UNIVERSITY OF NORTHERN BRITISH COLUMBIA BIOENERGY PLANT: PERFORMANCE REVIEW AND OPPORTUNITIES FOR IMPROVEMENT

by

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Abstract

The University of Northern British Columbia commissioned a biomass gasifier to generate heat to offset the use of natural gas in 2011. At an average boiler output of 6.9 GJ/hr the average thermal efficiency was determined to be 80% (LHV), the flue gas average temperature was 134°C with an energy content of 589 MJ/hr.

Options investigated to improve the efficiency of the bioenergy system include: Installing a flue gas condensing heat exchanger, reducing the flue gas O_2 percentage, pre-drying the fuel, installing a chiller, and installing a thermal storage tank. The most viable opportunity that exists is to add a flue gas condensing heat exchanger and connect the residences to the hot water loop.

Alternative technologies were compared to the bioenergy plant in terms of greenhouse gas displacement, and the system with the greatest potential is a slow pyrolysis system producing both heat and biochar for use in soils.

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Glossary

Ash Fusion – In the context of biomass, when the inorganic constituents reach a high enough temperature to melt and fuse together into a hard rock like material (slag or clinker)

Bioenergy System Yield - The ratio of useful energy out to the biomass input

Coefficient of Performance (COP) – For a chiller, the COP is the ratio of energy available for cooling to the energy input ($Q_{cooling} / Q_{input}$)

Condensate - The liquid produced from the condensable gases within flue gas

Displacement Factor – The CO_2 emissions avoided with the replacement of fossil fuels with bioenergy given in units of kg CO_2 per tonne of biomass

Dry Basis – Referring to units that exclude moisture. Example: Flue gas flow rate dry basis excludes the water vapour flow

Firing Rate - In the context of a biomass based energy system, it is the rate of fuel consumption

Flue Gas – Combustion exhaust gases (Primarily CO_2 , N_2 , and H_2O) released from the smoke stack of a combustion system

Gasification – Partial combustion in an oxygen starved environment to generate syngas comprised of CO, H_2 , and small concentrations of CH₄, CO₂ and tars

Heating Degree Days (HDD) – Relative to a reference temperature, HDD is an indication of the heating demand in a building. The colder the ambient conditions, the higher the HDD

Higher Heating Value (HHV) – The amount of heat released from complete combustion with condensation of the water vapour

Hog Fuel - sawmill residuals comprised of bark, sawdust, shavings and chips

Latent Heat – The amount of heat released or absorbed by a substance undergoing a change in state

Lower Heating Value (LHV) – The amount of heat released from complete combustion without condensation of the water vapour (typical industrial combustion conditions)

Oxidizer – In the context of gasification, oxygen is the oxidizer, which is the substance required for a particular material to combust

Pyrolysis – Thermal decomposition of a material in the absence of or with low concentrations of oxygen. Products produced are: charcoal, gas and tars

Sensible Heat – The amount of heat required to raise the temperature of a substance, but does not cause a change in state

Syngas – Gaseous mixture of CO, H_2 , and small concentrations of CH_4 , CO_2 and tars produced from gasification of biomass, coal and from the reformation of natural gas

Torrefaction – Low temperature pyrolysis (generally below 300°C) for the production of an energy pellet, which is more energy dense than traditional wood pellets and has water resistant properties

Turndown Ratio – In reference to a boiler, it is the percent output that the system can be reduced to while still operating. A turndown ratio of 2 means the boiler can operate at a minimum of 50% of the rated output. The turndown ratio of UNBC's gasifier is approximately 2.5

Wet Basis – Referring to units that include moisture. Example: Flue gas flow rate wet basis includes the water vapour flow

Introduction

The use of bioenergy technologies for heating is becoming an increasingly popular means for achieving greenhouse gas reductions while maintaining existing heating requirements. In British Columbia where public institutions are required to be carbon neutral, larger institutions such as universities have been converting natural gas heating systems to biomass based systems. Numerous technologies exist and the suitability depends on the specific application and the availability of fuels. In northern British Columbia, sawmill residuals and logging waste is readily available and is therefore the fuel of choice for bioenergy technologies in the region. Wood waste boilers have been in use for decades at pulp mills. Recent improvements in biomass gasification technologies are providing new opportunities due to the ability to produce a clean fuel capable of displacing natural gas (British Columbia Bioenergy Network 2010).

The University of Northern British Columbia in Prince George BC initiated a project in 2008 to design a bioenergy system to displace 85% of the campus natural gas usage in order to reduce greenhouse gas emissions. The bioenergy plant was commissioned in 2011 and consists of a gasifier supplied by Nexterra which converts sawmill residuals (hog fuel) into syngas through a process called gasification (See Appendix B for a schematic and Appendix C for a campus map). Gasification is generally referred to as incomplete combustion or partial oxidization where biomass is converted to syngas in a controlled environment with limited oxygen. This produces a gaseous mixture composed of H_2 , CO, CO₂ and CH₄ (Wang et al. 2008).

Heating to the main campus buildings is provided by a hot water loop with the Nexterra gasifier providing the majority of the heat and four natural gas fired boilers providing the back-up.



Figure 1.0 (A) UNBC Gasifier Process Flow Diagram (Source: Nexterra Website)



- A. Fuel pre-treatment (drying)
- B. Oxygen addition control for more efficient combustion
- C. Flue gas heat exchanger to recover waste heat
- D. Thermal storage on hot water loop to campus
- E. Adsorption chiller (not shown)

Figure 1.0 (B) Options for Increasing the Utilization Rate and Efficiency of the UNBC Gasifier (Source: Nexterra Website)

During peak heating demands in the winter, both the gasifier and the natural gas boilers operate in order to provide enough heat output. Heating to the residences is provided by a separate natural gas air handler and electric baseboards. The Northern Sports Centre also has a standalone heating system and is not connected to the campus hot water (See Appendix C for campus map).

1

In the UNBC bioenergy plant, the syngas is oxidized to generate heat for the campus water loop via a heat exchanger. The syngas displaces natural gas which remains as the supplemental and backup fuel source for the campus. The rated capacity of the Nexterra gasifier is 4.4 MW of thermal energy and consumes between 500-1000 kg of hog fuel per hour depending on the firing rate. Typical gasifier efficiencies range from 70 to 95% (hot gas efficiency) depending on the gasifier design (Quaak et al. 1999), with the majority of the losses in the flue gas. Options for increasing the UNBC bioenergy plant efficiency and utilization rate are outlined in Figure 1.0(B).

There are a number of technologies available for capturing residual heat in flue gas from industrial heating systems. The most common technology is a condensing heat exchanger which could be added to the flue gas stream in order to extract latent heat for use in an expanded hot water loop (Marbe et al. 2004). The student residences are currently heated with a combination of natural gas and electricity but there is the potential for connecting them to a new hot water loop from the bioenergy plant. In order to maximize the thermal efficiency of the condensing heat exchanger, the return water temperature needs to be below the condensation temperature in the flue gas heat exchanger. To reduce the water temperature after the water exits the heating loop in the residences, two options are discussed: One is to install a greenhouse which could then

be connected to the hot water loop; the second is to use the hot water to pre-heat the air for the oxidizer.

An additional system which could be added to the bioenergy plant is a thermal storage tank (Verda and Colella 2011). This tank would be installed in the main hot water loop between the bioenergy plant and the campus buildings. Thermal storage tanks are a common method to store heat energy from a bioenergy plant so that the heat supply to the end users can be evened out and the output of the bioenergy system can remain at a steady rate.

During the summer months, when the heating demands are at their lowest, there is an opportunity to install an adsorption chiller in the hot water loop (Maraver et al. 2013). This would enable the gasifier to remain at full output where the efficiency is greatest, and supply air conditioning to the campus buildings. This provides an option for maintaining the efficiency at peak levels without the need to reduce the gasifier output due to seasonal demands.

The objectives of this paper are to review data from the UNBC Nexterra gasifier (bioenergy plant), and the campus utilities in order to determine the thermal efficiency of the system and discuss opportunities for improvement. A detailed analysis of the gasifier performance will be carried out and a comparison will be made between the actual greenhouse gas savings and what the potential savings would be using alternative biomass conversion technologies. This will gauge the success of UNBC's overall objective of reducing greenhouse gases.

Section 1

1.0 Data Analysis

Data from the gasifier control system for the time period March 2012 to November 2013 was obtained and analyzed to review the performance and efficiency. Data was available for 15

minute intervals for hog fuel feed rate, air flow to the oxidizer, total air flow, temperatures at numerous points, and gasifier energy output to the campus. The main parameters calculated from the control system data which were used in the analysis are provided in Table 1.0.

	Average
Boiler Flue Gas Temp (°C)	134
Boiler Output (GJ/hr)	6.9
Hog Fuel Feed, Dry Basis (kg/hr)	495
Hog Fuel Feed, Wet Basis (kg/hr)	693
Hog Fuel Feed, Dry Basis (GJ/hr)	7.9
Hog Fuel Feed, Wet Basis (GJ/hr)	4.7
Hog Fuel Energy Density (MJ/kg)	16
Hog Fuel Moisture Content (%)	40%
Flue Gas Flow, Wet Basis (kg/hr)	671
Flue Gas Flow, Dry Basis (kg/hr)	440
Flue Gas Water Flow (kg/hr)	231
Flue Gas (kJ/hr)	588,512
Thermal Efficiency (HHV)	70%

Table 1.0 - Summary of Average Bioenergy System Data for March 2012 to November 2013.

Data from the campus utilities was also obtained for the same time period which includes downloads from meters that record building heating and cooling demands. Using a Pivot Table in Microsoft Excel 2010 (Microsoft, Redmond Washington), the data was converted to daily values and sorted into heating degree days (HDD) using a reference temperature of 15.5 °C.

Heating degree days are calculated using the following formula:

$$HDD = \sum_{t=0}^{24} (15.5^{\circ}C - T)$$
 (1)

Where T = outside temperature in °C and t = time in hours

If T > 15.5 then HDD = 0 for that interval

2.0 Gasifier Performance

The heat delivered to the entire campus including the residences using heat supplied by both natural gas and the gasifier is illustrated in Figure 2.0. The solid triangle data points represent the gasifier output and the solid circles represent the combined gasifier and natural gas supply. It can be seen in Figure 2.0 that for lower heating degree days, the gasifier is able to supply most of the heat demand for the campus. Above a HDD of approximately 20, the gasifier is not able to supply all the heat to the campus so natural gas is used to make up the difference.



Figure 2.0 - Campus Heating Supply and Demand vs. Heating Degree Days.

The overall heating supply and demand is illustrated in Figure 2.1. An explanation on the style of heat duration curves and how to interpret the data is provided in Appendix D. The closer the

smoothed average gasifier output line is to the heat supply line, the better the gasifier is matched to the campus heating requirements. Since the gasifier was not sized for peak demand during the coldest winter days, natural gas is used to supplement the gasifier output. Due to the low turndown ratio of the gasifier, it would not have been cost effective to size the output to match peak demand. Had it been sized to match the peak winter heating demand, the gasifier would not have been able to reduce the output enough during summer months. In this case the gasifier would have had to have been shut down entirely or operate with a larger percentage of the output exhausted.



Figure 2.1 - Heat Duration Curve - Campus Heat Supply and Demand over One Year.

For these reasons, the gasifier was sized to displace 85% of the campus' natural gas usage. As an approximation, Figures 2.0 and 2.1 appear to illustrate this sizing so the data looks like it matches the original design criteria of the bioenergy plant. The variability in the gasifier output illustrated in Figure 2.1 is shown in more detail in Figure 2.2 where one 24 hour period was focused on. The pattern of spikes in the natural gas boiler and drops in the gasifier output illustrated in Figure 2.2 is discussed in more detail in Appendix D. Possible explanations for this variation include: Differences in daytime and nighttime heating demand, system downtime, bioenergy system operating below capacity, and control system issues. There appears to be a pattern indicating a possible control or operations issue around balancing the gasifier output and the natural gas boiler output. See Appendix D for more details into the variability of the bioenergy plant output. Going into detail about these possibilities was outside the scope of this study but is a recommended area for further research.



Figure 2.2 - Campus heat demand for November 20th, 2012. Area below the solid line is heat supplied by the bioenergy system, area above the solid line represents heat supplied by natural gas.

The rated capacity of the gasifier boiler is 4.4 MW, but from the data presented in Figure 2.1, the peak output is approximately 3.5 MW. The reason for this is intentional as the campus engineers prefer to operate the boilers below 90% of capacity to be able to better respond to normal fluctuations in operation (Personal communication with Kevin Ericsson, UNBC Chief Engineer, March 2014).

A more detailed examination of the gasifier efficiency was carried out by looking at the relationship between the cumulative hog fuel deliveries and the cumulative heat delivered to the campus. This relationship is illustrated in Figure 2.3 where the upper line represents the data in terms of lower heating value (LHV) and the lower line representing the data in terms of higher heating value (HHV). The efficiency is represented by the slope of each line where on a LHV basis it is 80% and on a HHV basis it is 70%.



Figure 2.3 - Thermal Efficiency of the Gasifier as Determined by Cumulative Heat Delivered vs. Cumulative Hog Fuel Delivered.

In summary, the gasifier appears to be sized correctly for the heat demand profile. Specific issues are: Low efficiency and variable output. The system currently covers approximately 85% of the heat load, but should be able to cover well over 90% given the rated capacity of 4.4 MW (refer to Appendix D for details).

3.0 Options to Increase Bioenergy Plant Utilization

In this section, the following systems or additions to the bioenergy plant are reviewed in order to determine the most viable opportunity to increase the efficiency of the gasifier: Installing a condensing heat exchanger, reducing excess oxygen in the flue gas, pre-treating the fuel, installing a chiller, and installing a thermal storage tank.

3.1 Installing a Condensing Heat Exchanger

The largest opportunity for improvement of the UNBC bioenergy system efficiency is to extract residual heat in the flue gas which accounts for the majority of the losses in the system.

3.1.1 Flue Gas Energy Content

The flue gas has an average temperature of 134°C (Table 1.0) but varies seasonally with the gasifier output as illustrated in Figure 3.0. The high variability illustrated can be explained with the same reasoning as outlined in section 2.0 where the gasifier output in Figure 2.1 was described.



Figure 3.0 – Seasonal Boiler Flue Gas Temperature Fluctuation.

Although there are a few gaps in the data, a general trend can be seen where the temperature drops heading into the summer months when the gasifier is turned down. During winter months the gasifier is operating at a high rate and the flue gas temperature increases.

After grouping the data into 20 degree increments (where 60 represents data from 0 to 60 and 80 represents data from 61 to 80 etc.), the majority of the temperature measurements fall within a range of approximately 120°C to 180 °C as illustrated in Figure 3.1.



Figure 3.1 - Distribution of the Boiler Flue Gas Temperatures.

Using the latent heat of condensation for water of 2260 kJ/kg water, the average flue gas energy content is 589 MJ/hr (Table 1.0). The distribution of the flue gas energy content is illustrated in Figure 3.2. Approximately 80% of the data fell between 250 MJ/hr and 750 MJ/hr.

The flue gas energy content was determined by calculating the mass flow of water in the flue gas from the calculated flue gas mass flow and the measured humidity. Multiplying the mass flow of water by the latent heat of condensation equals the energy content of water vapour within the flue gas.



Figure 3.2 - Distribution of Boiler Flue Gas Energy Content (Sum of Latent and Sensible Heat).

In order to improve the overall efficiency of the gasifier, a greater percentage of the energy remaining in the flue gas would have to be utilized. One opportunity to improve the efficiency is to install a flue gas condensing heat exchanger and connect new end users to a new heating loop. This is a technology gaining attention throughout industry to extract both flue gas heat and water from energy systems (Chen et al. 2012, Kilkovsky et al. 2014). The gasifier's flue gas energy content varies depending on the performance of the gasifier and the hog fuel moisture content. As the moisture content of the fuel increases, the percentage of latent heat increases relative to the sensible heat (Swithenbank et al. 2011). In order to design a system to handle the variations in biomass fuel moisture contents, the flue gas heat exchanger needs to cool the gas (sensible heat transfer) and condense the water vapor (latent heat transfer) (Levy et al. 2011). A new hot water loop would be required as the existing campus water loop is a high temperature and pressure system. The heat extracted from a flue gas heat exchanger would be a lower temperature system and not necessarily pressurized. This will be discussed further in subsequent sections.

