Integrative Design of Energy & Mineral Engineering Systems

EME 580

IMPLEMENTATION OF BIOGAS OR BIOMASS AT THE PENNSYLVANIA STATE UNIVERSITY'S WEST CAMPUS STEAM PLANT

FINAL DESIGN REPORT

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EXECUTIVE SUMMARY

The feasibility of blending biomass and/or biogas with coal used at the West Campus Steam Plant (WCSP) of Penn State's University Park campus was studied to determine if biomass and/or biogas is a feasible option for reducing non-renewable energy consumption and decreasing operating costs of the campus. The WCSP generates all steam and approximately 6% of electricity at the University Park campus.

Biogas that is currently flared from Penn State's wastewater treatment plant (WWTP) was studied for technical and economic feasibility. At this time, the available biogas from the WWTP could offset 0.3% of the coal used at the WCSP by injecting it through existing natural gas injectors in the stoker boilers. The study indicated that **using existing biogas was not technically feasible** because the small quantities available would not be able to maintain combustion properly and would have low injection velocities with the existing injection system. Furthermore, the **biogas project was found to be economically unfeasible with more than a 400 year payback**. Other uses for the available biogas such as space heating and the potential for injecting the biogas if greater quantities are available are discussed.

The feasibility of using a 15% blend of biomass was also studied. A plentiful supply of waste wood from local businesses was identified and process equipment for drying and processing the wood so it is consistent with the coal was specified. Material and energy balances were performed and technical issues were addressed. The **biomass project**, which has a **7.4 year payback** and **15 year net present value (NPV) of $600,000**, has the potential to **reduce coal consumption by more than 11,000 tons annually** and **reduce carbon dioxide (CO_2) emissions by 92 tons annually**, while **diverting almost 17,000 tons of locally generated waste wood** from the landfill every year. Finally, next steps, such as obtaining actual equipment price quotes for pelletizing equipment and determining specific permit requirements, are recommended.

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1.0 Project Introduction

All steam and 6% of electricity consumed at the Penn State University Park campus are generated in the West Campus Steam Plant (WCSP). The WCSP consists of four coal-fired, water-tubed stoker boilers and one gas fired water-tubed boiler. The steam is used for heating, cooling, dehumidification, and processing (such as cooking, experimental work, and laundry) at the University Park campus.

The coal is burned on vibrating gas grate stokers manufactured by Detroit Stoker. The stokers were installed between 1961 and 1968. Each stoker can be co-fired with up to 25% natural gas; however, natural gas burners are currently primarily used for startup and shut down of the boilers or when wet coal is received.[1] The stokers were upgraded with co-firing capacity in 1970 after the Clean Air Act revisions were first enacted. At that time, the University engineers were ensuring that new particulate emission requirements were met, and co-firing with natural gas helped to decrease the particulate emissions from coal combustion. The University upgraded the WCSP in the mid-1980's to add a baghouse to control particulate emissions, so regular co-firing was halted.[2]

Moving into the 21st Century, the WCSP is still only fired by coal with approximately 20-30 trucks of coal being burned at approximately 23 tons per load. Meanwhile, in 2009, Penn State University was ranked #5 in the world in energy research by Elsevier, following the National Aeronautics and Space Administration's (NASA) Goddard Space Flight Center, the U.S. Department of Energy's (DoE) National Renewable Energy Laboratory, and two research laboratories in Germany.[3] Additionally, even though Penn State is a leader in the quality of energy research, some students and the community are questioning Penn State's use of coal on campus.[4]

In 2009, Penn State became a member of the U.S. Environmental Protection Agency's Sustainability Partnership Program and voluntarily committed to reducing energy use and greenhouse emissions by 17.5% by 2012.[5] In fact, as an example of the commitment to renewable energy, 20.5% of the electricity purchased by the University was renewable in 2006, including wind (8.1%), biomass (3.9%), low-impact certified hydroelectric (7.9%); and new technologies (solar and biomass) (0.6%).[6]

[1] Penn State Steam Services Fact Sheet. March 2007.
[2] Interview of Bill Serencits. Penn State OPP. January 2010.
[3] Penn State Institutes of Energy and the Environment. **"**Penn State ranked #5 Worldwide in Elsevier Alternative Energy Research Leadership Study". July 24, 2009. **(**http://www.psie.psu.edu/news/2009_news/july_2009/elsevier.asp)
[4] Sellers, Caitlyn. "Students 'heart clean air,' protest PSU's use of coal." Collegian Online. October 26, 2009.
[5] http://www.epa.gov/reg3wcmd/spp/. Accessed February 2010.
[6] "University awards environmentally friendly energy contracts to enhance existing green initiatives". Penn State Live press release. December 22, 2006.

Furthermore, the University's utility budget has been reduced by $1.5 million, providing a financial incentive to look for a low-cost, environmentally friendly option that can produce a large amount of steam and some electricity for University Park operations. [7]

Therefore, as part of this integrative design project, biomass and biogas are being evaluated as potential solutions to Penn State's financial and environmental goals. Biomass and biogas were selected as solutions to be evaluated because they are renewable resources and, in general, biomass and biogas tend to have a good potential in Pennsylvania due to the natural resources available.[8].

[7] Senate Committee on University Planning. "New Energy Conservation Policy." The Pennsylvania State University. September 1, 2009. (http://www.senate.psu.edu/agenda/2009-2010/Sept109/appi.pdf)
[8] Black & Veatch. "Economic Impact of Renewable Energy in Pennsylvania." Final Report. March 2004.

2.0 Overview of West Campus Steam Plant (WCSP)

Fig 1. West Campus Steam Plant

The WCSP was constructed in 1929. It consists of four 1960's vintage coal-fired boilers each rated at 110,000 pounds per hour steam production and one 1947 vintage coal-fired converted to natural gas fired boiler rated at 45,000 pounds per hour. The WCSP provides the primary steam supply to Penn State's University Park Campus. Steam is used for heating, cooling, dehumidification, and processing. Processing includes such uses as energy for cooking, experimental work, and laundry.

Low (13 psig) and medium (150-170 psig) steam pressure is delivered in separate distribution headers to campus. Low-pressure steam comes from backpressure steam turbines that drive pumps, fans, and generators. Two 1930's vintage backpressure steam turbines rated at 2.5 megawatt (MW) and 3.5 MW generate electricity to serve Penn State's emergency power needs as well as provide low-pressure steam to campus. Steam properties are shown in the following table.

Table1. Steam Properties[9]

Steam production rate	110,000 lb/hr
Steam pressure	240 psig
Steam temperature	540 °F
Type	Superheated

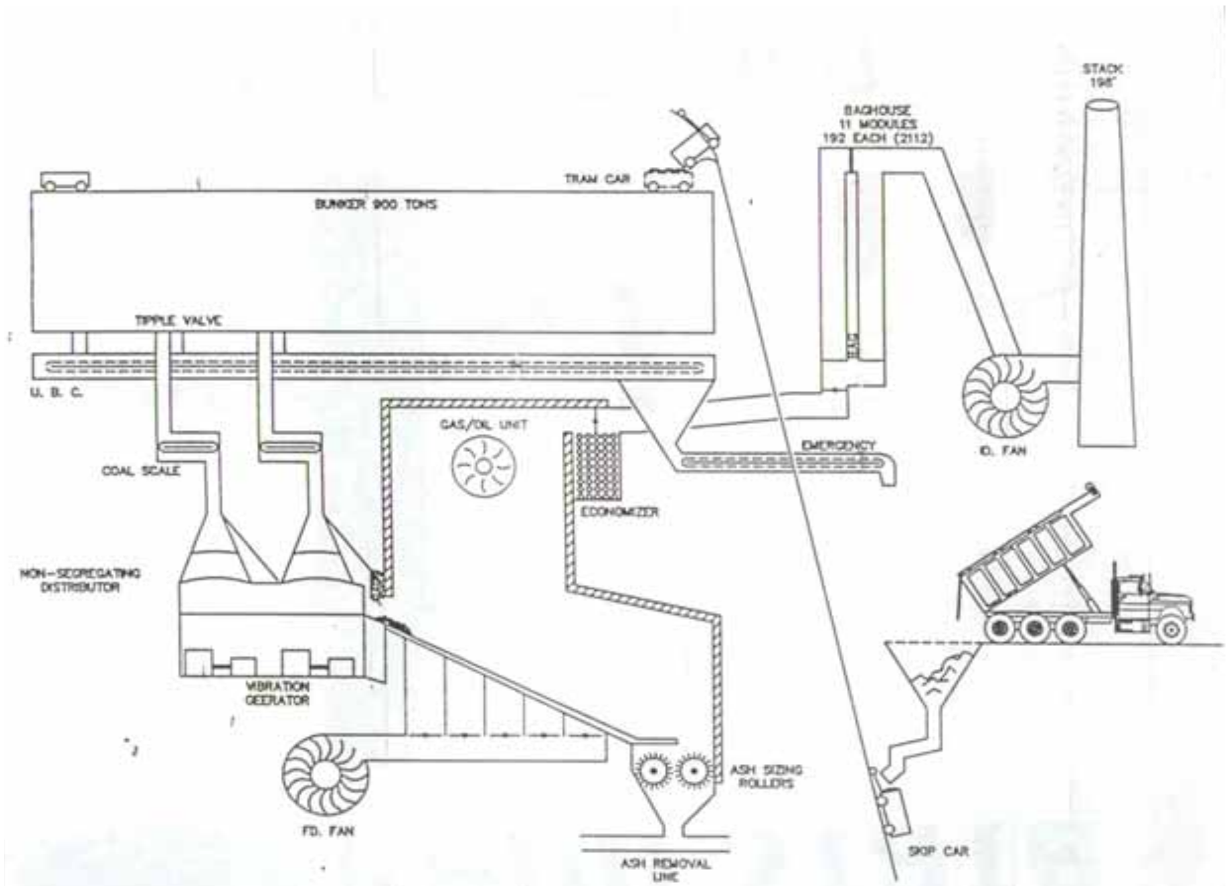
Power generated by the turbines amounts to less than 6% of Penn State's total power needs. However, the power generated by the turbines amounts to 100% of Penn State's emergency power needs.

Three Induced Draft (ID) fans provide airflow for the four coal-fired boilers. The coal handling system consists of a covered lay down yard that holds about 7,000 tons of coal. Tri-axle trucks holding about 23 tons per load deliver coal daily. In winter heating conditions the plant receives 20-30 trucks of coal per day from 7 a.m. to 3 p.m. A 900-ton bunker located inside the plant supplies coal to each of the boilers by gravity or by chain system referred to as the Under Bunker Conveyor system. Stock feeders weigh and deliver coal to the boiler distribution hoppers that feed the stoker beds.

Bottom ash meets beneficial use criteria set by Pennsylvania Department of Environmental Resources (DEP). Bottom ash has secondary uses such as road maintenance and feedstock for manufacturing architectural concrete blocks. Fly ash is disposed in a local landfill. A representation of the operations follows.

[9] Penn State Steam Services Fact Sheet. March 2007

Figure 2. Flow Diagram of WCSP



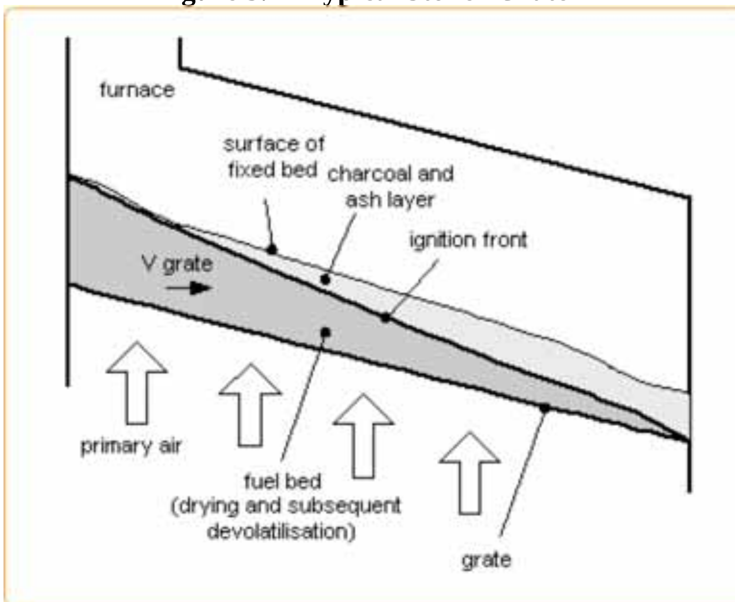
2.1 Stoker and Boiler Operation

Stokers are mechanical devices that feed coal to the firebox of a furnace, where the chemical energy in the fuel is converted to thermal energy. The thermal energy is absorbed by boiler surfaces to generate steam or produce high temperature water[10]. Stokers may be classified based on the direction of feed of fuel as a) overfeed and b) underfeed stokers. Overfeed stokers have the fuel entering the active combustion zone from above, in opposition to the primary airflow. Included in the overfeed group are spreader stokers and mass-burning stokers. Mass-burning or crossfeed stokers are more commonly referred to as either traveling-grate or vibrating-grate. The travelling-grate stoker can be used to burn most solid fuels. In addition, such waste and byproduct fuels such as coke breeze, anthracite dredged from river bottoms, and municipal refuse are burned effectively.[10]

[10] Singer, Joseph G. *Combustion Fossil Power Systems*. Combustion Engineering, Inc. 3rd Ed. 1981

The WCSP burns coal on vibrating grate stokers manufactured by Detroit Stoker. Each coal-fired boiler can be co-fired with natural gas up to about 25% on a heat basis. The natural gas burners are primarily used for startup and shutdown of the boilers but are also used when coal is wet.[11]

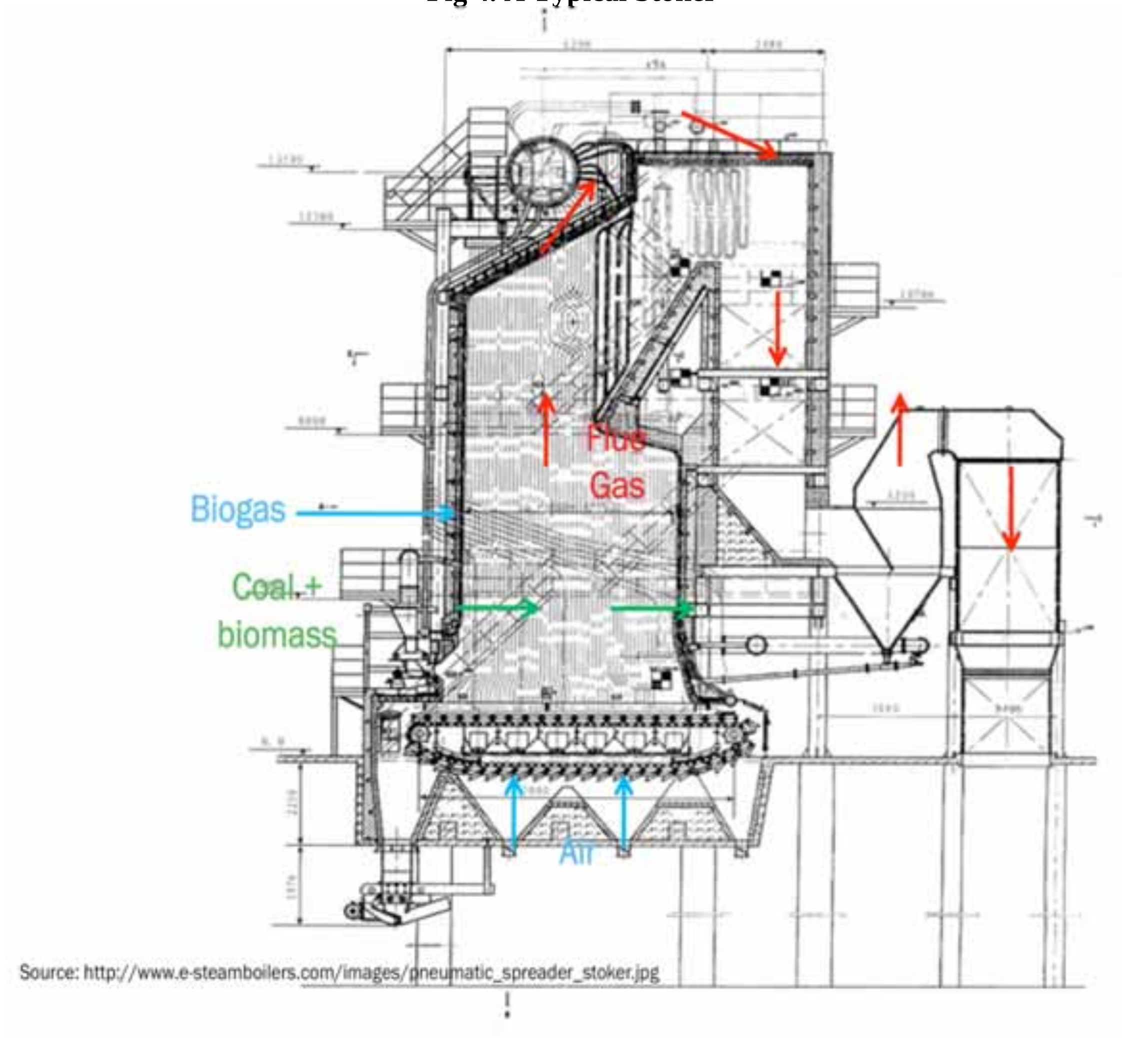
Figure 3. A Typical Stoker Grate[12]



The above figure shows a typical stoker grate where the fuel enters from the top on the left and moves to the right. As the fuel moves, it gets combusted at the ignition front and is converted to ash by the time it reaches the end of the grate. The figure below shows a typical stoker and operation.

