

FINAL REPORT

*Identifying Effective*

# BIOMASS

*Strategies*

*Quantifying Minnesota's Resources  
and Evaluating Future Opportunities*

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# FOREWORD

This report was funded by a grant from Xcel Energy's Renewable Development Fund (RDF). The purpose of the RDF is to promote the use of renewable fuels to generate electricity.

The Prairie Island agreement also ordered Xcel Energy (Northern States Power at the time) to create specific amounts of electric power from renewable fuels like wind and biomass. Since then, the RDF has funded a number of one-off biomass projects, but biomass power has not grown as quickly and surely as wind power. (For a history of biomass projects, see Chapter VII.) The biomass mandate of 1994 was not fulfilled until 2007 and has never met its original terms.

The reason for biomass's long gestation period seems to be that, while wind technology is well developed and understood, biomass projects are to some degree experimental. Biomass power is far more complicated and contingent than wind power. Neither the developers of biomass power projects or the regulators, policy makers, communities, and funders who must assess them have had enough information to make a confident evaluation.

This study attempts to provide an objective evaluation of Minnesota's biomass resources, not to argue for or against particular bio-power projects or initiatives. Because bio-power responds to emerging state and federal energy policies, bio-power projects almost certainly will be designed and built. The question is how best to accomplish that within the limitations of natural and financial resources, including the pocketbooks of electric ratepayers. Although its focus is electric generation, much of the study will also be useful to developers of other projects, like biofuels plants.

That is not to say that our study pretends to be the last word. It is just the first step toward any specific biomass project. Because of biomass's complexity and contingency, the developer of a specific project will need go into far more detail at the local level than this study could possibly provide.

A number of expert specialists have contributed to this project:

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# OVERVIEW

The profile of bio-power (electricity generated with biomass fuels) is rising with America's concerns about the effect of fossil fuels on the environment. Bio-power's contribution to U.S. energy supply has been flat since the mid 1990's. That soon may change, however. The federal Energy Information Administration expects bio-power generation to double by 2025.

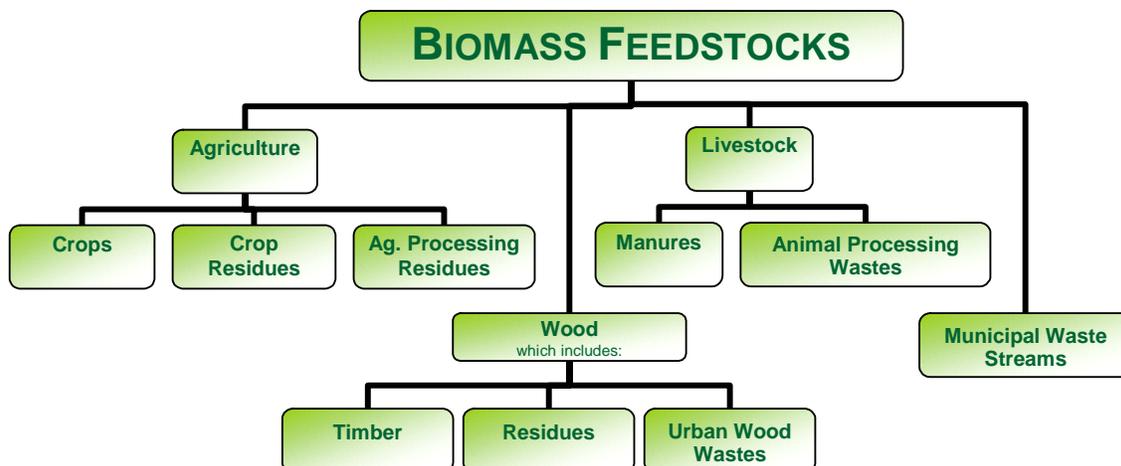
This study seeks to provide an objective evaluation of Minnesota's biomass resources, not to argue for or against particular bio-power projects or initiatives. Because bio-power responds to emerging state and federal energy policies, bio-power projects almost certainly will be designed and built. The question is how best to accomplish that within the limitations of natural and financial resources, including the pocketbooks of electric ratepayers.

To that end, this study can help developers evaluate, select, build, and operate effective bio-power projects, and help policy makers frame measures to support them. It has three components: (1.) a computer-based interactive calculator, the Bio-Power Evaluation Tool (BioPET), that identifies locations, types, and volumes of biomass fuels, adds construction and operation costs for various energy conversion technologies using them, and calculates the costs of power generated by various combinations of the above; (2.) a web-based, user-driven, electronic GIS tool, called *gopher*, that graphically represents the locations of, and relationships between, relevant infrastructure and biomass resources; and (3.) a written report providing background on technical, economic, political, and management issues central to the implementation of bio-power projects.

By using all three of these components in parallel, developers can determine optimal combinations of location, infrastructure, biomass fuels, processing and conversion technology for their projects; funders can verify them; and policy makers can gauge the practical consequences of rules, regulations, and laws. Conversely, communities and economic developers can use these tools to scope out local resources they might use to attract bio-power developments to their areas.

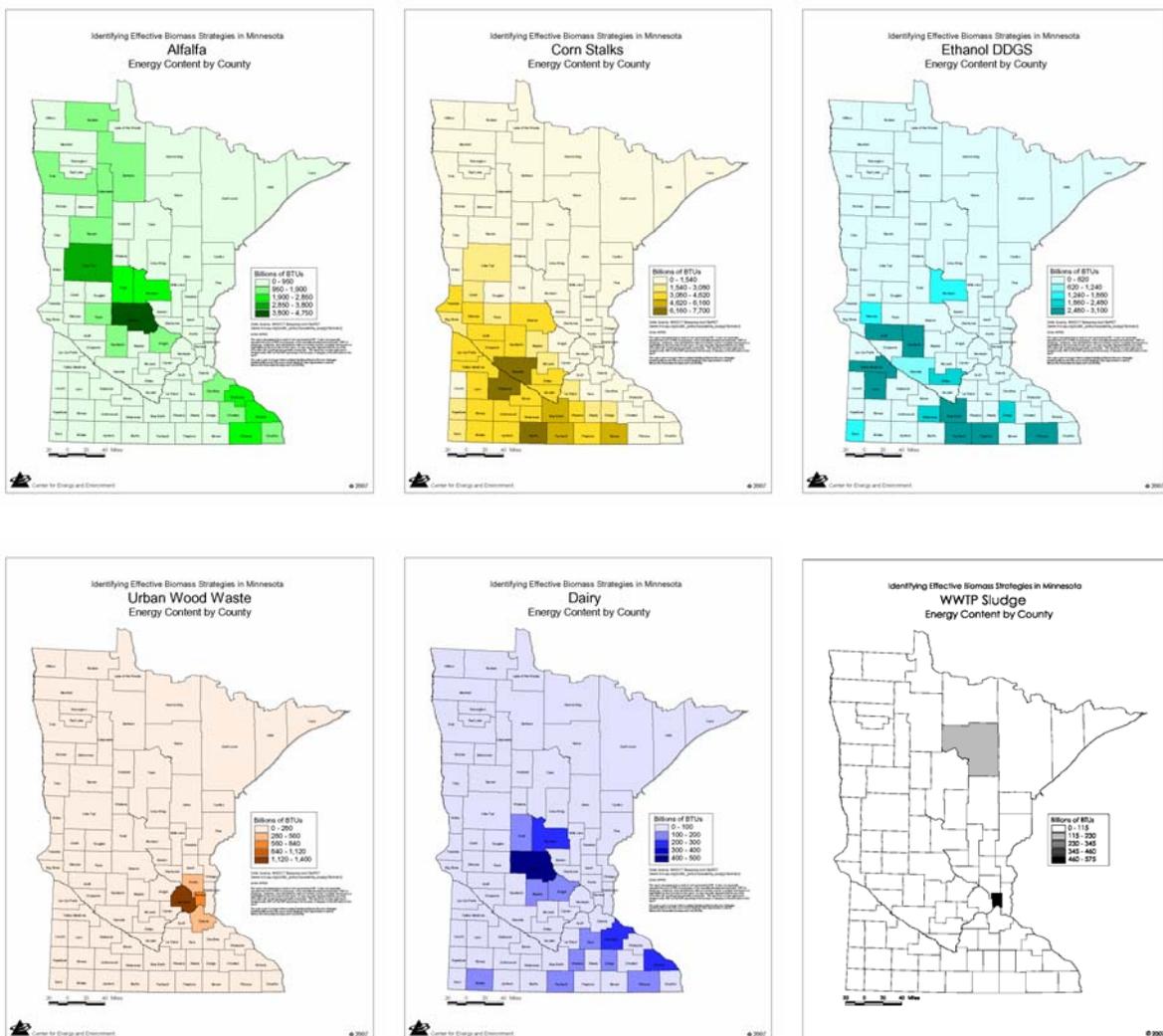
## IDENTIFYING RESOURCES AND STRATEGIES

### Chapter II & III: Biomass Fuels Available for Energy



The BioPET tool includes more than 60 biomass feedstocks from fields, forests, livestock barns, and municipal waste streams. They were selected because they exist in quantity in Minnesota. The written report's account of them may appear more authoritative than it really can be, having to rely as it does on assumptions and normalizations applied to an assortment of data from sources that used different methodologies. We detail our methodology in the appendices. If the BioPET user has better data, he/she is encouraged to substitute it into the computer-based evaluator. The text and the computer tool present our informed estimates, no more, no less.

Using estimates detailed in Chapter II as Minnesota's total growth or production of biomass feedstocks – their “theoretical potential” – Chapter III shows how much of those gross volumes can be captured physically – their “technical potential” – and how much of that might be usable for energy after deducting biomasses in high demand for other uses and hence too expensive to use as fuel.



Sample Inventory Maps

This net-net amount usable for fuel is called biomass's "economic potential." It consists primarily of straws and stalks, woody residues, and manures to which we add municipal wastes. Another category with potential, dedicated energy crops like hybrid trees, switchgrass and diverse prairie grasses, could add more to the pile but are not yet grown in volume.

One can argue over statistical and methodological issues that enter into the paper's estimate of the bottom-line quantity of biomass available for electric generation, but the goal of this analysis is not an absolute certainty that probably is impossible anyway. It is clear enough from this process of elimination that biomass is unlikely to supply a major share of Minnesota's electric power. That does not mean, however, that it is not worth considering. It will take a broad array of renewable fuels to supplant fossil fuels.

## Chapter IV: Biomass Harvesting, Processing and Transportation

Unlike coal and natural gas, biomass can't be taken out of the ground and simply tossed into a boiler. Different biomasses call for different collecting, processing, transporting, and storing regimes. This crucial transition from the field or forest to the facility can make or break a biomass project. Biomass may be waste to begin with, but after it is collected, processed, transported, stored, and delivered, on a BTU basis it costs more at the plant than coal.

A new generation of harvesting machines and procedures will do a better job of keeping crop wastes clean, and that will benefit not only bio-power but other emerging green industries like cellulosic ethanol as well. Contaminants like grit can destroy any kind of equipment. After harvest and collection, processing might include drying to reduce bulk and weight, baling, densification into pellets, or size reduction by chipping, grinding or chopping. Storage can occur anywhere along the path to the power plant, depending on local logistics, but drying is usually preliminary in order to minimize degradation of the biomass. Storage facilities can range from piles on the ground to enclosed and ventilated barns, but the desired end result is clean, high-quality fuel delivered to the power plant.

The *gopher* computer tool allows the user to select and stack geographical information with BioPET resource estimations to create a complete picture of biomass resources and relevant infrastructure.

## Chapter V & VI: Power Conversion Technologies and Applications

From the time cavemen first set wood on fire until a few centuries ago, combustion of biomass was humankind's main source of energy. In the past several centuries, however, fossil fuels like coal largely replaced biomass as fuel for combustion. Now that the world is once again looking to biomass fuels, engineers are exploring technologies better suited to their use. Simply substituting biomass one-for-one for coal in a boiler is impractical for reasons both technical and economic.

Some efficient combustion technologies, like fluidized beds and suspension burners, can burn properly prepared biomass. But most research on biomass energy focuses on more sophisticated technologies, like gasification and pyrolysis, which extract more energy from biomass. Both technologies heat biomass to very high temperatures in vessels starved of oxygen. Lacking oxygen for combustion, the biomass gives off volatile gases in gasification, or liquid fuels in pyrolysis. Gases become fuels for turbines that drive generators, and liquids become fuels for internal combustion engines, boilers and combustion turbines connected to generators. Biodiesel also can fuel generator sets.

**Co-firing.** The cheapest and quickest way to put biomass to work generating electricity is to meter it into an existing coal-fired power plant. Most coal plants can digest up to 5% biomass without major modifications. Gases from gasified biomass also may be co-fired in natural gas “peaking” plants, so called because they fire up that expensive fuel in periods of peak demand, like hot summer days when air conditioners run full blast.

**Combined Heat and Power (CHP).** Both fossil fuels and biomass have been widely used in CHP plants. This is a strategy that uses steam for power turbines and heat for industrial processes or space heating. CHP often is called “co-generation” because of its dual purpose.

Biomass in the form of waste streams in industrial plants has fueled co-generation for well over a century. Burning wastes is essential to the economics of pulp and paper mills and lumber mills, most of which dispose of their wood wastes that way and, in the process, generate much of their power and all of their process steam. The forest products industry is primarily responsible for the ranking of biomass as the second largest category of renewable energy in the U.S., after hydroelectricity.

Co-generation has the advantage of increasing the overall energy efficiency of its host plant by using steam for purposes beyond power generation. It has the potential to do even more than that. Academic and corporate researchers are developing new technologies that may turn major industrial facilities, like paper mills, into exporters of power to the grid.

Municipal applications of CHP are rare in Minnesota, but three noteworthy examples, St. Paul District Energy and the plants of the Laurentian Energy Authority in Hibbing and Virginia on the Iron Range, burn woody biomass in centralized energy plants to heat urban districts and generate power for Xcel Energy’s renewable portfolio.

**Gasification in ethanol plants.** Ethanol is raising concerns among environmentalists, food and feed processors and livestock producers, but it is a well established Minnesota industry with 16 plants and more to come. Natural gas is a major cost item for ethanol plants, and so several are using, or planning to use, gasified biomass as a substitute. The Central Minnesota Ethanol Co-operative (CMEC) in Little Falls has made the big step of installing a gasifier. It uses its former gas boiler for process heat and power generation and is the only Minnesota ethanol plant selling power to a utility – one MW to Xcel Energy. Another project, Chippewa Valley Ethanol Company in Benson, is in the process of installing two gasifiers and plan to market its technology to other ethanol producers.

**Municipal waste treatment.** The St. Paul Metro Plant uses a fluidized-bed incinerator burning bio-solids to produce steam that heats the plant in winter and generates 5 MW of power for internal use in the summer. The Empire Waste Water Treatment Plant in Dakota County burns bio-gas from an anaerobic digester to make steam and generate power, an example of a strategy discussed earlier – using gaseous or liquid fuels from biomass to fuel turbine generators.

**Bio-power from manure.** Two projects, one large and one small, are generating electricity from animal wastes. The Fibrowatt plant in Benson makes up to 55 MW of power from turkey litter (manure and wood shavings used for bedding) to sell to Xcel Energy. The Haubenschild farm near Princeton uses bio-gas from manure to generate 135 kW for internal use and for sale to the local power co-op.

## Chapter VII: Government Policies, Incentives, and Financing

The story of bio-power policy in Minnesota begins with the so-called "Prairie Island" legislation of 1994. It ordered Xcel Energy to create specific amounts of energy from a list of renewable fuels, including wind, biomass, solar, and geothermal, in return for permission to store nuclear waste on land at its Prairie Island plant. Unfortunately, because the law was so prescriptive, rigid, and overly ambitious (it demanded, for example, that biomass fuel come from dedicated "closed loop" energy crops that didn't exist then, and still don't), not a single biomass project could be built to meet it. By dint of many patchwork amendments, the biomass mandate finally was fulfilled thirteen long years later.

Minnesota has taken a huge step forward in promoting renewable electricity with the Renewable Energy Standards law of 2007. It requires utilities operating in the state to make gradual additions to their portfolios of renewable energy until 2025, at which point renewables will make up 25% of their total sales. Xcel Energy is held to a higher standard because of pre-existing renewable energy mandated by the Prairie Island Agreement. Xcel Energy's requirement is to provide 30% of retail sales through renewable resources by 2020.

The utilities are expecting to meet the Standards mostly with wind power. Xcel Energy has even announced a new policy of developing its own wind farms in addition to its established practice of signing Power Purchase Agreements (PPAs) with independent developers. Wind farms may be easier to develop than biomass plants, but a world-wide shortage of wind turbines is complicating matters. All utilities, including Xcel Energy, probably will be interested in purchasing power from biomass developers with well-conceived plans and good track records.

**Government incentives.** The most lucrative incentive offered by the State of Minnesota is called JOBZ. It exempts local property, state corporate, and sales taxes, including taxes on construction materials, until 2016. Since the statute excludes only retail from eligible projects, a power plant would be eligible. A project that expensive would save millions of dollars under JOBZ if the amendment is adopted.

A federal program, New Markets Tax Credits, can help developers raise equity capital for projects because it offers investors a return 39% higher than the face value of dividends. A power plant with a guaranteed income in the form of a PPA could be attractive to investors.

In 2007 the legislature extended Minnesota's Community-Based Energy Development (C-BED) legislation, which formerly applied only to wind projects, to any type of renewable energy project. This should be a boon to biomass projects because their relatively modest scale and dependence on local biomass resources are appropriate to community projects.

The NextGen act that also emerged from this energy-intensive session provides funding for renewable energy projects.

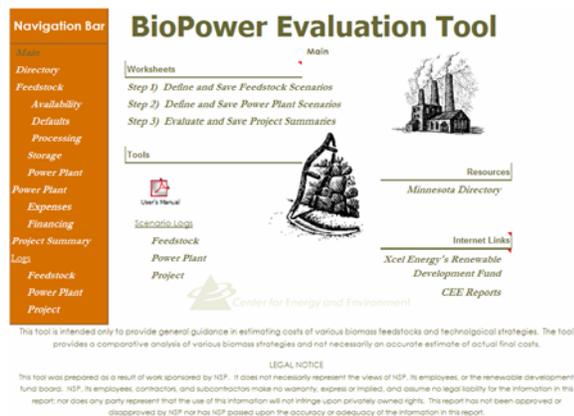
Beyond those programs are a multitude of smaller programs, some aimed at businesses in general and some at energy projects in particular. A number of these might be stitched together to fill financing gaps. If a project involves development of a new technology, the federal Small Business Innovation and Research (SBIR) program housed at the Minnesota Department of Employment and Economic Development might provide a grant.

# SELECTING AND IMPLEMENTING PROJECTS

Once potential resources are identified, the actual design, construction, and operation of a bio-power project can be a significant challenge. The second half of the report focuses on evaluation of specific projects.

## Chapter VIII: Economic Evaluations

Since only carefully thought-out projects are likely to attract financing, whether public or private, the tools that accompany this study attempt to steer the developer through the project selection process. The computer tools, BioPET and *gopher*, clarify issues of feedstocks, infrastructure, and financial assessments for user-specified, individual proposals. Their analyses culminate in outputs stated in terms of ¢/kWh and \$/kW. This is not to say that straight economics is the only driver for project selection, but that it must be considered and understood when dealing with public and/or ratepayer funds. Both tools are available on CEE's website ([www.mncee.org](http://www.mncee.org)).



BioPET Main Shot



Gopher Main Screen

## Chapter IX: Overcoming Barriers

Chapter IX, Overcoming Barriers, addresses some of the many challenges a bio-power project might face and suggests some responses to them. We won't list those challenges here because, out of context, they may appear hopelessly daunting. But developers who are able to confront and overcome those challenges will never have a better opportunity than this moment in history to move America into a new age of energy independence and environmental restoration.

## Chapter X: Opportunities

We have attempted to identify those opportunities that represent the highest likelihood of success. These strategies include, in rank order: co-firing biomass with coal in existing facilities, utilizing CHP strategies for both electric generation and steam heat, replacing existing fossil-fuel burning facilities with a biomass feedstock (such as ethanol plants), retrofitting existing biomass facilities to increase power outputs (such as pulp and paper mills), burning bio-diesel in stand-by electric generation sets, and then, possibly, electric-only, biomass-fueled electric power plants.

## **Chapter XI: Project Development Handbook**

The Biomass Power Project Development Handbook contains a list of procedural and documentary steps in constructing the financial and legal structure necessary to a project.

### **Appendices: Manuals, Resources, and References**

The first appendix is a software manual for using BioPET to compare different bio-power projects on an economic basis. Appendix B offers lists of organizations that are located or operating in Minnesota that may be able to assist you in developing a project. Appendices C and D detail many of our data assumptions and sources compiled in this study.



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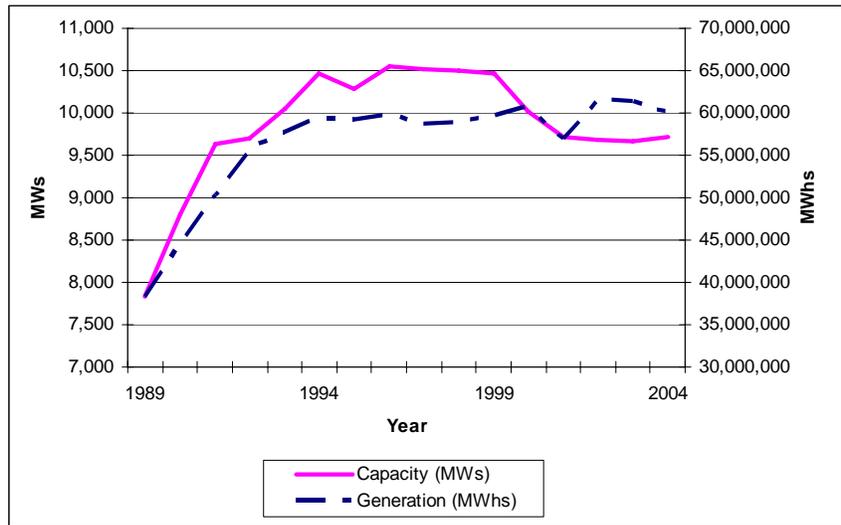
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# CHAPTER I : INTRODUCTION

Bio-power – electricity and heat generated from biomass fuels -- has played a long but minor role in U.S. electric generation. But its profile is rising. Concerns about the effects of imported fossil fuels on the country's environment and energy security have brought new attention to biomass power. Increasingly, bio-power is being discussed as a potential contributor to America's energy independence.