The output of the gasifier varies depending on a number of factors including maintenance and operation issues. The variable with the largest impact to the heat available in the flue gas is the hog fuel moisture content. In order to better understand the relationship, a comparison between boiler output, fuel moisture content and latent heat loss was carried out. This is illustrated in Figure 3.3 where it can be seen that other than low boiler output, the latent heat loss at any given fuel moisture remains relatively constant (see Appendix A for data table and sample calculation). But as the moisture content of the hog fuel increases, the latent heat loss percentage increases significantly. The sizing of the condensing heat exchanger would have to take this into account so as to extract the maximum heat available in the flue gas stream.



Figure 3.3 - Relationship between Boiler Output, Fuel Moisture and Latent Heat Loss in the Flue Gas. The typical boiler output ranges from 4 to 11 GJ/hr

3.1.2 Condensing Heat Exchangers

In a condensing heat exchanger, a water loop passes through the heat exchanger, extracts heat from the flue gas and can be used for heating (see Figure 3.4). The flue gas would then exit the bioenergy plant at a much lower temperature.

Flue gas heat exchangers can be of two basic designs – direct or indirect. In a direct heat exchanger, a water loop enters the hot flue gas stream where heat is transferred to the water in the pipe. In an indirect heat exchanger, cold water is sprayed into the hot flue gas and is collected and pumped back around through a pipe which is then used to heat another water loop (Chen et al. 2012).



Direct Heat Exchanger

Indirect Heat Exchanger



In order to maximize the heat extracted from the flue gas, there needs to be a properly sized heat exchanger, an end user of the heat, and a cool enough return temperature back to the heat exchanger. The relationship between the fuel moisture content and the required final flue gas temperature in order to get the maximum heat capture is illustrated in Figure 3.5 (see Appendix A, equations 54 to 58 for sample calculations). With the heat capture maximized, the overall system efficiency is increased. At approximately 3.5 MW boiler output, the flue gas would need to be cooled to 40°C to extract the maximum amount of the latent heat available assuming a fuel moisture content of 40%. The more water in the fuel, the more water there will be in the flue gas and therefore a higher condensation temperature will be able to extract the latent heat from the flue gas.



Figure 3.5 - Target Flue Gas Temperatures for Maximum Heat Extraction as a Function of Boiler Output and Fuel Moisture.

The amount of work the heat exchanger would be required to do in order to maximize the heat capture is illustrated in Figure 3.6 (see Appendix A, equations 54 to 58 for sample calculations). For example, at a boiler output of 3.5 MW and fuel moisture of 50%, the heat exchanger would have to be sized for a 600 kW duty. The impact boiler output has on flue gas heat capture is illustrated in Figure 3.6. At a 30% fuel moisture content, increasing the boiler output from 2 to 3 MW increases the flue gas heat capture from 200 kW to 300 kW.



Figure 3.6 - Flue Gas Heat Capture as a Function of Fuel Moisture and Boiler Output.

3.1.3 Heat Utilization

There are a number of opportunities for utilizing the additional heat available in a new hot water loop such as connecting the student residences, the Enhanced Forestry Lab or the Northern Sports Centre. The Enhanced Forestry Lab and the student residences are relatively close to the Bioenergy Building. The Enhanced Forestry Lab is already heated with biomass (a pellet system). Therefore the buildings that make the most practical sense to connect to the heating system are the residences. Currently the residences are heated by a combination of electric baseboards and a natural gas air handler. The new heating loop would displace the existing natural gas system which heats the hallways and the potable hot water.

The average heating demand for each residence is 130 kW (obtained from the natural gas meters) with a distribution as illustrated in Figure 3.7. Each residence has a similar heating demand profile peaking at approximately 250 kW.



Figure 3.7 – Annual Heating Demand for Each Residence. Data sorted based on total campus heat demand.

Comparing this to the average flue gas energy content of 589 MJ/hr or 164 kW from Table 1.0, there is enough energy remaining in the flue gas to meet the average heating demand of one of the residences. A comparison of the daily heating demand and the heat available in the flue gas is illustrated in Figure 3.8. The distribution of heat demand for the residences ranges from 4 to 16 GJ/day (50 to 200 kW) with 35% of the days having a heat demand of 12 GJ/day. The distribution of heat available from the flue gas ranges from 10 to 22 GJ/day (120 to 250 kW) with approximately 50% of the days with 16 to 18 GJ/day available. Comparing Figure 3.7 to Figure D9 in the Appendix, the residence heat demand matches the gasifier output. However, it is not practical to extract 100% of the energy in the flue gas. To maximize the energy extraction,

the flue gas needs to be cooled as much as possible. The degree to which the flue gas can be cooled depends on the return water temperature in the heat exchanger. Therefore the lower the water temperature returning to the flue gas heat exchanger, a greater percentage of energy can be extracted from the flue gas (see Appendix A, Figure A4 for details).

Depending on the exit temperature of the water loop for the residence, it is possible that further heat will need to be extracted in order to have a cool enough return temperature to the bioenergy plant. For this example, an estimated exit temperature from the residence of 55°C has been used. To further lower the water temperature, a few options have been illustrated in Figure 3.9. One option is to install a greenhouse between the residences and the bioenergy plant which would use the residual heat in the water loop. A second option could be to use the 55°C water for preheating the air for the oxidizer. The combustion calculations for the flue gas when cooled to 40°C using fuel with a moisture content of 40% are provided in Table A7. At full gasifier output the percentage of flue gas heat captured is 74% but when flue gas is only cooled to 55°C, the heat captured drops to 44% as illustrated in Table A8 (also using fuel at 40% moisture).



Figure 3.8 - Flue Gas Latent and Sensible Heat Content vs. Residence Heat Demand.

The box diagram (Figure 3.9) is for illustration purposes and shows a possible upgraded heating loop which would increase the overall bioenergy plant efficiency. The components of the box diagram will be discussed in subsequent sections (thick arrows represent water loops and the thinner arrows represent flue gas flow). The following discussion is based on dumping heat from the heating loop (to a greenhouse or cooling tower) to achieve a final flue gas temperature of 40°C.



Figure 3.9 - Box Diagram Illustrating Possible Upgraded Campus Hot Water Heating Loop. The thick arrows represent water lines and the thin arrows represent flue gas.

The installation of a greenhouse to utilize residual heat from a bioenergy fueled residence heating loop has been studied as part of the University's goal of expanding biomass heating to parts of the campus that are currently heated with natural gas. Renner (2011) notes that on average 4,000 GJ/yr of heat is required per hectare of greenhouse. Based on this rule of thumb, the potential size of an additional greenhouse is 0.32 hectare based on the bioenergy plant's hog fuel moisture content of 30%, the final flue gas temperature of 40°C and a boiler output of 3.5 MW. As this analysis is based on averages, during the coldest months when the heating demand of the campus buildings and residences are at the highest, there would be more residual heat available for a greenhouse. This is illustrated in Figure 3.6 where the maximum flue gas heat capture increases as the boiler output increases. A condensing heat exchanger can improve the thermal efficiency of a heating system by up to 20% (Neuenschwander 2011). The efficiency improvement when the flue gas heat is captured based on two scenarios is shown in Appendix A. The first scenario is 40% fuel moisture content with a final flue gas temperature of 40°C (Table A7), and the second scenario is 40% fuel moisture content with a final flue gas temperature of 55°C (Table A8). With the lower flue gas temperature, the efficiency improvement varies from 16.0% at a low boiler output to 18.5% at a high boiler output. At the higher flue gas temperature, the efficiency improvement varies from 8.5% at a low boiler output to 11.6% at a high boiler output. This means that the gasifier efficiency could increase from 80% (LHV) to between 87% and 95%. The condensing heat exchanger would then feed a new water loop connected to the residences and potentially a greenhouse operation as illustrated in Figure 3.9.

3.1.4 Flue Gas Condensate

Typically a boiler will produce 150 to 500 litres of condensate and 0.01 to 0.3 kg (dry basis) of sludge per MWh of thermal energy produced (Loo and Koppejan 2008). From Table 1.0, the bioenergy plant's average boiler output is 6.9 GJ/h or 1.9 MWh/h of thermal energy. Therefore the estimated condensate produced would be 300 to 1000 litres per hour and the sludge produced would be 0.02 to 0.6 kg/hour. These estimates agree with the calculated values outlined in Table A4 in Appendix A, where the total H₂O out ranges from 335 to 1094 kg/hour (based on 40% fuel moisture).

Condensates from the flue gas of biomass based energy systems typically contain a mixture of organics, inorganics and some heavy metals. Most of the heavy metals are precipitated out in the condensate sludge and can pose environmental concern (Loo and Koppejan 2008). In comparison, the condensate from the flue gas of coal fired power plants contain a much higher

percentage of harmful chemicals such as sulfuric acid and mercury resulting in the need for expensive treatment systems (Levy et al. 2011). Tests could be completed to determine the composition by taking a sample of the flue gas and analyzing the constituents in order to verify the chemicals that may be of concern. Condensate sludge can be separated from the condensate with a sedimentation tank, a wood filter, or a belt filter (Loo and Koppejan 2008).

The concentrations of the compounds in the condensate will vary depending on the moisture content of the hog fuel. Previous research has demonstrated that dry fuels have lower emissions of CO, hydrocarbons and polycyclic aromatic hydrocarbons (Atkins et al. 2010). Pre-drying the hog fuel will be discussed in a subsequent section.

3.2 Reducing the Excess Oxygen Content in the Flue Gas

Reducing the excess oxygen in the flue gas is an effective means to increase the overall efficiency in a biomass combustion plant (Loo and Koppejan 2008). The air required for complete fuel combustion is referred to as the stoichiometric air requirements. For example, if the formula for biomass is $CH_{1.5} O_{0.75}$ the stoichiometry is as follows:

$$CH_{1.5}O_{0.75} + O_2 \rightarrow CO_2 + 0.75H_2O$$
 (2)

Based on this equation, 1 tonne of biomass would require 1.3 tonnes of O_2 for complete combustion. To ensure complete combustion, excess air is normally added (Bain et al. 1998, Yin et al. 2008). The higher the excess air the higher the flue gas flow and therefore more heat loss with the flue gas (Figure 3.10).



Figure 3.10 – Relationship between Exhaust Gas Temperature and Losses with Different Excess Air Ratios. The ideal excess air ratio is 1.25 which results in a flue gas O₂ content of 6% (Yin 2008). At a flue gas temperature of 180°C and an excess air ratio of 1.25, the exhaust gas losses are approximately 9% (Figure 3.10). As the excess air ratio increases, so too does the oxygen content in the flue gas (not shown). There is no oxygen sensor on the gasifier so a calculation was made using the hog fuel inputs and combustion calculations (Table A4 in Appendix A). The percent oxygen varies between approximately 7% at low boiler output and 4.5 % at high boiler output (Figure 3.11) (see Appendix A, equation 32 for calculations).



Figure 3.11 - Percent Oxygen in Flue Gas as a Function of Boiler Output.

The Nexterra gasifier is not equipped with an oxygen sensor so it is not known what the oxygen percentage in the flue gas currently is. Based on the combustion calculations, it appears that the percentage is already low and Nexterra may require the oxygen percentage to remain fixed in order for their technology to work as designed. As a result, adjusting the excess oxygen level may not be a practical option for improving the system's efficiency.

3.3 Fuel Pre-treatment

Another option to extract the residual energy in the flue gas could be to capture the waste heat to pre-dry the hog fuel. If the hog fuel moisture content was lowered and became more uniform as a result, the overall gasifier efficiency would increase therefore increasing the heat output (Li et al. 2012). Lowering the fuel moisture content from 50% to 30% has the potential to improve the thermal efficiency of a biomass combustion plant by 8.7% (Loo and Koppejan 2008). The increased efficiency is due to the reduced latent and sensible heat loss that occurs with high moisture content fuel (based on a system without a flue gas condensing heat exchanger). The

sample calculations provided in Appendix E show the increased yield which results from drier fuel. The lower the fuel moisture content, the greater the heat output of the bioenergy system per tonne of biomass. For example, with a starting moisture content of 40% and a dried moisture content of 25%, there would be a 4.2% yield increase (Table E1). This means that 4% less hog fuel would be required for the same bioenergy plant output.

With uniform fuel moisture content, the gasifier controls would not have to adjust for varying inputs and would likely run more stable as a result. In terms of ideal fuel moisture contents, it varies by gasifier design but fuel moisture contents below 15% results in a more stable fuel bed temperature (Ruiz et al. 2013). In addition, dryer hog fuel would also improve the stack emissions as the concentrations of aromatic hydrocarbons will decrease as will the volume of condensate (Atkins et al. 2010).

The challenge for this option would be that adding a hog fuel drying stage to the existing bioenergy plant would be costly and not practical given that the existing hog fuel intake metering augers are close coupled to the gasifier. In addition, a drying stage in a bioenergy plant can represent the highest capital cost component (Brammer 1999). A drying stage would need to be installed between the hog fuel feed system and the gasifier, which in the existing design would require costly modifications. In addition to the high capital cost, dryer fuel would increase the combustion temperature of the fuel. As a result the ash fusion temperature could be approached resulting in slag formation (Amos 1998). Slag (sometimes referred to as clinker) would cause operational problems if it built up inside the gasifier or the ash removal system and caused plug ups. Due to the high variation in inorganic concentrations in biomass, testing for the ash fusion temperature is the most common test for determining the melting point of fuels (Vassilev 2014).
A series of these tests would have to be completed as part of any considerations of installing a biomass dryer.

3.4 Installation of a Chiller

Another option for utilizing the unused capacity in the summer is to install a chiller. Chillers are based on the principle of a closed loop cooling cycle using either a liquid-vapor phase (absorption) or a solid-liquid phase (adsorption) (Qian et al. 2013). The main differences between adsorption and absorption chillers are the materials and substance state. In absorption chillers a solution or solid absorbs a refrigerant becoming a uniform solution or body, whereas in adsorption chillers the refrigerant remains on the surface of a solid adsorber (Pang et al. 2013). In both cases, the refrigerant is regenerated by heating the absorbant or adsorber.

In terms of capital cost, adsorption chillers have a higher capital cost but a lower maintenance and operating cost. The reason for the high costs of adsorption chillers is due to their large volume and weight and the fact that the technology is relatively new in comparison to absorption chillers. The operating and maintenance costs for absorption chillers are high because they rely on corrosive salt solutions which require regular maintenance to regenerate the desiccant (Eco-Max white paper). In addition, the purchase cost and environmental costs to store the desiccant is high making the adsorption chiller design a more attractive solution in many cases as it simply uses water as the refrigerant.

Currently, the campus air conditioning is provided by a cold water system powered by electricity. The relationship between the campus cooling demand and the gasifier output is shown in Figure 3.12. During summer months when the heating demand is low, the gasifier is turned down and the air conditioning system is in use. If the gasifier was to remain at full output

all year, it may be possible for a portion of the cooling demand to be met with the addition of a chiller. The existing electric chiller system could remain as a back-up and once the adsorption chiller is in place, the operating cost would be the incremental hog purchases.



Figure 3.12 – Annual Heating and Cooling Demand on Campus and Heat Supply from the Gasifier and Natural Gas System.

In order to look more closely at the potential for a chiller, the gasifier data was divided into winter and summer months. During the colder months of the year, the gasifier is operating at or near full output and is turned down during the warmer months. This can be seen in Table 3.0 where the average boiler output is 2,368 kW during the 6 months from October through March and 1,527 kW April through September.

Averages	Oct	Nov	Dec	Jan	Feb	Mar	Winter Average
Boiler Output (kW)	1,935	2,621	2,584	2,348	2,325	2,397	2,368
Hog Fuel (kg/hr dry basis)	503	679	669	608	603	621	614
Averages	Apr	May	Jun	Jul	Aug	Sept	Summer Average
Boiler Output (kW)	2,182	1,692	1,418	1,250	1,308	1,313	1,527
						the second se	

Table 3.0 - Gasifier Performance during Winter and Summer Months.

Eco-Max Adsorption chillers distributed through Power Partners Inc. are designed for low temperature applications and are an example of a possible system to displace the existing air conditioning system at UNBC. These particular chillers require a minimum water temperature of 90°C and are available in capacities ranging from 35 kW to 1178 kW producing chilled water between 3°C and 20°C (Eco-Max specification sheet).

