a plant equipped with CCS, biomass crop production should occur in a sustainable manner that will not result in significant emissions from land use change, which have the potential to exceed benefits from the CCS scheme. Careful attention must be paid to the prior use of land converted to biomass cultivation as well as to the emissions from the production of biomass to avoid overall positive emissions from this system.

This study also demonstrates that to offset GHG emissions from aviation with biomass co-firing and CCS, coal plants will have to be able to handle 20% or greater biomass by heat value. In addition, the US will have to evaluate the effects of dedicating up to 17% of cropland to biomass production in order to offset emissions from aviation. Another promising policy would be to maximize forest residue collection and use in coal fired power plants. Co-firing 20% forest residues with coal and capturing 90% of carbon dioxide emissions has the potential to offset GHG emissions from military and general aviation aircraft as well as 18% of commercial aviation emissions.

As the DOE has already noted in their multi-year program plan for biomass, technologies need to be developed to facilitate the transition to 20% co-firing in existing power plants and to enable these facilities to maximize efficiency (USDOE, 2011b). The next chapter will quantify the economic cost of converting a coal fired plant to co-fire biomass.

Chapter 5. Economic Analysis of Biomass to Power and Biomass to Power with CCS

This thesis has shown that all biomass to power scenarios, including co-firing, direct firing, and with CCS, have the potential for significant decreases in GHG emissions. However, the implementation of these technologies will depend on their economic performance. This chapter contains estimates for the levelized cost of electricity for all scenarios modeled using the GREET adaptation model presented in Chapter 3. This chapter also presents a cost estimate for biomass to power coupled with CCS systems as presented in Chapter 4.

5.1 Literature Data

Cost estimates for biomass to power systems have significant variability due to the variation in fuel costs, variety of fuel options (the quality of the fuel affects the level of retrofits necessary to an existing coal plant), and state of the plant to be retrofitted. This study relied on estimates from several literature sources to calculate an approximation to the cost of implementing the scenarios modeled in previous chapters.

Variable operations and maintenance costs and the values used to calculate variable costs used in this study are shown in Table 23. Appendix 1 contains an example of the calculations from this chapter that shows the factors used to convert values in Table 23 to variable costs in dollars.

Table 23. Variable operations and maintenance cost for biomass to power (in blue) and CCS (in peach) systems. (EIA, 2011c; Gonzalez et al., 2012; IEAGHG & ECOFYS, 2011; NETL, 2010; NRC, 2011; Tharakan, Volk, Lindsey, Abrahamson, & White, 2005)

Feedstock	Price in $/d. ton
Short Rotation Woody Crops	$89
Forest Residues	$78
Switchgrass	$79.3
Uinta Basin coal	$41
Ash	in $/ton ash
Coal Ash credit	$2
Biomass/coal ash cost	$10
CO_2 handling	in $/tonne CO2
CO_2 transport	6.5
CO_2 storage	6.5
CCS material	in $/kWh net
MEA costs	$0.0003

The feedstock costs for short rotation woody crops and forest residues are both from a study by the National Research Council. These costs are estimated for a scenario where oil costs $111 per barrel and there are no policy incentives for the use of biomass for energy production (NRC, 2011). The switchgrass cost estimate was obtained from a study by Gonzalez et al (Gonzalez et al., 2012). This study used the spot price of Uinta Basin coal from December of 2011 for the price of coal. The Uinta basin is located in Utah and produces low sulfur (0.8% SO_2), high heating value (11700 BTU/lb) coal. Uinta Basin coal is used in this study because its heating value is the closest to the HHV used in the model. (EIA, 2011c) All prices are given for delivered feedstock.

Two categories were used for ash prices. When coal is fired alone the resulting ash can be sold for use in other industries at a price of $2 per ton. If biomass is co-fired with coal or fired alone, the ash can no longer be sold and the power plant must pay $10 per ton to dispose of it. (Tharakan et al., 2005) To calculate the ash produced from the burning of coal and coal and biomass the data in Table 24 on ash as a percentage of total feedstock on a mass basis was used.

Table 24. Ash content of fuels on a mass basis. (Klass, 1998; Loo & Koppejan, 2008; USDOE, 2004)

Fuel	**Ash content on mass basis**
Coal	8.70%
Farmed trees	2.00%
Herbaceous biomass	5.47%
Forest residue	2.00%

The same ash content used for farmed trees was also used for forest residue because an estimate for this value could not be found. Forest residue is a varied feedstock and the ash content will vary depending on the types of trees harvested and the portions of the trees that are included in the residue.

The estimates for CO_2 transport and storage after capture came from an IEAGHG and Ecofys study. The values given in Table 23 were used for the cost estimates in the IEGHG Ecofys study (IEAGHG & ECOFYS, 2011). Most cost estimates given in the IEAGHG Ecofys study are in Euros; the conversion of $1.3 to 1 Euro was used to convert between currencies.

When using post combustion capture to separate CO_2 from the power plant flue gas, there is some degradation of the absorbent. In this case it is assumed that the post combustion system will use the amine MEA as the solvent and that per kWh net of power generation the cost of replacement MEA purchase will be $0.00003 (NETL, 2010).

Table 25 shows a summary of the fixed operations and maintenance (O&M) values used in the cost analysis.

Table 25. Fixed operations and maintenance cost estimates for biomass to power (in blue) and for CCS (in peach). (IEA & ETSAP, 2010; IEAGHG & ECOFYS, 2011)

Fixed O&M	Price in $/kW yr
Fixed O&M for coal plant	$104
Additional O&M for biomass firing	$12
Additional O&M for CCS	$52

To calculate fixed O&M costs when co-firing biomass and coal the fixed O&M for a coal plant was added to the product of the additional O&M for biomass firing times the co-firing ratio (this calculation is detailed in Appendix 1). The source for the additional O&M for biomass firing cost estimate does not explicitly state that the value is per kW_e of biomass, but this value is listed with other values that are explicitly given per kW_e of biomass (IEA & ETSAP, 2010). Therefore the assumption is made that additional O&M for biomass firing is given per biomass capacity.

Table 26 shows a summary of the capital costs assumed for the retrofitting of a coal fired power plant to burn biomass and for the addition of a CCS unit.

Table 26. Capital costs for retrofitting a coal power plant to fire biomass and for the addition of a CCS unit to an existing plant. Costs are given per kW_e of biomass capacity per year unless otherwise noted. (Basu, Butler, & Leon, 2011; IEAGHG & ECOFYS, 2011; Y. Zhang, McKechnie, et al., 2010)

Capital Costs	Price in $/kW yr
Direct co-firing capital costs	$150
Indirect co-firing (in $/kW$_{th}$)	$139
Retrofitting for 100% biomass	$640
Additional CCS cost	$877.50

Direct co-firing refers to the burning of biomass with coal in the same boiler. For low co-firing ratios of 5-10%, minimal retrofits (the exact co-firing ratio for which direct co-firing can be used may vary, depending on the quality of the biomass feedstock) to the plant are needed and the biomass can be burned via direct co-firing (Bain et al., 1998; IEA, 2007). Zhang et al. report that retrofits to co-fire biomass at 10-20% has a capital cost of $150 to $300 per kW_e of biomass capacity (Y. Zhang, McKechnie, et al., 2010). It is assumed that for 5% to 10% co-firing the capital cost of retrofits is $150 per kW_e of biomass capacity. At higher co-firing ratios, 15% and 20% for our analysis, it is assumed that the plant will combust biomass via indirect co-firing. Indirect co-firing consists of burning biomass in a separate boiler and avoids the negative effects that higher co-firing ratios can have on the plant's boiler such as slagging and corrosion. The cost estimate used in our analysis is for the addition of a circulating fluidized bed boiler and is given in $/$kW_{th}$ of biomass (Basu et al., 2011). The mass of feedstock needed for annual operation of each plant scenario is converted to kWth of feedstock input using the HHV of each feedstock (see Ch. 3 for this data and Appendix 1 for a sample calculation). Cost estimates for retrofitting a coal plant to fire 100% biomass vary widely, but this analysis uses the estimate used in Zhang et al. ($640/$kW_e$) after reviewing cost estimates from various retrofitting projects (Y. Zhang, McKechnie, et al., 2010).

When it comes to CCS, the unit sizing is, in part, determined by the amount of flue gas the unit must process. Biomass combustion produces more flue gas because of the moisture content of the feedstock, which makes for a more dilute CO_2 stream than would be obtained from coal combustion alone (IEAGHG & ECOFYS, 2011). Therefore the estimate for retrofitting a plant with CCS from the IEAGHG/Ecofys study is used, which specifically calculates the cost of biomass co-combustion coupled with CCS to calculate the LCOE of all plants with CCS in this study.

