ECONOMIC IMPLICATIONS FOR THE GENERATION OF ELECTRICITY FROM BIOMASS FUEL SOURCES

by

THOMAS WAYNE CURTIS JR.

(Under the direction of John Bergstrom)

ABSTRACT

This study examines the economic theory, geographical implications, and relevant legislative history impacting the use of biomass fuel sources within the electric utility industry. Research has shown the use of nuclear and fossil fuels for the generation of electricity creates significant amounts of negative externalities. By increasing the generation capacity of renewable energy sources for electrical power generation, theory suggests the impacts of negative externalities can be moderately reduced. In order to do this, renewable energy sources must be feasible with respect to traditional fuel sources.

This research determines the feasibility of direct fire, co-fire, gasification, and pyrolysis technologies for the generation of electricity from Georgia's biomass sources. With the support of green power markets, production incentives, and tradeable permits for power plant emissions, biomass-fueled generation can become a competitive and renewable option for Georgia's electrical power industry.

INDEX WORDS: Georgia, Biomass, Biofuel, Green, Electric, Power, Economics, Feasibility, Emissions, Direct fire, Co-fire, Pyrolysis, Gasification

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B.S.A., The University of Georgia, 2000

A Thesis Submitted to the Graduate Faculty of The University of Georgia in Partial Fulfillment of the Requirements for the Degree

MASTER OF SCIENCE

ATHENS, GEORGIA

2002

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May 2003

DEDICATION

When looking back upon my life, I am proud to have had the pleasure and fulfillment of knowing a most exceptional man. Now that I have reached another unanticipated achievement, I am saddened with the thought of celebrating my commencement without his presence. However, I am grateful to realize his inspiring influence that has shaped my life in so many of the same morals, beliefs, and overall good nature of character.

I certainly feel inadequate, in any attempt whatsoever, that I may make in order to acknowledge the greatness of such a person. Nevertheless, I am compelled to make some attempt, meager as it may be, to assert his distinction in my life, my family, and so many others who were fortunate enough to know my grandfather. Therefore, I dedicate this achievement in my academic career in the remembrance of Dillard Michael. Thank you Papa Mike. You are remembered.

ACKNOWLEDGMENTS

First and foremost, I would like to thank Dr. John McKissick. His guidance and flexibility throughout the past year has allowed me to juggle my responsibilities pertaining to my assistantship, school work, and outside work according to my schedule. Without this luxury, I could not have reached the point where I am at today. Thanks for all that you have done. You have been a great mentor.

I would also like to express special gratitude to Dr. John Bergstrom and Dr. Andy Keeler for their commitment to this research and to my education. I appreciate their guidance, which has enabled me to develop a greater understanding of economic theory and has significantly enhanced my environmental awareness. Dr. Bergstrom, I thank you for introducing me into this research. I have continuously grown greater interest in the subject and would like to further pursue this area in my post-academic career. Dr. Keeler, I thank you for your flexibility and willingness to participate as a committee member. You have opened my eyes to more a practical approach of economic theory.

And finally, I would like to thank my family and friends for the support and encouragement they have given me. I have always known that I can depend on those closest to me. Without the strong support of my parents, Wayne and Sheryl Curtis, I would not have put forth such an effort to further my education. Thank you all very much.

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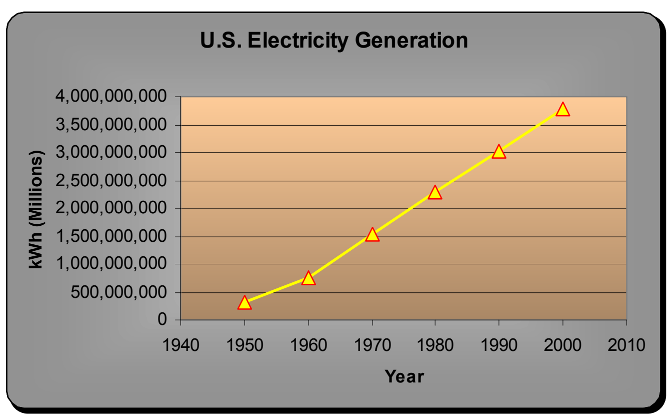
INTRODUCTION

In the late 1800's, soon after Thomas Edison's invention of the light bulb, new appliances such as electric fans, irons, and electrically operated streetcars established a versatile and lucrative demand for the electrical power market. Since that time, the demand for electrical power has steadily increased, with Americans consuming ten times more electricity today than consumed fifty years ago (figure 1-1). The continually increasing domestic population sets forth even greater demands for the Nation's future. The Energy Information Administration (EIA) predicts the U.S. electricity demand to grow by 1.8 % per year from 2000 through 2020.

Figure 1-1: U.S. Electricity Demand



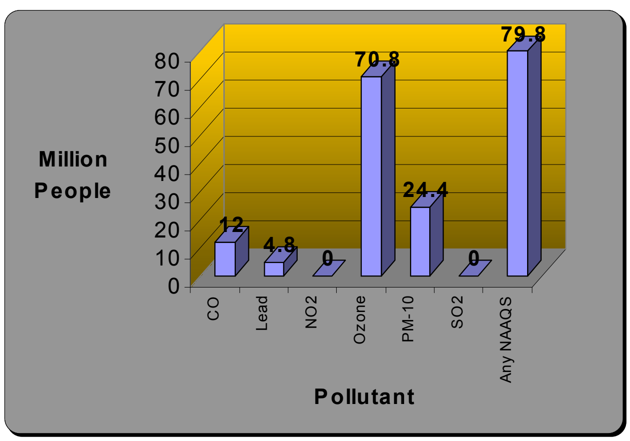
Created by: Wayne Curtis
Source Data: Energy Information Administration (EIA)

Over the past century, the U.S. has reached the point of electrical dependency, where the welfare of society is contingent upon a continuous flow of electrical power.

While at the same time, the Nation has also reached the point of electrical awareness, where concerns over the sources of energy, the means of generation, and the degrading quality of the environment, all pose real problems in meeting the increasing demands of the future.

The need for a comprehensive energy plan in the United States is widely acknowledged. Air pollution from coal-fired power plants is among America's largest sources of acid rain, urban ozone, and the greenhouse gases that drive global warming. As depicted in figure 1-2, nearly 80 million people in 1995 lived in counties with monitored air quality levels above national health-based air quality standards (EPA 2002). This figure illustrates the need for new policy, a new approach, intended to assist attainment of the Nation's air quality standards.

Figure 1-2: Number of People Living in Areas with Poor Air Quality within the U.S.



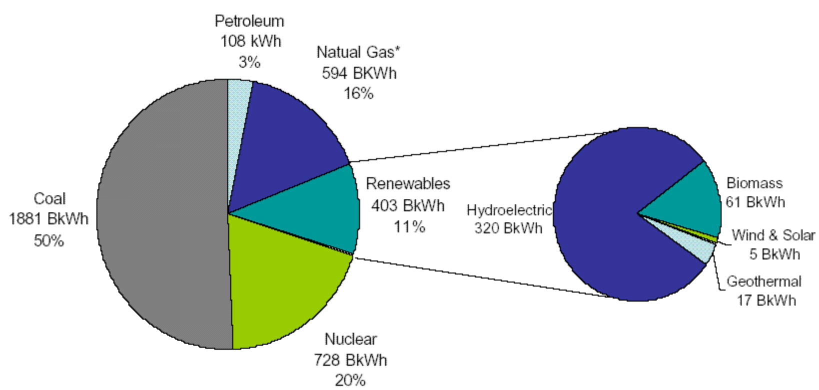
Created by: Wayne Curtis
Source Data: EPA. 2002. <u>Summary of Air Quality and Emission Trends</u>.

In recent years, energy security has become a great concern. Recent blackouts of power grids and mounting energy prices in California exhibit the need for a reliable and efficient power supply. The disaster of September 11, 2001 has increased the awareness towards a secure, sound energy policy for the short-term and long-term future as a measure of increased national security.

The Nation's dilemma is focused upon determining how the U.S. will meet the increasing demand for energy production while accounting for national security, reliability, efficiency, and environmental concerns. Through the implementation of a variety of new methods, technologies, and policies, an appropriate resolution can be achieved. But in order to focus on the solutions for America's future, one must first acknowledge the origins of the Nation's energy problems.

The United States' consumers demand a clean, cheap, and consistent flow of electricity. Power suppliers must initially focus on energy sources that will best meet the cumulative needs of their consumers. For this reason, the electrical energy supply relies primarily on fossil fuels: 50% coal, 16% natural gas, and 3% petroleum. Nuclear power generates 20% and renewables supply 11% of the electricity generated in the U.S. Figure 1-3 depicts these energy sources that fuel the electrical generation mix.

Figure 1-3: U.S. Electricity Generation by Source



Source: EIA, Monthly Energy Review, February 2001

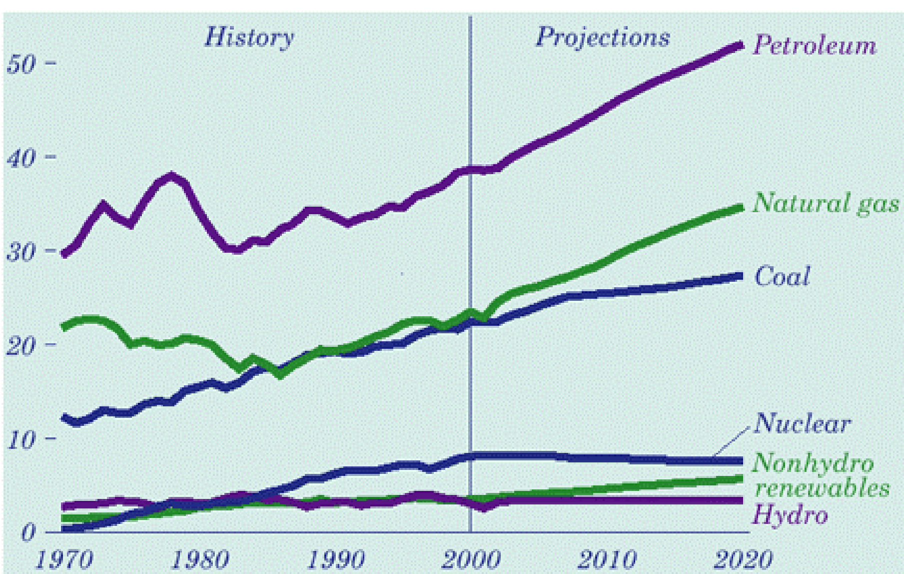
Notes: (1) Totals do not equal 100% due to rounding

(2) *Also includes other gases (approximately 11 billion kWh)

Coal

The world's first central generating plant, operating in New York City during the early 1900's, was fueled entirely by coal. Since that time, coal has continued to be the primary source of electrical energy throughout the United States. The Energy Information Administration predicts the Nation's electrical reliance on coal will not decrease over the next 20 years (figure 1-4). And though coal is a non-renewable resource, concern over coal's scarcity is not an issue today, nor will it be during the next 100 years. The United States has coal supplies found in 38 states, and these supplies are abundant enough to generate affordable and reliable electricity for the next 250 years. This great abundance of domestic coal reserves keeps the price of coal low and stable. Over the past 20 years, the price of coal has only increased 4% compared with a 211% increase in the price of natural gas and a 51% increase in the price of crude oil (Southworth, 2001).

Figure 1-4: Energy Production by Fuel 1970-2020



Source: Energy Information Administration, Annual Energy Review 2000.

New regulations require generation facilities to use low-sulfur coal, or clean coal. As a result, air pollution from coal-fired plants is decreasing. However the total amount of coal in use is increasing due to the rising electricity demand. Coal-fired power plants in the U.S. have reduced their sulfur dioxide emission rate by 71% from 1976 to 1999, although power plants have increased their coal use by 112% between 1976 to 1999 (Kentucky Foundation). Though the emission rate, or the amount of pollution per ton of coal burned, has been substantially reduced, the increase in new online generation plants may offset these advancements in emission rate efficiency. Coal is the most abundant, high-energy resource within the U.S. However, in order to reduce coal's damaging effects, power generators must lessen the share within the generation mix.

Nuclear

By increasing the generation capacity of existing facilities and constructing new facilities, nuclear power is an option capable of a significant contribution towards meeting increasing demands for electricity. The average capacity factor (a measure of efficiency) of U.S. nuclear power plants has risen over 16% since 1990 to 86.8%. That increase is the effective equivalent of adding more than 23 new 1,000 megawatt (MW) nuclear power plants online. The Energy Information Administration (EIA) projects a 90-percent capacity factor by 2015 (FERC, 2001).

Although electrical energy generated via nuclear power is relatively cheap and has little or no emissions of airborne pollutants, the costs and risks associated with construction and operation are immense. The start-up or "fixed" costs of construction are so large, that nuclear generation facilities are not feasible for most regions. Furthermore, a variety of risk and uncertainty associated with the daily operation of these facilities hinder any plans of a nuclear future.

There is great uncertainty in where nuclear waste will be disposed and in the methods of transport. The current administration, under President George W. Bush, is promoting plans for a national radioactive waste disposal site in Yucca Mountain, Nevada. In the meantime, radioactive waste is held on-site of each generation facility, waiting for disposal. Once Yucca Mountain becomes officially open as a nuclear waste repository, and a structured system for transportation of such material is established, then the costs of disposal can be better estimated. However, power companies must also consider the costs associated with the retirement of their nuclear reactors. Indeed, the facility itself must be disassembled and discarded in the same manner as the waste it once produced. This process will certainly bear an enormous cost. Until the costs of disposal can be realized, it will take decades for the true costs of nuclear generation to be known.

The role nuclear power will play in the nation's generation mix is as uncertain as its operation expenses. In reality, nuclear power still holds great potential for reducing air pollution and the nation's dependency on foreign fuels. But nuclear facilities are not only economically risky, but they are also socially and politically risky as well. Additional nuclear facilities will become more likely only with the aid of proper political backing.

The President's 2002 Energy Plan is promoting the use of nuclear power, although it appears to have poor political support. This may be because nuclear power plants possess the potential for large-scale catastrophe. The accidental meltdown of the nuclear power facility, Chernobyl, is commonly considered the largest accidental man-made disaster in the history of man. To add to the risk factor, increased threats of terrorist attacks on generation facilities prompts greater opposition towards a nuclear future. As a result, politicians may be reluctant to support the promotion of nuclear energy.

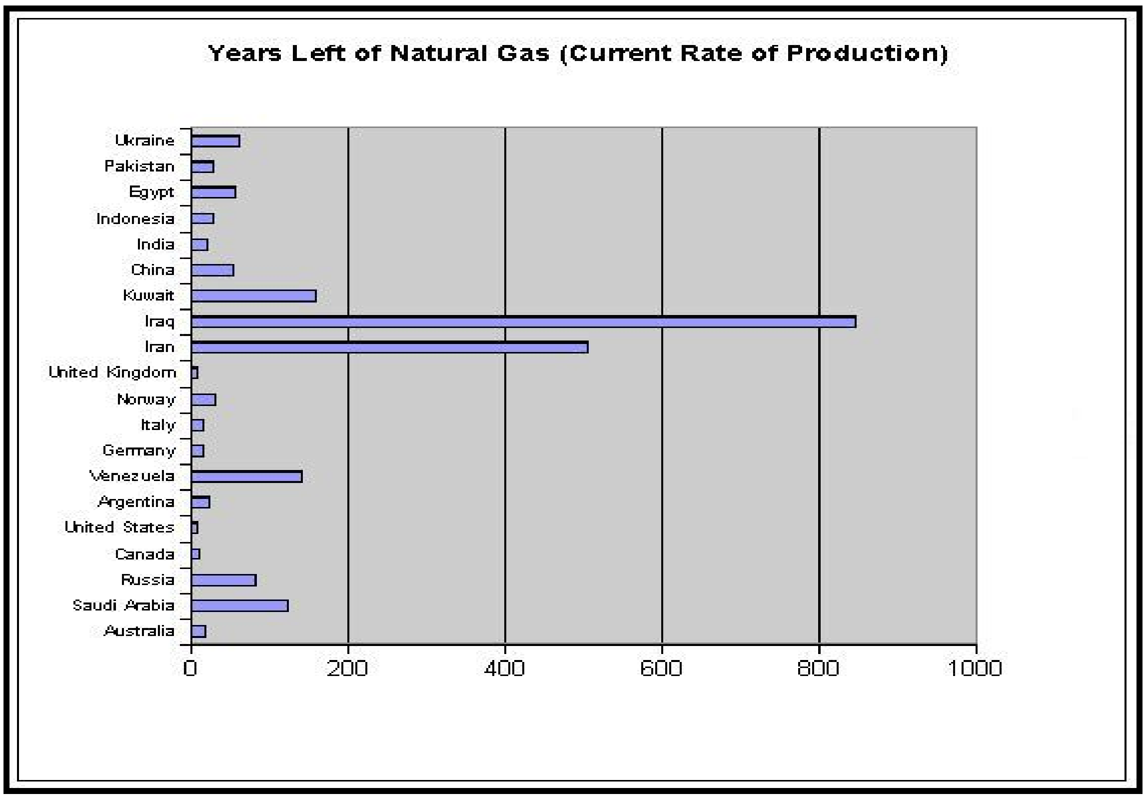
A recent federal law designed to help protect citizens in the case of an attack or meltdown of a nuclear plant calls for the distribution of potassium iodide tablets in a 20-mile radius from the facility. To many citizens, this is a meager attempt to restore confidence and safety in the threat of a grave hazard. However, tangible protection, like constructing a protective covering over nuclear reactors, would certainly add millions onto the price tag of each facility, thereby pushing nuclear generation further away from economically feasible levels. In light of these cumulative impacts to the nuclear power industry, it is certain that nuclear power growth will not be a reality until confidence is obtained in the system for nuclear waste disposal and in the overall safety of the facilities themselves.

As a result, electric utilities are not likely to subject themselves to such a costly, risky, and uncertain energy source. In fact, no new nuclear power plants have been ordered since 1979. And, of the 98 gigawatts of nuclear capacity available in 2000, 10 gigawatts are projected to be retired by 2020 (FERC 2001).

Natural Gas

Natural gas has become the primary fuel used to power new generation plants. Of the fossil fuels, natural gas produces less carbon dioxide (CO_2), sulfur dioxide (SO_2), and various oxides of nitrogen (NO_x). Of the 355 gigawatts (GW) of new generation capacity needed by 2020, 88% is projected to be fueled by natural gas. However, the natural gas reserves are largely foreign-based. Dr. Kyle Forinash, professor of Physics at Indiana University Southeast, claims the world's total natural gas may be in short supply in around 100 years. Domestic reserves could be depleted much sooner. Figure 1-5 displays Forinash's analysis of the years remaining for natural gas at current production rates. This graph is based on the total known reserves plus projected reserves and also assumes the current rates of production will neither increase nor decrease.

Figure 1-5: Years Left Until Depletion of Natural Gas Reserves



Source: Forinash, Kyle. Energy Reserves.
http://physics.ius.edu/~kyle/P310/right2.html

Because of the limited natural gas reserves, the U.S. must rely on natural gas imports. As a result, the nation must be concerned with fluctuations in the natural gas market and the correlated susceptibility to nation-wide energy crisis in the short and long-term future. During the Energy Crisis of the 1970's, the consequences of relying heavily upon foreign fuel sources were realized. As fuel sources came in short supply, energy prices soared to unprecedented levels. For the first time, concern over the reliability of the Nation's energy sources was of utmost importance.

The natural gas market has shown instability. Since 1967, the price of natural gas has fluctuated from $.84 to $5.28 (1996 US $/ thousand cubic feet), with an average of $2.69 and a substantial standard deviation of approximately $1.29. Domestically, only 3% of the known natural gas reserves are found within U.S. borders. And though natural gas generation offers many great benefits as opposed to more traditional methods, there are substantial economic risks to allocating 88% of new capacity towards a foreign-based market.

Renewables

One of the most widely encouraged strategies to assist in solving the Nation's energy problem is to increase the use of renewable energy resources. Solar, hydro, wind, geothermal, ocean thermal energy conversion, tidal energy, hydrogen burning, and biomass burning are all types of renewable energy sources in use today (refer back to figures 1-3 and 1-4). Renewable energy sources can provide sustainable, renewable energy while decreasing pollution levels. Renewable energy can also lesson the Nation's dependence on foreign fuels and nuclear power, while at the same time, provide jobs for local citizens.

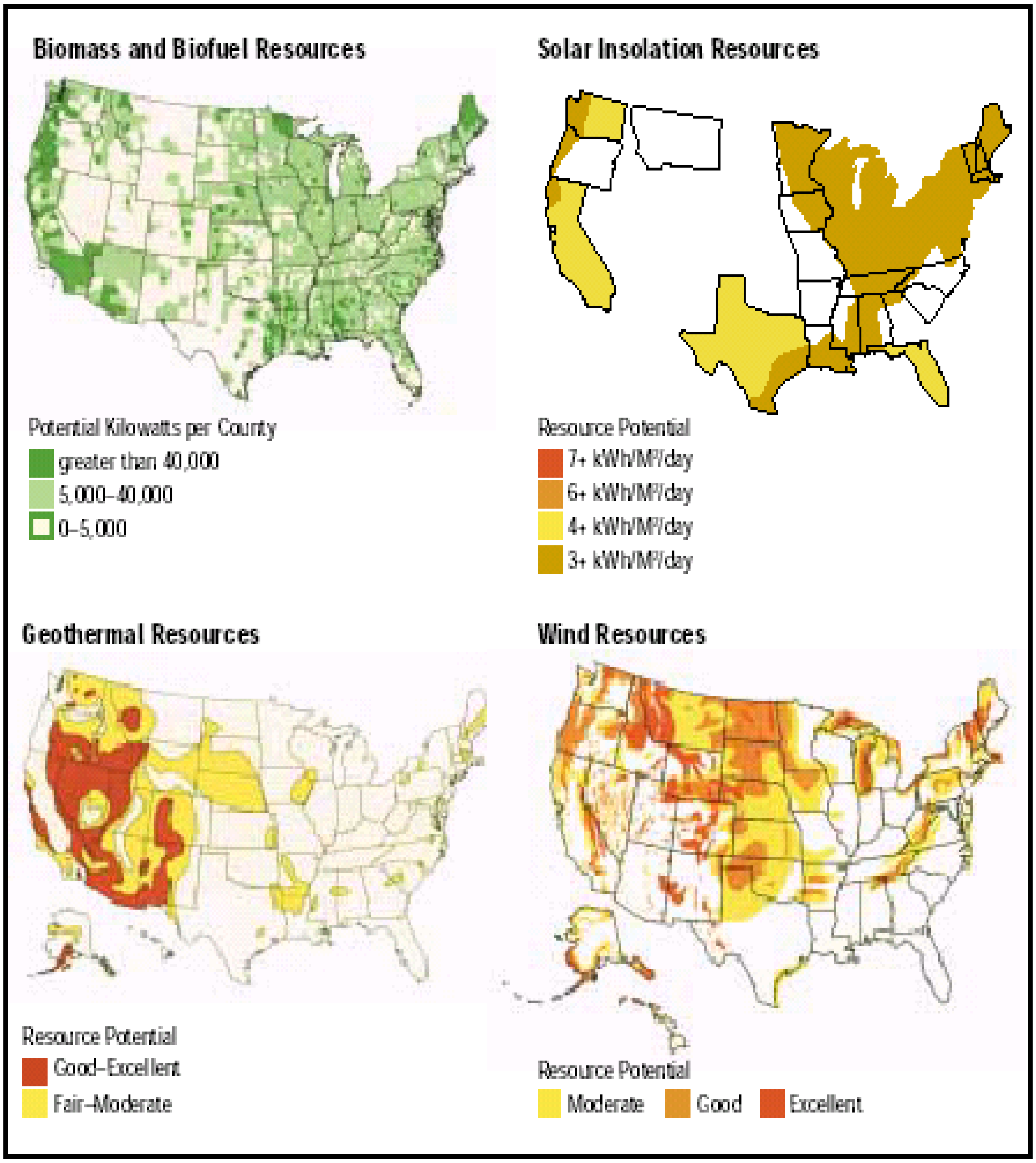
Unfortunately, renewable energy sources have their economic disadvantages. Competition for cheap, highly productive sources of energy drives the electric power industry. As a result, fossil fuels are the largest energy source for electric generation in the United States, accounting for approximately 70 percent of total generation. Due to the abundant supply and corresponding low prices, America's consumption of fossil fuels has not declined and is not projected to do so in the near future. Undoubtedly, these trends cannot sustain a viable solution to the accumulative problems associated with power generation.

In order to address sustainability, reliability, economic growth, and environmental health, the U.S. energy plan must focus on solutions known to alleviate all of these issues associated with electrical power generation. The most widely accepted method to help achieve these goals is to invest in renewable energy sources. Generally, all forms of renewable energy, like traditional generation methods, have their particular advantages and disadvantages.

The potential for renewable energy is largely dependent upon geography. As an example, solar power has greater potential in the sunny regions of Southern California, as opposed to Northern Alaska, where sunlight is indirect and limited much of the year. Therefore in order to conduct an in-depth analysis of renewable energy potential, the focus must be narrowed to specific regions.

The remainder of this thesis will narrow the focus onto the Southeastern region of the U.S, particularly the State of Georgia. Here, one of the oldest known energy sources also proves to be the most promising form of renewable energy. In a region where cloud cover limits the solar power potential, rolling terrain and dense woods slows the wind, and the earth's inner energy is not easily accessible, biomass is in abundant supply (figure 1-6).

Figure 1-6: Resource Potential for Renewable Energy



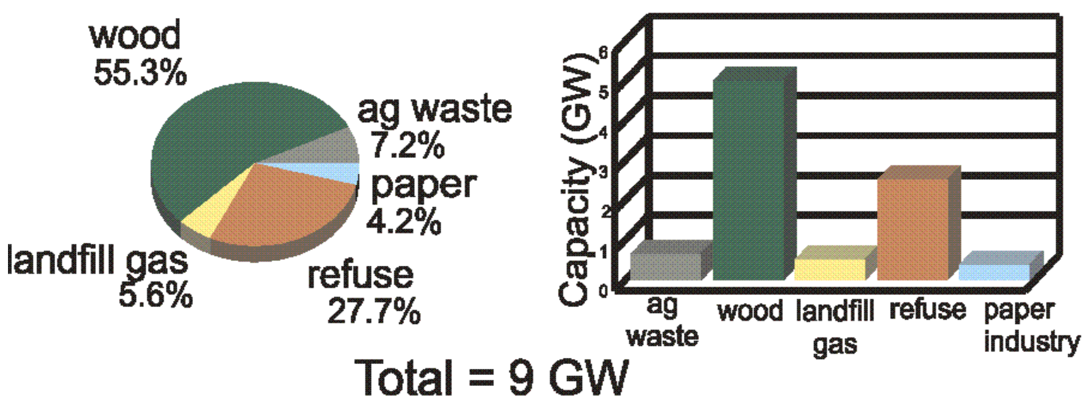
Source: U.S. Department of Energy, National Renewable Energy Laboratory
Notes: (1) Biomass posses the greatest renewable potential in Georgia

Of all alternative sources of energy, biomass ranks second in the nation behind hydropower, providing approximately 16% of the nation's renewable energy supply. Forecasts only show slight increases in the nation's non-hydro renewable power production (refer to figure 1-4); however, the potential for generated electricity from biomass-based fuels may be much more significant.

Biofuels and Technology

Bioenergy is stored energy in organic material, such as plant matter and animal by-products. This material, commonly referred to as biomass, must go through some type of energy conversion process, or be directly incinerated, in order to generate electrical power. The primary sources of biomass for electrical generation are shown in figure 1-7.

Figure 1-7: Current Grid Connected Electricity Sources from Biofuels

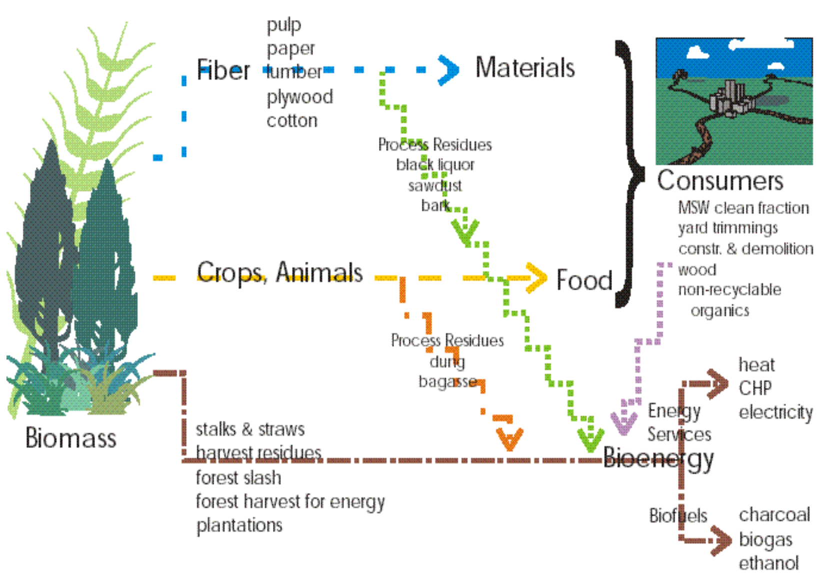


Source:	Edison Electric Institute, Energy Information Administration
Notes:	(1) Amounts reported for the paper industry represents only the total capacity dedicated to producing elecricity

Depending upon the type of biomass and the conversion technology, it is possible to convert solid biomass into a liquid fuel, such as synthetic biogasoline, bio-oils, biodiesel, and ethanol. These biofuels can then be used in high efficiency generation technologies. The Office of Technology Assessment suggests, the combined heat and power generation via biomass gasification techniques connected to gas-fired engines or gas turbines can achieve significantly higher electrical efficiencies, between 22 and 37%, compared to biomass combustion technologies with steam generation and steam turbine (15 to 18%). If the produced gas is used in fuel cells for power generation, an even higher overall electrical efficiency can be attained in the range between 25 and 50%, even in small scale biomass gasification plants and under partial load operation (TAB 2002).

The origin of biomass is commonly referred to as either closed-loop or open-loop. Closed-loop sources are grown and harvested specifically for power generation, switchgrass and poplar trees, for example. Biomass collected through open-loop production typically originates from municipal solid waste and agricultural by-products of production. Figure 1-8 illustrates the biomass to bioenergy flow.

Figure 1-8: Biomass Energy Flow

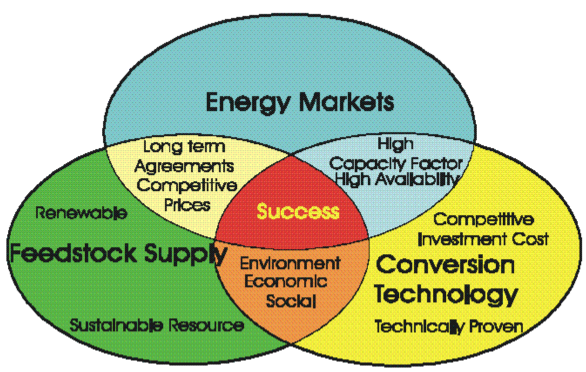


Source: National Renewable Energy Laboratory. Biopower.

The majority of open-loop sources are not used for generating electricity. Rather, they may be disposed of, where it bears some cost to the manufacturer and depletes landfill space. Alternatively, open-loop sources are sometimes left to decompose into the soil as a soil supplement. Some sources are used for a variety of other purposes. In summary, open-loop sources could come from any organic material; however, closed-loop biomass must be grown, harvested, used specifically for power generation, and then re-grown in order to continue the consistent cycle.

For the most part, biofuels are not applicable on large-scale basis. In order to be economically feasible in the production of electricity, biofuels must meet specific criteria for success (figure 1-9). One important criteria for success deals with the availability and efficiency of biomass sources. Biomass feedstocks must be of adequate energy content and provide a sufficient, continuos flow in order to reduce costly fuel stockpiles during non-harvest seasons. In addition, there are geographic implications to biofuel feasibility. The location of the biomass feedstock, must be relatively close to the generation facility in order to keep the costs of transportation at a minimum.

Figure 1-9: Bioenergy Criteria for Success



Source: National Renewable Energy Laboratory. <u>Biopower</u>.

Government-based incentives that promote biotechnology will advance biofuel feasibility. Implementation of government mandated emission taxes might also increase biofuel feasibility. The adoption of a renewable energy portfolio standard may set nation-wide goals for an increased percentage of renewable energy sources within the generation mix. The preceding are some primary examples of policies that could lessen the share of traditional fuel sources. But foremost, in order to increase the proportion of energy produced by biofuels, it must first become more feasible with respect to other fuel sources. The purpose of this thesis is to evaluate the economic implications for generating electrical power from Georgia's available biomass resources. The objectives and the corresponding organization of this thesis are described in the following sections:

Statement of Objectives

1. Discuss negative externalities and the corresponding economic implications of traditional and biomass fuel sources,
2. Research the share of pollution produced by the electrical power industry,
3. Compare and analyze the biofuel emission factors with fossil fuel sources,
4. Evaluate Georgia's current available biomass supply (open-loop) by county,
5. Study the feasibility of four biomass generation technologies (direct-fire, co-fire, gasification, and pyrolysis),
6. Relate Georgia's available biomass supply with the feasibility analysis to determine which biomass sources are most feasible, in what regions, and with what type of generation technology, and
7. Discuss and evaluate other options that may influence the feasibility of Georgia's biomass industry,

Thesis Organization

This thesis is composed of seven chapters with and three appendix sections. The next chapter will discuss negative externalities in more detail, relevant policies aimed to correct the impacts, and how this could affect the biofuel industry. Chapter Two also includes an evaluation of the emission factors, which compares the biomass industry with fossil fuel based generation. Chapter Three includes a discussion of the potential benefits for society by using biofuels, and concludes with the government-based policies that affect the biofuel industry, such as green power markets and renewable production incentives. Chapter Four describes the established federal policies that affect the biofuel industry, such as the Public Utility Regulatory Policy Act, the Clean Air Act, and the Energy Policy Act. Chapter Five focuses on Georgia's current available biomass supply based on quantity, location, cost, and energy content. Chapter Six introduces the feasibility case study by describing the capital and operational costs of direct-fire, co-fire, gasification, and pyrolysis generation technologies. This data is then related with the current regional electrical rates and the traditional operational cost averages to determine initial feasibility. The analysis will show the amount of biopower that could be produced from Georgia's current available biomass sources and the number of facilities that could be supplied. Chapter Six concludes with the implications of green power markets, production incentives, and emission trading costs, which are related to the initial feasibility figures to determine the potential overall feasibility. The final chapter includes some concluding remarks and potential areas for further study. The appendix sections shows data used to generate maps of Georgia's biomass potential, model representations of the generating technologies, and the percentage breakdown of operating costs.

CHAPTER 2

POLICIES AND ECONOMICS OF EXTERNALITIES

In the history of U.S. law, the environment has generally been used as an open access repository for emissions. It was both non-rival and non-exclusive, which means the atmosphere was available to all as a public dumping ground for emissions, and the use of the atmosphere by others did not hinder any person's ability to use the atmosphere for their own emissions. Only recently have environmental laws emerged, which provide the structure necessary for reducing the amount of emissions that can be released.

Environmental laws may have reduced the negative impacts of power generation; however, there are still significant impacts created from generation. The Union of Concerned Scientist (UCS) describe these impacts to include: human health problems caused by air pollution from the burning of coal and oil; damage to land from coal mining and to miners from black lung disease; environmental degradation caused by global warming, acid rain, and water pollution; and national security costs, such as protecting foreign sources of oil (UCS 2001). Since such costs are indirect and difficult to determine, they are external to the energy pricing system. And since they are external to the pricing market, neither the producers nor the consumers of electrical power pay for the costs of these externalities. Rather, society as a whole pays for them. As a result, the price of electricity is not as cheap as it appears. The UCS describes this pricing system to "mask the true costs of fossil fuels and results in damage to human health, the environment, and the economy" (UCS 2001).

In attempts to correct the impacts of these externalities, the federal government implements methods that may promote energy conservation, discourage wasteful energy use, demand cleaner production, and/or require generators to use more efficient technology. As implemented in the Public Utility Regulatory Policies Act (PURPA), former President Jimmy Carter vowed to correct the energy crisis by making it a top priority, claiming it to be the "moral equivalent of war." Carter attacked the energy shortage, not from the supply side, but first from the consumer's perspective. Carter claimed that conservation was the "quickest, cheapest, most practical source of energy," and he made it the cornerstone of his new policy. To encourage conservation, the President advocated the use of tax credits to spur individuals and businesses to insulate their homes, stores, and factories, thereby reducing energy consumption. In attempts to reduce negative externalities and wasteful energy use, he also lobbied for acceptance of energy taxes, such as a tax on gasoline up to 50 cents a gallon, as well as a tax on "gas guzzler" automobiles, if consumption did not decline as mandated.

Other mandates, such as the Clean Air Act (CAA), set forth policies designed to reduce negative impacts by directly regulating manufacturers. Some statutes specifically require emissions to fall within a given level. These regulations offer some flexibility by setting a nation-wide standard, and the method used for compliance is left up to the power producer. Other statutes require power producers to use specific abatement strategies or design standards. Incorporated in these regulations are terms such as "Best Available Control Technology" (BACT), which provide the legal structure to require emission reducing technology like scrubbers and bag houses.

To reduce negative externalities, lawmakers can structure environmental policy and enforcement strategies to best achieve the desired result. Long-term strategies should strive to optimize social welfare. For short-term solutions, policy makers may design regulations and enforcement strategies to ensure compliance before efficiency. The remainder of this section will focus on the economic theory behind negative externalities, their affects on social welfare, and the social welfare optimization goal to environmental policy.

Damages Caused by Externalities

The prevalence of externalities suggests that the optimality rules of economic theory, which usually assumes markets are driven to allocative efficiency, may not in fact lead to the most socially efficient outcome. The presence of externalities thus represents an example of market failure, because the market price of electricity does not reflect the damages caused by the externality, or the true societal costs of production.

Of the many negative externalities associated with power production, air pollution from the combustion of fossil fuels could be the most damaging. These atmospheric damages can be classified in two ways according to how it affects humans. First, human health can be directly impacted when harmful pollutants are inhaled. Second, gases that may have little or no direct adverse effect on the human body can accumulate in the upper surface layers of the atmosphere and gradually alter the stability of the climate. The following sections describe these two types of damages, air pollution and global warming, in greater detail.

Air Pollution

The first problem, air pollution, already contributes to a significant number of premature deaths and increased illness around the world. The primary source of these criteria pollutants comes from the combustion of the fossil fuels. This process releases sulfur dioxide (SO_2), particulate matter (PM), mercury, and oxides of nitrogen (NO_x) which furthermore leads to the formation of ground level ozone (O_3) – all of which have direct and indirect impacts on health.

Numerous studies have recently shown a direct correlation between areas with extensive levels of air pollution and an increase in respiratory illness. For example, data from 168 acute care hospitals in Canada discovered that ozone was shown to account for five percent of admissions for all respiratory conditions, including acute and chronic bronchitis, pneumonia, emphysema, asthma, and other diseases. The largest impact, approximately 16 percent of hospital admissions was seen in infants (Burnett).

Another study from Toronto and Southern Ontario, shows large increases in hospital admissions due to ozone and acidic air pollution, even at levels well below the current health standard. On average and peak summer pollution days, the pollution was linked to 24 and 50% of all respiratory admissions, respectively (Thurston 1994). A similar study from several New York metropolitan areas found that, "during the summers of 1988 and 1989, higher ozone levels led to greater numbers of hospital admissions for a variety of respiratory conditions including pneumonia, acute bronchitis, asthma, and other conditions" (Thurston 1992).

Unfortunately, research has not only found increases in respiratory illness as a result to air pollution exposure, but just as many credible studies have been able to show a direct relationship with air pollution exposure and increased mortality rates. A study conducted in 1995, which involved 151 U.S. metropolitan areas, observed the risk of death due to sulfate and fine particulate air pollution is 15 to 17% higher in cities with the most polluted air than in cities with the least polluted air. The risk of death in cities with average levels of air pollution is 7 to 8% higher than in cities with low levels of air pollution (Pope 1995). A study comparing individuals living in six American cities found that "those in the most polluted cities had a 26% greater mortality rate than those in the least polluted cities" (Dockery 1993). A study of ozone levels in Los Angeles and New York found a significant association between ozone and mortality. The study claimed, "a ten percent increase above average ozone levels was associated with approximately 2 additional deaths per 1000; similarly, a fifty percent increase above average ozone levels (not uncommon in the summer) was associated with 10 additional deaths per 1,000" (Kinney 1992). In Georgia, the American Lung Association estimates that over 4 million people live in areas with unhealthy air, with 9 counties receiving a grade of "F" for air quality.

The Greenhouse Effect

Possibly the most significant undesirable by-product of fossil fuel combustion is the emissions of greenhouse gases, which are gradually warming the Earth's atmosphere and causing global climate change. Carbon dioxide (CO_2) gas is an emission not listed as one of the CAA's criteria air pollutants; however it is the primary cause of the greenhouse effect. Fossil fuel combustion also releases nitrous oxide (N_2O), another greenhouse gas, with a global warming potential 310 times greater then CO_2. Consequently, even low levels of N_2O emissions can create a significant contribution to the greenhouse effect.

The repercussions of global climate change include: heat waves, disruption of previously stable weather systems, more frequent violent weather events, increased risks of infectious diseases, threats to food supplies, and coastal flooding. Based on direct measurements, the world's average temperature has risen by almost 1 degree Celsius over the past 138 years, and the 11 hottest years on record have occurred since 1982. According to the article, Economic and Social Dimensions of Climate Change by J. P. Bruce, the frequency of heavy one-day rains has increased by 20% in the United States this century, resulting in more flash flooding. Bruce claims sea levels continue to rise, with more frequent flooding of low-lying islands. On a global basis, Bruce evaluated the annual losses from natural disasters have risen from about $1 billion per year in the 1960's to more than $40 billion per year in the 1990's. Bruce states that climate change appears to have played a part, since the frequency of severe climate-related disasters (storms, floods, droughts, etc.) have increased three times as rapidly as for other natural disasters, such as earthquakes and volcanoes (Bruce 1995).

Global warming could potentially result in a significant loss of human life. The primary effect of global warming is excessively hot weather. Heat can complicate existing medical problems, particularly with the old, the young, and the ill. In 1995, a heat wave killed several hundred people in Chicago, and several thousand people in India and parts of central China. During the summer of 1998, severe heat waves struck North America, Europe, India, and China, accompanied by deaths, forest fires, and property loss.

Global warming would likely extend the territorial range and increase the abundance of insects and rodents which carry diseases such as malaria, dengue, toxoplasmosis, western and eastern equine encephalitis, snowshoe hare virus, yellow fever, Lyme disease, Rocky Mountain spotted fever, and hantavirus pulmonary syndrome. Global warming could also increase seasonal respiratory infections that would be worsened by climatic instability.

Climate models predict that global warming will cause severe and unstable weather patterns. Model results predict that for every increase of 1 degree Celsius, there will be a 2 percent increase in average precipitation, thereby resulting in floods of greater quantity and severity. These weather events can disrupt ecosystems, cause property damage, and divert normal rainfalls from productive agricultural lands.

However, as some areas become warmer and wetter, others will become warmer and drier. From the analysis of climate models, the Environmental Protection Agency suggests, the grain belt of the Great Plains will become drier as global warming proceeds. The decline in soil moisture will result in a reduction in agricultural productivity and could ultimately strain the food security of the Nation.

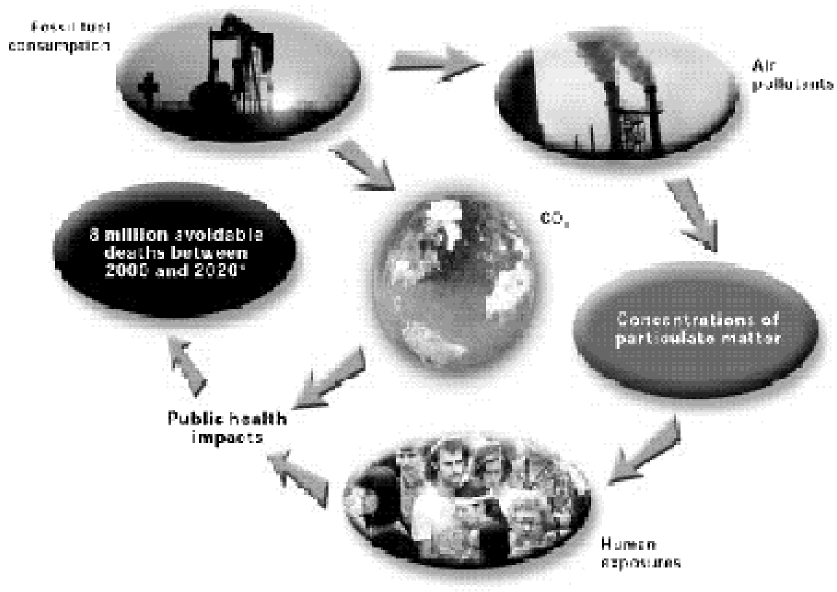
By continuing the current pattern of fossil fuel consumption, the resulting costs could have a significant impact on national economies. As the climate changes, more spending would be required on coastline protection, flood control, infrastructure, and health care. The Intergovernmental Panel on Climate Change (IPCC) stated, "the costs of damage due to climate change could range from 1 - 2% of gross domestic product for developed countries and 4 - 8% for developing countries" (Bruce 1995). The IPCC accredits these costs will arise from national declines in agricultural productivity, forestry, fisheries, and water availability.

