BERC
Renewable • Reliable • Resourceful
Biomass Energy Resource Center

FINAL REPORT

Engineering Feasibility Assessment of Biomass District Energy for the Town of Colebrook

Prepared For:

Kevin McKinnon
Director, Public Works Department
Town of Colebrook
17 Bridge Street
Colebrook, NH 03576

October 4, 2012

Evaluation of Biomass District Energy Options in Colebrook, New Hampshire

Engineering Feasibility Study – Final Report

Table of Contents

1.0 Introduction 2
1.1 Partners 2
1.2 Methodology 3
2.0 Biomass District Energy Overview 5
2.1 What is Biomass? 5
2.2 What is District Energy? 5
2.3 Community Benefits of District Energy 6
2.4 Advantages of Biomass Energy & Biomass District Systems 7
3.0 Review of Technology Options 9
3.1 Fully Automated Woodchip Boilers 9
3.2 District Heating 9
3.3 Organic Rankine Cycle (ORC) System 11
4.0 Assessment of Thermal Energy Demand in Colebrook 12
4.1 Assessment of Inclusion of Specific Heat Loads 12
4.2 Heating Load 14
4.3 Phase I Pipe Network 21
4.4 Phase I Conceptual System Design 23
5.0 Heat Utility Ownership and Project Financing 25
5.1 Public-Private Partnerships 25
5.2 Municipal Utility Model 25
5.3 Co-op and Local Investment Models 26
5.4 Sources of Capital 27
6.0 Environmental Impacts 29
6.1 Air Emissions from Woodchip Boilers 29
6.2 Control Devices for PM 29
6.3 Climate Change and Biomass Energy 31
7.0 Assessment of Available Wood Fuel Supply 32
7.1 Estimating In-Woods Capacity 34
7.2 Woodchip Competition 37
7.3 Woodchip Costs 37
8.0 District Energy Financial Feasibility 39
8.1 Analysis Methodology –Phase I 39
8.2 Analysis Methodology – Full Build Out 40
8.3 Phase One System 42
8.4 Full Build Out Scenario 44
8.5 Sensitivity Analyses 46
9.0 Conclusion and Recommendations 50
9.1 Economics 50
9.2 System Design and Expansion 50
9.3 Ownership & Business Model 51
9.4 Next Steps 51
9.5 Conceptual Project Timeline 52

Appendix A – Case Study: Mitter Transportation Fuel
Appendix B – Technology Options

Appendix C – Network Loads and Boiler Sizing Memo
Appendix D – Conceptual Plant Designs and Network Maps
Appendix E – CHP and Cooling Assessment
Appendix F – Economic Analyses
Appendix G – Conceptual Project Timeline

1.0 Introduction

The Town of Colebrook, New Hampshire is pursuing innovative energy solutions to bolster economic vitality, environmental sustainability, and community well-being. The town government is very interested in the economic and environmental benefits of biomass energy and applying them to the town, which is likely to be very supportive of the proposed biomass district energy (BDE) project.

The town authorized a Colebrook Energy Committee (CEC) to oversee a biomass district energy project. The objective of the project is to support the growth of business and industry; reduce heating and electrical costs for residents, institutions, commercial and municipal buildings; and maximize energy efficiency. There may also be opportunities to facilitate maintenance of existing municipal systems, such as water and sewer lines during the construction phase of the project. The use of local, renewable/sustainable energy resources, such as biomass, is an additional objective.

The Colebrook Energy Committee is a volunteer steering committee with a vision of making practical solutions that save money and the environment. The CEC, with $25,000 in funding from New Hampshire Charitable Foundation, awarded a preliminary feasibility study in Dec 2009. The preliminary feasibility study was conducted by M.E. McCormick Facilities Management Consultants. Encouraged by the positive results of the preliminary feasibility study, the Town of Colebrook was awarded a $100,000 grant from the Neil and Louise Tillotson Fund of the New Hampshire Charitable Foundation to conduct an engineering feasibility study for district heating, combined heat and power, and complementary energy solutions for the community. Additional funding has been provided by the Northern Forest Investment Zone and a Clean Air Cool Planet grant.

1.1 Partners

The study team included the Biomass Energy Resource Center, Community Biomass Systems, and Wilson Engineering.

Biomass Energy Resource Center (BERC) BERC is a national nonprofit organization based in Montpelier, Vermont.[1] Its mission is to achieve a healthier environment, strengthen local economies, and increase energy security across the United States through the development of sustainable biomass energy systems at the community level. BERC uses its expertise in institutional and community-scale wood-energy systems to assist communities, industries, schools, institutions, and others in initiating and constructing biomass projects for their heating and power needs.

Community Biomass Systems, Inc (CBSI)
Community Biomass Systems is a biomass project development and project management firm specializing in the implementation of community scale systems and district energy. CBSI brings a 25 year history of experience in the construction of successful biomass projects across the Northern Forest region. CBSI helps its clients focus on technology that works, drawing from the best US and European biomass and district energy technologies.

Wilson Engineering Services (WES)
Wilson Engineering Services, PC is a full service engineering firm specializing in the development and implementation of renewable energy and environmental remediation programs and projects. On a programmatic and policy level, WES provides program management, policy, and stakeholder outreach consulting services to develop and implement economically, environmentally, and socially sustainable programs at the federal, state

[1] It should be noted that the Biomass Energy Resource Center was acquired by the Vermont Energy Investment Corporation in July, 2012. For further details regarding this acquisition, view the following link - http://www.veic.org/docs/pr/VEIC-BERC-PR-July2012.pdf

and local levels. On a project level, WES provides engineering consulting services for all levels of project implementation, including: technology evaluation, project conceptual study, feasibility study, design, permitting, and construction management. WES has a history of successfully partnering with clients to implement renewable energy and environmental programs and projects.

1.2 Methodology

The team reviewed the previous study (henceforth referred to as the McCormick study) and confirmed the information in the study using satellite photos and town tax records. Site visits were conducted by the study team to assess the potential sites for the district energy plant, to gather fuel use data from as many buildings in town as possible, and to get detailed square footage information from town tax records.

An optimal first phase system was designed by the study team using the concept of anchor loads to define an optimal system. Anchor loads are relatively large heat users with relatively consistent energy use patterns. The higher & more consistent demands of these facilities provide enough demand to justify the installation of the main line distribution piping, allowing the benefits of district heating to be delivered to smaller residences and other facilities along the route.

Based on the projected heat load within the proposed district, recommended capacities for a biomass district plant were calculated and all available technology options for the recommended capacity of the project were identified.

Project viability was assessed at both the full build out level and at a pared down phase I level:

- Maximum Build Out – This scenario was based closely upon the work done in the McCormick study. The study team confirmed the extent of the BDE system studied in the McCormick report as the maximum build out extent of a viable BDE system and completed an independent assessment of the data for this scenario.

- Phase I Approach – The study team designed an optimized phase one approach for the biomass district energy system that was intended to best represent a viable first-stage BDE project.

In addition to the two primary scenarios listed above, the study team examined a district energy plant serving the town based on Scenario I with the addition of a possible future pellet mill at the industrial park to create a year-round thermal customer to support a viable combined heat and power (CHP) scenario. This assessment was hypothetical in nature because it hinges on a business like a pellet mill establishing itself and it agreeing to use the heat and power from the district energy plant to make pellets.

There are a number of commercially available biomass boilers covering a range of costs, quality, and biomass feedstocks. Technical specifications and cost estimates are based on recent bids and quotes for boiler systems and relevant system components. The assessment of each of the options was based on the performance and preliminary cost data provided by system vendors for this and other projects.

An assessment was conducted of how each of these technologies could be utilized to meet the town of Colebrook's energy requirements, including site suitability. Preliminary estimates in terms of initial capital costs and cost of fuel, operation, and maintenance are provided in this report. The costs and revenue streams for each option were evaluated, and both initial and twenty-year cash flow for each scenario for the project were calculated.

The report provides cost estimates and estimates of the economic feasibility of the business model for each option, from the perspective of the district energy company which would own and operate the system. The costs for connecting each building to the system were assumed to be borne by the BDE plant developer, largely to assure that the full capital outlay for building the system and connecting customers to the system were included in the assessment of project viability. In actual practice, when district heating systems are established customers generally pay some part of the cost of connecting their buildings to the network, in the form of hook-up charges – similar to those of a municipal water and sewer system.

Detailed boiler sizing, costing, and conceptual designs are provided for Phase I Scenario as the likely starting point for the build out of the Colebrook BDE system.

The analysis of the Full Build out Scenario is conceptual in nature. It defines a customer load consisting of all buildings within the geographic boundaries developed in the earlier McCormick study. It assumes that pipe would be run to all parts of the study area and that all buildings in the study area would be connected. This system would not be feasible to build at one time, due to both access to capital and logistics of laying miles of network piping. A system of this scale might take decades to build, in a number of phases over time – not all at once. For this reason, it is not possible to compare Phase I Scenario and Full Build out Scenario on an apples-to-apples basis. The Phase I Scenario analysis is based on preliminary engineering design and detailed cost estimation, while the Full Build out Scenario design and budget are much more conceptual. The analysis of Phase I considers the economics for this scenario as if it will not be further built out, which can be useful to compare to the economics of building the system out towards the conceptual maximum build out scenario over time. It is also important to note that year 1 of the Full Build out Scenario would in reality be year ten or fifteen of Phase I if the full build out of the system is achieved.

This report contains the following:

- An overview of the socio-economic and environmental benefits of biomass energy
- An overview of district energy concepts
- Analyses of the town of Colebrook's heating energy demand
- An assessment of current fuel usage and costs in Colebrook
- An assessment of current and projected local biomass fuel availability and costs
- An assessment of available biomass technologies, including CHP equipment
- An overview of funding opportunities and project ownership structures
- Projected costs of installing and operating each configuration of BDE system
- A financial feasibility analysis for each option identified
- Conclusions and recommended next steps

2.0 Biomass District Energy Overview

2.1 WHAT IS BIOMASS?

Biomass is any biological material that can be used as fuel. Biomass fuel is burned or converted in systems that produce heat, electricity, or both heat and power. Woodchips, wood pellets, and other low-grade wood wastes are the major type of biomass fuel. Other common biomass fuel sources are agricultural crop residues and farm animal wastes.

2.2 What is District Energy?

District energy systems use one or more central plants to provide thermal energy to multiple buildings. In a district energy system, insulated underground pipelines distribute thermal energy from the central plant to each of the buildings connected to the network. Energy is then extracted at the buildings and the water is brought back to the plant, through return pipes, to be heated again. In this way district energy systems can be an efficient form of municipal infrastructure, similar to public water or sewage systems.

District energy plants can be designed to produce not only thermal energy, but also electrical power. This is called cogeneration or combined heat and power (CHP). CHP plants are able to get more usable energy out of the input fuel than a plant that produces electricity only. A CHP project that is sized to the heating load but produces electricity as a secondary product is likely to have efficiencies as high as 60-80% compared to an electrical generating facility that does not use the thermal output and can have efficiencies as low as 20%.

District heating can employ a wide variety of fuels, including biomass, which is the fuel source being considered for Colebrook. A typical district energy system consists of the following subsystems:

- **Thermal energy generation.** The boilers where steam or hot water are produced
- **Thermal energy transmission and distribution (T&D).** The pipelines delivering the thermal energy medium (steam or water) from the production sources to the network of users
- **Customer Interface** The integration of thermal energy at the user's (customer's) location, also known as an Energy Transfer Station (ETS)
- **CHP component** The integration of electrical generation technology

Inside each connected building, there is an ETS. For a building with hot water heat (serving baseboard, radiators, unit heaters, or fan coil units for individual room heat), the ETS includes one water-to-water heat exchanger for space heat and a smaller one for domestic hot water (DHW) supply. Hot-air furnaces need to have water-to-air coils installed in the main heating ducts. Propane space heaters need to be removed and replaced with baseboard hot water for room heating.

District energy systems can provide space heating and domestic hot water for large office buildings, schools, college campuses, hotels, hospitals, apartment complexes, and other municipal, institutional, and commercial buildings. Systems can also be used to heat neighborhoods and single-family residences. Some district energy systems supply thermal energy to industrial customers for "process heat," while others capture low-grade waste heat from industry to sell to customers.

2.3 COMMUNITY BENEFITS OF DISTRICT ENERGY

A district energy system can provide, in one centralized system, the heat that would otherwise be produced in hundreds or thousands of smaller, individual heating systems. This reduces redundancy, and produces the following advantages for both system customers and the surrounding community:

Low, Predictable Energy Costs Higher fuel usage provides access to the lower costs associated with bulk purchasing. Additionally, when a district energy system has access to a locally available fuel source, such as locally grown biomass, to serve all or a portion of the fuel mix, this further enhances the cost-stabilizing and economic benefits of district energy. The price of wood fuel is not linked to world energy markets or unstable regions, but instead determined by local economic forces. For this reason, biomass systems do not experience the price instability of conventional fuel systems, especially in areas close to sources of wood fuels.

Air Quality Improvements Air quality improves—as does community livability—when emissions from a single, well-managed plant replace uncontrolled stack emissions from boilers and furnaces in many individual buildings. In addition, district heating systems are on a scale that makes it possible and economically feasible to install best available technology and emissions control equipment that is typically not feasible in individual building heating systems.

Revitalized Communities District energy infrastructure and stable energy rates improve a community's business climate. Local businesses can become more competitive with lower energy costs, which can help to revitalize downtowns and urban core areas helping to alleviate suburban sprawl. Using biomass as the fuel source, district energy can help build and support sustainable infrastructure.

Reliable Equipment District energy systems have an unparalleled record of reliable service. They achieve this by well-managed central plant operation, using multiple fuels, having backup boilers in one or more locations, and having standby power at the central plant.

Reduced Environmental Risks District energy systems can help to mitigate environmental risks by consolidating fuel storage to one or a very few locations compared to numerous onsite storage tanks that serve individual buildings. Conventional onsite fuel storage includes underground and aboveground storage tanks. Failing underground tanks can pose a threat to ground and surface waters. Aboveground tanks can pose fire hazards as well as the risk of dislodging in the event of a flood.

Power Generation Systems In addition to the need of finding new ways to heat buildings, there is also a need to provide electricity from locally available, renewable resources. New "emerging technologies," such as the Organic Rankine Cycle (ORC) technology and gasification for both small-scale CHP and utility-scale power plants, can become commercially available and deployed for the benefit of regions like rural New Hampshire.

Purchase Heat not Fuel In district heating systems, the customer purchases the actual amount of thermal energy used—as measured by a Btu meter—rather than the fuel required by a boiler (i.e., energy output rather than fuel input). Since all boilers waste heat through their chimneys and seasonal inefficiencies, the actual amount of heat energy (measured as millions of British thermal units, or MMBtu) required for any given building will be less than is used as purchased fuel in a conventional system. New district heat customers converting from older, inefficient boilers will realize greater returns than those that currently have highly efficient systems.

2.4 ADVANTAGES OF BIOMASS ENERGY & BIOMASS DISTRICT SYSTEMS

There are numerous environmental and socio-economic advantages to using sustainably procured biomass fuel to meet energy needs instead of fossil fuels, such as heating oil or propane. Several benefits are listed below, followed by more in-depth discussion of some of the most compelling reasons to choose biomass energy.

- Increased flexibility and reliability over other energy sources
- Low heating fuel price escalation (biomass fuel prices have historically escalated at a slower rate than fossil fuel prices)
- Support of local fuel supply will lead to increased economic opportunity in the region and state
- Support of local economies will contribute to the overall fiscal health of the community through additional purchases, jobs, and an increased tax base
- Decreased susceptibility to interruptions in fuel supply
- Potential eligibility for "carbon credits" or Renewable Energy Credits under New Hampshire's thermal RPS due to using a carbon neutral energy source to produce heat and/or electricity (in the case of biomass CHP)

Dollars Remain in the Local Economy. Unlike fossil fuels that come from outside the northern New England region, wood fuel is a local and regional resource. The businesses associated with wood supply (logging operations, trucking companies, and sawmills) tend to be locally owned, retaining profits in the regional economy. These activities contribute to the federal, state, and local tax base. Conversely, most fossil fuel dollars leave not only the community, but the country. Fuel supply is increasingly an issue of national security, especially for places, like New Hampshire, that rely heavily on heating fuels during much of the year. A study funded by the Northeast Regional Biomass Program (NRBP) found significant economic benefits from using wood for energy.

For each 1,000 tons of wood used, the following is added to the local economy[2]:

- Total net income increases by $73,573[3]
- 1.45 jobs are created in addition to the existing job market
- $3,579 is paid in state and local taxes
- $13,452 is paid in federal taxes

More Local Jobs. Conventional energy systems require labor in fuel extraction, processing, delivery, operation, and maintenance as well as in system construction and installation. Fossil fuel supply is based on energy resources outside the community, thus, all jobs associated with extraction and processing are also outside the local and regional economies. The Vermont Job Gap Study found that Vermonters spend more than $1 billion annually for fuel and energy imported from outside the state. By contrast, jobs associated with wood fuel extraction, reforestation, and fuel transport are within the local and regional economy. Money spent on biomass keeps energy dollars in the local economy and supports jobs and economic development in the forest products industry and agricultural sector.

Energy Self-Sufficiency. New Hampshire does not have oil fields, it does have trees.

[2] Figures represented in constant 1994 dollars.

[3] Net income accounts for the difference between direct payments associated with biomass energy and payments associated with conventional fuels, as well as indirect income from the multiplier effect as primary dollars circulate throughout the local and regional economies.

2.5 Impacts on Local Fuel Suppliers and Servicers

While these benefits are important to communities and individuals, it is important to also assess the impact of a BDE system on local businesses that currently provide heating services and fuels to the buildings in the town.

There are ten heating oil suppliers that currently service the Colebrook market. These suppliers could experience a loss in sales of up to $2.2 million dollars annually if 85% of their sales are replaced by the maximum build out BDE system. One or more of these suppliers would likely retain a small percentage of fuel sales as backup fuel to the BDE plant. Fuel suppliers in some towns that have put in BDE plants have adapted their business models accordingly. A case study on the impacts on local fuel suppliers and how they have responded in the town of Linz, Austria is attached as Appendix A – Case Study Mitter Transportation Fuel.

Local HVAC providers would experience mixed impacts from the installation of a BDE system. In the initial stages of construction, installation of the system would be a windfall as many customers will need alterations in their existing heating systems to tie into the BDE plant. Many customers will opt to keep their existing systems in place which will continue to require regular servicing. Other customers will opt to have their existing heating systems removed by HVAC professionals. Although on-going maintenance on the heating systems in buildings on the BDE system will be lowered, there will still continue to be some regular maintenance needed on the internal heat distribution systems in these buildings. Learning to service the energy transfer stations could be a valuable niche skill for local HVAC contractors as other district energy projects come online in the future.

It is important to note that while the downtown area studied will have significant impacts, the majority of the population in Colebrook as in most of northern New Hampshire is rural and outside the boundaries of the proposed district heating system and will still be customers of the existing heating oil and propane suppliers.

3.0 Review of Technology Options

Several technology options were evaluated in this study, including both thermal and combined heat and power (CHP) technologies.

The technologies selected for further review for this project are described below. A description of the full range of biomass energy technologies considered for the Town of Colebrook is included as Appendix B – Technology Options.

3.1 Fully Automated Woodchip Boilers

Fully automated systems generally require very little operator attention – typically about one hour daily. They are a good match for buildings where the maintenance staff has a large work load and does not want to spend much time on the heating plant. These systems are well suited to schools and other buildings with significant heat loads and high conventional fuel costs since the capital cost of the woodchip system is relatively high but the fuel costs are lower, compared to pellets. These systems can heat an individual building, two or more neighboring buildings (by piping heat between buildings), or they can be the technology employed in a district energy system (explained in more detail below).

Equipment provided and installed by the vendor includes the automated equipment to unload the woodchip storage bin, the fuel handling equipment that carries woodchip fuel to the boiler (conveyors and augers, and metering bin(s)), the combustion chamber and boiler, combustion air supply fans, boiler connection to the stack, system electronic controls, safety devices, and usually emissions control equipment.

Fully automated systems employ a chip storage bin, typically below-grade that can hold one and a half to two tractor loads of chips (approximately 25 tons per trailer). For this evaluation, the team assumed the chips would be located in a below-grade storage bin inside the boiler plant building. This bin could be placed outside of the building if that is the preference of the owner and/or final design team. The fuel storage bin is generally sized to store five days of woodchips if the system were operating continuously at peak load conditions. A self-unloading truck is required to load the bin. No on-site staff assistance is needed for supervising fuel deliveries. From the chip storage bin, the fuel is fed automatically to the boiler. No operator assistance is required for fuel handling.

3.2 District Heating

District heating systems use one or more central plants to provide thermal energy to multiple buildings. In a district heating system, insulated underground pipelines distribute thermal energy from the central plant to each of the buildings connected to the network. Heat is then transferred at the point of interface at the connected buildings (heat transfer stations) and the cooler water is brought back to the heating plant, through return pipes to be heated again. In this way, district energy systems can be an efficient form of centralized municipal infrastructure, similar to public water supply/waste water systems.

District heating can employ a wide variety of fuels, including woodchips, which is the fuel source being considered for Town of Colebrook. District heating systems can provide space heating and domestic hot water for large office buildings, schools, college campuses, hotels, hospitals, apartment complexes, and other municipal, institutional, and commercial buildings. Systems can also be used to heat neighborhoods and single-family residences. Some district energy systems supply thermal energy to industrial customers for "process heat" (for example heat to dry the wood feedstock at a pellet mill), while others capture low-grade waste heat from industry to sell to customers.

A typical district energy system consists of the following components:

- Thermal energy generation - the boilers where steam or hot water are produced
- Thermal energy transmission and distribution (T&D) – the pipelines that deliver the thermal energy medium (steam or water) from the production sources to the network of users
- Customer interface – the integration of thermal energy at the user's (customer's) location, also known as Energy Transfer Station (ETS)

Technology for thermal energy includes a biomass combustion chamber (furnace) and boiler. The plant would include a fully redundant oil backup system to provide energy for the system during downtime of the woodchip boilers. Natural gas would be the preferred fuel for the backup system as it is more efficient and generally less expensive than oil, however it is not available in Colebrook at this time. There are plans to expand the natural gas pipeline in northern New Hampshire, and if natural gas is available in Colebrook at the time of construction it would be the preferred fuel for the backup system.

The system can generate thermal energy as steam or hot water. While consideration was given to using high or low pressure steam technology, hot-water boilers and distribution are recommended because it is more efficient for delivering heat over distances (there is considerably less heat loss from piped hot water compared to piped steam) and the cost of hot-water piping is lower than steam piping. A hot-water system is also safer and less expensive to operate than steam.

The heat distribution main line piping is typically thin-wall welded steel with integral foam insulation and plastic jacketing, designed to be direct-buried at a depth of about three feet (above frost line). Pipes can be placed in tandem with supply pipes for the hot water from the plant and return pipes for the lower-temperature water being returned to the plant to be reheated. In some cases, combined supply and return pipes can be housed in one single large insulated plastic pipe. Each customer's building is served by a pair of side connection pipes from the supply and return main lines. Generally, these pipes enter the basement or utility room to connect to the heat transfer station which feeds the internal heat distribution system of a building. The central heating plant uses variable speed pump controls to minimize the amount of electricity used in the pumping process.

Inside each connected building, there is an "energy transfer station." For a building with hot water heat (serving baseboard, radiators, or unit heaters for individual room heat), the energy transfer station includes one water-to-water heat exchanger for space heat and a smaller one for

domestic hot water (DHW) supply. Hot air furnaces need to have water-to-air coils installed in the main heating ducts. Propane space heaters can be removed and replaced with baseboard hot water for room heating.

For the buildings in the Town of Colebrook, these heat exchangers would be compact and can be either floor or wall-mounted. The energy transfer station can also include a heat meter, which measures how much heat is taken out of the system water and transferred to the building for ease of monthly billing.

3.3 Organic Rankine Cycle (ORC) System

The Organic Rankine Cycle (ORC) technology was only examined for possibility of adding electricity production to the district heating plant under the scenario of a hypothetical pellet mill co-located adjacent to the district energy plant.

ORC is a thermodynamic process in which, instead of water, a low boiling organic fluid circulates as a working fluid. ORC uses non-flammable silicon oil as the working fluid. Biomass is burned in the combustion chamber and hot exhaust is streamed through the thermal oil boiler. The boiler heats this thermal oil to about 300° C (572° F). The hot thermal oil evaporates the working fluid from the ORC system in the evaporator, turning it into vapor. Under pressure this vapor is forced through the expander, turning it to spin an electric generator. The expander could be a twin screw expander or turbo expander. The vapor is cooled and condensed back into liquid in the condenser; this condensation is obtained by heating hot water. The hot water can then be used for space heating or any other thermal energy requirements. The working fluid liquid is then pumped and returned to the evaporator to repeat the process.

There are several advantages of the ORC system. It is a low pressure system, and so requires minimal operator attention and maintenance. ORC plants do not require stringent supervision by highly trained personnel, which means that the operation of the ORC is less expensive than for some other CHP systems. The system has a few moving parts and so long-term maintenance is also minor. The ORC system also does not require a water treatment system. It has better efficiency and more reliable operation. The expander has lower operating speed, and so is compatible with synchronous generators. ORC system capacities range from 50 kW to 2.2 MW, and can be stacked to provide much larger power outputs. There are a large number of CHP plants using ORC technology successfully running in Europe with continuous and unattended operation.[4] To be economically competitive, an ORC plant really needs to operate for at least 4,000 hours at full load.

[4] It should be noted that while ORC technology is proven and widely used throughout Europe, there are very few installed systems in North America. As a result ORC technology carries higher perceived risk.

4.0 Assessment of Thermal Energy Demand in Colebrook

4.1 Assessment of Inclusion of Specific Heat Loads

Municipal
The Town of Colebrook is envisioned as a leading member of the district energy system. The municipally owned buildings, including the schools, the town garages, the library and the town offices, provide important anchor loads for the district.

Upper Connecticut Valley Hospital
The Upper Connecticut Valley Hospital would be an important anchor load for the north end of the district energy system. The hospital uses an average of 54,598 gallons of fuel oil annually. At a fuel price of $3.50 per gallon for number 2 heating oil, the hospital would spend $191,093 on heating annually. If the BDE plant offers heat sales at 20% off the cost of oil, the first year savings alone would be just over $38,000.

The economic analyses assume that the BDE plant developers incur the full cost of connecting the hospital to the BDE system, with the hospital responsible only for any internal renovations required to their internal heat distribution system to interconnect with the energy transfer station. Estimating the scope and cost of any internal renovations was beyond the scope of this study but as the hospital already uses hot water distribution, the study team did not estimate that any major renovations would be necessary. These were the same assumptions included in the economic analysis, which was positive for the BDE system to build out to the hospital as an anchor load.

North Country Community Recreation Center
The North Country Community Recreation Center was not considered in the McCormick study but was surveyed for potential consideration in this study. The rec center uses an average of 7,026 gallons of fuel oil annually. At a fuel price of $3.50 per gallon for number 2 heating oil, the facility would spend $24,591 on heating annually. If the BDE plant offers heat sales at 20% off the cost of oil, the first year savings alone would be just over $4,900.

However, the rec center is a relatively small and isolated load. 1,978 of piping would be required to connect the rec center to the main line of the district heating system on Main St. At a cost of $275 per trench foot, the cost to connect the rec center to the main line of the district heating system would be $543,950 in piping cost alone, excluding the cost of the energy transfer station and internal renovations required in the building. In order to cover just the cost of this piping, the district heating plant would have to charge the rec center $72.95per MMBtu (rather than the price of $28.99 per MMBtu used in the analysis) just to break even on the cost of the network installation. Hence it was not a load considered in any of the options studied in more detail.

Fossil fuel prices would have to rise far faster than they have to date for any party to get a reasonable payback period on the investment that would be required for the rec center to join the BDE system. If the North Country Community Recreation Center desires to replace fossil fuel use with biomass fuel use, a pellet system at the site would be a much more feasible alternative.

Colebrook Industrial Park
The Colebrook Industrial Park has three existing buildings. Two are small manufacturing facilities. The other was formerly the site of a gunpowder factory and is currently unheated. The front half of this building is used for boat and RV storage while the rear half is empty. The facility at the industrial park with the highest fuel use is the D&E Screw facility. However, they use a good deal of their own waste oil for heating and purchase less than 850 gallons of heating oil per year.

With its current level of heating demand, the industrial park is a small load that does not justify the expense of running a line from the BDE plant. However the presence of a BDE plant could potentially attract new businesses to the industrial park with the offer of low cost space and process heat, and with new businesses the industrial park could easily become a key customer for the BDE system. With a heating load of 100,000 gallons per year, the park would become a viable customer for the BDE system. This is about three times the heat load of the Colebrook Elementary School. If a manufacturer with process heat needs were to move into the vacant building, its combined space and process heat loads could potentially meet this level of demand. Additionally, the availability of low cost process heat from the BDE system could attract new businesses to the industrial park.

Residential and Small Commercial Loads

Several residential zones and smaller commercial buildings that are included in the full build out analysis are not considered in Phase I as optimum for a first phase system because they do not contain an anchor load to justify the network piping in and of itself. For these areas, a very high percentage (between 80 and 90%) of the buildings would have to sign on to the district system to provide the load density needed to make laying the network piping economically viable. If there are neighborhoods that are particularly interested in joining the BDE in the beginning, signed commitments could be gathered and they could be included in a phase I build out.

The economic analyses for the business model assume that all costs of connecting customer facilities to the BDE system would be incurred by the project owners. The model was designed in this manner so that all costs for building the system would be accounted for in the assessment of project viability. However, some buildings may require internal renovations in their heating systems to interconnect with the energy transfer stations. In the detailed analysis of Phase I, the homes and businesses that had forced air or steam (and hence may require more expensive renovations) were not included as loads on the first phase system unless they were of a certain size. These buildings were considered potential customers in the more conceptual Full Build Out but no assumptions were made on the cost of internal renovations to these buildings.

Although the analyses presented in this report include all capital cost including customer interconnection as part of the total capital investment of the BDE project to assess the viability of the project, depending on the ownership and business model of the BDE system when it is eventually built, there may be some charges to customers to connect to the BDE system. For a homeowner with a $4,000 heating bill, the first year savings at a 20% discount on oil heat would be $800. The payback period on a hypothetical $5,000 investment in internal renovations and charges to interconnect to the BDE system would be approximately 6 years and 3 months. The BDE plant developers will ultimately have to decide whether or not to bear all of the costs of connecting each facility to the network or whether to charge building owners some fee to connect. To attract the maximum number of customers, this fee should be less than what it would cost a building owner to purchase and install a wood pellet system as their own source of biomass heating.