It will take a substantial increase in bio-power development to realize that potential. In 2003, U.S. bio-power provided 6,370 MW of net summer capacity and over 41 million MWh. In Minnesota, bio-power accounted for 275 MW and 760,570 MWh (EIA, 2005). As Figure I-1 shows, over the past decade those outputs haven't changed much. In its most recent Annual Energy Outlook, however, the Energy Information Administration (EIA) projects that energy from biomass will grow to more than 61 million MWh by 2010, 72 million MWh by 2020, and 81 million MWh by 2025. EIA further projects that nearly 5,400 MW of new bio-power capacity will come on line by 2025.



(compiled from EIA, 2001, 2002, 2005b)<sup>1</sup>

**Figure I-1: Total Annual U.S. Electricity Generated from Biomass**

Given the recent surge in interest in bio-power potential, this project was conceived. The goal is to summarize the current state of the bio-power industry, act as a resource when evaluating diverse bio-power projects, and make recommendations for future research areas and policy changes that would result in higher implementation of bio-power projects.

<sup>1</sup> 2004 data is preliminary.

# THE PROJECT: IDENTIFYING EFFECTIVE BIOMASS STRATEGIES

## Project History

The history of Minnesota biopower development is succinctly summarized in Xcel Energy's 2007 Renewable Development Fund Request for Proposals. The following is excerpted from this document with minor modifications and some updates.

Xcel Energy operates the Prairie Island Nuclear Generating Plant at Red Wing, Minnesota, which uses "dry casks" to store spent fuel from the plant. In 1994, the Minnesota legislature enacted legislation that established a "renewable development fund." This legislation required Xcel Energy to transfer to a renewable development account \$500,000 annually for each dry cask containing spent fuel that is located at Prairie Island after January 1, 1999.

In June 2003, the legislature passed new legislation that made changes to several provisions of the original legislation establishing the RDF program. Among other things, the new legislation increased the level of funding and distributions from the Fund. Specifically, the legislation provides for Xcel Energy to transfer to the Fund \$16,000,000 annually each year Prairie Island is in operation. From this amount, up to \$6,000,000 must be allocated to fund renewable energy production incentives for eligible wind and on-farm biogas facilities. Such production incentive payments are administered by the Minnesota Department of Commerce, which determines eligibility under Minnesota Statutes 2001, §216C.41.

The initial RDF funding cycle began with the release of the first RFP in mid-2001, which resulted in the selection of 19 projects receiving over \$15.5 million in funding. These projects included new energy production projects, as well as research and development into solar, wind, hydro and biomass technologies. The second funding cycle resulted in 28 projects being selected with a total award amount of \$26.5 million. Some of these projects entered into power purchase agreements to sell energy and/or capacity to Xcel Energy, while other projects consumed the electricity produced on-site. Descriptions of projects selected through the second funding cycle can be found at <http://www.xcelenergy.com/rdf>, click on "Renewable Development Fund" and "Project Selections" for Cycle 1 and Cycle 2 along the left side of the screen.

The RDF Board is responsible for administrating the Fund, including implementing the funding process, evaluating and selecting requests, and disbursing funds to successful applicants. All decisions of the Board are made by consensus and the Board relies on Xcel Energy RDF staff and technical consulting assistance as necessary to administrate the program. At this time, the Board consists of two representatives from Xcel Energy, Betsy Engelking and Brian Zelenak; two representatives from the environmental community, William Grant and Jack Keers; a representative from the Prairie Island Indian Community, Heather Westra; an Xcel Energy commercial ratepayer representative from the Minnesota Chamber of Commerce, Mike Franklin; and an Xcel Energy residential ratepayer representative from the Minnesota Department of Commerce, Assistant Deputy Commissioner Mike Bull.

The overall purpose (mission) of the RDF is to increase the market penetration of renewable energy resources at reasonable costs in the Xcel Energy service territory, promote the start-up, expansion, and attraction of renewable energy projects and companies in the Xcel Energy service territory and stimulate research and development

into renewable technologies that support this mission. Results of RDF projects are expected to become available to broad audiences.

The Board considers the primary objective of research projects to be testing a hypothesis or the marketability and application of an energy-related technology, with energy production being a by-product of the research.

The project before you was conceived in 2003, submitted for the second round of RDF funding on March 16, 2004, and ultimately began on August 1, 2005. This report and the associated tools developed as part of the overall program effort is the culmination of over two years of work by the project team.

## **Mission**

Minnesota has enacted a number of policies over the past decades that indicate a strong interest in expanding the biomass power industry within the state. The 1994 Biomass Mandate, the Renewable Energy Objective, and the recent Renewable Energy Standard have all provided support for bio-power within Minnesota. While general studies have indicated that Minnesota has significant potential to utilize existing biomass for electrical generation, no comprehensive statewide evaluation of Minnesota's biomass resources in relation to existing infrastructure and appropriate processing technologies has been completed. Biomass is increasingly more complex than traditional electric generation approaches. It encompasses a wide range of feedstocks (crops to residues to animal manures and even, by some definitions, municipal solid waste and landfill gas) and a wide range of technologies (standard combustion boilers to anaerobic digesters to gasification processes). This makes a side-by-side comparison of diverse projects even more difficult.

The concern becomes that without such a common framework from which to identify and compare diverse projects, projects may be selected for political expediency rather than technical and/or economic feasibility. The lack of a commonly accepted standard for decision making, combined with current regulatory and perceptual barriers in the biomass arena, complicates the selection process even further. The idea was therefore to provide tools and information to assist in the comparison of diverse biomass projects and allow for an objective evaluation. The result of this effort is before you.

This project fulfills the objective delineated in the R&D portion of the RDF for assisting new technologies to the point where they can begin the process of commercial introduction by providing objective information to minimize transaction costs in the evaluation, selection, and ultimate implementation of biomass projects.

## **Goals**

The goal of this project is to create a framework that communities and legislators can use to determine the feasibility of biomass generated electricity in their region and to develop cost-effective projects that use local biomass resources efficiently. Although biomass can offer multiple benefits as a fuel source, biomass resources are extremely diverse in their physical characteristics and their potential for energy generation. It is imperative that projects are designed with this diversity in mind and within the parameters established by local or regional contexts. This project developed a number of resources to aid in the identification of areas in the state where relationships between fuel sources, local conditions, and appropriate technologies produce a promising opportunity for a biomass project. With this information, funding organizations, policy makers and state regulators will be better able to select the most

cost-effective projects for implementation. The project does not advocate for or against specific bio-power projects. It helps to ensure that the state's limited resources are allocated to the best bio-power opportunities.

To achieve this goal, the project identified biomass opportunities throughout the state with a specific emphasis on local conditions that could impact the cost-effectiveness of a proposed project. The results of this survey are graphically presented with an internet based mapping tool so that the best opportunities for electrical generation can be more easily distinguished. In addition, an evaluation tool was developed to assess proposed biomass projects. This tool generates a cost approximation per kW and kWh so that various projects can be compared using a common denominator.

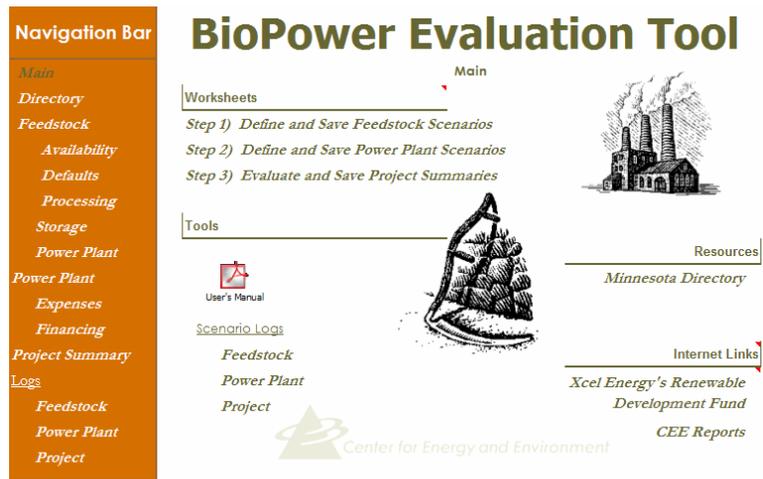
## **THE APPROACH: QUANTIFYING MINNESOTA'S RESOURCES AND EVALUATING FUTURE OPPORTUNITIES**

This project consists of a final report and two software tools. The basis for each of these is a comprehensive inventory of all biomass potential in Minnesota. All existing major biomass and bio-waste feedstocks were cataloged during the inventory, including major facilities that produce biomass or bio-waste. Existing energy infrastructure, including electric generation and transmission facilities, were mapped with a GIS system and overlaid with biomass sources and major biomass facilities. In addition to the inventory and infrastructure data, process technologies appropriate to each feedstock were identified and assessed using published data from actual projects whenever possible. The viability of each major feedstock and technology was assessed primarily by the reliability of the technology and its cost. Biomass project opportunities were then identified and prioritized based on feedstock availability and the scale and reliability of available technologies. All tools and reports from the project are available on CEE's website.

### **Final Report**

This report is designed to be a comprehensive biomass power resource. It contains both general information regarding the biomass power industry and significant details regarding the industry in Minnesota. The general sections include information on the nature of various bio-power feedstocks, the technologies that are available to process them and convert them to useful energy, and the different applications in which biomass power can be utilized. The challenges to implementing biomass projects and strategies to overcome these challenges were also identified. The Minnesota specific sections focus on the major biomass power facilities in Minnesota, a brief history of the industry and the policies that have shaped it, and suggestions for further policy initiatives that could move the industry forward.

# BioPET



This tool is intended only to provide general guidance in estimating costs of various biomass feedstocks and technological strategies. The tool provides a comparative analysis of various biomass strategies and not necessarily an accurate estimate of actual final costs.

#### LEGAL NOTICE

This tool was prepared as a result of work sponsored by NSP. It does not necessarily represent the views of NSP, its employees, or the renewable development fund board. NSP, its employees, contractors, and subcontractors make no warranty, express or implied, and assume no legal liability for the information in this report; nor does any party represent that the use of this information will not infringe upon privately owned rights. This report has not been approved or disapproved by NSP nor has NSP passed upon the accuracy or adequacy of the information in this report.

Figure I-2: BioPET Main Screen

BioPET is a spreadsheet tool designed to assist in comparing diverse bio-power projects by calculating a common economic metric (a levelized annual cost in ¢/kWh) for all projects. BioPET is designed merely as a screening tool and should not be a replacement for an in-depth engineering and econometric analysis. It is meant to be used as a means for narrowing one's focus from perhaps dozen of ideas to just a handful.

*gopher*

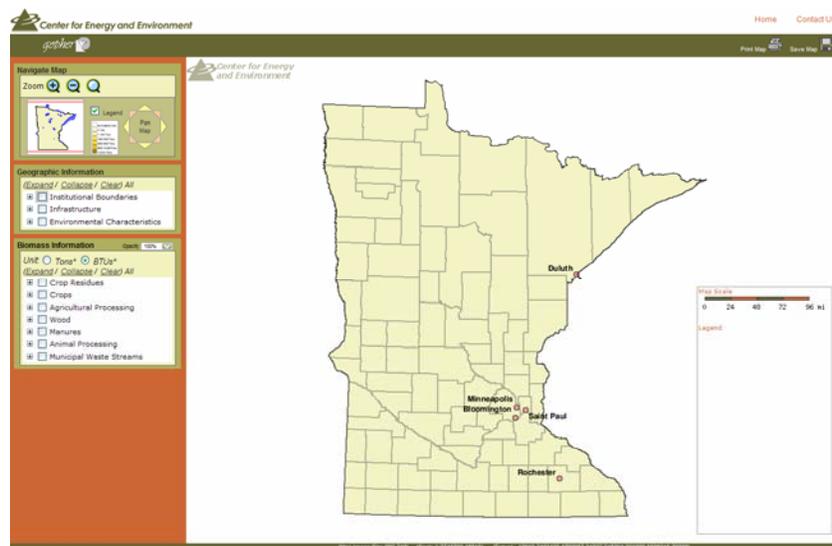


Figure I-3: *gopher* Screen Shot

The birth of *gopher* came through the acknowledgement that, given the wide variety biomass feedstocks, generation technologies, and infrastructure requirements, the project team would not be able to accurately predict or provide maps for all of the possible combination of resources to assist in specific project development. It was clear that simply providing a series of fixed maps would be too limiting and ultimately not very helpful. A flexible tool that would allow anyone to create their own map focusing only on the resources in which they are interested was deemed to provide the maximum amount of value to project developers. As with BioPET, *gopher* is designed as a screening tool and its accuracy is only as good as the resolution of the data collected at some time in the past. Before embarking on a specific project, “on the ground” analysis should be conducted to verify accuracy and adjust for recent developments.

# CHAPTER II : BIOMASS FUELS

## BIOMASS CATEGORIZATIONS

Our discussion of biomass power begins logically with the biomass resource itself. Biomass is not an exact term. It could be used to designate pretty much any carbon-based life form, be it flora or fauna. It also has vastly different referents in various parts of the world, depending on the local species. So we arbitrarily – however, we hope reasonably – define it as crops and residues available in Minnesota in quantities large enough to fuel a power plant. Those are the specific biomasses that appear in the BioPET computer tool and in this chapter of the Written Report.

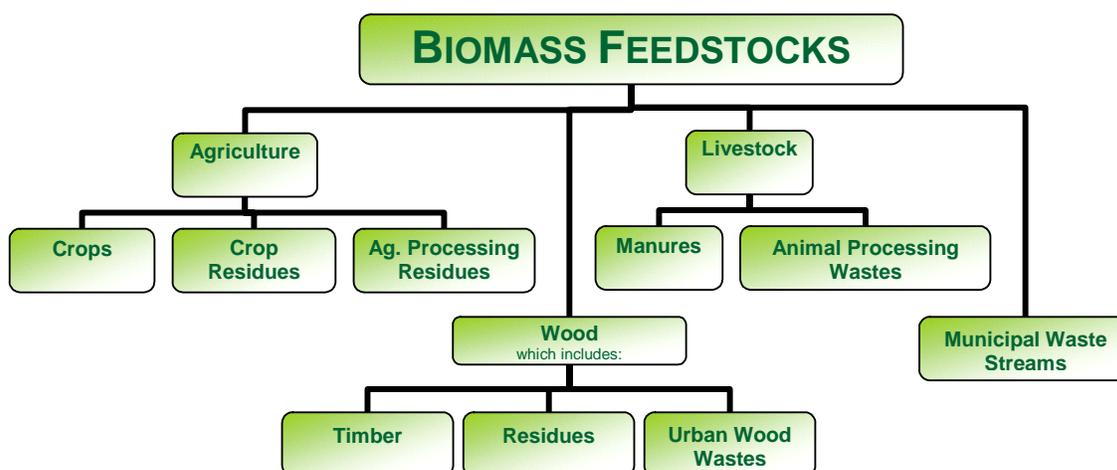


Figure II-1: Biomass Feedstocks Organizational Chart

We group those specific biomasses into seven general categories.

First, three categories from the agriculture industry:

- harvested crops,
- crop residues, and
- agricultural processing residues.

Second, one catchall category for wood-based resources:

- wood.

Third, two categories from the livestock industry:

- manures and
- animal processing wastes.

And fourth, three categories to address municipal waste streams:

- waste water treatment plant sludge,
- municipal solid waste, and
- landfill gas.

In addition, we include in BioPET a special category:

- fossil fuels.

These obviously are not biomass, but we include them for purposes of comparison and for calculating co-firing applications. Because Minnesota does not have any native fossil fuel resources, inventories are not included; however general fuel characteristics and prices are.

The other special category which is *not* included in BioPET but does come up for discussion in the paper is:

- dedicated energy crops.

Dedicated energy crops are not included in the BioPET tool as a separate category because thus far they are grown in test plots, not in fields as a commercial crop. But in this written report we describe research in herbaceous crops, switchgrass, and diverse prairie grasses because they are more likely to become important biomass energy crops in the near future.

## BioPET Assumptions and User-Defined Fields (UDFs)

The BioPET computer tool allows the user to explore volumes of specific biomasses in any county or combination of counties in the state. We used the same moisture and quality assumptions consistently across all 87 counties in Minnesota. The user can look up those assumptions in BioPET.

Although we made every effort to develop a comprehensive list of Minnesota biomass feedstocks available in quantity, the user may want to research an additional source or a very specific variation on one of the items listed above. For that reason BioPET is designed to also accept user inputs. Users can enter and save their own feedstock characteristics in any of the 12 UDFs provided in BioPET.

## Assessment

The general categories above define the areas in which we find biomass fuels. Within those categories lie a wide variety of specific feedstocks which we examine in terms of:

- energy content (millions of BTUs (MMBTUs) per dry ton),
- volumes of biomass by county in Minnesota (dry tons),
- estimated processing costs (\$/ton), and
- estimated delivery costs (\$/ton/mile).

BioPET presents analyses of these factors in an easy-to-use electronic format. The user of this computer tool can manipulate various feedstock, delivery and location scenarios in order to arrive at the optimal cost per MMBTU for fully processed fuel delivered to a power plant at a particular location in Minnesota.

## ESTIMATION OF FEEDSTOCK CHARACTERISTICS

Since statistical information on biomass fuels comes from a variety of sources that use differing methodologies, we have had to normalize them so their performance in various combustion and gasification processes can be compared. It should be noted that this still represents an 'nominal' value. Values can vary widely across regions and states. It is recommended that

when evaluating individual projects that the actual fuel to be consumed be tested and evaluated.

For this analysis, we begin by estimating the energy content of each potential feedstock in Minnesota on the basis of its dry-weight -- i.e., 0% moisture content by weight (MCW). That gives us a basis for calculating backward to any moisture content we find in the field.

We give the higher heating values (HHV) for each of the potential biomass feedstocks on a dry-weight basis, both in terms of BTU/lb and MJ/kg. In some cases, we obtain those directly from the sources noted. For others, we calculate them by using standard conversion formulas. But HHV is only a theoretical number. Actual recovered heat depends upon the technology used to convert the biomass into electricity. Lower heating values (LHVs) are available for some of the fuels listed, but we do not refer to them because that measure is not relevant to planning for electricity generation.

Energy content is measured through proximate analyses (moisture, free carbon, ash, etc.) and ultimate analyses (percent elemental carbon, hydrogen, etc.). From ultimate analyses, HHV can be calculated with any of several regression models. But we only occasionally use such equations for our estimates because HHV in nearly all cases can be obtained through proximate analyses.

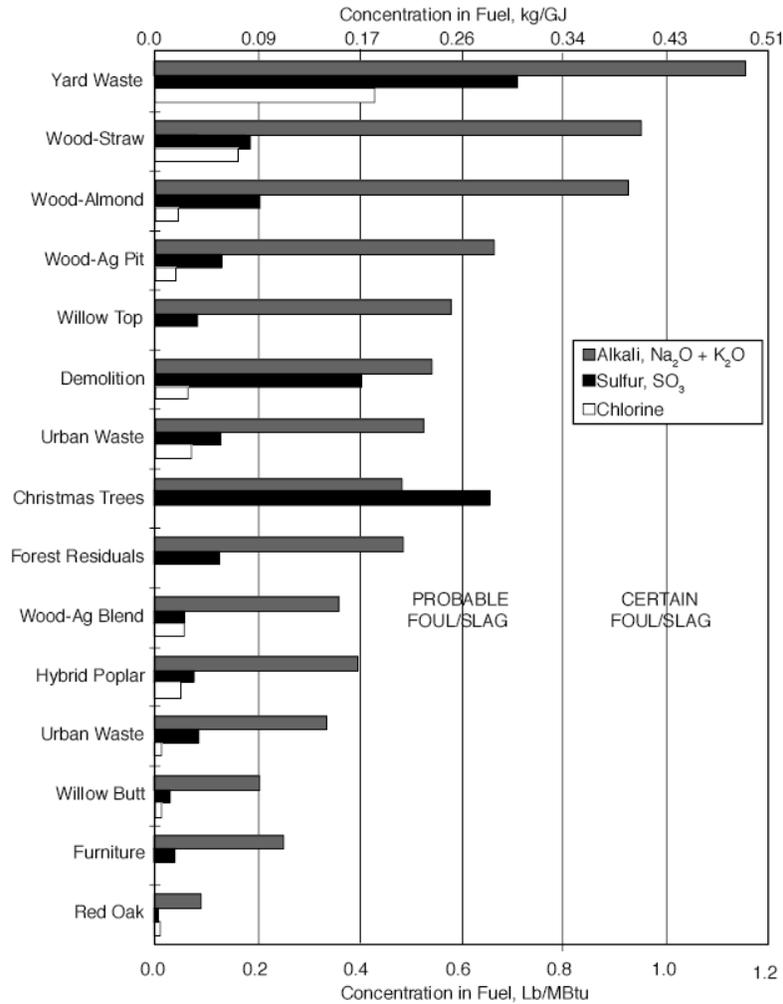
The BioPET tool contains our "official" estimates for purposes of a general comparative review. While we provide a single HHV number for each individual feedstock, biomass energy content—even on a dry-weight basis—actually varies widely. It depends upon the species/variety of crop, the animals' feed rations and bedding arrangements (in the case of manures), the part of the plant being processed, the soils on which the crop is grown, the time of year it is harvested, and the type of processing that precedes the laboratory analysis.

Our best estimates sometimes are averages of several samples and sometimes a selection from competing data sources. In associating these numbers with county-level biomass estimates, we round the heating values to the nearest 100 BTU/lb in order to avoid the suggestion of greater accuracy than is possible.

We find many inconsistencies in reported data, principally in the way they deal with moisture content. In some cases, such as wood heating values, we discover that some standard sources actually use a single HHV for all wood types and merely adjust individual species numbers by assuming varying moisture contents. In other cases, different laboratory procedures have led to different energy content estimates. And in some others, what at first appears to be independent laboratory analyses turns out to be a reissuing of other researchers' findings.

Gaur and Reed (1998) is the best single compilation of energy content we have found because it uses consistent reporting practices over the widest range of fuels. But it doesn't contain all the feedstocks included here, especially manures. AURI is the only set of analyses of Minnesota-grown biomass we know of.