The specific impact of the greenhouse effect is not entirely foreseeable. What is foreseeable is that global climate change holds the potential for large-scale disaster. Realistically, some regions could prosper from local climate change; however, climatically caused economic crisis in certain regions may result in global economic consequences. For many, the risks of potential consequences far outweigh the benefits within traditional energy sources. Supporters of the Kyoto Protocol advocate greenhouse gas mitigation practices in order to slow the rate of global warming.

Cumulative Impacts of Greenhouse Gases and Air Pollution

The detrimental impacts of the two negative externalities, air pollution and global warming, augment as they occur together. Pollutant emissions and high temperatures serve as a catalyst in the formation of other pollutants. For example, smog is created by increased atmospheric temperatures and/or ultraviolet radiation levels, which enhance the photochemical reaction that creates ground-level ozone and secondary organic particulates. As these factors compound on one another, increases in pollution related respiratory illness could be expected. A depiction of this cycle from the World Resources Institute is shown in Figure 2-1. Altogether, the widespread use of fossil fuels as an energy source creates a greater risk of illness, premature mortality, and is changing the delicate nature of the global environment.

Figure 2-1: The Global Impact on Public Health from Fossil Fuel Use

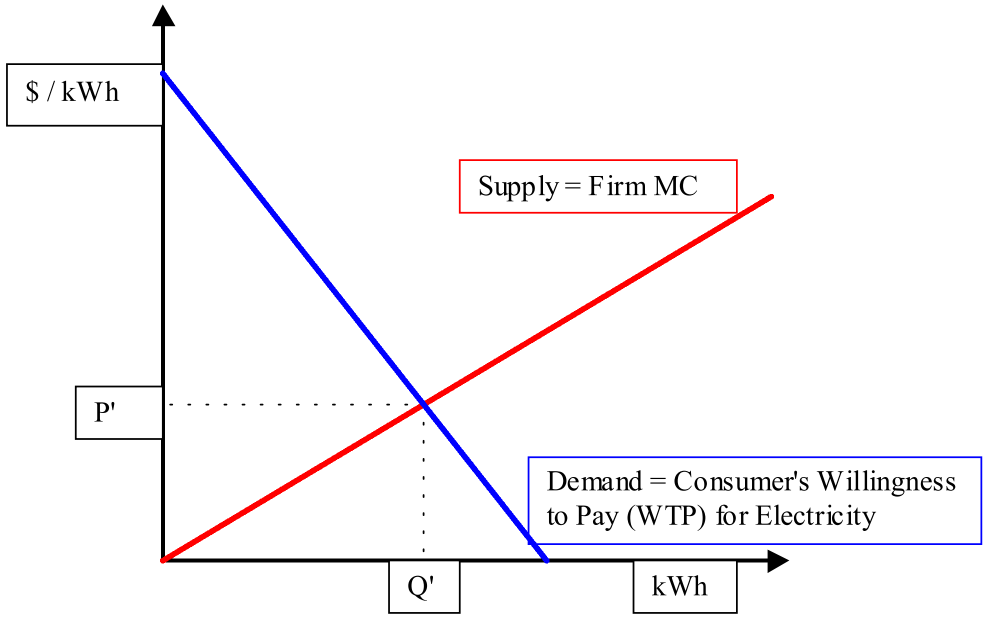


Source: World Resources Institute

Economics of Externalities

Figures 2-2 through 2-5 illustrates the implication of the aforementioned negative externalities on market efficiency. Figure 2-2 demonstrates an example of the supply curve, which represents the marginal costs (MC) of generating an additional unit of electricity, and the consumer's demand curve, or the average amount the consumer is willing-to-pay (WTP) for a varying amount of electricity. The demand curve displays an inverse relationship between price and quantity, because consumers are willing to pay for a greater quantity of power, as the price of electricity decreases. The supply curve displays a positive relationship with price and electricity, since firms will offer more electricity as the rates increase. As a result, consumers and producers will vary the production and consumption bundles, resulting in a stable equilibrium, where the power producer will produce Q' kilo-Watt hours (kWh) of electricity at a price of $P'. Figure 2-2 is the general example of a market driven to allocative efficiency.

Figure 2-2: Market Driven Equilibrium



Created by: Wayne Curtis

However in the presence of externalities, the external costs of pollution damage are not accounted for in this market structure. Figure 2-3 displays an example of how the marginal damage (MD) of pollution can shift the efficient level of production. The marginal damage curve represents the monetary damages resulting from polluting power generators, such as health care, flood protection, or property damage. The marginal damages increase incrementally for every unit increase in power production. In this example, the sum of the marginal cost (MC) curve and the marginal damage (MD) of pollution curve would yield the true, social marginal costs for power generation. The social marginal costs would therefore induce lower energy use (from Q' to Q*) at a higher price (from P' to P*) at market equilibrium.

Figure 2-3: Effects of Air Pollution on Society in an Unregulated Market

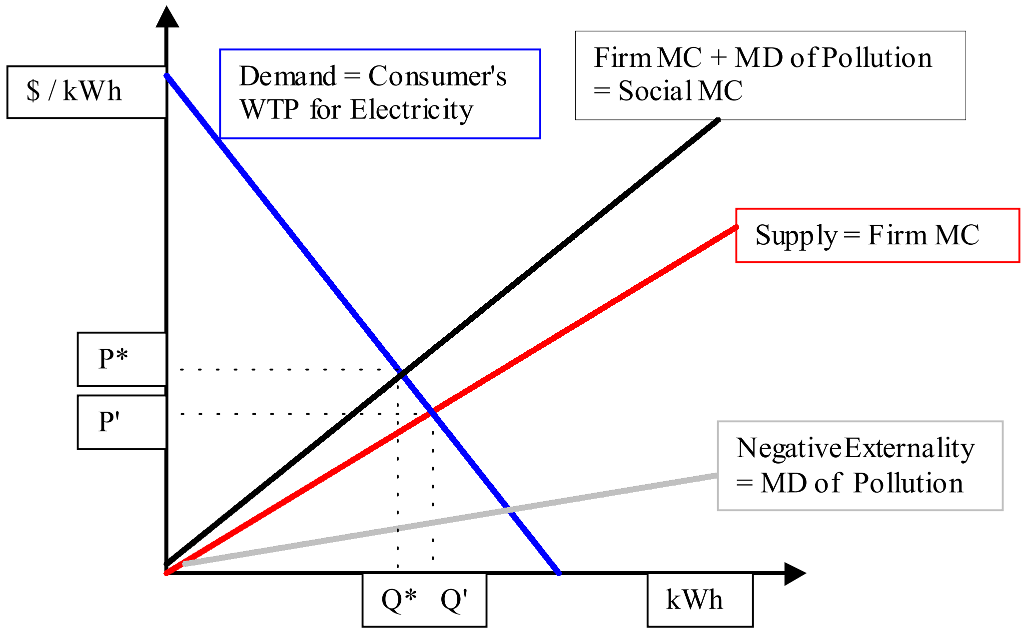
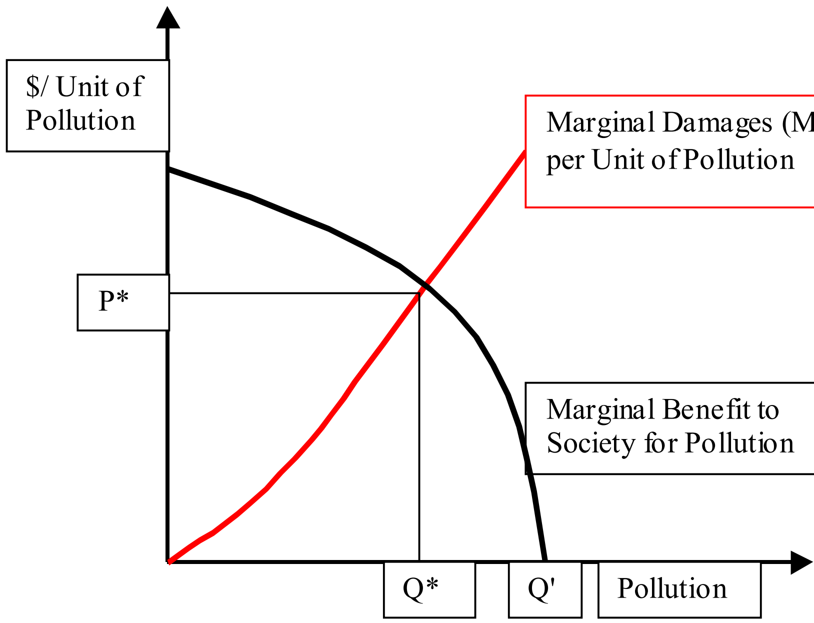


Figure Created by: Wayne Curtis

Without costly emission reduction practices, power producers are able to generate more electricity at cheaper rates. From this perspective, pollution can be viewed as a benefit to the generating facilities, or the producer's demand curve for pollution. Figure 2-4 displays the marginal benefit for pollution production, and the marginal damages caused by pollution emission. Since additional units of pollution will provide decreasing benefits to the generator, the marginal benefit curve has a downward slope. Alternatively, the damages caused by pollution increase for every additional unit of pollution. The socially optimum level of pollution occurs where the marginal benefits and marginal damages are equal (Q*, P*). Government-based policies designed to correct the impacts of negative externalities will often strive to achieve this level of efficiency. Without regulation, however, firms would produce the quantity, Q', where all benefits of pollution generation are realized and additional units of pollution will yield no more benefits.

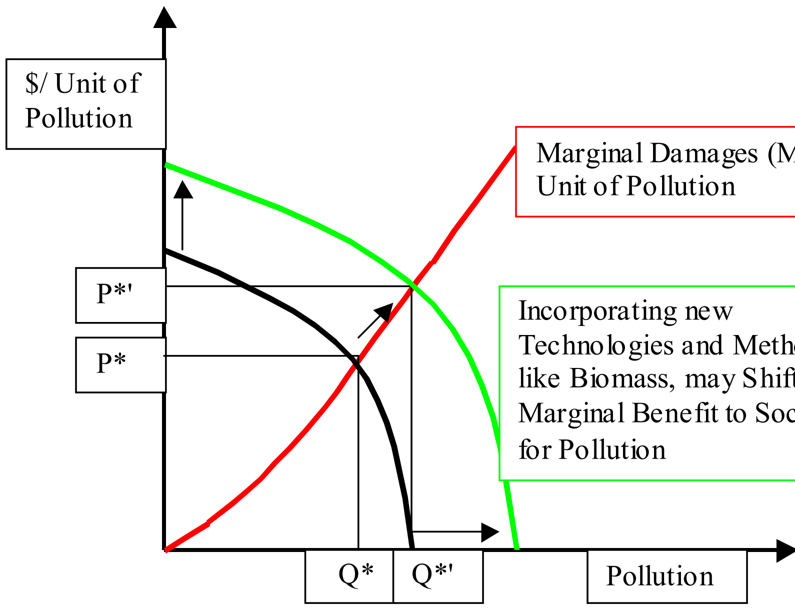
Figure 2-4: Marginal Benefits and Damages of Pollution



Created by: Wayne Curtis

This research studies the biomass potential for reducing emissions of some criteria pollutants. In theory, the increase in biomass-based power production could decrease the emission factor of some criteria pollutants, thereby shifting the marginal benefits of pollution. Figure 2-5 displays this relationship, assuming the marginal damages curve for producing pollution does not change. In this case, the marginal benefits curve shifts to the right. It is important to note this shift does not result in an increase in pollution. Rather, this shift indicates the benefits of polluting have increased per unit of pollution. In short, society receives more good for bad.

Figure 2-5: Incorporating Clean Practices Will Shift the Marginal Benefits Curve



Created by: Wayne Curtis

Regulation to Correct Externalities

With completely defined property rights, market-driven solutions could be a reality. However, defining rights to air, which lacks boundaries and is non-tangible in nature, would be impractical to say the least. Rather, to account for negative externalities like air pollution, which is generally non-rival and non-exclusive from one person to the next, government regulation is often necessary to increase the welfare of society.

The initial approach to solving the problem of externalities is the implementation of regulatory limits on the amount of the externality produced and the imposition of fines on those parties who exceed the regulated limit. This approach appears to offer a simple solution to limiting externalities by requiring all firms to reduce their externality by some quantity; however, they require extensive information and enforcement to be efficient. In order to regulate polluting firms, the enforcing body must be able to determine which activities produce pollution, determine which pollutants cause harm, and finally come up with an estimate of the damage being caused. Usually, only an estimate of damages can be obtained, meaning that the standard will only result in an outcome closer to the optimal position, rather than the exact level.

Next, the implementation of design standards on equipment and other inputs of production can further reduce the externality. For example, low-sulfur coal, bag houses, scrubbers, and other control technologies are required in coal fired power plants in order to reduce pollution levels. Unquestionably, design standards require more information to achieve the same level of efficiency as direct regulation. However, design standards work well to induce firms to become more efficient, while incorporating cleaner technologies into the production process.

Another possible solution to the problem of negative externalities is the imposition of corrective taxes, designed to induce producers to limit their production of electricity to the socially efficient level. A Pigouvian tax is a tax levied upon each unit of pollution in an amount just equal to the marginal damage it inflicts upon society at the efficient level of output. Pigouvian taxes are much more effective in achieving efficiency than regulatory limits or fines, and most importantly they induce an economic incentive to generate electricity while reducing the negative externality.

The most recent approach to negative externalities involves creating a market for pollution rights. In determining the number of pollution rights to be sold, the administrating body must estimate the point where the marginal benefit of pollution is equal to the marginal costs of pollution. The establishment of marketable permits for pollution rights can help achieve allocative efficiency, as a change in demand will be reflected in the price of the rights, but the amount of pollution produced will not exceed the optimal level determined by the number of pollution rights available. Marketable permits, through market-driven incentives, offers flexibility and induces improvements in technology while moving the industry towards the social optimum.

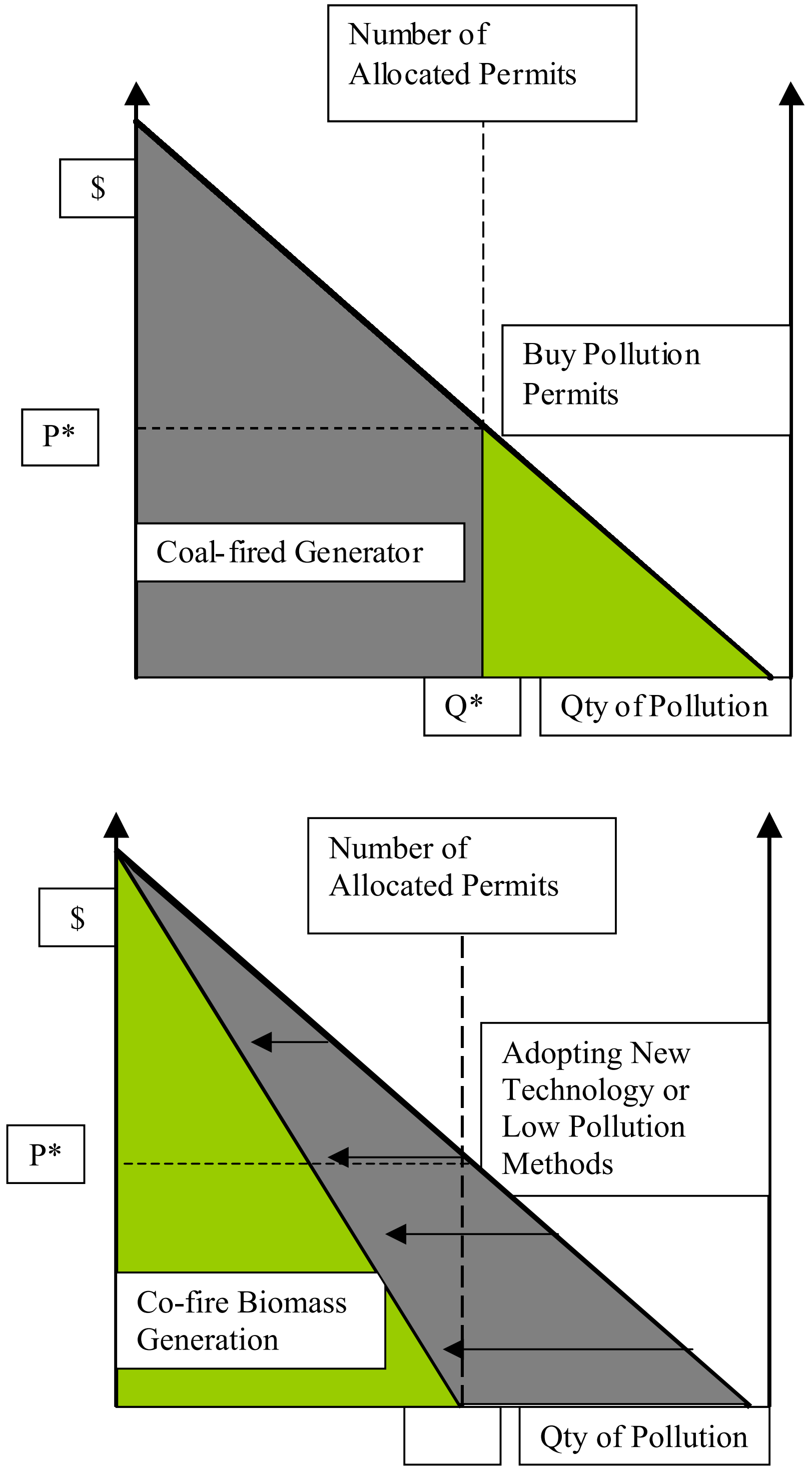
The Clean Air Act (CAA) Acid Rain Program is the most widely acknowledged success for trading emissions. Under the program, a market is created for utilities in order to reduce sulfur dioxide (SO_2) emissions. As a result, utilities now release 8.9 million tons of SO_2, down from 19.1 million tons in 1985. Though there are still some limitations, tradable permits should become more viable with improvements in information and technology.

Policy instruments that address externalities with market-based strategies, such as tradable permits, in conjunction with other relevant policy instruments, such as design standards, will pose the most practical methods to address air pollution in the future. Since the combustion of biomass generally has a lower emission factor for many pollutants, the implementation of these policy instruments will have great implications to the use of biofuels for electricity generation. As an example, coal and natural gas-fired generation facilities may include biomass in their generation mix in attempts to lower emissions. It may be cheaper to co-fire traditional fuels with biomass, rather than lowering production or purchasing pollution permits. The inclusion of biomass may enable certain facilities to sell unneeded permits. Altogether, if the policy is set to reduce the emission factor of a particular compound, and this compound is produced in less quantity per unit of electricity from biofuel sources, then bio-fueled generation will become more feasible.

Currently, there is no policy that allows tradable permits specifically for renewable power generators. Many predict new policies will be enforced in attempts to reduce emissions of greenhouse gases. If the U.S. becomes active in a global agreement to reduce greenhouse gases, tradable permits for renewable energy generation is likely. In this case, tradable permits will increase the feasibility for substitution of biomass in existing facilities and the construction of new biofuel-fired plants.

The most important principle of market-based strategies is that power producers must focus much more upon the fuel source and emission control costs with respect to the pollution emission rate for any given facility. In order to maximize profits, producers must consider all options available that can produce inexpensive electricity with low levels of emissions. Figure 2-6 depicts the marginal benefits of pollution for two options in power generation. The issuance of pollution rights, and hence the quantity of pollution produced, is fixed at quantity Q*. In the top figure, firms that want to produce electricity in amounts greater than Q* must purchase pollution rights. In the lower example, firms that adopt new technology or methods, thereby producing the same energy with decreased levels of pollution, will not be required to purchase pollution permits or cut back on their electricity production.

Figure 2-6: Options for Tradable Pollution Permits

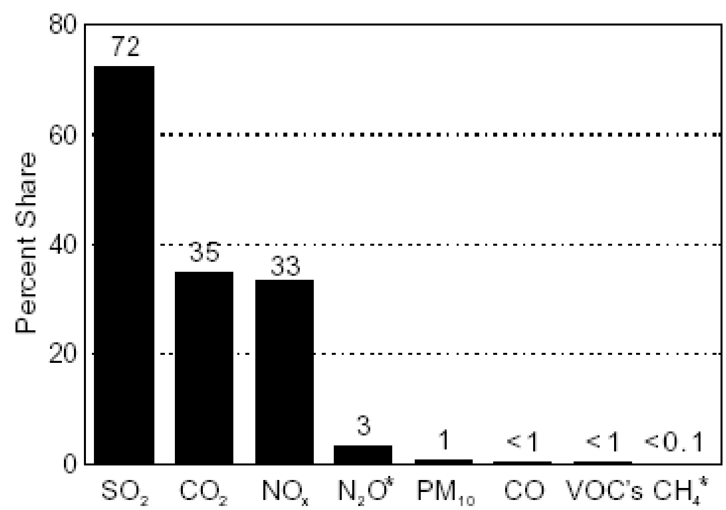


Created by: Wayne Curtis

Pollutant Emissions from Biomass and Fossil Fuel Sources

Electric utility power plants are the primary source of some pollutants, but not all. They currently account for only a small percentage of U.S. total particulate emissions because control devices, such as baghouse filters and electrostatic precipitators, remove most of the particulates from power plant waste gases (figure 2-7). Similarly, electric utility power plants contribute only small percentages of total emissions of volatile organic compounds (VOC's), carbon monoxide (CO), nitrous oxide (N_2O), and methane (CH_4). On the other hand, 72%, 35%, and 33% of total emissions of sulfur dioxide (SO_2), carbon dioxide (CO_2), and nitrogen oxides (NO_x), respectively, come from utility power plants (Carlin 1995). Since the electric utility industry contributes such a significant share of these three pollutants, the remainder of this section will focus on the biomass potential of reducing the emission levels of SO_2, CO_2, and NO_X.

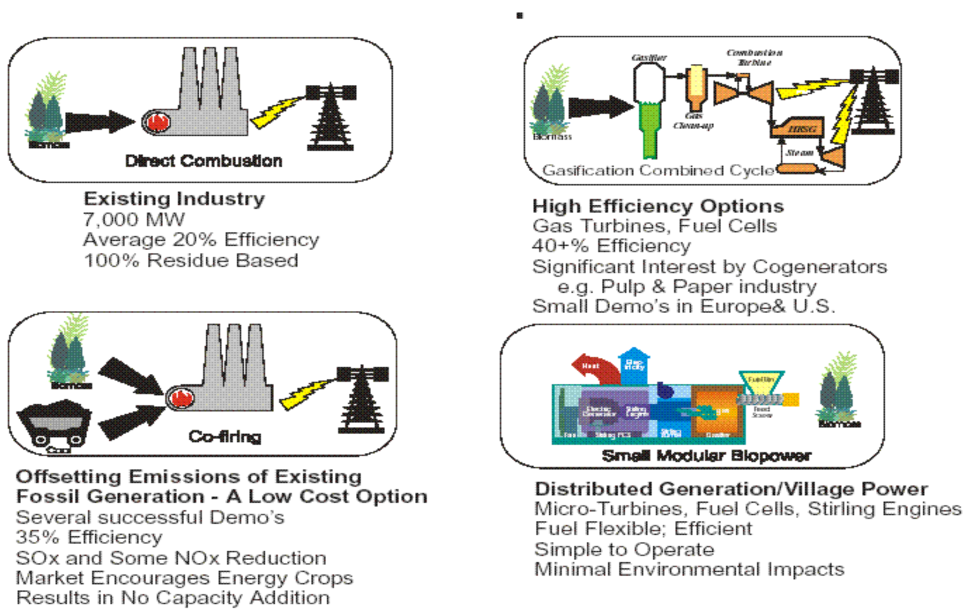
Figure 2-7: Electric Utilities' Share of Total U.S. Emissions, 1993



Source: ***Energy Information Administration. <u>Renewable Energy Annual 1995</u>.***

Though the level of emissions will vary depending upon the type of fuel, generation technology, size and efficiency of the plant, and applied emissions control technologies, we can generalize the emissions rate of biomass technologies in contrast with fossil fuel sources. Typical biomass fuel feedstocks contain almost no sulfer, have about 50% of the nitrogen content of coal, and would reduce the greenhouse gas emissions of Carbon Dioxide. Direct-fire or co-fire of biomass in existing generation facilities is often used as a method for reducing many of these airborne pollutants. Recognizing that coal provides almost 60% of electric utilities fuel resources, even small percentages of biomass-coal co-firing in base load facilities can have dramatic environmental effects. Emerging technologies, such as gasification and pyrolysis, are believed to further reduce emission levels; however, credible data for these new technologies is currently unavailable for comparison. Therefore, for the purpose of this study, the focus will be on the cumulative emissions data from the most common biopower generation technologies in use today (Figure 2-8).

Figure 2-8: Paths to Biopower



Source: National Renewable Energy Laboratory. Biopower.

Carbon Dioxide

Climate change due to emissions of greenhouse gases, particularly CO_2, becomes an issue when stored solar energy is converted to useable forms of energy (heat, electricity, fuels, chemicals) at a rate far exceeding the rate of formation. For coal, oil, and natural gas, the ratio of time between formation and use is on the order of 1 million to one, which means, the world uses in one year what took natural processes one million years to create. Only biomass among these stored forms has a time ratio that is within a human time frame of years or decades (Lawrence Berkely Laboratory). So as the biomass fuel grows, it takes in CO_2, and when it is incinerated for power production, it will release no more CO_2 than the same quantity as was previously stored in growth. Electrical power generation using closed-loop biomass sources must use and regrow the biofuel supply at a continuous rate. Since the combustion of biomass releases no more CO_2 emissions than the amount taken in from the original organism, and since closed-loop implies a consistent burn and regrow cycle, then closed-loop generation yields a zero net increase in CO_2 emissions.

This research focuses primarily upon open-loop biomass sources. In this case, various by-products are used for generation, and therefore may not lead to a zero net increase in CO_2 emissions. If the land from which the biomass was harvested is converted into some other use, then it could positively or negatively affect the net CO_2 emission level. For example, if 100 acres of hay is harvested and used to generate power, and the land is immediately developed for residential housing, then there may be an increase in the net CO_2 emissions. However, if the hay is harvested as a biofuel, and the land is replanted for pecan production, there may be a net decrease in CO_2 emissions.

Since this research focuses mostly upon agricultural waste by-products, it can be assumed that for most circumstances farmers will continue to keep their farmland in operation. In this case, the cycle of biomass burn to regrow will remain 1:1, resulting in a zero net increase of CO_2 emissions. This research also acknowledges the concept of using fossil fuels to harvest, process, and transport biomass sources. This process releases CO_2; however, CO_2 is also released as other fuel sources are harvested, processed, and transported. In order to reduce the complexity of such issues, this research will not consider these more indirect CO_2 releases, and will therefore assume a zero net increase in CO_2 emissions from all biomass sources.

Sulfur Dioxide

Fossil fuels also contain varying amounts of sulfur, which is oxidized to sulfur dioxide (SO_2) during combustion. The level of SO_2 emitted is a function of the type of fuel burned and the control equipment used rather than the combustion process (Carlin 1995). Therefore for comparison purposes, an analysis of the sulfur content of the fuel sources will estimate the correlated emission levels, without a detailed analysis of specific generation and control technologies.

Sulfur is present in virtually all coals and fuel oils at levels ranging from trace amounts to 6% by weight (Carlin 1995). Since 1990, the amount of sulfur used in fuels has been largely reduced. In Georgia, the average sulfur content found in coal has been reduced from 1.8% in 1990 to .8% in 1999 (EIA 2001). In a report prepared for the University of Georgia entitled: <u>Technical Data for the use of Agriculture and Forest Residues</u>, elemental analysis for various forms of biomass shows nearly all sources of biomass to be significantly lower in sulfur content than many conventional sources, with the exception of natural gas.

Table 2-1 shows the elemental analysis of many biomass fuel sources. From the table, most biomass sources contain less than .01% sulfur. Table 2-2 shows figures for the median and average element composition for biomass, as compared with the composition of Pittsburg seam coal. The green values indicate a lower percentage from coal. The red shaded columns indicate a greater percentage of compounds in biomass than coal. From the analysis, we can note nearly all sources of biomass contain less carbon, fixed carbon, nitrogen, and sulfur than Pittsburg seam coal. Alternatively, biomass sources produce more hydrogen, oxygen, and VOC's than the coal example. The release of hydrogen and oxygen pose no adverse affects to the environment. And since the electric power industry contributes less than 1% of the total emissions of VOC's, even an extensive expansion in biofuel-fired generation would not significantly increase the industry's total amount of VOC emissions.

Nitrogen Oxides

Nitrogen oxides (NO_x) result from the combustion of hydrocarbons in the presence of air, which is 21% oxygen and 78% nitrogen. During combustion, portions of both the atmospheric nitrogen and the fuel-bound nitrogen react with oxygen to form NO and NO_2 (Carlin 1995). These compounds are referred to collectively as nitrogen oxides.

Like SO_2, nitrogen oxide emissions levels are a function of the percent mass of polluting element within the fuel before combustion. However unlike SO_2, nitrogen oxides are much more dependent upon generation technologies and control methods.

Table 2-1: Difference of Compound Elements from Biomass Sources and Coal

Name	Fixed Carbon	Volatiles	Ash	C	H	O	N	S	HHV MEAS	HHV CALC
	%	%	%	%	%	%	%	%	kJ/g	kJ/g
WOOD										
Beech	-	-	0.65	51.64	6.26	41.45	0.00	0.00	20.38	21.10
Black Locust	18.26	80.94	0.80	50.73	5.71	41.93	0.57	0.01	19.71	20.12
Douglas Fir	17.70	81.50	0.80	52.30	6.30	40.50	0.10	0.00	21.05	21.48
Hickory	-	-	0.73	47.67	6.49	43.11	0.00	0.00	20.17	19.82
Maple	-	-	1.35	50.64	6.02	41.74	0.25	0.00	19.96	20.42
Ponderosa Pine	17.17	82.54	0.29	49.25	5.99	44.36	0.06	0.03	20.02	19.66
Poplar	-	-	0.65	51.64	6.26	41.45	0.00	0.00	20.75	21.10
Red Alder	12.50	87.10	0.40	49.55	6.06	43.78	0.13	0.07	19.30	19.91
Redwood	16.10	83.50	0.40	53.50	5.90	40.30	0.10	0.00	21.03	21.45
Western Hemlock	15.20	84.80	2.20	50.40	5.80	41.10	0.10	0.10	20.05	20.14
Yellow Pine	-	-	1.31	52.60	7.00	40.10	0.00	0.00	22.30	22.44
White Fir	16.58	83.17	0.25	49.00	5.98	44.75	0.05	0.01	19.95	19.52
White Oak	17.20	81.28	1.52	49.48	5.38	43.13	0.35	0.01	19.42	19.12
Madrone	12.00	87.80	0.20	48.94	6.03	44.75	0.05	0.02	19.51	19.56
Mango Wood	11.36	85.64	2.98	46.24	6.08	44.42	0.28		19.17	18.65
BARK										
Douglas Fir bark	25.80	73.00	1.20	56.20	5.90	36.70	0.00	0.00	22.10	22.75
Loblolly Pine bark	33.90	54.70	0.40	56.30	5.60	37.70	0.00	0.00	21.78	22.35
ENERGY CROPS										
Eucalyptus Camaldulensis	17.82	81.42	0.76	49.00	5.87	43.97	0.30	0.01	19.42	19.46
Casuarina	19.58	78.58	1.83	48.50	6.04	43.32	0.31	0.00	18.77	19.53
Poplar	16.35	82.32	1.33	48.45	5.85	43.69	0.47	0.01	19.38	19.26
Sudan Grass	18.60	72.75	8.65	44.58	5.35	39.18	1.21	0.01	17.39	17.62
PROCESSED BIOMASS										
Plywood	15.77	82.14	2.09	48.13	5.87	42.46	1.45	0.00	18.96	19.26
AGRICULTURAL										
Peach Pits	19.85	79.12	1.03	53.00	5.90	39.14	0.32	0.05	20.82	21.39
Walnut Shells	21.16	78.28	0.56	49.98	5.71	43.35	0.21	0.01	20.18	19.68
Almond Prunings	21.54	76.83	1.63	51.30	5.29	40.90	0.66	0.01	20.01	19.87
Black Walnut Prunings	18.56	80.69	0.78	49.80	5.82	43.25	0.22	0.01	19.83	19.75
Corncobs	18.54	80.10	1.36	46.58	5.87	45.46	0.47	0.01	18.77	18.44
Wheat Straw	19.80	71.30	8.90	43.20	5.00	39.40	0.61	0.11	17.51	16.71
Cotton Stalk	22.43	70.89	6.68	43.64	5.81	43.87	0.00	0.00	18.26	17.40
Corn Stover	19.25	75.17	5.58	43.65	5.56	43.31	0.61	0.01	17.65	17.19
Sugarcane Bagasse	14.95	73.78	11.27	44.80	5.35	39.55	0.38	0.01	17.33	17.61
Rice Hulls	15.80	63.60	20.60	38.30	4.36	35.45	0.83	0.06	14.89	14.40
Pine needles	26.12	72.38	1.50	48.21	6.57	43.72			20.12	20.02
Cotton gin trash	15.10	67.30	17.60	39.59	5.26	36.38	2.09	0.00	16.42	15.85
AQUATIC BIOMASS										
Water Hyacinth (Florida)	-	80.40	19.60	40.30	4.60	33.99	1.51	0.00	14.86	15.54
Brown Kelp,Giant, Soquel Point	-	57.90	42.10	27.80	3.77	23.69	4.63	1.05	10.75	10.85
AVERAGE		**77.13**	**4.72**	**47.91**	**5.74**	**40.98**	**0.52**	**0.05**	**19.11**	**19.15**
MEDIAN	**17.82**	**80.10**	**1.34**	**49.00**	**5.87**	**41.84**	**0.28**	**0.01**	**19.61**	**19.61**

Created by: Wayne Curtis
Data Source: Ankal Inc. 2001. Technical Data for the Use of Agricultural and Forest Residues, as Biomass for Producing Biofuel

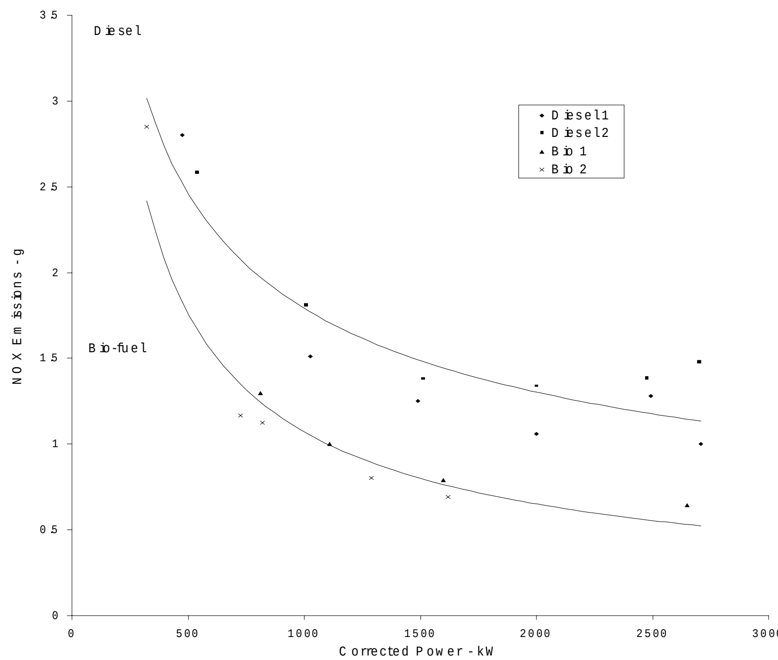
Table 2-2: Compound and Element Analysis of Common Biomass Sources

	Fixed Carbon	C	N	S	Ash	Volatiles	H	O
	%	%	%	%	%	%	%	%
AVERAGE	18.45	47.91	0.52	0.05	4.72	77.13	5.74	40.98
MEDIAN	17.82	49.00	0.28	0.01	1.34	80.10	5.87	41.84
Coal - Pittsburgh Seam	55.8	75.5	1.2	3.1	10.3	33.9	5	4.9
Deviation of Coal from Biomass Median	**37.98**	**26.50**	**0.92**	**3.09**	**8.96**	**-46.20**	**-0.87**	**-36.94**

Created by: Wayne Curtis
Data Source: EIA. 2001. http://www.eia.doe.gov

Figure 2-9 shows a pyrolysis case example of an exponentially decreasing emissions curve with increases in engine size. This type of relationship is common for most pollutants, with the exception of SO_2.

Figure 2-9: NOx Emissions for Varying Engine Size



Source: Button, Frank. Orenda Turbines. 2002. Gas Turbine Operation Using Biomass Derived Pyrolysis Fuel.

Emission Analysis

It is important to emphasize that emission levels will vary to some degree depending upon the type of fuel used and the generation technologies. Emerging technologies, such as gasification and pyrolysis, are not well established within the industry, and therefore credible emissions data is not readily accessible. However, from analysis of the chemical make-up of each fuel, research has shown that nearly all biomass sources will reduce SO_2, NO_x, and yield a zero net increase in CO_2 emissions. Research has also shown particulate and VOC emissions are more significant at biomass electric generating plants. By averaging fuel source and technology emission levels, biomass emissions can be compared with traditional fuel sources. The EIA evaluated the estimated emissions from electric power generation in tons/GWh using 1995 data (table 2-3). Emission figures for biomass generation includes the most common feedstock fuels and generation methods. Table 2-4 compares biofuel emissions with traditional fuels.

Table 2-3: Estimated Emissions from Electric Power Generation in tons/GWh

Fuel (tons/GWatt-h)	CO^2	SO^2	NO^x	PM^{10}	VOCs
Eastern Coal	1,000	1.7	2.9	0.1	0.06
Western Coal	1,039	0.8	2.2	0.06	0.09
Gas	640	0	0.57	0.02	0.05
Oil	840	0.5	0.63	0.02	0.03
Biomass	0	0.1	1.25	0.11	0.61

Data Source: Renewable Energy Annual 1995, Energy Information Administration, p. xiii, Table FE1

Table 2-4: Deviation from Biomass as percent change and lbs/GWh

Percent Change from Biomass Fuel Sources					
Fuel	CO^2	SO^2	NO^x	PM^{10}	VOCs
Eastern Coal	-100.00%	-96.55%	-56.90%	9.09%	90.16%
Western Coal	-100.00%	-92.59%	-43.18%	45.45%	85.25%
Gas	-100.00%	95.00%	54.40%	81.82%	91.80%
Oil	-100.00%	-88.24%	49.60%	81.82%	95.08%

Change in Emission Levels from Biomass Fuel Sources					
Fuel (lbs/GWatt-h)	CO^2	SO^2	NO^x	PM^{10}	VOCs
Eastern Coal	-2,000,000	-3,360	-3,300	20	1,100
Western Coal	-2,078,000	-1,500	-1,900	100	1,040
Gas	-1,280,000	114	1,360	180	1,120
Oil	-1,680,000	-900	1,240	180	1,160

Created by: Wayne Curtis
Data Source: Renewable Energy Annual 1995, Energy Information Administration, p. xiii, Table FE1

As shown in table 2-4, biomass fuel sources reduces emissions from the three most significant pollutants from the electric utilities, with only a few exceptions. The red shades indicate the percentage of biomass emissions that are exceeding traditional fuels.

The green shades indicate the percentage of biomass emissions that are less than traditional fuels.

Due to the zero net increase of CO_2 emissions, biofuels completely reduces this greenhouse gas as compared to traditional fossil fuel sources. Biomass reduces SO_2 emissions approximately 97% from eastern coal and 88% from oil fuel sources, or the equivalent of 3,360lbs/GWh and 900lbs/GWh, respectively. However since natural gas is primarily methane (CH_4), it contains approximately 75% hydrogen, 25% carbon, and only trace amounts of sulfur. As a result, biomass releases 95% more SO_2 emissions than natural gas, or the equivalent of 114 lbs/GWh.

Biomass releases 57% fewer NO_x emissions than eastern coal. However, biomass increases emissions of NO_x when compared with gas and oil sources by 54% and 50%, respectively. As noted earlier, biomass releases more particulates and volatile organic compounds than all other traditional sources. But since the electric utility industry is responsible for only 1% of these emissions with respect to other polluting sources, the addition of biomass fueled generation facilities would not significantly increase the total share for the industry in the near future.

CHAPTER 3

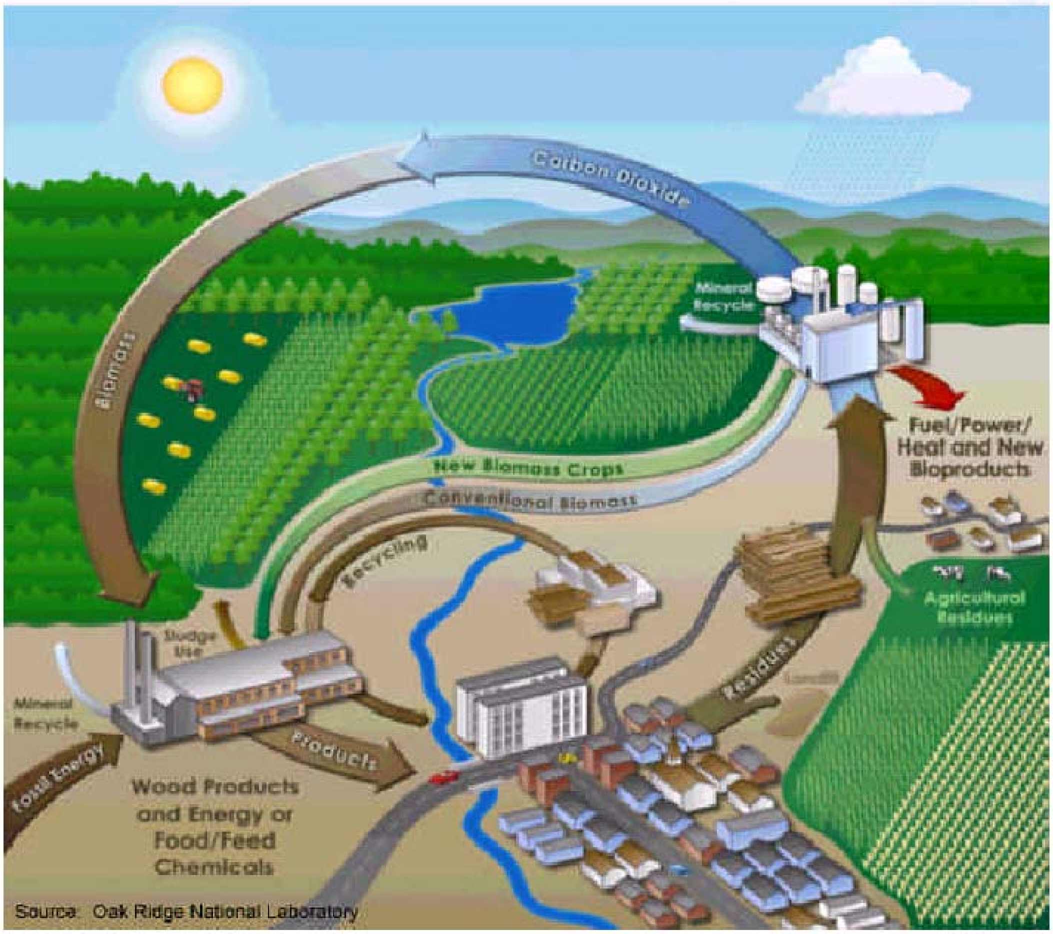
POTENTIAL BENEFITS

Biomass Fuels the Economy

The use of biomass within the electrical power generation mix possesses many potential benefits. First of all, biomass is available wherever plants grow or organic wastes are generated. Therefore, the construction of equipment and facilities for the production, distribution, and use of biomass can create local jobs and tax revenues. In the U.S., biomass power supports more than 66,000 jobs. The U.S. Department of Energy predicts that advanced technologies currently under development will help the biomass power industry install over 13,000 megawatts of biomass power by the year 2010, and create an additional 100,000 jobs. The Southern States Energy Board claims, "the use of locally produced fuels keeps energy expenditures in local communities where they produce economic growth and improve the quality of life, while studies have shown that up to 80 % of the money spent for petroleum fuels imported into a community leaves that community" (SSEB 2001).

The most common sources of useable biomass are agricultural by-products, forestry by-products, closed-loop sources, landfill gas, and municipal solid waste. These sources could provide benefits to the surrounding community by reducing the amount of waste sent to landfills, creating jobs and additional income for the agricultural industry, increasing U.S. energy security, and by providing new energy markets. The following illustration, figure 3-1, depicts the localized expenditures created by biofuel markets.

Figure 3-1: Internalization of Biomass Resources



Diversity in the Generation Mix

It is important to keep a diverse generation mix. Fuel diversity protects consumers and electric companies from fuel unavailability, price fluctuations, and changes in regulatory practices. Biofuels are subject to price affecting agents like: insects, diseases, and natural disasters such as droughts and fires. Traditional fuel sources are subject to price fluctuations from wars, cartel activity, and regulations. Diversity helps ensure economic stability along with electrical reliability of low prices and continuous supply. By investing in biofuel technology and other renewable fuel sources, the U.S. can increase diversity while decreasing the negative externalities caused by the use of traditional fuels.