The cooling demand illustrated in Figure 3.12 represents 177 days at an average demand of 406 kW and a peak of 1300 kW. In order for the gasifier to maintain the output required to meet the cooling demand through a chiller, more hog fuel would have to be consumed. Calculating the required tonnage based on the average consumption per kW of output works out to 900 tonnes of incremental hog fuel annually (calculation below).

406 kW cooling demand / 0.5 COP x (397 kg hog fuel / 1,527 kW output) x 24 hrs/day x 177 days/year / 1000 kg/tonne = 897 tonnes of hog fuel

The coefficient of performance (COP) for a chiller with a low temperature heat source is relatively low with a COP of 0.5 considered relatively good (Garimella S. 2012, Maraver et al. 2013). Assuming the available heat input to the chiller to be the difference between winter and summer boiler outputs from Table 3.0 at 841 kW, there would be 420 kW of available cooling based on a COP of 0.5. A chiller could therefore meet the average cooling demand for the campus, but not meet the peak demand during the warmest months.

3.5 Installation of a Thermal Storage Tank

The use of a thermal storage tank will provide a separation between the heat being generated in the energy system and the heat being supplied to the campus. Excess heat generated from the gasifier during periods of low demand could be stored until the demand increases (Eynard et al. 2012). It would provide a buffer between brief interruptions in the energy system operation and the end user, with the benefit being that during brief periods of downtime on either the end user side or on the fuel supply side, the heat generated would not be wasted (Stritih 2004). Interruptions in the UNBC system occur on the supply side so if a thermal storage tank was in place, the demand could still be met despite short periods of downtime at the gasifier. As the efficiency of the gasifier/boiler is highest when the system is operating at full output, the addition of a thermal storage tank will improve the overall thermal efficiency as the gasifier operating at a steady output, when the demand drops, heat would be put to storage and when demand picks up the heat can be delivered from the storage tank. Appendix D goes into further detail on thermal storage and how it could be used to smooth out the high variation in gasifier output which is illustrated in Figure D27.

As a rule of thumb, a minimum of 10 m³ of water storage are required for every 1 MW of boiler output. If the sizing was based on the peak output of the gasifier (3.5 MW) then the capacity of the storage tank would need to be 35 m³ (Viessmann presentation 2013). A further literature review of the recommended volume of water storage resulted in a wide range of recommendations. According to BSI, the United Kingdom's National Standards Body, 25 to 50 m³ per MW of peak load is recommended (BSI Technical Committee BS EN 1536-4-7, 2008). The calculations in Appendix D are based on modeling the existing bioenergy system with and without a thermal storage tank ranging in size from 1 GJ to 1,000 GJ, and determining the natural gas savings. A 10 GJ tank would provide roughly 3 hours of buffer between the supply and demand and decrease the natural gas consumption by approximately 7%.

While the sizing of the thermal storage system could be debated, they can improve the overall system output and act as a buffer between the supply and demand of heat. The location of the thermal storage tank would need to be between the bioenergy plant and the UNBC campus (Figure 3.9).

Since biomass energy systems do not have the same response time as fossil fuel systems that can ramp up and down rapidly, a thermal storage tank should be considered when designing a biomass energy system. In addition, bioenergy systems do not have the same turndown ratio as a natural gas boiler and as such need to operate at or near peak capacity for maximum efficiency. But in the case of the UNBC system, a thermal storage tank is not practical given the low temperature drop in the campus hot water loop. The resulting tank would have to be significantly large (800 m³) therefore making it uneconomical (refer to Appendix D for further details). The tank volume is much larger than the rules of thumb indicated due to the low temperature differential in the campus water loop (3°C).

4.0 Greenhouse Gas Offsets

Based on the data studied from March 2012 to November 2013, the UNBC residences use 4,550 GJ of natural gas annually (see Table 4.0 below). At an energy density of 38.5 GJ/m^3 (Fortis BC Heat Values) and 1.916 tonnes CO₂e/m³ (Environment Canada, National Inventory Report), there would be 225 tonnes of CO₂e offset each year if the residences were connected to a water loop

after the addition of a flue gas condensing heat exchanger. This assumes 100% of the natural gas would be displaced, whereas in fact the natural gas system would remain in place and be used in times when the bioenergy plant is not in operation.

Table 4.0 – Potential Greenhouse Gas Offsets from Displacing Natural Gas Consumed in the Student Residences.

Natural Gas Consumption (GJ)	Heat Content (GJ/1000m ³)	Tonnes CO ₂ /m ³	Tonnes CO ₂ / year
4,550	38.5	1.916	225

Since UNBC has a mandate to be greenhouse gas neutral (Greenhouse Gas Reductions Targets Act), a reduction 225 tonnes of CO_2e has a value of \$12,375/year based on a carbon tax of \$30/tonne and a carbon offset price of \$25.

A thermal storage tank could offset 50 tonnes $CO_2e/year$ the calculations for which are outlined in Appendix D. This would be achieved through the displacement of some of the natural gas spikes with heat from the storage tank. This would result in a 5% increase in hog fuel consumption. The system was modeled with different thermal storage capacities and illustrated in Figure D28. For a thermal storage tank with a 10 GJ capacity, there is an approximately 1,000 GJ drop in natural gas, which corresponds to 50 tonnes of CO_2e .

The installation of a chiller to offset electric air conditioning would offset 6,000 GJ of electricity. Based on an emission factor for BC Hydro of 6.9 kg/GJ (BC Ministry of Environment, 2012), there would be 41.4 tonnes of CO_2e offset valued at \$2,277.

5.0 Recommendations to Improve the Thermal Efficiency of the Bioenergy Plant

If the University wishes to pursue a project to increase the thermal efficiency of the bioenergy plant, the first step would be to complete a detailed energy balance for the heat supply and

demand for all campus buildings including the residences. This will confirm the available heat and required demand for heating and cooling on the campus during both summer and winter. Then capital costs should be obtained for the more viable opportunities starting with the installation of a condensing heat exchanger in order to tie in the residences to the heating loop. The condensing heat exchanger is likely the most viable opportunity for extracting residual heat and improving the overall thermal efficiency. Pre-drying the hog fuel using the waste heat is possible and would result in an efficiency improvement, but is likely not the most practical for an existing installation. Adding a thermal storage tank is not recommended for the system as the size requirements would make it cost prohibitive. The addition of a chiller should be explored as it provides a means to supply cooling to the campus while keeping the gasifier operating at full capacity. The challenge for the chiller option will be the capital costs as they will be high and the payback would be long given the relative low cost of the existing air conditioning system and the limited months of use. A summary of the overall impacts of the five options reviewed is outlined in Table 5.0.

Table 5.0 – Summary of Impacts to Efficiency, Hog Fuel Consumption and GHG Emissions for Each Improvement Option

Option	Efficiency	Hog Fuel	GHG Emissions
Condensing Heat Exchanger	10 – 20% increase	No change	225 tonnes CO ₂ / yr offset
Dryer	4% increase	4% decrease	No change
Thermal Storage	No change	5% increase	50 tonnes CO ₂ / yr offset
Chiller	No change	15% increase	41 tonnes CO ₂ / yr offset
Reduce Excess Air	No change	No change	No change

Based on the comparison (Table 5.0), adding a flue gas condensing heat exchanger stands out as showing the greatest potential to improve the existing system.

Section 2

6.0 Comparison of UNBC's Bioenergy Plant to Alternative Technologies

The gasifier's performance in terms of efficiency and options for improvement were reviewed in Section 1. The following discussion will review alternative renewable technologies that could be utilized to offset natural gas heating and achieve similar results at UNBC, plus to compare alternative uses for hog fuel. Three technologies will be discussed: Traditional biomass boilers, wood pellet boilers and the emerging technology of a pyrolysis system for the production of heat and charcoal. This review will then enable a comparison to be made between the gasifier's performance and alternatives in order to determine where the bioenergy plant ranks with other biomass conversion technologies in terms of greenhouse gas offsets.

6.1 Biomass Boilers

Traditional biomass fired boilers are considered a mature technology that have widespread use throughout industry and in commercial operations. They are commonly used due to their ability to handle a wide variety of biomass supplies with variable moisture content (Yin et al. 2008). The pulp and paper sector has used biomass boilers for over a century to generate steam for use in the pulp mill and for power generation via a steam turbine. Technological changes over time have made improvements to thermal efficiency, controls and emissions but the core technology has not changed in recent years. Two common types are stoker grate and fluidized bed boilers (Saidur et al. 2011). Stoker grate boilers can be subdivided into different designs depending on the grate system which can be fixed, travelling or vibrating (Duo 2007, Bain et al. 1998). The basic design is a fixed grate boiler where the biomass is fed onto a grate where combustion takes place. Ash removal takes place via a stoker which rakes the grate after a period of operation. In this design the combustion efficiency is the lowest of the boiler designs and residual carbon in the ash can be a problem depending on the control mechanism employed. Travelling or vibrating grates are designed to spread the biomass fuel evenly across the grate for improved combustion characteristics. In general, these grate designs result in higher combustion efficiency when compared to fixed grate boilers (Saidur et al. 2011).

The most modern boiler design is a fluidized bed boiler which was introduced due to its higher combustion efficiency and lower SO_2 and NO_x emissions (US Environmental Protection Agency 2007). The EPA report makes a comparison between stoker grate and fluidized bed boilers and found that at the same excess air ratio and exhaust temperature, the stoker grate boiler efficiency is 77% while the fluidized bed boiler efficiency is 80% (HHV). These numbers vary depending on operating conditions and fuel moisture content. An FPInnovations presentation by Duo (2007) reports a 68% (HHV) thermal efficiency in a stoker grate boiler using a fuel moisture of 50% (Duo 2007). The higher efficiency reported for a fluidized bed boiler is significant but comes with a higher capital cost. Fluidized bed boilers are also more suited for fuels with a low energy density and high ash content (Saidur et al. 2011).

Kraft pulp mills in Canada are all relatively old having been constructed in the 1960's so the majority of the boilers in operation are either fixed grate or moving grate designs. If a new boiler was installed today, it is likely that a fluidized bed (sometimes referred to as bubbling fluidized bed) boiler would be considered given the efficiency, improved emissions and the environmental benefits of lower ash volumes to be disposed of.

Although boilers are available in a wide range of sizes, the economics tend to be more favorable on a larger scale when looking at the capital cost per tonne of steam or kW of thermal energy produced (Kumar et al. 2003, Svanberg et al. 2013). As a result biomass boilers are the

technology of choice for the majority of the pulp and paper mills in operation today. In addition, they are well suited to handle a wide range of fuel moisture contents which is typical when utilizing hog fuel. In comparison, dealing with variable fuel moisture contents is not something current gasification systems are well suited to handle. The reason is the moisture can lead to an increased need for gas cleanup especially if the syngas is being produced for power generation (Asadullah 2014).

Biomass gasification has not gained market acceptance in large capacities and with the exception of a few larger installations, gasification systems are generally smaller in scale than the biomass systems required for a pulp mill. The two largest biomass gasifiers are in Finland; the one in Lahti is 160 MW_{th} and the one in Vaasa is 140 MW_{th} (IEA Task 40). Hog fuel fired biomass boilers at pulp and paper mills are typically much larger by comparison and can be up to 500 MW in size (Preto 2011).

Smaller boilers used in commercial heating operations are not as sophisticated as the boilers used in the pulp and paper sector (Alakangas et al. 2006). Both hot water and steam can be generated for use in thermal applications. Small-scale equipment does not usually have advanced control and gas cleaning and is often located in more populated areas. For these reasons, high quality fuel with low moisture (< 30%) and low ash (e.g. high quality pellets < 0.7%) is preferred (Alakangas et al. 2006).

6.2 Wood Pellet Boilers

A newer technology that is utilized in smaller applications for renewable heating is a wood pellet boiler. Although this technology has been in use for decades in Europe, it is only starting to make inroads in North America. Pellet boilers are typically used in smaller commercial

operations or district heating applications due to their availability in a variety of small to medium capacities. The advantage of a wood pellet boiler over a traditional biomass boiler is that they are designed around a fuel which is very uniform in both size and moisture content. This greatly impacts the ability to optimize the controls and maximize the efficiency (Alakangas et al. 2006). Another benefit is that wood pellets have a transportation advantage over unprocessed biomass/hog fuel due to the fact that they are dried and as such have a higher energy density. This enables jurisdictions that are not located near a source of unprocessed biomass to use wood pellet boilers as a viable source of renewable heat (Magelli et al. 2009). Yellowknife is an example of such a jurisdiction where they have an initiative to install wood pellet boilers and are importing the pellets as they do not have the biomass sources locally (City of Yellowknife NWT news article, Arctic Energy Alliance 2009).

Transporting biomass great distances impacts the lifecycle greenhouse gas emissions (Magelli et al. 2009, Dwivedi et al. 2014). Sawmill residuals or logging debris with a moisture content of 50% has an energy density of approximately 8 – 10 GJ/tonne, wet basis (information from Canfor Pulp). Wood pellets are typically 5 - 10% moisture and have an energy density of 18.5 - 20 GJ/tonne (Murray 2011). The more energy dense the fuel is the more efficient the transportation costs become on a per tonne basis due to there being less water. This is the main reason why it is not economical to transport sawmill residuals or logging debris long distances. In terms of the UNBC gasifier, the system is designed around hog fuel with a moisture content of up to 60%, which is typical of the hog fuel within the Prince George region. Although wood pellets are dry and of a uniform size, the costs are significantly higher than the available sawmill residuals so it would not make economic sense to design a similar gasifier to use wood pellets as the fuel. Hog fuel is delivered to UNBC for \$60/tonne (dry basis) whereas wood pellets would

likely cost more than \$100/tonne. Current delivered prices into Denmark are \$180/tonne which includes shipping and rail (Argus Biomass Markets, 2014). Bulk pellet costs in Western Canada range from 105 to \$160/tonne (Arctic Energy Alliance 2009).

6.3 Pyrolysis Technologies

A growing technology is the use of pyrolysis for the combined generation of heat and charcoal production. Pyrolysis is the thermal destruction of biomass in an inert atmosphere producing charcoal (biochar), oil and gas products (Ryu et al. 2007). Depending on the temperature and residence time, the weight fraction of charcoal, oil and gas products varies.

Pyrolysis technologies are distinguished as being either a fast or slow pyrolysis system. Fast pyrolysis systems target bio-oil as the primary product which is either used as a liquid fuel or further processed in to chemical by-products. For these systems, approximately 75% of the original mass is converted to bio-oil, 13% to gas and 12% to biochar. For a slow pyrolysis system, approximately 30% of the original mass is converted to bio-oil, 35% to gas and 35% to biochar (Sohi et al. 2009). These percentages vary depending on the reactor temperature and residence time. Increasing the reactor temperature from 350°C to 700°C decreases the charcoal yield from 35% to 20% (Ryu et al. 2007). As the yield of charcoal drops at higher temperatures, the weight percentage of carbon in the biochar increases as more volatiles are driven off (Ronsse et al. 2013).

Depending on the end use of the charcoal and whether it is to be used as an energy pellet or in agricultural applications, the pyrolysis systems are designed and operated differently. For a system designed for producing both charcoal and heat, a slow pyrolysis system is used where the bio-oil and gas generated are used as fuels for thermal applications.

6.3.1 Biochar

Biochar has been used in agricultural applications where it is used as a soil enhancer to improve crop yield (Lehmann 2007). Much research has gone into biochar where it has been shown to improve water retention, plant nutrient uptake, and lower soil bulk density all of which have resulted in increased crop yield (Laird 2008). Biochar has also been used to reclaim soils following mining activities, cleanup tailings ponds and other soils heavily impacted by industrial activity (Fellet et al. 2011). For example, when open pit mines are constructed, the biomass material that is removed could be converted to charcoal for use in soil reclamation or water filtration on site. Biochar is also claimed to be a form of long-term carbon sequestration, as the carbon in biochar is resistant to degradation (Gurwick et al. 2013, Roberts et al. 2010, Crombie et al. 2013). There are also discussions in publications about the role biochar could play in carbon-negative bioenergy production (Kauffman et al. 2014). This is due to the highly stable carbon that remains in the soil when biochar is used in agriculture.

