Biomass Utilization Study for Aitkin County, MN

SUBMITTED TO:

AURI
Randy Hilliard
P.O. Box 599
Crookston, MN 56716-0599
www.auri.org
Ph. 218-280-8573

Aitkin County Economic Development Office
Ross Wagner
217 Second Street NW Room 131
Aitkin, MN 56431
Ph. (218) 927-7305

Contractor Organization
BBI International
Engineering and Consulting
300 Union Blvd., Suite 325
Lakewood, CO 80228
www.bbiinternational.com

Contact Person
Jeff Coombe
Manager of Technical Studies
Ph. 303-526-5655
Fax 303-526-7776
jcoombe@bbiinternational.com

Renewable Energy Solutions

NOTICE

TABLE OF CONTENTS

I. Executive Summary **1**
II. Project Overview and Scope of Work **11**
Purpose of Study 11
Scope of Work 11
III. Project Site Description **13**
Overview of Study Area: Aitkin County, Minnesota 13
Site Evaluation Criteria 13
IV. Overview of Biomass as a Bioenergy Feedstock **17**
Biomass Feedstock Species and Types 17
Methodology 19
Projecting Biomass Yields 21
Biomass Harvesting Techniques and Equipment 22
Biomass Feedstock Composition 24
V. Local Feedstock Appraisal: Grasses and Shrubs **28**
Total Volume of Shrub and Grass Biomass 29
Grassy Biomass Feedstocks 31
Brush Biomass Feedstocks 37
Grass and Shrub Biomass Pricing 40
Conclusion: Grass and Brush Biomass Potential 40
VI. Local Feedstock Appraisal: Woody Biomass **41**
Woody Biomass 41
Roundwood Biomass Feedstocks 45
Logging Residue Biomass Feedstocks 47
Timber Industry Byproduct Feedstocks 48
Woody Biomass Pricing 50
Conclusion: Forest Residue Feedstock Potential 52
VII. Project Scale and Feedstock Supply **54**
Plant Scale 54
Potential Feedstock Blend 54
Feedstock Blend Price 55
Feedstock Blend Composition 56
VIII. Product Market Review **58**
Renewable Portfolio Standards 58
Minnesota Market for Renewable Energy 59
Biomass Fuel Pellet Market 63
Pellet Pricing 70
Biomass Power Generation Market 71
Heat and Power Pricing 73
IX. Technology Assessment **74**
Overview of Conversion Technologies 74
Pelletization 77
Combined Heat and Power (CHP) Production 79
Gasification 80

Biomass Boilers 83
Torrefaction 84
X. Project Statistics 85
Pellet and CHP Plant Statistics 85
Personnel Requirements 85
Assumptions Used in the Financial Forecast 86
XI. Financial Feasibility 89
Economic Modeling Results 89
Sensitivity and Breakeven Analysis 92
Appendix A:Financial Forecast 50,000TPY Pellet Plant 97
Appendix B:Financial Forecast 100,000TPY Pellet Plant 104
Appendix C:Financial Forecast 50,000TPY CHP Plant 111
Appendix D:Financial Forecast 100,000TPY CHP Plant 118
Appendix E:Minnesota Statute 2008-216B.1691 125

LIST OF FIGURES

Figure 1 – Aitkin County Land Cover Distribution 3
Figure 2 – U.S. Biomass Distribution 18
Figure 3 – Biomass Removal Nutrient Depletion 20
Figure 4 – Densities of Similar Woody Masses 22
Figure 5 – Photos of Grassy Biomass Harvesting Industrial Equipment 23
Figure 6 – Photo of Logging Residues for Collection 24
Figure 7 – Photo Sample of Aitkin County Grassy Biomass 29
Figure 8 – Grass-, Shrub-, and Cropland in Aitkin County 30
Figure 9 – Grass and Shrub Biomass Primary Distribution Corridor 32
Figure 10 – Photo of Harvested Grassland Field 33
Figure 11 – Accessible Grassland Biomass 34
Figure 12 – Accessible Grassland on Private Land 35
Figure 13 – Aitkin County Hayland Acres 36
Figure 14 – Photo Samples of Aitkin County Shrub Biomass 37
Figure 15 – Aitkin County Shrub and Brush Land 38
Figure 16 – MNDNR Shearing Projects: Public Land 39
Figure 17 – MNDNR Shearing Projects: Private Land 39
Figure 18 – Biomass Utilization of Tree Anatomy 41
Figure 19 – USFS Guide to Timber Grades 42
Figure 20 – Forest Cover Types in Aitkin County 44
Figure 21 – End Use of Minnesota Timber Mill Residues 49
Figure 22 – Minnesota Stumpage Prices 1999-2007 50
Figure 23 – Feedstock Prices; Actual and Dry Basis 56
Figure 24 – Projected Electricity Generation 61
Figure 25 – Projected Renewable Generation Capacity Required (8,400 hr/yr) 61
Figure 26 – Projected Renewable Generation Capacity Required (2,884 hr/yr) 62
Figure 27 – Coal and Natural Gas Prices in Minnesota 70
Figure 28 – Aitkin County Transmission Line Map 72
Figure 29 – Biomass Processing Pathways 74
Figure 30 – Pelletizing Benefits 76
Figure 31 – Pelletizing Die and Roll Assembly 78
Figure 32 – General Gasifier Diagram 81
Figure 33 – Biomass Gasification System 82
Figure 34 – Gasifier Configuration Schematics 83
Figure 35 – Fluidized Bed Illustration 83
Figure 36 – Aitkin County Project Annual ROI 90
Figure 37 – Effect of Feedstock Price on 11-year Average ROI 92
Figure 38 – Effect of Pellet Price on 11-year Average ROI 93
Figure 39 – Effect of CHP-Generated Electricity Price on 11-year Average ROI 93
Figure 40 – Effect of CHP-Generated Thermal Energy Price on 11-year Average ROI 94
Figure 41 – Effect of Capital Cost on 11-year Average ROI 94

LIST OF TABLES

Table 1 – Aitkin County Land Cover Distribution 4
Table 2 – Aitkin County Facility Feedstock Blend 6
Table 3 – Financial Modeling Results 8
Table 4 – Biofuel Shipment Analysis 14
Table 5 – Logging Residue in Debris Piles 22
Table 6 – Compositional Analysis of Woody Biomass Feedstocks 25
Table 7 – Compositional Analysis of Grassy Biomass Feedstocks 26
Table 8 – MNDNR 2008 Quantification of Aitkin County Biomass 31
Table 9 – Green Wood Conversion Factors 43
Table 10 – Volume of 2007 Roundwood Timber Harvest in Aitkin County 46
Table 11 – Aitkin County Timber Sales vs. Harvest Goals 47
Table 12 – Logging Residue Volume in Aitkin County 48
Table 13 – Logging Residue Volume in Aitkin County, ORC&D 48
Table 14 –Pulpwood Delivered Prices 51
Table 15 – Estimated Harvest Costs for Logging Residues 52
Table 16 – Aitkin County Facility Feedstocks Available 54
Table 17 – Aitkin County Facility Feedstock Blend 55
Table 18 – Project Feedstock Price (Dry Basis) 55
Table 19 – Compositional Analysis of Project Feedstock Blend 57
Table 20 – State RPS Requirements by Enactment Year 58
Table 21 – U.S. Energy Generation by Fuel Type (Million Megawatthours) 59
Table 22 – Minnesota Energy Generation (Million Megawatthours) 60
Table 23 – Pellet Fuel Institute 2008 Pellet Standards 65
Table 24 – European Pellet Standards 66
Table 25 – U.S. Biomass Co-firing in Utility Power Plants 69
Table 26 – Co-firing Pellet Value 2011-2020 71
Table 27 – Minnesota Biomass Electric Contracts 73
Table 28 – Value of Heat Energy sold by CHP Project 73
Table 29 – Biomass Combustion System Efficiencies 80
Table 30 – Project Statistics 85
Table 31 – Personnel Requirements 86
Table 32 – Aitkin County Project Average Capital Cost Estimate 88
Table 33 – Financial Modeling Results 89
Table 34 – Aitkin County Project Year 2 Income Statement 91
Table 35 – Sensitivity and Breakeven Analysis for 50,000tpy Pellet 95
Table 36 – Sensitivity and Breakeven Analysis for 100,000tpy Pellet 95
Table 37 – Sensitivity and Breakeven Analysis for 50,000tpy CHP 96
Table 38 – Sensitivity and Breakeven Analysis for 100,000tpy CHP 96

I. EXECUTIVE SUMMARY

The Agricultural Utilization Research Institute (AURI), in conjunction with the Center for Producer Owned Energy, Aitkin County Land Department, and the Aitkin County Economic Development/Forest Industry Coordinator, is exploring the opportunity to utilize biomass resources available in Aitkin County to generate renewable energy. The development of a biomass to bioenergy production system will drive economic development and create jobs in the area.

The overall objective of the study is to determine the volume of potentially accessible biomass in Aitkin County that is not already being harvested for other uses, and compare the economic feasibility of various technologies available to convert the harvestable biomass materials into renewable energy products. The combinations of biomass feedstocks and conversion technologies to end products will be collectively referred to as the 'Project'.

The Project group has retained BBI International (BBI) to conduct a feasibility study for the proposed Project. BBI assessed herbaceous and woody biomass throughout Aitkin County, utilizing GIS mapping software to identify the distribution and quantity of feedstocks available and potentially accessible to the Project. Process technologies were reviewed that are capable of converting the proposed feedstock materials into viable products, and markets for the products produced were analyzed. For the purposes of this study, two bioenergy production pathways were reviewed in depth; indirect energy production through manufacture of industrial fuel pellets at a commercial-scale pelletizing mill, or direct energy production through a combined heat and power (CHP) production facility. BBI compiled the assessed data into its proprietary economic modeling software to produce potential operating scenarios, expected returns on investment, and sensitivity analyses of key operating parameters.

Four economic scenarios were evaluated for the study. The scenarios are:

1. Process 50,000 tons of raw material per year into biomass pellets;
2. Process 100,000 tons of raw material per year into biomass pellets;
3. Process 50,000 tons of raw material per year into CHP energy; and
4. Process 100,000 tons of raw material per year into CHP energy.

Study Overview

Biomass, in various forms, is utilized as energy and fuel by several industry sectors. Pulp and wood mills, municipal waster treatment plants, and others have found ways to utilize their byproducts to make heat and power. Currently over 3% of energy production in the U.S. comes from biomass sources. As energy costs rise and traditional fossil energy sources become more scarce, biomass is a particularly attractive way to produce energy; biomass is massively abundant, does not compete directly with existing industries for raw material feedstocks, and is currently the only renewable source of transportation fuel.

Even though the number of projects utilizing biomass resources is growing rapidly, the industry is still very young. The major challenges facing the biomass industry, amongst the standard development challenges of obtaining financing and properly managing project timeframes and budgets, are obtaining a consistent supply of feedstocks that are not already harvested for other uses, at a reasonable price, and without disrupting the ecological cycles in the harvest area.

One of the primary drivers of biomass energy development is to add value to under-utilized and often ignored natural resources. For this same reason, biomass materials are logistically difficult to gather out of the forest or the field and to a place where they are useful. Systems to find, harvest, and transport biomass to a processing facility are still under development, but being discovered and refined at a rapid pace as the industry gains steam. Most potential biomass utilization projects will appear to have feedstock materials at the outset. However, the amount of biomass that exists in a given ecosystem is orders of magnitude higher than the technically viable harvest yield.

These challenges are combined with a very young conversion technology industry, still in the process of proving out the viability of operating systems. Many new technologies on the market promise a lot, but the actual production rates, system uptime, and other important process conditions have short track records. The technology risk is rapidly being reduced as new systems are built and processes are refined.

To address these challenges, BBI produced a conservatively-based analysis using only verifiable data. The feedstock supply analysis produced two sets of results for each biomass type; the total available biomass in the study area and the ‘accessible’ biomass that the proposed project can expect to obtain at a reasonable price, with minimal logistical difficulty. When reviewing available conversion technologies, those with a proven track record were given priority.

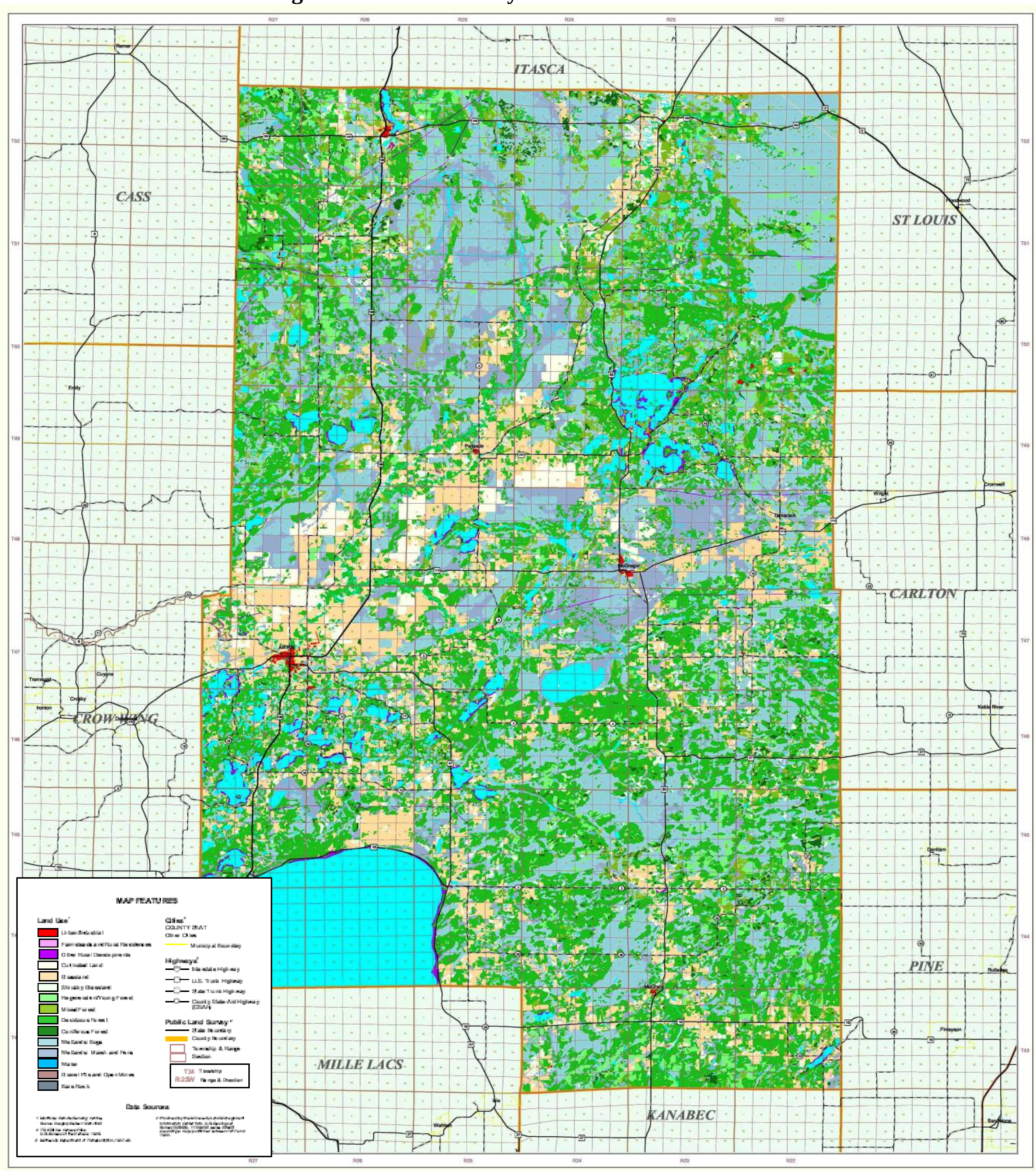
Government incentives for technology development and mandates for renewable energy generation are the economic drivers that will bring bioenergy production into mainstream commercial use. As with any emerging technology, external support is necessary to develop systems to the point where they can be competitive with existing technologies, and is especially important when the existing industry is as large and well-developed as the fossil fuel-based energy industry. This report discusses available support for bioenergy production and how these incentives and mandates will assist the Project. Minnesota has enacted several supportive measures for bioenergy production including a mandated level of renewable power generation through the state’s Renewable Portfolio Standard (RPS). Carbon valuation has not been included in the analysis, as it is still under debate at the time of the report completion.

Study Area

Aitkin County is a unique geographical location in Minnesota. It is a transition zone that forms the northern border of the corn / soybean / wheat farmland of the southern half of the state and the heavily forested north and northeast areas of the state. The dominant land cover classifications in the area are deciduous forest lands, wetlands, and grasslands.

Figure 1 shows the graphical distribution of all land types in Aitkin County.

Figure 1 – Aitkin County Land Cover Distribution



(Source: Minnesota Land Management Information Center)

Table 1 highlights the various land cover types and percentages of each that can be found in Aitkin County. The table corresponds to the mapped land type distributions in Figure 1.

Table 1 – Aitkin County Land Cover Distribution

Description	Acres	%Acres
Urban/Industrial	1,676	0.1
Farmsteads and Rural Residences	1,953	0.2
Other Rural Developments	6,713	0.5
Cultivated Land	18.509	1.5
Grassland	158,756	12.4
Shrubby Grassland	32,756	2.6
Regeneration/Young Forest	39,360	3.1
Mixed Forest	65,913	5.2
Deciduous Forest	370,165	29
Coniferous Forest	15,552	1.2
Wetlands: Bogs	310,104	24.3
Wetlands: Marsh and Fens	133,335	10.5
Water	120,407	9.4
Gravel Pits and Open Mines	556	<0.1
Bare Rock	2	<0.1
TOTAL	**1,275,776**	**100%**

(Source: Minnesota Land Management Information Center)

Biomass Feedstocks

The term ‘biomass’ encompasses a broad spectrum of materials. In its truest form, biomass is all materials created by live or derived from recently living biological organisms, i.e., organic matter. As an industry term, ‘biomass’ is those organic materials that can be used as feedstocks to produce energy or beneficial products. In addition, harvesting biomass material should not disrupt natural ecological cycles, nor be in competition with existing industries serving food, feed, or shelter markets. While initial studies suggest that while there is sufficient growing stock to harvest for biomass energy use, the nascent bioenergy industry needs to carefully assess the availability, accessibility, and sustainability of biomass within the context of existing industries and natural resource supplies.

Plant matter derived from trees, grasses, crops, shrubs etc., are the most commonly-recognized forms of biomass. Byproducts from animal husbandry and food processing are also forms of biomass, as are domestic organic wastes. One important distinction to make is that biomass is a feedstock or input product, it is not a finished or end use product.

The primary forms of biomass typically evaluated for use in bioenergy production are:

- ***Agricultural Residues***

  - Corn stover, wheat straw, and rice straw

- ***Forest Products***

  - Timber residues, thinning and stand improvement (TSI) products

- ***Secondary Products***

  - Mill wastes, agricultural processing residues

- ***Energy Crops***

  - Switchgrass, sweet sorghum, other grasses and shrubs

- ***Municipal and Industrial Wastes***

  - Municipal solid waste (MSW), wastewater

BBI analyzed several forms of biomass materials in Aitkin County to potentially supply the Project with necessary volumes of feedstock materials. Herbaceous materials, including poor-quality hay and shrubs, were reviewed for their quantity, quality, and accessibility. Likewise, woody materials including logging residues, mill residues, and under-utilized, low-value roundwood were also reviewed.

The feedstock analysis found that Aitkin County's land cover is primarily made up of forested and wetland areas, but there exists a significant grassland acreage component and a smaller but still notable shrubland component. Total grassland acreage in the county is 158,760 acres; total shrubland accounts for 32,800 acres. Wooded acreage in Aitkin County is 491,000 acres.

The grassland component of Aitkin County is reasonably accessible for harvest. Over 110,000 acres of grassland are within 1,000 meters of a roadway and are not on protected lands (wetlands, sensitive species land, etc.). Nearly all of this land, 108,563 acres, is also privately owned. 50,000 acres of grassland are currently harvested for hay, leaving approximately 50,000 acres of grassland available and accessible to the Project. If harvested, Aitkin County grassland biomass will yield 75,000 tons of feedstock material annually.

There are over 100,000 tons of logging residues produced in Aitkin County logging operations annually. The Project can expect to capture 37,500 tons of logging residues annually at an estimated 50% moisture content, accounting for harvest losses and competition. The price of logging residues delivered to the plant gate is estimated at $60 per wet ton. In addition, there are over 700 acres of timberland designated in the Aitkin County Timber Management Plan that goes unsold each year, or roughly 35,000 tons of biomass.

Mill wastes produced in Aitkin County are approximately 11,000 tons per year. The Project can expect to capture approximately half of the market by paying the premium lost in shipping costs by its competitors. This is approximately 5,500 tons of sawdust and other mill waste material annually. The delivered cost of mill residues is estimated at $50/ton.

Feedstock material supply for the Project is envisioned to be a mixture of herbaceous grass and shrub materials, combined with several forms of woody biomass. Table 17 shows the anticipated feedstock mix for the proposed Project. As the plant moves towards completion the ratio of the mixture may change based on the pricing and availability of the feedstocks.

Table 2 – Aitkin County Facility Feedstock Blend

Fuel Type	Feedstock Available (as rec'd)	Blend %	Feedstock Utilized (50K TPY)	Feedstock Utilized (100K TPY)
Grasses	75,000	63%	31,500	63,000
Roundwood *(TSI, undersold timber)*	35,000	17%	8,500	17,000
Logging Residues	37,500	15%	7,500	15,000
Mill Residues	5,000	5%	2,500	5,000
Total	**152,500**	**100%**	**50,000**	**100,000**

Product Markets and Demand

There are two biomass conversion technologies under review for the proposed project, pelletization and combined heat and power (CHP) energy production. The two products reviewed are pellets sold to the commercial and industrial solid fuel market, and CHP energy supplied to the grid. The CHP scenario involves the direct production of thermal and electrical energy, while the pellet scenario focuses only on the pellet product. Because the pellets will also be used to produce energy, the political incentive structure driving the sale of both products is similar.

The pellets produced by the proposed project will not meet the specification for U.S. premium pellets, as long as logging residues, grasses and/or brush are used as feedstock. Using presently known technologies, only clean, white wood can meet the ash limit of premium and super-premium pellets both in the U.S. market and in Europe. The primary market for utility-grade (non-residential) pellets will be co-firing with coal at power plants, driven by incentives and mandates to reach renewable energy production goals.

Over 150 power plants have combusted biomass in combination with coal either as experimental or ongoing projects, according to the International Energy Agency's Biomass Division. Forty of those projects have been in the U.S. One such project has been conducted in Minnesota to co-fire biomass with coal in utility power plants. Occurring at the Northern States Power -owned Allen S. King Generating Station in Stillwater, MN, the 560MWe cyclone coal boiler is currently in commercial operation combusting a blend of coal and biomass. Great River Energy is constructing a coal-fired power plant 250 miles from Aitkin in Spiritwood, North Dakota that can be co-fired with biomass at a 5-10% blend ratio. The plant is expected to be online by October 2010. These, and other local and regional coal-fired power plants with interest in co-firing biomass fuels, will be the primary market for mixed-biomass pellets.

A consistent pricing structure does not exist for utility-grade pellets. Natural gas prices will therefore be used as a benchmark for the value of pellets produced by the proposed facility. At the calculated heating value of 8,175 BTU/lb for the pellet feedstock mix proposed, and using the projected 10-yr forward average city gate natural gas price in Minnesota, the value of the pellets is $115.16/ton, or $7.20/MMBTU.

Minnesota has a mandate specifically for biomass power production, which incentivizes larger-scale projects. Signed in 1994, the mandate (Minn. Stat. §216B.2424, Sec. 3) required that Xcel Energy purchase or produce 125 MW of biomass-fueled electricity. Approximately half (75 MW) of that mandate has been met through existing or in-process contracts; the remainder of the power generating capacity has yet to be installed. In Aitkin County, two local power providers will be the initial point of contact for negotiating power purchase agreements; Minnesota Power and Great River Energy. The regional wholesale grid management organization, Midwest Independent Transmission System Operator (MISO), will also be involved in power purchase agreement negotiations.

The combination of state RPS goals and the Minnesota Biomass Power Mandate have created an attractive market for companies to sell power to the grid. The average rate for sale of power to the grid, through power purchase agreements signed to date, is 10.40 ¢/kWh. This value will be used in the financial analysis as the price the Project can expect to receive for produced renewable electricity.

The value of thermal energy that can be sold to a co-located industrial user (within 1 mile) is set to the value of natural gas, at a 15% discount to entice purchasers. The 10-year projected average value of CHP heat energy is estimated at $6.12/MMBTU.

Technology Assessment

Biomass can be made into a number of marketable products commonly called ‘bio-based products,’ as well as energy in the form of heat and/or power. In the context of energy production, biomass is processed via mechanical, thermal, and/or chemical means into biofuel. The two primary technologies under review for the proposed Project are pelletization, with the end product being fuel pellets, and gasification, with the end products being heat and electricity supplied to the grid and/or co-located industrial energy user.

Pelletizing is a mechanical densification process that converts biomass into compact, uniformly shaped fuel units for combustion. Pelletizing is technologically simple and has been applied in many industries over the years, but consistent production of high-quality pellets from mixed biomass sources is logistically challenging and requires careful machinery planning and feedstock management. Controlling chlorides, ash content, and silica content of the finished product are the major concerns in the pelletizing process.

CHP systems are more technologically advanced and carry a higher initial investment hurdle than pelletizing systems. Producing heat and power from biomass feedstocks involves combusting the fuel source in a boiler, which creates superheated water or steam to drive electricity-producing turbines. A portion of the remaining water, containing too little energy to drive electricity production, can be recovered for industrial process heat or to heat buildings.

Gasification technology, which is rapidly being refined for use in small and mid-size applications, partially combusts the feedstock fuel in a controlled-oxygen environment, which produces a secondary gaseous fuel instead of direct heat. This gaseous fuel, called syngas, can then be combusted in a boiler, direct-fired in a turbine or reciprocating engine, or, after gas quality upgrading, converted to chemicals and liquid fuels. The status quo technology combines a gasifier with a direct-fired gas turbine and heat recovery, termed 'biomass-integrated gasifier/gas turbine' (BIG/GT) power systems.

Financial Analysis

BBI prepared four financial scenarios to evaluate biomass utilization facilities in Aitkin County, Minnesota. The models evaluate two biomass conversion technologies—pelletizing and CHP energy production, at two project scales—50,000tpy and 100,000tpy feedstock input, on an as received moisture content basis. The two CHP plant scenarios are rated at 10MW and 20MW capacity, based on an operating rate of 8,400hrs/yr (350 days). The pelletizing plants will produce utility-grade pellets from the chosen biomass feedstock blend, and the CHP plants will produce electricity and thermal energy from the same biomass feedstock input.

The key model inputs include product yields, product and raw material pricing, labor costs, energy consumption and pricing, capital costs including engineering, procurement and construction of the plants and all supporting facilities and systems, project development costs, financing costs, start-up costs, working capital and inventory costs.

Pre-tax average annual Return on Investment (ROI) was used to measure the projected profitability of the project. The results are summarized in Table 33. The ROI is the average of the return for the 11 years of the financial forecast including the construction year. Results that are more detailed are shown on the following pages and the complete 11-year economic forecast for the project is included in the appendices.

Table 3 – Financial Modeling Results

Aitkin County Project	50K Pellet	100K Pellet	50K Energy	100K Energy
11-year Average Annual ROI	12.4%	26.8%	17.7%	23.2%
Internal Rate of Return	12.8%	24.1%	18.9%	22.0%
Average Annual Income	$673,742	$2,406,534	$2,935,014	$7,048,384
Total Capital Cost ($/raw ton/day)	$0.90	$0.75	$2.77	$2.53
Total Project Investment	$13,550,180	$22,490,480	$41,570,520	$75,855,110
40% Equity	$5,420,072	$8,996,192	$16,628,208	$30,342,044

Based on the results and competitive guidelines, all four scenarios produce positive returns on investment. From a purely financial perspective, the 100,000tpy pellet plant is the most attractive option, yielding a 26.8% ROI over the 11 years of project timeframe. The smaller-scale pellet plant produced the worst returns on investment of the analyzed scenarios, but still worthy of consideration at an ROI of 12.4%. The two CHP plant scenarios were both attractive, producing project returns of 17.7% and 23.2% at the 50,000tpy and 100,000tpy project scales, respectively. The capital investment for the pellet plants is lower than the CHP energy plants.

In general, the larger-scale scenarios tended to perform better than their smaller counterparts, which is commonly seen in financial modeling due to the inherent economies of scale in larger installations. The scale of the pellet plants has a much greater affect on project returns than it does for CHP plant returns, producing +14% ROI over the smaller scale pellet plant. The larger-scale CHP plant only increases project returns 6% over the CHP small-scale scenario.

As analyzed, the viability of the CHP plants hinges on its ability to sell produced electricity at a higher rate than the current industrial electricity rate in Minnesota. The combination of state renewable energy generation mandates is the driver behind this, and should allow the Project to negotiate an attractive power purchase agreement. For the pellet plant, positive returns on investment hinge on receiving a value for the pellets in the range of natural gas prices (on a BTU basis), as opposed to coal prices, the commodity the pellets are actually replacing. Coal prices in the U.S., without the use of a carbon credit or tax equalizer, are simply too cheap to allow renewable energy to compete. Again, renewable energy generation incentives and mandates provide the impetus for the increased valuation of the pellet product.

The variables that have the greatest impact on the Project's profitability are the delivered feedstock price and the finished product selling price. This is the case for all biomass facilities, not just the proposed Project(s). A series of sensitivity analyses were run to examine the effect of critical parameters on the projected 11-year Average Annual After-Tax ROI.

The sensitivity to feedstock price shows that the pellet plants, as a whole, are more sensitive than the CHP plants. The ROI breaks even at feedstock prices of $48/ton and $61/ton in the small and large pellet plant scenarios, respectively, and $123/ton and $136/ton for the two CHP plant scales. The larger plant scales are slightly less sensitive to feedstock pricing than the smaller plant scales, when comparing within the same conversion technologies.

The financial performance of pellet plants is highly sensitive to the value of finished pellets; the 50,000tpy pellet plant will break even at pellet prices of approximately $100/ton, while the 100,000tpy plant scale breaks even at pellet prices near $85/ton.

The primary sale product of CHP plants is electricity, and it is not surprising that the CHP plants are highly sensitive to the final sale price of electricity. The smaller plant scale can sell electricity at 6.72¢/kWh and break even financially, while the larger plant scale can sell electricity at a minimum price of 5.89¢/kWh without producing negative returns. The CHP plants derive revenue from the sale of thermal energy, but do not rely on those sales as much as the electricity sales to produce positive returns. The CHP plants would still produce positive returns if the thermal energy was given away or wasted, though at a lower rate.

Conclusions and Project Considerations

The study found that Aitkin County, Minnesota has ample biomass resources to support commercial biomass utilization operations. Furthermore, as analyzed, both pelletization and direct conversion to energy via CHP of the feedstocks appear to be logistically and financially viable business propositions.

Because the Project is attempting to use feedstocks whose harvest and delivery mechanisms have not been fully developed, and is using conversion technologies that are, in some cases, not fully commercially proven, a certain degree of risk is present in the Project. On the other hand, the upside of a successful Project appears to be quite positive. If it can be determined that the conditions presented herein are achievable on the ground, it is recommended that the Project go forward.

If the decision is made to proceed with further development of the Project, Aitkin County, AURI, and other Project members should focus efforts on:

- Attracting outside private investment and/or management for development of the Project
- Developing a biomass supply and procurement plan
  - Encouraging harvest of available herbaceous feedstocks
  - Negotiating terms and pricing for contracts with loggers for roundwood and logging residues
- Identifying best site for a plant based on both infrastructure and financial incentives
  - This activity may influence engineering work, and definitely the cost estimate, so it is important that it is done early
- Deciding between pelletizing or energy production technology
- Engaging detailed engineering services to design the facility
  - A detailed cost estimate ± 10% should come from this effort
  - This firm may also be able to assist in developing the construction timeline so that long lead-time items do not delay construction

Special emphasis should be placed on the issues that have the greatest impact on the project profitability: obtaining requisite volumes of feedstock at an optimal rate, maximizing revenue from produced products, and reducing product shipping costs and distances.

BBI thanks Aitkin County and AURI for the opportunity to work on this assessment of biomass utilization in the State of Minnesota.

II. PROJECT OVERVIEW AND SCOPE OF WORK

Purpose of Study

The Agricultural Utilization Research Institute (AURI), in conjunction with the Center for Producer Owned Energy, Aitkin County Land Department, and the Aitkin County Economic Development/ Forest Industry Coordinator, is exploring the opportunity to utilize biomass resources available in Aitkin County to produce energy, indirectly through a pelletizing mill or directly through a heat and power production facility (the project).

AURI has retained BBI International (BBI) to conduct a feasibility study for the proposed Project. Phase I of the project will define and characterize the various biomass resources in the county. Phase II will determine the economic viability of a biomass-to-energy project in Aitkin County.

BBI is an independent consulting firm with no stake in the proposed project. The information detailed in this report reflects, to the best of BBI's ability, a true and accurate evaluation of the current biomass industry, applicable markets, and the feasibility of the project.

The specific biomass harvesting and economic modeling conditions presented herein are hypothetical and based upon BBI's best representation of potential future operating parameters, and should not be viewed as actual plant results. As bioenergy production technology and supply-chain infrastructure improves, these potential economic returns may change.

Scope of Work

The facility envisioned will produce indirect energy in the form of pellets, or direct energy in the form of heat and power for a local end user. The scale of the facility will correspond to the accessible biomass resource in the county. The full feasibility study makes an evaluation of the following areas:

- Overview of Study Area
    - Transportation
    - Utilities
    - Water
    - Land Cost
    - Roads
    - Wastewater disposal
    - Site location relative to communities
    - Numerical ranking of site attributes
    - Required State and Federal permits
    - Site recommendation
- Overview of Project Feedstocks
    - Biomass Feedstock Types

  - Biomass Yields
  - Biomass Harvesting Techniques
- Analysis of Grass and Shrub Biomass
  - Total Volume and Distribution
  - Land Ownership
  - Restrictions and Accessibility
  - Determination of Accessible Resource
- Analysis of Woody Biomass
  - Total Volume and Distribution
  - Land Ownership
  - Restrictions and Accessibility
  - Determination of Accessible Resource
- Review of Energy Production Technologies
  - Overview of Technological Development
  - Description of Available Technologies
  - List of Technology Providers
  - Determination of Best Available Technology (BAT)
- Market Overview
  - Local Electricity Market Opportunities
  - Local Liquid Fuels Market Opportunities
  - Local Heating Market Opportunities
  - Review of Biomass Utilization Incentive Policies
- Project Statistics (inputs and outputs costs, personnel requirements)
  - Process Design Basis
  - Project Costs
- Financial Analysis
  - Process assumptions
  - Economic Modeling Results
- Summary and Recommendations
  - Plant Location
  - Feedstock Issues
  - Market Issues
  - Plant Size
  - Return on Investment
  - Challenges
  - Risk Factors

III. PROJECT SITE DESCRIPTION

Overview of Study Area: Aitkin County, Minnesota

Aitkin County is a unique geographical location in Minnesota. It is a transition zone that forms the northern border of the corn / soybean / wheat farmland of the southern half of the state and the heavily forested north and northeast areas of the state. In technical terms, the county is split between two ecological hierarchy sections, Western Superior Upland to the south and Northern Drift and Lake Plains sections to the north; both sections are part of the Laurentian Mixed Forest Province. Ecological subsections comprising the county are the Mille Lacs Uplands formation to the south, Tamarack Lowlands in the north and west, and St. Louis Moraines forming the upland areas through the center of the county and in its northwest corner.

The dominant land cover classifications in the area are deciduous forest lands, wetlands, and grasslands. Specific plant species that may be found in the county include pine, tamarack, true firs, poplars (especially aspen), birch, and ash; shrub species including willows (*Salix* spp.), red-osier dogwood (*Cornus sericea*), and speckled alder (*Alnus incana*); and species of grasses such as native bluestem and invasive species of common reed grass (*Phragmites australis*) and reed canary grass (*Phalaris arundinacea)*.

Site Evaluation Criteria

The criteria for a good biofuel plant site encompass many factors including feedstock proximity, road and rail access, and access to required utilities. Other considerations include a qualified and/or trainable labor force, and the presence of essential community services like medical facilities. Desirable site attributes include:

- Land availability
- Feedstock proximity
- Road and rail transportation infrastructure at the site
- Utilities including electricity, natural gas, water supply, and wastewater disposal
- Co-product market proximity
- Labor availability
- Community services such as welding, electrical shop, plumbing, schools, fire protection, hospital, and airport
- Zoning and proximity to communities

Below is a discussion of each of the key items that determine the suitability of a biofuel plant site. A more detailed review of the availability of feedstock and the product markets occurs in following sections of this report. The plant inputs and outputs discussed are for biofuel plants utilizing 50,000 or 100,000 tons per year (tpy) of feedstock on an as received or wet basis.

Land Availability

Raw feedstock storage represents the majority of the land required for the plant in these biomass utilization projects. For instance, a plant that process 4 tons of biomass per hour needs up to 24 acres, while the plant's footprint is less than ½ an acre. In either the pellet or power-producing scenario, the small plant is approximately 6 tons per hour, and the large plant approximately 13 tons per hour. Based on the similarly-sized 4 tons per hour plant, the small and large scenarios require 38 and 76 acres, respectively.

Feedstock Proximity

The proximity of feedstock is an important component of the site evaluation as well as the overall feasibility of a biofuel plant. An in-depth discussion and analysis of the availability of feedstock is found in the Feedstock sections of the report. Feedstock proximity takes into account the plant's feedstock requirement and the feedstock production within various distances.

Roads

Access to Class A roads is an imperative requirement for any type of biofuel plant. U.S. Hwy. 210 is the primary Class A road traversing Aitkin County. Hwy. 210 is also adjacent to rail line for a portion of its length. Final project siting should have easy accessibility to a Class A road.

An analysis of the road traffic for the proposed plant is in Table 4. As evidenced in the chart, the truck traffic for feedstock going into the facility is nearly 2,000 trucks/year for the 50,000tpy scenarios, and over 3,500 trucks/year for the 100,000tpy scenarios. Additionally, the pelletizing plant will have a flow of traffic going out of the plant carrying pellets to market. Pellet out-flow can be accomplished by rail, which appears to be necessary for at least the larger plant scale scenario.

Table 4 – Biofuel Shipment Analysis

Transportation Statistics	50K Pellet	100K Pellet	50K Energy	100K Energy
Incoming				
Feedstock (raw tons/yr)	50,000	100,000	50,000	100,000
Feedstock (Truckloads/yr)	1,812	3,623	1,812	3,623
Trucks/day	6	12	6	12
Outgoing				
Pellets (Truckloads)	1,606	3,212	0	0
Trucks/day	5	11	0	0
Pellets (Railcars)	443	886	0	0

Rail

Rail access can be a distinct advantage in plant siting, allowing products to be shipped great distances for much less cost than trucking. However, because the project envisioned collects feedstocks from the local area, moving feedstock via rail is not necessary. Therefore, only the pellet plants have a shippable end product and stand to gain from rail access. A Burlington Northern Santa Fe (BNSF) rail line traverses the county east to west.

Electrical Service

Based on an electrical energy input requirement of 51.2 kWh per raw ton of feedstock processed, the 50,000tpy pelletizing plant scale will require approximately 356 kW of power capacity, or 2,559,760 kWh per year (assuming 90% capacity factor). The 100,000tpy pelletizing plant scale will require approximately 711 kW of power capacity, or 5,119,520 kWh per year. The CHP plants are assumed to create the electricity they need to operate (parasitic load).

Thermal Energy and Natural Gas

Natural gas typically comes from a large gas transmission line with the biofuel plant installing a new line to the gas source, or from an existing gas distribution line with distribution costs paid to the local gas company. Either way, the natural gas is purchased on the open market with transmission fees paid to the transmission pipeline company, and then distribution costs paid to the local gas company if local distribution lines are utilized. The transmission and distribution costs are usually negotiable.

The 50,000tpy plant scale scenario may require 9,471 MMBTU/yr of thermal energy for feedstock drying. The 100,000tpy plant scale scenario may require 18,943 MMBTU/yr. Total thermal need is low because the incoming feedstock moisture level is very close to plant input requirements; with on-site air drying, a dryer, and therefore natural gas supply, may not be required. The CHP plant scenarios are assumed to produce all natural gas they need to operate.

Water

There are three basic sources of water used for biofuel plants: well water, municipal or district water, and surface or river water. Most plants use well water due to their rural location. Over the long term, well water is often less expensive. Cost of drilling, quality of well water, and long-term supply are important considerations when considering a water supply. The second option as a water source is city water or a rural water district, which may provide a more reliable source of water, but usually at a higher cost. The third option is surface or river water if a reliable source is available nearby. Water quality and long-term supply are important considerations just as they are with well water. The factors driving the choice of water supply are reliability, water quality, and price.

Wastewater

Most plants have utility blow-downs where water periodically discharges from the cooling tower and steam boiler to prevent scale buildup in the equipment. There may also be wastewater discharged from makeup water treatment equipment, such as a reverse osmosis system. The blowdown water is typically very similar to the makeup water, but with an increase in the hardness. Cooling tower and boiler blowdown typically meet the discharge requirements for release to a local sewer, to surface water with appropriate permits, or to an evaporation pond. The wastewater can also be used for irrigation of crops or landscaping.

Biofuel Market Proximity

A large local biofuel market provides a distinct advantage for a plant through lower shipping costs. Local, regional, and national markets for biofuel are differentiated by distance and transportation cost. Local markets are within 150 miles and are usually serviced by truck. Regional markets are generally considered to be within 450 miles and are serviced by truck and rail. National markets are more than 450 miles away and utilize rail.

Labor

The exact number of employees varies depending on the plant design and operating plan. It is usually preferable for the plant to obtain the majority of its workforce locally. However, the specialty positions such as the plant manager may require recruiting from greater distances.

Community Services

Community services within 20 miles of the processing plant site are important to provide quick response to the needs of the plant and to attract and retain top employees. Desirable community services include electrical maintenance, machine shop, welding, plumbing, hospital, airport, good schools, and fire protection.

Proximity to Communities

Biofuel plants bring numerous benefits to communities including job creation, adding value to local crops with diversified products, increased local tax revenues, and significant economic development across the community. There are, however, potential negative impacts associated with such facilities as well, such as increased traffic volume, visual impacts, and noise. While noise and odors from modern processing facilities are dealt with using engineering controls and operating procedures, issues such as traffic and visual impacts on the community must be considered during site selection.

In the context of site evaluation, a site in close proximity to a community or residential area will receive a lower score than a site located in a more isolated or industrial area or with a “buffer” of undeveloped land between it and its neighbors.

IV. OVERVIEW OF BIOMASS AS A BIOENERGY FEEDSTOCK

Biomass Feedstock Species and Types

The term ‘biomass’ encompasses a broad spectrum of materials. In its truest form, biomass is all materials created by live or derived from recently living biological organisms, i.e., organic matter. As an industry term, ‘biomass’ is those organic materials that can be used as feedstocks to produce energy or beneficial products. In addition, harvesting biomass material should not disrupt natural ecological cycles, nor be in competition with existing industries serving food, feed, or shelter markets. While initial studies suggest that while there is sufficient growing stock to harvest for biomass energy use, the nascent bioenergy industry needs to carefully assess the availability, accessibility, and sustainability of biomass within the context of existing industries and natural resource supplies.

Biomass, in various forms, is utilized as energy and fuel by several industry sectors. Pulp and wood mills, municipal waster treatment plants, and others have found ways to utilize their byproducts to make heat and power. Currently over 3% of energy production in the U.S. comes from biomass sources. As energy costs rise and traditional energy sources become more scarce, biomass is a particularly attractive way to produce energy; it is massively abundant, does not compete directly with existing industries for raw material feedstocks, and is currently the only renewable source of transportation fuel.