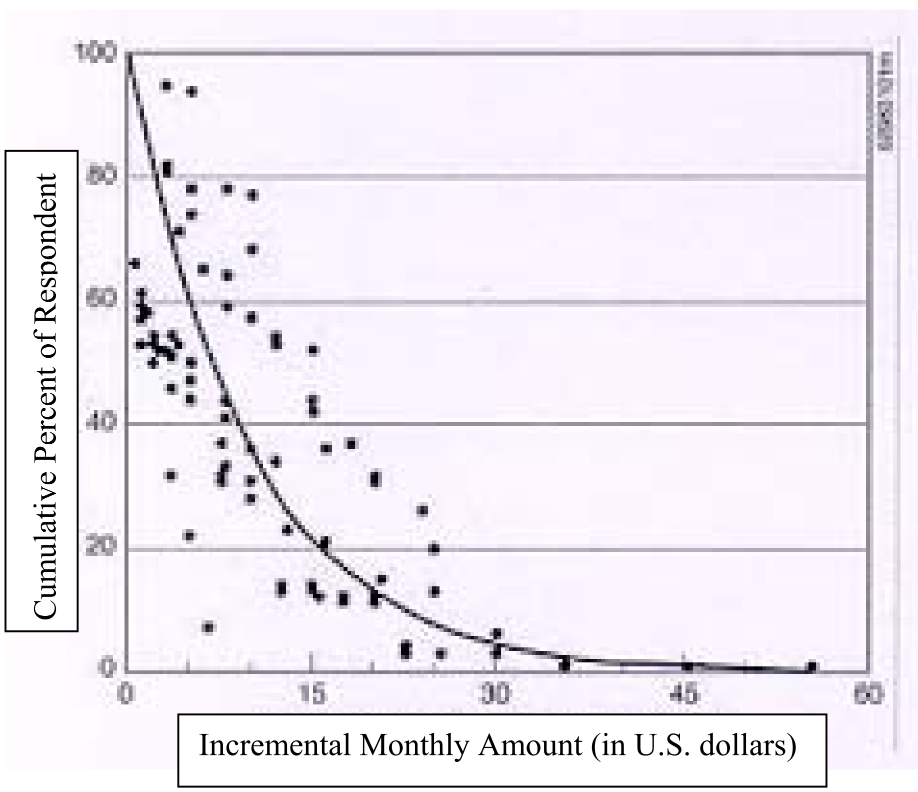
Green Power Markets

Power marketing has come a long way since the time of Samuel Insull and his innovations leading to the separation of markets for electricity. However, history often repeats itself, and the emergence of a new market is springing up nationwide. As consumers become more educated about the risks and damages created by traditional methods of power generation, some are willing to do what they can in order to reduce their contribution of these damaging effects.

The National Renewable Energy Laboratory (NREL) states from “nearly 20 years of opinion polling, national probability samples show that 56% to 80% of American voters say they are willing to pay more for environmental protection and for renewable electricity" (NREL 2001). More recently, a review and synthesis of 14 surveys conducted in 12 utility service territories (1995-1997) found that majority (52 to 95%) of residential customers said they were willing to pay more on their electric bills for power from renewable sources (NREL 2001). Figure 3-2 displays these integrated responses into willingness-to-pay (WTP) probability curve. This curve shows the percent of residential customers that indicate a WTP for renewable energy at different premium payment levels. However, it is important to note that the following figure represents the cumulative results of many contingent valuation surveys. Actual results would depend upon the presentation and questioning techniques used within each survey.

Figure 3-2 displays an inverse relationship with the cost of the premiums and the percent of respondents that are willing to pay for additional premiums. In other words, as the cost of the renewable energy premium increases, the amount of people willing to pay for renewable energy decreases. For purposes of this thesis, the following figure reveals that numerous surveys, which were reviewed by the National Renewable Energy Laboratory, determined a significant portion of respondents would be willing to pay some additional premium for an increased share of renewable energy. This research will further discuss the potential economic implications of these results in the feasibility section of this thesis.

Figure 3-2: WTP Probability Curve for Renewable Energy Premiums



Source: National Renewable Energy Laboratory. Willingness to Pay for Electricity from Renewable Resources: A Review of Utility Market Research

Until recently, there was not an established market available for consumers that wish to purchase power supplied from renewable energy sources, or "green power." In order to capture these environmentally considerate consumers, new green power pricing programs have appeared in over 85 utilities in 30 states. These programs typically focus on creating new capacity for green power, and therefore do not include existing facilities. As a result, new renewables can realize greater economic incentives and relaxed barriers to entry into the competitive power market. Today, green power supplies more than 430 MW of new renewables capacity, with an additional 330 MW in planning.

Georgia Case Study: Sterling Planet and Green Power EMC

Green Power markets set up a venue for consumers who wish to purchase their power from renewable sources. The first company to offer green power in Georgia was a Roswell-based company called Sterling Planet. Sterling Planet started offering green-power to Georgia's consumers in 2000. The company would sell green power to consumers who were willing to pay an additional 10 to 20% premium for the green power option. The consumer must purchase the power from their existing supplier and then pay the additional premium to Sterling Planet.

Unfortunately, Sterling Planet does not contract any green power generators from Georgia. Rather most green power generators were located in the western United States. This means Georgia's consumers do not actually use or receive any local benefit from Sterling's Green Power. Sterling Planet can best be explained as providing a market for people to promote alternative energy by paying a premium, so that a green power generator, which is located somewhere in America, can compete with traditional generation technologies.

In 2002, a new green power market became active in Georgia. Green Power EMC offers Georgia's consumers similar opportunities to purchase power blocks at a comparable premium. But since Green EMC generators are located within Georgia, it provides the same incentives for the renewable industry as Sterling Planet, while also providing the green energy benefits to local consumers.

Governor Roy Barnes declared April 22, 2002 as "Green Power Day" when 16 electric cooperatives, contracted through Green Power EMC, began selling green power over a limited number of 150 kWh blocks. The green power price is determined separately by each cooperative based on generating expenses and administrative costs. Georgia customers are expected to pay between $3 and $5 extra each month for the purchase of 150 kWh blocks of green power each month. Although the average home uses 1,600 kWh each month, most people are not willing to pay entirely for the added cost of green electricity. Reducing the power sells into blocks captures more consumers willing to pay for some portion of renewable energy within their personal consumption mix. Also, it allows for a greater distribution of the burden and reduces the temptation to free-ride off of those who are willing to purchase all of their electricity from green sources.

Initially, the amount of green power available is in short supply. The biomass-fueled generation will come from reclaimed methane gas at three North and Middle Georgia landfills. The blocks will be sold on a first come, first serve basis. They will produce eight megawatts (MW) of electricity the first year, which is enough green power to serve approximately 30,000 customers of the more than 900,000 Georgia homes, businesses, factories and farms served by the 16 cooperatives. Green Power EMC plans solar and low-impact hydroelectric energy sources will be added to its generating capacity in 2003.

For now, the most important implication to the Georgia Green Power Program is the availability of choice to Georgia's consumers. The creation of a market that gives consumers the ability to purchase their source of electricity will allow consumers to actively reduce their contribution to environmental damage while promoting renewable fuels. According to the EPA, Georgia's green power program will have the same environmental benefits as taking 114,000 cars off the road or planting 156,000 acres of forest.

Existing renewable generation facilities will not qualify for the green power EMC market. Rather, Green Power EMC intends to provide an immediate market for new online facilities. This has great implications on Georgia's biomass potential. By creating a separate market that demands cleaner sources of energy, biomass generation facilities will not have to face strict barriers of entry, such as competing with cheaper traditional fuel sources. And by only including new renewable generators, new facilities will not be forced to compete with existing renewable facilities.

On a large scale, biomass cannot support a highly significant share of Georgia's energy supply, or at least not at the present level of technology. In order to capitalize on the possible benefits of biofuels and reduce the negative externalities associated with traditional generation methods, it is necessary to bring biofuel-fired generation closer to competitive prices. This can be done through the introduction of green power markets and government decreed taxes and subsidies. As previously discussed, green power markets give market-based incentives for renewable energy introduction into the competitive energy industry. Alternatively, government based taxes on pollution provide incentives by discouraging those sources that produce negative externalities through taxation, thereby raising the costs of "bad" sources of energy. Subsidies provide incentives for renewables by providing production credits for green power generation, thereby lowering the costs of "good" sources of energy.

The introduction of these promotional programs will aid in the advancement of renewable energy technology and bring renewable energy generation closer to feasible rates in a shorter timeframe. As technology increases, biofuels are becoming more feasible. And as biofuels become more feasible, investors will assist in research and development programs that promote biofuel research and technology, thereby lowering costs, and ultimately expanding the share of biofuels within the generation mix. Since energy source diversity keeps electricity rates low and more stable, Georgians should not look forward to an exclusively green-fueled future. However, increasing the biofuel market share may help increase diversity, reduce energy imports, mitigate waste disposal issues, decrease the negative externalities associated with traditional fuels, and could also create local jobs and tax revenues.

Incentives for Biofuels – Subsidies and Taxes

Government policy can be set in order to promote "good" products and services, or discourage "bad" products and services. For example, President George W. Bush is attempting to increase the amount of minorities whom own homes. To do this, he will offer tax breaks to assist lower income, first-time homebuyers. Alternatively, the government often taxes products, such as carcinogenic tobacco products, which introduces a disincentive for consumers to purchase these "bad" products, thereby decreasing negative externalities while raising tax revenues. The same types of policy instruments are used in the power industry.

Environmental policy instruments are designed to alter production or consumption trends in order to achieve some desired outcome. Often, separate policies work together to obtain these results. For example, government mandates such as the Clean Air Act require power generators to use certain control technologies in order to reduce pollution levels. This raises the costs of fossil fuel power production, thereby bringing renewable energy closer to feasibility. Alternatively, statutes such as the Energy Policy Act, directly provides incentives for renewable energy providers through production credits. The Regional Clean Air Incentives Market (RECLAIM) is a market-based program intended to cut smog in Los Angeles by providing greater flexibility and the financial incentive to reduce air pollution beyond what clean air laws and traditional pollution control technology laws require.

Though these statutes have separate objectives, it is important to realize how distinct pieces of legislation can produce similar results. The Clean Air Act standards indirectly promote renewable generation by controlling more polluting sources of energy. Whereas, the Energy Policy Act is designed to directly increase the feasibility of renewables. The Regional Clean Air Incentives Market discourages pollution while encouraging cleaner production. The cumulative effect of these policies achieves the desired results by making less polluting forms of energy more feasible in relation to other, more polluting sources of energy. By implementing different methods of legislation, the utility industry will move progressively towards more efficient generation practices, without forcing the entire burden of transition onto any particular sector. The economic implications these policies could impose on biomass feasibility will be assessed following the initial feasibility section of this thesis.

CHAPTER 4

IMPORTANT LEGISISLATIVE HISTORY

Public Utility Regulatory Policy Act

In response to the energy crisis of the 1970's, congress enacted the Public Utility Regulatory Policy Act (PURPA) in 1978. PURPA was designed to reduce the dependence on foreign oil, promote alternative energy sources and efficiency, and to diversify the electric power industry (16 USC Sec. 2611). It requires electric utilities to interconnect with and buy all capacity and energy offered from "qualifying facilities" (QF's) at the utility's own avoided cost rates. Eligible electric generators, QF's, under criteria established by Federal Energy Regulatory Commission (FERC), could be either small renewable power producers or cogenerators.

To encourage entry into the market, Congress exempted QF's from rate and accounting regulation by FERC, from regulation by the Securities and Exchange Commission (SEC) under the Public Utility Holding Company Act (PUHCA), and from State rate, financial, and organizational regulation of utilities (15 USC Sec. 3211). This eliminated most of the regulatory and administrative burden that had previously rendered entry into the electricity market prohibitive for smaller entities. Most importantly, QF's were guaranteed a market for their power (16 USC Sec. 824a-3).

But despite its benefits, PURPA is no longer much help for renewables. Due to current low avoided costs, few renewables are able to compete with new natural gas turbines. Technically, PURPA only calls for renewable energy if it is cost competitive with conventional generation methods. Many of the benefits of renewables are not included in the price, such as clean air, but PURPA makes no provision for including these externalities. By strictly interpreting the law, the FERC has expressly forbidden non-price factors in PURPA decisions (15 USC Sec. 3201). According to the Union of Concerned Scientist, "as the guaranteed prices of PURPA contracts signed in the 1980's expire, many renewable power generators are going out of business" (UCS 2000).

Clean Air Act

The Clean Air Act (CAA), amended in 1990, significantly reduced emissions from electric power generation facilities. Titles I, III, and IV of the CAA (42 USCS § 7543) sets forth a framework which provides incentives for renewable sources of energy.

An analysis of the types of incentives offered within the CAA is beyond the scope of this paper; however, in general, these are market driven incentives that rely heavily on market-based control methods and pollution prevention strategies. The Center for Renewable Energy and Sustainable Technology (CREST) summarize the 1990 CAA amendments by noting that all key titles of the law require or allow some form of emissions trading, marketable permit programs, emissions fees, or early reduction credits (CREST). These programs promote economic efficiency by giving regulated industries greater flexibility to comply with anti-pollution regulations.

Presently, biofuel use can provide benefits within this market system. However, the system is still relatively new and not all renewable sources are able to benefit from the 1990 CAA amendments. Congress has both specifically and generally recognized the air pollution control potential of wind, geothermal, solar, and biomass technologies in existing and emerging emissions trading programs. At the present time, however, there is not a procedure in place whereby renewable energy facilities, which do not emit pollutants, have allowances that they may sell or where a direct financial incentive exists for utilities to reduce emissions through energy conservation and renewables (NREL 2002). The National Renewable Energy Laboratory describes the CAA's incentive programs have failed to provide incentives for renewable energy sources because of "poor design and the ease with which utilities were able to meet emissions limits from more conventional energy sources" (NREL 2002).

Energy Policy Act and the Renewable Energy Production Incentive

The Energy Policy Act (EPACT) of 1992 intended to increase the use of energy from renewable energy resources and enhance research and development in renewable energy technologies (26 U.S.C. 45). "EPACT established an incentive program whereby corporations, small businesses, and homeowners that generate electricity from closed-loop biomass (biomass grown exclusively for energy production) and wind energy are eligible to receive a production incentive for electricity sold during the 10 year period after the facility is placed into service" (NREL 2002). In November 1999, the production incentive was extended for 30 months under an agreement reached during the 2000 budget negotiations. The incentive is currently set at 1.8¢ per kilowatt-hour (kWh), and is adjusted annually for inflation.

Although the credit has been useful for wind-sourced power generation, biomass sourced generation has many barriers for use under EPACT. According to the Internal Revenue Service, no biomass project has ever claimed this credit. In addition, the IRS was aware of only one project being developed to grow energy crops for electricity production. This Non-Use of Section 45 (EPACT) is caused by restrictions in the Tax Code, prohibiting the use of Facilities built before 1992 from qualifying for the Credit. "This restriction eliminates the opportunity to modify the vast majority of boilers nationwide to use or co-fire biomass fuels (at a fraction of the capital cost in building a new Facility)" (Brown).

To address this issue, Congress passed the Ticket to Work and Work Incentives Improvement Act of 1999 (Public Law 106-170, 113 Stat. 1939). Section 507 provided a modification of credits for producing electricity from biomass and extended the sources to include poultry litter. A new piece of legislation currently in the Senate, the Energy Security Tax Incentive Act of 2001, specifically section 302, amends EPACT Section 45 to include open-loop biomass, including co-firing with biomass, and geothermal, landfill methane, incremental hydropower, municipal waste and steel cogeneration as qualifying energy resource (Bingamen 2001, 2).

CHAPTER 5

GEORGIA'S BIOMASS POTENTIAL

Georgia's power generation mix is not unlike the rest of the nation. Accordingly, the negative externalities associated with traditional methods of power generation impact Georgia's economy and environmental quality. Approximately 68% of Georgia's electricity is generated from coal-fired power plants. An additional 24% is generated from nuclear sources. In order to supply Georgia's coal-fired generation plants, an estimated $661, 557, 050 worth of coal is imported every year into the state. Georgia's Clean Energy Plan intends to reduce the impacts of coal-fired generation by calling for a gradual reduction in coal sources while increasing the share of biomass fuels. The goal is to increase the biomass fuel share to over 10% of all generation by the year 2020. Currently, Georgia ranks 5th in the nation for biomass-fueled generation, with biomass accounting for three million MW-hours, or 2.5% of the electricity generated in the state. A recent publication, <u>Biobased Fuels, Power, and Products State Profiles</u>, released from the Department of Energy's National Biomass Coordination Office, reports there are forty-seven bio-based facilities with the total capacity of 838 MW and employ 9,277 employees from biomass-sourced power production within Georgia.

Feedstock Issues

A barrier to private sector investment in biomass energy facilities is the lack of specific information regarding the quantity and quality of biomass feedstocks, the delivered cost of biomass to the plant site, and the best location for a proposed facility relative to both feedstock supply and markets for energy products. These issues are substantial since this study shows that biomass feedstock receiving and processing are consistently one of the highest capital costs, usually second behind the power generating equipment.

In order to optimize feasibility, feedstocks must provide generators with an abundant supply at the lowest cost of delivery possible. In addition, the heat content (BTU) of feedstocks vary depending upon the type of biomass, so a high energy fuel is critical. Biomass sources also differ in ash and moisture content. This affects the energy value of biofuels, since the chemical make-up of ash generally has no energy value and the amount of water in biofuel affects, in a decisive manner, the available energy within every biofuel.

Biomass sources also vary in weight and size. Types of biomass that are most dense, or can be processed to use less space per ton, will have the lowest costs of transport and storage. The altering weight, size, structure, and dimensions of biomass types results in different processing and equipment use, which ultimately influences the cost of source. Our study found those fuels with the lowest delivered cost per million BTU (MMBTU) are the most likely fuel sources for a biomass power generation facility.

Table 5-1 shows the delivered fuel costs for coal, petroleum, and natural gas. Table 5-2 shows the biomass feedstock quality and delivered cost for some common agricultural biomass sources in Georgia. Pecan Hulls are the least expensive agricultural feedstock to purchase and transport, costing only 86¢ per million (MM) BTU. Rye Straw is the most expensive, costing $10.70 per MM BTU. Comparing the delivered costs per

MM BTU on these two charts, there are two biomass feedstocks that can be delivered cheaper than coal ($1.56/MMBTU), five that are cheaper than natural gas ($2.49/MMBTU), and nine that are cheaper than petroleum ($3.90/MMBTU).

Table 5-1: Utility Delivered Fuel Costs and Quality for Coal, Petroleum, and Gas

Fuel	1990	1994	1999	Average Annual Rate of Change (Percent)
Coal (cents per million Btu) (1999 dollars)	216.5	184.6	154.6	-3.7
Average heat value (Btu per pound)	11,893	11,774	11,740	-0.1
Average sulfur Content(percent)	1.6	1.1	0.8	-7.6
Petroleum (cents per million Btu) (1999 dollars) . . .	588.5	432.6	389.6	-4.5
Average heat value (Btu per gallon)	139,814	138,484	138,495	-0.1
Average sulfur Content(percent)	2.4	0	0	-100.0
Gas (cents per million Btu) (1999 dollars)	359.7	350.2	248.9	-4.0
Average heat value (Btu per cubic foot)	1,024	1,025	1,032	0.1

Source: Energy Information Administration, State Electricity Profiles, Georgia, 2001

Table 5-2: Biomass Feedstock Quality & Delivered Cost

Biomass	Ash Content Dry Basis	mmBTU / ton	Price / Ton (low)	Price / Ton (high)	Average Price / Ton	Calculated Average $/mm BTU	Freight Cost per Ton mile	50 Mile Frt/Ton	50 Mile Frt/mm BTU	Delivered F/S $/mmBTU
Pecan Hulls*	5.80%	16.35	$7.00	$10.00	$8.50	$0.52	$0.11	$5.50	$0.34	$0.86
Gin Trash*	17.60%	13.10	$10.00	$12.00	$11.00	$0.84	$0.12	$6.00	$0.46	$1.30
Bark, Pine	3.30%	14.08	$16.00	$19.00	$17.50	$1.24	$0.10	$5.00	$0.36	$1.60
Poultry Litter	26.68%	8.89	$5.00	$15.00	$10.00	$1.13	$0.09	$4.50	$0.51	$1.64
Peanut Hulls	5.90%	16.03	$20.00	$30.00	$25.00	$1.56	$0.07	$3.50	$0.22	$1.78
Wood Chips	1.30%	9.09	$16.00	$19.00	$17.50	$1.93	$0.11	$5.50	$0.61	$2.53
Wood Residu	3.20%	8.86	$15.00	$25.00	$20.00	$2.26	$0.09	$4.50	$0.51	$2.76
Hay*	5.70%	14.00	$30.00	$40.00	$35.00	$2.50	$0.17	$8.50	$0.61	$3.11
Cotton Stalks	17.20%	12.37	$31.00	$49.00	$40.00	$3.23	$0.09	$4.50	$0.36	$3.60
Kenaf	3.60%	14.78	$50.00	$50.00	$50.00	$3.38	$0.17	$8.50	$0.58	$3.96
Corn Stalks*	6.40%	14.62	$40.00	$60.00	$50.00	$3.42	$0.17	$8.50	$0.58	$4.00
Switchgrass	5.40%	14.01	$60.00	$70.00	$65.00	$4.64	$0.17	$8.50	$0.61	$5.25
Wheat Straw	3.50%	14.57	$120.00	$130.00	$125.00	$8.58	$0.22	$11.00	$0.76	$9.34
Rye Straw*	3.00%	12.70	$120.00	$130.00	$125.00	$9.84	$0.22	$11.00	$0.87	$10.71
Natural Gas	0.00%	47.87	$120.00	$239.00	$179.50					

Created by: Wayne Curtis

Source Data: Ferland, Chris. 2001. Biomass Utilization, Supply and Economics

Barnes, Warren. 2002. Biomass Cogeneration: Final Report

Notes: (1) Biomass sources on the top that are shaded dark green are cheaper than coal, followed by sources that are cheaper than natural gas, and sources shaded in light green are cheaper than petroleum on a delivered cost per mm BTU basis.

Georgia's Agricultural Sources

This section will discuss the supply and costs associated with biomass feedstocks available in Georgia. The report titled: Biomass Utilization, Supply and Economics, prepared by Chris Ferland from the Center for Agribusiness and Economic Development, uses data from the 2000 Georgia Farm Gate Value Report to determine Georgia's agricultural feedstock potential. By starting with the annual yields of produce, Ferland evaluated the total agricultural by-products (open-loop) by multiplying the total yield mass with the percent of residues left over after harvest. Closed-loop feedstocks quantities were determined by multiplying the annual yield per acre by the total acres in production. Ferland further describes Georgia's biomass feedstock potential and pricing as the following:

> **Alternative Crops** – Kenaf and Switchgrass were identified as alternative possibilities for increasing farm income and biomass. Neither crop has been planted in large acreage tracks in Georgia. Research indicates both crops produce around 6-10 tons per acre. The cost per ton for ranges from $50-70.
>
> **Bark** - Foresters estimate that 322 cubic feet of bark is produced per acre. An estimated weight per cubic foot is 20 pounds. Using the total number of harvested acres multiplied by the total bark per acre results in 229,908 tons of available bark. Researchers in the Warnell School of Forestry at the University of Georgia mentioned that bark has two main outlets, power and landscaping. Many lumber and pulp mills use the bark to heat and fuel the machinery, with higher quality bark sold to the landscaping industry.

Corn Stalks – Upon completion of harvesting the grain, corn stalks remain in the field, a little bent and broken but still a good source for biomass. To harvest the remains, hay rake and baler will be implemented. The UGA Crop and Soil Science Department estimates 1200 pounds of stalks per acre after the grain is harvested. The Farmgate Report (2000) has total acres of corn at 347,358 multiplied by 1,200 pound per acre yields 208,415 tons annually.

Cotton Stalks – Many cotton producers cut and till cotton stalks back into the field. These stalks make a good biomass product. The total number was multiplied by the pounds of stalks available per acre to calculate the total. Researchers randomly cut cotton stalks of both irrigated and dry-land fields, weighed the stalks and converted it into an acreage figure. Irrigated cotton stalks yield 4,900 lbs per acre and dry-land yield 4,200 lbs per acre. The cost to harvest the cotton stalks using a forage harvester and nutrient replacement ranges from $27-49 depending on the machinery used and irrigated versus dry land. Georgia produced 3,363,000 tons of cotton stalks in 2000.

Excess Hay – In certain years hay production in Georgia is in excess of consumption. This may not be a consistent form of biomass but years with timely rainfalls will produce excess quantities of forage. Often farmers are willing to dispose of excess hay. The cost per ton for hay is $30-40. The hay baled in large round bales weighs approximately 1,000 pounds.

Gin Trash – According to researchers at the University of Georgia, every bale of cotton ginned produces 200 pounds of gin trash. The Center for Agribusiness and Economic Development's Farmgate Report was used to calculate the number of tons by taking the total production gathered by the ginned bales multiplied by 200 pounds per bale. There is approximately 182,005 tons of gin trash available in Georgia. The economics were more difficult to formulate. Gin trash is a light material and needs to be placed into the module builders. An estimate of .5¢ per pound was given by various sources for a cost of packing the gin trash into a module. The cost per ton ranges between $10-12. The only competition is cattle farmers who currently utilize gin trash as a supplemental feed source.

Peanut Hay – Each acre of peanuts produces 3-4 bales of peanut hay at 1,200 pounds per bale. Using the total acres of peanuts, Georgia produces 948,587 tons of peanut hay. Baling the hay is a relatively inexpensive venture, however, the market for peanut hay, even with it being illegal to sell, pushes the cost to around $15-20 a bale or $30-40 per ton.

Peanut Hulls – The totals tons available of peanut hulls is reflected by taking 24-25% of the total production. Hulls comprise approximately 25% of the weight of the peanuts. Using the Farmgate production, Georgia produced 702,785 tons of peanut hulls last year. Due to its light density, pelletizing was suggested as a means to create an efficient transportation system. This made the cost of hulls $20-30 per ton.

Pecan Hulls – To estimate the tons of pecan hulls available, the total production multiplied by 33% (typical shelling rate) then multiplied by 51%, the average percentage between meat and hulls. The total tons available in Georgia are 12,927. Two shellers said, "as long as we shovel the hulls, we can have them for free". The best way to shovel the pecan hulls would be mechanically. The rental price of a front-end loader is $130 per day. The company estimated 4-5 tons per hour can be shoveled by one person. Paying the employee $8 per hour and the front-end loader on an hourly rate of $16.25 create a total hourly figure of $26.25. Divide that by tons per hour and the cost per ton is $6.60.

Pine Straw – Using the total acreage of all pines in the state as provided by the United States Department of Agriculture, Forestry Service, multiplied by 25 bales per acre and 20 pounds per bales produced 11,531,625 tons of pine straw.

Poultry Litter – To arrive at the total tons of poultry litter produced in the state, the number of head for both broilers and layers was used in respect to their annual pounds of litter per head, 10.8 and 15.4 pounds, respectively. The total tons of poultry litter available are 6,640,380 broilers and 160,283 for layers. Poultry production is concentrated in Northeast Georgia. Farmers use poultry litter as fertilizer but are experiencing criticism in urban areas and with compliance with the Environmental Protection Agency regulations. Overuse of poultry litter raises the phosphorus level in soil to unacceptable amounts. Spreading of poultry litter will continue to be popular in areas of high farm production because the crops reduce the phosphorus levels, although in Northeast Georgia limited acreage of crops exist and alternatives to spreading the litter are continuously being researched. The average cost per ton of litter is $5-15.

Sawdust – The estimates for the tons of sawdust available, are from information obtained in Utilization of Southern Pines, by Koch A.H. The sawdust residue on southern pines sawed in Georgia amounts to 1 to 1.2 tons per million board feet (MBF). The researcher incorporated the 3,994.8 million board feet harvested in 1997 and multiplied it by 1.2 tons per MBF. The total yield was 4,794 tons of sawdust. Almost all of this sawdust is directed by the industry to produce power to run the lumber and pulp facilities. Dr. Larry Morris of the Warnell School of Forestry at the University of Georgia, explained that 85% or more is kept for a direct power source to the paper industry. Looking at 15% of the original amount of sawdust, leaves 719 tons leftover. The largest user of this component of sawdust is the poultry industry. Georgia is the number one grower of broilers in the country, so the researchers imagine sawdust is not likely a highly feasible option for biomass. A quoted price from a lumber facility ranged from $16-20 per ton depending on the mesh screen desired.

Soybean Hulls – According to the Report on the Feasibility of an Oilseed Processing Facility in Georgia, completed by the Center for Agribusiness and Economic Development at the University of Georgia, there are approximately 6,500 tons of soybeans hulls available in Georgia.

Wheat and Rye Straw – Each of these commodities produce between 110-120 square bales per acre. Straw has a relatively strong market in the landscape sector. Straw price per 30-pound bale is $2. If every acre of wheat and rye were baled, Georgia would produce 377,231 tons of wheat straw and 137,933 tons of rye straw. The cost per ton of straw based on the landscaping price is $120.

Wood chips – Koch (1976) wrote that 1.5 tons of wood chip residuals are produced per million board feet. Georgia's average harvest is 3994.8 million board feet per 476,000 acres. The total wood chips available would be 5,992 tons.

Wood Residue – Wood residues are the remains (branches, bark, needle) on the harvested acreage. It is estimated that 15% of the tree remains on the harvested acreage. The average yield per acre is 2,254 cubic feet. Meaning approximately

2,651 cubic feet exist per acre. A cubic foot of residues is estimated to weigh 49.9 pounds. The state average for harvested acreage is 476,000. This creates approximately 4.5 million tons of wood residues. One problem related to using wood residue is transportation. Stacking branches on the bed of a trailer and/or truck is not efficient. These branches will have to be processed through a wood chipper for the most efficient means of transporting the waste material. This adds cost to an almost free product. Another cost is the nutrient replacement back into the acreage. Foresters estimate that 85% of the nitrogen in the soil comes from the remains left after harvest. To replace this amount of nitrogen, researchers at the Warnell School of Forestry estimate the cost to be between $75-$85 per acre. Adding all the costs per ton of wood residue is approximately $15-25 per ton (Ferland 2001).

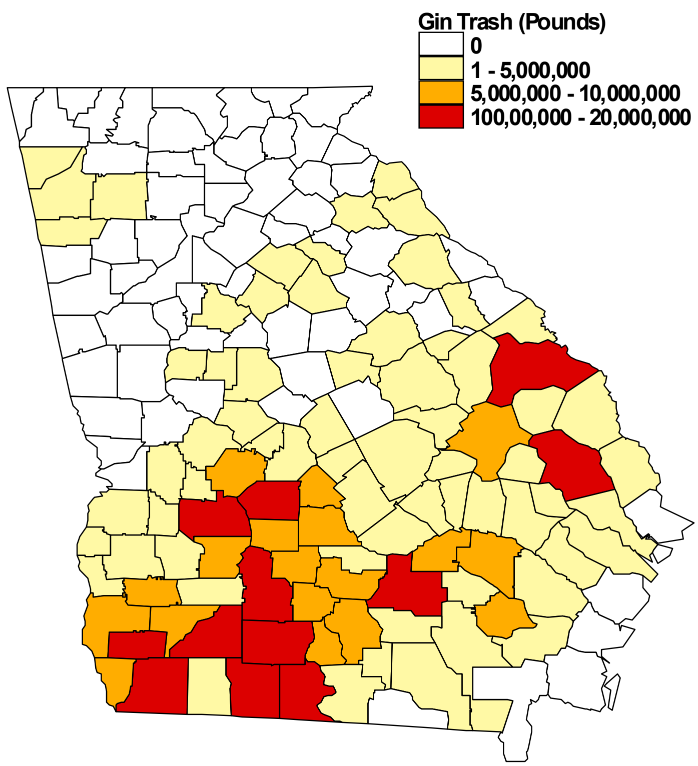
Ferland summarizes his findings in table 5-3, which shows the total tons of agricultural biomass produced, the price per ton, the delivered cost per ton, and the season of harvest. He further notes that feedstock prices may rise as the market for biomass residues becomes more established. "When usage increases, people notice a market emerging and will attempt to raise prices and/or lower supply in an effort to increase profits" (Ferland 2001). Currently, pecan hulls are the cheapest biomass feedstock source, followed by poultry litter, gin trash, and wood chips. These feedstock sources can be harvested and transported for less than $23 per ton. The 2000 Georgia Farm Gate Value Report geographically locates the most applicable feedstock supplies by county as shown in figures 5-3 through 5-9.

Table 5-3: Biomass Supply and Delivered Prices

BioMass	Tons Avaliable	Price/Ton	Average Price/Ton	Cost Per Ton Delivered @ ($1.70)/Mile	Season
Pecan Hulls	12,927	$7-10	$ 8.5	14.00	fall
Poultry Litter	6,800,663	$5-15	$ 10.0	14.50	year round
Gin Trash	182,005	$10-12	$ 11.0	17.00	late sum -early fall
Wood Chips	5,992	$16-19	$ 17.5	23.00	year round
Bark	229,908	$16-19	$ 17.5	22.50	year round
Wood Residue	4,015,343	$15-25	$ 20.0	24.50	year round
Peanut Hulls	702,785	$20-30	$ 25.0	28.50	late sum -early fall
Cotton Stalks(Irrigated)	1,524,307	$27-42	$ 34.5	39.00	late sum -early fall
Hay	1,026,653	$30-40	$ 35.0	43.50	late sum -early fall
Cotton Stalks(Dry Land)	1,839,306	$31-49	$ 40.0	44.50	late sum -early fall
Corn Stalks	208,415	$40-60	$ 50.0	58.50	mid sum -ealry fall
Kenaf(13,000 acres)	90,750	$50	$ 50.0	58.50	fall
Switchgrass(1000 acres)	6,000	$60-70	$ 65.0	58.50	fall
Wheat Straw	377,231	$120-130	$ 125.0	136.00	late spr -early sum
Rye Straw	137,933	$120-130	$ 125.0	136.00	late spr -early sum

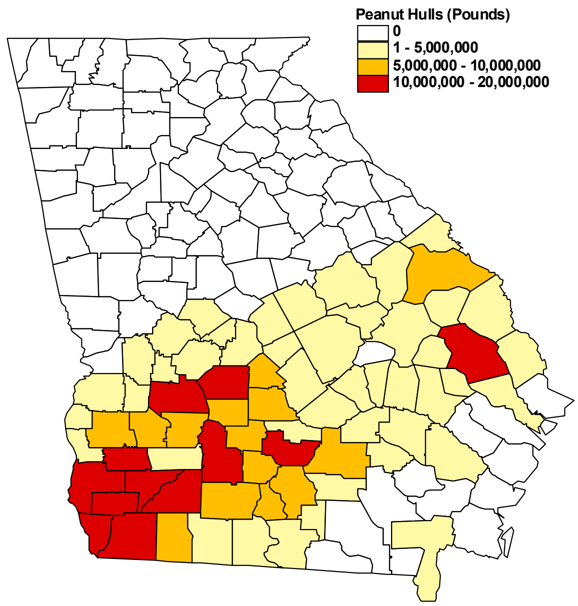
Source Data: Ferland, Chris. 2001. Biomass Utilization, Supply and Economics

Figure 5-1: Gin Trash by County 2000



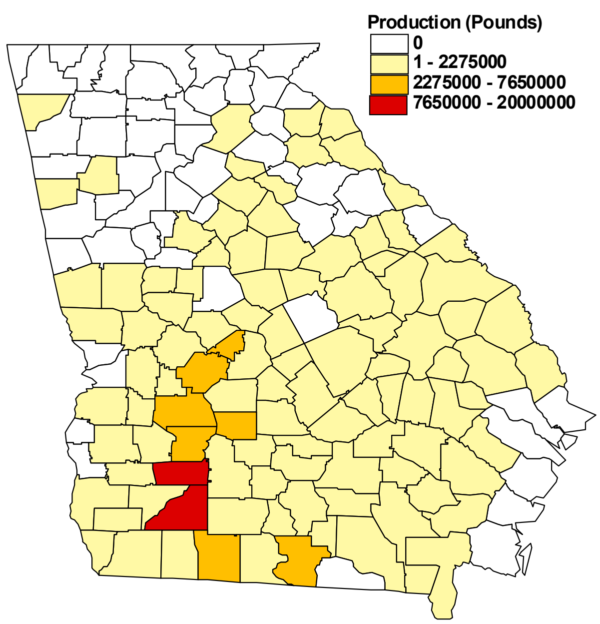
Source Data: Ferland, Chris. 2001. Biomass Utilization, Supply and Economics

Figure 5-2: Peanut Hulls 2000



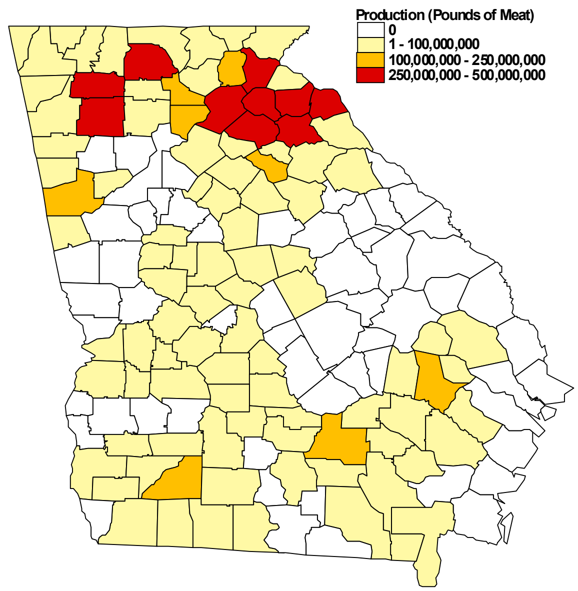
Source Data: Ferland, Chris. 2001. <u>Biomass Utilization, Supply and Economics</u>

Figure 5-3: Pecan Production 2000



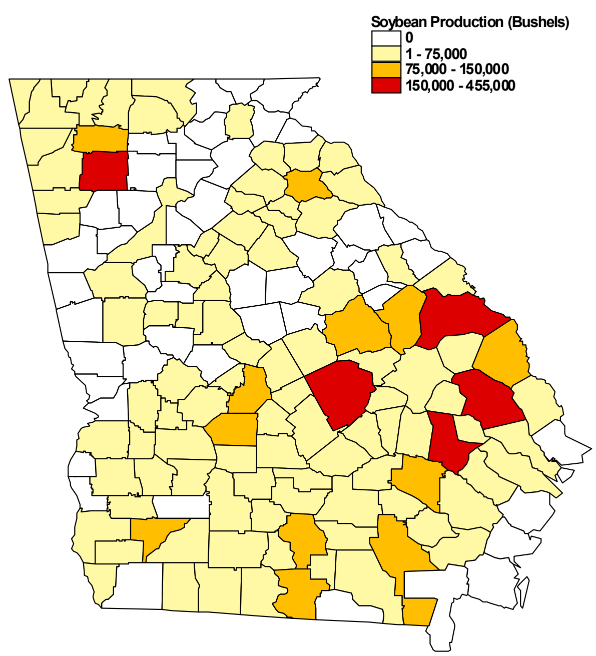
Source Data: Ferland, Chris. 2001. <u>Biomass Utilization, Supply and Economics</u>

Figure 5-4: Poultry Production 2000



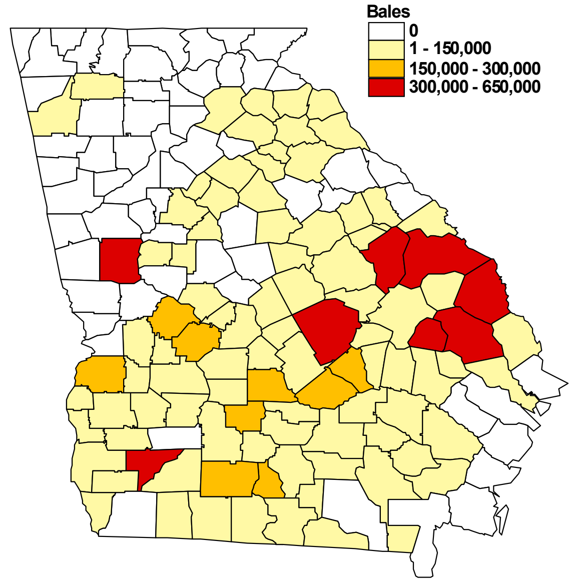
Source Data: Ferland, Chris. 2001. Biomass Utilization, Supply and Economics

Figure 5-5: Soybean Production 2000



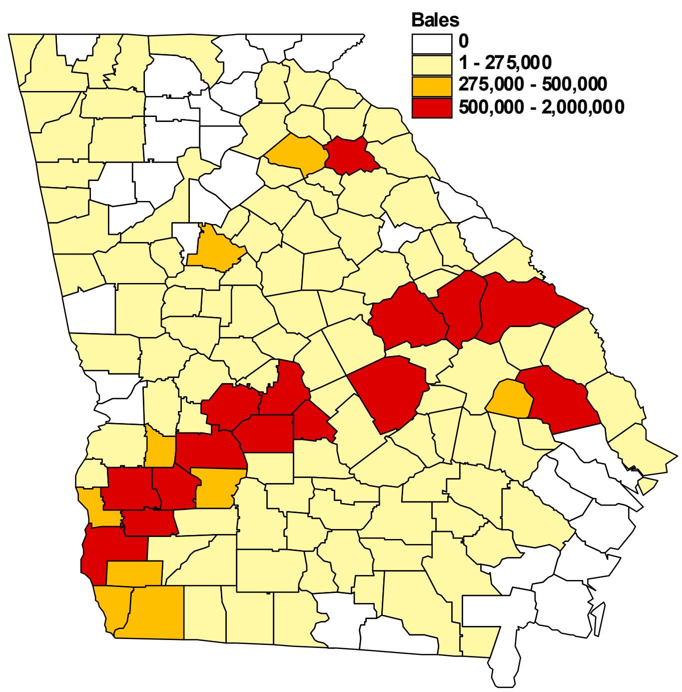
Source Data: Ferland, Chris. 2001. Biomass Utilization, Supply and Economics

Figure 5-6: Rye Straw Production 2000



Source Data: Ferland, Chris. 2001. Biomass Utilization, Supply and Economics

Figure 5-7: Wheat Straw Production 2000



Source Data: Ferland, Chris. 2001. Biomass Utilization, Supply and Economics

In order to determine the total biomass potential, further analysis of the BTU content must be applied to each corresponding feedstock source. Table 5-4 ranks the most applicable agricultural feedstock sources by tons available, price per ton, BTU content, and delivered price per MM BTU. For each applicable feedstock, this research derives the total supply potential by using the following methodology:

- Apply the conversion factors for each agricultural by-product to the agricultural production data for each county
- Multiplying the residue quantity by the BTU content
- Sort and assign to the Geographical Information System (GIS) Database

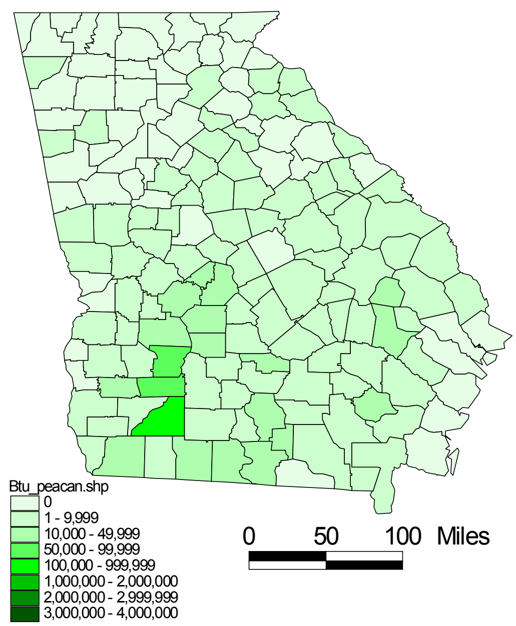
Table 5-4: Biomass Feedstock Comparison

Biomass	Tons Available	Rank	Average Price / Ton	Rank	MM BTU	Rank	Delivered Cost / MM BTU	Rank
Pecan Hulls	12,927	12	$8.50	1	211,307	12	$0.86	1
Gin Trash	182,005	9	$11.00	3	2,383,399	9	$1.30	2
Bark	229,908	7	$17.50	4	3,236,766	7	$1.60	3
Poultry Litter	6,800,663	1	$10.00	2	60,434,677	1	$1.64	4
Peanut Hulls	702,785	5	$25.00	7	11,266,186	5	$1.78	5
Wood Chips	5,992	14	$17.50	4	54,470	14	$2.53	6
Wood Residue	4,015,343	2	$20.00	6	35,579,095	3	$2.76	7
Hay	1,026,653	4	$35.00	8	14,373,142	4	$3.11	8
Cotton Stalks	3,363,613	3	$40.00	9	41,595,202	2	$3.60	9
Kenaf(13,000 acres)	90,750	11	$50.00	10	1,341,078	11	$3.96	10
Corn Stalks	208,415	8	$50.00	10	3,047,003	8	$4.00	11
Switchgrass(1000 acres)	6,000	13	$65.00	12	84,038	13	$5.25	12
Wheat Straw	377,231	6	$125.00	13	5,495,790	6	$9.34	13
Rye Straw	137,933	10	$125.00	13	1,752,198	10	$10.71	14
Total Tons Available	**17,160,218**							
Total BTU Available	**180,854,349**							
Median Price Per Ton	**$30.00**							
Median Delivered Cost/MMBTU	**$2.94**							

Calculations by: Wayne Curtis

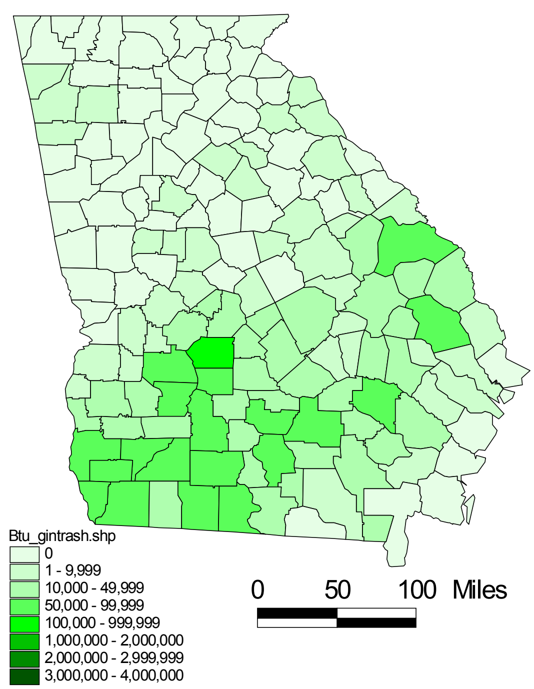
From the agricultural sources we have studied, we conclude that there is enough energy from these sources to power 10% of the State's total electricity needs, or over 25% of the State's residential consumers at the moderate level of 20% conversion efficiency. Figures 5-10 through 5-14 list specific biomass feedstock BTU content by MMBTU/County. The total energy content for all applicable agricultural by-products is shown in Figure 5-15.