Alkali content estimates were scattered and sparse. The only broad-scope source found was Miles, Miles, Baxter, Bryers, Jenkins, and Oden (1995). The key message from that study is nicely captured in the chart below showing the range of potential alkali problems in some—but by no means all—of the feedstocks dealt with here.



(Miles et. al., 1995)

Figure II-2: Example Alkali, Sulfur, and Chlorine Concentrations of Selected Wood Fuels

## Agricultural Crops

Specific goods raised on the land for on site use or for sale to markets such as food, feed, or bio-fuels. Specific crops listed in BioPET include:

Alfalfa, Barley, Canola, Corn Grain, Corn Silage, Dry Beans, Oats, Potatoes, Soybeans, Sugar Beets, Sunflower Seeds, Sweet Corn, and Wheat

Of all Minnesota's biomass categories, agriculture is the largest. And crops are the largest component of that largest category, containing approximately 846,000 billion BTU of energy, more than any other single biomass resource. Of that total crop energy, corn grain contributes the lion's share (51%). Soybeans and sugar beets take second and third place at 17% and 14% respectively. Other contributors are alfalfa hay (7%), wheat (4%), and corn silage (4%).

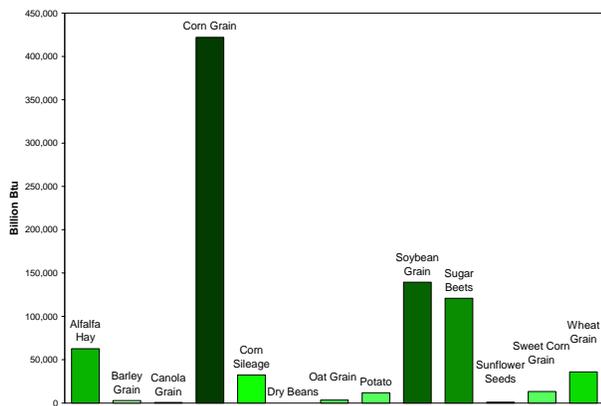


Figure II-3: Total Energy (Crops)

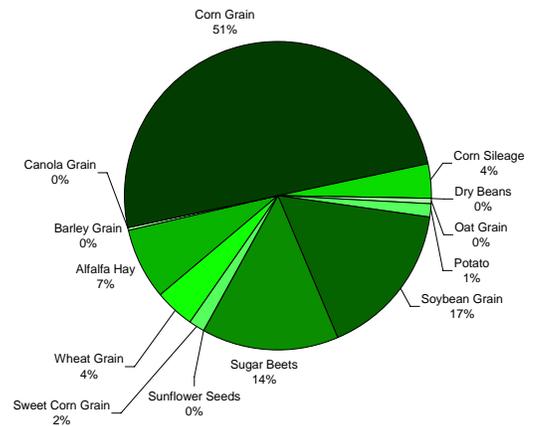
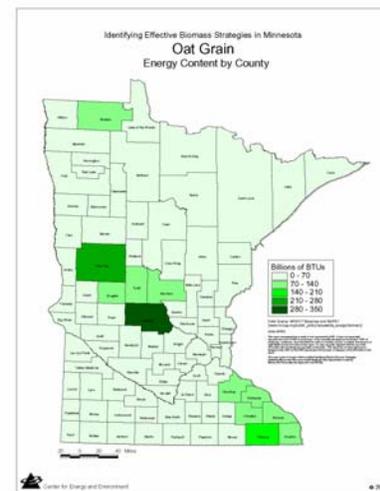
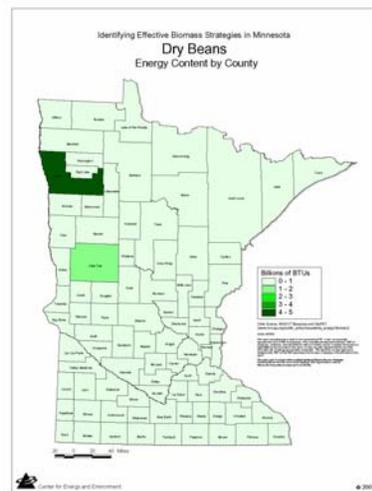
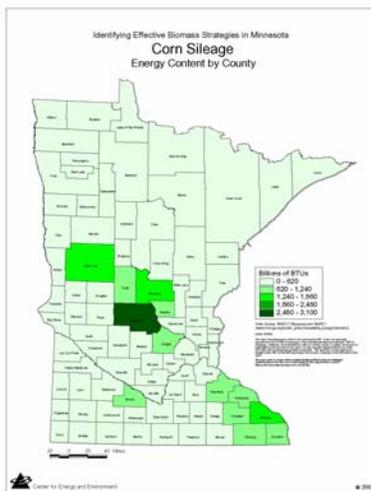
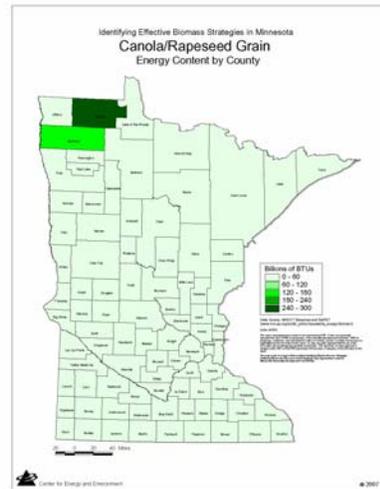
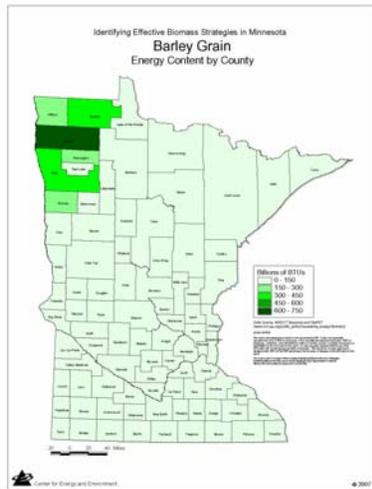
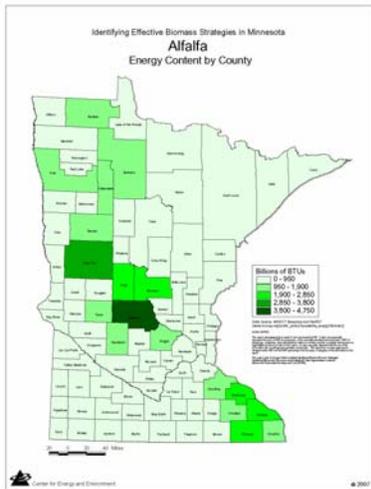
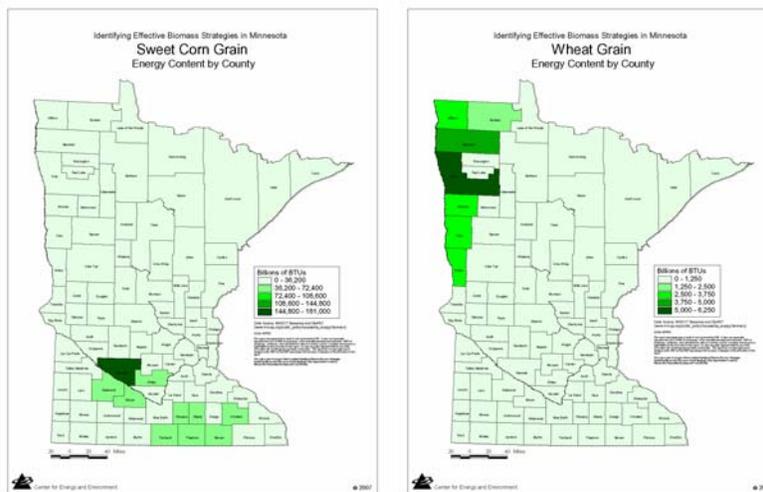
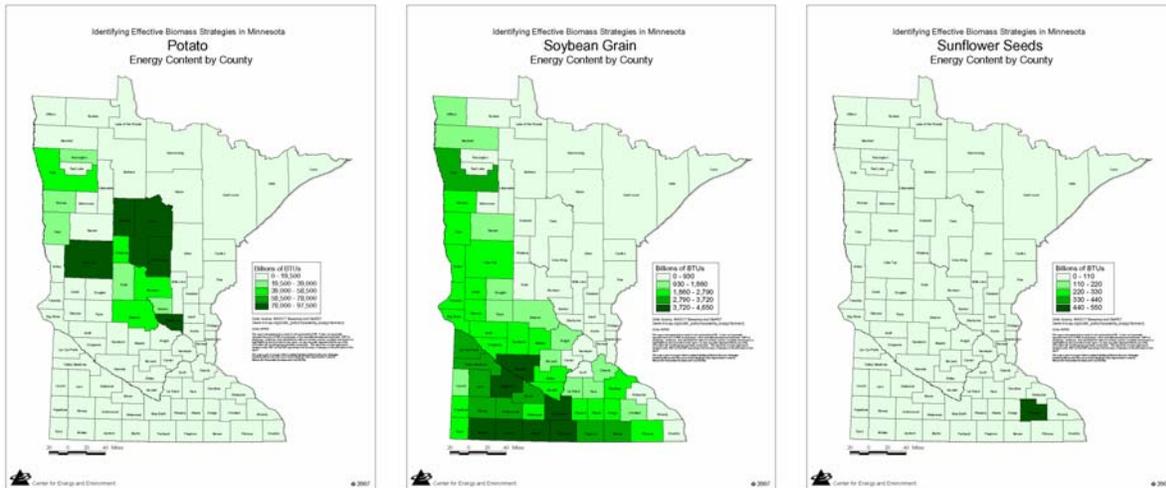


Figure II-4: Total Energy by Percentage (Crops)





## Crop Residues

Wastes from the field, like leaves, stems, and stalks, etc. Specific crop residues listed in BioPET include:

Barley Straw, Oat Straw, Wheat Straw, Corn Stover, Sunflower Stalks, Sweet Corn Stalks, and Other Hays/Switchgrass

Hays, straws and stalks constitute Minnesota's second-largest segment of agricultural biomass. Totalling approximately 434,000 billion BTU, residues represent slightly more than half of the energy value of crops, but they may offer more potential for bio-power development because, unlike crops which are sought-after commodities, residues are mostly unused (although researchers are studying how much has to be plowed under to maintain the health of soils). The single largest of these wastes is corn stover, 80% of the total. Other significant contributors are wheat straw (7%), hays and straws on CRP land (7%), and other hays/switchgrass (3%).

For purposes of this analysis, all hays, straws, and stalks were combined regardless of source (ie. crop or crop residue) due to their similarity in their handling and processing for energy generation.

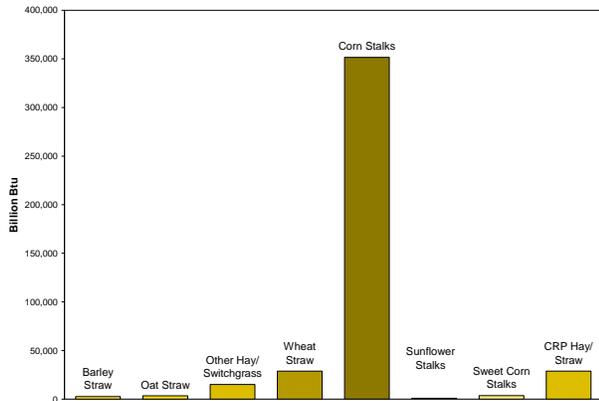


Figure II-5: Total Energy (Crop Residues)

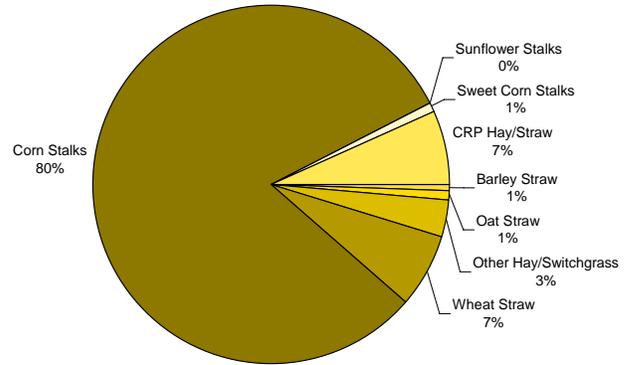
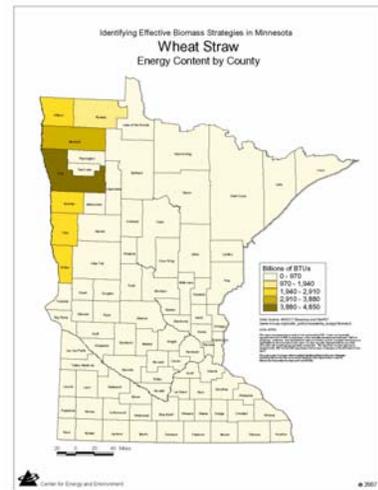
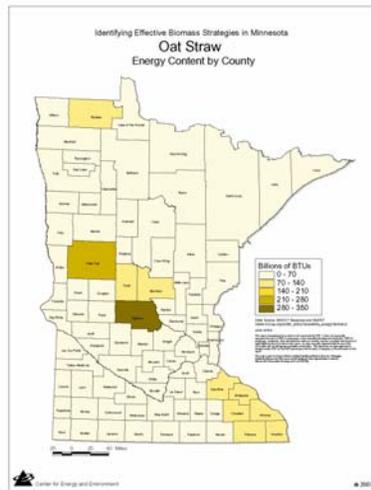
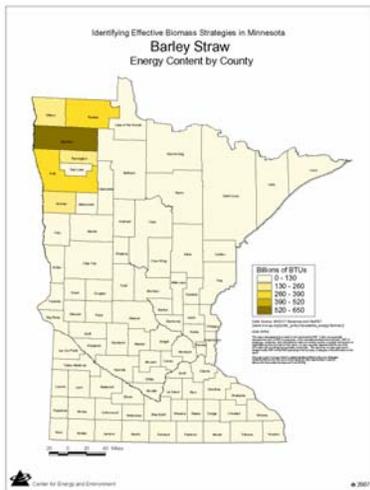
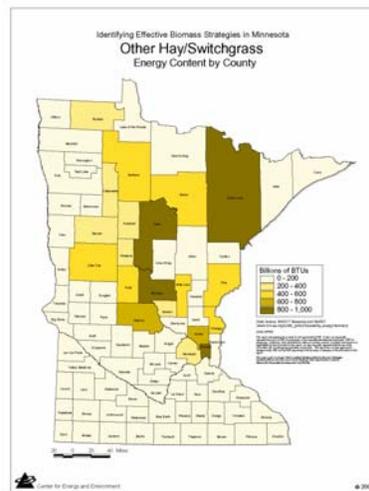
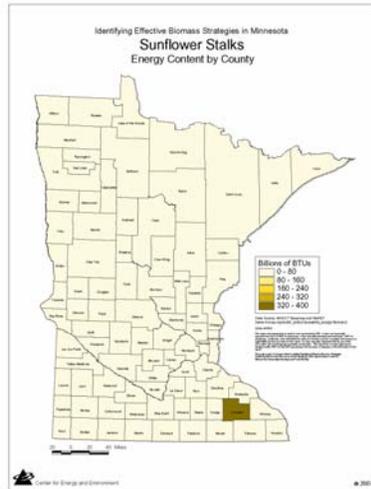
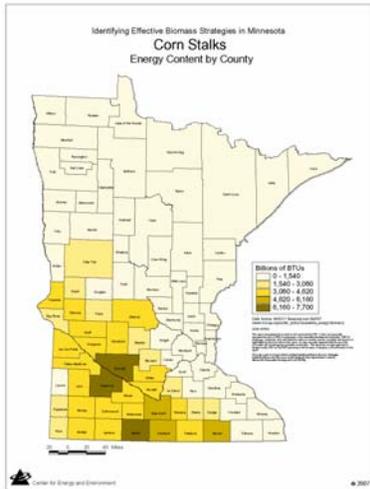


Figure II-6: Total Energy by Percentage (Crop Residues)





## Agricultural Processing Residues

Waste streams, like leaves, stems, stalks, roots, shells, pits, etc., found typically at processing plants. Specific agricultural processing residues listed in BioPET are:

Feedstocks include:

Ethanol DDGs, Ethanol Feed, Ethanol Oil, Glycerol, Soybean Hulls, Soybean Meal, Soybean Oil, Sugar Beet Molasses, Sugar Beet Pulp, Sugar Beet Tailings, Wheat Flour, and Wheat Midds

Residues from agricultural processing are the fourth largest biomass category. Annual residues from crop processing contain approximately 165,000 billion BTU. Soybean meal is the largest of these (38%), followed by ethanol DDGs (21%), and soybean oil (17%). Other contributors are wheat flour (13%) sugar beet pulp (4%), soybean hulls (3%), and wheat midds (3%).

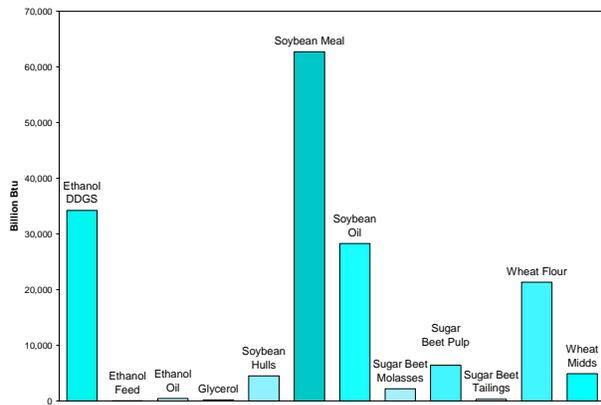


Figure II-7: Total Energy (Agricultural Processing Residues)

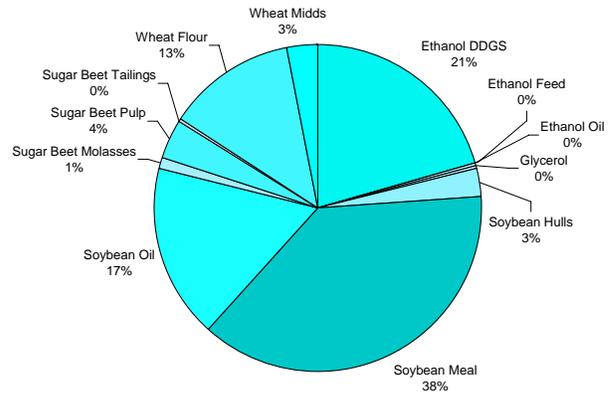
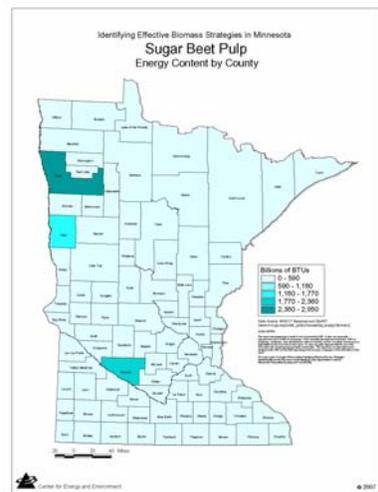
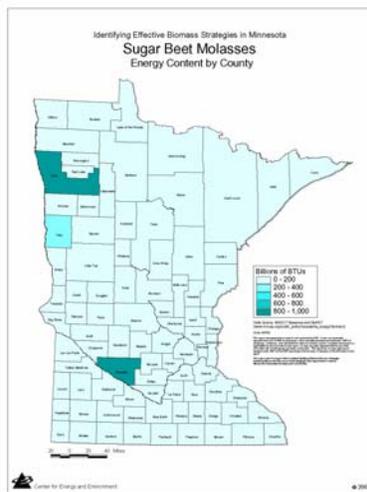
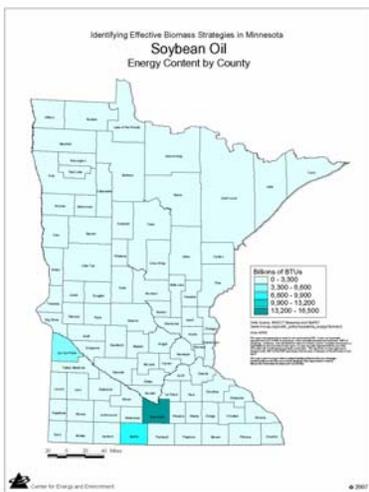
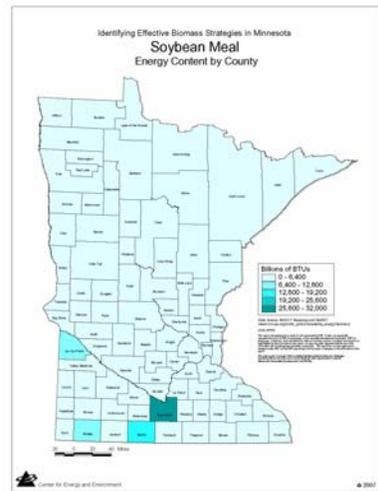
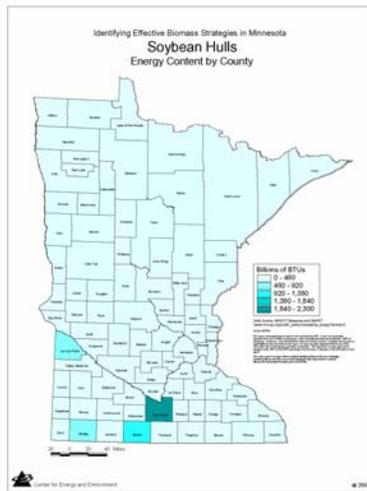
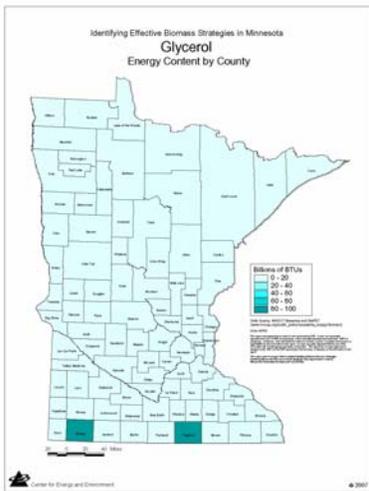
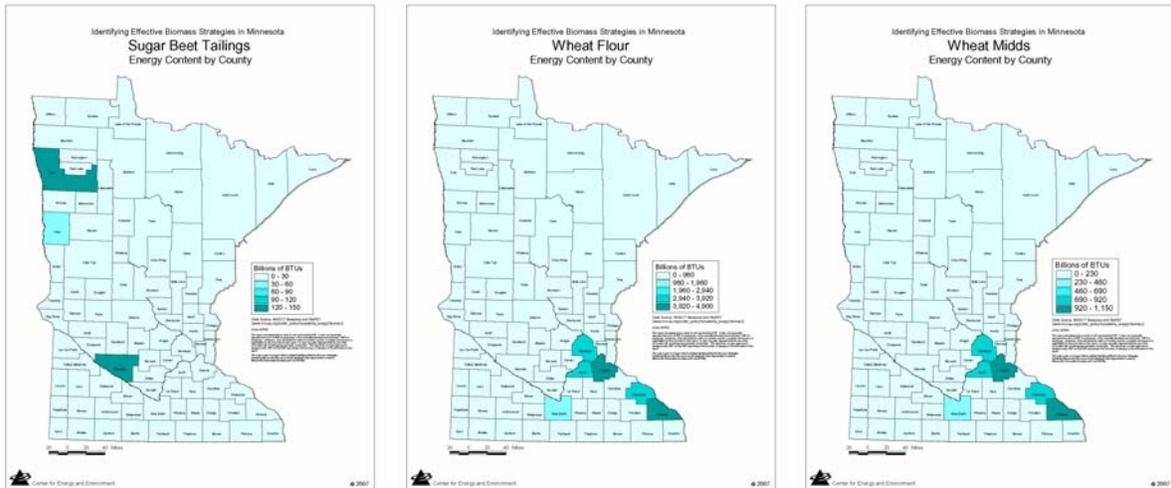


Figure II-8: Total Energy by Percentage (Agricultural Processing Residues)





## Wood

The wood category includes timber, harvest, and mill residues. Specific wood feedstocks in BioPET include:

Logging Residues, Aspen Timber, Hardwood Timber, Softwood Timber, Brushland, Trees (from CRP Lands), Urban Wood Waste, Mill Residues (Bark, Slabs, and Edgings), and Mill Residues (Sawdust/Shavings)

**Forest residue:** Logging wastes and other removable material left after carrying out timber harvest operations. This includes unmerchantable trees cut during logging operations, thinnings, "lilly pads" (sections trimmed from logs) and limbs. Logging residues comprises of unutilized trees cut or killed during logging operations or any of the unused portions that are left in the woods.