[11] Penn State Steam Services Fact Sheet. March 2007
[12] Van Loo, Sjaak and Japp Koppejan. *Handbook of biomass combustion and co-firing*. Jan 2008

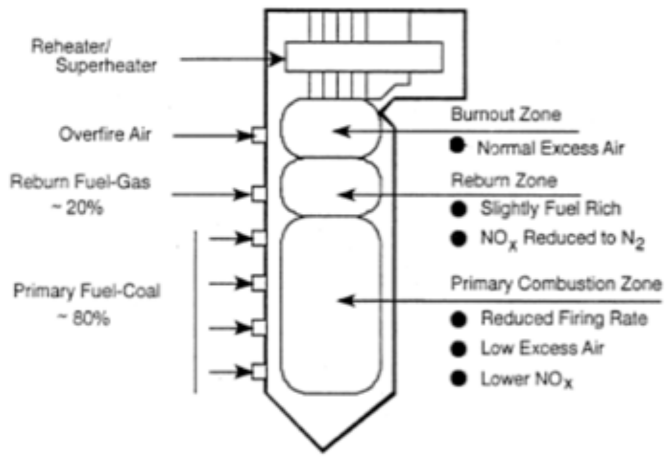
Fig 4. A Typical Stoker[13]



The following figure shows the schematic of staging combustion in a pulverized coal furnace using natural gas as the reburn fuel.

[13] www.e-steamboilers.com. Accessed February 2010.

Fig 5. Gas-Fired Reburn[14]



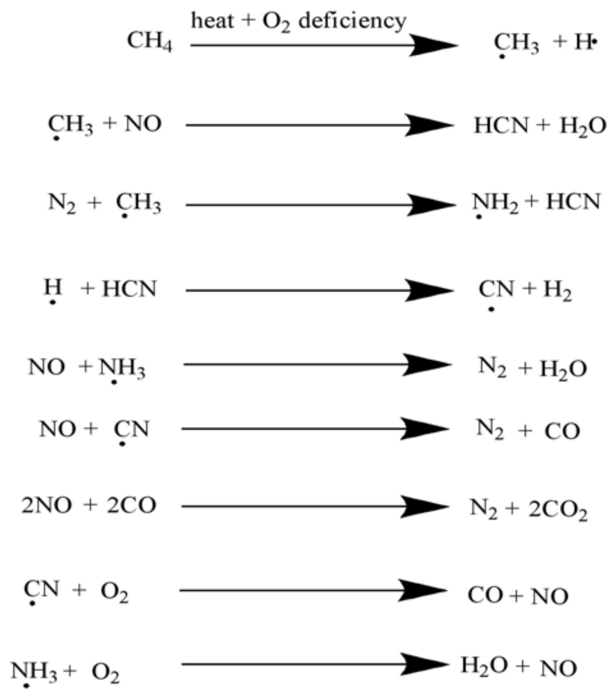
This technique is generally used for NO_x reduction in a coal furnace. In reburning, the main combustion zone operates at relatively low oxygen stoichiometry (about 0.9 to 1.1) and receives 80% to 90% of total heat input; the balance of the heat is injected above the main combustion zone through reburning injectors. Stoichiometry in the reburn zone is in the range of 0.85 to 0.95. To achieve this, the reburn fuel is injected at a stoichiometry of up to 0.4. The temperature in the reburn zone must be above 1,800°F (982°C) to decompose the reburn fuel.

Because the total reburn zone area of the upper furnace is sub-stoichiometric, any unburned fuel leaving the zone is then burned to completion in the burnout zone. This zone is where completion air (15% to 20% of the total combustion air) is introduced through the completion air ports. These ports are designed for adjustable air velocities to optimize the mixing and complete burnout of the natural gas before it exits the furnace.[15]

Kinetics of reaction during reburn is as follows[16]:

[14] Electric Power Research Institute, Inc., Gas Cofiring Assessment for Coal Fired Utility Boilers, 2000
[15] Ibid
[16] Ibid

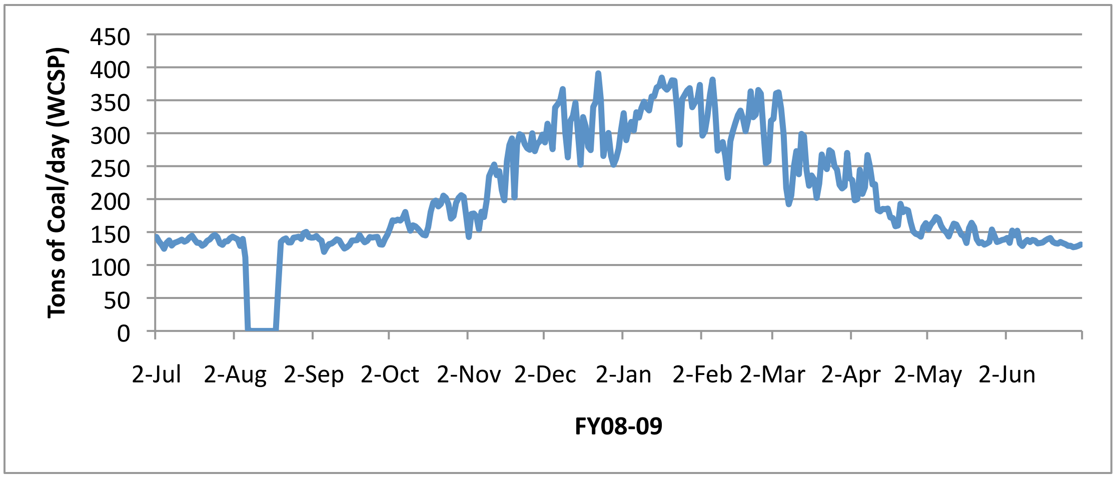
Fig 6. Kinetics of reaction during reburn



2.2 Coal Use at WCSP

The University Park campus uses on average 204 tons/day of coal, with consumption peaking in the Winter months. Daily consumption is shown in the following chart. In Fiscal Year 2008-2009, the WCSP consumed almost 74,800 tons of coal. As shown, the WCSP is taken offline for one week every summer for routine maintenance.

Fig 7. Daily Coal Consumption of WCSP[17]



A recent analysis of coal used at the WCSP that was provided by Penn State is included in Appendix A. Our team performed testing in March 2010 of coal used at WCSP and of potential biomass sources using an ultimate analyzer. A Leco (TruSpec) CHN analyzer and a Leco (TruSpec) S (sulfur) analyzer were used to conduct the ultimate analysis on coal. The samples were prepared by grinding the coal to fine particles and then introducing a measured amount of the sample into the CHN and S analyzers. For calculating the surface moisture, the unprepared coal was spread evenly on a dish and its mass was measured before drying it in an air-drying oven. The air-drying was maintained at 140°F until the sample's weight stopped changing. The results of the analyses are below.

[17] Provided by OPP. February 2010.

Table 2. Proximate Analysis of Coal

Total moisture	Surface moisture	Volatiles	Fixed Carbon	Ash	BTU/lb (wet)	BTU/lb (dry)
5.02%	2%	35.40%	50.90%	8.68%	12,749	13,424

The above values with the exception of surface moisture were obtained from the data provided by the WCSP located in Appendix A.

Table 3. Ultimate Analysis of Coal and Potential Biomass

	C	H	N	S
Coal: WCSP	78.16%	4.97%	0.62%	3.07%
Sawdust (pine)	50.65%	5.64%	1.37%	0.0014%
Bark	40.60%	6.00%	1.66%	0.016%
Wood Shavings	45.00%	6.05%	0.94%	0.04%
Oak	47.70%	5.72%	1.03%	-

3.0 Biogas

Biogas typically refers to a gas produced by microbial decomposition of organic substances under anaerobic conditions using a process known as anaerobic digestion. During anaerobic digestion organic matter like sewage sludge, agricultural wastes, manure, and effluents from food and beverages are converted to biogas, which is a mixture of methane and carbon dioxide and traces of other constituents.[18] Biogas typically contains about 60% methane and 40% CO_2 with trace amounts of sulfur and hydrogen.[19] Uses of biogas can vary from domestic cooking fuel to upgrading to pipeline quality methane to add to the local distribution network to generating electricity to sustain a farm's needs. In the early 2000s, in Sweden, which is among the largest producers of biogas in the world, the auto giant Volvo rolled out the S-60 2.4 Bi-fuel sedan which could run on CNG/biogas as well as petrol(in case of an emergency).[20,21]

Public perception is generally positive concerning small-scale biogas projects, such as the project that was studied during this project.[22]

Biogas, which is currently generated at Penn State's wastewater treatment facility's primary and secondary anaerobic digesters, was evaluated as a cofiring option because it is readily available and currently being flared for disposal/treatment.

3.1 Overview of Penn State Wastewater Treatment Plant

The wastewater treatment plant, which is on the east side of campus off of University Drive, currently treats wastewater from all of the University Park campus and some of the Borough of State College. Currently, the University treats an average of 3 million gallons of wastewater per day, through a fairly typical treatment facility.[23]

Of particular interest to this project were the primary and secondary digesters. During the breakdown of the sludge, bacteria generate biogas, which is captured in the tank. The captured gas is used to maintain the tank at 95°F (Mesophilic temperature)[24], which is necessary for the survival of the microbes. The remainder, however, is currently being flared off. A total of approximately 95,000 cubic feet of gas per day is generated when the students are in town.

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[18] "Anaerobic digestion: a waste treatment technology; Wheatley, Andrew; Elsevier Applied Science,1990
[19] "Cooperative approaches for implementation of dairy manure digesters". USDA research report 217 -2009.
[20] Kanter, James. "Sweden turning sewage into a gasoline substitute." New York Times, Tuesday, May 27, 2008
[21] http://www.carfolio.com/specifications/models/car/?car=106227 .Accessed May 1 2010
[22] Abraham, E.R., S. Ramachandran, and V. Ramalingam. "Biogas: Can It Be an Important Source of Energy?" Env Sci Pollut Res 14(1) 67-71 (2007)
[23] "Wastewater Treatment Plant." Walking tour guide. Provided by OPP in January 2010.
[24] "European Energy Manager Biogas Preparation Material", www.energymanager.eu/getResource/10018/biogas.pdf *Accessed-March 15 2010*

Typical makeup of biogas is shown below:

Table 4. Biogas Makeup[25]

Constituent	Typical Content
Methane	50-70%
Carbon dioxide	20-50% (typically 40%)
Water	Saturated
Hydrogen	0-5%
Hydrogen Sulfide	0-1%
Ammonia	Traces
Carbon Monoxide	0-1%
Nitrogen	0-3%
Oxygen	0-1%
Trace Organics	-
Calorific Value	20 MJ/m^3

One issue that was discovered during a meeting with Penn State Wastewater Services in January 2010, is that due to regulatory pressures by DEP, the current wastewater collection will change in the future. As mentioned, the WWTP accepts wastewater from both the University and the Borough of State College. Accepting the wastewater from the Borough helps to maintain the operations (which are two different process lines within the facility) during low flow times such as Spring Break and Winter Break, when students not at the University Park campus and immediate Borough area. Flexibility is necessary to maintain the facility operations (microbes, etc.). However, if the WWTP approaches peak loading, operators can easily reroute the wastewater to the University Area Joint Authority (UAJA), which is near the Nittany Mall (State College, PA). In general, 75% of the sewage at WWTP is supplied by the University and 25% by the Borough. DEP is requiring that only one facility receives the Borough wastewater, so a transition plan is being developed to gradually re-route all wastewater to the UAJA (instead of increasing capacity at the Penn State WWTP to ensure that peak loads can be accompanied). This change could reduce biogas availability in the future. However, during the same conversation, OPP indicated that the boilers used to fire the biogas to heat the secondary digesters are also going to be replaced in the near future with more efficient boilers.

Fig. 8 Primary Digester at WWTP

[25] "Anaerobic Digestion: A Waste Treatment Technology"; Wheatley Andrew; SCI; Elsevier Applied Science , 1990

At this time, since the University does not know the details, it was assumed for this analysis that the increase in boiler efficiency will offset the decrease in wastewater availability, so the biogas availability will remain constant in the future. However, there is a risk that biogas availability could decrease.

3.2 Benefits of Anaerobic Digestion

Some of the other benefits of using anaerobic digestion are noted below:

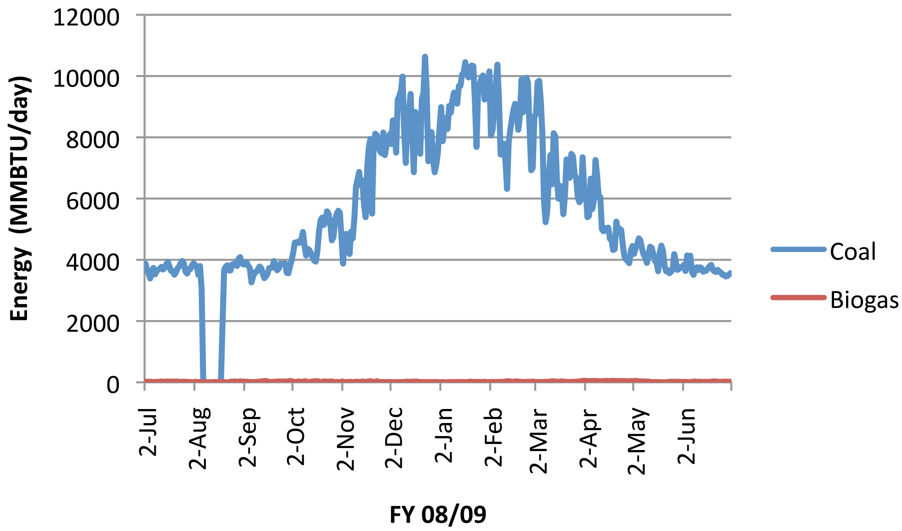
- Reduced electricity purchases
- Generate revenues from electricity sales
- Generate revenues from natural gas sales: Biogas scrubbed of carbon dioxide and impurities to generate a CH_4-enriched biogas (95–98% CH_4)[26]
- Generate heat for buildings
- Use or sell digested solids and effluent
- Sell carbon credits for the reduction of methane emissions
- Reduce odor
- Reduce environmental risk and potential liability costs

3.3 Biogas Feasibility in the WCSP

As of the fiscal year 2008-2009, the Penn State WWTP produced approximately 11 million cubic feet of excess biogas that was flared off. The energy content of the biogas flared off is approximately 6.6 Billion BTUs per year, or about 0.3% of the total energy produced at WCSP. A daily comparison of the energy content of the coal burned at the WCSP as compared to the energy content of biogas available was performed, is shown in the following chart.

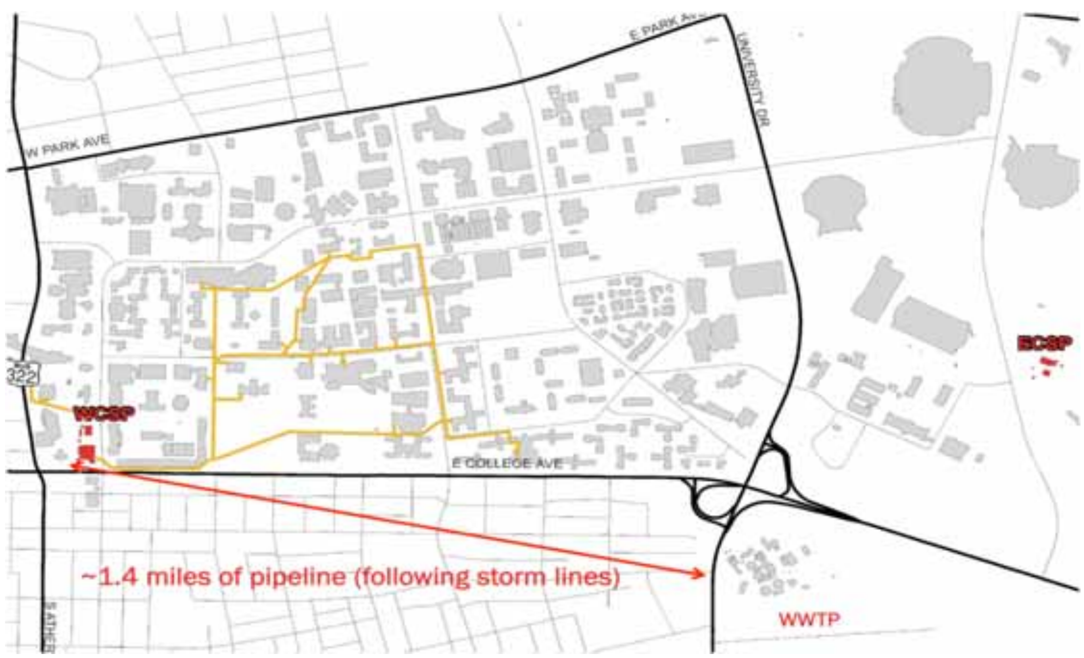
[26] Murphy, J.D., E. McKeogh, and G. Kiely. "Technical/economic/environmental analysis of biogas utilisation" Applied Energy. 77 (2004) 407-427.

Fig 9. Coal Use at the WCSP versus Biogas Availability from the Penn State WWTP



The gas would need to be piped approximately 1.4 miles, as shown in the following diagram.