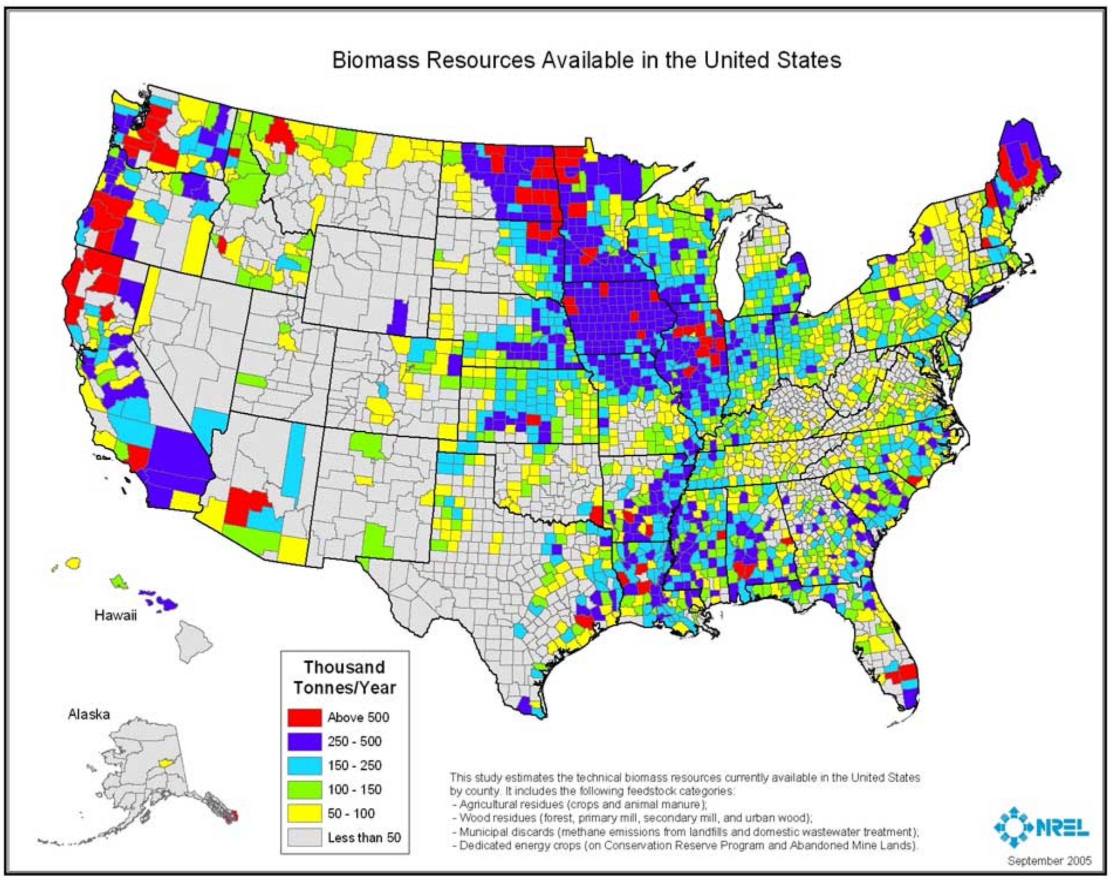
The primary forms of biomass are:

- ***Agricultural Residues***
  - Corn stover, wheat straw, and rice straw
- ***Forest Products***
  - Timber residues, thinning and stand improvement (TSI) products
- ***Secondary Products***
  - Mill wastes, agricultural processing residues
- ***Energy Crops***
  - Switchgrass, sweet sorghum, other grasses and shrubs
- ***Municipal and Industrial Wastes***
  - Municipal solid waste (MSW), wastewater

Biomass, as a feedstock for biofuels and bioenergy production, is a relatively new commodity. The U.S. Department of Agriculture (USDA) and U.S. Department of Energy (USDOE) jointly conducted a landmark review into the biomass potential of the U.S. referred to as the “Billion-Ton Biomass Study.” This review determined that there were over 1.3 billion tons of biomass feedstocks readily available annually in the country each year, from a combination of forest and agricultural resources. Furthermore, the study determined the use of these resources would not significantly impact any current markets or industries in a negative way, by competing with their raw material resource needs. 1.33 billion tons of biomass is sufficient to produce enough fuel to offset 30% of petroleum fuel consumption, even using a conservative conversion rate of ~25 gallons/ton.

The National Renewable Energy Laboratory (NREL) conducted a similar biomass resource assessment for the U.S. to determine the distribution of biomass resources. The quantified feedstocks included: agricultural residues (crops and animal manure), wood residues (forests, mills, and urban), municipal wastes (methane from landfills and wastewater treatment facilities), and dedicated energy crops (to be grown on Conservation Reserve Program lands and Abandoned Mine lands). As can be seen in Figure 2, the concentrations of biomass closely mirror the country's agricultural heartland, but also include the coastal areas as primary biomass resource areas.

Figure 2 – U.S. Biomass Distribution



(Source: NREL)

Aitkin County falls into the 50-100 thousand bone-dry tonnes per year category, indicated by a yellow color on the map. While this appears to be far less than other counties, it is still a substantial amount of biomass. The study was an overview of the entire country; individual county results can easily vary with a more in-depth study.

Methodology

Biomass resource assessments are relatively new, and the empirical data required to accurately depict biomass distributions and volumes are in varying development stages. Biomass used for energy resources is, by definition, a traditionally low-value resource. One of the primary drivers of biomass energy development is to add value to under-utilized, often ignored natural resources. Until recently very few researchers have found it worth the effort to develop the global biomass database. Information pertaining to the distribution, quality, and quantity of biomass resources is minimal at best, and non-existent in many cases.

This lack of available information becomes readily apparent when available biomass resources are compared to resources for the traditional high value agricultural crops of corn and wheat. For example, a quick search of the National Agricultural Statistics Service (USDA NASS), an indispensible tool for all bioenergy professionals, reveals over 80 thousand hits for both ‘corn’ and ‘wheat’ search terms, similar to what will be returned for any traditional crop. A search for the newest cash crop, ‘biomass,’ returned only 55 hits.

The figures presented in this report are based upon the best information and techniques currently available and represent the state of the art in biomass utilization assessments. However, field trials were outside of the scope of work for this analysis. The reported potential harvest sites, harvest yields, and other figures, techniques, and concepts that are centrally important to this study should be thoroughly tested under real-world conditions before being included in a biomass harvesting and management plan.

Available Versus Accessible Biomass

Because biomass is the most widespread natural and renewable resource on the planet, most potential biomass utilization sites will have abundant biomass resources nearby. However, the amount of biomass that exists in a given ecosystem is orders of magnitude higher than the technically viable harvest yield. In addition there is the economic feasibility challenge of finding, harvesting, and transporting biomass to a specific location. This analysis will produce two sets of results for each biomass type; the total available biomass in the study area and the ‘accessible’ biomass that the proposed project can expect to obtain at a reasonable price, with minimal logistical difficulty.

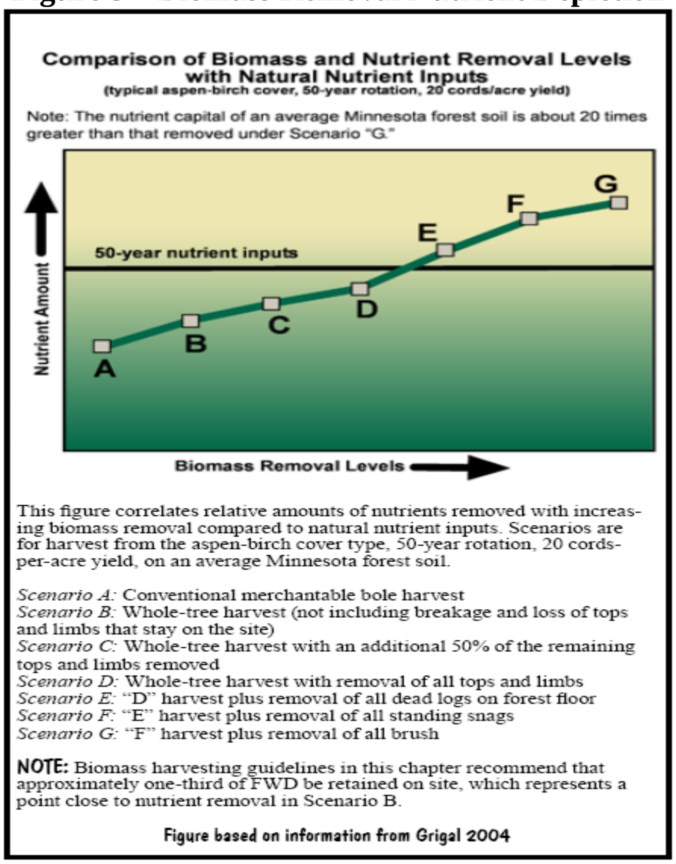
Sustainability

Additionally, it is important to remove from the ecosystem only what can be readily regenerated to ensure the Project will find sources of biomass continually available.

Retention of carbon and other nutrients in the ecosystem is a major concern in biomass harvesting. The nutrient capital of the land and naturally occurring soil nutrient input rates must be carefully reviewed prior to performing biomass removal operations. The ability of the land to recover and produce biomass again will affect the recoverable yield of an area, as well as the harvest intervals.

Figure 3 depicts the results of a nutrient depletion study conducted on various plots of average north-central U.S. forestland. It must be noted that special care should be taken to review the nutrient capital and input level prior to harvesting plots of land with sandy soils, low annual rainfall, low organic growth levels, etc. Many forms of biomass, even dead and down plants, provide protection against soil erosion and habitat cover for animals. Removal of more material than naturally occurs in the area will be detrimental to the ecosystem. The mechanical impact of harvesting activities must also be taken in to account.

Figure 3 – Biomass Removal Nutrient Depletion



(Source: MFRC Biomass Harvesting Guidelines)

Though the methods and guidelines for sustainable biomass harvest are still under development, a wealth of information already exists. It is recommended that project managers carefully review the local soil, flora, and fauna health and sensitivity prior to engaging in biomass harvesting activities. Several sources of information can assist in planning and executing biomass harvesting project without adverse environmental effects. In Minnesota, field guides have been prepared for woody biomass shrublands and grass biomass harvest. These guides can be found at: *"Biomass Harvesting Guidelines for Forestlands, Brushlands and Open Lands"*, December 2007, Minnesota Forest Resources Council (MFRC), www.frc.state.mn.us.

Projecting Biomass Yields

For the purposes of this analysis, yields will need to be determined for grassy biomass, brush, and woody biomass. The yield figures may vary from site to site but are based upon a generalized model that will remain consistent throughout the study area. The various yield figures used in this analysis are discussed below:

Grass Yield:

Grass yields for an area will be relatively consistent with the local hayland yields that can be expected from the area soils. Hayland will be cultivated, fertilized, etc. more than grassland biomass. This is offset by the several times more dense shrub/woody material that will be present in an untended grass field harvested for biomass. The average hayland yield per acre for Aitkin County has varied between 1.5 – 2.5 tons per acre per year throughout the 50-yr history of USDA's record-keeping on the subject.[1] A conservative figure of 1.5 tons per yr will be assumed for the grass biomass yield per acre in this analysis.

Brush Yield:

Brush is the most varied of the biomass feedstocks, both in terms of species encountered and stand density. Adding to the difficulty, very little direct research has been conducted on shrubland harvest. A study conducted by the University of Minnesota Natural Resources Research Institute found that unstocked brushy acres produced 4.2 dry tons per acre. The incremental addition of biomass tonnage was determined to be approximately 1.5 tons per acre per year (within the fully-stocked areas of the shrubland complex).[2] The yield of biomass within the Project study area is assumed to be 4.2 tons per acre with a harvest interval of at least 5 years to account for the unstocked nature of acreage. Stocked acreage can produce an order of magnitude more volume per acre.

Woody Biomass Yield:

Woody biomass is often reported in terms of timber harvest tonnage removed; in which case, a conversion factor is not necessary. For untapped resources, such as forest residues left behind during logging operations, the amount of biomass available is primarily a function of the type of wood being harvested (cover type), and also by the logging method (shortwood vs. treelength, etc) and harvest type (clear-cut or otherwise). Following are tonnage figures measured from actual logged areas. The report was conducted by the Minnesota Department of Natural Resources (MNDNR).[3]

---

[1] USDA NASS, http://www.nass.usda.gov/QuickStats

[2] Berguson, et al. "Minnesota's Woody Biomass Resources and Opportunities in the Emerging Energy Industry," UMinn Natural Resources Research Institute, 2007.

[3] Sorenson, et al. "Minnesota Logged Area Residue Analysis," Minnesota Department of Natural Resources, August 2006, revised April 2007.

Table 5 – Logging Residue in Debris Piles

Coarse and Fine Woody Debris Residue Amounts		
(by Cover Type)	Green tons	Cords
Aspen	12.8	5.7
Other hardwoods	19.2	7.54
Lowland conifers	9.5	4.3
Upland conifers	10.9	4.71
Unknown	13.8	6.12
Average:	13.24	5.674

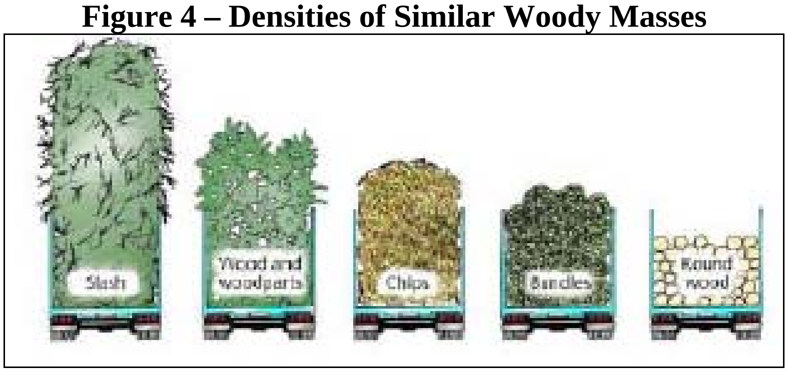
(Source: MNDNR)

The amount of that residue that is actually recoverable and utilizable is debatable. Some estimates put that number at 25-40%, others as high as 75%. The figure, as analyzed by the Onanegozie Resource Conservation and Development Council (ORC&D), which estimates 50% of logging residue material will be recoverable, appears reasonable. Applying this figure to the average debris amounts found at logging sites, and a potentially recoverable figure of 6.62 tons per acre emerges.

Biomass Harvesting Techniques and Equipment

Biomass harvesting techniques are evolving rapidly to meet the demands of this new industry. However, many of the techniques are still in the experimental stages and a large portion of the equipment used is not being used for its intended purpose, and has been individually modified by the users. Very little off-the-shelf technology exists for harvesting, transporting, and processing the odd sizes and shapes of biomass feedstocks. Figure 4 provides an indication that the density of a given feedstock can significantly affect the amount that can be transported.

Figure 4 – Densities of Similar Woody Masses



(Source: BBRG)

Outlined below are notes and tips about the various techniques and equipment employed to harvest, pre-process, and transport the analyzed types of biomass, prior to full processing at the central facility. These techniques are not the definitive solution to one of the most daunting logistical hurdles for biomass utilization, harvesting and collecting the material; they are meant as a starting point, to identify the framework of harvesting solutions, and estimate the amount of time and resources that will likely be required for such harvesting techniques. Field trials will be necessary to develop and solidify the best methods for this project.

Grass Biomass Harvesting Techniques and Equipment:

Harvesting grassy biomass is very similar to harvesting traditional grasses for hay. A first pass is made in the field to cut the materials and deposit into windrows. The second pass bales the materials. John Deere and other equipment manufacturers are developing single-pass equipment for gathering grass and agricultural residues, which are anticipated to be available to the public within a few years.

Grassy biomass has small-diameter twigs and sticks from the shrub and brush component, which will require industrial-size equipment such as the Vermeer 604M baler and Vermeer 830 mower pictured below (Figure 5). These bales weigh 1,400-1,900 lbs each, and can be loaded up to 20x on a flatbed trailer. This density allows the trucks to travel almost fully loaded, reducing the number of trips required to bring the biomass from field to processing facility.

Figure 5 – Photos of Grassy Biomass Harvesting Industrial Equipment

(Photos courtesy of DeMenge Farming and Excavating)

Shrub Biomass Harvesting Techniques and Equipment:

At this time, the most cost-effective methods for cutting and collecting shrub biomass have yet to be fully determined. The method to cut tall-standing shrub material is called ‘shearing,’ in which a bulldozer chops the shrubs off at the base after the ground has frozen. The next step, moving the material to a landing or other collection spot, has yet to be worked out. The Laurentian Energy Authority is currently studying various methods involving a modified forwarder to handle the small-diameter woody materials, but no results have been posted. Once at a landing, the material will likely be chipped to reduce its volume, then trucked to the processing facility.

Woody Debris Biomass Harvesting Techniques and Equipment:

Similar to shrub biomass, much of the woody debris from logging activities are small-diameter and/or oddly-shaped pieces. These materials are also difficult to transport, however many times this is not needed. It is common practice in the logging industry to move the majority of the slash into piles. Logging activities also create roads and chippers can be brought directly to the slash piles for size reduction. Logging residues may be one of the least logistically-challenging and equipment-intensive biomass resources to collect. The amount of biomass left after logging operations in Figure 6 (photo of freshly logged site in Aitkin County, south of Tamarack) shows that it is feasible to capture the proscribed 50% of logging residue.

Figure 6 – Photo of Logging Residues for Collection

(Source: BBI)

Biomass Feedstock Composition

The composition of the feedstock input has significant effects on the final product specifications in the biomass energy and products industry. It is not coincidental that cellulosic ethanol technologies under development are each focusing on a single, pure feedstock blend (despite claims of multi-feedstock capabilities). As it pertains to this study, burn characteristics are important whether the biomass is combusted directly for energy or pelletized for future combustion. Pelletizing adds several important characteristics to consider for proper operation of pelletizing machinery.

Biomass types are extremely varied in composition and behavior, even for closely related species. Table 6 and Table 7 are provided for reference, and show available compositional analysis of actual feedstocks input in biomass energy facilities, from a study conducted for NREL in 1995.[4] The primary constituents when discussing biomass energy potential are ash, chlorine, heating value, and moisture content as received.

[4] Miles, et al., "Alkali Deposits Found In Biomass Power Plants" NREL 1995.

Table 6 – Compositional Analysis of Woody Biomass Feedstocks

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

(Source: NREL)

As the tables show, there are major variations in the primary feedstock composition between different species and plant types, as well as between different products / wastes from the same species. The values differ between whole-tree poplar and polar chips, though they are products from the same or very similar species. Mill waste and sawdust also differ, though they are commonly classified together as 'mill residues'. Forest residues are a mix of many species, but have different characteristics than other woody species. Notable with forest residues is the high ash content compared to other woody biomass, which is related to high alkali content and can cause fouling and deposits in biomass energy equipment. The fir mill waste, though high in moisture when received, has excellent BTU content and very limited ash and other impurities.

Table 7 – Compositional Analysis of Grassy Biomass Feedstocks

Fuel	Grasses and Straws					
Type	***Sorghastrum avenaceum***		***Miscanthus sinensis***		**Imperial Wheat Straw**	
	As Rec'd	Dry	As Rec'd	Dry	As Rec'd	Dry
Ash	3.68	4.15	2.94	3.36	8.31	9.55
Moisture	11.33	--	12.51	--	13.01	--
Chlorine %	0.04	0.04	0.07	0.08	1.79	2.06
Alkali, Lb/MMBtu		0.46		0.78		4.15
HHV, BTU/lb	7,131	8,042	7,131	8,150	6,288	7,228
Ultimate Analysis						
Carbon	41.94	47.3	41.7	47.66	37.32	42.9
Hydrogen	5.33	6.01	5.03	5.75	4.44	5.11
Oxygen	37.4	42.18	37.39	42.73	36.2	41.62
Nitrogen	0.28	0.32	0.39	0.45	0.46	0.53
Sulfur	0.04	0.04	0.04	0.05	0.26	0.29
Ash	3.68	4.15	2.94	3.36	8.31	9.55
Moisture	11.33	--	12.51	--	13.01	--
TOTAL	**100**	**100**	**100**	**100**	**100**	**100**
Ash Composition						
SiO2		71.05		56.07		37.06
Al2O3		1.78		0.78		2.23
TiO2		0.02		0.02		0.17
Fe2O3		0.92		0.93		0.84
CaO		6.81		13.62		4.91
MgO		2.14		1.07		2.55
Na2O		0.24		0.27		9.74
K2O		8.7		18.7		21.7
SO3		1.08		1.7		4.44
P2O5		4.3		6.24		2.04
CO2/other						
Undetermined		2.96		0.6		14.32

(Source: NREL)

The listed grassy biomass species differ significantly from the woody biomass species, and also from each other. Ash, chlorine and alkali contents are much higher than woody materials, save the logging residues. Wheat straw is a very poor feedstock, due to its high ash content, corresponding high chlorine and alkali content, and low BTU value.

The same study discusses some of the problems experienced by power plants attempting to burn biomass-based fuels. The majority of the problems had to do with deposits forming on the fireside walls, on grates or on the beds in the combustion chamber. Flyash accumulations in gas ducts were also noted as an issue. The conditions that precipitated these deposits were complex, and have not been completely resolved by that study or subsequent research, but it is known that the major contributors are alkali and silica compounds forming as a result of the combustion. High ash content in the feedstock material is the primary indicator of potential problems, and is usually related to high silica and alkali content of the ash. As well, the chlorine content of the parent material, which creates potassium chloride and other alkali salts, must be controlled.

Pelletizing equipment looks for low moisture contents (<15%) to reduce or eliminate the need for drying, as well as low ash content (<1%) to achieve stringent product standard levels. These standards will be discussed in more detail later in the study.

V. LOCAL FEEDSTOCK APPRAISAL: GRASSES AND SHRUBS

This section reviews the distribution of grassland and shrubland in Aitkin County and determines the volumes of each that may be accessible as feedstock supply for the Project.

The biomass resources of grass and shrub (also known as brush, scrub, etc.) are highly varied in terms of their distributions in the study area, species make-up, and harvesting techniques. However, the fact that both are non-traditional resources and are not linked or dependent upon other industries makes their assessment process similar. The viability of both grasses and shrub/ brush is determined simply by the volumes available and the cost of harvesting. Therefore, they will be reviewed together in this section.

Common grassland that can potentially be used as biomass feedstock will consist of a range of grass species, as well as some brush and shrubs. Higher-quality grassland plots that are well-tended and without impurities are traditionally harvested for feed hay. Assuming this follows the standard biomass economic model, which essentially prohibits field management between harvests due to cost concerns, the grass harvested for biomass can be expected to be untended and highly variable. In Aitkin County, the species encountered will likely be native bluestem and invasive species common reed grass (*Phragmites australis*) and reed canary grass (*Phalaris arundinacea)*.

Brush and shrubs primarily consist of small-stem woody plants. Brush and shrubs are the most variable biomass type. Brush and shrublands are made up of a multitude of species and plant sizes, even between plots in a small geographical area, making quantification and utilization difficult. In Aitkin County, the species encountered will likely be willows (*Salix* spp.), red-osier dogwood (*Cornus sericea*), and speckled alder (*Alnus incana*), often mixed in with small trees, including species of poplars, birch, and ash, etc. In an area designated as shrubland, these tree species are highly dispersed and all plants in the brush and shrub areas stay below 16 ft tall. Taller stands of denser tree species fall under forest-land classifications.

The primary benefit of shrubland for biomass utilization is the density of plant matter. Plots sometimes achieve 10 tons/acre at harvest time and have short 2-3 year regeneration periods. Standard brush yields are estimated to be around 4 tons/acre, with 5 years of regrowth between cuttings. These are larger yields than grasslands can achieve, even with annual or 2-year growing periods. Grassland yields are estimated at 1.5 tons/acre of annual harvest. On the other hand, brush as a biomass feedstock suffers from logistical issues. Harvesting methods for brush are the least evolved of all harvesting methods, because brush has been considered a nuisance until its value as a biomass feedstock became apparent. Harvesting methods will be discussed in greater detail later in the section.

The volume of brush and grass in a given study area can be viewed in several different ways. Because the biomass is not cultivated specifically to allow for future harvesting, it may be difficult to reach, in an entirely inaccessible area, or on undulating or rocky land that harvesting equipment cannot operate on. It may also be growing on private land that the owner is not amenable to being cut, park land, or other sensitive habitats that cannot be disturbed and are otherwise off-limits for harvesting.

The quality and quantity of plant species growing also plays into the viability of a brush or grassland harvesting area. Land cover classification schemes traditionally focus on the land types that indicate profitable ventures, such as cultivatable land, timber forest, land zoned for commercial or residential construction, etc. Grass and brush land designations are often applied to the remainder of land that has not received some other designation. This is called a 'negative sort'. The land types that grassland, brushland, and shrubland consist of vary considerably on the ground. A conservative approach is recommended when attempting to attach an acreage or tonnage figure to the biomass potential of grass and shrubland.

Therefore, the volumes of brush and grassland biomass feedstock potential for this project will be reviewed by the total existing grass and brush in the area, and the potentially accessible biomass feedstocks, which will be broken out by biomass and land type quality as well as accessibility issues.

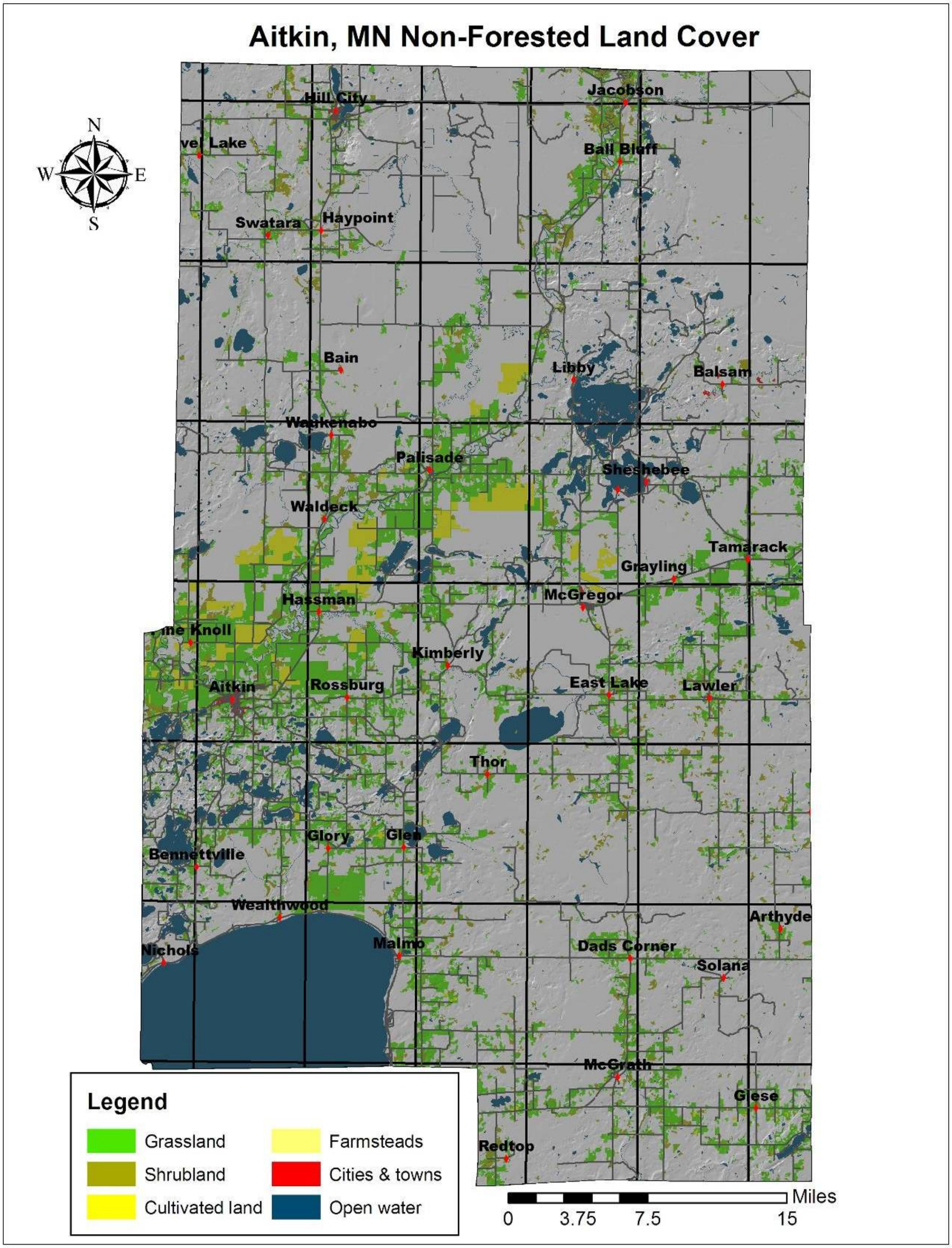
Figure 7 – Photo Sample of Aitkin County Grassy Biomass

(Source: BBI)

Total Volume of Shrub and Grass Biomass

The total acreage of grassland and shrubland in Aitkin County was determined using a geospatial dataset compiled by the MNDNR. The LandSat-Based Land Use / Land Cover dataset (LULC) uses GAP-2 Thematic Mapper satellite imaging of the entire land surface of Aitkin County in 30-square-meter sections, which were then digitized and separated by land cover type. Sixteen land cover types (not including roads) were identified from the data. Classification accuracy was over 95%. The LULC dataset, though compiled in 1996, was confirmed by local land-use experts as the definitive land cover analysis in Aitkin County, as well as most other regions of the state. The same data was used to create the overall county land-use map shown in Section IV. Figure 8 shows a map of the total non-forested land cover in the study area.

Figure 8 – Grass-, Shrub-, and Cropland in Aitkin County



(Source: BBI)

The amount of grassland in Aitkin County far outweighs shrubland and cultivated cropland. The total grassland acreage is 158,760 acres; total shrubland accounts for 32,800 acres. This is compared to only 18,500 acres of cropland.

Assuming a yield of grasses equal to the average hay yields, 1.5 tons per acre per crop year, the annual biomass tonnage potential of all of the grassland in Aitkin County is 238,140 tons. With 4.2 tons of biomass in each acre of shrubland and five-year harvest cycles, the total annual biomass tonnage potential of shrub/brush is 27,500 tons.

The MNDNR has conducted a map-based analysis of the grass and shrublands in Aitkin County using the LULC dataset in conjunction with several other datasets compiled over the years. This analysis painstakingly combed the land cover of Aitkin County and discovered over 600,000 acres of grass and shrubland, nearly half of the total acreage of the county (Table 8). The analysis was exacting to the point that, at times, it catalogued tiny patches of scrubland or grassland buried in forest or swamps. A large portion of the additional acreages discovered in by the MNDNR are not accessible or viable plots of land for biomass harvest.

Table 8 – MNDNR 2008 Quantification of Aitkin County Biomass

(acres)	County	State	Federal	Other Public	Private	Total
Herbaceous	6,191	28,983	3,054	47	207,557	245,832
Planted Vegetation	1,439	3,818	399	9	30,563	36,229
Shrublands	37,261	84,657	3,076	21	195,332	320,347
Total	**44,892**	**117,457**	**6,529**	**77**	**433,452**	**602,407**

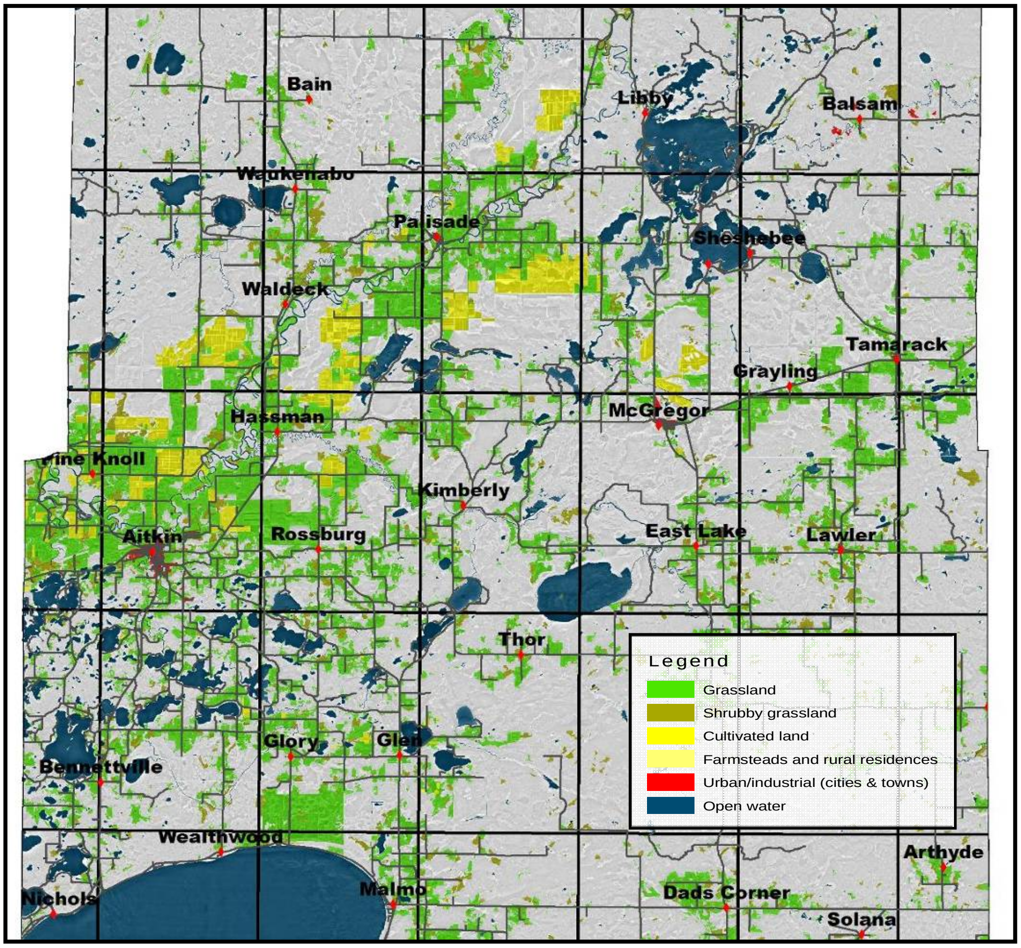
(Source: MNDNR Aitkin County Biomass Resourced Assessment)

This analysis will use the LULC dataset primarily for land cover information on the assumption that the LULC information maps the larger, contiguous land areas. Targeting these larger and more consistent land areas for biomass harvest better serves the purposes of the analysis. Land areas that may be too small or remote are effectively eliminated. However, it is useful information to know that the LULC dataset is a conservative estimation of the total land area, and in practice, additional parcels of land may be suitable for harvest.

Grassy Biomass Feedstocks

The distribution of grassland in the county is not even. The central region contains almost the entire acreage of grass, as the northern and southern thirds have only scattered grass acreage. Figure 9 shows the prime corridor of grassland in Aitkin County. There is significant grassland near the towns of Aitkin and Palisade, as indicated on the map, and smaller distributions near Tamarack to the east and Glory and Wealthwood to the southeast. Shrubland and cultivated lands are also distinguished in the map.

Figure 9 – Grass and Shrub Biomass Primary Distribution Corridor



(Source: BBI)

Figure 10 shows a plot of low-grade grassland north of Palisade that has been recently harvested. Though difficult to make out from the photo, weeds and small shrubs comprised a large portion of the land cover. A discussion with the contract harvester revealed that the baled grasses were sold as 'junk hay' to be used as mulch.

Not all of the grassland is accessible for harvest. Logistical limitations, such as lack of road access and lowland/swampland areas will reduce the acreage available for cutting. Other issues impacting availability include:

- ownership of land by parties not interested in harvesting
- ownership of land by parties legally bound to disallow cutting
- threatened / endangered species lands
- otherwise designated sensitive lands

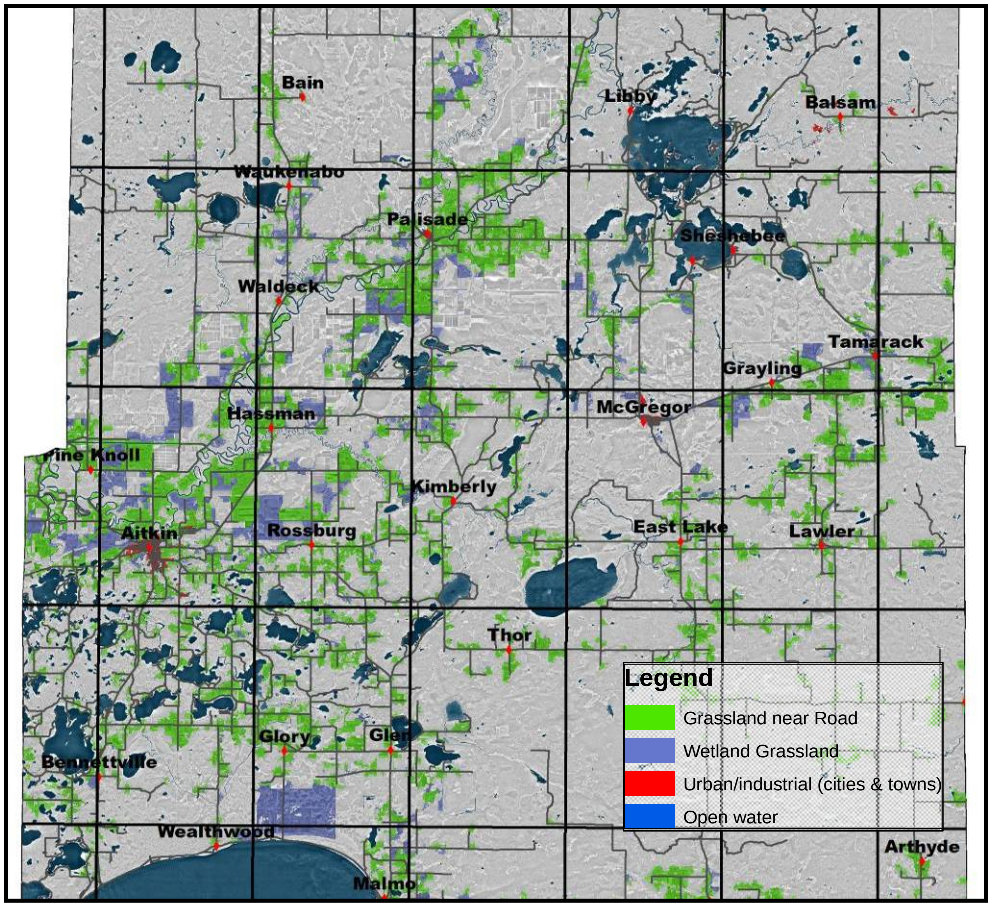
Figure 10 – Photo of Harvested Grassland Field

(Source: BBI)

This analysis will use the tools available through geospatial mapping software to identify and rule out the limiting agents such as sensitive or protected lands, wetlands, lands without road access, etc. Logistical limitations will be analyzed first, followed by administrative and land-ownership limitations. The resulting subset map will show the areas accessible for grassland harvesting in Aitkin County. Whether the land surface at each of those sites will allow cutting and whether the grass biomass growing there is worth the energy expenditure for removal will have to be conducted on a site-by-site analysis.

Figure 11 shows the grass biomass resource in the primary distribution corridor that is within 1,000 meters of a registered roadway and blocks out the portions of grassland that are designated 'wetland' by the U.S. Geologic Survey (USGS). This USGS 'wetland' determination includes swamps, bogs, marshes, as well as federally protected wetlands, and areas within 10 acres of a lake. As shown in the map, the majority of the grassland acres are still accessible. Only 16,330 acres of grass are not near a roadway, and another 31,873 acres are inaccessible as wetlands. This remaining acreage is referred to as the 'accessible grassland' acreage of Aitkin County, and covers 110,567 acres.

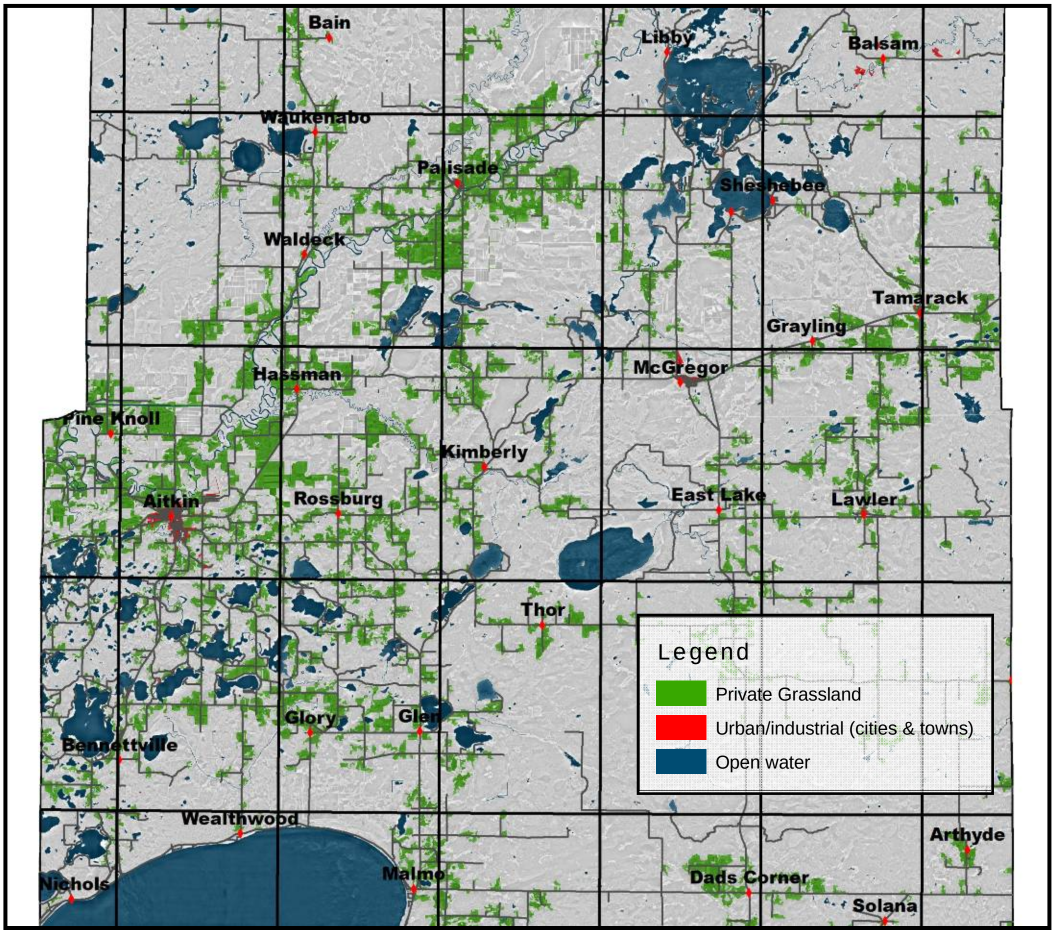
Figure 11 – Accessible Grassland Biomass



Several zones of the map have significant grassland acreage delineated as wetland. A portion of the grassland surrounding Aitkin, Pine Knoll, and Rossburg is inaccessible at this level of detail, as is almost the entire swath of grassland east of Wealthwood. Palisade retains almost all of its acreage except for some to the southeast of town. Tamarack also has minimal grassland designated as wetlands.

When the accessible grassland acreage map was compared to the land ownership map available from MNDNR, it becomes apparent that nearly all of the grassland occurs on private lands. 108,563 acres of land in Aitkin County are accessible grassland on privately-help land, as shown in Figure 12.

Figure 12 – Accessible Grassland on Private Land

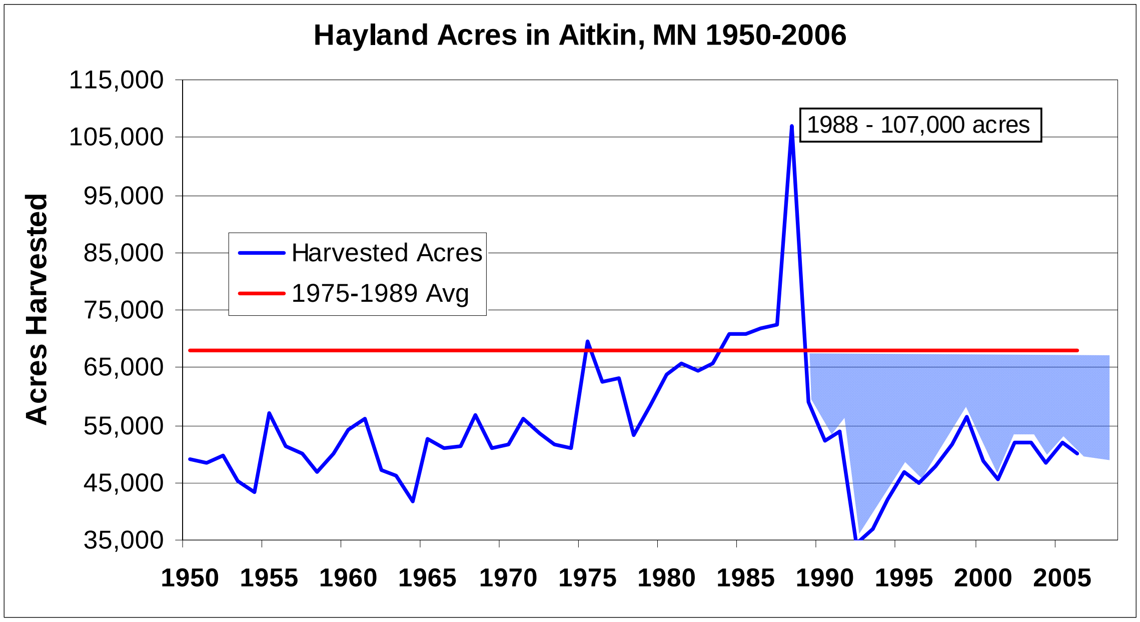


Underutilized Hayland Acreage

Aitkin County is too far north to support much corn or other rowcrops, but not quite in the heavily wooded northern Minnesota zones. The land has, however, supported a thriving hayland and grazing land industry for many years. The industry peaked in the late 1980s. The acreage that was cultivated for hay, but has now gone fallow, is one of the primary opportunities for grass biomass acquisition in Aitkin County.