Benefits for home owners (and other BDE customers) beyond the savings in heating costs include:

- Direct savings by avoiding capital equipment costs of replacing fuel tanks and boilers, and the time and expense of yearly maintenance
- Time savings in price-shopping and negotiating yearly contracts with fuel suppliers
- Stabilized heating costs since district heat pricing is less impacted by fluctuations in fuel prices
- Simplified building operations and reduced building maintenance costs
- Available space previously used for the boiler that can now be used for other purposes
- Reductions in risk of fire, carbon monoxide poisoning and other combustion-related hazards. In a district energy system, combustion happens centrally—not in individual buildings—significantly reducing risks in buildings in the system. In addition to making buildings safer, this reduced risk of

combustion-related hazards may reduce fire insurance and liability premiums to homes and businesses in the district.

- Reduced risk of power outage or other "down-time." District systems have back-up systems and back-up power sources as well as fuel stockpiles. The risk of heat interruption is almost nil as a result. Even when the system must shut down for short periods, the retained heat in the system is sufficient to provide continuous heat. As a result, the individual user does not need to worry about not having heat or hot water during a power outage.

4.2 Heating Load

The heat load is the total heating demand of the buildings in the proposed district area. The majority of buildings in Colebrook use fuel oil for heating, though some use propane or wood (cordwood or pellets). For the purposes of this study, all heating fuel consumption is reported in gallons of oil for ease of comparison; any propane or wood use was converted to oil equivalents.

Full Build out Scenario Heating Load

The annual fuel oil usage target for the Full Build Out scenario is 746,000 gallons. This is an average annual value based on very preliminary estimates on not based on collection of actual fuel usage or building modeling. The heating load will vary throughout the year, with peak heating load in the coldest winter months and a lower level of demand during the 'shoulder' heating season consisting of several weeks before and after the coldest winter months. Thus, to develop a load model, the average annual use is spread over a year with an average number of heating degree days (HDD). The long-term average is 9,118[5] HDD (base 65) per year based on 30-yr NCDC data for Colebrook. Daily surface temperature data obtained from NCDC for the Colebrook, NH weather station (USC00271647) shows that over the last 10 years, 2004 with 9,180 HDD (base 65) is the closest year to the long-term average. The 2004 daily surface temperature data is used to develop a model of the energy demand over the course of a year, and the result is presented in first graph below.

The hospital is the only significant individual summer load for the system, and fuel delivery records indicate that approximately 1,500 MMBtu/yr of the annual demand for the hospital is from May through September. A concept-level estimate of the domestic hot water load for the other 407 buildings identified in the full build-out scenario was conducted. This resulted in a combined year-round base load of 24 MMBtu/day of heat demand. This base load is used in the modeling of the space heating loads.

This scenario considered a district heating system for the town of Colebrook as defined by the McCormick study. Some additional facilities were considered for inclusion in the district network, such as the rec center as described above, but all were ruled out as having heating loads too small to justify inclusion in the system. The study team's analysis concurred with McCormick analysis on the maximum extent of the BDE system. The study area consists of 408 industrial, commercial, municipal, religious, state/federal and residential buildings. The square footage of each type of building was collected & compiled from the McCormick study and municipal tax records. The data is summarized below.

Table 1

Type	Commercial/ Municipal	Residential	Church	School	State/Fed	Unknown	Total
Total Square Ft	1,105,270	934,574	43,797	209,648	12,816	5,138	2,311,243

[5] 30-yr NCDC average data as reported by www.weather.com.

% excluded from DH	0.15	0.20	0.15	0.00	0.00	0.00	
Sq Ft for DH	939,480	747,659	37,227	209,648	12,816	5,138	1,951,968

Based on census records and experience with similar studies, it was estimated that some of the building area would be excluded from the district heating system. Some of the area was assumed to be unheated space. Other areas were assumed to be heated with wood pellet or cordwood stoves and hence less likely to join on to the BDE system as they are already heated with low-cost biomass fuels. For commercial and municipal buildings, this area was estimated at 15% of the total area. For residential buildings, this area was estimated at 20% of the total area. The schools and state buildings were assumed to be fully heated with heating oil.

The fuel use for the total area was calculated using an estimated fuel use for each category of building. These estimates were based on data collection in the town of Colebrook where actual fuel use data was available and compared with other studies with more data points for each type of building. The coefficients are displayed in the table below.

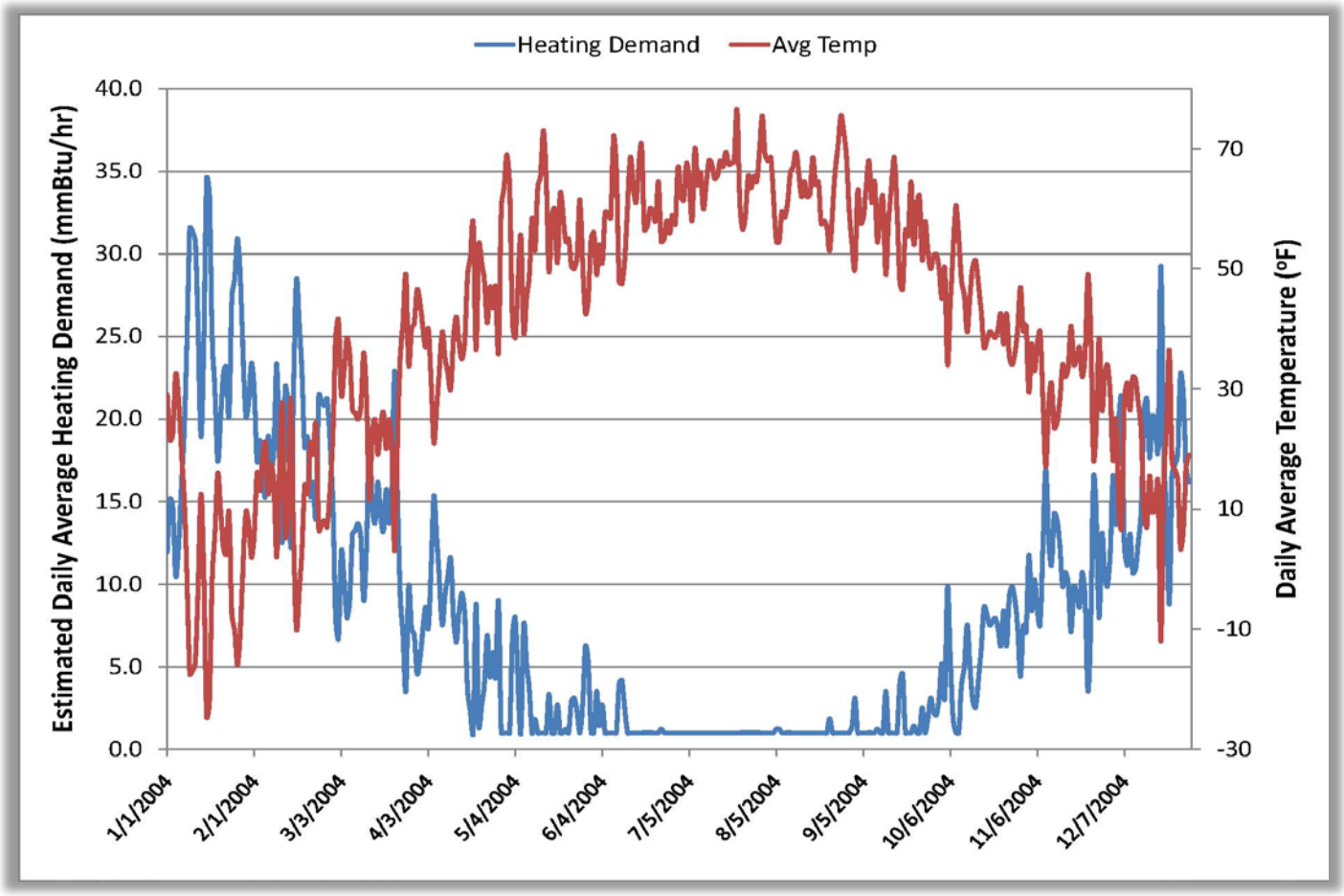
The total fuel use for the study region was calculated to be 746,000 gallons of oil annually.

A 50 MMBtu/hr central energy plant would be connected via buried hot-water distribution piping to the district energy grid system in order to deliver heat to the 408 industrial, commercial, and residential buildings in the study area. Heat exchangers and meters would be installed at each building to connect each user to the grid. As in Scenario I, the BDE plant would be located at the parcel adjacent to the town garage. A total of 55,000 trench feet of piping would be required to connect the 408 buildings to the BDE plant.

In this option, the BDE plant would require 16,360 green tons per year of woodchips (with an assumed value of 40% moisture content) in order to generate enough thermal energy to meet these buildings' heating demand. During standard operation, the BDE plant would require 1.01 million kWh of electricity annually, which would be purchased from the electrical utility.

The technologies considered were the same as those for Scenario I. As with Scenario I, there were not enough hours at full load operation to support a CHP project.

The seasonal heating demand for the buildings as identified in the Full Build Out scenario is illustrated by the following figure.



Phase I Scenario Heating Load

This scenario defined an optimal first phase installation for the district energy plant. The system was designed by the study team using the concept of anchor loads to define an optimal district heating system that best represents what a viable first phase project would look like. Anchor loads are relatively large heat users with relatively consistent energy use patterns. The higher & more consistent demands of these facilities provide enough demand to justify the installation of the main line distribution piping, allowing the benefits of district heating to be delivered to smaller residences and other facilities along the route. Facilities evaluated as potential anchor loads include the IGA, Upper Connecticut Valley Hospital, Colebrook Recreation Center, Colebrook Elementary School, the industrial park and the Colby Commons Apartments. Whether or not a building will provide an anchor load for the system depends on the ratio of energy use to distance from the district energy plant. The IGA, the Colebrook Recreation Center, the industrial park and Colby Commons were ruled out as potential anchor loads based on their current energy use and their distance from the proposed plant site and other major loads. This does not mean that they are ruled out as potential customers for the full build out of the district energy system, but that the heat loads would not justify a network branch to this customer alone. Such a branch would require multiple other facilities to sign up for the BDE system to reach the load density required make construction of the line economically feasible. Hence these routes were not identified as optimum for the initial build out of the system. The hospital and the Colebrook Elementary school were identified as anchor loads for the system.

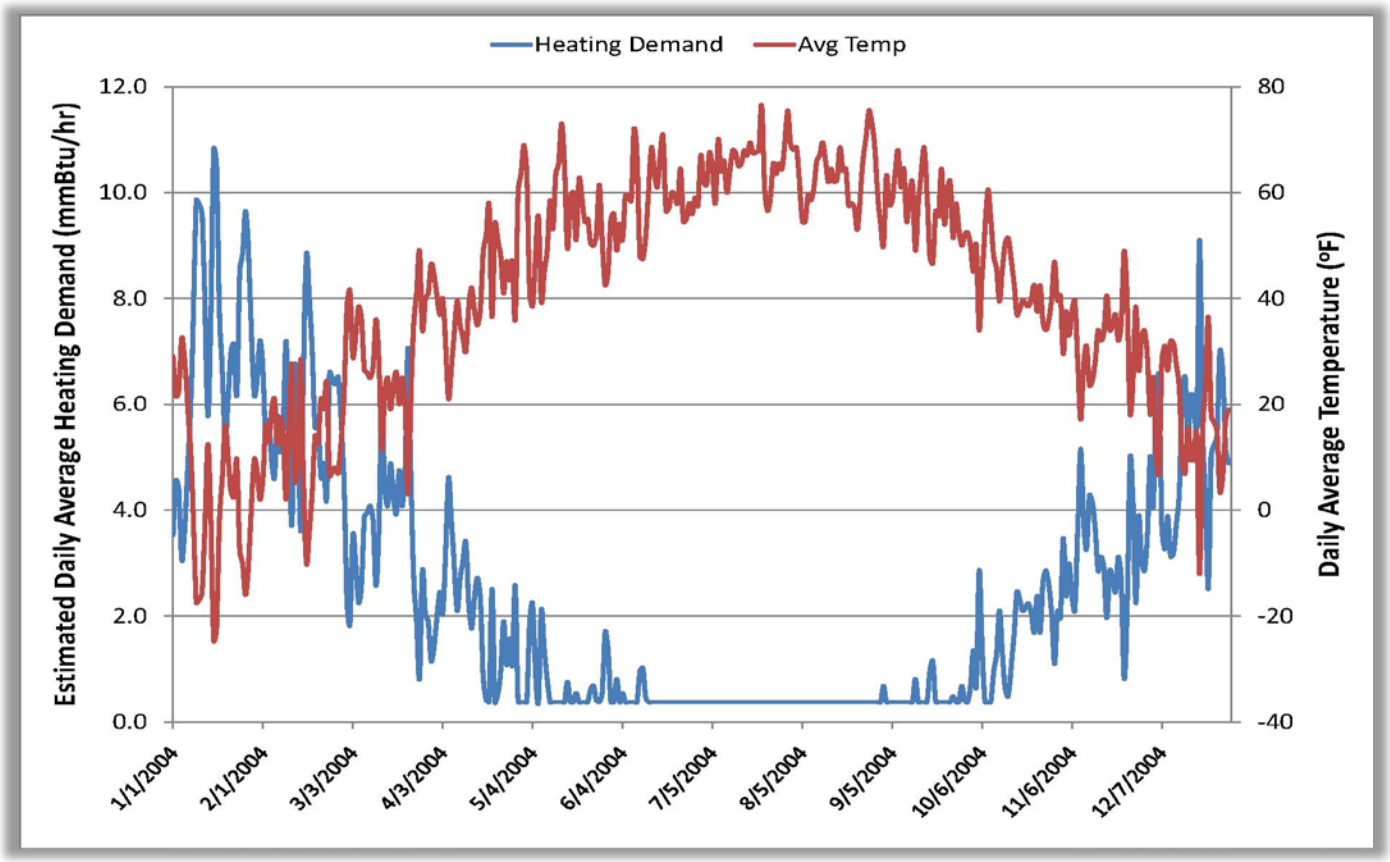
The Phase I load was calculated based on actual fuel use data for many of the buildings. Where fuel use data was not available, the fuel use was calculated based on the square footage using the following table:

Table 2

Building Type	Commercial[6]	Residential[7]	Church[8]	Municipal[9]	State/Federal[10]	Unknown[7]
Fuel Consumption (gallons of oil/ sq ft)	0.47	0.45	0.35	0.76	0.5	0.5

An additional factor in sizing a boiler for a district system is the percentage of the total maximum capacity that will be required by the system. The load coincidence factor is the quotient of the simultaneous peak heat demand by a number of customers, and the sum of the usually non-coincident individual peak demands by these customers in the same period of time. In other words, not all facilities on the system will be on-line and requiring their maximum demand at any given time. The load coincidence factor attempts to define what percentage of the total load would be likely to be required at any given time. The load coincidence factor in the technical analysis is assumed to be 80%.

The total load was calculated to be 205,343 gallons of oil annually (the number of gallons of oil that would be displaced by the BDE system if all buildings on the connection list signed up). The boiler size was calculated to be 13 MMBtu/hr. 10,500 trench feet of network piping would be required to connect 41 customer facilities to the BDE plant. The seasonal heating demand for the buildings targeted for Phase I is illustrated by the following figure.



[6] Colebrook data & Survey Results for Smethport PA, MESA Smethport Woody Biomass Demonstration Project Technical Report, Lahmeyer International, 2010
[7] Colebrook data & Calais VT study conducted by Community Biomass Systems
[8] Estimated to be the same as commercial usage based on Smythport, PA study
[9] Colebrook data
[10] Montpelier VT study by Community Biomass Systems

It is important to note that the graphs above provide an estimate of the daily average demand. During the course of a 24-hr period, the actual demand will fluctuate. It is not uncommon for actual hourly demand within individual facilities to fluctuate between 35% above and 35% below the daily average based on experience with usage records.

Full Build out Scenario Plant Sizing

To identify the peak load for the system, the peak daily average of 34.5 MMBtu/hr is increased by 35%, and a demand factor of 0.8 is used to account for variations in the timing of peak within each facility. This results in a peak value of 37.3 MMBtu/hr of heat to be delivered to facilities along the district heating system.

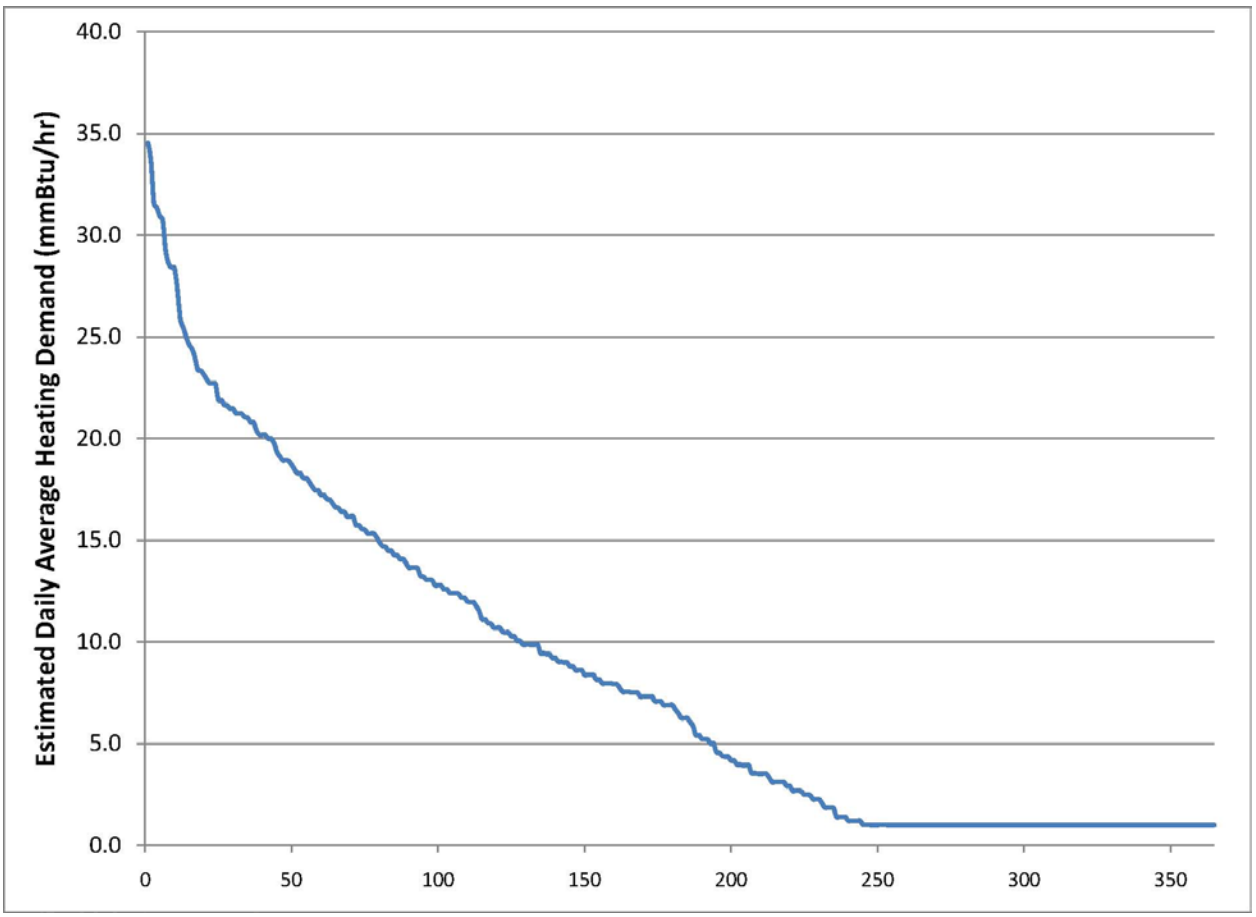


Figure 2 – Average Daily Thermal Demand Load Duration Curve (LDC)

Note: Figure shows the estimated daily average thermal demand based on average estimated fuel usage values and daily surface temperature data from NCDC for calendar year 2004 (Colebrook, NH station). During the course of each 24-hr period, the load will fluctuate from the average presented.

The approach taken to sizing the district heating plant is to provide year-round coverage of heating loads. This is done despite the low summer loads in order to allow full replacement of heating equipment within each owner's facility. This is necessary in order to keep home and business owners from realizing continued ownership and maintenance costs for heating equipment within their home/facility. Other approaches such as operating the biomass system only for the heating season and with one biomass unit were considered. However, these were eliminated due to occurrence of space heating demand during the period of May through September. Space heating demand during this period could not be covered by one biomass unit and would require system users to

maintain onsite backup equipment. The approach to covering the full annual load is to utilize two biomass units to provide for all load with full fuel oil backup available for emergencies and coverage of planned biomass system maintenance.

When evaluating the biomass system's ability to meet the thermal loads of users connected to the district system, heat loss from the distribution piping and equipment must be considered. The distribution system includes approximately 65,000 feet of supply and 65,000 feet of return piping within 65,000 linear feet of trench. This 130,000 feet of pipe does not include the length of small diameter piping leading to and from each individual home or business. The heat loss in the piping system is estimated at 1.95 MMBtu/hr for the entire period for which the biomass system will be operational. This heat loss will fluctuate somewhat based on seasonal adjustments in supply and return temperatures as well as ground temperature over the course of the year. However, for the purposes of this analysis, this value is kept constant.

Biomass unit sizes of 350-hp and 1,000-hp are selected for the system. The 350-hp unit will be capable of providing a peak of 11.72 MMBtu/hr of heat, 1.95 MMBtu/hr of which will be absorbed by heat loss in the distribution system. The biomass unit will be capable of operating efficiently down to 25% of rated capacity, and thus the minimum design supply rate to the users on the district system will be 0.98 MMBtu/hr (2.93 MMBtu/hr boiler output minus 1.95 MMBtu/hr heat loss). The 1,000-hp (33.48 MMBtu/hr) unit will be capable of effectively meeting user demands between 6.42 and 31.53 MMBtu/hr. The combined range of heat supply to the district users by the system will be 0.98 – 43.25 MMBtu/hr (2.93 – 45.20 MMBtu/hr boiler output). This range covers the minimum demands in the summer as well as the peak demand of 37.3 MMBtu/hr and provides room for future expansion. The biomass systems are able to fire below the minimum rate depending on the fuel moisture and other factors. However, it is not desirable from an efficiency or emissions standpoint to design in sustained operation below this rate.

The following graph shows that the proposed biomass units can cover 100% of the range in thermal demand on the system.

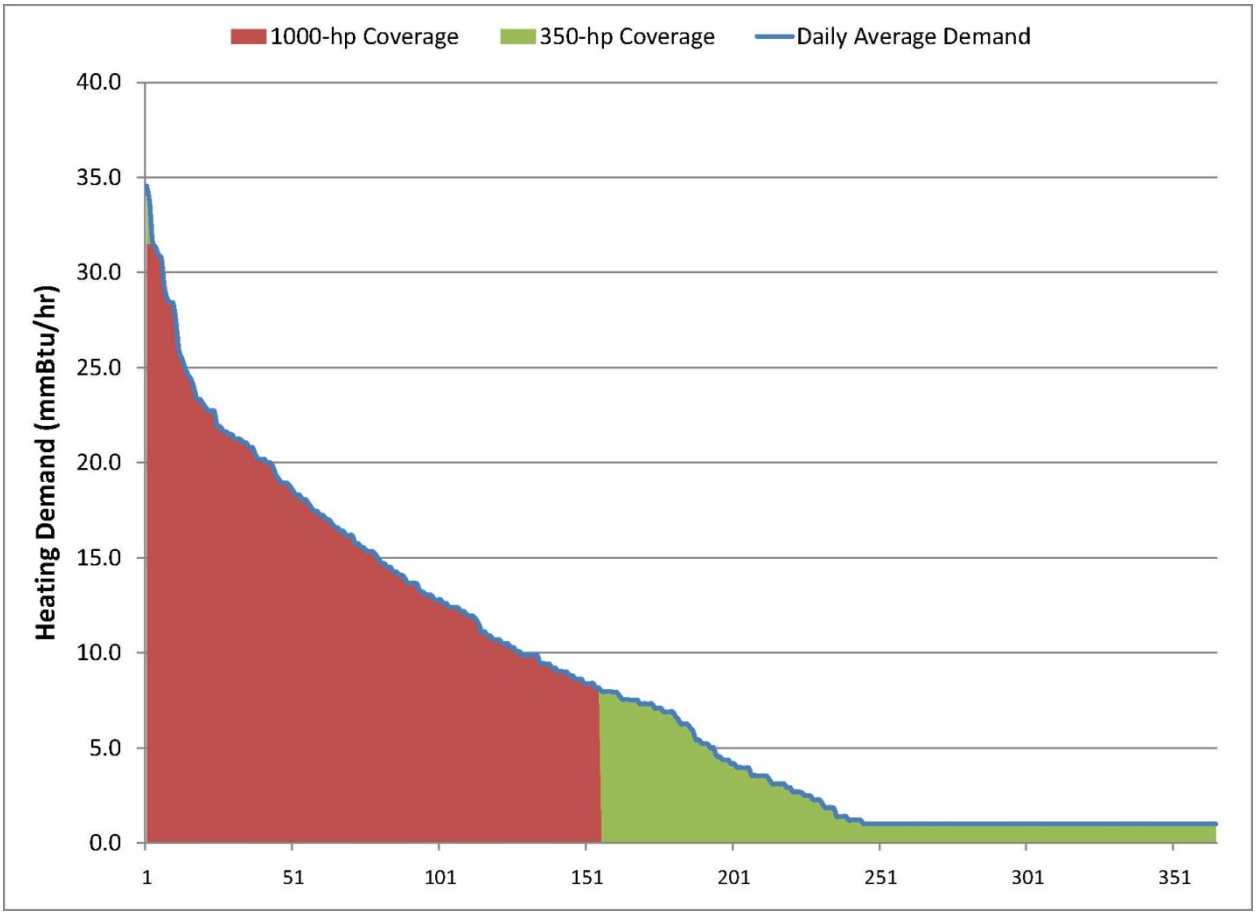


Figure 3 – Biomass System Coverage of Thermal Demand

Note: Figure shows coverage of thermal demand shown in Figures 1 and 2. The maximum thermal energy available to meet heating demands in the facilities connected to the district system is reduced by 1.95 mmBtu/hr due to system heat loss. This loss is reflected through direct reduction of the effective output of the biomass units.

A thermal storage unit is recommended for inclusion in the overall system. The storage will be set at a temperature above the desired supply temperature. Storage water will be blended with return water by a three-way mixing valve to meet the supply temperature. For the purposes of this report, a temperature of 220°F in the thermal storage tank is assumed with supply water temperature determined based on a seasonal reset and customer needs. A minimum design temperature delta of 40°F is assumed. During the peak heating season, this report assumes a supply temperature of 200°F with anticipated return temperature of 160°F or below. A 35,000 gallon thermal storage tank is recommended for this system. This will provide up to 5.8 MMBtu of stored energy to meet temporary peaks without a drop in supply temperature. In the shoulder season, when supply temperature is set at a lower point, the thermal storage tank will provide a heat sink. As an example, the storage tank will provide a minimum of a 14.5 MMBtu/hr heat sink with 170°F supply water. This heat sink allows the system to span short-term periods of low load with efficient operation.

The ability to utilize temperature resets will depend on the connected loads. For example, currently one half of the hospital's heating system utilizes lower temperature hot water when it is warmer outside. The other half uses 190°F hot water at all times of the year. It is possible that this could be adjusted if the district heating system is interconnected with the hospital load, but the ability of the heat distribution equipment within the hospital to meet loads with lower temperature water would need to be verified. Another key to supply water temperature is temperature drop along the pipeline during low-flow periods. Distribution system flows would typically be controlled by variable frequency drives based on the temperature difference between supply and return

temperature. However, during the shoulder seasons and summer, a minimum flow will need to be established to ensure adequate temperature can be provided at the Hospital or other higher temperature users.

