CO-FIRING STEAM GENERATORS: MODIFYING EQUIPMENT AND OPTIMIZING OPERATIONS

by

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Executive Summary

Electricity produced by steam turbines accounted for 70.45% of the U.S. net generation of electricity for all sectors in 2012.[i] Only 2.02% of the electricity generated from steam turbines identifies wood or waste as the fuel.[ii] This 2.02% reflects an 11.1% increase since 2005 of biomass' share of electricity generated by steam turbines. However, this is only a 3.6% increase in total electricity generation (Appendix 1, Table 1.1 and 1.2).

The scope of co-firing in this analysis is the thermo-chemical transformation of biomass in conventional coal plants, which uses alternative fuel to displace a percentage of coal. Co-firing is essentially burning multiple fuels in a single application, but biomass is significant in this analysis for its renewable fuel and lower emissions characteristics. Further, modifying an existing plant increases the value of this potentially sustainable resource by decreasing upfront capital expenditures. From the perspective of the electric utility industry, direct co-firing, rather than gasification or separate boiler combustion, is the most cost-effective approach to biomass.[iii] The general benefits of co-firing when compared to exclusive biomass systems can be summarized by three elements: decrease in investment per unit of installed capacity, higher efficiency generation and greater operational flexibility.

Biomass fuels impact the operations and equipment of an existing plant that traditionally burned coal due to the added complexities of contracting resources, transportation to the facility, boiler fuel feeding which usually requires a re-engineered conveyor system, combustion process monitoring and waste material and emissions management. Further, biomass requires a larger volume of fuel to create the same amount electricity due to its lower heat content.

Electricity generation equipment is manufactured and tested under certain conditions to provide efficiency and expected lifetime standards. Operating this equipment with a variety of fuel inputs, heat rates and physical mechanisms (fuel loading, for example), distorts these evaluations and further impacts complementary inputs, like those used for emission control systems, which may include limestone to remove sulfur and ammonia to reduce nitrogen oxides, and alters a plant's financial operations.

Further, units market co-firing because of the ability to change fuel sources depending on the available resources and the price of fuel and electricity. Public policy, through Renewable Portfolio Standards (RPS) in 35 states and the District of Columbia, incents biomass technologies with Renewable Energy Credits (RECs), rebates and tax breaks because these units are categorized as clean energy providers if the units meet certain requirements.[iv] When a unit has the capacity to burn more than one type of fuel, constant analyses of revenues and expenses need to be undertaken to evaluate returns and profits.

This study aims to assess the additional investments that are required to allow the baseline of a traditionally coal-fired unit to burn alternative fuel sources and the impacts that this decision has on the equipment and operations of the unit. The impacts are significant, but current public policy surrounding co-firing does not account for these expensive changes. The goal of this study is to share possible impacts attributed to co-firing on the plant and its operations that alter cash flows.

The importance of this research increases since the United States (US) Environmental Protection Agency (EPA) Mercury and Air Toxics Standards (MATS) regulations created to penalize new polluters and incent innovation to reduce the impacts of climate change have recently been updated and then delayed to meet lower emissions requirements. Other Clean Air Act and future greenhouse gas emission policies may require “dirty” coal-fired generators to retire or retrofit units. Since steam generators account for the majority of our nation’s electricity (70.45%, as addressed previously), understanding the costs associated with alternative fuel options is necessary to accurately evaluate this opportunity. This research has the potential to improve the public’s understanding of the fuel and generation decisions at the plant level, which should be accounted for in current policy reform and future state and federal electricity generation incentive programs.

To accomplish this task, the report will address relevant topics and materials in the following sections: Background, Case Study Description, Optimization, Application, Recommendation and Conclusion. The Background includes a technology overview and review of literature and other research on the topic. The Case Study reviews the data and materials at a specific plant, which were provided for research purposes. The Optimization describes the specific analysis of the Case Study materials by filtering for a number of outcomes and finding a best fit. The Application evaluates other opportunities to leverage the findings of the Case Study plant and includes future research opportunities. The Conclusion culminates the findings of the report and recognizes acknowledgements.

Background

This research aims to improve the public's understanding of the upfront investment and the ongoing operational adjustments required to co-fire biomass at existing coal-fired power plants. As a method to acquire renewable energy credits (RECs) in states and districts with renewable portfolio standards (RPS), plant management may leverage co-firing as a way to meet emission standards without installing expensive control systems. Efficient public policies and regulations should account for the entire costs and benefits of biomass co-firing initiatives, and this report aims to present the complexities of the variables involved in an accessible format.

Existing research focuses on the chemistry involved in co-firing, the costs of installments, the efficiencies of boilers and the impacts on emissions independently. This text brings together these related topics in a cohesive manner. By evaluating the operations of a plant testing fuel mix ratios, this report makes recommendations about conditions that create high value outcomes. By applying those findings to a coal-fired power plant in Colorado with similar characteristics, the report recommends that the plant should integrate biomass co-firing to resolve current challenges.

Setting the context of the technology used in co-firing applications allows for a more thorough discussion of the literature and past research that this study is founded on. The Technology Overview precedes a Literature Review in this section.

Technology Overview

The majority of power stations that leverage co-firing opportunities are pulverized coal boilers, which include tangentially-fired (T-fired), front-wall fired, back-wall fired, dual-wall fired and cyclone designs. Co-firing is generally applied to units between 50 and 700 megawatt electrical (MWe) due to the scale at which operations need to occur to capture benefits from RECs and to adapt to the limitations associated with the access to fuel sources. In an online database, the International Energy Agency (IEA) identified the 39 generators in the US co-firing in 2009 (Appendix 2, Table 2.1).[v] Of these, 72% use pulverized coal boilers, making up 95% of generating capacity in the database. The average capacity of these plants, when those with less than 1 megawatt (MW) of capacity are removed, is 165 MW. The IEA Database suggests that 77% of co-firing units in the United States combust at least one form of wood. This illustrates the scope of units currently testing and operating with biomass co-firing strategies.

The efficiency and cost of electricity generation is directly related to the method of co-firing, the fuel type used and the boiler's structure. The goal of a plant is to maximize the efficiency of the boiler's operations while minimizing fuel costs.

Boiler structure

The four main types of boilers used for electricity generation are: pulverized, cyclone, spreader stoker and fluidized bed. Pulverized coal and cyclone boilers can also be grouped as suspension firing boilers. The source for the descriptions below is the Eastern Research Group.[vi]

Utility and large industrial boilers primarily use pulverized fuel systems, which breaks down the fuel in a mill the consistency of a powder. The pulverized fuel feeds through the burners to the combustion chamber, where it burns in suspension (Appendix 3, Figure 3.1.1). Depending on the ash removal system, pulverized furnaces are either dry or wet bottom. Dry-bottom furnaces are tangential- or nontangential-fired units (Appendix 2, Figure 3.1.2). Nontangential-fired pulverized furnaces include wall-fired, turbo, cell-fired, vertical and arch. Dry-bottom furnaces fire fuels with high ash fusion temperatures; wet-bottom furnaces fire fuels with low ash fusion temperatures. Wet-bottom furnace designs are no longer manufactured and have higher NO_x emission rates.

Also used for utility and industrial applications, cyclone furnaces require fuels to be broken down to a consistent size, but not pulverized. (Appendix 3, Figure 3.2) Cyclone boilers burn fuels that have low ash fusion temperatures, which are fed tangentially to a horizontal cylindrical combustion chamber. Small particles burn in suspension and larger particles burn against the outer wall. Because of the high temperatures and the low ash fusion temperature of the fuel, the ash forms a liquid slag that drains from the bottom of the furnace.

In spreader stokers, fuel combusts in suspension and on a grate when it enters the furnace (Appendix 3, Figure 3.3). To improve efficiency, fly ash can be reinjected from mechanical collectors. Ash residue collects at the end of the grate. Fuels with low volatile matter content and relatively high ignition temperatures are not ideal for this boiler.

Fluidized bed combustors (FBC) introduce fuels to a bed of sorbent (limestone or dolomite) or inert material (like sand) that is fluidized by an upward flow of air (Appendix 3, Figure 3.4). Combustion takes place in the bed at lower temperatures than other boiler types. Fuel flexibility and low emissions are the primary benefits of this boiler, traditionally used for industrial purposes.

Boilers determine the way that fuel combusts, which is directly related to choosing the right method and fuel. Currently, 72% of co-firing facilities have pulverized burners. However, the engineering of the cyclone boilers seems to be the better suited for direct co-firing, but the capacity of the feeder is the limiting factor. The IEA co-firing database, includes units with bubbling and circulating fluidized bed boilers and stoker boilers co-firing biomass, suggesting that the technique is also successful with this equipment.[vii] Despite the market trends, this analysis will focus on opportunities for co-firing in fluidized bed boilers based on the data from the generator in the case study.

Method of co-firing

There are three methods for combusting biomass: separate units, direct firing in the same unit, and indirect firing in the same unit. Using a separate unit for biomass is out of the scope of this study because this process is more expensive and does not allow for the cost-savings, efficiency and flexibility associated with other methods of co-firing.[viii] For this reason the installation of a separate unit for burning biomass is not addressed in this text.

Direct co-firing is the most common method of co-firing and involves burning biomass in the same boiler. This straightforward approach involves blending the fuel before it feeds into the boiler or injecting the various fuels simultaneously into the boiler. The exact engineering of the system depends on the type of fuel and the type of boiler. Cyclone boilers prove to benefit from blending the fuels before, which is a process that requires manipulating the fuel inputs into a form that works with existing equipment at the boiler.[ix] Separate injections require more adjustments to the equipment and the process is very sensitive to the particle size. Generally, separate injections work well in T-fired pulverized coal boilers.[x] The case study in this report features a fluidized bed system with direct co-firing and separate injections.

It is important to recognize the opportunities associated with indirect co-firing. This method gasifies raw biomass materials and the burns this gas in the same furnace as the traditional resource. The benefit of this process is that the gasifier purifies the biomass before it is combusted in the boiler, so the emissions attributed to the biomass are cleaner, which directly impacts the backend equipment on a generating unit. The upfront expense of this system is more capital intensive, but the advantage is that the gasified biomass co-fires with natural gas very efficiently (Appendix 3, Table 3.1). Overall, indirect co-firing increases the flexibility of a unit because it can accommodate a wider range of biomass resources, but the additional cost associated with processing the biomass makes it unattractive to existing plants that traditionally burn coal.

Fuel type

The US Energy Information Administration (EIA) has ten categories for biomass; wood exclusively makes up three of those categories (Appendix 4, Table 4.1). In addition to potentially receiving different RECs depending on the biomass that a plant burns (in certain states, some fuels are not eligible for RECs at all), the operator must consider the availability, physical attributes and heat content of a fuel.

When considering which fuel to combust in a system, the availability of resources must be taken into account as well as policy regulations. From an engineering standpoint, evaluating the moisture content of the fuel, the resulting efficiency of burning it with the traditional fuel, the method of feeding it into the boiler and the granularity and consistency of the fuel source is important to capture the true cost of combusting the fuel to generate electricity. Also testing the impacts of the specific fuel on the specific equipment at the facility allows a plant to predict corrosion and fluctuations in emission contents.

Because fuels with lower heat content require a larger volume of fuel to produce the same heat output, it is important to consider the physical volume of fuel required to meet desired outcomes. Ranking fuel options by heating values reveals the generation capacity of a fuel (Appendix 3, Table 3.2). The structure of wood does not make it as efficient of a fuel if the volume of fuel is held constant (Appendix 4, Figures 4.1 and 4.2). The best scenario is to burn wood with low moisture and high energy density. However, these characteristics cannot always be fulfilled depending on the type and availability of the biomass. While contracts can specify certain qualities in the biomass, the organic nature of the fuel results in more variability than coal or natural gas. For this reason, a plant must be able to adapt to changes in the fuel when co-firing biomass. Blending biomass with a fuel that has higher energy intensity, like petroleum coke or tire-derived fuel (TDF), resolves the challenge of moving enough biomass volume into the boiler.

Modifications

Before the biomass reaches the boiler, there are a number of adaptations to an existing plant that must be accounted for (Appendix 5, Figure 5.1). To ensure proper size and moisture content, biomass may go through a pretreatment process. These may involve rotary driers, hammer mills, sieves to classify sizes and silos to store the biomass fuel. All of these technologies require upfront capital, maintenance and electricity, reducing cost-savings and net electricity production.

Further, biomass requires specially engineered handling adaptations. Biomass like sawdust and woodchips can be transported from storage areas or truck deliveries by air with the help of fans. Pipelines from rotary feeders are another way to transport biomass to burners. The most evident adjustment when integrating biomass is the feeding systems adaptations. A common adaptation to existing boilers is to inject the biomass through a duct at the center of the bottom of the boiler. This placement increases the residence time and reduces risk that unburned carbon will be present in the fly and bottom ash. It is also important to distribute fuel symmetrically and to consider the volume and capacity of the burners.

Burner and air duct adaptations can also improve operations. To prevent self-ignition risks, biomass needs ambient air temperature at the entrance of the burner, so modifying ducts to address this need will ensure a more reliable combustion process. Burner outlet modifications can improve flame formation and stability with more consistent air fluid dynamics.

Overall, equipment adjustments reduce the risk of blockages and ensure consistent burning.

Emissions Controls

Standardizing fuel reduces the variability in emissions, but emissions control adaptations require substantial testing to track operation and maintenance issues. Equipment like baghouses, selective catalytic reduction (SCR) units and flue gas desulfurization (FGD) units are sensitive to the temperature of emissions, the size of particles, the rate of flow and the chemical contents of the fuel. Due to the uncertainty of these impacts, the findings are discussed in the following section.

Literature Review

To build off of the previous sections on emissions the Literature Review will address emissions, fuel volatility, efficiency and overall feasibility.

Alternative fuels may reduce carbon dioxide (CO_2) and sulfur dioxide (SO_2), the implications on mono-nitrogen oxides (NO and NO_2, commonly referred to as NO_x) is uncertain. Since alternative fuels may have to be burned at a greater volume NO_x emission rates may increase when burning alternative fuels.[xi] Antonio Valero performed a study through the Center of Research for Power Plant Efficiency that analyzed the impacts on emissions of replacing 5% of coal with biomass.[xii] The study found a slight reduction of CO_2 (14 ppm to 13.5 ppm) and that NO_x emissions diminished on average 3%. The impacts on SO_2 and particulate matter were inconclusive. Since the moisture content of the biomass did not seem to have an impact, the operators suggested skipping the drying process in future trials.