Former hay acreage has the most potential as a grassland biomass feedstock because it was once profitably harvested land. Other, uncultivated lands may be turn out to be accessible and feasible for harvest, but it is known with a reasonable amount of certainty that these former haylands are possible to be harvested. The land was cleared of trees and rocks, leveled, and otherwise generally adapted to permit the operation of harvesting equipment.

Figure 13 – Aitkin County Hayland Acres



(Source: USDA NASS)

Figure 13 shows the Aitkin County hayland acreage usage through the years. Peak acreage in hay (all types) was in 1988, with 107,000 acres. Throughout the 1980s the amount of land devoted to hay production averaged nearly 70,000 acres. Considering that current hayland in Aitkin County hovers around 50,000 acres. It can be assumed that there are at least 20,000 acres of un-utilized former hay-growing land.

There are several possible explanations for why the grassland in Aitkin County is almost entirely on private land. Eliminating the 'wetland' category in a previous iteration assisted with this, as most wetlands are publicly owned. Another reason is due to the methodology behind creating the LULC dataset. The grassland acreage was far below the MNDNR's 2007 Biomass Assessment grassland acreage, likely because a tighter definition of 'grassland' was used. The land viewed as grassland by the LULC crew is quite possibly the acreages that have at some point in time been cleared and leveled for growing hay, producing a distinctive image in the satellite photos. Coincidentally, the 108,000 acres of accessible grassland on private land almost exactly matches the county's peak hayland acreage.

Therefore, the high-end estimates of useable land approach 58,563 acres, which is the remainder of the 108,563 acres delineated as privately-owned, accessible grassland in the LULC mapping software. That number will be rounded to a conservative 50,000 acres.

The 20-50,000 acres of grassland / unused hayland in Aitkin County can be brought back into service as biomass-producing land. Depending on how long it has been out of service for growing feed hay, grasses such as the native bluestem and grama, the invasive but highly productive reed canary-grass, as well as shrubs and brush such as willow and alder may be growing in these areas. The specific ecology of each section cannot be determined in this analysis, however it is expected that the hay is below cattle-feed grade. Currently, mulch is the only market for this type of hay, and competition for the resource will be sparse. The major limitations to harvesting will be convincing the landowner to allow harvest, and whether the specific logistics of the land plot will allow quick, easy, and therefore profitable, harvest. A coalition of farmers has voiced a willingness to harvest and deliver grassy biomass for the project, or at least allow their land to be harvested.

The available and accessible grassland acreage in Aitkin County will be estimated at 50,000 acres at present. At 1.5 tons per acre of recoverable material, this would account for approximately 75,000 tons of grassy biomass matter potentially available to the Project.

Brush Biomass Feedstocks

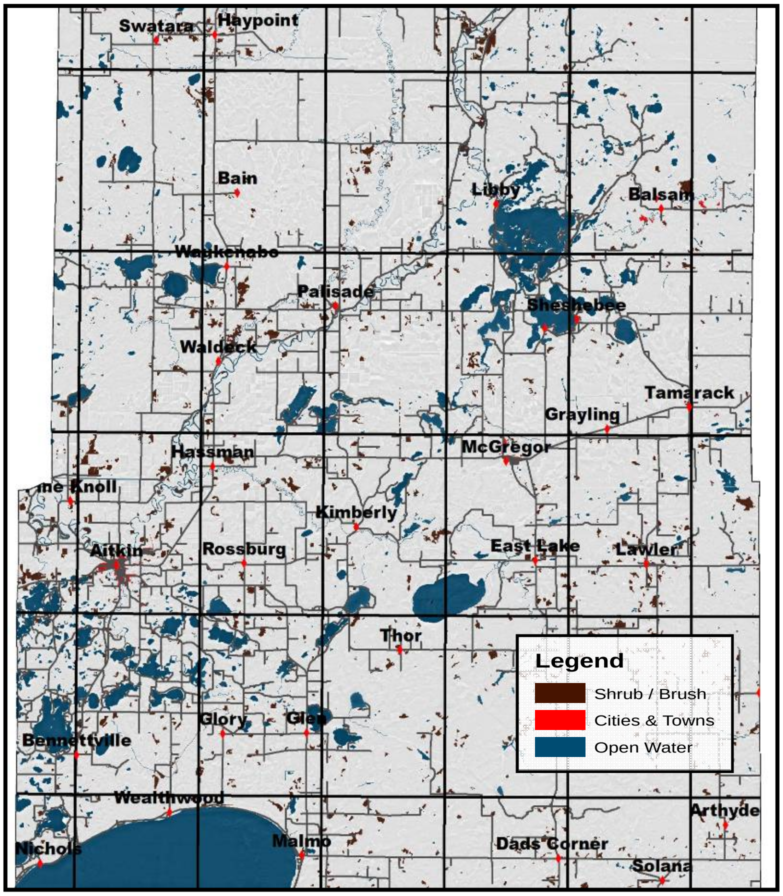
The total shrubland acreage in Aitkin County is 32,800 acres. If the entire acreage were accessible and harvestable, the yield would be 137,760 tons with 5-yr regeneration periods (or 27,500 tons annually). Shrub and brush biomass is the least studied and most variable of the biomass types. Figure 14 shows several sample photos of common shrub stands in Aitkin County. The photo on the left is a stand of young aspen shoots; on the right is a willow thicket.

Figure 14 – Photo Samples of Aitkin County Shrub Biomass

(Source: BBI)

The shrubland acreage is broadly scattered over the county, as can be seen in Figure 15. There is very little consolidation or pattern to any of the shrub / brush areas.

Figure 15 – Aitkin County Shrub and Brush Land

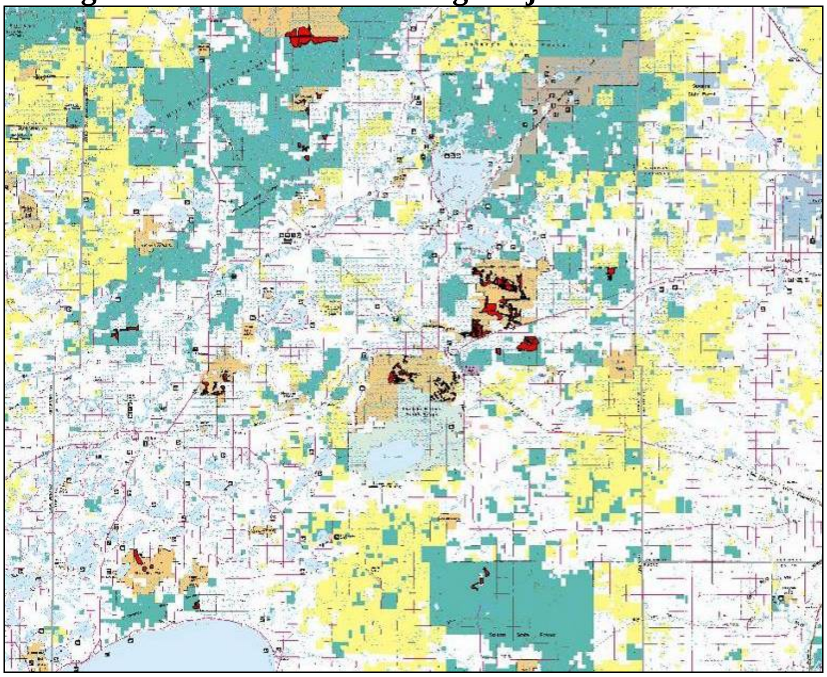


Almost no acres of shrubland have ever been cut. Over the past decade, the MNDNR has been conducting tests to see if shearing increases the quality and accessibility of wildlife habitat. Figure 16 and Figure 17 show the shearing test plot areas, which total less than 1,000 acres.

The experiments have been shown to improve habitat characteristics for sharp-tail grouse and white-tail deer, however no management plan has been formed based upon the experimentation. At present there are no plans to conduct widespread shearing projects in Aitkin County for wildlife habitat.

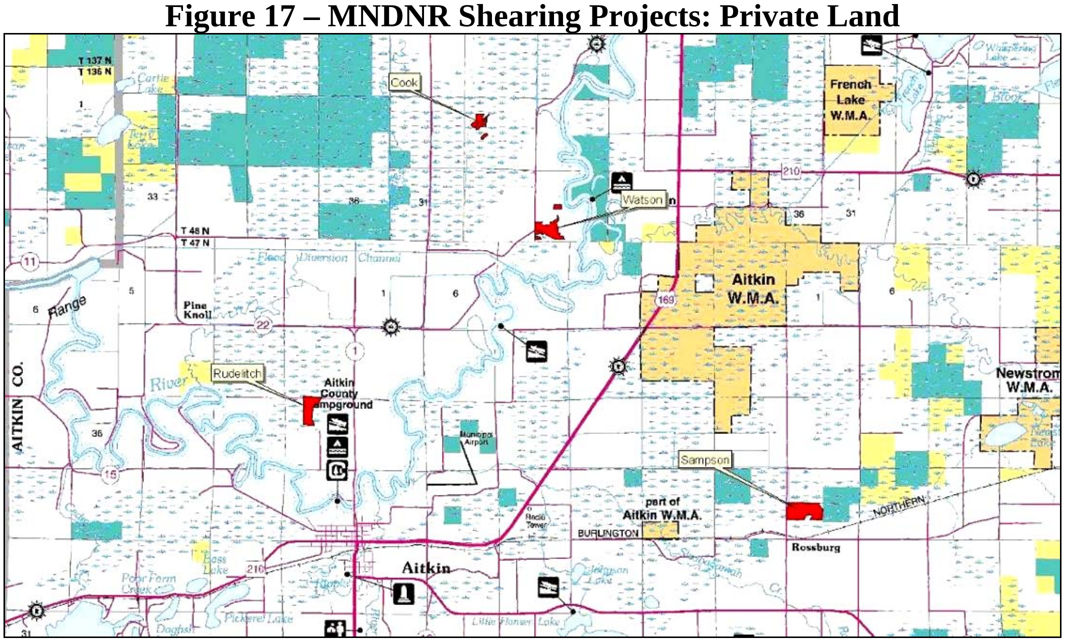
Combined with the lack of established harvesting techniques for brush, these limiting factors will likely delay the utilization of shrub and brush as biomass feedstocks. In the long term, the high yield and habitat improvement benefits of harvesting brush and shrub lands will make them a viable biomass feedstock, but for the purposes of this study they will be considered a negligible addition to the project's feedstock mix.

Figure 16 – MNDNR Shearing Projects: Public Land



(Source: MNDNR)

Figure 17 – MNDNR Shearing Projects: Private Land



(Source: MNDNR)

Grass and Shrub Biomass Pricing

Grass and shrub biomass have not developed a formal market for purchase. These feedstocks have not been collected and utilized in the past. Therefore, the value of grass and shrub biomass is a function of the cost of removal and delivery to the plant gate. For the purposes of this study, the price of these feedstocks will be linked to the price of hay, a similar product with established markets in the area.

Local hayers were polled to determine the going rate for hay products. DeMenge Farming and Excavating estimates that a 1,400-1,900 lb bale of quality hay sold for $20/bale, plus shipping, and a bale of course reed-canary grass hay sold for approximately $15/bale, again plus shipping. Assuming a bale weighing 1,500 lbs composed of low-value grasses, and including a $7/ton delivery charge, the suitable price of grassy biomass is $27/ton delivered. Harold Hatfield, another hayer in the area, also charges $15-20/bale, but the bale sizes produced by his machinery are 600-800 lbs each, and the price includes delivery. This equates to a delivered price of $37.50/ton.

The median price of delivered grass biomass is $32.25/ton. At a moisture content of 15%, the price of delivered grassy biomass feedstock to the proposed plant is set at $36/ton.

Conclusion: Grass and Brush Biomass Potential

Aitkin County’s land cover is primarily made up of forested and wetland areas, but there exists a significant grassland acreage component and a smaller but still notable shrubland component. Total grassland acreage in the county is 158,760 acres; total shrubland accounts for 32,800 acres. Assuming a yield of grasses equal to the average hay yields in the county, 1.5 tons per acre per crop year, the annual biomass tonnage potential of all of the grassland in Aitkin County is 238,140 tons. Assuming 4.2 tons of biomass in each acre of shrubland and five-year harvest cycles, the total annual biomass tonnage potential of shrub/brush is 27,500 tons.

The grassland component of Aitkin County is reasonably accessible for harvest. Over 110,000 acres of grassland are within 1,000 meters of a roadway and are not on protected lands (wetlands, sensitive species land, etc.). Nearly all of this land, 108,563 acres, is also privately owned.

Grassland designation very closely corresponds to the current and former hayland harvesting that used to be a staple crop in the region. 50,000 acres of grassland are currently harvested for hay annually, leaving between 20,000 and 58,000 acres available for biomass utilization. 50,000 acres of grassland harvested will yield 75,000 tons of accessible biomass for the Project.

There is 137,760 tons of shrub biomass in Aitkin County. The shrubland distribution is highly dispersed. However, combined with a very limited program for harvesting shrubland both in Aitkin County and elsewhere, this resource is not recommended for the project. As harvesting techniques improve and management plans are put in place, shrubland biomass may become a viable feedstock for the Project.

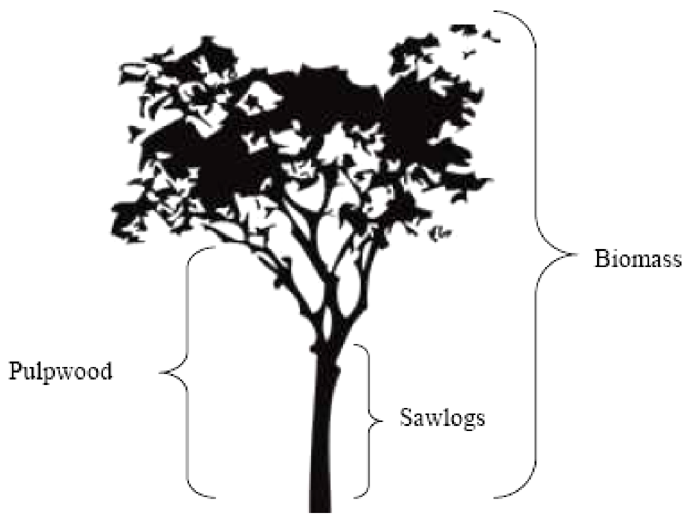
VI. LOCAL FEEDSTOCK APPRAISAL: WOODY BIOMASS

This section reviews the locally and regionally available feedstock to fuel the proposed project. Woody biomass sources analyzed below include low-value roundwood, wood chips, and sawdust from sawmills.

Woody Biomass

The term ‘woody biomass’ encompasses all feedstocks derived from harvested trees. It includes the trunk and main stem of a tree, as well as the limbs and twigs usually left behind in timber harvesting operations. Figure 18 below shows that harvesting for biomass will utilize a larger portion of the tree than will the traditional primary timber harvests for sawlogs (lumber feedstock) and pulpwood (paper feedstock).

Figure 18 – Biomass Utilization of Tree Anatomy



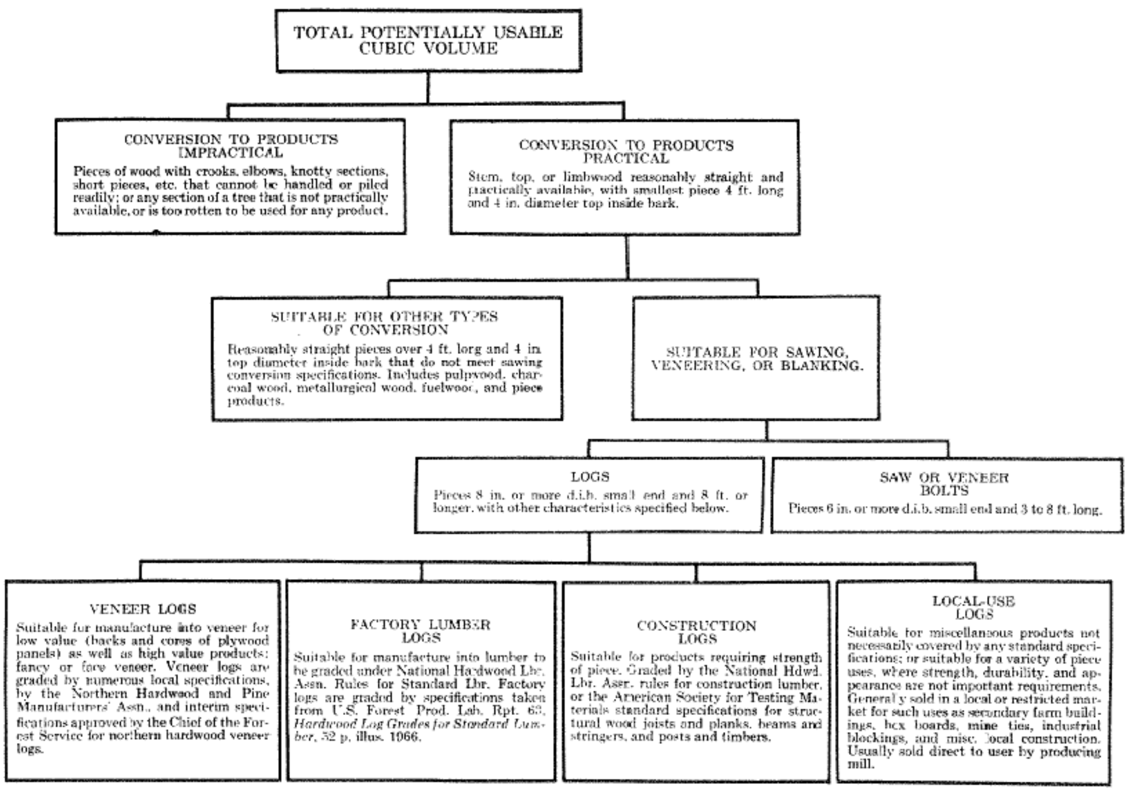
- *Saw logs = 10”+ diameter, at least 8’ long sections*
- *Pulpwood = 4”-8” diameter*
- *Biomass = <4” diameter*

(Source: Energy Center of Wisconsin[6])

In some instances, the entire body of a tree may be diverted to biomass utilization, but this usually will come at a price. Markets and competing uses exist for the majority of tree mass. The trunk of the tree, or any portion of the tree above 8-10” diameter, will fetch a higher price and will go to lumber uses. Any limbs above 4” diameter will command pulpwood value, and will likely go to that use. This is increasingly apparent as wood reserves shrink and mills continue to buy equipment to handle smaller and smaller diameter trees. Limbs, branches, and irregular or crooked stems (known as logging residues), secondary mill residues, and, in certain isolated instances, harvested low-value tree species round out the majority of woody biomass feedstocks.

Figure 19 shows the process utilized by a U.S. Forest Service timber grader on a timber cruise. Though there are many available uses for the timber – sawlogs for lumber, pallets, veneer, furniture, and bolts – a significant portion of each given tree does not fit within any of the useful categories. As well, several of the categories have no subsets, such as the category 'Conversion to Products Impractical' or 'Suitable for Other Types of Conversion.' These are the portions and trees that are ideal for biomass utilization. The material can be obtained for essentially the cost of collection and transport, and will not put upwards pressure on traditional forest products pricing schemes by increasing the demand for these products. The fibers and composite products markets are where opportunity exists for hardwoods; pulp and paper, chip wood, and engineered products, i.e., oriented-strand board, particleboard, etc. Fiber and composite are often used interchangeably, but the Forest Service draws a distinction between the terms. While fiber products are made from byproducts of other processing systems, composite products are made from specifically selected roundwood.

Figure 19 – USFS Guide to Timber Grades



(Source: USFS Guide to Hardwood Grading)

Softwoods can be categorized as sawlogs if over 10 inches in diameter and relatively free to bends, kinks, and knots; fuelwood if the diameter of the wood is large enough for splitting; or polewood if the tree is very tall, straight and thin. Softwoods are not commonly used as veneer, pallets, furniture, etc.

Below are listed the general conversion factors that will be used in this study. Density of wood varies greatly between species, and the makeup of the material being studied (bark vs. clean wood vs. tops and limbs) can also skew conversion factors. As well, the moisture content of wood will have a large effect on weight. Fresh cut wood will contain 40-50% water, greatly increasing the density without changing the BTU content of the material. All figures in this study, unless otherwise denoted, are given in 'green' or wet form and unusable water weight is assumed. The figures given below are generally accepted standards.

Table 9 – Green Wood Conversion Factors

POUNDS PER CORD (A)	TONS PER CORD	TONS PER M^3 (B)	FT^3 PER TON (B)	FT^3 PER CORD (STACKED)
5,500	**2.5**	**0.725**	**48.78**	**128**

A. Measurement is based on a rough average of weights measured in pulping experiments at the U.S. Forest Products Laboratory (Taras, 1956).
B. Measurements based on U.N. Food and Agriculture Organization (FAO) Unified Bioenergy Terminology (UBET), 2004.

Woody Biomass Supply and Demand Overview

Minnesota has some of the nation's healthiest and most productive forests. Forestland in the state has been steadily increasing over the past 50 years, primarily due to the conversion of marginal farmland back to forested land. Post-harvest regenerative tree planting programs help to retain and, in spots, increase forested acreage. The most abundant forest types are mixtures of hardwood varieties; maple-basswood, aspen-birch, and oak-hickory. Total forest land is 16.3 million acres, and the annual timber harvest is around 50,000 acres.

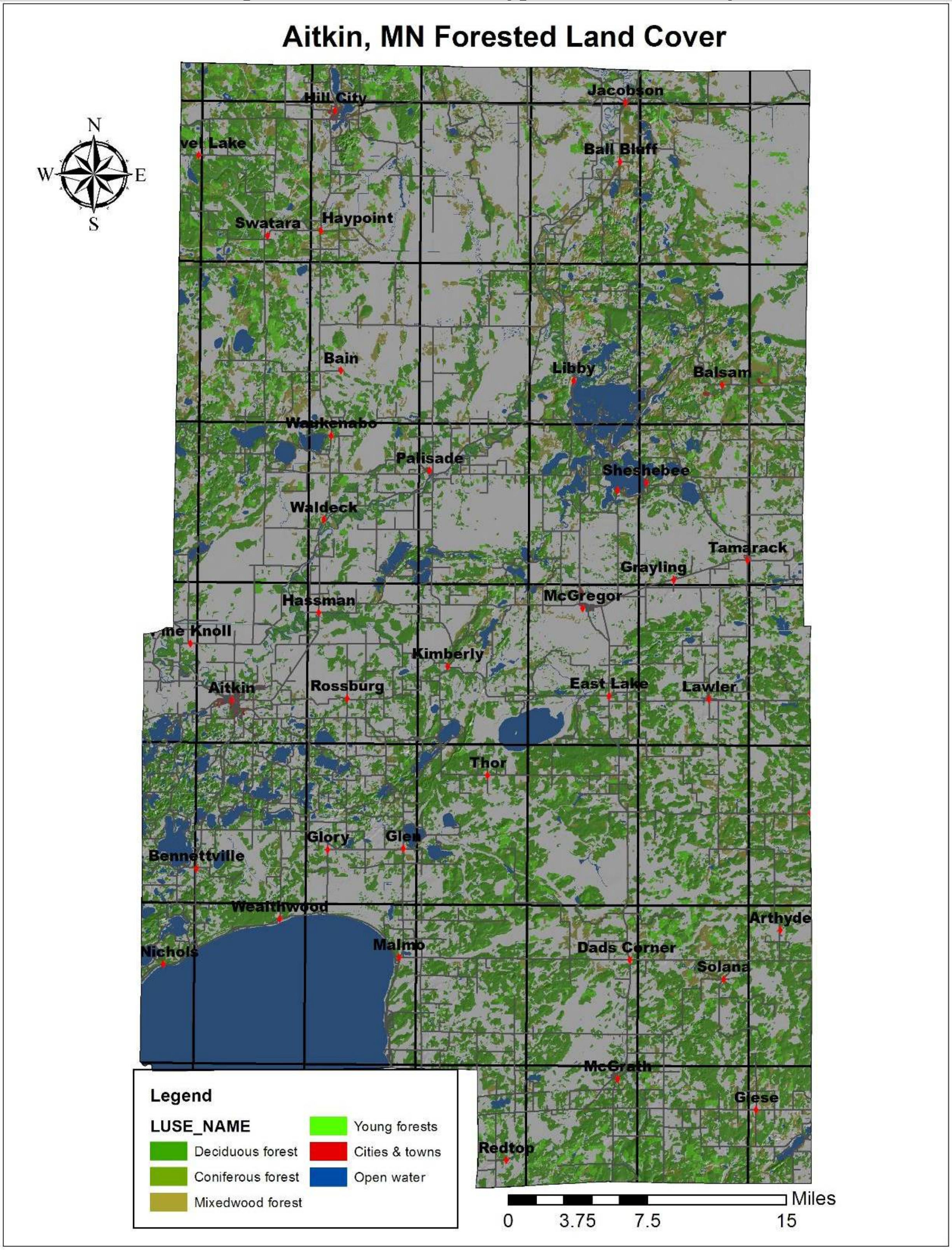
The Minnesota timber harvest has been relatively steady over the years, decreasing in saw log production but increasing in pulpwood production. 2004's harvest was 275 million cubic feet. Pulp represents 82% of the total roundwood production in Minnesota. Minnesota is the leading pulpwood producer in the region, far surpassing Canada and Wisconsin. Despite these seemingly positive numbers, the state forestry industry appears to be in steady decline in terms of jobs and profits earned.

There are over 400 mills in Minnesota classified as sawmills, pulpwood mills, or other types of mills[5]. The 'other' classification, which has seen a doubling of numbers of mills between 2001 and 2004, are the likely competition for the Project's feedstock.

Figure 20 shows the distribution of forestland in Aitkin County, including deciduous, coniferous, mixed, and young / regenerating forest types.

[5] Reading, Jacobsen, "The Minnesota Timber Industry – An Assessment of Timber Product Output and Use, 2004" USDA Forest Service Northern Research Station, 2009.

Figure 20 – Forest Cover Types in Aitkin County



(Source: BBI)

Roundwood Biomass Feedstocks

One of the foremost goals of the Project is to utilize natural resources that do not compete with existing markets or industries. The majority of the roundwood timber harvest will not be available as feedstock for biomass projects because of these non-compete goals. As well, because of these established markets most roundwood is priced out of the competing range of bioenergy projects. However, the byproducts of the timber harvesting and processing industry are prime targets for feedstock acquisition. In addition, there may be some low-grade timber that is passed over by the industry that is suitable for biomass utilization. While roundwood is usually not the cheapest biomass feedstock available, the consistency of product and highly developed collection methods make it worth looking into.

Table 10 shows the volumes of timber available and utilized in the local and regional areas surrounding Aitkin County. The figures were gathered through the USDA Forest Service Timber Product Output Report program.

The volume of wood cut and removed from Aitkin County forests as roundwood annually is over 11 million cubic feet, or 225,500 tons of biomass assuming a density of 0.725 tons/m^3 (0.0205 tons/ft^3), per the standard tree density determined by the FAO Unified Bioenergy Terminology committee. Consistent with the tree species available in Minnesota, the primary tree species harvested are hardwoods. Aspen is by far the leading individual tree species, accounting for 7.3 million cubic feet of roundwood removal, followed by oak and birch varieties. True firs and red pine are the most-harvested softwood varieties in Aitkin County.

Table 10 – Volume of 2007 Roundwood Timber Harvest in Aitkin County

Species	Saw Logs	Veneer Logs	Pulpwood	Composite Products	Fuelwood	All Products
	Thousand Cubic Feet					
Softwood						
Cedars	0	0	0	0	0	0
True firs	9	0	438	0	0	447
Larch	0	0	0	0	0	8
Jack pine	60	0	39	6	0	105
Red pine	67	0	158	0	0	225
White pine	39	0	3	0	0	42
Spruce	8	0	123	0	0	131
Total softwoods	**184**	**0**	**760**	**6**	**1**	**959**
Hardwood						
Ash	222	38	0	0	121	381
Aspen	552	31	3,892	2,827	32	7,335
Basswood	161	41	0	0	11	213
Yellow birch	0	0	0	0	0	0
Other birch	72	70	48	202	176	567
Black cherry	0	0	0	0	0	0
Elm	4	0	0	0	489	493
Hard maples	16	6	3	10	100	135
Soft maples	3	0	0	0	62	65
Select red oaks	372	0	0	0	319	690
Other red oaks	11	0	0	0	9	20
Select white oaks	26	0	0	0	184	209
Other hardwoods	0	0	0	0	0	1
Total hardwoods	**1,439**	**187**	**3,943**	**3,039**	**1,502**	**10,110**
All Species	**1,622**	**187**	**4,703**	**3,045**	**1,503**	**11,068**

MBF= Thousand board feet (1/4 inch rule); MCF= Thousand cubic feet; Cords= standard cords 4'x4'x8'. Numbers in rows and columns may not add to totals due to rounding.

(Source: USDA Forest Service)

The largest contributors to this figure are the not saw logs, traditionally the primary forest product. In Aitkin County, pulpwood and composite products' grade wood command the largest harvest volumes, accounting for approximately 7.7 million cubic feet of roundwood timber product, or 143,500 green tons of biomass material.

The Project may also seek timber that is cut and then not used by the industry, or timber sales that go unsold. Low-value roundwood that is passed over by the timber industry in timber sales can be bought and obtained by contract harvest, thereby providing additional income for logging companies, while at the same time meeting the local harvest goals. Table 11 compares the Aitkin County Forest Management Tactical Plan's goals to the 2008 timber harvest and the 2003-2007 5-yr average harvest.

Table 11 – Aitkin County Timber Sales vs. Harvest Goals

Cover Type	Annual Harvest Goal 2008-2010	2008 Harvest	2003-2007 Avg Harvest
Ash. Lowland Hdwds	300	337	157
Aspen	1,250	1,102	1,226
Balsam Fir	100	119	116
Birch	400	119	164
Black Spruce	80	0	118
Jack Pine	10	5	19
Northern Hardwoods	1,350	1,050	1,040
Norway Pine	140	190	107
Oak	250	252	342
Tamarack	160	7	60
White Spruce	40	252	33
TOTAL	**4,080**	**3,192**	**3,381**

(Source: Aitkin County Land Department 2008-2010 Tactical Forest Plan)

The 2008 harvest and the 5 previous years' average harvests have fallen short of the county harvest goals. Specifically, the cover types Basswood / Ash / Lowland Hardwoods, Birch, Tamarack, and Northern Hardwoods appear to be underutilized, with over 700 acres of planned timberland going unsold each year. These tree species with minimal demand provide an opportunity for biomass utilization. Conservatively figuring 50 tons per acre, purchasing these timber sales to supply the Project would yield 35,000 tons or more of woody biomass.

Some of this tonnage can also fall under the heading of thinning and stand improvement harvests (TSI). The Onanegozie Resource Conservation and Development Council (ORC&D) conducted an independent investigation, sponsored by the MNDNR, to review the biomass resource availability in the 7-county Onanegozie district. This report estimated that Aitkin County has nearly 30,000 tons per year of TSI wood available. The Project can obtain high-quality roundwood at competitive prices, and will not adversely impact the forest ecology and regeneration balance. As well, these harvests will provide opportunities for additional cutting jobs to the flagging timber industry.

Logging Residue Biomass Feedstocks

Although the majority of the Aitkin County tree harvest goes to non-traditional uses, it can be expected that these products have established markets and pricing beyond the means of a biomass energy product. Table 12 details the ownership and volumes of forest residues and other removals alongside the roundwood harvest figures. The logging residue produced in Aitkin County is 4.9 million cubic feet of wood, equaling ~100,000 green tons of potential biomass resource annually. Again, the bulk of the harvest is hardwood varieties and is relatively equally split between public and private lands.

Table 12 – Logging Residue Volume in Aitkin County

Ownership Group	Species Group	Roundwood Products	Logging Residues	All Removals
		Thousand cubic feet		
Public	Softwood	570	281	850
	Hardwood	5,789	2,672	8,461
	Total	**6,358**	**2,952**	**9,311**
Private	Softwood	389	188	578
	Hardwood	4,321	1,787	6,108
	Total	**4,710**	**1,975**	**6,685**
All Ownerships	**Softwood**	**959**	**469**	**1,428**
	Hardwood	**10,110**	**4,459**	**14,568**
	Total	**11,068**	**4,928**	**15,996**

(Source: USDA Forest Service)

The logging residues are 'removed' from the forest stock as it is reported in the data, but not all of it is actually removed from the forest. Applying the 50% recoverable matrix determined in Section III, approximately 50,000 tons of logging residue is available for use as woody biomass.

The ORC&D investigation also reviewed logging residues in the district. The report determined that 49,770 tons per year of logging residues were potentially recoverable (Table 13), very similar to the Forest Service conclusions.

Table 13 – Logging Residue Volume in Aitkin County, ORC&D

Type	Harvest Area (ac)	Woody Debris (ton)	Debris Piles (ton)	Standing Residual (ton)	Total (ton)	Recoverable * (ton)
Aspen/White Birch	4,198	53,839	5,667	25,031	84,537	29,753
Other Hardwoods	1,025	19,708	680	13,696	34,083	10,194
Lowland Conifer	533	5,042	2,685	82	7,810	3,864
Upland Conifer	962	10,512	1,406	24,907	36,825	5,959
Totals	6,718	89,101	10,438	63,716	163,255	49,770

** (50% total not incl. Standing Residual)*

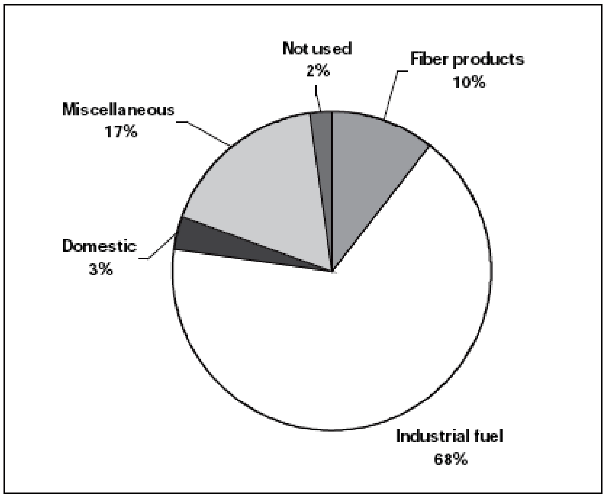
(Source: USDA Forest Service)

50,000 tons of logging residues are available for biomass utilization in Aitkin County annually. The Project cannot expect to recover the full amount of logging residue available due to the competition that will arise for an essentially free resource, however at present the Aitkin County land managers estimate that only 1% of the resides are being collected and removed from the forestland. The Project can reasonably expect to capture at least 75% of the available market going forward, or approximately 37,500 tons per year of logging residue.

Timber Industry Byproduct Feedstocks

Statewide, Minnesota's mills produced 1.9 million green tons of mill wastes in 2004, according to the latest available accounting of such figures. The Minnesota Timber Industry TPO Report surveyed the majority of mills in the state, and discovered that the majority (1.3 million tons) of the mill residues went to industrial fuel use (Figure 21). However, this number is somewhat misleading, as over 1 million tons of this industrial fuel was burned in the mills themselves. Residential fuel use of the mill wastes, primarily in the form of pelletized fuel, was 71,000 tons statewide, and another 115,000 tons was sold to third parties.

Figure 21 – End Use of Minnesota Timber Mill Residues



(Source: USDA Forest Service)

Aitkin County boasts 26 mills, though many are small and medium-sized mills. The volume of timber industry byproducts and waste products produced in Aitkin County is a smaller subset of the statewide total production. If obtainable, these wastes are a viable feedstock source for the project. Approximately 11,000 dry tons of waste are produced by the industry annually. The majority of these waste byproducts are in the form of coarse woody residues.

Sawdust is a very high-quality biomass for making pellets; particle size is already at the level needed for pelletizing and ash and moisture contents are very low. Savannah Pallets sells their coarse sawdust ‘chips’ at 4% ash and an energy content of 8,500 BTU/lb. This is especially beneficial to grassy biomass pellets. Grass has a high ash content and bonds poorly, both of which will be helped by the addition of sawdust into the pellet blend.

Competition from the operational, under construction, and planned pelletizing mills in the area will raise the price and reduce availability of mill residues flowing to the Project. Over 30 biomass energy or fuels projects already exist in the state of Minnesota. Nearby Aitkin County, pellet mills and biomass energy projects have been installed in Marcell, Virginia, and Hibbing, and mills are proposed in Duluth and Mountain Iron. Local mills report that mill byproduct sales have been steadily increasing in volume and price over the past several years. Savannah Pallets separates their sawdust by particle size and originating species to increase the value of the products. However, there are currently no pellet mills in Aitkin County, and the project can afford to pay a premium over the out-of-county pellet mills in exchange for the reduced shipping distance and corresponding fees. The accessible timber industry byproduct material in Aitkin County is estimated at 50% of the total available volume, or 5,500 tons per year.

Restrictions on Accessibility or Availability of Forest Residue Feedstocks

Forest health in Aitkin County is quite good. The only insect species causing noticeable damage to forest in Aitkin County is the larch casebearer, only impacting the northwestern corner of the county. The area is a moderate risk to emerald ash borer, but outbreaks have yet to be recorded.

The main restriction to accessing roundwood and logging residue biomass in Aitkin County has to do with ground stability. Much of the forestland the Project will be aiming for is on soft, moist soils which are close to, if not classified as, wetlands. The loggers cutting or collecting the biomass will need to wait until winter and ground freeze before commencing operations. This is not a new tactic, however, much of the area's timber operations work in this fashion already. The project site will need a large lay-down area to collect most of a year's worth of product in the winter months.

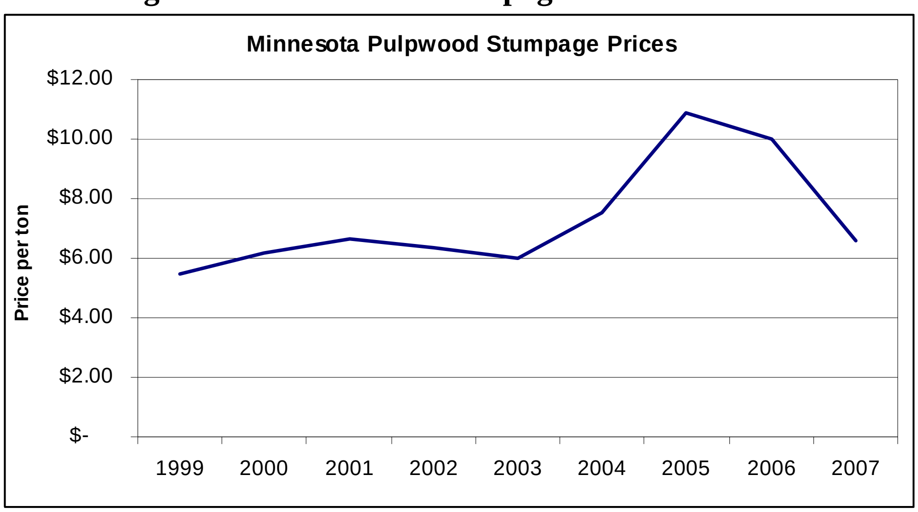
Woody Biomass Pricing

Woody biomass pricing will vary depending on the type of wood product delivered. Roundwood biomass will follow established markets, while logging residues and mill residues do not have formal markets for trade, and will follow other pricing patters. Mill residues are currently sold for a variety of uses, though pricing is established on a case-by-case basis. Logging residues are not currently harvested, and pricing is a function of the cost of removal and delivery to the plant gate.

Roundwood Biomass Pricing

Pulpwood pricing in Minnesota has experienced a decline in recent years, after peaking in 2005 and 2006. Stumpage prices can be a useful indicator of finished product pricing. Figure 22 shows Minnesota stumpage pricing from 1999-2007, as an average of all species of tree harvested. The current average stumpage price in the state is $6.07, down form $10.876 in 2005.

Figure 22 – Minnesota Stumpage Prices 1999-2007



(Source: MNDNR 2008 Forest Resources Report)

Table 14 lists prices for various species of pulpwood-grade logs to mills in the Lake State area, as gathered by forest resource consulting firm Prentiss and Carlisle in their Timber-Mart North Price Report. The cheapest delivered wood species is basswood, at $59/cord ($24/ton) delivered. The most expensive species are spruce and fir at $81/cord ($33/ton). Timber-Mart North reports that prices have been relatively unchanged when averaged over the past decade; mid-1990s prices were in the $55-$75/cord price range for delivered pulpwood.

Table 14 –Pulpwood Delivered Prices

Species	$ per cord
Jack Pine	$73
Red Pine	$72
Spruce/Fir	$81
Other Softwood	$62
Aspen	$71
White Birch	$79
Basswood	$59
Oak	$70
Other Hardwood	$76
Average Delivered	**$71**

(Source: Timber-Mart North)

The estimated delivered cost of roundwood pulpwood to the plant gate is $28.50/ton for raw or green wood containing approximately 50% moisture. On a dry basis, the value of roundwood pulpwood is set at $57/ton. The delivered price assumes a local shipping distance.

Logging Residue Pricing

Data is very limited regarding logging residue harvest and shipping costs, as these residues have until recently been under-utilized waste products. However, studies have been conducted to test the various harvesting methods and produce initial cost estimates. Table 15 is one such experiment, conducted by the University of Minnesota's Center for Integrated Natural Resources & Agricultural Management (CINRAM). The report estimates that the total delivered cost of logging residues are currently between $26-$32/ton. Other reports, including a study conducted for the Presque Isle Power Plant in Wisconsin, have concluded that approximately $30/ton for delivered product could be expected.[6] However, in the future as harvesting methods, supply lines, and established markets are developed, the equipment and labor costs are expected to go down, making logging residues a more attractive option. Note that logging residues are only considered from the local and county-regional area, logistical problems preclude harvesting and shipping of logging residues for long distances. As well, the prices estimated are for raw or green wood. At an estimated 50% moisture content, the price of logging residues delivered to the plant gate is estimated at $60/ton.

[6] Kramer & Weitner, "Woody Biomass Resource Assessment for Presque Isle Power Plant" Energy Center of Wisconsin, August 2008.

Table 15 – Estimated Harvest Costs for Logging Residues

Cut-to-Length – Harvester ~ Green Tons

	Cords/Acre	Tons /Acre	Harvesting	Forwarding	$ to Chip /Ton	Transport to Mill	$/Ton Stumpage	Total Price/Ton
Selective Cut - Hardwood, small area of clearcut Aspen	14 cords/acre 75% - Hardwood 14% -Aspen 11% -Balsam	11 tons	$0/ton	$12.30/ton	$5/ton	$9/ton	$0/ton	$26.30/ton
Land Clearing, Mainly Hardwood	29 cords/acre 84% - Hardwood 16% -Pine/Fir	33 tons	$0/ton	$9.20/ton	$5/ton	$12/ton	$0/ton	$26.20/ton
Shelterwood Harvest - Oak and Red and White Pine Left, Hardwood, Aspen, and Jack Pine Cut	12 cords/acre 40% -Hardwood 41% -Aspen 19% -Jack Pine	8 tons	$0/ton	$14.80/ton	$5/ton	$12/ton	$0/ton	$31.80/ton

(Source: "Economics of Biomass Harvest" CINRAM U of Minn.)

Mill Residue Pricing

Mill residue sales are private transactions that do not follow regional or national market trends. Several local mills, were surveyed to determine whether a baseline pricing structure exists. Prices were extremely varied, from as low as $10/ton up to $30/ton for sawdust, but with a relatively consistent price of $15/ton quoted. Shipping the material will cost about the same as shipping chipped materials, $10/ton for localized delivery (up to 100 miles). Considering that mill residues contain 50% moisture, the price per dry ton is $50. The delivered cost of mill residues is estimated at $50/ton.

Conclusion: Forest Residue Feedstock Potential

Minnesota's forest land covers over 16 million acres. Annually roughly 50,000 acres are harvested. Opportunities exist for the Project to obtain biomass through roundwood cutting of un-used timber sales, TSI thinning operations, logging residues, and mill wastes.

Roundwood timber is the highest quality wood that may be used as biomass for energy production, and therefore is also the most expensive. However, there is a significant acreage designated in the county timber management plan that goes unsold each year. In Aitkin County, there are over 700 acres of timber sale available or roughly 35,000 tons of biomass annually.

There are over 100,000 tons of logging residues produced in Aitkin County logging operations annually. 50% of that material is considered technically feasible to recover and beneficial to the recovery of the impacted land. Competition, though sparse at the moment, will likely be increasing in years to come. The Project can expect to capture at least 75% of the market going forward or 37,500 tons of logging residues annually.

Mill wastes produced in Aitkin County are approximately 11,000 tons per year. Competition for these materials is high, with the majority of product going out of the county. The Project can expect to capture half of the market by paying the premium lost in shipping costs by its competitors. The high quality of the sawdust makes it worthwhile to pay what it takes to capture that resource. The Project can expect to capture approximately 5,500 tons of sawdust and other mill waste material annually.

The total accessible woody biomass potential in Aitkin County is **78,000 tons** annually.