Figure 5-8: Total Pecan Hull BTU Content (In Millions)



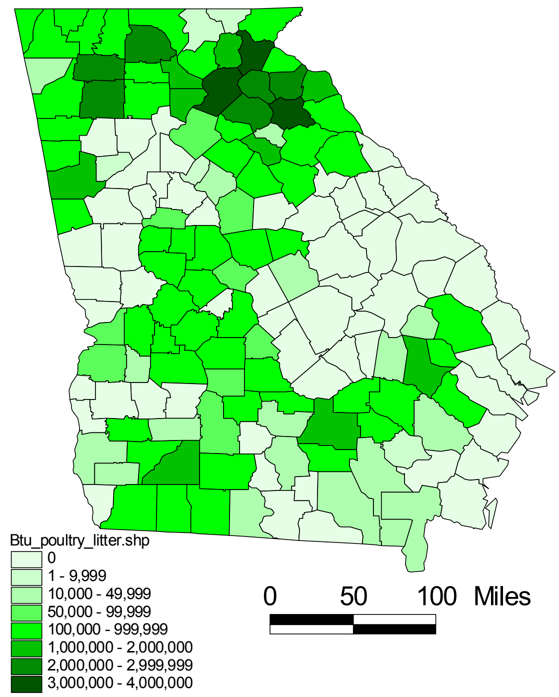
Created by: Wayne Curtis

Figure 5-9: Total Gin Trash BTU Content (In Millions)



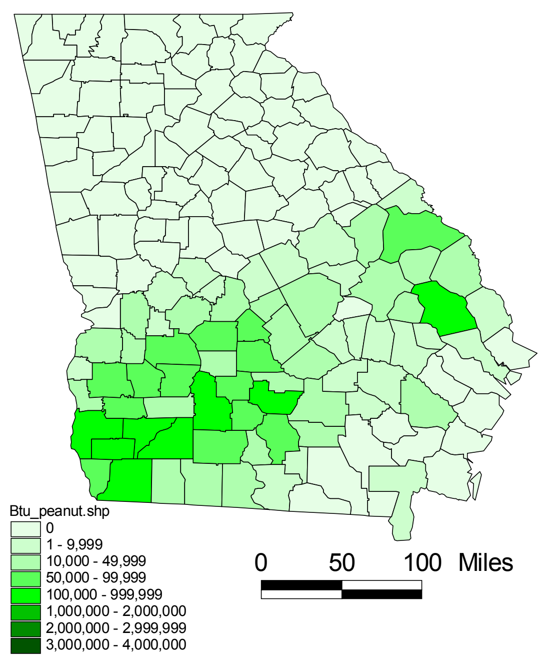
Created by: Wayne Curtis

Figure 5-10: Total Poultry Litter BTU Content (In Millions)



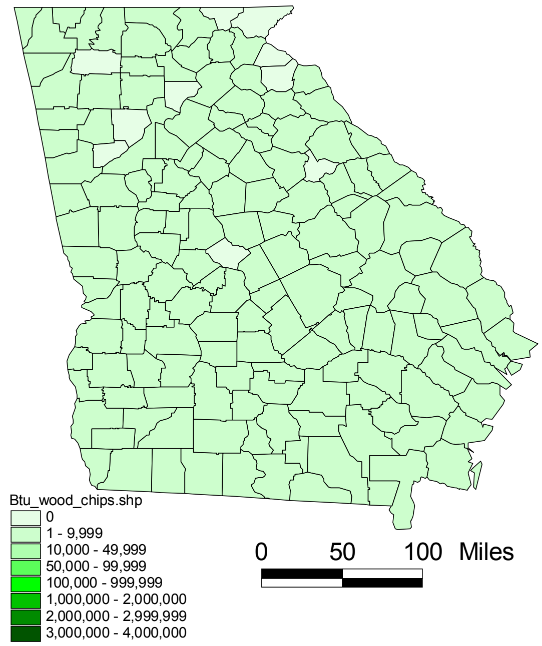
Created by: Wayne Curtis

Figure 5-11: Total Peanut Hulls BTU Content (In Millions)



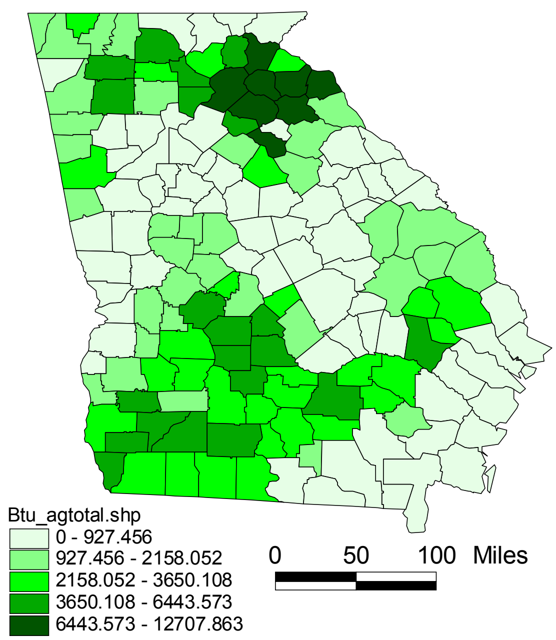
Created by: Wayne Curtis

Figure 5-12: Total Wood Chip BTU Content (In Millions)



Created by: Wayne Curtis

Figure 5-13: Total Agricultural BTU Content (In Millions)

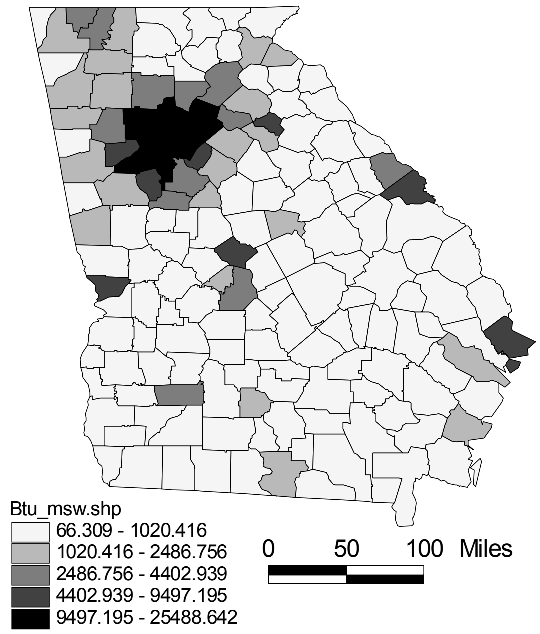


Created by: Wayne Curtis

Though the primary focus of this report is to determine the electricity potential in the use of agricultural residues, it is important to note there are many other significant sources of biomass. Landfill gas, sewage gas, and municipal solid waste (MSW) are common sources of electrical energy. Landfill gas and sewage gas are mostly considered to be pure biomass sources, but since MSW includes inorganic elements, often petroleum derivatives, many certification standards exclude MSW from other biomass fuel sources. Certification of MSW biomass sources is becoming more likely, since MSW is comprised mostly from organic material and the use of this material will save landfill space while providing a service to society.

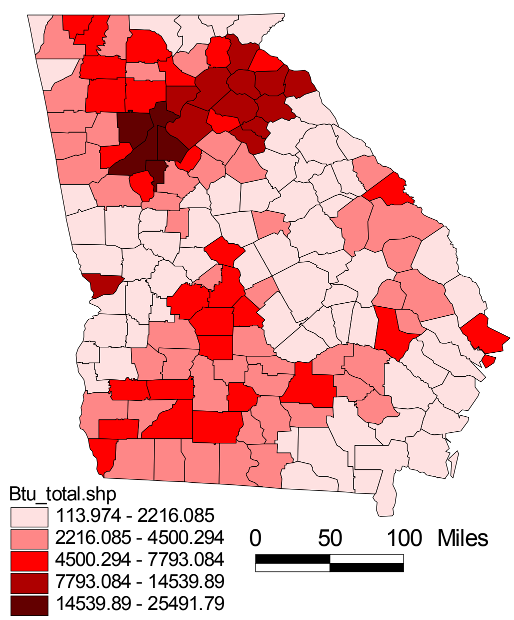
For comparison purposes, analysis of the BTU potential for MSW was evaluated based upon Georgia's waste production and population per county (figures 5-16 and 5-17). According to the Georgia Waste Management Report, Georgians generate an average of 6.3lbs of trash/person/day. This is nearly 2lbs more per person than the average U.S. citizen. MSW ranges from 9 to 12 MM BTU/ton. Therefore using a low average of 10MM BTU/ton, MSW can generate 5% of Georgia's electricity demand or 13% of all residential power at 20% generation efficiency. Together, agricultural residues and MSW can generate 38% of Georgia's residential consumers or 14% of Georgia's total power demand, assuming 20% conversion efficiency.

Figure 5-14: Total MSW BTU Content (In Millions)



Created by: Wayne Curtis

Figure 5-15: Total Agricultural and MSW BTU Content (In Millions)



Created by: Wayne Curtis

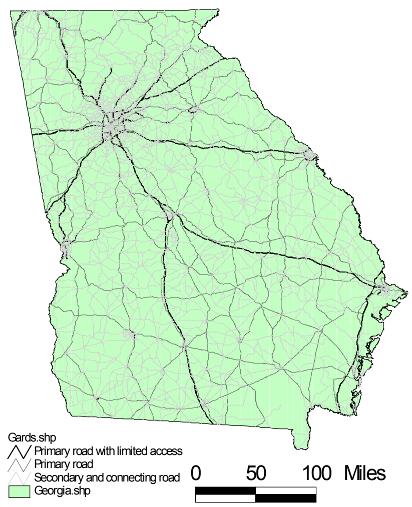
Siting the Biomass Facility

Initially, our study did not focus on feedstock characteristics and their role in the actual siting of the biomass generation facility, although this is a critical factor of feasibility and deserves further attention. In order to be feasible, the generation facility must be located in an accessible location, which minimizes transportation costs. In other words, the availability of low-cost feedstocks will have spatial variation.

Scientists from the University of Tennessee have developed a Geographical Information System, or GIS-based modeling system which captures the geographic variation in the major factors that determine supply and cost of biomass feedstocks derived from energy crops in order to define the optimal locations for siting bioenergy facilities. The GIS system includes soil quality, climate, land use and road network information, with transportation, economic, and environmental models to predict both where energy crops would be grown and the marginal cost of supplying biomass from energy crops to specific locations. From analysis of these variables, project managers will be able to construct an area that provides access to various feedstock supplies at the least cost per energy output. "The modeling system is designed to evaluate individual U.S. states but could readily be modified to evaluate larger or smaller geographic regions" (Graham 1999). The use of a GIS system can be information intensive; however, these systems are an efficient and accurate means of providing analysts and decision-makers with the information necessary in order to optimize the efficiency of biomass-sourced generation.

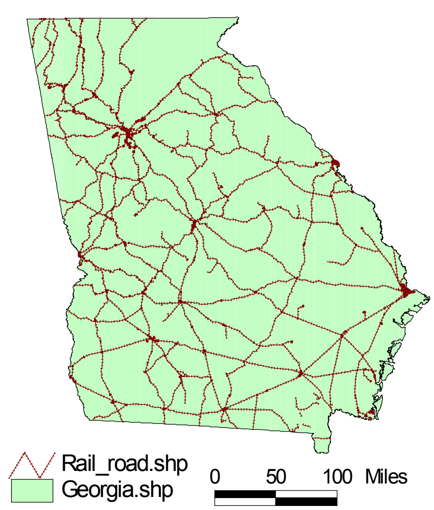
For purposes of this study, data has been acquired to evaluate the geographic implications of Georgia's electrical power network and the applicable venues for transporting biofuels. It is costly to transport biomass from agricultural regions that offer limited access to the State highway and railroad system. Figures 5-18 and 5-19 show Georgia's highway and railroad systems. Since our study assumes a 50-mile fuel transport distance, these two maps indicate that all regions have the adequate infrastructure for biomass transport anywhere within the State.

Figure 5-16: Georgia's Roadway Infrastructure



Created by: Wayne Curtis

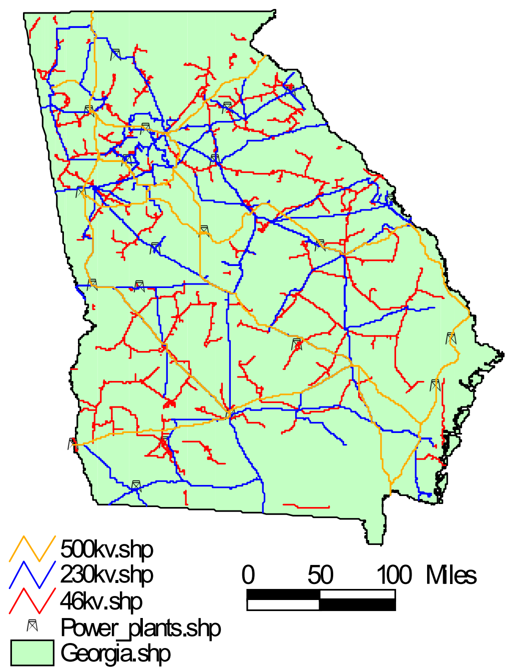
Figure 5-17: Georgia's Railway Infrastructure



Created by: Wayne Curtis

Although the facility must be located reasonably close to the feedstock supply, it must also be relatively assessable to the electrical power grid. Figure 5-18 shows the location of Georgia's largest power plants and the spread of the electrical power grid. As shown in the figure, Georgia has an extensive electrical grid infrastructure, which is accessible from any county. Overall, Georgia's has a well-established network of power lines, roads and railways, and therefore these factors represent no significant barrier to the siting of a biomass generation facility anywhere within the state.

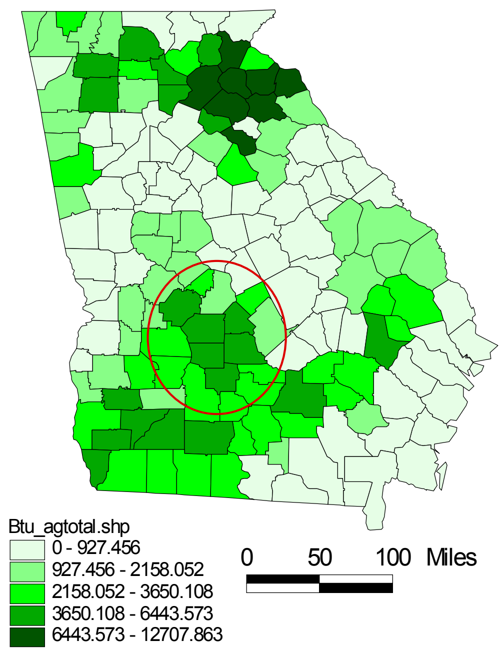
Figure 5-18: Georgia's Transmission Infrastructure



Created by: Wayne Curtis

This study calculated the transportation costs dependent upon an average distance of transport of 50 miles. Since rail and roadways are curved, the transport of biomass will be of longer distances than a direct path. For example a feedstock source 40 miles from the generation plant may travel 50 miles to reach the plant. Figure 5-21 displays the total agricultural BTU content overlaid by a circle with a 40-mile radius. This range proves to be adequate to fuel multiple generation facilities anywhere within the State. This will hold significance when evaluating the total delivered fuel costs. Though we assume a 50-mile transport distance, in most cases the generation facility can be sited much closer to the feedstock source, thereby resulting in a lower cost of transport.

Figure 5-19: Forty-mile Radius Illustration for Facility Supply Range



Created by: Wayne Curtis

CHAPTER 6

FEASIBILITY CASE STUDY

Introduction to the Study

The University of Georgia (UGA) Center for Agribusiness and Economic Development set out to determine the feasibility of agricultural biomass fuel sources used for power generation. UGA retained the consulting services of Frazier, Barnes & Associates (FBA), for engineering costs of alternative generation technologies. This study uses the engineering assessment performed by FBA to evaluate the feasibility of the generation technologies. Georgia's agricultural production data was obtained from the 2000 Georgia Farm Gate Report. Chris Ferland, from the Center for Agribusiness and Economic Development supplied the relative feedstock energy content. This study focuses on analysis of the corresponding biomass data in order to determine the following objectives:

1. Availability and price of various agricultural feedstocks within the state of Georgia
2. Transportation costs associated with the feedstocks
3. Feedstock energy content
4. Capital, operating costs, and overall feasibility of four currently commercialized or emerging technologies for biomass generation (Direct Fire, Co-fire, Gasification, and Pyrolysis)

5. Economy of scale impact by evaluating three different size facilities for each technology

This chapter will specifically describe the procedures and results of the aforementioned study. In addition, this chapter will conclude with an economic analysis of external factors, spatial variation, the renewable energy production incentive, green power premium potential, and the potential impacts of emission trading policies, all of which will impact the feasibility of these four biomass technologies.

Feedstock Assumptions

Typical biomass generation facilities utilize a variety of feedstocks. The practicality of feedstocks is limited by season, quantity, price, and various costs associated with the transportation, handling, and storage. Determining the effects of individual biomass sources in each technology would create hundreds of outcomes with similar results. Though specific types of biomass are an important variable when considering energy output per ton of fuel, some assumptions are made in order to reduce the complexity and focus more on the specific feasibility of biomass technologies. The assumptions taken in this study are listed below:

1. The biomass will be a combination of various types, therefore calculations will assume an average ash content of 8%, an average moisture content of 25%, and an average heat content of 13 million BTU/ton (6500 BTU/lb). After consulting with numerous biomass generation facilities, FBA found each generation facility utilizes some blend of biomass. These figures are consistent with typical biomass feedstocks.
2. Since the receiving system must be capable of handling the biomass mix and processing/blending them to a uniform heat content, a five-day supply of

feedstock is assumed to be sufficient to sustain the reliability of supply and the blending process to a uniform heat content

3. The generation plant is assumed to shut-down for maintenance approximately 5.5% of the operation time, therefore the plant will operate 345 days/year. In order to provide a consistent flow of power to clients, the sale of electricity is assumed to stay on a 365 day/year cycle. As a result, power must be purchased from the grid 20 days/year. The purchased power is assumed to cost the typical industrial rate of 5¢/kWh.
4. Feedstock quantity will vary by technology. The feedstock blend assumes 25% moisture content. The moisture content is consistent with typical feesdstock blends after harvest, transport, and storage. Since the original biomass input is not dried, the daily input feedstock quantity is designated in wet tons per day (WTPD). Georgia produces over 22 million tons of biomass each year, therefore, the feedstock blend is assumed to be available for the entire operational period, 345 days/year
5. Each facility requires electrical power in order to operate, therefore, some of power generated from the facility must be used internally. This power is deducted from the total amount generated to yield the net electrical output, measured in kilo-Watts per hour (kWh). The net electrical output is the total amount of saleable power produced and is subsequently used in all economic calculations at the end of this section.

Conversion Technologies

The relative efficiency of some technologies may be influenced by the size of the facility itself, referred to as the economy of scale impact. To determine how size would influence overall feasibility, this study evaluates three scenarios for each technology. Each scenario, designated as case 1, case 2, and case 3, require a similar amount of wet biomass input (WTPD) with respect to each generation technology. Case 1 represents the smallest facility studied and requires the least amount of biomass input. Case 3 represents the largest facility studied, therefore requires the greatest input of biomass. Case 2 is the middle scenario.

The preliminary assessment of the four generation technologies, along with their respective cases, was performed by FBA. Based on the original FBA engineering assessments, all economic calculations were reevaluated for the purposes of this study. The original basis for assessment, paraphrased from the FBA Biomass Cogeneration Final Report, is described below in greater detail.

Direct Fire - Direct fire combustion involves the burning of biomass with excess air, producing hot flue gases, which then produces steam in the heat exchange section of a boiler. The steam is then passed through a steam turbine generator to produce electric power. The direct fire technology was evaluated for 120, 200, and 400 WTPD of biomass input for Case 1, 2, and 3, respectively.

Co-fire - Co-firing refers to the practice of introducing biomass as a supplementary energy source in high efficiency boilers. The flue gases are then used to produce steam and/or electric power as in a direct fire technology. Co-fire is used when either the moisture content of the biomass is high or when the supply of biomass is intermittent. In each of the co-fire cases the biomass fuel supply deficit was supplemented with enough natural gas, measured in thousand cubic feet (MCF), to generate the same amount of power as in the direct fire cases. The corresponding levels of fuel are 60, 100, and 200 WTPD of biomass and 523, 872, and 1744 MCF of natural gas for Case 1, 2, and 3, respectively.

Gasification - Gasification for power production involves the chemical conversion of biomass in an atmosphere of steam or air to produce a medium or low calorific gas. This "biogas" is then used as a fuel in a power generation plant that includes a gas turbine generator for power production and a waste heat boiler for steam production. The steam can then be used to generate power. For this study the only heat available for power generation is assumed to be the heat content of the bio-gas. All other heat generated by the gasification process is used to dry the feedstock. The gasification technology was evaluated for 160, 267, and 533 WTPD of biomass input for Case 1, 2, and 3, respectively.

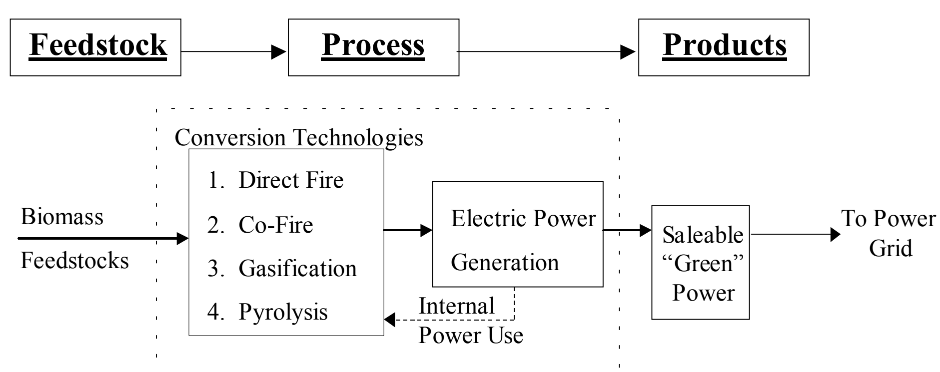
Pyrolysis - Pyrolysis is a process by which biomass is heated in the absence of oxygen. For this study the feedstock is assumed to be dried via heat generated by the pyrolysis process. As a result the biomass decomposes to generate mostly vapors, aerosols, and some charcoal. After cooling and condensation, a transportable dark brown liquid oil is formed which has approximately one half the heat content of conventional fuel oil. Bio-oil, is approximately 20% heavier than water and is both transportable and storable. The bio-oil can be fed directly to a turbine and combusted. Both power and steam can be generated from this process.

Energy from all bio-oil produced is saleable. Commercialization of the pyrolysis process is in its initial stages, although technology suppliers typically have small scale pilot plants and are working to build full size facilities. The pyrolysis process assumes biomass inputs at 160, 320, and 480 WTPD for case 1, 2, and 3, respectively. The pyrolysis technology used in this study is being commercialized by Renewable Oil International, LLC. This model envisions smaller plants located close to the source of the biomass. For this reason, pyrolysis assumes some geographic dependency, which is reflected in the biomass transportation costs. Case 1 scenario assumes the pyrolysis facility and the generation plant are co-located at the feedstock source and therefore bare no transportation fees. Case 2 assumes the same basis as the case 1 scenario plus an additional pyrolysis facility located 50-miles away from the generation plant. The bio-oil from the first facility still bears zero costs of transportation, while the bio-oil produced at the second, off-site feedstock location is charged 50-mile truck-load transportation fees. Case 3 assumes the same basis as the case 2 scenario plus an additional pyrolysis facility located 50-miles away from the generation plant. The two off-site facilities are charged 50-mile freight fees, while the on-site facility bears no charge (Frazier 2002).

Base Model

The base case model is generally non-site specific and utilizes a blend of biomass feedstocks with a conversion technology that produces electrical power. Figure 3 demonstrates a general depiction of this process.

Figure 6-1: Base Case Model



Source: FBA. 2002. Biomass Cogeneration: Final Report.

Appendix I contains case and technology specific figures adapted from the FBA Biomass Cogeneration Final Report. These figures show the process of biomass inputs, generation technology and requirements, and the resulting output for each size and type of technology. The output power displayed in Appendix I represents the total amount of electricity produced. Table 6-1 displays the net electrical output, or the total quantity of saleable power for each scenario. Table 6-2 displays the daily quantity of feedstock required. Table 6-3 calculates the total kilo-Watts produced per hour for each ton of biomass input.

Table 6-1: Net Electrical Output (kWh)

Plant Size	Direct Fire	Co-Fire	Gasification	Pyrolysis
Case #1	1386	1526	6294	4752
Case #2	2309	2543	10061	9570
Case #3	4623	5095	20227	14370

Source Data: FBA. 2002. Biomass Cogeneration: Final Report.

Table 6-2: Quantity of Feedstock Required (Wet Tons per Day)

Plant Size	Direct Fire	Co-Fire	Gasification	Pyrolysis
Case #1	120	60	160	160
Case #2	200	100	267	320
Case #3	400	200	533	480

Source Data: FBA. 2002. Biomass Cogeneration: Final Report.

Table 6-3: Electricity Produced (kWh) per Feedstock Ton

Plant Size	Direct Fire	Co-Fire	Gasification	Pyrolysis
Case #1	277.2	610.4	944.1	712.8
Case #2	277.08	610.32	904.3595506	717.75
Case #3	277.38	611.4	910.7842402	718.5

Source Data: FBA. 2002. Biomass Cogeneration: Final Report.
Calculations by: Wayne Curtis

The Costs of Capital

Both operating and capital costs of production increase with each technology case due to additional requirements on infrastructure, administration, and operational procedures necessary for additional biomass inputs. The capital costs for each technology are divided into three main categories, feedstock receiving and processing, land and infrastructure, and operational equipment. Tables 6-4 through 6-7 lists the capital costs for each technology. A more detailed description for each section of the capital costs follows Table 6-7.

Table 6-4: Capital Costs for Direct Fire Technology

Direct-Fire Capital Costs				
Plant Component		Case #1 120 WTPD	Case #2 200 WTPD	Case #3 400 WTPD
Feedstock Receiving & Processing				
1	Feedstock Truck Dump	$ 100,000	$ 100,000	$ 100,000
2	Front End Loader	$ 120,000	$ 120,000	$ 120,000
3	Fuel Processing Building	$ 700,000	$ 1,155,000	$ 1,990,000
4	Metal Removal Equipment	$ 15,000	$ 15,000	$ 15,000
5	Grinding/Sizing Equipment	$ 165,000	$ 185,000	$ 225,000
6	Blending Equipment	$ 75,000	$ 100,000	$ 125,000
7	Fuel Storage Bins	$ 100,000	$ 200,000	$ 400,000
8	Conveyors	$ 125,000	$ 125,000	$ 125,000
Operational Equipment				
1	Power Generation Equipment	$ 1,640,000	$ 2,120,000	$ 3,700,000
2	Demineralizer System	$ 115,000	$ 170,000	$ 260,000
3	Boiler	$ 290,000	$ 388,000	$ 900,000
4	Instrumentation & Controls	$ 150,000	$ 225,000	$ 300,000
Land and Infrastructure				
1	Land/ Site Preparation	$ 100,000	$ 150,000	$ 200,000
2	Buildings	$ 388,000	$ 512,000	$ 600,000
3	Eng/Permitting	$ 247,000	$ 425,000	$ 585,000
Sub-Total		$ 4,330,000	$ 5,990,000	$ 9,645,000
Contingency (20%)		$ 866,000	$ 1,198,000	$ 1,929,000
Total Capital		**$ 5,196,000**	**$ 7,188,000**	**$ 11,574,000**

Data Source: FBA. 2002. Biomass Cogeneration: Final Report

Table 6-5: Capital Costs for Co-Fire Technology

Co-Fire Capital Costs				
	Plant Component	Case #1 60 WTPD 523 MCF/Day	Case #2 100 WTPD 872 MCF/Day	Case #3 200 WTPD 1744 MCF/Day
Feedstock Receiving & Processing				
1	Feedstock Truck Dump	$ 100,000	$ 100,000	$ 100,000
2	Front End Loader	$ 120,000	$ 120,000	$ 120,000
3	Fuel Processing Building	$ 350,000	$ 577,500	$ 995,000
4	Metal Removal Equipment	$ 15,000	$ 15,000	$ 15,000
5	Grinding/Sizing Equipment	$ 145,000	$ 160,000	$ 185,000
6	Blending Equipment	$ 60,000	$ 70,000	$ 100,000
7	Fuel Storage Bins	$ 60,000	$ 100,000	$ 200,000
8	Conveyors	$ 125,000	$ 125,000	$ 125,000
Operational Equipment				
1	Power Generation Equipment	$ 1,640,000	$ 2,120,000	$ 3,730,000
2	Demineralizer System	$ 115,000	$ 170,000	$ 260,000
3	Boiler	$ 264,500	$ 364,500	$ 743,000
4	Instrumentation & Controls	$ 150,000	$ 225,000	$ 300,000
Land and Infrastructure				
1	Land/ Site Preparation	$ 100,000	$ 150,000	$ 200,000
2	Buildings	$ 331,000	$ 406,000	$ 468,000
3	Eng/Permitting	$ 247,000	$ 425,000	$ 585,000
Sub-Total		$ 3,822,500	$ 5,128,000	$ 8,126,000
Contingency (20%)		$ 764,500	$ 1,025,600	$ 1,625,200
Total Capital		**$ 4,587,000**	**$ 6,153,600**	**$ 9,751,200**

Data Source: FBA. 2002. Biomass Cogeneration: Final Report

Table 6-6: Capital Costs for Gasification Technology

Gasification Capital Costs				
	Plant Component	Case #1 160 WTPD	Case #2 267 WTPD	Case #3 533 WTPD
Feedstock Receiving & Processing				
1	Feedstock Truck Dump	$ 100,000	$ 100,000	$ 100,000
2	Front End Loader	$ 120,000	$ 120,000	$ 120,000
3	Fuel Processing Building	$ 700,000	$ 1,155,000	$ 1,990,000
4	Metal Removal Equipment	$ 15,000	$ 15,000	$ 15,000
5	Grinding/Sizing Equipment	$ 165,000	$ 185,000	$ 225,000
6	Blending Equipment	$ 75,000	$ 100,000	$ 125,000
7	Fuel Storage Bins	$ 100,000	$ 200,000	$ 400,000
8	Conveyors	$ 125,000	$ 125,000	$ 125,000
Operational Equipment				
1	Power Generation Equipment	$ 5,243,000	$ 7,388,000	$ 13,090,000
2	Gasification Process	$ 4,900,000	$ 7,500,000	$ 11,300,000
3	Interconnections	$ 900,000	$ 1,300,000	$ 2,000,000
4	Waste Heat Boiler	$ 2,125,000	$ 2,780,000	$ 5,500,000
5	Heat Recovery	$ 500,000	$ 1,700,000	$ 1,300,000
Land and Infrastructure				
1	Land/ Site Preparation	$ 110,000	$ 150,000	$ 200,000
2	Buildings	$ 510,000	$ 612,000	$ 810,000
3	Eng/Permitting	$ 247,000	$ 425,000	$ 585,000
Sub-Total		$ 15,935,000	$ 23,855,000	$ 37,885,000
Contingency (20%)		$ 3,187,000	$ 4,771,000	$ 7,577,000
Total Capital		**$ 19,122,000**	**$ 28,626,000**	**$ 45,462,000**

Data Source: FBA. 2002. Biomass Cogeneration: Final Report

Table 6-7: Capital Costs for Pyrolysis Technology

Pyrolysis Capital Costs				
Plant Component		Case #1 160 WTPD	Case #2 320 WTPD	Case #3 480 WTPD
Feedstock Receiving & Processing				
1	Feedstock Truck Dump	$ 100,000	$ 200,000	$ 300,000
2	Front End Loader	$ 120,000	$ 240,000	$ 360,000
3	Fuel Processing Building	$ 700,000	$ 1,155,000	$ 1,990,000
4	Metal Removal Equipment	$ 15,000	$ 30,000	$ 45,000
5	Grinding/Sizing Equipment	$ 165,000	$ 330,000	$ 495,000
6	Blending Equipment	$ 75,000	$ 150,000	$ 225,000
7	Fuel Storage Bins	$ 100,000	$ 200,000	$ 300,000
8	Conveyors	$ 125,000	$ 250,000	$ 375,000
Operational Equipment				
1	Power Generation Equipment	$ 5,890,000	$ 8,900,000	$ 11,390,000
2	Pyrolysis Process	$ 1,300,000	$ 2,600,000	$ 3,900,000
3	Waste Heat Boiler	$ 2,000,000	$ 3,130,000	$ 4,080,000
4	Demineralizer System	$ 125,000	$ 250,000	$ 375,000
Land and Infrastructure				
1	Land/ Site Preparation	$ 100,000	$ 200,000	$ 300,000
2	Buildings	$ 510,000	$ 1,020,000	$ 1,530,000
3	Eng/Permitting	$ 300,000	$ 529,000	$ 800,000
Sub-Total		$ 11,625,000	$ 19,184,000	$ 26,465,000
Contingency (20%)		$ 2,325,000	$ 3,836,800	$ 5,293,000
Total Capital		**$ 13,950,000**	**$ 23,020,800**	**$ 31,758,000**

Data Source: FBA. 2002. Biomass Cogeneration: Final Report

The feedstock receiving and processing costs were determined based on six criteria: feedstock truck dump, front-end loader, metal removal equipment, grinding/sizing equipment, blending equipment, and conveyors. These criteria were assessed by FBA and vary proportionally to the set quantity of feedstock inputs.

The land and infrastructure cost section consists of the land value and site preparation, engineering and permitting, and the construction costs for all buildings. With the exception of pyrolysis, land requirements were assumed to increase 2.5 acres for every increase in case scenario. The acreage requirement is 5, 7.5, and 10 acres for case 1, 2, and 3 scenarios, and each are assessed at $20,000/acre. Pyrolysis is assumed to require an additional 2.5 acres of land for each off-site pyrolysis facility, resulting in 5, 10, and 15 acres for case 1, 2, and 3 scenarios, each assessed at $20,000/acre.

The engineering and permitting cost section was assessed by FBA and is the same for each technology, with the exception of pyrolysis. Since pyrolysis is a more complex and emerging technology, the engineering costs exceed direct-fire, co-fire, and gasification by approximately 20%.

The building line item includes the costs of buildings to house boiler, turbines, maintenance area, offices, and other required facilities. This item was assessed by FBA and is directly correlated to the technology level of each generation method. For this reason, direct-fire and co-fire technologies are significantly less expensive than gasification and pyrolysis technologies.

The operational equipment assessment is based upon technology specific criteria. These costs become significantly higher as the level of technology increases. The power generation equipment is consistently the largest capital cost for each technology, ranging from nearly $4 million in case 3 of the direct-fire and co-fire technologies to over $11 million in case 3 of the gasification and pyrolysis technologies. The boilers used in direct-fire and co-fire cost under $1 million, while the waste heat boilers for pyrolysis and gasification cost over $4 million. The instrumentation and demineralizer systems used in case 3 direct and co-fire technologies cost approximately $1 million, while the system for the pyrolysis process costs nearly $4 million and over $11 million for the gasification system.

In conclusion, the costs of capital ranged from approximately $4 million to $38 million. The least expensive technology is co-fire, followed by direct-fire, then pyrolysis, and lastly gasification. A contingency factor, calculated at 20% of total capital, was added to the final costs of each technology in order to account for any unforeseen expenses. Table 6-8 summarizes the final capital costs for each technology.

Table 6-8: Capital Cost Summary

Calculations by: Wayne Curtis

Technology	Summary of Capital Costs			
Direct - Fire	Sub-Total	$ 4,330,000	$ 5,990,000	$ 9,645,000
	Contingency (20%)	$ 866,000	$ 1,198,000	$ 1,929,000
	Total Capital	**$ 5,196,000**	**$ 7,188,000**	**$ 11,574,000**
Co - Fire	Sub-Total	$ 3,822,500	$ 5,128,000	$ 8,126,000
	Contingency (20%)	$ 764,500	$ 1,025,600	$ 1,625,200
	Total Capital	**$ 4,587,000**	**$ 6,153,600**	**$ 9,751,200**
Gasification	Sub-Total	$ 15,935,000	$ 23,855,000	$ 37,885,000
	Contingency (20%)	$ 3,187,000	$ 4,771,000	$ 7,577,000
	Total Capital	**$ 19,122,000**	**$ 28,626,000**	**$ 45,462,000**
Pyrolysis	Sub-Total	$ 11,625,000	$ 19,184,000	$ 26,465,000
	Contingency (20%)	$ 2,325,000	$ 3,836,800	$ 5,293,000
	Total Capital	**$ 13,950,000**	**$ 23,020,800**	**$ 31,758,000**

Data Source: FBA. 2002. Biomass Cogeneration: Final Report

Operating Cost

The operating costs increase from case 1 to case 3 for each technology due to the additional requirements necessary for operation of the larger facilities. These costs were calculated based upon three primary criteria: overhead and administration fees, variable costs of operation, and the yearly expenditures on capital. Tables 9 through 12 summarize the operating costs for each technology. A more detailed description of the operating costs and revenue analysis follows table 12. Appendix II displays the accounting spreadsheets used in all calculations for the capital, operating, and marginal costs of production (refer to the Appendix II spreadsheets to view all calculations in greater detail). The percent share for each operating cost is displayed in the Appendix III graphs. Since case 3 is consistently the most efficient scenario, the Appendix III graphs display each technology for case 3 for low, medium, and high fuel cost.

Table 6-9: Direct Fire Annual Operating Costs

Direct Fire							
		Case # 1		Case # 2		Case # 3	
Biomass Input (Wet Tons per Day)		120		200		400	
Net Generation (kilo-Watts per hour)		1,386		2,309		4,623	
Overhead and Administration							
1	General Manger	$	108,800	$	128,000	$	140,800
2	Accounting Support	$	64,000	$	89,600	$	115,200
3	Clerical Support	$	25,600	$	56,320	$	96,000
	Total	**$**	**198,400**	**$**	**273,920**	**$**	**352,000**
Variable Cost of Operation							
1	Purchasing Cost for Downtime Electricity per Year	$	33,264	$	55,416	$	110,952
2.1	Fuel Costs per Year (Low at $10/ton)	$	414,000	$	690,000	$	1,380,000
2.2	Fuel Costs per Year (Medium at $20/ton)	$	828,000	$	1,380,000	$	2,760,000
2.3	Fuel Costs per Year (High at $35/ton)	$	1,449,000	$	2,415,000	$	4,830,000
3	Ash Disposal Cost per Year	$	66,240	$	110,400	$	220,800
4	Water and Water Treatment	$	22,000	$	57,000	$	159,000
5	Labor	$	240,000	$	240,000	$	240,000
6	Workers' Compensation	$	16,800	$	16,800	$	16,800
7	Miscellaneous	$	39,000	$	39,000	$	39,000
8.1	Interest on Working Capital ($10/ton feedstock)	$	13,855	$	20,144	$	36,109
8.2	Interest on Working Capital ($20/ton feedstock)	$	20,755	$	31,644	$	59,109
8.3	Interest on Working Capital ($35/ton feedstock)	$	31,105	$	48,894	$	93,609
	Total (Low Fuel Cost - $10/ton)	**$**	**845,159**	**$**	**1,228,760**	**$**	**2,202,661**
	Total (Medium Fuel Cost - $20/ton)	**$**	**1,266,059**	**$**	**1,930,260**	**$**	**3,605,661**
	Total (High Fuel Cost - $35/ton)	**$**	**1,897,409**	**$**	**2,982,510**	**$**	**5,710,161**
Yearly Expenditures on Capital							
1	Yearly Taxes and Insurance Costs	$	77,940	$	107,820	$	173,610
2	Yearly Maintenance Costs	$	103,920	$	143,760	$	231,480
3	Depriciation - Buildings	$	59,400	$	93,350	$	149,500
4	Depreciation - Equipment	$	250,500	$	316,000	$	497,000
5	Interest on Investment - Buildings	$	29,700	$	46,675	$	74,750
6	Interest on Investment - Equipment	$	69,875	$	88,700	$	146,750
	Total	**$**	**591,335**	**$**	**796,305**	**$**	**1,273,090**
Total Operational Costs							
Operational Costs/yr (Low at $10/ton)		$	1,634,894	$	2,298,985	$	3,827,751
Operational Costs/yr (Medium at $20/ton)		$	2,055,794	$	3,000,485	$	5,230,751
Operational Costs/yr (High at $35/ton)		$	2,687,144	$	4,052,735	$	7,335,251
Generation Analysis							
kilo-Watts Sold per Year			12,141,360		20,226,840		40,497,480
Marginal Costs/yr (Low at $10/ton)		**$**	**0.13465**	**$**	**0.11366**	**$**	**0.09452**
Operational Costs/yr (Medium at $20/ton)		**$**	**0.16932**	**$**	**0.14834**	**$**	**0.12916**
Operational Costs/yr (High at $35/ton)		**$**	**0.22132**	**$**	**0.20036**	**$**	**0.18113**

Calculations by: Wayne Curtis
Data Source: FBA. 2002. Biomass Cogeneration: Final Report

Table 6-10: Co-Fire Annual Operating Costs

Co-Fire							
		Case # 1		Case # 2		Case # 3	
Biomass Input (Wet Tons per Day)			60		100		200
Net Generation (kilo-Watts per hour)			1,526		2,543		5,095
Overhead and Administration							
1	General Manger	$	108,800	$	128,000	$	140,800
2	Accounting Support	$	64,000	$	89,600	$	115,200
3	Clerical Support	$	25,600	$	56,320	$	96,000
Total		**$**	**198,400**	**$**	**273,920**	**$**	**352,000**
Variable Cost of Operation							
1	Purchasing Cost for Downtime Electricity per Year	$	36,624	$	61,032	$	122,280
2.1	Biomass Costs per Year (Low at $10/ton)	$	207,000	$	345,000	$	690,000
2.2	Biomass Costs per Year (Medium at $20/ton)	$	414,000	$	690,000	$	1,380,000
2.3	Biomass Costs per Year (High at $35/ton)	$	724,500	$	1,207,500	$	2,415,000
3	Naturla Gas Costs per Year	$	249,000	$	415,159	$	830,318
4	Ash Disposal Cost per Year	$	33,120	$	55,200	$	110,400
5	Water and Water Treatment	$	22,000	$	57,000	$	159,000
6	Labor	$	240,000	$	240,000	$	240,000
7	Workers' Compensation	$	16,800	$	16,800	$	16,800
8	Miscellaneous	$	39,000	$	39,000	$	39,000
9.1	Interest on Working Capital ($10/ton feedstock)	$	14,059	$	20,487	$	36,797
9.2	Interest on Working Capital ($20/ton feedstock)	$	17,509	$	26,237	$	48,297
9.3	Interest on Working Capital ($35/ton feedstock)	$	22,684	$	34,862	$	65,547
Total (Low Fuel Cost - $10/ton)		**$**	**857,603**	**$**	**1,249,678**	**$**	**2,244,595**
Total (Medium Fuel Cost - $20/ton)		**$**	**1,068,053**	**$**	**1,600,428**	**$**	**2,946,095**
Total (High Fuel Cost - $35/ton)		**$**	**1,383,728**	**$**	**2,126,553**	**$**	**3,998,345**
Yearly Expenditures on Capital							
1	Yearly Taxes and Insurance Costs	$	68,805	$	68,805	$	146,268
2	Yearly Maintenance Costs	$	91,740	$	91,740	$	195,024
3	Depriciation - Buildings	$	37,050	$	37,050	$	83,150
4	Depreciation - Equipment	$	247,000	$	247,000	$	493,500
5	Interest on Investment - Buildings	$	18,525	$	18,525	$	41,575
6	Interest on Investment - Equipment	$	68,363	$	68,363	$	141,950
Total		**$**	**531,483**	**$**	**531,483**	**$**	**1,101,467**
Total Operational Costs							
Operational Costs/yr (Low at $10/ton)		$	1,587,486	$	2,055,080	$	3,698,062
Operational Costs/yr (Medium at $20/ton)		$	1,797,936	$	2,405,830	$	4,399,562
Operational Costs/yr (High at $35/ton)		$	2,113,611	$	2,931,955	$	5,451,812
Generation Analysis							
kilo-Watts Sold per Year			13,367,760		22,276,680		44,632,200
Marginal Costs/yr (Low at $10/ton)		**$**	**0.11875**	**$**	**0.09225**	**$**	**0.08286**
Operational Costs/yr (Medium at $20/ton)		**$**	**0.13450**	**$**	**0.10800**	**$**	**0.09857**
Operational Costs/yr (High at $35/ton)		**$**	**0.15811**	**$**	**0.13162**	**$**	**0.12215**

Calculations by: Wayne Curtis
Data Source: FBA. 2002. Biomass Cogeneration: Final Report