Valero's study concluded that the volatile content of the fuel when biomass was added did not meet the boiler's requirements.[xiii] Because of this, the flame could potentially burn differently. Through analyzing the heat transfer and irradiation charts, the central coal flame was adjusted to be more centered with biomass, and the change in the flame was not significant enough to alter boiler heat transfer. Even large fuel particle size (5 mm) had no impact on the efficiency of the boiler. More tests need to be performed to determine if a full load of biomass would have dramatically different effects, but overall the load did not seem to impact the functioning of the equipment. This is just one example, but it is a data point in the analysis being performed to see if biomass co-firing is an acceptable fuel to integrate at existing fossil fuel plants.

Regarding efficiency, The Department of Energy (DOE) evaluated biomass fuel switching and concluded that the boiler will be as efficient as a coal-only operation and that biomass costs 20% less than coal.[xiv] The report admits that maintaining this efficiency requires some design and operational changes and that efficiency can decrease by 2% without these adjustments, which occurred with a pulverized coal boiler at a heat input level from biomass of 10%.[xv] The report reassures that these losses can be avoided with equipment modifications. The basis of this report is to evaluate specific examples of co-fired generators as case studies to either support or challenge these claims.

Another study by MitsuiBabcock presents co-firing as a strategy to offset the large volume of resources required to meet electricity demands with biomass alone. [xvi] The study identifies receiving, storing and handling biomass and blending fuels as the most complicated undertakings of co-firing units. MitsuiBabcock concludes that project risks of co-firing increase with the ratio of co-firing since it becomes more difficult to ensure access to high quality fuel, but the study ultimately states that "Large scale biomass co-firing is one of the most efficient and low cost approaches to generating electricity from renewable sources."[xvii]

Plants converting to co-firing with biomass must prove the technical, environmental and economic feasibility of the project. The number of variables (from sourcing fuel to cleaning emissions and disposing of waste) complicates this assessment, especially when the variables are bundled with the public policies in a given region or state and the credits or penalties are associated with burning different fuels in different applications.

Case Study Description

The purpose of the case study is to test the impacts on equipment and operations of co-firing fuels at an existing coal-fired plant. Modifying an existing plant requires capital investments and changes revenue streams; this financial information is necessary to make decisions about fuel choices and operations. Because research does not exist in an accessible and transparent format, it may be difficult for policymakers to gain a full understanding surrounding the complexities of co-firing. A better understanding allows for a more robust analysis and more efficient investment decisions surrounding co-firing units; being able to incorporate market drivers, like future greenhouse gas mitigation policies, makes for an even more comprehensive approach to co-firing decisions. The goal of this research is to identify best practices and optimize the operations at generators to make for economically sustainable co-firing systems, which take into account the additional construction, operations and maintenance costs.

To capture the costs and revenues associated with each fuel type, this report sourced hourly data points from a unit testing co-firing with different fuel mixes and fuels of different energy density. It reveals that slight variations in inputs can result in substantially different heat rates and the subsequent delivery of electricity to the grid. Due to the proprietary nature of this resource, the research cannot give credit to the provider, but a full explanation of the plant and its operations follows. The value of this real-time and granular tracking of inputs and outputs makes this data valuable despite its anonymity.

One reason why it is so valuable is the applications that the data can reveal. In general, the outcomes of the different methods of burning should be able to be projected to other plants of similar size and structure (boiler type, emissions systems and feeder equipment, specifically). After analyzing the operations of this unit, the domestic opportunity for similar installations can be assessed by filtering and sorting existing units that do not yet co-fire to make recommendations about which systems are best suited for this modification. From there, policymakers will have the information necessary to propose new regulations to penalize those plants not taking the initiative to make the investments.

In addition to the economic and technical impacts of co-firing different fuel types and mixes on the equipment and operations, hourly data allows for an assessment of the transition between fuel types and the time required to switch fuels. While the set of data is not over a period of time that is long enough to make annual or lifetime assumptions about maintenance, it does reflect the short-term impacts from switching fuels. Scheduled outages occur in May (15-21 days) and October (7-10 days).[xviii] These are not captured within the data source, so the data does not capture this substantial downtime, but the analysis anticipates the annual costs of this maintenance. As suspected, the more consistently a generator burns a specific type and mix of inputs, the greater the cost savings since this reduces the amount of downtime and ramping up or ramping down costs.

The partnership with the company testing co-firing fuel mixes at a privately-owned generator resulted in 2,700 data points over a four month period of time, from June to September of 2012. This plant serves as the basis of evaluation for the capacity to install similar systems at other plants with a similar size and structure. The following analysis evaluates the efficiencies of combustion at this plant.

Equipment

The unit is a 51 net MW (54 MW nameplate) facility with permits to combust green biomass, clean construction and debris (C&D) wood waste, TDF, petroleum coke and coal. The majority of biofuel needs are met with C&D wood. The system has a circulating fluidized bed (CFB) boiler with modified fuel handling facilities and system upgrades (Appendix 6, Table 6.1). The group also refurbished the steam turbine, and this analysis captures the costs of these improvements wherever possible.

The facility ramps up from cold to full load in 24 hours and from hot to full in 12 hours. The ramp rate is 6 MW per hour above 30 MW. This is important to take into consideration when fuels switch or access to fuel is uncertain. It also alters the costs of maintenance in terms of additional time and labor required to fully engage or disengage during that period of time.

The plant has three emissions control systems: it blends limestone with fuel to control SO_2, uses ammonia and Selective Non-Catalytic Reduction (SNCR) to control NO_x and a baghouse to control particulates. The entire system is controlled by Continuous Emission Monitors (CEMs) to track emissions.

The fuel yard holds 7,000 tons of wood (2,000 tons in a coverall tent building), 3,000 tons of TDF and 3,000 tons of coal. Silos in the generating facility allow the fuel to be blended and differentiated between REC-eligible mixes; the silos hold 2,000 tons of fuel.

Fuel and ash are handled with conveyor, classifier and truck systems. Fuel is fed to the boiler with front and rear wall feeders. Coal, petroleum coke and TDF use the front wall feeders; the rear wall feeders are more adaptable and can handle all fuel types. With this set-up, the facility can reduce outage time by shifting to the front wall feeders without tripping the turbine or losing boiler steam if the biomass blocks the rear wall feeders.

Backup auxiliary and feedwater heating systems are in the process of being eliminated. These additional alterations impact operating costs and avoided future maintenance.

Operations and Fuel

The goal of operating a power plant with a CFB is consistency. The most efficient way to operate is to minimize the amount of time the generator spends offline and control for risks by offering consistent generation. According to the report, the plant aims to send the same amount of heat content in MMBtus to the boiler under all fuel mix scenarios. The data reflects this because over the four month period of data points, the average heat content was 528 MMBtu with a range of 523-534 with 95% confidence level. (This analysis does not include values below 150 MMBtu, which were attributed to ramping up or ramping down periods. The overall average was 387 MMBtu when these data points were included.)

Before the testing period, the plant generally burned a ratio of 70% biomass, 25% tires and 5% coal; under these conditions, the plant is capable of reaching 47 MW of net generation with a heat rate of 13,500 Btu per kilowatt-hour (kWh). There are no limitations on the amount of coal or biomass that the unit can burn, but it cannot burn more than 40% of TDF and small amounts of petroleum coke and waste lubricating oil (Appendix 6, Table 6.2). Based on the available data, the average TDF burned per hour was 32% (Appendix 6, Table 6.3).

From the plant's report, the plant's stated daily combustion rate is 550-600 tons of C&D wood, and it generally operates every day of the week. However, during the time period used in this analysis, average daily combustion was 495 tons of wood. The plant receives deliveries Monday through Friday, with the possibility of receiving a lower volume on Saturday. The plant burns almost entirely REC-eligible wood, which includes up to 5% of glued wood (Appendix 6, Table 6.2).

The plant sells power as a merchant and receives RECs from the associated public institution for burning biomass, depending on the percentage of British thermal units (Btu) attributed to wood. The operators negotiated a 10 year contract that expires in 2018, and eligible fuels receive $11.99 per megawatt hour (MWh). The contract requires a minimum input of 33% of REC-eligible fuel by Btu. While the plant has not met its annual obligation the last two years, it has not been penalized due to further negotiations. Based on the data, it seems that the plant will not reach these minimums in 2012 since the months associated with the data in this research are not burning a high enough volume of wood consistently. Despite this potential to not reach minimum requirements for burning, the plant averages a generation of 11.56 RECs per hour, which is $138.56 in revenue when multiplied by the MWh rate of $11.99. In a 24 hour period, that results in an average total of $3,326. With an 91.5% operating efficiency, as suggested by the report that states a maximum of 31 days of outages each year, the plant is expected to generate over $1.1 million annually in revenue from RECs alone.

The plant in this case study has the ability to provide steam to a nearby manufacturing plant, but it no longer does this. Reestablishing this contract would add another revenue stream, but it is outside the scope of this report.

The fuel is sourced from over 30 different regional suppliers and the team managing this is made up of four experienced employees. The team manages logistics, equipment decisions and transportation; it is essential for this group to collaborate on operations with the plant staff. Further, processing of fuels occurs either at an internally owned center or through third parties, so quality control of fuels is also part of their responsibility.

From the report, the fuel managers believe that the availability of C&D wood is adequate for consistent operations. C&D is solid waste from construction, remodeling or demolition projects and does not contain hazardous or industrial waste. This service is beneficial to companies that want to divert debris away from landfills, which can be costly in some areas. Contracts ensure that the wood has less than 0.5% of non-wood contaminants (although soil and stone is not counted in this calculation), and that it is less than 1% adulterated wood (which includes treated, painted, stained and copper-contaminated wood). It is also contracted to have the following attributes: 6,000 Btu/lb heating value or higher, less than 30% moisture content, less than 3% volume of oversized pieces, which are greater than 3 inches on any given side (Appendix 6, Table 6.2).

Costs

The plant manager in the case study claims that the major operational costs associated with burning biomass are the processing and transportation of the fuel since urban wood "is generally priced at or near $0 per ton." Often, the plant is paid to remove the debris from a site. The plant also has an opportunity to receive chipped forest wood waste, which is generally of higher grade with lower moisture content and lower ash than urban wood. Since urban wood is readily available and chipped forest wood has a resale value, sometimes the fuel operators can receive revenue from distributing this to customers.

Another cost associated with the biomass is fuel storage. Due to the heat content of wood, co-firing with biomass requires more storage space. There is storage onsite, but the plant also rents space for 25,000 tons of biomass storage at two offsite locations. The exact rate of this rental is not available.

The plant has 37 people in total employed to operate it. When the plant started co-firing, the management team added four full time fuel program employees. This 10% increase in staff is sure to have a substantial impact on its operating costs. Exact salaries were not available in the report, nor were these amounts accounted for in the calculation of additional costs incurred (Appendix 6, Table 6.1).

Potentially a special circumstance, the plant installed a dust control system to satisfy lease conditions. This installation involved building a coverall to mitigate dust attributed to biomass, specifically. However, in some examples other plants must install similar structures for coal dust, so this is a cost that might be avoided, either if it is not necessary given the fuel type or if it is a sunk cost already confronted by the existing plant.

The relationship between limestone and biomass is not clear from the data. A linear regression of the data points suggests that there is a slight increase in limestone consumed with more wood (in tons) is combusted (Appendix 6, Figure 6.1). However, when other conditions, like coal and TDF rates were held constant, linear regressions illustrated slight decreases in limestone use (Appendix 6, Figures 6.2-6.4). This can be explained that in the data set, coal use is always accompanied with wood, so perhaps there is a positive relationship between coal and limestone, which happens to be accompanied by an increase in wood. For this reason, it seems that the plant would reduce limestone use while co-firing and encounter cost-savings, correcting the positive correlation between the amounts of limestone and wood that was initially identified.

Savings

Clearer savings than those correlated with limestone, when burning biomass the plant saves money from not purchasing coal and ammonia (raw materials cost), producing less ash (disposal costs) and emitting less SO_2 (abatement costs). Unfortunately this study does not quantify or aggregate these savings. The plant's report included a table of initial costs with operating benefits (Appendix 6, Table 6.1). These benefits substantially outweigh the costs, and the payback period is seven months based on the summation.

Less clear potential savings opportunities involve ash disposal, emissions and taxes.

One thing that complicates the ash disposal cost is that the quality of the ash produced is lower and the resale value does not exist as it may under certain circumstances where only coal is burned.

To address emissions offsets the plant in the case study has not had to purchase NO_x or SO_2 emission offsets since burning biomass. For the purpose of this study, we can assume that a unit of similar size and burning a percentage of biomass fuel of equal value will also avoid emissions offsets. In the written report about the plant, the generator will no longer use the SNCR unit, which suggest that other plants with NO_x control units will not have to use those either. For that reason the research suggests that an alternative to installing a NO_x emission control system could instead burn biomass and avoid paying offset penalties.

In a similar fashion, the plant believes that it can meet new mercury regulations with periodic testing, which means that it avoids the costs of installing and operating new equipment. Since this equipment is not yet installed, but would have to be if the plant were to continue to burn only coal, this value may be captured in the valuation of the benefit of burning biomass fuel. This is a significant dollar amount that is available to the plant at the present time, instead of having to install additional equipment that will not be used at a later date, like the SNCR unit.

While not available in a quantitative or dollar value, the report of the plant suggests that the property and tax credits available to the operator for including biomass in the fuel mix are of value. This report does not attempt to capture such values because they vary significantly from region to region. Instead, it is viewed as an added benefit of burning biomass that is not captured.

High Value Scenarios

The purpose of this section is to track daily scenarios with high Independent Service Operator (ISO) net outputs, limestone usage and REC production. By making assumptions about the conditions impacting these variables, the case study will be able to suggest best practices in electricity generation at such a plant.