The availability of biochar is currently limited to small quantities from various pilot plants working to commercialize their technology. The market is new and a full acceptance and understanding of the pros and cons are still in the early stages. A local study showed that biochar addition could enhance soil properties and the early growth of pine and alder in some sub-boreal forest soils (Robertson et al. 2012). However, more research is required to be able to fully quantify the benefits and opportunities as not only are soil conditions highly variable, so too are the properties of biochar. Biochar research is summarized in Lehmann (2007). A recent review highlights the uncertainty about how biochar production and application affect whole-system greenhouse gas budgets (Gurwick et al. 2013).

6.3.2 Activated Carbon

There is also growing interest in the use of charcoal to produce activated carbon for water and air filtration. Activated carbon is a form of charcoal that has undergone further processing, or activation, resulting in a material that has a very high surface area (Mohan and Pittman 2006). Currently, activated carbon is produced from a variety of sources including wood, coconut shells, wheat straw (Schroder et al. 2007) and petroleum coke (Kawano et al. 2008). Activated carbon can be produced economically from biomass which is favorable over coal based products due to the growing interest in organic farming utilizing renewable materials.

Using activated carbon for flue gas cleanup and mercury removal in a coal fired power plant is a common practice (Yang et al. 2007). With the growing awareness of oil sand development impacts, activated carbon could also be used for contaminated water cleanup. Activated carbon is a very large industry and one would expect it to grow given the sensitivities around air emissions from industry, waste water cleanup and the production of clean drinking water.

6.3.3 Fuel Flexibility

Pyrolysis systems are not limited to using wood waste as a fuel; any source of biomass can be broken down with pyrolysis. Agriculture waste products, bio-solids and other organics can all be utilized therefore taking a waste product that would have otherwise been composted or landfilled and using it to generate heat and biochar. There is great potential for such a conversion technology due to the fact that there is a significant supply of fuels that are currently being disposed of at a cost. This includes all organic material that is currently ending up in landfills, which are costly to operate and have significant environmental impacts.

6.3.4 Carbon Offset Potential

Generating renewable heat from a pyrolysis based system could offset natural gas in the same manner as other technologies, but producing biochar for agricultural use can reduce greenhouse gas emissions (Gurwick et al. 2013, Roberts et al. 2010, Crombie et al. 2013). The reason is that while the flue gases and tars produced from the pyrolysis system can be used for heat and/or power generation, biochar, which has a high carbon content, can be considered a form of carbon sequestration when applied to soils. Efforts are underway to develop a carbon offset methodology through an organization comprised of: The Climate Trust, The Prasino Group, the International Biochar Initiative and Carbon Consulting (www.biochar-international.org). This is being submitted to the American Carbon Registry (ACR), which is a voluntary carbon market offset program. The protocol centers on developing an accepted scientific test to quantify biochar stability in soils so as to verify the lifespan of the carbon when mixed in soils. Once the carbon offset protocol is in place, it would be expected that the market for biochar will improve as there would then be a process to verify the benefits and quantify the carbon credits.

The methane that is produced when organics breakdown in a landfill has a global warming potential 21 times that of carbon dioxide (BC Ministry of Environment, 2012). Biochar is high in carbon which does not leach out in the soil; rather it remains in the soil as demonstrated in the Amazon where biochar has remained in the soil for thousands of years (Lehmann 2007). This persistence in the soil can therefore be viewed as avoided methane and carbon dioxide generation.

A pyrolysis system which produced a clean source of heat could offset natural gas plus the biochar could sequester carbon when used in agriculture applications. Approximately 50% of the carbon contained in the biomass remains in the biochar as compared to biomass combustion

which releases all but around 3% in the form of carbon dioxide (McHenry 2009). Conservatively, 80% of the carbon in biochar (40% of the carbon in the original biomass) is predicted to be stable over very long (100's of years) time periods (Roberts et al. 2010, Crombie et al. 2013).

6.3.5 Torrefaction

A low temperature pyrolysis system that is gaining interest in the wood pellet industry is torrefaction, which produces an energy pellet with improved properties. At a temperature of between 250°C and 300°C, hemicellulose decomposes leaving the remaining cellulose and lignin which can then form a pellet with water resistance and a higher energy density (Prins 2006). One of the major challenges that the wood pellet industry faces is the lack of water resistance. Wood pellets are transported in bulk and their lack of water resistance results in the need for higher transportation and storage cost. Torrefied pellets have water resistance due to the fact that when heated, hydroxyl groups are destroyed in the biomass by dehydration reactions resulting in the inability to form hydrogen bonds with water (Usla et al. 2008). In addition, the low temperature pyrolysis process results in approximately 30% weight loss so more biomass is required per tonne of final product. The higher energy density comes from the fact that 70% of the initial mass remains with 90% of the energy (Dutta and Leon 2011, Wannapeera et al. 2011, Yan et al. 2009).

The required heat for the torrefaction process is provided by either combusting waste wood or by combusting a combination of natural gas and the volatiles released during the process (UBC Biomass Pelletization Workshop, 2011). This is an area of product development which requires further research and will greatly impact the overall mass and energy balance of the system. In a high temperature pyrolysis system, there is enough energy contained within the volatiles driven

off to combust and provide all the necessary heat for the system to operate without the need for natural gas (other than a pilot) (Lee et al. 2010). Torrefaction on the other hand, only drives off a portion of the volatiles so additional heat sources are required to keep the system operating. Fuels with moisture contents greater that 15-20% would require a separate dryer heated with another fuel due to the limited volatiles available as a heat source (Kiel et al. 2008).

The target market for torrefied wood pellets is the export market; predominantly Europe. There is a transportation advantage due to the higher energy density, plus water resistance (Uslu et al. 2008). Although torrefied pellets are not available yet on a large commercial scale, pricing is expected to be higher than wood pellets due to the added processing costs (Uslu et al. 2008).

There have been a number of projects announced for the construction of a commercial scale torrefied wood pellet plant, but none appear to be in full operation. One such company which has made headlines in the Canadian Biomass Magazine in early 2014 is Zilkha Biomass Energy which has announced a 275,000 tonne per year torrefied pellet plant for Selma, Alabama scheduled to be completed in 2015 (Canadian Biomass Magazine online article).

7.0 Available Biomass Supplies in BC

Biomass supplies cannot be considered an unlimited source of fuel. This section is a brief review of available biomass supplies in BC.

British Columbia's forest industry generates significant volume of biomass that is utilized in the pulp and paper industry and numerous industrial and commercial energy systems. But forestry residuals are not the only source of biomass in the province. Table 7.0 breaks down the available biomass supplies and the percent of fossil fuel energy that it could displace. Harvesting sustainably as well as mountain pine beetle timber that no longer has value as saw logs or pulp

wood could displace half of the fossil fuels consumed in the province. The mountain pine beetle timber was forecasted to be available for 20 years from 2006 when the data in Table 7.0 was published. This does not assume that all the pine beetle timber would be economical to harvest so the total economically available pine beetle timber is likely less. The sustainable forestry estimates are net of timber processed into lumber and other solid wood products. A detailed analysis on the availability of mountain pine beetle timber is outside the scope of this report.

 Table 7.0 – Sources of Biomass in British Columbia and Bioenergy Potential as a Percentage of Total Fossil

 Fuel Demand. (2006 data).

	Tonnes/year	PJ/yr	% of Potential	% of Fossil Fuel Epergy
Municipal Solid				Direigy
Waste	948,450	15.2	2.9	1.6
Sustainable				
Agriculture	3,266,505	52.1	10.1	5.7
Sustainable Forestry	17,114,615	273.8	52.9	29.8
Mountain Pine Beetle	11,014,618	176.2	34.1	19.2
Total	32,344,188	517.4	100	56.2
Total Fossil Fuel				
Demand		920		

(Reproduced from the British Columbia Bioenergy Network: An Information Guide on Pursuing Biomass Energy Opportunities and Technologies in British Columbia. August 2010)

Mountain pine beetle biomass is not be sustainable over the long term, and may not be economical over the short term. This leaves over 10 million tonnes of forestry biomass per year available for bioenergy. The sustainable forestry category in Table 7.0 includes 11.9 million tonnes of annual harvest residues, based on the assumption that 70% of forestry residues (17.1 million tonnes/year) can be harvested sustainably. Dymond et al. (2010) estimate sustainable residues at 8 million tonnes per year (50% of the 15.5 million tonnes total clearcut residues). Kumarappan et al. (2009) estimate 8.7 million tonnes of forest residues and 8.4 million tonnes of mill residues available at a cost of less than \$100/tonne. The forest industry including pulp and paper are large consumers of biomass and are significant producers of bioenergy using residuals from their operations. But there are large untapped sources available such as municipal solid waste and agricultural residuals. While they may not make up a large portion of the province's inventory of biomass, they are readily available and are suitable for smaller renewable energy systems. Such biomass supplies are often suitable for universities and commercial operations which have much smaller energy needs than that of a pulp mill. In addition, smaller bioenergy systems generally cannot compete for forestry residuals as they are tied up in contracts with the pulp and paper mills.

8.0 Greenhouse Gas Life-Cycle Emissions

The greenhouse gas intensity of biomass energy is highly dependent on a number of variables such as transportation distances, harvesting methods, and processing requirements. In terms of which bioenergy option has the lowest greenhouse gas life-cycle cost, it would likely involve locally sourced biomass with the least amount of processing (when comparing to the same fossil fuel displaced). In other words hog fuel would have a lower life-cycle cost than wood pellets sourced from the same area due to the energy required to produce wood pellets. Due to the lower moisture content wood pellets have the advantage when long transportation distances are required (Uslu et al. 2008). Locally sourced biomass is generally preferable when simply looking at fuel costs. This may change in the future depending on biomass availability, fossil fuel prices, financial incentives and a greater adoption of renewable technologies.

8.1 Displacement Factor Calculation

A common method to compare bioenergy systems is through the use of displacement factors. The displacement factor is the amount of fossil fuel emissions that is directly offset by replacing the fossil fuel with biomass (Schlamadinger and Marland 1996). Displacement factor units are typically kg CO₂ per tonne of biomass (Laser at al. 2009).

A number of formulas can be used to calculate the displacement factor, depending on the data available. The formula used in this study is based on the one presented in Laser et al. (2009) (equation 3). This formula was chosen as it uses variables for which data was either available or could be calculated.

$$DF = (X1) x (X2) x (X3) - X4$$
(3)

X1 = fossil fuel carbon intensity (kg CO₂/GJ displaced)

X2 = bioenergy efficiency / fossil fuel efficiency – processing losses (GJ displaced/GJ biomass)
 X3 = biomass energy density (GJ biomass/tonne dry biomass)

 $X4 = transportation emissions (kgCO_2/tonne dry biomass)$

Displacement factors are used in carbon balance models. For example, they have been used to compare carbon sequestration in forests vs using short rotation forestry to grow biomass for bioenergy and coal displacement (Barala and Guhab 2004, Schlamadinger and Marland 1996, Yemshanov and McKenney 2008). These studies used displacement factors of 1,330, 1,100, and 1,750 kg fossil fuel CO₂ displaced per tonne of biomass for coal displacement. The large variability is due to different assumptions on bioenergy and fossil fuel efficiencies. The larger number is based on the assumption that bioenergy use compared to carbon sequestration in forests (Marland and Schlamadinger 1997). For liquid fuel production, displacement factors range from 970 to 1,260 kg fossil fuel CO₂ displaced per tonne of biomass (Laser et al. 2009). These displacement factors are not appropriate for use in BC due to the low carbon electricity generation and limited coal use.

8.2 Carbon Neutrality of Biomass

Comparing the full life-cycle assessments of biomass based renewable energy to fossil fuels has undergone much debate recently. The US Environmental Protection Agency (EPA) is currently reviewing regulations surrounding the carbon neutrality of biomass and biogenic emissions accounting (US Environmental Protection Agency 2014). Different life-cycle assessment methodologies do not always have the same results, and as such there is debate as to the appropriate regulations to use for biomass energy (Sedjo 2013). The debate in the US centers around the point that there are CO₂ emissions at a biomass energy plant in the same manner as there would be in an energy system based on fossil fuels. In addition, land use changes may result in large carbon emissions over the short and medium term (Johnson 2009). The key is that over the longer term, the CO₂ emissions are considered neutral as long as the biomass consumed is regrown so as to complete the carbon cycle. While there is controversy over the carbon neutrality of many biomass sources, wood waste that would have decomposed or somehow returned its carbon to the atmosphere anyway is usually considered carbon neutral (Johnson 2009). Differing opinions on the full life-cycle emissions for biomass have created confusion and, as a result, one must use existing life-cycle assessment tools with caution.

At the United Nations Climate Change Conference in Durban South Africa in 2011 (BC Ministry of Environment, June 2012), new rules were agreed upon for carbon accounting in forestry. Key updates include the point that wood used for bioenergy would be accounted for as an immediate release of greenhouse gas, and forests that have been negatively impacted by outbreaks such as the pine beetle or wild fires will not negatively impact carbon accounting (BC Ministry of Environment 2012). It is expected that these updates from the United Nations will be

incorporated into revised greenhouse gas reporting in all reporting countries, and will help to clarify the questions around carbon accounting in bioenergy.

8.3 Fossil Fuel Carbon Intensity

The net greenhouse gas life-cycle cost savings when using biomass are dependent on the fossil fuel displaced. Displacing coal with biomass for example will displace more greenhouse gas than displacing natural gas due to the higher carbon content of coal. The carbon intensity for coal is 69 kg CO₂ per GJ compared to 50 for natural gas (Table 8.2). Electricity supply in British Columbia is primarily hydroelectricity which has a low carbon intensity of 6.9 kg CO₂ per GJ (Table 8.2). The carbon intensity of electricity generation does vary year to year depending on the mix of generation plants in use. The range is 2.5 to 10 kg CO₂ per GJ (Environment Canada 2014). The breakdown of electricity generation by category in British Columbia for the periods 2007 through to 2010 is shown in Table 8.0.

Table 8.0 – Electricity Generation in British Columbia by Category from 2007 to 2010	•
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	Ele	ectricity Gene	ration (GWh	/yr)
	2007	2008	2009	2010
Refined Petroleum Products	70	70	100	80
Natural Gas	2,660	3,080	2,610	2,430
Hydro	54,700	48,600	46,300	44,400
Biomass	670	560	400	630
Total	58,100	52,310	49,410	47,540

(Reproduced from the British Columbia Greenhouse Gas Inventory Report 2010)

8.4 Bioenergy Efficiencies

A report by Envirochem Services Inc. determined the electricity generation potential per bonne dry tonne (BDT) of wood chips at 50% moisture content. A selection of the conversion technologies is provided below in Table 8.1 (Tampier et al. 2004).

				Small Steam
	Large Steam	Bio-Oil	Gasification	Condensing
	Condensing Cycle	Conversion	Conversion	Cycle
kWh/BDT wood	1,659	363	440	563
Efficiency (wood to electricity)	30%	6.5%	7.9%	10%

 Table 8.1 – Electricity Generation Potential of Wood Chips (Reproduced from Table 2.4.6 Tampier et al. 2004).

The large steam condensing cycle has the greatest specific electricity generation per bone dry tonne (BDT) of wood chips due to economies of scale and the high efficiency of steam turbines. This refers to larger biomass boilers combined with a condensing steam turbine and commonly found in a pulp mill. They are only economical on a large scale so are not suitable for smaller commercial operations. The bio-oil conversion has the potential to produce the least amount of electricity due to the fact that only a percentage of the biomass ends up as oil (Singh et al. 2010). This is reflected in the efficiency of 6.5% (Table 8.1). The balance of energy in a bio-oil conversion process is made up of volatiles and a small percentage of charcoal. The value for both the gasification conversion and the small steam condensing cycle assumes all the heat generated is utilized for power generation (Tampier et al. 2004).

The emissions for wood pellets include 16.2 kg CO_{2e} for drying and 7.9 kg CO_{2e} for processing per tonne of pellets produced (Murray 2013, Bradley 2006). Burning wood pellets is more efficient than burning wet biomass, especially if there is no flue gas condensing heat exchanger. Production of wood pellets typically consumes 10 - 15% of the total biomass supply to dry the incoming biomass (Magelli et al. 2009). This results in a 15% processing loss in the production of wood pellets and torrefied wood pellets (Table 8.2).