5.2 Methodology

For this analysis the levelized cost of electricity (LCOE) for a coal power plant retrofitted to co-fire biomass is compared to the marginal cost of electricity from an existing coal plant. This comparison is used to evaluate how the price of electricity will compare between a coal plant that does not retrofit to co-combust biomass and one that does undergo retrofits. The LCOE calculated excludes the sunk capital costs of the coal plant being retrofitted to fire biomass. Therefore costs in this study can be viewed as an additional cost onto the levelized capital costs of the power plant. The LCOE equation is shown as Equation 6.

$$\mathrm{LCOE} = \frac{\mathrm{CCF(TOC)} + \mathrm{FOM}}{8760\mathrm{(CF)(MW)}} + \mathrm{VOM} \qquad \text{(Eq. 6)}$$

The variables in Equation 6 are:

CCF= Capital charge factor, which annualizes capital costs over the project lifetime. The value used here for the CCF is 0.15/yr

TOC= Total overnight capital, which consists of the capital costs outlined in Table 26. For this analysis 110% of the total capital costs in Table 26 are used to account for capital cost overruns.

FOM= Fixed operating costs for the plant (values used for calculating this term are given in Table 25)

CF= Capacity factor of the plant, here 0.8 is used.

VOM= Variable O&M costs, values used to calculate this term are given in Table 23; fuel costs are also included in VOM

MW= Output of the plant

In this analysis the price of carbon is included as a variable operating cost. To understand how carbon price legislation would affect the economics of a coal and biomass plant, the LCOE including a price on carbon ranging from \$0/ton CO_2 equivalent to \$150/ton CO_2 equivalent is used. This price of carbon is used in conjunction with the fuel cycle emissions per kWh calculated in Chapters 3 and 4 for biomass and coal co-firing and then with the addition of CCS.

In calculating any cost given in $/kW$_e$, the original capacity of the power plant before de-rating due to biomass co-firing and CCS is used. The original plant capacity for these calculations is used because it is assumed that the plant is sized for the pre-derating capacity and therefore retrofits will occur for a plant of the derated size. Appendix 1 contains sample calculations that clarify how all calculations were carried out.

5.3 Results

Through the calculation of the LCOE of coal plants retrofitted for biomass combustion and the marginal cost of power from coal at different GHG prices, the minimum price of GHG emissions needed to make biomass to power economically viable was estimated. Figure 6, Figure 7, and Figure 8 show the results of the LCOE calculation for farmed trees, switchgrass, and forest residues.

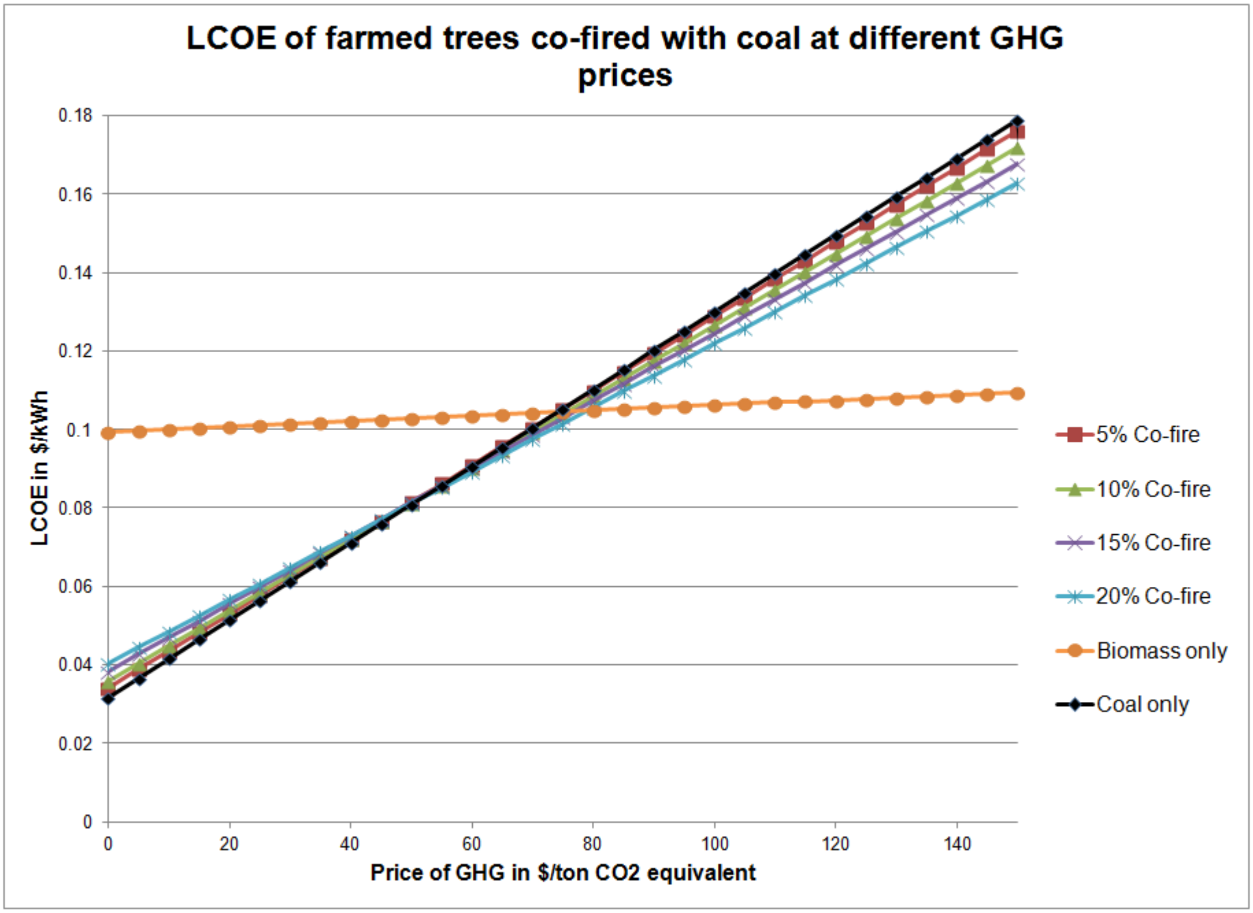

Figure 6. Plot of the LCOE of co-firing farmed trees at existing coal plants at different ratios compared to firing coal and farmed trees alone.

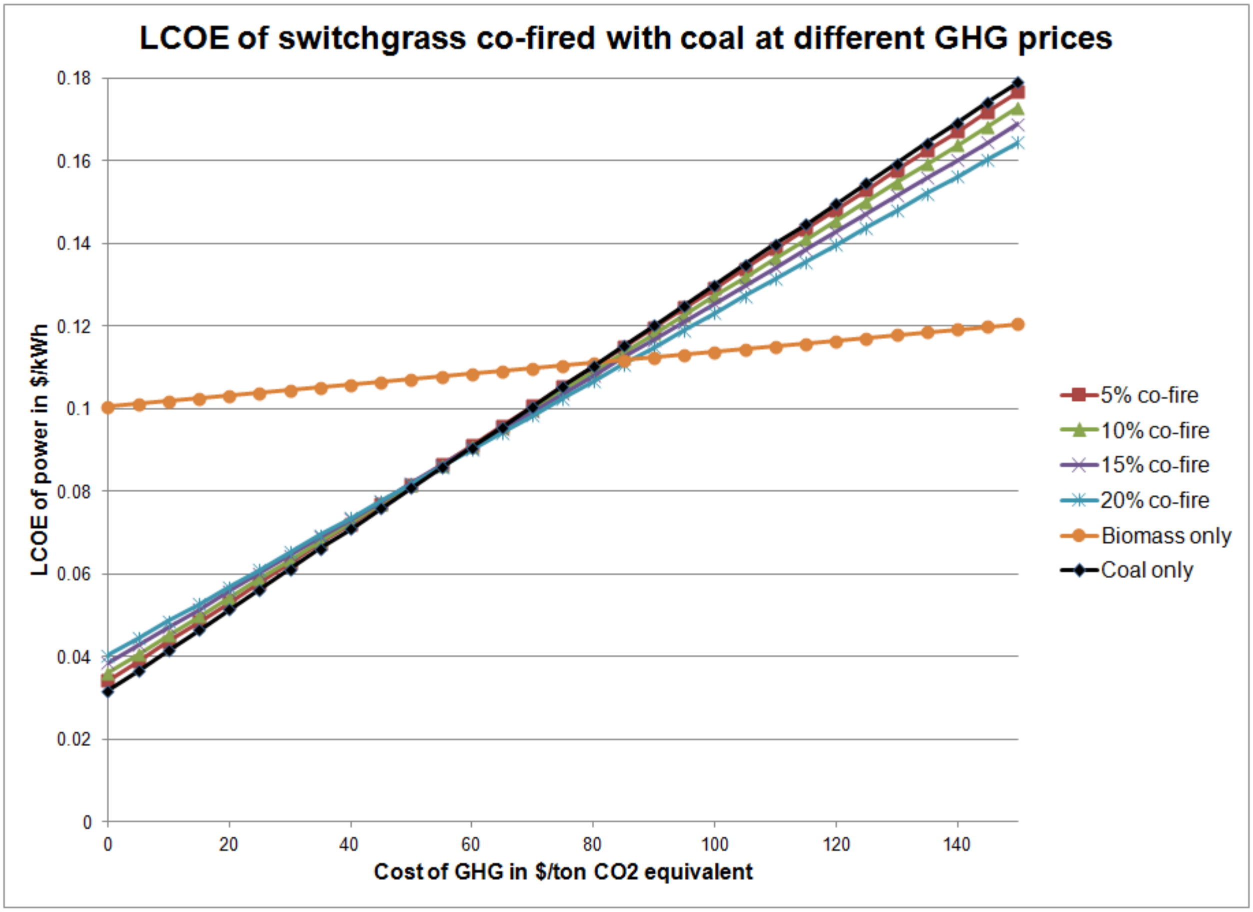

Figure 7. Plot of the LCOE of co-firing switchgrass at existing coal plants at different ratios compared to coal and switchgrass only power generation.