Fig 10. Map of State College Borough



A natural gas distribution system was used to estimate the characteristics of the biogas distribution system. Typically, the smallest pipe used for distribution of natural gas has a 2 inch diameter. Assuming no losses through the pipe and a continuous flow of gas through the pipe, a maximum pressure of 1.06 atm inside the pipe can be obtained or a flow rate of 2.7 MPH which is much less than the recommended velocity of 21.7 MPH. Adding a carrier gas to increase injection velocities would further reduce the Lower Heating Value (LHV) of biogas making it ineffective.

Since the WCSP has four stokers with four natural gas injectors each, which when fired together can provide up to 25% of the total BTUs generated at the WCSP. Each injector could contribute up to 1.56% of the total BTUs. Assuming cofiring is done in only one of the stokers, it would mean the biogas generated at WWTP would provide 0.075% of the total BTUs from the gas per injector. This quantity is believed to be too small to sustain an efficient combustion using the available gas supply from WWTP.

Even though low injection velocities and inefficient quantities to sustain combustion were identified as technical barriers, a rough economic analysis was performed. The results are in the following two tables

Table 5. Biogas: Annual Operating Costs Changes

Operating Cost	Amount	Cost	Impact/yr
Coal reduction (0.3%)	224 tons	$100/ton	($22,400)
Biogas	6,572 ccf	$0/ccf	$0
H2S treatment	6,572 ccf	$3/ccf	$20,000
Cost savings	--	--	$2,400 savings

Table 6. Biogas: Rough Economic Analysis

	Result
Annual savings	$2,400
Pipeline costs[27]	$984,000
Simple payback	410 years

Therefore, the available biogas cannot be effectively utilized in the WCSP.

[27] Penn State OPP. Personal correspondence. Based on quote for similar work. April 2010

3.4 Additional Considerations

Process optimization: 5% biogas blend

An optimum cofiring system with biogas replaces 5%-7% of the total energy consumption of the coal in a furnace design similar to Fuel Lean Gas Reburn (FLGR) technology which has a limit of approximately 7% heat input by natural gas.[28] The advantages of this type of arrangement includes reduced gas input compared to conventional reburn systems and do not require completion over-fire-air to achieve carbon monoxide (CO) burnout. Finally, the system does not significantly impact the primary furnace combustion.

Due to the advantages of a 5%-7% biogas mixture, it is recommended that the University consider additional biogas sources, such as biodigesters for agriculture waste. However, due to the high capital costs of these systems, this project is not economically justified at this time.

Biogas from WWTPs would not be in sufficient quantity due to a limited population in Centre County. A conservative estimate is that 40,000 people supply the Penn State WWTP with sewage at any time. To replace 5% of the total BTUs from WCSP using biogas, a population of around 660,000 people would be required to provide sufficient sewage.

Future considerations for potential uses of available biogas

Although using biogas for cofiring in the Penn State WWTP is not feasible due to technical and economic issues, additional uses for this gas should be considered since this energy source is currently flared for treatment/disposal. Two options are discussed below.

- Space Heating
  The offices at WWTP facility use baseboard radiator heating system. These systems utilize steam to transfer heat from the heat source to the rooms before the heat is radiated through radiators. Since part of the biogas is used to generate steam to maintain the primary digesters at a constant 95°F, a steam generating unit is already available. If the excess biogas is used to generate extra steam, which may be directed to the offices at WWTP, the local heating requirements could be met with minimal investment and changes.
  The WWTP currently flares off around 11MCF of biogas annually, which may generate approx 6600 MMBTUs annually[29]. The offices at WWTP utilize 2084 MMBTU[30]. Assuming that all the heat required by the wastewater treatment plant is during the heating season – October to April. Based on the available data, a total of 4010 MMBTU[31] from biogas is available during the heating season. The excess heat may be used to heat Nelson Hall (1781

[28] Electric Power Research Institute, Inc. *Gas Cofiring Assessment for Coal Fired Utility Boilers*. 2000
[29] Check Appendix B for calculations
[30] http://energy.opp.psu.edu/energy-programs/energy-consumption/university-park/up-buildings-mmbtu. Accessed: May 1, 2010
[31] Check Appendix B for calculations

MMBTUs/year) or Beecher dock house (773 MMBTUs) which are right across University Drive along the East College Avenue.

- Pipeline quality methane generation
  Biogas may be scrubbed off its CO_2 and H_2S and upgraded to pipeline quality methane.
  a) Methane could be used to fueling the in-house trucks if they could be modified using over the counter equipment to utilize natural gas (which has over 95% methane).
  b) Methane could be used for in house heating. The gas could be added to the local supply although the dividends of this would be low. However natural gas buying rate may be lower than the selling rate so the economics need to be considered.

4.0 Biomass

Biomass was the second of two options that were evaluated as a solution to reducing Penn State's consumption of nonrenewable resources in the WCSP and reducing operating costs. Next to hydropower, more electricity is generated from biomass than any other renewable energy.

Biomass is a renewable energy resource that is biologically derived from living or recently living organisms.[32] For example, it includes a broad range of materials biological in nature, such as agricultural and forestry products, farm and wood waste products, selected garbage, animal and human wastes convertible to solid or gaseous fuels.[33] Biomass is commonly divided into three categories: waste, forestry products, and energy crops.

Waste*:* Biomass as a waste product generally comes from either 1) landfills or municipal waste or 2) industrial waste. Municipal solid waste is roughly 60% organic materials or biomass. Industrial waste consists of various kinds of refuse that can be burned also ultimately to produce electricity. Food operating companies are especially plentiful sources of waste residues and matter. Wood pulp, chips, and sawdust are also considered biomass waste and sometimes referred to, once converted to liquid form, as "black liquor".[34]

Forestry products*:* Natural forests are considered a biomass source albeit one that is not highly productive in the sense that trees take time to grow and mature. Nevertheless, research and development in recent years has resulted in fast-growing trees and woody plants that can be grown and harvested in a timely and productive manner. Wood is a traditional fuel source and will continue to be an important source of energy.

Energy crops*:* These biomass sources, such as ethanol and biofuel, originate as crops. Corn, sugarcane, and soybeans are typical biofuel sources but virtually any other agricultural crop can produce alcohols once fermented. Ethanol and biofuels are currently used as a blend (E20 or E85) with gasoline, but eventually it is projected that vehicles will be fueled 100% by ethanol or biofuels.[35]

Pennsylvania is a considered to have a high potential for biomass co-firing. The primary factors considered were state coal prices, estimated low-cost biomass residue supply density, and average state landfill tipping fees. Biomass cubes can be manufactured and delivered to the power plant for a little over $0.3/million BTUs or less than $5/ton.[36]

[32] wikipedia.org. Accessed in February 2010
[33] Flora, J. (1995, December). *The use of biomass fuels in South Carolina*. Prepared for the State Energy Office. Columbia: SC, p. 1.
[34] Berinstein, P. (2001). *Alternative energy: facts, statistics, and issues.* Westport, CT: Oryx Press, p. 87.
[35] Flora, J. (1995). *The use of biomass fuels in South Carolina*. Prepared for the State Energy Office. Columbia: SC, p. 1.
[36] US Department of Energy, Energy Efficiency and Renewable Energy, *Federal Energy Management Program, Federal Technology Alert.* (DOE/EE-0288).

4.1 Characteristics of Biomass

Volatile matter is higher in biomass than in coal. Pyrolysis starts earlier for biomass fuels than for coal. The fraction of heat contributed by volatile substances in biomass is approximately 70% compared with 30-40% in coal. The specific heat of volatiles per kilogram is lower for biomass compared for coal.

Table 7. Proximate and Ultimate Analysis of Various Fuels Compared with Coal[37]

Fuel	LHV (daf) Btu/lb	Volatile matter % w/w (daf)	Ash content % w/w (dry)	Ultimate Analysis % s/s (daf)				
				C	H	O	N	S
Straw	7823.7	81.3	6.6	49.0	6.0	44.0	0.8	0.2
Wood	8038.6	83.0	1.8	50.5	6.1	43.0	0.3	0.1
Bark	6963.9	76.0	7.0	50.5	5.8	43.2	0.4	0.1
Rape oil	15389.4	100.0	0	77.0	12.0	10.9	0.1	0
Peat	8167.6	74.2	2.7	52.6	5.8	40.6	0.9	0.1
Bituminous Coal	1367	34.7	8.3	82.4	5.1	10.3	1.4	0.8

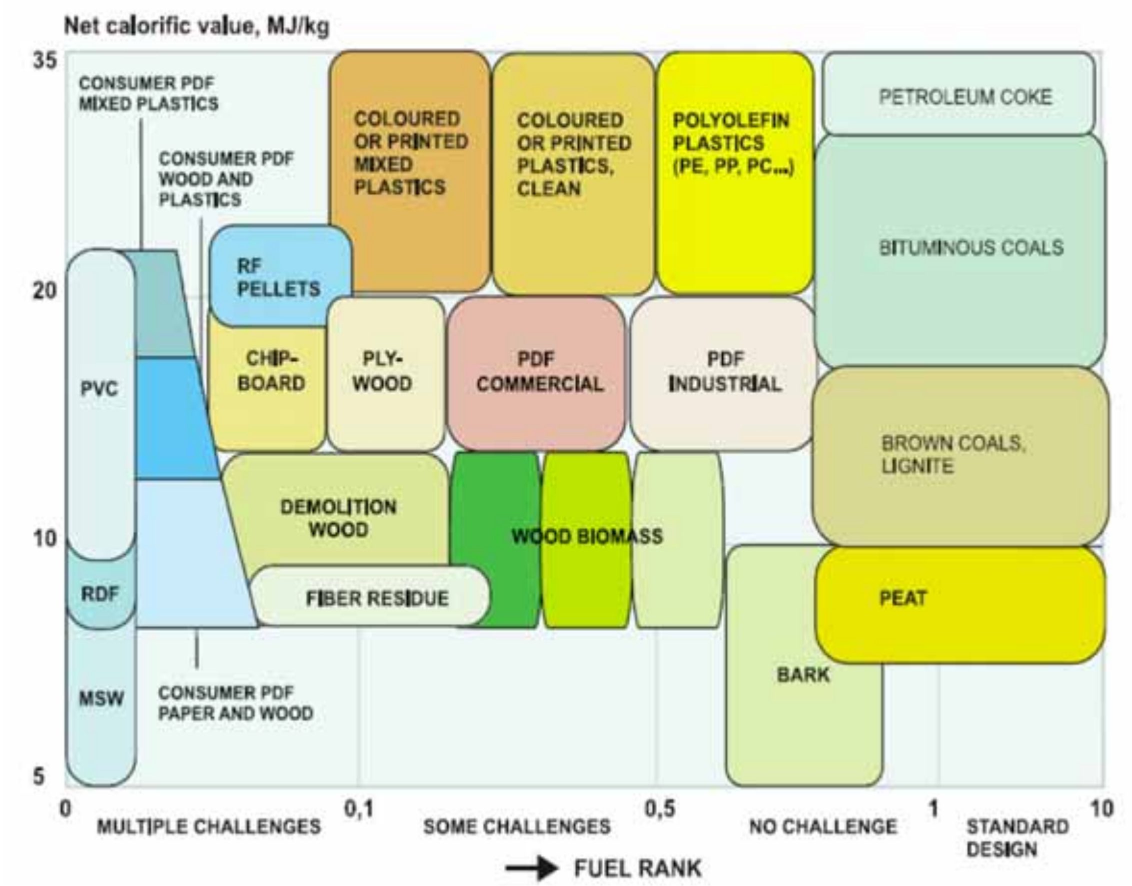
Biomass char has more oxygen than coal and is more porous and reactive. Biomass has high chlorine, but typically has low sulfur and ash content than coal.[38] Biomass has a lower heating value (LHV), varying chemical compositions and peculiar physical properties (e.g., wide range of particle size, high moisture content, irregular shapes, low bulk densities) compared to coal. The higher volatile content of biomass led to two distinct stages of weight losses, with gas phase oxidation at the beginning and char oxidation in the second stage, whereas the latter dominated the entire process for coal. Energy from the biomass combustion comes mainly from volatile matter reaction, whereas almost all of the energy for coal comes from char oxidation. Hence, the mechanisms of biomass and coal combustion differ somewhat, although biomass follows the same sequence of pyrolysis, devolatilization, and combustion as for combustion of low-rank coal. Biomass can burn more intensively and may give rise to higher local peak temperatures due to its higher reactivity than coal. The combustion rate of biomass char is slightly higher because of a more disordered carbon structure (biomass char is highly irregular with a collapsed matrix and this has been attribute to high volatile content and enormous devolatilization. Coal char consists of more regular particles[39]) while biomass char burning rates are comparable to burning rates of high volatile bituminous coal chars.
Premixing biomass and coal can enhance the combustion of the two fuels, whereas poorly mixed biomass and coal tend to burn independently at different rates.[40] The general reactivity is in the

[37] Chmielniak and Sciazko. Co-gasification of biomass and coal for methanol synthesis. 2003
[38] Networks, European Bioenergy, *Biomass Co-firing - An efficient way to reduce greenhouse gas emissions.*
[39] Haykiri-Acma, H. and S. Yaman, *Synergy in devolatilization characteristics of lignite and hazelnut shell during co-pyrolysis.* Fuel, 2007. 86(3): p. 373-380.
[40] Dai, J.J., et al., *Overview and some issues related to co-firing biomass and coal.* Canadian Journal of Chemical Engineering, 2008. 86(3): p. 367-386.

order: biomass > lignite > hard coal and this is again attributed to the fact that they have a porous and highly disordered carbon structure. The influence of biomass on combustion was greater for lower rank coal than for higher rank coal mixtures as biomass chars reacted in a temperature region close to low rank coal chars that would allow interactions. In the case of high rank coal, the biomass reaction was clearly differentiated from coal and this might be the cause of inconsiderable interaction between the constituent parts.[41]

Since the coal combusted at the WCSP is a high volatile coal, we expect that there will be some good interactions between the coal and biomass due to reasons cited above, thus increasing burnout and carbon conversion efficiency.

Fig 11. Ease of Burning with Fuel Rank[42]



The above diagram shows design challenges for various solid fuels based on rank and calorific value. As can be seen, there are currently no challenges in the conventional design for firing coals whereas challenges come up when using wood based biomass and plastics and a lot of

[41] Kastanaki, E. and D. Vamvuka, *A comparative reactivity and kinetic study on the combustion of coal-biomass char blends.* Fuel, 2006. 85(9): p. 1186-1193.
[42] Ibid

challenges (like corrosion and slagging) crop up for municipal solid waste, paper, animal manures, and refuse derived fuel.[43]

The below table lists the energy content of some common biomass.

Table 8. Energy Content of Common Biomass[44]

Biomass Type	Energy Content (BTU/lb)
Wood (dry)	7600 to 9600
Wood (20% moisture)	6400
Agricultural Residues	4300 to 7300
Black Liquor	5900
Sludge Wood	5000
Municipal Solid Waste	5000
Peat	4000
Sludge Waste	3700
Digester Gas	800
Methane	470
Landfill Gas	250

Source: Energy Information Administration (1999)

4.2 Biomass Energy Conversion Options[45]

Most small facilities such as university facilities meet most of the criteria for biomass co-firing like use of coal-fired boiler, access to steady supply of competitively priced biomass, high coal prices, and favorable regulatory and market conditions for renewable energy use and waste reduction. Stokers are considered a popular, inexpensive, and viable method to combust biomass and refuse-derived fuel.[46] Wood products, agriculture, textiles, chemicals, straw, waste fuels, and peat are used in ongoing stoker boiler projects.[47]

There is no change to boiler efficiency unless a very wet biomass is used. Coal can mitigate the effects of variations in biomass feedstock quality and buffer the system when there is insufficient biomass feedstock.[48] Stoker based systems also have the advantage in terms of cost involved in feed particle size reduction as the feed size for stokers is much larger compared to pulverized coal and fluidized bed systems.

[43] Networks, European Bioenergy, *Biomass Co-firing - An efficient way to reduce greenhouse gas emissions.*
[44] "Generating Electricity from Biomass in Centre County, Pennsylvania" Prepared in EME 580 by LaTosha Gibson, Junichiro Kugai, Charles Winslow, and Chao Xie. May 4, 2007.
[45] Personal Communication: Dr. Dave Tillman, Engineer, Foster Wheeler Corporation. Feb 16, 2010
[46] Basics of boiler and HRSG design, Brad Buecker. April 2010
[47] Networks, European Bioenergy, *Biomass Co-firing - An efficient way to reduce greenhouse gas emissions.*
[48] Dai, J.J., et al., *Overview and some issues related to co-firing biomass and coal.* Canadian Journal of Chemical Engineering, 2008. 86(3): pp. 367-386.

Direct Combustion of biomass in utility boilers to produce electricity or steam is the most feasible option currently. Gasification of biomass to produce syngas and subsequently other products from syngas, is currently unfeasible due to large plant size and low energy gas. Hydrolysis and Fermentation of biomass are also not feasible. Direct Liquefaction, i.e. biomass to liquids (BTL) to produce liquids is not feasible unless fuel prices reduce.

Three types of combustion are possible for co-firing:

- Direct, where the biomass and fossil fuel are combusted in a single chamber
- Indirect, where the fossil fuel and previously gasified fuel are combusted, and
- Parallel combustion where two boilers run parallel, one for biomass and the other for the fossil fuel.[49]

Biomass can either be blended with the main fuel or it can be injected into the system separately. The former requires less modifications a plant. Co-firing of biomass requires biomass particle size to be 0.25 inches or smaller, with moisture levels less than 25% when firing in the range 5-15% on a heat input basis.[50]

The blended fuel option will be evaluated for this project as this saves on modification costs and also there is enough storage space available at WCSP by means of bunkers and hoppers.