Phase I Plant Sizing

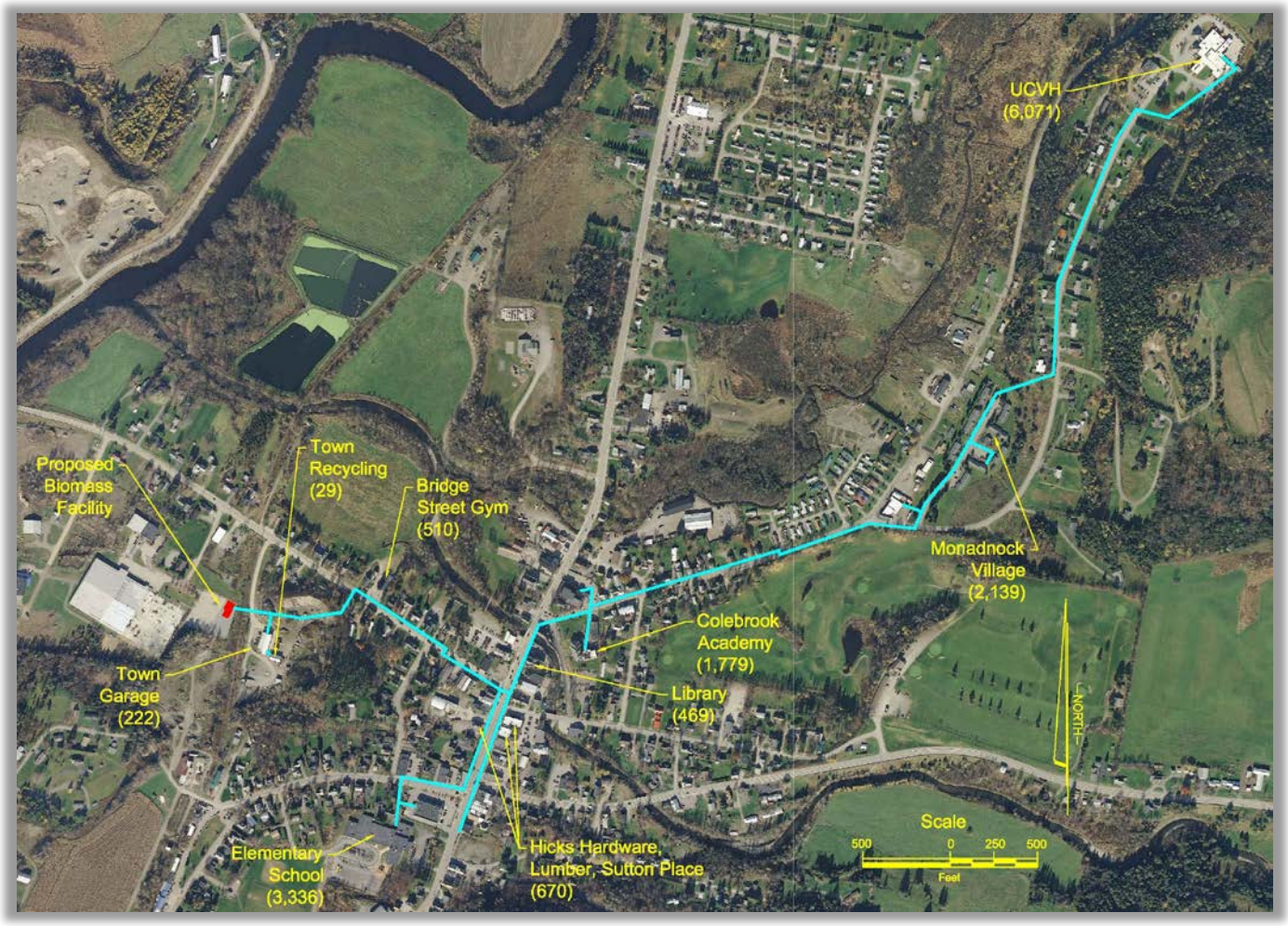
To identify the peak load for the system, the peak daily average of 10.8 MMBtu/hr is increased by 35%, and a demand factor of 0.8 is used to account for variations in the timing of peak within each facility. This results in a peak value of 11.7 MMBtu/hr of heat to be delivered to facilities along the district heating system. The biomass boiler units are designed for the current peak value to ensure efficient system operations for the initial system, and the building will be dimensioned so as to allow for an increase in boiler system capacity. The potential exists for future expansion of the district heating system. Distribution piping will be sized to allow a 50% increase in peak demand for a peak of 17.5 MMBtu/hr. This increase in pipe sizing results in a moderate increase in initial costs, but is necessary to allow future build out of the system over its 25 year or greater life.

The approach taken to sizing the district heating plant is to provide year-round coverage of heating loads. This is done despite the low summer loads in order to allow full replacement of heating equipment within each owner's facility. This is necessary in order to keep home and business owners from realizing continued ownership and maintenance costs for heating equipment within their home/facility. Other approaches such as operating the biomass system only for the heating season and with one biomass unit were considered. However, these were eliminated due to occurrence of space heating demand during the period of May through September. Space heating demand during this period could not be covered by one biomass unit and would require system users to maintain onsite backup equipment. The approach to covering the full annual load is to utilize two biomass units to provide for all load with full fuel oil backup available for emergencies and coverage of planned biomass system maintenance.

When evaluating the biomass system's ability to meet the thermal loads of users connected to the district system, heat loss from the distribution piping and equipment must be considered. The distribution system includes 10,500 feet of supply and 10,500 feet of return piping within 10,500 linear feet of trench. These 21,000 feet of pipe does not include the length of small diameter piping leading to and from each individual home or business. The heat loss in the piping system is estimated at 0.52 MMBtu/hr for the entire period for which the biomass system will be operational. This heat loss will fluctuate somewhat based on seasonal adjustments in supply and return temperatures as well as ground temperature over the course of the year. However, for the purposes of this analysis, this value is kept constant.

4.3 Phase I Pipe Network

A map of the proposed BDE network for the Phase I follows:



The district piping system is sized to allow a 50% increase in peak demand, and the heating plant is sized to accommodate a 50% increase in annual load while still maintaining 95% or higher coverage with wood. The central plant for Scenario I includes two advanced biomass combustion units and hot water boilers (300 hp and 100 hp) and fossil fuel backup boilers (300 hp and 150 hp). The boilers are rated at 150 psig. Appendix D – Conceptual Plant Designs and Network Maps includes a boiler plant layout and a schematic showing equipment interconnection. The central plant includes approximately 300 cubic yards (roughly 90 green tons or three tractor trailer loads) of usable wood chip fuel storage. This is equivalent to approximately 2 days of use at maximum system output. The building housing the boiler room and fuel storage is just over 5,900 sf.

In this option, the BDE plant would be located adjacent to the town garage. The plant would require 3,940 tons per year of green woodchips (with an assumed value of 40% moisture content) in order to generate enough thermal energy to meet these buildings' heating demand. During standard operation, the BDE plant would require about 265,000 kWh of electricity annually, which would be purchased from the existing electrical grid.

Technology Description Based on the study team's review, a fully automated woodchip combustion system was considered for this option. The system can generate thermal energy as steam or hot water. While consideration was given to using high-pressure steam technology, hot-water distribution is recommended because it is more efficient for delivering heat over long distances (there are considerably lower heat losses from piped hot water compared to piped steam) and the cost of hot-water distribution piping is lower than for steam piping. A hot-water system is also safer and less expensive to operate than steam.

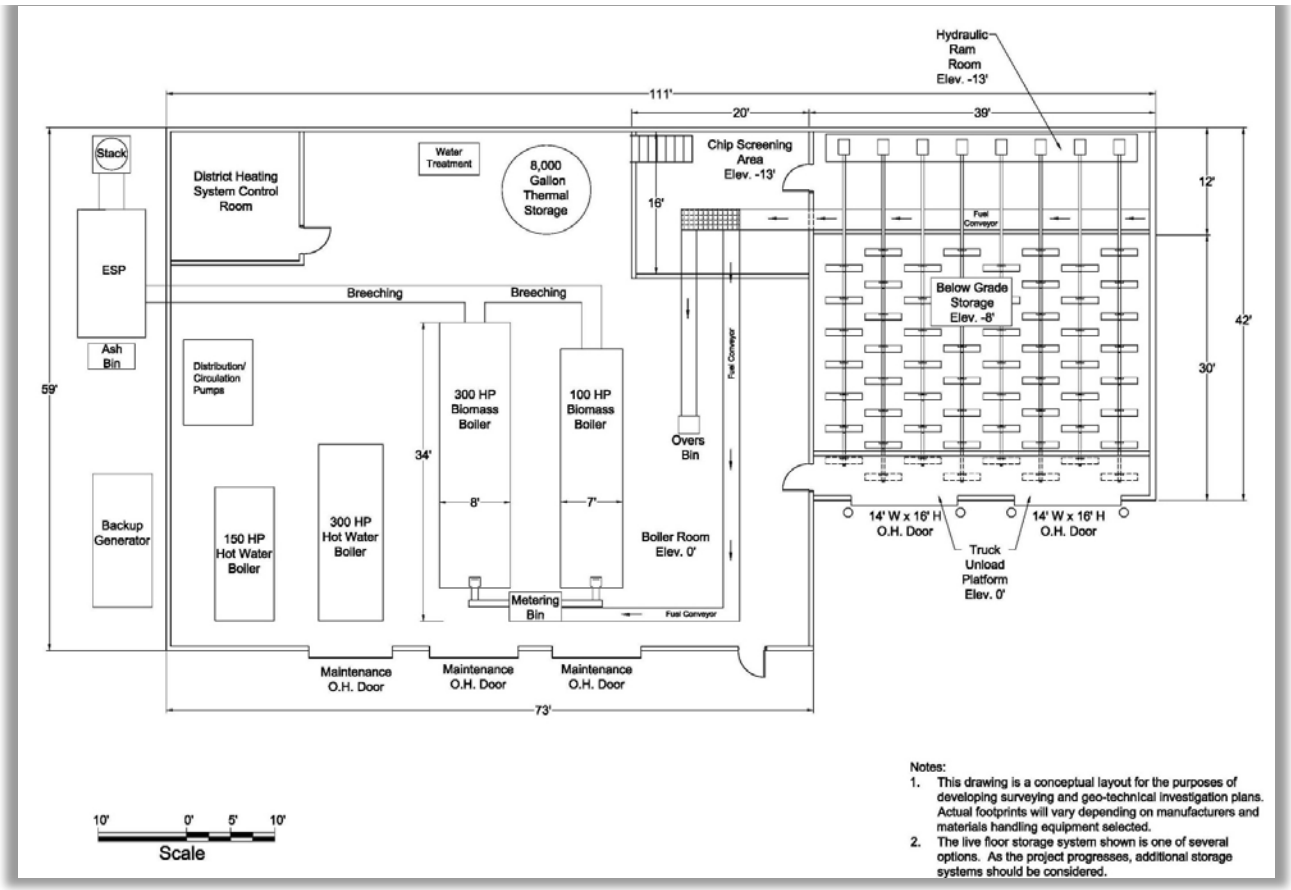
4.4 Phase I Conceptual System Design

Siting

The study team visited several potential sites for the district energy plant. One site was land located at the Town Garage but this site was ruled out for several reasons. Another site located within the Industrial Park was identified and deemed the best site based on the opportunity to allow possible future expansion of the District Energy plant to possibly provide both process heat and electricity to a new business that may locate to the Industrial Park at some point in the future.

Energy Plant Building A building to house system equipment and a biomass fuel storage area will need to be constructed at the plant site. The site selected as optimal by the study team was the town garage parcel. This site is close to many of the major anchor loads, reducing network costs, and is owned by the town, reducing the capital costs (assuming municipal ownership). The biomass boiler plant will have direct access from the main road for easier woodchip deliveries. A building just under 6,000 square feet would be sufficient to house the necessary equipment considered in the preliminary design stage for this study. A conceptual layout of the energy plant is provided as Figure 3, with the full conceptual designs included as Appendix D – Conceptual Plant Designs and Network Maps. Should the project move forward, final designs will need to be confirmed after the equipment vendors are selected as each vendor's system has its own specific space & interconnection requirements.

Figure 1



A stack and ESP must be installed on the central energy plant to effectively reduce and disperse any emissions in order to ensure minimal impact on air quality in the surrounding area. A dispersion modeling study will determine the appropriate height and location of the stack, accounting for weather patterns, local topography, neighboring facilities, and wind direction.

5.0 HEAT UTILITY OWNERSHIP AND PROJECT FINANCING

5.1 Public-Private Partnerships

There is a growing interest among New England communities in developing BDE systems. There are few U.S. examples of community-scale biomass district energy systems, but a wealth of examples from Europe and other countries that can be adapted to work in the U.S. In regions of Europe, especially, biomass district heating has grown to be the predominant method of community heating. Communities, therefore have the option to seek out partners in the non-profit, for-profit and governmental sectors here and abroad to help understand and implement district energy systems.

Among companies and organizations in the non-profit sector, BERC and the International District Energy Association (IDEA) are two of the most prominent resources for communities interested in exploring the concept of BDE systems. In the commercial sector there are yet more partnership options including: district energy companies, energy developers, biomass project developers, utilities, engineering firms, energy services companies (ESCOs) and performance contractors. In order for a municipality to develop a project it may be necessary to form a partnership with one or more such entities from the non-profit and for-profit sectors. While these companies can offer expertise, local partnership and leadership is important to ensure that the project fits the community's needs and circumstances, from feasibility, through financing, construction, start-up and future operation.

5.2 Municipal Utility Model

A municipal ownership model of a district energy facility means ownership by one or more municipal governments. Municipal ownership can take the form of an entire facility or portions thereof, such as the underlying land or the means of energy transmission.

A potentially important and valuable advantage of a municipality in the development of a district energy facility is the power of eminent domain. Under the power of eminent domain condemnation may be necessary in regard to locating a facility or the means of transmission. This municipal power may also be relevant in a private ownership model to the extent that a municipality may own some of the components of the facility (i.e. heat distribution piping, district heating facility, land the facility is located on, or any combination of the above).

The viability of any municipal model rests on a determination that the district energy facility will be of financial benefit to the municipality. There must also be the political will to communicate that benefit to the public and then to carry out the development and operation of such a facility. There are examples of municipalities operating their own electric departments as well as other similar services such as cable and internet access, water supply and distribution systems, as well as sewage systems and treatment facilities.

The viability of developing a district energy facility would follow the same path as such existing models of governmental services. The greatest disadvantages to a municipal model are the political hurdles that must be overcome in approving a facility. The political climate, such as the view of public versus private services, within municipal government as well as the population generally can be determinative.

The advantage of a municipal owned district energy utility system is that the local government/municipality can exercise its influence on business decisions of the utility (for example price regulation, environmental regulations, impact assessment) especially in the cases where the public administration has a mandate for these issues, or specific legislation, in national or regional law.

A major benefit of municipal ownership lies in the fact that municipalities are place-based companies like consumer-owned utility cooperatives and non-profit organizations. They are managed by local people, serve local energy needs and offer local control over utility policies. Since they are public enterprises shaped by and accountable to place and constituents, they can be structured to reduce weaknesses and maximize community control rather than be dominated by a select group of politicians. Short-term deals, brokered between politicians and utilities, can often drain local resources and have long-term fiscal and social consequences for a community. Many public power utilities appoint citizen panels to advise them on all aspects of the company, from services to reliability and rates, thereby minimizing the possibility of corruption and fiscal leakage.

Community citizens have a direct voice in the policy and utility decisions that affect them. Public utility meetings are open to the public unlike independently operated utility meetings which are often conducted in secret with only the key stakeholders present. Resident citizens, empowered to elect board members of local utilities instead of politicians appointing them, can reduce undue political influence. If local communities enact strict campaign-finance reform and lobbying laws they could increase the likelihood of community representation at all levels of the public utility company and provide a check and balance system against political maneuverings.

5.3 Co-op and Local Investment Models

In the long term, there is little doubt that a biomass district energy system can deliver heat at lower and less volatile cost if oil prices stay at current rates, or, as we expect, if they increase significantly over the coming years. In fact, as thermal energy accounts for a full 30% of oil usage nationally, implementing biomass district energy systems where wood is plentiful and relatively inexpensive can reduce the cost of oil by reserving oil usage for those systems in which it is truly the best or only fuel option. However, the biggest barriers to entry are the relatively high capital costs of developing a district heating systems and unfamiliarity with them throughout most of the U.S. If up-front capital can be reasonably obtained, there is evidence from decades of success in similar European communities that long-term benefits will more than compensate for the up-front costs.

The European district heating model that appears to have the most favorable economics is the cooperative ownership model in which the users of the system are also the owners of the system. While such co-op models of district heating system ownership are currently non-existent in the U.S., co-ops are successfully used here in many other applications, including wind farms and ethanol plants, and they are very commonly used to organize district heating systems in Europe. In a co-op BDE model, each building owner invests a certain amount in the system at the start, which buys them a share in its ownership and one vote as a co-op member. The board of the co-op, including member representatives, decides on the issues of finance and management, including: establishing the BDE system, setting rates for metered purchase of heat from the system; disposition of revenue in excess of expenses; establishing reserve funds; use of surplus funds; payment of member dividends; hiring contractors and purchasing equipment for establishing the system; hiring staff; undertaking expansion projects; marketing to potential new customers; and more.

If potential member-owners are unable or unwilling to commit enough funds to establish a reasonable equity share of the project cost, it may be advisable to attract investment from other stakeholders in the community. Such stakeholders may include local banks, businesses in the forest products industry, local forest-land owners, large customers seeking a higher investment and ownership of the system, and possibly fuel dealers. In return for this investment, these stakeholders would likely expect dividends or some other form of repayment over time. It is important for district energy co-ops that attempt to attract some non-customer investment to assure that the customer-owners' control over key decisions is not eroded by non-customer equity shares.

In the European co-op model for community district energy systems, member equity targets are often about 20 percent of total project cost, while the balance is achieved from securing grants and financing through public or private institutions.

5.4 Sources of Capital

There are many potential sources of capital to build a district energy system, and any system is likely to put together a finance package using a number of different sources. While the recent economic down-turn has crimped the financial and credit markets, it has opened up new funding opportunities through the American Recovery and Reinvestment Act (ARRA), and the interest in alternative energy options is high for certain investors. A broad outline of potential funding sources includes:

• Equity investment by: users of the system, municipality itself; private and non-profit partners; and private investors
• Grants and tax credits from state or federal agencies or other sources
• Loans through: the municipal bond market (revenue bonds or general obligation bonds); commercial bank loans from local or other banks; loans from federal, state, or other public-sector sources (such as USDA Rural Development)

Grant Opportunities
Until recently grant opportunities specific to district energy have been practically non-existent. There have been some grant opportunities and incentives for green power projects, but not for renewable energy heating. Grant opportunities vary greatly from year to year. Potential grant sources include interested foundations and state government agencies. Federal agencies that sometimes provide grant programs for which a biomass district energy project may be eligible include:

- the Department of Energy http://www.science.doe.gov/grants/
- the USDA Rural Development program http://www.rurdev.usda.gov/Home.html
- and the US Forest Service http://www.fs.fed.us/woodybiomass/opportunities.shtml

District energy projects may also be eligible for federal and state grant programs that have non-energy related objectives. For example, Community Development Block Grant funds are available for projects that stimulate economic development or benefit low-moderate income people. Other programs may assist certain users (e.g., housing facilities, hospitals) with hook-up and conversion fees.

Loan Sources
There are numerous low-interest and other loan sources that could be used for district energy.

Commercial loans may be available from one or a consortium of banks. District heating systems, which have been well-established and seen as low-risk in Europe for decades, are a new concept in the United States. In the current economy, it is unknown how commercial lenders will view community district energy loan applications. Local banks may be more interested in supporting these projects on the basis of local economic development and stimulus to the local economy. Banks may be incentivized by federal low-interest loan and loan guarantee programs available from a number of federal agencies, including USDA Rural Development, or through advances for community and economic development through the Federal Home Loan Bank available for its member banks.

If a community wishes to promote the district energy system, it may use its bonding authority by issuing 'general obligation' bonds or revenue bonds. General obligation bonds are backed by the full faith and credit of the municipality, and revenue bonds are issued on the strength of the project finances and repaid from them.

The Emergency Economic Stabilization Act passed in the fall of 2008 includes a new category of tax credit bonds called “Qualified Energy Conservation Bonds” (QECBs). QECBs are expected to perform as no-interest bonds for the end user. The bondholder will receive federal tax credits in lieu of traditional interest. QECBs can support a variety of energy conservation and possibly renewable energy purposes including capital expenditures for publicly-owned buildings and certain demonstration projects. QECBs could possibly be used as a finance source for district energy projects. As a new federal program, the applicability of QECBs will not be certain until the IRS issues rules, and ownership structure may affect a project’s eligibility.

In addition to the traditional loan sources described here, there are constantly evolving less-traditional and new approaches that could be creatively combined in innovative ways to finance the debt portion of the capital requirements of the project. Current non-traditional loan sources should be evaluated at the time that funding for the project is being acquired.

6.0 Environmental Impacts

6.1 Air Emissions from Woodchip Boilers

As the number of biomass energy systems increases across the United States and throughout the world, there is growing concern about the potential emissions from biomass systems and their impact on air quality.

Emissions from wood-fired boilers are different than emissions from propane or oil boilers. A number of these components are air pollutants and are discussed below. Boiler emissions are typically measured in pounds of pollutant per MMBtu (1 MMBtu is the amount of heat energy roughly equivalent to that produced by burning 8 gallons of gasoline, or 121 lbs of dry woodchips).

All heating fuels— including wood—produce particulate matter (PM), carbon monoxide (CO), nitrogen oxides (NO_x), and sulfur dioxide (SO_2) in varying amounts. Burning wood in a modern and well-maintained woodchip boiler, for example, produces more particulate matter than burning oil, but less SO_2 than oil. Emissions rates are given in Figure II below (in lbs per MMBtu) for woodchip and oil boilers.

Modern wood systems produce less than 2% the SO_2 emissions of fuel oil. Wood and fuel oil combustion have similar levels of NOx emissions.

All fuel combustion processes produce CO. The level produced by wood combustion depends very much on how well the system is tuned. Wood combustion produces significantly more CO than oil. This, in addition to PM, is a good reason to make sure the facility is fitted with the best available controls and that the stack is tall enough to disperse any remaining emissions away from ground level. However, CO emissions from burning wood are of relatively minor concern to air quality regulators, except in areas like cities that have high levels of CO in the air from automobile exhaust.

Volatile organic compounds (VOC) are one component of total organic compounds (TOC), another pollutant of concern. VOCs are a large family of air pollutants, some of which are produced by fuel combustion. Some are toxic and others are carcinogenic. In addition, VOCs elevate ozone and smog levels in the lower atmosphere, causing respiratory problems. Both wood and oil combustion produce VOCs—wood is higher in some compounds and oil is higher in others. VOC emissions can be minimized with good combustion practices.

In terms of health impacts from wood combustion, PM is the air pollutant of greatest concern. Particulates are pieces of solid matter or very fine droplets, ranging in size from visible to invisible. Relatively small PM, 10 micrometers or less in diameter, is called PM10. Small PM is of greater concern for human health than larger PM, since small particles remain airborne for longer distances and can be inhaled deep within the lungs. PM exacerbates asthma, lung diseases and increases mortality among sensitive populations.

Fine particulates (PM2.5) are a growing concern as they are known to increase health-related problems as compared to the larger particulates. Work investigating woodchip and pellet boiler emissions of very fine particulates is ongoing.

6.2 Control Devices for PM

As described above, fine PM is the pollutant of greatest concern with regard to wood systems. Even with the greater climate change benefits of wood energy, the PM2.5 issue needs to be considered as the regulatory framework is changing. The National Ambient Air Quality Standard for PM2.5 has recently been changed, with the standard becoming tighter. The region of Colebrook, New Hampshire is expected to be in compliance with the revised standards based on EPA designations. The AP42 uncontrolled PM emission factor (EPA accepted measurement of emissions) is 0.29 lb/MMBtu for wet wood, which can be reduced to 0.20 lb/MMBtu by installing a

mechanical collector. Some uncontrolled small wood-fired boilers of modern design with a gasifier or staged combustion have uncontrolled emission rates of between 0.1 and 0.2 lb/MMBtu.

Currently, the four most common air pollution control devices used to reduce PM emissions from wood-fired boilers are mechanical collectors (cyclones and core separators), wet scrubbers, electrostatic precipitators (ESPs), and fabric filters. Such devices can reduce PM emissions by 70 to 99.9%. Core separators and water scrubbers of the size suitable for boilers such as those being considered for the Colebrook BDE system are not commercially available in the United States.

Multicyclones Multicyclones, or multiple tube cyclones, are mechanical separators that use the velocity differential across the cyclone to separate particles. Multicyclones are more efficient collectors than cyclones because a multicyclone uses several smaller diameter cyclones to improve efficiency. Overall efficiency ranges from 65% to 95% but multicyclones, like cyclones, are more efficient in collecting larger particles and their collection efficiency falls off at small particle sizes. The AP42 lists multicyclone controlled emission rates that indicate a control efficiency of 73% for PM10 when the uncontrolled emission rate is 0.71 lb/MMBtu. The resulting multicyclone controlled emission rate is 0.19 lb/MMBtu. When the uncontrolled emission rate is as low as 0.1 to 0.2 lb/MMBtu the overall control efficiency will be lower. Some combustion units could meet an emission level of 0.1 lb/MMBtu with a multicyclone.

Electrostatic Precipitators (ESP) ESPs are widely used for the control of particulates from a variety of combustion sources including wood combustion. An ESP is a particle control device that employs electric fields to collect particles from the gas stream on to collector plates from where they can be removed. There are a number of different designs that achieve very high overall control efficiencies.

Control efficiencies typically average over 99% with control efficiencies almost as high for particle sizes of 1 micrometer or less. Two designs were considered for smaller boilers: a dry ESP and a wet ESP. The systems are basically similar except that wet ESPs use water to flush the captured particles from the collectors. The advantage of dry systems is that they may have a lower capital cost and reduced waste disposal problems. Wet systems may be less expensive to operate and are probably slightly more efficient at capturing very small particles that may include toxic metals.

Fabric Filters or Baghouses With the correct design and choice of fabric, particulate control efficiencies of over 99% can be achieved even for very small particles (1 micrometer or less) by fabric filters or baghouses. The lowest emission rate for large wood-fired boilers controlled by fabric filters reported is 0.01 lb/MMBtu. Operating experience with baghouses on larger wood-fired boilers indicates that there is a fire risk, due to caking of the filters with unburned wood dust. It is possible to control or manage this risk by installation of a mechanical collector upstream of the fabric filter to remove large burning particles of fly ash (i.e. “sparklers”). A cyclone-baghouse combination reduces the fire risk.

BERC recommends the installation of an electrostatic precipitator at the Colebrook biomass district energy plant. Federal Area Source PM emission limits (as of June 2012) for Options I and III would be 0.03 lbs/mmBtu, and the requirement for Option II would be 0.07 lbs/mmBtu. BERC recommends the installation of an ESP to biomass systems in community settings because of the particular vulnerability of certain populations to health impacts from fine particulates released by wood combustion. The use of these advanced controls also ensures the project is serving as a model demonstration of the best system possible. The cost of an electrostatic precipitator has been included in the economic analyses presented here.

BERC is actively engaged in this on-going discussion and will continue to recommend changes in combustion techniques and pollution control options as appropriate based on the current state of the scientific information.

6.3 Climate Change and Biomass Energy

Global climate change is one of the most pressing environmental challenges of our time, and the major cause of climate change is emissions of carbon dioxide (CO_2) from burning fossil fuels. When biomass is used sustainably to displace fossil fuels, the net impact is a lower CO_2 level in the atmosphere. This is because burning fossil fuels takes carbon that was locked away underground (as crude oil, gas, and coal) and transfers it to the atmosphere as CO_2. Wood combustion, however, recycles carbon that was already in the atmospheric carbon cycle, the net effect being that no *new* CO_2 is added to the atmosphere as long ***as the forests from which the wood came are sustainably managed.***

Most biomass fuel is produced within an average human lifetime, and is therefore considered an active component of the global carbon cycle, a process that transports carbon in various forms throughout the earth's natural systems. Significant quantities of CO_2 are absorbed by plants through photosynthesis, and then released through plant decay. Removing biomass fuel from forests using sustainable forestry practices stimulates the growth of replacement wood. This replacement growth absorbs approximately the same amount of CO_2 as was released during combustion.

The US Environmental Protection Agency reports, "CO_2 from this source [biomass] is generally not counted as greenhouse gas emissions because it is considered part of the short-term CO_2 cycle of the biosphere." Fossil fuels, such as coal, oil, or natural gas deposits, are produced within a geologic timeframe. The carbon in these long-term deposits is considered 'sequestered' from the global carbon cycle, and, when used for energy, add to the cycle additional new carbon that would have remained underground. If a gas or oil heating system is converted to wood, net CO_2 emissions are reduced by 75-90 percent over time, depending upon how much of the fossil fuel use is displaced. For this reason heating with wood is a powerful tool for a community interested in meaningfully addressing climate change and renewable energy through its energy use.

A large percentage of the biomass that is burned to generate energy is waste from the forest products industry, such as sawmill waste. This waste would also release CO_2, often along with methane (a greenhouse gas that is more potent than CO_2), while decomposing in landfills and waste piles. Therefore, using biomass waste to produce energy minimizes methane emissions while also both displacing fossil-fuel use and contributing low net CO_2 to the atmosphere.

By burning approximately 746,000 gallons of oil for space heating at 22 pounds of atmospheric CO_2 emitted per gallon of heating oil, the buildings in the study area contribute approximately 8,349 tons of carbon dioxide to the atmosphere annually. This is as much CO_2 as produced by 1378 cars annually[11]. If these buildings were to instead connect to a wood-fired BDE plant, net CO_2 emissions for heating would be reduced by 75-90% (depending on how much the plant has to rely on back-up fossil fuel boilers). A 75% reduction in CO_2 emissions would be the equivalent of taking 1,033 cars off the road.

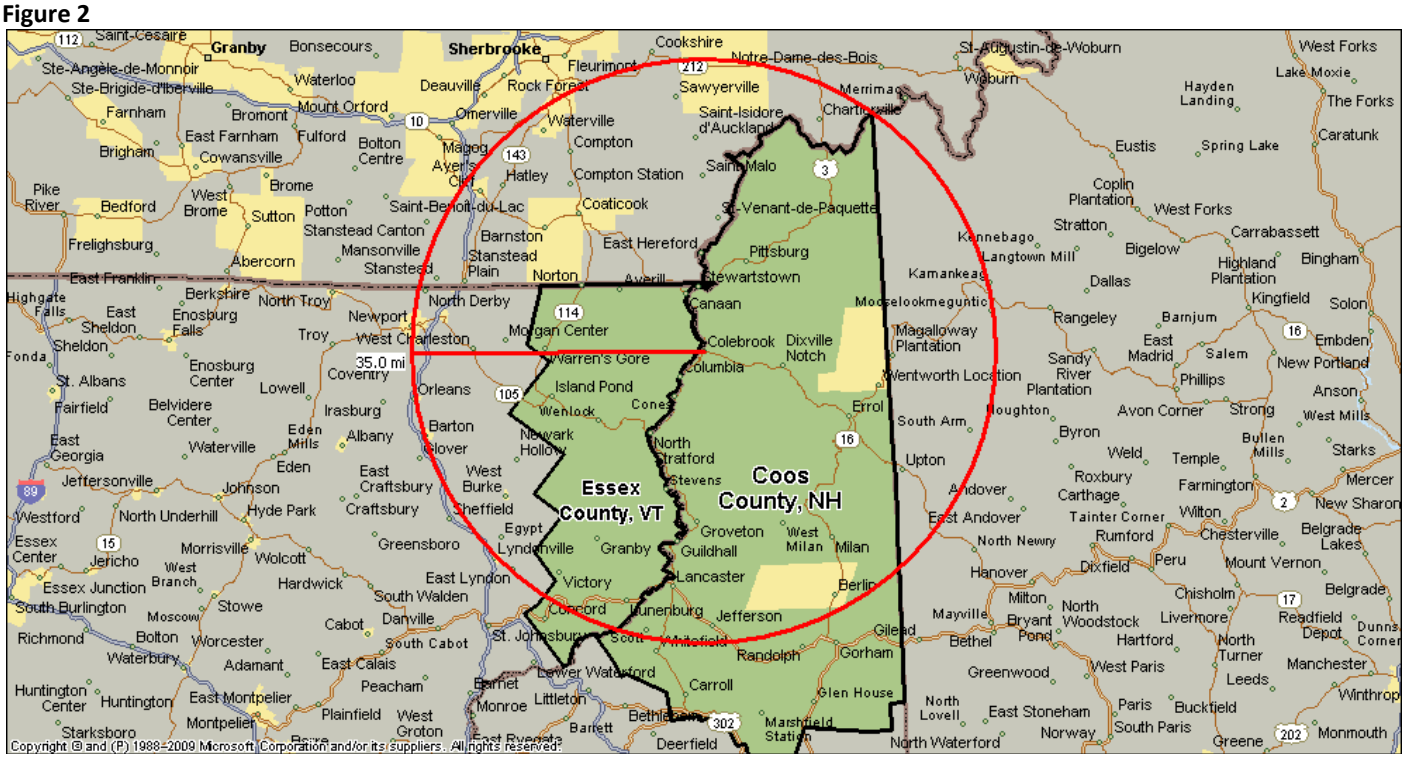
[11] Greenhouse Gas Emissions from a Typical Passenger Vehicle. 2005 EPA Publication EPA420-F-05-004

7.0 Assessment of Available Wood Fuel Supply

Woodchips have historically been almost exclusively a by-product of timber harvesting in the woods, lumber production at sawmills, and clean wood waste recycling efforts from communities. In recent years increased market demand for chips as fuel and decreased sawmill activity has prompted a gradual shift towards woodchips sourced as a commodity wood fuel harvested directly from the forest, rather than a by-product produced from higher-value wood harvesting and processing.