VII. PROJECT SCALE AND FEEDSTOCK SUPPLY

Feedstock for the plant is envisioned to be a mixture of herbaceous grass and shrub materials, combined with several forms of woody biomass. As the plant moves towards completion the ratio of the mixture may change based on the pricing and availability of the feedstocks.

Plant Scale

The available and accessible feedstocks to be utilized by the proposed facility are analyzed in the previous sections. As analyzed, the total tonnage of the feedstocks available and accessible per year are listed below.

Table 16 – Aitkin County Facility Feedstocks Available

Fuel Type	Feedstock Available (as rec'd)	Moisture Content	Feedstock Available (dry basis)
Grasses	75,000	15%	63,750
Roundwood *(TSI, undersold timber)*	35,000	50%	17,500
Logging Residues	37,500	50%	18,750
Mill Residues	5,000	50%	2,500
Total	**152,500**	**---**	**102,500**

At its maximum feasible size, a biomass utilization plant in Aitkin County can conceivably throughput 152,500 wet tons per year (102,500 tons on a dry basis). The undeveloped market and processes of several key plant feedstocks speaks to a need for caution when calculating the size of the operation. The economic health of a project suffers when the requisite amount of feedstock cannot be moved to the plant for a reasonable price; a condition known as stranded capital. On the other hand, significant economies of scale exist in this industry. Sizing a plant too small, and missing potential revenue streams, can also reduce the profitability of a project. The feedstock analysis conducted for this study trends to the conservative.

For the purposes of this analysis, plant scales of 100,000tpy and 50,000tpy of feedstock input (as received or wet tons basis) will be analyzed. The larger scale utilizes a high percentage of the feedstocks available in the area, and is on the larger scale of currently constructed biomass utilization facilities. An analysis of a 50,000tpy facility will be included for comparison purposes, to determine if a smaller-scale plant with reduced capital outlay and feedstock acquisition logistics can also be profitable.

Potential Feedstock Blend

Table 17 shows the anticipated feedstock mix for the Aitkin project. The ratio of inputs was determined by the availability of feedstocks for the larger plant scale scenario. This ratio was carried through to the smaller plant scale scenario to simplify further composition and processing cost analyses. The feedstock mix is set at 63% grassy biomass, 17% roundwood or whole trees, consisting of TSI thinning and undersold timber, 15% logging residues, and 5% mill residues.

Table 17 – Aitkin County Facility Feedstock Blend

Fuel Type	Feedstock Available (as rec'd)	Blend %	Feedstock Utilized (50K TPY)	Feedstock Utilized (100K TPY)
Grasses	75,000	63%	31,500	63,000
Roundwood *(TSI, undersold timber)*	35,000	17%	8,500	17,000
Logging Residues	37,500	15%	7,500	15,000
Mill Residues	5,000	5%	2,500	5,000
Total	**152,500**	**100%**	**50,000**	**100,000**

The smaller plant scale has more flexibility to choose its feedstock blend ratios. As the project develops further, the feedstock composition may vary based on the input requirements of the chosen conversion technology. In either scenario, grassy biomass utilization should be the majority of the feedstock mix, both due to its relative abundance and minimal product competition as well being the lowest-cost feedstock. Many conversion technologies have difficulty processing 100% herbaceous matter, however. Regardless of the price and availability of grass biomass, a component of woody biomass should be included.

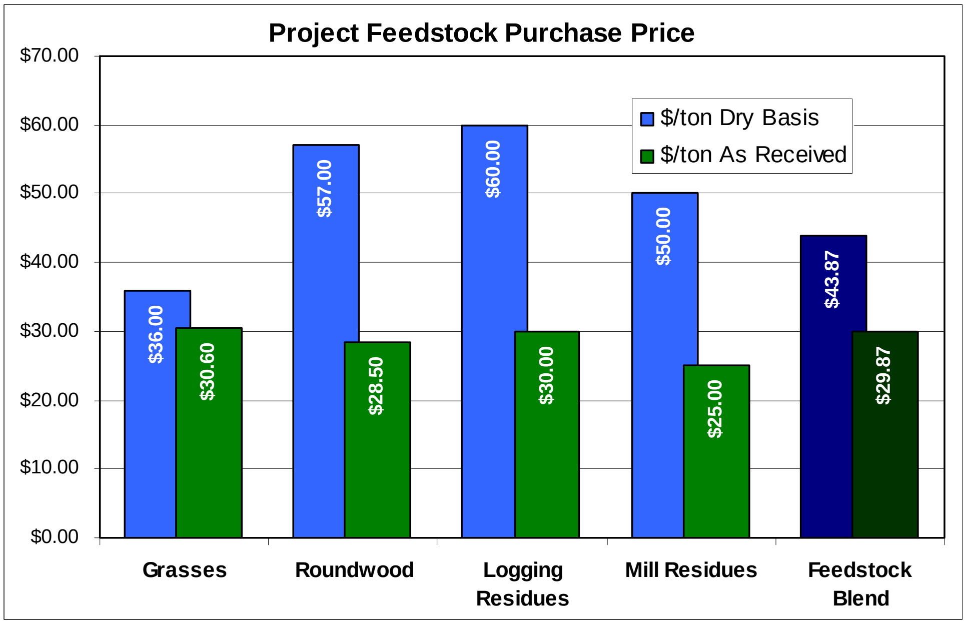
Feedstock Blend Price

According to the feedstock blends noted above, and the prices for various feedstock types calculated in the previous sections, the total price of feedstock at the plant gate is $43.87/ton. Table 18 and Figure 23 show the breakout of feedstock pricing per ton of feedstock utilized by the project.

Table 18 – Project Feedstock Price (Dry Basis)

Fuel Type	$/ton As Received	$/ton Dry Basis	Blend %	$/ton of Feedstock Blend (Dry Basis)
Grasses	$30.60	$36.00	63%	$22.68
Roundwood	$28.50	$57.00	17%	$9.69
Logging Residues	$30.00	$60.00	15%	$9.00
Mill Residues	$25.00	$50.00	5%	$2.50
Total	**---**	**---**	**100%**	**$43.87**

Figure 23 – Feedstock Prices; Actual and Dry Basis



Feedstock Blend Composition

According to the blend ratios calculated above, the feedstock composition of the proposed plant will feature 63% grassy biomass, 17% roundwood or whole trees, consisting of TSI thinning and undersold timber, 15% logging residues, and 5% mill residues. This blend was compared to the available compositional analysis for various feedstocks. Part of the information was received from NREL and part from AURI's pelletizing laboratory in Waseca, MN. Actual analysis of the feedstocks in Aitkin County was not available for the study. It is important to note that a combination woody biomass and grass and shrub feedstock used by the project will have unique characteristics, depending on the species of wood and grasses that are common to the Aitkin County area, as well as the portion of the plant mass (i.e., heavily barked logging residues versus roundwood). Table 19 shows the characteristics of the feedstocks proposed for the project, based on the available compositional analyses.

Table 19 – Compositional Analysis of Project Feedstock Blend

Fuel	Wood			Grass	Total
Sub-Type	**Chips**	**Forest Residues**	**Sawdust**	**Big Bluestem**	*(by Feedstock Blend)**
Carbon	50.82	50.31	51.02	44.40	**46.71**
Hydrogen	5.89	4.59	5.80	6.10	**5.82**
Oxygen	41.08	39.99	38.54	42.60	**41.75**
Nitrogen	0.59	1.03	0.46	0.80	**0.78**
Sulfur	0.02	0.11	0.05	0.10	**0.09**
Ash	1.60	3.97	4.13	6.10	**4.92**
Moisture (as rec'd)	6.74	48.91	52.63	12.00	**18.67**
Chlorine %	0.04	0.04	0.02	0.18	**0.13**
SiO2	0.88	17.78	35.36	---	---
Alkali, Lb/MMBtu	0.40	0.49	0.35	---	---
HHV, Btu/lb	8,139	8,670	8,760	8,020	**8174.73**

** Feedstock blend assumes 17% Chips, 15% Forest Residues, 5% Sawdust, and 63% Grass*

(Source: NREL, AURI)

According to this analysis, the combined values of the mixed product streams results in a final plant feedstock with moisture-free higher heating value (HHV) of 8,175 BTU/lb, an excellent energy density for biomass products. It does not appear the feedstock blend will be able to compete with pure roundwood biomass due to product impurities. The feedstock blend will potentially contain a relatively high ash content of 4.92%, and chlorine content of 0.13%. Silica (SiO_2) content is also above roundwood levels; silica content was not available for the bluestem species, which may contain high levels of silica, given such high ash content. The effects of the BTU content of the feedstock and its impurities levels will be discussed in more detail as they pertain to finished products and conversion technologies.

VIII. PRODUCT MARKET REVIEW

This analysis will review the market supply, demand, and pricing trends for the primary products manufactured by the proposed project.

There are two biomass conversion technologies under review for the proposed project, pelletization and combined heat and power (CHP) energy production. The two products to be reviewed are pellets sold to the commercial and industrial solid fuel market, and CHP energy supplied to the grid. Both involve production of thermal and electrical energy as end products, CHP directly and pellet manufacturing through combustion of the pellets produced. Therefore a discussion of the energy production market and incentives for the production of biomass-based energy will be included as relative to both product markets.

Renewable Portfolio Standards

Renewable energy generation is becoming an essential and sizeable addition to the U.S. energy portfolio. Governments are recognizing the need to transition to renewable energy sources, and are applying mandates to accelerate the process. Twenty-five states and the District of Columbia have Renewable Portfolio Standards (RPS) in place. An RPS is a policy requiring electricity providers obtain a minimum percentage or amount of power from renewable energy resources by a specified date, through generation or, in some cases, power purchasing agreements. The states that have RPS represent more than half of the electricity usage in the U.S. Additionally, four other states have non-binding goals for renewable energy, rather than an RPS.[7] Unprocessed woody biomass and wood pellets represent potential renewable fuels that will help electricity providers meet the RPS requirements. The following table shows the states with an RPS.

Table 20 – State RPS Requirements by Enactment Year

Year[a]	State (Maximum RPS Amount)
N/A	Iowa (105 MW)
2009	Massachusetts (4%)
2010	California (20%)
2013	New York (24%)
2015	Montana (15%); Nevada (20%); Texas (5,880 MW); Wisconsin (~10%)
2017	Maine (10%)
2019	Delaware (20%)
2020	Colorado (20%); Connecticut (23%); Hawaii (20%); New Mexico (20%); Pennsylvania (18%); Rhode Island (15%); Washington (15%)
2021	New Jersey (22.50%); North Carolina (12.50%)
2022	District of Columbia (11%); Maryland (9.50%)
2025	Arizona (15%); Illinois (25%); **Minnesota (25%)**; New Hampshire (16%); Oregon (25%); Utah (20%)

[a] When maximum RPS goes into effect.

(Source: EERE)

[7] Illinois (25% by 2025), Missouri (11% by 2020), Vermont (10% by 2013), and Virginia (12% by 2022).

By 2025, if all current RPS statues are satisfied, approximately 16% of the electricity in the U.S. will come from renewable sources. Therefore, the easily accessible market for renewable energy is the disparity between current generation and future requirements. In 2007, the U.S. generated the most renewable energy in the past 5 years; however, the largest percentage of renewable energy generation was in 2008 (Table 21).

Table 21 – U.S. Energy Generation by Fuel Type (Million Megawatthours)

Year	Coal[a]	Petroleum[b]	Natural Gas	Nuclear	Net Hydro	Other Renewable[c]	Total[d,e]	% Renewable
2004	1,978	121	710	789	260	83	3,971	2.09%
2005	2,013	122	761	782	264	87	4,055	2.15%
2006	1,991	64	816	787	283	97	4,065	2.37%
2007	2,016	66	897	806	241	105	4,157	2.53%
2008	1,994	45	877	806	242	124	4,110	3.01%

[a] Anthracite, bituminous, sub-bituminous, lignite, waste coal, and coal synfuel.
[b] Distillate fuel oil, residual fuel oil, jet fuel, kerosene, waste oil, and coke.
[c] Also includes blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels.
[d] Wood, black liquor, other wood waste, biogenic municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind.
[e] Also includes non-biogenic municipal solid waste, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, tire-derived fuel, and miscellaneous technologies.

(Source: EIA)

In 2008, 3% of U.S. electricity came from renewable sources. Assuming 2008 levels, currently enacted RPS necessitate an additional 623 million megawatthours of electricity derive from renewable sources by 2025. Put another way, that represents the construction or conversion of approximately 76,819 MW of generating capacity (assuming plant operations 8,400 hours/yr).

Minnesota Market for Renewable Energy

Minnesota's RPS is governed by statue §216B.1691. It defines the eligible energy technologies for satisfying the RPS as solar, wind, hydroelectric (capacity <100 MW per each facility), biomass, and/or hydrogen generated from an approved source. The statute requires electric utilities to generate or procure at least the following renewable energy:

- 2012, 12%;
- 2016, 17%;
- 2020, 20%; and
- 2025, 25%.

There is a separate requirement for electric utilities that owned nuclear power generating facilities. If the utility owned a nuclear plant as of January 1, 2007, their standards are as follows:

- 2010, 15%;
- 2012, 18%;
- 2016, 25%; and
- 2020, 30%.
- By 2020, at least 25% of the renewable energy (7.5% total energy) must be wind-derived.

There is only one utility company with nuclear plants in Minnesota—and thereby having the 30% RPS. However, it represents 54% of the state's installed generation capacity. Because of the different RPS for nuclear power owning companies, this company has to generate or purchase 30% renewables by 2025; 25% or which must be wind generated. Therefore, even though these companies have larger net renewable requirements, the wind requirement reduces the statewide available capacity for other renewables (like biomass, wood pellets, etc.) to 23.7%.

In addition, in the case of blending or co-firing an approved fuel, only the electricity generated by the approved fuel in that operation is eligible for inclusion under the statute. For instance, if a 90% coal/10% wood pellet blend generates 100 units of electricity, only 10 of those units count towards the RPS requirement.[8]

The Minnesota Department of Commerce is responsible for enforcing the RPS requirements as published in the statute. If an electric utility is non-compliant, they can be ordered to construct facilities, purchase credits, or to pursue other activities to reach compliance. On the other hand, the commission responsible for enforcement may also modify or delay the implementation if it determines such action is in the best public interest. For additional details, see Appendix E for a copy of the statute. As noted above, Minnesota's RPS requires 25% renewable energy content in electricity generation by the end of 2025. The following table shows Minnesota's 5-year historical energy generation characteristics.

Table 22 – Minnesota Energy Generation (Million Megawatthours)

Year	Fossil Fuel[a]	Nuclear	Biomass[b]	Other Renewables[c]	Other	Total	% Renewables
2003	76.7	26.8	2.3	3.6	0.66	110	5.3%
2004	72.5	26.6	2.0	3.1	0.58	105	4.8%
2005	72.9	25.7	2.1	4.7	0.65	106	6.7%
2006	72.3	26.4	2.0	5.3	0.60	106	6.8%
2007	72.9	26.2	2.6	6.6	0.65	109	8.4%

[a] Fossil Fuel includes coal, natural gas, other gasses, and petroleum
[b] Biomass includes wood & wood derived fuels and other biomass
[c] Renewables includes net hydroelectric (conventional - pumped storage), geothermal, solar thermal & photovoltaic, and wind

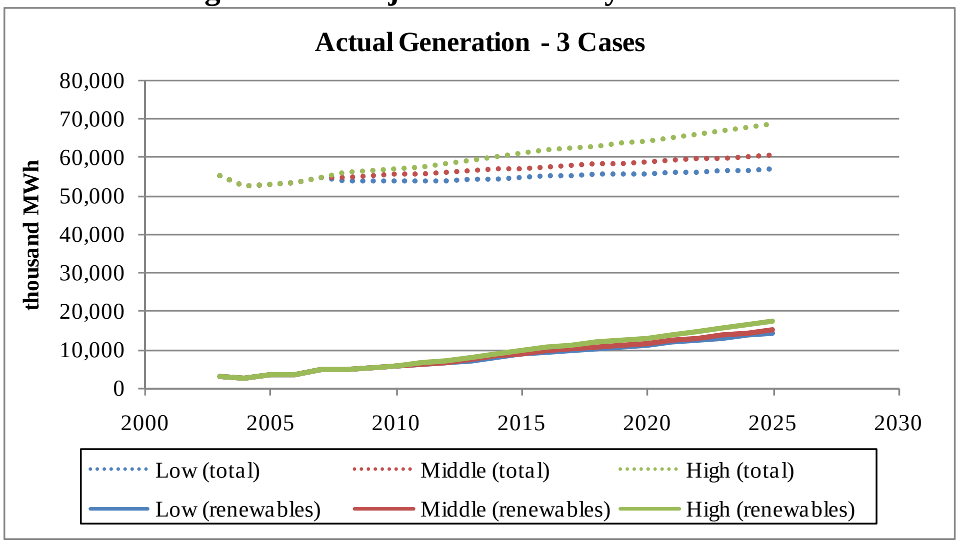
(Source: EIA)

BBI prepared low, middle, and high cases for electricity generation in Minnesota through 2025 (Figure 24). The low case assumes that statewide energy generation continues along the 5-year historical trends per each source; interestingly, these linear trends result in overshooting the RPS in 2012 (12.12%) and 2020 (20.1%). The middle case assumes that total electricity generation follows projected population growth on a per capita basis, and that the RPS benchmarks are the percentage of total. The high case makes several complex assumptions based on each source individually. The high case assumes that coal and nuclear-based generation remains constant at

[8] The Minnesota Department of Commerce has not yet determined how to determine the fuel/energy distribution. For instance, a 50/50 mixture by weight of wood pellets (~8,000 BTU/lb) and coal (~12,000 BTU/lb) would be a 40/60 mixture by energy content. Therefore, the most logical scenario would base the distribution on incoming energy content rather than weight or volume.

5-year average levels; natural gas and other gases follow per capita growth trends; petroleum-based generation follows its 5-year historical trend dropping to zero in 2011; the other category decreases very slightly following its 5-year historical trend; and that total renewables are added in to the total generation to hit the RPS benchmarks. All cases assume that the non-nuclear RPS is the standard.

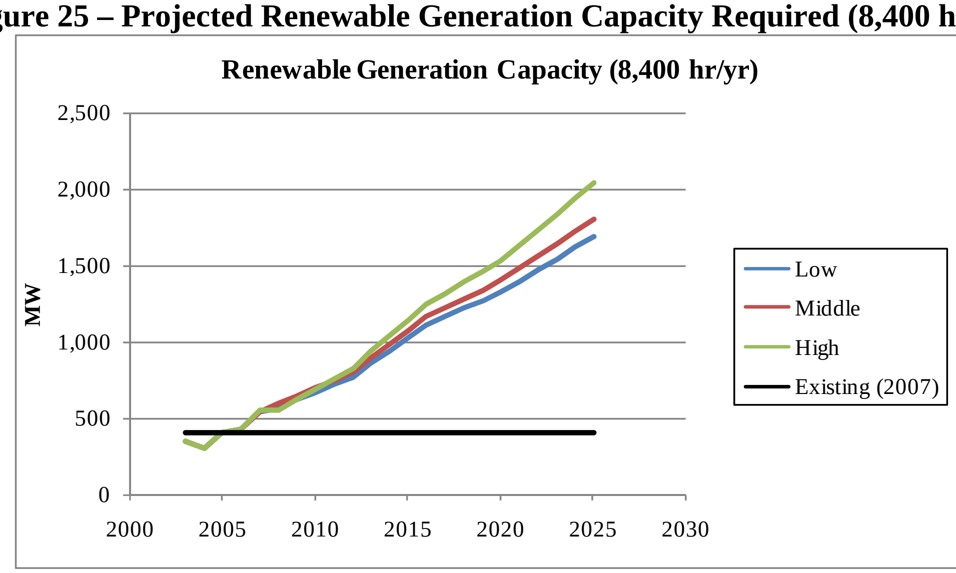
Figure 24 – Projected Electricity Generation



(Source: EIA, BBI analysis)

According to these projections, Minnesota needs between 9.6 and 12.5 million megawatthours of renewable energy production by 2025 to meet the 25% RPS. This additional generation can come from either converting existing capacity (in the case of co-firing coal and wood chips or pellets) or installing new capacity. The following figure shows the capacity addition/conversion required to generate the electricity in each case.

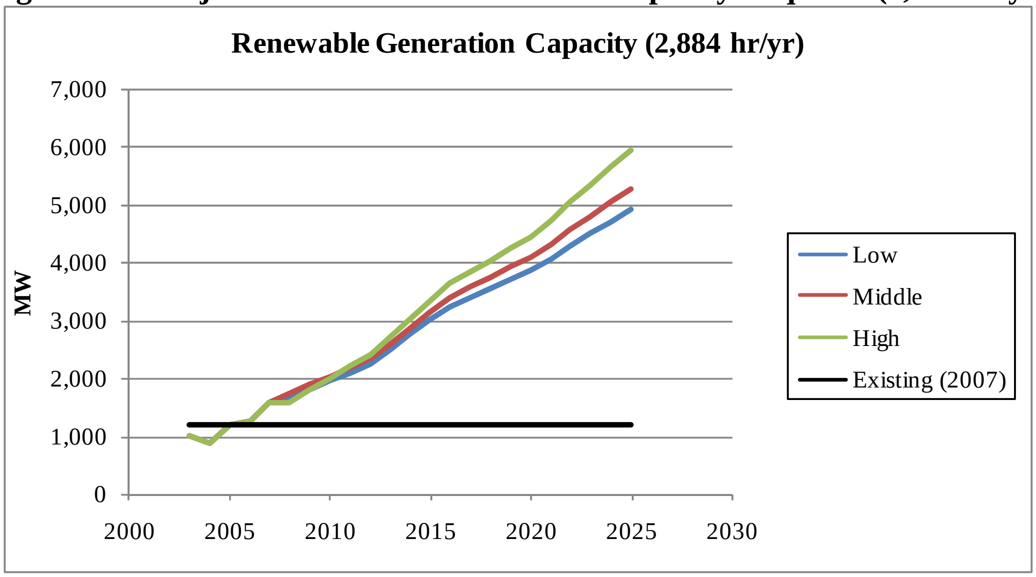
Figure 25 – Projected Renewable Generation Capacity Required (8,400 hr/yr)



(Source: EIA, BBI analysis)

Figure 25 shows capacity figures calculated by BBI based on an 8,400 hr operating year. The EIA's State Renewable Electricity Profile data for Minnesota shows that Minnesota had 1,259 MW of renewable energy generation capacity in 2006.[9] Based on Minnesota's actual renewable generation in 2006 of 3.6 million MWh, renewable generation sources in Minnesota have an average operating year of 2,884 hours. This number is low because in 2006 wind represented about 65% of Minnesota's renewable energy capacity, while generating only 57% of the state's renewable energy. Wind is a very intermittent source, and because it is currently the largest renewable source in Minnesota, and should continue to be at least a significant contributor, it is reasonable to use 2,884 hr/yr to project the upper end of the capacity requirement.

Figure 26 – Projected Renewable Generation Capacity Required (2,884 hr/yr)



(Source: EIA, BBI analysis)

Figure 26 clearly shows that even in the low and middle cases, in order to achieve the 25% RPS, between 3,300 and 3,600 MW of additional renewable capacity are needed; for the high case, nearly 4,300 MW of additional capacity. Between these two figures (Figure 25 and Figure 26), the apparent market size for this new renewable generation capacity is between 1,150 MW and 4,350 MW. This presents a great opportunity for either of the proposed project's scenarios. Whether producing the power directly, or making wood pellets for use in others' plants, this RPS-generated market has the potential to be massive.

EIA has data released in January 2009, which details planned generation capacity through 2012. Based on the data there are 372.4 MW of planned renewable capacity in Minnesota through 2009. No data on Minnesota for 2010-2012 was available. All of this capacity is wind-based.

[9] 2007 data is scheduled for release in May 2009. It was not available as of 5/13/09.

Biomass Fuel Pellet Market

Pelletizing creates a highly densified material. The chemical structure of the biomass is not significantly changed through the pelletizing process, but physical structure is altered considerably. Pelletizing processes improve handling characteristics and reduce transport costs by creating a uniform, dense fuel. Through careful management of feedstock input blends, the end product characteristics can be kept consistent despite the use of a wide range of feedstock types. Pellets are also more resistant to weather degradation than chipped, hogged, or otherwise minimally-processed biomass. Industrial power equipment that has been tailored to burn biomass sources such as wood chips can also combust pellets, opening new uses for herbaceous biomass, usually too loosely consolidated to combust effectively.

The biomass pellet fuel industry got its start in the U.S. in the early 1980s, in response to the energy price shocks of the 1970s. The industry stayed relatively small through the 1980s and 1990s, with less than a dozen commercial producers of fuel pellets, and not many more producing appliances tailored to burn the fuel. Home heating applications were the only market of size for both pellets and equipment. Since 2000, the industry has grown rapidly, partially due to increasingly volatile energy prices, advances in appliance efficiency, and policy and incentives for production of renewable energy. The industry has expanded to commercial and industrial applications as well, though the U.S. lags behind Europe in this department.

The pellet industry is dominated by woody biomass, almost completely relying on mill residue supplies (sawdust, chips, shavings, etc). Pelletizing facilities are often co-located with sawmills to easily access the waste stream. As the industry has grown, roundwood pulpwood has contributed a significant. Ag residues, grass & brush pellets compose a tiny fraction of the industry—too small to be tracked as a separate group. BBI estimates that only 2-3 mills in the U.S. use a significant amount of non-woody biomass in their processes; a handful of additional research agencies / location are studying the process and results.

Pellet Specification

The Pellet Fuels Institute (PFI), a trade association representing pellet manufacturers, industry suppliers, appliance manufacturers and retailers, released an original set of standards for the pellet industry in 1995. The standard included two grades of pellets, independent of feedstock material; Premium pellets and Standard pellets. Compliance is not mandatory—the limits and specifications are an attempt by the industry to regulate itself and avoid government intervention and forced compliance. Though limits have been issued, requirements for regular testing and the methods by which testing occurs are limited at best. Significant supplies of product not meeting PFI specification are sold to the unsuspecting residential market, often causing damage to pellet-burning appliances.

Biomass Magazine, a BBI publication, reported on the problems associated with pellet standards in the July 2008 issue.

> *The weak points of the standards were a lack of any sort of schedule of testing and acceptable test methods. "It became kind of an optional sort of thing—if you*

> *want to use them go ahead," (Chris) Wiberg, of Twin Ports Testing, says. "The Pellet Fuels Institute put them out there as standards but there was no enforcement."*
>
> *What happened is that some manufacturers wound up testing their products only once, and assumed their products would continue to match that initial analysis. "So you had people who tested their product one time and it looked like premium [grade] so they sold their pellets as premium from there on out," Wiberg says.*
>
> *After a discussion about standards at a Pellet Fuels Institute meeting, Wiberg was approached by a manufacturer who said he would have to start testing his product. "I asked if he had ever tested his product and he hadn't," he continues. "The strange thing about it was that he didn't even know he had to. When he went out for his initial order of bags, the bag supplier printed a guaranteed analysis on the bag, even though there was never an analysis of the material. So it is definitely an industry where some people think a pellet is a pellet is a pellet."*

To address these issues, the PFI is in the process of creating new standards with stricter, comprehensive testing procedures. These standards were drafted in late 2007 and finalized in June of 2008, but are still in the process if being adopted by the industry. PFI officials report that the new program has been met with positive response and is likely to be implemented industry-wide by the end of 2009. It is important to note that compliance with the standards is still not required. In the residential market, most pellet sales outlets adhere to the standards, but in the commercial and industrial markets they are considered only guidelines; test burns and specific equipment specifications determine the limits bulk purchasers require.

The new classification scheme consists of four grades of fuel pellets. The grades of pellets are Super Premium, Premium, Standard, and Utility. Table 23 is an excerpt from the "PFI Standard Specification for Residential/Commercial Fuel" guidance document, specifying the requirements of the four grades of fuel pellets.

Table 23 – Pellet Fuel Institute 2008 Pellet Standards

	Residential/Commercial Densified Fuel Standards - See Notes 1 - 9			
Fuel Property	PFI Super Premium	PFI Premium	PFI Standard	PFI Utility
Bulk Density, lb./cubic foot	40.0 - 46.0	40.0 - 46.0	38.0 - 46.0	38.0 - 46.0
Diameter, inches	0.250 - 0.285	0.250 - 0.285	0.250 - 0.285	0.250 - 0.285
Diameter, mm	6.35 - 7.25	6.35 - 7.25	6.35 - 7.25	6.35 - 7.25
Pellet Durability Index	≥ 97.5	≥ 97.5	≥ 95.0	≥ 95.0
Fines, % (at the mill gate)	≤ 0.50	≤ 0.50	≤ 0.50	≤ 0.50
Inorganic Ash, % - See Note 1	≤ 0.50	≤ 1.0	≤ 2.0	≤ 6.0
Length, % greater than 1.50 inches	≤ 1.0	≤ 1.0	≤ 1.0	≤ 1.0
Moisture, %	≤ 6.0	≤ 8.0	≤ 8.0	≤ 10.0
Chloride, ppm	≤ 300	≤ 300	≤ 300	≤ 300
Ash Fusion - See Note 8	NA	NA	NA	NA
Heating Value - See Note 1	As-Rec. ± 2SD	As-Rec. ± 2SD	As-Rec. ± 2SD	As-Rec. ± 2SD

1. There is no required value or range for Heating Value. It is required to print the mean higher heating value in BTU per pound as well as the ash content on the fuel bag label using a bar scale to represent the mean value ± 2 Std. Dev. See note 9.
2. The bag must be labeled indicating which PFI grade of material is in the bag. See note 9.
3. The bag label must also disclose the type of materials as well as all additives used. For purposes of this standard specification, additives are defined in 3.1.10. See note 9.
4. It is required that manufacturers include on their bags the PFI logo and in a printed block the guaranteed analysis of the fuel. See note 9.
5. PFI prohibits the use of any chemically treated materials. For purposes of this standard specification, chemically treated materials are defined in 3.1.11.
6. The following applies to all limits in this table: For purposes of determining the fuel grade, all properties must fall at or within the specified limits listed for a particular grade. Observed or calculated values obtained from analysis shall be rounded to the nearest unit in the last right hand place of the figures used in expressing the limit in accordance with ASTM E 29-06b *Standard Practice for Using Significant Digits in Test Data to Determine Conformance with Specifications*.
7. It is the intent of these fuel grade requirements that failure to meet any fuel property requirement of a given grade does not automatically place a fuel in the next lower grade unless it meets all requirements of the lower grade.
8. It is required to report ash fusion properties at a frequency as specified in the PFI *Quality Assurance/Quality Control (QA/QC) Program for Residential/Commercial Densified Fuels*.
9. Refer to PFI *Quality Assurance/Quality Control (QA/QC) Program for Residential/Commercial Densified Fuels* for specific labeling requirements for fuel properties and other information.

The complete guidance document is available at:
http://pelletheat.org/2/StandardSpecificationWithCopyright%20.pdf

Many foreign markets have each adopted their own standards. Germany, Austria, and Sweden have each released their own set of standards regarding fuel pellet specifications. The European Committee for Standardization (CEN), akin to the U.S. ASTM International, is developing a common European pellet standard, CEN/TC 14961. The various country standards are compared to the proposed CEN standard in Table 24.

Table 24 – European Pellet Standards

Specification	Austria ÖNORM M7135		Sweden SS 18 71 20			Germany DIN 51731 / DIN plus	CEN CEN/TS 14961:2005 Annex A
	Wood pellets	Bark pellets	Group 1	Group 2	Group 3	5 size classes [cm]	
Origin							Chemically untreated wood without bark
Size	- Pellets : 4 - 20 mm Ø max.100 mm lg.	-Briketts: 20 -120 mm Ø max. 400 mm lg.	max. 4 Ø**)	max. 5 Ø	max. 6 Ø	Length Ø HP1 >30 >10 HP2 15-30 6-10 HP3 10-15 3-7 HP4 <10 1-4 HP5 <5 0,4-1	D06 ≤ 6 mm ± 0,5 mm and L ≤ 5 x Diameter D08 ≤ 8 mm ± 0,5 mm and L ≤ 4 x Diameter
Bulk density			≥ 600 kg/m^3**)	≥ 500 kg/m^3	≥ 500 kg/m^3		Recommended to be stated if traded by volume basis
Fines in % <3mm			≤ 0,8	≤ 1,5	≤ 1,5		F1.0 ≤ 1,0 % F2.0 ≤ 2,0 %
Unit density	≥ 1,0 kg/dm^3	≥ 1,0 kg/dm^3				1-1,4 g/cm^3	
Moisture content	≤ 12 %	≤ 18 %	≤ 10 %	≤ 10 %	≤ 12 %	<12 %	M10 ≤ 10 %
Ash content	≤ 0,5 % *)	≤ 6,0%*)	≤ 0,7 %	≤ 1,5 %	>1,5 %	< 1,5 %	A0.7 ≤ 0,7 %
Calorific value	≥ 18,0 MJ/kg*)	≥ 18,0 MJ/kg*)	≥ 16,9MJ/kg ≥ 4,7 kWh/kg	≥ 16,9MJ/kg 4,7 kWh/kg	≥ 16,9MJ/kg 4,7 kWh/kg	17,5 - 19,5 MJ/kg ***)	16,9 MJ/kg 4,7 kWh/kg
Sulphur	≤ 0,04 %*)	≤ 0,08 %*)	≤ 0,08 %	≤ 0,08 %	anges	< 0,08	S0.05 ≤ 0,05 %
Nitrogen	≤ 0,3 %*)	≤ 0,6%*)				< 0,3	N0.3 ≤ 0,3 % N0.5 ≤ 0,5 % N1.0 ≤ 1,0 % N3.0 ≤ 3,0 % N3.0+ > 3,0 % (actual value to be stated)
Chlorine	≤ 0,02%*)	≤ 0,04%*)	≤ 0,03%	≤ 0,03%	anges	< 0,03	Recommended to be stated in category: CL 0.03 CL 0.07 CL 0.10 CL 0.10+ (if CL>0.10 % the actual value to be stated)
Arsenic						<0,8 mg/kg	
Cadmium						<0,5 mg/kg	
Chromium						<8 mg/kg	
Copper						<5 mg/kg	
Mercury						<0,05 mg/kg	
Lead						<10 mg/kg	
Zinc						<100 mg/kg	
EOX, extractabl.org. halogens						<3 mg/kg	
Fines. bevor delivery to costumer	max. 1 %					max. 1 %	
Additives	max. 2 % only natural		to be stated				< 2w-% of dry basis. Only products from the primarily agricultural and forest biomass that are not chemically modified are approved to be added as a pressing aids. Type and amount of additive has to be stated.
Ash melting point			temperatur to be stated				
Durability							DU97.5 ≥ 97,5

*) of dry basis **) at factory ***) witout ash and water

(Source: European Pellet Centre)

Pellet Market

The pellets produced by the proposed Project will not meet the specification for U.S. premium pellets, as long as logging residues, grasses and/or brush are used as feedstock. Using presently known technologies, only clean, white wood can meet the ash limit of premium and super-premium pellets both in the U.S. market and in Europe. The ash content of the pellets produced (4.9% ash)—considering a feedstock mix heavily weighted towards grasses and logging residue—will likely classify the pellets as 'utility' grade in the U.S. (<6%), sold as 'bark' grade in Austria(<6%), and off-graded elsewhere. This significantly affects the market the proposed Project can sell pellets into, virtually eliminating the residential market.

Thus far, the U.S. market for pellets has been limited largely to residential heating and fireplaces. Premium pellets (denoted using the old grading system) make up 95% of the organized U.S. market, estimated at 2 million tons per year. Over 80 companies are now producing pellets for sale to the residential market, according to the PFI. The majority of these plants are scaled at around 25,000 tons per year of production.

Commercial or industrial process heat applications are a smaller, but still significant market for pellets that meet standard- or utility-grade. Equipment used in these application include school boilers, commercial office buildings, and, in increasing numbers, industrial plants with significant thermal loads that want to get away from the volatile natural gas market.

Data regarding the utility pellet market is limited. Contracts for utility-grade pellets are done on an individual basis directly between the pellet manufacturer and end user, and rarely is PFI or other organizations that may collect market data notified. It can be assumed that the domestic utility-grade pellet market is quite a bit larger than the 100,000tpy figure estimated by PFI, but still relatively limited.

The global market is estimated at around 9 million metric tones per year. In the global market, the use of pellets for commercial and industrial heating has accelerated, and by 2006 was nearly equal with residential use, according to news source Renewable Energy. The majority of this growth has occurred in the European markets, much more advanced with district heating, CHP, and industrial thermal load, driven by higher heating and electrical prices than are seen in the U.S.

European and Canadian pellet fuel manufacturing has grown faster than the U.S. industry. The European production capacity is over 6 million tons per year, but demand exceeds that by approximately 2 million more tons per year. Export to the European market is becoming one of the favorite outlets for U.S. pellet producers, especially for the largest commercial mills. A massive 560,000tpy facility was constructed by Green Circle Bio Energy in Florida in 2008, with the stated product market exclusively aimed at export to Europe.

Pellet production in Europe is ramping up as well. The production volume in 2001 was 1.07 million tonnes, and has increased to over 6 million tonnes by 2008.

Industrial Co-Firing Pellet Market

Pelletization is not required for standalone biomass energy plants specifically designed to handle biomass feedstocks on their un-processed forms. The primary market for utility-grade (non-residential) pellets will be co-firing with coal at power plants, driven by incentives and mandates to reach renewable energy production goals. This market is small at present, but will likely grow quickly. Wind, solar, and standalone biomass energy generation capacity advances will need help from co-firing of biomass in existing coal power plants to meet Minnesota's aggressive RPS goals.

Over 150 power plants have combusted biomass in combination with coal either as experimental or ongoing projects, according to the International Energy Agency's Biomass Division (as of 2005, the most recent data available). Forty of those projects have been in the U.S. Table 25 describes the projects (data also from IEA Biomass Division). Despite the surprisingly large number of conducted experiments, co-firing is still considered in its infancy by utility power plants using it.

One project has been conducted in Minnesota to co-fire biomass with coal in utility power plants. Occurring at the Northern States Power (Xcel) -owned Allen S. King Generating Station in Stillwater, MN, the 560MWe cyclone coal boiler is currently in commercial operation combusting biomass. The generating station is using wood waste as fuel instead of pelletized or briquetted fuel.

Only one project known to BBI is co-firing pelletized biomass with coal. The Sibley Generating Station in Sibley, MO, and owned by Kansas City Power and Light, is purchasing wood and agriculture pellets from Show Me Energy Cooperative in Missouri to co-fire with its current pulverized coal fuel. The plant is the middle of its third test phase with the pellet fuel, this phase for a 12-month period and combusting 12,000 tons of pellets. The common blend of pellets to coal will be tested at 5%, but Sibley plant officials will test-fire up to 40% biomass-coal mixes. Pellets are blended in whole, after the coal is pulverized. This allows for a simpler injection system and increased control over blend ratios.

Although plant officials recognize that the project is going well, and no plant shut-downs have occurred as a result of the biomass input, the fuel is not economical without government subsidy or mandate at present time. When asked, the officials stated that the Missouri state RPS was the driving factor behind the biomass fuel program. Pellets are the most consistent and energy-dense fuel they have found for the project, outperforming less-expensive wood chips and other biomass forms.

Great River Energy is constructing a coal-fired power plant 250 miles from Aitkin in Spiritwood, North Dakota that can be co-fired with biomass at a 5-10% blend ratio. The plant is expected to be online by October 2010. The fluidized-bed design of the plant allows for a range of biomass feedstock types and particle sizes. The company has thus far not signed a biomass feedstock agreement, and is interested in receiving supply offers.

Table 25 – U.S. Biomass Co-firing in Utility Power Plants

Location	Location	Plant name	Owner	Output (MWe)	% heat	Cofired fuel(s)	Status
Stillwater	Minnesota	King (Allen S.) Generating Station #1	Northern States Power	560	5% wt	Kiln dried wood / pet. coke / PRB blend	2 years (In commercial operation)
Sibley	Missouri	Siblye Generating Station	Kansas City (MO) Power & Light	840	5% wt	Pellets	12 month test phase
Gadsden	Alabama	Gadsden Steam Plant #2	Southern Company/Alabama Power Company	60	12% wt	Switchgrass	3-4 weeks
Lakeland	Florida	Lakeland Electric #3	Lakeland Electric	350	2% heat	RDF	
Tampa	Florida	Gannon (F.J.) Generating Station #3	Tampa Electric Company (TECO)	165	5% wt	Paper pellets	21 days (over a 60 day period)
Dublin	Georgia		Southeast Paper	65		sludge	
Milledgeville, Atlanta	Georgia	Harlee Branch Generating Station	Southern Company/Georgia Power Company	250, 319, 480, 49	1% heat	Sander dust	continuous (several years)
Port Wentworth	Georgia	Kraft / Riverside Plants #2	Southern Company/Savannah Electric and Power Company (SEPCO)	46	36% heat	Sawdust from pallets	11 tests, 8-10 hours a day
Oakwood	Illinois	Vermilion Power Station #1	Illinois Power Company (IP)	75	25% heat	Railroad ties	3 hours
Lake Michigan	Indiana	Michigan City Generating Station #12	Northern Indiana Public Service Company (NIPSCO)	469	20% wt	Urban wood waste / Shoshone coal / PRB blend	6 tests over 5 days
Marshalltown	Iowa	Ottumwa Generating Station #1	IES Utilities Inc	650	2.5% heat	Switchgrass	Ongoing
Rumford	Maine	Rumford Cogen Co.	Rumford Cogen Co.	76		oil, wood	
Prewitt	New Mexico	Escalante Generating Station #1	Tri-State Generating & Transmission Association, Inc.	250	1% wt	Waste paper sludge	2 years
Dresden	New York	Dunkirk Steam Station #1	Niagara Mohawk Power Corp.	90	20 % heat	Wood Residue and willow	Long-term (six months) planned
Dresden	New York	Greenidge Generating Station #6	New York State Electric and Gas (NYSEG)	108	30% wt	Wood chips	16 hrs/day
Johnstown	Pennsylvania	Shawville Generating Station #2	Reliant Energy	138	3% wt	Various ground wood	7 days, 3-4 hours
Johnstown	Pennsylvania	Shawville Generating Station #3	Reliant Energy	190	3% wt	Various ground wood	7 days, 3-4 hours
Pittsburgh	Pennsylvania	National Institute of Occupational Safety and Health (NIOSH)	NIOSH (National Institute Occupational Safety and Health)		40% wt	Wood chips	5 burns
Pittsburgh	Pennsylvania	Pittsburgh Brewing Company	Pittsburgh Brewing Company		40% wt	wood chips	16 burns of 4-16 hours, One 72 hour burn
Pittsburgh	Pennsylvania	Seward Generating Station #12	Reliant Energy	32	12 % wt	sawdust	Ongoing
Spring Grove	Pennsylvania	Spring Grove Paper Mill	P.H.Glatfelter Co			anthracite, wood, oil	
Moncks Corner	South Carolina	Jefferies Generating Station #3 and #4	Santee Cooper	165	20% wt	Wood chips	6 months
Pelzer	South Carolina	Lee (W.S) Steam Station #3	Duke Power Company	170	5% wt	Shredded railroad ties	2 days
Milbank	South Dakota	Big Stone Plant #1	Otter Tail Power Co.	450	1% heat	Seed corn and soy beans	continuous (several years)
Memphis	Tennessee	Allen (T.H) Fossil Plant	TVA	272	20% wt	Sawdust	10-24 tests, 3-6 hours each
Oakridge	Tennessee	Kingston Fossil Plant #5	TVA	180	5% wt	Hardwood sawdust	9 tests, 3-4 hours each
Tacoma	Washington	City Of Tacoma Steam Plant No. 2	Tacoma Public Utilities	18	80% heat	wood, refuse-derived fuel (RDF)	Ongoing
Ashland	Wisconsin	Bay Front Station	Northern States Power Company	44	100% wt	wood, shredded rubber, railroad ties	continuous
Madison	Wisconsin	Blount Street	Madison Gas and Electric Company	2 x 50	15% wt	Switchgrass	unknown
Tuscumbia	Alabama	Colbert Fossil Plant #1	TVA	182	5% wt	Sawdust	Up to 24 hours tests (ongoing)
Coosa	Georgia	Hammond Generating Station #1	Southern Company/Georgia Power Company	100	13% wt	Sawdust and tree trim	3 days
Hammond	Georgia	Georgia Power		100		waste wood	
Chesterton	Indiana	Bailey Generating Station #7	NIPSCO	160	10% wt	urban wood waste, petroleum coke	57 tests, 300 hours total
Thomas Hill Reservoir,	Missouri	Thomas Hill Energy Center #2	Associated Electric Cooperative, Inc.	175	7% wt	Railroad ties	1 week
Bismark	North Dakota	North Dakota State Penitentiary	North Dakota Dept. of Corrections and Rehabilitation			wood waste	not yet finished
Burlington	Vermont	McNeil Generating Station	Future Energy Resources (FERCO)	50	15% heat	Wood chips	since 1998
England		BL Station #1	Northern States Power Company	120	12% wt	Shredded pallet wood waste	2 months, 2 days with TDF, wood, and coal
Fort Drum			Black River Partners			anthracite, wood	
Niagara Falls			UDG Niagara Goodyear			tyres	
Savannah		SEPCO		54		waste wood	

Local Competition

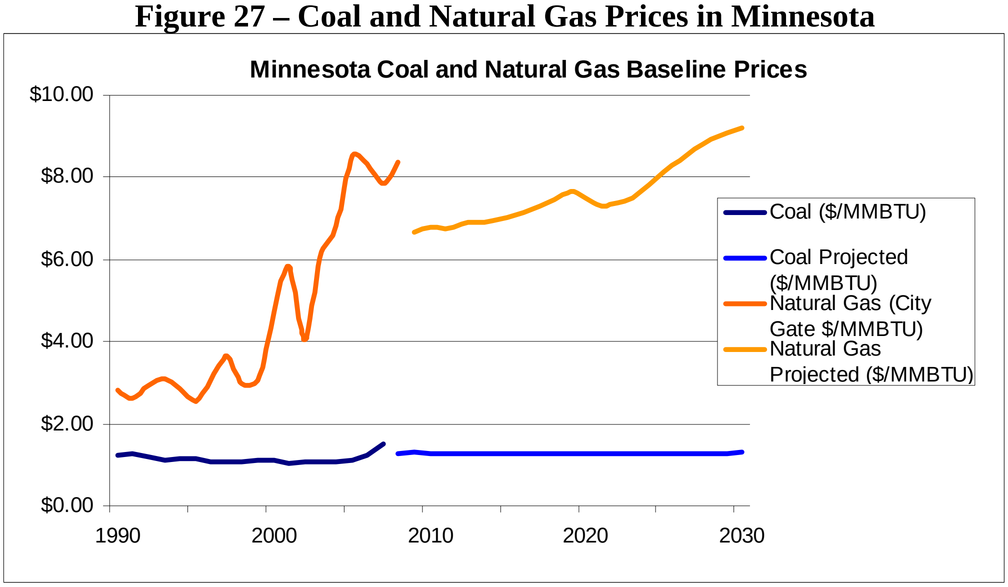
As mentioned earlier, in the local area one pellet mill already exists, in Marcell, Minnesota. A pellet mill of unknown size is planned for Duluth, and will likely sell product to Europe through the Great Lakes shipping corridors. Pellet mills are also planned for Mountain Iron, MN, where Mountain Timber company is advancing the first of at least two plants to produce approximately 100,000tpy of wood pellets, and Orr, MN, where Renewafuels, a subsidiary of Cliffs Natural Resources, plans to use internally-sourced barked wood products to make industrial briquettes. Several other plants are in the initial feasibility stages. The Renewafuels mill is the likely the only plant that will compete for the commercial and industrial pellet market. Mountain Iron is considering installing a briquetting mill for lower-grade feedstocks, but has not committed to the project yet. The rest of the Minnesota pellet mills appear focused on high-value feedstocks producing premium-grade pellets.