4.3 Biomass at Penn State

The Penn State University Park campus, which is located in Centre County, PA, has many potential biomass sources nearby:

- Construction waste
- Municipal solid waste from the Centre County Solid Waste Authority (CCSWA) which has reported 88,556 tons of waste handled in 2009[51]
- Agricultural/animal waste: Centre County, PA has a total of 1,146 farms with a total area of 148,464 acres, with an average farm size of 130 acres.[52] Animal waste calculations (amount of dry biomass) were performed using equations in National Engineering Handbook, Part 651, Agricultural Waste Management Field Handbook, Chapter 4, USDA and the 2007 census report from USDA. Approximately 38,900 tons/year of dry biomass (animal waste) is available.
- Reed Canary grass grown on Penn State's wastewater treatment facility's effluent spray field
- Agricultural plastics including horticulture hard plastics and plastic bags, bale tarps, and silo bunker covers
- Tires
- Wood shavings and chips from the surrounding community
- Sewage sludge

[49] Networks, European Bioenergy, *Biomass Co-firing - An efficient way to reduce greenhouse gas emissions.*
[50] US Department of Energy, Energy Efficiency and Renewable Energy, *Federal Energy Management Program, Federal Technology Alert.* (DOE/EE-0288).
[51] Personal Communication: Amy Shirf, CCSWA. February 18, 2010.
[52] 2007 Census of Agriculture, Centre County, USDA

Other sources of biomass for the plant could be identified with the Pennsylvania Material Trader (www.materialtrader.org) where there are listings for various types of wastes including wood. For example, currently there is a posting in Huntingdon, PA for wood waste available at the rate of 80 tons every 5 days which translates to about 5,760 tons/yr.

Additional information about biomass availability is included in Appendix D.

In addition to availability, some of the reasons that biomass may be a feasible option at Penn State include[53]:

- Continue the use of coal, which is currently the most economical and readily available fuel source for Penn State. Price stability of coal is very good compared to oil and natural gas that are on the rise.
- Reduce the amount of agricultural and other biomass waste products of which disposal is becoming more difficult and expensive
- Use waste biofuels, which reduces the amount of CO_2 being emitted (assuming biomass is a carbon neutral fuel)

Ease of usage:
Woody biomass is the form of biomass that is the easiest to use. The ease of use decreases as we move from wood to urban wood waste to wood from energy crops to straw, agricultural wastes, orchard nuts, and vineyard wastes. Manures are the form of biomass which is most difficult to use and they are generally not preferred to co-fire with coal.[54]

The WCSP would require 16,988.33 tons/yr of biomass considering 15% coal replacement on a heat basis and a heat content of 9,000 Btu/lb. This amount of biomass is readily available in Centre County. From Appendix D, Centre County has 38,898 tons/yr of animal waste (dry) and more than 90,000 tons/yr of wood based biomass. University Park campus itself has 18,183 tons/yr of animal waste, 842 tons/yr of wood/farm waste and another 11,166.2 tons/yr of miscellaneous biomass waste.

4.4 Pollutant Issues with regard to Co-firing Coal and Biomass

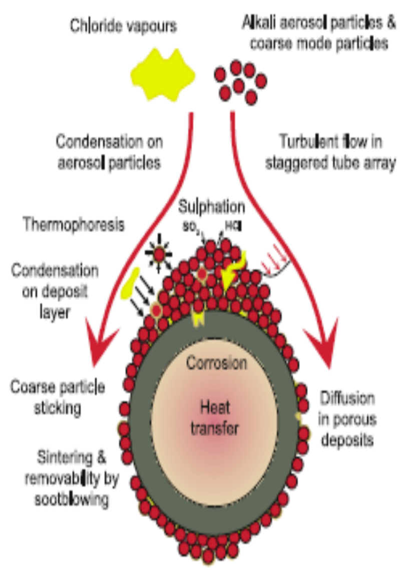
Biomass typically is low in sulfur and nitrogen.[55] There is lower net CO_2 and improved compliance with NO_x and SO_x. It has been found that pollutants decrease as the proportion of biomass increases. Alkaline ash from biomass may capture some SO_2 generated during

[53] Bruce G. Miller, S.F.M., Robert Cooper, John Gauldip, Matthew Lapinsky, Rhett McLaren, William Serencsits, Neil Raskin, Tom Steits, Joseph J. Batista, *Feasibility Analysis for Installing a Circulating Fluidized Bed Boiler for Cofiring Multiple Biofuels and Other Wastes with Coal at Penn State University.* 2003.
[54] Personal Communication: Dr. Dave Tillman, Engineer, Foster Wheeler Corporation February 16, 2010
[55] US Department of Energy, Energy Efficiency and Renewable Energy, *Federal Energy Management Program, Federal Technology Alert.* (DOE/EE-0288). May 2004

combustion[56]). The fuel nitrogen content of biomass is mainly converted to ammonia during combustion, contributing to decreasing NO_x for co-firing. Hydrocarbons from biomass can also react with NO_x , producing molecular N_2. Hence, biomass has the potential to be an effective additional fuel when coal is the primary fuel. In addition, ammonia (NH_3) found in the biomass (e.g., animal wastes) or formed during combustion of biomass may contribute to the catalytic reduction of NO_x. Wood is the most favorable co-firing fuel in terms of ease of combustion and reduced emissions of NO_x and SO_2.[57] Injecting higher-N fuel (coal) in the center of the burner and the lower-N fuel (biomass) on the outer annulus, results in lower NO_x emissions as the center fuel goes into the fuel rich recirculating zone. So, biomass is an excellent option for air staging and reburning. When sewage sludge was co-fired with coal, heavy metal and trace elements are below acceptable limits. Also, Zn, P, Cr, Pb, Cu, Co, and Ni were found to be slightly higher in the particles but well below acceptable limits. SO_2 emissions depend on fuel-S and conversion to SO_2 is as high as 90%. There is higher burnout and lower CO emissions.[58] Particulate matter emissions are generally lower while co-firing the blended fuel and this is primarily due to the reduced ash content of the blended fuels.

4.5 Ash and Depositional Issues with regard to Co-firing of Coal and Biomass

Fig 12. Process of corrosion



Ash deposits accumulate on heat transfer surfaces by five different means:

a. Inertial impaction - deposition by means of inertia when fly ash hit heat transfer surfaces
b. Thermophoresis - due to temperature difference in the gas

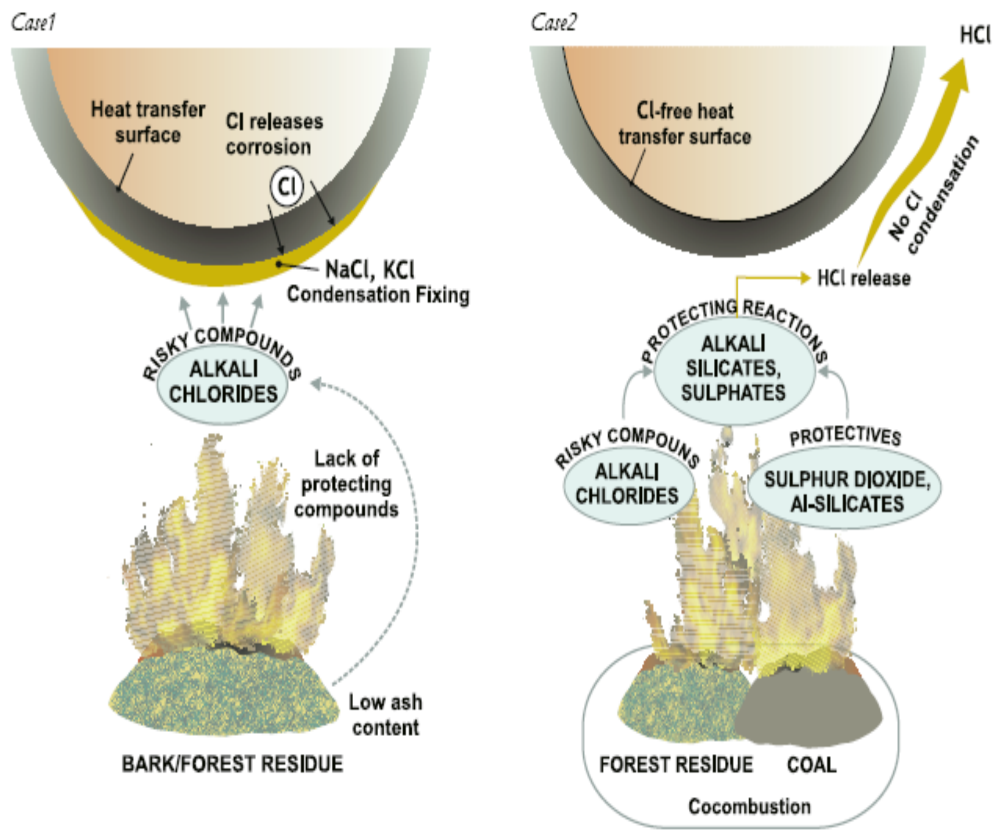
[56] Folgueras, M.B., R.M. Diaz, and J. Xiberta, Sulphur retention during co-combustion of coal and sewage sludge. Fuel, 2004. 83(10): p. 1315-1322.
[57] Dai, J.J., et al., *Overview and some issues related to co-firing biomass and coal.* Canadian Journal of Chemical Engineering, 2008. 86(3): p. 367-386.
[58] Hein, K.R.G. and J.M. Bemtgen, *EU clean coal technology - co-combustion of coal and biomass.* Fuel Processing Technology, 1998. 54(1-3): p. 159-169.

c. Condensation of vaporized compounds - occurs when the heat transfer surfaces are at a sufficiently low temperature
d. Diffusion - important for particles less than 1 micron (μ)
e. Chemical reactions - within the deposit layer between gaseous and solid compounds

The degree and nature of fouling depends on local gas temperatures, tube temperatures, temperature differences, gas velocities, tube orientation, local heat flux on particles, and fuel composition.

Biomass in general has a higher chlorine content and low ash content (ash content also varies from very low in wood (0.2%) to very high in sewage sludge (30-60%)[59])[60] and also a higher concentration of alkaline and alkaline earth metals compared to coal. The higher alkaline content can result in ash that has a higher propensity to form liquid phases at lower temperatures, causing corrosion. Among the alkalis, potassium has higher propensity to form liquid phases compared to calcium. If biomass is co-fired at <20% thermal input, then there does not seem to be an increase risk of ash deposition or slagging.[61] This is because the sulfur and aluminum silicates from coal ash are able to form alkali silicates and alkali sulfates. Chlorine is released as HCl in flue gases and alkali metals are bound in compounds that have high melting point and no corroding effect.

Fig 13. Case 1: No co-firing Case 2: Co-firing

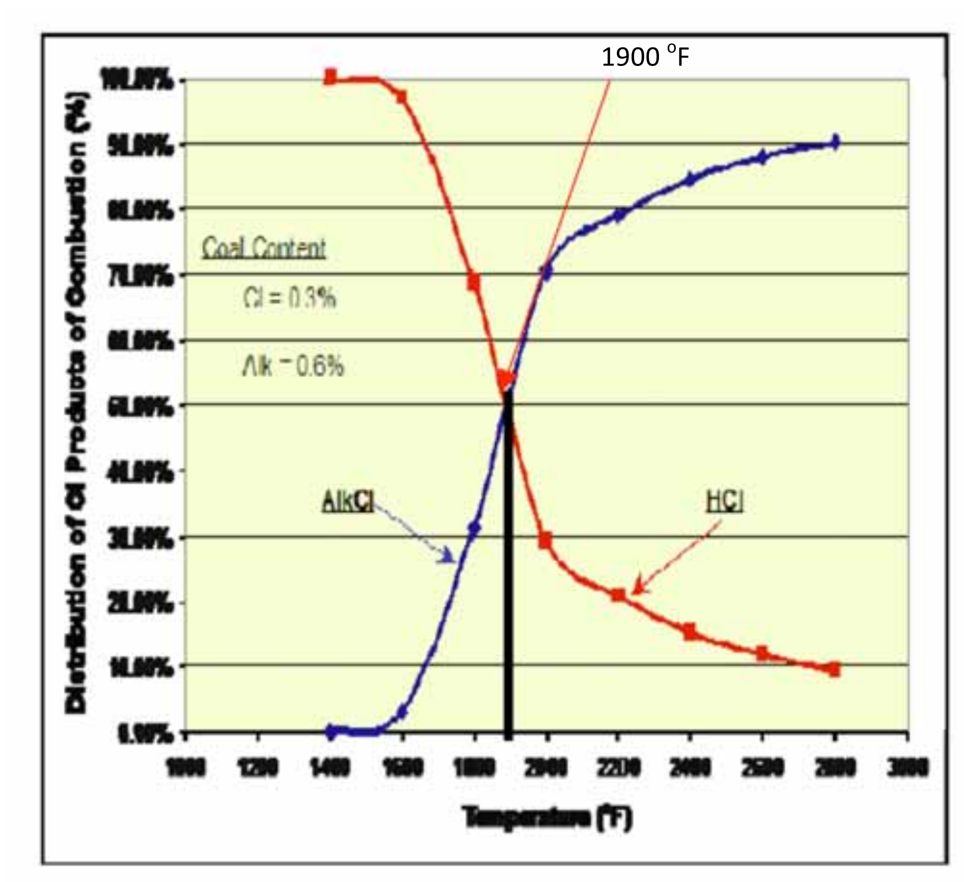


59 Hein, K.R.G. and J.M. Bemtgen, *EU clean coal technology - co-combustion of coal and biomass.* Fuel Processing Technology, 1998. 54(1-3): p. 159-169.
60 Networks, European Bioenergy, *Biomass Co-firing - An efficient way to reduce greenhouse gas emissions.*
61 Sharon Falcone Miller, B.G.M., *The occurrence or inorganic elements in various biofuels and its effect on ash chemistry and behavior and use in combustion products.* Fuel Processing Technology, 2007.

The reactions are taking place are:

$2KCl + SO_2 + 1/2\ O_2 + H_2O \dashrightarrow K_2SO_4 + 2\ HCl$
$Al_2O_3.2SiO_2 + 2\ KCl + H_2O \dashrightarrow K_2O.Al_2O_3.2SiO_2 + 2\ HCl$ [62]
If S/Cl ratio is less than 2, there is high risk of superheater corrosion. When the ratio is at least 4, the blend could be regarded as non-corrosive[63].

Fig 14. Variation of Chloride Compounds with Furnace Temperature



In the boiler, HCl is the main product below 1900°F. Above 1900°F, alkali chlorides are the main product[64]. Normal stoker operation is at temperatures above this so it is expected that there will be more alkali chlorides compared to HCl and so, more propensity for corrosion. The coal

[62] Dao N.B. Duong, Clinton, NJ, *Chlorine Issues with Biomass Cofiring in Pulverized Coal Boilers: Sources, Reactions and Consequences - A Literature Review.*
[63] Networks, European Bioenergy, *Biomass Co-firing - An efficient way to reduce greenhouse gas emissions.*
[64] Dao N.B. Duong, Clinton, NJ, *Chlorine Issues with Biomass Cofiring in Pulverized Coal Boilers: Sources, Reactions and Consequences - A Literature Review.*

analysis shows that WCSP uses a medium sulfur coal (around 1%). This is beneficial to some extent to mitigate chlorine corrosion as explained above. Some other solutions would be to inject ammonium sulfate into the flue gas to convert gaseous potassium chloride to potassium sulfate or pretreating biomass by leaching it with water to reduce sulfur, chlorine, and alkalis. Large portions of Cl-rich biomass (meat and bone meal (MBM) and refuse-derived fuel (RDF)) have been co-fired with selected coals without operational problems.[65] Also, injecting kaolinite ($Al_2Si_2O_5(OH)_4$) into the system increases aluminum in the system and shifts the equilibrium away from formation of phases having low melting point.[66]

In general, the following interactions are expected when coal and biomass are co-fired[67]:

a. increased rate of deposit formation
b. shorter sootblowing interval
c. cleaning of heat transfer surfaces in revisions may be required
d. higher risk of corrosion of heat transfer surfaces
e. bed material agglomeration

Slagging Potential of Various Solid Fuels:

The ash properties of various fuels are given in Appendix D.

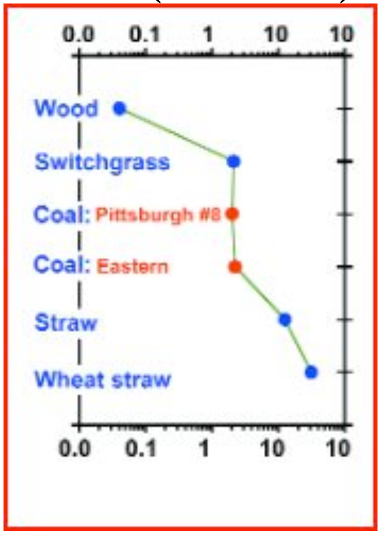
Oxides are classified into:

B (low melting temperature oxides) = (Fe_2O_3+CaO+MgO+Na_2O+K_2O)
A (high melting temperature oxides) = (SiO_2+Al_2O_3+TiO_2)
The B/A ratio gives the slagging potential of each type of fuel. When the ratio increases, the slagging (ash melts and fuses) and corrosion increases. It can be seen that coal has the lowest B/A ratio followed by wood and farm-based biomass and the worst being animal manure.[68]

The below figure shows that wood has the least ash deposition rate, even lower than most coals, while switchgrass, straw and wheat straw have much higher ash deposition rates.