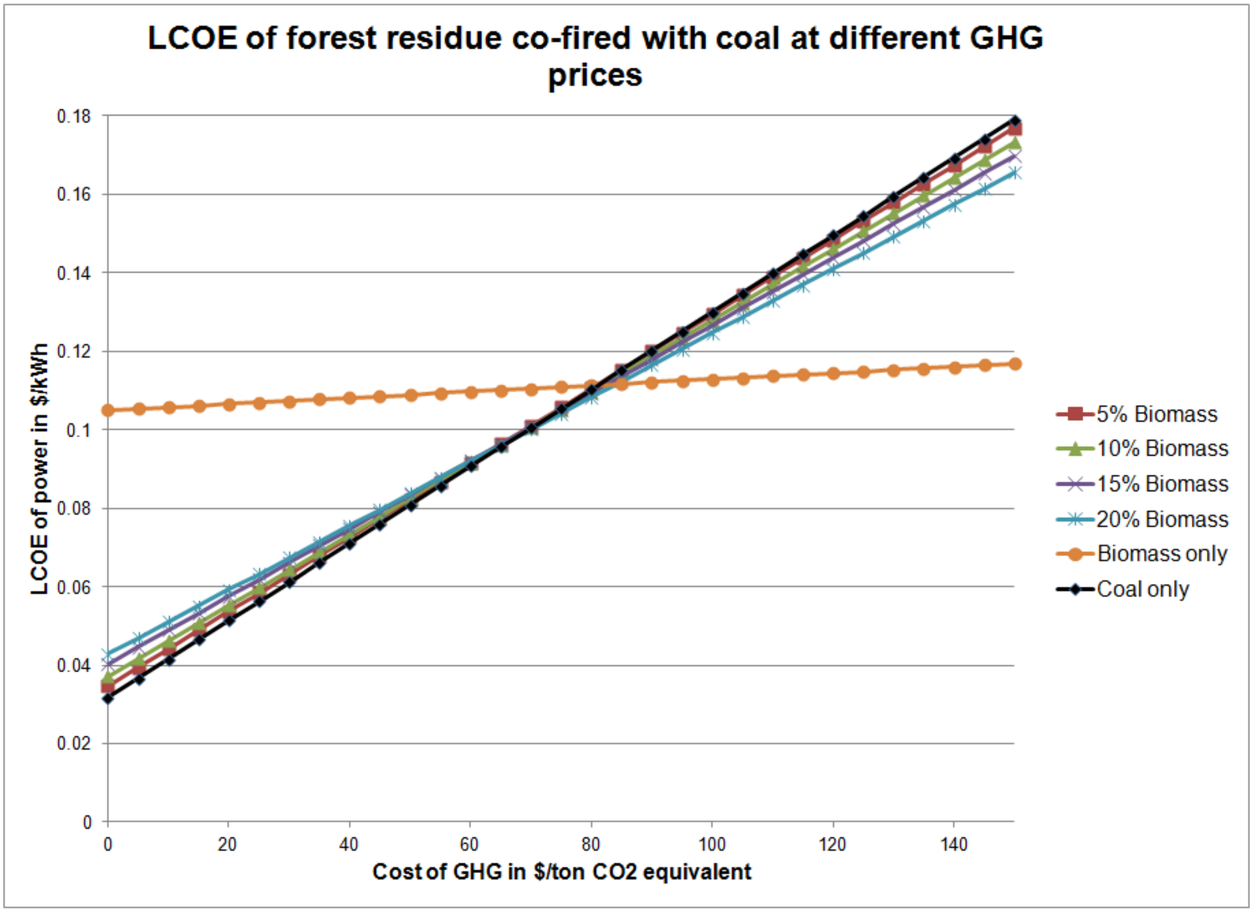

Figure 8. Plot of the LCOE of co-firing forest residue at existing coal plants at different ratios compared to coal and residue only power generation.

To give greater resolution to the cost of GHG that will make biomass co-firing competitive with coal only, the interception points of each co-firing option with the coal only cost curve was calculated. These results are shown in Table 27.

Table 27. Cost of GHG at which the coal only cost curve intercepts the biomass co-firing LCOE curve.

Coal/biomass interception points	Cost of GHG in $/CO$_2$ equivalent		
Co-firing ratio	Farmed Trees	Switchgrass	Forest Residue
5%	$69	$76	$76
10%	$57	$62	$63
15%	$55	$60	$61
20%	$52	$56	$57
100%	$74	$81	$81

The GHG costs shown in Table 27 are the cost of GHG at which plant operators would retrofit their plants to co-combust biomass. Co-firing farmed trees becomes economical at the lowest GHG cost for all co-firing ratios. The break-even (with coal firing alone) GHG cost for farmed trees is the second highest at 5% co-firing because GHG emissions do not decrease significantly yet the plant is still subject to retrofit capital costs and the higher cost of the biomass feedstock. As the co-firing rate increases, the decreased emissions mean that these plants are economical at lower GHG prices. When firing biomass alone, the high cost of the biomass feedstock and capital expenses mean that a higher GHG cost is needed to make these plants economical. Table 28 shows a breakdown of the cost components of LCOE given in percentage of the total cost at a GHG cost of \$50 per ton CO_2 equivalent.

Table 28. Components of the LCOE for farmed trees with a GHG price of \$50/ton CO_2 equivalent.

Co-firing ratio	TOC (CCF)	FOM	VOM
0%	0.0%	18.4%	81.6%
5%	0.1%	18.6%	81.4%
10%	0.1%	18.8%	81.1%
15%	0.6%	19.1%	80.3%
20%	0.8%	19.5%	79.8%
100%	5.4%	25.2%	69.4%

The results in Table 28 show that for 100% biomass firing the total overnight cost times the CCF contributes more to the LCOE than for other co-firing ratios, and variable costs contribute less to the cost for dedicated biomass plants. Therefore although firing 100% biomass has greater benefits in terms of CO_2 emissions, which results in a lower VOM, the increased capital costs (part of TOC) and feedstock costs (part of VOM) result in a higher LCOE than for 15% and 20% co-firing.

Despite the low projected GHG cost necessary to make co-firing 15% and 20% biomass economical, there is little experience with co-firing at these ratios in large installations in the US. Most installations co-fire 5% to 10% biomass or are dedicated biomass facilities. Therefore the cost estimates at 15% and 20% biomass co-firing have a higher uncertainty compared to the other co-firing ratios.

Figure 9, Figure 10, and Figure 11 show the results of the economic analysis for the addition of a CCS unit to the biomass co-firing plant. The case of coal alone without CCS (the red line) is included in all graphs to show the cost of GHG emissions at which a coal plant would find it economically favorable to add CCS to their plant.