To determine an appropriate sized area to study, to start with BERC examined a 35-mile radius area surrounding the Town of Colebrook. From there a more sophisticated approach modeling drive time analysis was explored. These two approaches were use to determine that the target counties from which fuel would likely be sourced are Coos County, NH and Essex County, VT.

Figure 2



Sawmills

The business of sawing round logs into dimensional lumber produces a significant amount of by-product wood. Sawmills produce three main categories of by-product wood—bark stripped from the log prior to sawing, chips produced from the unusable slabs cut from the out curve of the log, and fine sawdust created from the cutting teeth of the saw.

bs and off-cuts from lumber production at larger sawmills is typically chipped and shipped to regional pulpmills, biomass power plants or woodchip heated institutions. These “mill” or “paper” chips are the best suited for use as fuel in biomass heating systems. Mill chips tend to be the highest quality chips available for woodchip-fueled heating systems. Because logs are debarked before sawing the chips, mill chips are very clean and have relatively low ash content. Mill chips are also commonly screened to remove over-sized stringers and fines. Wasted wood from sawmills is commonly chipped on a continual basis as logs are sawn and chips are blown directly into dedicated box trailers. When the trailers are full they are shipped to the various markets and an empty trailer is set in its place.

While there are a handful of sawmills still operating in the larger supply area, many are operating a far less than full capacity due to the down turn in the housing market and the lower demand from dimensional lumber products. What little wood by-products they currently produce are by in large already spoken for by existing markets such as pulpmills, power plants, pellet mills, farmers, and landscapers. Wood chip supply from sawmills for the Colebrook BDE project should not be expected.

Whole-tree Harvesting

Commercial harvesting of sawlogs and pulpwood removes the main stem or bole of the tree from the woods and leaves the tops & limbs either scattered in the woods near the stump or in a large pile at the log landing. Whole-tree harvesting—mechanized harvesting where entire trees, as opposed to just the log, are dragged (skidded) from the stump to the central log landing—requires the tops & limbs be removed and piled at the log landing. This leftover wood can be chipped into biomass fuel commonly known as whole-tree chips. In some cases entire trees, not just the tops and limbs, are fed to the chipper to also produce whole-tree chips. It is common practice for the wood to be chipped in the woods at the log landing into box trailers which are transported directly to large users like biomass power plants and pulpmills that are equipped with trailer tippers to unload the chips from the box trailers.

It will be assumed that the Colebrook BDE plant will not have a trailer tipper and therefore woodchip fuel delivery will require the use of live-bottom trailers. For this reason, the use of whole-tree chips supplied from in-woods chipping may be limited—a majority of log landings where this material is chipped have poor access and conditions, limiting them to the use of box trailers which would require tippers for unloading. Self-unloading trailers are very expensive and most chip contractors prefer to keep these trailers out of the woods so they are not unnecessarily damaged.

Stem-Only Harvesting

Timber harvesting can be performed where only the merchantable roundwood is removed from the stump to the landing or roadside—meaning once the tree is felled it is de-limbed there at the stump leaving the tops and limbs

scattered in the woods. Stem only harvesting can conducted using manual cutting and processing (logger with chainsaw and skidder) or can use Cut-to-Length equipment (mechanized harvester and forwarder).

Stem only harvesting only extracts roundwood and leaves tops in the woods. While many studies have examined the mechanical and logistical feasibility of a second entry to gather, extract, and process chips from stem only harvests, the costs of a second entry are prohibitively high (not to mention the additional soil compaction and possible further damage to the residual stand). The only feasible chipwood from stem only harvesting is smaller diameter and pulp-grade main stems. However, a portion of this wood currently left behind could cost-effectively be extracted if a portion of the logging workforce converted their operations from stem-only to whole-tree.

Chip Yards and Chipmills

Bole chips are produced from low-grade wood or pulpwood. The difference between whole-tree chips and bole chips is that bole chips do not include the branches or foliage. When the trees are harvested the limbs are removed and the slash is left on the ground in the woods or at the log landing (depending on where the tree is de-limbed). While bole chips can make for higher-quality fuel and help forest soil health by returning a portion of the biomass and nutrients to the soil, they are significantly more expensive than sawmill chips and whole-tree chips which are both by-products. In the past, sawlog prices were high enough that low-grade wood could be extracted at the same time as sawlogs and still be profitable for the logger and pay the landowner stumpage. With recent drops in the sawlog market, however, low-grade wood like pulp, chips and firewood can no longer rely on subsidized costs—this low-grade wood must pay its own way out of the woods.

Bole chips can be produced by chipping roundwood at the log landing where the wood was harvested, at a remote yard used by the logging/chipping contractor, or at the energy plant's wood storage yard.

Chip yards are usually small basic yards where pulpwood can be stored and periodically chipped using mobile equipment. Chip mills are larger established facilities with stationary equipment that often supply regional pulpmills with paper-grade chips.

7.1 Estimating In-Woods Capacity

While some wood fuel sourced for the Colebrook BDE plant may be by-product material, a majority of the supply will likely come directly from harvesting low-grade wood from regional forestland. Because wood is not infinite in its supply, careful attention must be paid to the question of how much wood is available or we run the risk of growing our wood fuel demand beyond our forests' capacity to supply.

In an effort to better understand the potential capacity of the region's forests to provide increased amounts of wood fuel for wood energy systems, such as the Colebrook BDE plant, the forestland within the procurement area was identified and the current inventory of wood on this forestland was estimated.

Table 1

County	Total Forest Area (Acres)	Accessible and Appropriate Forest Area (Acres)	Managed, Accessible and Appropriate Forest Area (Acres)
Coos, NH	1,024,610	818,070	613,553
Essex, VT	374,191	258,012	193,509
GRAND TOTAL	**1,398,801**	**1,076,082**	**807,062**

The right hand column of the table above provides the estimates of the remaining accessible, ecologically appropriate, and actively managed timberland within the study area. The 807,000 acres of forestland that are accessible, appropriate, and estimated to be actively managed for harvesting now become the footprint for estimating the low-grade wood that could be available annually from the forests for use as biomass fuel.

The following tables give the total above-ground forest inventory, by county, of all live trees in the study area on the portion of timberland that was estimated to be accessible and actively managed as described above. These inventories include both high- and low-grade wood, shown below as growing stock and cull/non-commercial categories, respectively.

Table 2

County	Growing-Stock & Cull Inventory		
	Bole	Tops & Limbs	Total
Coos, NH	40,552,976	5,816,893	46,369,869
Essex, VT	11,397,896	3,076,951	14,474,847
GRAND TOTAL	**51,950,872**	**8,893,844**	**60,844,716**

In total, there are over 60 million green tons of standing, live trees (inventory) on the accessible and actively managed forestland footprint within this two-county procurement area.

In addition to determining the amount of standing wood (or inventory) and the forest's composition, knowing how much the forests are growing and what level of harvest can be sustained over time gives a clearer picture of wood fuel availability and the viability of woody biomass energy. Rates of forest growth fluctuate widely depending on the age and composition of a forest as well as the site's soil and aspect. For the purpose of this assessment, the net annual growth of new amounts of wood was chosen as the indicator of how much wood the forests of these counties can provide on a sustained-yield basis.

In addition to accounting for the forestland area that is not physically accessible and the forestland area that is not managed and periodically harvested, it would be inappropriate to include high quality trees otherwise capable of yielding merchantable wood for sawlog production. For these reasons, a series of assumptions were used in this wood fuel supply assessment to target a more appropriate amount of wood that could be available for use as wood fuel.

Table 3

County	Growing Stock and Cull Wood Combined (Green Tons)		
	Bole	**Tops & Limbs**	**Total**
Coos, NH	533,603	N/A	533,603
Essex, VT	149,464	N/A	149,464
TOTAL		N/A	

As can be seen in the tables above, more than 683,067 green tons of low-grade wood grow annually on this forested footprint that can be harvested on a sustained-yield basis. While this may sound like a large amount of wood, it should be noted that there is significant existing demand for low-grade wood within this region. The next steps are to quantify the existing annual demand of low-grade wood and then determine the remaining quantity that could be available. The following sections discuss this further.

The net annual growth presented above does not account for existing levels of harvesting for pulpwood, residential firewood, and woodchips. New Hampshire accurately and consistently tracks annual harvesting via the State's tax department's taxation on stumpage revenue paid to landowners. These data were used for the New Hampshire Counties within the study area. The State of Vermont gathers annual data on harvested timber via a survey of timber product consumers throughout the region (PA to Quebec).

Table 4

County	Annual Harvest of Low-Grade Wood (Green Tons)		
	Firewood	**Pulp**	**Chips**
Coos, NH	9,000	285,000	179,000
Essex, VT	24,684	30,101	12,560
TOTAL			191,560

Harvest data for pulpwood, residential firewood, and whole-tree chips in the study area indicate that approximately 191,560 green tons of low-grade wood is removed annually from forestland in these counties.

The difference between the rates of annual growth of low-grade wood and the current rates of harvest presented in the two previous sections and tables is the net amount of low-grade wood that could be available for use as biomass fuel, referred to here as the net available low-grade growth (NALG). The following table shows this remaining volume of net annual low-grade growth after current demands are accounted for.

Table 5

County	Remaining Net Annual Growth		
	Bole NALG Wood	Tops & Limb NALG Wood	Total NALG Wood
Coos, NH	194,853	N/A	194,853
Essex, VT	91,539	N/A	91,539
TOTAL		N/A	286,392

As can be seen above, there is an estimated annual surplus capacity of slightly more than 286,392 green tons of low-grade wood within the total study area after the firewood, pulp, and other market demands are added up and compared to the estimated annual growth of low-grade wood on accessible and actively managed forestland. It is very important to note that while softwood species can make excellent fuel when dried, in traditional green fuel format softwood chips are not generally recommended. For the target supply area FIA data indicate that hardwoods account for approximately 75% of the current stocking and softwoods account of only 25%. If green chips are sourced, hardwoods would be preferred. To further account for this preference the numbers in the table above should be further discounted to reflect only 75% of the total NALG wood.

At the absolute maximum (assuming a large year round thermal load like a pellet mill were tied into the plant), Colebrook BDE plant would consume roughly 25,000 green tons annually. Therefore, there is currently ample supply of low-grade wood to fuel this facility without over-burdening the local forests given all the other functions they provide.

7.2 Woodchip Competition

There are one major wood energy project under development that if constructed would have an impact on the supply landscape as it relates to the Colebrook BDE plant's fuel supply. Burgess BioPower is a 75 megawatt power station to be located at the site of the former Fraser Paper mill in Berlin, New Hampshire. This facility would consume roughly 750,000 green tons annually—primarily whole-tree chips. The project has been financed, permitted and holds a power purchase agreement with PSNH. Construction is scheduled for 2013.

7.3 Woodchip Costs

Woodchip pricing is widely variable based on the sources, quality of the chipped fuel, and the volume of annual demand. For the past few decades woodchips have exclusively been supplied as a byproduct of the timber and lumber industries that have experienced cyclical periods of strong market conditions followed by weak market conditions. This ebb and flow in the demand (and therefore the supply) of timber has historically driven the availability and pricing of chips. More recently, increased market demand for wood fuels coupled with declining generation of by-products has changed the pricing landscape.

The price of wood is affected by numerous factors, but the primary ones are:

- **Wood source and production costs.** This varies widely depending on whether the wood is a by-product of some more lucrative activity.
- **Strength of the sawlog market.** Higher prices paid for veneer and sawlogs can help lower prices for pulp and chips. More demand for roundwood timber products also produces more chips from slash.

- **Regional balance of supply and demand for low-grade wood.** Both supply and demand for low-grade wood wax and wane over time. Shortage of supply during periods of wet weather coupled with higher demand can drive prices upward. Conversely, surplus supply at times of weak demand cause prices to drop.
- **Trucking distance from point of generation to end market.** The cost of trucking is discussed in greater detail in the section below. In short, the price paid per ton of feedstock is dependent heavily on the cost to transport the material; this cost rises with higher diesel prices and with greater trucking distances. Further examination of the major trucking cost variables of distance and diesel fuel costs is provided in the tables and graphs below.

Based on using BERC's economic models and staff telephone and in-person interviews with whole-tree chip contractors, chip mill owners, and chip brokers, BERC estimates bole woodchips to cost $50.00 per green ton delivered to the proposed Colebrook BDE plant using self-unloading trailers. These prices reflect current market conditions, diesel fuel costs, and the given transport distance.

8.0 District Energy Financial Feasibility

8.1 Analysis Methodology –Phase I

All the detailed engineering load calculations and project capital costs developed by Wilson Engineering were fed into BERC's proprietary economic analysis tool to examine the costs and cash flow for these configurations for a BDE system in Colebrook on a "whole-project" basis. The basic framework of the tool is a business pro forma that compares the revenue generated by selling heat to its customers against the expenses of building, fueling and operating the plant. The analysis model uses financial assumptions and estimates based on actual data and utility operations to examine the overall economic feasibility of each option. The analysis is applied in year one of the analysis period and includes the ongoing costs of fueling, operating, and maintaining the system in each configuration as well as the sale of heat and/or power. Annual inflated costs and revenues were calculated over a 20 year period. The result is annual costs and revenues, net 20-year cash flow presented in 2012 dollars, and a timeframe for simple payback for each configuration option. Full economic analyses are included as Appendix F – Economic Analyses.

The analyses do not make any assumptions about the ownership model of the system and could be operated by the municipality, a private developer, an energy cooperative, or any combination of these possibilities. As no ownership model is assumed for the project, no taxes are figured into the model. If the system is ultimately constructed and operated by a for-profit entity, taxes would be assessed on the revenue streams for the project.

Consumers would be expected to enter into long-term contracts to pay for heat on a metered, per MMBtu basis. The base analysis assumes that the cost of heat to members in the first year would be indexed at a 20% savings from the current cost of fuel oil as a minimum to incentivize them to sign up to connect to the district heating plant. A sensitivity analysis is also included that examines the performance of the business model for the project with a range of heating cost savings to the consumer.

A fuel oil price of $3.50 per gallon is the equivalent of paying $36.23 per MMBtu; a customer beginning a contract when fuel oil prices are at $3.50 a gallon would pay $28.99 per MMBtu for heat from the district energy plant. The purchase heat contracts would increase the price of heat each year at the rate of general inflation (3.25%). Fuel oil prices generally rise faster than the rate of general inflation. If fuel oil rates rise at a conservative estimate of 4.75%, and the price of heat from the district heating plant rises at the current rate of general inflation, by year 20, the price of oil heat will have risen to $91.66 per MMBtu while the price of heat from the district energy plant will have risen to $54.95 per MMBtu. Under this conservative assumption, the savings to the consumer in year 10 would be 30% off the cost of heating with oil, and by year 20 would be 40% off the cost of heating with oil.

Customers of the district heating system would also be provided with additional economic benefits through avoiding capital costs for replacing their heating equipment as well as routine maintenance costs. As an example, over the minimum 30-year life of the district heating system, a residential homeowner would be expected to replace their fuel oil boiler. Including installation, this is currently a cost of approximately $4,800 for a 100,000 Btu/hr high efficiency system. In addition, biannual inspections of fossil fuel heating equipment are a good practice. This typically costs $50 - $200 every other year. These and other replacement and maintenance costs would be avoided by the homeowner through connection to the district heating system.

Funds for the project will likely come from a blend of owner equity, commercial financing, and grant funding. In the base analyses, it was assumed that the project would obtain $5 million in grant funding. A sensitivity analysis is included that assess the impact of varying degrees of grant funding (20%, 40% and 60%) on the performance of the business model.

The economic analyses for Full Build out and Phase I were conducted assuming that the entire plant and distribution network would be built at the same time with all the target customers connected at the start.

8.2 Analysis Methodology – Full Build Out

Preliminary load calculations and system costs for the Full Build Out were developed by the study team, including Community Biomass Systems and Wilson Engineering, based on the more detailed examination of loads and costs developed for Phase I. These were fed into BERC's proprietary economic analysis tool to examine the costs and cash flow for the eventual expansion of the BDE system to a maximum build out scenario. The same pro forma tool was used to assess the overall economic feasibility for this option and to calculate the annual costs and revenues, net 20-year cash flow presented in 2012 dollars, and a timeframe for simple payback. The full economic analysis is also included in Appendix F – Economic Analyses.

As with Phase I, the analyses do not make any assumptions about the ownership model of the system and it could be operated by the municipality, a private developer, an energy cooperative, or any combination of these possibilities. As no ownership model is assumed for the project, no taxes are figured into the model. If the system is ultimately constructed and operated by a for-profit entity, taxes would be assessed on the revenue streams for the project.

Unlike Phase I, which was envisioned as a system that would built in one phase as the initial BDE system, this analysis looked at a full build out scenario that would represent the maximum possible build out of a BDE system in Colebrook. The construction of this system would occur over many years in a phased approach. This analysis does not consider the detailed phasing of the system; the construction timetable and geographical extent of each phase will depend on consumer interest and the business model of the final BDE plant developer. This analysis is conducted for the full build out of this scenario, beginning when the entire network has been constructed and all customers are connected.

It was assumed that the initial project capital would amount to $9.56 million as identified in Phase I, $5 million of which would be obtained through grants and the balance of which would be obtained by commercial financing. The estimated capital costs of the maximum build out scenario are $36.47 million dollars. This means that $26.91 million dollars would need to be invested over a period of time to build the system out to the one considered in the Full Build Out. The model assumed that 50% of these funds ($13.46 million) would come through additional commercial financing and 50% of these funds would be an equity investment out of the project revenue streams.

It is important to note that year one of the analysis for Full Build Out is not the same year as year one for the analyses of Phase I, but would occur many years after initial construction. If Full Build Out were presented to be an accurate extension of Phase I, the model should assume higher prices for energy sales (as well as other costs due to inflation) than those presented in Phase I. However, as the phasing of the project over time is unknown, it would be entirely speculative. Further, the intent of including an analysis of both an initial phase of the BDE project and a maximum build out scenario for the BDE project is to assess whether or not it makes sense to build out from the smaller system based on anchor loads towards the inclusion of all possible customers, or if this is chasing smaller and smaller revenues with diminishing returns. Thus both were considered to have the same starting costs so that comparisons could easily be made between the two.

Assumptions Used in the Economic Analyses

The following assumptions were made in estimating the capital cost for each configuration option:

- System costs are based on recent bids and quotes from several vendors
- All costs are estimates based on experience with similar projects; these cost estimates are intended as the basis for preliminary feasibility analysis and are expected to be within +/- 15% and subject to change
- A fully redundant oil backup system will be installed alongside the biomass system
- The analysis includes the full cost to connect each building to the BDE network.
- Peak heating season is four months out of the year. Three months of the year are "shoulder" months where some heating is required, though not all the time or to a lesser degree
- A load coincidence factor of 80% was assumed
- Regional woody biomass fuels average 16.5 million Btu(s) per dry ton
- The average moisture content of woodchips is 40 percent, meaning each ton delivered to the boiler contains 9.9 MMBtu
- The price of woodchips was estimated at $50 per ton
- The average seasonal efficiency of the central plant woodchip boiler combustion equipment is 78%; the average seasonal efficiency for individual heating systems is 70%[12]
- The rate of general inflation was assumed to be 3.25% annually, with fossil fuel prices inflating at 4.75% and wood fuel prices inflating at 3.75%
- Heat will be sold on a metered, per Btu basis to each consumer facility. The sale price of heat from the plant to the consumer will be 20% below the price of heating oil
- The initial price of heating oil is $3.50 per gallon, or $36.23 per MMBtu
- First year sale of heat price is $28.99 per MMBtu

Some additional assumptions were made specifically for each of the individual configurations options. Because these additional assumptions do not apply to each of the options (or they vary between options), they are explained below within the context of each separate option.

[12] The heating loads & boiler sizing for Scenarios I and I were calculated using actual data where possible and using a 75% efficiency for oil systems where data did not exist. A lower efficiency of 70% was assumed as the seasonal average for the economic analysis.

8.3 Phase One System

Capital Cost The capital cost for Phase I was estimated to be $ 9,564,741 and is itemized below.

Table 6

Capital Cost – Scenario I	
300 hp biomass combustion unit, 150 psig hot water boiler, breeching, stack, installed	$650,000
100 hp biomass combustion unit, 150 psig hot water boiler, installed	$350,000
150 hp and 300 hp fuel oil fired 150 psig hot water boilers	$225,000
Biomass boiler room piping and specialties, biomass system controls, installed	$200,000
Fuel bunker receiving, storage, screening, material transfer, installed	$250,000
Boiler platform, stairs, and ladders installed	$25,000
8,000 gallon thermal storage tank, installed	$80,000
ESP, Installed	$375,000
Sub-total	$2,155,000
Boiler Manufacturer Bid Bond and Insurance 2%	*$43,100*
Total Boiler Manufacturer Contract	**$2,198,100**
Biomass Boiler Building and Chip Storage Pit (5,945 sf @ $180 per sf)	$1,070,100
Site work	$100,000
Main distribution pipe system - 10,500 lf. (one-way distance), installed	$2,640,000
Connection of identified loads	$610,000
Central Plant Electrical	$300,000
Central Plant Mechanical	$250,000
Sub-Total	$4,970,100
Contractor profit overhead and insurance 16%	$795,216
Sub-Total	$5,765,316
Contingency 10%	*$576,532*
Total General Contract Building and Site	**$6,341,848**
Project Sub-Total (Boiler and General Contracts)	8,539,948
Professional Services 12%	*1,024,794*
Total Project Cost	**$9,564,741**

Additional Assumptions The following additional assumptions were made in the economic analysis of Scenario I:

- Fuel consumption for the study area was calculated at 205,343 gallons of oil annually
- To obtain the electric usage for the plant, a total of 2,297 hours of full load plant operation was assumed (the plant load for Phase I is projected to vary as shown in Figure 1)
- Total annual operation and maintenance (O&M) costs are estimated at $299,811

Table 7

O&M Costs (annual)			
Purchased wood			$188,440
Purchased KWh (electricity consumption by plant)		262,553	
Electric price/KWh		$0.11	
Cost of electricity			$28,881
Hourly wage, labor		$20	
Labor	1.0	FTE	$41,600
Other O&M			$143,471
Total O&M			$402,392

Cash Flow and Simple Payback Period. The model predicts that the first year expenses of operating the project would be $733,985; including $331,592 in capital and financing costs, and $402,392 in operating and maintenance costs. The first year revenues would be $766,870 for the sale of 26,457 MMBtu of heat at $28.99 per MMBtu.

With these assumptions, the project shows positive cash flow from year one. The first year cash flow would be $32,885, and annual cash flow would increase in each following year. If not further expanded, the project would have a 20 year cumulative cash flow of $1,905,725 (in 2012 dollars).

With such a low first year cash flow, the simple payback period on the project would be over 100 years. The cumulative payback period (when cumulative cash flow reaches the amount of the initial investment) on the owner investment would be approximately 24 years, with cumulative payback on the total project of 36 years. Clearly this option must be the first step to a larger mature system.

8.4 Full Build Out Scenario

Capital Cost Total capital cost for full build out was estimated to be $36,472,699 and is itemized below.

Table 8

Capital Cost – Option I			
2 wood boilers installed			$4,520,000
Day bin equip installed			$528,000
Building, 10,000 sq. ft.			$1,600,000
Backup oil boilers			$350,000
Utilities to site			$100,000
Plant mechanical			$300,000
Plant electrical			$100,000
Backup generator			$250,000
DH pumps & controls			$250,000
Buried pipe system			$15,125,000
Building connections:			
Residential	349		$4,502,449
Commercial, small	47		$606,347
Commercial, large	7		$122,500
Schools	2		$50,000
Hospital	1		$40,000
Housing units	2		$50,000
Total connected buildings:	408		$5,371,296
Total installed equipment			$28,494,296
GC markup	16%		$4,559,087
Total general contract			$33,053,383
Prof., project mgmt., permitting	12%		$3,419,316
TOTAL PROJECT COST			$36,472,699

Additional Assumptions The following additional assumptions were made in the economic analysis of Scenario III:

- Fuel consumption for the study area was calculated at 746,000 gallons of oil annually
- A total of 2,297 hours of full load plant operation was assumed (the plant would operate at minimum capacity in the warmer months to provide summer heating needs and domestic hot water)
- Total annual operation and maintenance (O&M) costs are estimated at $1,295,800

Table 9

O&M Costs (annual)			
Purchased wood			$818,020
Purchased KWh (electrcicity consumption plant)		1,009,818	
Electric price/KWh		$0.11	
Cost of electricity			$111,080
Hourly wage, labor		$20	
Labor	2.0	FTE	$83,200
Other O&M			$547,090
Total O&M			$1,559,390

Cash Flow and Payback Period. The model predicts that the first year expenses of operating the project would be $2,869,762, including $1,310,372 in capital and financing costs, and $1,559,390 in operating and maintenance costs. The first year revenues would be $3,328,986 for the sale of 114,850 MMBtu of heat at $28.99 per MMBtu.

With these assumptions, the project shows positive cash flow from year one. The first year cash flow would be $459,223, and annual cash flow would increase in each following year. The project would have a 20 year cumulative cash flow of $13,350,707 (in 2012 dollars).

The simple payback period on for the project would be 79.42 years. The simple payback on the equity invested in the project (in the form of $13.46 million in revenues used to expand the project) would be 29.30 years.

8.5 Sensitivity Analyses

BERC conducted sensitivity analyses for some of the project variables that will affect business model performance. In the following analyses (as well as in the Conclusions section of the report), the outputs of Phase I should be given particular weight when assessing the effects of the analyses on first year cash flow as the likely starting point of the system (the first year cash flow of Full Build Out being basically a hypothetical number). The effects on 10 and 20 year cash flow (which have in all analyses been discounted back to 2012 dollars) can be compared between Phase I and Full Build Out to assess the impacts of the particular analysis as the BDE project is built out over time.

Modeling Efficiency Improvements

A major focus of the Colebrook Energy Committee is improving the energy efficiency of buildings in the town of Colebrook. The committee seeks to improve energy efficiency on a building basis by 20% throughout the town. The reduced demand would have minimal impact on project costs (as the costs of the plant building and distribution piping network would remain the same and the boilers would only be very slightly reduced in price) but would result in a reduction in heat sales to the existing facilities. It would have the following impacts on the business model performance for the BDE business:

Table 10

	Full Build Out existing demand	Full Build Out 20% efficiency improvements	Phase I existing demand	Phase I 20% efficiency improvements
Oil use offset	746,000	596,800	205,343	164274.4
Heat sales (MMBtu/yr)	114,850	91,880	26,457	21165.6
Year 1 revenue	$3,328,986	$2,663,188	$766,870	$613,496
Year 1 cash flow	$459,223	-$42,970	$32,885	-$82,801
Year 10 cash flow	$5,522,122	$999,076	$645,254	-$396,681
Year 20 cash flow	$13,350,707	$4,518,675	$1,905,725	-$128,833
Simple payback period	79.42 years	cannot be calculated	290.85 years	cannot be calculated

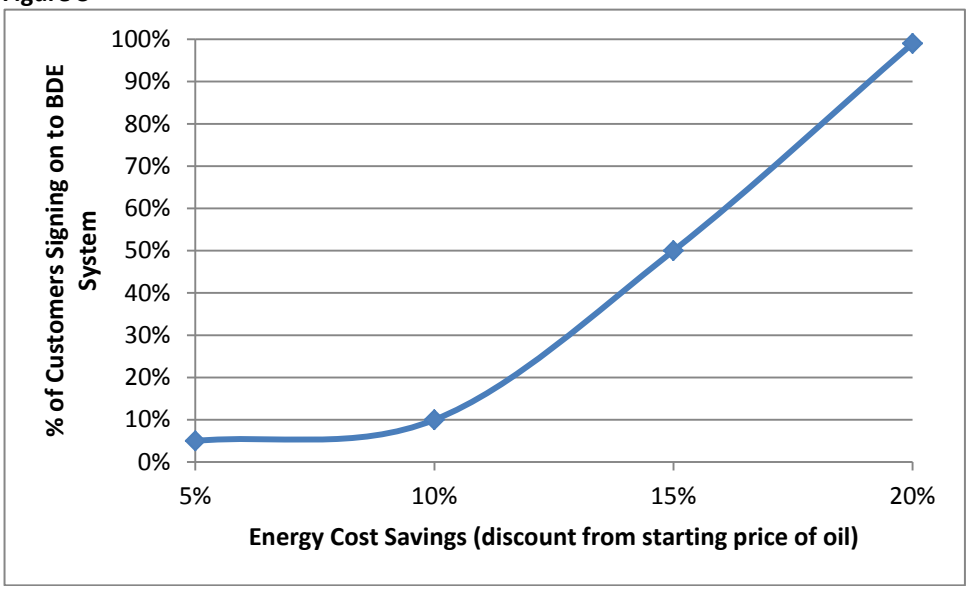
Improving building efficiency will save consumers and benefit the environment by conserving resources. However the table above shows that the efficiency gains will negatively impact the business model performance. At today's oil prices, it would make the Phase I challenging as first phase option economically. Annual cash flow would not become positive until year 10. If these gains in efficiency are achieved, the network would need to be expanded beyond the scope considered in Scenario I in order to reach a level of heat sales that would produce a positive cash flow. The cash flow for the larger build out would also be impacted to the extent that it would be impossible to attract a commercial project developer and would be a poor investment on the part of a municipal or coop owner.