[65] Dai, J.J., et al., *Overview and some issues related to co-firing biomass and coal.* Canadian Journal of Chemical Engineering, 2008. **86**(3): p. 367-386.
[66] Bruce G. Miller, S.F.M., Robert Cooper, John Gauldip, Matthew Lapinsky, Rhett McLaren, William Serencsits, Neil Raskin, Tom Steits, Joseph J. Batista, *Feasibility Analysis for Installing a Circulating Fluidized Bed Boiler for Cofiring Multiple Biofuels and Other Wastes with Coal at Penn State University.* 2003.
[67] Networks, European Bioenergy, *Biomass Co-firing - An efficient way to reduce greenhouse gas emissions.*
[68] Masia, A.A.T., et al., *Characterising ash of biomass and waste.* Fuel Processing Technology, 2007. **88**(11-12): p. 1071-1081.

Fig 15. Ash Deposition Rates (lb/1000 lb fuel) for Various Fuels[69]



Ash for concrete:

Total ash generated from the co-fired process will be less than ash generated during 100% coal firing due to lower ash content of woody biomass compared to coal. Concrete admixtures represent an important market for some coal combustion ash by-products. Current ASTM standards for concrete admixtures require that the ash be 100% coal ash. Efforts are under way to demonstrate the suitability of commingled biomass and coal ash in concrete admixtures, but in the near term, cofired ash will not meet ASTM specifications. This is a serious problem for some utility-scale power plants that obtain a significant amount of revenue from selling ash.[70] Currently the WCSP disposes of fly ash in a landfill. Bottom ash meets beneficial use criteria set by DEP. It is used locally for road maintenance and also for manufacturing architectural concrete blocks.[71] Bottom ash from co-firing coal and biomass can still continue to be used for road construction and landscaping materials and this accounts for about 20% of the total ash. The other 80% is fly ash and is currently landfilled has the potential to be used for cement blends, mortars, and lightweight aggregates in the future depending on approval.

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[69] Sjaak Van Loo, Japp Koppejan, *Handbook of biomass combustion and co-firing*. Jan 2008
[70] US Department of Energy, Energy Efficiency and Renewable Energy, *Federal Energy Management Program, Federal Technology Alert.* (DOE/EE-0288).
[71] Penn State Steam Services Fact Sheet. March 2007.

Fig 16. Amount of Aerating Agent Required to Generate Air Entrainment[72]

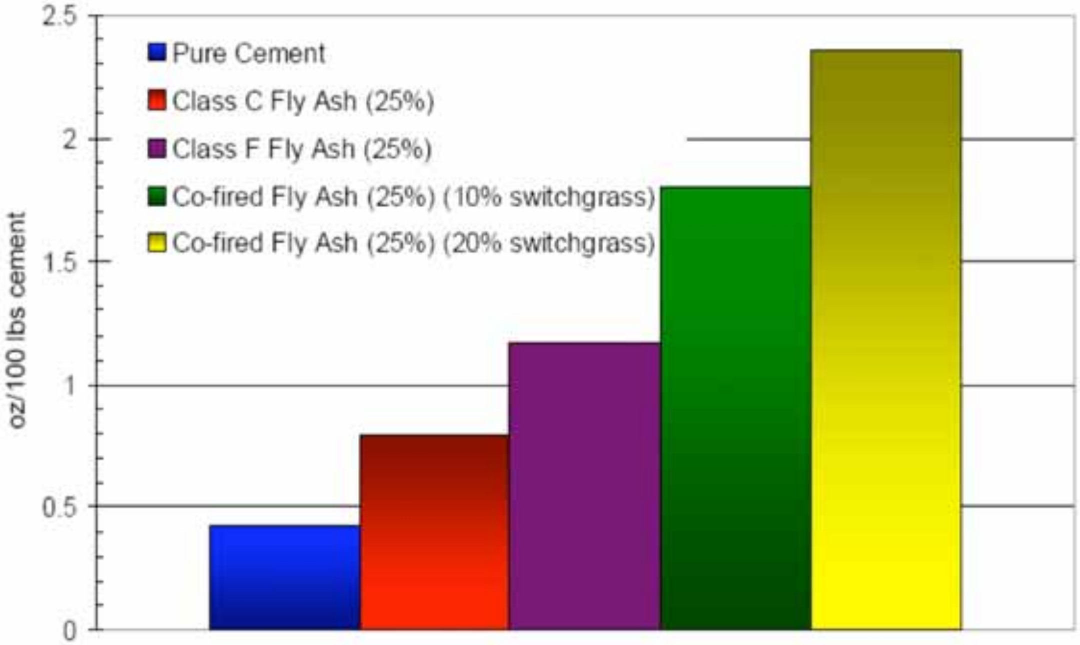
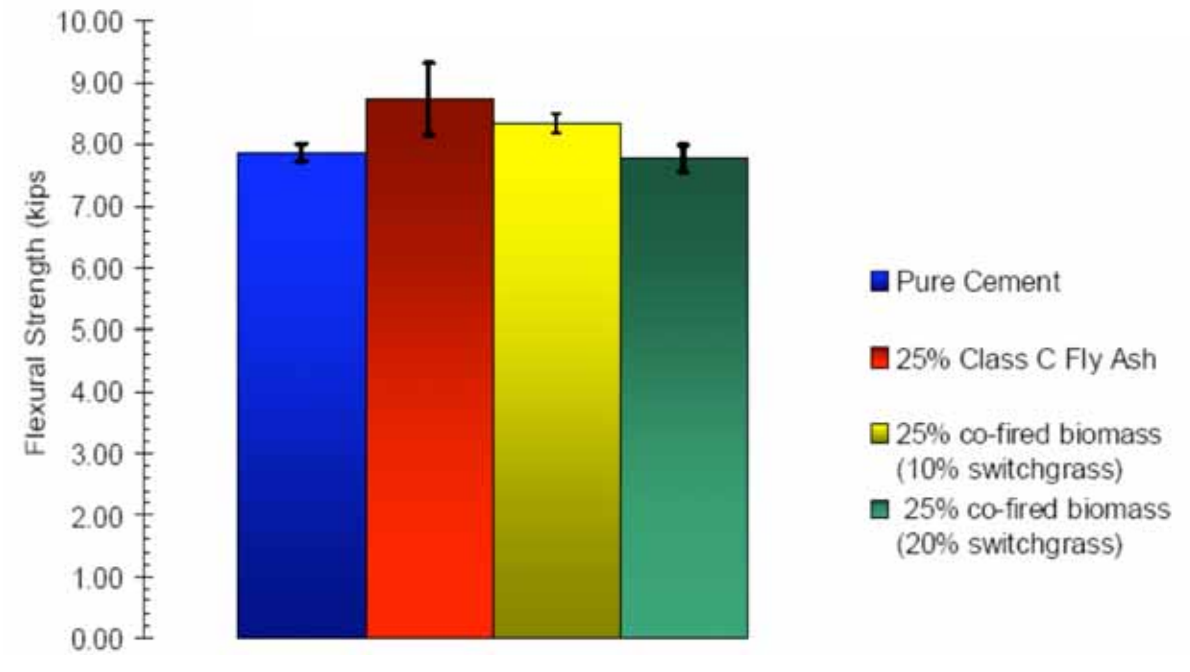


Fig 17. Flexural Strength and its Dependence on Fly Ash Composition[64]



[72] Larry Baxter, Jaap Koppejan. Biomass-coal co-combustion: Opportunity for Affordable renewable energy. IEA State of the art combustion technology overview.

The figure on aerating agent shows that the amount of aerating agent required for concrete from co-fired ash is more than that required for concrete from pure coal ash but this is inexpensive. Also, from the figure above, shows that the flexural strength shows little significant difference among pure cement, class C fly ash cement and co-fired fly ash cement.[73] Hence, there exists a very promising opportunity to use co-fired fly ash in concrete ad-mixtures.

4.6 WCSP Plant Design for Biomass Co-firing

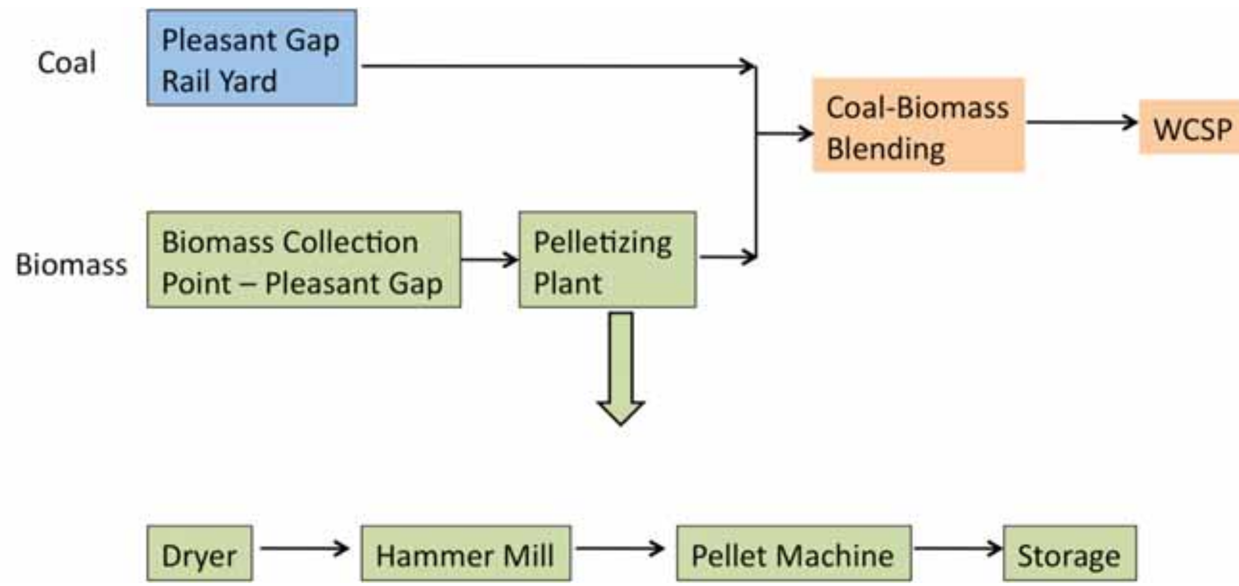
Woody biomass has been selected as the fuel for co-firing because of high energy content compared to other biomass, ease of use, low CO_2, SO_2, NO_x and CO emissions, low ash and depositional issues and higher ash fusion temperatures compared to other biomass. Also, wood waste from local businesses is recommended because it is currently being landfilled, and is carbon neutral, and is inexpensive.

Biomass and coal will be collected at separate locations in Pleasant Gap, PA. The woody biomass is sent to a pelletizing plant where it is first dried in a drier to reduce moisture content. Then it is sent to a hammer mill to reduce the size of big pieces. Then it is pelletized by compression into pellets the size of stoker coal (1 1/4" to 3/4"). After this it is sent to a cooler and then stored. If the coal arriving by train is very wet, the drier can be used to remove excess surface moisture, thus increasing the heat content. The biomass and coal are then blended in a pug mill and then sent by trucks to WCSP for firing. Due to the lower density of biomass, there will be an increase in the number of truck trips.

A finalized list of biomass sources is included in Appendix E. Examples of a pelletizing plant and pug mill are included Appendix E.

[73] Van Loo, Sjaak and Japp Koppejan. *Handbook of biomass combustion and cofiring*. January 2008

Fig 18. Overall Process Flow Diagram



The below figure shows the amount of energy from coal offset with biomass.

Fig 19. Amount of energy from coal offset with biomass

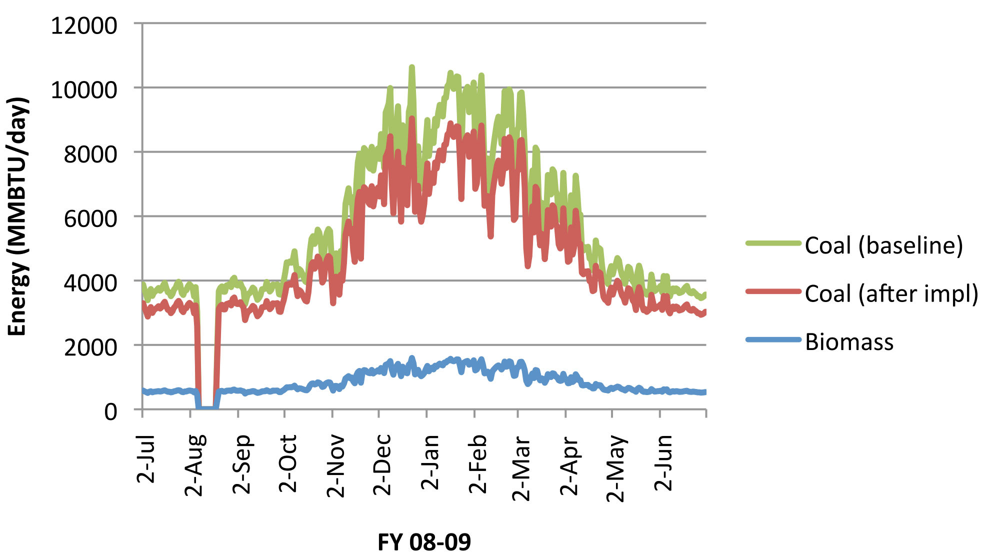
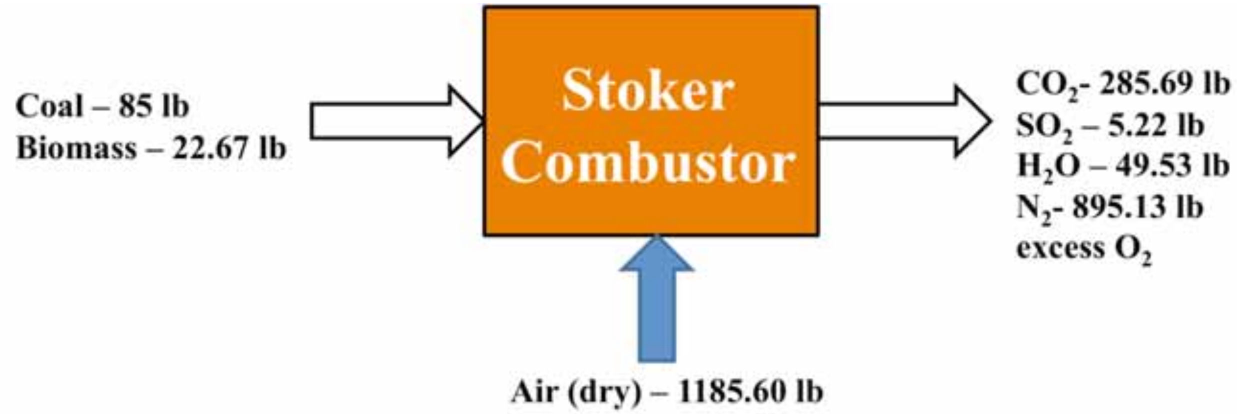


Fig 20. Mass Balance:

Basis: 100 lb coal



A coal-biomass blend of 15% on a heat basis and 21% on a mass basis has been selected. The reason for selection is because biomass can have high amount of alkali or chlorine content or both. The problems with these have already been discussed earlier in section 4.5 and these problems can be minimized if the biomass contribution to the boiler heat input is limited to 15% or less on a heat basis[74].

From the mass balance calculations, it has been found that with the current levels as a basis,

Reduction in CO_2 - 15%

Reduction in SO_2 - 15%

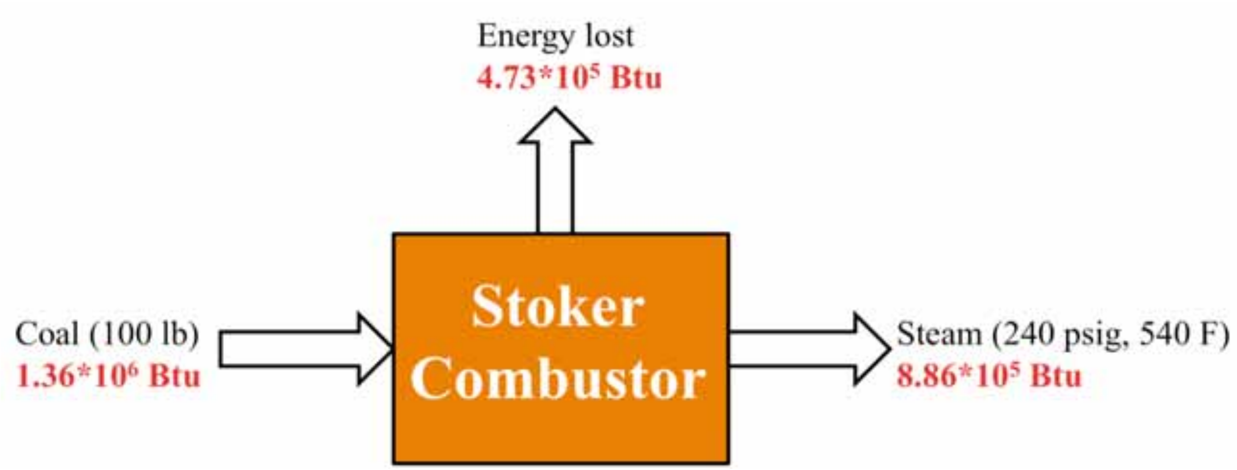
Increase in H_2O - 10.72%

Reduction in air - 6.23%

Overall, the University would reduce CO_2 emissions by 32,155 lb/yr and SO_2 emissions by 688 lb/yr by transitioning from 100% coal to 15% biomass-85% coal (heat basis).