Initially, looking at net outputs, three days with high ISO net output values occur in the second months of testing: August 6th, September 15th and September 23rd (Appendix 7, Figures 7.1-7.3). On average throughout the testing period, the plant generated 637 MWh ISO net output per day, 26.5 MWh per hour. All three days have an average hourly net output between 41 and 44 MWh per hour. Although August 6th does not have data for the entire day, the hours that do have data are consistently above 42 MWh per hour and the day created 366 RECs (Appendix 7, Figure 7.1). However, the amount of wood drops to 40% around hour 5, which is a 30% decrease from hour 3 to 5. September 15th is a day with greater volatility throughout the day. Producing a total ISO net output of 987 MWh, an average of 41 MWh per hour, the generator receives 465 RECs that day (Appendix 7, Figure 7.2). The volatility can be seen as the output drops below 30 MWh per hour at hour 4 and jumps to 46.5 MWh at hour 13. Based on the research of efficient generators, this is not an ideal scenario since consistent operations and electricity generation is the most cost effective means to produce a desired outcome given a sufficient supply of fuel. From these three days of high ISO net output, September 23 seems to be the most ideal. ISO net output has little variability with a range of 2.3 MWh, between a maximum of 44 MWh and a minimum of 42 MWh in the 24 hour period of time. This day generates a total of 1,032 MWh with 570 tons of wood, at an average of 48% wood, with 495 RECs created throughout the day. This scenario is the best example of generation based on the assumption that consistent operations minimize costs.

Shifting the analysis to evaluating inputs, the data illustrates relationships between limestone and the generation of electricity. Three days with particularly high limestone usage are June 28th, September 29th and July 7th. Throughout the testing period, daily average limestone use was 26 tons. June 28th used 50 tons of limestone, injecting an average of 4,000 pounds of limestone every hour with a range of 1,900 to 8,600 pounds. The variability of limestone mimics the ISO net output values, but this day in particular used only coal and TDF to generate electricity. These fuels generated 840 MWh but no RECs over the 24 hour period. This mix of fuels and the high use of limestone make this an unattractive scenario, but a useful benchmark. September 29th used 65 tons of limestone, an average of 5,400 pounds every hour, with a maximum injection of 11,200 pounds at hour 17. At this hour, the plant was burning 47% wood, 24.4 tons, which was not the most quantity of wood burned that day. It also wasn't the highest heat rate achieved that day. In total, the plant produced 1000 MWh ISO net output and 493 RECs that day. The excessive use of limestone does not seem to have a good explanation from the data. July 7th is a day with higher average heat rates, 60 tons of limestone. The limestone use is more consistent, varying only from 3,300 pounds to 8,300 pounds per hour. The plant burned an average of 45% wood to produce 983 MWh through the course of the day, but the variability is substantial: at hour 21, the generator is burning more than 61% biomass, but in the next hour it burns only 27% biomass and in hour 8 it only burned 34% biomass. With 443 RECs, this combination of elements seems to be the least excessive scenario of the extreme settings. While none of these maximum scenarios of limestone are optimal, it is valuable to look at the most reasonable of these potentially expensive situations with high rates of inputs. Perhaps this was a testing day to deal with worst case scenarios to see if burning a highly variable volume of biomass with a high amount of limestone is still a financially feasible process. Unfortunately this study is not able to determine that precisely, but the number of RECs with the net output suggests that the variable costs could be offset be the revenues even in these extreme circumstances.

Depending on the contracted value of the RECs, these credits may or may not be a determining revenue stream for a plant burning fuels which are REC eligible. This report analyzes three days of high REC production: July 17th, July 10th and September 28th. The day that generated the most RECs within the data set is July 17th with 677 RECs. In the case of this plant, that reflects a value of $8,120, just in one day of generation, or nearly $3 million if this rate were to continue over the course of an entire year, taking into account downtime of 31 days in a calendar year. While this may not be a realistic forecast of actual production, it serves a role as a comparative value. The daily average percentage of wood burned in an hour was 93%, nearly 100%. During this day, there were examples of extreme variability, seen at hour 6, when less than 1 ton of wood was burned, 4.5% of the total volume of fuel, and only 0.6 RECs ($6.78) were generated in an hour. Despite the somewhat consistent generation of electricity as exhibited by the ISO net output numbers (712 MWh in total, average of 30 MW per hour), this specific example within this scenario is far from the ideal situation. Another example of a day that generated a high amount of RECs is July 10th. This is also not a realistically sustainable option since the percentage of wood combusted is nearly 99% for the hours in which it operated. Unless a plant of this size has access to nearly 20 tons of wood for every hour that it operates, the outcome of REC generation will not be of this value. Despite this consistent usage of wood, the variability of ISO net output and heat rates is within the normal boundaries of a daily production of electricity. Further the generation of RECs for the day was only 486 credits, or $5,800 primarily due to the 4 hours where RECs weren't produced when no wood was burned. The most realistic of the scenarios in this analysis occurs on September 28th. This is a more normal generation example, with wood making up an average of 54% of the fuel burned. The total RECs generated amounts to 509, or $6,100 for the day. While the ISO net output shifts from an average of 34 MWh per hour in hours 1-6 of the day and 42 MWh per hour in the remaining 17 hours of the day, the tons of wood burned averages to 25 tons per hour. The sustainability of generation at this rate is the true determining factor in this situation. If feasible, this is the most attractive scenario of the three referenced above due to the consistent generation of RECs and electricity. Producing at a rate like this will allow plant managers to make realistic forecasts of generation and revenues.

The trends in the data are the next part of this analysis. For example, a series of days in July seem to produce a high number of RECs while the majority of September produces a consistent amount of RECs (Appendix 8, Figure 8.1). The patterns suggest that the plant tested extreme scenarios, but eventually worked within a range of sustainable options.

By plotting RECs with estimated heat rates for the nearly two thousand data points that contain data for both variables above zero, the most populated cluster suggests the boundaries of the value associated with the majority of the operating hours within the scope of this testing period (Appendix 8, Figure 8.2). However, more significant than this cluster is the optimal horizon, those points on the upper right that form a trend line of combination of maximum values, the production possibilities frontier. By picking out these points in the data, the study aims to balance the value of generating a high number of RECs with the ability to produce high heat rates and the associated net output of MWh. Both of these fields are revenue-producing elements, which need to be weighed against fields requiring cost: coal, potentially TDF and limestone, for example.

None of the seven scenarios along this feasibility horizon of high REC production and high heat rates selected for a deeper dive into the fuel mix and combustion use coal (Appendix 8, Table 1). This alone suggests a high economic efficient since each example completely avoids fuel as an expense. By focusing on the somewhat labor-intense activity of sourcing TDF and wood, the data suggests that this generating unit can produce valuable heat rates while using significant amounts of REC-eligible wood.

The one hour data points occur on seven different dates: June 9th, July 16th, 17th and 20th, August 5th and 27th and September 16th.

July 20th uses a higher amount of TDF (50% by weight) than is used on an average basis (32% for the year), so this data point does not seem like a sustainable option under current conditions. Without a conversion of tons to volume, this report cannot say with certainty that this fuel mix fits within the boundary of 40% maximum TDF by volume. Additionally, the number of RECs produced is at the average for the entire data set, so this data point does not optimize conditions unless TDF is a fuel that is acquired and combusted in a way that cuts costs. Without this information, the report cannot conclude that this mix is ideal. Further the impacts on the equipment of burning TDF at this rate may require additional maintenance and downtime (source, if true).

August 27th fails to produce an economically attractive amount of RECs due to the low volume of fuel even though the estimated heat rate is the highest of the seven data points; this hour generates an ISO net output of less than 5 MWh in one hour (Appendix 8, Table 8.2).

With two dates discarded (July 20th and August 27th), the analysis of the remaining five points on the optimal frontier includes points with varying combinations of wood and TDF. All data points are above the hourly average of 26.9 MWh ISO net output values for the entire sample. July 16th and 17th produce the highest RECs, 31 and 33 respectively, but the data points have the lowest ISO net output of the remaining data points, 31.2 and 32.8 MWh in an hour.

By assigning a rating system that divides the data point's actual production of RECs and ISO net output by the maximum values of the data set, the desired outcomes are compared in a quantitative way (Appendix 8, Table 8.3). As can be expected, the point with the highest RECs rating, July 17th, has the lowest Output rating of the remaining five data points. In contrast, the data point with the highest Output rating, September 16th, has the lowest RECs rating. If either RECs or ISO net output had a greater degree of significance when making generation decisions, then this analysis would recommend one of these data points as the optimal fuel mix. Since this information is not available, the study takes on the assumption that both outputs have equal importance.

When the individual ratings for RECs and ISO net output are summed, two data points, June 9th and August 5th, generate higher combined scores than the highest ranked data point in either field (RECs and ISO net output) independently.

Before the report addresses the highest scoring outcomes, it is important to note that July 16th ranks fourth out of the five with 31 MWh of RECs and 31.2 MWh of generation. July 16th burns a larger amount of wood and the same amount of TDF, uses the same amount of limestone and yet this point generates less electricity and fewer RECs. This can be explained since, holding all other inputs constant, the estimated heat rate decreases with an increase in the percentage of wood burned, from 13,174 tons on July 16th to 9,470 tons on July 17th. Because of the similarities in these two data points, July 17th is always a more optimal fuel mix based on the generation of RECs and ISO net output.

The highest scoring outcomes when both RECs and ISO net output are taken into account are June 9th and August 5th. The fuel mix between these two data points is similar, but overall June 9th seems to be the preferred combination because it generates slightly higher RECs with less fuel despite the wood having a lower heat content, which creates a lower estimated heat rate. Both combinations create around 27 RECs, but with closer precision, August 5th produces 26.7 RECs while June 9th produces 27.0 RECs. Over the entire year, this difference sums to 2,410 RECs and $28,907 of revenue. This impact scaled to an annual output demonstrates the degree to which small variations can alter the benefit of inputs.

Another variation to examine more thoroughly is the difference in the heat content of the wood. June 9th wood heat content is 5,852 Btu/lb, which is well below the average heat content of 6,271 Btu/lb for all data points. While changing this input in the spreadsheet does not reflect the higher ISO net output generation that would be associated with this, it does increase the RECs generated by 5,316 over the course of the year, or $63,743. While it is tempting to negate small variations in inputs, it is clear that changes of this nature can alter the outcomes in a way that would encourage a plant to change business decisions. The difference between these two data points when the June 9th values include the higher wood Btu/lb value increases to $92,651 for a year of generation with these inputs, 3.6% higher. This is with a value of 5.8% fewer fuel inputs (including nearly 7,000 tons less TDF and 18,724 tons less wood when scaled over the course of a year) and the generation of 2.6% higher ISO net outputs. With this standardization of wood heat content, June 9th is the clear preference of these two data points.

This analysis does not take into account the higher costs associated with limestone. The data suggests that the fuel mix of June 9th would require 2,695 additional tons of limestone annually, 25.5% more than August 5th requires. Depending on the cost of this input, this may be a deciding factor for the feasibility of this fuel mix. Another uncertainty is that June 9th occurred so early in the testing period that perhaps the operating team became better educated about how to apply limestone throughout the course of the testing period. By looking at six data points throughout the year with similar amounts of inputs (10-12 tons of TDF, more than 36 tons of wood), it appears that, in reality, 1.62 tons of is the average. Because of this, it seems that the variation in limestone is perhaps just an anomaly and may not actually be that different if operating with the fuel mix on a consistent basis. When plotted, limestone usage does not have a correlation with wood (Appendix 6, Figure 6.1), but the trend line suggests that combusting more wood requires more limestone. However, this fails to hold the other variables constant. When TDF is held constant in the range of 10.3 to 11.2 tons, the correlations are no more apparent, and trend lines suggest a slightly negative correlation with amount of fuel and amount of limestone (Appendix 6, Figures 6.2-6.4). Even when the points that burn coal are filtered, the trend is that more fuel (either wood or coal) is associated with less limestone. From this, the ability to predict limestone application is inconclusive and requires further analysis than this data set can illustrate.

The biggest limitation of either of the options, June 9th and August 5th is the amount of wood that is required to meet these outcomes. To produce such RECs requires a substantial amount of wood. These two data points are actually the two highest values of wood in tons from the entire data set. Depending on the feasibility of having access to this amount on an hourly basis, the ability to produce such results may not be realistic. However, this study assumes that since this set of inputs produces the optimal outcomes, it is in the plant’s best interest to acquire fuel, even if it comes with a slight cost. With increasing fees for wood disposal, access to materials may become easier over time. Another benefit of having such consistently high demands for the materials is the building of relationships with vendors and suppliers of these materials.

In reality, the average amount of wood burned hourly throughout the data set is 13.4 tons, and filtering out days that don’t burn any wood or burn low quantities only increases this average to

19.2 tons. This alone is an item of concern to be taken into account when making a recommendation for generation since it is possible that the volume of wood is not a feasible amount to burn on a consistent basis. The total amount of wood needed for the June 9th generation is 338,640 tons and August 5th requires 357,365 tons. Under closer inspection, August 5th uses only dry wood in combustion, while June 9th uses 86.3% wet wood in combustion.

Using the Emissions and Generation Resource Integrated (eGRID) 2009 database, there are twenty plants with 43 boilers in total with coal-fired fluidized bed boilers that do not have NO_x control systems (Appendix 9, Table 9.1).[xix] The significance of this is that the case study plant's report claimed that it would no longer use the SNCR unit. For this reason, co-firing biomass becomes even more valuable to these plants to avoid meeting NO_x emission standards and installing this equipment. These 43 boilers represent 4,975 MW of capacity.

Additional filters can help narrow this field of potential units to convert to co-firing. Since the case study is a unit with a 54 MW boiler, plants with a boiler of similar size are the most appropriate to analyze in this study. Also the exact nameplate capacity of the boiler is not certain if there are multiple boilers at a plant because that information is not available within the eGRID database. This report assumes that all of the boilers are of similar size, dividing the nameplate capacity by the number of boilers to get the average nameplate per boiler.

Filtering for actual size of the boiler (those within 25 MW capacity of the case study boiler), which includes a sensitivity for the number of boilers at a plant (more than two decreases the likelihood that a boiler exists with the predicted nameplate). This reduces the list to Lamar Plant, Rumford Cogeneration and Purdue University with Wyandotte added to the list, even though it is more than 25 MW larger, since there is only one boiler, which guarantees that the capacity is 78.4 MW (Appendix 9, Table 2).