**Mill residue:** Waste generated in the manufacturing of forest products. Mill waste typically consists of chips, off-fall, trimmings, slabs, shavings, sawdust, bark, veneer clippings, cores, and pulp screenings. Our definition includes all mill residues whether recycled as byproducts or disposed of as waste.

**Urban wood waste:** Material generated by major construction activity, land clearing and tree trimming in urban areas.

Minnesota's third-largest category is woody biomass, whose annual growth of 423,000 billion BTUs is nearly as much as hays, straws and stalks. Softwood timber growth accounts for approximately 65% of the total available energy from woody biomass, aspen and other hardwood species contribute 25%, and logging residues, urban wood waste, and brushland add small percentages of 4%, 3%, and 3% respectively.

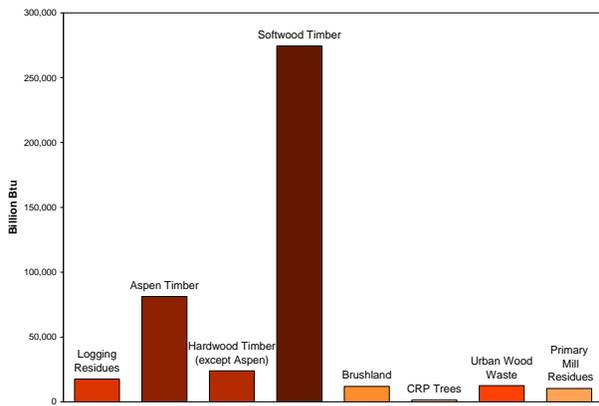


Figure II-9: Total Energy (Wood)

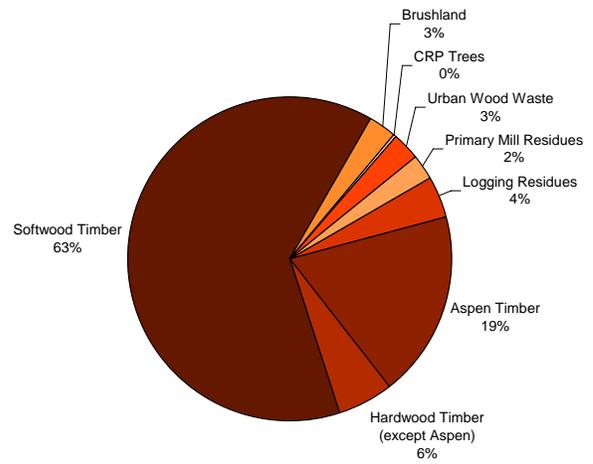
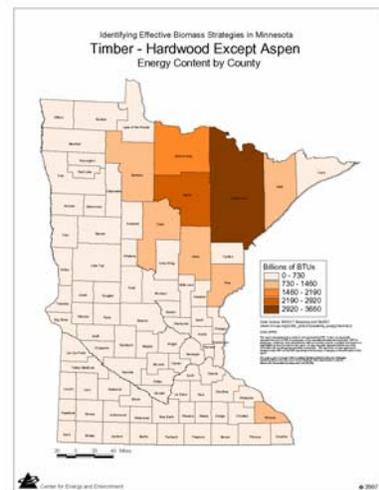
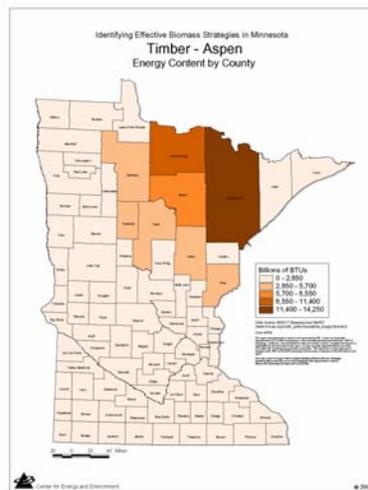
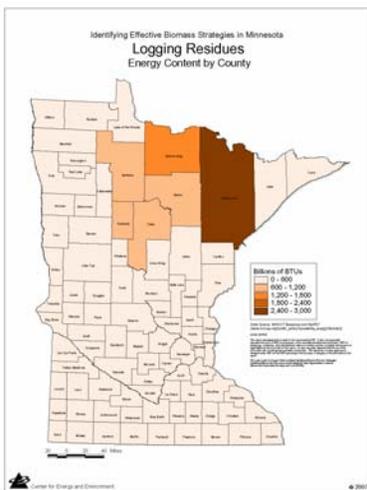
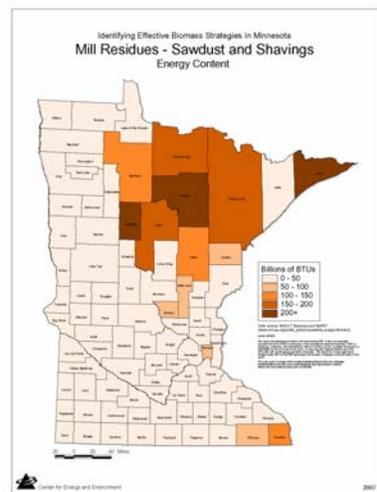
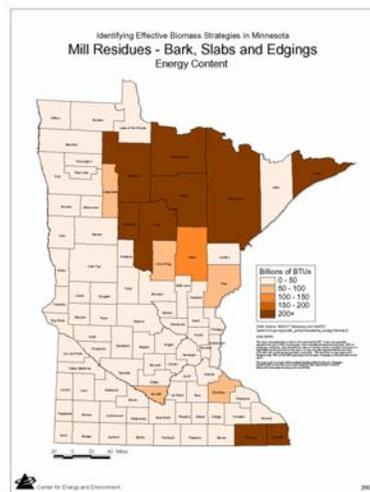
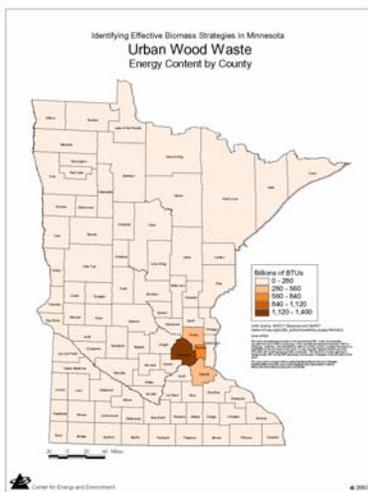
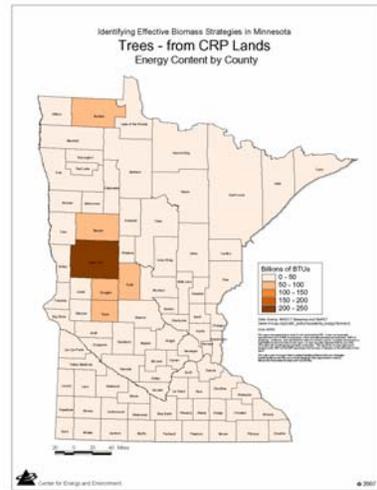
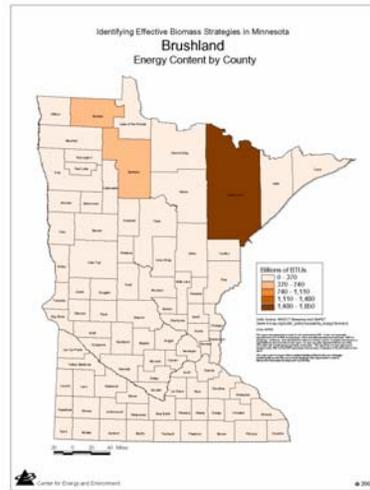
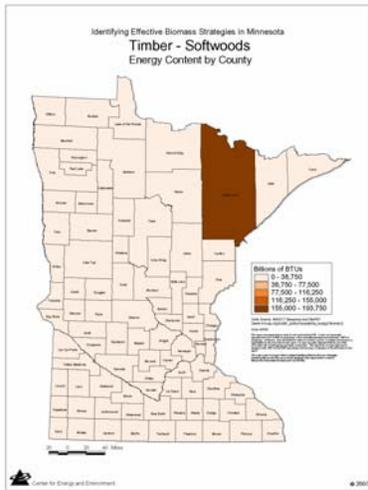


Figure II-10: Total Energy by Percentage (Wood)





## Manures

Wastes generated by livestock. The specific manures listed in BioPET are from:

Feedstocks include manures from:

Beef, Dairy, Hogs, Sheep, Broilers, Layers, and Turkeys

Manure is the fifth-largest category of biomass in Minnesota. Minnesota livestock annually produce manure containing approximately 72,000 billion BTUs. Dairy and beef manure contribute the most with approximately 37% and 31% respectively. Hog manure is next with 19%, and other sources are turkey manure (8%) and sheep manure (3%).

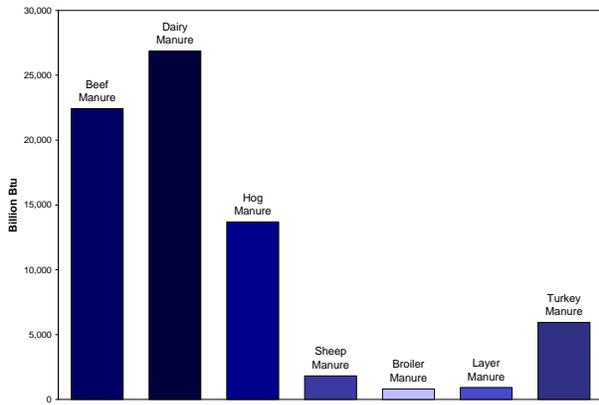


Figure II-11: Total Energy (Manures)

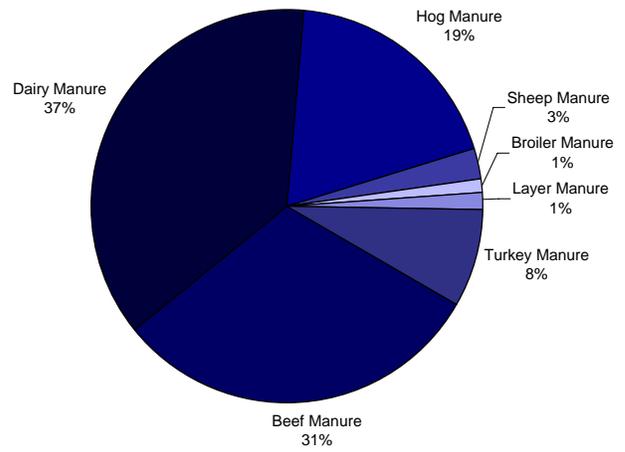
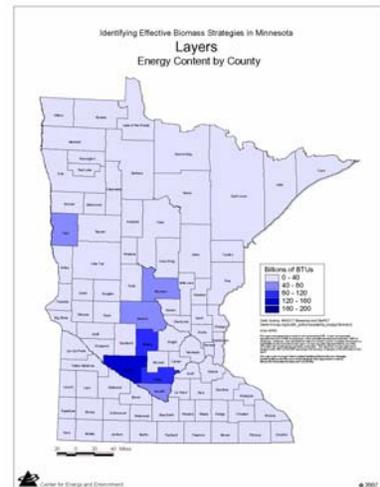
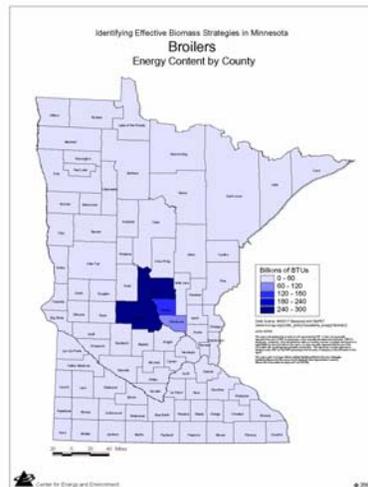
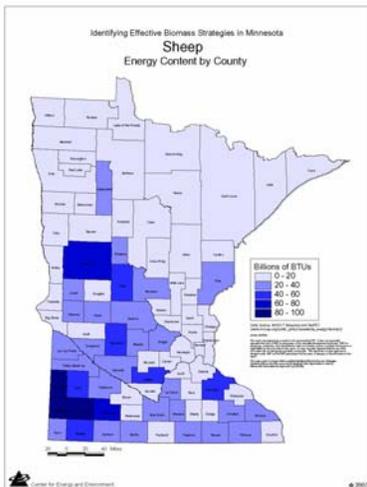
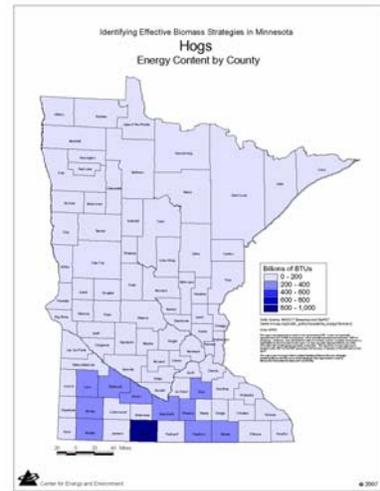
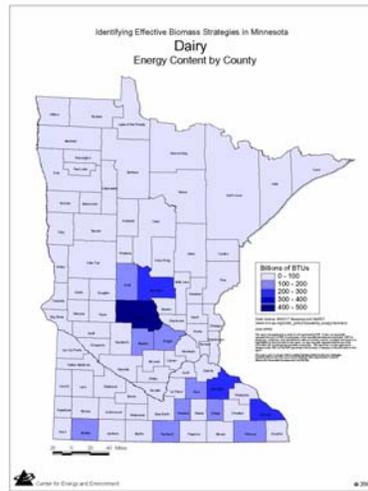
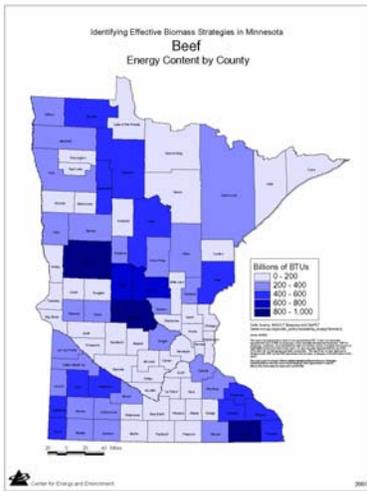
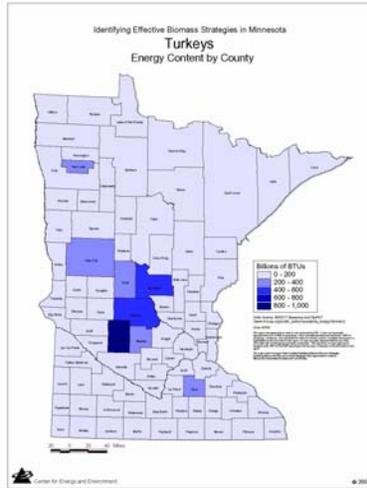


Figure II-12: Total Energy by Percentage (Manures)





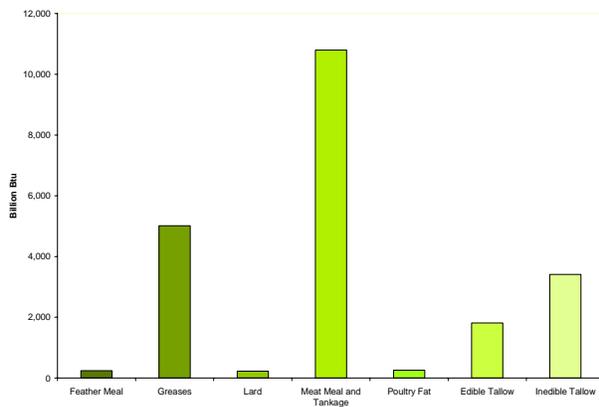
## Animal Processing

Byproducts of animal slaughter and meat processing. Specific animal processing wastes listed in BioPET are:

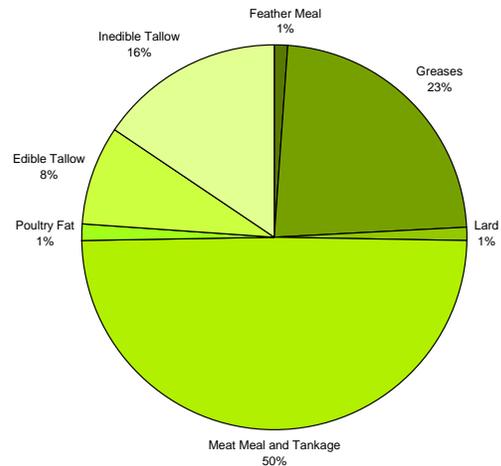
Feedstocks include:

Feather Meal, Greases, Lard, Meat Meal and Tankage, Poultry Fat, Edible Tallows, and Inedible Tallows

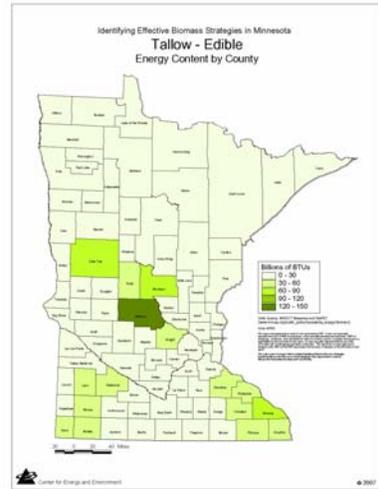
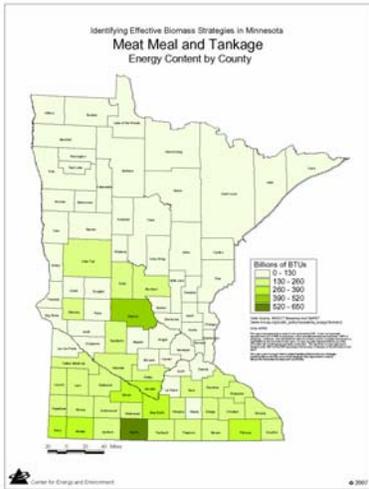
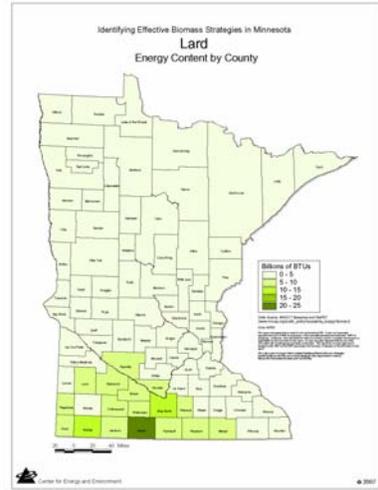
Animal processing residues are the smallest category of biomass in the state, with annual production of approximately 23,000 billion BTU. Meal and tankage are almost half of that at 47%. Other contributors are greases (22%), inedible tallow (15%), edible tallow (8%), and waste water treatment plant sludge (5%).