Before conducting the final design for the BDE plant, the committee and project developers should work together to assess how effective the efficiency campaign has been and how much the thermal demand has been reduced throughout the buildings in the study area.

Energy Cost to Seasonal Heat Customers

The cost of energy to consumers will be a key variable in the success of the BDE system. The analyses above are based on an assumption that heat will be offered to seasonal heating users at a 20% discount on the cost of heating with oil. However, it is important to consider a range of heat sales prices and how they will impact the performance of the business model. The higher the price of heat is to the consumer, the BDE will make a higher profit margin on each Btu delivered, but less customers will sign on to the system. Conversely, the lower the price of energy is to the consumer, the less the BDE plant will make on each Btu sold but more customers will sign up for the system. Figure 7 below illustrates the effects of decreasing heat sales costs on the percentage of potential customers who would likely sign up on to the system.

Figure 3



BERC has attempted to identify the 'sweet spot' that will produce the best performance for the business model of the project. The following table displays the results of the analysis if heat is sold at 5%, 20% and 50% less than the cost of heating with oil and 100% of customers signed on to the system. (It is important to note that in reality, a lesser percentage will sign on with each raise in price).

Table 11

	Scenario I				Scenario III			
	5% discount	10% discount	20% discount	50% discount	5% discount	10% discount	20% discount	50% discount
Sale price of heat	$34.42	$32.61	$28.99	$18.12	$34.42	$32.61	$28.99	$18.12
Year 1 revenue	$910,658	$862,728	$766,870	$479,293	$3,953,170	$3,745,109	$3,328,986	$2,080,616
Year 1 cash flow	$176,673	$128,744	$32,885	-$254,691	$1,083,408	$875,346	$459,223	-$789,146
NPV of 20 year cumulative cash flow	$4,474,440	$3,618,202	$1,905,725	-$3,231,704	$24,501,514	$20,784,578	$13,350,707	-$8,950,906
Simple payback on total project	54.14 years	74.29 years	290.85 years	cannot be calculated	33.66 years	41.67 years	79.42 years	cannot be calculated

At 5%, while huge profits would be generated if 100% of consumers would sign on, very few would likely be induced to join the network at that level of savings. For a customer with a $4000 annual heating bill, the annual savings would be $200. At a cost of $5000 as an initial investment to join the system (for customer share of the installation of the energy transfer station and alterations in the existing heating distribution system in the building to be compatible with the BDE system), the average consumer would see a 25 year payback period on their investment. This would be unacceptable for building owners or BDE plant owners as a return on investment. At a heat sale price of 50% over the cost of oil, the business model for the project would not be economically viable. The lowest heat sale price the model could bear that would still produce a positive cash flow for the maximum build out scenario would be $25.00 per MMBtu, a 31% savings on the cost of heating with oil. This sale price however would render the first phase project non-viable. A sale price of 20% savings on the cost of oil ($28.99 per MMBtu) was identified as providing enough savings to attract a maximum number of customers and still produce enough of a positive return on investment to represent a fundable business model.

Energy Cost of Year Round Thermal Sales (Pellet Mill Scenario)

Another variable to consider is if the town could attract a business to the industrial park to create new jobs. If such a business could be attracted to set up operations at the industrial park and required a steady and year-round supply of heat, like a pellet mill, it could dramatically improve the economics of the district energy plant. However, due to economies of scale, a large year round heat user on the scale of the pellet mill could likely be able to produce their own process heat for considerably less than $28.99 per MMBtu. It would therefore be necessary to offer heat at a lesser price to a large year round user than to typical seasonal heating customers. A sensitivity analysis was run to determine the impacts of heat sales price to the year round heat user. Scenarios were run with the pellet mill purchasing heat at 33% less than seasonal heat users, 50% less than seasonal heat users, and 66% less than seasonal heat users.

	33% discount	50% discount	66% discount
Sale price of heat	$19.13	$14.49	$9.57
Year 1 revenue	$4,438,390	$3,735,967	$2,989,642
Year 1 cash flow	$1,255,621	$553,197	-$193,127
NPV of 20 year cumulative cash flow	$27,694,604	$15,146,100	$1,813,315
Simple payback on total project	19.56 years	44.40 years	cannot be calculated

It was estimated by the study team that the pellet plant could produce their own heat for approximately $1,500,000 per year, only slightly more than they would pay for heat in the scenario offering this customer heat at a 66% discount on the price of heat offered to seasonal users (the total heat sales to the pellet plant at a 66% discount would be $1,448,748 per year). Due to the high capital cost of the equipment for this option, it would produce poor return on investment for the BDE plant owner. The base analysis was run with heat sales to the pellet mill at a 50% discount on the cost of heat to seasonal heating users. This was determined to be a key threshold below which the sale of heat would not benefit the BDE plant owners. This may still be a difficult sale price to attract a large thermal user.

There is very little room for a profit margin on the sale of energy to such a large user in order to offer heat at a price that they would be willing to pay for it. The main benefit of such an arrangement would be to increase the operating hours of the plant in order to make CHP viable. This will only result in improved economic performance of the business model if the feed-in tariff for the electricity produced

is high enough to compensate for the additional capital investment that would be required to install the CHP equipment and the additional boilers that would be necessary to meet the heat demand of the pellet plant. Biomass electrical generation is considered a Class 3 source under New Hampshire's Renewable Portfolio Standards statutes, and utilities are mandated to increase their Class 3 electrical generation by 6.5% by 2025. This will incentivize the market and may produce a high enough rate to make the payback period on this equipment feasible at such a time as a year round energy consumer desires to partner with the BDE plant as a key thermal customer.

Attracting multiple smaller users of process heat would ultimately be more beneficial to the project than partnering with a single large user who can produce their own process heat at nearly the same price as it would cost the BDE plant to produce it.

9.0 Conclusion and Recommendations

The analysis of the biomass district energy system in Colebrook, New Hampshire indicated that all options studied could produce a successful business model for the BDE plant owners while providing energy cost savings and price stability for customers of the system.

9.1 Economics

The best economics are presented by the long-term objective of the full build out of the system. Even better economics could be produced by this system if the industrial park were filled to capacity with users of process heat purchasing heat from the BDE plant with a rate close to that of the seasonal heat users. Such customers may be attracted to the industrial park once the plant is on the ground and able to provide low cost process heat for their operations. As the project enters the stages of final design and construction, it should be built with consideration for the potential for expansion to add additional boilers and CHP equipment in mind.

While the 20 year pro forma of Phase I are not strong if Phase I were considered as a full build out scenario (with the operation of the system continuing without further expansion for 20 years), this represents a strong starting point for a BDE system. The less than stellar economics of this option are driven by economies of scale. The capital costs for the Phase I system are more than 25% of the costs for the Full Build Out, while the revenues are less than 20% of those that could be produced by the larger system. The modeling predicts that the economics of the project will improve over time if expanded towards the maximum build out scenario. It is important to note that should oil prices rise in the next few years the performance of a Phase I BDE plant will be greatly improved.

9.2 System Design and Expansion

The reasons for starting with a smaller system and building to a larger one are largely related to access to capital. It will likely be much easier to raise $9.56 million for the capital costs associated with the first phase project studied as opposed to $36.47 million for the maximum build out scenario. With the plant in place, further expansion will follow naturally as new customers seek to join the system and owners begin to see return on their investment.

There are two key factors to consider in planning for expansion of the plant. One is the concept of diminishing returns. Phase I and Full Build Out were both designed around the concept that it takes a relatively high load density to justify the expense of laying district energy piping. Care should be taken not to overreach in developing any phase of the project to the detriment of the overall economics.

Another important and related factor that came up in designing the various scenarios was whether the cost of expansion of the BDE network to include a given customer would be less than what it would cost that facility to build their own biomass facility. For the rec center, it was determined that installing their own biomass heating system would be far less expensive and produce much better return on investment than joining the BDE network. For the hospital, it was determined that the cost to join the network would be less than that of installation of their own woodchip boiler. For the proposed pellet mill, it would be very close to a wash. The same concept applies to a residential home and whether or not the cost to connect that load would be more or less than the cost of a residential pellet system.

9.3 Ownership & Business Model

While the economics for the BDE plant generate robust cumulative cash flow over time, none of the scenarios studied result in a rate of return that would be likely to attract a commercial developer to the project. However, they do produce a fundable business model for a municipal or energy cooperative ownership model. These would be the most likely ownership models for the energy committee to pursue going forward.

It is also important to note that these analyses were all based on an oil price of $3.50 a gallon with the revenues of the initial heat sales of the plant tied to the starting price of oil. As the price of oil is only likely to rise in the future, at some point the economics could improve to the point of attracting a commercial developer.

9.4 Next Steps

If the town decides to pursue the concept further, the Colebrook District Energy Committee should take the following steps (which do not require funding):

- Form a committee of BDE stakeholders, including building owners and administrators – participation of individuals with political capital and a history of getting things done will be important
- Continue providing community education to expand the list of individuals and business owners who consider themselves stakeholders and to make BDE known to the taxpayers and members of the larger Colebrook community
- Decide upon a preferred ownership model for the project. Make a Go/No Go decision on forming a new district energy co-operative or a municipal commission to build the project
- Explore sources of funding for development of the project and capital for establishing the first phase of implementation
- Begin gauging the interest of key potential customers through one-on-one meetings and site visits to large energy users within the proposed service territory, as a first step in getting buy-in and commitment

Without funding, project development work can only go so far. Once development funding is secured, work can proceed as outlined below.

- New district energy co-op board or municipal commission is formed
- Co-op board/ municipal commission assembles implementation team and secures development funding
- When funding allows, hire staff
- Apply for grant funding to complete the project development phase
- Hire professional design team (district energy design experience is critical)
- Obtain signed commitments from customers (“If you build the system, I will connect”)
- Equipment specifications produced
- Engineering and design completed
- Final project financing secured (grants and loans)
- Construction starts
- System construction completed and system begins producing energy
- Facility is commissioned

9.5 Conceptual Project Timeline

A concept-level project schedule has been developed as part of this feasibility study and is provided in Appendix G – Conceptual Project Timeline. The schedule assumes a design-build project implementation model. The schedule includes time for development of a design-build request for proposals and bidding process, as well as the design, permitting, construction, and commissioning of the project. The total project duration is shown as just under 2 years. Meeting this schedule requires completing engineering and permitting in time to allow the significant excavation, district piping, and restoration work to begin in late spring. Should timing of key schedule items not allow this to happen, the project could be delayed substantially by splitting excavation and pipe installation over two construction seasons.

Appendix A – Case Study: Mitter Transportation Fuel

BIOMASS

CASE STUDIES SERIES

MITTER TRANSPORTE FUEL COMPANY, LINZ, AUSTRIA

Going with the Future: A Transporting Company Shifts to Pellets

Wood Pellet Heating System

Heating Capacity (output): Two 49 kW (170,000 Btu/hr) boilers

Emissions Reduction and Combustion Control Equipment: O_2 sensor control

Year Installed: 2009

Thermal Output: Hot water

A few years ago, Mitter Transporte (a fuel transporting company) in the suburban town of Haid outside the central Austrian city of Linz felt strongly the currents of change—and its managers responded.

"It was clear that we had to incorporate wood supply into our business," recalls Michael Nagl, the company's fuel procurement manager. "The sooner the better!"

The pressures to move toward renewable fuels in Upper Austria, one of the country's nine states, have converged from the state, national, and international levels. The European Union (EU) has adopted an initiative to increase to 20 percent by 2020 its share of all energy produced by renewable fuels (the current level is 8.5 percent), and to reduce carbon dioxide emissions by 20 percent in the same period—an initiative known as "20/20/20."

EU member countries have until 2012 to develop action plans for achieving the 20/20/20 goals. The EU's executive branch, the European Commission, has set legally binding individual renewable energy (RE) targets for each member country to meet, with stiff monetary "infringement" penalties if they don't.

Austria has been among the most aggressive EU nations in developing RE uses—and Upper Austria has been a leader within the country, ahead of most of Europe, in implementing both efficiency and RE measures. Both the national and state governments are providing strong incentives to reduce fossil-fuel heating; Upper Austria has set a target of zero fossil fuels used for space heating by 2030.

While EU incentives are going to large research and development projects, and Austrian federal incentives are supporting large RE and biomass projects, Upper Austria has made a major commitment of funds for incentives to support residential, commercial, and district energy installations—efficiency, RE, biomass,

and pellet installations. The state's Biomass Action Plan has set challenging goals for increasing biomass district energy use in towns and cities, and for speedily ramping up the use of pellet boilers in residences and businesses. The state's "Heat with Pellets" educational campaign has placed billboards all over Upper Austria.

Renewing a Business with Tested Expertise

It was clear to Mitter's managers that they could not viably stick with a business model based on transporting fuel oil. They responded, first, by searching out reliable sources of top-quality pellets (Austria has well-defined quality standards for different grades of pellets, based on ash content, type of wood used, moisture content, pellet size, and more).

Next, the company bought a pellet-delivery truck and trailer. Both the truck and trailer can hold 12 tonnes (13 US tons) of pellets, about enough to do six to eight home deliveries.

The demand for pellets was rising quickly and Mitter reacted by buying a second truck. It started delivering pellets from Vienna in the east all the way to Innsbruck in the west. Now, Mitter was running two trucks and transporting fuel from two different pellet manufacturers.

over

BERC

Renewable • Reliable • Resourceful

Biomass Energy Resource Center

Pictured on front: Mitter's pre-fabricated pellet boiler plant, located behind the oil company offices. The boiler plant module was craned from the delivery truck to the concrete pad built by the owners. Right: One of two pellet boilers in the plant, showing the ash drawer.

The business leaders didn't stop there.

"Our transport business has been successful over the years because we understand our customers and their needs," Nagl says. "We saw that we had to better understand the heating needs of our customers, just as we are experts in oil delivery."

So the company decided to install its own pellet boiler system, to heat three buildings with a total area of about 1,200 square meters (13,000 square feet)—its offices, its truck garage, and a maintenance shop.

Managers chose a Hargassner packaged boiler plant with two 49 kW pellet boilers (170,000 Btu/hour) capacity each. The system was delivered on a single truck, in two pieces that were essentially concrete boxes: the boiler room and the storage bin, the latter with a 22-tonne (25 US-ton) capacity.

The system manufacturer needed just two days to drop the boiler room and the storage-system boxes onto a concrete slab, bolt them down, put in the boilers, and connect the electrical and piping system, the latter to supply and return piping that Mitter had laid in from the three buildings to the slab.

In early 2009, one month after starting the project, Mitter was heating with pellets. The investment was €75,000-80,000 ($95,000-$105,000 US), partly defrayed by a government subsidy.

The new system displaces more than 15,000 liters (4,000 US gallons) of oil per year at a price of €1 per liter ($5 US per gallon) for a total oil savings of €15,000. Now, Mitter burns pellets at €215 per tonne ($200 US per US ton) and expects that the system will pay for itself within five years.

Each of the boilers automatically removes ash to a drawer, which is emptied periodically. Fuel is moved automatically from the storage bin to the adjoining boilers.

The heating system has been in operation only since the end of March 2009—too early to know the amount of pellets that will be used each year. Mitter Transporte is confident that the system will be a success.

This case studies series was made possible by a generous grant from the US Endowment for Forestry and Communities and through the support of the US Department of Energy.

For more information on this and other biomass energy projects, contact:

Biomass Energy Resource Center
PO Box 1611, Montpelier, VT 05601
ph 802-223-7770 | fax 802-223-7772
info@biomasscenter.org
www.biomasscenter.org

© Copyright 2009 Biomass Energy Resource Center. All rights reserved.

Appendix B – Technology Options

Technology Options

This study explored various technology options which could be consider for possible inclusion in the Colebrook district energy system.

Woodchip District Heating

Technology for thermal energy includes a biomass combustion chamber (furnace) and boiler, a biomass gas turbine and biomass gasification. Based on BERC's review, a fully automated woodchip combustion system was considered for this option. The system can generate thermal energy as steam or hot water. While consideration was given to using high-pressure steam technology, hot-water distribution is recommended because it is more efficient for delivering heat over long distances (there are considerably lower heat losses from piped hot water compared to piped steam) and the cost of hot water distribution piping is lower than for steam piping. A hot-water system is also safer and less expensive to operate than steam.

Gasifiers

Gasification is a thermo-chemical process which converts biomass materials (like woodchips or wood pellets) into *syn gas*, containing carbon monoxide, hydrogen, methane and nitrogen. Cooled and cleaned syn gas can be used to generate electricity in a gas spark-ignition engine or diesel engine with minimal engine modification. For trouble-free operation, the syn gas must be sufficiently free from tars, dust, and acids. Removing tar and particulate matter from syn gas is one of the more difficult problems in the development of commercial gasifier technology.

Theoretically, almost all kinds of biomass with a moisture content between 5 and 20 percent can be gasified. Gasifiers have fairly strict fuel quality requirements, including specifications for fuel particle shape and size, moisture, volatile matter, carbon and ash content.

Gasifier Technology

The complete gasification system consists of the gasifier, a gas cooling and cleaning system, and an energy converter (either a gas burner or an internal combustion engine). The gasification system can either be used to convert biomass into thermal energy, power, or combined heat and power at efficiencies superior to those of direct biomass combustion. The main advantage of this technology is the increased self-reliance that comes from a decentralized (i.e. on-site rather than from the grid) energy conversion process that can be economical even at a small scale. These systems, however, are in an early stage of demonstration and commercialization in the US market. One company which has developed a gasifier product and installed a number in demonstration projects in the United States is detailed below.

Community Power Corporation, Colorado

Equipment Description – Community Power Corporation (CPC) has developed the "BioMax" power system for the US market. The BioMax system is still a pre-commercial technology not recommended for either 24/7 or unmanned operation. CPC suggests a maximum operation time of 16 hours per day, provided there are skilled staff available on-site for all 16 hours.

The system components include a feeder, sorting screen, dryer, fuel feeder, gasifier, heat exchanger, filter, engine generator, and flare control system. The BioMax Power System has fully automatic startup, operation and shutdown; a microprocessor based control system; a non-condensing system; dry gas clean-up, with no liquid effluents and no toxic wastes; and can use a variety of woody biomass fuels (woodchips, pellets, scraps, nut shells, etc). The system can be either trailer- or skid-mounted.

The largest unit supplied by CPC is the BioMax 50. The BioMax 50 system will generate 50 kW of electricity and 0.5 MMBH for space heating. The system will require propane as both a startup and backup fuel. The time for full cold startup on wood gas would be about 15 minutes.
Syn Gas Composition – The syn gas is comprised of H_2 (20 percent), CO (20 percent), CO_2 (seven percent), CH_4 (two percent) and N_2. The tar content of the gas going to the engine is reported to be less than five parts per million. The syn gas has a maximum low heating value (LHV) of 130 Btu/standard cubic foot (SCF).

Demonstration Projects

Mt. Wachusett Community College, Massachusetts – CPC recommends the BioMax system be used as a demonstration project in those places where current economics are not as important as some identified future benefits. One BioMax 50 unit has been installed as a demonstration project at Mt. Wachusett Community College in Gardner, Massachusetts. BERC visited the College, toured the site, and discussed the project with facilities director Rob Rizzo.

This gasifier uses an 8.1 liter GM stationary engine with a 60 kW generator and is planned to be operating on 100 percent syn gas. The project cost was $1.2 million. There have been a number of challenges, most of which are being addressed at this time. Rob Rizzo has said he will be happy to share his experiences after at least 6 months of successful operation. He recommends that all interested project owners wait to see how his project is operating after six months of continuous successful operation before investing in another demonstration project.

Fully Automated Woodchip Boilers

Fully automated systems generally require very little operator attention – typically about one hour daily. They are a good match for buildings where the maintenance staff has a large work load and does not want to spend much time on the heating plant. These systems are best suited to schools and other buildings with significant heat loads and high conventional fuel costs since the capital cost of the system is relatively high but the fuel costs are lower.

Equipment provided and installed by the vendor includes the automated equipment to unload the woodchip storage bin, the fuel handling equipment that carries woodchip fuel to the boiler (conveyors and augers), the combustion chamber and boiler, combustion air supply fans, boiler connection to the stack, controls, safety devices and possibly emissions control equipment.
Fully automated systems employ a chip storage bin, typically below-grade that can hold one and a half to two tractor loads of chips (35-50 tons per trailer). For this evaluation, BERC assumed the chips would be located in a bunker below-grade inside the boiler building. The bunker could be placed outside of the building if that is the determination of the owner and/or architect. The bin is sized to store five days worth of woodchips if the system were operating at peak load, which totals roughly XX tons. While the storage bin could be sized to hold a lesser amount of fuel, this design limits the amount of tractor-trailer traffic in and around the campus. A self-unloading truck loads the bin with no need for on-site staff assistance. From the chip storage bunker, the fuel is fed automatically to the boiler. No operator assistance is required for fuel handling. Vendor systems vary in terms of capacity and automation features.

Cooling

Hot water systems can provide space cooling by incorporating an absorption chiller into the system.

Vapor Absorption Chillers

Hot water systems can provide space cooling by incorporating an absorption chiller into the system. The absorption cycle is similar to the compression cycle, except for the method of raising the pressure of the refrigerant vapor. Absorption chillers differ from the more prevalent compression chillers by the fact that the cooling effect is driven by heat energy, rather than mechanical energy in the form of compressors. In the absorption system, the compressor is replaced by an absorber that dissolves the refrigerant in a suitable liquid, a liquid pump which raises the pressure and a generator which, on heat addition, drives off the refrigerant vapor from the high-pressure liquid. Some work is required by the liquid pump but, for a given quantity of refrigerant, it is much smaller than needed by the compressor in the vapor compression cycle. In an absorption chiller, a suitable combination of refrigerant and absorbent is used. The most common combinations are ammonia (refrigerant) and water (absorbent), and water (refrigerant) and lithium bromide (absorbent).

Indirect-fired absorption chillers use steam or hot water from the boiler or turbine. These chillers could be well suited for integration into a biomass heating or CHP system by utilizing the byproduct heat produced from generating electricity. This provides higher operating efficiencies by using an otherwise wasted energy source. If a facility with a hot water or steam boiler already has a central chiller near the boiler room – or is planning to install one – absorption chillers can be a cost-effective option. Compared with mechanical chillers, absorption chillers have a low coefficient of performance (COP, defined as the chiller's ratio of cooling to energy consumption). However absorption chillers can substantially reduce operating costs when they are powered by low-grade waste heat. Single effect machines can provide a thermal COP of roughly 3.25[1] and require 18 lbs of steam at 15 psig per hour per ton of refrigeration of cooling. Absorption chillers require additional mechanical room space and a minimal amount of additional staff time to operate and maintain.

Combined Heat and Power (CHP)

This technology builds on the woodchip heating system, with biomass being used for thermal energy production; however, in this CHP option, the heat generated by combusting woodchips will be also be used to produce electricity. As indicated earlier, the electric generation system would be sized to the heat load so that heat would be the primary product and, when excess heat is available, electricity would be produced as the secondary product. This configuration is significantly more efficient than sizing CHP systems to the electrical load and producing heat as a by-product.

There are several technology options for woodchip CHP. The most effective option for Colebrook is to install a woodchip boiler and an Organic Rankine Cycle (ORC) system to generate electricity. The ORC system uses a thermal oil loop to generate electricity at lower temperatures than high-pressure steam generators. The captured heat from the ORC system will then heat water for distribution to the district energy network. Advantages of the ORC system include better efficiency than the steam turbine system and lower staff-time requirements, since this is a low pressure application that will not require 24/7 operator attention.

Combined heat and power (CHP), or cogeneration, is the on-site generation of electricity and the recovery of useable heat produced during electric generation. The recovered heat can be used for space heating or other demands for thermal energy. Typically the energy requirements are met by using a boiler to make steam and purchasing electricity from the grid. Cogeneration allows the facility to make steam and provide some or all of its electric requirements on-site. By design, CHP is intended to improve overall energy efficiency of fuel use, reduce total emissions, and save the facility money.

CHP is not a single technology but an integrated energy system that can be modified depending on the energy needs of the end user. CHP is a good option if the facility has excess steam capacity, room for the additional equipment, and competent staff able to manage and maintain the additional equipment. CHP systems are considered more efficient (and thus a better use of the heating fuel), but can be considerably more expensive and complex to permit and install.

Biomass CHP

Biomass CHP uses the same downstream equipment, but employs biomass as fuel for the steam generation. The back-up fossil fuel boilers are still used to provide heat during downtimes. Other additional requirements for biomass CHP are solid fuel storage and fuel handling equipment, which can take up more space than liquid fossil fuel storage and handling systems. Generating energy with biomass can recoup the energy value in the material and avoid the environmental and monetary costs of disposal or open burning of low-value biomass wastes. In addition to the need for added space and equipment, biomass CHP will require added operation and maintenance time, and as much as a half-time staff person to manage the system, make sure the boiler is cleaned, monitor outputs, and operate the system efficiently. These tasks also require a person who is technically competent and able to manage the system for efficiency and maximum output.

During normal operation, the system would run in parallel with the utility and would operate in standalone mode during power emergencies.

There are four technology options for CHP projects:

- Option A: Steam CHP
- Option B: Biomass Gas Turbine
- Option C: Gasifier
- Option D: Organic Rankine Cycle System

A brief description of each of the four options with its merits and limitations follows.

Option A - Steam CHP

Key components of a steam CHP system include a medium- to high-pressure steam boiler, boiler controls, a steam turbine and electrical generator, fuel storage, and an exhaust stack. With steam CHP, steam is used to run a turbine before entering the heating distribution system either as low-pressure steam or, with a heat exchanger, as hot water. Electricity is generated whenever there is sufficient steam load to run the turbine. The turbine does not consume steam. All the steam entering the turbine leaves through the exhaust. The turbine only reduces the pressure and temperature of the steam. When boiler losses are taken into account, the overall system efficiency of a steam turbine cogeneration system ranges from 75 percent to 82 percent. The high efficiency and low cost is obtained only if all the exhaust steam is used for some productive purposes. In addition to producing heat and electricity, steam CHP systems can also provide space cooling by incorporating an absorption chiller into the system.

Turbine

A steam turbine converts the energy in high-pressure, high-temperature steam into mechanical power that can turn a generator to produce electricity (see the description of the generator below). The high pressure steam can be generated from an enormous variety of fuels including wood, wood waste and agricultural by-products.

A large variety of turbines exists for different sizes, inlet pressures and temperatures, and outlet conditions. The performance specifications of the turbine must include the inlet pressure and temperature and the steam rate (in lb/kWh) of the turbine.

There are two types of steam turbines, described below, known as *back-pressure steam turbines* and *extraction/condensing steam turbines*.

Back Pressure Steam Turbine -The back-pressure turbine generator is the oldest distributed generation technology. A back-pressure steam turbine outputs the steam from the turbine at temperatures high enough to be useful for the thermal load. Back-pressure turbines are very efficient because the exhaust steam is used for some other productive purpose, but this same characteristic limits its output. The drawback of such an arrangement is a low output of electricity compared to heat (a high heat to power ratio) and less flexibility meeting varying electrical loads. The back-pressure turbine system is simple, fully automatic, and requires minimum operator attendance. About two-to-three worker days per year would typically be required for lubrication, parts replacement, and other maintenance for the turbine.

Extraction/Condensing Turbine -To increase the electrical output from the cycle, a condensing turbine can be used. In such a system the output pressure of the turbine is lowered to well below atmospheric pressure. In an extraction/condensing turbine, however, the steam is extracted from the turbine at an intermediate pressure and temperature, one high enough to meet heating demands. The primary advantage is the flexibility to meet varying loads by changing the extraction rate.

An important advantage of the condensing turbine systems is that electrical output is not limited by the use of process steam for heating. However extraction turbines are considerably more expensive.
Even the best condensing turbine systems can only achieve a total system efficiency of 30-40%, or less than half of the overall efficiency of a back-pressure turbine.

Generator

There are two types of generators, synchronous and induction generators.
Synchronous Generator - A synchronous generator produces its own reactive power and regulates its voltage, even when it is not connected to the utility. This means that it can operate either in parallel with the utility or it can operate in stand-alone mode. Another advantage of a synchronous generator is it can improve the plant power factor. However, a synchronous generator requires a somewhat more elaborate control system and is usually more expensive than an induction generator.

Induction Generator -The induction generator is the simplest and usually the least expensive type of generator. It cannot produce electricity until it is connected to the utility. If the generator is more than around a third of the total plant load, an induction generator can adversely affect the plant's power factor.

Determining System Capacity

The power output from a steam turbine generator is a function of four variables: steam flow rate, inlet pressure, inlet temperature, and exhaust pressure. When any of the first three are raised, the power output will increase. When the exhaust pressure is increased, the power output will decrease.
The most efficient way to design a CHP plant is to focus on thermal, rather than power, needs. This approach ensures the greatest fuel efficiency, meaning the amount of useful power recovered from the fuel being used is maximized. It also provides the lowest possible operating costs and reduces greenhouse gas emissions.

The characteristics of a cost-effective CHP system include a steam flow rate of at least 10,000 lbs/hr, a steam load factor of more than six months/year, and a pressure drop across the turbine of at least 100 psi. The difference between the actual steam temperature and the steam saturation temperature at a

given pressure is known as superheat. Adding a certain amount of superheat greatly improves efficiency and ensures that moisture in the turbine will not be a problem.

Option B - Biomass Gas Turbines

There is emerging technology that uses wood fuel to produce electricity and steam (or hot water) employing a hot gas turbine (not to be confused with a gas combustion turbine).The system consists of a pressurized combustor, which generates hot, high-pressure gases that in turn pass through a cyclonic separator into a gas turbine, transforming biomass into electricity and process heat. Ambient air is pressurized in the gas turbine compressor section to provide air for combustion. Small dry particles of biomass are fed into a hopper and mixed with the compressed air. The combustor burns the mixture of biomass and compressed air and produces hot gases. The combustion gases are cleaned using a cyclonic filter before they are ducted to the gas turbine hot section. The gas turbine hot section drives the generator.