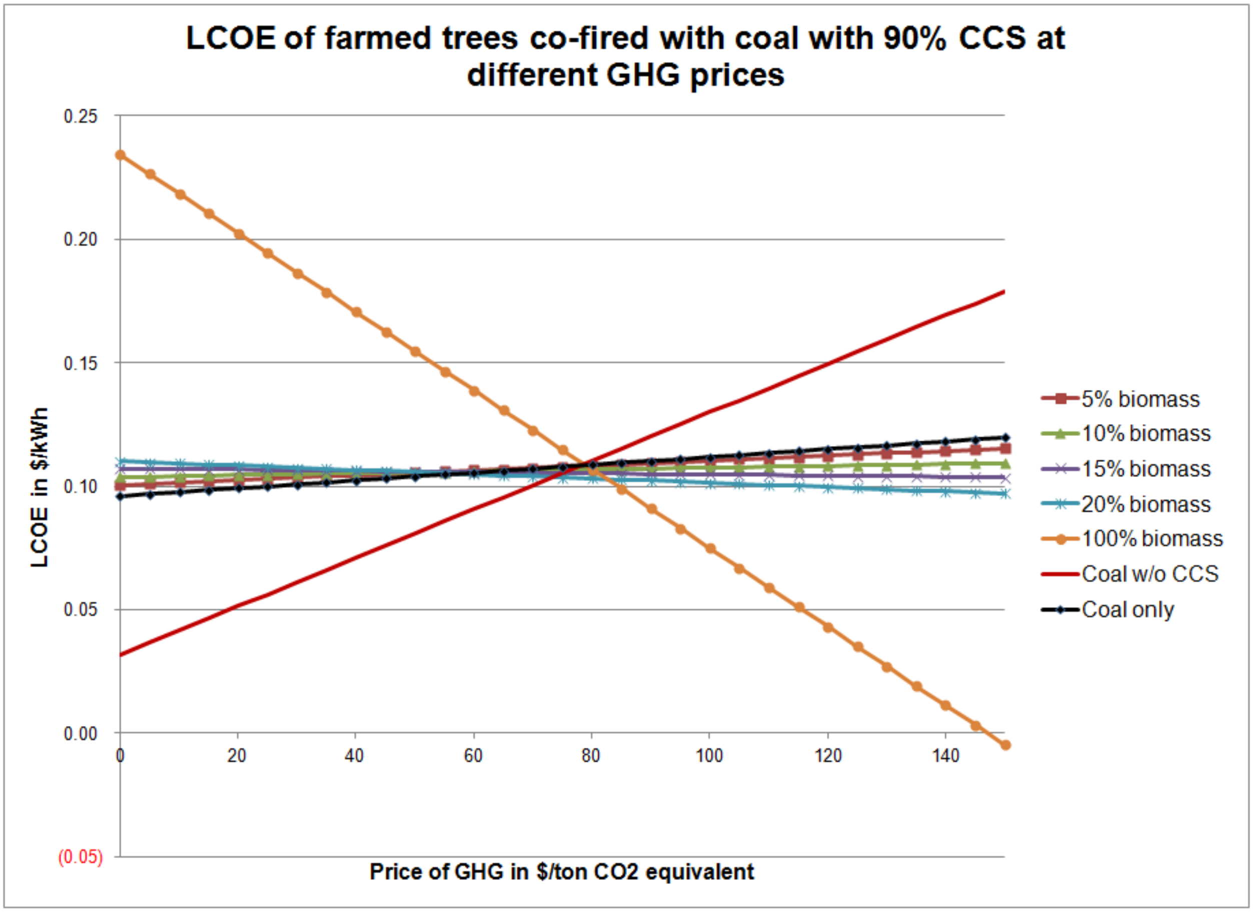

Figure 9. Plot of the LCOE curves for coal, farmed trees and coal, and farmed trees alone with 90% CCS at different GHG prices.

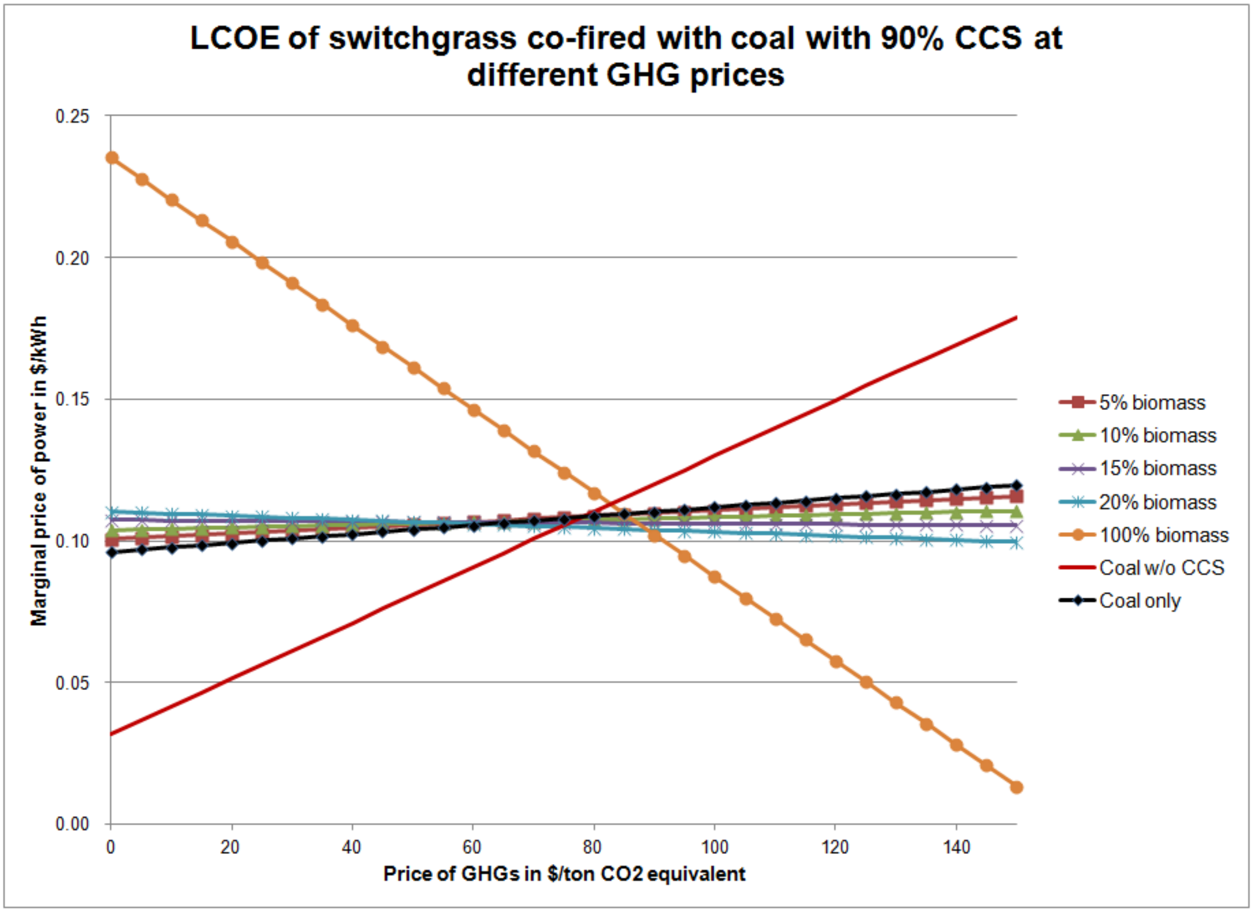

Figure 10. Plot of the LCOE curves for coal, switchgrass and coal, and switchgrass alone with 90% CCS at different GHG prices.

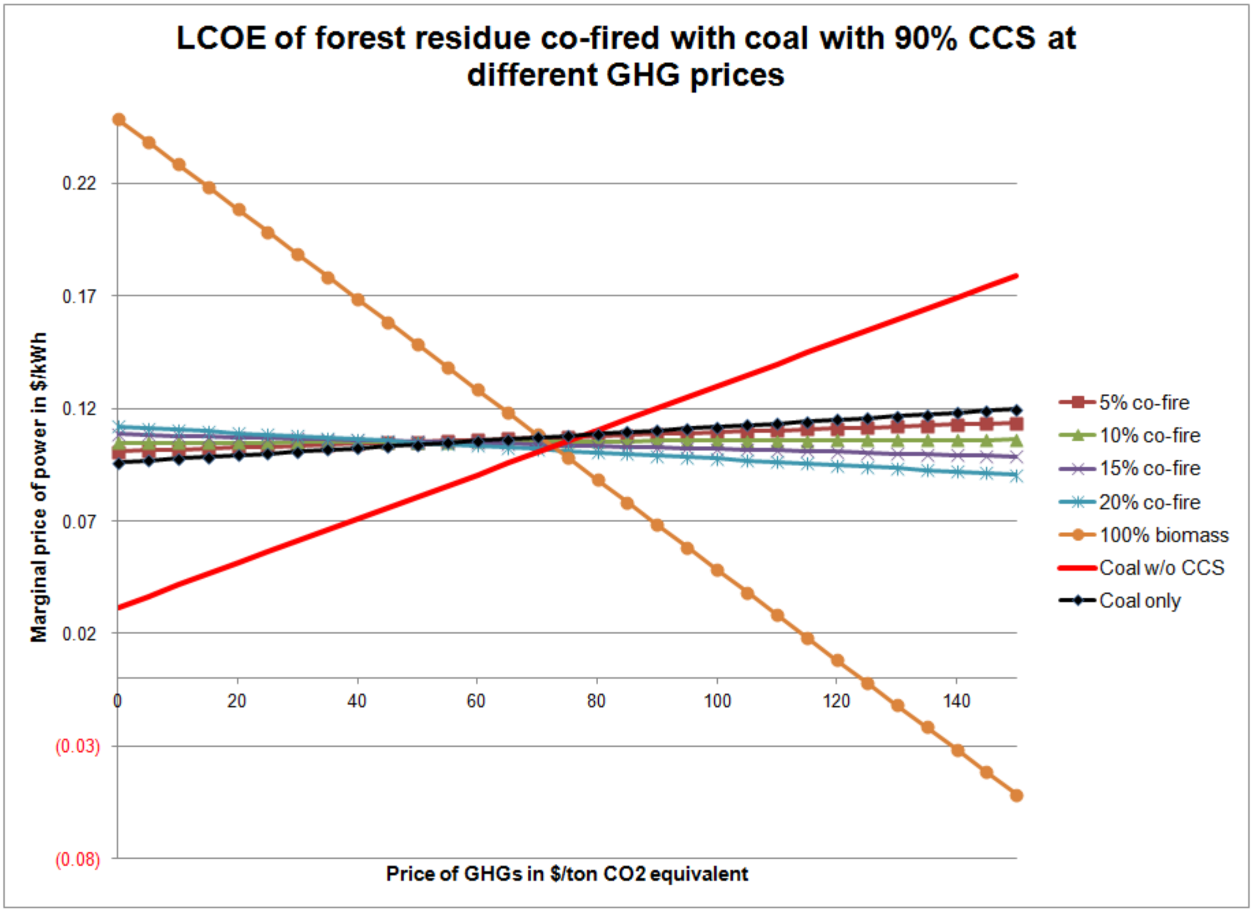

Figure 11. Plot of the LCOE curves for coal, forest residue and coal, and forest residue alone with 90% CCS at different GHG prices.