[74] US Department of Energy, Energy Efficiency and Renewable Energy, *Federal Energy Management Program, Federal Technology Alert.* (DOE/EE-0288). May 2004

Fig 21. Energy Balance:



The energy balance does not change with co-firing as the substitution is done on a heat basis.

The above calculations were performed assuming that 6.9 lb of water is evaporated for every lb of coal[75] and that the specific enthalpy of steam at 240 psig and 540°F is $2.99*10^6$ J/kg.[76]

[75] Airesman, H.D. *Stoker Handbook*. 1939
[76] Spirax Sarco steam tables (http://www.spiraxsarco.com/)

5.0 Biomass Implementation Considerations

Many technical aspects of cofiring with biomass were discussed in Section 4.0. Additional implementation considerations, including public perception; environmental, health, and safety compliance; environmental impacts; and economics are discussed in this section.

5.1 Public Perception

Large scale biomass electricity projects have met substantial local opposition. Previous research showed that the opposition was a result of the public's unfamiliarity with biomass energy.[77] Some critics have accused biomass co-firing plants to be "greenwashing," extending the life of a coal plant unnecessarily.[78]

Because this project has the potential to help to address public perception issues of the University, in addition to reducing dependence on non-renewable energy resources and reducing costs, a study may be warranted in the case of actual implementation to determine the perceptions of the students and local community of the biomass projects. However, because this is a transitional technology, it is recommended that the University focus on the next technology instead of this transitional biomass cofiring solution.

5.2 Environmental, Health, and Safety Compliance Issues

Air Compliance and Quality

Air

Although the biomass project has the potential to reduce greenhouse gas emissions, there are currently no regulatory incentives to implement this project. The University is currently under permit limitations for emissions. The existing air permit regulates NO_x and PM emissions and sulfur content of the coal. Flue gas emissions from the coal-fired boilers are filtered through a baghouse consisting of 2,112 Gore-Tex bags each 23.5 feet long by 8 inches in diameter.

In addition to compliance standards, local air quality was evaluated. The following table shows 2005 data (the most recent data available) of air pollutant concentrations:

[77] Upreti, Bishu Raj and Dan van der Horst. "National Renewable Energy Policy and Local Opposition in the UK: The Failed Development of a Biomass Electricity Plant." Biomass and Bioenergy. 26 (2004) 61-69
[78] Black & Veatch. "Economic Impact of Renewable Energy in Pennsylvania." Final Report. March 2004.

Table 9. Air Pollution in Centre County (2005)[79]

Constituent	Measured Level	Standard Limit
NO_2	0.009 ppm	0.053 ppm
Ozone (1-hour)	0.091 ppm	0.12 ppm
Ozone (8-hour)	**0.083 ppm**	0.08 ppm
Particulate Matter ($PM_{2.5}$) Annual	13.4 $\mu g/m^3$	15.0 $\mu g/m^3$
$PM_{2.5}$ 24-hour	**40 $\mu g/m^3$**	35 $\mu g/m^3$
SO_x Annual	0.005 ppm	0.03 ppm
SO_x 24-hour	0.018 ppm	0.14 ppm

Measured levels of all constituents were near U.S. averages. Note that ozone and particulate matter exceeded the U.S. Standard for the 8-hour test. These are some of the pollutants regulated under the Clean Air Act by National Ambient Air Quality Standards (NAAQS). Because these regulations are not met, Centre County, and more specifically State College, is considered a "nonattainment" area and is subject to more stringent air quality regulations.[80] Based on the design of the system, it is expected that particulates will not increase because they will be adequately controlled by the baghouse at the WCSP. It is in the University's and community's best interest to obtain attainment because air compliance requirements decrease when attainment is met.

Any modifications to the WCSP will require an air permit modification, because the existing permit is for coal, fuel oil, and natural gas. The impacts on emissions were discussed in Section 4.4. The typical first step in Pennsylvania for determining exact air compliance requirements in a region is submitting a Request for Determination. It is recommended that a pre-application meeting be held with the Northcentral Regional office of the Pennsylvania Department of Environmental Protection (DEP) for determining specific requirements and that a Request for Determination is submitted to DEP. The expected process is described below.

When biomass was previously evaluated by Penn State, DEP informally indicated that a New Source Review (NSR) would be required.[81] An NSR is required for new facilities or modifications to existing facilities with the potential to emit at least 100 tons/year or more of NO_x or 50 tons/year of volatile organic compounds (VOCs). NSRs are required in nonttainment areas (see above discussion of Centre County pollutants that currently lead to nonattainment) and specifically address issues to not decrease attainment issues.

Some NSR requirements include:

- Installation of controls to meet the Lowest Achievable Emission Rate (LAER) (For example, the modified WCSP must have emissions less than the new source performance standard.)

[79] http://www.city-data.com/county/Centre_County-PA.html. Accessed 2010.
[80] 40 CFR 50. As of July 1, 2009.
[81] Personal correspondence with OPP. January 2010.

- If emissions are expected to exceed thresholds described in 40 CFR 127.203, then the increased emissions must be offset by Emission Reduction Credits (ERCs) which are from reducing emissions from other existing sources
- An analysis is required to determine if alternative sites, etc., are feasible and to determine the environmental and social costs of the project versus the potential benefits

An exemption may be able to be obtained if the maximum emission level does not increase. A careful study of the potential emissions that would result from the biomass implementation was performed to determine whether or not an exemption from NSR may be possible. Because the particulates will be controlled by the baghouse and because ozone emissions are not expected to increase as a result of the biomass blend, a *de minimus* exemption may be able to be obtained after the project is reviewed by DEP.[82] However, even though the University may be exempt from NSR, a permit modification would still be necessary to incorporate the use of biomass, which expected to take months for approval.

Waste

Currently, bottom ash from the WCSP is used for road maintenance and manufacturing block. Fly ash is currently disposed of in a landfill. The implications of implementing the biomass blend were considered. According to information identified[83], the quality of the bottom ash will not significantly decrease. Therefore, existing reuse of ash can continue and additional disposal will not be needed. Additionally, the quantity of bottom ash is expected to decrease due to a lower ash content of wood as compared to coal (refer to Section 4.1). The potential effects of the projects on ash are described in Sections 4.5.

Because wood waste from businesses is being pelletized, Pennsylvania's residual waste processing regulations were considered and a review of Pennsylvania Code was performed. Residual waste is all nonhazardous industrial, agricultural, and mining waste generated in Pennsylvania. Pennsylvania is the only state with this set of regulations of nonhazardous waste. After a review of Code, it appears that the businesses may be eligible for a coproduct determination (25 Pa. Code §287.8). To obtain a coproduct determination, the residual waste must have similar characteristics compared to an intentionally manufactured product. Upon review, it appears that each of the waste wood suppliers could perform the coproduct determinations and maintain that paperwork. If the University only accepts the coproducts (with the associated paperwork), instead of residual waste, it would be exempt from residual waste processing permits, which requires one year of lead time and adds additional recordkeeping and storage requirements.

Water

Stormwater runoff issues should be considered at the pelletizing plant. The National Pollutant Discharge Elimination System (NPDES) requires that stormwater from industrial sites such as this site be monitored. Even if the facility is under a roof, a Non-Exposure Certificate will be

[82] Pennsylvania Department of Environmental Protection. www.dep.state.pa.us. Accessed February 2010.
[83] Van Loo, Sjaak and Japp Koppejan. *Handbook of biomass combustion and cofiring*. January 2008

required to be submitted to DEP. This paperwork would need to be submitted prior to construction.

Worker Safety

No safety compliance issues that would hinder implementation of the pelletizing plant and transition to 15% biomass blend were identified. However, many issues need to be considered in order to keep existing and new employees safe. Some examples include:

- Maintain good housekeeping
- Manage dust, particularly indoors where there is the potential for combustible gas explosions
- Develop an emergency action plan and fire prevention plan
- Implement a lockout/tag out program for equipment maintenance
- Ensure that all equipment is electrically classified as Class II, Division 1 or 2, as appropriate in accordance with NFPA 70, due to the potential combustible dust
- Use personal equipment, such as safety glasses and hearing protection, as identified by the hazard assessment of the facility
- Take advantage of machine guarding to protect workers
- Implement a hearing protection program
- Ensure that all workers affected are properly trained.

It is recommended that Penn State consider the introduction of this potentially hazardous process to workers as compared to the potential cost savings. Potential liability associated with injuries was not included in the economic analysis, because it is assumed that a robust training model will be implemented that would reduce avoidable injuries and associated costs.

5.3 Environmental Impact Analysis

An environmental impact analysis was performed to determine the impact of the 15% biomass blend.

Although related to overall air quality and energy issues and not to air permitting regulatory requirements, another issue that should be considered is the gasoline/diesel used to transport the pelletized biomass from the CCSWA to the WCSP. Additional trucks will be required daily due to decreased density and energy content of the biomass as compared to coal. However, the biomass will need to travel a shorter distance as compared to the coal, which is transported by train from Kentucky to Pleasant Gap, PA and then brought by coal truck to the WCSP. Additionally, electricity used by the pelletizing equipment should be considered in the overall assessment of the project since one goal of the project is to reduce Penn State's dependence on nonrenewable energy.

Sources have indicated that co-firing with biomass typically reduces SO_x, CO_2, NO_x, and heavy metal emissions.[84]

Table 10. Air Emission Analysis: Annual Impact of Implementing 15% Biomass Blend

Activity	CO_2 Emissions	NO_x Emissions	SO_2 Emissions
Decreased coal consumption (blend 15% biomass by energy content)	(16.1 tons)	--	(0.3 tons)
Increased diesel truck trips carrying biomass	5.8 tons	0.3 tons	--
Increase electricity consumption: pelletizing plant	681.2 tons	1.5 tons	5.3 tons
Decrease train trips	(763.2 tons)	(4.0 tons)	--
TOTAL IMPACT	**92.3 ton decrease**	**2.2 ton decrease**	**5.0 ton increase**

Key assumptions for these calculations include:

- Biomass is carbon neutral. Existing wood waste currently being landfilled would be used for this project.
- A diesel truck averages 8 miles per gallon.
- CO_2 emissions from diesel combustion is 2,778 grams/gallon.[85]
- Electricity consumption is estimated based on 100-1000 kg/hr pelletizing plants.[86]
- Assumed electricity is from the grid and standard emission factors for Pennsylvania were used.
- Freight trains emit 0.2306 lbs CO_2 per ton-mile.[87]
- A train can move one ton of freight 457 miles on one gallon of fuel.[88]
- One gallon of diesel used in freight trains emits 249.4 grams of NO_x.[89]

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[84] Black & Veatch. "Economic Impact of Renewable Energy in Pennsylvania." Final Report. March 2004.
[85] "Emission Facts: Average Carbon Dioxide Emissions Resulting from Gasoline and Diesel Fuel." U.S. Environmental Protection Agency. EPA420-F-05-001. February 2005.
[86] AGICO Group & GEMCO Energy Machinery, Inc. http://www.biofuelmachine.com/Small-Mobile-Pellet-Plant.html. Accessed March 2010.
[87] Carbon Fund.org. http://www.carbonfund.org/site/pages/carbon_calculators/category/Assumptions. Accessed April 2010
[88] "Railroads: Green from the Start." Association of American Railroads. July 2009
[89] U.S. EPA, *Locomotive Emissions Standards, Regulatory Support Document*, April 1998.

5.4 Economic Analysis

While it currently appears that biomass is both technically and logistically viable, a thorough economic analysis was performed to determine if biomass is a feasible solution to reducing Penn State's costs. Implementation and operating cost considerations and the economic analysis are described below.

Capital Costs

An estimate of the capital costs to implement this project is shown in the following table. The majority of the equipment costs were from Processco Inc., who are equipment suppliers in this area, and based on a 3 ton/hour pelletizing plant. McLanahan provided a quote for a pug mill. It was assumed that permitting issues would require approximately 1 full-time equivalent (FTE) at $70,000 plus Penn State fringe (benefits).

Table 11. Biomass Project Capital Costs, including Pelletizing Equipment[90]

	Cost: 15% Blend
Dryer	$714,000
Hammer mill	$122,000
Pellet machine	$285,000
Cooler	$19,000
Storage Conveyors, Separators	$438,000
Peripheral equipment	$754,000
Buildings	$826,000
Pug mill[91]	$35,000
Permitting	$100,000
5% Contingency	$165,000
TOTAL CAPITAL COSTS	**$3,458,000**

Note that a flat rate of 5% contingency was included in the analysis. Recent literature has shown that capital estimating using risk analysis (ESA) is a simple, more accurate approach to incorporate the risks of cost differences. To perform an ESA, a team-based approach is used to identify and assign costs to the uncertainties of a capital cost estimate prior to project start.[92] Due to our small team size and limited knowledge about specific equipment costs, the ESA approach was not used. However, this analysis method could be used in the final financial analysis if Penn State chooses to evaluate this technology. Additionally, a conservative contingency fee was added because the research has shown that estimates for the fees tend to be too high.

[90] Processco Inc. http://www.processco.net/pdf/Wood%20pellet%20Costs.pdf. Accessed March 2010
[91] McLanahan Quote. March 2010.
[92] Mak, Stephen, Jenny Wong, and David Picken. "The effect on contingency allowances of using risk analysis in capital cost estimating: a Hong Kong cast study". Construction Management & Economics. Vol. 16 Issue 6, November 1998. pp 615-619

One state program was identified that could help to offset some implementation costs. The Pennsylvania Energy Development Authority (PEDA) grant program provides funding for innovative, advanced energy projects and the guidelines include biomass projects. This grant program, which has opened every spring since 2004, offsets implementation costs, including equipment purchase, construction, contractor expenses, and engineering design necessary for construction or installation. The maximum grant amount is $1,000,000, but the average award is $375,000. There is a $150 application fee to apply for this grant. Applying for this grant is recommended to offset implementation costs of this project if it is pursued. However, because it is unknown if the University would pursue obtaining a PEDA grant and if it would be awarded, a potential grant was not included in the economic analysis so that our analysis is conservative.

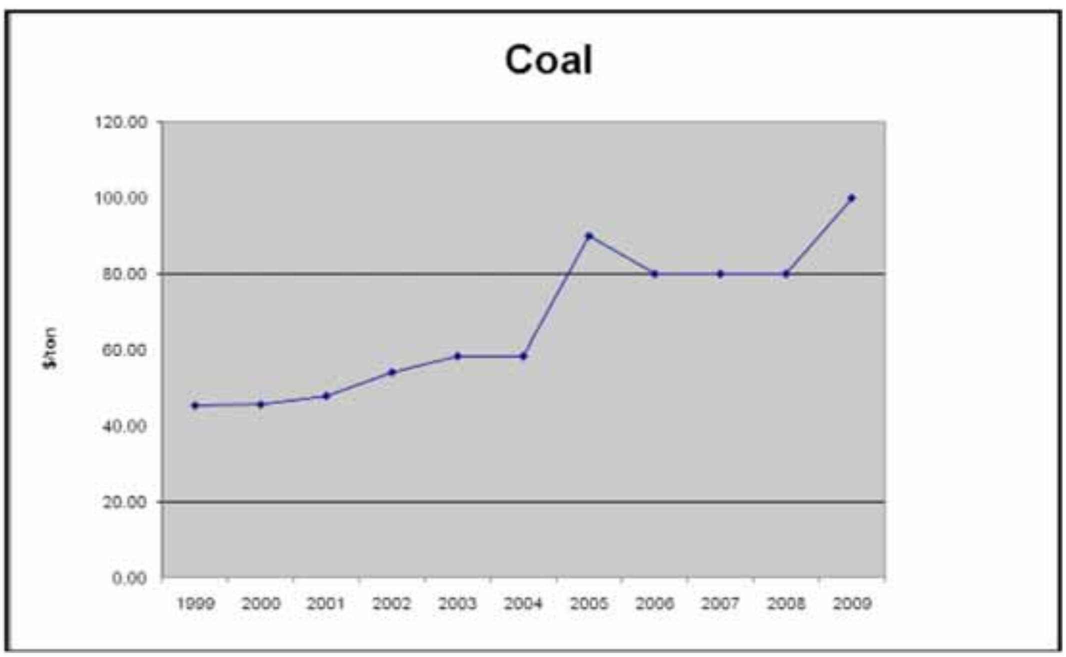
<u>Operating Costs</u>

Implementing biomass will offset some coal use, but will increase some other operating costs. The overall impact on operating costs is discussed in this section.

<u>Coal Costs</u>

As shown below, the cost that Penn State incurs for coal has more than doubled in the past 10 years.