The system is developed by Zilkha Biomass Energy to produce from 1 to 10 megawatts of electrical power, which can either be used on-site to serve the specific electrical needs of the host facility or sold to a local utility or neighboring facility. In addition to electricity, the high temperature (approximately 1,000° F) gases exhausted from the turbine can be used directly as a source of thermal energy for production processes such as drying. This exhaust heat can also be fed into a waste heat recovery steam generator or existing boiler to produce steam for process applications, or to generate more electricity by using a conventional steam turbine. In order to use solid fuels in a direct-fired gas turbine configuration, a pressurized external biomass combustor—not directly attached to the gas turbine—capable of operating at the temperature and pressure levels required by gas turbines has been developed. This unit also incorporates a proprietary cyclonic separation system intended to reduce particulate matter entrained in the combustion gas stream to a level acceptable for extended gas turbine operation. A computerized control system with internet accessibility can be designed to provide the system with state-of-the-art management, dual fuel capability, high-speed data logging, and instantaneous shutdown capability from both local and remote locations.

Zilkha Biomass Energy operates somewhat like an energy services company (ESCO), in that their business model retains ownership and operation of the biomass equipment while selling the electricity and thermal energy to the host site. A first-of-its-kind project has been installed at New England Wood Pellet at their manufacturing plant in Jaffrey, New Hampshire. Zilkha is not interested in supplying this technology and equipment at this time; however, Zilkha may be interested in selling electricity and thermal energy to facilities in the future.

Option C – Gasifiers

Gasification is a thermo-chemical process which converts biomass materials (like woodchips or wood pellets) into *syn gas*, containing carbon monoxide, hydrogen, methane and nitrogen. Cooled and cleaned syn gas can be used to generate electricity in a gas spark ignition engine or diesel engine with minimal engine modification. For trouble-free operation, the syn gas must be sufficiently free from tars, dust and acids. Removing tar and particulate matter from syn gas is one of the more difficult problems in the development of commercial gasifier technology.

Theoretically, almost all kinds of biomass with MC between 5 and 20 percent can be gasified.
Gasifiers have fairly strict fuel quality requirements, including specifications for fuel particle shape and size, moisture, volatile matter, carbon and ash content.

Gasifier Technology

The complete gasification system consists of the gasifier, a gas cooling and cleaning system and an energy converter (either a gas burner or an internal combustion engine). The gasification system can either be used to convert biomass into thermal energy, power, or combined heat and power at efficiencies superior to those of direct biomass combustion. The main advantage of this technology is the increased self-reliance that comes from a decentralized (i.e. on-site rather than from the grid) energy conversion process that can be economical even at a small scale. These systems, however, are in an early stage of demonstration and commercialization in the US market.

Option D – Organic Rankine Cycle (ORC) System

The Organic Rankine Cycle (ORC) is a thermodynamic process in which, instead of water, a low boiling organic fluid circulates as a working fluid. ORC uses non-flammable silicon oil as the working fluid. Biomass is burned in the combustion chamber and hot exhaust is streamed through the thermal oil boiler. The boiler heats this thermal oil to about 300° C (572° F). The hot thermal oil evaporates the working fluid from the ORC system in the evaporator, turning it into vapor. Under pressure this vapor is forced through the expander, turning it to spin an electric generator. The expander could be a twin screw expander or turbo expander. The vapor is cooled and condensed back into liquid in the condenser; this condensation is obtained by heating hot water. The hot water can then be used for space heating or any other thermal energy requirements. The working fluid liquid is then pumped and returned to the evaporator to repeat the process.

There are several advantages of the ORC system. It is a low pressure system, and so requires minimal operator attention and maintenance. ORC plants do not require stringent supervision by highly trained personnel, which means that the operation of the ORC is less expensive than for some other CHP systems. The system has a few moving parts and so long-term maintenance is also minor. The ORC system also does not require a water treatment system. It has better efficiency and more reliable operation. The expander has lower operating speed, and so is compatible with synchronous generators. ORC system capacities range from 50 kW to 2.2 MW, and can be stacked to provide much larger power outputs. There are a large number of CHP plants using ORC technology successfully running in Europe with continuous and unattended operation.

To be economically competitive, and ORC plant really needs to operate for at least 4,000 hours at full load. Additionally, this equipment is not currently available in the US and there would be a higher cost associated with importing this equipment from Europe. Steam downstream of the ORC system is possible but makes it much more complicated. The electrical efficiency of an ORC system with steam as the heat output will be lower because condensing happens at a higher temperature. Converting from steam heating to hot water heating can often make more sense. Also, this system would require a hot water distribution system.

The operating parameters considered were a steam inlet pressure of 320 pounds per square inch absolute (psia), with temperatures as required to give 100º F superheat, and a saturated steam outlet pressure of 60 psia. All components of the system will be chosen from standard available types whenever possible. The efficiency of the generator would be about 60 percent.

Appendix C – Network Loads and Boiler Sizing Memo

Annual Heating Demand for District Heating System with Reduced Scope

Loads are developed based on March 29-30 site visits of potential key users by Wilson Engineering Services, PC and May 2, 2012 collection of tax record square footage data for buildings in Colebrook by Community Biomass Systems, Inc. (CBS). Key users provided average annual fuel usage. Actual fuel deliveries provided by UCVH only. From tax records, CBS determined which facilities utilize fuel oil and have central hot water systems. Buildings along pipe routes over 2,000 square feet are included in the load information. Buildings over 7,000 sf with propane are also included. Usage per square foot values from past studies for Smethport, PA and Maple Corner, VT were used to obtain usage per square foot values where actual load data did not exist. No estimate of load reduction is made for potential wood stove use within buildings. The tables note which facilities were visited. Pipeline routes are selected by BERC based on serving major loads and incorporating key sections of the town.

Address or Name	Current Fuel	Heated Square Footage	Assumed Gallons/sf/yr	Current Annual Usage, gal/yr	Heating Demand, mmBtu/yr
Bridge Street Gym - Site Visit	Propane	3,963	-	7,000	510
34 Bridge Street	Fuel Oil	1,876	0.45	844	88
32 Bridge Street	Fuel Oil	2,130	0.45	959	100
26 Bridge Street	Fuel Oil	2,048	0.45	921	96
Methodist Church	Fuel Oil	7,850	0.47	3,690	385
17 Bridge Street	Fuel Oil	8,436	0.47	3,965	413
9 Bridge Street	Fuel Oil	2,930	0.45	1,318	137
121 Main Street	Fuel Oil	3,570	0.47	1,678	175
119 Main Street	Fuel Oil	5,581	0.47	2,623	273
109 Main Street - Sutton Place - Site Visit	Fuel Oil	3,114	-	1,054	110
107 Main Street	Fuel Oil	3,009	0.47	1,414	147
103 Main Street	Fuel Oil	4,888	0.47	2,297	239
10 Colby Street	Fuel Oil	2,294	0.47	1,078	112
91 Main Street - Rite Aid - Site Visit	Propane	12,090	0.72	8,704	594
Elementary School - Site Visit	Fuel Oil	129,670	-	30,000	3,336
88 Main Street	Fuel Oil	3,224	0.47	1,515	158
94 Main Street	Fuel Oil	7,211	0.47	3,389	353
98 Main Street	Fuel Oil	3,386	0.47	1,591	166
100 Main Street	Fuel Oil	3,715	0.47	1,746	182
102 Main Street	Fuel Oil	2,082	0.47	978	102
104 Main Street	Fuel Oil	6,797	0.47	3,194	333
108 Main Street	Fuel Oil	3,769	0.47	1,771	185
110 Main Street	Fuel Oil	3,180	0.47	1,495	156
118 Main Street - Hicks Lumber, Site Visit	Fuel Oil	14,385	-	2,280	254
120 Main Street - Hicks Hardware, Site Visit	Fuel Oil	10,859	-	2,760	307
122 Main Street	Fuel Oil	3,400	0.47	1,598	167
124 Main Street	Fuel Oil	4,635	0.47	2,178	227
126 Main Street - Library, Site Visit	Fuel Oil	8,666	-	4,220	411
138 Main Street	Fuel Oil	5,895	0.47	2,771	289
Colebrook Academy - Site Vsisit	Fuel Oil	33,422	-	16,000	1,779
154 Main Street - Family Dollar, Site Visit	Propane	22,740	0.72	16,373	1,117
19 Park Street	Fuel Oil	4,845	0.45	2,180	227
29 Park Street	Fuel Oil	1,816	0.45	817	85
33 Park Street	Fuel Oil	2,287	0.45	1,029	107
39 Park Street	Fuel Oil	1,708	0.45	768	80
41 Park Street	Fuel Oil	1,753	0.45	789	82
Dosties Furniture	Propane	6,308	0.72	4,542	310
Monadnock Village - Site Visit	Fuel Oil	62,400	-	19,233	2,139
UCVH - Site Visit	Fuel Oil	not obtained	-	54,598	6,071
Town Recycling - Site Visit	Fuel Oil	575	-	275	27
Town Garage - Site Visit	Fuel Oil	4,581	-	2,000	209
Total					**22,239**

Total Estimated Propane Usage, gallons	**36,619**
Total Estimated Fuel Oil Usage, gallons	**181,019**

Wilson Engineering Services, PC
9006 Mercer Pike
Meadville, PA 16335
Office: (814) 337-8223

M E M O R A N D U M

Date: **June 18, 2012**

To: **Hillary Emick, BERC**

By: **Dan Wilson, WES**

CC:

RE: **Colebrook Biomass System Option Sizing**

This memorandum provides graphs and text on sizing for the Colebrook project for BERC's use in the overall feasibility report. The options sized include:

- Scenario 1 – Reduced Scope District Heating System
- Scenario 2 – 50,000 tpy Pellet Plant and Reduced Scope District Heating System

The recommended system for Scenario 1 includes a 300-hp (10.0 mmBtu/hr) advanced biomass combustion unit and 150 psig rated hot water boiler, a 100-hp (3.3 mmBtu/hr) advanced biomass combustion unit and 150 psig rated hot water boiler, and 8,000 gallons of thermal storage. The recommended system for Scenario 2 includes a 1,250-hp (41.8 mmBtu/hr) advanced biomass combustion unit and thermal oil heater in conjunction with a 2.2 MWe ORC system.

SCENARIO 1 THERMAL LOADS

Heat demand modeling for the district heating system is based on an average annual thermal demand of 22,200 mmBtu/yr. This annual demand is based on records from owners of key heating loads and on square footage estimates for smaller residential and commercial users. Details on the heating loads and assumptions made regarding existing system efficiencies are provided in Attachment A. With a few exceptions, the data provided by owners was an average value not tied to a specific year. Thus, to develop a load model, the average annual use is spread over a year with an average number of heating degree days (HDD). The long-term average is 9,118[1] HDD (base 65) per year based on 30-yr NCDC data for Colebrook. Daily surface temperature data obtained from NCDC for the Colebrook, NH weather station (USC00271647) shows that over the last 10 years, 2004 with 9,180 HDD (base 65) is the closest year to the long-term average. The 2004 daily surface temperature data is used to develop a model of the energy demand over the course of a year, and the result is presented in Figure 1.

[1] 30-yr NCDC average data as reported by www.weather.com.

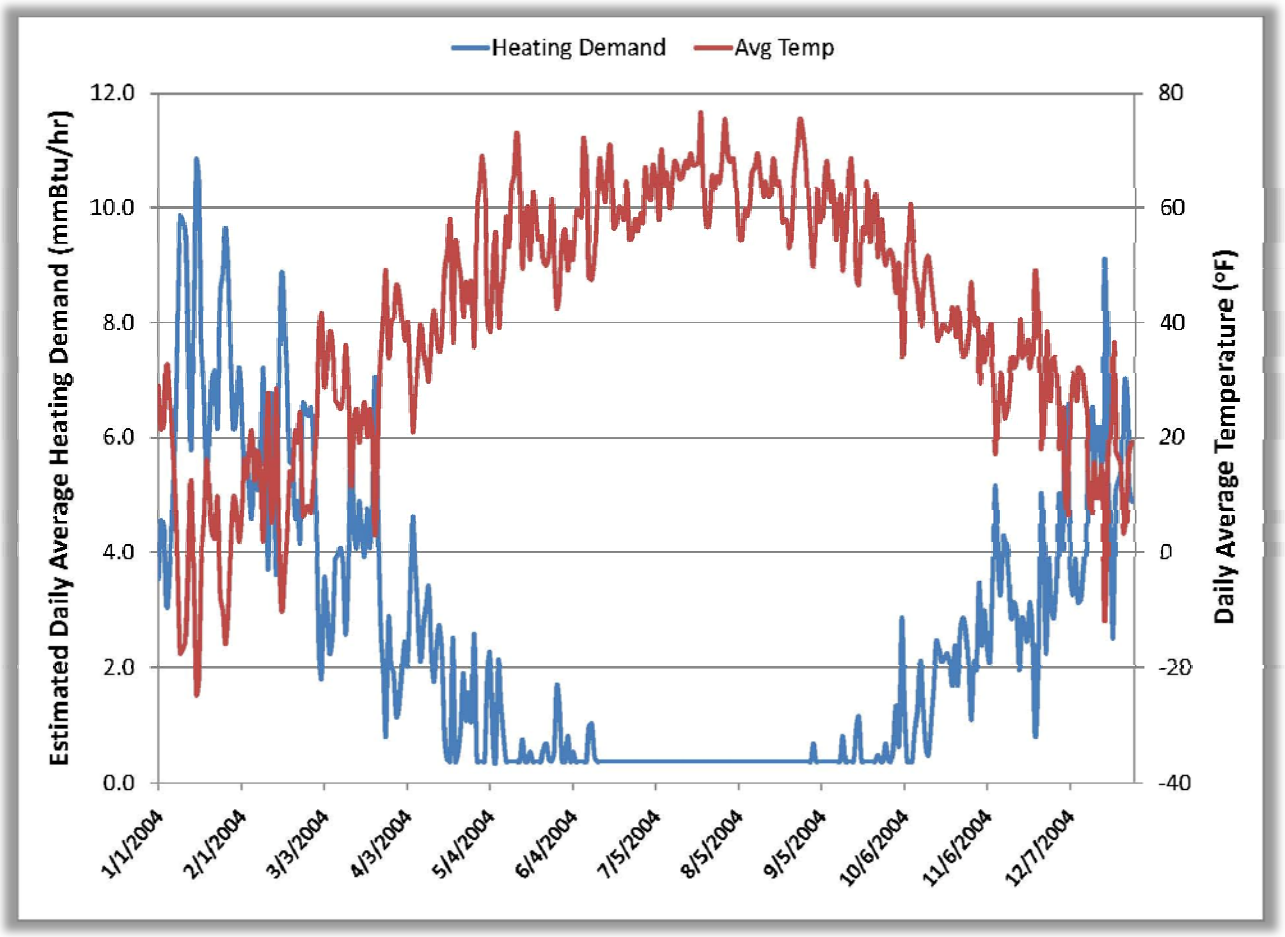


Figure 1 – Estimated Average Daily Heating (Thermal) Demand

Note: Figure shows the estimated daily average thermal demand based on average estimated fuel usage values and daily surface temperature data from NCDC for calendar year 2004 (Colebrook, NH station). During the course of each 24-hr period, the load will fluctuate from the average presented.

It is important to note that this graph provides an estimate of the daily average demand. During the course of a 24-hr period, the actual demand will fluctuate. It is not uncommon for actual hourly demand within individual facilities to fluctuate between 35% above and 35% below the daily average based on experience with usage records. To identify the peak load for the system, the peak daily average of 10.8 mmBtu/hr is increased by 35%, and a demand factor of 0.8 is used to account for variations in the timing of peak within each facility. This results in a peak value of 11.7 mmBtu/hr of heat to be delivered to facilities along the district heating system. The biomass boiler units are designed for the current peak value to ensure efficient system operations for the initial system, and the building will be dimensioned so as to allow for an increase in boiler system capacity.

The potential exists for future expansion of the district heating system. Distribution piping will be sized to allow a 50% increase in peak demand for a peak of 17.5 mmBtu/hr. This increase in pipe sizing results in a moderate increase in initial costs, but is necessary to allow future build out of the system over its 25 year or greater life.

The hospital is the only significant summer load for the system, and delivery records indicate that approximately 1,500 mmBtu/yr of the annual demand for the hospital is from May through September.

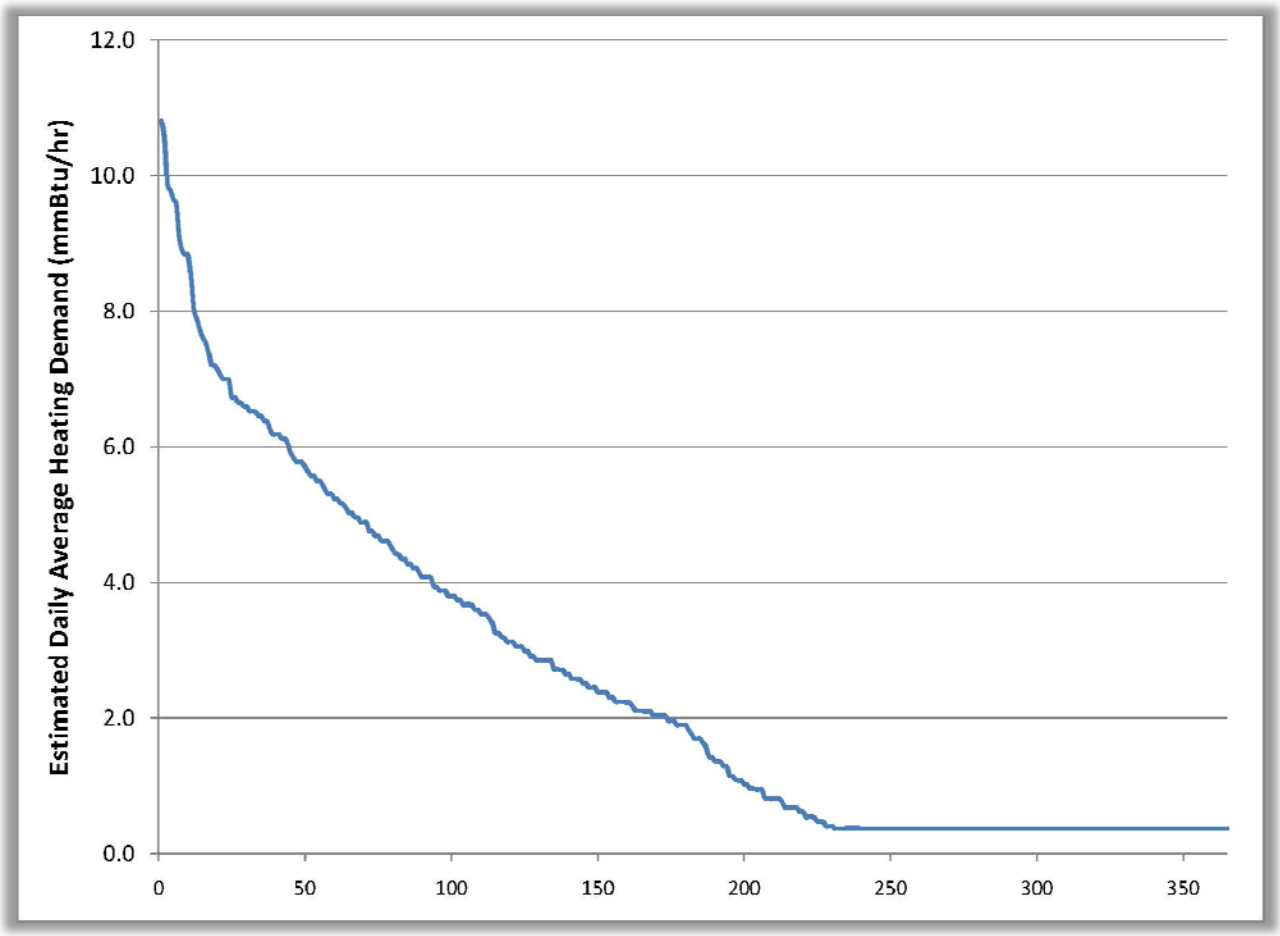


Figure 2 – Average Daily Thermal Demand Load Duration Curve (LDC)

Note: Figure shows the estimated daily average thermal demand based on average estimated fuel usage values and daily surface temperature data from NCDC for calendar year 2004 (Colebrook, NH station). During the course of each 24-hr period, the load will fluctuate from the average presented.

SCENARIO1 SYSTEM SIZING

The approach taken to sizing the district heating plant is to provide year-round coverage of heating loads. This is done despite the low summer loads in order to allow full replacement of heating equipment within each owner's facility. This is necessary in order to keep home and business owners from realizing continued ownership and maintenance costs for heating equipment within their home/facility. Other approaches such as operating the biomass system only for the heating season and with one biomass unit were considered. However, these were eliminated due to occurrence of space heating demand during the period of May through September. Space heating demand during this period could not be covered by one biomass unit and would require system users to maintain onsite backup equipment. The approach to covering the full annual load is to utilize two biomass units to provide for all load with full fuel oil backup available for emergencies and coverage of planned biomass system maintenance.

When evaluating the biomass system's ability to meet the thermal loads of users connected to the district system, heat loss from the distribution piping and equipment must be considered. The distribution system includes 10,500 feet of supply and 10,500 feet of return piping within 10,500 linear feet of trench. This 21,000 feet of pipe does not include the length of small diameter piping leading to and from each individual home or business. The heat loss in the piping system is estimated at 0.52 mmBtu/hr for the entire period for which the biomass system will be operational. This heat loss will fluctuate somewhat based on seasonal adjustments in supply and return temperatures as well as ground temperature over the course of the year. However, for the purposes of this analysis, this value is kept constant.

Biomass unit sizes of 100-hp and 300-hp are selected for the system. The 100-hp unit will be capable of providing a peak of 3.35 mmBtu/hr of heat, 0.52 mmBtu/hr of which will be absorbed by heat loss in the distribution system. The biomass unit will be capable of operating efficiently down to 25% of rated capacity, and thus the minimum design supply rate to the users on the district system will be 0.32 mmBtu/hr (0.84 mmBtu/hr boiler output minus 0.52 mmBtu/hr heat loss). The 250-hp (8.37 mmBtu/hr) unit will be capable of effectively meeting user demands between 1.57 and 7.85 mmBtu/hr. The combined range of heat supply to the district users by the system will be 0.32 – 12.87 mmBtu/hr (0.84 – 13.39 mmBtu/hr boiler output). This range covers the minimum demands in the summer as well as the peak demand of 11.7 mmBtu/hr. The biomass systems are able to fire below the minimum rate depending on the fuel moisture and other factors. However, it is not desirable from an efficiency or emissions standpoint to design in sustained operation below this rate.

Figure 3 shows that the proposed biomass units can cover 100% of the range in thermal demand on the system.

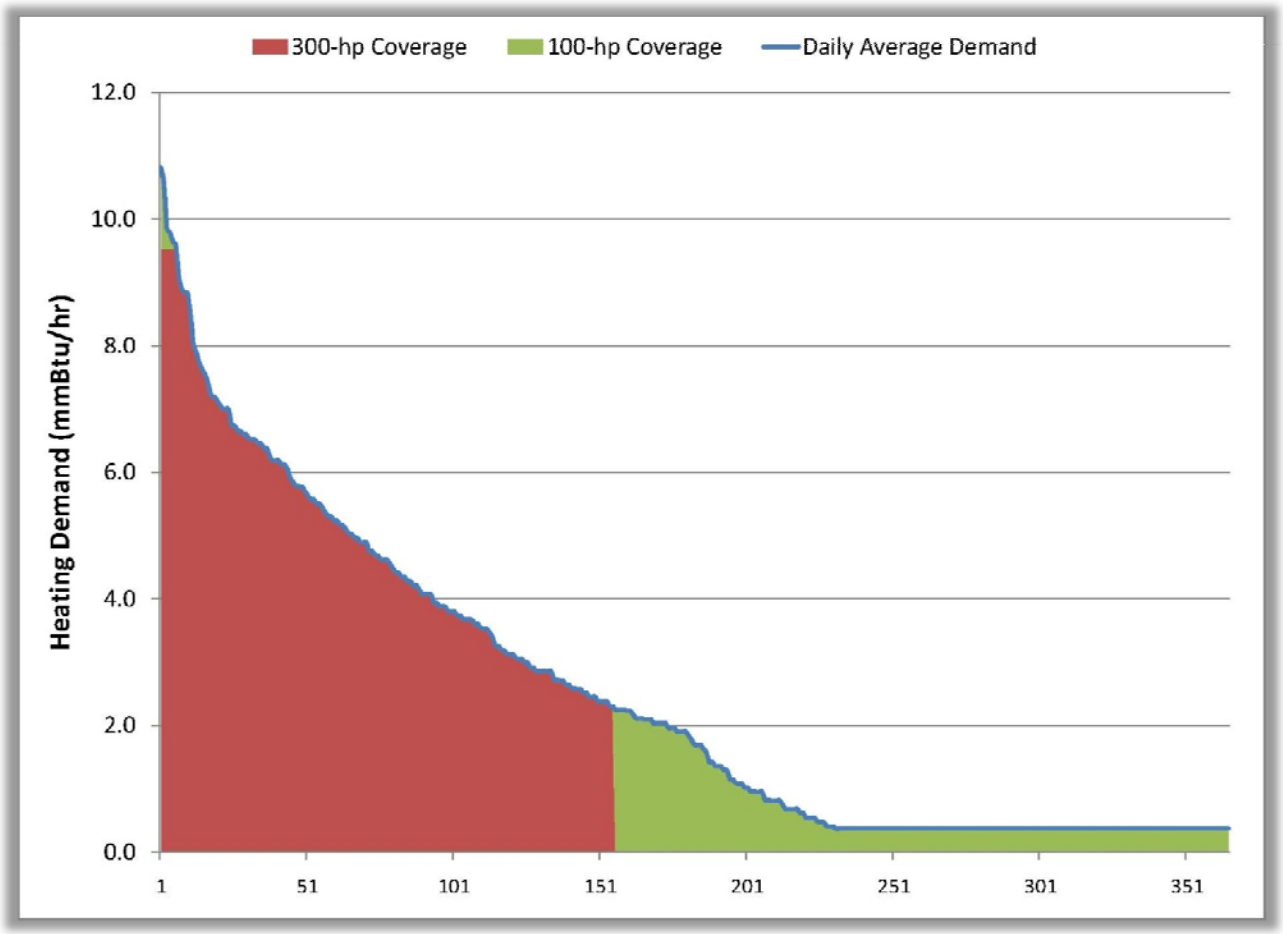


Figure 3 – 250-hp Biomass System Coverage of Thermal Demand

Note: Figure shows coverage of thermal demand shown in Figures 1 and 2. The maximum thermal energy available to meet heating demands in the facilities connected to the district system is reduced by 0.52 mmBtu/hr due to system heat loss. This loss is reflected through direct reduction of the effective output of the biomass units.

The anticipated system operating pressure within the biomass plant is 60 psig, which allows operating water temperatures of 220-230°F. A thermal storage unit is recommended for inclusion in the overall system. The storage will be set at a temperature above the desired supply temperature. Storage water will be blended with return water by a three-way mixing valve to meet the supply temperature. For the purposes of this report, a temperature of 220°F in the thermal storage tank is assumed with supply water temperature determined based on a seasonal reset and customer needs. A minimum design temperature delta of 40°F is assumed. During the peak heating season, this report assumes a supply temperature of 200°F with anticipated return temperature of 160°F or below. An 8,000 gallon thermal storage tank is recommended for this system. This will provide up to 1.3 mmBtu of stored energy to meet temporary peaks without a drop in supply temperature. In the shoulder season, when supply temperature is set at a lower point, the thermal storage tank will provide a heat sink. As an example, the storage tank will provide a minimum of a 3.3 mmBtu/hr heat sink with 170°F supply water. This heat sink allows the system to span short-term periods of low load with efficient operation.

The ability to utilize temperature resets will depend on the Hospital load. Currently one half of the hospital's heating system utilizes lower temperature hot water when it is warmer outside. The other half uses 190°F hot water at all times of the year. It is possible that this could be adjusted if the district heating system is interconnected with the hospital load, but the ability of the heat distribution equipment within the hospital to meet loads with lower temperature water would need to be verified. Another key to supply water temperature is temperature drop along the pipeline during low-flow periods. Distribution system flows would typically be controlled by variable frequency drives based on the temperature difference between supply and return temperature. However, during the shoulder seasons and summer, a minimum flow will need to be established to ensure adequate temperature can be provided at the Hospital, which is the furthest load from the central plant.

SCENARIO 2 THERMAL LOADS

The thermal demand for Scenario 2 includes the same loads for the district heating system as identified in Scenario 1 as well as the thermal demand for a 50,000 ton per year pellet plant. The load from the pellet plant is added in order to show the impacts of a large energy user on the economics of a district heating system. For the purposes of this report, the constraints placed on the pellet plant are that it utilize hot water for drying to accommodate the output from an Organic Rankine Cycle (ORC) unit. A value of just over 3 mmBtu/hr of hot water at 200°F per ton of pellets produced is used for this report based on plant monitoring results in Germany[2]. An operational rate of 95% and 50,000 tons per year are used to identify 6 tons/hr as the production rate of the plant. This leads to a thermal demand of 18.2 mmBtu/hr of 200°F hot water in the plant at maximum plant production. The production of an actual plant depends on market demand, however, the load is assumed to be constant for demand modeling purposes in this report. Reality is that there will also be down time for the plant. Planned outages would occur in the summer months. Figure 4 shows the estimated daily average thermal demand for the pellet plant and the district heating system. Figure 5 shows the load duration curve for this load.

[2] Duvia & Tavolo (Turboden), "Applications of ORC Units in the Pellet Production Field: Technical-Economic Considerations and Overview of the Operational Results of an ORC Plant in the Industry Installed in Mudau, Germany."