Table 29 gives numerical values for the cost of GHG at which adding a co-firing unit to a coal plant, biomass plant and co-firing plant becomes economically favorable over firing coal only in a plant without CCS.

Table 29. Cost of GHG at which the coal with CCS and biomass with CCS cost curves intercept the coal only without CCS cost curve.

Coal/biomass interception points	Cost of GHG in $/CO$_2$ equivalent		
Co-firing ratio	Farmed Trees	Switchgrass	Forest Residue
Coal only	$78	$78	$78
5%	$78	$78	$77
10%	$76	$77	$75
15%	$75	$76	$73
20%	$73	$75	$71
100%	$79	$83	$73

Table 29 shows that forest residue co-firing with coal coupled with CCS becomes economically preferable to coal combustion without CCS at the lowest cost of GHG. This result stems from the low CO_2 equivalent emissions per kWh of forest residue combined with coal; forest residue has the lowest emissions of all feedstocks analyzed. For the biomass with CCS scenarios the same dynamics seen in the non-CCS cases in Table 27 are present. High capital costs and feedstock costs for the 100% biomass case overwhelm the decreased CO_2 emissions as compared to 20% biomass co-firing such that a higher cost of GHG emissions is needed for dedicated biomass firing to become economical than for 20% co-firing. Table 30 shows the breakdown of the LCOE for the coal, biomass, and co-firing scenarios with CCS. Total overnight costs (TOC) times the capital charge factor (CCF) is a greater contributor to the LCOE for dedicated biomass than for the co-firing scenarios. This breakdown explains why the intersection point for 100% biomass is greater than for 20% co-firing—the high capital costs for a dedicated biomass plant contribute to the LCOE more than the decreased GHG emissions (part of VOM) decrease the LCOE.

Table 30. LCOE breakdown for plants with CCS co-firing farmed trees with a GHG price of $50 per ton CO_2 equivalent.

Co-firing ratio	TOC (CCF)	FOM	VOM
0.0%	27.2%	29.3%	43.5%
5.0%	27.5%	29.5%	43.0%
10.0%	28.0%	29.9%	42.2%
15.0%	29.1%	30.0%	40.9%
20.0%	29.9%	30.3%	39.9%
100.0%	48.0%	32.2%	19.8%

Of note in Figure 9, Figure 10, and Figure 11 is the negative slope for the LCOE curve for co-firing ratios of 15% and higher. As noted in Chapter 4, co-firing ratios equal to 15% and higher have negative emissions. Therefore the LCOE of these co-firing ratios decreases as the cost (or benefit they receive for negative emissions) of GHG increases. Firing biomass alone coupled with CCS even attains a negative LCOE for forest residue and farmed trees (meaning that the plant could earn money by selling carbon credits) at high enough GHG prices. Table 31 shows the price of GHGs at which dedicated biomass plants have a zero LCOE, which is also the cost of avoided GHG emissions.

Table 31. Price of GHG at which the LCOE of a dedicated biomass plant is zero, also the cost of avoided GHG emissions.

Feedstock	GHG cost at which LCOE is zero
Farmed Trees	$147
Switchgrass	$159
Forest Residue	$124

As a means of verifying the results from this analysis the cost of avoided GHG emissions in Table 31 are compared with results from Ranjan (2010). Ranjan's report gives an estimate for the cost of avoided GHG emissions from switchgrass costing $3 to $8/GJ. Using this feedstock cost range Ranjan reports that the cost of avoided emissions is $110 to $178 per ton CO_2 avoided; this study finds the cost of avoided emissions to be $159/ton CO_2 equivalent. Given that the cost of switchgrass used in this study is at the lower end of the range given by Ranjan (we use $4.8/GJ for switchgrass in this study), Ranjan's results verify the findings presented here (Ranjan, 2010).

5.4 Sensitivity Analysis

To understand how variations in the capital costs and feedstock costs can affect the overall economics of biomass to power generation and CCS, a sensitivity analysis of these variables was conducted. As noted in other studies, the capital costs of coal plant retrofits to combust biomass can vary and are difficult to generalize (IEAGHG & ECOFYS, 2011; Y. Zhang, McKechnie, et al., 2010). Likewise the cost of biomass feedstocks can vary depending on the exact feedstock being used and its availability locally. In addition, if demand for biomass feedstocks increase, the price may also increase. Therefore for the sensitivity analysis a high and low cost scenario for both capital and feedstock costs is analyzed. The cost of coal is not varied in this analysis. Table 32 shows the costs used in each scenario examined. The medium scenario is the base case used for the analysis in the previous section.

Table 32. Scenarios used in sensitivity analysis; medium scenarios were used in the base case analysis in the previous section.

Capital Costs	In $/kW$_e$ unless otherwise noted		
	Low scenario	Med. (Base) Scenario	High Scenario
Direct co-firing capital costs	50.00	150.00	300.00
Indirect co-firing	50.00	139.00 ($/kW$_{th}$)	400.00
Retrofitting for 100% biomass	150.00	640.00	1500.00
additional CCS cost (co-firing)	600.00	877.50	1050.00
Feedstock	In $/ton		
	Low scenario	Med. (Base) Scenario	High Scenario
Short Rotation Woody Crops	53.00	89.00	100.00
Forest Residues	42.00	78.00	100.00
Switchgrass	42.00	79.30	100.00

The low scenario capital costs used in our analysis are from the lower end of cost estimates reported in the literature. ECOFYS and IEA report that retrofitting a coal plant to co-fire biomass can cost as little as $50 per kW$_e$ (IEA, 2007; IEAGHG & ECOFYS, 2011). Zhang et al. reported that on the high end retrofitting a coal plant for co-firing can cost as much as $300 per kW(Y. Zhang, McKechnie, et al., 2010). Although the price range given by Zhang applies co-firing ratios of 10% to 20%, which would include the 15% and 20% co-firing scenario in this study, our previous estimate of $139/kW$_{th}$ (equivalent to approximately $355 per kW) is slightly higher than $300 per kW. Therefore $400 per kW for the capital cost for indirect co-firing is used in the high scenario. Zhang et al. also report that studies of coal power plant retrofits to combust 100% biomass range from $150/kW to $1500/kW; therefore this range is used in the sensitivity analysis. For the CCS cost range values from a study by IEAGHG and Foster Wheeler were used. In their estimate for adding a CCS unit to a circulating fluidized bed dedicated biomass plant they used approximately $1000/kW; the value used for biomass co-firing was approximately $800/kW. Here $1050/kW was used for the high cost scenario and, given that the IEAGHG study did not differ much from the Ecofys cost used in the medium scenario, $600/kW was estimated for the low cost scenario.

In terms of feedstock costs, the low cost scenario corresponds to a price of $2.70 per GJ, which was the estimate for minimum non-delivered biomass price used in a study by Tharakan et al. of $2.13/GJ (Tharakan et al., 2005) added to the medium transport cost ($0.52/GJ) given in the Ecofys study (IEAGHG & ECOFYS, 2011). The high cost for biomass feedstocks was chosen arbitrarily.

The capital cost sensitivity analysis is run with feedstock costs in the medium/base scenario. Table 33 shows the coal without CCS cost curve interception points with the co-firing with CCS cost curve at the high and low capital cost scenarios.

Table 33. Results of capital cost sensitivity analysis.

Coal/biomass interception points	Low capital cost scenario, W/O CCS			High capital cost scenario, W/O CCS		
Co-firing ratio	Farmed Trees	Switchgrass	Forest Residue	Farmed Trees	Switchgrass	Forest Residue
5%	$66	$72	$73	$74	$81	$81
10%	$53	$58	$60	$61	$67	$68
15%	$46	$50	$52	$57	$61	$63
20%	$43	$47	$48	$53	$57	$59
100%	$57	$63	$64	$104	$113	$111
	Low capital cost scenario,with CCS			High capital cost scenario,with CCS		
5%	$67	$68	$67	$85	$85	$84
10%	$66	$67	$66	$83	$84	$81
15%	$64	$65	$64	$81	$82	$82
20%	$63	$64	$63	$79	$80	$80
100%	$64	$67	$65	$98	$103	$94

The results in Table 33 show that the low capital cost results in a moderate decrease in the coal/biomass cost curve intersection point of 4% to 6% for the 5% co-firing case without CCS. The CCS scenarios, in contrast, show larger decreases in the intersection of the coal only curve and the co-firing cost curves of about 15% to 16%. These results reflect the larger contribution of TOC in the LCOE breakdown shown in Table 30 for plants with CCS than in Table 28 for plants without CCS. In the low capital cost scenario co-firing biomass without CCS becomes economical at $43 per ton CO_2 equivalent at the least, a decrease over the base scenario of 17%. When CCS is added the lowest cost at which the co-firing system becomes economical is $63 per ton CO_2, which is a decrease over the base case scenario of 11%. This effect results from the change in capital costs between the base case and the low capital cost scenario. For a plant without CCS, the capital cost decreases by 86% over the base case, whereas for a plant with CCS the capital cost in the low scenario decreases by 35% over the base case. Although the effect of TOC(CCF) on the LCOE for a plant without CCS is smaller than for a plant with CCS (see Table 28 and Table 30), the higher increase in the capital costs for a plant without CCS overcomes the lower TOC(CCF) as compared to a plant with CCS.