Fig 22. Trends in Coal Costs at Penn State[93]



[93] Senate Committee on University Planning. "New Energy Conservation Policy." The Pennsylvania State University. September 1, 2009. http://www.senate.psu.edu/agenda/2009-2010/Sept109/appi.pdf

Because of the wide range of estimates provided and because the documentation makes it appear that the cost per ton is closer to $100, a sensitivity analysis was performed. (Refer to "Sensitivity Analysis" at the end of this section)

Operating Cost Impacts

After a thorough analysis of the operations at the WCSP and the implications of implementing a 15% blend of biomass, the following issues were determined to have the greatest impact on the operating costs:

- Coal reduction – 15% of the coal would be offset by this project. It was estimated that the coal is $100/ton. (A sensitivity analysis was also performed for a change in operating costs.)
- Biomass – A plentiful supply of wood waste is available near the Philipsburg facility, as described in Appendix E. A weighted average of $12.90/ton of wood waste was assumed for this analysis. Additionally, the additional amount of biomass needed as a result of the lower density and lower energy content were accounted for by increasing the amount of biomass required.
- Labor – It was assumed that the pellet plant and biomass aggregation facility would operate two shifts per day with two full-time staff during each shift to account for operating the equipment, tracking supply, recordkeeping, enduring proper blending, etc. Additionally, more truck loads would be required between the Philipsburg facility and the WCSP. It was assumed that hourly laborers would drive these additional truckloads (approximately 1.2 trucks/day).
- Electricity – Operating the pelletizing equipment, dryer, hammermill, and other equipment necessary to ensure the proper size and quality of the biomass will require a significant amount of electricity.[94] Although the University would be billed as a commercial user (for both demand and total usage of electricity), the cost typically averages out to a little less than 8¢/kWh.

A summary of the operating costs changes is shown in the below table. A total of $470,464 could be saved annually by implementing the 15% biomass blend.

[94] AGICO Group and GEMCO Energy Machinery Co., Ltd. http://www.biofuelmachine.com/Small-Mobile-Pellet-Plant.html Accessed April 2010.

Table 12. Estimated Operating Cost Impact of Biomass Implementation

	Amount	Cost	Impact/year
Coal reduction (15%)	11,220 tons	$100/ton	$1,122,000
Biomass	16,954 tons	$12.90/ton	($218,707)
Labor: pellet plant operators (2 shifts/day)	4 laborers	$40,000/yr each + benefits	($207,840)
Labor: truck drivers	3 hr/trip; 434 extra trips/yr	$20/hr + benefits	($28,201)
Electricity	1.1 million kWh/yr	$0.08/kWh	($88,000)
Contingency to account for miscellaneous costs (disposal, maintenance, additional cable replacement, etc.)	20%	$108,788	($108,788)
Cost savings	--	--	**$470,464**

The 20% contingency was added to the operating costs to reduce risk. Some factors could not be included in this analysis due to lack of information about the specific WCSP operations and without exact information about the pelletizing equipment. For example, oil or other lubricating fluids will need to be used with the machinery so there will be the costs of purchasing that fluid and the potential cost of disposing of it or recycling it.

Another example of a potential additional cost is cable replacement at the WCSP. During the WCSP tour, it was discovered that one of the highest regular maintenance costs of the plant is taking the tram cars offline to periodically replace cables. There are two tram cars that are alternately filled by skip cars and are pulled by cable to the proper hopper. A control on the hopper that needs to be filled opens the bottom of the tram car and it empties into the hopper.

OPP has learned over time that the cables need to be replaced after a certain number of times that the tram car is filled. The number was not available for this project. This is important because a cable breaking would be dangerous for operators and is difficult to repair. If transitioning the biomass, the maintenance costs would increase because the hopper would need to be filled more often for the same amount of energy (due to decreased density and energy content of the biomass). However, the exact information about how often the cables are currently replaced and how much the maintenance costs (labor and materials) is not available from OPP. Because costs are not available, they are incorporated into the analysis, but are expected to be accounted for in the contingency.

Fig 23. Coal Loading mechanism at WCSP

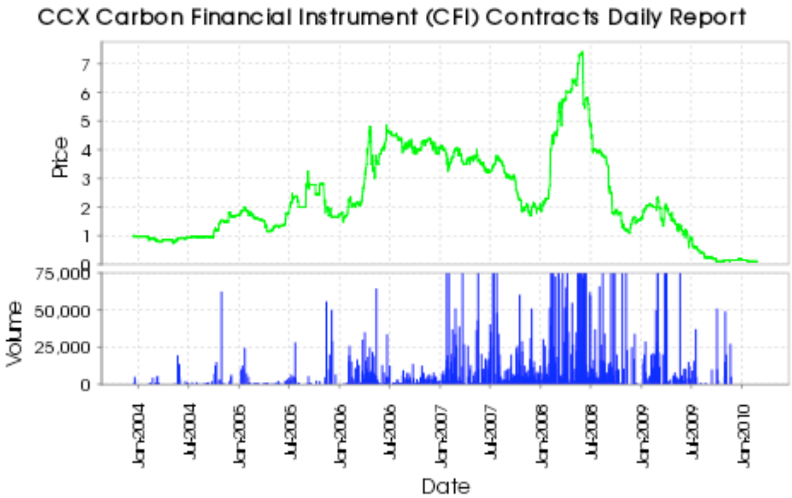
<u>Potential Additional Sources of Lowering Operating Costs</u>

Carbon trading and Renewable Energy Credits (RECs) were also evaluated a potential way to generate revenue from the biomass project. These two incentives are discussed below.

<u>Carbon trading</u>

The Chicago Climate Exchange (CCX) is a financial institution that operates a voluntary cap and trade program. Many offsets of greenhouse gases (GHGs), such as carbon dioxide (CO_2), can be traded for money with the members of this consortium. The members have voluntarily agreed to make a legal binding commitment to meet annual GHG reduction targets. When they cannot meet these targets, they purchase offsets from other companies in the United States, primarily, that have reduced their GHG emissions. Trends since this program launched in January 2004 are shown in the following chart.

Fig 24. Historic Trading Volumes and Trading Prices (in $/metric ton)[95]



Carbon trading could only reduce operating costs by a maximum of $185-$646/yr for a 15% biomass blend

For small scale biogas projects, the following eligibility requirements apply:

"Basic Specifications:

- Small Scale Renewable Biogas projects undertaken on or after January 1, 2003 may qualify.
- Eligible projects shall not be required by any federal, state or local regulation or other legally binding framework.
- Qualifying projects may earn Offsets during the years 2003-2010.
- Project Proponents must demonstrate clear ownership of the GHG mitigation rights associated with the project.
- All projects must be independently verified by a CCX-Approved Verifier."[96]

The biomass co-firing project is not included in the eligible project list, but there is a potential to petition for consideration if the program becomes active again.

Because the biogas emission offset volume will be small, an aggregator should be considered. One of the largest aggregators and traders, Environmental Credit Corporation, is located in downtown State College, PA. An aggregator's role is to combine renewable energy projects so a larger volume could be traded at one time, offering purchasing power and lower administrative costs.

Some monitoring requirements would include metering energy produced and monitoring and estimating annual operating hours.[97] The monitoring requirements are consistent with information already collected by OPP, so would not represent an additional labor cost or burden.

[95] http://www.chicagoclimatex.com/market/data/summary.jsf. Accessed February 2010.
[96] Ibid
[97] "Chicago Climate Exchange®. Small Scale Renewable Biogas Offset Project Protocol." Chicago Climate Exchange, Inc. 2009.

RECs from this project would only offset about $83/year of the RECs purchased by Penn State.

Because the current market period expires on December 31, 2010, and a new market period has not been announced to date, possible revenue from trading offsets on the CCX were not included in the economic analysis, but were evaluated to determine the potential impact.

However, by considering the overall project offset of 184,509 lb of CO_2 (refer to Section 5.3), the annual impact would only be $185 to $646 assuming a $2/ton to $7/ton trading value. However, if the oversight committee decides to only evaluate the emissions at the power plant and agrees that biomass use (particularly waste wood), the carbon trading value could be as low as $32-$113, assuming a $2/ton to $7/ton trading value and 32,155 lbs of CO_2.

Based on the low trading value, it would not be feasible to trade even if the markets recovered unless it is aggregated with other projects at Penn State or in the community.

Renewable Energy Credits

Renewable energy credits (RECs) are renewable energy commodities that represent 1 MWh of electricity. These credits can be traded so that others may claim that they use renewable energy. Trading values are shown below.

Table 13. Some Residential Price Premiums related to Biomass Projects[98] (last updated May 2008)

Certificate Marketer	Renewable Resource	Location of Renewable Resource	Residential Price Premium
Carbon Solutions Group	biomass, biogas, wind, solar, hydro	Nationwide	0.9¢/kWh
Good Energy	various	Nationwide	0.4¢/kWh-1.5¢/kWh
Green Mountain Energy	wind, solar, biomass	Nationwide	1.4¢/kWh

Due to the nature of Penn State's policy to generate renewable energy, it is assumed that the University would not trade the RECs but would rather keep the RECs to meet their own goals. According to Penn State's energy dashboard[99], the Penn State University Park campus consumed 165,447,260 kWh between November 2008 and October 2009. As mentioned previously, the WCSP generates approximately 6% of the campus' electricity, or approximately 11,126,836 kWh. Because this project would offset 15% of the coal with biomass, approximately 1,669,025 kWh of the campus' electricity would be generated with this renewable resource.

The value of the RECs could be $16,690 if traded at $0.01/kWh. However, the University would not supply this electricity to the grid for a financial return. Instead, it is more likely that it would reduce the amount of RECs that it is currently purchasing. While the University paid up to

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[98] U.S. Department of Energy. Energy Efficiency & Renewable Energy. http://apps3.eere.energy.gov/greenpower/markets/certificates.shtml?page=1. Accessed February 2010.
[99] http://opp2166.opp.psu.edu/dashboard/EnergyDashboard.html. Accessed April 2010.

$14/MWh for renewable energy purchased in the past, it currently has a 5-year contract for $5/MWh for purchasing renewable energy from the grid.[100] Therefore, it would only save about $83 annually with this project.

Economic Indicators

With a $3.5 million capital cost and a $470K/year operating cost reduction, the simple payback of the 15% biomass blend is approximately 7.4 years. To evaluate the net present value (NPV) and internal rate of return (IRR), many assumptions were made. Key assumptions included:

- Equipment lifetime: 15 years
- Depreciation period: 5 years
- Depreciation method: DDB (200% Declining Balance, switching to straight line). Depreciated amount (for tax deductions) included:
    - Year 1: $ 691,600
    - Year 2: $1,106,560
    - Year 3: $ 663,936
    - Year 4: $ 398,362
    - Year 5: $ 398,362
    - Year 6: $ 199,181
- Inflation rate: 3.5% (applied same cost escalation rate to labor costs and material costs)
- Electricity cost escalation rate: 5%
- Contingency cost escalation rate: 0%

The incremental profitability analysis, which was performed with P2FINANCE, is shown in the following table. P2 FINANCE is software developed by the U.S. Environmental Protection Agency that is used for financial evaluations of current and potential investments and includes traditional obstacles to pollution prevention investments. More specifically, it can account for indirect and less tangible environmental costs not included in typical analyses and longer time horizons.

[100] "University awards environmentally friendly energy contracts to enhance existing green initiatives". Penn State Live press release. December 22, 2006.

Table 14. Incremental Profitability Analysis, 15% blend (performed with P2FINANCE)

	Years 0-5	Years 0-10	Years 0-15
Net present value (NPV)	($1,220,847)	($197,833)	$591,936
Internal rate of return (IRR)	(4.0%)	10.5%	15.1%

An analysis was also performed for selling all capital equipment at 30% of its original value ($710,000) in Year 6, since this is a transition technology. However, this consideration leads to a negative NPV and IRR. Therefore, this project should only be used if it is needed as a longer term (e.g., 10 year) transitional technology.

Sensitivity Analysis

One of the greatest impacts on the annual operating costs is the current cost of coal. A sensitivity analysis was performed, varying the coal by an increase and decrease of 25% and the simple payback was evaluated.

Table 15. Sensitivity Analysis, Coal Cost

	Scenario 1	Scenario 2	Scenario 3
Capital Cost	$3,458,000	$3,458,000	$3,458,000
Coal Cost	$75/ton	$100/ton	$125/ton
Annual Cost Savings	$189,964	$470,464	$750,964
Simple payback	18.2 yr	7.4 yr	4.6 yr

As shown, the analysis is very dependent on the cost of coal. If this project is pursued, an attempt should be made to forecast coal costs.

6.0 Recommendations

Recommendations for further analysis are discussed listed below.

<u>Biogas:</u>
- Economic study to explore whether it is feasible to transport steam generated at WWTP to South Halls.
- Determine other possible sources of feedstock to the biodigesters.
- Identify feasible locations to build new biodigesters.
- Study scrubbing of biogas in further detail.

<u>Biomass:</u>
- Look at ways to use other types of biomass that have a lower energy content than woody biomass at WCSP with careful consideration of their slagging and fouling characteristics.
- More detailed engineering calculations and experiments on actual systems to verify optimal co-biomass blends for various types of biomass.
- Look at implementing other types of advanced boilers and scrubbing systems and slowly phasing out the age old stokers.
- Detailed study on co-fire ash characteristics and end use possibilities.
- Detailed engineering calculations after incorporation of losses like carbon loss, blowdown loss, stack loss, convection and radiation loss.
- Creating a computational fluid dynamics model after incorporation of reaction kinetics

<u>Environmental compliance:</u>
Recommendations for additional work:
- Submit a RFD to DEP to determine specific air compliance requirements and potential permit modifications that will be necessary

<u>Economic Analysis</u>
Recommendation: Only transition to cofiring if it is expected to be used for a longer (e.g., 10 year) timeframe.

Recommendations for additional work:
- Obtain pelletizing plant quote for this transitional technology
- Penn State OPP should review operating cost estimates and provide feedback
- Incorporate estimating risk analysis (ESA) instead of contingency in the financial model, using a team of OPP engineers, for a better risk assessment than a flat contingency percentage to account for cost risk. The economic risk can then be measured and adjusted as project implementation progresses.

- Determine how much wood waste is currently disposed at Penn State (if any) and incorporate into the economic analysis, including the free source and offsetting landfill costs/tipping fees
- Perform coal cost forecasting and incorporate those costs into the economic analysis

7.0 Conclusions

At this time, using biogas from Penn State's wastewater treatment plant is not technically or economically feasible. Technically, it would have insufficient quantities to maintain proper combustion and sufficient injection velocities. However, other uses for the biogas such as heating buildings should be considered.

Co-firing with 15% biomass (waste wood) appears to be technically feasible. After installing after installing a pelletizing plant, the transition would a 7.4 year payback, with very conservative assumptions made for the economic analysis. When evaluating the overall environmental impacts, cofiring has the potential to reduce 92.3 tons of CO_2 and 2.2 tons of NO_x annually, but SO_2 emissions of the overall process would increase due to electricity usage for the pelletizing plant. Further consideration of this technology is recommended.

Appendix A.

Additional Coal Usage Information

Penn State Utility Services provided a recent analysis of coal in February 2010. The analysis results are shown below.

Figure A1. Coal Analysis

CERTIFICATE OF ANALYSIS

	ASTM METHOD	AS RECEIVED	DRY BASIS
MOISTURE	D2961 D3302 D3173	5.02%	
VOLATILE	D3175M	35.40%	37.27%
FIXED CARBON	D3172	50.90%	53.59%
ASH	D3174	8.68%	9.14%
SULFUR	D4239 METHOD B	1.08%	1.14%
BTU/LB	D5865	12749	13424
MAF BTU/LB			14774
LBS OF SO2 PER MILLION BTU			1.70
LBS OF SULFUR PER MILLION BTU		0.847	
FREE SWELLING INDEX	D720	7.0	
CHLORINE	D4208	0.25%	0.26%

ASH FUSION TEMPERATURE(S)

D1857	REDUCING ATMOSPHERE
INITIAL DEFORMATION	2760
SOFTENING TEMPERATURE	2795
HEMISPHERICAL TEMPERATURE	OVER 2800
FLUID TEMPERATURE	OVER 2800

Appendix B.

Biogas Production/Combustion Information at WWTP/WCSP

Table B1. Biogas Produced at WWTP and potential to replace coal at WCSP

Month	Coal consumed at WCSP tons	GAS available at WWTP cubic feet (flared off)	Amount of coal to be replaced tonnes	Biogas needed cf (5% on heat basis)
Jul-08	4230.2	918630	20.26389706	7670762.667
Aug-08	2564.5	549570	12.12286765	4650373.12
Sep-08	4084.3	1101130	24.28963235	7406197.33
Oct-08	5445.4	989000	21.81617647	9874325.33
Nov-08	7187.6	745430	16.44330882	13033514.67
Dec-08	9518.6	572010	12.61786765	17260394.67
Jan-09	10738.899	460200	10.15147059	19473203.52
Feb-09	8731.6	824060	18.17779412	15833301.33
Mar-09	7966.9	1048170	23.12139706	14446645.33
Apr-09	5654.7	2044530	45.09992647	10253856
May-09	4614.8	872720	19.25117647	8368170.67
Jun-09	4060.2	827350	18.25036765	7362496

Biogas requirement calculations

The number of BTUs currently available from the WWTP may be calculated as follows:

Energy content of coal (@WCSP) = 13,600 Btu/lb (dry)
total tonnage of coal = 74,947.95 tons/yr (US)
= 149,895,900 lb
so, total energy from coal = $2.039*10^{12}$ Btu/yr or $2.039*10^{6}$ MMBTUs/year

total gas available from WWTP per year (gas flared off)

= 10,952,800 cf

Calorific value of biogas = 600 BTU/cf

Total BTUs available from WWTP per year

= 10952800*600

=$6.572*10^{9}$ BTU/yr

=$6.572*10^{3}$ MMBTU/yr

Fraction of energy generated at WCSP which could be provided by biogas

= $6.572*10^{3}/2.039*10^{6}$

= 0.00323

=0.3% of the total energy produced at WCSP

Amount of biogas required to replace 5% of the energy produced at WCSP

=$0.5*2.039*10^{12}/600$

=$1.7*10^{8}$ cf

=$1.7*10^{6}$ ccf

Thus, the current facility does not generate sufficient amount of biogas needed for co-firing and a newer facility may be needed to fulfill the demand.