Selecting the best fit, Lamar Plant, it is possible to dive deeper to evaluate how valuable a co-firing initiative would be at this plant. Located in Colorado, which is an area different than the plant in the case study, this plant is virtually the same size as the case study plant. While building costs may be substantially different, it can be assumed that the upfront costs will be similar to those confronted in the case study, which totaled to $10.2 million. Benefits of steam revenue, grants, beneficial use determination (BUD) values on ash and TDF fluff cannot be assumed to be the same. The research performed for this report was not able to estimate a long-term contract for RECs, but it is not likely to reach the $11.99/MWh attributed to biomass that the case study plant was able to capture based on the current uncertainties of the market for such credits.

Regardless of these uncertainties, this report strongly recommends the Lamar Plant to undergo a conversion to co-firing for the following reasons: aligns with RPS standard, reduces plant emissions and improves public relations.

Colorado has an RPS that accepts biomass to meet the goal of 30% renewable energy by 2020.[xx] As time moves forward, opportunities for the state to meet that goal become more valuable. Converting an existing 55.7 MW plant represents a cost-effective way for Colorado to meet those requirements. The RPS has a multiplier of 1.25 for those credits produced within the state. Located in southern Colorado, the plant serves nearby communities in Colorado and New Mexico.[xxi]

The plant has confronted a number of emissions challenges since it converted to coal from natural gas in 2003.[xxii] This was a $153 million project, which boosted the capacity from 25 to 43 MW.[xxiii] In September 2012, a judge ruled that the Lamar Power Plant had not met a requirement for regulating emissions of hazardous pollutants for the coal-burning plant, for four years; the plant likely violated the Clean Air Act and will face monetary penalties, according to the Chieftan.[xxiv] The plant has struggled with controlling the dust attributed to the plant, which has impacted the neighboring community without any alleviation of this problem.[xxv] Taken offline in November 2011, the plant is losing substantial revenues; electricity rates in the region are nearly 50% higher than the national average, at 14.83 cents per kilowatt hour (kWh) in 2011[xxvi] compared to 9.9 cents per kWh nationally[xxvii]. Even before the lawsuit, the plant operated 1,500 hours in 2004, which is about 80% less than normal operations when compared to the case study plant.[xxviii] Co-firing with biomass not only reduces the amount of coal dust onsite but also improves emissions on the back end, according to the research referenced in this study.

To further cut down on costs and improve overall public relations, this report suggests that the Lamar plant offset coal with biomass and TDF. The town of Hudson processes tire waste, and it is located three hours from the Lamar plant. With a recently upgraded boiler, it is not efficient for the utility not correct the operations and structure of the plant to produce electricity and meet current power plant regulations. Assuming the $10 million of conversion cost to co-fire is substantially lower than the lost revenue from not operating. The violation fee of potentially $37,500 for each day during the period of violation (totaling to $54.8 million over 4 years), the Lamar plant can potentially negotiate these charges by demonstrating an investment in clean and renewable energy practices.

Based on the alignment with Colorado's RPS, the reduction of emissions and the improvement of public relations, even without a granular net present value calculation it is apparent that the initiative is positive based on the experience of the case study plant, which has similar plant characteristics. Taking into account that the plant has access to fuel resources, a net positive electricity sales structure and potential for additional REC revenues, it is in the plant's best interest to get back online as quickly as possible.

While this is only one example of an application of converting an existing coal-fired power plant to co-fire with biomass, this analysis creates a foundation for further research. More specific and a wider array of information related to the upfront expenses of converting to co-firing would substantiate the claims and findings of the case study referenced in this report. A model that captured the current status of a plant at a particular size with certain equipment conditions would be a valuable tool for policymakers and operators to enter the plant's conditions and calculate potential savings from the conversion.

Even more specific, research related to the biomass process would help capture the impact of co-firing. Research related to the pretreatment of biomass with rotary driers and sifters and comparing that to burning unprocessed biomass would be beneficial to see if that investment has a positive outcome in terms of electricity produced with the available fuel. Innovations to fuel handling and feeding systems to standardize the way that those are adapted would allow a plant to make a more educated decision about the engineering of the modified system. A closer look at the harvesting of biomass would help a plant understand long term impacts of relying on fuel that has less certain availability than coal. A sensitivity analysis around the price of biomass could show conditions in which biomass costs more to transport than it offers in value of combustion. Of course the environmental impacts of all of these conditions are significant and relevant to the research initiated with this report.

Finally, accessible and transparent research related to the combustion process in terms of chemical reactions could help policymakers understand the complexity of fuels to make effective policies that promote efficient energy systems. This efficiency could also be looked at through the lens of access to alternative fuels and evaluating how to better guarantee those supplies.

Clearly this text opened the opportunity to evaluate co-firing biomass from a number of different perspectives that better capture its long term costs and benefits given a set of conditions.

Conclusion

This report accomplished two goals: (1) to present complex information about co-firing with biomass at existing plants in a format that is accessible to policymakers and (2) to apply the optimal findings from a case study to capture the opportunity in the US market for similar conversions.

By understanding the systems required to co-fire biomass, policymakers can design regulations that account for the costs and benefits of these initiatives. Creating similar evaluations for other technologies eligible for RECs will level the playing field and help government entities and electricity companies alike make educated decisions about how to meet current and future energy demands in the most efficient manner, both technologically and economically.

While there are opportunities to capture these costs and savings in a more quantitative way, this report forms a foundation of knowledge with a complementary case study to give readers a sense of the intricate evaluations that each unit needs to perform to determine how to attain the desired outcome of production at the lowest cost.

Acknowledgements

Tim Johnson, Associate Professor of the Practice in Energy and the Environment at the Nicholas School of the Environment is my primary advisor responsible for evaluating this project. I would like to acknowledge the data contributed to this research by a professional working in the field. The amount of information I was able to capture from the hourly data points shared with me was instrumental in my evaluation process.

Appendices

Appendix 1: Electricity Generation

Table 1.1. Net Generation by Energy Source: Total (All Sectors), 2002-December 2012[xxix]

Year	Coal	Petroleum Liquids	Petroleum Coke	Natural Gas	Other Gas	Nuclear	Hydro	Other renewables	Hydro Pumped Storage	Other	Total
2002	1,933,130	78,701	15,867	691,006	11,463	780,064	264,329	79,109	-8,743	13,527	3,858,452
2003	1,973,737	102,734	16,672	649,908	15,600	763,733	275,806	79,487	-8,535	14,045	3,883,185
2004	1,978,301	100,391	20,754	710,100	15,252	788,528	268,417	83,067	-8,488	14,232	3,970,555
2005	2,012,873	99,840	22,385	760,960	13,464	781,986	270,321	87,329	-6,558	12,821	4,055,423
2006	1,990,511	44,460	19,706	816,441	14,177	787,219	289,246	96,525	-6,558	12,974	4,064,702
2007	2,016,456	49,505	16,234	896,590	13,453	806,425	247,510	105,238	-6,896	12,231	4,156,745
2008	1,985,801	31,917	14,325	882,981	11,707	806,208	254,831	126,101	-6,288	11,804	4,119,388
2009	1,755,904	25,972	12,964	920,979	10,632	798,855	273,445	144,279	-4,627	11,928	3,950,331
2010	1,847,290	23,337	13,724	987,697	11,313	806,968	260,203	167,173	-5,501	12,855	4,125,060
2011	1,733,430	16,086	14,096	1,013,689	11,566	790,204	319,355	193,981	-5,905	14,154	4,100,656
2012	1,517,203	13,209	9,691	1,230,708	11,212	769,331	276,535	218,787	-4,658	12,466	4,054,485

Table 1.2. Net Generation, Disaggregated Steam Turbine and Biomass[xxx]

Produced by steam turbines (%)	Produced with biomass given steam turbine (%)	Total annual generation from biomass (GWh)
72.53%	1.92%	53,709
72.79%	1.89%	53,341
72.87%	1.85%	53,538
73.44%	1.82%	54,276
72.69%	1.86%	54,861
73.67%	1.81%	55,539
72.74%	1.84%	55,034
70.78%	1.95%	54,493
71.63%	1.90%	56,089
69.77%	1.98%	56,671
70.45%	2.02%	57,565
Increase since 2007	11.1%	3.6%

Appendix 2: Biomass Units

Table 2.1 Database of US Co-firing Initiatives[xxxi]

State	Plant name	Co-firing type	Boiler	Burner configuration	Thermal Output (MWe)	Wood?
GA	Harlee Branch Generating Station	Direct	PF	Opposed fired	1539	Yes
KS	La Cygne Generating Station #1	Direct	PF	Cyclone, supercritical	840	Yes, some
IO	Ottumwa Generating Station #1	Direct	PF	T-fired with 6 levels	650	No
MN	King (Allen S.) Generating Station #1	Direct	PF	Cyclone	560	Yes, some
IN	Michigan City Generating Station #12	Direct	PF	Cyclone	469	Yes, some
SD	Big Stone Plant #1	Direct	PF	Cyclone	450	No
FL	Lakeland Electric #3	Direct	PF	Wall fired	350	No
TN	Allen (T.H.) Fossil Plant	Direct	PF	Cyclone	272	Yes
NM	Escalante Generating Station #1	Direct	PF	T-fired with 5 levels	250	No
PA	Shawville Generating Station #3	Direct	PF	T-fired with twin furnace	190	Yes
AL	Colbert Fossil Plant #1	Direct	PF	Front wall fired	182	Yes
TN	Kingston Fossil Plant #5	Direct	PF	T-fired with 3 levels	180	Yes
MO	Thomas Hill Energy Center #2	Direct	PF	Cyclone	175	Yes
SC	Lee (W.S.) Steam Station #3	Direct	PF	T-fired with 5 levels	170	Yes
SC	Jefferies Generating Station #3 and #4	Direct	PF	Wall fired	165	Yes
FL	Gannon (F.J.) Generating Station #3	Direct	PF	Cyclone	165	No
IN	Bailey Generating Station #7	Direct	PF	Cyclone	160	Yes, some
PA	Shawville Generating Station #2	Direct	PF	Wall fired	138	Yes
NJ	BL Station #1	Direct	PF	Cyclone, Front wall fired	120	Yes
NY	Greenidge Generating Station #6	Direct	PF	T-fired with 4 levels	108	Yes
GA	Hammond Generating Station #1	Direct	PF	Front wall fired	100	Yes
WI	Blount Street	Direct	PF	Wall fired	100	No
NY	Dunkirk Steam Station #1	Direct	PF	T-fired, natural circulation	90	Yes, some
ME	Rumford Cogen Co.	Direct	CFB	Circulating fluidized bed	76	Yes, some
IL	Vermilion Power Station #1	Direct	PF	T-fired	75	Yes
GA	Southeast Paper	Direct	CFB	Circulating fluidized bed	65	No
AL	Gadsden Steam Plant #2	Direct	PF	T-fired with 3 levels	60	No
GA	Savannah Electric and Power Company	Direct	PF		54	Yes
VT	McNeil Generating Station	Indirect	Grate	Stoker grate boiler	50	Yes
GA	Kraft / Riverside Plants #2	Direct	PF	T-fired with 2 levels	46	Yes
WI	Bay Front Station	Direct	Grate	Stoker grate boiler	44	Yes, some
PA	Seward Generating Station #12	Direct	PF	Wall fired	32	Yes
WA	City Of Tacoma Steam Plant No. 2	Direct	BFB	Bubbling fluidized bed	18	Yes, some
NY	ReEnergy Black River	Direct	CFB	Circulating fluidized bed	56	Yes, some
NY	UDG Niagara Goodyear	Direct	CFB	Circulating fluidized bed	56	No
PA	Spring Grove Paper Mill	Direct	CFB	Circulating fluidized bed	70	Yes, some
ND	North Dakota State Penitentiary	Direct	Grate	Traveling grate	<1	Yes
PA	NIOSH	Direct	Grate	Stoker grate boiler	<1	Yes
PA	Pittsburgh Brewing Company	Direct	Grate	Traveling grate	<1	Yes

Appendix 3: Combustion

Figure 3.1.1 Pulverized Fuel Boiler[xxxii]

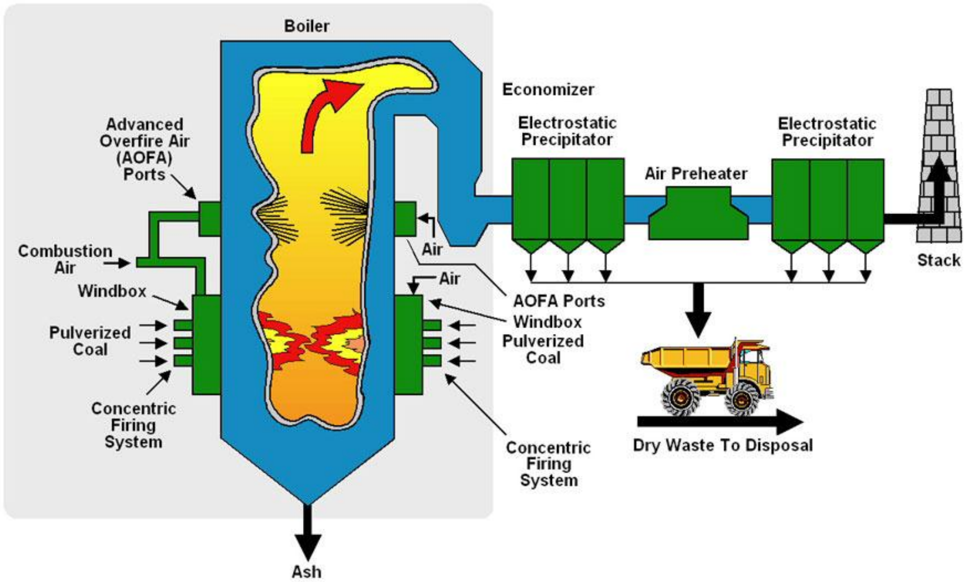


Figure 3.1.2 Non-Tangential (A) Vs. Tangential (B) Firing[xxxiii]

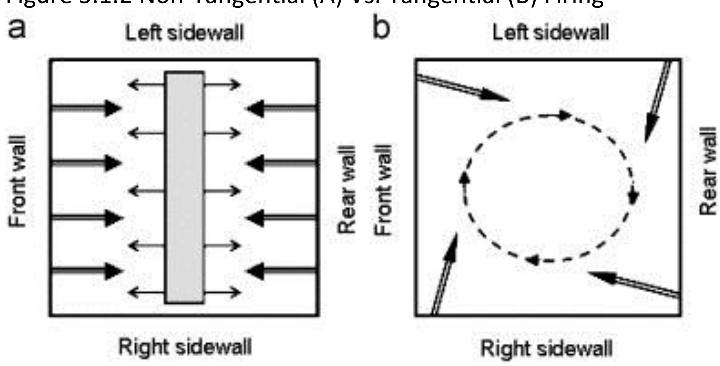


Figure 3.2 Cyclone Boiler[xxxiv]