**Figure II-13: Total Energy  
 (Animal Processing Residues)**



**Figure II-14: Total Energy by Percentage  
 (Animal Processing Residues)**



# Municipal Waste Streams

Waste from urban centers. Specific waste streams include:

Landfill Gas, Municipal Solid Waste (MSW), WWTP sludge

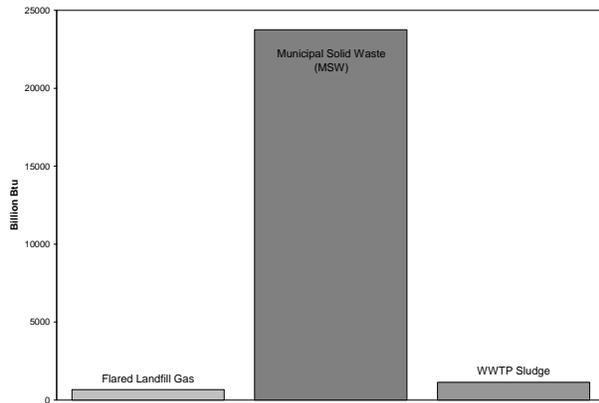


Figure II-15: Total Energy (Municipal Waste Streams)

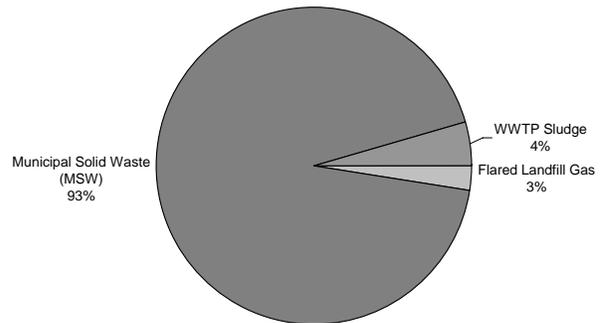
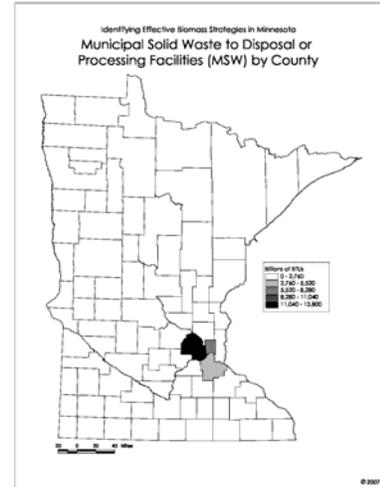
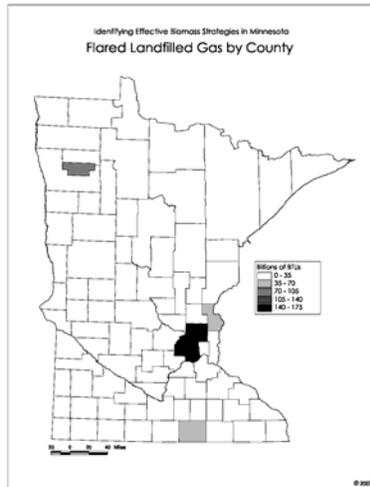
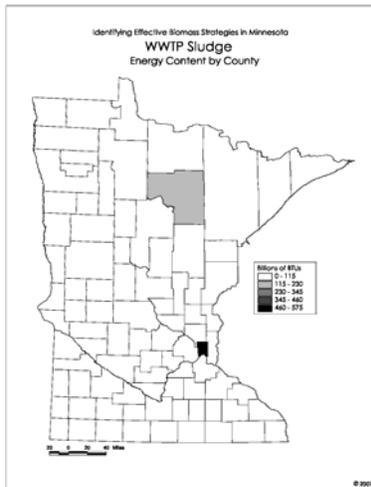


Figure II-16: Total Energy by Percentage (Municipal Waste Streams)



# Fossil Fuels

Both for comparison purposes as well as for co-firing applications, fossil fuel resources are listed. Although individual inventories were not determined since Minnesota does not have any native sources of fossil fuels, general fuel characteristics and prices were entered included in BioPET.

Fossil fuels include:

Minnesota Average Coal, Bituminous, Sub-Bituminous, Lignite, Fuel Oil (#2 and #6), Diesel Fuel (#2), Natural Gas, and Propane

## Dedicated Energy Crops

Crops raised for the sole purpose of producing energy in the forms of electricity and/or heat.

Over the past several decades, much research has looked into the possibility of using dedicated crops to produce energy, particularly short-rotation woody crops like hybrid poplar and willow and herbaceous crops like switchgrass, reed canary grass, and miscanthus. The research led by David Tilman at the University of Minnesota has brought attention also to the potential advantages of perennial prairie grasses.

Although BioPET does not include dedicated energy crops, we include them in this written report because of their great potential. Among the benefits expected from using perennial crops for energy are high biomass accumulation and low tillage, soil erosion, and herbicide applications. Since these crops regenerate after harvest, they do not need to be reestablished for a number of years. But they are not low input crops. With the exception of diverse prairie grasses (see below), the continual harvest of biomass from perennial biomass plots requires nutrient replacement at levels similar to annual row crops (Brummer, Burras, Duffy, and Moore, 2002).

Dedicated energy crops may end up costing more than agricultural or forest residues because they must cover the full costs of land and the establishment and maintenance of the stand. In contrast, residues like corn stover or logging wastes are byproducts of primary products like corn grain or roundwood that carry the costs of establishment, maintenance, land rents, and harvest. Usually, the price of residues is based only on the added costs of handling them. But, on the other hand, the cost of establishing and maintaining prairie grasses should not be high. Their economic outcomes will have to await their planting in substantial acreages.

**Herbaceous crops.** Much of the research in herbaceous cellulosic feedstocks like switchgrass, reed canary grass, and miscanthus has focused on perennial monocultures. But it is also possible to seed switchgrass stands with legumes such as alfalfa. This offers the farmer the benefits of reduced nitrogen applications and the use the first cut from the field as forage and the second cut as fuel.

**Switchgrass.** Switchgrass is perhaps the best studied perennial grass in the US – it has even been mentioned in a State of the Union address. A switchgrass stand successfully established in year one can be harvested in the fall of year two and for several years thereafter. Switchgrass stands are expected to last for ten years before reestablishment, but some may remain productive much longer. Yields vary widely depending on soils and rainfall. They tend to be lower in the dry high plains states than they are in the moist southeastern states. In Iowa yields range from 1 to 5.25 tons per acre, with an average of roughly 2.5 tons per acre. A detailed study of switchgrass production costs in southern Iowa estimates a cost of \$70/ton with a yield of 4 tons/acre (Brummer et al., 2002).

**Diverse prairie grasses.** In recent years ecologists have found increasing evidence that ecological diversity creates greater biomass yield and stability than a monoculture does. In a recent publication, ecologists at the University of Minnesota summarized the results of a long-term study of biomass yields and carbon sequestration on plots of degraded land containing 1,2,4,8 or 16 different perennial grassland species. They found that the most diverse plots produced 238% more bio-energy than monoculture prairie grasses and claimed to sequester 4.4 MG h<sup>-1</sup> year<sup>-1</sup> in the soil and roots, compared to 0.14 MG ha<sup>-1</sup> year<sup>-1</sup> for monoculture crops. The researchers estimate, from these figures, that energy derived from such diverse plots will be carbon negative (ie. that the plants will store more carbon in the soil each year than the fossil

fuels for producing, harvesting and transporting them will release into the air). (NSF, 2006; Hill and Tilman, 2006, 2007).

Diverse prairie grasses for energy feedstocks offers a number of advantages over monocultures. Once established, diverse prairie plots are remarkably stable. Theoretically, they never need to be reestablished. If the plants are harvested after they have become dormant in the late fall, they require no nitrogen fertilizers because legumes provide all the needed nitrogen, and they need very little fertilizer to replace other nutrients because they send most nutrients down into the plant's root systems in the fall.

Diverse prairie plots provide other benefits, like habitat for game birds and other wildlife species. But most importantly, prairie grasses not only thrive on severely degraded agricultural lands, they actually improve their health over time. These ecological benefits may persuade the federal government to allow the planting and harvesting of diverse prairie grasses on CRP lands, where harvests currently are prohibited.

## NOTES ON DATA RESOURCES

Most of the potential biomass energy feedstocks quantified in BioPET already are in use for other purposes. Even though they seem already to be spoken for, we include them all because future increases in energy costs may make them more valuable for energy than for their current uses. If that becomes the case, policy issues will arise. A currently controversial case of that shift from food to fuel is corn ethanol. But critical as biomass energy policy is, it is not the subject of the BioPET tool.

BioPET bases its estimates mainly on the best available *public* information. Most data on commercial enterprises are proprietary and therefore unavailable for public analysis. Nevertheless, we have to gain some understanding of the scale of those activities in order to assess opportunities for sound energy development and sound public policy. It should be noted that in practice many of these figures will vary across the state due to climate, soil types, market changes, and other regional variations. Our numbers, imperfect though they may be, are the best estimates we can make using available data sources.

### Agriculture (Crops and Crop Residues)

Minnesota crop acreages and yields by county are obtained from the National Agricultural Statistics Service (NASS) database for the most recently available three- year period (2002-2004). Since NASS records yields "as reported" without making moisture or quality adjustments, we have to convert the "as reported" quantities into tons of dry matter.

NASS data are published by county. The production of counties with fewer than 1,000 acres of a crop generally is combined with other counties in the same Crop Reporting District (CRD) and their totals are reported as "other counties" in the CRD summary or, for a few low-volume crops, as "Other Districts" in the state summary. This is done to protect the privacy of producers who are distinctive enough in their counties to be clearly identifiable. For our study, these combined acres are allocated back to individual counties. Biomass summaries are computed for the three-year average production. Using the moisture content assumptions as presented in BioPET, all quantities were converted to dry tons.

The derived yield estimates are *not* net of "downstream" processing. Therefore we make no distinction between acreage used solely for energy purposes and acreage used for some other

primary purpose, like food, animal feed, and so on. The figures represent annual growth of biomasses, not their ultimate markets.

Values in the NASS database are based upon bushels harvested. Using nominal industry rules of thumb, assumptions were used to convert biomass inventories to a dry-ton basis. These assumptions are listed below.

**Table II-1: Crop Assumptions**

Crop	Weight per Bushel	Moisture Content
Alfalfa	--	9.6%
Barley	48 lbs	14.5 %
Canola	--	13 %
Corn	56 lbs	15.5 %
Corn Silage	--	70 %
Dry Beans	--	10 %
Oats	32 lbs	14%
Potatoes	--	21.2 %
Soybeans	60 lbs	13 %
Sugar Beets	--	16.4 %
Sunflowers	--	10 %
Sweet Corn	56 lbs	10.3 %
Wheat	60 lbs	13.5 %

Assumptions were also necessary for estimating the amount of crop residues generated per bushel of crop harvested. These are shown table II-2.

**Table II-2: Crop Residue Assumptions**

Crop Residues	% of grain weight	Moisture Content
Barley Straw	90 %	10 %
Oat Straw	90 %	10.4 %
Wheat Straw	90 %	16 %
Corn Stalks	85 %	0 %
Sunflower stalks	90 %	10 %
Sweet Corn Stalks	100 %	76 %
Other Hays	--	12 %

## Agricultural Processing Wastes

**Ethanol.** A growing proportion of Minnesota corn is going into ethanol production. BioPET has modeled the production process of ethanol by-products [i.e., oil (the corn syrup plus other soluble materials), feed, and DDGs] using parameters developed by Jordan and Taff, 2005. The principal by-product with energy potential is dried distillers grains (DDGs), which now are sold principally for livestock feed. However, a few plants are beginning to use them for internal energy needs. These estimates assume that, for now, all the ethanol by-products are available for external energy production.

**Flour milling.** The milling of wheat results in two products: flour and wheat midds. Estimates are calculated by applying the same production model to each major flour mill in Minnesota.

**Soybean oils.** Almost all Minnesota soybeans are crushed for livestock feed and soybean oils. Both these products could be energy sources, but currently only oils are being used for energy through conversion into biodiesel. These estimates assume that all the soybean meal and all the

oil not converted into biodiesel are available for energy use. Biodiesel itself is reported as if it were fuel for electricity production.

**Sugar beet by-products.** Sugar beet processing in Minnesota is confined to three locations. BioPET's numbers are based on production records the plants themselves keep on four products: sugar, beet pulp pellets, molasses, and tailings. All except tailings currently are sold in separate product markets. The bulk of the potential biomass energy produced at these plants is embedded in the sugar itself.

## Wood

**Forests.** The U.S. Forest Service Minnesota makes periodic estimates of forest productivity (it has done so annually since 2004) and reports it in the Forest Inventory Analysis (FIA) database. Data are reported for each tree species in each county, but these local estimated means vary widely, as the Forest Service acknowledges. Consulting with the staff that maintains the FIA database, we use the county mean acreage for three species groupings -- softwoods, aspen, and non-aspen hardwoods. With these acreage numbers, along with multi-county annual increment (based on the four Minnesota FS analysis region boundaries for this assignment), we estimate the annual green-ton growth for three groupings in each county and use an average moisture content estimate to convert green-ton estimates to dry tons per year. Energy equivalents are calculated using the feedstock energy parameters already mentioned, updated where necessary.

**Woody crops.** The two primary short rotation woody crops that have been studied in the US are hybrid poplars and willow. Hybrid poplars have been studied in Minnesota for a number of years. In 2004 the first commercial hybrid poplar plantings for energy were initiated by the Laurentian Energy Authority, in the expectation that they will use the trees as fuel for their boilers (CERTs, 2005).

It will generally take a year to prepare the ground for planting of hybrid poplars, and the initial harvest is generally expected to take place 10 to 12 years after planting. The accumulation of biomass in hybrid poplar stands is expected to be 3 dry tons per acre per year in Minnesota (Riemenschneider, Netzer, and Berguson, 1996).

**Paper mills.** BioPET models paper production among all Minnesota mills with common process parameters. The mills already use black liquor and wood wastes to generate process steam and electricity for internal use, and some also use mill sludge.

**Wood processing industries.** OSB production is modeled for Minnesota mills using common process parameters. Most plants already use waste wood for internal energy needs.

**Urban wood waste.** BioPET's figures in this category come from two sources, one local, the other national. The local estimate is based on consumption by the District Energy facility in St. Paul which, according to anecdotal reports, currently uses all the wood waste readily available in the seven-county Twin Cities metropolitan area. From District Energy's annual consumption we calculate the tons per capita of waste wood available in the metro area and apply that ratio to the urban population of each county as recorded by the US Census. The national source, the "Billion Ton Study." by Oak Ridge National Laboratory (Perlack, Wright, Turhollow, Graham, Stokes, and Erbach, 2005), estimates the amount of urban waste wood available each year in each county. BioPET uses both local and national sources but tends to favor the ORNL numbers.

## Manures

**Variability.** Depending on their species, housing systems, diets, and digestions, livestock produce manures that contain different moisture levels and BTU densities. Beyond that inherent variability, certain amendments like rinse water, wood shavings, straw, and corn stover that are added to manure for easier handling or livestock comfort, introduce further inconsistencies.

**Limited data.** Calculating manures for BioPET from available data can be a challenge. The starting point is the NASS database of Minnesota livestock production numbers by county, but limitations in those data force us to derive figures from other clues as well. For example, since NASS doesn't track all animal species found on farms, we model numbers and sizes of animals based on our knowledge of the way livestock are raised. Since NASS takes inventories of various species of livestock at various times of the year, the data do not provide a snapshot. Some data are not reported at all because of privacy.

**Inferences.** We have to infer the number of livestock on farms in each county from no less than sixty columns of figures on thirty-five classes of livestock raised or fed in Minnesota. In some cases we base our categories on amounts of corn, soybean meal, and oats consumed by those thirty-five animal classes. In other cases we base estimates on the number of days in a year that a particular class of animal is alive on a Minnesota farm to eat feed and excrete manure. We gather estimates of days on feed from published budgets and from University of Minnesota animal scientists who have specific information on livestock. We assume that some classes of livestock, like dairy cows, are alive 365 days a year, while others, like broilers, live just 56 days. We calculate pounds of manure excreted daily for each class of livestock on a wet basis and a dry basis. Excreted manure of poultry tends to be 25% total solids, while swine manure tends to be 10% total solids (MWPS, 2004).

Our numbers for animals of a particular class reflect either NASS data or estimates by the project team. The number of animals in each county is derived from the various crop reporting districts of the state. Final values show the number of tons of manure annually produced by the classes of livestock in each county. We show estimates for both wet and dry tons in order to help the developer assess transportation costs and calculate BTUs on a dry-ton basis.

## The Conservation Reserve Program (CRP)

The federal Conservation Reserve Program (CRP) pays landowners to convert their cropland to permanent cover, such as grassland or trees, for a term of ten or fifteen years. Under current program rules, lands in CRP cannot be harvested. But if that policy changes, they could grow biomass for energy.

We calculate potential energy contents of these lands by first aggregating all 25 official cover types (warm season grass, wetlands, wildlife plots, cool season grass, etc.) into the three main categories of grass, trees, and other, and then applying a common yield estimate for each of these broad categories. For grasses, we estimate 2.2 tons per acre per year based on the research of Tilman, Reich, Knops, Wedin, Mielke, and Lehman, 2001. For brushland, we settle on 1 ton per acre per year based on a low-yield estimate in the forest softwood feedstock calculations. We then calculate the energy content of each broad category using the parameters mentioned previously.

## Data on Municipal Sludge

Nearly all municipal wastewater treatment plant (WWTP) sludge is currently spread on farmland to take advantage of its significant nutrient and tilth-building components. Currently, only a few plants use sludge for internal energy, mostly in the form of heat. The estimates in BioPET indicate the amount of energy that would be produced if all plants in the county used all of their sludge to produce biomass energy. Values are based on the annual sludge management report of the Minnesota Pollution Control Agency, which itemizes it by county on a dry-ton basis. We calculate its energy content in the way described previously.

## FUEL SELECTION CONSIDERATIONS

We stress that, while BioPET offers the best generalizations that can be made using existing data, it does not pretend to make the kind of exhaustive, definitive evaluation a developer will want in selecting an individual fuel for a specific biomass power plant. Our estimates serve only as a preliminary screen for more in-depth technical analyses. The Agricultural Utilizations Research Institute (AURI) is an excellent resource for providing up-to-date information on feedstock regional variations within Minnesota.

An outline for a more in-depth analysis of potential biomass fuels might include the following items (Miles et al. 1995):

- Collecting representative samples of all fuels being used and those being considered.
- Engaging a laboratory with experience in biomass fuel analysis to analyze the samples for proximate, ultimate, total chlorine, and elemental ash.
- Calculating the concentration of alkalis and sulfur compounds (MMBTU/lb or kJ/kg, dry basis)
- Comparing the level of alkali in the fuel with experiences of other plants in burning similar fuels
- Striving to find fuels with alkali levels of 0.4 lb/MMBTU (0.17 kg/GJ) or less or blend fuels to this maximum level. If a high alkali fuel is used, attention should be paid to ways of minimizing its formation and consequent damage to the system.
- Preparing a schedule of blends by fuel types so that fuel entering the boiler has predictable deposit characteristics.
- When fouling cannot be explained, having an experienced laboratory examine the deposits and identify the constituents that contribute to fouling.

Attention to these fuel performance issues will minimize expensive surprises and help ensure the installation and operation of a well designed, sustainable bio-power system.

We estimate biomass volumes by referring to variety of sources and contacts as well as the extensive experience and insight of members of the project team. *These estimates are not net of "downstream" processing.* For example, we estimate corn grain production prior to its use as livestock feed and, hence, manure production. A finer stage of analysis would decrement the corn grain estimate by the appropriate amount in order to avoid double-counting of energy potential.

A power plant developer also has to consider carefully any current or potential downstream competition for biomass. BioPET estimates the gross theoretical availability without reference to present or future withdrawals of biomass. The following chapter presents formulae for reducing the *theoretical* biomass availability (the gross annual growth shown in BioPET) down to the *technical* availability (the volume that could be delivered considering limitations imposed by

equipment, logistics, soil health, etc.) and then reducing that amount further down to *economic* availability by eliminating biomass that is too expensive to be used as fuel because of competition from other uses. Since the reduction formulae involve a number of complicated, ever-changing factors, the developer of a specific project in a specific location at a specific time using specific fuels will want to make that critical estimate himself or herself.)

We next then estimate collection and initial processing costs for each of the relevant feedstocks. The result is a “supply curve” for biomass at the county level: how much will it cost per ton (or per BTU) to produce a “pile” of a given biomass feedstock in the county, ready for shipment to a power plant.

# CHAPTER III : BIOMASS AVAILABILITY FOR ENERGY

The preceding chapter told what volumes of biomass are produced each year in Minnesota. It's important to know that. But if all that biomass were to go into energy, people and animals would go hungry. So it's even more important to know what portion of total biomass can be considered for fuel. That is the subject of this chapter.

## CURRENT BIOMASS POTENTIAL RELATIVE TO STATEWIDE ENERGY USE

The following graphs show that biomass is unlikely to provide more than a portion of Minnesota's demand for energy. These charts comparing existing biomass resources to total energy consumption, electricity consumption, and summer demand with the energy contained in all Minnesota biomass that can be harvested and brought to market – both food crops and residues. It would take almost every available bit of biomass in Minnesota to meet the state's electricity needs.

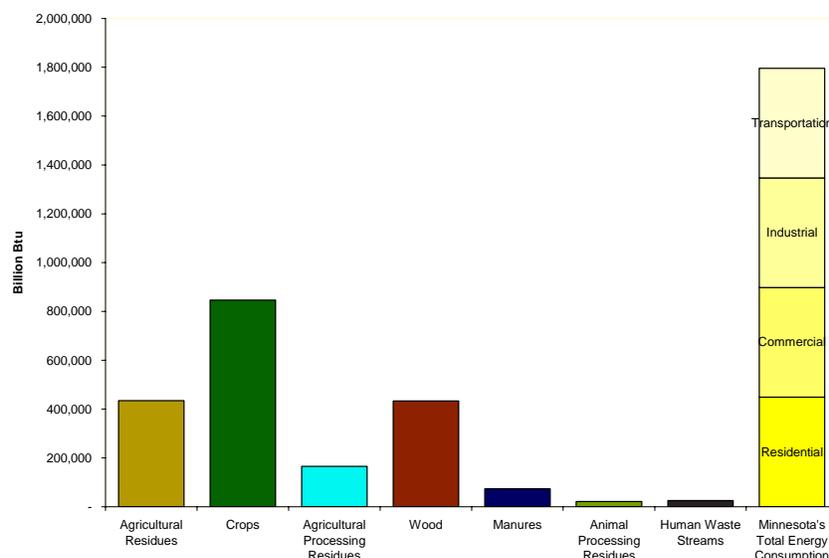


Figure III-1: Total Theoretical Energy Potential

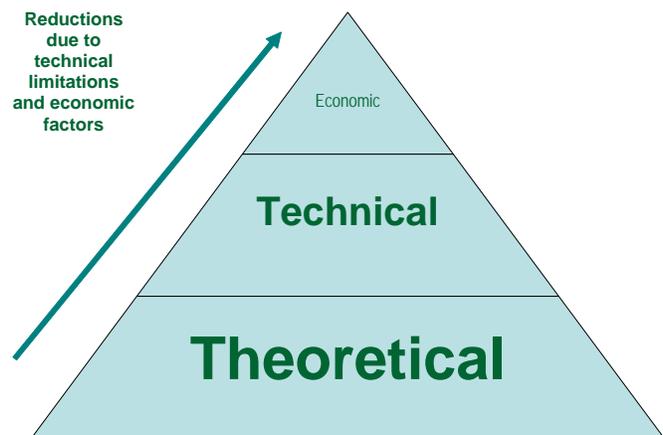
That obviously is not a possibility. Most biomass, especially in large categories like crops and wood, is destined to be made into products like food, lumber and paper. Some liquid fuel manufacturers, like corn ethanol producers, may be able to outbid food manufacturers for crops because their prices track ever more costly petroleum. But prices of fuels for electric power are constrained by the low prices of its competition, coal and nuclear fuels. Biomass power plants will have to live on the leavings, like the hays, straws and stalks that contain approximately 10% of Minnesota's annual energy consumption, or manures and woody residues, which each contain about 1%. Or perhaps future dedicated energy crops, like switchgrass or prairie grasses, which are not accounted for in current growth statistics.