Other bioenergy options such as the production of liquid fuels (bio-oil, gasoline, and diesel) and biochar do not require external energy sources for production (except for transportation). A

portion of the energy contained in the wood is used to power the process. For liquid fuels (gasoline and diesel), 35 - 50% of the original energy from the biomass remains in the final product (Singh et al. 2010). For bio-oil, 65 - 70% of the original energy remains in the final product (Singh et al. 2010). During the production of biochar, 30 - 55% of the original biomass energy remains in the final product (Matovic 2010, Weifu et al. 2010, Roberts et al. 2010). For all of these options, there can be some excess energy that could be used for heating or electricity generation.

8.5 Comparison of Displacement Factors Including UNBC's Bioenergy Systems

An analysis was carried out to compare the life-cycle greenhouse gas displacement potential for a selection of bioenergy options as compared to the existing gasifier. Displacement Factors were calculated using fossil fuel emission factors (8.3) and bioenergy system efficiencies (8.4). Details are outlined in Table 8.2. UNBC's bioenergy plant can be compared to alternative technologies in terms of CO₂ displacement. The existing bioenergy plant, referred to as the base case in Table 8.2, displaces 782 kg CO₂ per tonne of hog fuel consumed. This can be increased to 882 kg CO₂ with the addition of a flue gas condensing heat exchanger. The addition of a chiller to the gasifier water loop only increases the CO₂ displaced by 3.5 kg due to the fact that it displacing hydroelectricity which already has a low greenhouse gas intensity.

Table 8.2 - Calculated CO₂ Displacement Factors

							Energy Density	Processing	
				Ratio of			of biomass input	& Transport	Displacement
			Efficiency of	efficiency (GJ		Net GJ	(GJ	for Export	Factor (kg
	kg CO2/GJ	Conversion	existing	displaced/GJ	Processing	displaced/GJ	biomass/tonne	(kg	CO2/tonne
Control	Displaced	Efficiency	sytem	biomass)	Losses (%)	biomass	biomass)	CO2/tonne)	biomass)
Base Case (notice) and displacement) ^a	40.0	900/	P/08/	1008/		1009/	16	16.0	703
Base Case (natural gas displacement)	49.9	80%	80%	100%		100%	16	16.0	/82
Flue Gas Cond. Heat Exchanger (nat. gas displacement)	49,9	90%	80%	113%		113%	16	16.0	882
Chiller (hydro electricity displacement)	6.9	50%							3.5
Wood Pellets (natural gas displacement) ^{a,o}	49.9	90%	70%	129%	15%	109%	18	51.7	930
Liquid biofuel (gasoline & diesel displacement) a,c,d	66.8					50%	18	16.0	585
Slow Pyrolysis A									1108
Heat (natural gas displacement) ^{a,b,c}	49.9					45%	18	17.1	404
Biochar for soils (carbon capture) b,c,f	97.8					40%	18	16.5	704
Slow Pyrolysis B									959
Heat (natural gas displacement) ^{a.b.e}	49.9					15%	18	5.7	135
Biochar pellets for export (coal displacement) b.c.g	69					70%	18	45.2	824
Fast Pyrolysis Plant								+	885
Bio-oil (natural gas displacement) ^{a,b,c}	49.9					75%	18	17.1	674
Biochar for soils (carbon capture) b.e.f	97.8					12%	18	16.5	211
Biomass Cogeneration									422
Heat (natural gas displacement) ^{a,b}	49.9					50%	16	16.0	399
Electricity (hydro electricity displacement) ^{a,b}	6.9					35%	16	16.0	23
Pellets for Export (coal displacement) b,g	69			85%	15%	72%	18	81.3	816
Torrefied Pellets for Export (coal displacement) b,g	69			100%	15%	85%	18	81.3	974

a - British Columbia Ministry of Environment, 2012 BC Best Practices Methodology for Quantifying Greenhouse Gas Emissions. September 2012

b - Bradley D. GHG Impacts of Pellet Production from Woody Biomass Sources in BC, Canada. Climate Change Solutions. May 24, 2006

c - Van Vliet O.P.R., et al. Fischer-Tropsch diesel production in a well-to-wheel perspective: A carbon, energy flow and cost analysis. Energy Conversion and Management 50 (2009) 855-876

d - Piekarczyk W., Czarnowska L., Ptasinski K., and Stanek W. Thermodynamic evaluation of biomass-to-biofuels production systems. Energy 62 (2013) 95-194

e - Discussions with Phil Marsh, Chief Technology Officer, BC Biocarbon

f - Assume charcol is 80% fixed carbon, 44 kg CO_2/12 kg C, & 30 GJ/tonne

g - Environment Canada, National Inventory Report Greenhouse Gases Sources and Sinks Part 2. The Canadian Government Submission to the UN Framework Convention on Climate Change All units in lower heating value (LHV)



Figure 8.0 – Ranking of Displacement Factors for Bioenergy Systems.

The displacement factors from Table 8.2 were ranked in order in Figure 8.0 and it can be observed that the system with the potential to displace the greatest amount of greenhouse gases is the slow pyrolysis system producing heat and biochar for soils. This system could offset 404 kg CO_2 for heating and 704 kg CO_2 when the biochar is utilized as a soil amendment for a total of 1,108 kg CO_2 /tonne biomass. The biochar component is based on 80% of the biochar's mass being stable carbon which remains in the soil, with an energy density of 30 GJ/tonne and converting the carbon to CO_2 (Usla et al. 2008). If a slow pyrolysis system had been designed in place of the existing UNBC gasification plant, more biomass would have been consumed to output the same heating load because only bio-oil (30%) and gas (35%) would have been available for heating. Therefore, 35% more biomass would have to be purchased in order to meet the same heating demands of the campus. The biochar produced could have become a by-product for sale and/or used for research activities such as in greenhouses or field trials on or off campus, potentially offsetting the additional cost of hog fuel.

The next two highest ranked systems are the slow pyrolysis heat and biochar energy pellet combined system, and torrefied pellet for export for coal displacement. These rank high due to the component of coal that is offset, despite the transportation penalty when shipping pellets to Europe. The impact of the transportation is 81.3 kg CO_2 per tonne of biomass which is significant, but overall there is still a net reduction when comparing to coal (Bradley 2006). The greatest displacement factor would be if wood pellets were used domestically to displace coal (e.g. in Alberta) as the impact of the transportation would be greatly reduced.

Wood pellet boilers like the one installed in UNBC's Enhanced Forestry lab (EFL), are higher in efficiency when compared to a biomass gasifier and as such they have a higher displacement factor. The displacement was calculated to be 930 kg CO₂/tonne biomass as compared to 782 kg CO₂/tonne biomass for the gasifier. The wood pellet boiler conversion efficiency is higher than that of the gasifier plus it is displacing a less efficient natural gas system. The old natural gas boiler in the EFL only has an efficiency of 70% compared to 80% for the main campus natural gas boilers (Table 8.2).

The system with the lowest displacement factor is a biomass based power plant displacing hydroelectricity, which makes sense given the low displacement factor for hydroelectricity. A liquid biofuel displacement factor was calculated to be 585 kg CO₂/tonne biomass which is lower than literature values (Laser et al. 2009). A significant by-product of liquid biofuel production is electricity. The British Columbia electricity emissions intensity is only 6.9 kg CO₂/GJ of electricity versus the literature value of 180 kg CO₂/GJ of electricity (Laser et al. 2009).

UNBC uses approximately 4,300 tonnes of hog fuel per year, based on the average hourly consumption from Table 1.0 of 495 kg/hr and assuming 365 days of operation per year. Using this annual consumption estimate, the total greenhouse gas offset potential for selected options are outlined in Table 8.3.

Table 8.3 - Total Annual Greenhouse Gas Displacement Potential.

	Tonnes CO ₂
Gasifier Base Case	3,364
Gasifier with Flue Gas Condenser	3,794
Pellets for Export	3,509
Torrefied Pellets for Export	4,188
Slow Pyrolysis Heat & Biochar for Soils	4,765

At 3,364 tonnes of CO_2 displaced annually, UNBC's gasifier demonstrates a viable option for reducing greenhouse gas emissions. As newer technologies mature, other options may become an attractive alternative for projects with a similar scope.

8.6 Bioenergy Potential in British Columbia

Using a conservative estimate of 10 million tonnes of biomass available each year (7.0), the GHG offset potential was calculated for four bioenergy options (Table 8.4). This analysis does not include pine beetle timber.

	Conversion Efficiency	Energy / Year (PJ)	Displacement Factor (kg CO ₂ /tonne biomass)	GHG Offset Potential (tonnes CO ₂ /year)
Electricity	30%	54	23	230,000
Liquid Fuels	50%	90	585	5,850,000
Heat	80%	144	880	8,800,000
Biochar	45%	81	1108	11,080,000

 Table 8.4 – Greenhouse Gas Offset and Bioenergy Potential in British Columbia by Available Biomass

 Supplies.

Based on the total electrical demand in 2010 of 170 PJ/year (Table 8.0 where 1 GWh = 3.6×10^{-3} PJ) biomass based electricity generation could supply 32% of the provinces electricity. Based on the total liquid fuels demand of 460 PJ/year (NRCan 2014) biomass based liquid fuels could supply 20% of the provinces liquid fuel demand. Based on the total natural gas demand of 260 PJ/year (NRCan 2014), biomass could supply 56% of the provinces heating demand. This assumes natural gas is primarily used for heating. The largest GHG offset potential could come from the combined slow pyrolysis for heat and biochar which could offset 11 million tonnes of CO₂ through combined carbon storage in biochar and natural gas displacement. This represents 18% of BC's 62 million tonnes of GHG emissions (British Columbia Greenhouse Gas Inventory Report 2010).

9.0 Conclusion

The analysis of UNBC's bioenergy plant has revealed that at an average output of 6.9 GJ/hr and a thermal efficiency of 80% (LHV), the system displaces 3,364 tonnes of CO_2 through displacing the use of natural gas.

Options to improve the efficiency were explored and it was determined that the most viable opportunity would be to install a flue gas condensing heat exchanger and extract more residual heat. By connecting the student residences to a new hot water loop, a greater percentage of the gasifier's output would be utilized. It is estimated that an efficiency improvement of 8.5% to 18.5% could be possible with the use of a flue gas condensing heat exchanger. This would increase the CO_2 displaced to 3,794 tonnes. An additional system worth exploring is the addition of a chiller which would enable the gasifier to meet the cooling demand of the campus. This would allow the gasifier to operate at or near capacity all year meeting the heating demand

during the winter and cooling demand during the summer. The chiller would have a negligible impact to CO₂ displacement.

The installation of a dryer or thermal storage system could increase the gasifier utilization by approximately 5%. The more significant issue is the variable output of the gasifier. This should be addressed first before the dryer and thermal storage option can be fully evaluated. If the gasifier could operate at a steady output, there is the potential for the bioenergy system to meet 94% of the campus heating demand, as opposed to the current 85%.

A review of alternative renewable technologies and their potential for greenhouse gas displacement showed that slow pyrolysis systems with combined heat and biochar output have the greatest offset potential. Wood pellets exported to Europe also have a high displacement factor due to the fact that they are used to offset coal. In BC, for bioenergy to play the largest role in reducing GHG emissions, natural gas displacement is the best option with current renewable technologies. The UNBC system is a good example of current technologies displacing natural gas. As pyrolysis and biochar technologies mature, greater GHG offset potential will emerge. Using available forestry residuals, up to 18% of the provinces GHG emissions could be offset.

Future work into the performance of the bioenergy plant should focus on the following: Establish the reason for the high variation in the gasifier output and the spikes in the natural gas boiler output (Figures 2.1, 2.2 and Appendix D), then develop a more effective control strategy to balance the output from the bioenergy plant to the campus demand.

Appendix A

Note: all calculations represented in appendix A assume a final flue gas temperature of 40°C and a hog fuel moisture content of 40%

Fuel MC % vs. Boiler Output (MW)	0%	10%	20%	30%	40%	50%
0.83	11.5%	13.8%	16.7%	20.3%	25.2%	32.1%
1.11	10.1%	12.1%	14.6%	17.8%	22.1%	28.1%
1.39	9.3%	11.2%	13.5%	16.5%	20.4%	26.0%
1.67	8.9%	10.6%	12.8%	15.7%	19.5%	24.8%
1.94	8.6%	10.3%	12.5%	15.2%	18.9%	24.1%
2.22	8.5%	10.2%	12.3%	15.0%	18.6%	23.7%
2.50	8.4%	10.1%	12.2%	14.9%	18.5%	23.6%
2.78	8.5%	10.1%	12.2%	14.9%	18.5%	23.6%
3.06	8.5%	10.2%	12.3%	15.0%	18.6%	23.7%
3.33	8.6%	10.3%	12.4%	15.2%	18.8%	23.9%
3.61	8.7%	10.4%	12.6%	15.3%	19.0%	24.2%

 Table A1 – Data Table for Figure 3.3. Latent Heat Loss % as a Function of Fuel MC% and Boiler Output (MW).

Latent heat loss (%) =
$$\frac{m_{H_20,out}}{1,000} \frac{\Delta H_{latent}}{Q_{delivered}} 100$$
 (4)

Table A2 - Hog Fuel Properties.

Fuel properties	Dry wt%	HHV _{td}	20.27	GJ/tonne
X _c	49.3%	latent heat of steam	2.26	GJ/t
Х _н	6.2%			
Xs	0.0%			
Xo	40.2%	T ref	298	К
X _N	0.0%	R	8314.32	J/kmol K
X _{ash}	4.3%	P _{FG}	1	atm

Molecular weights (g/mol)					
Mc	12.0112				
M _H	1.0080				
M _{H2}	2.0159				
Ms	32.0640				
M _{co2}	44.0100				
M _{H2O}	18.0153				
M _{soz}	64.0628				
M _{o2}	31.9988				
M _{N2}	28.0134				
M _{H20} /M _{H2}	8.9364				

Empirical biomass, air and flue gas temperature correlations:

Based on operating data, empirical relationships were developed for biomass input, air input, and flue gas temperature for a range of gasifier operating conditions.

Gasifier Data Points:

Data used for calculations are indicated in the following figure:



The fresh air flow rate ($m_{\mbox{\scriptsize Fresh}}$) and the recirculation air flow rate ($m_{\mbox{\scriptsize Recirc}}$) are unkown.

Figure A1 – Diagram Illustrating Data Points.

Unit conversions from the supplied data to metric units used Microsoft Excel Convert function.

Air flow calculations

The incoming fresh air flow rate is unknown, but can be found using an energy balance on the gasifier air, recirculation air and fresh air:

$$m_{Gas} c_P (T_{Gas} - T_{REF}) = m_{Fresh} c_P (T_{Fresh} - T_{REF}) + m_{Recirc} c_P (T_{Recirc} - T_{REF})$$
(5)

If T_{REF} is taken as 0, and C_P is assumed to be constant, then:

$$m_{Gas} c_P T_{Gas} = m_{Fresh} c_P T_{Fresh} + m_{Recirc} c_P T_{Recirc}$$
(6)

Also, assuming constant density:

$$m_{Gas} = m_{Fresh} + m_{Recirc} \tag{7}$$

Combining, and solving for Q_F:

$$m_{Fresh} = \frac{m_{Gas}T_{Recirc} - m_{Gas}T_{Gas}}{T_{Recirc} - T_{Fresh}}$$
(8)

Total air flow into gasifier/oxidizer system:

$$m_{air,in} = m_{Fresh} + m_{Oxid} \tag{9}$$

The uncertainty in the fresh air calculation is large, however the fresh air flow rate is small compared to the oxidizer air flow rate (fresh air flow is 2 to 5% of oxidizer flow).

Biomass calibration

Biomass feed is measured with the feed auger, given as % of maximum auger rotation speed. The maximum auger rotation speed is 210 rotations/hour. The volume of biomass moved per rotation depends on moisture content, but is approximately 1630 kg/hour at maximum rotation speed according to data supplied by Nexterra. Cumulative hog fuel deliveries were compared with cumulative GJ delivered and cumulative auger rotations. From this data a value of 8.94 kg hog fuel/rotation was determined. Also, shown by the data is the close correlation between heat out and auger rotations and hog fuel deliveries.

$$hog fuel\left(\frac{kg}{hour}\right) = 8.94 \times \frac{auger \, rotations}{hour} \tag{10}$$



Figure A2 - Correlation between Heat Output, tonnes of Biomass Delivered and Auger Rotations.