Pellet Pricing

As of early 2009, the average price for premium pellets in the U.S. is $296/ton, according to woodpelletprice.com. The price has risen considerably in the past few years, corresponding to an exponential rise in pellet burning appliances that has led to supply shortages. This value is for premium standard wood pellets, sold in 40 lb bags; publically-available data does not exist for bulk-sold lower-grade pellets in the U.S. In Europe, industry trade group Pellet Atlas reports that mixed-biomass pellets currently sell for €164/ton, or $218/ton.

Pricing of utility-grade pellets produced by the proposed facility will likely track the fuels they are replacing, i.e., coal and natural gas. Figure 27 shows the prices in Minnesota pricing structure for coal and natural gas, as reported to the Energy Information Agency. Normalized pricing is extended out to 2030 for each commodity.

Figure 27 – Coal and Natural Gas Prices in Minnesota



(Source: Energy Information Administration, BBI analysis)

To be truly competitive in the marketplace, a project would have to sell pelletized fuel at a BTU-normalized price equal to or less than that of coal. However, coal is a very inexpensive fuel source in the U.S., and no plant can match that price, even if the feedstock were delivered to the plant free of charge. Incentive structures must exist for biomass co-firing to be a viable commercial operation.

Natural gas prices will be used as a benchmark for the value of pellets produced by the proposed facility. At the calculated heating value of 8,175 BTU/lb for the pellet feedstock mix proposed, the value of the pellets equal to the 10-yr forward average city gate natural gas price in Minnesota is $115.16/ton, or $7.20/MMBTU. By comparison, the price per value of coal on a BTU basis is $20.71/ton or $1.27/MMBTU.

Table 26 shows the 10-year forward pricing for coal and natural gas in Minnesota, and corresponding values for co-firing pellets on a BTU basis. The values assume the project will begin construction in 2011 and produce pellets by 2012.

Table 26 – Co-firing Pellet Value 2011-2020

Pricing Structures	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	10-yr AVG
Coal ($/MMBTU)	$1.29	$1.29	$1.29	$1.27	$1.27	$1.27	$1.27	$1.26	$1.26	$1.26	**$1.27**
Coal-Basis Pellets ($/ton)	**$20.92**	**$20.92**	**$20.92**	**$20.69**	**$20.69**	**$20.61**	**$20.61**	**$20.54**	**$20.46**	**$20.46**	**$20.71**
Natural Gas ($/MMBTU)	$6.88	$6.89	$6.95	$7.02	$7.13	$7.28	$7.47	$7.64	$7.52	$7.32	**$7.20**
NatGas-Basis Pellets ($/ton)	**$110.07**	**$110.22**	**$111.12**	**$112.32**	**$114.13**	**$116.53**	**$119.53**	**$122.23**	**$120.28**	**$117.13**	**$115.16**

(Source: Energy Information Administration, BBI analysis)

Biomass Power Generation Market

Minnesota has a mandate specifically for biomass power production, which incentivizes larger-scale projects. Signed in 1994, the mandate (Minn. Stat. §216B.2424, Sec. 3) required that Xcel Energy purchase or produce 125 MW of biomass-fueled electricity. Approximately half (75 MW) of that mandate has been met through existing or in-process contracts; the remainder of the power generating capacity has yet to be installed. This mandate creates both a built-in market for biomass power, as well as providing for attractive electricity selling rates. The mandate has been rolled into the RPS as of its 2007 adoption.

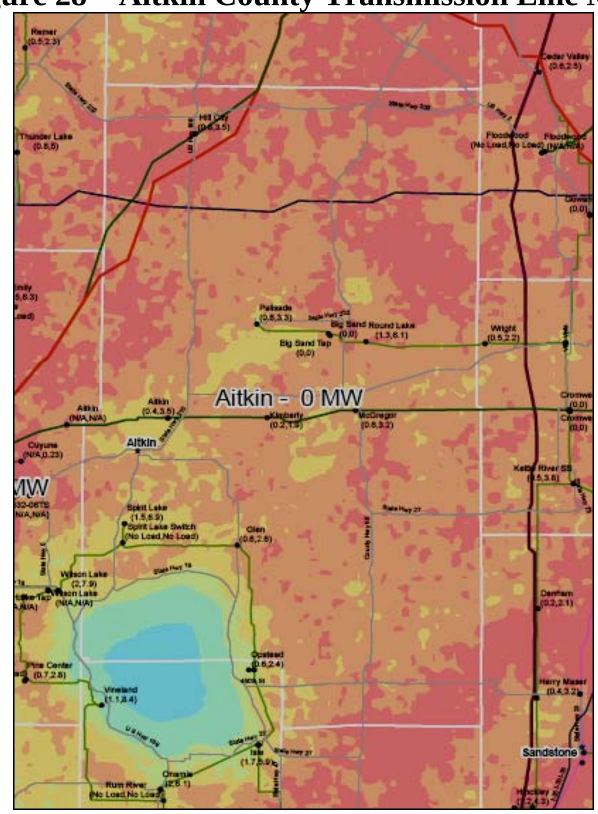
Projects that have been installed since the 1994 mandate took effect are the Minnesota Valley Alfalfa Producers (MinVAP), fueled by alfalfa stems; District Energy, fueled by wood wastes; Fibrominn, fueled by poultry litter; Energy Performance Systems and R.W. Beck (EPS/Beck), which operate two plants fueled by hybrid poplar and willow; Itasca Power (fuel unknown); and the Laurentian Energy Authority. The Laurentian Energy Authority (LEA), a joint powers public authority formed between the municipal utilities of Virginia and Hibbing, put two combined heat and power renewable energy biomass plants on line during the winter of 2007. These plants consist of traditional biomass boilers fueled by hybrid polar and wood waste, and produce a combined 35 MWe of power sold through a power purchase agreement to Xcel Energy.

In Aitkin County, two local power providers will be the initial point of contact for negotiating power purchase agreements. Minnesota Power, the local utility supplier to the city of Aitkin, has created a Distributed Generation program to facilitate additions to the company's renewable energy generating capacity. The Distributed Generation program streamlines the application and tie-in process for facilities producing less than 10MW of power. Minnesota Power, under the agreement, is required to purchase all power tied into its system, but does not specify the rate at which the power will be purchased. Likely, larger facilities up to the 10MW cap will have better negotiating position. The other local power provider is Great River Energy, headquartered near Minneapolis. Great River supplies power to the majority of the county, not including the city of Aitkin.

Power generating facilities larger than 10MW are required to receive Federal Energy Regulatory Commission (FERC) approval as a Qualifying Facility (QF). A generating facility which meets the requirements for QF status under the Public Utility Regulatory Policies Act of 1978 and part 292 of the Commission's Regulations (18 C.F.R. Part 292), then obtains certification of its QF status and is able to begin negotiations with utilities.

At this larger scale, negotiations for grid access will involve both Northern States Power (Xcel) and Minnesota Power / Great River Energy, through the regional wholesale grid management organization, Midwest Independent Transmission System Operator (MISO). Great River Energy is referring interested developers to United Services Group (USG) who will log interconnection requests and begin the evaluation process for proposed projects.

Figure 28 – Aitkin County Transmission Line Map



(Source: Minnesota Electric Transmission Planning)

Figure 28 shows the transmission power lines serving Aitkin County. As noted in the map, there is currently no generating capacity in Aitkin County. The county has limited transmission capacity to handle new power generation. There are two large-scale transmission line traversing Aitkin County—Minnesota Power's 115kV AC #13 line. The line runs east-west across the middle of the county. A 250KV DC line runs across the northern portion of the county. Final project siting will need to take into account access to transmission lines.

Heat and Power Pricing

Minnesota Biomass Power Electricity Price

The combination of RPS goals and the Minnesota Biomass Power Mandate have created an attractive market for companies to sell power to the grid. Electricity prices obtained through power purchase agreements signed thus far are higher than the current rate that electricity *costs* in the state (approximately 5¢/kWh for industrial customers). Table 27 lists the available power rates obtained due to the biomass mandate. Note that the average length of contract is nearly 20 years, sufficient for stable long-term projection of revenues. The average rate for sale of power to the grid is 10.40 ¢/kWh. This is set as the anticipated price the proposed project will receive for electricity produced by the installed CHP system.

Table 27 – Minnesota Biomass Electric Contracts

Biomass Mandate Contract Costs		
Project	¢/kWh	Years of Contract
MnVAP (*est)	10.50	12
EPS/Beck 25 MW	12.98	20
EPS/Beck 50 MW	10.54	20
District Energy 25 MW	9.52	20
Fibrominn 50 MW	8.60	21
NGPP/Virginia-Hibbing 35 MW	10.28	20
Average	**10.40¢**	**19**

(Source: Institute of Local Self-Reliance)

Anticipated Heat Value

Heat energy that cannot be used to create electricity can be recovered and sold to a nearby township as district heat, or to a co-located industrial facility as process heat. The value for the heat energy is assumed to be indexed to the natural gas price, at a 15% discount to entice purchasers. Table 28 shows the 10-yr price for heat energy sold by the proposed CHP project.

Table 28 – Value of Heat Energy sold by CHP Project

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	10-yr AVG
Heat Value ($/MMBTU)	$5.85	$5.86	$5.90	$5.97	$6.06	$6.19	$6.35	$6.49	$6.39	$6.22	**$6.12**

IX. TECHNOLOGY ASSESSMENT

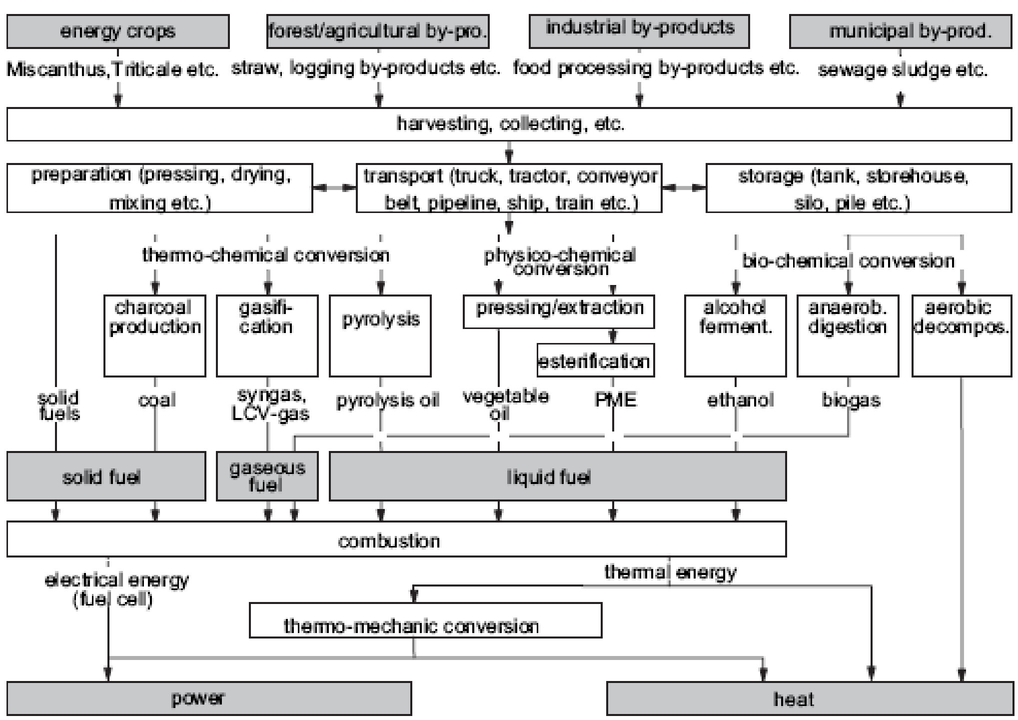
This section will review the various technologies available for conversion of raw biomass into merchantable products. The two primary technologies under review for the proposed Project are pelletization, with the sale product being fuel pellets, and combustion / gasification, with the sale products being heat and electricity supplied to the grid and/or co-located industrial energy user. Torrefaction will also be reviewed but at present does not have a formal market.

Feedstock for the plant is envisioned to be herbaceous grassy biomass material combined a mixture of woody biomass, including chipped wood, logging residues, and mill residues.

Overview of Conversion Technologies

Biomass can be made into a number of saleable products commonly called ‘bio-based products,’ as well as energy in the form of heat and/or power. In the context of energy production, biomass is processed via mechanical, thermal, and/or chemical means into biofuel. Figure 29 briefly outlines the various pathways in which biomass is converted to biofuel, as determined by the United Nations Food and Agriculture Organization’s United Bioenergy Terminology committee. This is not a comprehensive list of all systems, as additional sources and uses of biomass are being discovered daily.

Figure 29 – Biomass Processing Pathways



(Source: FAO UBET)

Biomass is converted into biofuel for two primary reasons:

- To increase the energy density of the biomass
- To convert the energy contained within the biomass into a commonly-useable form

The first reason is relatively self-explanatory; rarely is energy used where it was created, and therefore must be transported to a final destination. The more energy per unit weight of a fuel source, the faster, cheaper, and easier it can be transported.

This also highlights one of the primary limitations with biomass as a biofuel feedstock. The raw material often has very poor energy density, especially when considering grasses and agricultural residues. This is due to the light, porous structures of the materials, non-uniform stacking characteristics, and water content approaching 50% by weight. These limitations greatly reduce the distance biomass can be economically transported prior to use. Particle-size reduction and drying technologies need to be employed when dealing with these types of material.

The second reason biomass is converted is to match it to the existing energy-production infrastructure. Biomass can be converted into a solid, liquid, or gaseous biofuel, depending on the intended end-use. Biofuels for transportation rely on liquid fuels for their transportability and high energy density, while solid-state energy producing equipment uses all three states of matter.

As mentioned previously, biomass is the only currently-known source of renewable transportation fuel. Intense amounts of research is being conducted to discover cost-effective pathways to produce liquid fuel for transportation vehicles. The majority of this work is geared toward efficiently producing ethanol or other substitutes for gasoline and a smaller portion devoted to replacing petroleum diesel. Work towards these goals is progressing at an astounding rate, with over 40 cellulosic ethanol demonstration plants under construction in the U.S. alone.

The processes available to convert biomass directly into energy fall under several general categories. These categories are:

Thermochemical Conversion, in which biomass is either partially or fully combusted to release energy and other useful compounds. Thermochemical conversion of biomass to energy is the technical explanation of burning wood in a fireplace to heat a home. Examples of advanced thermochemical conversion technologies include:

- Industrial Boilers
- Combined Heat and Power (CHP)
- Gasification
- Pyrolysis

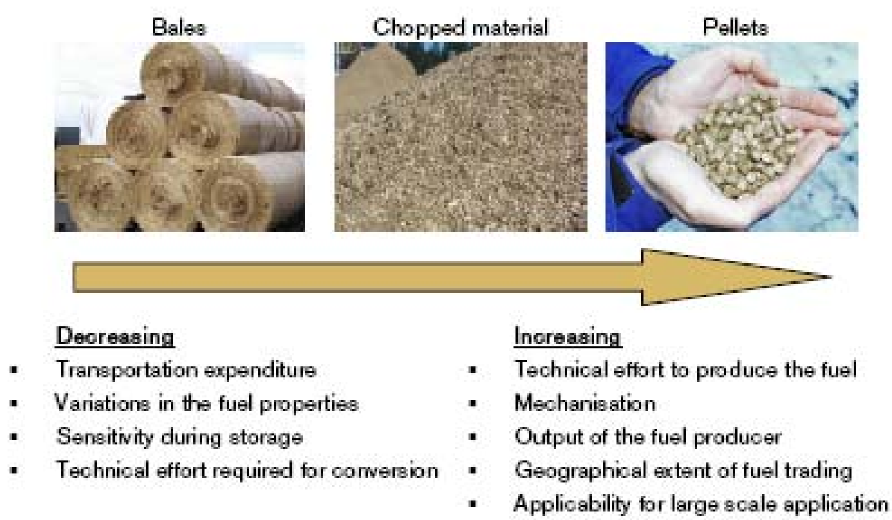
Physiochemical Conversion, in which biomass is both mechanically and physically changed to create a fuel source. Usually this occurs as a two-step process, the first being mechanical separation of desirable and undesirable products, and the second stage chemically processing the feedstock into a fuel. The most commonly-known physiochemical conversion process is transesterificaiton, where fats and oils are converted into biodiesel. Torrefaction is a recently developed method of physiochemcical conversion.

Biochemical Conversion, in which microbial agents are used to convert biomass into liquid or gaseous fuels. Two common forms of biochemical conversion exist in the marketplace today; anaerobic digestion and fermentation. The end product of anaerobic digestion is methane, a gaseous fuel, and the end product of fermentation is commonly fuel ethanol, though a number of products can be produced depending on the microbe used to facilitate the conversion.

A forth category, *Mechanical Conversion*, densifies or otherwise repackages biomass into an energy-bearing fuel, both for simplified transport and to make the fuel compatible with common combustion technology. Chipping is the simplest form of mechanical conversion. Pelletizing is a somewhat more advanced method, in which the biomass is highly compressed into uniform-size pellets or briquettes.

Figure 30 is a useful and quick way to explain the benefits associated with further processing of agricultural materials, from bales through to pellets. Transportation, variation of final product, sensitivity to degredation during storage, etc. are reduced as the material is further processed, while the output and the geographical reach of the producer are increased. Of course, and important to note, the mechanization and associated cost are increased with additional processing as well. The graph is provided in a study of pelletizing reed canary grass, conducted at the Swedish University of Agricultural Sciences.[10]

Figure 30 – Pelletizing Benefits



[10] Larsson, S. "Fuel Pellet Production from Reed Canary Grass", Swedish University of Agricultural Sciences, 2008.

Pelletization

Pelletizing is a mechancial densification process that converts biomass into compact, uniformly shaped fuel units for combustion. Briquettes, pucks, densified logs, and other manual densification processes are considered variations of pellets for the purposes of this study, and the equipment and process to make briquettes will be reviewed in conjunction with pelletization processes.

Technology Overview

The majority of pellets produced and sold are cylindrical, approximately 1.5 inches long by 0.25-0.3 inches diameter. Briquette sizes vary, but are commonly 3 inches by 3-6 inches square, and up to 6 inches tall. Pellets and briquettes do not use glues or other binding agents. Their ability to remain consolidated into a uniform shape is a result of the heat and compression energy applied in the pelletizing or briquetting operation.

In order to produce a pellet or briquette, the feedstock material must be of uniform size and moisture content. Initially, the incoming biomass material can be up to several feet long. A chopper or chipper takes care of the gross size reduction. Hammermills and/or tub grinders reduce the biomass to a fine powder.

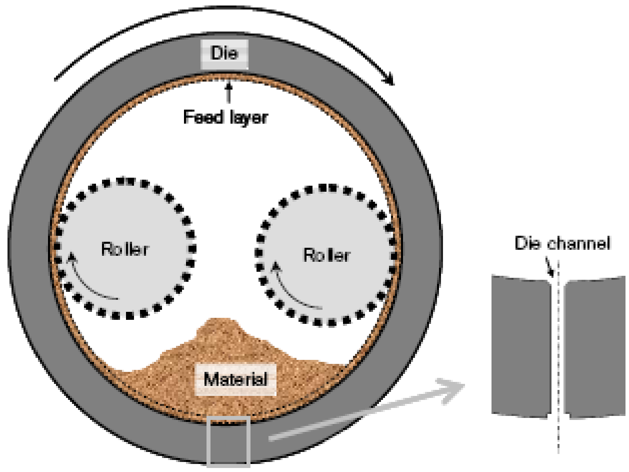
Concurrent with the particle size reduction processes, stones and other impurities are removed from the material. Depending on the incoming materials, drying or moisturizing may need to occur. Pelletizing equipment operates most efficiently (and produces the most consistent density pellets/briquettes) when the material is at ~12% moisture content upon entry into the machinery. Woody biomass will contain 30-50% moisture, and will require drying. On the other hand, grasses and agriculture residues often arrive at the plant below 10% moisture, and to avoid clogging of machinery sometimes need additional moisture.

Once the feedstock is to the proper particle size and moisture content, and the blend ratio of feedstocks is optimized, the material is ready to be fed into the pelletizing or briquetting machine. Cyclones complete the work of removing air and partially compacting the materials to be fed into the pelletizing equipment, which then uses augers to drive a constant stream of product into the mouth of the pelletizing or briquetting machine. The addition of 3-4% water content in the form of steam keeps the material from sticking and helps increase compression.

Most pelletizers use a ring-type dye with perforations arranged in a uniform geometric pattern. The perforations or holes are the diameter required of the pellet being produced— 0.25 to 0.3 inches. A roller presses material through the die, and blades cut the pellet to the desired length on the outside of the die. Briquetting equipment, on the other hand, uses a press and mold to densify materials.

Figure 31 shows a generalized view of the pelletizing die and roll assembly. Heat is also applied to make the material entering the process more malleable. For sizing a pelletizing machine, a common rule is 1 HP of machine can pelletize one ton per hour.

Figure 31 – Pelletizing Die and Roll Assembly



(Source: Larsson, S.[10])

After going through a press, pellets are usually very hot and soft. After a rapid cooling process to avoid moisture uptake and crumbling of the hot weakened pellets, they are screened to remove fines, which are recycled back into the system. The pellets are then ready for storage, packaging or sale.

Pelletizing Biomass Challenges

Pelleting biomass feedstocks, such as the grassy biomass, logging residues, and mill residue mix proposed for the Aitkin project, differs significantly from traditional woody biomass pelletizing methods. The materials are more fibrous and less malleable than the woody materials traditionally pelleted, and can jam an unprepared pelletizing machine. An experiment was conducted in Erie, PA attempting to pelletize corn stover, which “jammed the works from front to back” according to one observer. Careful design and execution of equipment specifically for herbaceous biomass is required for successful pelletizing.

Alan Doering with AURI, which has conducted extensive agricultural product pelletization testing in its Waseca, MN laboratory, feels it is likely that a blend of 85% reed canary grass (at 8% moisture) and 15% woody biomass (40% moisture) may meet the moisture specification of the pelletizing machine, eliminating the need for drying.

Steve Flick of Show Me Energy Cooperative was interviewed to gain insight into agricultural residue pelletizing. Show Me Energy completed in 2007 a 100k ton/yr biomass pelletizing plant in Centerview, MO, operating almost entirely on herbaceous biomass feedstocks. Mr. Flick stressed the significance of feedstock blending to produce pellets with consistently in-spec composition. The proper blend is important for both allowing materials to pass through the pelleting equipment cleanly, and also to produce the proper burn characteristics that customers need to keep boilers operational.

Show Me Energy has developed proprietary software to precicely manage the pelletizing machinery’s feedstock mix, based on chloride content, moisture content, and ash content.

Chlorides are the primary concern, and the deciding factor in Show Me Energy's feedstock mix. Moisture content is also a primary concern. Especially if a dryer is not purchased, the use of inherently dry grasses and brush is necessary to reduce the moisture content of the blend. Show Me Energy's plant does not incorporate a dryer, instead using the feedstock blend to dictate input moisture levels.

Ash content is a secondary concern, less so than for manufacturers of residential pellets. Industrial power generation boilers are capable of handling higher ash content. Silica (SiO_2) is abrasive to machinery, and high amounts can damage pelletizing equipment. Additional equipment may be required to separate out silica prior to pelletization. Adjustment of the blend ratio to reduce chloride and ash content is primarily a concern for the burn characteristics of the pellet, not its processing. Chloride, moisture, silica and ash content in a feedstock blend can also be controlled through careful feedstock management resulting in a consistent pellet composition through time. Licenses for Show Me Energy's proprietary software are available through the company.

Combined Heat and Power (CHP) Production

Producing heat and power from biomass feedstocks involves combusting the fuel source in a boiler, which creates superheated water or steam to drive electricity-producing turbines. A portion of the remaining steam or hot water, containing too little energy to drive electricity production, can be recovered for industrial process heat or to heat buildings. Gasification technology, which is rapidly being refined for use in small and mid-size applications, partially combusts the feedstock fuel in a controlled-oxygen environment, which produces a secondary gaseous fuel instead of direct heat. This gaseous fuel, called syngas, can then be combusted in a boiler, direct-fired in a turbine or reciprocating engine, or, after gas quality upgrading, converted to chemicals and liquid fuels. The status quo technology combines a gasifier with a direct-fired gas turbine and heat recovery, termed 'biomass-integrated gasifier/gas turbine' (BIG/GT) power systems.

Both systems have benefits and drawbacks. Traditional biomass boilers are a well-proven technology based on relatively simple and robust machinery. This allows for less-expensive capital and ongoing maintenance costs. Gasifiers will cost more upfront, but utilize a wider variety of feedstocks more efficiently. Due to their much higher operating temperature (1,000 ºC vs. 500 ºC), gasifiers produce less volatiles, ash, and slag.

The efficiency of biomass conversion to useable energy also varies between technologies. Table 29 shows the efficiency gains achieved over time for biomass boilers, co-firing of biomass in coal power plants, and biomass gasification systems. Gasification systems continue to produce higher electrical efficiencies (37.0% as of 2010) than both biomass boilers and co-firing systems (27.7% and 32.5%, respectively). The chart, provided by NREL, is not specific to any one technology provider. Results will vary between specific technology providers, feedstocks, and configurations.

Table 29 – Biomass Combustion System Efficiencies

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

(Source: NREL)

The cost of gasification equipment has been falling rapidly in recent years as more systems are installed. An established engineering firm that is designing a CHP system specifically to power ethanol plants believes gasifier CHP systems in the 100-500tpd capacity range will be roughly equal in cost to traditional boiler systems within 5 years. This is consistent with the data provided by NREL.

The combination of nearly 40% better electrical efficiency rates and a quickly closing capital cost gap leads BBI to believe that gasifier / gas-turbine systems will supplant boilers in mid-size CHP applications within a few years. Small-scale systems primarily used to create heat (such as for schools and buildings) will continue to utilize boilers primarily. The financial model will assume gasification as the conversion method for the proposed project, however both boilers and gasification processes will be discussed below.

Gasification

The process of gasification has been around since the 1800s, where it was developed to produce ‘town gas’ for heat and lighting, similar to the natural gas distribution systems in use today. The primary benefit of gasification is converting solid materials into gaseous fuels and/or feedstocks for reforming operations. It is desired over standard fuel combustion due to the higher efficiencies that can be achieved, as well as the ability to separate the elements that constitute the feedstock. Gasification is a partial combustion process in a controlled-oxygen environment, deconstructing the carbon-based fuel into elemental gasses that can then be combusted or used as base materials for additional processing (in the case of CO, H_2, and CH_4,), removed for sale (in the case of sulfur), or captured for sequestration or other pollution-reduction effort (in the case of CO_2).

The majority of gasifiers currently in use are very large-scale coal or natural-gas fired units. There are over 140 commercial plants operating over 440 gasification units worldwide, with standard capacities in the range of 50,000 MWth (thermal heat megawatts). By volume, chemicals are the largest end product, at 44%, followed by Fischer-Tropsch (F-T) liquids at 30%, and power at 18%. This is somewhat misleading because the Fischer-Tropsch units are over-scaled compared to other types of systems and number much fewer. They are mostly concentrated in South Africa and China. In recent years high energy prices have rapidly increased R&D and construction of gasification plants, and have also created a market for small and mid-size gasification units. Gasifiers are one of the most versatile distributed energy production units available due to the wide range of feedstocks that can be utilized.

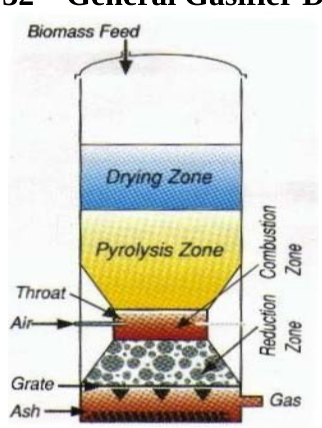
Gasification has shown to reduce the occurrence and significance of equipment fouling when combusting biomass feedstocks. The higher temperature, controlled-oxygen burn environment is more efficient at completely reducing feedstock material. This primary benefit of gasification systems also results in greater electricity conversion efficiencies. As it pertains to CHP production, gasification is quickly becoming the preferred conversion technology.

Technology Overview

Gasification is a process where heat (750 °C – 1,000 °C), limited air, and pressure are applied to carbon based material to produce syngas—primarily a combination of hydrogen and carbon monoxide. Gasification differs from combustion primarily in the strict control of oxygen in the reactor chamber. The stoichiometric ratio of air to fuel required for complete combustion is roughly 6:1; gasification reduces this ratio to between 1.5 and 1.8 to one. This semi-starved environment breaks the carbon-based materials into their base units – primarily CO, H_2, CO_2, CH_4, N_2 (if the system is fed with ambient air), along with trace compounds of varying composition. CO and H_2 are the desired molecules from the reaction, and are called syngas.

Figure 32 shows a generalized biomass gasification reaction and reactor vessel. As the figure indicates, the reaction includes several zones or stages. While there is some overlap of zones, they are relatively differentiable. In the first zone, initial contact of fuel with heat occurs, and water and other light gasses are removed. In the second zone, pyrolysis occurs, producing tars and other complex liquid compounds. In the throat of the gasifier, air is introduced to the system, changing the reaction characteristics. The tars are further reduced to their elemental components, at which point they are called ‘producer gas’ or ‘syngas’. Inorganics are reduced to ash and slag and are removed from the system as a byproduct.

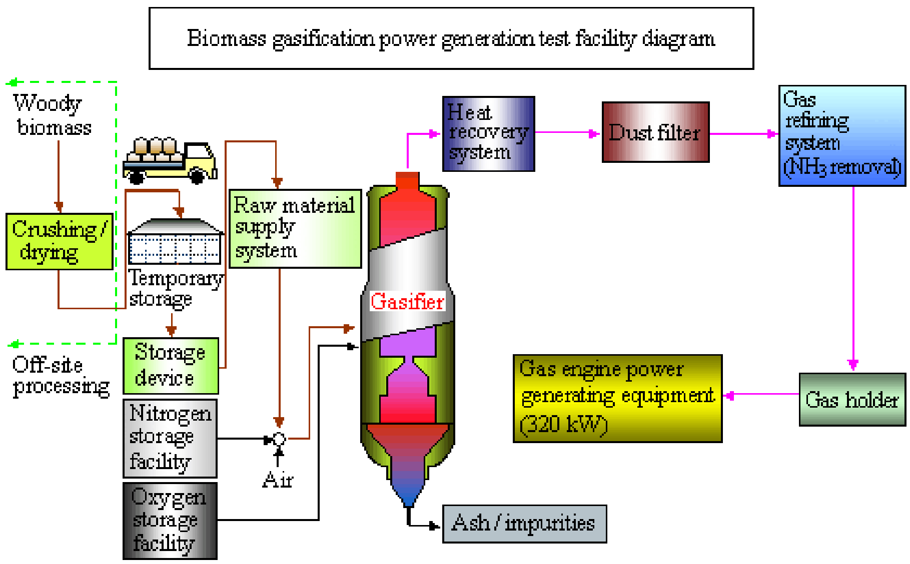
Figure 32 – General Gasifier Diagram



(Source: Ankur Scientific)

Figure 33 depicts the broader system required for gasifier operation. In most systems, feedstock handling equipment is required to produce the correct size material with acceptable moisture content to feed the reactor. Post-reaction, the syngas goes through a series of cleansing steps if it is destined for further reaction to produce chemicals or fuels. In CHP systems, as is shown below, the syngas can often be combusted directly in gas turbines to produce electricity. The combustion of syngas is usually accomplished in direct-fired Brayton cycle turbines, which are much more efficient than steam-powered turbines. A steam-powered turbine can be installed at the back end of the system to produce additional electricity from the direct-fired turbine's exhaust.

Figure 33 – Biomass Gasification System

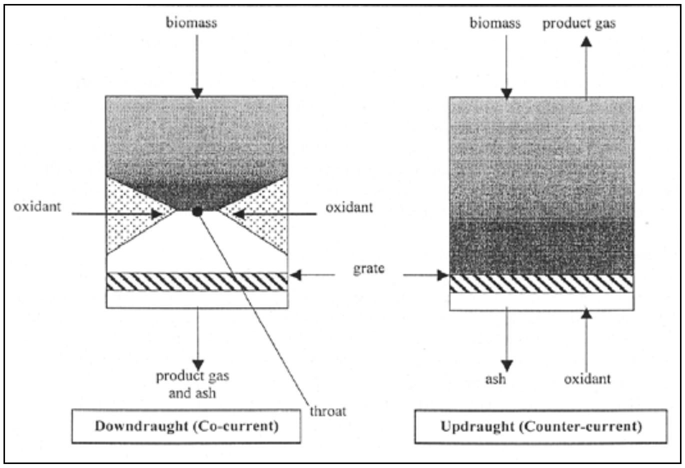


(Source: NREL)

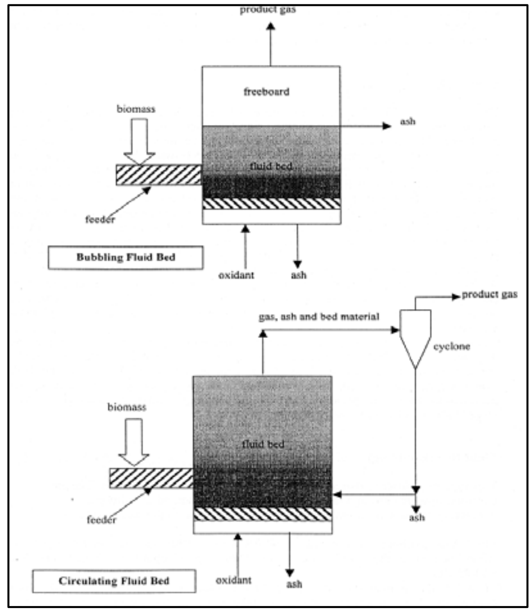
Standard Gasifier Configurations

General configurations of gasifiers available include updraft or downdraft design, and fixed-bed or fluidized bed designs. Figure 34 provides simple schematics for both updraft and downdraft gasifiers with fixed beds, and schematics for bubbling and circulating fluidized beds. Updraft-style gasifiers are the simplest configuration to build, as produced gasses will naturally rise. The feed rate is not as critical when compared with other gasifier types and there is high thermal efficiency. Updraft gasifiers are commonly built for heat production, however, power production is possible if significant syngas scrubbing equipment is employed. Downdraft-style gasifiers require more advanced control technology, but produce cleaner syngas with low tar content. Downdraft gasifiers also produce less ash, especially important for biomass feedstocks. Fixed-bed and fluidized-bed systems are the major demarcations; novel systems using carbon or molten metal are also utilized.

Figure 34 – Gasifier Configuration Schematics



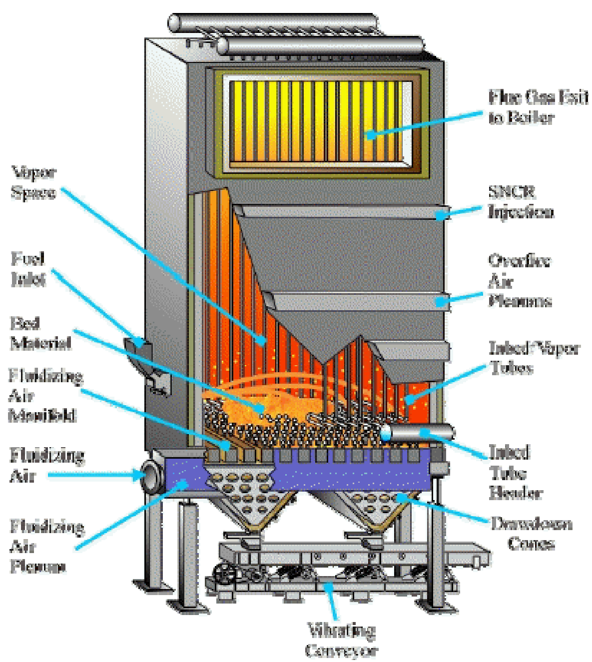
(Source: Loughborough University)



Biomass Boilers

A biomass boiler is also a consideration for direct combustion of the aforementioned process co-products. There are several types of boilers available, however, the primary type for CHP applications is a fluidized bed. Fluidized beds were designed for burning pulverized coal but are capable of utilizing other feedstocks.

Figure 35 – Fluidized Bed Illustration



(Source: EPI)

The biomass materials are burned in a bed of inert material (typically sand) with forced air. The gas passes upward through the packed bed causing a pressure drop which increases the velocity until the bed particles expand and become supported in the gas stream with high rates of heat transfer. Figure 35 shows a drawing of a fluidized bed to give a better understanding of the process.

After the biomass material is combusted, the fuel gas exits to a boiler, heating water to steam. The steam is forced through a turbine to create electricity, and the remaining latent heat can be recovered and sold as process heat or district heat. Biomass boiler efficiencies and outputs are shown in the previous section.

Torrefaction

The process for densifying and drying biomass known as torrefaction has been developed since the 1980s. Torrefaction is a pre-processing method used to consolidate the energy contained in biomass materials, as well as to remove water, carbon dioxide, and other volatiles. The resulting material is commonly pelletized to produce a pellet containing a heat value of 9,000-14,000 BTU/lb. In Europe, France in particular, extensive research is being conducted into the processes of creating and combusting torrefied biomass. Several companies in the U.S. are working towards those goals as well, but at a much reduced level than European counterparts.

The process of torrefaction involves heating the biomass material to 200 ºC-300 ºC in the absence of oxygen. This drives off water and other volatiles, densifying the energy contained in the material, as well as reducing its fibrous nature and making the end product brittle and easy to grind. The resulting material has 80-90% of the original energy content. Once the energy cost of torrefaction (and pelletizing of the resulting material) are included, the energy balance of torrefaction is greatly reduced. Technology providers are working to create systems in which the gasses produced through torrefaction are combusted to power the system.
Torrefaction is a relatively new technology, and torrefied biomass has not been test co-fired with coal in the U.S., as far as publically-available information indicates. The additional cost of torrefaction, and the inherent energy loss produced by the partial combustion of the material, result in a material that cannot compete cost-effectively with pellets or other biomass fuels. In addition, there is a debate over whether the energy efficiency of the process as a whole is negative, i.e., it takes more energy to complete the torrefaction process than is contained within the material. For these reasons, torrefaction is not considered a commercially-viable technology at present.

X. PROJECT STATISTICS

The project statistics shown in the following tables are general guidelines only, and may change with the specific plant design and other project variables. Refer to the Appendices for each plant scenario's specific statistics.

Pellet and CHP Plant Statistics

The project statistics calculated for the four plant scenarios are shown in the following table.

Table 30 – Project Statistics

Project Statistics	50K Pellet	100K Pellet	50K Energy	100K Energy
Plant Inputs				
Feedstock (raw tons/yr)	50,000	100,000	50,000	100,000
Feedstock (dry tons/yr)	40,665	81,330	40,665	81,330
Water (gal/yr)	1,300,000	2,600,000	0	0
Thermal Energy (MMBTU/yr)	9,471	18,943	0	0
Electricity (kWh/yr)	2,559,760	5,119,520	0	0
Plant Outputs				
Pellets (ton/yr)	44,325	88,650	0	0
Electricity (kWh/yr)			86,752,638	173,505,275
Thermal Energy (MMBTU/yr)			320,000	640,000
Transportation Statistics	**50K Pellet**	**100K Pellet**	**50K Energy**	**100K Energy**
Incoming				
Feedstock (raw tons/yr)	50,000	100,000	50,000	100,000
Feedstock (Truckloads/yr)	1,812	3,623	1,812	3,623
Trucks/day	6	12	6	12
Outgoing				
Pellets (Truckloads)	1,606	3,212	0	0
Trucks/day	5	11	0	0
Pellets (Railcars)	443	886	0	0

Personnel Requirements

The personnel requirements used in the feasibility study are listed in Table 31. The positions and salaries shown are typical of the industry.

Table 31 – Personnel Requirements

Position	50K Pellet	100K Pellet	50K Energy	100K Energy	Annual Salary
Administration/Management					
General Manager	0	0	0	0	128,700
Plant Manager	1	1	1	1	94,100
Production Labor					
Shift Team Leader	2	2	2	2	43,600
Shift Operator	2	2	2	2	36,600
Yard/Commodities Labor	2	3	3	4	26,700
Maintenance					
Maintenance Manager	1	1	1	1	54,500
Boiler Operator	0	0	1	1	49,500
Maintenance Worker	1	1	2	2	36,600
Welder	0	0	0	0	41,600
Electrician	0	0	0	0	39,600
Instrument Technician	0	0	0	0	39,600
Total Number of Employees	9	10	12	13	

(Source: BBI analysis)

Assumptions Used in the Financial Forecast

The major variables for the financial analysis are feedstock price, pellet sale price, electrical energy sale price, thermal energy sale price, and input energy prices. In addition to these issues, various financial model input sensitivities were analyzed and are described below. The assumptions used in the financial forecasts that have the greatest impact on the project risk and return are:

- *Feedstock Price*. The delivered feedstock price for biomass in the analysis is $35.68 per dry ton for all scenarios.

- *Pellet Price*. The pellet price used in the financial forecast for the pellet plant scenarios is indexed to the city-gate natural gas price in Minnesota going forward. The ten-year average value for pellets is $115.16/ton, less 1% sales commission. Shipping cost is unknown.

- *Pellet Yield*. The pellet yield used in the financial analysis for pellet plant scenarios is 1.06 tons per dry ton of feedstock processed. The yield is greater than 1:1 because the financial model assumes bone-dry (0% moisture) feedstock going into the process and 12% moisture pellets exiting the process. A 3% loss of material is calculated.

- *CHP Electricity Selling Price*. The sale price of electricity from the CHP plants is set equal to the average of the power purchase agreements made in Minnesota. This value is set at 10.4¢/kWh.

- *CHP Electrical Efficiency*. The electrical efficiency of gasification / gas-turbine CHP plants is calculated by NREL to be 37% of the total energy input.

- *CHP Recovered Heat Selling Price*. The sale price of thermal energy from the CHP plants is indexed to the natural gas price in Minnesota. The ten-year average heat value is $6.12/MMBTU.

- *CHP Recovered Heat Efficiency*. The commonly accepted value for CHP system heat recovery is 40% of the total energy input.

- *Electricity Price.* The electric rate is based on the Minnesota industrial electrical rate going forward. The ten-year average electricity price is 5.58¢/kWh.