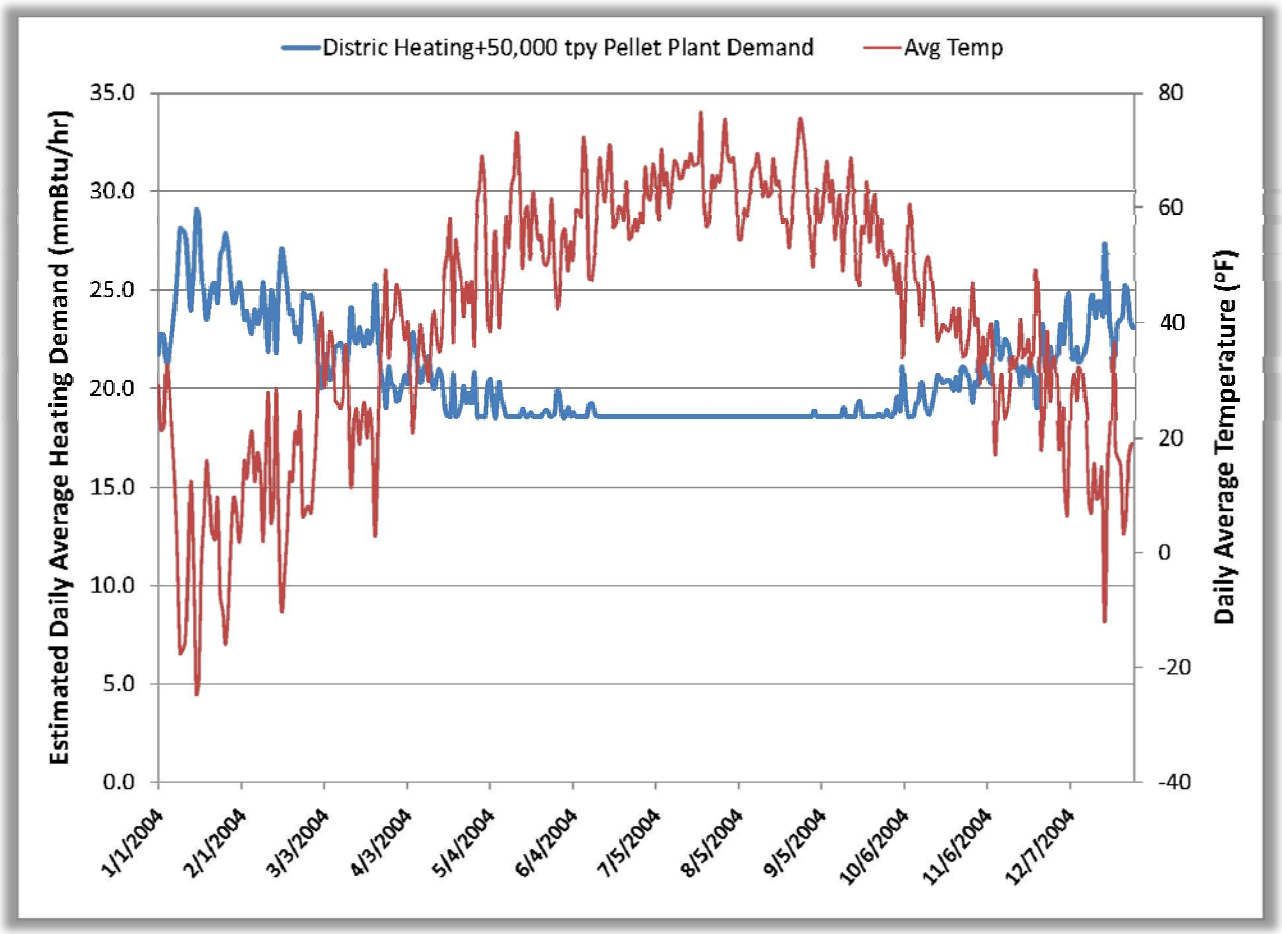


Figure 4 – Estimated Average Daily Thermal Demand

Note: Figure shows the estimated daily average thermal demand based 50,000 ton per year pellet plant and district heating loads as discussed in Option 2 Thermal Loads section. During the course of each 24-hr period, the load will fluctuate from the average presented.

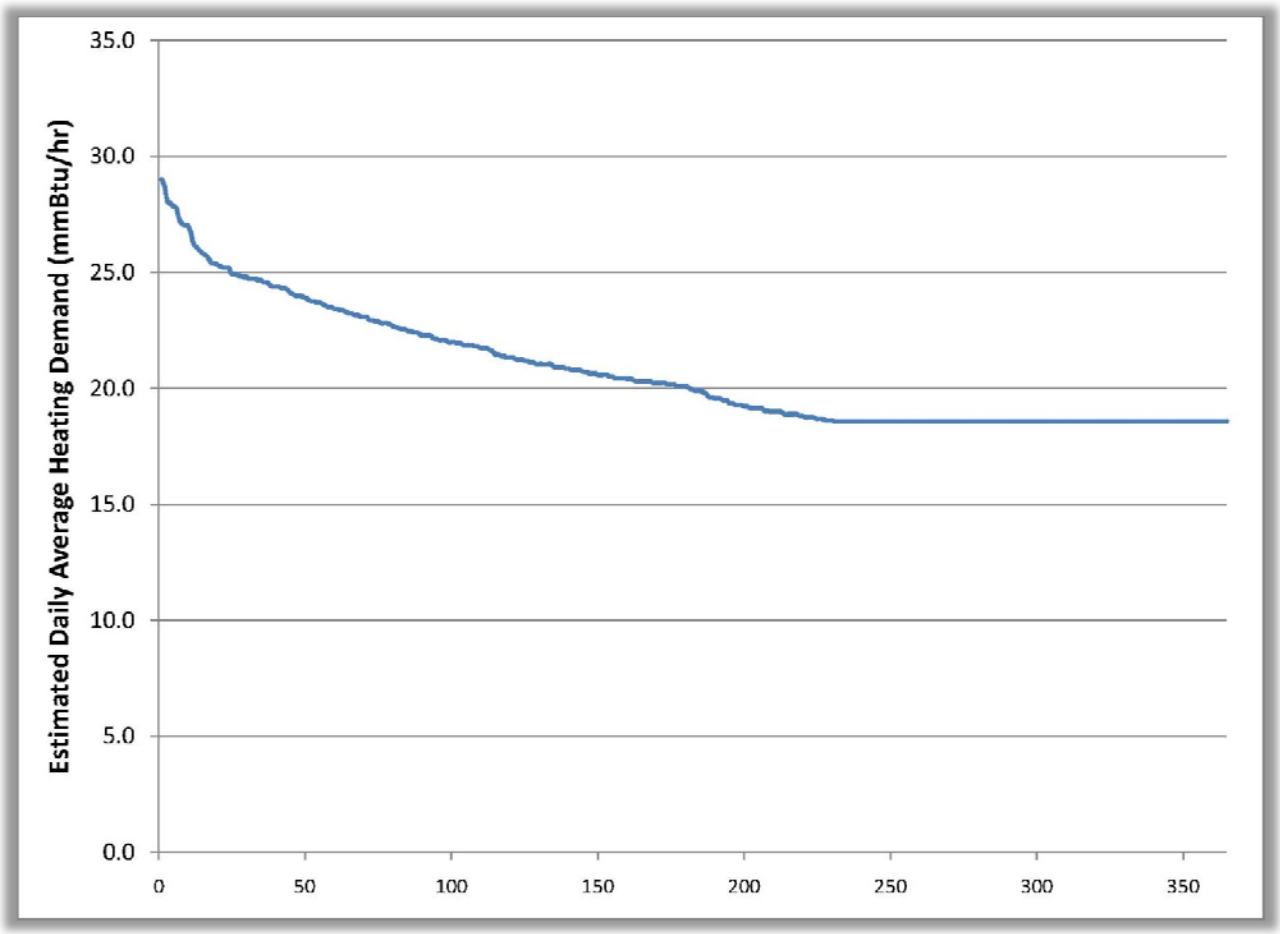


Figure 5 –Average Daily Thermal Demand LDC – District Heating + Pellet Plant

Note: Figure shows the estimated daily average thermal demand based 50,000 ton per year pellet plant and district heating loads as discussed in Option 2 Thermal Loads section. During the course of each 24-hr period, the load will fluctuate from the average presented.

SCENARIO 2 SYSTEM SIZING

The sizing approach for Scenario 2 is slightly different than that for Scenario 1. With Scenario 2 there is a year-round demand of 18.2 MMBtu/hr from the wood pellet plant. This steady and significant demand allows sizing of one biomass unit to ensure coverage of the peak demand without sacrificing coverage of lower demands. For example, the peak demand for the pellet plant and the additional district heating system load is approximately 30 MMBtu/hr. The minimum demand is 18.2 MMBtu/hr, which is 60% of the peak load.

To size the biomass and ORC system, the peak demand of 30 mmBtu/hr is divided by the approximate ORC thermal yield of 81%. This refers to the fact that of the energy from the thermal oil put into the ORC unit, 81% comes out in the form of 200°F hot water, a net of 16.7% comes out as electricity, and 2.3% is lost as part of the process. This yields a demand from the thermal oil heater of 37 mmBtu/hr. The peak electric production of the ORC unit would depend on the manufacturer and exact system specified, but the net output when matching a peak demand of 30 mmBtu/hr would be approximately 1.8 MWe. The system would be run as a thermally-led system, meaning that electricity would be generated at a rate allowing all hot

water from the system to be utilized. This approach provides cost effective electric generation and ensures maximum overall system efficiency.

A thermal oil boiler sized at 1,250 hp and an ORC unit accepting a similar thermal input are selected for the purposes of this report. This system would be capable of providing approximately 34 mmBtu/hr to the pellet plant and district heating system, and a have peak electrical output of 2.0 MWe at max thermal demand. Figure 6 shows that the system is capable of 100% coverage of the modeled load.

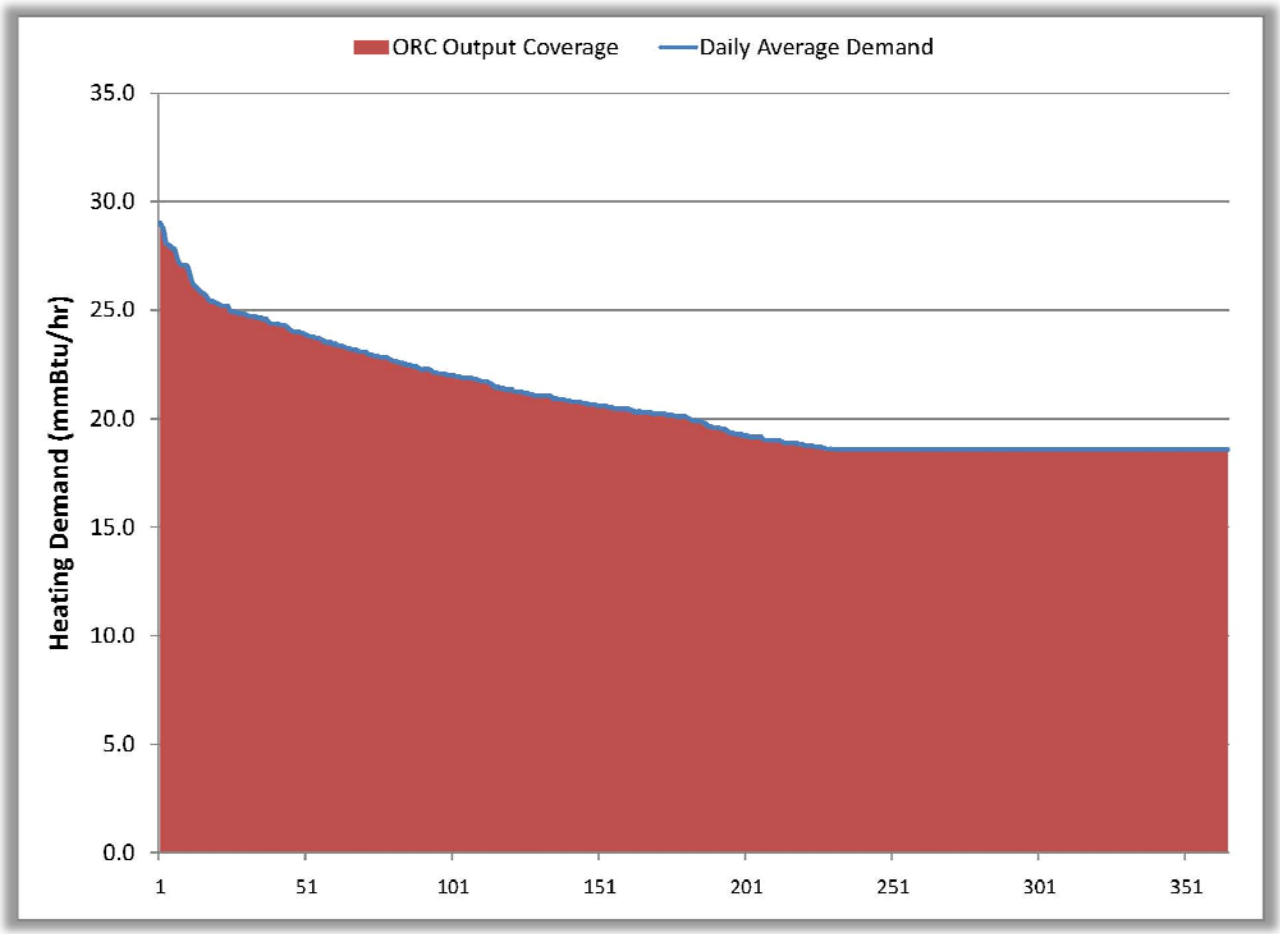


Figure 6 –1,250 hp Thermal Oil Heater and 2.2 MWe ORC System Coverage of Loads

Note: Figure shows the estimated daily average thermal demand based 50,000 ton per year pellet plant and district heating loads as discussed in Option 2 Thermal Loads section. During the course of each 24-hr period, the load will fluctuate from the average presented.

Appendix D – Conceptual Plant Designs and Network Maps

Note: Values listed for key users are mmBtu/yr of heating demand.

Legend:

Distribution Pipeline Route

Designed	CTH	5-16-12
Drawn	CTH	5-16-12
Checked	DAW	6-1-12

Date ____
Job Class ____

Approved ____
Title ____

Colebrook Biomass District Heating System

Colebrook, New Hampshire

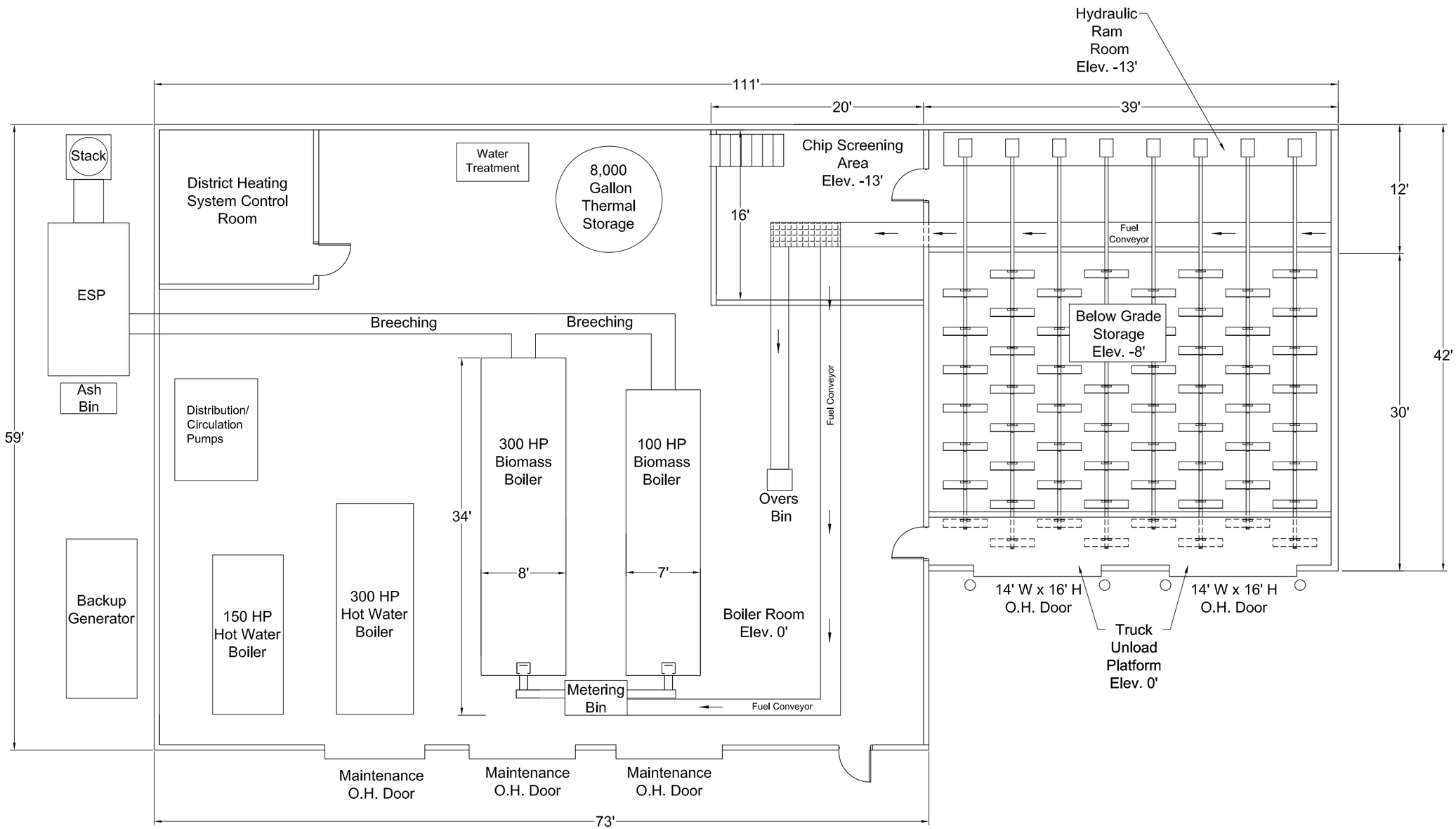
District Heating Distribution Pipe Route

WES
Wilson Engineering Services, PC
www.wilsonengineeringservices.com
9006 Mercer Pike Meadville, PA 16335

REVISIONS

Date	Description	Approved

Appendix A.1



10' 0' 5' 10'

Scale

Notes:

1. This drawing is a conceptual layout for the purposes of developing surveying and geo-technlcal investigation plans. Actual footprints will vary depending on manufacturers and materials handling equipment selected.
2. The live floor storage system shown is one of several options. As the project progresses, additional storage systems should be considered.

Designed	CTH	6-04-12
Drawn	CTH	6-04-12
Checked	DAW	6-13-12

Approved _____ Date _____

Title _____ Job Class _____

Colebrook District Energy System

Colebrook, NH

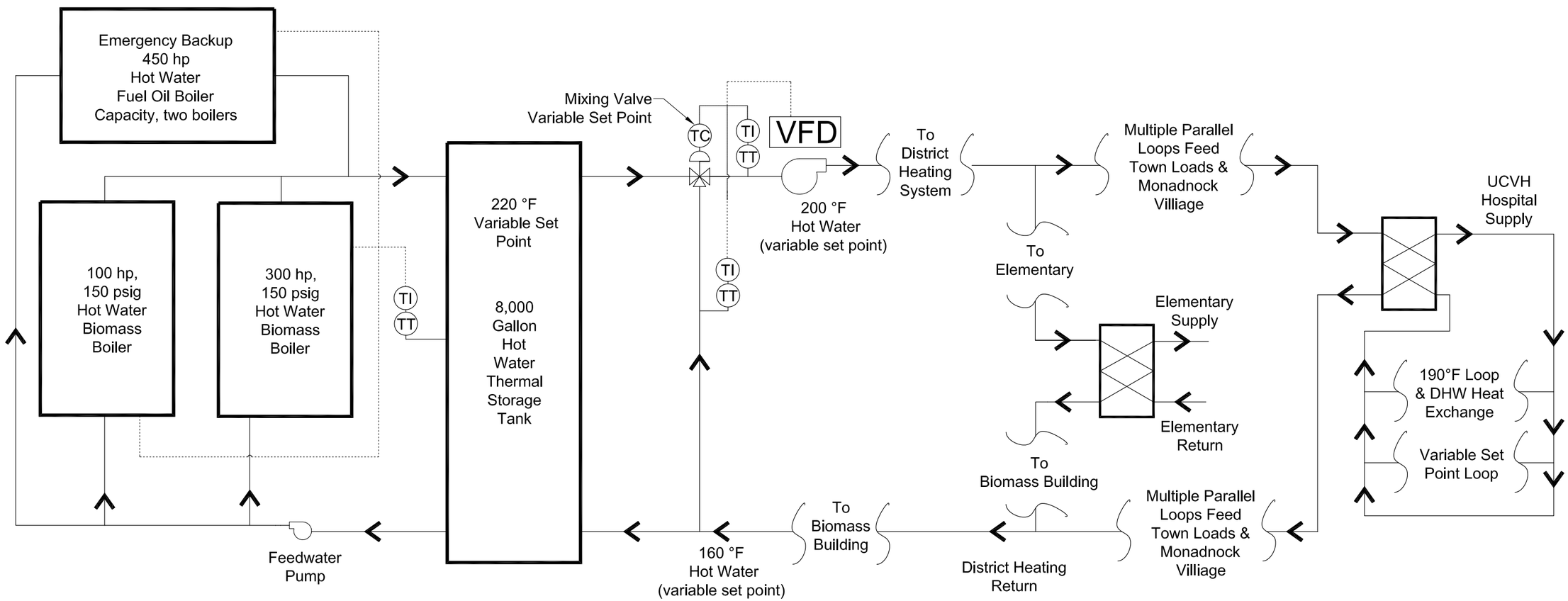
Phase I Option Biomass Building Layout

WES
Wilson Engineering Services, PC
www.wilsonengineeringservices.com
9006 Mercer Pike Meadville, PA 16335

REVISIONS

Date	Description	Approved

Appendix A.2



Legend:

- Three-way Control Valve
- TT Temperature transmitter
- TI Temperature indicator
- TC Temperature control
- VFD Variable Frequency Drive

Notes:

1. This is a feasbility level drawing only. Detailed design of biomass system, distribution, and tie-in is required.
2. Mixing valve blends return water with high temperature water from thermal storage to meet variable set point. Variable set point allows optimization of thermal storage capacity and fossil fuel offset. Temperatures shown are for purpose of example only.
3. Fuel oil boilers will be set to automatically feed heating loop to provide full backup if biomass system is not operational.

Designed DAW 6-02-12
Drawn CTH 6-11-12
Checked DAW 6-12-12

Approved ____ Date ____
Title ____ Job Class ____

Colebrook Biomass District Heating System

Colebrook, New Hampshire

Phase I Option Biomass System Schematic

WES
Wilson Engineering Services, PC
www.wilsonengineeringservices.com
9006 Mercer Pike Meadville, PA 16335

REVISIONS

Date	Description	Approved

Appendix A.6

Biomass Boiler Manufacturer Contract

Line Item		Cost
300 hp biomass combustion unit, 150 psig hot water boiler, breeching, stack, installed		$ 650,000
100 hp biomass combustion unit, 150 psig hot water boiler, installed		$ 350,000
150 hp and 300 hp fossil fuel fired 150 psig hot water boilers		$ 225,000
Biomass boiler room piping and specialties, biomass system controls, installed		$ 200,000
Fuel bunker receiving, storage, screening, material transfer, installed		$ 250,000
Boiler platform, stairs, and ladders installed		$ 25,000
8,000 gallon thermal storage tank, installed		$ 80,000
ESP, Installed		$ 375,000
Sub-total		$ 2,155,000
Boiler Manufacturer Bid Bond and Insurance	*2%*	$ 43,100
Total Boiler Manufacturer Contract		**$ 2,198,100**

General Contract

Line Item		Cost
Biomass Boiler Building and Chip Storage Pit (5,945 sf @ $180 per sf)[1]		$ 1,070,100
Site work		$ 100,000
Main distribution pipe system - 10,900 lf. (one-way distance), installed [2]		$ 2,760,000
Connection of identified loads		$ 610,000
Town of Colebrook Quote to Connect Biomass System to Gas Transmission Line		$ 350,000
Central Plant Electrical		$ 300,000
Central Plant Mechanical		$ 250,000
Sub-Total		$ 5,440,100
Contractor profit overhead and insurance	*16%*	$ 870,416
Sub-Total		$ 6,310,516
Contingency	*10%*	*$ 631,052*
Total General Contract Building and Site		**$ 6,941,568**

Total Project Cost

Line Item		Cost
Project Sub-Total (Boiler and General Contracts)		$ 9,139,668
Professional Services [3]	*12%*	*$ 1,096,760*
Total Project Cost[4,5,6,7]		**$ 10,236,428**

Notes:
1 - The building is assumed to be a simple pre-engineered building. Aesthetic improvements will increase cost.
2 - Exact pipe routes and connections should be evaluated in additional detail as the project moves forward.
3 - Professional Services includes engineering, permitting, legal, and project management.
4 - Assumes that biomass boiler and general contract are bid separately.
5 - GC costs are approximate. A detailed geotechnical study is required to identify final site and building costs.
6 - Estimate is based on competitive bidding.
7 - Boiler manufacturer contract includes all mechanical work associated with the boiler side of the distribution system through the thermal storage tank. GC mechanical responsibility starts at the demand side of the thermal storage tank. GC is responsible for biomass building electrical, HVAC, plumbing, site work, foundations, and structures. Boiler manufacturer is responsible for all electrical and controls for boiler system from a panel provided by the GC.

Pipeline Cost Summary

Pipe Diameter	Material	Trench Distance, ft	Length, ft	Cost	Cost per LF Trench
10	Sch. 40 Steel	1,922	3,844	$622,372	$324
8	Sch. 40 Steel	3,265	6,530	$887,356	$272
6	Sch. 40 Steel	158	316	$38,427	$243
5	Sch. 40 Steel	3,817	7,634	$883,575	$231
4	PEX	350	700	$74,200	$212
3.5	PEX	140	280	$28,544	$204
3	PEX	982	1,963	$187,450	$191
2	PEX	286	572	$41,180	$144
		10,920	**21,839**	**$2,763,104**	

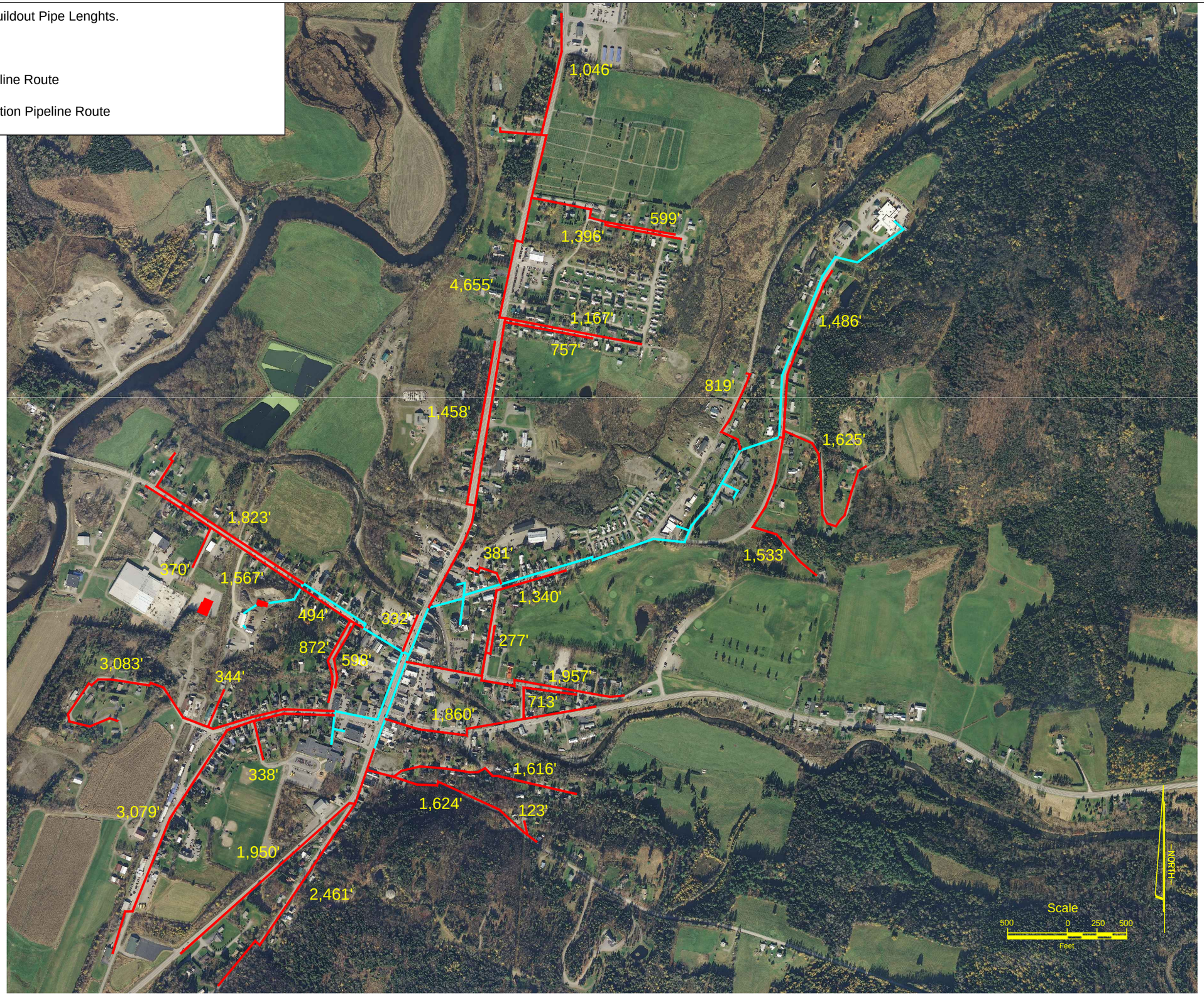
Notes:
1-Pipes are sized for current projected connected load plus an additional 50% increase in system demand.
2-Sizing for current projection of connected load would result in a reduction of pipe diameters.
3-The proposed system design does not utilize water temperatures above 200°F or pressures above 200 psig in the district system. This allows the use of pre-insulated pex pipe.

Note: Values listed for Buildout Pipe Lenghts.