Empirical Relationships

Using data collected at 15 minute intervals from the gasifier, JMP 8 was used to develop empirical relationships between hog fuel consumed and heat output, between total air input and hog fuel consumed, and between flue gas temperature and heat output. The empirical relationships are:

$$m_{biomass,in} \left[\frac{kg}{hour} \right] = \left(12.42 + 1.35 \, Q_{delivered} \left[\frac{GJ}{hour} \right] \right)^2 \tag{11}$$

$$m_{air,in} \left[\frac{kg}{hour} \right] = 560.9 + 7.16 \, m_{biomass,in} \left[\frac{kg}{hour} \right] \tag{12}$$

$$T_{Flue} [°C] = 92.9 + 6.18 Q_{delivered} \left[\frac{GJ}{hour}\right]$$
(13)

The following tables represent the output from the JMP 8 Analysis:

	· ·	[!	ſ '	['	· · ·		Г <u></u> ,	Air-to-
	1 '	Biomass input	1 '	!	1	1	/	Biomass (kg
Heat output	Heat output	(kg dry	Air input	Flue gas T	Flue gas T	Thermal	Thermal Yield	air/kg dry
(GJ/hour)	(MW)	fuel/hour)	(kg/hour)	(°C)	<u>(K)</u>	Yield (GJ/t)	HHV (GJ/GJ)	fuel)
Q _{delivered}	Q _{delivered}	m _{biomass,in}	m _{air,in}	T_{flue}	T _{flue}	Y _{biomass}	Y _{HHV}	X _{air/biomass}
3	0.83	273.57	2517.09	111.43	384.58	10.97	0.54	9.20
4	1.11	319.52	2845.51	117.61	390.76	12.52	. 0.62	8.91
5	1.39	369.03	3199.40	123.78	396.93	13.55	0.67	8.67
6	1.67	422.11	3578.78	129.96	403.11	14.21	0.70	8.48
7	1.94	478.75	3983.64	136.14	409.29	14.62	. 0.72	8.32
8	2.22	538.96	4413.98	142.32	415.47	14.84	0.73	8.19
9	2.50	602.74	4869.81	148.50	421.65	14.93	0.74	8.08
10	2.78	670.08	5351.11	154.68	427.83	14.92	0.74	7.99
11	3.06	740.98	5857.90	160.86	434.01	14.85	0.73	7.91
12	3.33	815.45	6390.16	167.04	440.19	14.72	. 0.73	7.84
13	3.61	893.49	6947.91	173.22	446.37	14.55	0.72	7.78

 Table A3 – Combustion Calculations and Empirical Correlations.






Heat output unit conversion:

$$Q_{delivered}[MW] = \frac{Q_{delivered}[G]/hour]}{3.6}$$
(14)

The gasifier output range is approximately 3 to 13 GJ/hour (0.8 to 3.6 MW). All of the following calculations were over this range of gasifier output.

Biomass input [kg/hour] as a function of gasifier heat output [GJ/hour]:

$$m_{biomass,in} = (12.534555 + 1.3351295 \, Q_{delivered})^2 \tag{15}$$

Air input [kg/hour] as a function of biomass input [kg/hour]:

$$m_{biomass,in} = 561.76649 + 7.1474496 \, m_{biomass,in} \tag{16}$$

Flue gas temperature [°C] as a function of gasifier heat output [GJ/hour]:

$$T_{flue} = 92.890192 + 6.178879 \, Q_{delivered} \tag{17}$$

Flue gas temperature conversion:

$$T_{flue}[K] = T_{flue}[^{\circ}C] + 273.15$$
(18)

Bioenergy system yield [GJ heat delivered per tonne biomass]

$$Y_{biomass} = \frac{Q_{delivered}}{m_{biomass,in}} 1,000 \tag{19}$$

Bioenergy system yield [GJ heat delivered per GJ biomass [HHV]]

$$Y_{HHV} = \frac{Y_{biomass}}{HHV}$$
(20)

The bioenergy system yield decreases at low gasifier output as illustrated below:



Figure A3 – Relationship between Heat Output and Bioenergy System Yield.

Air to biomass ratio:

$$x_{air/biomass} = \frac{m_{air,in}}{m_{biomass,in}}$$
(21)

This is the ratio of total air input to total biomass input.

Table A4 on the following page has the results of the gasifier mass and energy balances

Table A4 - Gasifier Mass & Energy Balances.

Heat output (GJ/hour)	Cin (kg/hour)	Hin (kg/hour)	Oin (kg/hour)	Nin (kg/hour)	ash in (kg/hour)	CO2 out (kg/hour)	total H2O out (kg/hour)	O2 out (kg/hour)	N2 out (kg/hour)	ash out (kg/hour)	O ₂ in flue gas (%)	H ₂ O in flue gas (%)	stoichiometric air (kg/hour)	excess air ratio
Qdelivered	m _{C,in}	m _{H,in}	m _{O,in}	m _{N,in}	m _{ash,in}	m _{CO2,out}	m _{H2O.out}	m _{02,out}	m _{N2,out}	m _{ash,out}	Y _{O2}	Y _{H20}	mair.stoich	λ
3	134.9	17.0	693.2	1919.9	11.8	494.5	335.0	197.9	1919.9	11.8	7.19	0.18	1663.05	1.51
4	157.5	19.8	787.8	2170.4	13.7	577.6	391.3	209.3	2170.4	13.7	6.73	0.18	1942.37	1.46
5	181.9	22.9	889.7	2440.4	15.9	667.1	451.9	221.5	2440.4	15.9	6.34	0.19	2243.37	1.43
6	208.1	26.2	999.0	2729.7	18.2	763.0	516.9	234.7	2729.7	18.2	6.00	0.19	2566.04	1.39
7	236.0	29.7	1115.6	3038.6	20.6	865.4	586.3	248.7	3038.6	20.6	5.72	0.19	2910.38	1.37
8	265.7	33.4	1239.5	3366.8	23.2	974.3	660.1	263.6	3366.8	23.2	5.47	0.20	3276.40	1.35
9	297.1	37.4	1370.8	3714.5	25.9	1089.5	738.2	279.4	3714.5	25.9	5.25	0.20	3664.08	1.33
10	330.3	41.5	1509.4	4081.6	28.8	1211.3	820.6	296.1	4081.6	28.8	5.07	0.20	4073.44	1.31
11	365.3	45.9	1655.3	4468.2	31.9	1339.4	907.5	313.6	4468.2	31.9	4.90	0.20	4504.48	1.30
12	402.0	50.6	1808.6	4874.2	35.1	1474.1	998.7	332.1	4874.2	35.1	4.76	0.20	4957.18	1.29
13	440.5	55.4	1969.2	5299.6	38.4	1615.1	1094.2	351.4	5299.6	38.4	4.63	0.20	5431.56	1.28

•

Mass flow of carbon into gasifier [kg/hour]:

$$m_{C,in} = m_{biomass,in} X_C \tag{22}$$

Mass flow of hydrogen into gasifier [kg/hour]:

$$m_{H,in} = m_{biomass,in} X_H \tag{23}$$

Mass flow of oxygen into gasifier [kg/hour]:

$$m_{0,in} = m_{biomass,in} X_0 + 0.21 \ m_{air,in} \frac{M_{0_2}}{M_{air}}$$
(24)

Oxygen input includes the oxygen content of the biomass and oxygen content of the air. Oxygen content of water is not included in the calculation since the water does not react to oxygen.

Mass flow of nitrogen into gasifier [kg/hour]:

$$m_{N,in} = 0.79 \ m_{air,in} \frac{M_{N_2}}{M_{air}} \tag{25}$$

Nitrogen input is from the air (biomass N content is ignored).

Mass flow of ash into gasifier [kg/hour]:

$$m_{ash,in} = m_{biomass,in} X_{ash} \tag{26}$$

Mass flow of CO₂ out of the oxidizer [kg/hour]:

$$m_{CO_2,out} = m_{C,in} \frac{M_{CO_2}}{M_C}$$
(27)

All of the carbon input with the biomass is converted into CO_2 . Carbon content of ash is ignored, as is CO_2 content of input air. If biomass is 5% ash, an this ash has 20% carbon (both high estimates), then carbon lost with the ash is 1%.

Mass flow of H₂O out of the oxidizer [kg/hour]:

$$m_{H_2O,out} = m_{biomass,in} \frac{MC_{wb}}{1 - MC_{wb}} + m_{H,in} \frac{M_{H_2O}}{M_{H_2}}$$
(28)

Water out in the flue gas is equal to the water coming in with the biomass (moisture content) plus the water formed from hydrogen oxidation during combustion.

Mass flow of O₂ out of the oxidizer [kg/hour]:

$$m_{O_2,out} = m_{O,in} - \left(m_{CO_2,out} - m_{C,in}\right) - \left(m_{H,in} \frac{M_{H_2O}}{M_{H_2}} - m_{H,in}\right)$$
(29)

Oxygen out in the flue gas is equal to the oxygen in (oxygen in biomass + oxygen in air), minus the oxygen that is converted into CO_2 , minus the oxygen that is converted into H_2O .

Mass flow of N₂ out of the oxidizer [kg/hour]:

$$m_{N_2,out} = m_{N_2,in} \tag{30}$$

Mass flow of ash out of the gasifier & oxidizer [kg/hour]:

$$m_{ash,out} = m_{ash,in} \tag{31}$$

Mole fraction O₂ in flue gas (dry basis):

$$Y_{O_2} = \frac{\frac{m_{O_2,out}}{M_{O_2}}}{\frac{m_{CO_2,out}}{M_{CO_2}} + \frac{m_{O_2,out}}{M_{O_2}} + \frac{m_{N_2,out}}{M_{N_2}}}$$
(32)

Mole fraction H₂O in flue gas:

$$Y_{H_2O} = \frac{\frac{\frac{m_{H_2O,out}}{M_{H_2O}}}{\frac{m_{CO_2,out}}{M_{CO_2}} + \frac{m_{O_2,out}}{M_{O_2}} + \frac{m_{H_2O,out}}{M_{N_2}}} (33)$$

69

Stoichiometric air requirement [kg/hour]:

$$m_{air,stoich} = m_{biomass,in} \left(\frac{2X_C}{M_C} + \frac{X_H}{2M_H} - \frac{X_O}{M_O} \right) \frac{M_{air}}{2 \times 0.21}$$
(34)

2 moles O required for every mole of C, 1/2 mole O for every mole of H, minus 1 mole of O for every mole of O already in the biomass. Divided by 2 to convert mole O to mole O_2 .

Excess air ratio:

$$\lambda = \frac{m_{air,in}}{m_{air,stoich}} \tag{35}$$

Table A5 - Combustion Calculations, Gasifier System Energy Balances.

	{						1	· · · · · · · · · · · · · · · · · · ·		
	1				flue gas	flue gas	flue gas latent			flue gas total
Heat output	CO2	H2O	02	N2	sensible heat	sensible heat	heat loss	flue gas latent	Other losses	heat loss
(GJ/hour)	(kJ/hour)	(kJ/hour)	(kJ/hour)	(kJ/hour)	loss (GJ/hour)	loss (%)	(GJ/hour)	heat loss (%)	(%)	(GJ/hour)
Qdelivered	Q _{CO2}	Q _{H2O}	Q ₀₂	Q _{N2}	Qsensible	Y _{sensible}	Qlatent	Ylatent	Qother	Qfluc
3	-37904	-54488	-15881	-173105	0.28	5.07%	0.76	13.66%	27.17%	, 1.04
4	-47581	-68225	-18007	-209712	0.34	5.30%	0.88	13.66%	19.28%	1.23
5	-58798	-84102	-20348	-251566	0.41	5.55%	1.02	13.66%	13.95%	1.44
6	-71677	-102274	-22919	-299049	0.50	5.80%	1.17	13.66%	10.42%	1.66
7	-86339	-122899	-25738	-352541	0.59	6.05%	1.33	13.66%	8.15%	, 1.91
8	-102905	-146137	-28820	-412423	0.69	6.32%	1.49	13.66%	6.79%	2.18
9	-121498	-172144	-32180	-479075	0.80	6.59%	1.67	13.66%	6.09%	2.47
10	-142243	-201082	-35835	-552881	0.93	6.86%	1.85	13.66%	5.85%	, 2.79
11	-165264	-233108	-39801	-634223	1.07	7.14%	2.05	13.66%	5.96%	, 3.12
12	-190689	-268385	-44094	-723483	1.23	7.42%	2.26	13.66%	6.32%	3.48
13	-218643	-307072	-48730	-821046	1.40	7.71%	2.47	13.66%	6.85%	3.87

Flue gas energy content for each gas [kJ/hour]:

$$Q_{gas} = \frac{m_{gas}}{M_{gas}} \left(a_1 (T_{ref}) + \frac{a_2}{2} (T_{ref})^2 + \frac{a_3}{3} (T_{ref})^3 + \frac{a_4}{4} (T_{ref})^4 + \frac{a_5}{5} (T_{ref})^5 + a_6 - a_1 (T_{flue}) - \frac{a_2}{2} (T_{flue})^2 - \frac{a_3}{3} (T_{flue})^3 - \frac{a_4}{4} (T_{flue})^4 - \frac{a_5}{5} (T_{flue})^5 - a_6 \right) \frac{R}{1,000}$$
(36)

This formula calculates the thermal energy content of each gas compared to a reference

temperature (energy content at the reference temperature is defined as 0).

• *al* through *a6* are constants specific for each gas.

Enthalpy Constants	a1 (T)	a2 (T^2)	a3 (T^3)	a4 (T^4)	a5 (T^5)	a6
CO2	2.35677352	0.0089846	-7.12356E-06	2.45919E-09	-1.437E-13	-48371.9697
H2O	4.19864056	-0.0020364	6.5204E-06	-5.48797E-09	1.77198E-12	-30293.7267
SO2	2.911438	0.00810302	-6.90671E-06	3.32902E-09	-8.77712E-13	-36878.81
02	3.78245636	-0.0029967	9.8473E-06	-9.6813E-09	3.24373E-12	-1063.94356
N2	3.298677	0.00140824	-3.96322E-06	5.64152E-09	-2.44485E-12	-1020.8999

Table A6 – Constants for Enthalpy Calculations.

Flue gas sensible heat loss [GJ/hour]:

$$Q_{sensible} = \frac{Q_{CO_2} + Q_{H_2O} + Q_{O_2} + Q_{N_2}}{1,000,000}$$
(37)

Sensible heat loss calculates the heat loss due to the flue gas being warmer than the fuel input and the surroundings. The amount of sensible heat loss depends on the reference temperature, which was taken as 25 °C (this is a conservative estimate, heat loss will be higher using lower reference temperatures).

% Flue gas sensible heat loss [GJ/hour]:

$$Y_{sensible} = \frac{Q_{sensible}}{m_{biomass,in}HHV} 1,000 \times 100$$
(38)

Flue gas latent heat loss [GJ/hour]:

$$Q_{latent} = \frac{m_{H_2O,out}}{1,000} \Delta H_{latent}$$
(39)

This formula calculates the energy loss for water leaving the system in vapour state (as opposed to liquid). For water, $\Delta H_{latent} = 2.26 \text{ GJ/t.}$

% Flue gas latent heat loss [GJ/hour]:

$$Y_{latent} = \frac{Q_{latent}}{m_{biomass,in}HHV} 1,000 \times 100$$
⁽⁴⁰⁾

Unaccounted for heat loss [GJ/hour]:

$$Q_{other} = 1 - \frac{Q_{delivered}}{m_{biomass,in}HHV} 1,000 - \frac{Q_{sensible}}{Q_{delivered}} - \frac{Q_{latent}}{Q_{delivered}}$$
(41)

$$Q_{other} = 1 - Y_{HHV} - Y_{sensible} - Y_{latent}$$
(42)

 Q_{other} includes radiant heat loss and uncertainties in heat loss calculations.

Flue gas total heat loss [GJ/hour]:

$$Q_{flue} = Q_{sensible} + Q_{latent} \tag{43}$$

The majority of the heat loss is due to latent heat loss, especially at higher hog fuel moisture content.