Similar to the low capital cost scenario, the high capital cost analysis also shows small deviations from the base case. When co-firing 5% biomass in a plant without CCS, the high capital costs increase the cost curve intersection point with the coal only cost curve by 6% to 7%. Likewise the change in the cost curve intersection point for the plants with CCS increases by 8% in the high capital cost scenario.

The results in Table 33 show that a decrease in the capital cost of CCS and co-firing retrofits can make plants with these retrofits more economically favorable. Decreases in capital costs can also benefit plants without CCS, but the effect will be lower at low co-firing ratios than for high co-firing ratios.

Table 34 shows the results of the feedstock cost sensitivity analysis. For this analysis the medium scenario capital cost scenario was used.

Table 34. Results of feedstock cost sensitivity analysis with and without CCS.

Coal/biomass interception points	Low feedstock cost scenario, W/O CCS			High feedstock cost scenario, W/O CCS		
Co-firing ratio	Farmed Trees	Switchgrass	Forest Residue	Farmed Trees	Switchgrass	Forest Residue
5%	$42	$45	$42	$77	$94	$96
10%	$31	$34	$31	$64	$78	$81
15%	$31	$33	$31	$62	$75	$78
20%	$28	$30	$29	$58	$71	$74
100%	$47	$51	$47	$82	$99	$101
	Low feedstock cost scenario,with CCS			High feedstock cost scenario,with CCS		
5%	$76	$77	$75	$78	$78	$78
10%	$73	$74	$72	$77	$77	$77
15%	$71	$72	$69	$76	$76	$76
20%	$68	$69	$66	$75	$75	$75
100%	$64	$66	$57	$83	$92	$82

The feedstock sensitivity analysis showed a more severe effect on the coal/biomass cost curve intersection points. For the low feedstock scenario the intersection point between the coal only curve and the 5% co-firing curve without CCS for forest residue decreased by approximately 64% to 81%. Co-firing 20% farmed trees with biomass becomes economically feasible at a GHG price of $28 per ton CO_2 equivalent at which point electricity costs approximately 6 cents per kWh.

The low feedstock costs result in a smaller decrease in the biomass/coal cost curve intersection points for plants with CCS. The intersection point for 100% forests residue with CCS drops to $57 per ton CO_2 equivalent from $73 per ton CO_2 equivalent in the base case (a decrease of 22% over the base case). For the high cost scenario the 5% biomass co-firing intersection point increases without CCS over the base case of 12% to 26% without CCS and of 1% with CCS. Because a plant operating at 5% requires little biomass, the effect of feedstock costs on the 5% biomass co-firing on a CCS plant also small, particularly compared to the high capital costs of retrofitting the plant to co-fire biomass and capture CO_2. The LCOE breakdown for the high feedstock scenario shows an increase in the VOM (which includes feedstock costs) for 5% farmed trees co-firing of 0.2 percentage points over the base case scenario, demonstrating that the change in the cost of the feedstock has a very small effect on the LCOE. At 100% biomass co-firing with CCS the intersection of the cost curve with the coal only cost curve increases by 12% to 26%, which reflects the increase of 5.4 percentage points in the VOM contribution to LCOE over the base case. Table 35 contains the LCOE breakdown at a GHG cost of $50 per ton CO_2 equivalent for farmed trees in the high feedstock cost scenario.

Table 35. Breakdown of LCOE for farmed trees at a GHG cost of $50/ton CO_2 equivalent and the high feedstock scenario.

Co-firing ratio	TOC (CCF)	FOM	VOM
0.0%	27.2%	29.3%	43.5%
5.0%	27.4%	29.4%	43.2%
10.0%	27.8%	29.7%	42.6%
15.0%	28.8%	29.7%	41.5%
20.0%	29.4%	29.8%	40.7%
100.0%	44.8%	30.1%	25.1%

The feedstock sensitivity analysis shows the importance of low feedstock costs in making biomass firing and co-firing cost competitive with coal fired power plants at lower GHG costs in the cases without CCS. When CCS is added changes in the feedstock cost have a small effect on the co-firing scenarios, but can have a greater effect on the cost intersection points for the 100% biomass with CCS cases because feedstock is a larger portion of the LCOE for dedicated biomass plants. Therefore a decrease in the cost of feedstocks can have a more significant effect on the economics of biomass co-firing without CCS than decreases in the capital costs of retrofitting a plant. Nonetheless, decreasing feedstock costs will have a smaller effect on co-firing plants that implement carbon capture and sequestration. Because the change in feestock costs is uniform for all scenarios modeled, the discontinuous effects on the cost curve intersection points noted for the capital cost sensitivity analysis, resulting from non-uniform changes in the capital costs for different scenarios, were not observed.

5.5 Conclusion

The economic analysis in this chapter suggests that converting existing coal plants to co-fire and fire biomass is economically favorable at costs of \$52 to \$57 per ton CO_2 equivalent. In addition a plant co-firing biomass and equipped with a CCS unit becomes economically viable at a cost of about \$71 to \$73 per ton of CO_2 equivalent. Therefore by ascribing a price to the benefit of biomass firing and co-firing, namely the decrease in GHG emissions, these plants can become economically viable.

Another result from this analysis is the importance of low feedstock costs and capital costs for decreasing the GHG cost necessary to make co-firing economically favorable. Although technology development and policies that lower the capital costs of coal plant retrofits for co-firing biomass and adding CCS units will help the economics of biomass to power plants, they will not have a uniform benefit for all co-firing ratios because the level of decreases cited in the literature and assumed here are not the same for all co-firing scenarios. Therefore when it comes to decreases in the capital costs of co-firing, these efforts should be targeted to the desired co-firing ratio and CCS capabilities of the plant, which then determines the level of GHG emissions change. An effort that decreases the cost of feedstock, on the other hand, will be beneficial to more plants (those in the high and low capital cost scenario), and therefore could have a greater effect on the GHG emissions from more facilities.

Chapter 6. Policy Analysis and Recommendations

This chapter recommends policy measures to incentivize biomass to power deployment. The first section reviews the possible environmental benefits of biomass to power and the hurdles that must be overcome for widespread adoption of this technology. Upcoming national policies that recognize the benefits of biomass to power and the existing state policies that promote renewable electricity generation are also reviewed. Despite the existence of policies that promote the development and purchase of renewable energy, biomass to power has had limited growth in the US. In the Policy Recommendation section measures are proposed that could make biomass a more appealing renewable energy technology and will allow the US to capture the environmental benefit of using biomass for electricity generation.

6.1 Benefits and Challenges for Biomass to Power

In previous chapters, the fuel cycle emissions analysis showed that co-firing biomass with coal at ratios of 5% to 100% on a heat basis results in a decrease in GHG emissions over dedicated coal firing when there are no land use change emissions. Likewise the inclusion of carbon capture and sequestration (CCS) in the biomass firing model demonstrated that at co-firing ratios of 15% and higher these systems result in negative GHG emissions, essentially air capture of CO_2. In addition co-firing biomass may result in a decrease in ash, dust, SO_2, and NO_x emissions over coal firing alone, depending on the feedstock and co-firing method (IEAGHG & ECOFYS, 2011). Burning biomass in retrofit coal plants also has the benefit of using a proven technology and having relatively low capital costs. In addition biomass to power enjoys a benefit that few renewable energy sources can claim: dispatchable power. Unlike wind or solar power, biomass is not an intermittent power source.

Nonetheless, the economic analysis undertaken in Chapter 5 showed that biomass co-firing with coal and dedicated biomass firing generally results in a higher LCOE than coal fired power generation when there is not a price associated with GHG emissions.

A recent concern with biomass to power is the carbon neutrality of biomass feedstocks. In 2010 the Manomet Center for Conservation Sciences issued a report commissioned by the Commonwealth of Massachusetts to quantify the effects on GHG emissions from converting biomass to power. The Manomet study, focused on converting forest wood into power, found that, depending on the fossil fuel displaced, carbon neutrality is only achieved after 5 (when fired in a CHP plant or replacing oil fired generation) to over 90 years (when replacing natural gas fired electric power). When biomass replaces coal fired electric generation, carbon neutrality is only achieved after 21 years of operation. (Manomet, 2010) The Manomet study takes into consideration forest management techniques in Massachusetts to determine how long forest regrowth will take to capture the emissions from biomass combustion at a power plant. This study prompted Massachusetts to revisit their definition of renewable energy, and tighten the definition for biomass in an effort to ensure a decrease in GHG emissions in the short term.