Table 6-11: Gasification Annual Operating Costs

Gasification				
		Case # 1	Case # 2	Case # 3
	Biomass Input (Wet Tons per Day)	160	267	533
	Net Generation (kilo-Watts per hour)	6,294	10,061	20,227
Overhead and Administration				
1	General Manger	$ 108,800	$ 128,000	$ 140,800
2	Accounting Support	$ 64,000	$ 89,600	$ 115,200
3	Clerical Support	$ 25,600	$ 56,320	$ 96,000
	Total	**$ 198,400**	**$ 273,920**	**$ 352,000**
Variable Cost of Operation				
1	Purchasing Cost for Downtime Electricity per Year	$ 151,056	$ 241,464	$ 485,448
2.1	Fuel Costs per Year (Low at $10/ton)	$ 552,000	$ 921,150	$ 1,838,850
2.2	Fuel Costs per Year (Medium at $20/ton)	$ 1,104,000	$ 1,842,300	$ 3,677,700
2.3	Fuel Costs per Year (High at $35/ton)	$ 1,932,000	$ 3,224,025	$ 6,435,975
3	Ash Disposal Cost per Year	$ 13,000	$ 27,000	$ 54,000
4	Water and Water Treatment	$ 22,000	$ 57,000	$ 159,000
5	Labor	$ 540,000	$ 540,000	$ 600,000
6	Workers' Compensation	$ 37,800	$ 37,800	$ 42,000
7	Miscellaneous	$ 39,000	$ 39,000	$ 39,000
8	Inert Gas	$ 10,000	$ 10,000	$ 10,000
9.1	Interest on Working Capital ($10/ton feedstock)	$ 22,748	$ 31,224	$ 53,805
9.2	Interest on Working Capital ($20/ton feedstock)	$ 31,948	$ 46,576	$ 84,452
9.3	Interest on Working Capital ($35/ton feedstock)	$ 45,748	$ 69,605	$ 130,424
	Total (Low Fuel Cost - $10/ton)	**$ 1,387,604**	**$ 1,904,638**	**$ 3,282,103**
	Total (Medium Fuel Cost - $20/ton)	**$ 1,948,804**	**$ 2,841,140**	**$ 5,151,600**
	Total (High Fuel Cost - $35/ton)	**$ 2,790,604**	**$ 4,245,894**	**$ 7,955,847**
Yearly Expenditures on Capital				
1	Yearly Taxes and Insurance Costs	$ 286,830	$ 398,790	$ 658,530
2	Yearly Maintenance Costs	$ 382,440	$ 531,720	$ 878,040
3	Depriciation - Buildings	$ 65,500	$ 98,350	$ 160,000
4	Depreciation - Equipment	$ 1,286,800	$ 1,831,300	$ 3,060,000
5	Interest on Investment - Buildings	$ 32,750	$ 49,175	$ 80,000
6	Interest on Investment - Equipment	$ 356,700	$ 490,325	$ 815,000
	Total	**$ 2,411,020**	**$ 3,399,660**	**$ 5,651,570**
Total Operational Costs				
Operational Costs/yr (Low at $10/ton)		$ 3,997,024	$ 5,578,218	$ 9,285,673
Operational Costs/yr (Medium at $20/ton)		$ 4,558,224	$ 6,514,720	$ 11,155,170
Operational Costs/yr (High at $35/ton)		$ 5,400,024	$ 7,919,474	$ 13,959,417
Generation Analysis				
kilo-Watts Sold per Year		55,135,440	88,134,360	177,188,520
Marginal Costs/yr (Low at $10/ton)		**$ 0.07249**	**$ 0.06329**	**$ 0.05241**
Operational Costs/yr (Medium at $20/ton)		**$ 0.08267**	**$ 0.07392**	**$ 0.06296**
Operational Costs/yr (High at $35/ton)		**$ 0.09794**	**$ 0.08986**	**$ 0.07878**

Calculations by: Wayne Curtis
Data Source: FBA. 2002. Biomass Cogeneration: Final Report

Table 6-12: Pyrolysis Annual Operating Costs

Pyrolysis							
		Case # 1		Case # 2		Case # 3	
	Biomass Input (Wet Tons per Day)	120		200		400	
	Net Generation (kilo-Watts per hour)	4,752		9,570		14,370	
Overhead and Administration							
1	General Manger	$	108,800	$	128,000	$	140,800
2	Accounting Support	$	64,000	$	89,600	$	115,200
3	Clerical Support	$	25,600	$	56,320	$	96,000
	Total	**$**	**198,400**	**$**	**273,920**	**$**	**352,000**
Variable Cost of Operation							
1	Purchasing Cost for Downtime Electricity per Year	$	114,048	$	229,680	$	344,880
2.1	Fuel Costs per Year (Low at $10/ton)	$	552,000	$	1,104,000	$	1,656,000
2.2	Fuel Costs per Year (Medium at $20/ton)	$	1,104,000	$	2,208,000	$	3,312,000
2.3	Fuel Costs per Year (High at $35/ton)	$	1,932,000	$	3,864,000	$	5,796,000
3	Ash Disposal Cost per Year	$	17,500	$	35,000	$	52,000
4	Water and Water Treatment	$	22,000	$	57,000	$	159,000
5	Labor	$	510,000	$	1,020,000	$	1,530,000
6	Workers' Compensation	$	35,700	$	71,400	$	107,100
7	Miscellaneous	$	39,000	$	39,000	$	39,000
8.1	Interest on Working Capital ($10/ton feedstock)	$	21,504	$	42,601	$	64,800
8.2	Interest on Working Capital ($20/ton feedstock)	$	30,704	$	61,001	$	92,400
8.3	Interest on Working Capital ($35/ton feedstock)	$	44,504	$	88,601	$	133,800
	Total (Low Fuel Cost - $10/ton)	**$**	**1,311,752**	**$**	**2,598,681**	**$**	**3,952,780**
	Total (Medium Fuel Cost - $20/ton)	**$**	**1,872,952**	**$**	**3,721,081**	**$**	**5,636,380**
	Total (High Fuel Cost - $35/ton)	**$**	**2,714,752**	**$**	**5,404,681**	**$**	**8,161,780**
Yearly Expenditures on Capital							
1	Yearly Taxes and Insurance Costs	$	198,270	$	324,630	$	445,230
2	Yearly Maintenance Costs	$	264,360	$	432,840	$	593,640
3	Depriciation - Buildings	$	45,000	$	77,750	$	129,500
4	Depreciation - Equipment	$	991,500	$	1,608,000	$	2,154,500
5	Interest on Investment - Buildings	$	22,500	$	38,875	$	64,750
6	Interest on Investment - Equipment	$	247,875	$	402,000	$	538,625
	Total	**$**	**1,769,505**	**$**	**2,884,095**	**$**	**3,926,245**
Total Operational Costs							
Operational Costs/yr (Low at $10/ton)		$	3,279,657	$	5,756,696	$	8,231,025
Operational Costs/yr (Medium at $20/ton)		$	3,840,857	$	6,879,096	$	9,914,625
Operational Costs/yr (High at $35/ton)		$	4,682,657	$	8,562,696	$	12,440,025
Generation Analysis							
kilo-Watts Sold per Year		41,627,520		83,833,200		125,881,200	
Marginal Costs/yr (Low at $10/ton)		**$**	**0.07879**	**$**	**0.06867**	**$**	**0.06539**
Operational Costs/yr (Medium at $20/ton)		**$**	**0.09227**	**$**	**0.08206**	**$**	**0.07876**
Operational Costs/yr (High at $35/ton)		**$**	**0.11249**	**$**	**0.10214**	**$**	**0.09882**

Calculations by: Wayne Curtis
Data Source: FBA. 2002. Biomass Cogeneration: Final Report

Overhead and Administration

The overhead and administration section deals primarily with the annual salary of the general manager, accounting support, and clerical services. Each technology was assumed to require an equal amount of services from a general manager, accounting department, and clerical support; therefore, these services for direct-fire case 1 will incur the same amount as all other case 1 technologies. Case 2 and case 3 are respectively equal for each technology.

Company benefits are assessed within the salary for the general manager, accounting, and clerical support services. These benefits are intended to include typical employee benefits, such as health insurance, dental, vacation time, and 401K. Benefits are assessed at a flat rate of 28% of the yearly employee salary.

Variable Costs of Operation

The variable costs of operation are dependent upon the costs of fuel, operating labor, purchased power for plant downtime, worker's compensation benefits, water and water treatment, ash disposal, interest on working capital, and miscellaneous variable costs. The following sections describes the variable costs of operation in greater detail.

Fuel Cost - Areas that are most dense in biomass potential may be able to purchase a variety of biomass at low costs. Areas that are less dense may not be able to purchase low-cost biomass fuels. Georgia's five cheapest biomass sources cost $14/ton on average, and Georgia's ten cheapest biomass sources cost $23.5/ton. For these reason's the costs of biomass fuels were assessed in low ($10/ton), medium ($20/ton), and high cost scenarios ($35/ton). For co-fire technology, the natural gas fuel charge is assessed at $1.38 per thousand cubic feet, which is consistent with long-term regional averages. Fuel costs, even at the lowest price of $10/ton, is generally the single largest operational cost for any given technology.

Operating Labor - The operating laborer's section relates to the manpower necessary for the operation of each facility. Some technologies will require more manpower than others. In order to operate the direct-fire and co-fire technologies, eight laborers will be required for case 1, eight for case 2, and ten for case 3. Gasification technology requires 18, 18, and 20 for case 1, 2, and 3, respectively. Pyrolysis requires 17, 34, and 51 laborers for case 1, 2, and 3, respectively. Laborers for each technology are assumed to earn an average of $30,000 per year. Generally, the operating labor cost the second largest variable cost of operation, next to the fuel costs.

Worker's Compensation – To account for any injury that may occur during operation, worker's compensation benefits are assessed for all laborers. These benefits are intended to cover plant workers, such as loader operators, plant technicians, and mechanics. Worker's compensation is assessed at the typical rate of 7% of the laborer's total yearly salary.

Interest on Working Capital – Working capital was assessed to cover two months of the variable costs of operation. Since there are three fuel cost scenarios, the interest on working capital was assessed for each. The total variable costs of operation for two months time period was assessed for the short-term rate of 10%. This cost is intended to cover any lag-time between the start of operation and the incoming revenue stream.

Ash Disposal - This study assumes an 8% ash content, so the ash disposal fees are assessed by multiplying the yearly tons of biomass by 8%, and then by the ash disposal rate of $20/ton. The gasification and pyrolysis case studies incur the least amount in ash disposal fees due to the biomass feedstock conversion process, which creates a more condensed biofuel. Ash is generated at approximately 1.4 and 1.6% of the original biomass feedstock for gasification and pyrolysis, respectively.

Water Fees - The amount of boiler feed water used is dependent upon the generating capacity. Increased generation will require more steam to turn the turbine and also require more water for cooling. Direct-fire and co-fire models use the same multi-stage turbine generator with equal water requirements. The gasification model utilizes the waste heat from the turbine generator to produce steam in a boiler for an additional multi-stage turbine generator. The water requirement for gasification is not significantly different from the direct-fire and co-fire models. Therefore, the water costs for the direct fire, co-fire, and gasification models are equal. The pyrolysis technology also utilizes the waste heat from the turbine generator to produce steam in a boiler for an additional multi-stage turbine generator. Since the pyrolysis model requires less energy input, there is less waste heat generated from the gas turbine. This reduces the amount of steam that can be produced within the boiler. As a result, the pyrolysis model requires the least amount of water requirements.

In order to feed the boiler, direct-fire, co-fire, and gasification take in the same 4.5, 7.4, and 14.8 million gallons of water per year for case 1, 2, and 3, respectively. Pyrolysis generation requires inputs of 3.6, 7.2, and 10.8 million gallons per year for case 1, 2, and 3, respectively. Sewer water loads are determined as a function of the boiler feed water. About 1/3 of the boiler feed water evaporates through the cooling towers. Therefore, 2/3 of the boiler feed water load equals the total sewer load. Water and water treatment rates increase as the water requirements increase for each case study. Cumulatively, water and water treatment amount to approximately .49¢, .77¢, and 1.1¢ per gallon of water input for case 1, 2, and 3, respectively.

Taxes and Insurance – Taxes and insurance are assessed a flat rate of 1.5% of capital for each technology.

Maintenance - Maintenance is assessed at 2% of capital for direct-fire and co-fire technologies and 3% of capital for the more technical gasification and pyrolysis systems.

Inert Gas – In the gasification process, combustible gases are created by heating dried biomass within a reactor vessel. In this model, the heat is introduced by a heat exchange medium that uses sand, char, steam, and inert gas. The inert gas needed for the gasification process is assessed at $10,000 per year for each case scenario.

Miscellaneous – Various expenditures for items, parts, and services will be required to keep the facility in regular operation. The miscellaneous section is intended to capture these expenditures, which may include: contractual administrative support, office supplies, maintenance supplies, safety gear, or any other required expense.

Expenditures on Capital

The third primary category that influences the yearly operational costs is the yearly expenditures on capital. These costs include both depreciation and interest for buildings and equipment. This research assumes the plant will remain in operation as long as it is economically and mechanically practical; therefore, zero salvage value was assessed for the plant buildings and equipment. Depreciation on buildings is assessed at a 20-year lifetime, while depreciation on equipment is assessed at a 10-year lifetime. The interest on investment is calculated at the typical interest rate of 5% for the total capital costs of buildings and equipment.

Marginal Cost of Generation

The marginal cost analysis ($/kWh) for each technology is located on the lower half of tables 12, 13, 14, and 15. The plant is assumed to operate 345 days per year and shut-down for maintenance during the remaining time. In order to provide a constant flow of power to the generator's contractors, the generator must purchase the power it usually produces from the electrical power grid. This power is used to supply power consumers during the maintenance shut-down periods. The total yearly quantity of power produced is derived from the net generating capacity multiplied by 345 days/year. The total amount of power sold is derived from multiplying the net generating capacity by 365 days/year. The marginal cost of electricity, or the cost per kWh, is derived from the total amount of power sold divided by the annual operating costs.

The total amount of power sold is used to determine the price per kWh, because in order to supply contracted customers, the generator must sell power continuously for the entire year. During maintenance periods, the plant is shut down, and the generator is assumed to act as a sub-contractor, by purchasing power at the typical industrial rate of 5¢/kWh. The generator then sells the purchased power back to the consumer at the generator's usual fee. The generator does not alter the set contract price when the facility undergoes maintenance. In addition, the generator must account for the purchased power as an annual cost, while accounting for the revenue it receives from the resold power. If the final cost per kWh is calculated using the total amount of power produced during a 345-day period, this would defer the revenue gained from the resold power the additional 20 days per year.

Electricity Rate Comparison

In Georgia, the retail sale of electricity is separated into three primary markets, commercial, industrial, and residential. Although these sectors use roughly the same amount of electricity, the electrical power rate is determined by the individual consumer's demand for power. Since industrial facilities buy electricity in bulk loads, power generators will offer consumers in the industrial sector the least expensive rate for electricity. Industrial rates are typically fixed for wholesale electricity markets. Commercial consumers pay around 2¢-3¢ more per kWh than the industrial sector. The commercial sector consumes virtually the same amount of electricity as the industrial sector; however, these facilities pay higher rates because they require less power on a site-by-site basis. The residential sector requires the least amount of electricity on a site-by-site basis, but consumes the greatest total quantity. As a result, the residential sector is charged the highest rate for electricity, typically 1-2¢ more than the commercial rate.

Southeastern rates averaged 7.86¢/kWh for the residential sector, 6.56¢/kWh for the commercial sector, and 4.3¢/kWh for the industrial sector. Georgia's utility retail sales and revenue data is shown in Table 6-13. As shown in the table, Georgia sold 112,656 MegaWatt-hours of electricity in 1999 at the average rate of 6.24¢/kWh.

Table 6-13: Georgia Utility Retail Sales, Revenue, and Average Revenue per kWh

Item	Investor-Owned	Public	Federal	Cooperative	Total
Number of Utilities	2	53	0	43	98
Number of Retail Customers	1,982,155	320,723	0	1,429,267	3,732,145
Retail Sales (thousand megawatthours)	74,685	10,871	0	27,100	112,656
Percentage of Retail Sales	66.3	9.7	0	24.1	100
Revenue from Retail Sales (million 1999 dollars)	4,368	682	0	1,975	7,025
Percentage of Revenue	62.2	9.7	0	28.1	100
Average Revenue per Kilowatthour (cents/kWh)	5.85	6.27	0	7.29	6.24

Source: Energy Information Administration.
http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia/ga.html#t9

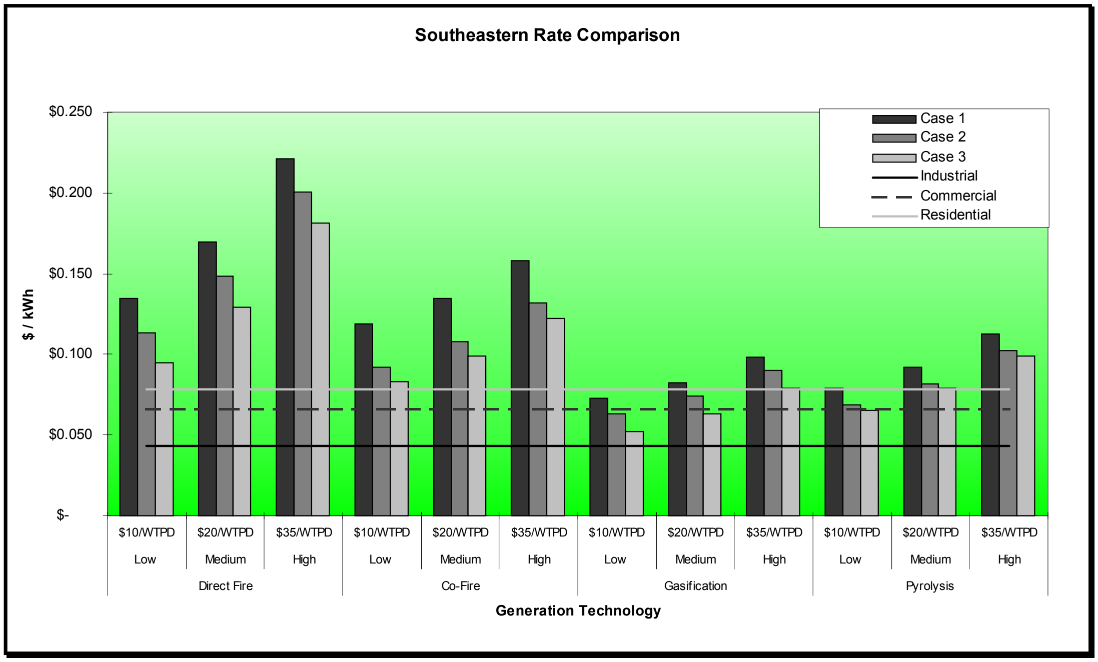
Table 6-14 summarizes the cost of generating power ($/kWh) for each technology. We can employ a direct comparison among the operating costs of each technology and the average annual rates for commercial, industrial, and residential consumers. Since electricity generation in the southeastern United States is slightly cheaper than the national average, Figure 6-2 compares each technology with the rate averages for the southeastern region. It is important to note that transmission and distribution costs, which are reflected in the Southeastern rates for electricity, are not accounted for in the marginal costs of the biomass generation technologies.

Table 6-14: Summary of Operating Costs in $/kWh

Summary of Operating Costs $/kWh				
Technology	**Scenario**	**Case #1**	**Case #2**	**Case #3**
Direct - Fire	Low Fuel Cost Scenario	$ 0.126	$ 0.111	$ 0.096
	Medium Fuel Cost Scenario	$ 0.160	$ 0.145	$ 0.130
	High Fuel Cost Scenario	$ 0.212	$ 0.196	$ 0.181
Co - Fire	Low Fuel Cost Scenario	$ 0.146	$ 0.132	$ 0.119
	Medium Fuel Cost Scenario	$ 0.162	$ 0.148	$ 0.134
	High Fuel Cost Scenario	$ 0.185	$ 0.171	$ 0.157
Gasification	Low Fuel Cost Scenario	$ 0.068	$ 0.062	$ 0.051
	Medium Fuel Cost Scenario	$ 0.078	$ 0.072	$ 0.061
	High Fuel Cost Scenario	$ 0.093	$ 0.088	$ 0.077
Pyrolysis	Low Fuel Cost Scenario	$ 0.073	$ 0.066	$ 0.063
	Medium Fuel Cost Scenario	$ 0.087	$ 0.079	$ 0.076
	High Fuel Cost Scenario	$ 0.107	$ 0.099	$ 0.096

Calculations by: Wayne Curtis
Data Source: FBA. 2002. Biomass Cogeneration: Final Report

Figure 6-2: Southeastern Rate Comparison



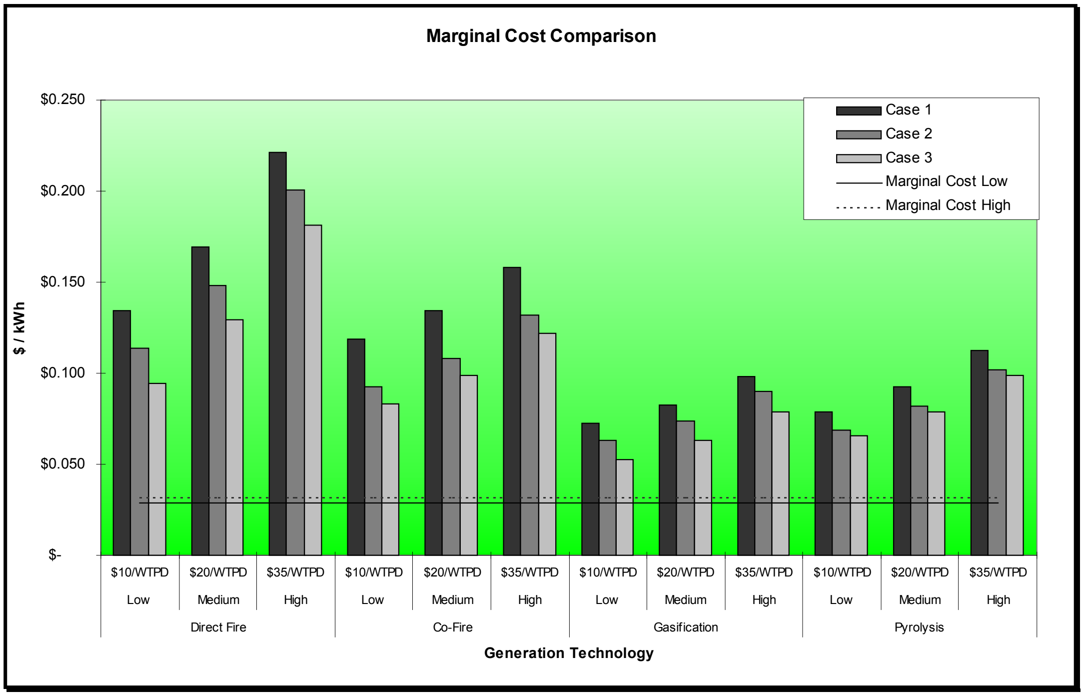
Created by: Wayne Curtis

Marginal Cost Comparison

Data provided from *Customer Choice, Consumer Value: An Analysis of Retail Competition in America's Electric Utility Industry* indicate that the marginal cost of production from existing steam facilities is 1.7¢/kWh. The full costs, including capital, were assessed at approximately 3¢/kWh. The 1998 Annual Energy Outlook reports similar figures for the capital and fuel costs, at approximately 3.2 and 2.9¢ per kWh for coal-fired and natural gas combined cycle generation, respectively.

Figure 6-3 shows the marginal cost comparison of the biomass generation technologies with the marginal cost of generation for existing facilities. As displayed in the following graph, there is a direct relationship with the larger facilities and lowered electricity costs. Therefore, case 3 proves to be the best-case scenario for each technology. For simplicity, further discussion on feasibility will focus on case 3 for each technology, unless otherwise noted.

Figure 6-3: Marginal Cost Comparison



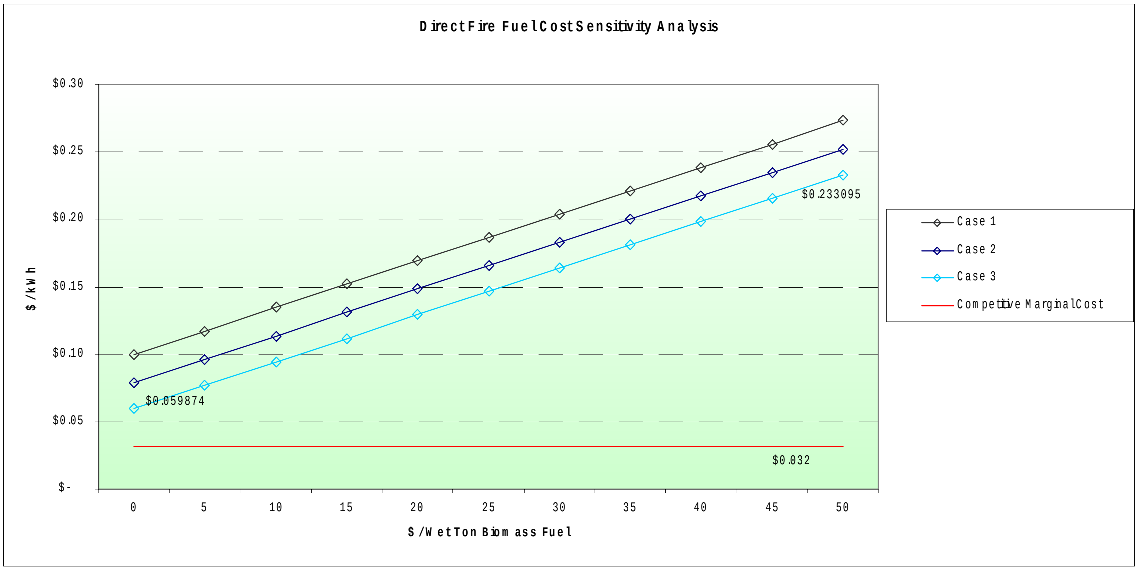
Created by: Wayne Curtis

Of the four technologies, none are shown to be competitive with existing generation facilities. The low-fuel cost gasification case 3 scenario can generate electricity at 5.2¢ per kWh, which is above the highest marginal cost by 2¢ per kWh.

Sensitivity Analysis

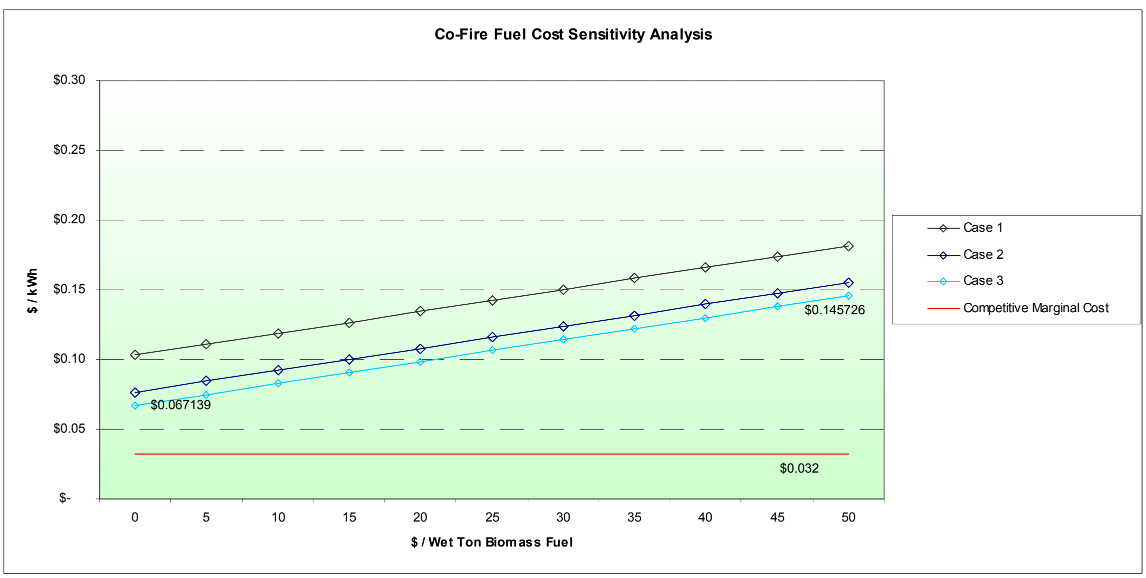
The most significant cost variables, fuel cost and capital costs, were altered to determine the overall affect on the marginal cost of production. The capital costs were altered 10% higher and lower than the original assessment. Fuel costs were assessed from $0 to $50 per wet ton. Figures 6-4 through 6-11 displays the results of the sensitivity analysis.

Figure 6-4: Direct Fire Fuel Cost Sensitivity



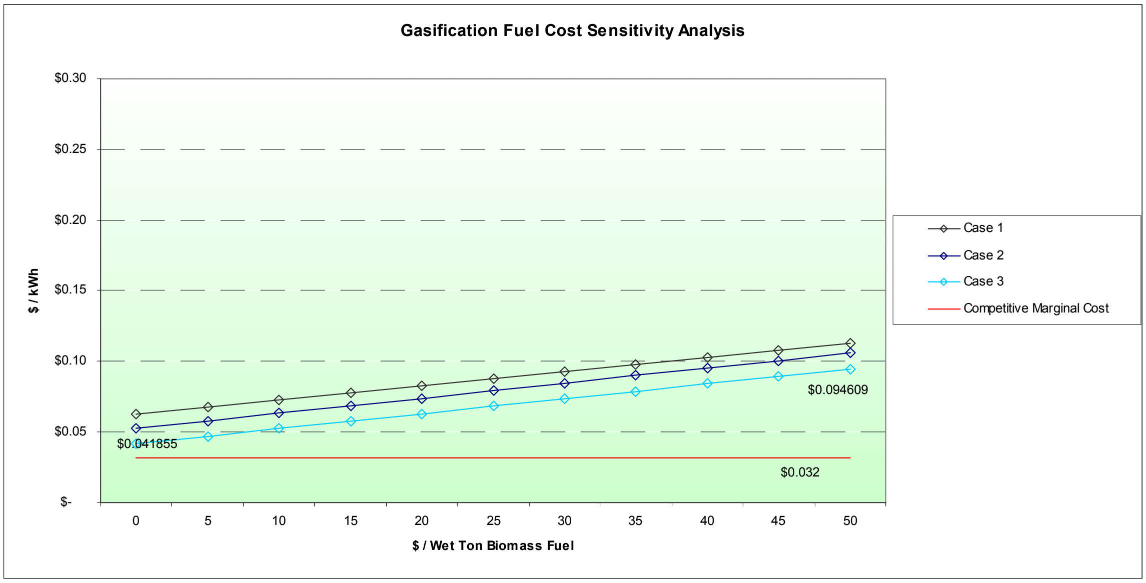
Calculations by: Wayne Curtis

Figure 6-5: Co-Fire Fuel Cost Sensitivity



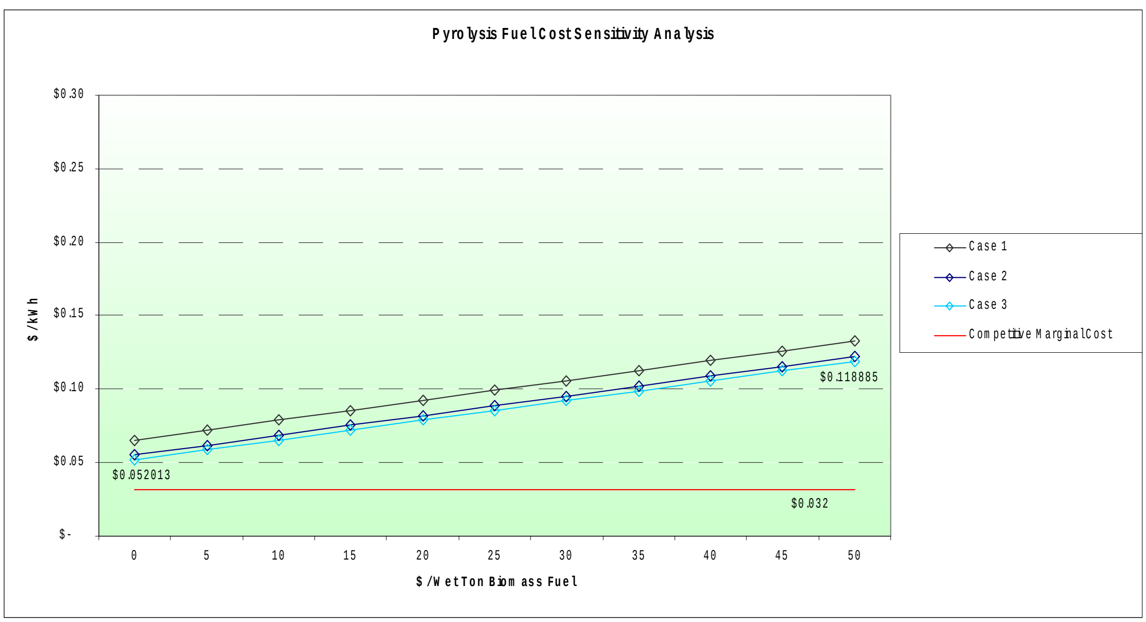
Calculations by: Wayne Curtis

Figure6-6: Gasification Fuel Cost Sensitivity



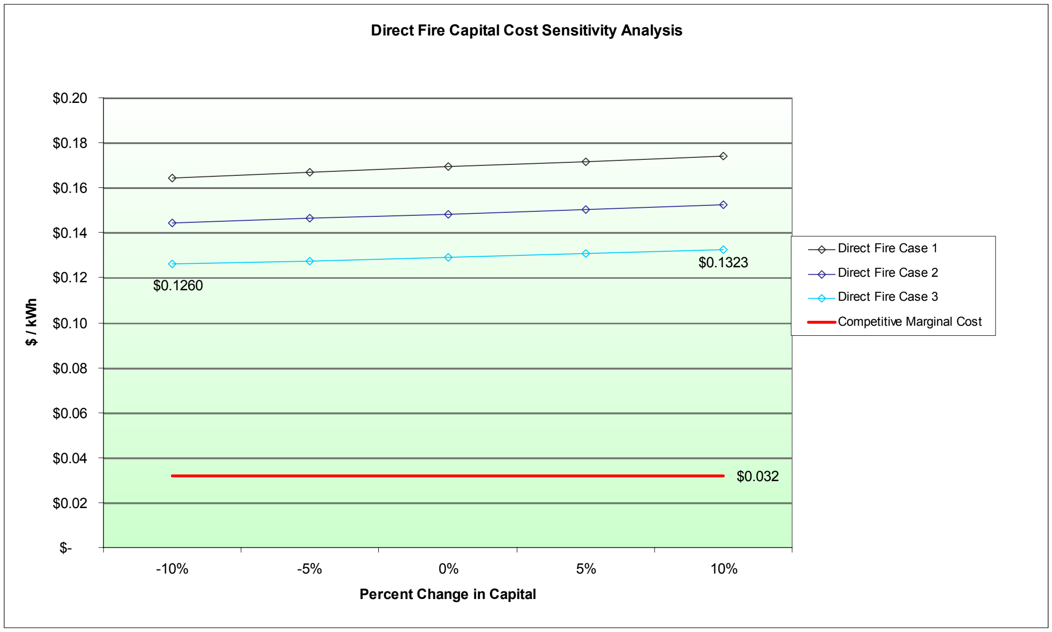
Calculations by: Wayne Curtis

Figure 6-7: Pyrolysis Fuel Cost Sensitivity



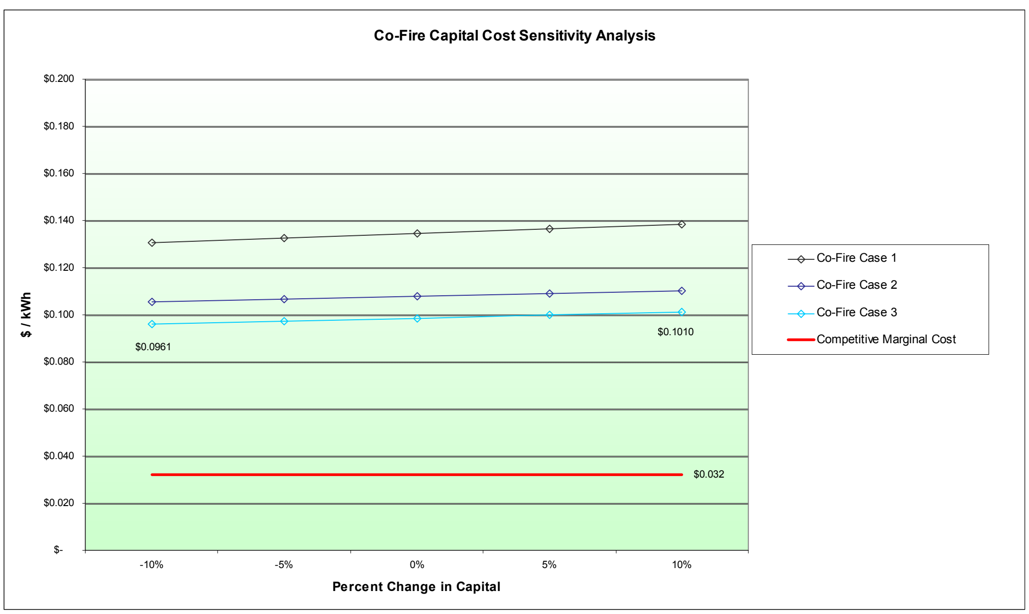
Calculations by: Wayne Curtis

Figure 6-8: Direct Fire Capital Cost Sensitivity



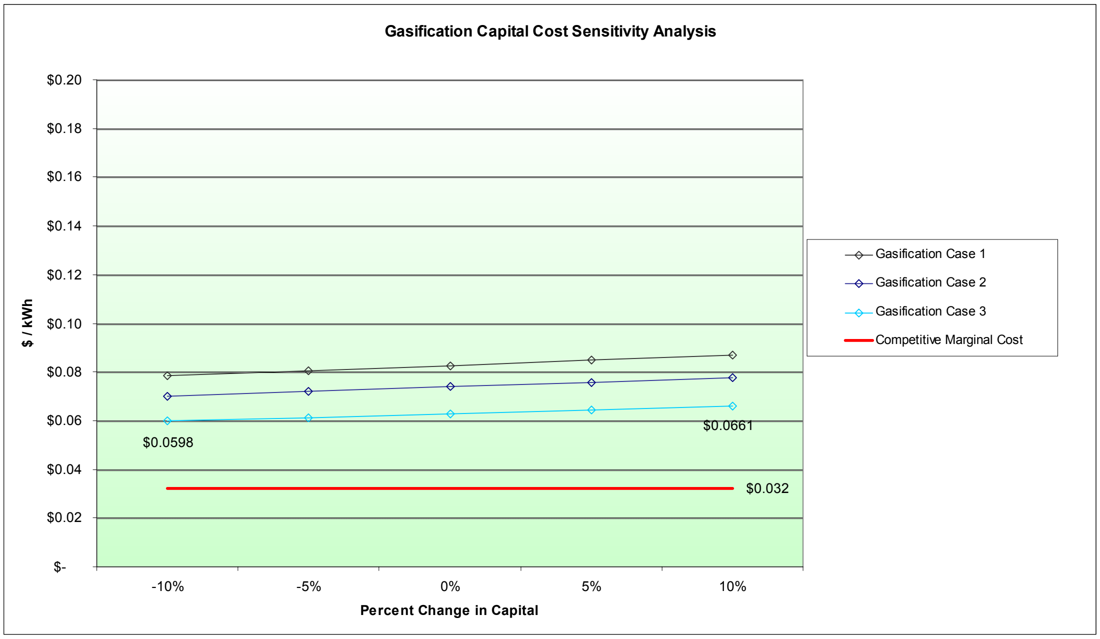
Calculations by: Wayne Curtis

Figure 6-9: Co-Fire Capital Cost Sensitivity



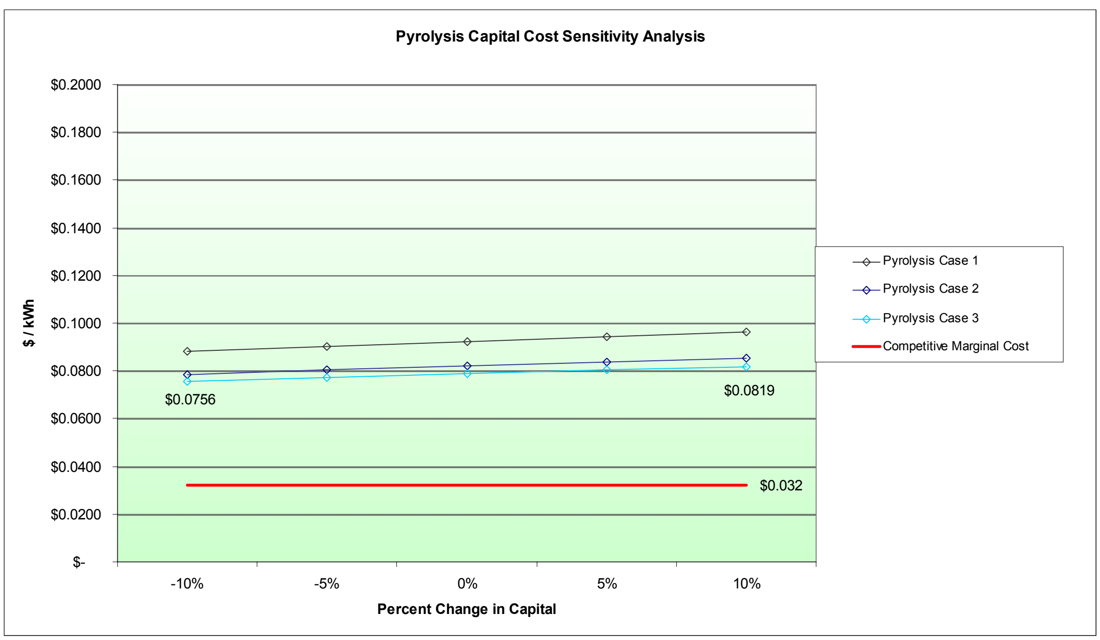
Calculations by: Wayne Curtis

Figure 6-10: Gasification Capital Cost Sensitivity



Calculations by: Wayne Curtis

Figure 6-11: Pyrolysis Capital Cost Sensitivity



Calculations by: Wayne Curtis

Fuel Cost Sensitivity – As shown in the preceding figures, direct-fire is the most sensitive technology, with respect to changes in fuel costs. Co-fire, pyrolysis, and gasification display respectively decreasing sensitivity to changes in fuel cost. Fuel cost sensitivity is dependant upon the feedstock input to operational cost ratio. Technologies that utilize the greatest amount of biomass input per dollar of total operational cost, will be the most sensitive to feedstock price changes. This analysis concludes that no technology is competitive with traditional generation methods, even at zero fuel cost.

Capital Cost Sensitivity – As displayed in figures 6-8 through 6-11, none of the four generation technologies are significantly sensitive to changes in capital cost. Co-fire is the least sensitive, with a total price change of .51¢ between the positive and negative 10% change in capital cost. Direct fire, gasification, and pyrolysis all exhibit a total price change of .63¢ between the range of capital cost. None are shown to be competitive with traditional generation technologies.

Renewable Energy Production Incentive

Due to it's many potential benefits, renewable energy resources, such as biomass generation technologies, can sometimes qualify for certain incentives to help encourage entry into the competitive electric utility industry. The most substantial government-based incentive is the renewable energy production incentive. This incentive can be obtained for closed-loop biomass and poultry litter feedstocks. The incentive is adjusted annually for inflation and is currently set at 1.8¢ per kWh. The inclusion of this incentive would shift the low fuel cost gasification case 3 scenario to be near competitive cost levels. Assuming proper biomass feedstocks, all technologies could qualify for the production incentive, except co-fire. Since co-firing mixes fossil fuels with biomass, it does not qualify for the production incentive.

Green Power Markets

Each technology, with the exception of co-fire, are authentic green power sources. Therefore the electricity generated can be sold in separate green power markets. Green power markets, such as Georgia's newly established Green Power EMC, sells green power in 150 kWh blocks to consumers who wish to purchase some of their energy from renewable sources. Georgia's green power generators are currently fueled from landfill gas. Any new green power facility can take advantage of Georgia's green power market.

The green power premium will be set at the average rate for all green power generation. For example, Georgia's green power market may eventually consist of 25% landfill gas, 25% hydro, 25% direct-fire, and 25% gasification. The break-even rate of electricity will vary with each technology. Example rates could be 8¢, 11¢, 15¢, and 6¢ per kWh, respectively. In Georgia, the green power premium would be set from average of the green power generation rates, which would be 10¢ per kWh in this example. Subtracting the regional residential average rate of 7.8¢ from 10¢ would yield a set premium at 2.2¢ per kWh. The consumers will withdraw the power they use from the grid, and the green power contractor will bill the consumer at the premium rate for the amount of green power bought, currently sold in monthly 150kWh blocks. A premium of 2.2¢ per kWh for a monthly 150 kWh block of green power would raise the price to the consumer by $3.30 per month, which is consistent with the current Green Power EMC premium.

This research compares studies on consumer's willingness-to-pay for green power premiums performed by the National Renewable Energy Laboratory (NREL). A review and synthesis of 14 surveys conducted in 12 utility service territories (1995-1997) found that majority (52 to 95%) of residential customers said they were willing to pay more on their electric bills for power from renewable sources (NREL 2001). The NREL studies indicate that a fewer percentage of respondents are willing to pay for green power as the premium increases. Relating the NREL results to the current Green EMC premium, this research shows most respondents are willing to pay for this type of premium. The more competitive rates for gasification and pyrolysis would aid in lowering the market premium, thereby increasing the feasibility for all green power sources allocated through the green power market.