[[Flue gas	Water	[Water		Flue gas	Flue gas		
Heat	Cooled					sensible heat	partial		saturation	Portion of	latent heat	total heat		
output	flue gas T	CO2	H2O	02	N2	capture	pressure	Condensation	pressure	water that	capture	capture	% of flue gas	
(GJ/hour)	(K)	(kJ/hour)	(kJ/hour)	(kJ/hour)	(kJ/hour)	(GJ/hour)	(mmHg)	T (℃)	(mmHg)	condenses	(GJ/hour)	(GJ/hour)	heat captured	% Efficiency Improvement
Q _{dclivered}	T _{flue,cool}	Q _{CO2.cool}	Q _{H2O,cool}	Q _{02,cool}	Q _{N2.cool}	Q _{sensible,cool}	P _{H2O}	T _{cond}	P _{H20,sat}	X _{H2O,cond}	Qlatent.cool	Q _{flue.cool}	Q _{fluc.cool} /Q _{fluc}	$Q_{flue,cool}/(Q_{flue,cool}+Q_{delivered})$
3	313	-31527	-45015	-13124	-142902	0.23	135.23	57.86	55.33	0.591	0.45	0.68	65.47%	18.5%
4	313	-40132	-57161	-15092	-175568	0.29	138.93	58.43	55.33	0.602	0.53	0.82	66.79%	17.0%
5	313	-50195	-71322	-17262	-213176	0.35	142.03	58.91	55.33	0.610	0.62	0.98	67.92%	16.3%
6	313	-61837	-87657	-19651	-256107	0.43	144.66	59.30	55.33	0.617	0.72	1,15	68.90%	16.0%
7	313	-75178	-106321	-22274	-304741	0.51	146.89	59.63	55.33	0.623	0.83	1.33	69.77%	16.0%
8	313	-90340	-127473	-25148	-359458	0.60	148.80	59.91	55.33	0.628	0.94	1.54	70.55%	16.1%
9	313	-107447	-151272	-28288	-420641	0.71	150.44	60.14	55.33	0.632	1.05	1.76	71.26%	16.4%
10	313	-126622	-177878	-31711	-488672	0.82	151.87	60.35	55.33	0.636	1.18	2.00	71.91%	16.7%
11	313	-147990	-207449	-35433	-563933	0.95	153.12	60.53	55.33	0.639	1.31	2.26	72.51%	17.1%
12	313	-171679	-240146	-39469	-646806	1.10	154.21	60.68	55.33	0.641	1.45	2.55	73.06%	17.5%
13	313	-197814	-276131	-43836	-737677	1.26	155.17	60.81	55.33	0.643	1.59	2.85	73.58%	18.0%

All calculations based on fuel with a moisture content of 40% and cooling the flue gas to 40°C

						Flue gas	Water		Water		Flue gas	Flue gas		
Heat	Cooled					sensible heat	partial		saturation	Portion of	latent heat	total heat		
output	flue gas T	CO2	H2O	02	N2	capture	pressure	Condensation	pressure	water that	capture	capture	% of flue gas	
(GJ/hour)	(K)	(kJ/hour)	(kJ/hour)	(kJ/hour)	(kJ/hour)	(GJ/hour)	(mmHg)	T (°C)	(mmHg)	condenses	(GJ/hour)	(GJ/hour)	heat captured	% Efficiency Improvement
													,	
Q _{delivered}	T _{fluc,cool}	Q _{CO2.cool}	QH20,cool	Q _{02,cool}	Q _{N2,cool}	Q _{sensible.cool}	P _{H20}	T _{cond}	P _{H2O.sat}	X _{H2O.cond}	Q _{latent.cool}	Q _{fluc.cool}	Qflue.cool/Qflue	$Q_{flue.cool}/(Q_{flue.cool}+Q_{delivered})$
3	313	-31527	-45015	-13124	-142902	0.23	135.23	57.86	55.33	0.591	0.45	0.68	65.47%	18.5%
4	313	-40132	-57161	-15092	-175568	0.29	138.93	58.43	55.33	0.602	0.53	0.82	66.79%	17.0%
5	313	-50195	-71322	-17262	-213176	0.35	142.03	58.91	55.33	0.610	0.62	0.98	67.92%	16.3%
6	313	-61837	-87657	-19651	-256107	0.43	144.66	59.30	55.33	0.617	0.72	1.15	68.90%	16.0%
7	313	-75178	-106321	-22274	-304741	0.51	146.89	59.63	55.33	0.623	0.83	1.33	69.77%	16.0%
8	313	-90340	-127473	-25148	-359458	0.60	148.80	59.91	55.33	0.628	0.94	1.54	70.55%	16.1%
9	313	-107447	-151272	-28288	-420641	0.71	150.44	60.14	55.33	0.632	1.05	1.76	71.26%	16.4%
10	313	-126622	-177878	-31711	-488672	0.82	151.87	60.35	55.33	0.636	1,18	2.00	71.91%	16.7%
11	313	-147990	-207449	-35433	-563933	0.95	153.12	60.53	55.33	0.639	1.31	2.26	72.51%	17.1%
12	313	-171679	-240146	-39469	-646806	1.10	154.21	60.68	55.33	0.641	1.45	2.55	73.06%	17.5%
13	313	-197814	-276131	-43836	-737677	1.26	155.17	60.81	55.33	0.643	1.59	2.85	73.58%	18.0%

All calculations based on fuel with a moisture content of 40% and cooling the flue gas to 55°C

Heat exchanger energy capture is from 1) cooling the flue gas (sensible heat capture); and 2) condensing the water vapour (latent heat capture). For latent heat capture, the amount of water that will condense in the heat exchanger needs to be calculated.

Potential sensible energy recovery for each gas [kJ/hour]:

$$Q_{gas,cool} = \frac{m_{gas}}{M_{gas}} \left(a_1 (T_{flue,cool}) + \frac{a_2}{2} (T_{flue,cool})^2 + \frac{a_3}{3} (T_{flue,cool})^3 + \frac{a_4}{4} (T_{flue,cool})^4 + \frac{a_5}{5} (T_{flue,cool})^5 + a_6 - a_1 (T_{flue}) - \frac{a_2}{2} (T_{flue})^2 - \frac{a_3}{3} (T_{flue})^3 - \frac{a_4}{4} (T_{flue})^4 - \frac{a_5}{5} (T_{flue})^5 - a_6 \right) \frac{R}{1,000}$$

$$(44)$$

This formula calculates the difference in thermal energy content of each gas between the original (current) flue gas temperature and the flue gas temperature after a heat exchanger. Temperatures must in in Kelvin.

Potential total sensible heat recovery [GJ/hour]:

$$Q_{sensible,cool} = \frac{Q_{CO_2,cool} + Q_{H_2O,cool} + Q_{O_2,cool} + Q_{N_2,cool}}{1,000,000}$$
(45)

Water vapour pressure in flue gas [mm Hg]:

$$P_{H_20} = Y_{H_20} P_{flue} \times 760 \tag{46}$$

 P_{flue} is the pressure of the flue gas, and is assumed to be 1 atm (760 mm Hg).

Temperature at which water vapour will condense [°C]:

$$T_{cond} = \frac{B}{A - LOG(P_{H_2O})} - C \tag{47}$$

 P_{H2O} must be in mm Hg, see below for constants A, B and C.

Saturated water vapour pressure at cooled flue gas exit temperature [mm Hg]:

$$P_{H_2O,sat} = 10^{A - \frac{B}{T_{flue,cool} - C}}$$

$$\tag{48}$$

A, B, and C are constants, and depend on the final temperature of the flue gas ($T_{flue,cool}$). $T_{flue,cool}$ must be in °C. If the flue gas is cooled below T_{cond} , then some or all of the water vapour will condense.

 Antoine Constants
 0 to 60 °C
 60 to 150 °C

 A
 8.10765
 7.96681

 B
 1750.286
 1668.21

 C
 235
 228

Table A9 - Antoine Constants for Saturated Vapour Pressure and Condensation Temperature Calculations.

Fraction of water vapour that will condense:

$$IF T_{flue,cool} > T_{cond} \rightarrow x_{H_2O} = 0 (no \ condensation)$$
(49)

$$IF T_{flue,cool} < T_{cond} \to x_{H_2O} = \frac{Y_{H_2O} - \frac{P_{H_2O,sat}}{760}}{Y_{H_2O}}$$
(50)

As the flue gas is cooled below the water vapour condensation temperature, water vapour will start to condense. The further the flue gas is cooled, the greater the amount of water that will condense.

Potential total latent heat recovery [GJ/hour]:

$$Q_{latent,cool} = x_{H_2O} \frac{m_{H_2O,out}}{1,000} \Delta H_{latent}$$
(51)

Potential flue gas total heat recovery [GJ/hour]:

$$Q_{flue,cool} = Q_{sensible,cool} + Q_{latent,cool}$$
⁽⁵²⁾

Potential flue gas total heat recovery [%]:

$$\frac{Q_{flue,cool}}{Q_{flue}} 100 \tag{53}$$

The heat captured using a heat exchanger compared to the total heat loss in the flue gas without a heat exchanger.

Flue gas heat capture as a function of available cooling water temperature:

Depending on the temperature of the heating load, not all of the heat captured from the flue gas can be used. In order to capture the maximum amount of heat from the flue gas, the cooling water needs to be as cold as possible. If the flue gas needs to be cooled below the temperature of the external heat load, then a significant fraction of the captured heat will need to be dumped in a cooling tower (or greenhouse).

Fraction of captured flue gas used for heating:



Total energy captured from flue gas heat exchanger:

$$Q_{flue,cool} = m_{cooling water} c(T_{HOT} - T_{COLD})$$
(54)

 T_{HOT} is the temperature of the hot water leaving the counter current flue gas heat exchanger. For most calculations, T_{HOT} is assumed to be 85 °C T_{HOT} needs to be below the incoming temperature of the flue gas (120 °C).

 T_{COLD} is the temperature of the water returning from the cooling tower (or greenhouse) to the flue gas heat exchanger. T_{COLD} is varied from 55 to 15 °C. The flue gas exit temperature ($T_{flue,cool}$) is assumed to be 5 °C warmer than T_{COLD} (a 5 °C temperature difference is required to drive the heat transfer from the flue gas to the water loop).

Energy delivered to heat load:

$$Q_{used} = m_{cooling water} c (T_{HOT} - T_{COOL})$$
⁽⁵⁵⁾

 T_{COOL} is the temperature of the water leaving the heat load (e.g. the residences). For most calculations, T_{COOL} is assumed to be 55 °C. A typical space heating load (heating a room to 20 °C) will return the cooling water at 25 to 30 °C. A hot water heating load (60+ °C) will return cooling water at 65 to 70 °C.

Fraction of captured flue gas heat used for heating:

$$\frac{Q_{used}}{Q_{flue,cool}} = \frac{(T_{HOT} - T_{COOL})}{(T_{HOT} - T_{COLD})}$$
(56)

Usable flue gas thermal energy [GJ/hour]:

 $Q_{used} = Q_{flue,cool} \frac{(T_{HOT} - T_{COOL})}{(T_{HOT} - T_{COLD})}$ (57)

Usable flue gas thermal energy [kW]:

$$Q_{used} = Q_{flue,cool} \frac{(T_{HOT} - T_{COOL})}{(T_{HOT} - T_{COLD})} \frac{1,000}{3.6}$$
(58)

The captured heat from the flue gas $(Q_{flue,cool})$ increases as T_{COLD} decreases – the more the flue gas is cooled the greater the energy capture (solid line in Figure A4). However, the fraction of

useful heat (dashed line in Figure A4) increases as T_{COLD} approaches T_{COOL} (decreasing the need to waste heat in a cooling tower). The system can be optimized to find the maximum Q_{used} by performing the calculations at a range of flue gas exit temperatures. In Figure A5, which has calculations for maximum heat output at 40% hog fuel moisture, the optimum temperature to maximize flue gas heat utilization is 40 °C. This was obtained by multiplying the two curves from Figure A4 (the total heat captured times the fraction of the heat that is usable).



Figure A4 – Correlation between Total Heat Captured, Flue Gas Temperature and Usable Heat (for 40% moisture fuel).



Figure A5 – Usable Heat Captured as a Function of Final Flue Gas Temperature. For 40% moisture content fuel (The maximum usable heat is obtained if the flue gas is cooled to 40°C).



Appendix C

Campus Map



Appendix D

Heat Duration Curves, Gasifier Output Variability and Thermal Storage

Heat duration curves are a useful tool to analyze data that has a significant degree of process variation, and are often used to size biomass heating systems. Heat duration curves are demonstrated using campus heat demand data in Figure D1 and Figure D2. In Figure D1, the daily heat demand is graphed chronologically. The campus heat demand increases in the winter, and is highly variable (Figure D1). To construct a heat duration curve, the heat demand data is sorted from highest to lowest and graphed versus time (Figure D2). The heat duration curve is used to determine the number of days that the gasifier is operating at high output versus low output. By simply looking at the raw data points in Figure D1, it is difficult to extract the same information.



Figure D1 – Daily Campus Heat Demand over a 1 year Time Period.



Figure D2 – Heat duration curve example, using the same daily total campus heat demand data presented in Figure D1.

One use for heat duration curves is for sizing biomass heating systems. Due to limited turndown ratios, biomass heating systems tend to have a small range over which they can be efficiently operated. When looked at on an hourly basis, campus heat demand can be as high as 6 MW. A 6 MW biomass heating system with a 2.5 turndown ratio is capable of producing from 6 MW to 2.4 MW. This system would not run efficiently during the summer months and would cover only 64% (shaded area of chart) of the total campus heat demand (Figure D3). A smaller heating system with a 2.5 turndown ratio would cover much more of the campus heating needs (Figure D4). This system would need supplemental heating on cold days (heat demand > 3 MW), but over the year would provide 94% (shaded area of chart) of the campus heat demand. A 3.5 MW system with a 2.5 turndown ratio would supply 97% of the campus heating needs (not shown).



Figure D3 – Heat Duration Curve for 6 MW system and 2.5 Turndown. The darker shaded area represents the heat demand covered by a 6 MW biomass heating system with a 2.5 turndown ratio.



Figure D4 – Heat Duration Curve for a 3 MW system and 2.5 Turndown. The darker shaded area represents the heat demand covered by a 3 MW biomass heating system with a 2.5 turndown ratio.

The campus heat demand graphed in Figure D1 is supplied by the Nexterra gasifier system and by the older natural gas boilers (Figure D5). There were days in the shoulder season (October) when the bioenergy system was not operating well, and there were days in the fall through spring when natural gas was used to supply heat above what the bioenergy system was supplying (Figure D5). If the data is sorted using the total heat demand, from highest to lowest, a heat duration curve is obtained (Figure D6). The heat duration curve in Figure D6 is similar to the theoretical 3 MW bioenergy system graphed in Figure D4, but with more variability. The large deviations of the biomass heating system curve from the total heat demand curve are due to the days of low biomass system output in October.



Figure D5 – Daily Campus Heat Demand over a 1 year Time Period Showing Variability. The shaded area below the solid line represents the heat supplied by the UNBC bioenergy system (gasifier). The shaded area above the solid line represents the heat demand supplied by natural gas.

If the data is sorted using the gasifier heat output, from highest to lowest, a heat duration curve is obtained (Figure D7). The maximum gasifier output on a daily basis is approximately 3.3 MW, with a noticeable range between 2.1 to 3.0 MW covering the high heating demand season. The gasifier output in Figure D7 represents 85% of the total campus heat demand (area under the solid line compared to the total shaded area). This compares to 94% theoretical for a 3.0 MW bioenergy system. The heat demand during the low gasifier output on the far right side of the x-axis in Figure D7 is supplied by natural gas. This natural gas represents 4% of the heating demand that could otherwise have been covered by the gasifier, had it been operating effectively.



Figure D6 – Heat Duration Curve for 1 year time period. Using the same daily total campus heat demand and bioenergy system data presented in Figure D5. Area below the solid line represents heat supplied by the bioenergy system. Shaded area above the solid line represents heat supplied by natural gas.

If hourly data is used in place of daily data, much greater variability is seen (Figures D8 and D9). It appears to be common for the bioenergy system output to decrease dramatically for an hour or several hours at a time (Figure D8). The heat duration curve for the UNBC bioenergy system (Figure D9) is different from the theoretical 3 MW bioenergy system represented in Figure D4, with less of the total heat demand covered by the actual system due to the large variability in output. Similar to Figure D7, the hourly data was sorted based on gasifier output (Figure D10). The results are similar to those described in Figure D7, with the exception that the hourly gasifier output is slightly higher reaching 3.8 MW.