- *Natural Gas Price*. City-gate natural gas price in Minnesota, going forward, is calculated for all scenarios. The ten-year average natural gas price is $7.21/MMBTU.

- *Operating Days per Year.* The days of operation per year is set at 300 days/yr for all scenarios. Plants using established production technologies often operate 350 days/yr, but the volatility of pellet production and the relative youth of gasification processes forces a reduced operating rate.

- *Incentive Payments.* The financial forecast does not include any state tax credits or ethanol incentive payments.

- *Financing*. For all scenarios financing is assumed at 40% equity and 60% debt at 8% interest, amortized over 10 years. Interest-only payments are allowed for the first years of operation. These are common values experienced in the industry.

Table 32 shows a breakdown of the ethanol plant capital costs and owner's costs. Capital costs presented are order-of-magnitude estimations (+/- 30%). Actual costs will vary depending on the technology provider and general contractor chosen for the project.

Table 32 – Aitkin County Project Average Capital Cost Estimate

Capital Cost Estimate	50K Pellet	100K Pellet	50K Energy	100K Energy
Project Engineering & Construction Costs				
EPC Contract	$6,326,000	$12,019,000	$32,194,000	$63,003,000
Site Development	$1,705,000	$2,105,000	$1,705,000	$2,105,000
Rail	$1,335,000	$1,995,000	$0	$0
Contingency	$645,000	$1,075,000	$1,980,000	$3,612,000
Total Engineering and Construction Cost	**$10,011,000**	**$17,194,000**	**$35,879,000**	**$68,720,000**
Development and Start-up Costs				
Inventory - Feedstock	$178,000	$357,000	$178,000	$357,000
Inventory - Spare Parts	$300,000	$400,000	$200,000	$300,000
Start-up Costs	$33,200	$44,700	$29,900	$31,500
Land	$76,000	$151,900	$76,000	$151,900
Admin Building & Office Equipment	$100,000	$100,000	$100,000	$100,000
Insurance & Performance Bond	$127,400	$168,100	$170,800	$299,000
Rolling Stock & Shop Equipment	$710,000	$710,000	$560,000	$560,000
Organizational Costs & Permits	$709,400	$969,800	$984,100	$1,697,100
Capitalized Interest & Financing Costs	$711,270	$1,386,880	$2,787,840	$2,543,780
Working Capital/Risk Management	$594,000	$1,091,000	$605,000	$1,095,000
Total Development Costs	**$3,539,270**	**$5,379,380**	**$5,691,640**	**$7,135,280**
Total Uses	**$13,550,270**	**$22,573,380**	**$41,570,640**	**$75,855,280**

(Source: BBI analysis)

XI. FINANCIAL FEASIBILITY

BBI prepared four financial scenarios to evaluate biomass utilization facilities in Aitkin County, Minnesota. The models evaluate two biomass conversion technologies—pelletizing and CHP energy production, at two project scales—50,000tpy and 100,000tpy feedstock input, on an as received moisture content basis. The two CHP plant scenarios are rated at 10MW and 20MW capacity, based on the industry standard operating rate of 8,400hrs/yr. The pelletizing plants will produce utility-grade pellets from the chosen biomass feedstock blend, and the CHP plants will produce electricity and thermal energy from the same biomass feedstock input.

The key model inputs include product yields, product and raw material pricing, labor costs, energy consumption and pricing, capital costs including engineering, procurement and construction of the plants and all supporting facilities and systems, project development costs, financing costs, start-up costs, working capital and inventory costs.

The BBI models produce ten-year operating forecasts for the projects including a balance sheet, income statement, and cash flow statement. Complete 11-year proformas for the four scenarios are included in the appendix. The impacts of critical project variables have been determined and the viability of the projects with regard to each has been evaluated.

Economic Modeling Results

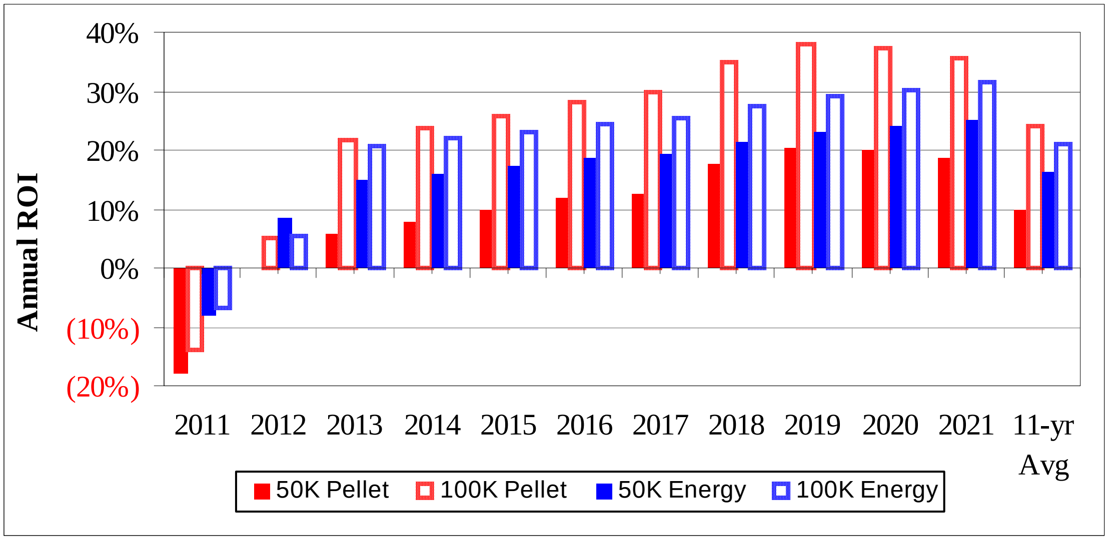
Pre-tax average annual Return on Investment (ROI) was used to measure the projected profitability of the project. The results are summarized in Table 33. The ROI is the average of the return for the 11 years of the financial forecast including the construction year. Results that are more detailed are shown on the following pages and the complete 11-year economic forecast for the project is included in the appendices.

Table 33 – Financial Modeling Results

Aitkin County Project	50K Pellet	100K Pellet	50K Energy	100K Energy
11-year Average Annual ROI	12.4%	26.8%	17.7%	23.2%
Internal Rate of Return	12.8%	24.1%	18.9%	22.0%
Average Annual Income	$673,742	$2,406,534	$2,935,014	$7,048,384
Total Capital Cost ($/raw ton/day)	$0.90	$0.75	$2.77	$2.53
Total Project Investment	$13,550,180	$22,490,480	$41,570,520	$75,855,110
40% Equity	$5,420,072	$8,996,192	$16,628,208	$30,342,044

Figure 36 graphically illustrates the ROI for each year of plant operation in each scenario, starting with plant construction in year 2011 (inherently a negative return year), and going out to year 10 of operation, here 2021.

Figure 36 – Aitkin County Project Annual ROI



Based on the results and competitive guidelines, all four scenarios produce positive returns on investment. From a purely financial perspective, the 100,000tpy pellet plant is the most attractive option, yielding a 26.8% ROI over the 11 years of project timeframe. The smaller-scale pellet plant scenario produced the worst returns on investment, while still worthy of consideration at 12.4%. The two CHP plant scenarios were both attractive, producing project returns of 17.7% and 23.2% at the 50,000tpy and 100,000tpy project scales, respectively. The investment for the pellet plants is much reduced compared to the CHP energy plants.

In general, the larger-scale scenarios tended to perform better than their smaller counterparts, which is commonly seem in financial modeling due to the inherent economies of scale in larger installations. The scale of the pellet plants has a much greater affect on project returns than it does for CHP plant returns, producing +14% ROI over the smaller scale pellet plant. The larger-scale CHP plant only increases project returns 6% over the CHP small-scale scenario.

The better financial performance of the larger-scale scenarios does not necessarily mean it is wise to build the largest installation possible. The feedstock analysis attempted to take into account feedstock acquisition logistics, using conservative calculations for potentially available feedstock material. However, if the volume of feedstock required to keep the plant running at full operational capacity can be acquired at a reasonable price, the plant runs at a lower rate, severely affecting returns. This condition is known as stranded capital.

After servicing construction debt, long-term financial performance of a biofuels plant is primarily dependent on the feedstock cost and finished product selling price. In the case of these proposed Project scenarios, feedstock volume acquisition is the variable determining the success of the proposed Projects. Feedstock price variability, as well as finished product price variability, is discussed in the sensitivity analyses further in the report.

The complete year two income statement is available below. The complete summary of the scenarios is in Appendices A-D.

Table 34 – Aitkin County Project Year 2 Income Statement

Proforma Income Statement for Year 2	50K Pellet		100K Pellet		50K Energy		100K Energy	
		$/ton		$/ton		$/ton		$/ton
Net Revenue	**$/Year**	**Feed**	**$/Year**	**Feed**	**$/Year**	**Feed**	**$/Year**	**Feed**
Pellets	$4,836,818	$96.74	$9,673,635	$96.74	$0	$0.00	$0	$0.00
Heat	$0	$0.00	$0	$0.00	$1,818,351	$36.37	$3,636,703	$36.37
Power	$0	$0.00	$0	$0.00	$8,951,431	$179.03	$17,902,862	$179.03
Total Revenue	**$4,836,818**	**$96.74**	**$9,673,635**	**$96.74**	**$10,769,782**	**$215.40**	**$21,539,565**	**$215.40**
Production & Operating Expenses								
Feedstocks	$1,801,840	$36.04	$3,603,680	$36.04	$1,801,840	$36.04	$3,603,680	$36.04
Chemicals	$0	$0.00	$0	$0.00	$0	$0.00	$0	$0.00
Natural Gas	$65,249	$1.31	$130,497	$1.31	$0	$0.00	$0	$0.00
Electricity	$140,479	$2.81	$280,959	$2.81	$0	$0.00	$0	$0.00
Makeup Water	$657	$0.01	$1,313	$0.01	$0	$0.00	$0	$0.00
Wastewater Disposal	$0	$0.00	$0	$0.00	$0	$0.00	$0	$0.00
Direct Labor & Benefits	$273,931	$5.48	$308,141	$3.08	$308,141	$6.16	$342,350	$3.42
Total Production Costs	**$2,282,156**	**$45.64**	**$4,324,590**	**$43.25**	**$2,109,981**	**$42.20**	**$3,946,030**	**$39.46**
Gross Profit	**$2,554,662**	**$51.09**	**$5,349,046**	**$53.49**	**$8,659,802**	**$173.20**	**$17,593,535**	**$175.94**
Administrative & Operating Expenses								
Maintenance Materials & Services	$128,418	$2.57	$243,986	$2.44	$653,538	$13.07	$1,278,961	$12.79
Repairs & Maintenance - Wages & Benefits	$116,722	$2.33	$116,722	$1.17	$227,038	$4.54	$227,038	$2.27
Consulting, Management and Bank Fees	$0	$0.00	$0	$0.00	$0	$0.00	$0	$0.00
Property Taxes & Insurance	$138,159	$2.76	$229,402	$2.29	$459,457	$9.19	$872,370	$8.72
Admin. Salaries, Wages & Benefits	$120,566	$2.41	$120,566	$1.21	$120,566	$2.41	$120,566	$1.21
Legal & Accounting/Community Affairs	$61,200	$1.22	$61,200	$0.61	$122,400	$2.45	$122,400	$1.22
Office/Lab Supplies & Expenses	$73,440	$1.47	$73,440	$0.73	$97,920	$1.96	$97,920	$0.98
Travel, Training & Miscellaneous	$34,000	$0.68	$34,000	$0.34	$34,000	$0.68	$34,000	$0.34
Total Administrative & Operating Expenses	**$672,504**	**$13.45**	**$879,315**	**$8.79**	**$1,714,918**	**$34.30**	**$2,753,254**	**$27.53**
EBITDA	**$1,882,158**	**$37.64**	**$4,469,731**	**$44.70**	**$6,944,884**	**$138.90**	**$14,840,281**	**$148.40**
Less:								
Interest - Operating Line of Credit	$0	$0.00	$0	$0.00	$0	$0.00	$0	$0.00
Interest - Senior Debt	$588,309	$11.77	$976,471	$9.76	$1,804,871	$36.10	$3,293,408	$32.93
Interest - Working Capital	$0	$0.00	$0	$0.00	$0	$0.00	$0	$0.00
Depreciation & Amortization	$822,863	$16.46	$1,282,004	$12.82	$2,419,986	$48.40	$4,498,650	$44.99
Current Income Taxes	$0	$0.00	$0	$0.00	$0	$0.00	$0	$0.00
Year 2 Net Earnings Before Income Taxes	**$470,986**	**$9.42**	**$2,211,255**	**$22.11**	**$2,720,026**	**$54.40**	**$7,048,223**	**$70.48**
11-Year Average Annual Pre-Tax Income	**$673,742**	**$13.47**	**$2,406,534**	**$24.07**	**$2,935,014**	**$58.70**	**$7,048,384**	**$70.48**
11-Year Average Annual Pre-Tax ROI	**12.4%**		**26.8%**		**17.7%**		**23.2%**	
Internal Rate of Return (IRR)	**12.8%**		**24.1%**		**18.9%**		**22.0%**	

Sensitivity and Breakeven Analysis

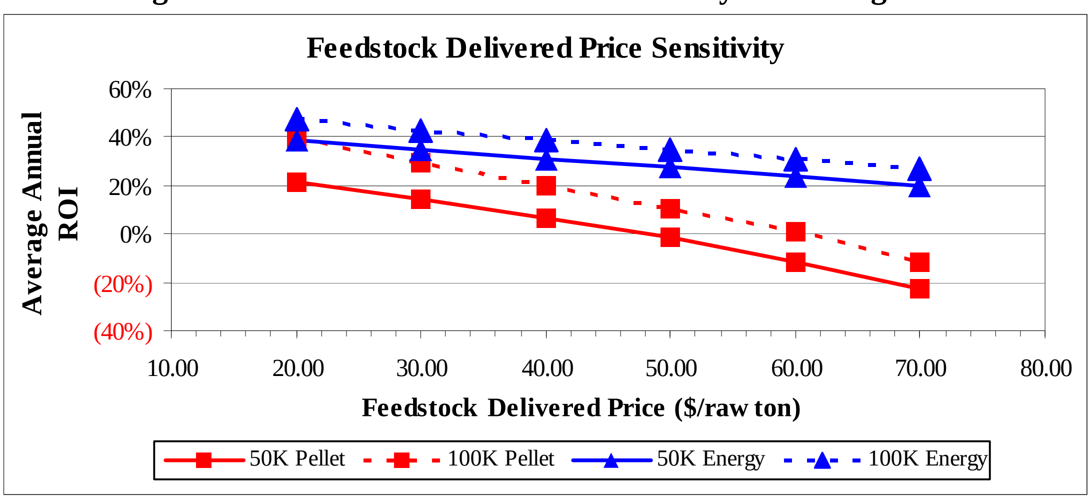
The variables that have the greatest impact on the project's profitability are the delivered feedstock price and the finished product selling price. This is the case for all biomass facilities, not just the proposed projects. A series of sensitivity analyses were run to examine the effect of critical parameters on the projected 11-year Average Annual After-Tax ROI. The parameters analyzed include:

- Feedstock Price
- Pellet Sale Price
- CHP-generated Electricity Energy Sale Price
- CHP-generated Thermal Energy Sale Price
- Capital Cost

The results of these parameter studies are shown in the graphs that follow. Each of the sensitivity figures assumes that only one variable is changing and that all others are constant as listed in the financial assumptions towards the beginning of this section. As expected, the projected profitability as measured by the ROI is very sensitive to feedstock and primary product prices prices; moderately sensitive to initial capital expenditure and co-product pricing; and relatively insensitive to the utility input prices of natural gas and electricity.

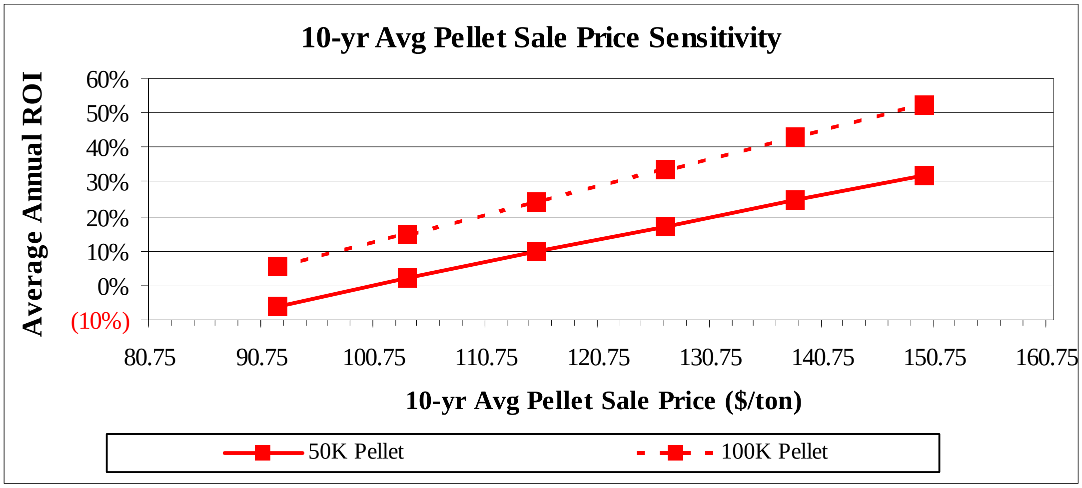
The sensitivity to feedstock price shows that the pellet plants, as a whole, are more sensitive than the CHP plants (Figure 37). The ROI breaks even at feedstock prices of \$48/ton and \$61/ton in the small and large pellet plant scenarios, respectively, and \$123/ton and \$136/ton for the two CHP plant scales. The larger plant scales are slightly less sensitive to feedstock pricing than the smaller plant scales, when comparing within the same conversion technologies.

Figure 37 – Effect of Feedstock Price on 11-year Average ROI



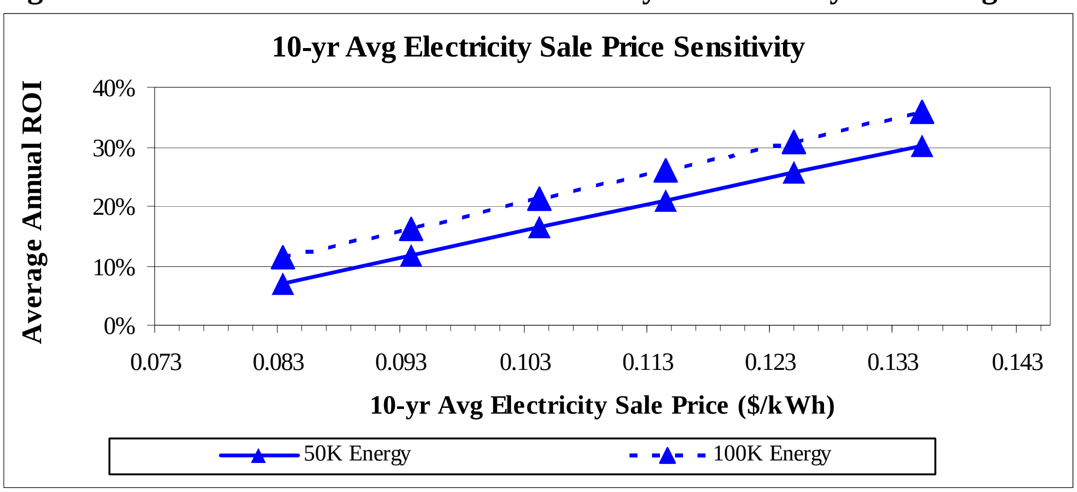
The pellet plants are highly sensitive to the value of finished pellets, as can be expected (Figure 38). The 50,000tpy pellet plant will break even at pellet prices of approximately \$100, while the 100,000tpy plant scale breaks even at pellet prices near \$85. Again, the larger scale is only slightly less sensitive to pellet price fluctuations.

Figure 38 – Effect of Pellet Price on 11-year Average ROI



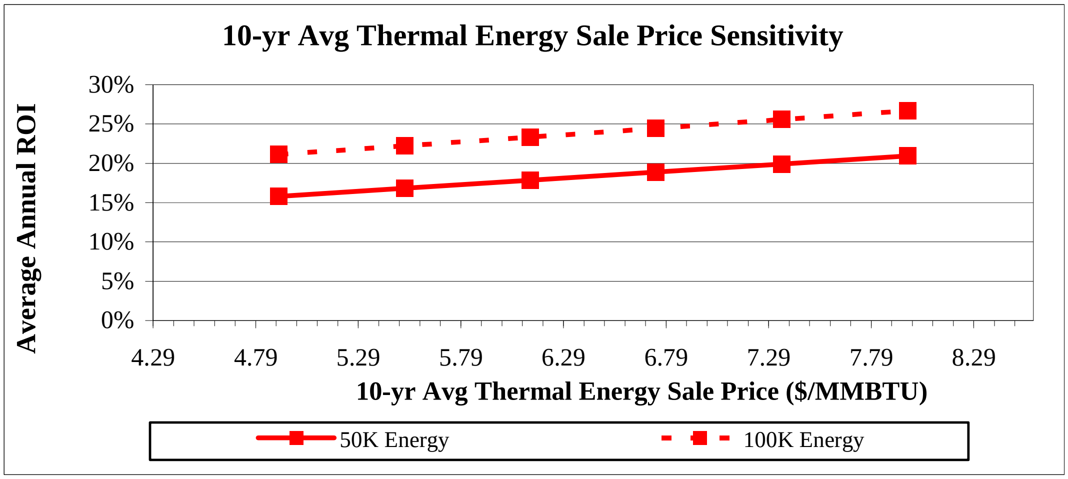
The primary sale product of CHP plants is electricity, and the CHP plants are highly sensitive to the final sale price of electricity (Figure 39). The smaller plant scale can sell electricity at 6.72¢/kWh and break even financially, while the larger plant scale can sell electricity at a minimum price of 5.89¢/kWh without producing negative returns.

Figure 39 – Effect of CHP-Generated Electricity Price on 11-year Average ROI



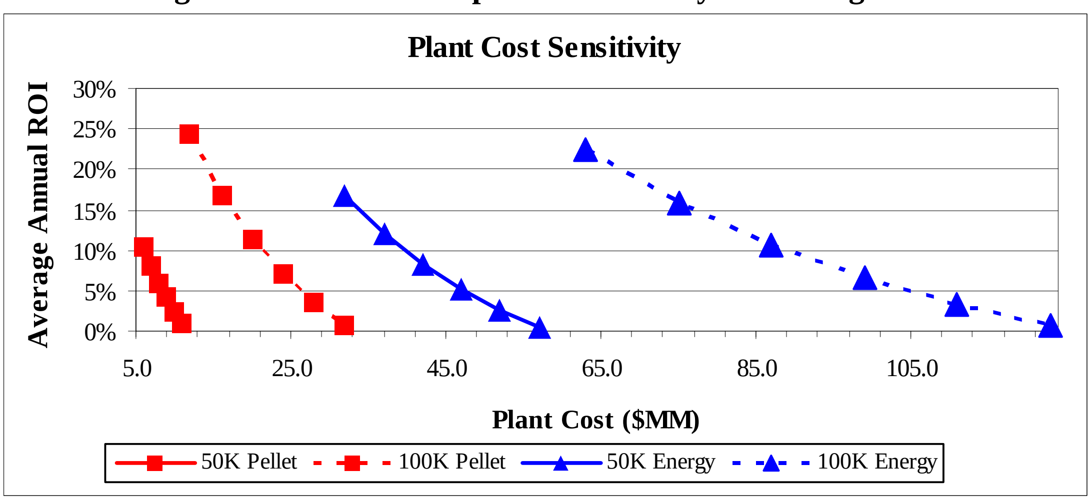
The CHP plants derive revenue from the sale of thermal energy, but do not rely on those sales as much as the electricity sales to produce positive returns. Figure 40 shows the CHP plant sensitivities to thermal energy sale price. Both plant scales will still produce positive financial returns if the thermal energy is not sold (break even price is below $0.00/MMBTU).

Figure 40 – Effect of CHP-Generated Thermal Energy Price on 11-year Average ROI



Capital cost figures are presented as an order-of-magnitude estimate (+/- 30%) in the study, due to the price variation between technology providers, site requirements, and other costs that cannot be projected at present. However, the plants are only moderately sensitive to changes in capital costs, and, except for the small-scale pellet plant, can survive significant increases in initial expenditure (Figure 41).

Figure 41 – Effect of Capital Cost on 11-year Average ROI



The following table shows the change in the projected average annual ROI for the project for changes in both feedstock and finished product pricing. For the CHP plants, the electricity price is the variable of choice, while the less sensitive thermal energy sale price is kept constant.

Table 35 – Sensitivity and Breakeven Analysis for 50,000tpy Pellet

Feedstock and Ethanol Price Sensitivity
11-Year Average Annual Return on Investment
AURI - 50K Pellet

Feedstock Delivered Price ($/raw ton)	10-yr Avg Pellet Sale Price ($/ton)										
	57.68	69.21	80.75	92.28	103.82	115.36	126.89	138.43	149.96	161.50	173.03
11.68	-11.2%	-1.7%	5.8%	13.3%	20.8%	28.2%	35.7%	43.2%	50.7%	58.1%	65.6%
14.68	-14.5%	-4.3%	3.5%	11.0%	18.4%	25.9%	33.4%	40.9%	48.3%	55.8%	63.3%
17.68	-17.7%	-7.4%	1.2%	8.6%	16.1%	23.6%	31.1%	38.6%	46.0%	53.5%	61.0%
20.68	-21.1%	-10.6%	-1.1%	6.3%	13.8%	21.3%	28.8%	36.2%	43.7%	51.2%	58.7%
23.68	-24.4%	-13.8%	-3.7%	4.0%	11.5%	19.0%	26.4%	33.9%	41.4%	48.9%	56.3%
26.68	-27.7%	-17.1%	-6.7%	1.7%	9.2%	16.6%	24.1%	31.6%	39.1%	46.6%	54.0%
29.68	-31.0%	-20.4%	-9.9%	-0.6%	6.9%	14.3%	21.8%	29.3%	36.8%	44.2%	51.7%
32.68	-34.6%	-23.8%	-13.2%	-3.1%	4.5%	12.0%	19.5%	27.0%	34.4%	41.9%	49.4%
35.68	-37.9%	-27.1%	-16.5%	-6.1%	2.2%	9.7%	17.2%	24.6%	32.1%	39.6%	47.1%
38.68	-41.2%	-30.4%	-19.8%	-9.3%	-0.1%	7.4%	14.8%	22.3%	29.8%	37.3%	44.8%
41.68	-44.6%	-33.9%	-23.1%	-12.6%	-2.5%	5.1%	12.5%	20.0%	27.5%	35.0%	42.4%
44.68	-47.9%	-37.3%	-26.4%	-15.8%	-5.5%	2.7%	10.2%	17.7%	25.2%	32.6%	40.1%
47.68	-51.3%	-40.6%	-29.7%	-19.2%	-8.7%	0.4%	7.9%	15.4%	22.8%	30.3%	37.8%
50.68	-54.6%	-43.9%	-33.3%	-22.5%	-11.9%	-1.9%	5.6%	13.1%	20.5%	28.0%	35.5%
53.68	-58.0%	-47.3%	-36.6%	-25.8%	-15.2%	-4.9%	3.3%	10.7%	18.2%	25.7%	33.2%
56.68	-61.3%	-50.6%	-40.0%	-29.1%	-18.5%	-8.0%	0.9%	8.4%	15.9%	23.4%	30.8%
59.68	-64.7%	-54.0%	-43.3%	-32.5%	-21.8%	-11.3%	-1.4%	6.1%	13.6%	21.0%	28.5%

(Source: BBI analysis)

Table 36 – Sensitivity and Breakeven Analysis for 100,000tpy Pellet

Feedstock and Ethanol Price Sensitivity
11-Year Average Annual Return on Investment
AURI - 100K Pellet

Feedstock Delivered Price ($/raw ton)	10-yr Avg Pellet Sale Price ($/ton)										
	57.68	69.21	80.75	92.28	103.82	115.36	126.89	138.43	149.96	161.50	173.03
11.68	0.8%	10.1%	19.4%	28.7%	38.0%	47.3%	56.5%	65.8%	75.1%	84.4%	93.7%
14.68	-2.2%	7.2%	16.5%	25.8%	35.1%	44.4%	53.7%	63.0%	72.3%	81.5%	90.8%
17.68	-6.0%	4.3%	13.6%	22.9%	32.2%	41.5%	50.8%	60.1%	69.4%	78.7%	88.0%
20.68	-10.1%	1.4%	10.7%	20.0%	29.3%	38.6%	47.9%	57.2%	66.5%	75.8%	85.1%
23.68	-14.2%	-1.5%	7.8%	17.1%	26.4%	35.7%	45.0%	54.3%	63.6%	72.9%	82.2%
26.68	-18.3%	-5.2%	5.0%	14.3%	23.5%	32.8%	42.1%	51.4%	60.7%	70.0%	79.3%
29.68	-22.4%	-9.3%	2.1%	11.4%	20.7%	30.0%	39.3%	48.5%	57.8%	67.1%	76.4%
32.68	-26.5%	-13.4%	-0.8%	8.5%	17.8%	27.1%	36.4%	45.7%	55.0%	64.3%	73.6%
35.68	-30.7%	-17.5%	-4.5%	5.6%	14.9%	24.2%	33.5%	42.8%	52.1%	61.4%	70.7%
38.68	-34.8%	-21.6%	-8.5%	2.7%	12.0%	21.3%	30.6%	39.9%	49.2%	58.5%	67.8%
41.68	-38.9%	-25.7%	-12.6%	-0.2%	9.1%	18.4%	27.7%	37.0%	46.3%	55.6%	64.9%
44.68	-43.0%	-29.8%	-16.7%	-3.7%	6.3%	15.5%	24.8%	34.1%	43.4%	52.7%	62.0%
47.68	-47.2%	-34.0%	-20.8%	-7.7%	3.4%	12.7%	22.0%	31.3%	40.6%	49.8%	59.1%
50.68	-51.3%	-38.1%	-24.9%	-11.8%	0.5%	9.8%	19.1%	28.4%	37.7%	47.0%	56.3%
53.68	-55.4%	-42.3%	-29.0%	-15.9%	-2.9%	6.9%	16.2%	25.5%	34.8%	44.1%	53.4%
56.68	-59.6%	-46.4%	-33.2%	-20.0%	-6.9%	4.0%	13.3%	22.6%	31.9%	41.2%	50.5%
59.68	-63.7%	-50.5%	-37.3%	-24.1%	-11.0%	1.1%	10.4%	19.7%	29.0%	38.3%	47.6%

(Source: BBI analysis)

Table 37 – Sensitivity and Breakeven Analysis for 50,000tpy CHP

Feedstock and Ethanol Price Sensitivity
11-Year Average Annual Return on Investment
AURI - 50K Energy

Feedstock Delivered Price ($/raw ton)	10-yr Avg Electricity Sale Price ($/kWh)										
	0.052	**0.062**	**0.073**	**0.083**	**0.094**	**0.104**	**0.114**	**0.125**	**0.135**	**0.146**	**0.156**
11.68	-0.2%	4.4%	9.1%	13.7%	18.4%	23.0%	27.7%	32.3%	37.0%	41.6%	46.3%
14.68	-1.0%	3.6%	8.3%	12.9%	17.5%	22.2%	26.8%	31.5%	36.1%	40.8%	45.4%
17.68	-1.9%	2.8%	7.4%	12.1%	16.7%	21.4%	26.0%	30.7%	35.3%	40.0%	44.6%
20.68	-2.9%	2.0%	6.6%	11.3%	15.9%	20.6%	25.2%	29.9%	34.5%	39.2%	43.8%
23.68	-4.0%	1.2%	5.8%	10.5%	15.1%	19.7%	24.4%	29.0%	33.7%	38.3%	43.0%
26.68	-5.1%	0.3%	5.0%	9.6%	14.3%	18.9%	23.6%	28.2%	32.9%	37.5%	42.2%
29.68	-6.2%	-0.5%	4.2%	8.8%	13.5%	18.1%	22.8%	27.4%	32.1%	36.7%	41.4%
32.68	-7.3%	-1.3%	3.4%	8.0%	12.7%	17.3%	22.0%	26.6%	31.2%	35.9%	40.5%
35.68	-8.5%	-2.2%	2.5%	7.2%	11.8%	16.5%	21.1%	25.8%	30.4%	35.1%	39.7%
38.68	-9.6%	-3.2%	1.7%	6.4%	11.0%	15.7%	20.3%	25.0%	29.6%	34.3%	38.9%
41.68	-10.8%	-4.3%	0.9%	5.6%	10.2%	14.9%	19.5%	24.2%	28.8%	33.4%	38.1%
44.68	-11.9%	-5.4%	0.1%	4.7%	9.4%	14.0%	18.7%	23.3%	28.0%	32.6%	37.3%
47.68	-13.1%	-6.5%	-0.7%	3.9%	8.6%	13.2%	17.9%	22.5%	27.2%	31.8%	36.5%
50.68	-14.3%	-7.7%	-1.5%	3.1%	7.8%	12.4%	17.1%	21.7%	26.4%	31.0%	35.7%
53.68	-15.4%	-8.8%	-2.5%	2.3%	6.9%	11.6%	16.2%	20.9%	25.5%	30.2%	34.8%
56.68	-16.6%	-10.0%	-3.6%	1.5%	6.1%	10.8%	15.4%	20.1%	24.7%	29.4%	34.0%
59.68	-17.8%	-11.1%	-4.6%	0.7%	5.3%	10.0%	14.6%	19.3%	23.9%	28.6%	33.2%

(Source: BBI analysis)

Table 38 – Sensitivity and Breakeven Analysis for 100,000tpy CHP

Feedstock and Ethanol Price Sensitivity
11-Year Average Annual Return on Investment
AURI - 100K Energy

Feedstock Delivered Price ($/raw ton)	10-yr Avg Electricity Sale Price ($/kWh)										
	0.052	**0.062**	**0.073**	**0.083**	**0.094**	**0.104**	**0.114**	**0.125**	**0.135**	**0.146**	**0.156**
11.68	4.2%	9.3%	14.4%	19.5%	24.6%	29.7%	34.8%	39.9%	45.0%	50.1%	55.2%
14.68	3.3%	8.4%	13.5%	18.6%	23.7%	28.8%	33.9%	39.0%	44.1%	49.2%	54.3%
17.68	2.4%	7.5%	12.6%	17.7%	22.8%	27.9%	33.0%	38.1%	43.2%	48.3%	53.4%
20.68	1.5%	6.6%	11.7%	16.8%	21.9%	27.0%	32.1%	37.2%	42.3%	47.4%	52.5%
23.68	0.6%	5.7%	10.8%	15.9%	21.0%	26.1%	31.2%	36.3%	41.4%	46.5%	51.6%
26.68	-0.3%	4.8%	9.9%	15.0%	20.1%	25.2%	30.3%	35.4%	40.5%	45.6%	50.7%
29.68	-1.5%	3.9%	9.0%	14.1%	19.2%	24.3%	29.4%	34.5%	39.6%	44.7%	49.8%
32.68	-2.8%	3.0%	8.1%	13.2%	18.3%	23.4%	28.5%	33.6%	38.7%	43.8%	48.9%
35.68	-4.0%	2.1%	7.2%	12.3%	17.4%	22.5%	27.6%	32.7%	37.8%	42.9%	48.0%
38.68	-5.3%	1.2%	6.3%	11.4%	16.5%	21.6%	26.7%	31.8%	36.9%	42.0%	47.1%
41.68	-6.6%	0.3%	5.4%	10.5%	15.6%	20.7%	25.8%	30.9%	36.0%	41.1%	46.2%
44.68	-7.9%	-0.6%	4.5%	9.6%	14.7%	19.8%	24.9%	30.0%	35.1%	40.2%	45.3%
47.68	-9.3%	-1.9%	3.6%	8.7%	13.8%	18.9%	24.0%	29.1%	34.2%	39.3%	44.4%
50.68	-10.6%	-3.2%	2.7%	7.8%	12.9%	18.0%	23.1%	28.2%	33.3%	38.4%	43.5%
53.68	-11.8%	-4.5%	1.8%	6.9%	12.0%	17.1%	22.2%	27.3%	32.4%	37.5%	42.6%
56.68	-13.1%	-5.8%	0.9%	6.0%	11.1%	16.2%	21.3%	26.4%	31.5%	36.6%	41.7%
59.68	-14.4%	-7.1%	0.0%	5.1%	10.2%	15.3%	20.4%	25.5%	30.6%	35.7%	40.9%

(Source: BBI analysis)

APPENDIX A:

FINANCIAL FORECAST 50,000TPY PELLET PLANT

AURI - 50K Pellet
Production Assumptions

Nameplate Plant Scale (raw tons feedstock/year)	50,000
Operating Days Per Year	300

	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Feedstock Inputs											
Total Feedstock Purchase (raw ton/year)	48,750	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	
Feedstock Usage (raw ton/year)	43,750	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	
Feedstock Moisture Content (%)	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%	
Feedstock HHV (btu/lb)	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	
Feedstock Usage (dry ton/year)	35,582	40,665	40,665	40,665	40,665	40,665	40,665	40,665	40,665	40,665	
Delivered Feedstock Price ($/raw ton)	$35.68	$36.04	$36.40	$36.76	$37.13	$37.50	$37.88	$38.25	$38.64	$39.02	1.00%
Delivered Price ($/dry ton)	$43.87	$44.31	$44.75	$45.20	$45.65	$46.11	$46.57	$47.04	$47.51	$47.98	1.00%
Production Outputs											
Heat & Power											
Co-generation Efficiency (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Heat Recovery (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Total Raw Feedstock Energy Content (MMBTU/yr)	700,000	800,000	800,000	800,000	800,000	800,000	800,000	800,000	800,000	800,000	
Electricity Production (kWh/yr)	0	0	0	0	0	0	0	0	0	0	
Electricity Available for Sale (kWh/yr)	0	0	0	0	0	0	0	0	0	0	
Electricity Sale Price ($/kWh)	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	
Thermal Energy Production (MMBTU/yr)	0	0	0	0	0	0	0	0	0	0	
Thermal Energy Available for Sale (MMBTU/yr)	0	0	0	0	0	0	0	0	0	0	
Thermal Energy Sale Price ($/MMBTU)	$5.8477	$5.8557	$5.9035	$5.9673	$6.0629	$6.1904	$6.3499	$6.4933	$6.3897	$6.2223	
Utility Usage											
Thermal Energy Required (BTU/raw ton feedstock)	189,428	189,428	189,428	189,428	189,428	189,428	189,428	189,428	189,428	189,428	
Thermal Energy Generated (BTU/raw ton)	0	0	0	0	0	0	0	0	0	0	
Makeup Energy Needed (BTU/raw ton)	189,428	189,428	189,428	189,428	189,428	189,428	189,428	189,428	189,428	189,428	
Thermal Energy Price ($/MMBTU)	6.88	6.89	6.95	7.02	7.13	7.28	7.47	7.64	7.52	7.32	
Annual Thermal Energy Use (MMBTU/yr)	8,287	9,471	9,471	9,471	9,471	9,471	9,471	9,471	9,471	9,471	
Electricity Required (kWh/raw ton feedstock)	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	
Electricity Generated (kWh/raw ton)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Makeup Electricity Needed (kWh/raw ton)	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	
Electricity Price ($/kWh)	0.0548	0.0549	0.0548	0.0550	0.0552	0.0556	0.0561	0.0568	0.0572	0.0571	
Annual Electricity Use (kWh/year)	2,239,790	2,559,760	2,559,760	2,559,760	2,559,760	2,559,760	2,559,760	2,559,760	2,559,760	2,559,760	
Electricity Demand (MW)	0.311	0.356	0.356	0.356	0.356	0.356	0.356	0.356	0.356	0.356	
Makeup Water Use (1000 gal/raw ton)	0.026	0.026	0.026	0.026	0.026	0.026	0.026	0.026	0.026	0.026	
Makeup Water Price ($/1000 gallons)	0.50	0.51	0.51	0.52	0.52	0.53	0.53	0.54	0.54	0.55	1.00%
Makeup Water Flow Rate (gpm)	3	3	3	3	3	3	3	3	3	3	
Daily Makeup Water (gpd)	3,792	4,333	4,333	4,333	4,333	4,333	4,333	4,333	4,333	4,333	
Waste Effluent Flow Rate (1000 gal/raw ton)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
Waste Effluent Price ($/1000 gallons)	1.00	1.01	1.02	1.03	1.04	1.05	1.06	1.07	1.08	1.09	1.00%
Waste Effluent Flow Rate (gpm)	0	0	0	0	0	0	0	0	0	0	
Daily Waste Effluent (gpd)	0	0	0	0	0	0	0	0	0	0	
Number of Employees	9	9	9	9	9	9	9	9	9	9	
Average Salary Including Benefits	$55,417	$56,802	$58,222	$59,678	$61,170	$62,699	$64,266	$65,873	$67,520	$69,208	2.50%
Maintenance Materials & Services (% of Capital Equipme	2.000%	2.030%	2.060%	2.091%	2.123%	2.155%	2.187%	2.220%	2.253%	2.287%	1.50%
Property Tax & Insurance (% of Depreciated Property, Pl	1.300%	1.339%	1.379%	1.421%	1.463%	1.507%	1.552%	1.599%	1.647%	1.696%	3.00%
Inflation for all other Administrative Expense Categories											2.00%

AURI - 50K Pellet
Financial Assumptions

USE OF FUNDS:	
Project Engineering & Construction Costs	
EPC Contract	$6,326,000
Site Development	$1,705,000
Rail	$1,335,000
Barge Unloading	$0
Additional Grain Storage	$0
Contingency	$645,000
Total Engineering and Construction Cost	$10,011,000
Development and Start-up Costs	
Inventory - Feedstock	$178,000
Inventory - Chemicals, Yeast, Denaturant	$0
Inventory - Spare Parts	$300,000
Start-up Costs	$33,200
Land	$76,000
Fire Protection & Potable Water	$0
Administration Building & Office Equipment	$100,000
Insurance & Performance Bond	$127,400
Rolling Stock & Shop Equipment	$710,000
Organizational Costs & Permits	$709,400
Capitalized Interest & Financing Costs	$711,270
Working Capital/Risk Management	$594,000
Total Development Costs	$3,539,270
TOTAL USES	**$13,550,270**

SOURCE OF FUNDS:		
Senior Debt		
Principal	$8,130,162	60.00%
Interest Rate	8.00% fixed	
Lender and Misc. Fees	$81,302	1.000%
Placement Fees	$0	0.000%
Amortization Period	10 years	
Cash Sweep	0.000%	
Subordinate Debt		
Principal	$0	0.00%
Interest Rate	8.00%	interest only
Lender Fees	$0	0.000%
Placement Fees	$0	1.500%
Amortization Period	10 years	
Equity Investment		
Total Equity Amount	$5,420,108	40.00%
Placement Fees	$0	0.000%
Common Equity	$5,420,108	100.000%
Preferred Equity	$0	0.000%
Grants		
Amount	$0	0.00%
TOTAL SOURCES	**$13,550,270**	

Accounts Payable, Receivable & Inventories	Receivable (# Days)	Payable (# Days)	Inventories (# Days)
Finished Products	14		8
Chemicals		15	20
Feedstock		10	30
Utilities		15	

Investment Activities	
Income Tax Rate	0.00%
Investment Interest	3.00%
Operating Line Interest	8.00%
State Producer Payment	
Producer payment, $/gal	$0
Estimated annual payment	$0
Incentive duration, years	0
Other Incentive Payments	
Small Producer Tax Credit	0
Maximum Cellulose Tax Credit	$0.00

Plant Operating Rate

Month	% of Nameplate
13	0.0%
14	50.0%
15	100.0%
16	100.0%
17	100.0%
18	100.0%
19	100.0%
20	100.0%
21	100.0%
22	100.0%
23	100.0%
24	100.0%