The economic potential for Georgia's green power premiums could be highly significant. Table 18 shows Georgia's power sales and corresponding price rate for Georgia's electricity sectors. Green power rates were calculated by setting premiums at 5, 10, and 15%. The inclusion of a premium would raise the initial cost per kWh by approximately 4 mills (tenths of a cent) for each 5% increase in the premium.

Table 6-15: Impact on Electricity Rates for Green Power Premiums

	Utility Retail Sales (GWh)	Revenue (million 1999 dollars)	Average Revenue per kWh	Av Cost per kWh with the 5% premium	Av Cost per kWh with the 10% premium	Av Cost per kWh with the 15% premium
Residential	41,767	$ 3,159	$ 0.0756	$ 0.07942	$ 0.08320	$ 0.08698
Commercial	34,093	$ 2,272	$ 0.0666	$ 0.06997	$ 0.07331	$ 0.07664
Industrial	35,255	$ 1,463	$ 0.0415	$ 0.04357	$ 0.04565	$ 0.04772
Other	1,541	$ 130	$ 0.0844	$ 0.08858	$ 0.09280	$ 0.09701
Total	112,656	$ 7,024	$ 0.0623	$ 0.06547	$ 0.06858	$ 0.07170

Created by: Wayne Curtis

For Georgia's residential consumers, the 5% premium would raise the cost of electricity approximately $6 month. Research has shown that most consumers are willing to pay for this type of premium. If 40% of Georgia's residential consumers purchased the 5% green power premium, 470 thousand 150kWh power blocks would be demanded each month in the residential sector alone. If 10% of Georgia's residential, industrial, and commercial consumers contributed a 5% premium towards their power bills, over six million green power blocks could be sold each month. One case 3 gasification plant could generate approximately 91,700 green power blocks, monthly. Therefore, if 10% of Georgia’s consumers purchased green power at a 5% premium, this would support approximately 65 case 3 gasification plants. Currently, the 16 Green EMC cooperatives serve only 900,000 Georgia homes, businesses, factories, and farms, however as new renewable generation comes online, Green EMC will be able to expand the green power option to more of Georgia's consumers.

Marketable Permits for CO_2, SO_2, and NO_x

The 1990 CAA amendments contains many provisions that require or encourage use of emissions trading or other forms of economic instruments to control air pollution. Since this research determined biomass used for electrical generation produces less pollution than most fuel sources, market-based policies can directly increase the revenue of biomass generation, while increasing the costs of fossil fuel generation. As a result, biomass-based generation could become more feasible with respect to more polluting sources of energy.

In order to determine how pollution taxes could affect biomass feasibility, emission allowance data was acquired for the electric industry's most significant pollutants, CO_2, SO_2, and NO_x. Data on recent market prices per unit of pollution were derived from the Regional Clean Air Incentives Market (RECLAIM), the Clean Air Act's Allowance Trading Markets, and Kyoto simulation models for carbon emissions. Most importantly, this data represents the most reasonable estimates of the marginal value of reducing air pollution from electricity generation.

For analysis purposes, a low and high bid was assessed for each pollutant. Carbon emissions were assessed at $20 and $50/ton. Sulfur Dioxide emissions were assessed at $150 and $200 per ton. Oxides of Nitrogen were assessed at $2,000 and $8,000 per ton of emission. These figures were related to the corresponding quantity of pollution created by each fuel within Georgia. Table 6-16 displays the potential cumulative economic impact if a market for CO_2, SO_2, and NO_x emissions were established.

Table 6-16: Marketable Permits Potential Industry Impacts

Total $/kWh	CO2 $5.5/ton	CO2 $13.6/ton	SO2 $150/ton	SO2 $200/ton	NOx $1/lb	NOx $4/lb
Western Coal	$ 0.0037	$ 0.00921	$ 0.0001	$ 0.0001	$ 0.0029	$ 0.0114
Gas	$ 0.0001	$ 0.00024	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0001
Oil	$ 0.0001	$ 0.00017	$ 0.0000	$ 0.0000	$ 0.0000	$ 0.0001
Biomass	$ -	$ -	$ 0.0000	$ 0.0000	$ 0.0001	$ 0.0003
Average Rate Increase	$ 0.003847	$ 0.009617	$ 0.000080	$ 0.000107	$ 0.002972	$ 0.011889

	Low Costs	High Costs
Industry Rate Increase for all Pollutants ($/kWh)	$ 0.0069	$ 0.0216
Biomass Rate Increase ($/kWh)	$ 0.0025	$ 0.0100
Amount of Positive Impact on Biofuel Feasibility ($/kWh)	$ 0.0044	$ 0.0116

Created by: Wayne Curtis

From this analysis displayed in table 6-16, biomass is shown to become more feasible with respect to other polluting forms of energy. At the low price range, marketable permits would increase biomass feasibility by .44¢ per kWh. At the high price of allowances, biomass feasibility increases by 1.16¢ per kWh.

The Acid Rain Program, which sets allowances for emissions of SO_2, bears little significance on the biomass industry at current allowance prices. However, if markets were established for Carbon and NO_x emission trading, the cumulative industry impact would provide greater economic incentives for electricity generation from biofuel energy sources. Fossil fuel generators would trade pollution permits with generators that have lower abatement costs, thereby providing an economic incentive for firms to install more cost-effective technologies or alter their production methods. The potential cumulative industry impact has shown the marginal benefits for reducing the per unit level of pollution from traditional fuel sources via biofuel technology increases, thereby providing an economic incentive for increasing the biomass-based generation share within the generation mix.

Feasibility Summary

Currently, biomass accounts for 2.5% of Georgia's electrical supply. From the agricultural sources studied, this research determines there is enough energy from these sources to power nearly 12% of the State's total electrical demand, or over 31% of the State's residential consumers at 25% conversion efficiency. However, economic analysis revealed direct-fire, co-fire, gasification, and pyrolysis are not competitive with existing generation facilities. With the inclusion of the renewable energy production incentive

(1.8¢/kWh), the gasification generation technology (5.2¢/kWh) was shown to be .2¢ above the competitive marginal cost rate (3.2¢/kWh).

Out of the four technologies studied, gasification and pyrolysis are proven to be the most feasible for electricity generation from biomass fuel sources. Currently, these technologies can become economically feasible, only with the aid of green power programs. Green technologies that can produce electricity near competitive rates, such as gasification and pyrolysis, could aid in reducing the green power premium for all green power sources.

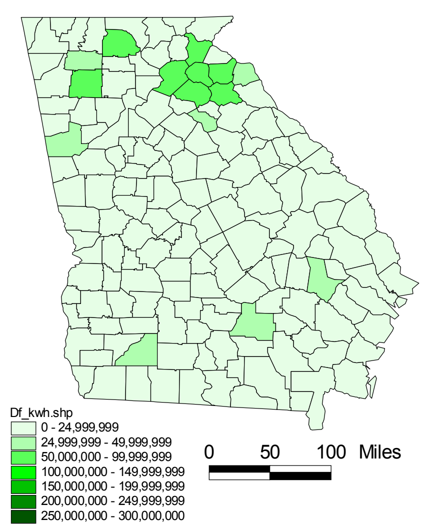
The renewable energy production incentive will further enhance the feasibility of these two technologies, but specific feedstock criteria must be met in order to qualify for this credit. By itself, the inclusion of the production incentive does not result in a feasible outcome for any of the generation technologies. However if a marketable permit system was established for Carbon Dioxide and Nitrogen Oxide emissions, biofuels would become even more feasible with respect to traditional fuels. Together, these two policies could increase the feasibility of green power sources by 2.96¢/kWh. In this case, both gasification and pyrolysis technologies could generate power at a competitive price.

Georgia's Most Feasible Counties

This research assumes geographic independence. For this reason, we have evaluated the final cost of bio-power for low, medium, and high fuel costs. Some facilities, which are located adjacent to an abundant feedstock supply, may be able to fuel the facility at the low cost scenario. These cases would be rare, although there is a substantial amount of biomass that can be delivered between the low ($10/ton) and medium ($20/ton) fuel cost price. Using spreadsheet analysis and the ArcView GIS system for display, the cheapest fuels per heat content were calculated and sorted by county. These biomass feedstocks can be delivered for less than $25/ton. They include pecan hulls, gin trash, poultry litter, peanut hulls, wood chips, and wood residue. The final results were tallied for each technology, which locates the kWh potential and the number of facilities that can be supplied in Georgia's most feasible counties from Georgia's agricultural residues.

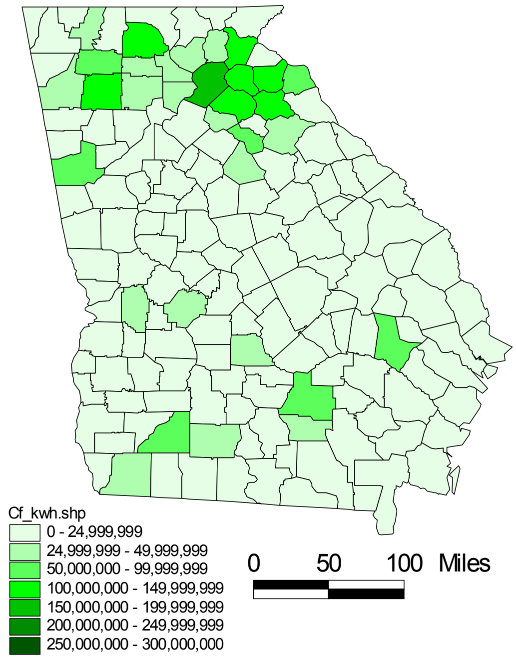
Figures 6-12 through 6-15 show the kWh potential per county for each case 3 technology. Figures 6-16 through 6-19 display the number of facilities that can be supplied in each county. It is important to note that these figures focus on Georgia's most efficient feedstocks). Therefore, it is safe to assume the kWh potential from figures 6-12 through 6-15 could be supplied by the number of facilities from figures 6-16 through 6-19 near the low fuel-cost scenario.

Figure 6-12: Total Direct-fire kWh Potential for Delivered Biomass under $25/ton



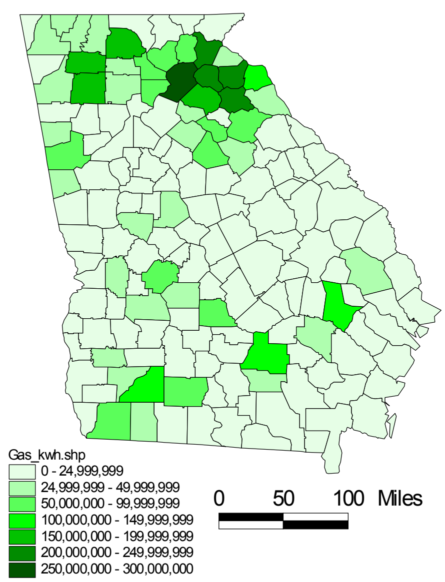
Created by: Wayne Curtis

Figure 6-13: Total Co-fire kWh Potential for Delivered Biomass under $25/ton



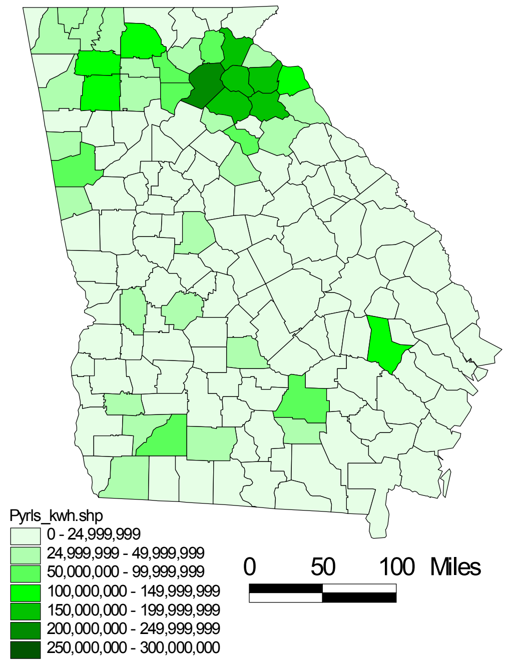
Created by: Wayne Curtis

Figure 6-14: Total Gasification kWh Potential for Delivered Biomass under $25/ton



Created by: Wayne Curtis

Figure 6-15: Total Pyrolysis kWh Potential for Delivered Biomass under $25/ton



Created by: Wayne Curtis

Figure 6-16: Potential for Direct-fire Generation Plants for under $25/ton

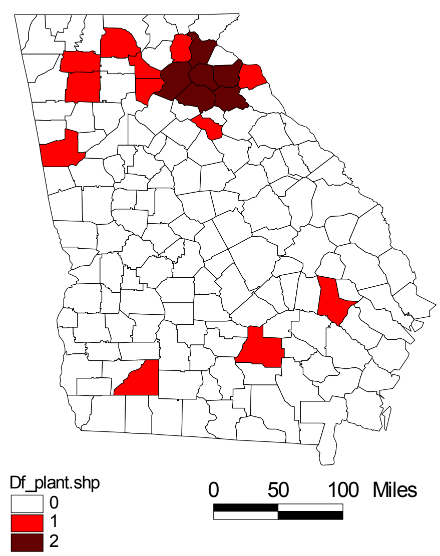


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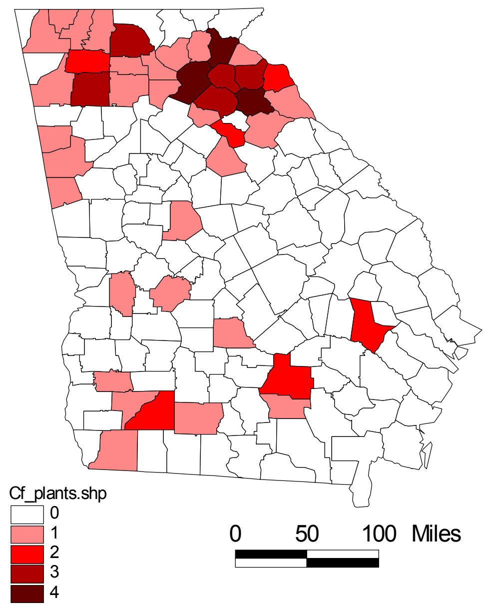
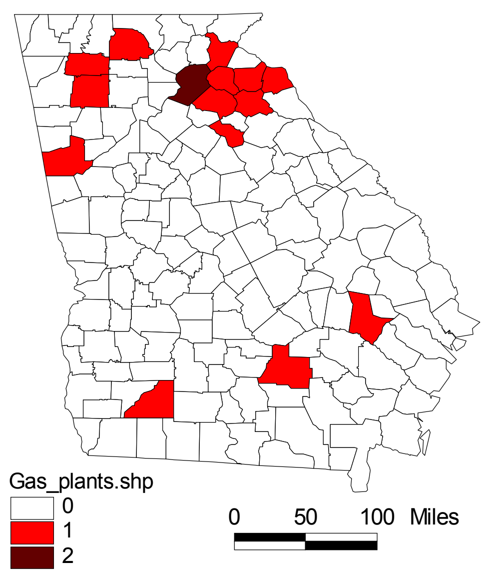
Figure 6-17: Potential for Co-fire Generation Plants for under $25/ton



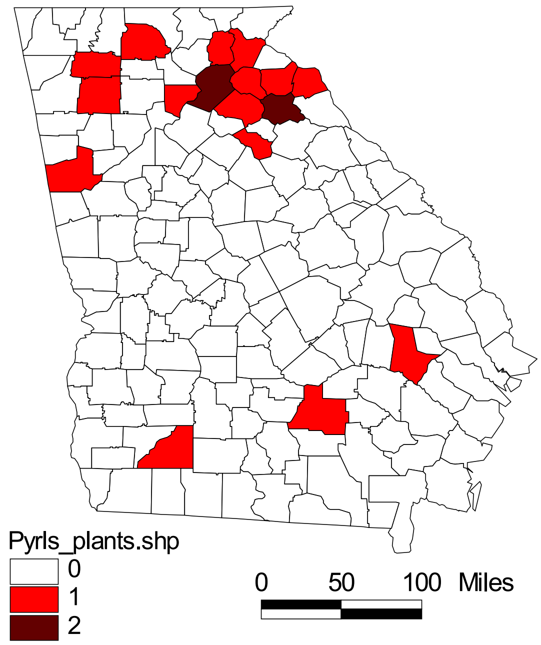
Created by: Wayne Curtis

Figure 6-18: Potential for Gasification Generation Plants for under $25/ton



Created by: Wayne Curtis

Figure 6-19: Potential for Pyrolysis Generation Plants for under $25/ton



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When siting biomass-fueled facilities, utilities should first look at locations within these most feasible counties. After the local feedstock supply is depleted, generators may be forced to expand the transport distance and utilize more expensive feedstocks. In this case, the medium fuel cost scenario would be the most appropriate. Our model assumes a 50-mile transport distance; however, transport across the largest of Georgia's counties would not exceed 30 miles. Therefore, facilities located in regions with the least amount of available feedstock, would still be able to transport the biomass from the surrounding counties at the medium fuel cost scenario.

The study of feasibility performed for this thesis focuses on relatively small power plants. Gasification proved to be the cheapest and most fuel-efficient technology studied for our analysis. In 2001, Georgia sold over 112 million megawatt-hours of electricity (Figure 6-20). The gasification technology we studied could supply approximately 8% of these sales from the use of agricultural residues and an additional 5% from municipal solid waste. Some counties could derive their total electricity consumption from agricultural residues through gasification technology. Figure 6-20 displays the percent of electricity demand, which could potentially be supplied from agricultural residues via gasification technology. Table 6-17 displays the total number of facilities that could be fueled from Georgia's biomass resources. Georgia's agricultural residues could feed 50 case 3 gasification plants.

Figure 6-20: Electricity Demand

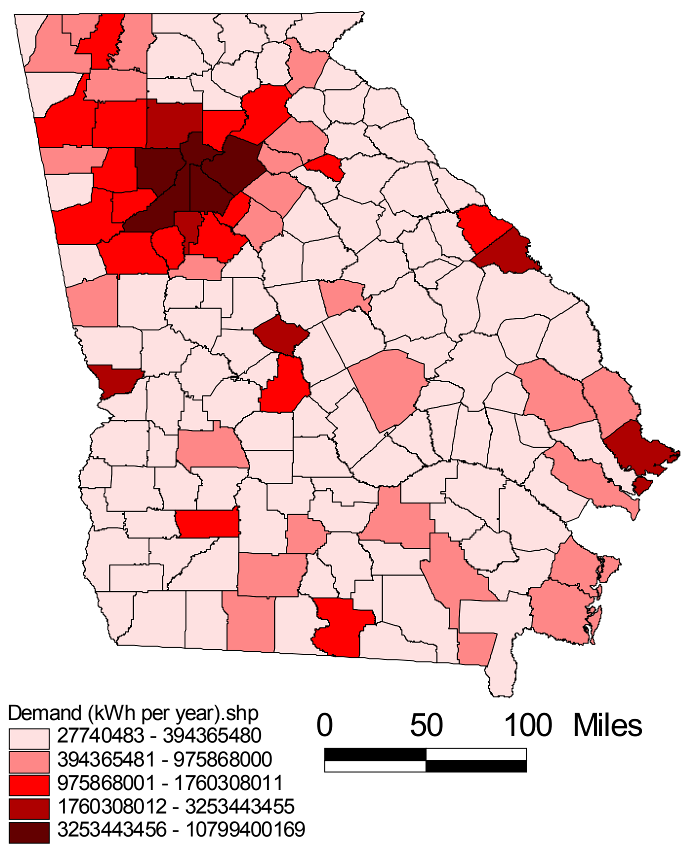

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Figure 6-21: Percentage of Demand Potential from Agricultural Biomass

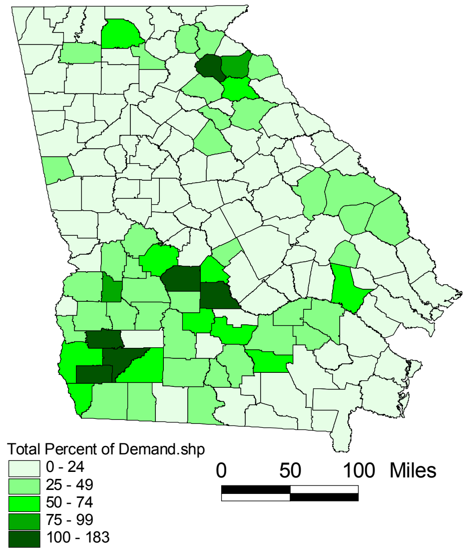

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Table 6-17: Number of Plants Able to be supplied by Georgia's Biomass Resources

Technology	Number of Generation Plants	Agriculutural Residues for $20/ton	All Agricultural Residues	Municipal Solid Waste	Total Biomass (MSW included)
Direct Fire	Case 1	127	223	167	389
	Case 2	76	134	100	234
	Case 3	38	67	50	117
Co-Fire	Case 1	255	445	333	779
	Case 2	153	267	200	467
	Case 3	76	134	100	234
Gasification	Case 1	96	167	125	292
	Case 2	57	100	75	175
	Case 3	29	50	38	88
Pyrolysis	Case 1	96	167	125	292
	Case 2	48	84	63	146
	Case 3	32	56	42	97

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CHAPTER 7

SUMMARY

The research presented in this thesis is intended to give the reader an in-depth view towards the external variables that will impact the future of power generation and the relative feasibility of Georgia's biomass resources. This thesis provides a well-rounded view of the variables that impact power generation, so that the reader can understand why increasing the share of renewable-based generation is difficult, but important. Until the present, renewable power has been far too expensive to generate a significant share of the Nation's power supply. Because of advancements in technology, some locations are now able to apply renewable generation technologies at competitive rates.

If introduced, legislature such as the renewable portfolio standard would require states to generate a given percentage, usually 20% by the year 2020, of their power from renewable resources. Likewise, acceptance of global mitigation agreements, such as the Kyoto protocol, could open the door to more emission trading initiatives, while mandating lowered emissions. If marketable permits are implemented for carbon and NO_x emissions, biomass-based generation will become more feasible with respect to fossil fuel sources, thereby increasing the biofuel share within the generation mix, and potentially leading to a more socially efficient outcome for the generation of electricity. Though the U.S. has not acted upon these initiatives, it is likely the Nation will adopt some form of legislation intended to utilize more renewable resources.

Concluding Remarks

In Georgia, biomass is the most practical renewable resource. Emerging technologies, such as gasification and pyrolysis, are shown to convert waste residues into electricity at competitive rates and lowered emissions. With the use of green power programs and the renewable energy production incentive, even expensive renewable technologies can become economically feasible. And since each fuel source has its own inherent risks and disadvantages, fuel diversity is the most important element in the security of the Nation's electrical supply. The ability to utilize different sources of energy reduces the risk of an insufficient fuel supply and price volatility. Naturally, the most economical fuel source, coal, shares the most generating percentage. Although as negative externalities become more apparent, the damages caused from utilizing such a large share may exceed the benefits. In this case, a transition towards less damaging fuels is necessary. Currently, biomass accounts for 2.5% of Georgia's electrical supply. With the aid of green power programs, this research indicates that Georgia's biomass resources could supply over 13% of the state's electrical demand at economically feasible levels.

Approximately 68% of Georgia's electrical demand is supplied by coal. In order to pay for this demand, over $661 million of coal is imported into Georgia every year. If Georgia increased the share of biomass-based generation to 13% and reduced coal-fired generation by the same amount, coal imports would reduce by $70 million. At the same time, Georgia's biomass industry could create more local jobs and increase tax revenue. In order to supply 13% of Georgia's electrical demand with gasification technology, 1760 jobs would be needed at the plant, raising nearly $53 million in salaries. In addition, farmers would raise nearly $92 million in revenue from the sale of agricultural residues at the conservative price of $10/ton, and Georgia's biomass generators could raise over $737 million in revenue each year, assuming a set rate of $.05/kWh.

Increasing the share of biomass-based generation would sustain localized expenditures and revenue streams, which would be reflected in Georgia's economy for many years. Georgia would also notice a decrease in most forms of emissions from power plant point sources. Altogether, our trash and byproducts of production have great value. Some types of biomass are used for landscaping aesthetics or soil supplements. Other forms are simply discarded, thereby placing some burden on society. As biomass-fueled generation becomes more feasible, Georgians can now realize the potential to use everyday byproducts for a valuable societal service, generating power.

At full potential, bio-power may result in some local benefits, while decreasing the negative externalities associated with the electrical power industry. Though difficult to measure, the full utilization of Georgia's biomass resources would likely induce an increase in efficiency at the State level. It could decrease energy imports, increase localized expenditures, and increase society's benefit per unit of pollution. For these reasons, Georgia's policy makers may consider a renewable portfolio standard which mandates an increase in biomass-based generation.

Further Study

The primary focus of this study was to determine the overall feasibility for agricultural residues as used in the direct-fire, co-fire, gasification, and pyrolysis generation technologies. If this study had considered the cumulative potential for closed-loop sources and other conversion technologies, such as ethanol-based generation, then Georgia's biomass potential would be much more significant.

In addition, the bio-based industry can produce a variety of fuels and other products, which are not used in the electrical power industry. Organically derived plastics are slowly emerging into the marketplace. Bio-diesel fuel can be used directly or mixed with regular diesel fuel for powering the trucking industry. In order to increase the economy-to-scale, bio-refineries may produce bio-power, biofuels, steam for heating, bio-plastics, and other bio-based products simultaneously. Further study may focus on Georgia's bio-industry potential.

Lastly, since gasification and pyrolysis are new and emerging technologies, applicable data was not available for the comparison of emission factors for each technology. It would be useful to determine the emission factors for each technology and each important compound on a weight/kWh basis. These figures could be linked with the feasibility results to determine the most efficient biomass fueled technology.

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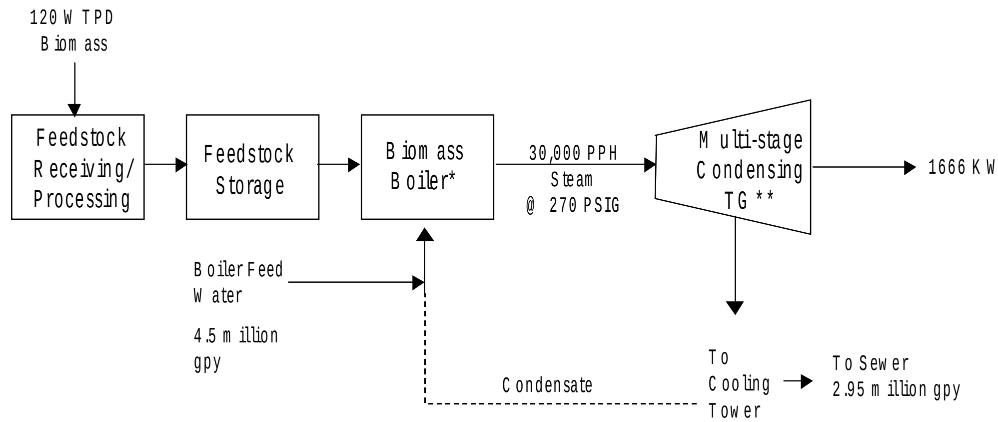
APPENDIX I

Figure A-1: Direct Fire Process Flow Diagram, Case # 1 (120 WTPD)



**TG = Turbine generator

Note: (1) Boiler system design pressure for steam is assumed to be 300 pounds per square inch gauge (psig) with 270 psig turbine inlet pressure in all cases. Higher design pressures would increase capital and maintenance costs but also increase slightly the electric power generated. Note that boiler feed water requirements are to replace that lost to boiler blow down (5%), cooling tower blow down (5%) and evaporation losses in the cooling tower (5%). Sewer water load consists of boiler and cooling tower blow down. Gallons per year = gpy.

Figure A-2: Direct Fire Process Flow Diagram, Case # 2 (200 WTPD)

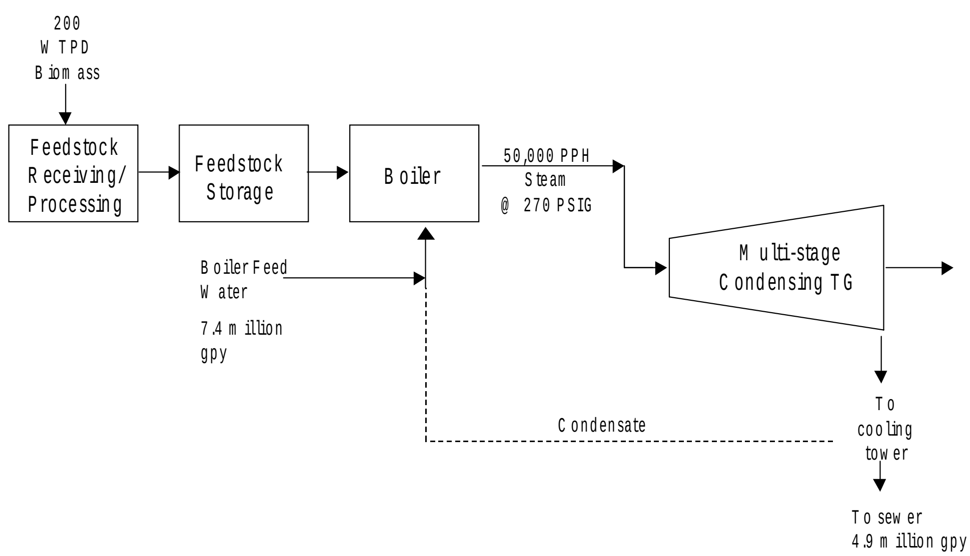


Figure A-3: Direct Fire Process Flow Diagram, Case # 3 (400 WTPD)

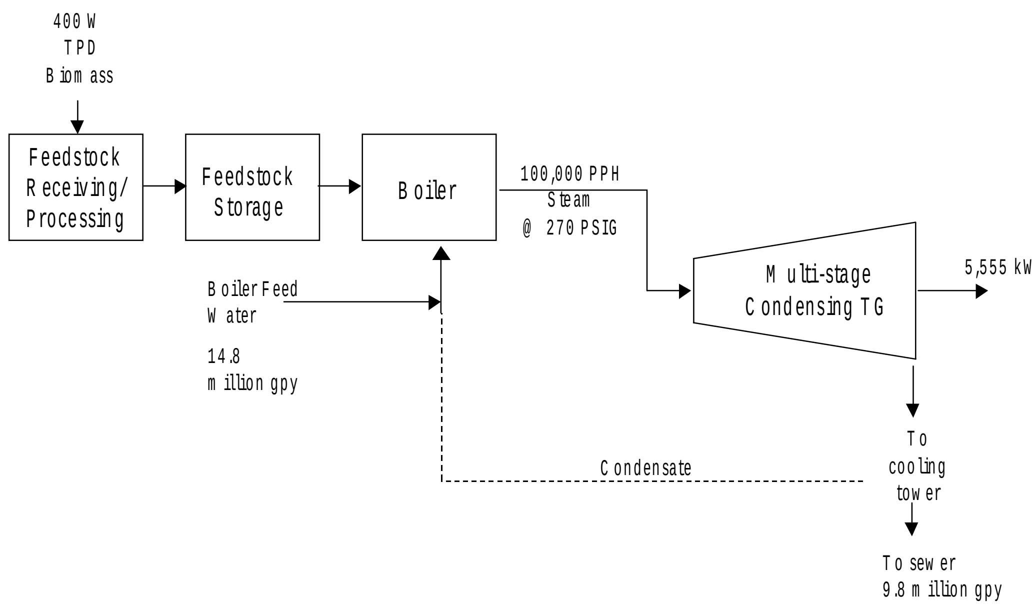


Figure A-4: Co-Fire Process Flow Diagram, Case # 1 (60 WTPD)

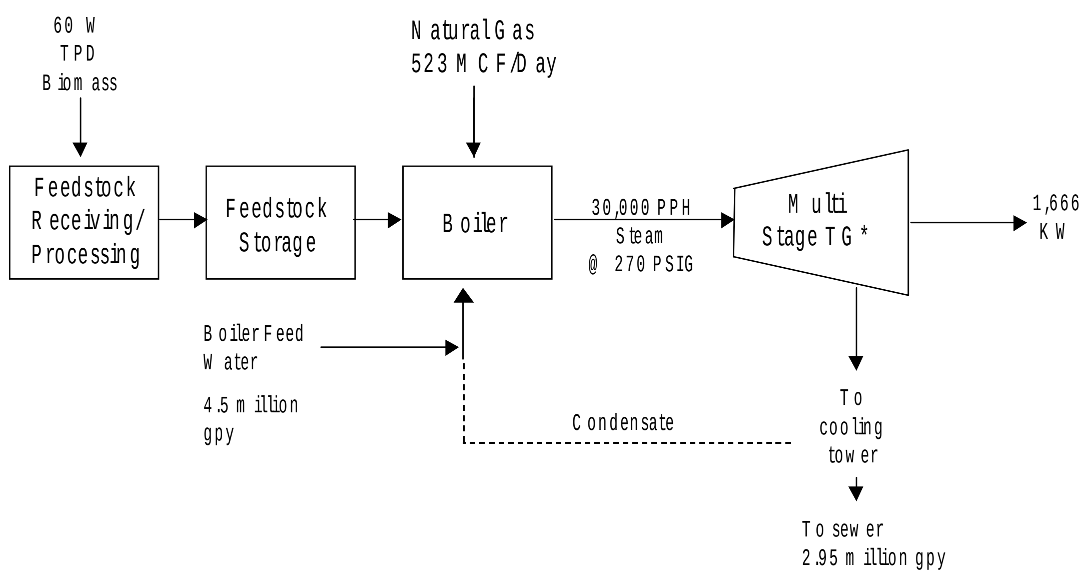


Figure A-5: Co-Fire Process Flow Diagram, Case # 2 (100 WTPD)

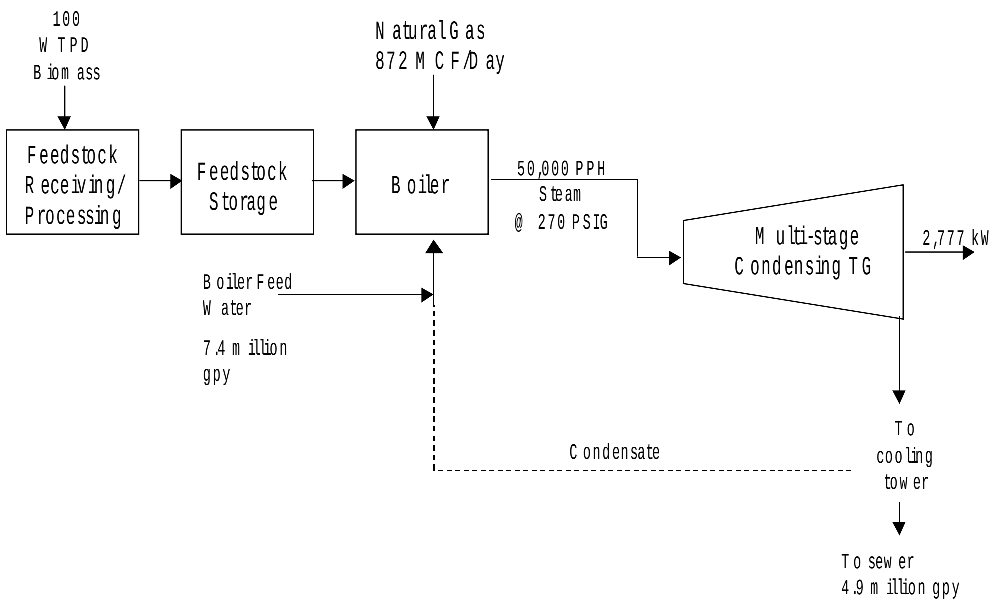


Figure A-6: Co-Fire Process Flow Diagram, Case # 3 (200 WTPD)

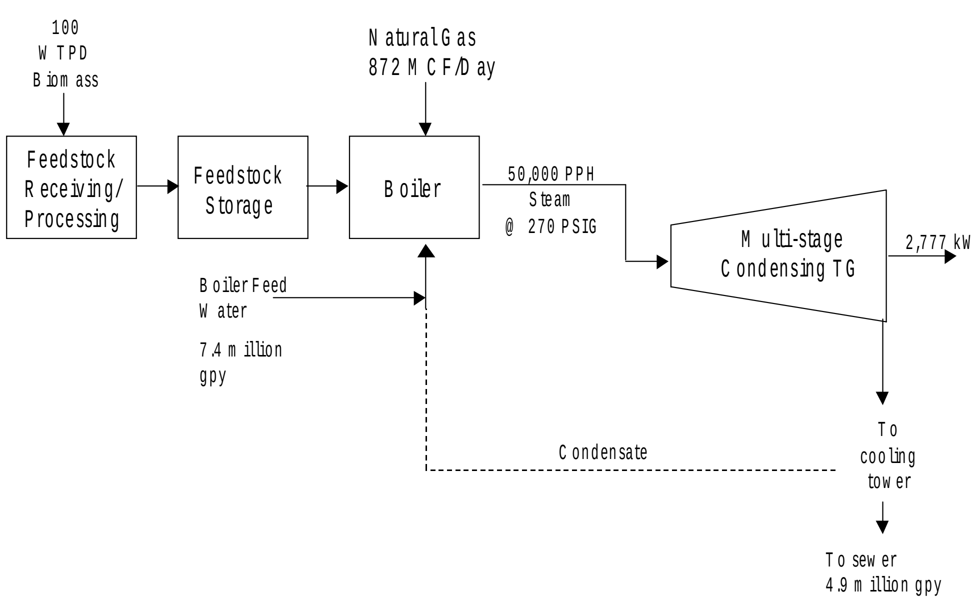
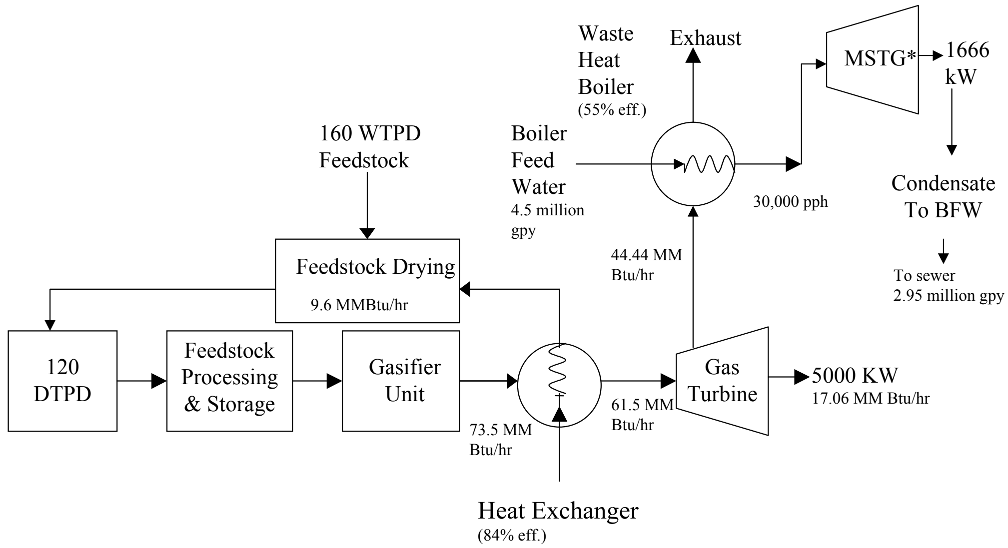


Figure A-7: Gasifier Flow Diagram, Case # 1 (160 WTPD)



* MSTG = Multi-Stage Turbine Generator

Figure A-8: Gasifier Flow Diagram, Case # 2 (267 WTPD)

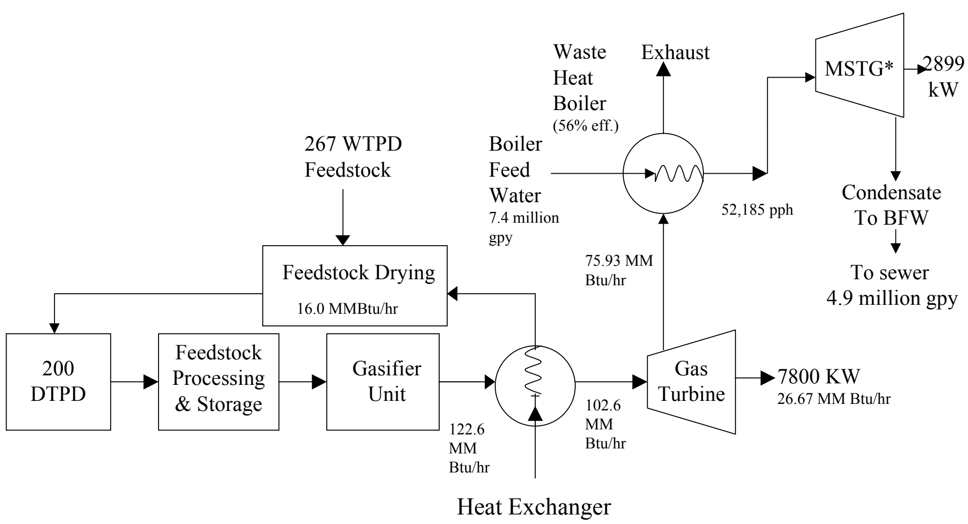


Figure A-9: Gasifier Flow Diagram, Case # 3 (533 WTPD)

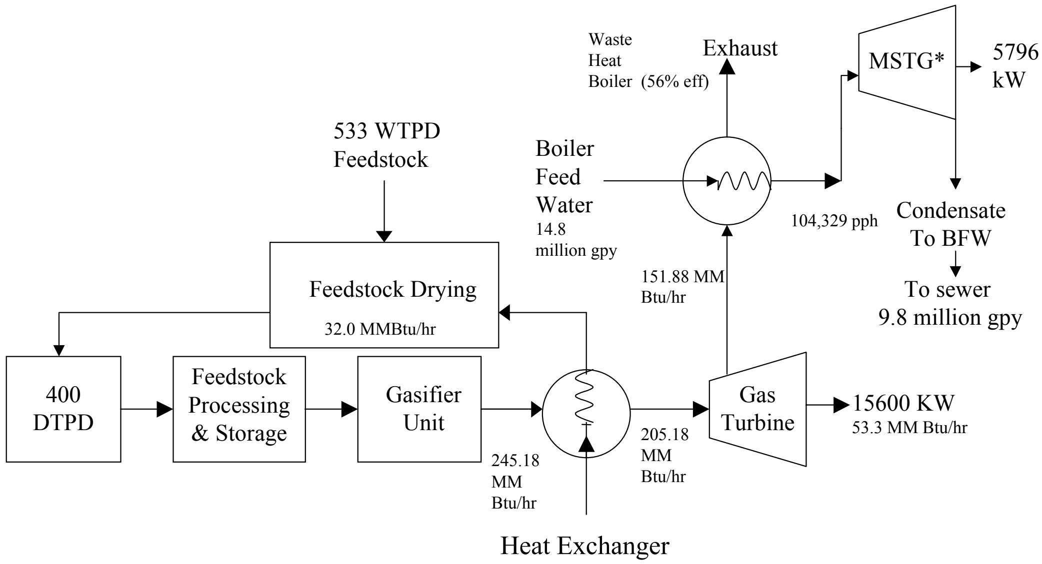
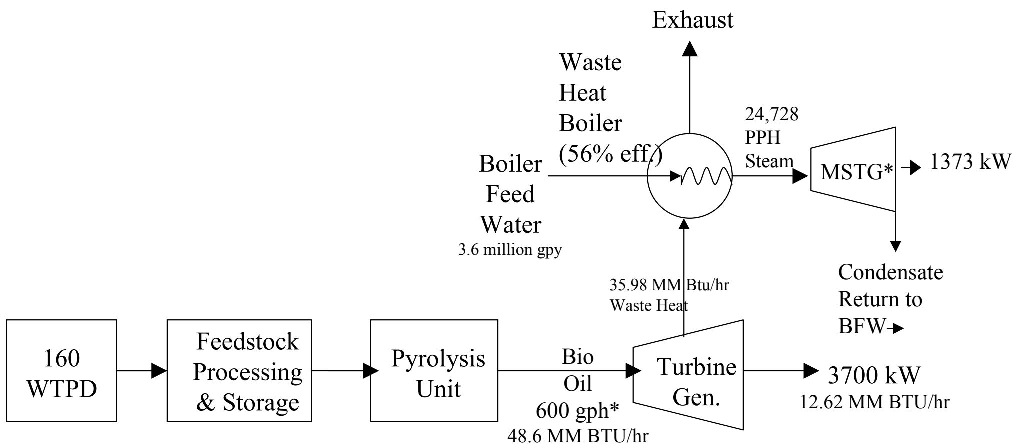


Figure A-10: Pyrolysis Process Flow Diagram, Case # 1 (160 WTPD)



* MSTG = Multi-Stage Turbine Generator
gph = Gallons per Hour

Figure A-11: Pyrolysis Process Flow Diagram, Case # 2 (320 WTPD)