Even a limited contribution to Minnesota's energy portfolio is a contribution worth having. It will take a broad, diverse portfolio of renewable, sustainable fuels to replace a cheap, abundant (but polluting) fossil fuel like coal. Biomass will be one of a number of essential contributors.

Since the biomass energy contents of biomass reported in the previous chapter represent gross annual growth *not net* of other non-energy uses, the pertinent question for the bio-power developer becomes: how much of that gross biomass energy actually *is* available for power generation? To answer that question, we have to make calculations not contained within the BioPET tool.

## From Theoretical to Technical to Economic Availability

We begin those calculations with BioPET's figures for gross annual growth, which we'll call the **Theoretical Biomass Energy Potential**. Some of that potential can't be used for any purpose at all because it is lost in harvesting, storage, or transportation, or it must be plowed under to maintain the health of soils. We subtract that to arrive at the **Technical Biomass Energy Potential**. A large portion of that technically available potential energy will be too expensive to use for fuel because it is in demand for non-energy products or for other reasons, like logistics. Subtracting that high-priced portion from the Technical Biomass Energy Potential leaves us with the **Economic Biomass Energy Potential** available for biomass energy. This process of elimination can apply at any scale – statewide by using as a starting point the gross BioPET values for all 87 Minnesota counties; regional by aggregating gross BioPET values for a cluster of counties; or local by looking at gross BioPET values for just one county.



Running statewide BioPET numbers through that process of elimination, we arrive at four categories of biomass that seem to have the greatest **Economic Biomass Energy Potential**:

- hays, straws and stalks,
- woody residues,
- wet manures and
- dry manures

## Theoretical Biomass Energy Potential

The *theoretical biomass energy potential* is calculated by applying the following formula to the dry-ton biomass inventories in BioPET.

$$\text{Energy}_{\text{Theoretical}} = \frac{\text{Dry Tons} * \text{Energy Content}_{\text{BTU/pound}} * 2000_{\text{pounds/ton}}}{1,000,000 \text{ BTU/MMBTU}}$$

Where:

Energy<sub>Theoretical</sub> = The total energy content in MMBTU for a given feedstock in each county.

Dry Tons = The estimated quantity in dry tons of a given feedstock in each county.  
 Energy Content = The BTU content of a dry pound of a given feedstock

## Technical Biomass Energy Potential

Since Theoretical Biomass Energy Potential does not account for physical factors which reduce biomass harvests, like inefficient harvest technologies or the need to leave residues on the land to maintain soil fertility and prevent erosion. We estimate the *technical biomass energy potential* of each feedstock using the following equation.

$$\text{Energy}_{\text{Technical}} = \frac{\text{Dry Tons} * \text{RP} * (1 - \text{MR}) * \text{Energy Content}_{\text{BTU/pound}} * 2000_{\text{pounds/ton}}}{1,000,000 \text{ BTU/MMBTU}}$$

Where:

$\text{Energy}_{\text{Technical}}$  = The energy content in MMBTU for a given feedstock in each county that is available for use as a bio-power feedstock.

Dry Tons = the estimated quantity in dry tons of a given feedstock in each county.

RP = The recoverable portion, expressed as a percentage, of a given feedstock that can be technically recovered for use as a bio-power feedstock. This value also includes expected losses due to storage, transportation, etc.

MR = The portion, expressed as a percentage, of a given feedstock that must remain on the land for reasons of preventing soil erosion, maintaining soil productivity etc.

Energy Content = the BTU content of a dry pound of a given feedstock.

The theoretical potential for wet manures of sheep and beef cattle is further reduced because they usually are not housed in an enclosure where their manure can be collected for a digester. (Fehrs, 2000).

## Economic Biomass Energy Potential

After we have arrived at an estimate of *technical biomass energy potential*, we subject feedstocks to a series of screening criteria to determine which have *economic biomass energy potential* for electric generation. Manures, a potentially important feedstock, call for a special analysis detailed below. Other feedstocks are screened on the bases of price compared to traditional fuels, and competition from non-energy industrial users.

**Manures.** To begin the screening of dairy and swine manures, we find in NASS, 2006 county data that 13% of Minnesota's cows live in 65 herds of more than 500 head, the smallest herd that can support an anaerobic digester paired with an electrical generator (DOC, 2003a). Using these values to calculate the average energy available at large dairy farms, we estimate the economic potential of dairy manure in each county using the following formula:

$$\text{Dairy Energy}_{\text{Technical}} = ((\text{Energy}_{\text{Technical}} * 13\%) / 65) * \# \text{ Farms}$$

Where:

$\text{Dairy Energy}_{\text{Technical}}$  = The energy content, in MMBTU, of the dairy manure technically available as a bio-power feedstock in a given county.

13% = The percentage of Minnesota's dairy cows found in herds greater than 500 head.

65 = The number of dairy farms in Minnesota with herds greater than 500 head.

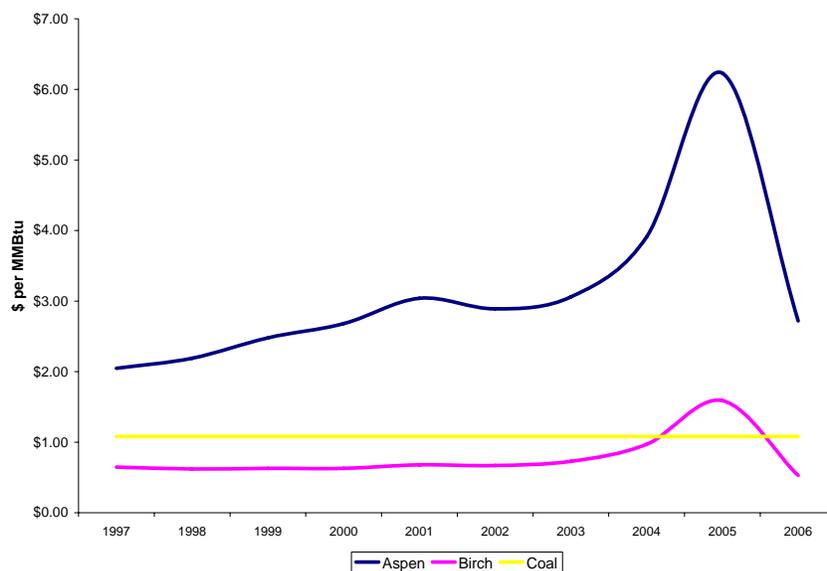
# Farms = The number of dairy farms in a given county with herds greater than 500 head.

Since NASS doesn't provide a similar data set for Minnesota's swine herds, we use a different method to estimate the technical energy potential of swine manure. Economic analyses of anaerobic digesters running swine manure suggest they need a herd of at least 12,000 to operate economically in Minnesota. Unfortunately, NASS provides a state inventory of only swine herds greater than 5,000 head, encompassing 46% of Minnesota's pigs (NASS, 2006). We estimate technically available swine manure at 46% of county-level theoretical estimates, but since many states don't have such herds, the resulting figure probably overstates the state-wide technical potential. Lacking more precise information on the size and geographical distribution of the state's large swine operations, however, we can't provide a more exact calculation.

**Further screens.** We next subject other biomass categories to a series of screens, beginning with price. Feedstocks more expensive than natural gas are eliminated because they aren't cost-effective for base-load generation. That eliminates most animal processing wastes, crops and crop-processing residues.

The next screen rules out feedstocks used by industries to create high-value products. Most of those feedstocks are ~ 3 times the price of coal and therefore uncompetitive for base-load power generation. They probably would become even less competitive if a power facility bid up their price, assuming that current industrial consumers could outbid bio-power facilities. So this screen eliminates agricultural crops.

Timber in the form of cordwood also drops out. On a BTU basis, stumpage (the price of unharvested timber stands) of aspen, Minnesota's largest wood crop, is at least twice what Minnesota's power plants pay for coal (DNR, 2005; Jacobsen, 2006; and EIA, 2006b). That doesn't take into account harvesting and trucking, which are 89% of the cost of wood delivered to the mill. Delivered prices of other species, like birch, have been lower than aspen but still higher than coal on a BTU basis.



**Figure III-2: Price comparison: aspen and birch pulpwood on the stump and coal delivered to MN in 2004**

Wood waste, on the other hand, may be affordable for biomass fuel. Wood is the densest and most transportable form of biomass available, and loggers are eager to sell harvest residues, like limbs, lily pads and tops, and unmerchantable species, that they have to harvest to meet

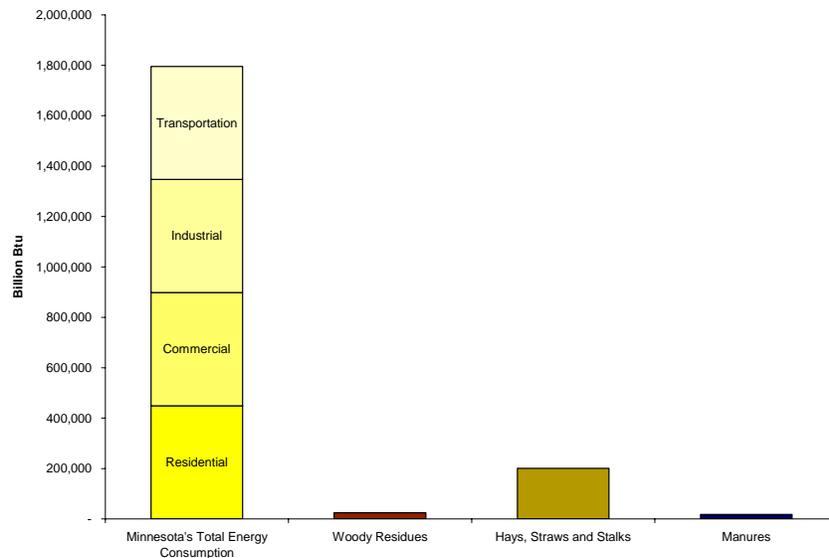
contract requirements. In the absence of established markets, price information on wood residues is sketchy. But the advent of new users like the Laurentian Energy Authority in Hibbing and Virginia may improve that situation.

Our final screen eliminates hays and trees grown on CRP lands which, under current CRP regulations, can't be harvested. There has been an ongoing discussion of making CRP biomass available for biomass energy, but no change in the established policy.

## CATEGORIES WITH GREATEST ECONOMIC BIOMASS ENERGY POTENTIAL

Following this process of elimination, four categories of biomass are left standing.

- **hays, straws and stalks**  
Straws from barley, oats, and wheat, hay categorized as switchgrass/other hay, and stalks from sunflowers, grain corn and sweet corn.
- **woody residues**  
Logging residues (tops, limbs, lilly pads), mill wastes (bark, slabs, sawdust, off-fall), brush, thinnings and urban tree waste.
- **wet manures**  
Manures from dairy cows and hogs.
- **dry manures.**  
Manures from broilers, layers and turkeys.



**Figure III-3: Economic Potential and Minnesota Energy Consumption**

The component breakouts of each category are detailed in the following charts.

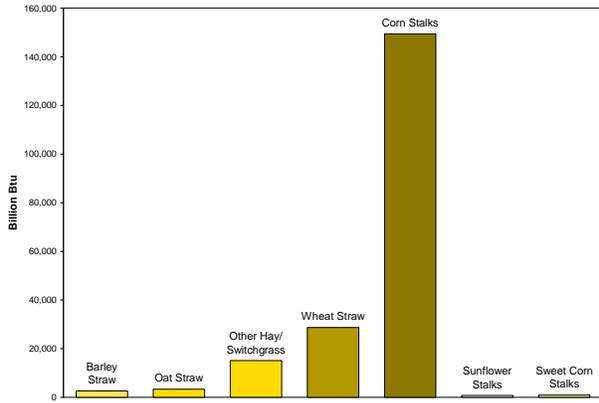


Figure III-4: Economic Energy Potential (Hays, Straws, and Stalks)

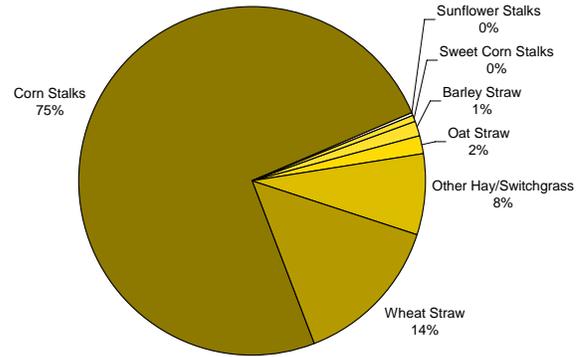


Figure III-5: Economic Energy Potential by Percentage (Hays, Straws and Stalks)

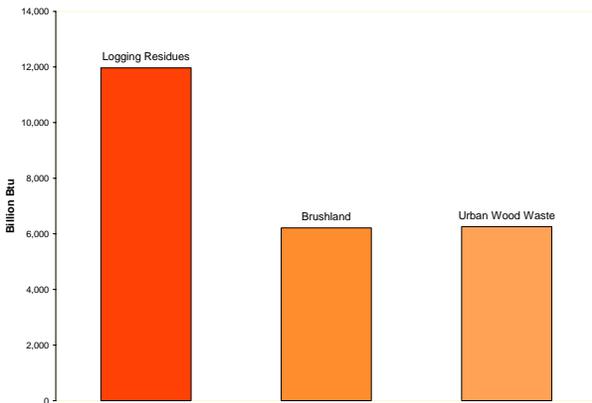


Figure III-6: Economic Energy Potential (Wood)

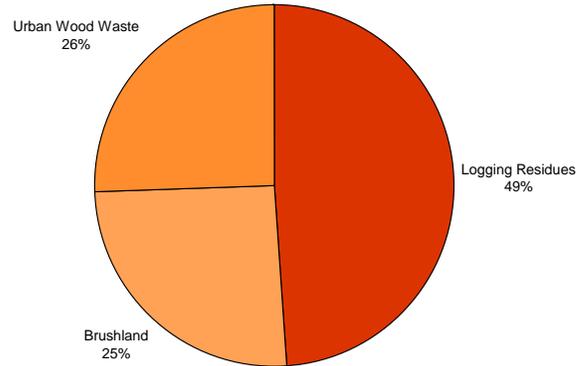


Figure III-7: Economic Energy Potential by Percentage (Wood)

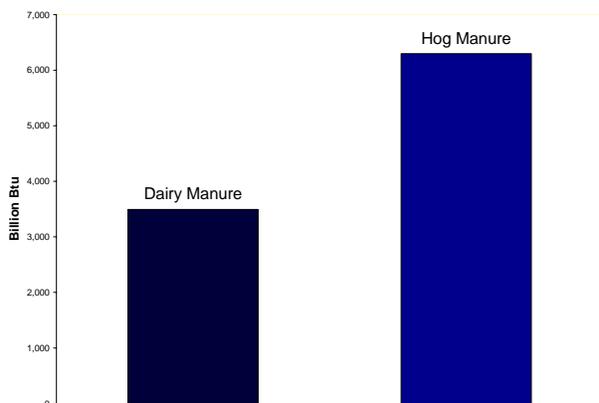


Figure III-8: Economic Energy Potential (Wet Manures)

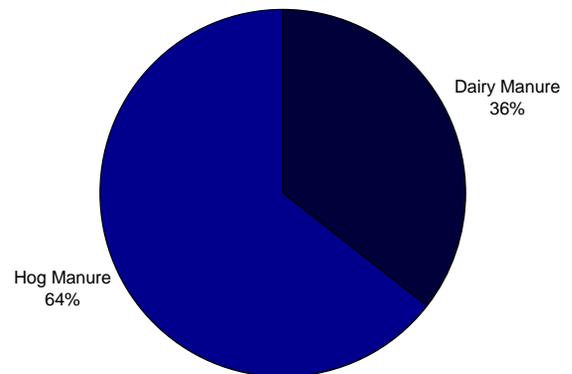


Figure III-9: Economic Energy Potential by Percentage (Wet Manures)

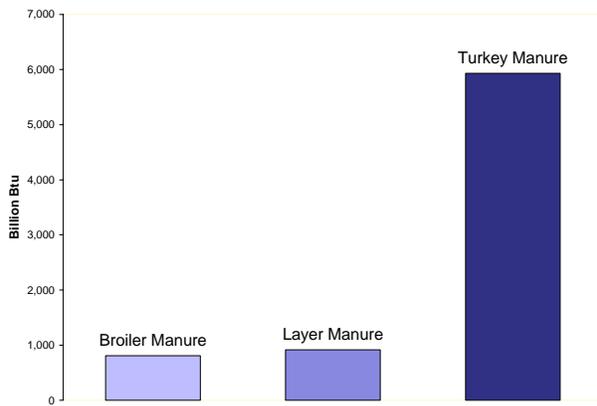


Figure III-10: Economic Energy Potential (Dry Manures)

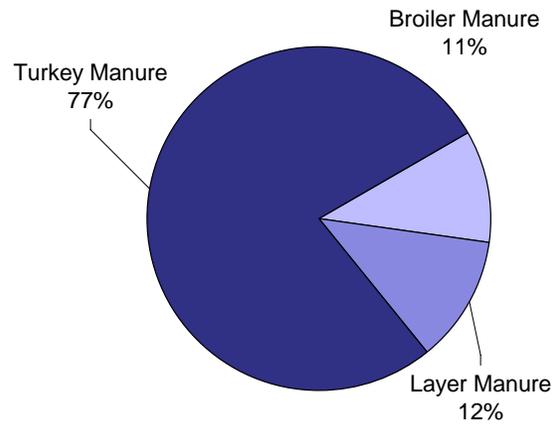


Figure III-11: Economic Energy Potential by Percentage (Dry Manures)

## Conversion to Units of Electricity

The following formula is applied to find the potential electric energy potential of each feedstock:

$$\text{Electricity}_{\text{Potential}} = \frac{1,000,000 \text{ BTU/MMBTU} * \text{Energy}_{\text{Tech}} * \text{Efficiency}_{\text{Elec}} * 1,000 \text{ kWh/MWh}}{3412_{\text{BTU}/\text{kWh}}}$$

Where:

Electrical Potential = The megawatt-hours of electricity that could be generated with a given feedstock.

Energy<sub>Tech</sub> = The energy content, in million BTUs, technically available for use as a bio-power feedstock.

Efficiency<sub>Elec</sub> = The conversion efficiency of biomass feedstocks to electricity. For hays/straws, woody residues and dry manures an efficiency of 25% was used. For wet manures an efficiency of 12% was used. This efficiency represents the net electrical efficiency from the energy content of raw manure. It incorporates the efficiency of biogas production by the digester and the electrical efficiency of the electrical generating equipment (in many cases a biogas enabled engine generator set).

To estimate the generating capacity that each potential feedstock could support the following formula was applied.

$$\text{Capacity}_{\text{Potential}} = \frac{\text{Electricity}_{\text{Potential}}}{(8760_{\text{hours}/\text{year}} * \text{Capacity Factor})}$$

Where:

Capacity<sub>Potential</sub> = The electrical generating capacity, in megawatts, that can be supported by a given bio-power feedstock.

Capacity Factor = The amount of time in a given year, expressed as a percentage, that an electrical generator is expected to be available for operation. A capacity factor of 85% was used for each potential bio-power feedstock.

## Comparing Theoretical, Technical and Economic Availability

The green columns (*technical potential*) and pink columns (*theoretical potential*) show that some biomass categories are virtually 100% technically available, while others drop off dramatically. Crops, processing residues and animal processing residues are all 100% technically available. Woody materials are generally available, but almost half of hays, straws and stalks are technically unavailable because of technological and ecological factors mentioned earlier. Because beef and sheep manures are difficult to recover, only 63% of them are expected to be technically available

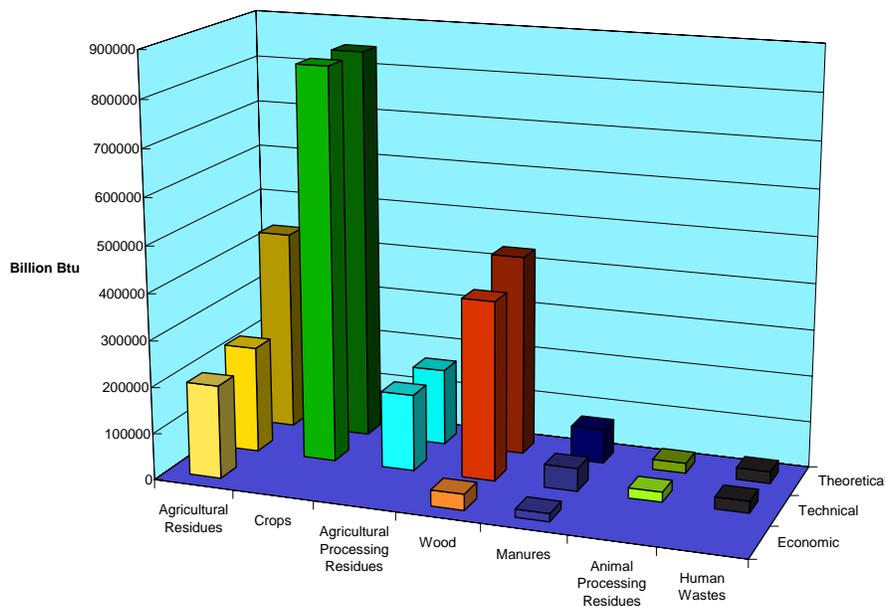


Figure III-12: Theoretical, Technical, and Economically Available Energy

Stepping down from *technical availability* to *economic availability*, the blue columns (*economic availability*), or lack thereof, show that crops, agricultural processing residues and animal processing residues are totally eliminated by economic criteria. Only a small portion of hays, straws and stalks are eliminated by restrictions on harvesting CRP lands. Assuming that logs are too expensive to use for fuel, woody materials drop off steeply. A significant portion of dairy and swine manures can't be captured because only very large herds produce enough to make anaerobic digesters economically feasible.