AURI - 50K Pellet
Proforma Balance Sheet

	Construction (Year 0) 2011	1st Year Operations 2012	2nd Year Operations 2013	3rd Year Operations 2014	4th Year Operations 2015	5th Year Operations 2016	6th Year Operations 2017	7th Year Operations 2018	8th Year Operations 2019	9th Year Operations 2020	10th Year Operations 2021
ASSETS											
Current Assets:											
Cash & Cash Equivalents	0	816,995	1,353,318	1,951,435	2,568,693	3,229,544	3,959,124	4,784,561	5,691,909	6,489,099	7,118,393
Accounts Receivable - Trade	0	187,842	225,718	227,562	230,020	233,707	238,623	244,768	250,299	246,304	239,852
Inventories											
Feedstock	0	156,100	180,184	181,986	183,806	185,644	187,500	189,375	191,269	193,182	195,113
Chemicals, Enzymes & Yeast	0	0	0	0	0	0	0	0	0	0	0
Finished Product Inventory	0	53,563	60,857	61,531	62,235	62,962	63,717	64,499	65,300	66,020	66,694
Spare Parts	0	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000
Total Inventories	0	509,663	541,041	543,517	546,041	548,606	551,217	553,875	556,569	559,202	561,808
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Other Current Assets	0	0	0	0	0	0	0	0	0	0	0
Total Current Assets	0	1,514,500	2,120,078	2,722,514	3,344,753	4,011,857	4,748,964	5,583,204	6,498,776	7,294,605	7,920,053
Land	76,000	76,000	76,000	76,000	76,000	76,000	76,000	76,000	76,000	76,000	76,000
Property, Plant & Equipment											
Property, Plant & Equipment, at cost	9,023,900	11,045,000	11,145,000	11,245,000	11,345,000	11,445,000	11,545,000	11,645,000	11,745,000	11,845,000	11,945,000
Less Accumulated Depreciation & Amortization	0	802,936	1,598,762	2,328,531	3,020,044	3,690,157	4,469,068	5,110,017	5,755,408	6,405,618	7,060,996
Net Property, Plant & Equipment	9,023,900	10,242,064	9,546,238	8,916,469	8,324,956	7,754,843	7,075,932	6,534,983	5,989,592	5,439,382	4,884,004
Capitalized Fees & Interest	181,961	270,363	243,327	216,290	189,254	162,218	135,182	108,145	81,109	54,073	27,036
Total Assets	9,281,861	12,102,928	11,985,642	11,931,273	11,934,964	12,004,918	12,036,077	12,302,332	12,645,477	12,864,060	12,907,093
LIABILITIES & EQUITIES											
Current Liabilities:											
Accounts Payable	0	58,144	70,381	71,000	71,666	72,364	73,101	73,878	74,675	75,310	75,845
Notes Payable	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Senior Debt (incl. sweeps)	0	600,503	650,004	703,585	761,583	824,362	892,316	965,872	1,045,491	1,131,673	0
Current Maturities of Working Capital	0	0	0	0	0	0	0	0	0	0	0
Total Current Liabilities	0	658,648	720,385	774,586	833,250	896,726	965,417	1,039,749	1,120,166	1,206,983	75,845
Senior Debt (excluding current maturities)	4,956,755	6,974,887	6,324,882	5,621,297	4,859,714	4,035,352	3,143,035	2,177,163	1,131,673	0	0
Working Capital (excluding current maturities)	0	0	0	0	0	0	0	0	0	0	0
Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Total Liabilities	4,956,755	7,633,534	7,045,267	6,395,883	5,692,963	4,932,078	4,108,452	3,216,913	2,251,838	1,206,983	75,845
Capital Units & Equities											
Common Equity	5,420,108	5,420,108	5,420,108	5,420,108	5,420,108	5,420,108	5,420,108	5,420,108	5,420,108	5,420,108	5,420,108
Preferred Equity	0	0	0	0	0	0	0	0	0	0	0
Grants (capital improvements)	0	0	0	0	0	0	0	0	0	0	0
Distribution to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	(1,095,001)	(950,715)	(479,733)	115,282	821,893	1,652,733	2,507,517	3,665,311	4,973,531	6,236,969	7,411,140
Total Capital Shares & Equities	4,325,107	4,469,393	4,940,375	5,535,390	6,242,001	7,072,841	7,927,625	9,085,419	10,393,639	11,657,077	12,831,248
Total Liabilities & Equities	9,281,861	12,102,928	11,985,642	11,931,273	11,934,964	12,004,918	12,036,077	12,302,332	12,645,477	12,864,060	12,907,093

AURI - 50K Pellet
Proforma Income Statement

	Construction (Year 0) 2011	1st Year Operations 2012	2nd Year Operations 2013	3rd Year Operations 2014	4th Year Operations 2015	5th Year Operations 2016	6th Year Operations 2017	7th Year Operations 2018	8th Year Operations 2019	9th Year Operations 2020	10th Year Operations 2021
Revenue											
Pellets	0	4,215,721	4,836,818	4,876,322	4,928,995	5,008,004	5,113,349	5,245,030	5,363,544	5,277,951	5,139,685
Heat	0	0	0	0	0	0	0	0	0	0	0
Power	0	0	0	0	0	0	0	0	0	0	0
Total Revenue	0	4,215,721	4,836,818	4,876,322	4,928,995	5,008,004	5,113,349	5,245,030	5,363,544	5,277,951	5,139,685
Production & Operating Expenses											
Feedstocks	0	1,561,000	1,801,840	1,819,858	1,838,057	1,856,438	1,875,002	1,893,752	1,912,689	1,931,816	1,951,135
Chemicals	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	57,015	65,249	65,782	66,492	67,558	68,979	70,755	72,354	71,200	69,334
Electricity	0	122,783	140,479	140,323	140,792	141,417	142,354	143,604	145,322	146,416	146,103
Makeup Water	0	569	657	663	670	676	683	690	697	704	711
Wastewater Disposal	0	0	0	0	0	0	0	0	0	0	0
Direct Labor & Benefits	44,542	267,250	273,931	280,780	287,799	294,994	302,369	309,928	317,676	325,618	333,759
Total Production Costs	44,542	2,008,616	2,282,156	2,307,406	2,333,810	2,361,083	2,389,387	2,418,729	2,448,739	2,475,754	2,501,042
Gross Profit	(44,542)	2,207,104	2,554,662	2,568,916	2,595,185	2,646,921	2,723,962	2,826,301	2,914,805	2,802,197	2,638,643
Administrative & Operating Expenses											
Maintenance Materials & Services	0	110,705	128,418	130,344	132,299	134,284	136,298	138,342	140,418	142,524	144,662
Repairs & Maintenance - Wages & Benefits	18,979	113,875	116,722	119,640	122,631	125,697	128,839	132,060	135,362	138,746	142,214
Consulting, Management and Bank Fees	0	0	0	0	0	0	0	0	0	0	0
Property Taxes & Insurance	23,660	118,299	138,159	132,707	127,742	122,920	118,015	111,017	105,699	99,888	93,552
Admin. Salaries, Wages & Benefits	98,021	117,625	120,566	123,580	126,669	129,836	133,082	136,409	139,819	143,315	146,898
Legal & Accounting/Community Affairs	659,400	60,000	61,200	62,424	63,672	64,946	66,245	67,570	68,921	70,300	71,706
Office/Lab Supplies & Expenses	50,400	72,000	73,440	74,909	76,407	77,935	79,494	81,084	82,705	84,359	86,047
Travel, Training & Miscellaneous	200,000	33,333	34,000	34,680	35,374	36,081	36,803	37,539	38,290	39,055	39,836
Total Administrative & Operating Expenses	1,050,460	625,837	672,504	678,284	684,795	691,698	698,776	704,021	711,213	718,187	724,914
EBITDA	(1,095,001)	1,581,267	1,882,158	1,890,633	1,910,390	1,955,223	2,025,186	2,122,280	2,203,591	2,084,010	1,913,729
Less:											
Interest - Operating Line of Credit	0	0	0	0	0	0	0	0	0	0	0
Interest - Senior Debt	0	634,044	588,313	538,813	485,231	427,233	364,454	296,500	222,945	143,326	57,144
Interest - Working Capital	0	0	0	0	0	0	0	0	0	0	0
Depreciation & Amortization	0	802,936	822,863	756,805	718,548	697,150	805,948	667,985	672,427	677,246	682,415
Pre-Tax Income	(1,095,001)	144,287	470,982	595,015	706,611	830,840	854,784	1,157,794	1,308,219	1,263,439	1,174,170
Current Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Net Earnings (Loss) for the Year	(1,095,001)	144,287	470,982	595,015	706,611	830,840	854,784	1,157,794	1,308,219	1,263,439	1,174,170
Pre-Tax Return on Investment	-20.2%	2.7%	8.7%	11.0%	13.0%	15.3%	15.8%	21.4%	24.1%	23.3%	21.7%
11-Year Average Annual Pre-Tax ROI	12.4%										

AURI - 50K Pellet
Proforma Statements of Cash Flows

Cash provided by (used in)	Construction (Year 0) 2011	1st Year Operations 2012	2nd Year Operations 2013	3rd Year Operations 2014	4th Year Operations 2015	5th Year Operations 2016	6th Year Operations 2017	7th Year Operations 2018	8th Year Operations 2019	9th Year Operations 2020	10th Year Operations 2021
Operating Activities											
Net Earnings (loss)	(1,095,001)	144,287	470,982	595,015	706,611	830,840	854,784	1,157,794	1,308,219	1,263,439	1,174,170
Non cash charges to operations											
Depreciation & Amortization	0	802,936	822,863	756,805	718,548	697,150	805,948	667,985	672,427	677,246	682,415
	(1,095,001)	947,223	1,293,844	1,351,820	1,425,159	1,527,990	1,660,732	1,825,780	1,980,647	1,940,684	1,856,585
Changes in non-cash working capital balances											
Accounts Receivable	0	187,842	37,876	1,844	2,458	3,687	4,916	6,145	5,531	(3,994)	(6,452)
Inventories	0	509,663	31,378	2,475	2,524	2,565	2,611	2,657	2,694	2,633	2,606
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Accounts Payable	0	(58,144)	(12,236)	(620)	(666)	(698)	(737)	(777)	(797)	(635)	(535)
	0	639,361	57,018	3,699	4,316	5,555	6,790	8,026	7,427	(1,996)	(4,382)
Investing Activities											
Land Purchase	76,000	0	0	0	0	0	0	0	0	0	0
Fixed Asset Purchases	9,023,900	2,021,100	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Capitalized Fees & Interest	181,961	88,402	0	0	0	0	0	0	0	0	0
	9,281,861	2,109,502	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Financing Activities											
Senior Debt Advances	4,956,755	3,173,407	0	0	0	0	0	0	0	0	0
Repayment of Senior Debt	0	(554,772)	(600,503)	(650,004)	(703,585)	(761,583)	(824,362)	(892,316)	(965,872)	(1,045,491)	(1,131,673)
Working Capital Advances	0	0	0	0	0	0	0	0	0	0	0
Repayment of Subordinate Debt	0	0	0	0	0	0	0	0	0	0	0
Equity Investment	5,420,108	0	0	0	0	0	0	0	0	0	0
Grants	0	0	0	0	0	0	0	0	0	0	0
Cash Sweep for Debt Service	0	0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Net Increase (Decrease) in Cash	0	816,995	536,323	598,117	617,258	660,851	729,579	825,438	907,348	797,190	629,294
Cash (Indebtedness), Beginning of Year	0	0	816,995	1,353,318	1,951,435	2,568,693	3,229,544	3,959,124	4,784,561	5,691,909	6,489,099
Cash (Bank Indebtedness), End of Year	0	816,995	1,353,318	1,951,435	2,568,693	3,229,544	3,959,124	4,784,561	5,691,909	6,489,099	7,118,393
IRR	12.8%										

AURI - 50K Pellet

Debt Coverage Ratio

		1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
EBITDA		1,581,267	1,882,158	1,890,633	1,910,390	1,955,223	2,025,186	2,122,280	2,203,591	2,084,010	1,913,729
Taxes Paid		0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders		0	0	0	0	0	0	0	0	0	0
Changes in non-cash working capital balances		(639,361)	(57,018)	(3,699)	(4,316)	(5,555)	(6,790)	(8,026)	(7,427)	1,996	4,382
Investing Activities (Capital Expenditures)		(2,109,502)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)
Senior Debt Advances		3,173,407	0	0	0	0	0	0	0	0	0
Working Capital Advances		0	0	0	0	0	0	0	0	0	0
Cash Available for Debt Service		2,005,812	1,725,140	1,786,934	1,806,074	1,849,668	1,918,396	2,014,254	2,096,164	1,986,006	1,818,111
Senior Debt P&I Payment		1,188,817	1,188,817	1,188,817	1,188,817	1,188,817	1,188,817	1,188,817	1,188,817	1,188,817	1,188,817
Suboridinate Debt P&I Payment		0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio (senior + subdebt)		1.69	1.45	1.50	1.52	1.56	1.61	1.69	1.76	1.67	1.53
10-year Average Debt Coverage Ratio	**1.60**										

Note: the '1st Year Operations' consists of 2 months of construction and startup, plus 10 months of commercial operation

Depreciation Schedules

	Depreciation Method (note1)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Major process equipment	15 year SLN	438,720	438,720	438,720	438,720	438,720	438,720	438,720	438,720	438,720	438,720
Minor process equipment	15 year SLN	96,777	96,777	96,777	96,777	96,777	96,777	96,777	96,777	96,777	96,777
Process buildings	30 year DDB	115,453	107,756	100,572	93,867	87,609	81,769	76,318	71,230	66,481	62,049
Vehicles	5 year DDB	142,000	170,400	102,240	61,344	36,806	142,000	0	0	0	0
Office building	30 year DDB	6,667	6,222	5,807	5,420	5,059	4,722	4,407	4,113	3,839	3,583
Office equipment	5 year DDB	0	0	0	0	0	0	0	0	0	0
Start-up cost	20 year DDB	3,320	2,988	2,689	2,420	2,178	1,960	1,764	1,588	1,429	1,286
Annual capital expenditures	10 year SLN	0	0	10,000	20,000	30,000	40,000	50,000	60,000	70,000	80,000
Total Depreciation		802,936	822,863	756,805	718,548	697,150	805,948	667,985	672,427	677,246	682,415

Note 1: Depreciation Method = DDB (Double Declining Balance) or SLN (Straight Line)

APPENDIX B:
FINANCIAL FORECAST 100,000TPY PELLET PLANT

AURI - 100K Pellet
Production Assumptions

Nameplate Plant Scale (raw tons feedstock/year)	100,000
Operating Days Per Year	300

	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Feedstock Inputs											
Total Feedstock Purchase (raw ton/year)	80,833	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	
Feedstock Usage (raw ton/year)	70,833	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	
Feedstock Moisture Content (%)	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%	
Feedstock HHV (btu/lb)	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	
Feedstock Usage (dry ton/year)	57,609	81,330	81,330	81,330	81,330	81,330	81,330	81,330	81,330	81,330	
Delivered Feedstock Price ($/raw ton)	$35.68	$36.04	$36.40	$36.76	$37.13	$37.50	$37.88	$38.25	$38.64	$39.02	1.00%
Delivered Price ($/dry ton)	$43.87	$44.31	$44.75	$45.20	$45.65	$46.11	$46.57	$47.04	$47.51	$47.98	1.00%
Production Outputs											
Heat & Power											
Co-generation Efficiency (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Heat Recovery (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
Total Raw Feedstock Energy Content (MMBTU/yr)	1,133,333	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	
Electricity Production (kWh/yr)	0	0	0	0	0	0	0	0	0	0	
Electricity Available for Sale (kWh/yr)	0	0	0	0	0	0	0	0	0	0	
Electricity Sale Price ($/kWh)	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	
Thermal Energy Production (MMBTU/yr)	0	0	0	0	0	0	0	0	0	0	
Thermal Energy Available for Sale (MMBTU/yr)	0	0	0	0	0	0	0	0	0	0	
Thermal Energy Sale Price ($/MMBTU)	$5.8477	$5.8557	$5.9035	$5.9673	$6.0629	$6.1904	$6.3499	$6.4933	$6.3897	$6.2223	
Utility Usage											
Thermal Energy Required (BTU/raw ton feedstock)	189,428	189,428	189,428	189,428	189,428	189,428	189,428	189,428	189,428	189,428	
Thermal Energy Generated (BTU/raw ton)	0	0	0	0	0	0	0	0	0	0	
Makeup Energy Needed (BTU/raw ton)	189,428	189,428	189,428	189,428	189,428	189,428	189,428	189,428	189,428	189,428	
Thermal Energy Price ($/MMBTU)	6.88	6.89	6.95	7.02	7.13	7.28	7.47	7.64	7.52	7.32	
Annual Thermal Energy Use (MMBTU/yr)	13,418	18,943	18,943	18,943	18,943	18,943	18,943	18,943	18,943	18,943	
Electricity Required (kWh/raw ton feedstock)	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	
Electricity Generated (kWh/raw ton)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Makeup Electricity Needed (kWh/raw ton)	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	51.2	
Electricity Price ($/kWh)	0.0548	0.0549	0.0548	0.0550	0.0552	0.0556	0.0561	0.0568	0.0572	0.0571	
Annual Electricity Use (kWh/year)	3,626,327	5,119,520	5,119,520	5,119,520	5,119,520	5,119,520	5,119,520	5,119,520	5,119,520	5,119,520	
Electricity Demand (MW)	0.504	0.711	0.711	0.711	0.711	0.711	0.711	0.711	0.711	0.711	
Makeup Water Use (1000 gal/raw ton)	0.026	0.026	0.026	0.026	0.026	0.026	0.026	0.026	0.026	0.026	
Makeup Water Price ($/1000 gallons)	0.50	0.51	0.51	0.52	0.52	0.53	0.53	0.54	0.54	0.55	1.00%
Makeup Water Flow Rate (gpm)	4	6	6	6	6	6	6	6	6	6	
Daily Makeup Water (gpd)	6,139	8,667	8,667	8,667	8,667	8,667	8,667	8,667	8,667	8,667	
Waste Effluent Flow Rate (1000 gal/raw ton)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
Waste Effluent Price ($/1000 gallons)	1.00	1.01	1.02	1.03	1.04	1.05	1.06	1.07	1.08	1.09	1.00%
Waste Effluent Flow Rate (gpm)	0	0	0	0	0	0	0	0	0	0	
Daily Waste Effluent (gpd)	0	0	0	0	0	0	0	0	0	0	
Number of Employees	10	10	10	10	10	10	10	10	10	10	
Average Salary Including Benefits	$53,213	$54,543	$55,906	$57,304	$58,737	$60,205	$61,710	$63,253	$64,834	$66,455	2.50%
Maintenance Materials & Services (% of Capital Equipme	2.000%	2.030%	2.060%	2.091%	2.123%	2.155%	2.187%	2.220%	2.253%	2.287%	1.50%
Property Tax & Insurance (% of Depreciated Property, Pl	1.300%	1.339%	1.379%	1.421%	1.463%	1.507%	1.552%	1.599%	1.647%	1.696%	3.00%
Inflation for all other Administrative Expense Categories											2.00%

AURI - 100K Pellet
Financial Assumptions

USE OF FUNDS:	
Project Engineering & Construction Costs	
EPC Contract	$12,019,000
Site Development	$2,105,000
Rail	$1,995,000
Barge Unloading	$0
Additional Grain Storage	$0
Contingency	$1,075,000
Total Engineering and Construction Cost	$17,194,000
Development and Start-up Costs	
Inventory - Feedstock	$357,000
Inventory - Chemicals, Yeast, Denaturant	$0
Inventory - Spare Parts	$400,000
Start-up Costs	$44,700
Land	$151,900
Fire Protection & Potable Water	$0
Administration Building & Office Equipment	$100,000
Insurance & Performance Bond	$168,100
Rolling Stock & Shop Equipment	$710,000
Organizational Costs & Permits	$969,800
Capitalized Interest & Financing Costs	$1,386,880
Working Capital/Risk Management	$1,091,000
Total Development Costs	$5,379,380
TOTAL USES	**$22,573,380**

SOURCE OF FUNDS:		
Senior Debt		
Principal	$13,544,028	60.00%
Interest Rate	8.00% fixed	
Lender and Misc. Fees	$135,440	1.000%
Placement Fees	$0	0.000%
Amortization Period	10 years	
Cash Sweep	0.000%	
Subordinate Debt		
Principal	$0	0.00%
Interest Rate	8.00%	interest only
Lender Fees	$0	0.000%
Placement Fees	$0	1.500%
Amortization Period	10 years	
Equity Investment		
Total Equity Amount	$9,029,352	40.00%
Placement Fees	$0	0.000%
Common Equity	$9,029,352	100.000%
Preferred Equity	$0	0.000%
Grants		
Amount	$0	0.00%
TOTAL SOURCES	**$22,573,380**	

Investment Activities	
Income Tax Rate	0.00%
Investment Interest	3.00%
Operating Line Interest	8.00%
State Producer Payment	
Producer payment, $/gal	$0
Estimated annual payment	$0
Incentive duration, years	0
Other Incentive Payments	
Small Producer Tax Credit	0
Maximum Cellulose Tax Credit	$0.00

Plant Operating Rate

Month	% of Nameplate
13	0.0%
14	0.0%
15	0.0%
16	50.0%
17	100.0%
18	100.0%
19	100.0%
20	100.0%
21	100.0%
22	100.0%
23	100.0%
24	100.0%

Accounts Payable, Receivable & Inventories	Receivable (# Days)	Payable (# Days)	Inventories (# Days)
Finished Products	14		8
Chemicals		15	20
Feedstock		10	30
Utilities		15	

AURI - 100K Pellet
Proforma Balance Sheet

ASSETS	Construction (Year 0) 2011	1st Year Operations 2012	2nd Year Operations 2013	3rd Year Operations 2014	4th Year Operations 2015	5th Year Operations 2016	6th Year Operations 2017	7th Year Operations 2018	8th Year Operations 2019	9th Year Operations 2020	10th Year Operations 2021
Current Assets:											
Cash & Cash Equivalents	0	2,200,903	4,399,098	6,811,236	9,275,904	11,842,738	14,562,532	17,488,085	20,593,831	23,495,818	26,078,747
Accounts Receivable - Trade	0	375,685	451,436	455,123	460,040	467,414	477,246	489,536	500,597	492,609	479,704
Inventories											
Feedstock	0	252,733	360,368	363,972	367,611	371,288	375,000	378,750	382,538	386,363	390,227
Chemicals, Enzymes & Yeast	0	0	0	0	0	0	0	0	0	0	0
Finished Product Inventory	0	83,199	115,322	116,509	117,754	119,040	120,378	121,766	123,186	124,441	125,600
Spare Parts	0	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000	400,000
Total Inventories	0	735,933	875,690	880,481	885,365	890,328	895,378	900,517	905,724	910,805	915,827
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Other Current Assets	0	0	0	0	0	0	0	0	0	0	0
Total Current Assets	0	3,312,521	5,726,225	8,146,840	10,621,308	13,200,479	15,935,156	18,878,138	22,000,152	24,899,232	27,474,278
Land	151,900	151,900	151,900	151,900	151,900	151,900	151,900	151,900	151,900	151,900	151,900
Property, Plant & Equipment											
Property, Plant & Equipment, at cost	15,412,700	18,252,100	18,352,100	18,452,100	18,552,100	18,652,100	18,752,100	18,852,100	18,952,100	19,052,100	19,152,100
Less Accumulated Depreciation & Amortization	0	1,267,930	2,491,036	3,642,863	4,751,563	5,834,320	7,021,639	8,067,043	9,113,202	10,160,741	11,210,241
Net Property, Plant & Equipment	15,412,700	16,984,170	15,861,064	14,809,237	13,800,537	12,817,780	11,730,461	10,785,057	9,838,898	8,891,359	7,941,859
Capitalized Fees & Interest	294,103	591,502	532,351	473,201	414,051	354,901	295,751	236,601	177,450	118,300	59,150
Total Assets	15,858,703	21,040,093	22,271,540	23,581,178	24,987,797	26,525,060	28,113,269	30,051,696	32,168,401	34,060,791	35,627,187
LIABILITIES & EQUITIES											
Current Liabilities:											
Accounts Payable	0	116,289	140,761	142,001	143,333	144,728	146,202	147,755	149,350	150,620	151,690
Notes Payable	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Senior Debt (incl. sweeps)	0	1,000,378	1,082,841	1,172,102	1,268,721	1,373,304	1,486,509	1,609,045	1,741,682	1,885,252	0
Current Maturities of Working Capital	0	0	0	0	0	0	0	0	0	0	0
Total Current Liabilities	0	1,116,667	1,223,602	1,314,103	1,412,053	1,518,032	1,632,710	1,756,800	1,891,032	2,035,872	151,690
Senior Debt (excluding current maturities)	8,157,123	11,619,456	10,536,615	9,364,513	8,095,792	6,722,488	5,235,979	3,626,934	1,885,252	0	0
Working Capital (excluding current maturities)	0	0	0	0	0	0	0	0	0	0	0
Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Total Liabilities	8,157,123	12,736,122	11,760,217	10,678,616	9,507,845	8,240,520	6,868,690	5,383,734	3,776,284	2,035,872	151,690
Capital Units & Equities											
Common Equity	9,029,352	9,029,352	9,029,352	9,029,352	9,029,352	9,029,352	9,029,352	9,029,352	9,029,352	9,029,352	9,029,352
Preferred Equity	0	0	0	0	0	0	0	0	0	0	0
Grants (capital improvements)	0	0	0	0	0	0	0	0	0	0	0
Distribution to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	(1,327,772)	(725,382)	1,481,971	3,873,210	6,450,599	9,255,188	12,215,227	15,638,610	19,362,764	22,995,567	26,446,145
Total Capital Shares & Equities	7,701,580	8,303,970	10,511,323	12,902,562	15,479,951	18,284,540	21,244,579	24,667,962	28,392,116	32,024,919	35,475,497
Total Liabilities & Equities	15,858,703	21,040,093	22,271,540	23,581,178	24,987,797	26,525,060	28,113,269	30,051,696	32,168,401	34,060,791	35,627,187

AURI - 100K Pellet
Proforma Income Statement

	Construction (Year 0) 2011	1st Year Operations 2012	2nd Year Operations 2013	3rd Year Operations 2014	4th Year Operations 2015	5th Year Operations 2016	6th Year Operations 2017	7th Year Operations 2018	8th Year Operations 2019	9th Year Operations 2020	10th Year Operations 2021
Revenue											
Pellets	0	6,815,996	9,673,635	9,752,644	9,857,989	10,016,007	10,226,698	10,490,061	10,727,087	10,555,901	10,279,370
Heat	0	0	0	0	0	0	0	0	0	0	0
Power	0	0	0	0	0	0	0	0	0	0	0
Total Revenue	0	6,815,996	9,673,635	9,752,644	9,857,989	10,016,007	10,226,698	10,490,061	10,727,087	10,555,901	10,279,370
Production & Operating Expenses											
Feedstocks	0	2,527,333	3,603,680	3,639,717	3,676,114	3,712,875	3,750,004	3,787,504	3,825,379	3,863,633	3,902,269
Chemicals	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	92,310	130,497	131,563	132,984	135,116	137,958	141,511	144,708	142,399	138,669
Electricity	0	198,791	280,959	280,646	281,584	282,834	284,708	287,208	290,644	292,832	292,207
Makeup Water	0	921	1,313	1,326	1,339	1,353	1,366	1,380	1,394	1,408	1,422
Wastewater Disposal	0	0	0	0	0	0	0	0	0	0	0
Direct Labor & Benefits	50,104	300,625	308,141	315,844	323,740	331,834	340,130	348,633	357,349	366,282	375,439
Total Production Costs	50,104	3,119,980	4,324,590	4,369,097	4,415,762	4,464,011	4,514,166	4,566,235	4,619,474	4,666,553	4,710,006
Gross Profit	(50,104)	3,696,016	5,349,046	5,383,548	5,442,228	5,551,996	5,712,532	5,923,825	6,107,613	5,889,348	5,569,365
Administrative & Operating Expenses											
Maintenance Materials & Services	0	170,269	243,986	247,645	251,360	255,131	258,958	262,842	266,785	270,786	274,848
Repairs & Maintenance - Wages & Benefits	18,979	113,875	116,722	119,640	122,631	125,697	128,839	132,060	135,362	138,746	142,214
Consulting, Management and Bank Fees	0	0	0	0	0	0	0	0	0	0	0
Property Taxes & Insurance	40,468	202,340	229,452	220,846	212,530	204,147	195,460	184,446	174,864	164,529	153,392
Admin. Salaries, Wages & Benefits	98,021	117,625	120,566	123,580	126,669	129,836	133,082	136,409	139,819	143,315	146,898
Legal & Accounting/Community Affairs	869,800	60,000	61,200	62,424	63,672	64,946	66,245	67,570	68,921	70,300	71,706
Office/Lab Supplies & Expenses	50,400	72,000	73,440	74,909	76,407	77,935	79,494	81,084	82,705	84,359	86,047
Travel, Training & Miscellaneous	200,000	33,333	34,000	34,680	35,374	36,081	36,803	37,539	38,290	39,055	39,836
Total Administrative & Operating Expenses	1,277,668	769,442	879,365	883,724	888,643	893,772	898,880	901,949	906,745	911,089	914,941
EBITDA	(1,327,772)	2,926,574	4,469,680	4,499,824	4,553,585	4,658,224	4,813,651	5,021,876	5,200,868	4,978,258	4,654,424
Less:											
Interest - Operating Line of Credit	0	0	0	0	0	0	0	0	0	0	0
Interest - Senior Debt	0	1,056,254	980,071	897,607	808,346	711,727	607,144	493,940	371,403	238,766	95,196
Interest - Working Capital	0	0	0	0	0	0	0	0	0	0	0
Depreciation & Amortization	0	1,267,930	1,282,257	1,210,977	1,167,850	1,141,908	1,246,468	1,104,554	1,105,309	1,106,689	1,108,651
Pre-Tax Income	(1,327,772)	602,390	2,207,353	2,391,239	2,577,389	2,804,589	2,960,039	3,423,383	3,724,155	3,632,803	3,450,578
Current Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Net Earnings (Loss) for the Year	(1,327,772)	602,390	2,207,353	2,391,239	2,577,389	2,804,589	2,960,039	3,423,383	3,724,155	3,632,803	3,450,578
Pre-Tax Return on Investment	-14.7%	6.7%	24.4%	26.5%	28.5%	31.1%	32.8%	37.9%	41.2%	40.2%	38.2%
11-Year Average Annual Pre-Tax ROI	26.6%										

AURI - 100K Pellet
Proforma Statements of Cash Flows

	Construction (Year 0) 2011	1st Year Operations 2012	2nd Year Operations 2013	3rd Year Operations 2014	4th Year Operations 2015	5th Year Operations 2016	6th Year Operations 2017	7th Year Operations 2018	8th Year Operations 2019	9th Year Operations 2020	10th Year Operations 2021
Cash provided by (used in)											
Operating Activities											
Net Earnings (loss)	(1,327,772)	602,390	2,207,353	2,391,239	2,577,389	2,804,589	2,960,039	3,423,383	3,724,155	3,632,803	3,450,578
Non cash charges to operations											
Depreciation & Amortization	0	1,267,930	1,282,257	1,210,977	1,167,850	1,141,908	1,246,468	1,104,554	1,105,309	1,106,689	1,108,651
	(1,327,772)	1,870,320	3,489,610	3,602,216	3,745,238	3,946,497	4,206,507	4,527,937	4,829,464	4,739,492	4,559,228
Changes in non-cash working capital balances											
Accounts Receivable	0	375,685	75,751	3,687	4,916	7,374	9,832	12,290	11,061	(7,989)	(12,905)
Inventories	0	735,933	139,758	4,791	4,884	4,963	5,050	5,139	5,207	5,081	5,022
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Accounts Payable	0	(116,289)	(24,472)	(1,240)	(1,332)	(1,395)	(1,474)	(1,553)	(1,595)	(1,270)	(1,071)
	0	995,329	191,037	7,238	8,468	10,942	13,408	15,875	14,674	(4,178)	(8,953)
Investing Activities											
Land Purchase	151,900	0	0	0	0	0	0	0	0	0	0
Fixed Asset Purchases	15,412,700	2,839,400	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Capitalized Fees & Interest	294,103	297,399	0	0	0	0	0	0	0	0	0
	15,858,703	3,136,799	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Financing Activities											
Senior Debt Advances	8,157,123	5,386,905	0	0	0	0	0	0	0	0	0
Repayment of Senior Debt	0	(924,194)	(1,000,378)	(1,082,841)	(1,172,102)	(1,268,721)	(1,373,304)	(1,486,509)	(1,609,045)	(1,741,682)	(1,885,252)
Working Capital Advances	0	0	0	0	0	0	0	0	0	0	0
Repayment of Subordinate Debt	0	0	0	0	0	0	0	0	0	0	0
Equity Investment	9,029,352	0	0	0	0	0	0	0	0	0	0
Grants	0	0	0	0	0	0	0	0	0	0	0
Cash Sweep for Debt Service	0	0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Net Increase (Decrease) in Cash	0	2,200,903	2,198,195	2,412,137	2,464,668	2,566,834	2,719,795	2,925,552	3,105,746	2,901,988	2,582,929
Cash (Indebtedness), Beginning of Year	0	0	2,200,903	4,399,098	6,811,236	9,275,904	11,842,738	14,562,532	17,488,085	20,593,831	23,495,818
Cash (Bank Indebtedness), End of Year	0	2,200,903	4,399,098	6,811,236	9,275,904	11,842,738	14,562,532	17,488,085	20,593,831	23,495,818	26,078,747
IRR	24.1%										

AURI - 100K Pellet

Debt Coverage Ratio

		1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
EBITDA		2,926,574	4,469,680	4,499,824	4,553,585	4,658,224	4,813,651	5,021,876	5,200,868	4,978,258	4,654,424
Taxes Paid		0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders		0	0	0	0	0	0	0	0	0	0
Changes in non-cash working capital balances		(995,329)	(191,037)	(7,238)	(8,468)	(10,942)	(13,408)	(15,875)	(14,674)	4,178	8,953
Investing Activities (Capital Expenditures)		(3,136,799)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)
Senior Debt Advances		5,386,905	0	0	0	0	0	0	0	0	0
Working Capital Advances		0	0	0	0	0	0	0	0	0	0
Cash Available for Debt Service		4,181,351	4,178,644	4,392,586	4,445,116	4,547,282	4,700,243	4,906,001	5,086,194	4,882,436	4,563,377
Senior Debt P&I Payment		1,980,448	1,980,448	1,980,448	1,980,448	1,980,448	1,980,448	1,980,448	1,980,448	1,980,448	1,980,448
Suboridinate Debt P&I Payment		0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio (senior + subdebt)		2.11	2.11	2.22	2.24	2.30	2.37	2.48	2.57	2.47	2.30
10-year Average Debt Coverage Ratio	**2.32**										

Note: the '1st Year Operations' consists of 2 months of construction and startup, plus 10 months of commercial operation

Depreciation Schedules

	Depreciation Method (note1)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Major process equipment	15 year SLN	751,337	751,337	751,337	751,337	751,337	751,337	751,337	751,337	751,337	751,337
Minor process equipment	15 year SLN	165,736	165,736	165,736	165,736	165,736	165,736	165,736	165,736	165,736	165,736
Process buildings	30 year DDB	197,720	184,539	172,236	160,754	150,037	140,034	130,699	121,986	113,853	106,263
Vehicles	5 year DDB	142,000	170,400	102,240	61,344	36,806	142,000	0	0	0	0
Office building	30 year DDB	6,667	6,222	5,807	5,420	5,059	4,722	4,407	4,113	3,839	3,583
Office equipment	5 year DDB	0	0	0	0	0	0	0	0	0	0
Start-up cost	20 year DDB	4,470	4,023	3,621	3,259	2,933	2,639	2,376	2,138	1,924	1,732
Annual capital expenditures	10 year SLN	0	0	10,000	20,000	30,000	40,000	50,000	60,000	70,000	80,000
Total Depreciation		1,267,930	1,282,257	1,210,977	1,167,850	1,141,908	1,246,468	1,104,554	1,105,309	1,106,689	1,108,651

Note 1: Depreciation Method = DDB (Double Declining Balance) or SLN (Straight Line)

APPENDIX C:
FINANCIAL FORECAST 50,000TPY CHP PLANT

AURI - 50K Energy
Production Assumptions

Nameplate Plant Scale (raw tons feedstock/year)	50,000
Operating Days Per Year	300

	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Feedstock Inputs											
Total Feedstock Purchase (raw ton/year)	48,750	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	
Feedstock Usage (raw ton/year)	43,750	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000	
Feedstock Moisture Content (%)	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%	
Feedstock HHV (btu/lb)	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	
Feedstock Usage (dry ton/year)	35,582	40,665	40,665	40,665	40,665	40,665	40,665	40,665	40,665	40,665	
Delivered Feedstock Price ($/raw ton)	$35.68	$36.04	$36.40	$36.76	$37.13	$37.50	$37.88	$38.25	$38.64	$39.02	1.00%
Delivered Price ($/dry ton)	$43.87	$44.31	$44.75	$45.20	$45.65	$46.11	$46.57	$47.04	$47.51	$47.98	1.00%
Production Outputs											
Heat & Power											
Co-generation Efficiency (%)	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	
Heat Recovery (%)	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	
Total Raw Feedstock Energy Content (MMBTU/yr)	700,000	800,000	800,000	800,000	800,000	800,000	800,000	800,000	800,000	800,000	
Electricity Production (kWh/yr)	75,908,558	86,752,638	86,752,638	86,752,638	86,752,638	86,752,638	86,752,638	86,752,638	86,752,638	86,752,638	
Electricity Available for Sale (kWh/yr)	75,312,522	86,071,453	86,071,453	86,071,453	86,071,453	86,071,453	86,071,453	86,071,453	86,071,453	86,071,453	
Electricity Sale Price ($/kWh)	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	
Thermal Energy Production (MMBTU/yr)	280,000	320,000	320,000	320,000	320,000	320,000	320,000	320,000	320,000	320,000	
Thermal Energy Available for Sale (MMBTU/yr)	271,713	310,529	310,529	310,529	310,529	310,529	310,529	310,529	310,529	310,529	
Thermal Energy Sale Price ($/MMBTU)	$5.8477	$5.8557	$5.9035	$5.9673	$6.0629	$6.1904	$6.3499	$6.4933	$6.3897	$6.2223	
Utility Usage											
Thermal Energy Required (BTU/raw ton feedstock)	189,428	189,428	189,428	189,428	189,428	189,428	189,428	189,428	189,428	189,428	
Thermal Energy Generated (BTU/raw ton)	6,400,000	6,400,000	6,400,000	6,400,000	6,400,000	6,400,000	6,400,000	6,400,000	6,400,000	6,400,000	
Makeup Energy Needed (BTU/raw ton)	0	0	0	0	0	0	0	0	0	0	
Thermal Energy Price ($/MMBTU)	6.88	6.89	6.95	7.02	7.13	7.28	7.47	7.64	7.52	7.32	
Annual Thermal Energy Use (MMBTU/yr)	0	0	0	0	0	0	0	0	0	0	
Electricity Required (kWh/raw ton feedstock)	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	
Electricity Generated (kWh/raw ton)	1735.1	1735.1	1735.1	1735.1	1735.1	1735.1	1735.1	1735.1	1735.1	1735.1	
Makeup Electricity Needed (kWh/raw ton)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Electricity Price ($/kWh)	0.0548	0.0549	0.0548	0.0550	0.0552	0.0556	0.0561	0.0568	0.0572	0.0571	
Annual Electricity Use (kWh/year)	0	0	0	0	0	0	0	0	0	0	
Electricity Demand (MW)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Makeup Water Use (1000 gal/raw ton)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Makeup Water Price ($/1000 gallons)	0.50	0.51	0.51	0.52	0.52	0.53	0.53	0.54	0.54	0.55	1.00%
Makeup Water Flow Rate (gpm)	0	0	0	0	0	0	0	0	0	0	
Daily Makeup Water (gpd)	0	0	0	0	0	0	0	0	0	0	
Waste Effluent Flow Rate (1000 gal/raw ton)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
Waste Effluent Price ($/1000 gallons)	1.00	1.01	1.02	1.03	1.04	1.05	1.06	1.07	1.08	1.09	1.00%
Waste Effluent Flow Rate (gpm)	0	0	0	0	0	0	0	0	0	0	
Daily Waste Effluent (gpd)	0	0	0	0	0	0	0	0	0	0	
Number of Employees	12	12	12	12	12	12	12	12	12	12	
Average Salary Including Benefits	$53,313	$54,645	$56,011	$57,412	$58,847	$60,318	$61,826	$63,372	$64,956	$66,580	2.50%
Maintenance Materials & Services (% of Capital Equipme	2.000%	2.030%	2.060%	2.091%	2.123%	2.155%	2.187%	2.220%	2.253%	2.287%	1.50%
Property Tax & Insurance (% of Depreciated Property, Pl	1.300%	1.339%	1.379%	1.421%	1.463%	1.507%	1.552%	1.599%	1.647%	1.696%	3.00%
Inflation for all other Administrative Expense Categories											2.00%

AURI - 50K Energy
Financial Assumptions

USE OF FUNDS:	
Project Engineering & Construction Costs	
EPC Contract	$32,194,000
Site Development	$1,705,000
Rail	$0
Barge Unloading	$0
Additional Grain Storage	$0
Contingency	$1,980,000
Total Engineering and Construction Cost	$35,879,000
Development and Start-up Costs	
Inventory - Feedstock	$178,000
Inventory - Chemicals, Yeast, Denaturant	$0
Inventory - Spare Parts	$200,000
Start-up Costs	$29,900
Land	$76,000
Fire Protection & Potable Water	$0
Administration Building & Office Equipment	$100,000
Insurance & Performance Bond	$170,800
Rolling Stock & Shop Equipment	$560,000
Organizational Costs & Permits	$984,100
Capitalized Interest & Financing Costs	$2,787,840
Working Capital/Risk Management	$605,000
Total Development Costs	$5,691,640
TOTAL USES	**$41,570,640**

SOURCE OF FUNDS:		
Senior Debt		
Principal	$24,942,384	60.00%
Interest Rate	8.00% fixed	
Lender and Misc. Fees	$249,424	1.000%
Placement Fees	$0	0.000%
Amortization Period	10 years	
Cash Sweep	0.000%	
Subordinate Debt		
Principal	$0	0.00%
Interest Rate	8.00%	interest only
Lender Fees	$0	0.000%
Placement Fees	$0	1.500%
Amortization Period	10 years	
Equity Investment		
Total Equity Amount	$16,628,256	40.00%
Placement Fees	$0	0.000%
Common Equity	$16,628,256	100.000%
Preferred Equity	$0	0.000%
Grants		
Amount	$0	0.00%
TOTAL SOURCES	**$41,570,640**	

Accounts Payable, Receivable & Inventories	Receivable (# Days)	Payable (# Days)	Inventories (# Days)
Finished Products	14		8
Chemicals		15	20
Feedstock		10	30
Utilities		15	

Investment Activities	
Income Tax Rate	0.00%
Investment Interest	3.00%
Operating Line Interest	8.00%
State Producer Payment	
Producer payment, $/gal	$0
Estimated annual payment	$0
Incentive duration, years	0
Other Incentive Payments	
Small Producer Tax Credit	0
Maximum Cellulose Tax Credit	$0.00

Plant Operating Rate

Month	% of Nameplate
13	0.0%
14	50.0%
15	100.0%
16	100.0%
17	100.0%
18	100.0%
19	100.0%
20	100.0%
21	100.0%
22	100.0%
23	100.0%
24	100.0%

AURI - 50K Energy
Proforma Balance Sheet

	Construction (Year 0) 2011	1st Year Operations 2012	2nd Year Operations 2013	3rd Year Operations 2014	4th Year Operations 2015	5th Year Operations 2016	6th Year Operations 2017	7th Year Operations 2018	8th Year Operations 2019	9th Year Operations 2020	10th Year Operations 2021
ASSETS											
Current Assets:											
Cash & Cash Equivalents	0	4,518,615	7,696,148	10,874,535	14,039,992	17,202,326	20,371,558	23,559,330	26,759,496	29,895,881	32,949,310
Accounts Receivable - Trade	0	0	0	0	0	0	0	0	0	0	0
Inventories											
Feedstock	0	156,100	180,184	181,986	183,806	185,644	187,500	189,375	191,269	193,182	195,113
Chemicals, Enzymes & Yeast	0	0	0	0	0	0	0	0	0	0	0
Finished Product Inventory	0	49,643	56,266	56,952	57,648	58,354	59,070	59,797	60,534	61,283	62,042
Spare Parts	0	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
Total Inventories	0	405,743	436,450	438,938	441,454	443,998	446,570	449,172	451,803	454,464	457,155
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Other Current Assets	0	0	0	0	0	0	0	0	0	0	0
Total Current Assets	0	4,924,359	8,132,598	11,313,473	14,481,445	17,646,324	20,818,129	24,008,502	27,211,299	30,350,345	33,406,465
Land	76,000	76,000	76,000	76,000	76,000	76,000	76,000	76,000	76,000	76,000	76,000
Property, Plant & Equipment											
Property, Plant & Equipment, at cost	32,305,100	36,663,000	36,763,000	36,863,000	36,963,000	37,063,000	37,163,000	37,263,000	37,363,000	37,463,000	37,563,000
Less Accumulated Depreciation & Amortization	0	2,425,571	4,756,915	7,018,389	9,233,247	11,416,024	13,670,565	15,803,321	17,927,617	20,044,689	22,155,690
Net Property, Plant & Equipment	32,305,100	34,237,429	32,006,085	29,844,611	27,729,753	25,646,976	23,492,435	21,459,679	19,435,383	17,418,311	15,407,310
Capitalized Fees & Interest	602,857	886,428	797,785	709,142	620,500	531,857	443,214	354,571	265,928	177,286	88,643
Total Assets	32,983,957	40,124,216	41,012,469	41,943,227	42,907,698	43,901,157	44,829,778	45,898,752	46,988,610	48,021,942	48,978,418
LIABILITIES & EQUITIES											
Current Liabilities:											
Accounts Payable	0	49,556	60,061	60,662	61,269	61,881	62,500	63,125	63,756	64,394	65,038
Notes Payable	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Senior Debt (incl. sweeps)	0	1,842,274	1,994,136	2,158,517	2,336,448	2,529,047	2,737,522	2,963,182	3,207,443	3,471,839	0
Current Maturities of Working Capital	0	0	0	0	0	0	0	0	0	0	0
Total Current Liabilities	0	1,891,829	2,054,198	2,219,179	2,397,717	2,590,928	2,800,022	3,026,307	3,271,199	3,536,233	65,038
Senior Debt (excluding current maturities)	17,765,921	21,398,134	19,403,998	17,245,481	14,909,033	12,379,986	9,642,464	6,679,282	3,471,839	0	0
Working Capital (excluding current maturities)	0	0	0	0	0	0	0	0	0	0	0
Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Total Liabilities	17,765,921	23,289,963	21,458,196	19,464,660	17,306,749	14,970,914	12,442,486	9,705,589	6,743,039	3,536,233	65,038
Capital Units & Equities											
Common Equity	16,628,256	16,628,256	16,628,256	16,628,256	16,628,256	16,628,256	16,628,256	16,628,256	16,628,256	16,628,256	16,628,256
Preferred Equity	0	0	0	0	0	0	0	0	0	0	0
Grants (capital improvements)	0	0	0	0	0	0	0	0	0	0	0
Distribution to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	(1,410,220)	205,996	2,926,017	5,850,311	8,972,693	12,301,987	15,759,036	19,564,907	23,617,316	27,857,453	32,285,124
Total Capital Shares & Equities	15,218,036	16,834,252	19,554,273	22,478,567	25,600,949	28,930,243	32,387,292	36,193,163	40,245,572	44,485,709	48,913,380
Total Liabilities & Equities	32,983,957	40,124,216	41,012,469	41,943,227	42,907,698	43,901,157	44,829,778	45,898,752	46,988,610	48,021,942	48,978,418