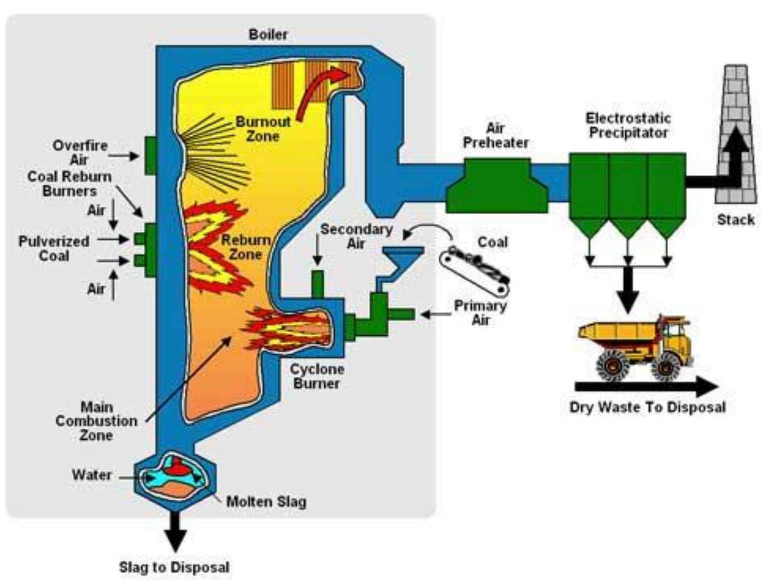


Figure 3.3 Stoker Boiler[xxxv]

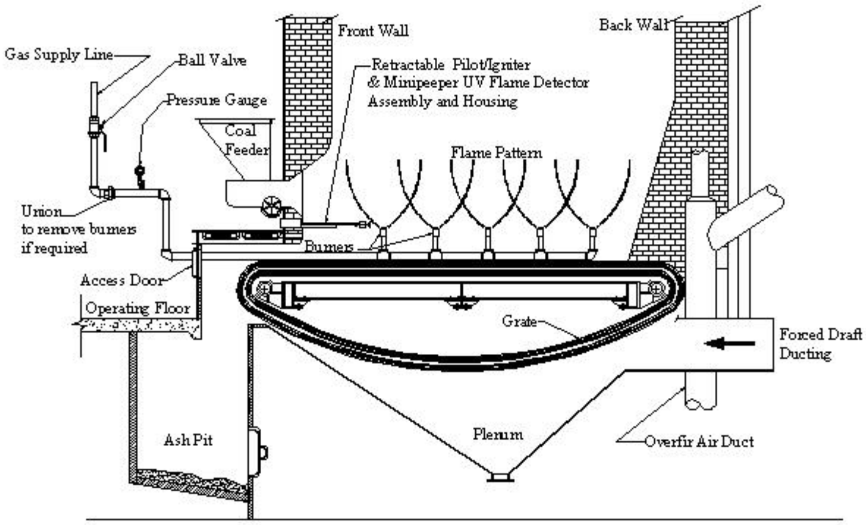


Figure 3.4 Fluidized Bed Combustion Boiler System[xxxvi]

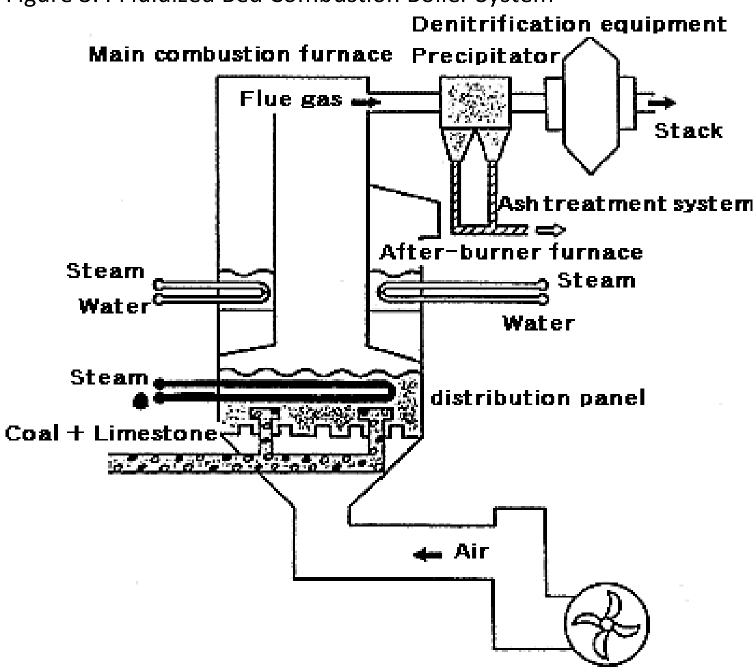


Table 3.1 Biomass Combustion System Efficiencies[xxxvii]

Direct Fired Biomass Boiler vs. Co-fired Biomass vs. Gasification Combined Cycle						
	1995	2000	2005	**2010**	2015	2020
Capacity Factor %						
Boiler	80	80	80	**80**	80	80
Co-fired	85	85	85	**85**	85	85
Gasification	80	80	80	**80**	80	80
Electrical Efficiency %						
Boiler	23.0	27.7	27.7	**27.7**	30.8	33.9
Co-fired	32.7	32.5	32.5	**32.5**	32.5	32.5
Gasification	36.0	36.0	37.0	**37.0**	39.3	41.5
Net Heat Rate (BTU/kWh)						
Boiler	14,483	12,322	12,322	**12,322**	11,194	10,066
Co-fired	10,440	10,489	10,489	**10,489**	10,489	10,489
Gasification	9,478	9,478	9,222	**9,222**	8,720	8,218

Table 3.2 Fuel Characteristics[xxxviii]

	LHV (MJ/kg)	Density (kg/m^3)	Energy density (MJ/m^3)
High rank coal	26.0	1,500	39,000
Low rank coal	16.3	1,000	16,300
Forest biomass	17.2	700	12,040
Olive tree	19.0	1,000	19,000

Table 3.3 Compositional Analysis of Woody Biomass Feedstocks[xxxix]

Fuel	Woody Biomass									
Type	Hybrid Poplar		Poplar Chips - Coarse		Fir Mill Waste		Alder/Fir Sawdust		Forest Residuals	
	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry
Ash	2.51	2.7	1.49	1.6	0.15	0.41	1.96	4.13	2.03	3.97
Moisture	6.89	--	6.74	--	63	--	52.63	--	48.91	--
Chlorine %	0.01	0.01	0.04	0.04	0.07	0.19	<0.01	0.02	0.02	0.04
Alkali, Lb/MMBtu		0.32		0.4		0.14		0.35		0.49
HHV, BTU/lb	7,615	8,178	7,590	8,139	3,248	8,779	4,150	8,760	4,429	8,670
Ultimate Analysis										
Carbon	46.72	50.18	47.39	50.82	18.95	51.23	24.17	51.02	25.7	50.31
Hydrogen	5.64	6.06	5.49	5.89	2.21	5.98	2.75	5.8	2.35	4.59
Oxygen	37.66	40.44	38.32	41.08	15.66	42.29	18.25	38.54	20.42	39.99
Nitrogen	0.56	0.6	0.55	0.59	0.02	0.06	0.22	0.46	0.53	1.03
Sulfur	0.02	0.02	0.02	0.02	0.01	0.03	0.02	0.05	0.06	0.11
Ash	2.51	2.7	1.49	1.6	0.15	0.41	1.96	4.13	2.03	3.97
Moisture	6.89	--	6.74	--	63	--	52.63		48.91	--
TOTAL	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**
Ash Composition										
SiO2		5.9		0.88		15.17		35.36		17.78
Al2O3		0.84		0.31		3.96		11.54		3.55
TiO2		0.3		0.16		0.27		0.92		0.5
Fe2O3		1.4		0.57		6.58		7.62		1.58
CaO		49.92		44.4		11.9		24.9		45.46
MgO		18.4		4.32		4.59		3.81		7.48
Na2O		0.13		0.23		23.5		1.71		2.13
K2O		9.64		20.08		7		5.75		8.52
SO3		2.04		3.95		2.93		0.78		2.78
P2O5		1.34		0.15		2.87		1.9		7.44
CO2/other		8.18		19.52		18.92		1.85		
Undetermined		1.91		5.43		2.31		3.86		2.78

Table 3.4 Fuel Analysis Of Biomass

	Sawdust	Urban wood waste	Switchgrass	Alfalfa stalks
Proximate analysis (wt%)				
Fixed carbon	9.34	12.5	12.19	15.62
Volatile matter	55.03	52.56	65.19	68.06
Ash	0.69	4.08	7.63	5.84
Moisture	34.93	30.78	15	10.48
Ultimate analysis (wt%)				
Carbon	32.06	33.22	39.68	40.6
Hydrogen	3.86	3.84	4.95	5.15
Oxygen	28.17	27.04	31.77	36.02
Nitrogen	0.26	1	0.65	1.83
Sulfur	0.01	0.07	0.16	0.09
Ash	0.69	3.99	7.63	5.9
Moisture	34.93	30.84	15	10.48
Higher heating value (GJ/t)	10.39	11.07	12.62	13.59
Higher heating value (Btu/lb)	5431	5788	6601	7108
Volatile/fixed carbon ratio	5.89	4.2	5.35	4.35

Table 3.5 Fuel Analysis Of Coals

	Black thunder	White oak (PRB)	Upper freeport (UT)	Illinois #6 (PA)
Proximate analysis (wt%)				
Fixed carbon	34.94	43.34	56.76	44.98
Volatile matter	30.72	38.23	22.69	35.32
Ash	5.19	7.84	13.03	7.43
Moisture	29.15	10.59	7.52	12.27
Ultimate analysis (wt%)				
Carbon	51.3	63.5	69.14	66.04
Hydrogen	2.87	4.37	4.04	4.38
Oxygen	10.46	12.24	2.54	5.66
Nitrogen	0.68	0.9	1.18	1.4
Sulfur	0.35	0.56	2.13	2.79
Ash	5.19	7.84	13.03	7.43
Moisture	29.15	10.59	7.52	12.27
Higher heating	17	22	23.02	22.44
Higher heating value (Btu/lb)	8888	11499	12035	11731
Volatile/fixed carbon ratio	5.89	4.2	5.35	4.35

Appendix 4: Biomass Fuels

Table 4.1 Energy Source Descriptions[xl]

Renewable Fuels - Biomass		
AB	ORW	Agricultural Crop Byproducts/Straw/Energy Crops
MSB	MLG	Municipal Solid Waste – Biogenic component
OBS	ORW	Other Biomass Solids
WDS	WWW	Wood/Wood Waste Solids (paper pellets, railroad ties, utility poles, wood chips, bark, other wood waste solids)
OBL	ORW	Other Biomass Liquids
BLQ	WWW	Black Liquor
SLW	ORW	Sludge Waste
WDL	WWW	Wood Waste Liquids excluding Black Liquor (Includes red liquor, sludge wood, spent sulfite liquor, other wood-based liquids)
LFG	MLG	Landfill Gas
OBG	ORW	Other Biomass Gas(includes digester gas, methane, and other biomass gases)

Figure 4.1 Representative Structure of Softwood Lignin[xli]

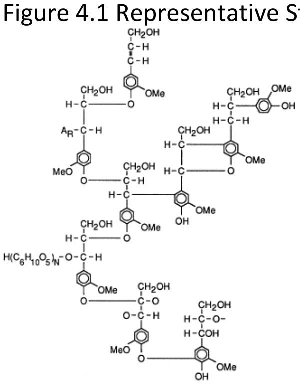
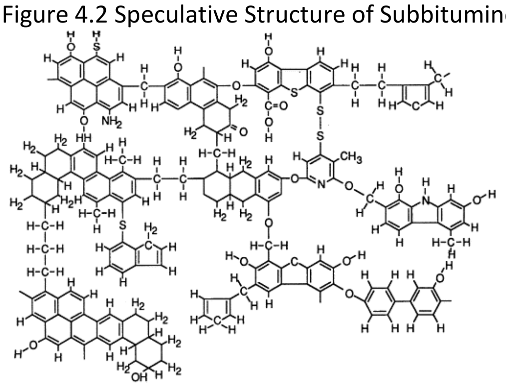
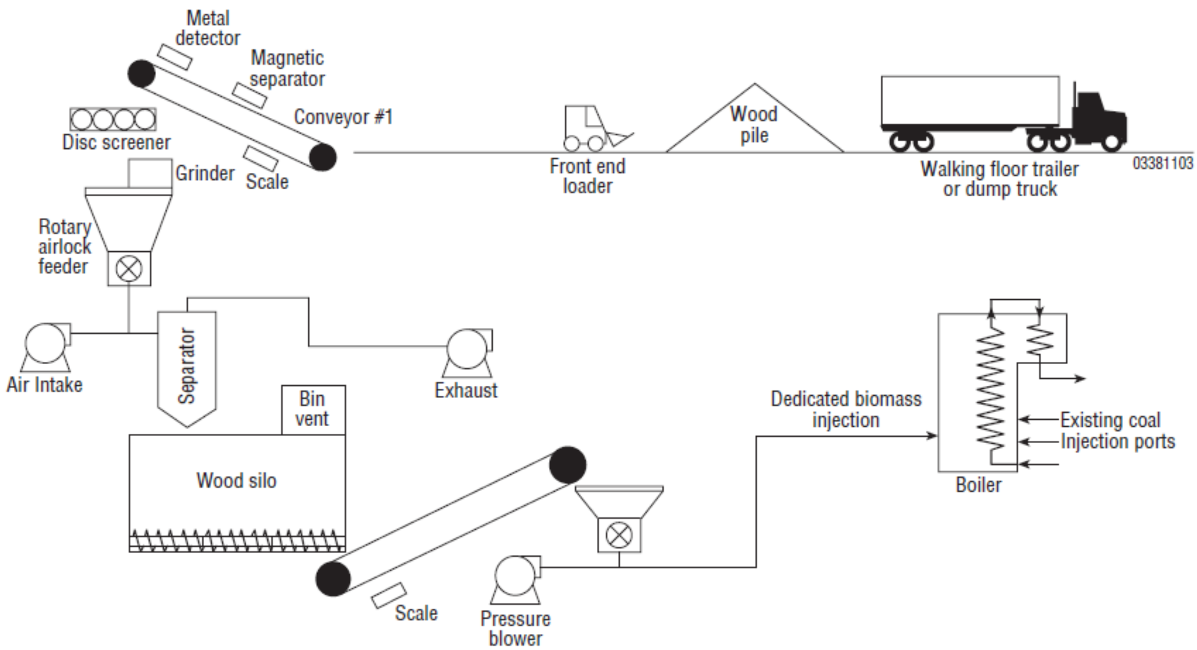