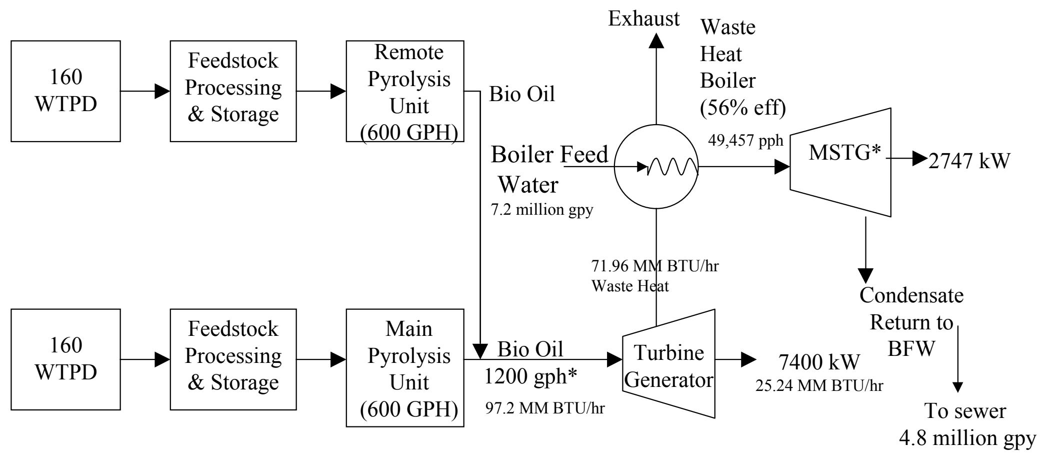
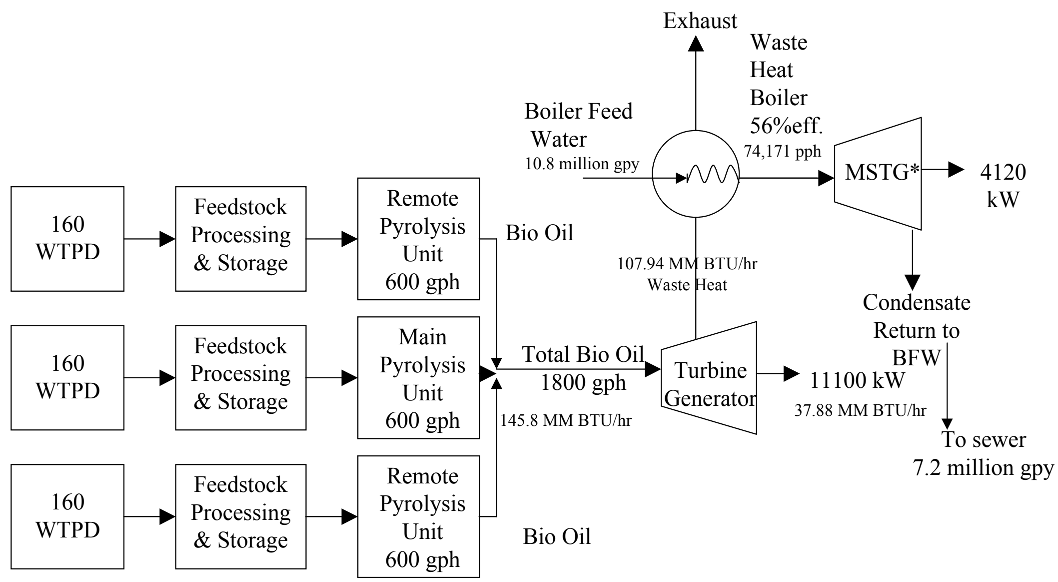


Figure A-12: Pyrolysis Process Flow Diagram, Case # 3 (480 WTPD)



APPENDIX II

Direct Fire Generation - Full Capacity

Case # 1

Days Per Year	365
Hours Per Year	8,760
Days of Maintenance Downtime per Year	20
Hours of Maintenance Downtime per Year	480
Operational Hours per year	8,280
Plant Capacity (kWh)	1,666
Internal Power Used (kWh)	280
Net Generating Capacity (kWh)	1,386
Total Quantity of Electricity Sold (kWh per Year)	12,141,360
Total Quantity of Electricity Produced per Year	11,476,080
Biomass Input (WTPD)	120
Biomass Input (WT per Year)	41,400
Biomass Efficiency (kWh per Wet Ton of Biomass)	277

Operating Cost

				Total $	$ / kWh ($20/Wet ton)
Overhead and Administration		Salary	Benefits		
1	General Manger	$ 85,000	28%	$ 108,800	$ 0.008961
2	Accounting Support	$ 50,000	28%	$ 64,000	$ 0.005271
3	Clerical Support	$ 20,000	28%	$ 25,600	$ 0.002108
	Total	$ 155,000	28%	$ 198,400	$ 0.016341
Variable Cost of Operation		Maintenance Downtime (kW/yr)	Industrial $/kWh		
1	Purchasing Cost for Downtime Electricity per Year	665,280	$ 0.0500	$ 33,264	$ 0.002740
		Wet Tons per Year	Price / ton		
2.1	Fuel Costs per Year (Low at $10/ton)	41,400	$ 10	$ 414,000	NA
2.2	Fuel Costs per Year (Medium at $20/ton)	41,400	$ 20	$ 828,000	$ 0.068197
2.3	Fuel Costs per Year (High at $35/ton)	41,400	$ 35	$ 1,449,000	NA
		Ash (Tons per Yr)	Disposal $/ton		
3	Ash Disposal Cost per Year	3312	$ 20.00	$ 66,240	$ 0.005456
4	Water and Water Treatment			$ 22,000	$ 0.001812
		Employees	Averaage Salary		
5	Labor	8	$ 30,000	$ 240,000	$ 0.019767
		Total Salary per Year	Workers Comp.		
6	Workers' Compensation	$ 240,000	7%	$ 16,800	$ 0.001384
7	Miscellaneous			$ 39,000	$ 0.003212
		Total Capital	Percent of Capital		
8	Yearly Taxes and Insurance Costs	$ 5,196,000	1.50%	$ 77,940	$ 0.006419
9	Yearly Maintenance Costs	$ 5,196,000	2.00%	$ 103,920	$ 0.008559
	Sub-total (Low Fuel Cost $10/ton)			$ 1,013,164	NA
	Sub-total (Medium Fuel Cost $20/ton)			$ 1,427,164	$ 0.117546
	Sub-total (High Fuel Cost $35/ton)			$ 2,048,164	NA
		Rate	2 Months Working Capital	Total $	
10.1	Interest on Working Capital ($10/ton feedstock)	10%	$ 168,860.67	$ 16,886	NA
10.2	Interest on Working Capital ($20/ton feedstock)	10%	$ 237,860.67	$ 23,786	$ 0.001959
10.3	Interest on Working Capital ($35/ton feedstock)	10%	$ 341,360.67	$ 34,136	NA
	Total (Low Fuel Cost $10/ton)			$ 1,030,050	NA
	Total (Medium Fuel Cost $20/ton)			$ 1,450,950	$ 0.119505
	Total (High Fuel Cost $35/ton)			$ 2,082,300	NA
Yearly Expenditures on Capital		Salvage	Lifetime (Years)		
1	Depriciation - Buildings	0	20	$ 59,400	$ 0.004892
2	Depreciation - Equipment	0	10	$ 250,500	$ 0.020632
		Capital	Interest Rate		
3	Interest on Investment - Buildings	$ 1,188,000	5%	$ 29,700	$ 0.002446
4	Interest on Investment - Equipment	$ 2,795,000	5%	$ 69,875	$ 0.005755
	Total			$ 409,475	$ 0.033726
Total Operational Costs per Year				**Total $**	**Marginal Cost ($/kWh)**
	Low Fuel Cost $10/ton			$ 1,637,925	$ 0.134905
	Medium Fuel Cost $20/ton			$ 2,058,825	$ 0.169571
	High Fuel Cost $35/ton			$ 2,690,175	$ 0.221571

Feedstock Receiving and Processing			
1	Feedstock Truck Dump	$	100,000
2	Front End Loader	$	120,000
3	Metal Removal Equipment	$	15,000
4	Grinding/Sizing Equipment	$	165,000
5	Blending Equipment	$	75,000
6	Conveyors	$	125,000
	Total	$	600,000
Operational Equipment			
1	Power Generation Equipment	$	1,640,000
2	Demineralizer System	$	115,000
3	Boiler	$	290,000
4	Instrumentation & Controls	$	150,000
	Total	$	2,195,000
Land and Infrastructure			
1	Land/ Site Preparation	$	100,000
2	Plant Buildings	$	388,000
3	Eng/Permitting	$	247,000
4	Fuel Processing Building	$	700,000
5	Fuel Storage Bins	$	100,000
	Total	$	1,535,000
	Sub-Total	$	4,330,000
	Contingency (20%)	$	866,000
	Total Capital	$	5,196,000

Direct Fire Generation - Full Capacity

Case # 2

	Days Per Year	365			
	Hours Per Year	8,760			
	Days of Maintenance Downtime per Year	20			
	Hours of Maintenance Downtime per Year	480			
	Operational Hours per year	8,280			
	Plant Capacity (kWh)	2,777			
	Internal Power Used (kWh)	468			
	Net Generating Capacity (kWh)	2,309			
	Total Quantity of Electricity Sold (kWh per Year)	20,226,840			
	Total Quantity of Electricity Produced per Year	19,118,520			
	Biomass Input (WTPD)	200			
	Biomass Input (WT per Year)	69,000			
	Biomass Efficiency (kWh per Wet Ton of Biomass)	277			
Operating Cost					
Overhead and Administration		Salary	Benefits	**Total $**	**$ / kWh ($20/Wet ton)**
1	General Manger	$ 100,000	28%	$ 128,000	$ 0.006328
2	Accounting Support	$ 70,000	28%	$ 89,600	$ 0.004430
3	Clerical Support	$ 44,000	28%	$ 56,320	$ 0.002784
	Total	$ 214,000	28%	$ 273,920	$ 0.013542
Variable Cost of Operation		Maintenance Downtime (kW/yr)	Industrial $/kWh		
1	Purchasing Cost for Downtime Electricity per Year	1,108,320	$ 0.0500	$ 55,416	$ 0.002740
		Wet Tons per Year	Price / ton		
2.1	Fuel Costs per Year (Low at $10/ton)	69,000	$ 10	$ 690,000	NA
2.2	Fuel Costs per Year (Medium at $20/ton)	69,000	$ 20	$ 1,380,000	$ 0.068226
2.3	Fuel Costs per Year (High at $35/ton)	69,000	$ 35	$ 2,415,000	NA
		Ash (Tons per Yr)	Disposal $/ton		
3	Ash Disposal Cost per Year	5520	$ 20.00	$ 110,400	$ 0.005458
4	Water and Water Treatment			$ 57,000	$ 0.002818
		Employees	Averaage Salary		
5	Labor	8	$ 30,000	$ 240,000	$ 0.011865
		Total Salary per Year	Workers Comp.		
6	Workers' Compensation	$ 240,000	7%	$ 16,800	$ 0.000831
7	Miscellaneous			$ 39,000	$ 0.001928
		Total Capital	Percent of Capital		
8	Yearly Taxes and Insurance Costs	$ 7,188,000	1.50%	$ 107,820	$ 0.005331
9	Yearly Maintenance Costs	$ 7,188,000	2.00%	$ 143,760	$ 0.007107
	Sub-total (Low Fuel Cost $10/ton)			$ 1,460,196	NA
	Sub-total (Medium Fuel Cost $20/ton)			$ 2,150,196	$ 0.106304
	Sub-total (High Fuel Cost $35/ton)			$ 3,185,196	NA
		Rate	2 Months Working Capital	Total $	
10.1	Interest on Working Capital ($10/ton feedstock)	10%	$ 243,366.00	$ 24,337	NA
10.2	Interest on Working Capital ($20/ton feedstock)	10%	$ 358,366.00	$ 35,837	$ 0.001772
10.3	Interest on Working Capital ($35/ton feedstock)	10%	$ 530,866.00	$ 53,087	NA
	Total (Low Fuel Cost $10/ton)			$ 1,484,533	NA
	Total (Medium Fuel Cost $20/ton)			$ 2,186,033	$ 0.108076
	Total (High Fuel Cost $35/ton)			$ 3,238,283	NA
Yearly Expenditures on Capital					
		Salvage	Lifetime (Years)		
1	Depriciation - Buildings	0	20	$ 93,350	$ 0.004615
2	Depreciation - Equipment	0	10	$ 316,000	$ 0.015623
		Capital	Interest Rate		
3	Interest on Investment - Buildings	$ 1,867,000	5%	$ 46,675	$ 0.002308
4	Interest on Investment - Equipment	$ 3,548,000	5%	$ 88,700	$ 0.004385
	Total			$ 544,725	$ 0.026931
Total Operational Costs per Year				**Total $**	**Marginal Cost ($/kWh)**
	Low Fuel Cost $10/ton			$ 2,303,178	$ 0.113867
	Medium Fuel Cost $20/ton			$ 3,004,678	$ 0.148549
	High Fuel Cost $35/ton			$ 4,056,928	$ 0.200571

Feedstock Receiving and Processing			
1	Feedstock Truck Dump	$	100,000
2	Front End Loader	$	120,000
3	Metal Removal Equipment	$	15,000
4	Grinding/Sizing Equipment	$	185,000
5	Blending Equipment	$	100,000
6	**Conveyors**	$	125,000
	Total	$	645,000
Operational Equipment			
1	Power Generation Equipment	$	2,120,000
2	Demineralizer System	$	170,000
3	Boiler	$	388,000
4	Instrumentation & Controls	$	225,000
	Total	$	2,903,000
Land and Infrastructure			
1	Land/ Site Preparation	$	150,000
2	Plant Buildings	$	512,000
3	Eng/Permitting	$	425,000
4	Fuel Processing Building	$	1,155,000
5	Fuel Storage Bins	$	200,000
	Total	$	2,442,000
	Sub-Total	$	5,990,000
	Contingency (20%)	$	1,198,000
	Total Capital	$	7,188,000

Direct Fire Generation - Full Capacity					
Case # 3					
Days Per Year	365				
Hours Per Year	8,760				
Days of Maintenance Downtime per Year	20				
Hours of Maintenance Downtime per Year	480				
Operational Hours per year	8,280				
Plant Capacity (kWh)	5,555				
Internal Power Used (kWh)	932				
Net Generating Capacity (kWh)	4,623				
Total Quantity of Electricity Sold (kWh per Year)	40,497,480				
Total Quantity of Electricity Produced per Year	38,278,440				
Biomass Input (WTPD)	400				
Biomass Input (WT per Year)	138,000				
Biomass Efficiency (kWh per Wet Ton of Biomass)	277				
Operating Cost					
Overhead and Administration	Salary	Benefits		**Total $**	**$ / kWh ($20/Wet ton)**
1 General Manger	$ 110,000	28%		$ 140,800	$ 0.003477
2 Accounting Support	$ 90,000	28%		$ 115,200	$ 0.002845
3 Clerical Support	$ 75,000	28%		$ 96,000	$ 0.002371
Total	$ 275,000	28%		$ 352,000	$ 0.008692
Variable Cost of Operation	Maintenance Downtime (kW/yr)	Industrial $/kWh			
1 Purchasing Cost for Downtime Electricity per Year	2,219,040	$ 0.0500		$ 110,952	$ 0.002740
	Wet Tons per Year	Price / ton			
2.1 Fuel Costs per Year (Low at $10/ton)	138,000	$ 10		$ 1,380,000	NA
2.2 Fuel Costs per Year (Medium at $20/ton)	138,000	$ 20		$ 2,760,000	$ 0.068152
2.3 Fuel Costs per Year (High at $35/ton)	138,000	$ 35		$ 4,830,000	NA
	Ash (Tons per Yr)	Disposal $/ton			
3 Ash Disposal Cost per Year	11040	$ 20.00		$ 220,800	$ 0.005452
4 Water and Water Treatment				$ 159,000	$ 0.003926
	Employees	Averaage Salary			
5 Labor	8	$ 30,000		$ 240,000	$ 0.005926
	Total Salary per Year	Workers Comp.			
6 Workers' Compensation	$ 240,000	7%		$ 16,800	$ 0.000415
7 Miscellaneous				$ 39,000	$ 0.000963
	Total Capital	Percent of Capital			
8 Yearly Taxes and Insurance Costs	$ 11,574,000	1.50%		$ 173,610	$ 0.004287
9 Yearly Maintenance Costs	$ 11,574,000	2.00%		$ 231,480	$ 0.005716
Sub-total (Low Fuel Cost $10/ton)				$ 2,571,642	NA
Sub-total (Medium Fuel Cost $20/ton)				$ 3,951,642	$ 0.097577
Sub-total (High Fuel Cost $35/ton)				$ 6,021,642	NA
	Rate	2 Months Working Capital		Total $	
10.1 Interest on Working Capital ($10/ton feedstock)	10%	$ 428,607.00		$ 42,861	NA
10.2 Interest on Working Capital ($20/ton feedstock)	10%	$ 658,607.00		$ 65,861	$ 0.001626
10.3 Interest on Working Capital ($35/ton feedstock)	10%	$ 1,003,607.00		$ 100,361	NA
Total (Low Fuel Cost $10/ton)				$ 2,614,503	NA
Total (Medium Fuel Cost $20/ton)				$ 4,017,503	$ 0.099204
Total (High Fuel Cost $35/ton)				$ 6,122,003	NA
Yearly Expenditures on Capital					
	Salvage	Lifetime (Years)			
1 Depriciation - Buildings	0	20		$ 149,500	$ 0.003692
2 Depreciation - Equipment	0	10		$ 497,000	$ 0.012272
	Capital	Interest Rate			
3 Interest on Investment - Buildings	$ 2,990,000	5%		$ 74,750	$ 0.001846
4 Interest on Investment - Equipment	$ 5,870,000	5%		$ 146,750	$ 0.003624
Total				$ 868,000	$ 0.021433
Total Operational Costs per Year				**Total $**	**Marginal Cost ($/kWh)**
Low Fuel Cost $10/ton				$ 3,834,503	$ 0.094685
Medium Fuel Cost $20/ton				$ 5,237,503	$ 0.129329
High Fuel Cost $35/ton				$ 7,342,003	$ 0.181295

Feedstock Receiving and Processing			
1	Feedstock Truck Dump	$	100,000
2	Front End Loader	$	120,000
3	Metal Removal Equipment	$	15,000
4	Grinding/Sizing Equipment	$	225,000
5	Blending Equipment	$	125,000
6	**Conveyors**	$	125,000
	Total	$	710,000
Operational Equipment			
1	Power Generation Equipment	$	3,700,000
2	Demineralizer System	$	260,000
3	Boiler	$	900,000
4	Instrumentation & Controls	$	300,000
	Total	$	5,160,000
Land and Infrastructure			
1	Land/ Site Preparation	$	200,000
2	Plant Buildings	$	600,000
3	Eng/Permitting	$	585,000
4	Fuel Processing Building	$	1,990,000
5	Fuel Storage Bins	$	400,000
	Total	$	3,775,000
	Sub-Total	$	9,645,000
	Contingency (20%)	$	1,929,000
	Total Capital	$	11,574,000

Co-Fire Generation - Full Capacity

Case # 1

	Days Per Year	365			
	Hours Per Year	8,760			
	Days of Maintenance Downtime per Year	20			
	Hours of Maintenance Downtime per Year	480			
	Operational Hours per year	8,280			
	Plant Capacity (kWh)	1,666			
	Internal Power Used (kWh)	140			
	Net Generating Capacity (kWh)	1,526			
	Total Quantity of Electricity Sold (kWh per Year)	13,367,760			
	Total Quantity of Electricity Produced per Year	12,635,280			
	Biomass Input (WTPD)	60			
	Biomass Input (WT per Year)	20,700			
	Biomass Efficiency (kWh per Wet Ton of Biomass)	610			
Operating Cost					
Overhead and Administration		Salary	Benefits	**Total $**	**$ / kWh ($20/Wet ton)**
1	General Manger	$ 85,000	28%	$ 108,800	$ 0.008139
2	Accounting Support	$ 50,000	28%	$ 64,000	$ 0.004788
3	Clerical Support	$ 20,000	28%	$ 25,600	$ 0.001915
	Total	$ 155,000	28%	$ 198,400	$ 0.014842
Variable Cost of Operation		Maintenance Downtime (kW/yr)	Industrial $/kWh		
1	Purchasing Cost for Downtime Electricity per Year	732,480	$ 0.0500	$ 36,624	$ 0.002740
		Wet Tons per Year	Price / ton		
2.1	Biomass Costs per Year (Low at $10/ton)	20,700	$ 10	$ 207,000	NA
2.2	Biomass Costs per Year (Medium at $20/ton)	20,700	$ 20	$ 414,000	$ 0.030970
2.3	Biomass Costs per Year (High at $35/ton)	20,700	$ 35	$ 724,500	NA
		Quantity (MCF/day)	Gas Costs ($/MCF)		
3	Naturla Gas Costs per Year	523	$ 1.38	$ 249,000	$ 0.018627
		Ash (Tons per Yr)	Disposal $/ton		
4	Ash Disposal Cost per Year	1656	$ 20.00	$ 33,120	$ 0.002478
5	Water and Water Treatment			$ 22,000	$ 0.001646
		Employees	Averaage Salary		
6	Labor	8	$ 30,000	$ 240,000	$ 0.017954
		Total Salary	Workers Comp.		
7	Workers' Compensation	$ 240,000	7%	$ 16,800	$ 0.001257
8	Miscellaneous			$ 39,000	$ 0.002917
		Total Capital	Percent of Capital		
9	Yearly Taxes and Insurance Costs	$ 4,587,000	1.50%	$ 68,805	$ 0.005147
10	Yearly Maintenance Costs	$ 4,587,000	2.00%	$ 91,740	$ 0.006863
	Sub-total (Low Fuel Cost $10/ton)			$ 1,004,089	NA
	Sub-total (Medium Fuel Cost $20/ton)			$ 1,211,089	$ 0.090598
	Sub-total (High Fuel Cost $35/ton)			$ 1,521,589	NA
		Rate	2 Months Working Capital	Total $	
11.1	Interest on Working Capital ($10/ton feedstock)	10%	$ 167,348.22	$ 16,735	NA
11.2	Interest on Working Capital ($20/ton feedstock)	10%	$ 201,848.22	$ 20,185	$ 0.001510
11.3	Interest on Working Capital ($35/ton feedstock)	10%	$ 253,598.22	$ 25,360	NA
	Total (Low Fuel Cost $10/ton)			$ 1,020,824	NA
	Total (Medium Fuel Cost $20/ton)			$ 1,231,274	$ 0.092108
	Total (High Fuel Cost $35/ton)			$ 1,546,949	NA
Yearly Expenditures on Capital					
		Salvage	Lifetime (Years)		
1	Depriciation - Buildings	0	20	$ 37,050	$ 0.002772
2	Depreciation - Equipment	0	10	$ 247,000	$ 0.018477
		Capital	Interest Rate		
3	Interest on Investment - Buildings	$ 741,000	5%	$ 18,525	$ 0.001386
4	Interest on Investment - Equipment	$ 2,734,500	5%	$ 68,363	$ 0.005114
	Total			$ 370,938	$ 0.027749
Total Operational Costs per Year				**Total $**	**Marginal Cost ($/kWh)**
	Low Fuel Cost $10/ton			$ 1,590,162	$ 0.118955
	Medium Fuel Cost $20/ton			$ 1,800,612	$ 0.134698
	High Fuel Cost $35/ton			$ 2,116,287	$ 0.158313

Feedstock Receiving and Processing			
1	Feedstock Truck Dump	$	100,000
2	Front End Loader	$	120,000
3	Metal Removal Equipment	$	15,000
4	Grinding/Sizing Equipment	$	145,000
5	Blending Equipment	$	60,000
6	Conveyors	$	125,000
	Total	$	565,000
Operational Equipment			
1	Power Generation Equipment	$	1,640,000
2	Demineralizer System	$	115,000
3	Boiler	$	264,500
4	Instrumentation & Controls	$	150,000
	Total	$	2,169,500
Land and Infrastructure			
1	Land/ Site Preparation	$	100,000
2	Plant Buildings	$	331,000
3	Eng/Permitting	$	247,000
4	Fuel Processing Building	$	350,000
5	Fuel Storage Bins	$	60,000
	Total	$	1,088,000
	Sub-Total	$	3,822,500
	Contingency (20%)	$	764,500
	Total Capital	$	4,587,000

Co-Fire Generation - Full Capacity

Case # 2

	Days Per Year	365			
	Hours Per Year	8,760			
	Days of Maintenance Downtime per Year	20			
	Hours of Maintenance Downtime per Year	480			
	Operational Hours per year	8,280			
	Plant Capacity (kWh)	2,777			
	Internal Power Used (kWh)	234			
	Net Generating Capacity (kWh)	2,543			
	Total Quantity of Electricity Sold (kWh per Year)	22,276,680			
	Total Quantity of Electricity Produced per Year	21,056,040			
	Biomass Input (WTPD)	100			
	Biomass Input (WT per Year)	34,500			
	Biomass Efficiency (kWh per Wet Ton of Biomass)	610			
Operating Cost					
Overhead and Administration		Salary	Benefits	**Total $**	**$ / kWh ($20/Wet ton)**
1	General Manger	$ 100,000	28%	$ 128,000	$ 0.005746
2	Accounting Support	$ 70,000	28%	$ 89,600	$ 0.004022
3	Clerical Support	$ 44,000	28%	$ 56,320	$ 0.002528
	Total	$ 214,000	28%	$ 273,920	$ 0.012296
Variable Cost of Operation					
		Maintenance Downtime (kW/yr)	Industrial $/kWh		
1	Purchasing Cost for Downtime Electricity per Year	1,220,640	$ 0.0500	$ 61,032	$ 0.002740
		Wet Tons per Year	Price / ton		
2.1	Fuel Costs per Year (Low at $10/ton)	34,500	$ 10	$ 345,000	NA
2.2	Fuel Costs per Year (Medium at $20/ton)	34,500	$ 20	$ 690,000	$ 0.030974
2.3	Fuel Costs per Year (High at $35/ton)	34,500	$ 35	$ 1,207,500	NA
		Quantity (MCF/day)	Gas Costs ($/MCF)		
3	Naturla Gas Costs per Year	872	$ 1.38	$ 415,159	$ 0.018636
		Ash (Tons per Yr)	Disposal $/ton		
4	Ash Disposal Cost per Year	2760	$ 20.00	$ 55,200	$ 0.002478
5	Water and Water Treatment			$ 57,000	$ 0.002559
		Employees	Averaage Salary		
6	Labor	8	$ 30,000	$ 240,000	$ 0.010774
		Total Salary	Workers Comp.		
7	Workers' Compensation	$ 240,000	7%	$ 16,800	$ 0.000754
8	Miscellaneous			$ 39,000	$ 0.001751
		Total Capital	Percent of Capital		
9	Yearly Taxes and Insurance Costs	$ 6,153,600	1.50%	$ 92,304	$ 0.004144
10	Yearly Maintenance Costs	$ 6,153,600	2.00%	$ 123,072	$ 0.005525
	Sub-total (Low Fuel Cost $10/ton)			$ 1,444,567	NA
	Sub-total (Medium Fuel Cost $20/ton)			$ 1,789,567	$ 0.080334
	Sub-total (High Fuel Cost $35/ton)			$ 2,307,067	NA
		Rate	2 Months Working Capital	Total $	
11.1	Interest on Working Capital ($10/ton feedstock)	10%	$ 240,761.20	$ 24,076	NA
11.2	Interest on Working Capital ($20/ton feedstock)	10%	$ 298,261.20	$ 29,826	$ 0.001339
11.3	Interest on Working Capital ($35/ton feedstock)	10%	$ 384,511.20	$ 38,451	NA
	Total (Low Fuel Cost $10/ton)			$ 1,468,643	NA
	Total (Medium Fuel Cost $20/ton)			$ 1,819,393	$ 0.081673
	Total (High Fuel Cost $35/ton)			$ 2,345,518	NA
Yearly Expenditures on Capital					
		Salvage	Lifetime (Years)		
1	Depriciation - Buildings	0	20	$ 54,175	$ 0.002432
2	Depreciation - Equipment	0	10	$ 310,500	$ 0.013938
		Capital	Interest Rate		
3	Interest on Investment - Buildings	$ 1,083,500	5%	$ 27,088	$ 0.001216
4	Interest on Investment - Equipment	$ 3,469,500	5%	$ 86,738	$ 0.003894
	Total			$ 478,500	$ 0.021480
Total Operational Costs per Year				**Total $**	**Marginal Cost ($/kWh)**
	Low Fuel Cost $10/ton			$ 2,221,063	$ 0.099704
	Medium Fuel Cost $20/ton			$ 2,571,813	$ 0.115449
	High Fuel Cost $35/ton			$ 3,097,938	$ 0.139066

Feedstock Receiving and Processing		
1	Feedstock Truck Dump	$ 100,000
2	Front End Loader	$ 120,000
3	Metal Removal Equipment	$ 15,000
4	Grinding/Sizing Equipment	$ 160,000
5	Blending Equipment	$ 70,000
6	Conveyors	$ 125,000
	Total	$ 590,000
Operational Equipment		
1	Power Generation Equipment	$ 2,120,000
2	Demineralizer System	$ 170,000
3	Boiler	$ 364,500
4	Instrumentation & Controls	$ 225,000
	Total	$ 2,879,500
Land and Infrastructure		
1	Land/ Site Preparation	$ 150,000
2	Plant Buildings	$ 406,000
3	Eng/Permitting	$ 425,000
4	Fuel Processing Building	$ 577,500
5	Fuel Storage Bins	$ 100,000
	Total	$ 1,658,500
	Sub-Total	$ 5,128,000
	Contingency (20%)	$ 1,025,600
	Total Capital	$ 6,153,600

Co-Fire Generation - Full Capacity

Case # 3

Days Per Year	365			
Hours Per Year	8,760			
Days of Maintenance Downtime per Year	20			
Hours of Maintenance Downtime per Year	480			
Operational Hours per year	8,280			
Plant Capacity (kWh)	5,555			
Internal Power Used (kWh)	460			
Net Generating Capacity (kWh)	5,095			
Total Quantity of Electricity Sold (kWh per Year)	44,632,200			
Total Quantity of Electricity Produced per Year	42,186,600			
Biomass Input (WTPD)	200			
Biomass Input (WT per Year)	69,000			
Biomass Efficiency (kWh per Wet Ton of Biomass)	611			
Operating Cost				
Overhead and Administration	Salary	Benefits	**Total $**	**$ / kWh ($20/Wet ton)**
1 General Manger	$ 110,000	28%	$ 140,800	$ 0.003155
2 Accounting Support	$ 90,000	28%	$ 115,200	$ 0.002581
3 Clerical Support	$ 75,000	28%	$ 96,000	$ 0.002151
Total	$ 275,000	28%	$ 352,000	$ 0.007887
Variable Cost of Operation				
	Maintenance Downtime (kW/yr)	Industrial $/kWh		
1 Purchasing Cost for Downtime Electricity per Year	2,445,600	$ 0.0500	$ 122,280	$ 0.002740
	Wet Tons per Year	Price / ton		
2.1 Fuel Costs per Year (Low at $10/ton)	69,000	$ 10	$ 690,000	NA
2.2 Fuel Costs per Year (Medium at $20/ton)	69,000	$ 20	$ 1,380,000	$ 0.030919
2.3 Fuel Costs per Year (High at $35/ton)	69,000	$ 35	$ 2,415,000	NA
	Quantity (MCF/day)	Gas Costs ($/MCF)		
3 Naturla Gas Costs per Year	1744	$ 1.38	$ 830,318	$ 0.018604
	Ash (Tons per Yr)	Disposal $/ton		
4 Ash Disposal Cost per Year	5520	$ 20.00	$ 110,400	$ 0.002474
5 Water and Water Treatment			$ 159,000	$ 0.003562
	Employees	Averaage Salary		
6 Labor	8	$ 30,000	$ 240,000	$ 0.005377
	Total Salary	Workers Comp.		
7 Workers' Compensation	$ 240,000	7%	$ 16,800	$ 0.000376
8 Miscellaneous			$ 39,000	$ 0.000874
	Total Capital	Percent of Capital		
9 Yearly Taxes and Insurance Costs	$ 9,751,200	1.50%	$ 146,268	$ 0.003277
10 Yearly Maintenance Costs	$ 9,751,200	2.00%	$ 195,024	$ 0.004370
Sub-total (Low Fuel Cost $10/ton)			$ 2,549,090	NA
Sub-total (Medium Fuel Cost $20/ton)			$ 3,239,090	$ 0.072573
Sub-total (High Fuel Cost $35/ton)			$ 4,274,090	NA
	Rate	2 Months Working Capital	Total $	
11.1 Interest on Working Capital ($10/ton feedstock)	10%	$ 424,848.40	$ 42,485	NA
11.2 Interest on Working Capital ($20/ton feedstock)	10%	$ 539,848.40	$ 53,985	$ 0.001210
11.3 Interest on Working Capital ($35/ton feedstock)	10%	$ 712,348.40	$ 71,235	NA
Total (Low Fuel Cost $10/ton)			$ 2,591,575	NA
Total (Medium Fuel Cost $20/ton)			$ 3,293,075	$ 0.073782
Total (High Fuel Cost $35/ton)			$ 4,345,325	NA
Yearly Expenditures on Capital				
	Salvage	Lifetime (Years)		
1 Depriciation - Buildings	0	20	$ 83,150	$ 0.001863
2 Depreciation - Equipment	0	10	$ 493,500	$ 0.011057
	Capital	Interest Rate		
3 Interest on Investment - Buildings	$ 1,663,000	5%	$ 41,575	$ 0.000932
4 Interest on Investment - Equipment	$ 5,678,000	5%	$ 141,950	$ 0.003180
Total			$ 760,175	$ 0.017032
Total Operational Costs per Year			**Total $**	**Marginal Cost ($/kWh)**
Low Fuel Cost $10/ton			$ 3,703,750	$ 0.082984
Medium Fuel Cost $20/ton			$ 4,405,250	$ 0.098701
High Fuel Cost $35/ton			$ 5,457,500	$ 0.122277

Feedstock Receiving and Processing			
1	Feedstock Truck Dump	$	100,000
2	Front End Loader	$	120,000
3	Metal Removal Equipment	$	15,000
4	Grinding/Sizing Equipment	$	185,000
5	Blending Equipment	$	100,000
6	**Conveyors**	$	125,000
	Total	$	645,000
Operational Equipment			
1	Power Generation Equipment	$	3,730,000
2	Demineralizer System	$	260,000
3	Boiler	$	743,000
4	Instrumentation & Controls	$	300,000
	Total	$	5,033,000
Land and Infrastructure			
1	Land/ Site Preparation	$	200,000
2	Plant Buildings	$	468,000
3	Eng/Permitting	$	585,000
4	Fuel Processing Building	$	995,000
5	Fuel Storage Bins	$	200,000
	Total	$	2,448,000
	Sub-Total	$	8,126,000
	Contingency (20%)	$	1,625,200
	Total Capital	$	9,751,200

Gasification Generation - Full Capacity					
	Case # 1				
	Days Per Year	365			
	Hours Per Year	8,760			
	Days of Maintenance Downtime per Year	20			
	Hours of Maintenance Downtime per Year	480			
	Operational Hours per year	8,280			
	Plant Capacity (kWh)	6,666			
	Internal Power Used (kWh)	372			
	Net Generating Capacity (kWh)	6,294			
	Total Quantity of Electricity Sold (kWh per Year)	55,135,440			
	Total Quantity of Electricity Produced per Year	52,114,320			
	Biomass Input (WTPD)	160			
	Biomass Input (WT per Year)	55,200			
	Biomass Efficiency (kWh per Wet Ton of Biomass)	944			
Operating Cost					
Overhead and Administration		Salary	Benefits	**Total $**	**$ / kWh ($20/Wet ton)**
1	General Manger	$ 85,000	28%	$ 108,800	$ 0.001973
2	Accounting Support	$ 50,000	28%	$ 64,000	$ 0.001161
3	Clerical Support	$ 20,000	28%	$ 25,600	$ 0.000464
	Total	$ 155,000	28%	$ 198,400	$ 0.003598
Variable Cost of Operation		Maintenance Downtime (kW/yr)	Industrial $/kWh		
1	Purchasing Cost for Downtime Electricity per Year	3,021,120	$ 0.0500	$ 151,056	$ 0.002740
		Wet Tons per Year	Price / ton		
2.1	Fuel Costs per Year (Low at $10/ton)	55,200	$ 10	$ 552,000	NA
2.2	Fuel Costs per Year (Medium at $20/ton)	55,200	$ 20	$ 1,104,000	$ 0.020023
2.3	Fuel Costs per Year (High at $35/ton)	55,200	$ 35	$ 1,932,000	NA
		Ash (Tons per Yr)	Disposal $/ton		
3	Ash Disposal Cost per Year	650	$ 20.00	$ 13,000	$ 0.000236
4	Water and Water Treatment			$ 22,000	$ 0.000399
		Employees	Averaage Salary		
5	Labor	18	$ 30,000	$ 540,000	$ 0.009794
		Total Salary per Year	Workers Comp.		
6	Workers' Compensation	$ 540,000	7%	$ 37,800	$ 0.000686
7	Miscellaneous			$ 39,000	$ 0.000707
8	Inert Gas			$ 10,000	$ 0.000181
		Total Capital	Percent of Capital		
9	Yearly Taxes and Insurance Costs	$ 19,122,000	1.50%	$ 286,830	$ 0.005202
10	Yearly Maintenance Costs	$ 19,122,000	2.00%	$ 382,440	$ 0.006936
	Sub-total (Low Fuel Cost $10/ton)			$ 2,034,126	NA
	Sub-total (Medium Fuel Cost $20/ton)			$ 2,586,126	$ 0.046905
	Sub-total (High Fuel Cost $35/ton)			$ 3,414,126	NA
		Rate	2 Months Working Capital	Total $	
11.1	Interest on Working Capital ($10/ton feedstock)	10%	$ 339,021.00	$ 33,902	NA
11.2	Interest on Working Capital ($20/ton feedstock)	10%	$ 431,021.00	$ 43,102	$ 0.000782
11.3	Interest on Working Capital ($35/ton feedstock)	10%	$ 569,021.00	$ 56,902	NA
	Total (Low Fuel Cost $10/ton)			$ 2,068,028	NA
	Total (Medium Fuel Cost $20/ton)			$ 2,629,228	$ 0.047687
	Total (High Fuel Cost $35/ton)			$ 3,471,028	NA
Yearly Expenditures on Capital					
		Salvage	Lifetime (Years)		
1	Depriciation - Buildings	0	20	$ 65,500	$ 0.001188
2	Depreciation - Equipment	0	10	$ 1,286,800	$ 0.023339
		Capital	Interest Rate		
3	Interest on Investment - Buildings	$ 1,310,000	5%	$ 32,750	$ 0.000594
4	Interest on Investment - Equipment	$ 14,268,000	5%	$ 356,700	$ 0.006470
	Total			$ 1,741,750	$ 0.031590
Total Operational Costs per Year				**Total $**	**Marginal Cost ($/kWh)**
	Low Fuel Cost $10/ton			$ 4,008,178	$ 0.072697
	Medium Fuel Cost $20/ton			$ 4,569,378	$ 0.082876
	High Fuel Cost $35/ton			$ 5,411,178	$ 0.098143

Feedstock Receiving and Processing			
1	Feedstock Truck Dump	$	100,000
2	Front End Loader	$	120,000
3	Metal Removal Equipment	$	15,000
4	Grinding/Sizing Equipment	$	165,000
5	Blending Equipment	$	75,000
6	Conveyors	$	125,000
	Total	$	600,000
Operational Equipment			
1	Power Generation Equipment	$	5,243,000
2	Gasification Process	$	4,900,000
3	Interconnections	$	900,000
4	Waste Heat Boiler	$	2,125,000
5	Heat Recovery	$	500,000
	Total	$	13,668,000
Land and Infrastructure			
1	Land/ Site Preparation	$	110,000
2	Plant Buildings	$	510,000
3	Eng/Permitting	$	247,000
4	Fuel Processing Building	$	700,000
5	Fuel Storage Bins	$	100,000
	Total	$	1,667,000
	Sub-Total	$	15,935,000
	Contingency (20%)	$	3,187,000
	Total Capital	$	19,122,000

Gasification Generation - Full Capacity					
	Case # 2				
	Days Per Year	365			
	Hours Per Year	8,760			
	Days of Maintenance Downtime per Year	20			
	Hours of Maintenance Downtime per Year	480			
	Operational Hours per year	8,280			
	Plant Capacity (kWh)	10,699			
	Internal Power Used (kWh)	638			
	Net Generating Capacity (kWh)	10,061			
	Total Quantity of Electricity Sold (kWh per Year)	88,134,360			
	Total Quantity of Electricity Produced per Year	83,305,080			
	Biomass Input (WTPD)	267			
	Biomass Input (WT per Year)	92,115			
	Biomass Efficiency (kWh per Wet Ton of Biomass)	904			
Operating Cost					
Overhead and Administration		Salary	Benefits	**Total $**	**$ / kWh ($20/Wet ton)**
1	General Manger	$ 100,000	28%	$ 128,000	$ 0.001452
2	Accounting Support	$ 70,000	28%	$ 89,600	$ 0.001017
3	Clerical Support	$ 44,000	28%	$ 56,320	$ 0.000639
	Total	$ 214,000	28%	$ 273,920	$ 0.003108
Variable Cost of Operation		Maintenance Downtime (kW/yr)	Industrial $/kWh		
1	Purchasing Cost for Downtime Electricity per Year	4,829,280	$ 0.0500	$ 241,464	$ 0.002740
		Wet Tons per Year	Price / ton		
2.1	Fuel Costs per Year (Low at $10/ton)	92,115	$ 10	$ 921,150	NA
2.2	Fuel Costs per Year (Medium at $20/ton)	92,115	$ 20	$ 1,842,300	$ 0.020903
2.3	Fuel Costs per Year (High at $35/ton)	92,115	$ 35	$ 3,224,025	NA
		Ash (Tons per Yr)	Disposal $/ton		
3	Ash Disposal Cost per Year	1350	$ 20.00	$ 27,000	$ 0.000306
4	Water and Water Treatment			$ 57,000	$ 0.000647
		Employees	Averaage Salary		
5	Labor	18	$ 30,000	$ 540,000	$ 0.006127
		Total Salary per Year	Workers Comp.		
6	Workers' Compensation	$ 540,000	7%	$ 37,800	$ 0.000429
7	Miscellaneous			$ 39,000	$ 0.000443
8	Inert Gas			$ 10,000	$ 0.000113
		Total Capital	Percent of Capital		
9	Yearly Taxes and Insurance Costs	$ 26,586,000	1.50%	$ 398,790	$ 0.004525
10	Yearly Maintenance Costs	$ 26,586,000	2.00%	$ 531,720	$ 0.006033
	Sub-total (Low Fuel Cost $10/ton)			$ 2,803,924	NA
	Sub-total (Medium Fuel Cost $20/ton)			$ 3,725,074	$ 0.042266
	Sub-total (High Fuel Cost $35/ton)			$ 5,106,799	NA
		Rate	2 Months Working Capital	Total $	
11.1	Interest on Working Capital ($10/ton feedstock)	10%	$ 467,320.67	$ 46,732	NA
11.2	Interest on Working Capital ($20/ton feedstock)	10%	$ 620,845.67	$ 62,085	$ 0.000704
11.3	Interest on Working Capital ($35/ton feedstock)	10%	$ 851,133.17	$ 85,113	NA
	Total (Low Fuel Cost $10/ton)			$ 2,850,656	NA
	Total (Medium Fuel Cost $20/ton)			$ 3,787,159	$ 0.042970
	Total (High Fuel Cost $35/ton)			$ 5,191,912	NA
Yearly Expenditures on Capital					
		Salvage	Lifetime (Years)		
1	Depriciation - Buildings	0	20	$ 98,350	$ 0.001116
2	Depreciation - Equipment	0	10	$ 1,831,300	$ 0.020779
		Capital	Interest Rate		
3	Interest on Investment - Buildings	$ 1,967,000	5%	$ 49,175	$ 0.000558
4	Interest on Investment - Equipment	$ 19,613,000	5%	$ 490,325	$ 0.005563
	Total			$ 2,469,150	$ 0.028016
Total Operational Costs per Year				**Total $**	**Marginal Cost ($/kWh)**
	Low Fuel Cost $10/ton			$ 5,593,726	$ 0.063468
	Medium Fuel Cost $20/ton			$ 6,530,229	$ 0.074094
	High Fuel Cost $35/ton			$ 7,934,982	$ 0.090033

Feedstock Receiving and Processing		
1 Feedstock Truck Dump	$	100,000
2 Front End Loader	$	120,000
3 Metal Removal Equipment	$	15,000
4 Grinding/Sizing Equipment	$	185,000
5 Blending Equipment	$	100,000
6 Conveyors	$	125,000
Total	$	645,000
Operational Equipment		
1 Power Generation Equipment	$	7,388,000
2 Gasification Process	$	7,500,000
3 Interconnections	$	1,300,000
4 Waste Heat Boiler	$	2,780,000
5 Heat Recovery	$	1,700,000
Total	$	18,968,000
Land and Infrastructure		
1 Land/ Site Preparation	$	150,000
2 Plant Buildings	$	612,000
3 Eng/Permitting	$	425,000
4 Fuel Processing Building	$	1,155,000
5 Fuel Storage Bins	$	200,000
Total	$	2,542,000
Sub-Total	$	22,155,000
Contingency (20%)	$	4,431,000
Total Capital	$	26,586,000