6.2 The Success of Biomass to Biofuels

As previously discussed, more biomass is used for biofuel production than power generation. Biofuel generation has benefited significantly from a national push for energy independence meant to limit the nation's dependence on imported fuels that support regimes hostile to the United States. The Renewable Fuel Standard (RFS), created under the Energy Policy Act of 2005, mandated the volume of renewable fuel production in the US on an annual basis. In 2007 the Energy Independence and Security Act (EISA) expanded the RFS and mandated the current biofuel target of 36 billion gallons of renewable fuel to be produced in 2022. Although the EISA also mandated that new renewable fuels have lower GHG emissions than their petroleum counterparts, the law is still focused on a pathway towards energy independence. (EPA, 2012a) Because biomass generated electric power would displace domestic energy sources (such as coal and natural gas), there is no energy security motivation for promoting its adoption.

Another factor favoring biomass conversion to transportation fuels such as ethanol and biodiesel is the higher value added of these products. Whereas power is a relatively low priced commodity, the price of transportation fuels has been on an upward trend in recent years, which provides greater margins for biofuel producers. Federal subsidies and support for biofuels also makes biofuel production more economically favorable.

Given that biomass to power does not currently further national security concerns nor does it participate in a market that supports the high price of biomass power generation, the best means of incentivizing biomass firing and co-firing is through the monetization of the decreased GHG and hazardous air emissions from these systems. Nonetheless policy makers should be conscious of the potential for high emissions from land use change and of the potential for a long time span before a biomass fuel achieves carbon neutrality.

6.3 Existing Policies: National Level

At a national level there are two proposed EPA rules that regulate GHG emissions and hazardous air pollutant emissions that could incentivize biomass use in power plants. Although these rules have the potential to promote biomass to power, they fall short. Because these rules have not yet been finalized, though, there is a chance that they may be amended to recognize the potential benefit biomass to power can have on the regulated emissions.

In 2007 the US Supreme Court ruled that GHGs meet the definition of a pollutant as defined in the Clean Air Act (CAA) in the case Massachusetts v. EPA. This case eventually led to a rule proposal in 2012 to revisit CAA power plant regulations that did not limit GHG emissions. The ‘Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units’ was proposed on April 13, 2012 by the Environmental Protection Agency (EPA). The rule limits CO_2 emissions from new fossil fuel power plants to 1000 lb CO_2 per MWh gross for plants larger than 25 MW. This limit is slightly above the emissions of a natural gas fired plant and about half the emissions from coal fired power generation calculated in this thesis. If an out of compliance plant plans to add CCS to achieve the emissions limit, they can average the plant’s emissions over 30 years to prove compliance rather than remaining below the limit each year. Because this rule applies only to fossil fuel plants, it does not apply to a plant firing biomass or one that co-fires fossil fuels with less than 250 million BTU per hour. Although biomass only plants are exempt from the rule, there is no mention in the proposed rule whether biomass co-firing is an acceptable carbon mitigation option or if biomass emissions are considered carbon neutral. Also, the rule does not apply to existing power plants, so it does not encourage retrofitting existing plants to combust biomass, the conversion route studied in this thesis. Although this rule does limit GHG emissions, one of the benefits of co-firing biomass with coal, the rule does not incentivize biomass to power schemes in existing or new plants as written. (EPA, 2012b)

In December of 2011 the EPA released the proposed rule commonly known as the Boiler MACT. This rule is an update to an existing rule that regulates hazardous air pollutant (HAP) emissions from industrial, commercial, and institutional boilers and process heaters. In particular the rule limits emissions of hydrochloric acid (HCl), particulate matter (PM), carbon monoxide (CO) and mercury (Hg). Under this rule plants firing greater than 10% biomass on an average heat input basis have to comply with emission limits for the solid fuel category (which includes limits for HCl and Hg emissions) and the biomass category that corresponds to the combustion technology in use (includes limits for PM and CO emissions). The emission limit for solid fuels is the same for biomass and coal facilities co-firing less than 10% biomass. For the biomass conversion technology specific emissions (PM and CO), though, the biomass categories have a higher emissions limit than for coal conversion technologies. (EPA, 2011) This thesis does not undergo an estimation of the emissions of hazardous air pollutants from firing biomass or co-firing biomass with coal. Therefore it can only be assumed, based on other studies, that biomass will have lower emissions of hazardous air pollutants than coal. If further research determines the effect on hazardous air pollutant emissions from firing and co-firing biomass the Boiler MACT rule may incentivize coal plants to add biomass to their feedstock instead of installing costly emissions control technology.

Although the proposed Boiler MACT rule and carbon emissions standards put forth by the EPA recognize the emissions benefits of biomass to power, it is questionable whether they will promote a widespread adoption of biomass for power generation. More research is needed to determine whether co-firing biomass with coal will allow a plant to comply with the HAP limits in the Boiler MACT rule at a lower cost than adding emissions control technology to the plant. Because the Boiler MACT rule applies to existing plants as well as new plants, it may also incentivize existing coal plants to retrofit to be able to fire biomass. In contrast, the carbon emission standards proposed by the EPA only apply to new power plants and therefore do not incentivize current plant retrofits to fire biomass. For new plants biomass co-firing with coal is not mentioned as a means of decreasing CO_2 emissions. Therefore there is no incentive for a new coal-fired power plant to be built with the capability of co-firing biomass. The carbon emissions standard only applies to fossil fuel power generation, therefore new dedicated biomass plants are exempt from the rule, which may serve as an incentive for the construction of biomass fired power plants.

6.4 Existing Policies: State Level

National carbon legislation that would likely assign a price to GHG emissions appeared to be on the cusp of acceptance in 2007 (Lash, 2006). Nonetheless, a climate policy was not passed, and carbon markets only exist in California and the Northeast (RGGI). The California cap and trade program goes into effect in 2013 and covers electric generators emitting greater than 25,000 tons of CO_2 equivalent per year in California and power importers to the state. Biomass-derived fuels may be used to meet emissions limits in some situations for the California program. By allowing a polluting entity to use biomass-derived fuels to meet their emissions limits, the California cap and trade program may incentivize deployment of biomass power generation if the cost of a carbon credit is high enough. The California law may also encourage biomass fired power generation in other states through its requirement that electricity importers also meet the State’s emission cap.

Likewise the Regional Greenhouse Gas Initiative (RGGI) considers sustainably harvested biomass as carbon neutral when calculating a plant’s compliance with carbon emission caps. RGGI is a cap and trade system for the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. Each state has the responsibility of defining what constitutes sustainable biomass for the purposes of carbon accounting. (Austin, 2010) Although this law values one of the main benefits of converting biomass to power, namely the decrease in GHG emissions, the variable definition of sustainable biomass creates an additional burden for plants seeking to lower emissions through the combustion of biomass.

A more popular state level policy promoting renewable power generation is the renewable portfolio standard (RPS). In the US 33 states have a mandatory or voluntary renewable portfolio standard. An RPS requires retail electric providers to supply customers with a minimum amount of renewable electricity. In many states an RPS functions through the generation of renewable energy certificates (RECs) by renewable generators that are then sold to utilities and retail power providers to meet the RPS. (EPA, 2009) Each state defines what power sources qualify as renewable for the purposes of the RPS. After the release of the Manomet study in 2010, Massachusetts revisited its definition of renewable biomass power to avoid the pitfalls highlighted in the Manomet study. The significant changes to the Massachusetts biomass guidelines include the requirement that units trying to qualify for a class I REC must conduct a lifecycle analysis of the biomass fuel to demonstrate that the system achieves an emission reduction of 50% over 20 years. Biomass facilities are also required to operate at an overall efficiency of 40% to earn half an REC and at 60% efficiency to qualify for a full REC. This requirement is designed to redirect biomass projects to combined heat and power applications, the only biomass fired plant that is likely to achieve the high efficiency requirements. The Massachusetts guidelines also exclude construction and demolition waste from the list of eligible biomass, which limits forest derived fuels to forest residue, limited thinning of forests, and salvaged forest wood from natural disasters or pest infestation. Whole trees are not counted as eligible biomass and there is a limit on the mass of biomass removed from forest sources that can qualify as eligible biomass in order to maintain a sufficient amount of nutrients in forest soil. Dedicated energy crops and yard waste are considered eligible biomass for the Massachusetts guidelines. (Commonwealth of Massachusetts, 2011)

Although the Massachusetts regulations will make the five biomass plants in the New England grid ineligible for Massachusetts RECs, RPS standards in other states have succeeded in promoting biomass to power plants elsewhere. Dominion Virginia Power Corp. is converting three coal plants to biomass as part of its actions to meet the State’s voluntary RPS (Austin, 2012a). In Oregon Klamath Falls Bioenergy is proposing a plant that will burn waste wood, including trees felled to prevent the spread of the mountain pine beetle, and help meet the states renewable energy mandates (Austin, 2012b).

The effect of state level RPS policies on co-firing has been small. In particular concerns over the environmental effects of continuing to fire some coal with biomass have discouraged the deployment of co-firing options (McElroy, 2008).