Figure 4.2 Speculative Structure of Subbituminous Coal[xlii]



Appendix 5: Biomass Technology

Figure 5.1 Schematic of a Separate Feed Co-firing Arrangement for a Pulverised Coal Boiler[xliii]



Appendix 6: Case Study Data

Table 6.1 Initiatives Undertaken During the Restart Process

Initiative	Cost ($000's)	Annual Benefit ($000's/yr)
Modify Title V; Contract for C&D; BUD for C&D		2,500
Develop C&D Processing Facility	5,500	5,000
Grant for C&D Processing Facility		3,000
Contract for Steam Sales	3,200	3,000
Contract for River Water Purchase	900	300
Reconfigure Fuel Handling and Dust Mitigation	200	500
Ash Metal Removal	150	500
Wood Metal Removal	50	40
Ash Beneficial Use Determination (BUD)		1,000
Excess REC Marketing		100
TDF Fluff Beneficial Use Determination (BUD)		1,300
Lease Hauling Trailers		90
Transformer	190	
Turbine Water Induction Protection Valves	36	
Total	10,226	17,330
Payback (months)	7.1	

Table 6.2 Fuel-Related Standards

Standards or limits (Maximum or minimum)	Max.	Min.
Coal (% by volume)	100%	
TDF (% volume)	40%	
Biomass (% volume)	100%	
Biomass attributes		
Glued wood (% of wood by volume)	5%	
Heating value (Btu/lb)		6,000
Moisture content (% by volume)	30%	
Non-wood contaminants	0.5%	
Adulterated wood	1%	
Size, length of each side (inches)	3	
Oversize pieces, more than 3 inches, % volume)	3%	

Table 6.3 Hourly Averages

Hourly averages by fuel	% by weight	% by Btu	Btu/lb	MMBtu/hr
TDF	32.14%	60.57%	14,115	196.01
Wood	61.32%	34.24%	6,271	243.39
Coal	5.06%	4.74%	10,653	129.11
Hourly averages for plant				
Total MMBtu/hr	387.23			
Est Heat Rate (Net)	12,021.15			
Est Heat Rate (Gross)	11,349.03			
RECs Generated (MWh)	11.56			

Figure 6.1 Limestone Regression

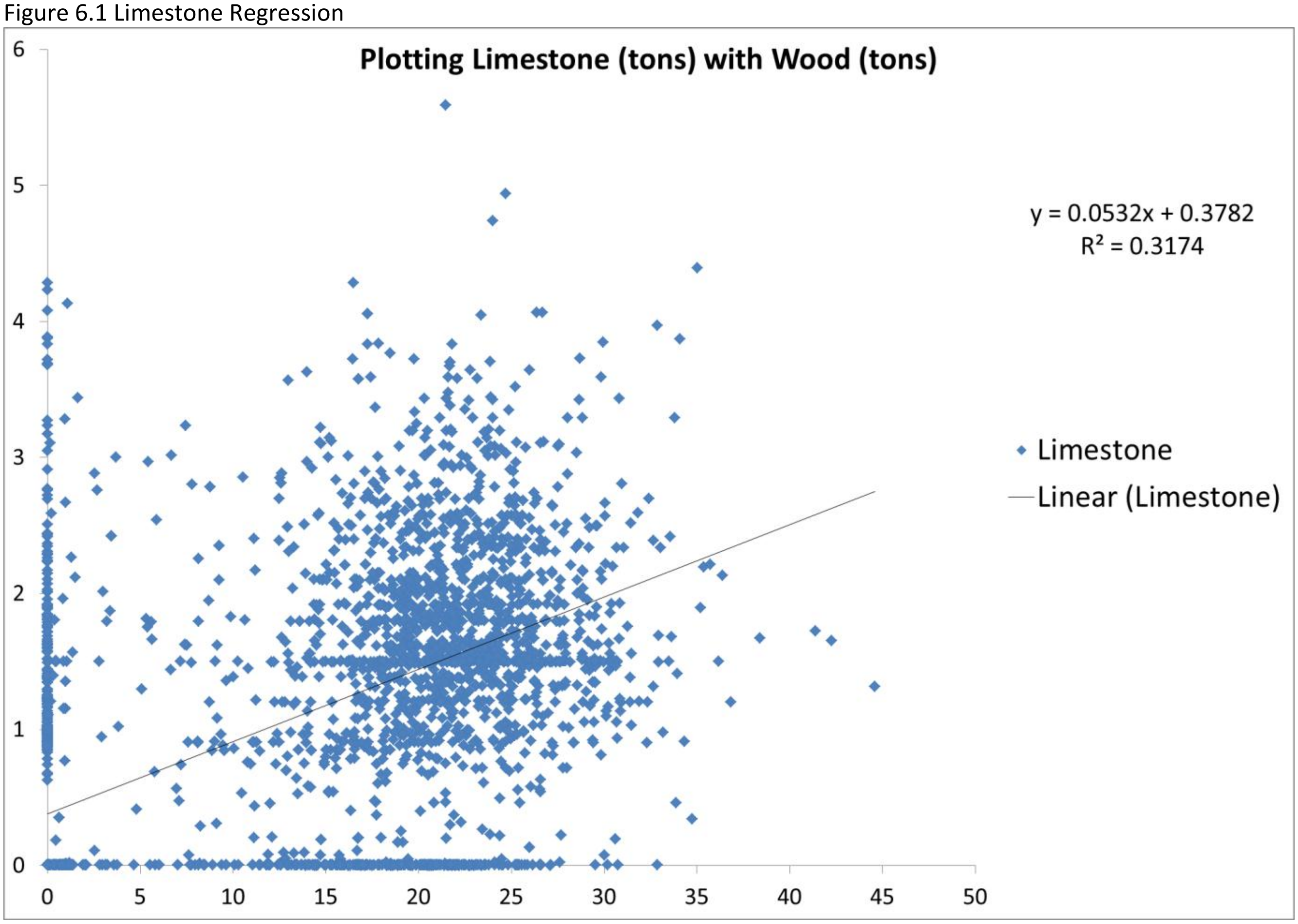


Figure 6.2 Limestone, Holding TDF Constant Within the Range of 10.3-11.2 Tons

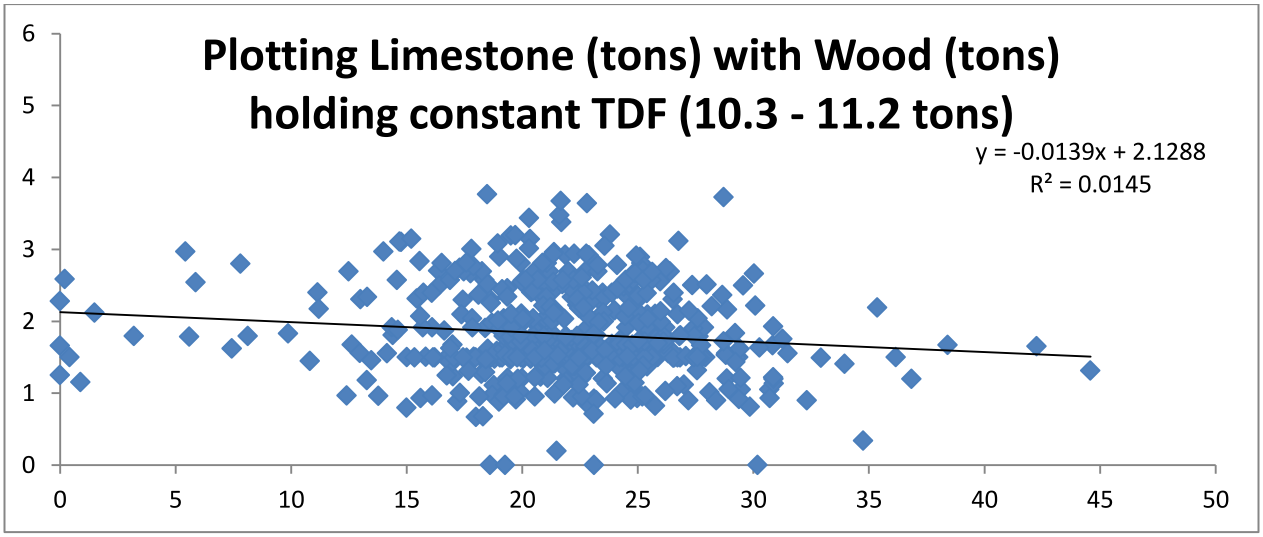


Figure 6.3 Limestone When Coal is Burned, Holding TDF Constant Within the Range of 10.3-11.2 Tons

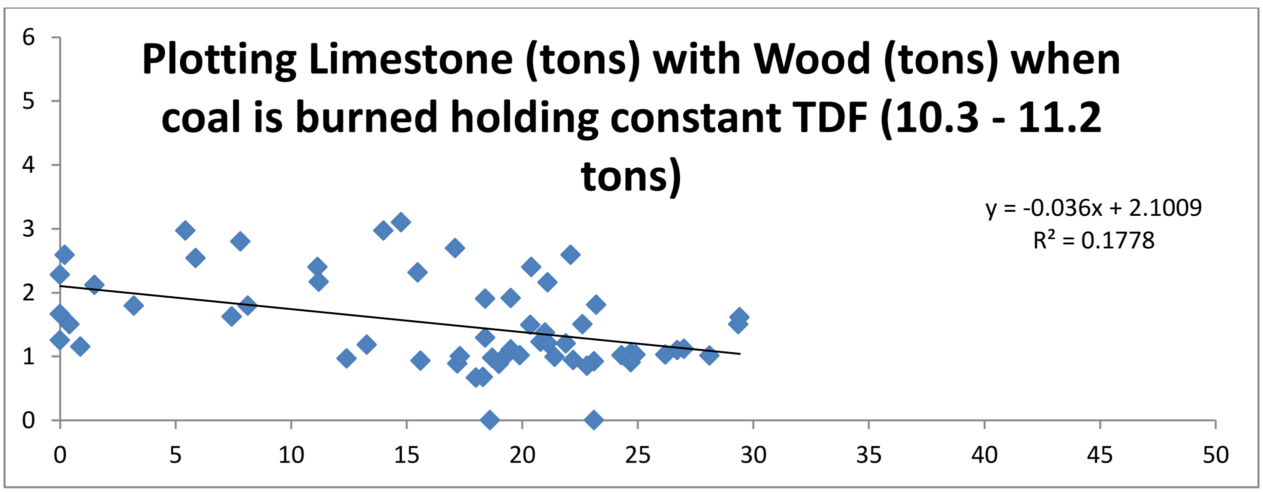
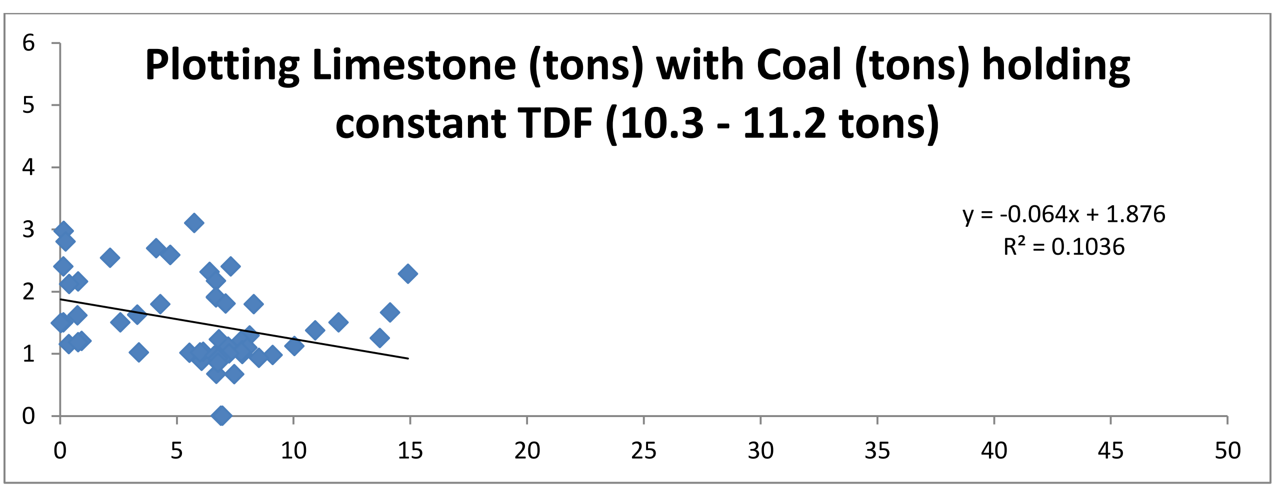
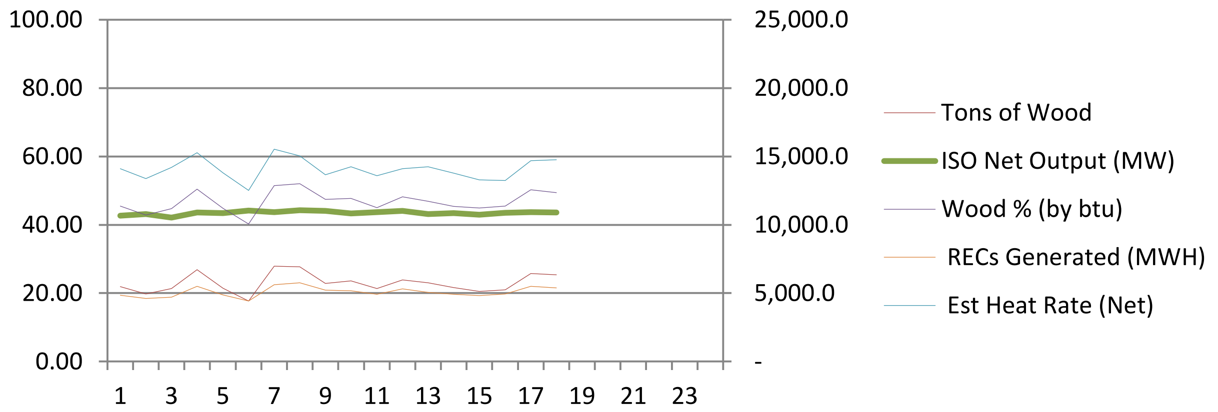