Legend:

Distribution Pipeline Route

Buildout Distribution Pipeline Route



Designed	CTH	6-29-12
Drawn	CTH	6-29-12
Checked	DAW	6-29-12

Approved _____ Date ____

Title _____ Job Class ____

Colebrook Biomass District Heating System

Colebrook, New Hampshire

District Heating Distribution Pipe Route Buildout

WES

Wilson Engineering Services, PC

www.wilsonengineeringservices.com

9006 Mercer Pike Meadville, PA 16335

REVISIONS

Date	Description	Approved

Appendix A.1

Appendix E – CHP and Cooling Assessment

APPENDIX C- CHP AND COOLING OPTIONS

COMBINED HEAT AND POWER:

Scenario 1 is analyzed for this project as a heat only system. The ability to add thermally-led combined heat and power production is analyzed as an alternative to consider with this option. There are two options for combined heat and power at this scale with biomass that are widely considered commercially available. These are ORC and backpressure steam. Table xx presents the approximate economics for each of these alternatives based on varying unit rates for electricity that can be obtained by the owner. A value of $0.02/kWh is subtracted from each of the listed unit rates in the calculation of annual value to account for wood costs and operation and maintenance costs. The annual electric generation is calculated based on the Option 2 thermal load model. The added costs for the backpressure steam turbine include, steam specialties, increased boiler costs, turbine and generator set, switch gear, contractor overhead and profit, engineering, and a 15% contingency. The added costs for the ORC unit include added room in the boiler plant, increased cost for thermal oil heater, cost of the ORC unit, contractor overhead and profit, engineering, and a 15% contingency.

Table XX – Evaluation of CHP Alternatives for Option 2

Alternative	Size, kWe	Added Initial Cost	Net Annual Electric Generation, kWh	Annual Value ($0.08/kWh)	Annual Value ($0.14/kWh)	Annual Value ($0.19/kWh)
Backpressure Steam	200	$520,000	354,213	$21,253	$42,506	$60,216
ORC	600	$2,420,000	1,379,135	$82,748	$165,496	$234,453
Simple Payback Backpressure Steam				**24**	**12**	**9**
Simple Payback ORC				**29**	**15**	**10**

Note: Table assumes wood & O&M cost for electric production of $0.02/kWh and this is subtracted from the unit rate for each annual value calculation, REC value of $0.04/kWh, annual thermal load as modeled for Option 2, operating steam pressure of 150 psia & single-stage backpressure steam turbine, net ORC electrical efficiency of 16.7%.

Table XX shows that the CHP options have the potential to provide paybacks in the 9-10 year range, but this will greatly depend the value that can be obtained for the electricity generated. The economics of the CHP options would also improve with increased thermal demand over the summer months. This would allow electric generation during the summer as well as during the heating season.

The value of the electricity will be greatly dependent on the owner's ability to leverage existing electric demand. Net metering of electricity to offset the owner's use would allow the best

value for the electricity generated. The owner is paid at the calculated rate for avoided energy and capacity costs for electricity generated over what the owner offsets. This value was approximately $0.04/kWh for 2012. The electric generated would also be eligible for RECs, which are worth approximately $0.04/kWh. This REC value is highly subject to market fluctuations.

ABSORPTION COOLING:

Utilizing low cost biomass fuel to generate hot water for absorption cooling can increase effective operating hours and efficiency of a biomass boiler system. This study evaluates absorption chillers being owned by individual users and utilizing hot water from the district heating loop to generate chilled water. This configuration eliminates additional pipes, pumps, and heat gain from the ground for distributing chilled water from a central cooling plant. The economic feasibility of absorption cooling depends on the annual cooling load, efficiency of electric chillers being replaced, electricity price, biomass fuel price, operation and maintenance (O&M) costs, and installed capital costs for equipment.

Cooling Degree Days (CDD) can be used to analyze cooling loads. Table 1 provides annual CDD for 2009 through 2011 for Colebrook, NH compared to the Northeast Regional Climate Center (NRCC) using a base outside air temperature of 65°F. A load profile was generated using daily CDD at Colebrook, NH with a modified base temperature of 60°F.

Table 1 - Annual Cooling Degree Days

Year	CDD for Northeast Region (Base 65°F)	CDD for Colebrook, NH (Base 65°F)	CDD for Colebrook, NH (Base 60°F)
2009	367	90	296
2010	652	216	528
2011	568	112	396
3 Year Average	**529**	**140**	**407**

Note:

1- Weather data is from www.ncdc.noaa.gov/oa/documentlibrary/hcs/hcs.html for the NRCC and weather station USC00271647 located in Colebrook, NH.

2- The NRCC serves a 12 state region that includes Maine, Vermont, New Hampshire, New York, Massachusetts, Delaware, New Jersey, Rhode Island, Maryland, Connecticut, Pennsylvania, and West Virginia.

Table 1 shows there are approximately 75% fewer CDD recorded for Colebrook, NH than for the Northeast Region. Although comparing CDD is not as accurate as a cooling load model, it does provide an order of magnitude for the evaluation of annual cooling demand. Table 2 provides

the cost of cooling for water cooled chiller technologies including a reciprocating chiller using electricity at $0.15/kWh and a single stage absorption chiller using hot water generated from a biomass boiler at $45.00/ton.

Table 2 – Cost of Cooling Comparison for Electric and Absorption Chillers

Chiller Compressor Technology	Fuel, Unit	Cost per Unit	Estimated COP	Cost per Ton-Hour
Single Effect Absorption Chiller	Biomass, Ton	$45.00	0.7	$0.110
Reciprocating Electric Chiller	Electricity, kWh	$0.15	4.5	$0.117

Note: Table assumes a biomass boiler efficiency of 70%, and the cost per ton-hour only considers the COP of the compressors. Parasitic loads for cooling towers, pumps, and ancillary equipment are not included in the cost per ton-hour.

A cooling load model was developed considering a building located in Colebrook, NH with a peak cooling demand of 200 tons. This is equivalent to a medium to large commercial building (over 150,000 sf). Table 3 provides the modeled annual cooling load using daily CDD at a base temperature of 60°F, costs to generate cooling with electric and absorption chillers at current fuel costs, and potential annual absorption chiller savings.

Table 3 - Annual Cooling Load, Cooling Costs, and Annual Absorption Cooling Savings

Year	Estimated Annual Cooling Load (Ton-Hours)	Annual Absorption Chilling Cost	Annual Electric Chilling Cost	Estimated Annual Absorption Cooling Savings
2009	69,452	$7,640	$8,126	$486
2010	84,160	$9,258	$9,847	$589
2011	75,090	$8,260	$8,786	$526
3 Year Average	**76,234**	**$8,386**	**$8,919**	**$534**

Note:

1- *Table only identifies compressor costs and savings. Operating costs for cooling water pumps, fans, cooling tower heaters, etc. are not considered.*

A sensitivity analysis was developed to show the cost of cooling versus the cost of electricity for electric chillers and biomass fuel for absorption chillers. The analysis assumes a 70% biomass boiler efficiency, 10 mmBtu/ton of biomass, a COP of 0.7 for absorption chillers, and a COP of 4.5 for electric chillers.

Table 4 - Annual Cooling Load, Cooling Costs, and Annual Absorption Cooling Savings

Absorption Cooling		Electric Cooling	
Biomass Price ($/Ton)	**Cost of Cooling ($/Ton-Hour)**	**Blended Electricity Price ($/kWh)**	**Cost of Cooling ($/Ton-Hour)**
$20.00	$0.0490	$0.10	$0.0782
$25.00	$0.0612	$0.11	$0.0860
$30.00	$0.0735	$0.12	$0.0938
$35.00	$0.0857	$0.13	$0.1016
$40.00	$0.0980	$0.14	$0.1094
$45.00	$0.1102	$0.15	$0.1172
$50.00	$0.1224	$0.16	$0.1250
$55.00	$0.1347	$0.17	$0.1329
$60.00	$0.1469	$0.18	$0.1407
$65.00	$0.1592	$0.19	$0.1485
$70.00	$0.1714	$0.20	$0.1563

Note: Table assumes a biomass boiler efficiency of 70%, COP of 0.7 for absorption chillers, COP of 4.5 for electric chillers, and the cost per ton-hour only considers energy usage by the compressors. Parasitic loads for cooling towers, pumps, and ancillary equipment are not included in the cost per ton-hour shown.

Current fuel prices show that absorption cooling could provide an annual cooling cost savings of approximately $500 over a reciprocating electric driven chiller for a large commercial building. Absorption cooling equipment capital costs are typically greater than electric driven equipment by at least 50%. Thus, it may be difficult for an end user to justify the capital costs associated with an absorption chiller. It also should be noted that the reciprocating compressor technology for electric chillers used as a comparison to absorption chillers is less efficient than screw and centrifugal compressor technology. Higher efficiency electric chiller compressors would reduce the potential savings from utilizing absorption chilling.

Appendix F – Economic Analyses

Scenario I – Economic Analysis

Key Inputs & Calculated Values		
Oil consumption	205,343	gal/yr
Oil system efficiency, average	70%	
Oil price	$3.50	/gal
Current price of oil heat	$36.23	/MMBtu
System load	26,457	MMBtu/yr
Piping loss	2,646	MMBtu/yr
Plant output	29,103	MMBtu/yr
Load coincidence factor	85%	
Output Capacity of woodchip boiler	13.00	MMBtu/Hr
Wood boiler efficiency	78%	
Wood moisutre content	40%	
Wood Btu content on dry basis	8,250	Btu/lb
Wood requirement	3,769	tons/yr
Wood price	$50	/ton
Price reduction on cost of heating oil	20%	
Sale price of heat - year 1	$34.42	/MMBtu
Hours of full load operation	2,297	/yr

Financing (US $ million)		
Percent grants	52%	
Amount grants	$5.00	
Percent debt	48%	
Amount debt	$4.56	
Interest rate	4.00%	
Term	20	years
First annual payment	$331,592	
Simple Payback for total project	**290.85**	**yr**

O&M Costs (annual)			
Purchased wood			$188,440
Purchased KWh (electrcicity consumption plant)		262,553	
Electric price/KWh		$0.11	
Cost of electricity			$28,881
Hourly wage, labor		$20	
Labor	1.0 FTE		$41,600
Other O&M			$143,471
Total O&M			$402,392

Results	
Year One Total Expense	$733,985
Year One Heat Revenue	$766,870
Year One Cash Flow	$32,885
NPV of 20 Year Cash Flow	$1,905,725

Version Date: 21-Jun-12
Latest Version By: Hillary

Description	Units	1	Year 2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
OIL PRICE	**$/gal**	**3.5**																				
BORROWING	**%**	**50%**																				
Key Inputs & Calculated Value																						
General annual inflation rate		**3.25%**																				
Fossil Fuel inflation (w/ genl inflation)		**4.75%**																				
Wood inflation (w/ genl inflation)		**3.75%**																				
Oil displaced	gal/yr	205,343	205,343	205,343	205,343	205,343	205,343	205,343	205,343	205,343	205,343	205,343	205,343	205,343	205,343	205,343	205,343	205,343	205,343	205,343	205,343	205,343
Oil system efficiency, average		70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
Oil price	/gal	$3.50	$3.67	$3.84	$4.02	$4.21	$4.41	$4.62	$4.84	$5.07	$5.31	$5.57	$5.83	$6.11	$6.40	$6.70	$7.02	$7.35	$7.70	$8.07	$8.45	$8.85
System load	MMBtu/yr	26,457																				$91,68
Piping loss	%	0%																				
Piping loss	MMBtu/yr	2,646																				
Plant output	MMBtu/yr	29,103																				
Load coincidence factor		85%																				
Capacity of woodchip boiler	MMBtu/HH	13																				
	MW	4																				
Wood boiler efficiency		78%																				
Wood moisutre content		40%																				
Wood Btu content	Btu/lb	8,250																				
Wood requirement	tons/yr	3,769	3,769	3,769	3,769	3,769	3,769	3,769	3,769	3,769	3,769	3,769	3,769	3,769	3,769	3,769	3,769	3,769	3,769	3,769	3,769	3,769
Wood price	/ton	$50	$51.88	$53.82	$55.84	$57.93	$60.10	$62.36	$64.70	$67.12	$69.64	$72.25	$74.96	$77.77	$80.69	$83.72	$86.85	$90.11	$93.49	$97.00	$100.63	$104.41
Price reduction on cost of heating oil		**20%**																				
Sale price of heat - year 1	**/MMBtu**	**$28.99**	**$29.928**	**$30.900**	**$31.904**	**$32.941**	**$34.012**	**$35.117**	**$36.259**	**$37.437**	**$38.654**	**$39.910**	**$41.207**	**$42.546**	**$43.929**	**$45.357**	**$46.831**	**$48.353**	**$49.924**	**$51.547**	**$53.222**	**$54.952**
	kWh	0.099																				
Current price of oil heat	/MMBtu	$36.23																				
	kWh	0.124																				
Hours of full load operation	/yr	2,297																				
O&M Costs (annual)																						
Purchased wood		$188,440	$195,507	$202,838	$210,445	$218,339	$226,524	$235,018	$243,832	$252,975	$262,462	$272,304	$282,514	$293,116	$304,103	$315,506	$327,337	$339,612	$352,348	$365,561	$379,269	$393,492
Purchased KWh (electricicity consumption plant)		262,553	262,553	262,553	262,553	262,553	262,553	262,553	262,553	262,553	262,553	262,553	262,553	262,553	262,553	262,553	262,553	262,553	262,553	262,553	262,553	262,553
Electric price/KWh		$0.11	$0.114	$0.117	$0.121	$0.125	$0.129	$0.133	$0.138	$0.142	$0.147	$0.151	$0.156	$0.161	$0.167	$0.172	$0.178	$0.183	$0.189	$0.196	$0.202	$0.209
Cost of electricity		$28,881	$29,819	$30,789	$31,789	$32,822	$33,889	$34,990	$36,126	$37,302	$38,514	$39,766	$41,058	$42,393	$43,770	$45,193	$46,662	$48,178	$49,744	$51,361	$53,030	$54,753
Hourly wage, labor		$20	$20,650	$21,321	$22,014	$22,730	$23,468	$24,231	$25,018	$25,832	$26,671	$27,538	$28,433	$29,357	$30,311	$31,296	$32,313	$33,363	$34,448	$35,567	$36,723	$37,917
Labor	FTE	1.0																				
Labor		$41,600	$42,952	$44,348	$45,788	$47,277	$48,814	$50,400	$52,038	$53,730	$55,476	$57,279	$59,140	$61,061	$63,047	$65,099	$67,212	$69,396	$71,651	$73,980	$76,384	$78,867
Other O&M		$143,471	$148,133,926	$152,948,279	$157,919,098	$163,051,469	$168,350,641	$173,822,037	$179,471,253	$185,304,069	$191,326,451	$197,544,561	$203,964,759	$210,593,614	$217,437,906	$224,504,638	$231,801,039	$239,334,573	$247,112,946	$255,144,117	$263,436,301	$271,997,981
Total O&M		$402,392	$416,412	$430,923	$445,942	$461,487	$477,576	$494,231	$511,468	$529,311	$547,778	$566,894	$586,679	$607,159	$628,357	$650,299	$673,01	$696,52	$720,85	$746,04	$772,12	$799,11

Capital Cost (US $ million)		$ 9.56																				
Financing (US $ million)																						
Percent grants		52%																				
Amount grants		$5.00																				
Percent equity		0%																				
Amount equity		$0.00																				
Member equity		0%																				
Member equity		$0.00																				
Other local equity		0%																				
Other local equity		$0.00																				
Percent debt		48%																				
Amount debt		$4.56																				
Interest rate		4.00%																				
Term	years	20																				
Annual paymen		$331,592	$331,592	$331,592	$331,592	$331,592	$331,592	$331,592	$331,592	$331,592	$331,592	$331,592	$331,592	$331,592	$331,592	$331,592	$331,592	$331,592	$331,592	$331,592	$331,592	$331,592
Year One Total Expense		$733,985	$748,004	$762,515	$777,538	$793,081	$809,176	$825,824	$843,061	$860,903	$879,37	$898,488	$918,27	$938,75	$959,94	$981,89	$1,004,60	$1,028,11	$1,052,44	$1,077,63	$1,103,71	$1,130,70
Year One Heat Revenue		$766,870	$791,793	$817,52	$844,09	$871,52	$899,85	$929,09	$959,29	$990,47	$1,022,66	$1,055,89	$1,090,21	$1,125,64	$1,162,23	$1,200,00	$1,239,00	$1,279,27	$1,320,84	$1,363,77	$1,408,09	$1,453,88
Year One Cash Flow		$32,885	$43,788	$55,01	$66,56	$78,44	$90,68	$103,27	$116,23	$129,56	$143,29	$157,41	$171,94	$186,89	$202,28	$218,11	$234,39	$251,15	$268,39	$286,13	$304,38	$323,15
Cumulative Cash flow		**$32,885**	$76,673	$131,684	$198,245	$276,694	$367,378	$470,653	$586,885	$716,454	$859,745	$1,017,157	$1,189,101	$1,375,996	$1,578,278	$1,796,389	$2,030,789	$2,281,946	$2,550,345	$2,836,482	$3,140,867	$3,464,025

% savings over fue
0.400470495

Present value of 10
$645,254

Present value of 20
$1,905,725

Scenario III – Economic Analysis

Key Inputs & Calculated Values		
Oil consumption	746,000	gal/yr
Oil system efficiency, average	70%	
Oil price	$3.50	/gal
Current price of oil heat	$36.23	/MMBtu
System load	114,850	MMBtu/yr
Piping loss	11,485	MMBtu/yr
Plant output	126,335	MMBtu/yr
Load coincidence factor	80%	
Output Capacity of woodchip boilers	50.0	MMBtu/Hr
Wood boiler efficiency	78%	
Wood moisutre content	40%	
Wood Btu content on dry basis	8,250	Btu/lb
Wood requirement	16,360	tons/yr
Wood price	$50	/ton
Price reduction on cost of heating oil	20%	
Sale price of heat - year 1	$28.99	/MMBtu
Hours of full load operation	2,297	/yr

Financing (US $ million)		
Percent grants	14%	
Amount grants	$5.00	
Percent equity	37%	
Amount equity	$13.46	
Percent debt	49%	
Amount debt	$18.02	
Interest rate	4.00%	
Term	20	years
First annual payment	$1,310,372	
Simple Payback for total project	**79.42**	**yr**

O&M Costs (annual)			
Purchased wood			$818,020
Purchased KWh (electrcicity consumption plant)		1,009,818	
Electric price/KWh		$0.11	
Cost of electricity			$111,080
Hourly wage, labor		$20	
Labor	2.0 FTE		$83,200
Other O&M			$547,090
Total O&M			$1,559,390

Results	
Year One Total Expense	$2,869,762
Year One Heat Revenue	$3,328,986
Year One Cash Flow	$459,223

#REF!

Version Date: 4-Aug-09
Latest Version By: Hillary

Description	Units		Year																			
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	
OIL PRICE	**$/gal**	**2.5**																				
BORROWING	**%**	**30%**																				
Key Inputs & Calculated Values																						
General annual inflation rate		**3.25%**																				
Fossil Fuel inflation (w/ genl inflation)		**4.75%**																				
Wood inflation (w/ genl inflation)		**3.75%**																				
Oil displaced	gal/yr	746,000	746,000	746,000	746,000	746,000	746,000	746,000	746,000	746,000	746,000	746,000	746,000	746,000	746,000	746,000	746,000	746,000	746,000	746,000	746,000	746,000
Oil system efficiency, average		70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
Oil price	/gal	$3.50	$3.67	$3.84	$4.02	$4.21	$4.41	$4.62	$4.84	$5.07	$5.31	$5.57	$5.83	$6.11	$6.40	$6.70	$7.02	$7.35	$7.70	$8.07	$8.45	$8.85
System load	MMBtu/yr	114,850																				$91.66
Piping loss	%	0%																				
Piping loss	MMBtu/yr	11,485																				
Plant output	MMBtu/yr	126,335																				
Load coincidence factor		80%																				
Capacity of woodchip boiler	MMBtu/Hr	50																				
	MW	15																				
Wood boiler efficiency		78%																				
Wood moisutre content		40%																				
Wood Btu content	Btu/lb	8,250																				
Wood requirement	tons/yr	16,360	16,360	16,360	16,360	16,360	16,360	16,360	16,360	16,360	16,360	16,360	16,360	16,360	16,360	16,360	16,360	16,360	16,360	16,360	16,360	16,360
Wood price	/ton	$50	$51.88	$53.82	$55.84	$57.93	$60.10	$62.36	$64.70	$67.12	$69.64	$72.25	$74.96	$77.77	$80.69	$83.72	$86.85	$90.11	$93.49	$97.00	$100.63	$104.41
Price reduction on cost of heating oil		**20%**																				
Sale price of heat - year 1	**/MMBtu**	**$28.99**	**$29.928**	**$30.900**	**$31.904**	**$32.941**	**$34.012**	**$35.117**	**$36.259**	**$37.437**	**$38.654**	**$39.910**	**$41.207**	**$42.546**	**$43.929**	**$45.357**	**$46.831**	**$48.353**	**$49.924**	**$51.547**	**$53.222**	**$54.952**
	kWh	0.099																				
Current price of oil heat	/MMBtu	$36.23																				
	kWh	0.124																				
Hours of full load operation	/yr	2,297																				
O&M Costs (annual)																						
Purchased wood		$818,020	$848,696	$880,522	$913,541	$947,799	$983,342	$1,020,217	$1,058,475	$1,098,168	$1,139,349	$1,182,075	$1,226,403	$1,272,393	$1,320,107	$1,369,611	$1,420,972	$1,474,258	$1,529,543	$1,586,901	$1,646,410	$1,708,150
Purchased KWh (electricity consumption plant)		1,009,818	1,009,818	1,009,818	1,009,818	1,009,818	1,009,818	1,009,818	1,009,818	1,009,818	1,009,818	1,009,818	1,009,818	1,009,818	1,009,818	1,009,818	1,009,818	1,009,818	1,009,818	1,009,818	1,009,818	1,009,818
Electric price/KWh		$0.11	$0.114	$0.117	$0.121	$0.125	$0.129	$0.133	$0.138	$0.142	$0.147	$0.151	$0.156	$0.161	$0.167	$0.172	$0.178	$0.183	$0.189	$0.196	$0.202	$0.209
Cost of electricity		$111,080	$114,690	$118,418	$122,266	$126,240	$130,343	$134,579	$138,952	$143,468	$148,131	$152,945	$157,916	$163,048	$168,348	$173,819	$179,468	$185,301	$191,323	$197,541	$203,961	$210,590
Hourly wage, labor		$20	$20.650	$21.321	$22.014	$22.730	$23.468	$24.231	$25.018	$25.832	$26.671	$27.538	$28.433	$29.357	$30.311	$31.296	$32.313	$33.363	$34.448	$35.567	$36.723	$37.917
Labor	FTE	2.0																				
Labor		$83,200	$85,904	$88,696	$91,578	$94,555	$97,628	$100,801	$104,077	$107,459	$110,952	$114,558	$118,281	$122,125	$126,094	$130,192	$134,423	$138,792	$143,303	$147,960	$152,769	$157,734
Other O&M		$547,090	$564,870.924	$583,229.229	$602,184.179	$621,755.165	$641,962.208	$662,825.979	$684,367.824	$706,609.778	$729,574.596	$753,285.770	$777,767.558	$803,045.003	$829,143.966	$856,091.145	$883,914.107	$912,641.315	$942,302.158	$972,926.978	$1,004,547.105	$1,037,194.886
Total O&M		$1,559,390	$1,614,161	$1,670,864	$1,729,570	$1,790,349	$1,853,274	$1,918,422	$1,985,872	$2,055,705	$2,128,007	$2,202,864	$2,280,367	$2,360,611	$2,443,693	$2,529,713	$2,618,777	$2,710,992	$2,806,471	$2,905,329	$3,007,686	$3,113,668
Capital Cost (US $ million)		$ 36.47																				
Financing (US $ million)																						
Percent grants		14%																				
Amount grants		$5.00																				
Percent equity		37%																				
Amount equity		$13.46																				
Member equity		0%																				
Member equity		$0.00																				
Other local equity		0%																				
Other local equity		$0.00																				
Percent debt		49%																				
Amount debt		$18.02																				
Interest rate		4.00%																				
Term	years	20																				
Annual payment		$1,310,372	$1,310,372	$1,310,372	$1,310,372	$1,310,372	$1,310,372	$1,310,372	$1,310,372	$1,310,372	$1,310,372	$1,310,372	$1,310,372	$1,310,372	$1,310,372	$1,310,372	$1,310,372	$1,310,372	$1,310,372	$1,310,372	$1,310,372	$1,310,372
Year One Total Expense		$2,869,762	$2,924,533	$2,981,236	$3,039,942	$3,100,721	$3,163,646	$3,228,794	$3,296,244	$3,366,077	$3,438,378	$3,513,235	$3,590,739	$3,670,983	$3,754,065	$3,840,085	$3,929,149	$4,021,364	$4,116,843	$4,215,701	$4,318,058	$4,424,040
Year One Heat Revenue		$3,328,986	$3,437,178	$3,548,886	$3,664,225	$3,783,312	$3,906,270	$4,033,223	$4,164,303	$4,299,643	$4,439,381	$4,583,661	$4,732,630	$4,886,441	$5,045,250	$5,209,221	$5,378,520	$5,553,322	$5,733,805	$5,920,154	$6,112,559	$6,311,217
Year One Cash Flow		$459,223	$512,645	$567,650	$624,283	$682,591	$742,623	$804,429	$868,059	$933,566	$1,001,003	$1,070,426	$1,141,891	$1,215,458	$1,291,185	$1,369,135	$1,449,371	$1,531,958	$1,616,963	$1,704,453	$1,794,501	$1,887,177
Cumulative Cash flow		**$459,223**	$971,868	$1,539,518	$2,163,800	$2,846,391	$3,589,015	$4,393,444	$5,261,503	$6,195,069	$7,196,072	$8,266,497	$9,408,389	$10,623,846	$11,915,032	$13,284,167	$14,733,538	$16,265,497	$17,882,459	$19,586,912	$21,381,413	$23,268,590

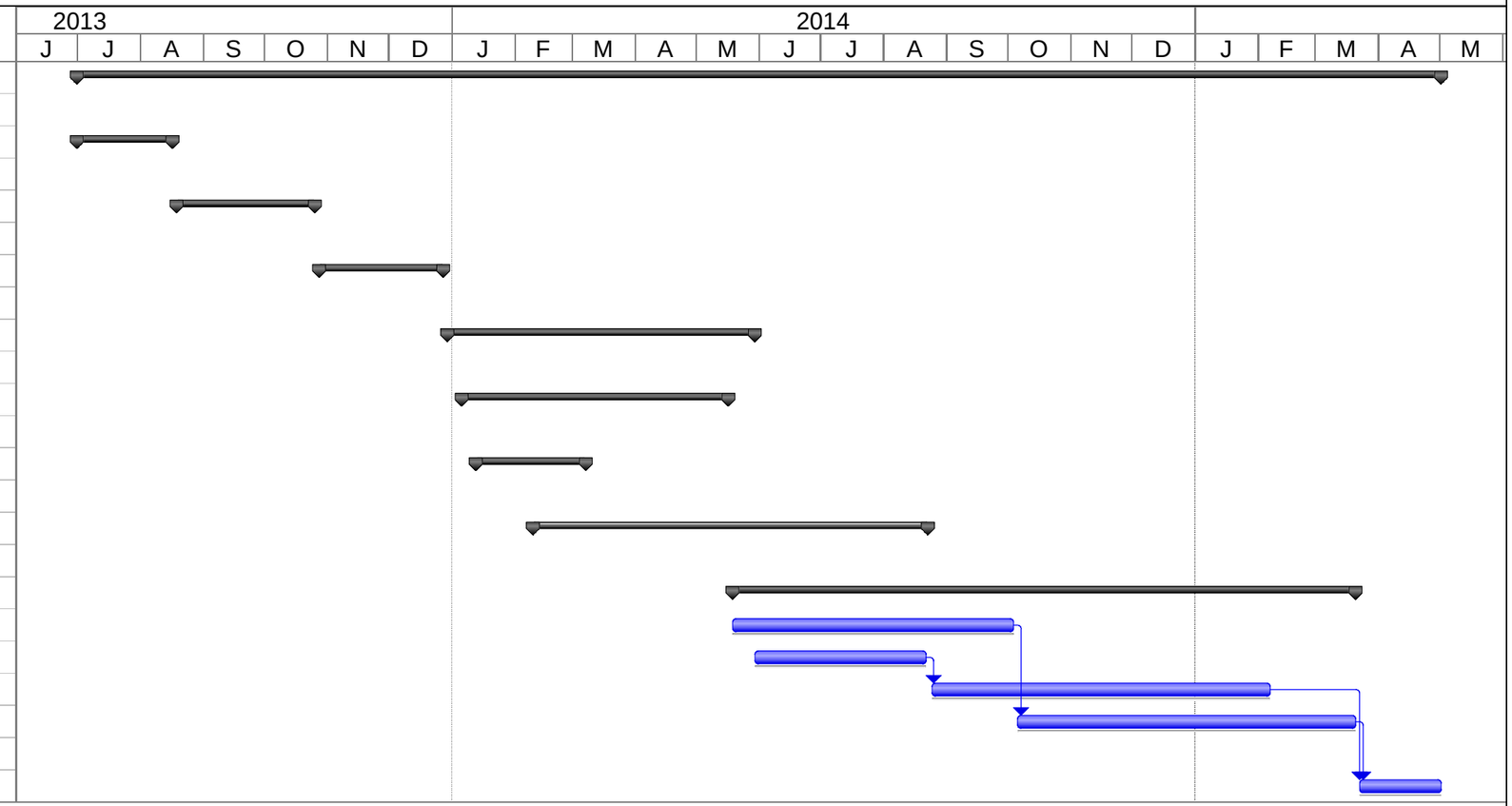
% savings over fuel oil in y
0.400470495

Present value of 10 year ca
$5,522,122
Present value of 20 yr cash
$13,350,707

Appendix G – Conceptual Project Timeline

Colebrook, NH Biomass District Heating Project: Concept Schedule

ID	Task Name
1	**Colebrook Biomass Project**
2	
3	**Funding/Procurement Decision Process**
6	
7	**Basis of Design/RFP Development**
11	
12	**Design Build Contractor RFP Process**
18	
19	**Engineering**
39	
40	**Permitting**
51	
52	**Owner Review & Comment**
58	
59	**Procurement**
77	
78	**Construction**
79	District Piping
80	Biomass Plant Building
81	Mechanical/Electrical Work in Central Plant
82	Mechanical/Electrical Work for Tie-in at Users
83	
84	Start Up & Commisioning



Project: Colebrook, NH Biomass
Date: 6/22/2012

Task | Progress | Summary | External Tasks | Deadline
Split | Milestone | Project Summary | External Milestone