6.5 Proposed Policies

The analysis in this thesis demonstrates that through the combustion of waste biomass and cropped biomass that do not incur land use change emissions, GHG emissions from a coal power plant can decrease significantly. In addition if a biomass fired or co-fired plant is combined with a CCS unit emissions decrease further and can even be negative. Although policy makers may be concerned about the prospect of emissions from continuing to burn coal, setting the policy stage for development of biomass conversion systems and of a sustainable biomass market is an important first step in capturing the GHG emission benefits of biomass to power. Biomass as it is available today, dried or pelletized, may not be an ideal fuel for all power generation technologies. Nonetheless, through the continued development of biomass pre-processing technologies, such as torrefaction and gasification, these fuels will become easier to convert and have improved performance. To enable the continued development of low emissions biomass sources and thereby encourage the development of refined biomass fuels, two policy actions should be taken. First, policymakers should work with experts to define sustainability criteria and initiate a certification process so that biomass providers have a fixed set of guidelines to determine whether their feedstocks qualify as renewable energy sources. In addition policymakers, either at a state or national level, should establish policies that recognize the benefits of producing power from biomass that meets the certification criteria.

Given that biomass energy sources are not necessarily beneficial to the environment, establishing sustainability guidelines for biomass to qualify as a renewable energy source is important to gain the public's confidence and support for biomass. By defining sustainability criteria and instituting a certification process, policy makers can design a system such that excessive land use change emissions or environmentally harmful harvesting methods do not outweigh the benefits of displacing fossil fuels with biomass for power generation. These standards, though, should be accepted for all state renewable energy laws in order to establish a nationwide market for biomass feedstocks. A nationwide market would drive down biomass prices and limit risk for power plant operators.

The second component of biomass to power policy has to be a consistent, predictable policy that recognizes the benefits of biomass to power. A price on GHG emissions or renewable energy target that recognizes certified biomass power as either carbon neutral or an eligible renewable energy source are two possibilities. The economic analysis in Chapter 5 showed that, without CCS, co-firing 20% farmed trees with biomass equals the price of coal fired power at a GHG price of \$52 per ton of CO_2 equivalent. With the addition of a CCS unit, co-firing 20% farmed trees with coal becomes economically favorable at a GHG price of \$73 per ton of CO_2 equivalent. Therefore to incentivize widespread co-firing of biomass with coal a policy measure that would assign a price for GHG of at least $52 per ton of CO_2 equivalent is needed. As noted throughout this work, though, the cost of co-firing and firing biomass in an existing power plant can vary depending on the cost of biomass and extent of retrofits necessary to the plant. Therefore a GHG price less than $52 per ton of CO_2 equivalent may still be sufficient to incentivize those plants that can easily and inexpensively transition to biomass co-firing and firing. The addition of CCS to a biomass power plant requires an even higher cost of GHGs to be economically feasible, despite the system's potential for removing CO_2 from the atmosphere.

Although pricing GHG emissions from power plants is a system that could provide the necessary incentives for biomass to power, politically such a system is unlikely to be installed in the near future. Likewise renewable energy targets have been limited to state level policies. With a uniform biomass certifying system, though, state level efforts may be sufficient to create the demand necessary to spur a thriving biomass feedstock market that can provide the necessary fuel when a national level policy is passed. Such policies will set the stage for technological advances in the processing of biomass that will make biomass a more competitive feedstock in the future while still capturing the benefits of biomass to power in the present. In addition, biomass to power with CCS is a technology option that has the benefit of removing CO_2 from the atmosphere, which may become more valuable as the effects of climate change become more severe or if emission mitigation does not succeed in meeting atmospheric GHG concentration targets.

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Appendix 1: Sample Calculations for LCOE

The LCOE calculation in Chapter 5 required the conversion of the values in Table 36 and Table 37 to units of dollars. The entries in these tables will make up the Total Overnight Cost and Fixed O&M costs in the LCOE equation.

Table 36. Cost components for TOC.

Capital Costs	Price in $/kW yr
Direct co-firing capital costs	$150
Indirect co-firing (in $/kW$_{th}$)	$139
Retrofitting for 100% biomass	$640
Additional CCS cost	$877.50

Table 37. Cost components for FOM.

Fixed O&M	Price in $/kW yr
Fixed O&M for coal plant	$104
Additional O&M for biomass firing	$12
Additional O&M for CCS	$52.00

Equation 7 was used to calculate the TOC for the co-firing ratios where direct co-firing was assumed (5% and 10% biomass). Equations 8 and 9 were used for indirect and 100% biomass firing, respectively.

$$R_{DCC}(BM)(200MW)(1000\,{}^{kW}\!/_{MW}) = TOC_{DCC} \qquad \text{(Eq. 7)}$$

$$R_{ICC}(BM)\left(\frac{200MW * 1000\,{}^{kW}\!/_{MW}}{\eta}\right) = TOC_{ICC} \qquad \text{(Eq. 8)}$$

$$R_{DBM}(200MW)\left(1000kW\!/_{MW}\right) = TOC_{DBM} \qquad \text{(Eq. 9)}$$

Equation 9 is also used to calculate the cost of adding CCS to a power plant. When calculating the CCS cost, R_{DBM} is substituted for the cost given in Table 36. All the applicable TOC terms (depending on the co-firing ratio of the plant and whether it includes CCS) are then summed to calculate the TOC term used in the LCOE calculation.

For Equations 7 to 9 the variables are:

R = retrofit costs

BM = biomass ratio co-fired with coal on a heat basis

η = efficiency of the power plant when co-firing

The subscripts in Equations 7 through 9 refer to:

DCC = direct co-firing

ICC = indirect co-firing

DBM = dedicated biomass

The Fixed O&M (FOM in the LCOE equation) is calculated as shown in Equation 10.

$$[OM_{cp} + BM(OM_{BM}) + OM_{CCS}] * 200MW * {}^{1000kW}\!/_{MW} = FOM \qquad \text{(Eq. 10)}$$

In Equation 10 the following variables are used in addition to the variables defined above:

OM_{CP} = Fixed O&M for a coal plant

OM_{BM} = Additional fixed O&M for the addition of biomass firing

OM_{CCS} = Additional fixed O&M for the addition of CCS

The fixed O&M term for CCS is only used in those cases where a CCS unit is simulated with the power plant.

For the calculation of FOM and TOC we multiply prices in $/kW by the original capacity of the plant (before derating due to biomass co-firing or CCS) because the plant is originally sized for this capacity and we expect retrofits to be conducted for a plant of the non-derated size.

The variable O&M term needs to be given in units of $/kWh for the LCOE equation. Table 38 shows the literature prices used in the calculation of VOM.

Table 38. Cost components for VOM.

Feedstock	Price in $/d. ton
Short Rotation Woody Crops	$89
Forest Residues	$78
Switchgrass	$79.3
Uinta Basin coal	$41
Ash	in $/ton ash
Coal Ash credit	$2
Biomass/coal ash cost	$10
CO_2 handling	in $/tonne CO2
CO_2 transport	6.5
CO_2 storage	6.5
CCS material	in $/kWh net
MEA costs	$0.0003

Equation 11 shows how the values in Table 38 were converted to the proper units for inclusion in the LCOE calculation.

$$\frac{M_{BM}(P_{BM}+A_{BM}*P_{Ash})+M_{C}(P_{C}+A_{C}*P_{Ash})+M_{CO2}(P_{CO2T}+P_{CO2S})}{MW_{DR}*8760\,{}^{hrs}\!/_{yr}*CF}+P_{MEA}=VOM$$

(Eq. 11)

The variables in Equation 11in addition to variables defined above are:

M_{BM} = Mass of biomass required for a year of plant operation; these values were obtained from the adapted GREET model

P_{BM} = Price of the biomass feedstock in $/ton

A_{BM}= Ratio of ash in each biomass feedstock on a mass basis (values are given in Table 24)

P_{Ash} = cost of ash disposal in $/ton ash. When no biomass is co-fired, this price changes from an ash disposal cost to the coal ash credit as shown in Table 38

M_C= Mass of coal required for a year of plant operation; obtained from the adapted GREET model

P_C = Price of coal in $/ton

A_C= Ratio of ash in coal on a mass basis (given in Table 24)

M_{CO2} = Mass of combustion CO_2 emissions from the power plant; results are obtained from the adapted GREET model

P_{CO2T}= Price of CO_2 transportation in \$/ton CO_2; excluded when the plant was not modeled with a CCS unit

P_{CO2S}= Price of CO_2 storage in \$/ton CO_2; excluded when CCS was not part of the plant simulated

MW_{DR} = Derated plant capacity

CF = Capacity factor; 0.8 was used

P_{MEA} = Annual price of MEA solvent for operation of the CCS unit; not included when CCS was not added to the power plant

The values for TOC, FOM, and VOM calculated in the above equations were then integrated into the LCOE equation as shown in Equation 12.

$$\mathrm{LCOE} = \frac{\mathrm{CCF} * 1.1 * (\mathrm{TOC}) + \mathrm{FOM}}{8760\ {}^{hrs}\!/_{yr}\,(\mathrm{CF})(\mathrm{MW_{DR}})} + \mathrm{VOM} \qquad \text{(Eq. 12)}$$