Figure 6.4 Limestone Plotted With Coal, Holding TDF Constant Within the Range of 10.3-11.2 Tons

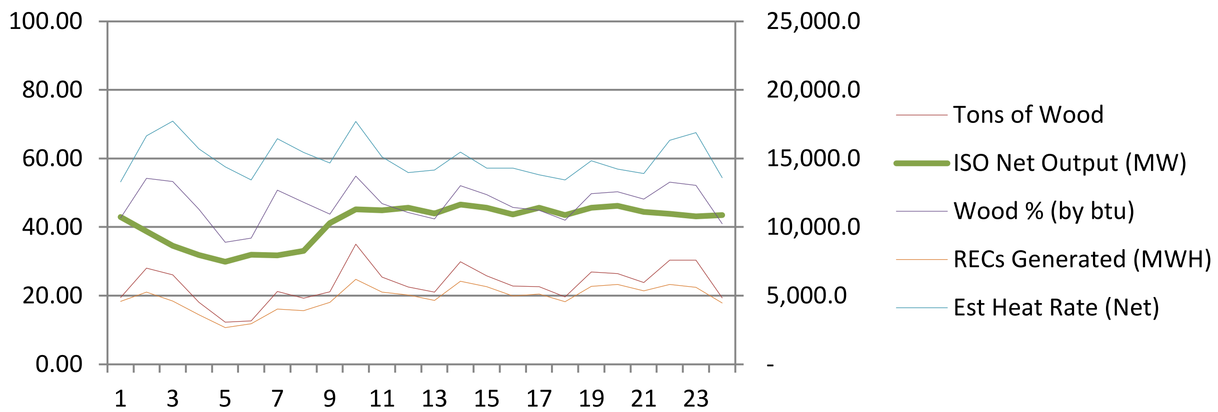


Appendix 7: Case Study Data – High Net Output
Figures 7.1-7.3

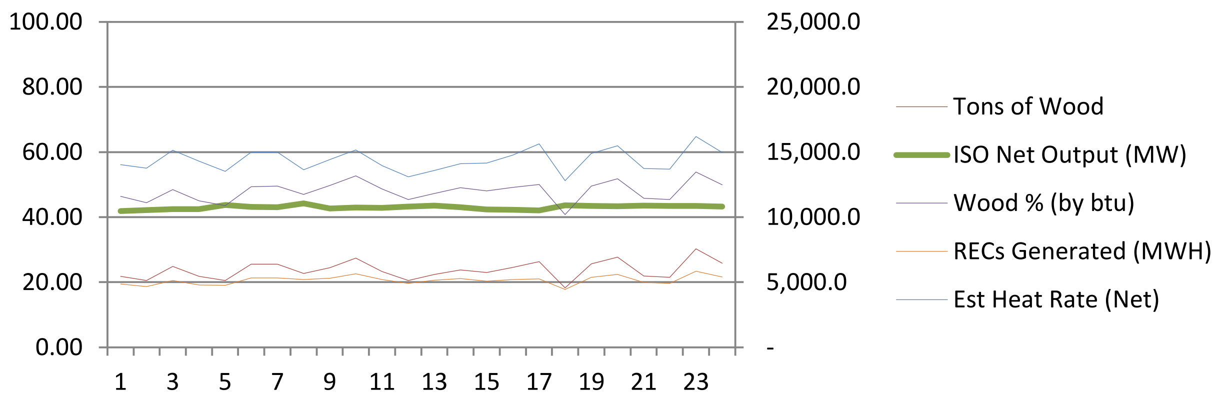
8/6 783 ISO Net Output (MWh)



9/15 987 ISO Net Output (MWh)

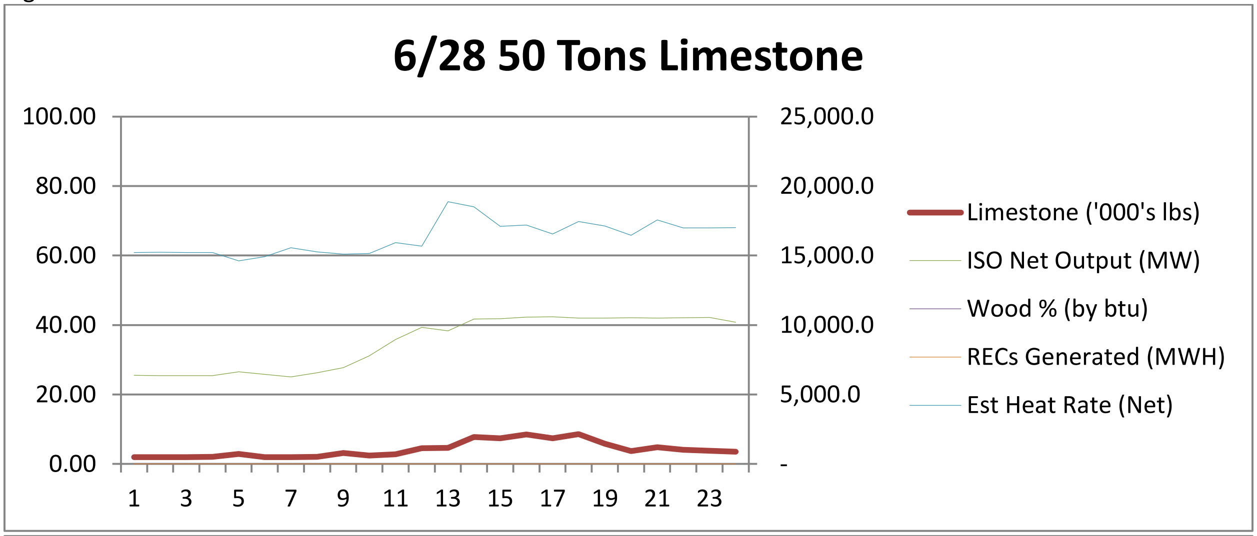


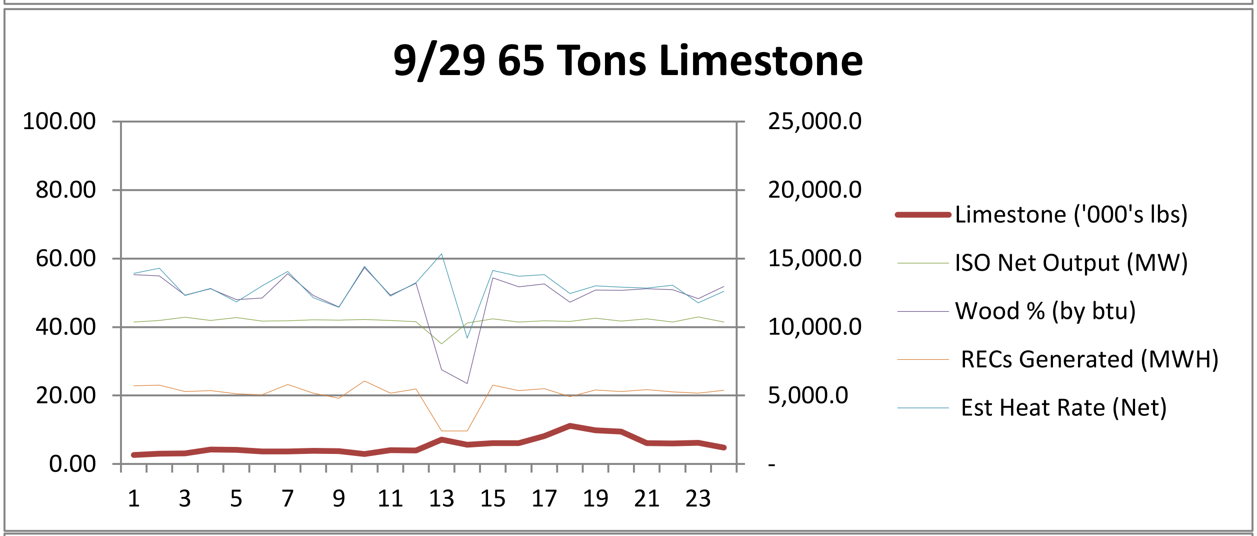
9/23 1032 ISO Net Output (MWh)