Figure III-12 shows that technical limitations on biomass availability are much less important than economic ones. The majority of the state's biomass is unlikely to become bio-power feedstock because it is too expensive for base-load generation. This is ironic because unlike individual wind turbines, a biomass power plant could theoretically dispatch baseload power 24/7 if it were not too expensive. But with the appropriate gasification conversion technology biomass fuel someday may replace natural gas in peaking plants.

**Most promising categories.** The bar graph below narrows our focus to the categories we have identified as economically feasible for bio-power applications. The gap between technical and economic limitations varies by feedstock type. Technical limitations account for most of the difference between the total energy and bio-power potential energy of hays, straws and stalks. For woody biomass, most of the difference between total energy content and bio-power potential is due to economic limitations. For manures each limitation plays a roughly equal role.

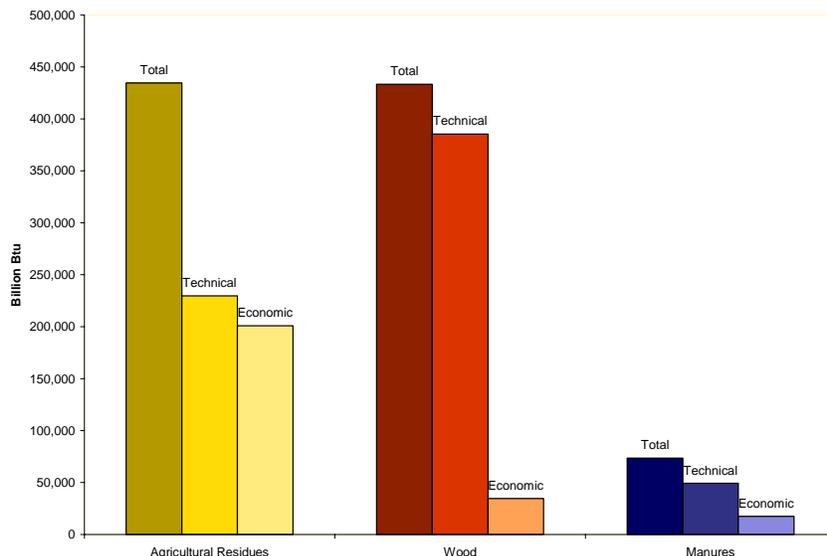


Figure III-13: Theoretical, Technical, and Economic Potential of Crop Residues, Wood, and Manures

## Comparing Costs of Biomass and Fossil Fuels

Hays, straws, and stalks and woody residues are the most abundant sources for biomass power feedstocks, but currently tend to be more expensive than coal. Figure III-14 illustrates the cost components of baled switchgrass, logging residues, and hybrid poplars in comparison to delivered coal. It is important to note that, as with other products, the per unit price of coal may decrease with higher volumes. Large scale coal-fired power plants (hundreds of MWs) operated under long-term utility contracts may pay around \$1.08/MMBtu while smaller facilities (hundreds of kW to tens of MWs) will pay higher amounts around \$2.60/MMBtu (Lindquist, 2007). When comparing fuels for smaller plants, a higher cost of coal estimate would be more appropriate.

This of course does not include any added environmental taxes that may be implemented at a later date (something to consider with such long-term operation schedules). Much discussion surrounds the idea of establishing carbon taxes to combat global warming. If such taxes were instituted, the price of coal could increase dramatically.



Figure III-14: Comparisons of Typical Delivered Fuel Costs

## SUMMARY

In summary, biomass can be used as a source of energy using a variety of technologies, and in a wide variety of applications. Many of the more advanced technologies available for converting biomass to energy are in a period of rapid technological advance and commercial deployment. Through their ability to improve the efficiency of biomass utilization and their ability to transform biomass into higher value products, such as liquid fuels and chemical feedstocks, these advanced technologies have the potential to revolutionize the economics of using biomass as an energy source.

The challenge for policy makers in designing policies to advance the use of biomass as an energy source is to arrive at policies that will encourage the use of biomass while allowing market forces to sort out the combination of applications and technologies that will provide the greatest economic benefit. The combination of policies that will most effectively meet that challenge will depend, in part, upon the specific goal that policy makers wish to achieve. If the goal is to increase the use of biomass as an energy source a different set of policies would be used than if the goal is to increase the use of biomass to generate electricity.

# CHAPTER IV : BIOMASS HARVESTING, PROCESSING AND TRANSPORTATION

The next step after determining which biomass fuels are appropriate to the project is to decide the best way to handle them between the field and the power plant. Biomass has to be:

- harvested without contamination
- collected
- processed (including drying, size reduction, and/or densification),
- transported to the power plant
- stored

Except for the obvious first step – harvesting – other steps might occur in various orders and places, depending on cost factors and logistics. Storage, for example, might occur at the harvest site, collection site, plant site, or all of the above. The same is true of processing. In order to reduce transportation costs, biomass may be dried and/or size-reduced at the farm or collection point and then further processed into fuel at the power plant.

Since so much of the cost of biomass fuel stems from its harvesting, collecting, storing, processing and transporting, the financial success of a project may rely as much on the thought and ingenuity that go into these steps as it does on the generation technology itself. Some schemes go so far as to envision small, portable gasifiers installed on flatbed trucks going from farm to farm, collecting biomass, reducing it to gases and char, and delivering those fuels to a power plant – providing in one fell swoop all intermediate steps but harvesting. Whatever the scenario, efficient handling of low-density, low BTU material like biomass is key to the economic success of a biomass power project.

## HARVESTING AGRICULTURAL BIOMASS

Growers have to make a paradigm shift to sell biomass fuel. They must come to see residues, like straw and corn stover, as valuable commodities due to their energy content and treat them as such. If stover, for example, comes in contact with the soil, its usefulness as fuel is diminished. Up until now, farmers have left stover in the field. Recently, however, manufacturers of harvesting machinery have begun to develop new models that capture these by-products with the same care as crops. Those machines will allow growers to sell residues for production of cellulosic ethanol as well as biomass power generation. Once those markets become established, it won't take long for growers or contract harvesters to adopt the new paradigm.

## HARVESTING TIMBER

Loggers also will have to view residues as a valuable part of their harvest. Because of its density and high BTU content, wood is the easiest form of biomass to transport and burn in a power plant. But as we'll see later, if silica, or grit, is delivered with the wood, it will slag, or cake, on boiler surfaces and cause damage. Some plants using wood fuel have had to reject deliveries of woody residues because of contamination. To sell into energy markets loggers will have to learn to keep slash – limbs, leaves and tops – off the ground.

# PHYSICAL FACTORS AFFECTING BIOMASS PROCESSING

Depending on cost factors, processing may be done at the source, at the plant, or somewhere in between. But there are physical and logistical factors to consider as well.

## Moisture Content

Biomass fuels exist in a wide range of moisture contents which have a substantial effect on biomass fuels' transportation costs, degradation in long-term storage, processing, and conversion into energy. Therefore moisture content underlies decisions in all those areas.

**Agricultural biomass.** The timing of the harvest affects its processing after harvest. A biomass's moisture content fluctuates throughout the year. Herbaceous crops, like switchgrass, and grain crops, like corn, begin to dry even before harvest. Switchgrass can drop up to 15% of its moisture late in the season and be ready to bale immediately after harvest. Switchgrass cut earlier than that has to be dried before baling.

The moisture content of any biomass fuel drops after harvest. Crops like corn stover or switchgrass can dry enough to bale within hours or days of harvest regardless of the date. The biomass's original moisture content, the weather conditions, and the arrangement of the harvest in the field all affect drying time. Material spread evenly over a field typically dries much faster than it does in windrows.

**Woody biomass.** Wood can be passively or actively dried. Logs left to dry in the open air typically drop to 30% to 50% moisture content within a year after harvest. Active methods, like blowing air through logs under shelter or placing them in rotary drum driers like those used to dry alfalfa, can lower moisture more quickly. Rotary drum driers usually burn natural gas, but some newer models run on electricity or waste process heat. Some even pull a vacuum. Infra-red drying, a technology used in the lumber and paint industries, also has come into use for logs. Infra-red drying is most effective for products that already are at less than 30% moisture.

The cost of drying will vary considerably depending on material, initial moisture content, and many other factors. Drying costs range widely from \$0.50 to \$15 per ton.

## Wood Particle Size

Each biomass power plant will specify the particle size needed for efficient and safe operation. Particles too large will burn incompletely, thereby increasing costs of fuel and disposal. At the other extreme, particles too small – dust – can be explosive in boilers and processing and handling equipment. Hence most facilities remove dust. District Energy St. Paul, for example, screens feedstocks with a ¼" trommel to remove all sawdust and grit. Some facilities dispose of collected dust while others carefully remix it with fuel to burn it safely.

The two most common size-reduction machines used on logs are chippers and tub grinders. Chippers cut consistently sized angular chips with roughly equal sides. Tub grinders produce long, stringy particles, usually about 1" by 2" by 6", that almost always have "tails" on their ends. Grinders usually are used to make wood mulch because the tails hold it in place on a planting bed. But tails can bridge in storage bins and jam bucket elevators and auger conveyors.



(Washington State University, n.d.)

**Figure IV-1: Tub Grinder**

Log size is an important consideration in deciding which machine to use. Tub grinders can handle trees and stumps up to 14' diameter. But even the largest chippers do not work well on trees larger than 2' in diameter. Logs larger than that have to be split by shears into pieces with a diameter less than 2' in order to enter a chipper. Thus tub grinders reduce large logs more cheaply than chippers because only one step with one machine is involved. But if the tub grinder can't make wood particles small enough to meet specifications in one pass, that becomes a false economy because the wood has to run through the machine a second time, adding cost. If possible, the plant should select a machine that produces its size specification in a single pass.

In Minnesota, the usual cost of grinding or chipping logs and brush to a particle size of less than 2" would be \$8.00 to \$15.00 per ton, not including transportation and tipping fees. Adding delivery would about double the cost. To grind or shred wood to 1/4" or 1/2" would probably increase the cost by another \$3 to \$10 per ton. Therefore biomass facilities designed to accept larger particle sizes can buy their feedstocks cheaper.

## **Anaerobic Digester Particle Size**

Particle size also affects the performance of anaerobic digesters. A size of 1.5 inch or less works best for high-solids anaerobic digesters. Besides traditional grinders and chippers, size reduction drums and thermal treatments can be used to reduce feedstock sizes. There is a trend toward doing more processing of municipal solid waste (MSW) in central facilities. Source-separated organics (SSO) programs, like one in Hutchinson, Minnesota, are appearing in many U.S. communities. Minneapolis and St. Paul are planning SSO programs.

Some European and Canadian SSO plants prepare waste for anaerobic digestion by rolling it in drums 8 feet to 12 feet in diameter. Internal risers or shelves lift the waste until it tumbles down. Liquids taken from anaerobic digesters are reintroduced into the drum to inoculate the waste. The liquid combined with the tumbling produces 1.5-inch particles.

Thermal treatment of SSO also involves a mixing drum. Pressurizing the drum for ten to thirty minutes with steam breaks down the cell walls of the biomass to reduce its size. Thermal treatment typically increases the moisture content of the feedstock by 10% and adds roughly \$3.00 to \$7.00 per ton to processing costs.

## Chemical Composition and Physical Characteristics

Chemical composition and physical characteristics influence fuel handling and processing decisions. Some straws, like flax and hemp, are abrasive. Flax chive, a by-product produced by pounding, not only is abrasive; in handling it compresses into small, hard balls that bridge in storage bins and conveying equipment to cause blockages. Many straws contain silica. Others contain corrosive chemicals.

Some feedstocks corrode handling equipment, some attack boilers, and some pollute the air. Some do several of these things at once. Within a few months of operation, municipal solid waste can corrode augers and steel conveyors to the point of uselessness. Chlorides destroy boilers, which is why oat hulls, which contain chlorine, usually are mixed with other biomass, like wood, to make boiler fuel. Wood off the stump is benign, but wood waste from factories that make secondary wood products, like millwork, furniture and cabinets, often contains resins and plastics that off-gas chlorides that corrode boilers and pollute the air. Some biomasses contain high levels of nitrogen that contribute to NO<sub>x</sub> emissions. This is a manageable problem that includes such strategies as mixing materials with low-nitrogen wood to mitigate the problem.

Another problem in burning some biomass feedstocks is slagging caused by certain salts and high pH. Potassium can contribute to slagging in boilers, but silica and silicon dioxide can be more problematic culprits. Silica has a melting point of 1710° C, but in high pH environments, melting temperatures might be considerably lower than that. When silica melts in a boiler or gasifier, it forms glass that hardens on heat exchangers, pipes, and exhaust systems. It also forms a toxic compound called cristobalite when it cools. Removing slag is a tough job that adds to downtime and operating costs.

The following table shows the silica content of ash from various biomass feedstocks for comparison. Silica itself may not be a problem unless it is introduced into a high pH environment. As a previous chapter suggests, a thorough chemical analysis of feedstocks and their potential effects on all stages of power production is an important preliminary to planning a biomass facility.

Table IV-1: Silica in Biomass Ash

Biomass Fuel	Silica Ash Content (% dry weight basis)
Urban Tree Waste	28%-55%
Red Oak	21%
Willow	8%-17%
Switch Grass	61%-65%
Plywood	29%
Barley	25%-60%
Canary Reed Grass	78%
Grass Clippings	68%
Corn Stover	52%
Straw	54%
Oat Hull	61%-70%
Oats	62%
Sorgum Grass	71%
Rice Hull	75%-96%

(Miles et. Al. 1995; Klass, 1998)

There are three ways to reduce slagging of silica and cristobalite:

- Operate boilers at temperatures below silica's melting point;
- Use feedstocks with lower pH that will raise the melting temperature of silica;
- Mix problem feedstocks with those that have low pH and/or silica content. (For example, mixing 15% oat hulls with wood wastes.)

## Issues of Scale

A project's scale can determine where its fuel is processed. Very small facilities often require that fuel be delivered ready to use in order to avoid investing in equipment, paying labor, and dedicating scarce space to fuel processing. But they will pay a premium for fuels delivered to specification unless they are giving suppliers an opportunity to avoid the disposal cost of a waste product.

At the other extreme, very large facilities may use their greater buying power to make suppliers deliver fuel to specification in order to minimize processing costs. But most facilities probably will not have enough buying power to impose high standards on their fuel suppliers. Unless they can afford to pay a premium, facilities of middle size may have to process their own fuel on site.

## PROCESSING FOR TRANSPORTATION

To make it ready for shipping to a power plant, biomass fuel usually has to be dried to reduce weight and compacted to reduce bulk. Shredding, chipping, grinding, baling, or some combination thereof increases biomass bulk density. Baling of crop residues like corn stover or energy crops like switch grass is a must for long distance trucking. But for rail shipping, biomass can be put into wet storage without baling. For example, corn stover usually is chopped into one-foot lengths for wet storage and then trucked to a local collection center to be loaded into a gondola car (a railroad car with an open top but enclosed sides and ends, used to haul bulk commodities).

## Wood Chipping

Trees and logging residues may be chipped before shipping to reduce its volume and help dry it out. The challenge is finding the cheapest way to do it. One way, chipping wood residues at the logging site, reduces the number of times the wood has to be handled. But it might increase other costs.



(Photo by Warren Gretz (NREL, n.d.)

**Figure IV-2: Tree Chipper**

For example, if mobile chippers were moved from logging site to logging site, those expensive machines would spend much of their time moving up and down roads instead of chipping wood. The opposite option, hauling logging residues or logs to a central chipping yard, keeps the chipper busy but complicates logistics. Which strategy is cheapest depends largely on the kind of equipment the logging company already owns. Even if it could chip wood more efficiently, new equipment might cost more than the money it would save.

## Baling

Balers come in a variety of sizes and prices. Some make round bales and some square. Farmers tend to use round balers because they are less expensive. But biomass energy facilities may call for large, square bales because they are easier to load, unload and stack with equipment designed to handle them.

Round bales can be re-baled at an approximate cost of \$5 per bale. Some farmers choose to bale their biomass in round bales initially and then pay to have them re-baled before delivery to a facility.



(Photo by Warren Gretz (NREL, n.d.))

**Figure IV-3: Baling Corn Stover**

## Pelleting

Pelleting is another method of preparing biomass for transport. It improves biomass's handling qualities, reduces its moisture content, and densifies it so it's cheaper to haul. Most pellets are made by forcing finely ground material through an extrusion die. It emerges as a long, moving spaghetti-like strand that shears cut into short lengths. The process works best with softer forms of biomass, like stalks, grasses or sawdust. Even when they can be crushed, glues or lignin-based chemicals are needed to hold them together.

Pelleting grains, high bulk density, and starch based materials is very efficient resulting in some industries obtaining pelleting costs as low as \$5 per ton (Doering, 2007). Biomass material that is typically fibrous and low in bulk density requires greater horsepower to achieve desired throughput, thus resulting in pelleting cost ranging from \$29 to \$36 per ton (Doering, 2007). At such high costs, pelleting, specifically for electric generating power projects is used only in the absence of any other alternative.

## PROCESSING FOR STORAGE

A number of biomass fuels, like switchgrass and corn stover, are harvested annually in a brief period each year. To serve as fuel over the course of the year, they must be processed and stored without degradation. Operating conditions also impose some level of storage. Where biomass is to be co-fired as a secondary fuel with coal, a one-week supply on-site may be enough. But investors in some large biomass facilities have required them to maintain a 60 to 90 day supply.

## Baled Agricultural Biomass

Preparing switchgrass or dried corn stover for storage may amount to little more than baling it at a suitable moisture content and storing the bales until needed. Baled biomass can be stored in a variety of ways: stacked and uncovered in a field, wrapped with plastic and left in a field, stacked under a simple roofed structure or stacked in a large fully enclosed storage facilities.

Each of these techniques offers certain benefits and incurs certain costs. Generally speaking, the more exposed the bales are to the elements, the lower their storage costs will be. But losses to degradation can offset savings. At a minimum, bales stored in the open need some kind of protection from water, like a tarp or plastic sleeve. Care should also be taken to protect the bottoms of stacks from infiltration by soil and rocks. Storing baled biomass in sheds costs more, but it preserves more of its original value.



(CVBP Interim Test Burn Emissions Report, 2003, Appendix G)

Figure IV-4: Storing Switchgrass Bales

## Woody Fuels

Processing woody materials for storage is similar to processing them for combustion. They are screened for contaminants, sorted by size (large chunks may be chopped up), and then sent to the storage pile. Wood chips can be stored outside in a pile for up to a year before odors become a problem, but piles that grow too high can combust spontaneously. Some facilities spread new chips over the length of a pile to increase its heterogeneity and minimize variations in fuel quality.



(Photo by Dave Parsons (NREL, n.d.))

**Figure IV-5: Wood chips stored at the McNeil Generating Station in Burlington, VT**

## Fuel Degradation and Decomposition

Moisture content, odor, particle size, and fire hazards all are considerations in storing biomass fuels. Storing grasses or plant leaves with moisture content above 15% leads to partial biodegradation or composting of the biomass. Freshly cut biomass with green foliage holds substantial moisture within cell walls. Microbes can thrive in this moisture and decompose the stored biomass, reducing its energy content and its structural integrity, making piles unstable and bales difficult to move.

Some biomasses present fire hazards. Dusts from wood and grains are explosive. Brush chips, with small particle sizes and a 30:1 ratio of carbon to nitrogen, are highly combustible. Nitrogen is contained in green leaves or green stems in the form of proteins, and carbon is concentrated in the woody stems. The mix of chips and leaves in brush piles makes for rapid composting at temperatures as high as 120° to 180° F. But since those high temperatures can lead to spontaneous combustion, long-term storage of brush chips presents a serious fire hazard. Corn stover can pose the same problem in storage. Drying is the best preventative. Lowering Moisture content to 15% limits the microbial action that causes high temperatures. In addition, rules have been developed to provide standards and specifications pertaining to chip and sawdust pile geometries that minimizes combustion problems.

## Odors

Wet biomass can give off unpleasant smells from the breakdown of protein and fats. When the interior of a biomass pile lacks oxygen, anaerobes release ammonia and/or sulfur compounds. The buyer can minimize those emissions by checking moisture content at delivery and rejecting

fuels exceeding the moisture content standard. Several wood-fired facilities eliminated odor problems by adopting “first-in, first-out” inventory policies or limiting storage of fuel to less than one year.

## Processing Corn Stover for Wet Storage

Current corn harvest practices leave stover in the field to be collected and baled once the grain is harvested. Making two passes increases harvest costs, compacts soils, and adds dirt to stover. So farm machinery manufacturers are working on designs that will harvest both corn grain and stover in one pass.

One-pass machines open up new possibilities for biomass marketing. Currently, corn harvest begins when the moisture content of corn kernels has dropped to 24% or less. But at that point, stover still is too wet for baling. With a “one-pass” harvest system, clean (but wet) stover could be separated from grain at a collection site for drying and baling so it is free of dirt and stones.

An alternative that bypasses drying would ensile stover or put it into wet storage, like bagasse at a pulp mill. On a dry ton basis, it costs more to truck wet corn stover than dry, but it eliminates fire risk, reduces storage space, prevents losses in baling and hauling, and produces better overall quality. Piles of wet stover might freeze during cold winters in the Northern Corn Belt States, but feedlot operators who work with corn silage don't regard that as a problem (Atchison and Hettenhaus, 2003)

Processing corn stover for wet storage is similar in many ways to processing other types of biomass. It must be cleaned of dirt, rocks and other foreign material with magnets and screens. It then may be shredded in a hammer mill, slurried to 3% solids, and pumped to the top of a storage pile. (Piles can measure up to 200 x 300 meters at the base and 40 meters tall.) The storage pile is allowed to settle and create an anaerobic (oxygen-free) condition within the pile. Since it can't oxidize, the stored material remains in perfect condition. When it is needed, the stored biomass passes through a screw press that squeezes its moisture down to 50%.