Figure D7 - Heat Duration Curve for 1 year Time Period. Using the same daily total campus heat demand and bioenergy system data presented in Figure D5. Area below the solid line represents heat supplied by the bioenergy system. Shaded area above the solid line represents heat supplied by natural gas. Sort based on the bioenergy system output.



Figure D8 – Hourly Campus Heat Demand over a 1 Year Time Period. The shaded area below the solid line represents the heat supplied by the bioenergy system. The shaded area above the solid line represent the heat demand supplied by natural gas.



Figure D9 – Heat Duration Curve for Hourly Heat Demand Data from Figure D8. Area below the solid line represents heat supplied by the bioenergy system. Shaded area above the solid line represents heat supplied by natural gas. White line is a moving average of the bioenergy system output.



Figure D10 - Heat Duration Curve for 1 Year Time Period. Using the same daily total campus heat demand and bioenergy system data presented in Figure D8. Area below the solid line represents heat supplied by the bioenergy system. Shaded area above the solid line represents heat supplied by natural gas. Sort based on the bioenergy system output.

Variability in Gasifier Output

The hourly heating data presented in Figures D8 and D9 is difficult to interpret due to the large variability in heat demand and in bioenergy system output, and the 1 year time scale of the graphs. Select days are represented in Figures D11 through D25 for a closer investigation of the variability. While no definitive conclusions can be made, there are several patterns in the variability that help explain the data presented in Figures D5 to D10.

One common occurrence is a morning spike in heat demand (Figures D11 to D 20, D24 and D25). The majority of the increase in morning heat demand is usually supplied by natural gas, which appears to have a faster response time than the bioenergy system. Sometimes a spike in

natural gas usage is followed by a decrease in gasifer output as illustrated in Figures D11 to D14. This may be due to the control systems. When natural gas adds heat to the main water loop, the temperature of the water in the loop increases and the bioenergy systems responds by lowering output. These behaviours contribute to the variability in the heat duration curves since high heat demand is often matched with low bioenergy heat output.

On some days both the heat demand and the bioenergy system output are highly variable (Figures D15 to D20). The reason for this is unknown, but appears to be due to operational problems with the bioenergy system. These operational problems often seem to follow increases in bioenergy system output and may be due to increases in temperature in the gasifier leading to over-temperature alarms and subsequent slowdowns.

On other days the bioenergy system obviously has operational and/or maintenance issues and is turned down for hours at a time (Figures D21 to D24). There are also days that the bioenergy system is not operational at all due to yearly maintenance (not shown). The final example of variability is shown in Figure D25. Here the bioenergy system has steady output (significantly below the rated capacity of 4.4 MW) and remains at this output level all day even as the heat demand increases.

Explanations for variability in the heat duration curves include: a non-optimized control system between the natural gas and bioenergy systems; short-term (< 1 hour) operational issues with the bioenergy system; long-term operational issues with the bioenergy system; and the bioenergy system often running well below capacity.



Figure D11 – Campus Heat Demand for October 25th, 2012. Area below the solid line is heat supplied by the bioenergy system, area above the solid line represents heat supplied by natural gas.



Figure D12 – Campus Heat Demand for October 27th, 2012. Area below the solid line is heat supplied by the bioenergy system, area above the solid line represents heat supplied by natural gas.



Figure D13 – Campus Heat Demand for October 28th, 2012. Area below the solid line is heat supplied by the bioenergy system, area above the solid line represents heat supplied by natural gas.



Figure D14 – Campus Heat Demand for March 2^{nd} , 2012. Area below the solid line is heat supplied by the bioenergy system, area above the solid line represents heat supplied by natural gas.



Figure D15 – Campus Heat Demand for November 10th, 2012. Area below the solid line is heat supplied by the bioenergy system, area above the solid line represents heat supplied by natural gas.



Figure D16 – Campus Heat Demand for November 20th, 2012. Area below the solid line is heat supplied by the bioenergy system, area above the solid line represents heat supplied by natural gas.



Figure D17 – Campus Heat Demand for March 13th, 2013. Area below the solid line is heat supplied by the bioenergy system, area above the solid line represents heat supplied by natural gas.



Figure D18 – Campus Heat Demand for March 14th, 2013. Area below the solid line is heat supplied by the bioenergy system, area above the solid line represents heat supplied by natural gas.



Figure D19 – Campus Heat Demand for January 11th, 2013. Area below the solid line is heat supplied by the bioenergy system, area above the solid line represents heat supplied by natural gas.



Figure D20 – Campus Heat Demand for December 22nd, 2012. Area below the solid line is heat supplied by the bioenergy system, area above the solid line represents heat supplied by natural gas.



Figure D21 – Campus Heat Demand for March 14th, 2012. Area below the solid line is heat supplied by the bioenergy system, area above the solid line represents heat supplied by natural gas.



Figure D22 – Campus Heat Demand for March 29th, 2012. Area below the solid line is heat supplied by the bioenergy system, area above the solid line represents heat supplied by natural gas.


Figure D23 – Campus Heat Demand for July 7th, 2012. Area below the solid line is heat supplied by the bioenergy system, area above the solid line represents heat supplied by natural gas.



Figure D24 – Campus Heat Demand for February 12th, 2013. Area below the solid line is heat supplied by the bioenergy system, area above the solid line represents heat supplied by natural gas.



Figure D25 – Campus Heat Demand for December 26th, 2012. Area below the solid line is heat supplied by the bioenergy system, area above the solid line represents heat supplied by natural gas.

Thermal Storage

One option to decrease variability in the bioenergy system output would be to add a thermal storage system. A thermal storage system is basically just a large tank of water. When building heat demand is low, hot water is added to the top of the storage tank. When building heat demand is high, hot water from the storage tank is used to help meet the heat demand. For the current UNBC bioenergy system, this may address two issues. First, short term outages (e.g. Figures D17 and D18) could be covered by heat in the thermal storage tank instead of natural gas. Second, the bioenergy system would be able to run at a steady rate (it would not be turned down at night but would be used to fill the thermal storage tank). The increase in morning heat demand could be supplied from the thermal storage tank and the bioenergy system could

continue running at a steady rate. This may avoid operational problems illustrated in Figures D11 to D14. Thermal storage should help smooth the bioenergy system output on days similar to those shown in Figures D15 to D20, however this will depend in part on what the operational issues are. In all of these cases, by improving operation of the bioenergy system and by providing a heat buffer for the morning demand, thermal storage should decrease natural gas consumption. Unless the tank was very large, thermal storage would not help with prolonged bioenergy system shutdowns shown in Figures D22 to D24. Thermal storage would not help with situations when the bioenergy system is running below capacity (Figure D25).

To determine the impact of thermal storage on natural gas consumption, a model was used. The model assumes that the bioenergy system can operate at rated capacity indefinitely. When heat demand is less than the rated capacity, heat is added to storage. When heat demand is greater than the rated capacity, heat is taken from storage.

The amount of heat in the thermal storage system for each 15 minute interval is calculated as follows:

The bioenergy system output is assumed to run at either the heat demand or at the rated capacity (if the heat demand is equal to or greater than the rated capacity)

$$BIO_{OUT} = MIN(HD, 0.9 \times BIO_{MW})$$
⁽⁵⁹⁾

For a 15 minute interval: 1 MW = 1 MJ/s x 60 s/min x 15 min x 1 GJ/1000 MJ = 0.9 GJ

Adding heat to thermal storage (up to STO_{MAX}):

$$IF (HD < 0.9 \times MW_{BIO} \text{ and } IF STO < STO_{MAX}) t hen STO = STO + (0.9 \times MW_{BIO} - HD)$$
(60)

Removing heat from thermal storage (as long as there is heat available STO > 0):

$$IF (HD > 0.9 \times MW_{BIO} \text{ and } IF STO > 0) then STO = STO + (0.9 \times MW_{BIO} - HD)$$
(61)

All other cases: STO = STO + 0

Where HD = heating demand (GJ); MW_{BIO} = rated capacity of bioenergy system (MW);

STO = heat stored in thermal storage tank (GJ); STO_{MAX} = maximum heat storage capacity in thermal storage tank (GJ);

Natural gas is used to meet high demand beyond the capacity of the bioenergy and thermal storage systems:

IF IF $(HD < 0.9 \times MW_{BIO} \text{ and } IF STO < STO_{MAX})$

$$NG = \frac{HD - BIO_{OUT} - (0.9 \times MW_{BIO} - HD)}{\eta_{NG}}$$
(62)

else (if there is no demand from storage or if storage is empty):

$$NG = \frac{HD - BIO_{OUT}}{\eta_{NG}}$$
(63)

Where NG = natural gas consumption (GJ) and η_{NG} = efficiency of the natural gas boilers (assumed to be 0.8).

Results from thermal storage calculations are presented in Figures D26 and D27. The calculated heat duration curves are much smoother than the actual bioenergy system heat duration curve. This is predominantly due to the assumption that the bioenergy system can operate at the rated capacity. This assumption has a much greater impact on the results than the size of thermal

storage. The heat duration curves for a modeled 3.5 MW biomass system with and without 10 GJ of thermal storage almost overlap in Figure D26. Both curves are significantly above the actual bioenergy system heat duration curve (dotted line).



Figure D26 – Heat Duration Curve with and without Thermal Storage. Jagged dotted line represents daily bioenergy system output.



Figure D27 – Heat Duration Curve with Thermal Storage and Varied Output. Jagged dotted line represents daily bioenergy system output. Horizontal lines represent modeled bioenergy systems with 10 GJ of thermal storage and a maximum output of 4, 3.5, 3, 2.5 and 2 MW from top to bottom.

As can be seen in Figure D27, the UNBC bioenergy system appears to operate between 2.5 and 3 MW for much of the time even though the heat demand is higher.

Assuming an ideal bioenergy system (as modeled), increasing thermal storage size decreases natural gas consumption as heat is stored during low demand periods and used in high demand periods in place of natural gas. A 10 GJ thermal storage tank size should decrease natural gas consumption by $\sim 7\%$ (Figure D28). This should also provide a ~ 3 hour heat supply buffer for system operational difficulties. Further increases in thermal storage tank size have diminishing returns in decreasing natural gas consumption. The higher the bioenergy system capacity, the lower the natural gas consumption.



Figure D28 – Impact of Thermal Storage Capacity on Natural Gas Consumption. 2.5 MW (solid line), 3 MW (dashed line) and 3.5 MW (dotted line) bioenergy systems.

The size of the thermal storage tank depends on both the amount of heat to be stored and the temperature difference between the hot water and cold water:

$$Vol = \frac{STO \times 10^6}{4.2 \times \Delta T} \tag{65}$$

Where Vol = volume of thermal storage tank (in m³, assuming density of water is 1,000 kg/m³); STO = capacity of thermal storage tank (GJ); 4.2 = the heat capacity of water (kJ/kg/°C); and ΔT = the temperature change in the water loop (°C).

For the UNBC bioenergy system, the temperature difference on the bioenergy system hot water loop is 3 °C. For the main campus hot water loop the temperature difference is 5 to 10 °C. These are small values and make thermal storage system impractically large (Table D1). Even with a 10 $^{\circ}$ C temperature change on the hot water loop, a 10 GJ thermal storage tank would require a volume of 238 m³. This corresponds to a 6.2 m x 6.2 m x 6.2 m tank (although thermal storage tanks are cylindrical). This is a very large tank, indicating thermal storage is probably not economically viable unless there is a larger temperature drop in the heating system.

 Table D1 – Size of Thermal Storage tank as a Function of Required Capacity and the Difference between

 Supply and Return Water Temperatures.

Thermal storage	Vol (m ³)	Vol (m ³)	Vol (m ³)
capacity (GJ)	$(if \Delta T = 3 \circ C)$	$(if \Delta T = 5 \circ C)$	$(if \Delta T = 10 \circ C)$
1	79.4	47.6	23.8
3	238	143	71.4
5	397	238	119
10	794	476	238
100	7,940	4,760	2,380
500	39,700	23,800	11,900

Appendix E

Hog Fuel Drying Calculations

Drying calculations are similar to the calculations presented in Appendix A.

For bioenergy calculations, wood moisture content is usually given on a wet basis (mass of water per total mass). To convert from wet basis to dry basis (mass of water per mass of dry wood):

$$MC_{db} = \frac{MC_{wb}}{100 - MC_{wb}} 100 \tag{66}$$

Where MC_{db} is the % moisture on a dry basis (tonne water/tonne dry wood) and MC_{wb} is the % moisture content on a wet basis (tonne water/total tonne).

In addition to free water (water that can be removed in an oven), wood also contains hydrogen which forms water during combustion:

$$CH_{1.5}O_{0.75} + O_2 \rightarrow CO_2 + 0.75H_2O$$

From this reaction, for every tonne of dry wood burnt, 1.3 tonnes of O_2 is consumed, 1.8 tonnes of CO_2 is produced, and 0.55 tonnes of H_2O is produced. The water released (in tonnes) per tonne of dry wood during combustion is:

$$H_2 O = 0.55 + \frac{MC_{wb}}{100 - MC_{wb}} \tag{67}$$

The increase in efficiency of a bioenergy system due to drying the wood prior to combustion can be estimated by calculating the decrease in energy loss due to less water in the flue gas. Water in the flue gas contains both latent and sensible heat, and if there is no flue gas heat exchanger this heat is lost to the atmosphere. Difference in flue gas water content (in tonnes water per tonne dry biomass) between burning wet and dried wood:

$$\Delta m_{H_2O} = \frac{MC_{wb,w}}{100 - MC_{wb,w}} - \frac{MC_{wb,d}}{100 - MC_{wb,d}}$$
(68)

Where $MC_{wb,w}$ is the % moisture content of the wet wood on a wet basis (tonne water/total tonne) and $MC_{wb,d}$ is the % moisture content of the dried wood on a wet basis (tonne water/total tonne).

Latent heat loss with water (in GJ per tonne dry biomass):

$$\Delta H_{latent} = \Delta m_{H_20} \times 2.26 \tag{69}$$

Where 2.26 is the latent heat of water in GJ/tonne water.

Sensible heat loss with water (in GJ per tonne dry biomass):

$$\Delta H_{sensible} = \Delta m_{H_2O} \times 0.00188 \times \Delta T \tag{70}$$

Where 0.00188 is the heat capacity of water vapour in GJ/tonne water/°C and ΔT is the temperature of the flue gas above ambient temperature. ΔT is assumed to be 125 °C

Increase in efficiency due to less water in the flue gas:

$$\eta_{gain} = \frac{\Delta H_{latent} + \Delta H_{sensible}}{20} 100 \tag{71}$$

Where 20 is the energy content of 1 tonne of dry wood (in GJ/tonne dry wood)

Results from several calculations are listed in Table E1. The higher the moisture content of the incoming wood, and the lower the moisture content of the dried wood, the less water in the flue gas and the higher

the yield of the bioenergy system. For a typical case of 40% wet wood dried to 25%, the bioenergy system yield should increase by 4% compared to a system without drying. This will result in 4% less wood required for the same heat output. There is still energy loss with the flue gas due to water vapour.

Wet wood moisture content (wet basis)	Dried wood moisture content (wet basis)	Difference in flue gas water content (tonne water/tonne dry wood)	Heat loss due to water (GJ/tonne dry wood)	% increase in bioenergy system yield
50	25	0.67	1.66	8.3
40	25	0.33	0.83	4.2
30	25	0.095	0.24	1.2
50	20	0.75	1.87	9.4
40	20	0.42	1.04	1.0
30	20	0.18	0.45	0.4

Table E1 - Potential Increase in Bioenergy System Yield with Wood Pre-drying.

Water vapour in the flue gas for burning 40% moisture content wood is 1.2 tonnes water/tonne dry wood, with a corresponding efficiency loss of 15% due to latent and sensible heat of the water vapour. Water vapour in the flue gas for burning 25% moisture content wood is 0.87 tonnes water/tonne dry wood, with a corresponding efficiency loss of 11% due to latent and sensible heat of the water vapour. The addition of a dryer decreases the heat losses associated with water vapour in flue gas from 15 to 11%, for a 4% increase in yield.

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