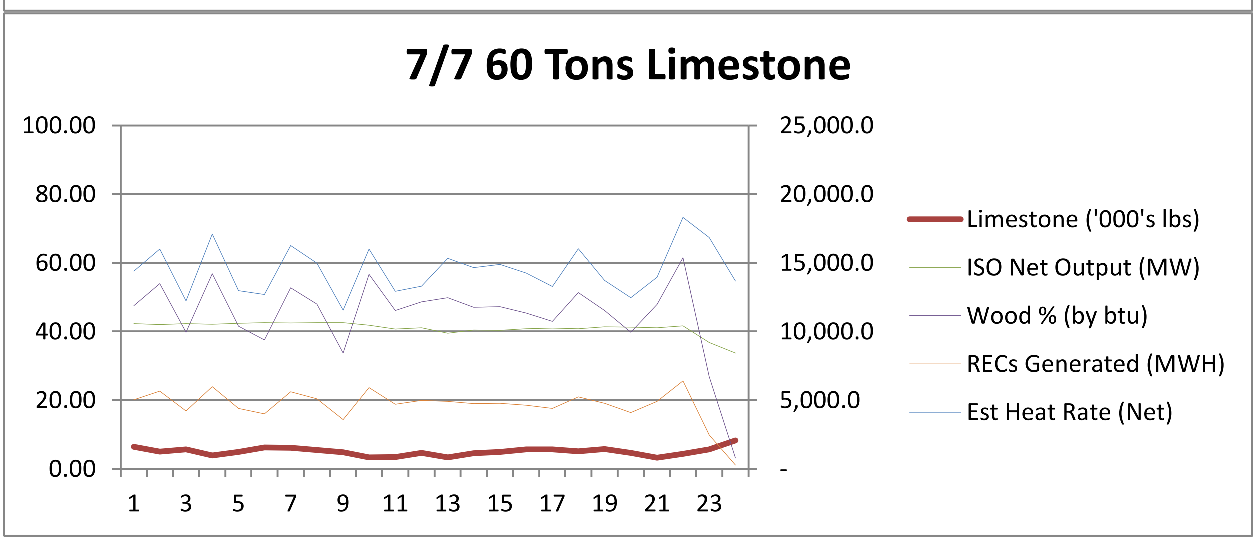


Appendix 8: Case Study Data – High Limestone

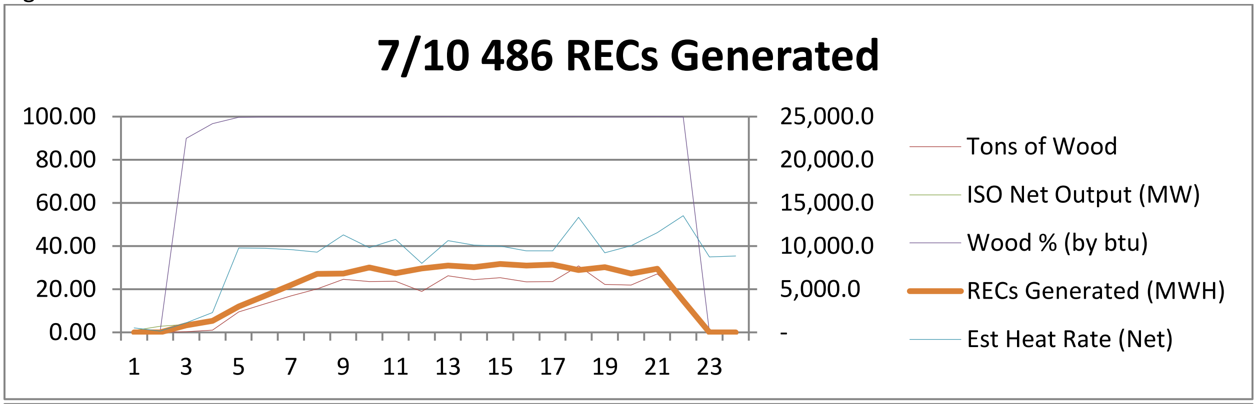
Figures 8.1-8.3

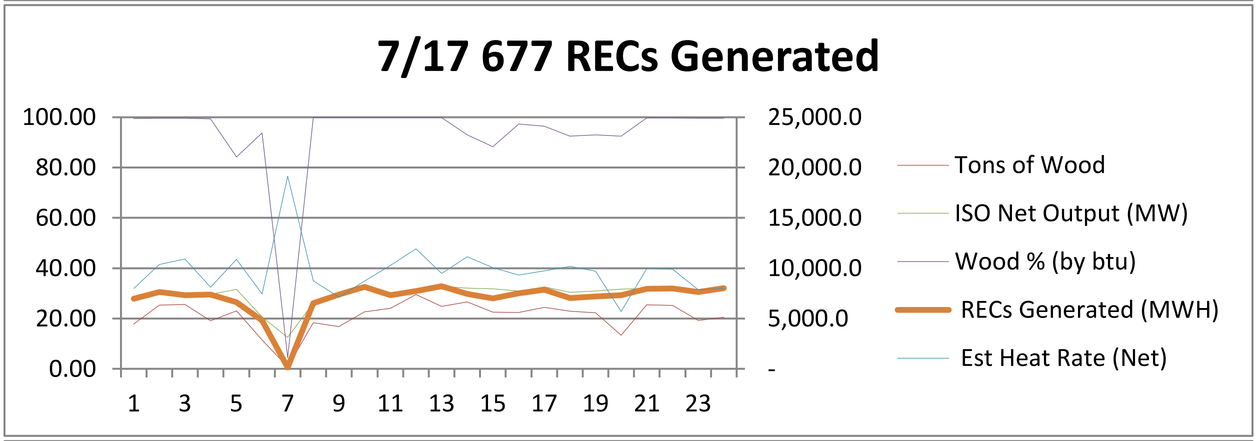


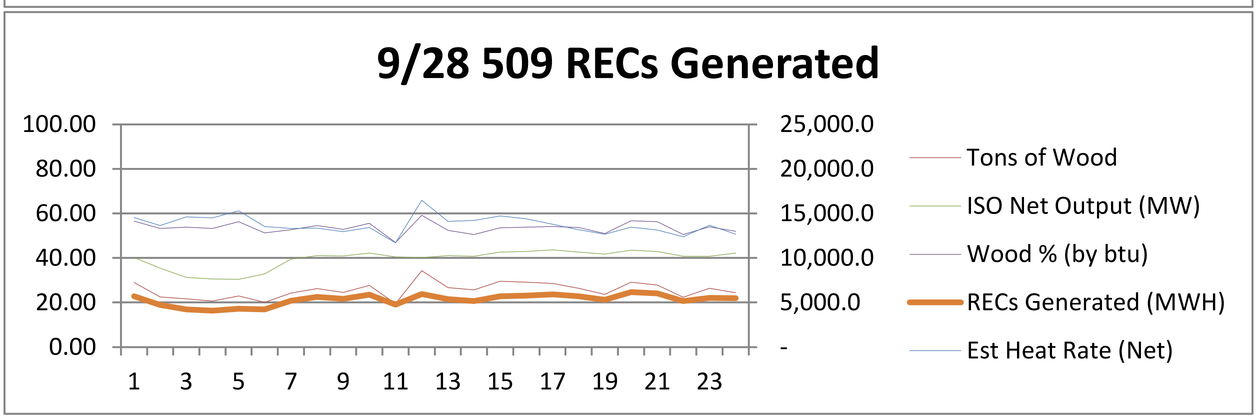




Appendix 9: Case Study Data – High RECs
Figures 9.1-9.3







Appendix 8

Figure 8.1 Recs Generated During the Testing Period

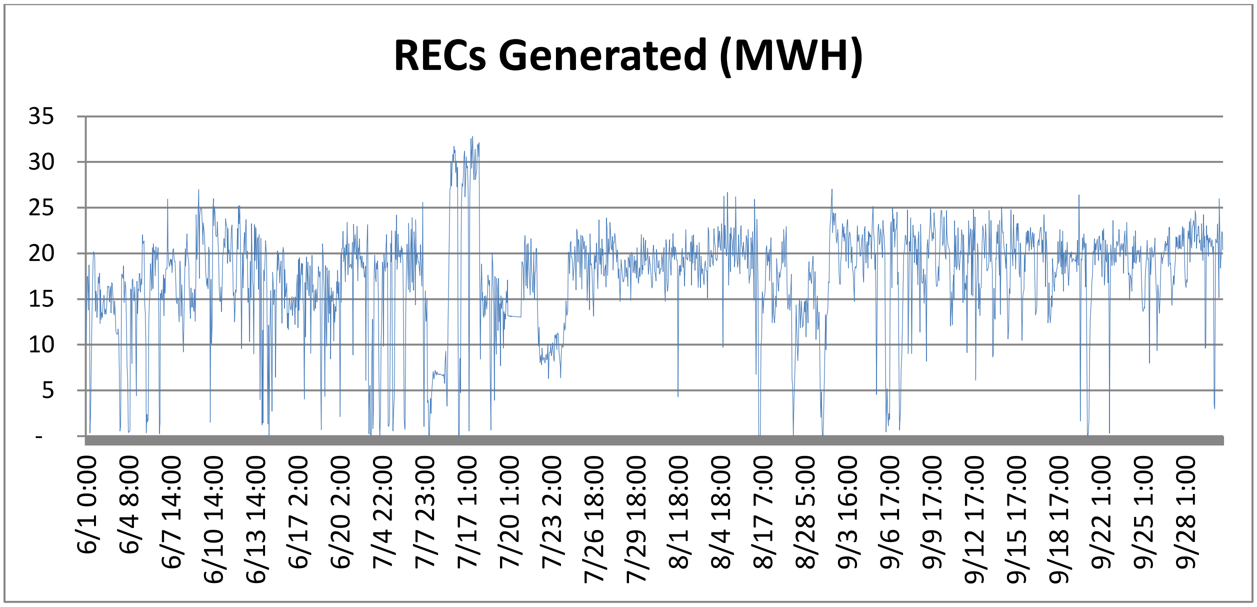


Figure 8.2 Comparing REC Generation With Estimated Heat Rate for Data Points

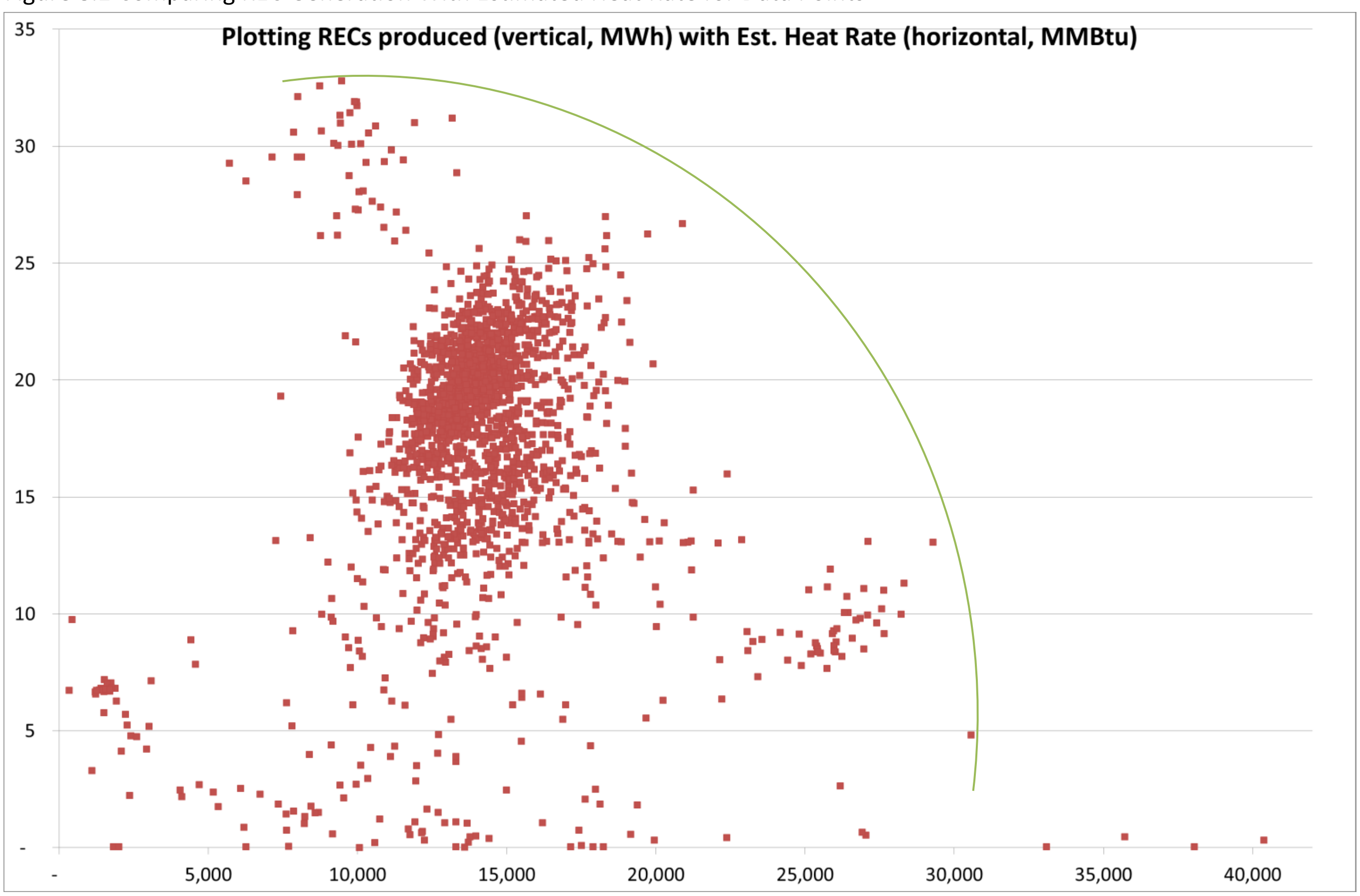


Table 8.1 Optimizing Outputs: MWh

Date, hour	Wood (tons)	TDF (tons)	Total Tons	TDF (% tons)	Limestone (tons)	ISO Net Output (MW)	Turbine Output (MW)	Generation Loss (%)
9/16 10:00	21.38	10.95	32.33	33.9%	2.030	44.40	51.95	14.5%
7/20 5:00	30.6	30.6	61.20	50.0%	0.194	43.38	50.51	14.1%
6/9 14:00	42.25	10.32	52.57	19.6%	1.654	43.00	50.09	14.1%
8/5 7:00	44.58	11.19	55.78	20.1%	1.317	41.91	49.38	15.1%
7/17 12:00	24.83	0.01	24.84	0.1%	0.003	32.84	38.96	15.7%
7/16 22:00	32.85	0.01	32.87	0.04%	0.003	31.23	37.18	16.0%
8/27 12:00	12.90	0.01	12.92	0.1%	0.005	4.83	9.10	47.0%
Average	29.91	9.02	38.93	0.18	0.74	34.51	41.02	19.5%
Max	44.58	30.60	61.20	0.50	2.03	44.40	51.95	47.0%
Min	12.90	0.01	12.92	0.00	0.00	4.83	9.10	14.1%
Range	31.68	30.59	48.28	0.50	2.03	39.58	42.84	32.9%

Table 8.2 Optimizing Outputs: RECs

Date, hour	Wood (Btu/lb)	TDF Btu/lb)	Wood MMBtu	TDF MMBtu	Total Est MMBtu	TDF (% Btu)	Est Heat Rate (Net)	RECs (MWh)
9/16 10:00	6,255	14,500	267.5	317.4	584.9	54.3%	13,174	20
7/20 5:00	6,255	14,500	382.8	887.4	1,270.2	69.9%	29,284	13
6/9 14:00	5,852	14,200	494.5	293.1	787.6	37.2%	18,316	27
8/5 7:00	6,255	14,200	557.8	317.9	875.7	36.3%	20,893	27
7/17 12:00	6,255	14,500	310.6	0.4	311.0	0.1%	9,470	33
7/16 22:00	6,255	14,500	411.0	0.4	411.4	0.1%	13,174	31
8/27 12:00	5,700	13,500	147.1	0.4	147.5	0.3%	30,565	5
Average	6,118	14,271	367.3	259.6	626.9	28.3%	19,268	22
Max	6,255	14,500	557.8	887.4	1,270.2	69.9%	30,565	33
Min	5,700	13,500	147.1	0.4	147.5	0.1%	9,470	5
Range	555	1,000	410.6	887.0	1,122.7	69.8%	21,095	28

Table 8.3 Normalizing Values Based on Optimal Outcomes

Date, hour	RECs rating	Output rating	Overall rating
9/16 10:00	0.62	1.00	1.62
7/20 5:00	0.40	0.98	
6/9 14:00	0.82	0.97	1.79
8/5 7:00	0.81	0.94	1.76
7/17 12:00	1.00	0.74	1.74
7/16 22:00	0.95	0.70	1.65
8/27 12:00	0.15	0.11	

Appendix 9 Sizing the Market

Table 9.1 Plants Burning Coal With Fluidized Boilers[xliv]

State	Plant name	Plant nameplate	Average boiler nameplate	Acid Rain Program?	Boiler primary fuel
CA	ACE Cogeneration Facility	108.0	108.0		BIT
CO	Lamar Plant	55.7	55.7	Yes	SUB
CO	Nucla	113.8	113.8	Yes	BIT
CT	AES Thames	213.9	107.0		BIT
HI	AES Hawaii	203.0	101.5		BIT
IA	Archer Daniels Midland Cedar Rapids	256.1	51.2		SUB
IL	Archer Daniels Midland Decatur	335.0	37.2		BIT
IL	Tate & Lyle Decatur Plant Cogen	62.0	31.0		BIT
IN	Purdue University	43.2	43.2		BIT
KY	Shawnee	1750.0	1750.0	Yes	BIT
LA	Nelson Industrial Steam Company	227.2	113.6		PC
ME	Rumford Cogeneration	102.6	51.3		TDF
MI	DTE Pontiac North LLC	28.9	28.9		BIT
MI	Wyandotte	78.4	78.4	Yes	BIT
NY	Black River Generation	55.5	18.5		BIT
OH	Bay Shore	655.4	655.4	Yes	PC
OK	AES Shady Point LLC	350.0	87.5		SUB
WI	Green Bay West Mill	129.0	129.0		PC
WI	Manitowoc	138.4	138.4	Yes	PC
WV	Morgantown Energy Facility	68.9	34.5		BIT

Table 9.2 Ranked by Relevance to Case Study Generator[xlv]

State	Plant name	Plant nameplate	Average boiler nameplate	Acid Rain Program?	Boiler primary fuel
CO	Lamar Plant	55.7	55.7	Yes	SUB
ME	Rumford Cogeneration	102.6	51.3		TDF
IA	Archer Daniels Midland Cedar Rapids	256.1	51.2		SUB
IN	Purdue University	43.2	43.2		BIT
IL	Archer Daniels Midland Decatur	335.0	37.2		BIT
WV	Morgantown Energy Facility	68.9	34.5		BIT
IL	Tate & Lyle Decatur Plant Cogen	62.0	31.0		BIT
MI	Wyandotte	78.4	78.4	Yes	BIT
MI	DTE Pontiac North LLC	28.9	28.9		BIT
OK	AES Shady Point LLC	350.0	87.5		SUB
NY	Black River Generation	55.5	18.5		BIT
HI	AES Hawaii	203.0	101.5		BIT
CT	AES Thames	213.9	107.0		BIT
CA	ACE Cogeneration Facility	108.0	108.0		BIT
LA	Nelson Industrial Steam Company	227.2	113.6		PC
CO	Nucla	113.8	113.8	Yes	BIT
WI	Green Bay West Mill	129.0	129.0		PC
WI	Manitowoc	138.4	138.4	Yes	PC
OH	Bay Shore	655.4	655.4	Yes	PC
KY	Shawnee	1750.0	1750.0	Yes	BIT

Other resources

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