Biogas: Economic Analysis

1) **Cost Savings using available biogas**:

Assuming no changes to WCSP or WWTP and no other costs:

Biogas available from WWTP – 6,572 ccf

Coal replaced at WCSP – 0.3% = 224 ton

Cost of coal used at WCSP - $223/ton

Cost savings for replacing 0.3% coal at WCSP
= 223*224
= $49,952 ~ $50,000

Cost of H_2S treatment of Biogas - $3/ccf

Total cost of treating available biogas of H_2S
= 3*6572
=$19,716 ~ $20,000

Net Savings = 50000-20000
=$30,000/year

2) **Cost savings replacing 5% of the heat generated by coal with biogas**

= 30000*5/0.3
= $500,000/year

3) **Cost of laying pipeline from WWTP to WCSP**

=$984,000

4) **Simple payback period**

a) When replacing 0.3% coal

=984000/30000
=32.8 years ~ 33 years

b) When replacing 5% coal
= 984000/500000
=1.97 years ~ 2 years

Calculations for the BTUs generated from biogas

Calorific value of biogas: 600 BTU/CF at STP

1) Total BTUs generated from biogas in year:

   Total amount of biogas generated per year: 10.95 MCF
   Total number of BTUs generated from biogas =10.95 * 600
   = 6571.68 MMBTU

2) Amount of biogas generated during the heating season from September to April

   Total amount of biogas generated during the heating season: 6.68 MCF
   Total number of BTUs generated during the heating season =6.68*600
   =4010 MMBTU

Appendix C.

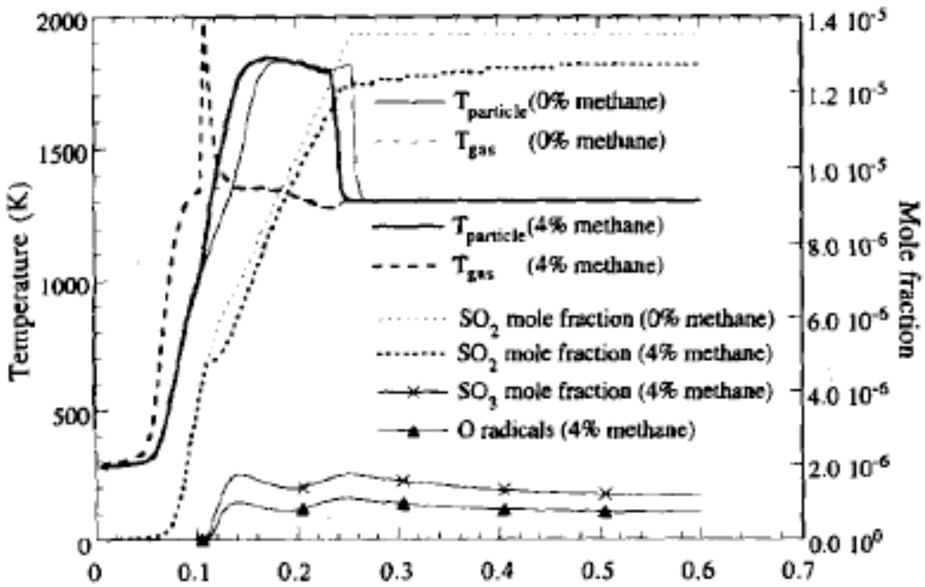
Biogas: Assumptions and Combustion Issues

Assumption:
Biogas is assumed to behave similar to natural gas albeit with higher CO_2 content (40% CO_2). [101]

Issues:
Generally natural gas is cofired with coal to reduce NO_x (reburning).[102] This occurs by firing excess natural gas to make the region fuel rich and thus reduce NO_x to N_2. Cofiring coal with natural gas has shown to produce lower SO_2 emissions because sulfur leveraging in the ash.[103] However this occurs at a furnace temperature of 1300K and rapidly falls with decrease in temperature, becoming negligible at around 1500K. However, since the temperature inside the furnace would be over 1550K, this phenomenon may not occur, thus requiring addition of alkalis like CaO to the reaction system.

The figure and the tables below display results about **reduction of SO_2 emissions when co-firing with methane and reduction of leverage of sulfur by the ash with increasing temperature** :

Figure C1. SO_2 mole fraction over the tube length



Distance from the top of the tube (m) [104]

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[101] Cooperative approaches for implementation of dairy manure digesters'; USDA research report 217
[102] Electric Power Research Institute, Inc., Gas Cofiring Assessment for Coal Fired Utility Boilers, 2000
[103] Bayless et. Al., The Effects of Cofiring Natural Gas and Coal on Sulfur Retention in Ash, *COMBUSTIONAND FLAME 106: 231-240 (1996)*
[104] Ibid

Table C1. Summery of Sulfur Retention Experiments

Coal	Size (μm)	CH_4 (%)	CH_4/O_2	Furnace Temp (K)	% Original Suflur Retained (Experimental)	% Original Carbon Retained (Experimental)
1519	125–150	0	0.000	1300	3.29	1.85
	125–150	1.1	0.047	1300	8.34	2.85
	125–150	2.5	0.096	1300	10.01	3.30
	125–150	3	0.097	1300	9.92	0.95
	125–150	4	0.143	1300	12.06	3.89
	125–150	0	0.000	1550	2.35	1.02
	125–150	4	0.143	1550	2.95	0.75
	125–150	4	0.143[a]	1300	5.16	3.03
	90–106	4	0.143	1300	2.59	1.55
1524	125–150	0	0.000	1300	3.80	3.07
	125–150	2	0.083	1300	7.96	3.18
	125–150	4	0.143	1300	10.43	2.81
	125–150	0	0.000	1550	2.04	1.44
	125–150	4	0.143	1550	2.71	1.57
	90–106	0	0.000	1300	3.13	1.87
	90–106	4	0.143	1300	3.43	1.85
1508	125–150	0	0.000	1300	3.67	3.64
	125–150	2	0.083	1300	7.43	3.51
	125–150	4	0.143	1300	12.55	3.44
	125–150	0	0.000[b]	1300	6.45	3.76
	125–150	4	0.143[b]	1300	58.43	4.16

[a] Carrier gas was changed from N_2 to CO_2.
[b] 200 ppm SO_2 was added to the initial gas stream.

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It is known that H^+ radicals are said to improve the rate of reaction and support the progress of a reaction. This theory should similarly apply for natural gas, which is rich in hydrogen, which can be a potential source of H^+ ions in the primary combustion zone. Thus methane should improve the combustion efficiency of coal.

However steam that is eventually formed is responsible for the loss of some furnace heat through the flue stack which eventually leads to ~4% reduction in the efficiency of the system. [106] Also, the furnace temperature cannot be dropped too low because condensation of steam may take place and steam may react with SO_2 to form sulfuric acid [107]which can cause further damage to the furnace.

If the biogas is added to the reburn zone, there would be negligible amount of ash in the system based on the inherent design of a stoker boiler and the way fuel is fired in a stoker and thus sulfur may not get leveraged while reburning in a stoker. This is an issue which has not been considered in any paper that was reviewed.

Since biogas contains 40% CO_2, there may be some minor losses of heat due to the presence of CO_2 in the system. Thus, the results of the papers as well as the process conditions inside the power plant point that sulfur leveraging may not occur and there may be a loss of efficiency in the reactor. However, since biogas is a carbon neutral fuel and it is currently being flared off, this minor loss of efficiency would be insignificant. Also, NO_x emissions are shown to reduce using the tried and tested method of reburning coal with natural gas.

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[105] Bayless et. Al., The Effects of Cofiring Natural Gas and Coal on Sulfur Retention in Ash, *COMBUSTIONAND FLAME 106: 231-240 (1996)*
[106] Electric Power Research Institute, Inc., Gas Cofiring Assessment for Coal Fired Utility Boilers, 2000
[107] ‘Cooperative approaches for implementation of dairy manure digesters’; USDA research report 217

Biogas: Scrubbing Unwanted Gases

Biogas has a significant amount of hydrogen sulfide (up to 1,000 ppm)[108]. Hydrogen sulfide is very corrosive and needs to be removed before biogas is transported. Generally it is preferred to remove acid gases prior to use using scrubbing technologies. Usually for small installations, calcium hydroxide is used for removal of carbon dioxide and hydrogen sulfide is removed by passing the gas over heated iron oxide (iron sponge).[109]

For biogas with low levels of CO_2, the Girbotol Process may be used for removal of hydrogen sulfide. Carbon dioxide, when in high concentrations, may be removed by physisorption by carbonate processes like potassium carbonate or an organic carbonate, which are added along with catalysts or activators. Molecular sieve absorbents like synthetic Zeolites can also be used to absorb CO_2 and water vapor and are regenerated by heating.

[108] "Cooperative approaches for implementation of dairy manure digesters"; USDA research report 217 DATE
[109] "Methane Production from waste organic matter"; Stafford, D.A.; Hawkes, A.L.; Horton, R.; CRC press;1981

Appendix D.

Biomass Availability/Combustion Information for WCSP

Table D1. Biomass Availability near University Park, PA[110]

Material	Quantity (tons/yr)	
Biomass at University Park		
Animal Wastes:		
Dairy manure (tie stall and free stall mixed with leaves)	13,200	
Manure from covered manure barn (poultry litter, horse barn, misc.)	1,180	
Beef manure	1,033	
Sheep manure	265	
Swine waste (@ 2.2% solids)	2,505	
Wood waste/brush	150	
Pallets	92	
Reed Canary grass	600	
Other Wastes at University Park		
Sewage sludge (@ 2.2% solids)	2,708	latest: 3397.63 tons/yr
Bottom ash	6,990	
Fly ash	1,445	
Agricultural Plastics - total	2.1	
Horticulture hard plastics	0.2	
Horticulture plastic bags	1	
Bale tarps	0.5	
Silo bunker covers	0.4	
Used oil	14	
Tires	5	
Biomass from Surrounding Region (within 45 miles of University Park)		
Wood products (chips/shavings)	>90,000	

110 Bruce G. Miller, S.F.M., Robert Cooper, John Gauldip, Matthew Lapinsky, Rhett McLaren, William Serencsits, Neil Raskin, Tom Steits, Joseph J. Batista, *Feasibility Analysis for Installing a Circulating Fluidized Bed Boiler for Cofiring Multiple Biofuels and Other Wastes with Coal at Penn State University.* 2003.

Table D2. Coal consumption at WCSP and potential to be replaced by biomass

Month	Coal consumed tons	Biomass needed tons (15% on heat basis)	Amount of coal replaced tonnes
Jul-08	4230.2	958.85	634.53
Aug-08	2564.5	581.3	384.675
Sep-08	4084.3	925.77	612.645
Oct-08	5445.4	1234.29	816.81
Nov-08	7187.6	1629.19	1078.14
Dec-08	9518.6	2157.55	1427.79
Jan-09	10738.899	2434.15	1610.835
Feb-09	8731.6	1979.16	1309.74
Mar-09	7966.9	1805.83	1195.035
Apr-09	5654.7	1281.73	848.205
May-09	4614.8	1046.02	692.22
Jun-09	4060.2	920.31	609.03

Table D3. Livestock in Centre County[111]

Animal	Number in Centre County	Amount of dry biomass (tons/yr)
Horses and ponies	2,714	5,448
Cattle and calves	29,037	32,725
Layers, broiler, meat type chicken	7,542	54
Pigs and Hogs	5,267	670
Total	**44,830**	**38,897**

Biomass Requirement for Penn State:

Energy content of coal (@WCSP) = 13,600 Btu/lb (dry)
total tonnage of coal = 74,947.95 tons/yr (US)
= 149,895,900 lb
so, total energy from coal = $2.039*10^{12}$ Btu/yr
assuming we are replacing with 15% biomass (heat basis),
heat from biomass = $(15/100)*2.039*10^{12} = 3.0579*10^{11}$ Btu/yr
woody biomass energy content = 9,000 Btu/lb
amount required = $3.0579*10^{11}/9{,}000$ = 33,976,666.67 lb = 16,988.33 tons/yr

[111] 2007 USDA Census of Agriculture. Centre County

Table D4. Various Ash Properties of Solid

Table 5
Results from deposition indices

	Coal	Pine Chips	Corn straw	Rape straw	Biomass mix	PGW	B-Wood	Palm kernels	Olive Residue	Pepper plant	Chicken litter	MBM
R(b/a)	0.12	0.21	0.40	0.99	0.56	1.54	1.24	1.03	0.79	2.38	9.04	17.95
Rb (%)	7.67	21.37	31.40	43.70	30.14	60.40	46.00	41.24	51.20	67.10	57.82	53.15
Sd (%)	0.60	0.08	0.06	0.10	0.74	-	-	0.26	0.21	0.49	0.74	1.27
B/A	0.13	0.28	0.65	1.37	0.64	1.82	1.64	1.70	2.40	3.73	10.89	21.87
Rs	0.08	0.02	0.04	0.14	0.48	–	–	0.44	0.50	1.83	8.06	27.78
Fu	0.13	1.61	8.17	17.15	2.79	19.15	21.44	27.99	82.85	95.06	108.56	212.16
B/A+p	0.14	0.30	0.70	1.43	1.03	1.94	2.00	2.97	2.63	4.02	13.15	38.95
Rs+p	0.09	0.02	0.04	0.14	0.76	–	–	0.77	0.55	1.97	9.73	49.47
Fu+p	0.14	1.73	8.71	17.93	4.46	20.37	26.20	48.76	90.78	102.43	131.09	377.82
S_R	88.87	81.22	69.66	46.11	57.28	36.27	40.93	42.06	51.73	23.25	8.60	0.05
Fe2O3/CaO	1.33	0.69	0.17	0.07	0.79	0.71	0.15	0.99	0.15	0.06	0.01	0.01
AI(kg/GJ)	0.04	0.17	0.54	0.32	0.29	1.50	0.12	0.41	1.14	2.39	2.53	1.25

Appendix E.

Biomass Supply Chain

Table E1. Potential wood waste sources from businesses in a 25 mile radius [112]

Business	Available (tons/week)	Miles to Pleasant Gap	FOB ($/ton)	Chips	Slab wood
Thomas Timberland Enterprises	300	1	$13.33	X	
Saw-rite Sawmill	60	20	$13	X	
CL Price Sawmill & Planning	40	21	$15		X
Urbanik Lumber	75	24	$10		
Total/Average	475	-	$12.90	360 tons/week	115 tons/week
Required	325.15	-	-	X	X

Businesses with wood chips and slab wood were focused on because sawdust currently has a high demand and high cost and it is not suitable for the proposed processing and pelletizing equipment.

Business contact information:

C L Price Sawmill and Planning
319 W Alley St,
Aaronsburg, PA 16820
814-349-4431 and 814-349-5505

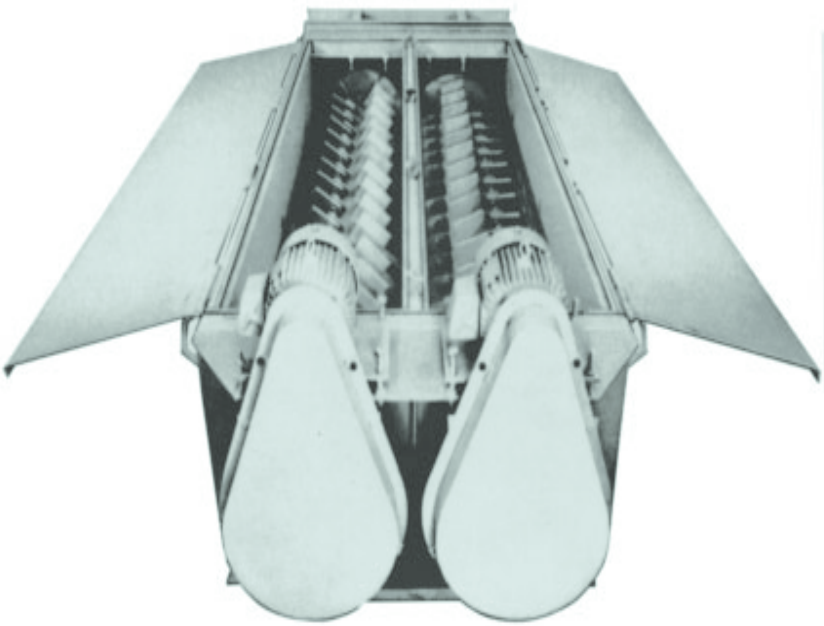
Saw-Rite Sawmill
74 Airstrip Drive
Millheim, PA 16854
814-349-1210

Thomas Timberlands Enterprises
Box 5075, Route 26
Pleasant Gap, PA 16823
814-359-2890

Urbanik Lumber
Box 195
Clarence, PA 16829
814-387-4098

[112] Based on "Feasibility Analysis for Installing a Circulating Fluidized Bed Boiler for Cofiring Multiple Biofuels and Other Wastes with Coal at Penn State University", Miller et al.2003

Fig E. Picture of the biomass pelletizing plant and pug mill[113] [114]



[113]http://www.biofuelmachine.com/Small-Mobile-Pellet-Plant.html. Accessed April 2010.
[114] Blendmaster medium duty pug mill, Mclanahan Corp. Accessed April 2010.