Gasification Generation - Full Capacity					
	Case # 3				
	Days Per Year	365			
	Hours Per Year	8,760			
	Days of Maintenance Downtime per Year	20			
	Hours of Maintenance Downtime per Year	480			
	Operational Hours per year	8,280			
	Plant Capacity (kWh)	21,396			
	Internal Power Used (kWh)	1,169			
	Net Generating Capacity (kWh)	20,227			
	Total Quantity of Electricity Sold (kWh per Year)	177,188,520			
	Total Quantity of Electricity Produced per Year	167,479,560			
	Biomass Input (WTPD)	533			
	Biomass Input (WT per Year)	183,885			
	Biomass Efficiency (kWh per Wet Ton of Biomass)	911			
Operating Cost					
Overhead and Administration		Salary	Benefits	**Total $**	**$ / kWh ($20/Wet ton)**
1	General Manger	$ 110,000	28%	$ 140,800	$ 0.000795
2	Accounting Support	$ 90,000	28%	$ 115,200	$ 0.000650
3	Clerical Support	$ 75,000	28%	$ 96,000	$ 0.000542
	Total	$ 275,000	28%	$ 352,000	$ 0.001987
Variable Cost of Operation		Maintenance Downtime (kW/yr)	Industrial $/kWh		
1	Purchasing Cost for Downtime Electricity per Year	9,708,960	$ 0.0500	$ 485,448	$ 0.002740
		Wet Tons per Year	Price / ton		
2.1	Fuel Costs per Year (Low at $10/ton)	183,885	$ 10	$ 1,838,850	NA
2.2	Fuel Costs per Year (Medium at $20/ton)	183,885	$ 20	$ 3,677,700	$ 0.020756
2.3	Fuel Costs per Year (High at $35/ton)	183,885	$ 35	$ 6,435,975	NA
		Ash (Tons per Yr)	Disposal $/ton		
3	Ash Disposal Cost per Year	2700	$ 20.00	$ 54,000	$ 0.000305
4	Water and Water Treatment			$ 159,000	$ 0.000897
		Employees	Averaage Salary		
5	Labor	20	$ 30,000	$ 600,000	$ 0.003386
		Total Salary per Year	Workers Comp.		
6	Workers' Compensation	$ 600,000	7%	$ 42,000	$ 0.000237
7	Miscellaneous			$ 39,000	$ 0.000220
8	Inert Gas			$ 10,000	$ 0.000056
		Total Capital	Percent of Capital		
9	Yearly Taxes and Insurance Costs	$ 43,902,000	1.50%	$ 658,530	$ 0.003717
10	Yearly Maintenance Costs	$ 43,902,000	2.00%	$ 878,040	$ 0.004955
	Sub-total (Low Fuel Cost $10/ton)			$ 4,764,868	NA
	Sub-total (Medium Fuel Cost $20/ton)			$ 6,603,718	$ 0.037269
	Sub-total (High Fuel Cost $35/ton)			$ 9,361,993	NA
		Rate	2 Months Working Capital	Total $	
11.1	Interest on Working Capital ($10/ton feedstock)	10%	$ 794,144.67	$ 79,414	NA
11.2	Interest on Working Capital ($20/ton feedstock)	10%	$ 1,100,619.67	$ 110,062	$ 0.000621
11.3	Interest on Working Capital ($35/ton feedstock)	10%	$ 1,560,332.17	$ 156,033	NA
	Total (Low Fuel Cost $10/ton)			$ 4,844,282	NA
	Total (Medium Fuel Cost $20/ton)			$ 6,713,780	$ 0.037891
	Total (High Fuel Cost $35/ton)			$ 9,518,026	NA
Yearly Expenditures on Capital					
		Salvage	Lifetime (Years)		
1	Depriciation - Buildings	0	20	$ 160,000	$ 0.000903
2	Depreciation - Equipment	0	10	$ 3,060,000	$ 0.017270
		Capital	Interest Rate		
3	Interest on Investment - Buildings	$ 3,200,000	5%	$ 80,000	$ 0.000451
4	Interest on Investment - Equipment	$ 32,600,000	5%	$ 815,000	$ 0.004600
	Total			$ 4,115,000	$ 0.023224
Total Operational Costs per Year				**Total $**	**Marginal Cost ($/kWh)**
	Low Fuel Cost $10/ton			$ 9,311,282	$ 0.052550
	Medium Fuel Cost $20/ton			$ 11,180,780	$ 0.063101
	High Fuel Cost $35/ton			$ 13,985,026	$ 0.078927

Feedstock Receiving and Processing			
1	Feedstock Truck Dump	$	100,000
2	Front End Loader	$	120,000
3	Metal Removal Equipment	$	15,000
4	Grinding/Sizing Equipment	$	225,000
5	Blending Equipment	$	125,000
6	Conveyors	$	125,000
	Total	$	710,000
Operational Equipment			
1	Power Generation Equipment	$	13,090,000
2	Gasification Process	$	11,300,000
3	Interconnections	$	2,000,000
4	Waste Heat Boiler	$	5,500,000
5	Heat Recovery	$	1,300,000
	Total	$	31,890,000
Land and Infrastructure			
1	Land/ Site Preparation	$	200,000
2	Plant Buildings	$	810,000
3	Eng/Permitting	$	585,000
4	Fuel Processing Building	$	1,990,000
5	Fuel Storage Bins	$	400,000
	Total	$	3,985,000
	Sub-Total	$	36,585,000
	Contingency (20%)	$	7,317,000
	Total Capital	$	43,902,000

Pyrolysis Generation - Full Capacity

Case # 1

Days Per Year	365
Hours Per Year	8,760
Days of Maintenance Downtime per Year	20
Hours of Maintenance Downtime per Year	480
Operational Hours per year	8,280
Plant Capacity (kWh)	5,073
Internal Power Used (kWh)	321
Net Generating Capacity (kWh)	4,752
Total Quantity of Electricity Sold (kWh per Year)	41,627,520
Total Quantity of Electricity Produced per Year	39,346,560
Biomass Input (WTPD)	160
Biomass Input (WT per Year)	55,200
Biomass Efficiency (kWh per Wet Ton of Biomass)	713

Operating Cost									
Overhead and Administration			Salary		Benefits		**Total $**		**$ / kWh ($20/Wet ton)**
1	General Manger	$	85,000		28%	$	108,800	$	0.002614
2	Accounting Support	$	50,000		28%	$	64,000	$	0.001537
3	Clerical Support	$	20,000		28%	$	25,600	$	0.000615
	Total	$	155,000		28%	$	198,400	$	0.004766
Variable Cost of Operation			Maintenance Downtime (kW/yr)		Industrial $/kWh				
1	Purchasing Cost for Downtime Electricity per Year		2,280,960	$	0.0500	$	114,048	$	0.002740
			Wet Tons per Year		Price / ton				
2.1	Fuel Costs per Year (Low at $10/ton)		55,200	$	10	$	552,000		NA
2.2	Fuel Costs per Year (Medium at $20/ton)		55,200	$	20	$	1,104,000	$	0.026521
2.3	Fuel Costs per Year (High at $35/ton)		55,200	$	35	$	1,932,000		NA
			Ash (Tons per Yr)		Disposal $/ton				
3	Ash Disposal Cost per Year		875	$	20.00	$	17,500	$	0.000420
4	Water and Water Treatment					$	22,000	$	0.000528
			Employees		Averaage Salary				
5	Labor		17	$	30,000	$	510,000	$	0.012252
			Total Salary per Year		Workers Comp.				
6	Workers' Compensation	$	510,000		7%	$	35,700	$	0.000858
7	Miscellaneous					$	39,000	$	0.000937
			Total Capital		Percent of Capital				
8	Yearly Taxes and Insurance Costs	$	13,218,000		1.50%	$	198,270	$	0.004763
9	Yearly Maintenance Costs	$	13,218,000		2.00%	$	264,360	$	0.006351
	Sub-total (Low Fuel Cost $10/ton)					$	1,752,878		NA
	Sub-total (Medium Fuel Cost $20/ton)					$	2,304,878	$	0.055369
	Sub-total (High Fuel Cost $35/ton)					$	3,132,878		NA
			Rate		2 Months Working Capital		Total $		
10.1	Interest on Working Capital ($10/ton feedstock)		10%	$	292,146.33	$	29,215		NA
10.2	Interest on Working Capital ($20/ton feedstock)		10%	$	384,146.33	$	38,415	$	0.000923
10.3	Interest on Working Capital ($35/ton feedstock)		10%	$	522,146.33	$	52,215		NA
	Total (Low Fuel Cost $10/ton)					$	1,782,093		NA
	Total (Medium Fuel Cost $20/ton)					$	2,343,293	$	0.056292
	Total (High Fuel Cost $35/ton)					$	3,185,093		NA
Yearly Expenditures on Capital									
			Salvage		Lifetime (Years)				
1	Depriciation - Buildings		0		20	$	45,000	$	0.001081
2	Depreciation - Equipment		0		10	$	991,500	$	0.023818
			Capital		Interest Rate				
3	Interest on Investment - Buildings	$	900,000		5%	$	22,500	$	0.000541
4	Interest on Investment - Equipment	$	9,915,000		5%	$	247,875	$	0.005955
	Total					$	1,306,875	$	0.031394
Total Operational Costs per Year							**Total $**		**Marginal Cost ($/kWh)**
	Low Fuel Cost $10/ton					$	3,287,368	$	0.078971
	Medium Fuel Cost $20/ton					$	3,848,568	$	0.092452
	High Fuel Cost $35/ton					$	4,690,368	$	0.112675

Feedstock Receiving and Processing			
1	Feedstock Truck Dump	$	100,000
2	Front End Loader	$	120,000
3	Metal Removal Equipment	$	15,000
4	Grinding/Sizing Equipment	$	165,000
5	Blending Equipment	$	75,000
6	Conveyors	$	125,000
	Total	$	600,000
Operational Equipment			
1	Power Generation Equipment	$	5,890,000
2	Demineralizer System	$	1,300,000
3	Boiler	$	2,000,000
4	Instrumentation & Controls	$	125,000
	Total	$	9,315,000
Land and Infrastructure			
1	Land/ Site Preparation	$	100,000
2	Plant Buildings	$	100,000
3	Eng/Permitting	$	100,000
4	Fuel Processing Building	$	700,000
5	Fuel Storage Bins	$	100,000
	Total	$	1,100,000
	Sub-Total	$	11,015,000
	Contingency (20%)	$	2,203,000
	Total Capital	$	13,218,000

Pyrolysis Generation - Full Capacity

Case # 2

	Days Per Year	365			
	Hours Per Year	8,760			
	Days of Maintenance Downtime per Year	20			
	Hours of Maintenance Downtime per Year	480			
	Operational Hours per year	8,280			
	Plant Capacity (kWh)	10,147			
	Internal Power Used (kWh)	577			
	Net Generating Capacity (kWh)	9,570			
	Total Quantity of Electricity Sold (kWh per Year)	83,833,200			
	Total Quantity of Electricity Produced per Year	79,239,600			
	Biomass Input (WTPD)	320			
	Biomass Input (WT per Year)	110,400			
	Biomass Efficiency (kWh per Wet Ton of Biomass)	718			
Operating Cost					
Overhead and Administration		Salary	Benefits	**Total $**	**$ / kWh ($20/Wet ton)**
1	General Manger	$ 100,000	28%	$ 128,000	$ 0.001527
2	Accounting Support	$ 70,000	28%	$ 89,600	$ 0.001069
3	Clerical Support	$ 44,000	28%	$ 56,320	$ 0.000672
	Total	$ 214,000	28%	$ 273,920	$ 0.003267
Variable Cost of Operation		Maintenance Downtime (kW/yr)	Industrial $/kWh		
1	Purchasing Cost for Downtime Electricity per Year	4,593,600	$ 0.0500	$ 229,680	$ 0.002740
		Wet Tons per Year	Price / ton		
2.1	Fuel Costs per Year (Low at $10/ton)	110,400	$ 10	$ 1,104,000	NA
2.2	Fuel Costs per Year (Medium at $20/ton)	110,400	$ 20	$ 2,208,000	$ 0.026338
2.3	Fuel Costs per Year (High at $35/ton)	110,400	$ 35	$ 3,864,000	NA
		Ash (Tons per Yr)	Disposal $/ton		
3	Ash Disposal Cost per Year	1750	$ 20.00	$ 35,000	$ 0.000417
4	Water and Water Treatment			$ 57,000	$ 0.000680
		Employees	Average Salary	Total $	
5	Labor	34	$ 30,000	$ 1,020,000	$ 0.012167
		Total Salary per Year	Workers Comp.		
6	Workers' Compensation	$ 1,020,000	7%	$ 71,400	$ 0.000852
7	Miscellaneous			$ 39,000	$ 0.000465
		Total Capital	Percent of Capital		
8	Yearly Taxes and Insurance Costs	$ 21,642,000	1.50%	$ 324,630	$ 0.003872
9	Yearly Maintenance Costs	$ 21,642,000	2.00%	$ 432,840	$ 0.005163
	Sub-total (Low Fuel Cost $10/ton)			$ 3,313,550	NA
	Sub-total (Medium Fuel Cost $20/ton)			$ 4,417,550	$ 0.052695
	Sub-total (High Fuel Cost $35/ton)			$ 6,073,550	NA
		Rate	2 Months Working Capital	Total $	
10.1	Interest on Working Capital ($10/ton feedstock)	10%	$ 552,258.33	$ 55,226	NA
10.2	Interest on Working Capital ($20/ton feedstock)	10%	$ 736,258.33	$ 73,626	$ 0.000878
10.3	Interest on Working Capital ($35/ton feedstock)	10%	$ 1,012,258.33	$ 101,226	NA
	Total (Low Fuel Cost $10/ton)			$ 3,368,776	NA
	Total (Medium Fuel Cost $20/ton)			$ 4,491,176	$ 0.053573
	Total (High Fuel Cost $35/ton)			$ 6,174,776	NA
Yearly Expenditures on Capital					
		Salvage	Lifetime (Years)		
1	Depriciation - Buildings	0	20	$ 77,750	$ 0.000927
2	Depreciation - Equipment	0	10	$ 1,608,000	$ 0.019181
		Capital	Interest Rate		
3	Interest on Investment - Buildings	$ 1,555,000	5%	$ 38,875	$ 0.000464
4	Interest on Investment - Equipment	$ 16,080,000	5%	$ 402,000	$ 0.004795
	Total			$ 2,126,625	$ 0.025367
Total Operational Costs per Year				**Total $**	**Marginal Cost ($/kWh)**
	Low Fuel Cost $10/ton			$ 5,769,321	$ 0.068819
	Medium Fuel Cost $20/ton			$ 6,891,721	$ 0.082208
	High Fuel Cost $35/ton			$ 8,575,321	$ 0.102290

Feedstock Receiving and Processing		
1 Feedstock Truck Dump	$	200,000
2 Front End Loader	$	240,000
3 Metal Removal Equipment	$	30,000
4 Grinding/Sizing Equipment	$	330,000
5 Blending Equipment	$	150,000
6 Conveyors	$	250,000
Total	$	1,200,000
Operational Equipment		
1 Power Generation Equipment	$	8,900,000
2 Pyrolysis Process	$	2,600,000
3 Waste Heat Boiler	$	3,130,000
4 Demineralizer System	$	250,000
Total	$	14,880,000
Land and Infrastructure		
1 Land/ Site Preparation	$	200,000
2 Plant Buildings	$	200,000
3 Eng/Permitting	$	200,000
4 Fuel Processing Building	$	1,155,000
5 Fuel Storage Bins	$	200,000
Total	$	1,955,000
Sub-Total	$	18,035,000
Contingency (20%)	$	3,607,000
Total Capital	$	21,642,000

Pyrolysis Generation - Full Capacity

Case # 3

	Days Per Year		365						
	Hours Per Year		8,760						
	Days of Maintenance Downtime per Year		20						
	Hours of Maintenance Downtime per Year		480						
	Operational Hours per year		8,280						
	Plant Capacity (kWh)		15,220						
	Internal Power Used (kWh)		850						
	Net Generating Capacity (kWh)		14,370						
	Total Quantity of Electricity Sold (kWh per Year)		125,881,200						
	Total Quantity of Electricity Produced per Year		118,983,600						
	Biomass Input (WTPD)		480						
	Biomass Input (WT per Year)		165,600						
	Biomass Efficiency (kWh per Wet Ton of Biomass)		719						
Operating Cost									
Overhead and Administration			Salary		Benefits		**Total $**		**$ / kWh ($20/Wet ton)**
1	General Manger	$	110,000		28%	$	140,800	$	0.001119
2	Accounting Support	$	90,000		28%	$	115,200	$	0.000915
3	Clerical Support	$	75,000		28%	$	96,000	$	0.000763
	Total	$	275,000		28%	$	352,000	$	0.002796
Variable Cost of Operation									
			Maintenance Downtime (kW/yr)		Industrial $/kWh				
1	Purchasing Cost for Downtime Electricity per Year		6,897,600	$	0.0500	$	344,880	$	0.002740
			Wet Tons per Year		Price / ton				
2.1	Fuel Costs per Year (Low at $10/ton)		165,600	$	10	$	1,656,000		NA
2.2	Fuel Costs per Year (Medium at $20/ton)		165,600	$	20	$	3,312,000	$	0.026311
2.3	Fuel Costs per Year (High at $35/ton)		165,600	$	35	$	5,796,000		NA
			Ash (Tons per Yr)		Disposal $/ton				
3	Ash Disposal Cost per Year		2600	$	20.00	$	52,000	$	0.000413
4	Water and Water Treatment					$	159,000	$	0.001263
			Employees		Average Salary				
5	Labor		51	$	30,000	$	1,530,000	$	0.012154
			Total Salary per Year		Workers Comp.				
6	Workers' Compensation	$	1,530,000		7%	$	107,100	$	0.000851
7	Miscellaneous					$	39,000	$	0.000310
			Total Capital		Percent of Capital				
8	Yearly Taxes and Insurance Costs	$	29,682,000		1.50%	$	445,230	$	0.003537
9	Yearly Maintenance Costs	$	29,682,000		2.00%	$	593,640	$	0.004716
	Sub-total (Low Fuel Cost $10/ton)					$	4,926,850		NA
	Sub-total (Medium Fuel Cost $20/ton)					$	6,582,850	$	0.052294
	Sub-total (High Fuel Cost $35/ton)					$	9,066,850		NA
			Rate		2 Months Working Capital		Total $		
10.1	Interest on Working Capital ($10/ton feedstock)		10%	$	821,141.67	$	82,114		NA
10.2	Interest on Working Capital ($20/ton feedstock)		10%	$	1,097,141.67	$	109,714	$	0.000872
10.3	Interest on Working Capital ($35/ton feedstock)		10%	$	1,511,141.67	$	151,114		NA
	Total (Low Fuel Cost $10/ton)					$	5,008,964		NA
	Total (Medium Fuel Cost $20/ton)					$	6,692,564	$	0.053166
	Total (High Fuel Cost $35/ton)					$	9,217,964		NA
Yearly Expenditures on Capital									
			Salvage		Lifetime (Years)				
1	Depriciation - Buildings		0		20	$	129,500	$	0.001029
2	Depreciation - Equipment		0		10	$	2,154,500	$	0.017115
			Capital		Interest Rate				
3	Interest on Investment - Buildings	$	2,590,000		5%	$	64,750	$	0.000514
4	Interest on Investment - Equipment	$	21,545,000		5%	$	538,625	$	0.004279
	Total					$	2,887,375	$	0.022937
Total Operational Costs per Year							**Total $**		**Marginal Cost ($/kWh)**
	Low Fuel Cost $10/ton					$	8,248,339	$	0.065525
	Medium Fuel Cost $20/ton					$	9,931,939	$	0.078899
	High Fuel Cost $35/ton					$	12,457,339	$	0.098961

Feedstock Receiving and Processing			
1	Feedstock Truck Dump	$	300,000
2	Front End Loader	$	360,000
3	Metal Removal Equipment	$	45,000
4	Grinding/Sizing Equipment	$	495,000
5	Blending Equipment	$	225,000
6	Conveyors	$	375,000
	Total	$	1,800,000
Operational Equipment			
1	Power Generation Equipment	$	11,390,000
2	Demineralizer System	$	3,900,000
3	Boiler	$	4,080,000
4	Instrumentation & Controls	$	375,000
	Total	$	19,745,000
Land and Infrastructure			
1	Land/ Site Preparation	$	300,000
2	Plant Buildings	$	300,000
3	Eng/Permitting	$	300,000
4	Fuel Processing Building	$	1,990,000
5	Fuel Storage Bins	$	300,000
	Total	$	3,190,000
	Sub-Total	$	24,735,000
	Contingency (20%)	$	4,947,000
	Total Capital	$	29,682,000

APPENDIX III

Figure A-25: Direct Fire Operational Cost Breakdown ($10/ton)

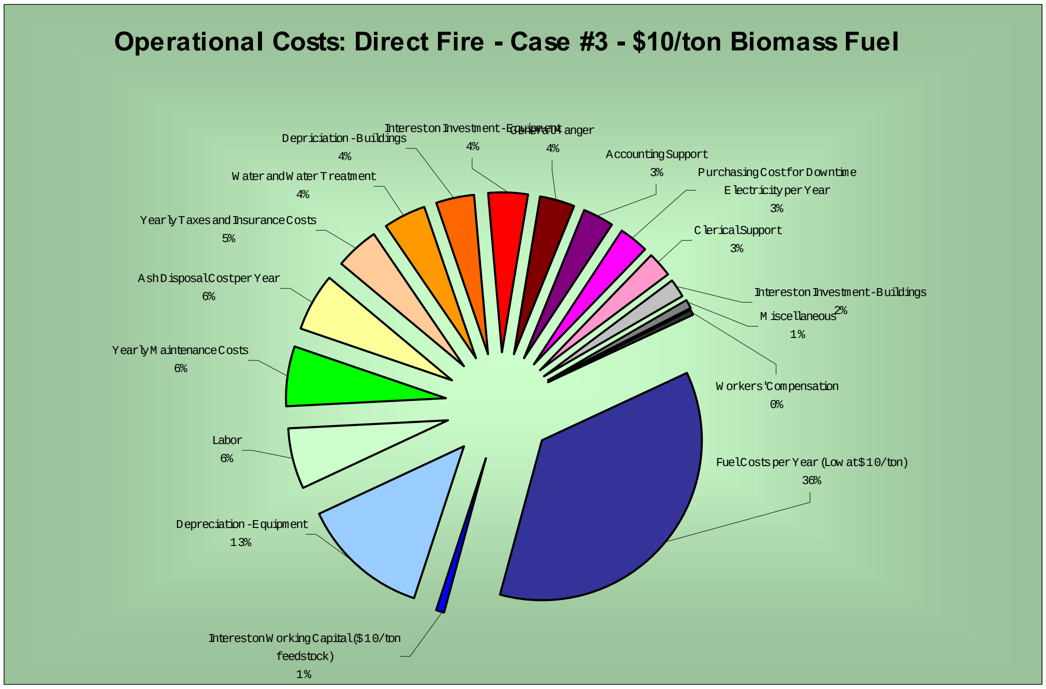


Figure A-26: Direct Fire Operational Cost Breakdown ($20/ton)

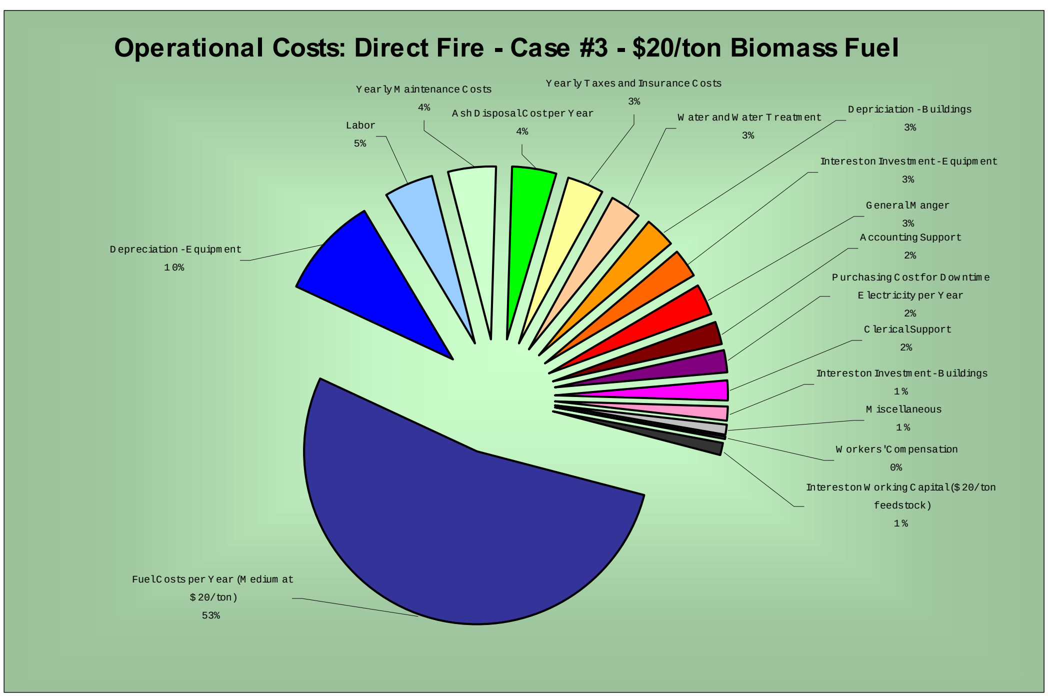


Figure A-27: Direct Fire Operational Cost Breakdown ($35/ton)

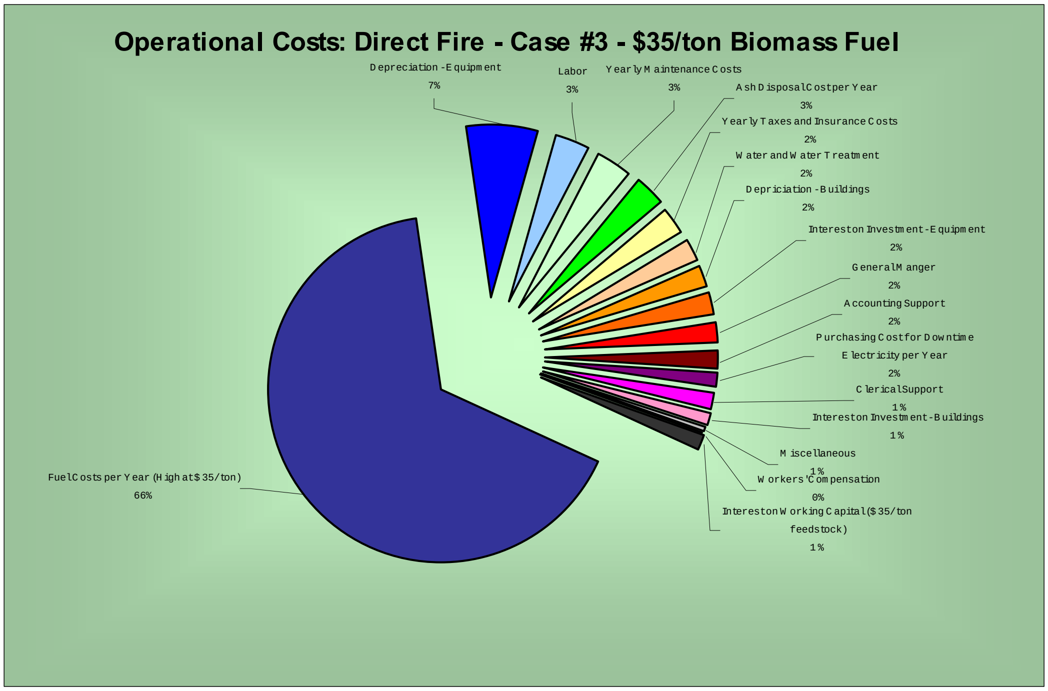


Figure A-28: Co-Fire Operational Cost Breakdown ($10/ton)

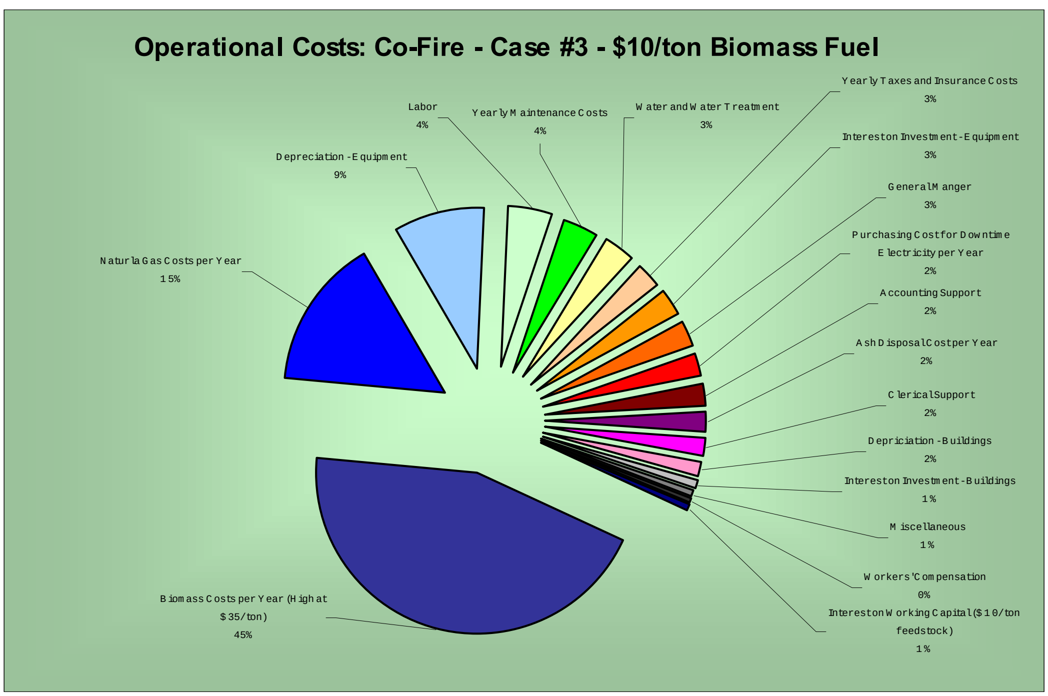


Figure A-29: Co-Fire Operational Cost Breakdown ($20/ton)

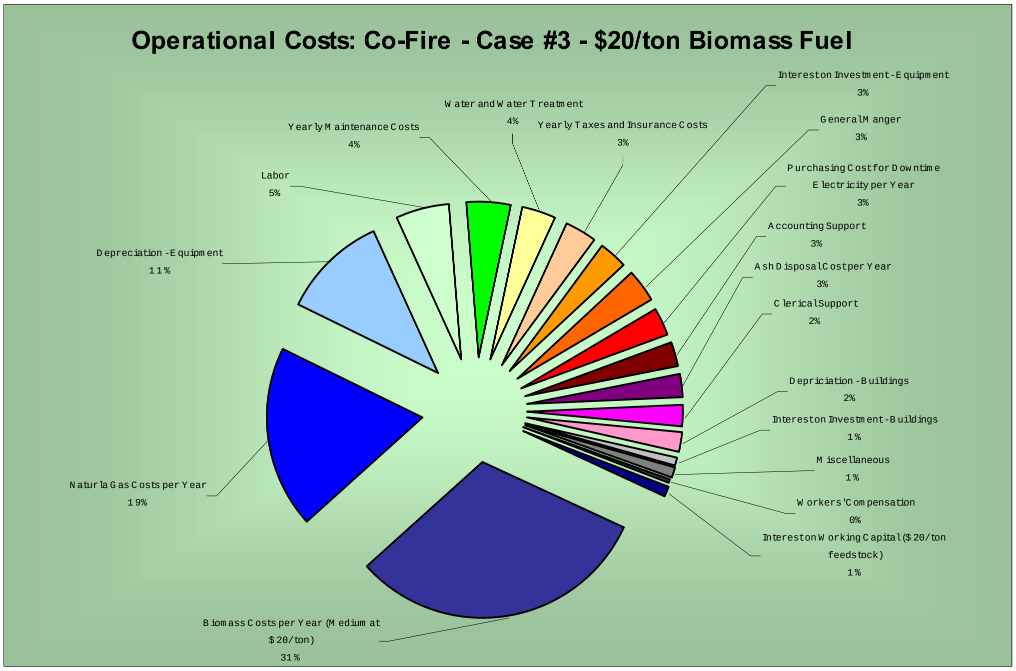


Figure A-30: Co-Fire Operational Cost Breakdown ($35/ton)

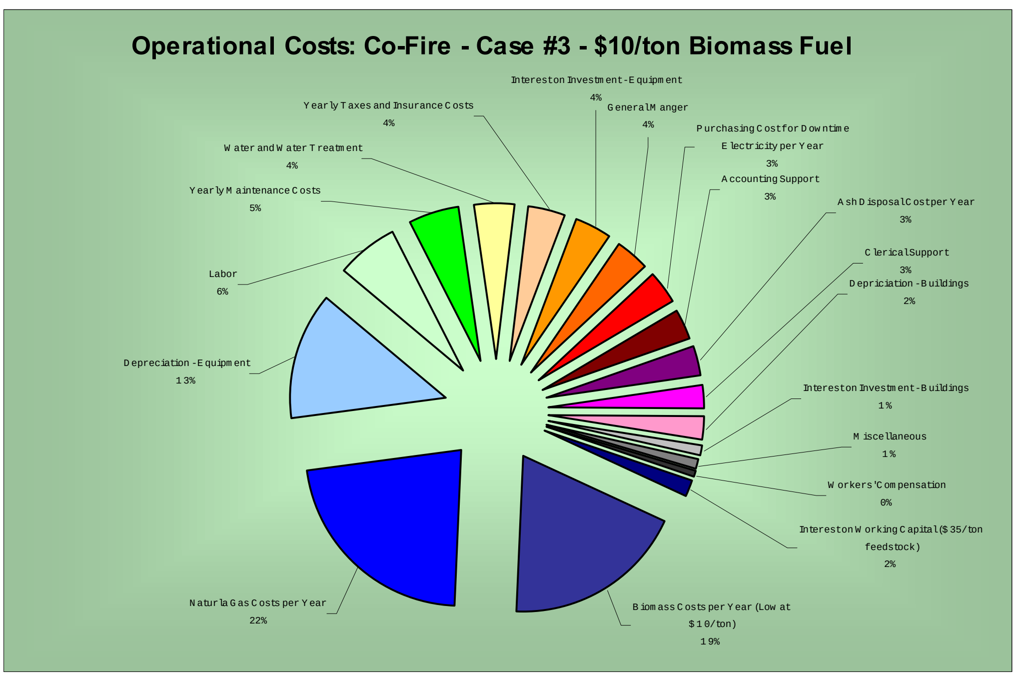


Figure A-31: Gasicfication Operational Cost Breakdown ($10/ton)

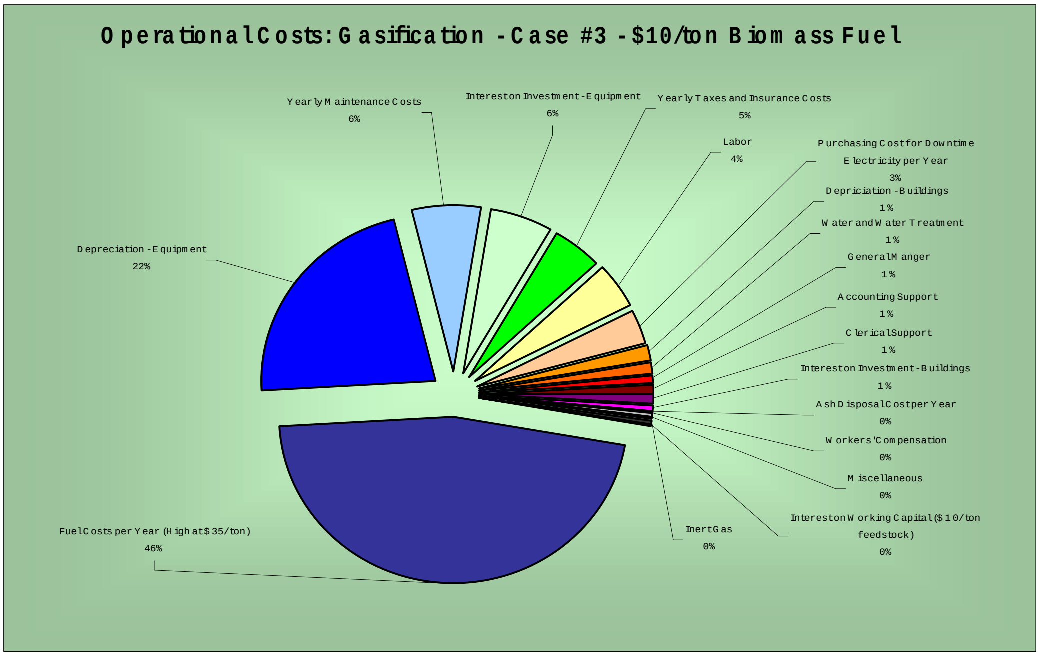


Figure A-25: Gasification Operational Cost Breakdown ($20/ton)

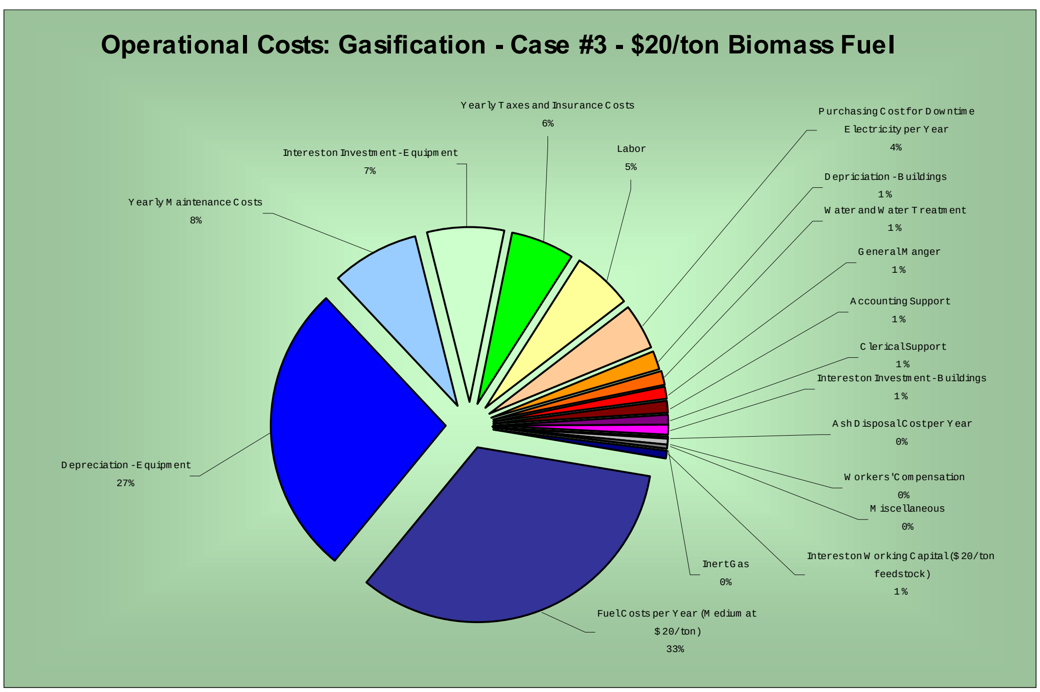


Figure A-31: Gasification Operational Cost Breakdown ($35/ton)

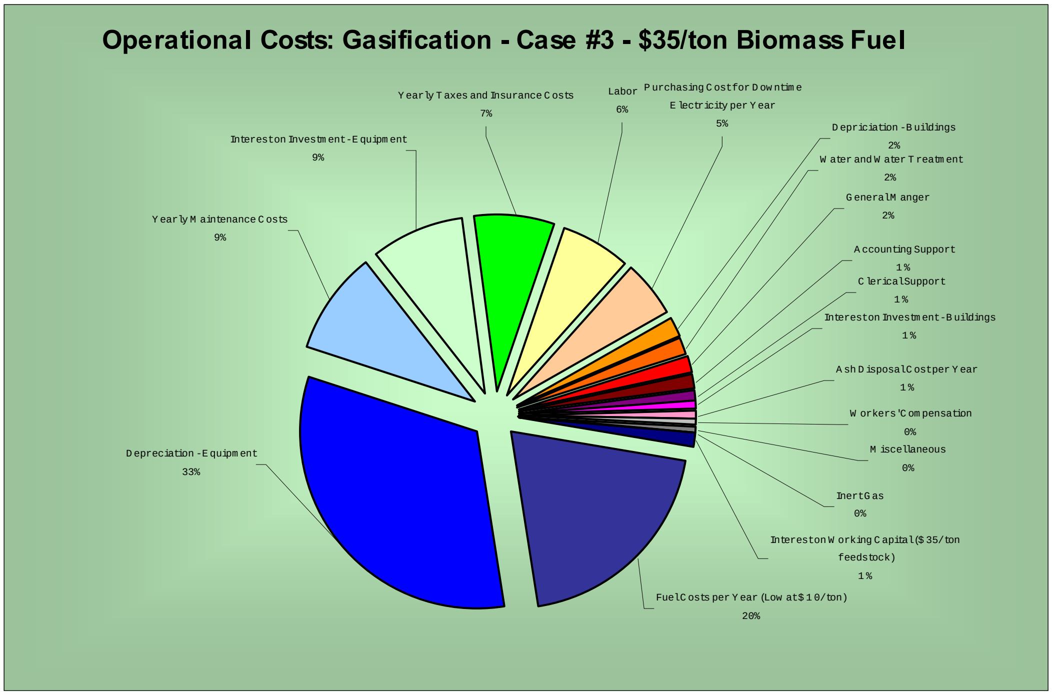


Figure A-33: Pyrolysis Operational Cost Breakdown ($10/ton)

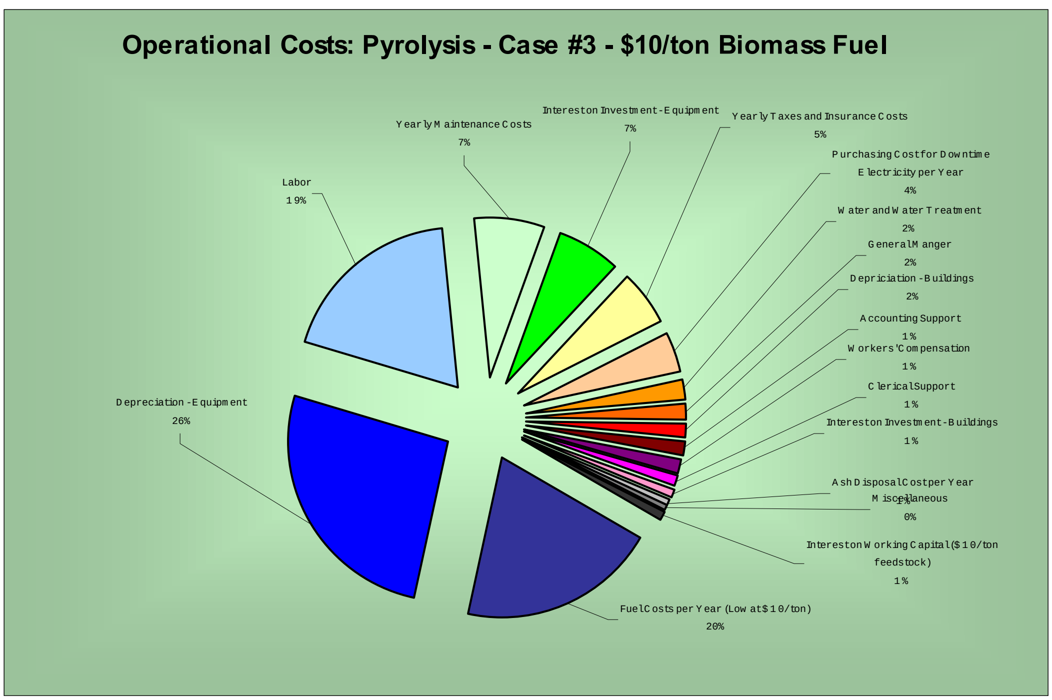


Figure A-34: Pyrolysis Operational Cost Breakdown ($20/ton)

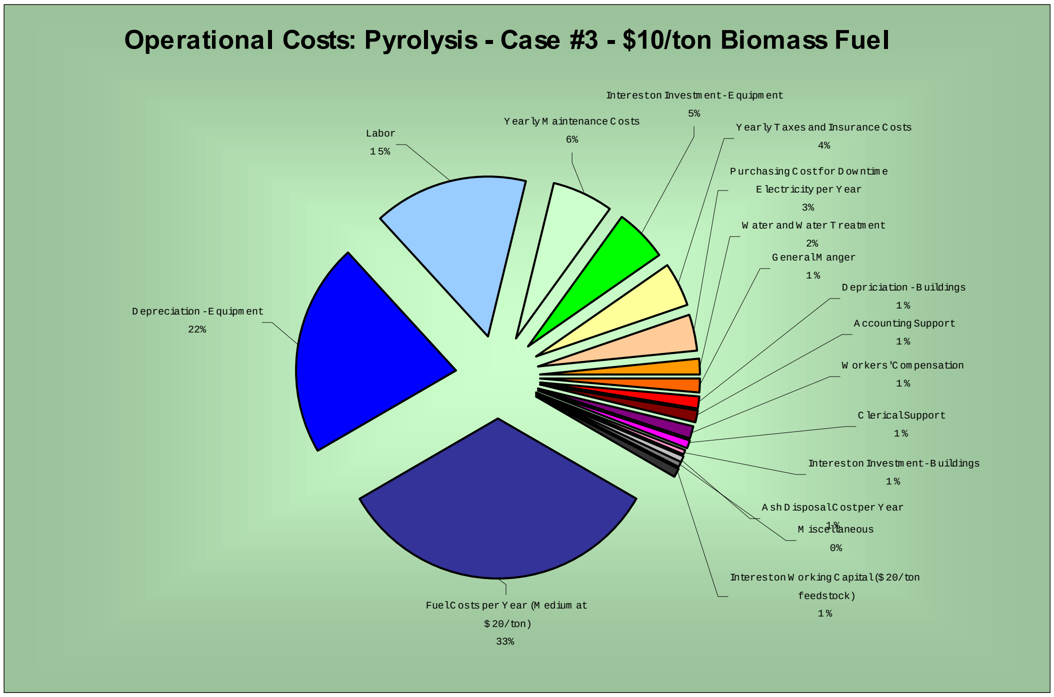


Figure A-35: Pyrolysis Operational Cost Breakdown ($35/ton)