AURI - 50K Energy
Proforma Income Statement

	Construction (Year 0) 2011	1st Year Operations 2012	2nd Year Operations 2013	3rd Year Operations 2014	4th Year Operations 2015	5th Year Operations 2016	6th Year Operations 2017	7th Year Operations 2018	8th Year Operations 2019	9th Year Operations 2020	10th Year Operations 2021
Revenue											
Pellets	0	0	0	0	0	0	0	0	0	0	0
Heat	0	1,588,892	1,818,351	1,833,203	1,853,004	1,882,707	1,922,310	1,971,815	2,016,368	1,984,191	1,932,211
Power	0	7,832,502	8,951,431	8,951,431	8,951,431	8,951,431	8,951,431	8,951,431	8,951,431	8,951,431	8,951,431
Total Revenue	0	9,421,394	10,769,782	10,784,634	10,804,435	10,834,138	10,873,741	10,923,246	10,967,800	10,935,622	10,883,642
Production & Operating Expenses											
Feedstocks	0	1,561,000	1,801,840	1,819,858	1,838,057	1,856,438	1,875,002	1,893,752	1,912,689	1,931,816	1,951,135
Chemicals	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0	0	0	0	0	0
Electricity	0	0	0	0	0	0	0	0	0	0	0
Makeup Water	0	0	0	0	0	0	0	0	0	0	0
Wastewater Disposal	0	0	0	0	0	0	0	0	0	0	0
Direct Labor & Benefits	50,104	300,625	308,141	315,844	323,740	331,834	340,130	348,633	357,349	366,282	375,439
Total Production Costs	50,104	1,861,625	2,109,981	2,135,703	2,161,797	2,188,271	2,215,132	2,242,385	2,270,038	2,298,099	2,326,574
Gross Profit	(50,104)	7,559,769	8,659,802	8,648,931	8,642,638	8,645,867	8,658,610	8,680,861	8,697,761	8,637,523	8,557,068
Administrative & Operating Expenses											
Maintenance Materials & Services	0	563,395	653,538	663,341	673,291	683,391	693,642	704,046	714,607	725,326	736,206
Repairs & Maintenance - Wages & Benefits	26,604	221,500	227,038	232,713	238,531	244,495	250,607	256,872	263,294	269,876	276,623
Consulting, Management and Bank Fees	0	0	0	0	0	0	0	0	0	0	0
Property Taxes & Insurance	84,191	420,954	459,457	442,466	425,036	406,843	387,660	365,845	344,320	321,314	296,739
Admin. Salaries, Wages & Benefits	98,021	117,625	120,566	123,580	126,669	129,836	133,082	136,409	139,819	143,315	146,898
Legal & Accounting/Community Affairs	884,100	120,000	122,400	124,848	127,345	129,892	132,490	135,139	137,842	140,599	143,411
Office/Lab Supplies & Expenses	67,200	96,000	97,920	99,878	101,876	103,913	105,992	108,112	110,274	112,479	114,729
Travel, Training & Miscellaneous	200,000	33,333	34,000	34,680	35,374	36,081	36,803	37,539	38,290	39,055	39,836
Total Administrative & Operating Expenses	1,360,116	1,572,808	1,714,918	1,721,507	1,728,122	1,734,451	1,740,274	1,743,962	1,748,446	1,751,964	1,754,442
EBITDA	(1,410,220)	5,986,961	6,944,884	6,927,424	6,914,516	6,911,416	6,918,336	6,936,899	6,949,316	6,885,559	6,802,626
Less:											
Interest - Operating Line of Credit	0	0	0	0	0	0	0	0	0	0	0
Interest - Senior Debt	0	1,945,174	1,804,876	1,653,014	1,488,633	1,310,702	1,118,103	909,628	683,968	439,707	175,311
Interest - Working Capital	0	0	0	0	0	0	0	0	0	0	0
Depreciation & Amortization	0	2,425,571	2,419,986	2,350,117	2,303,501	2,271,420	2,343,184	2,221,399	2,212,939	2,205,715	2,199,644
Pre-Tax Income	(1,410,220)	1,616,216	2,720,021	2,924,293	3,122,382	3,329,295	3,457,048	3,805,871	4,052,408	4,240,137	4,427,672
Current Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Net Earnings (Loss) for the Year	(1,410,220)	1,616,216	2,720,021	2,924,293	3,122,382	3,329,295	3,457,048	3,805,871	4,052,408	4,240,137	4,427,672
Pre-Tax Return on Investment	-8.5%	9.7%	16.4%	17.6%	18.8%	20.0%	20.8%	22.9%	24.4%	25.5%	26.6%
11-Year Average Annual Pre-Tax ROI	17.7%										

AURI - 50K Energy
Proforma Statements of Cash Flows

	Construction (Year 0) 2011	1st Year Operations 2012	2nd Year Operations 2013	3rd Year Operations 2014	4th Year Operations 2015	5th Year Operations 2016	6th Year Operations 2017	7th Year Operations 2018	8th Year Operations 2019	9th Year Operations 2020	10th Year Operations 2021
Cash provided by (used in)											
Operating Activities											
Net Earnings (loss)	(1,410,220)	1,616,216	2,720,021	2,924,293	3,122,382	3,329,295	3,457,048	3,805,871	4,052,408	4,240,137	4,427,672
Non cash charges to operations											
Depreciation & Amortization	0	2,425,571	2,419,986	2,350,117	2,303,501	2,271,420	2,343,184	2,221,399	2,212,939	2,205,715	2,199,644
	(1,410,220)	4,041,787	5,140,007	5,274,410	5,425,883	5,600,714	5,800,233	6,027,270	6,265,347	6,445,852	6,627,315
Changes in non-cash working capital balances											
Accounts Receivable	0	0	0	0	0	0	0	0	0	0	0
Inventories	0	405,743	30,707	2,488	2,516	2,544	2,573	2,602	2,631	2,661	2,691
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Accounts Payable	0	(49,556)	(10,506)	(601)	(607)	(613)	(619)	(625)	(631)	(638)	(644)
	0	356,188	20,201	1,887	1,909	1,931	1,954	1,977	2,000	2,023	2,047
Investing Activities											
Land Purchase	76,000	0	0	0	0	0	0	0	0	0	0
Fixed Asset Purchases	32,305,100	4,357,900	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Capitalized Fees & Interest	602,857	283,571	0	0	0	0	0	0	0	0	0
	32,983,957	4,641,471	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Financing Activities											
Senior Debt Advances	17,765,921	7,176,463	0	0	0	0	0	0	0	0	0
Repayment of Senior Debt	0	(1,701,976)	(1,842,274)	(1,994,136)	(2,158,517)	(2,336,448)	(2,529,047)	(2,737,522)	(2,963,182)	(3,207,443)	(3,471,839)
Working Capital Advances	0	0	0	0	0	0	0	0	0	0	0
Repayment of Subordinate Debt	0	0	0	0	0	0	0	0	0	0	0
Equity Investment	16,628,256	0	0	0	0	0	0	0	0	0	0
Grants	0	0	0	0	0	0	0	0	0	0	0
Cash Sweep for Debt Service	0	0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Net Increase (Decrease) in Cash	0	4,518,615	3,177,533	3,178,387	3,165,457	3,162,335	3,169,232	3,187,772	3,200,166	3,136,385	3,053,429
Cash (Indebtedness), Beginning of Year	0	0	4,518,615	7,696,148	10,874,535	14,039,992	17,202,326	20,371,558	23,559,330	26,759,496	29,895,881
Cash (Bank Indebtedness), End of Year	0	4,518,615	7,696,148	10,874,535	14,039,992	17,202,326	20,371,558	23,559,330	26,759,496	29,895,881	32,949,310
IRR	18.9%										

AURI - 50K Energy

Debt Coverage Ratio

		1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
EBITDA		5,986,961	6,944,884	6,927,424	6,914,516	6,911,416	6,918,336	6,936,899	6,949,316	6,885,559	6,802,626
Taxes Paid		0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders		0	0	0	0	0	0	0	0	0	0
Changes in non-cash working capital balances		(356,188)	(20,201)	(1,887)	(1,909)	(1,931)	(1,954)	(1,977)	(2,000)	(2,023)	(2,047)
Investing Activities (Capital Expenditures)		(4,641,471)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)
Senior Debt Advances		7,176,463	0	0	0	0	0	0	0	0	0
Working Capital Advances		0	0	0	0	0	0	0	0	0	0
Cash Available for Debt Service		8,165,765	6,824,683	6,825,537	6,812,607	6,809,485	6,816,382	6,834,922	6,847,316	6,783,535	6,700,579
Senior Debt P&I Payment		3,647,150	3,647,150	3,647,150	3,647,150	3,647,150	3,647,150	3,647,150	3,647,150	3,647,150	3,647,150
Suboridinate Debt P&I Payment		0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio (senior + subdebt)		2.24	1.87	1.87	1.87	1.87	1.87	1.87	1.88	1.86	1.84
10-year Average Debt Coverage Ratio	**1.90**										

Note: the '1st Year Operations' consists of 2 months of construction and startup, plus 10 months of commercial operation

Depreciation Schedules

	Depreciation Method (note1)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Major process equipment	15 year SLN	1,552,769	1,552,769	1,552,769	1,552,769	1,552,769	1,552,769	1,552,769	1,552,769	1,552,769	1,552,769
Minor process equipment	15 year SLN	342,523	342,523	342,523	342,523	342,523	342,523	342,523	342,523	342,523	342,523
Process buildings	30 year DDB	408,623	381,382	355,956	332,226	310,078	289,406	270,112	252,105	235,298	219,611
Vehicles	5 year DDB	112,000	134,400	80,640	48,384	29,030	112,000	0	0	0	0
Office building	30 year DDB	6,667	6,222	5,807	5,420	5,059	4,722	4,407	4,113	3,839	3,583
Office equipment	5 year DDB	0	0	0	0	0	0	0	0	0	0
Start-up cost	20 year DDB	2,990	2,691	2,422	2,180	1,962	1,766	1,589	1,430	1,287	1,158
Annual capital expenditures	10 year SLN	0	0	10,000	20,000	30,000	40,000	50,000	60,000	70,000	80,000
Total Depreciation		2,425,571	2,419,986	2,350,117	2,303,501	2,271,420	2,343,184	2,221,399	2,212,939	2,205,715	2,199,644

Note 1: Depreciation Method = DDB (Double Declining Balance) or SLN (Straight Line)

APPENDIX D:
FINANCIAL FORECAST 100,000TPY CHP PLANT

AURI - 100K Energy
Production Assumptions

Nameplate Plant Scale (raw tons feedstock/year)	100,000
Operating Days Per Year	300

	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations	Annual Escalation
Feedstock Inputs											
Total Feedstock Purchase (raw ton/year)	80,833	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	
Feedstock Usage (raw ton/year)	70,833	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	
Feedstock Moisture Content (%)	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%	18.7%	
Feedstock HHV (btu/lb)	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	
Feedstock Usage (dry ton/year)	57,609	81,330	81,330	81,330	81,330	81,330	81,330	81,330	81,330	81,330	
Delivered Feedstock Price ($/raw ton)	$35.68	$36.04	$36.40	$36.76	$37.13	$37.50	$37.88	$38.25	$38.64	$39.02	1.00%
Delivered Price ($/dry ton)	$43.87	$44.31	$44.75	$45.20	$45.65	$46.11	$46.57	$47.04	$47.51	$47.98	1.00%
Production Outputs											
Heat & Power											
Co-generation Efficiency (%)	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	37.0%	
Heat Recovery (%)	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	
Total Raw Feedstock Energy Content (MMBTU/yr)	1,133,333	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	1,600,000	
Electricity Production (kWh/yr)	122,899,570	173,505,275	173,505,275	173,505,275	173,505,275	173,505,275	173,505,275	173,505,275	173,505,275	173,505,275	
Electricity Available for Sale (kWh/yr)	121,934,559	172,142,907	172,142,907	172,142,907	172,142,907	172,142,907	172,142,907	172,142,907	172,142,907	172,142,907	
Electricity Sale Price ($/kWh)	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	$0.1040	
Thermal Energy Production (MMBTU/yr)	453,333	640,000	640,000	640,000	640,000	640,000	640,000	640,000	640,000	640,000	
Thermal Energy Available for Sale (MMBTU/yr)	439,916	621,057	621,057	621,057	621,057	621,057	621,057	621,057	621,057	621,057	
Thermal Energy Sale Price ($/MMBTU)	$5.8477	$5.8557	$5.9035	$5.9673	$6.0629	$6.1904	$6.3499	$6.4933	$6.3897	$6.2223	
Utility Usage											
Thermal Energy Required (BTU/raw ton feedstock)	189,428	189,428	189,428	189,428	189,428	189,428	189,428	189,428	189,428	189,428	
Thermal Energy Generated (BTU/raw ton)	6,400,000	6,400,000	6,400,000	6,400,000	6,400,000	6,400,000	6,400,000	6,400,000	6,400,000	6,400,000	
Makeup Energy Needed (BTU/raw ton)	0	0	0	0	0	0	0	0	0	0	
Thermal Energy Price ($/MMBTU)	6.88	6.89	6.95	7.02	7.13	7.28	7.47	7.64	7.52	7.32	
Annual Thermal Energy Use (MMBTU/yr)	0	0	0	0	0	0	0	0	0	0	
Electricity Required (kWh/raw ton feedstock)	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	
Electricity Generated (kWh/raw ton)	1735.1	1735.1	1735.1	1735.1	1735.1	1735.1	1735.1	1735.1	1735.1	1735.1	
Makeup Electricity Needed (kWh/raw ton)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Electricity Price ($/kWh)	0.0548	0.0549	0.0548	0.0550	0.0552	0.0556	0.0561	0.0568	0.0572	0.0571	
Annual Electricity Use (kWh/year)	0	0	0	0	0	0	0	0	0	0	
Electricity Demand (MW)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Makeup Water Use (1000 gal/raw ton)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Makeup Water Price ($/1000 gallons)	0.50	0.51	0.51	0.52	0.52	0.53	0.53	0.54	0.54	0.55	1.00%
Makeup Water Flow Rate (gpm)	0	0	0	0	0	0	0	0	0	0	
Daily Makeup Water (gpd)	0	0	0	0	0	0	0	0	0	0	
Waste Effluent Flow Rate (1000 gal/raw ton)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
Waste Effluent Price ($/1000 gallons)	1.00	1.01	1.02	1.03	1.04	1.05	1.06	1.07	1.08	1.09	1.00%
Waste Effluent Flow Rate (gpm)	0	0	0	0	0	0	0	0	0	0	
Daily Waste Effluent (gpd)	0	0	0	0	0	0	0	0	0	0	
Number of Employees	13	13	13	13	13	13	13	13	13	13	
Average Salary Including Benefits	$51,779	$53,073	$54,400	$55,760	$57,154	$58,583	$60,048	$61,549	$63,087	$64,665	2.50%
Maintenance Materials & Services (% of Capital Equipme	2.000%	2.030%	2.060%	2.091%	2.123%	2.155%	2.187%	2.220%	2.253%	2.287%	1.50%
Property Tax & Insurance (% of Depreciated Property, Pl	1.300%	1.339%	1.379%	1.421%	1.463%	1.507%	1.552%	1.599%	1.647%	1.696%	3.00%
Inflation for all other Administrative Expense Categories											2.00%

AURI - 100K Energy
Financial Assumptions

USE OF FUNDS:	
Project Engineering & Construction Costs	
EPC Contract	$63,003,000
Site Development	$2,105,000
Rail	$0
Barge Unloading	$0
Additional Grain Storage	$0
Contingency	$3,612,000
Total Engineering and Construction Cost	$68,720,000
Development and Start-up Costs	
Inventory - Feedstock	$357,000
Inventory - Chemicals, Yeast, Denaturant	$0
Inventory - Spare Parts	$300,000
Start-up Costs	$31,500
Land	$151,900
Fire Protection & Potable Water	$0
Administration Building & Office Equipment	$100,000
Insurance & Performance Bond	$299,000
Rolling Stock & Shop Equipment	$560,000
Organizational Costs & Permits	$1,697,100
Capitalized Interest & Financing Costs	$2,543,780
Working Capital/Risk Management	$1,095,000
Total Development Costs	$7,135,280
TOTAL USES	**$75,855,280**

SOURCE OF FUNDS:		
Senior Debt		
Principal	$45,513,168	60.00%
Interest Rate	8.00% fixed	
Lender and Misc. Fees	$455,132	1.000%
Placement Fees	$0	0.000%
Amortization Period	10 years	
Cash Sweep	0.000%	
Subordinate Debt		
Principal	$0	0.00%
Interest Rate	8.00%	interest only
Lender Fees	$0	0.000%
Placement Fees	$0	1.500%
Amortization Period	10 years	
Equity Investment		
Total Equity Amount	$30,342,112	40.00%
Placement Fees	$0	0.000%
Common Equity	$30,342,112	100.000%
Preferred Equity	$0	0.000%
Grants		
Amount	$0	0.00%
TOTAL SOURCES	**$75,855,280**	

Accounts Payable, Receivable & Inventories	Receivable (# Days)	Payable (# Days)	Inventories (# Days)
Finished Products	14		8
Chemicals		15	20
Feedstock		10	30
Utilities		15	

Investment Activities	
Income Tax Rate	0.00%
Investment Interest	3.00%
Operating Line Interest	8.00%
State Producer Payment	
Producer payment, $/gal	$0
Estimated annual payment	$0
Incentive duration, years	0
Other Incentive Payments	
Small Producer Tax Credit	0
Maximum Cellulose Tax Credit	$0.00

Plant Operating Rate

Month	% of Nameplate
13	0.0%
14	0.0%
15	0.0%
16	50.0%
17	100.0%
18	100.0%
19	100.0%
20	100.0%
21	100.0%
22	100.0%
23	100.0%
24	100.0%

AURI - 100K Energy
Proforma Balance Sheet

ASSETS	Construction (Year 0) 2011	1st Year Operations 2012	2nd Year Operations 2013	3rd Year Operations 2014	4th Year Operations 2015	5th Year Operations 2016	6th Year Operations 2017	7th Year Operations 2018	8th Year Operations 2019	9th Year Operations 2020	10th Year Operations 2021
Current Assets:											
Cash & Cash Equivalents	0	4,906,943	12,876,603	20,942,056	29,001,387	37,074,938	45,183,312	53,348,792	61,561,076	69,668,112	77,631,836
Accounts Receivable - Trade	0	0	0	0	0	0	0	0	0	0	0
Inventories											
Feedstock	0	252,733	360,368	363,972	367,611	371,288	375,000	378,750	382,538	386,363	390,227
Chemicals, Enzymes & Yeast	0	0	0	0	0	0	0	0	0	0	0
Finished Product Inventory	0	76,302	105,227	106,417	107,621	108,841	110,077	111,329	112,597	113,882	115,184
Spare Parts	0	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000	300,000
Total Inventories	0	629,036	765,595	770,388	775,233	780,129	785,078	790,079	795,135	800,245	805,411
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Other Current Assets	0	0	0	0	0	0	0	0	0	0	0
Total Current Assets	0	5,535,978	13,642,199	21,712,444	29,776,620	37,855,067	45,968,390	54,138,871	62,356,211	70,468,357	78,437,246
Land	151,900	151,900	151,900	151,900	151,900	151,900	151,900	151,900	151,900	151,900	151,900
Property, Plant & Equipment											
Property, Plant & Equipment, at cost	61,786,100	69,528,100	69,628,100	69,728,100	69,828,100	69,928,100	70,028,100	70,128,100	70,228,100	70,328,100	70,428,100
Less Accumulated Depreciation & Amortization	0	4,529,121	8,824,384	13,026,550	17,160,423	21,241,982	25,376,422	29,371,454	33,341,576	37,289,123	41,216,270
Net Property, Plant & Equipment	61,786,100	64,998,979	60,803,716	56,701,550	52,667,677	48,686,118	44,651,678	40,756,646	36,886,524	33,038,977	29,211,830
Capitalized Fees & Interest	1,191,417	2,033,868	1,830,481	1,627,094	1,423,708	1,220,321	1,016,934	813,547	610,160	406,774	203,387
Total Assets	63,129,417	72,720,725	76,428,296	80,192,988	84,019,904	87,913,405	91,788,901	95,860,965	100,004,796	104,066,008	108,004,363
LIABILITIES & EQUITIES											
Current Liabilities:											
Accounts Payable	0	99,111	120,123	121,324	122,537	123,763	125,000	126,250	127,513	128,788	130,076
Notes Payable	0	0	0	0	0	0	0	0	0	0	0
Current Maturities of Senior Debt (incl. sweeps)	0	3,361,656	3,638,764	3,938,716	4,263,392	4,614,833	4,995,244	5,407,012	5,852,724	6,335,177	0
Current Maturities of Working Capital	0	0	0	0	0	0	0	0	0	0	0
Total Current Liabilities	0	3,460,767	3,758,887	4,060,039	4,385,929	4,738,595	5,120,244	5,533,262	5,980,237	6,463,965	130,076
Senior Debt (excluding current maturities)	34,942,936	39,045,862	35,407,098	31,468,382	27,204,990	22,590,157	17,594,913	12,187,901	6,335,177	0	0
Working Capital (excluding current maturities)	0	0	0	0	0	0	0	0	0	0	0
Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Total Liabilities	34,942,936	42,506,629	39,165,985	35,528,422	31,590,919	27,328,752	22,715,157	17,721,163	12,315,413	6,463,965	130,076
Capital Units & Equities											
Common Equity	30,342,112	30,342,112	30,342,112	30,342,112	30,342,112	30,342,112	30,342,112	30,342,112	30,342,112	30,342,112	30,342,112
Preferred Equity	0	0	0	0	0	0	0	0	0	0	0
Grants (capital improvements)	0	0	0	0	0	0	0	0	0	0	0
Distribution to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Retained Earnings	(2,155,630)	(128,016)	6,920,200	14,322,455	22,086,873	30,242,541	38,731,632	47,797,690	57,347,270	67,259,932	77,532,176
Total Capital Shares & Equities	28,186,482	30,214,096	37,262,312	44,664,567	52,428,985	60,584,653	69,073,744	78,139,802	87,689,382	97,602,044	107,874,288
Total Liabilities & Equities	63,129,417	72,720,725	76,428,296	80,192,988	84,019,904	87,913,405	91,788,901	95,860,965	100,004,796	104,066,008	108,004,363

AURI - 100K Energy
Proforma Income Statement

	Construction (Year 0) 2011	1st Year Operations 2012	2nd Year Operations 2013	3rd Year Operations 2014	4th Year Operations 2015	5th Year Operations 2016	6th Year Operations 2017	7th Year Operations 2018	8th Year Operations 2019	9th Year Operations 2020	10th Year Operations 2021
Revenue											
Pellets	0	0	0	0	0	0	0	0	0	0	0
Heat	0	2,572,491	3,636,703	3,666,405	3,706,009	3,765,414	3,844,621	3,943,629	4,032,737	3,968,381	3,864,422
Power	0	12,681,194	17,902,862	17,902,862	17,902,862	17,902,862	17,902,862	17,902,862	17,902,862	17,902,862	17,902,862
Total Revenue	0	15,253,685	21,539,565	21,569,268	21,608,871	21,668,276	21,747,483	21,846,492	21,935,599	21,871,244	21,767,285
Production & Operating Expenses											
Feedstocks	0	2,527,333	3,603,680	3,639,717	3,676,114	3,712,875	3,750,004	3,787,504	3,825,379	3,863,633	3,902,269
Chemicals	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	0	0	0	0	0	0	0	0	0	0	0
Electricity	0	0	0	0	0	0	0	0	0	0	0
Makeup Water	0	0	0	0	0	0	0	0	0	0	0
Wastewater Disposal	0	0	0	0	0	0	0	0	0	0	0
Direct Labor & Benefits	55,667	334,000	342,350	350,909	359,681	368,674	377,890	387,338	397,021	406,947	417,120
Total Production Costs	55,667	2,861,333	3,946,030	3,990,626	4,035,795	4,081,549	4,127,894	4,174,841	4,222,400	4,270,579	4,319,389
Gross Profit	(55,667)	12,392,352	17,593,535	17,578,642	17,573,076	17,586,727	17,619,589	17,671,650	17,713,199	17,600,664	17,447,895
Administrative & Operating Expenses											
Maintenance Materials & Services	0	892,543	1,278,961	1,298,145	1,317,617	1,337,382	1,357,442	1,377,804	1,398,471	1,419,448	1,440,740
Repairs & Maintenance - Wages & Benefits	26,604	221,500	227,038	232,713	238,531	244,495	250,607	256,872	263,294	269,876	276,623
Consulting, Management and Bank Fees	0	0	0	0	0	0	0	0	0	0	0
Property Taxes & Insurance	161,039	805,194	872,370	840,682	807,629	772,836	736,016	695,472	654,061	609,949	562,985
Admin. Salaries, Wages & Benefits	98,021	117,625	120,566	123,580	126,669	129,836	133,082	136,409	139,819	143,315	146,898
Legal & Accounting/Community Affairs	1,547,100	120,000	122,400	124,848	127,345	129,892	132,490	135,139	137,842	140,599	143,411
Office/Lab Supplies & Expenses	67,200	96,000	97,920	99,878	101,876	103,913	105,992	108,112	110,274	112,479	114,729
Travel, Training & Miscellaneous	200,000	33,333	34,000	34,680	35,374	36,081	36,803	37,539	38,290	39,055	39,836
Total Administrative & Operating Expenses	2,099,964	2,286,195	2,753,254	2,754,526	2,755,041	2,754,434	2,752,432	2,747,347	2,742,050	2,734,722	2,725,222
EBITDA	(2,155,630)	10,106,157	14,840,281	14,824,115	14,818,034	14,832,293	14,867,157	14,924,303	14,971,149	14,865,942	14,722,673
Less:											
Interest - Operating Line of Credit	0	0	0	0	0	0	0	0	0	0	0
Interest - Senior Debt	0	3,549,421	3,293,416	3,016,307	2,716,356	2,391,679	2,040,239	1,659,828	1,248,059	802,348	319,895
Interest - Working Capital	0	0	0	0	0	0	0	0	0	0	0
Depreciation & Amortization	0	4,529,121	4,498,650	4,405,553	4,337,260	4,284,946	4,337,827	4,198,418	4,173,509	4,150,933	4,130,534
Pre-Tax Income	(2,155,630)	2,027,615	7,048,215	7,402,255	7,764,419	8,155,668	8,489,091	9,066,057	9,549,580	9,912,662	10,272,244
Current Income Taxes	0	0	0	0	0	0	0	0	0	0	0
Net Earnings (Loss) for the Year	(2,155,630)	2,027,615	7,048,215	7,402,255	7,764,419	8,155,668	8,489,091	9,066,057	9,549,580	9,912,662	10,272,244
Pre-Tax Return on Investment	-7.1%	6.7%	23.2%	24.4%	25.6%	26.9%	28.0%	29.9%	31.5%	32.7%	33.9%
11-Year Average Annual Pre-Tax ROI	23.2%										

AURI - 100K Energy
Proforma Statements of Cash Flows

Cash provided by (used in)	Construction (Year 0) 2011	1st Year Operations 2012	2nd Year Operations 2013	3rd Year Operations 2014	4th Year Operations 2015	5th Year Operations 2016	6th Year Operations 2017	7th Year Operations 2018	8th Year Operations 2019	9th Year Operations 2020	10th Year Operations 2021
Operating Activities											
Net Earnings (loss)	(2,155,630)	2,027,615	7,048,215	7,402,255	7,764,419	8,155,668	8,489,091	9,066,057	9,549,580	9,912,662	10,272,244
Non cash charges to operations											
Depreciation & Amortization	0	4,529,121	4,498,650	4,405,553	4,337,260	4,284,946	4,337,827	4,198,418	4,173,509	4,150,933	4,130,534
	(2,155,630)	6,556,736	11,546,865	11,807,808	12,101,678	12,440,614	12,826,918	13,264,476	13,723,090	14,063,595	14,402,778
Changes in non-cash working capital balances											
Accounts Receivable	0	0	0	0	0	0	0	0	0	0	0
Inventories	0	629,036	136,560	4,793	4,844	4,896	4,949	5,002	5,056	5,110	5,165
Prepaid Expenses	0	0	0	0	0	0	0	0	0	0	0
Accounts Payable	0	(99,111)	(21,012)	(1,201)	(1,213)	(1,225)	(1,238)	(1,250)	(1,263)	(1,275)	(1,288)
	0	529,924	115,548	3,592	3,631	3,671	3,711	3,752	3,793	3,835	3,877
Investing Activities											
Land Purchase	151,900	0	0	0	0	0	0	0	0	0	0
Fixed Asset Purchases	61,786,100	7,742,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Capitalized Fees & Interest	1,191,417	842,451	0	0	0	0	0	0	0	0	0
	63,129,417	8,584,451	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Financing Activities											
Senior Debt Advances	34,942,936	10,570,232	0	0	0	0	0	0	0	0	0
Repayment of Senior Debt	0	(3,105,650)	(3,361,656)	(3,638,764)	(3,938,716)	(4,263,392)	(4,614,833)	(4,995,244)	(5,407,012)	(5,852,724)	(6,335,177)
Working Capital Advances	0	0	0	0	0	0	0	0	0	0	0
Repayment of Subordinate Debt	0	0	0	0	0	0	0	0	0	0	0
Equity Investment	30,342,112	0	0	0	0	0	0	0	0	0	0
Grants	0	0	0	0	0	0	0	0	0	0	0
Cash Sweep for Debt Service	0	0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders	0	0	0	0	0	0	0	0	0	0	0
Net Increase (Decrease) in Cash	0	4,906,943	7,969,661	8,065,452	8,059,332	8,073,551	8,108,374	8,165,480	8,212,284	8,107,036	7,963,724
Cash (Indebtedness), Beginning of Year	0	0	4,906,943	12,876,603	20,942,056	29,001,387	37,074,938	45,183,312	53,348,792	61,561,076	69,668,112
Cash (Bank Indebtedness), End of Year	0	4,906,943	12,876,603	20,942,056	29,001,387	37,074,938	45,183,312	53,348,792	61,561,076	69,668,112	77,631,836
IRR	22.0%										

AURI - 100K Energy

Debt Coverage Ratio

		1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
EBITDA		10,106,157	14,840,281	14,824,115	14,818,034	14,832,293	14,867,157	14,924,303	14,971,149	14,865,942	14,722,673
Taxes Paid		0	0	0	0	0	0	0	0	0	0
Distributions to Shareholders		0	0	0	0	0	0	0	0	0	0
Changes in non-cash working capital balances		(529,924)	(115,548)	(3,592)	(3,631)	(3,671)	(3,711)	(3,752)	(3,793)	(3,835)	(3,877)
Investing Activities (Capital Expenditures)		(8,584,451)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)	(100,000)
Senior Debt Advances		10,570,232	0	0	0	0	0	0	0	0	0
Working Capital Advances		0	0	0	0	0	0	0	0	0	0
Cash Available for Debt Service		11,562,014	14,624,732	14,720,524	14,714,403	14,728,622	14,763,446	14,820,552	14,867,356	14,762,107	14,618,796
Senior Debt P&I Payment		6,655,072	6,655,072	6,655,072	6,655,072	6,655,072	6,655,072	6,655,072	6,655,072	6,655,072	6,655,072
Suboridinate Debt P&I Payment		0	0	0	0	0	0	0	0	0	0
Debt Coverage Ratio (senior + subdebt)		1.74	2.20	2.21	2.21	2.21	2.22	2.23	2.23	2.22	2.20
10-year Average Debt Coverage Ratio	**2.17**										

Note: the '1st Year Operations' consists of 2 months of construction and startup, plus 10 months of commercial operation

Depreciation Schedules

	Depreciation Method (note1)	1st Year Operations	2nd Year Operations	3rd Year Operations	4th Year Operations	5th Year Operations	6th Year Operations	7th Year Operations	8th Year Operations	9th Year Operations	10th Year Operations
Major process equipment	15 year SLN	2,970,390	2,970,390	2,970,390	2,970,390	2,970,390	2,970,390	2,970,390	2,970,390	2,970,390	2,970,390
Minor process equipment	15 year SLN	655,233	655,233	655,233	655,233	655,233	655,233	655,233	655,233	655,233	655,233
Process buildings	30 year DDB	781,682	729,569	680,931	635,536	593,167	553,623	516,714	482,267	450,116	420,108
Vehicles	5 year DDB	112,000	134,400	80,640	48,384	29,030	112,000	0	0	0	0
Office building	30 year DDB	6,667	6,222	5,807	5,420	5,059	4,722	4,407	4,113	3,839	3,583
Office equipment	5 year DDB	0	0	0	0	0	0	0	0	0	0
Start-up cost	20 year DDB	3,150	2,835	2,552	2,296	2,067	1,860	1,674	1,507	1,356	1,220
Annual capital expenditures	10 year SLN	0	0	10,000	20,000	30,000	40,000	50,000	60,000	70,000	80,000
Total Depreciation		4,529,121	4,498,650	4,405,553	4,337,260	4,284,946	4,337,827	4,198,418	4,173,509	4,150,933	4,130,534

Note 1: Depreciation Method = DDB (Double Declining Balance) or SLN (Straight Line)

APPENDIX E:
MINNESOTA STATUTE 2008-216B.1691

216B.1691 RENEWABLE ENERGY OBJECTIVES.

Subdivision 1. **Definitions.** (a) Unless otherwise specified in law, "eligible energy technology" means an energy technology that generates electricity from the following renewable energy sources: (1) solar; (2) wind; (3) hydroelectric with a capacity of less than 100 megawatts; (4) hydrogen, provided that after January 1, 2010, the hydrogen must be generated from the resources listed in this clause; or (5) biomass, which includes, without limitation, landfill gas; an anaerobic digester system; the predominantly organic components of wastewater effluent, sludge, or related byproducts from publicly owned treatment works, but not including incineration of wastewater sludge to produce electricity; and an energy recovery facility used to capture the heat value of mixed municipal solid waste or refuse-derived fuel from mixed municipal solid waste as a primary fuel.

(b) "Electric utility" means a public utility providing electric service, a generation and transmission cooperative electric association, a municipal power agency, or a power district.

(c) "Total retail electric sales" means the kilowatt-hours of electricity sold in a year by an electric utility to retail customers of the electric utility or to a distribution utility for distribution to the retail customers of the distribution utility.

Subd. 2. **Eligible energy objectives.** Each electric utility shall make a good faith effort to generate or procure sufficient electricity generated by an eligible energy technology to provide its retail consumers, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that commencing in 2005, at least one percent of the electric utility's total retail electric sales to retail customers in Minnesota is generated by eligible energy technologies and seven percent of the electric utility's total retail electric sales to retail customers in Minnesota by 2010 is generated by eligible energy technologies.

Subd. 2a. **Eligible energy technology standard.** (a) Except as provided in paragraph (b), each electric utility shall generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota are generated by eligible energy technologies by the end of the year indicated:

(1)	2012	12 percent
(2)	2016	17 percent
(3)	2020	20 percent
(4)	2025	25 percent.

(b) An electric utility that owned a nuclear generating facility as of January 1, 2007, must meet the requirements of this paragraph rather than paragraph (a). An electric utility subject to this paragraph must generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota or the retail customer of a distribution utility to which the electric utility provides wholesale electric service so that at least the following percentages of the electric utility's total retail electric sales to retail customers in Minnesota are generated by eligible energy technologies by the end of the year indicated:

(1)	2010	15 percent
(2)	2012	18 percent
(3)	2016	25 percent
(4)	2020	30 percent.

Of the 30 percent in 2020, at least 25 percent must be generated by wind energy conversion systems and the remaining five percent by other eligible energy technology.

Subd. 2b. **Modification or delay of standard.** (a) The commission shall modify or delay the implementation of a standard obligation, in whole or in part, if the commission determines it is in the public interest to do so. The commission, when requested to modify or delay implementation of a standard, must consider:

(1) the impact of implementing the standard on its customers' utility costs, including the economic and competitive pressure on the utility's customers;

(2) the effects of implementing the standard on the reliability of the electric system;

(3) technical advances or technical concerns;

(4) delays in acquiring sites or routes due to rejection or delays of necessary siting or other permitting approvals;

(5) delays, cancellations, or nondelivery of necessary equipment for construction or commercial operation of an eligible energy technology facility;

(6) transmission constraints preventing delivery of service; and

(7) other statutory obligations imposed on the commission or a utility.

The commission may modify or delay implementation of a standard obligation under clauses (1) to (3) only if it finds implementation would cause significant rate impact, requires significant measures to address reliability, or raises significant technical issues. The commission may modify or delay implementation of a standard obligation under clauses (4) to (6) only if it finds that the circumstances described in those clauses were due to circumstances beyond an electric utility's control and make compliance not feasible.

(b) When considering whether to delay or modify implementation of a standard obligation, the commission must give due consideration to a preference for electric generation through use of eligible energy technology and to the achievement of the standards set by this section.

(c) An electric utility requesting a modification or delay in the implementation of a standard must file a plan to comply with its standard obligation in the same proceeding that it is requesting the delay.

Subd. 2c. **Use of integrated resource planning process.** The commission may exercise its authority under subdivision 2b to modify or delay implementation of a standard obligation as part of an integrated resource planning proceeding under section 216B.2422. The commission's authority must be exercised according to subdivision 2b. The order to delay or modify shall not be considered advisory with respect to any electric utility. This subdivision is in addition to and does not limit the commission's authority to modify or delay implementation of a standard obligation in other proceedings before the commission.

Subd. 2d. **Commission order.** The commission shall issue necessary orders detailing the criteria and standards by which it will measure an electric utility's efforts to meet the renewable energy objectives of subdivision 2 to determine whether the utility is making the required good faith effort. In this order, the commission shall include criteria and standards that protect against undesirable impacts on the reliability of the utility's system and economic impacts on the utility's ratepayers and that consider technical feasibility.

Subd. 3. **Utility plans filed with commission.** (a) Each electric utility shall report on its plans, activities, and progress with regard to the objectives and standards of this section in its filings under section 216B.2422 or in a separate report submitted to the commission every two years, whichever is more frequent, demonstrating to the commission the utility's effort to comply with this section. In its resource plan or a separate report, each electric utility shall provide a description of:

(1) the status of the utility's renewable energy mix relative to the objective and standards;

(2) efforts taken to meet the objective and standards;

(3) any obstacles encountered or anticipated in meeting the objective or standards; and

(4) potential solutions to the obstacles.

(b) The commissioner shall compile the information provided to the commission under paragraph (a), and report to the chairs of the house of representatives and senate committees with jurisdiction over energy and environment policy issues as to the progress of utilities in the state, including the progress of each individual electric utility, in increasing the amount of renewable energy provided to retail customers, with any recommendations for regulatory or legislative action, by January 15 of each odd-numbered year.

Subd. 4. **Renewable energy credits.** (a) To facilitate compliance with this section, the commission, by rule or order, shall establish by January 1, 2008, a program for tradable renewable energy credits for electricity generated by eligible energy technology. The credits must represent energy produced by an eligible energy technology, as defined in subdivision 1. Each kilowatt-hour of renewable energy credits must be treated the same as a kilowatt-hour of eligible energy technology generated or procured by an electric utility if it is produced by an eligible energy technology. The program must permit a credit to be used only once. The program must treat all eligible energy technology equally and shall not give more or less credit to energy based on the state where the energy was generated or the technology with which the energy was generated. The commission must determine the period in which the credits may be used for purposes of the program.

(b) In lieu of generating or procuring energy directly to satisfy the eligible energy technology objective or standard of this section, an electric utility may utilize renewable energy credits allowed under the program to satisfy the objective or standard.

(c) The commission shall facilitate the trading of renewable energy credits between states.

(d) The commission shall require all electric utilities to participate in a commission-approved credit-tracking system or systems. Once a credit-tracking system is in operation, the commission shall issue an order establishing protocols for trading credits.

(e) An electric utility subject to subdivision 2a, paragraph (b), may not sell renewable energy credits to an electric utility subject to subdivision 2a, paragraph (a), until 2021.

Subd. 5. **Technology based on fuel combustion.** (a) Electricity produced by fuel combustion through fuel blending or co-firing under paragraph (b) may only count toward a utility's objectives or standards if the generation facility:

(1) was constructed in compliance with new source performance standards promulgated under the federal Clean Air Act for a generation facility of that type; or

(2) employs the maximum achievable or best available control technology available for a generation facility of that type.

(b) An eligible energy technology may blend or co-fire a fuel listed in subdivision 1, paragraph (a), clause (5), with other fuels in the generation facility, but only the percentage of electricity that is attributable to a fuel listed in that clause can be counted toward an electric utility's renewable energy objectives.

Subd. 6. [Repealed by amendment, 2007 c 3 s 1]

Subd. 7. **Compliance.** The commission must regularly investigate whether an electric utility is in compliance with its good faith objective under subdivision 2 and standard obligation under subdivision 2a. If the commission finds noncompliance, it may order the electric utility to construct facilities, purchase energy generated by eligible energy technology, purchase renewable energy credits, or engage in other activities to achieve compliance. If an electric utility fails to comply with an order under this subdivision, the commission may impose a financial penalty on the electric utility in an amount not to exceed the estimated cost of the electric utility to achieve compliance. The penalty may not exceed the lesser of the cost of constructing facilities or purchasing credits. The commission must deposit financial penalties imposed under this subdivision in the energy and conservation account established in the special revenue fund under section 216B.241, subdivision 2a. This subdivision is in addition to and does not limit any other authority of the commission to enforce this section.

Subd. 8. **Relation to other law.** This section does not limit the authority of the commission under any other law, including, without limitation, sections 216B.2422 and 216B.243.

Subd. 9. **Local benefits.** The commission shall take all reasonable actions within its statutory authority to ensure this section is implemented to maximize benefits to Minnesota citizens, balancing factors such as local ownership of or participation in energy production, development and ownership of eligible energy technology facilities by independent power producers, Minnesota utility ownership of eligible energy technology facilities, the costs of energy generation to satisfy the renewable standard, and the reliability of electric service to Minnesotans.

Subd. 10. **Utility acquisition of resources.** A competitive resource acquisition process established by the commission prior to June 1, 2007, shall not apply to a utility for the construction, ownership, and operation of generation facilities used to satisfy the requirements of this section unless, upon a finding that it is in the public interest, the commission issues an order on or after June 1, 2007, that requires compliance by a utility with a competitive resource acquisition process. A utility that owns a nuclear generation facility and intends to construct, own, or operate facilities under this section shall file with the commission on or before March 1, 2008, a renewable energy plan setting forth the manner in which the utility proposes to meet the requirements of this section, including a proposed schedule for purchasing renewable energy from C-BED and non-C-BED projects. The utility shall update the plan as necessary in its filing under section 216B.2422. The commission shall approve the plan unless it determines, after public hearing and comment, that the plan is not in the public interest. As part of its determination of public interest, the commission shall consider the plan's allocation of projects among C-BED, non-C-BED, and utility-owned projects, balancing the state's interest in:

(1) promoting the policy of economic development in rural areas through the development of renewable energy projects, as expressed in subdivision 9;

(2) maintaining the reliability of the state's electric power grid; and

(3) minimizing cost impacts on ratepayers.

History: *2001 c 212 art 8 s 3; 2002 c 398 s 3; 1Sp2003 c 11 art 2 s 3; 2007 c 3 s 1; 2007 c 136 art 4 s 10; art 6 s 1,2; 2008 c 258 s 1*