Silage and wet storage often come up in discussions of cellulosic ethanol plants, bio-refineries, and other facilities that use corn stover. The cost of dewatering stover to 50% MCW may price it out of those markets, but further study is warranted.

## PROCESSING BIOMASS FOR CONVERSION TO POWER

The final step in processing biomass fuel is to bring it into conformity to power plant specifications. As when processing fuels for transport and storage, the primary considerations are size, moisture content, and cleanliness.

Woody fuels are nearly boiler-ready after their initial processing for storage. On their way to the power plant, woodchips are cleaned once more to remove metal and other foreign materials missed the first time. They then are screened for size (oversized materials go to a hammer mill for size reduction) and, if the facility uses a variety of fuels, blended before going to the boiler.

The Ottumwa Generating Station in Ottumwa, Iowa, which has been experimenting with co-firing switchgrass and coal, provides a template for final processing of baled biomass fuels. Bales of switchgrass or stover are taken from storage stacks and placed on a conveyor. Twine is cut from the bales and removed to prevent fouling of the hammer mills. The bales then pass through a debaler, which chops the bales apart from below and above. The debaled

switchgrass moves on to an attrition mill, which pulverizes it, and then to a surge bin to wait for pressurized air to blow it into the boiler.



(CVBP Interim Test Burn Emissions Report, 2003, Appendix G)

Figure IV-6: Removing Twine from Bales

## Biomass Transportation and Infrastructure

Biomass power travels in two directions: as feedstock into the power plant via road, rail or water; and as electricity out of the power plant through connections to the grid or local power networks. Since roads and power lines usually precede power plants, the biomass power developer typically will look for sites where those infrastructures already exist. A good source of water is another essential item because water usually is needed for fuel processing, steam generation, and/or cooling.

The following maps illustrate elements of infrastructure. The *gopher* GIS Computer tool allows the developer to stack the maps in order to find sites where all necessary infrastructures converge. Combined with the biomass maps in BioPET and reproduced in Chapter I, this array of computer tools points the way toward feasible plant locations.

### *gopher*

GIS maps of infrastructure and other development resources.

- **Roads.** State highway maps show interstate and trunk highways, but county maps in specific areas of interest can be consulted for details on county roads. Seasonal load restrictions have to be taken into account. Individual farms and logging sites may be served by gravel roads, but collection points and power plants have to be connected by ten-ton all-weather paved roads.

- **Rail.** For most biomass plants, whose sizes are limited by fuel collection radii which themselves are limited by transportation costs, rail probably is not needed. On Class One rail lines, service can be sporadic because they give priority to unit trains and other long hauls. Short lines often don't reach places where fuel is available. As a rule, hauls shorter than a few hundred miles are cheaper and quicker by truck. Sites on rail are fewer and more expensive than those on road. Nevertheless, a plant designed for municipal solid waste might choose to be on rail in order to import feedstocks from far-flung communities.
- **Barge and ship routes.** In a few places in Minnesota, like ports on Lake Superior and on the larger rivers, cheap water shipping might be an option. Ports already have docks and equipment to handle wood and agricultural material, and some ports, like the Port of Duluth, have land available for plant sites. Port facilities usually have good connections to the grid and to other modes of transportation like rail and highway.
- **The electric grid.** A connection to the grid provides a power plant with a national market, but its cost has to be carefully scrutinized. In certain locations, higher connection costs can more than offset lower operating costs. Therefore, from a financial perspective, the output side of the equation is at least as important as the input side in choosing a site.
- **Local transmission networks.** Small local municipal or co-operative utilities may be the best customers for biomass plants. By providing jobs and markets for local growers, the biomass plant becomes a key player in the local economy that supports the local utility. The plant developer does, however, have to emphasize the plant's role as a local amenity because NIMBY confrontations with local residents can unravel an entire project. (We do not map these local networks.)
- **Water.** Another potential tie-in to a local community is the possible use of its gray water for process steam and cooling. The plant's use of waste water might reduce the city's treatment costs and keep its effluents within permitted limits. But permitting cuts both ways. Some environmental regulations ban the use of untreated gray water. So it's important to check with permitting authorities before considering that option. Natural streams of course provide another source of non-potable water, but DNR regulates their use.

Electric transmission maps are provided by the Land Management Center (LMIC, 2004) at the Minnesota Department of Administration. They show electric substations and transmission lines greater than 60 kV, which seem adequate for a power plant supplying energy to the grid.

This information is presented with information from the Minnesota Department of Transportation on railways, roadways, and waterways, all ways to ship large volumes of biomass fuel on a continuing basis. Besides transportation, waterways can supply water for process steam and cooling. Ground water is also a potential source for process cooling and that information is included as well.

These are but a sample of the data compiled as part of this project. Please refer to *gopher*, as discussed in Chapter I, for additional maps.

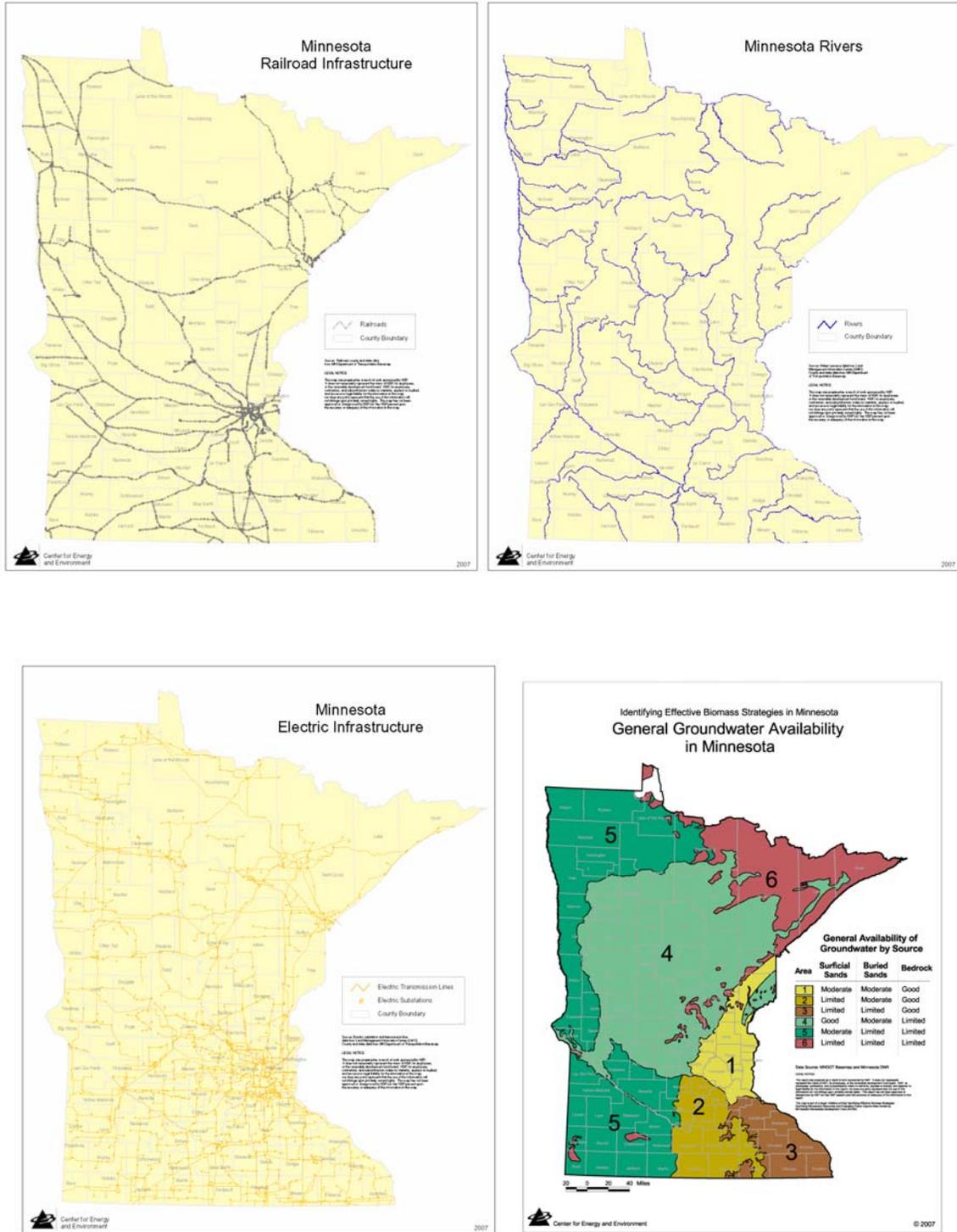


Figure IV-7: Infrastructure Maps

# CHAPTER V : BIO-POWER CONVERSION TECHNOLOGIES

Human beings have used biomass fuel since cavemen learned how to set wood on fire. Biomass eventually was supplanted with coal, gas and petroleum, which remain the predominant fuels for generating power to the present day. Until recently, advances in energy technologies meant extracting *more* energy from the combustion (or burning) of hydrocarbon fuels, not inventing *other ways* of extracting it.

Most non-nuclear power plants still rely on combustion; they burn fossil fuels (coal, oil, natural gas) in boilers to turn water into steam that drives turbines connected to electrical generators.

Back in the gaslight era, engineers began to develop a different way to produce energy. Instead of burning fuel in oxygen-rich boilers, carbonization or gasification heated coal to high temperatures in oxygen-lean “anaerobic” vessels. Since the vessels lacked oxygen to support combustion, the superheated coal didn’t burn. Rather it gave off a synthetic gas, called “town gas” or “coal gas,” that could be used for lighting, heating and cooking. The remaining charcoal could fuel heat-intensive industrial processes like smelting. In the 1930s and 1940s, German scientists made further innovations in order to replace petroleum supplies cut off by the war.

Our discussion divides into those two main topics: combustion and gasification. Both conversion technologies are in use today. But combustion systems far outnumber gasification systems, and within combustion plants, fossil fuels (coal, natural gas, petroleum) far overshadow biomass fuels. Recently, however, the environmental consequences of burning fossil fuels have created new interest in humankind’s original fuel source, biomass.

In a combustion power plant, differences in processing the two classes of fuels, fossil and biomass, appear in the front end where fuel is handled, processed and burned. Beyond the boiler, both fuels drive power generation in exactly the same way. So we focus on the distinctive characteristics of biomass fuels that affect their handling, processing, burning and waste removal in a power plant.

A more recent technology than combustion, gasification, has a host of potential applications in waste reduction, biorefining, transport fuels and so on. But we are concerned here with only its application to the generation of electric power. As is the case of combustion, biomass in a gasifier usually substitutes for fossil fuel. And since gasification can produce both gaseous and liquid fuels, that means it can offer substitutes for natural gas, oil, and diesel fuel.

The diagram below illustrates our selection of topics. Issues in boldface are subjects of this chapter.



## Pile Burners

Pile burners are a very simple – as the term implies, they contain a pile of fuel, usually wood, on a stationary grate under a boiler. Combustion air is fed upward through the grate and walls, and fresh fuel is added continually to the top of the pile or to its bottom through a screw auger. This latter “underfeed” method makes for more even burning, but it raises the cost of equipment and maintenance and lowers its reliability. Removing ash involves shutting down the combustion chamber until it is cool and dumping the ash manually.

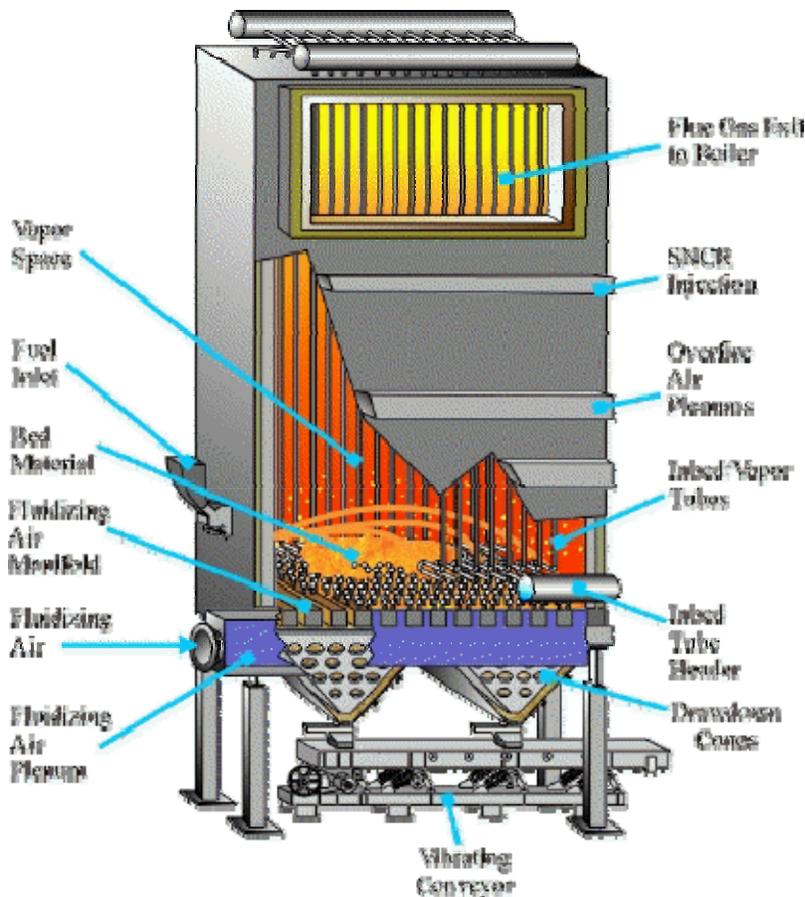
Pile burners handle fuels that are dirtier or wetter (up to 65% moisture), have less stringent fuel processing requirements, and cost less to build and operate than other systems. But they are less efficient, take more downtime, and are harder to regulate. Their erratic combustion cycles and slow response times make them unsuited to load-following operations connected to power transmission networks.

## Stoker Grates

Stoker grates are widely used in bio-power plants like the Laurentian Energy Authority's facilities in Hibbing and Virginia, MN because they distribute fuel more evenly for efficient burning and don't have to shut down for ash removal. A further refinement of the stoker grate, The Kabliz grate, slopes down from the fuel feed and reciprocates to tumble the pile continually forward and incorporates cooling water within its structure. Its relative simplicity and low fly ash carryover make it an attractive option.

## Fluidized Beds

Atmospheric fluidized bed combustion (FBC) systems are increasingly used to burn biomass. In this system, the grate is replaced by a bed of inert granular material, usually sand or crushed limestone. Air is blown upwards through the granular bed with such force that the granules in the bed circulate and bubble randomly, like a boiling liquid. Finely-ground fuel is blown into the combustion chamber to burn in suspension. Because the fuel particles are tiny, their surface area is large relative to their mass, assuring complete combustion.



(Energy Products of Idaho, 2007)

**Figure V-3: Fluidized Bed Boiler System**

FBC systems can handle a wide variety of fuels -- singly or in blends -- that have high ash contents, irregularly shaped particles, and high moisture contents (Badger, 2002). They respond quickly to changing load requirements, burn fuels efficiently, and are inexpensive to maintain. But they do cost more to build than other types.

The usual reason for adopting fluidized bed systems is to reduce emissions. Their consistent low combustion temperatures keep NO<sub>x</sub> emissions low, and some types of FBC systems use limestone and tune temperatures to optimize limestone/sulfur reactions in order to control SO<sub>2</sub>. Process controls like those eliminate the need for equipment to remove sulfur at the stack.

## Suspension Burners

Suspension burners inject dry, finely ground biomass fuel high into the boiler to burn in mid-air. This makes for very efficient burning in a small space, and it allows for quick responses to changing energy demands because only a small amount of fuel is burning at any given moment. (Badger, 2002). But drying the fuel and reducing it to small, uniform particles adds capital and operating costs at the front end.

All suspension burners burn fine particles suspended in a turbulent stream of air, but they come in two different versions: cyclone burners and pneumatic spreader-stoker systems. Cyclone burners inject fuel particles pneumatically into horizontal or vertical cylinders where swirling air

suspends them as they burn. Spreader-stokers blow fuel horizontally into a combustion chamber where most of it burns in the air.

## **SOLVING PROBLEMS IN BIOMASS COMBUSTION**

The chemical composition of biomass fuels creates some technical problems not seen in fossil fuels. Some of the problem materials that lead to fouling and slagging in boilers are alkali, water soluble alkali, sulfates or chlorides, and silica.

Slagging, fouling, and deposits of the boiler need to be reduced as much as possible because they:

- increase maintenance outages and costs,
- deteriorate steam plant efficiency or capacity,
- clog fuel supply, and
- increase corrosion (Miles et al. 1995).

These problems sometimes can be minimized by screening fuel. But many agricultural fuels simply won't work in unmodified biomass boilers as a large part of the total fuel supply. Straw and other annual herbaceous plant materials cause rapid fouling of heat transfer surfaces, furnace slagging, and clumping in fluidized beds (Miles et al. 1995). Superheater fouling is perhaps the most critical problem.

### **Alkali Compounds in Conventional Boilers**

In coal-fired systems, sodium usually is the most troublesome alkali component. But in biomass-fired systems, potassium and, in some cases, chlorine are the major alkali problems (Miles et al. 1995), especially when burning annual grassy crops and residues. Alkali is less of a concern with most woody materials and other biomass fuels low in alkali compounds (FEMP, 2004).

Conventional coal boilers are not designed for fuels with a high alkali content, but special designs with low furnace exit gas temperatures can take the curse off crops and agricultural residues like grasses and straws. Modifications should include: adequate waterwall surface area or parallel heat exchange surfaces, combustion air metering to control gas temperatures, grates that can remove large quantities of ash, and blowers to remove soot.

Problems with high-alkali fuels have led many plants to limit them to no more than a 5% blend. This level still result in significant operating problems and cleaning costs (Miles et al. 1995). The industry needs new boiler designs that can better control combustion and furnace exit temperatures, and remove alkali and alkali compounds as they form on boiler grates, walls, or other convective surfaces (Miles et al. 1995). Fluidized beds can fire somewhat higher percentages of alkali fuels, but deposits still form. In biofuels production, gasification or pyrolysis may reduce alkali volatilization, but retrofitting an existing boiler with the necessary equipment has yet to be demonstrated (Miles et al. 1995).

### **Calcium Deposits in Fluidized Bed Boilers**

Calcium can deposit on the boilers convection surfaces (as  $\text{CaCO}_3$ ,  $\text{CaSO}_4$ ). Limestone added to fluidized bed boilers appears to reduce deposition, but does not prevent it. High alumina sand also reduces clumping in a circulating fluidized beds but does not change the composition of deposits on the superheater tubes.

## ***Curing Deposition***

Plant operators can use a variety of methods to reduce fouling and slagging (Miles, et. al. 1995):

### Fuel Management

- eliminating worst-acting fuel components;
- diluting "dirty" fuels with clean fuels;
- scheduling worst fuels prior to scheduled outages;
- analyzing ash chemistry;
- limiting suspected fuels in fuel mix to less than 5%; and
- screening to remove particulates.

### Boiler Controls

- operator training and sensitivity
- tuning combustion controls to limit temperature deviation.

### Cleaning and additives

- blowing down fluidized bed media with compressed air,
- sootblowing and hydroblasting
- addition of limestone

## ***Fly Ash***

Ash from coal-fired power plants can be sold to the concrete products industry as an additive, but according to ASTM standards, only if it is 100% from coal (FEMP, 2004).

## ***Emissions***

Biomass fuels produce fewer emissions than coal. The table below compares the environmental impacts of seven technologies. Actual emissions will depend on feedstock types, operating conditions, and other factors. We also include in this table emissions from gasification, a technology we discuss in the following section.

The table cites stack emission values normally used in comparative analyses. Thus CO<sub>2</sub> shows a positive number as a point source emission at the plant. But that of course doesn't take into account the argument that biomass is a net zero carbon source because carbon emitted is matched by carbon consumed by new biomass growth, a claim that can't be made for natural gas, coal, and fuel oil.

Table V-1: Emission Rates (lbs/MWh) for Various Energy Technologies

	Natural Gas <sup>(1)</sup>	Coal <sup>(1)</sup>	Oil <sup>(1)</sup>	Direct Combustion Biomass <sup>(1)</sup>	Gasification <sup>(2)</sup>	Landfill Gas/Biogas <sup>(3)</sup>	Landfill Gas/Biogas <sup>(3)</sup>
Technology Type	Generic Natural Gas Fired Turbine Combined Cycle Plant	Generic Utility Boiler Firing Bituminous Coal Plant	Generic Utility Boiler Firing Only No. 6 Fuel	Typical Stoker Grate Wood-Fired Biomass Plant	Combined Cycle Biomass Gasification Plant	Typical Gas Turbine (>3 MW)	Fuel Cell (PAFC)
NO <sub>x</sub>	0.06	3.1	2.5	1.5	1.08	0.44-2.2	0.003
CO	0.03	0.21	0.35	3.556	0.001	0.6	0.015
SO <sub>2</sub>	0.02	15	10.4	0.4	0.58	0.65	0.006
PM	0.08	1.5	0.87	1.5	0.05	0.07	Negligible
CO <sub>2</sub>	750	2,296	1,708	3,407	1,962	1,958-3,132	1,078

(Xenergy and Energetic Management Associates, 2003)

1. Massachusetts Biomass Energy Working Group Technology Assessment, 2001

2. Mann, M & Spath, P. "Life Cycle Assessment of a Biomass Gasification Combined-Cycle System," December 1997.

3. Arthur D. Little, Inc. "Profiles of Leading Renewable Energy Technologies for the Massachusetts Renewable Energy Trust Fund," October 10, 1998.

## GASIFICATION

### Biological Gasification

**Anaerobic digestion** falls within a general category called *biological gasification*, the process of generating biogas from decomposing organic matter. It can take place in a vessel containing oxygen, in which case it is called *aerobic digestion*, or in a vessel deprived of oxygen, in which case it is called *anaerobic digestion*.

The process of anaerobic digestion is simple: a conveyor meters sludge, garbage and other wastes into the end of a long revolving sealed cylinder. The inside of the cylinder is heated to grow bacteria that decompose waste to produce methane. The cylinder slants down from the infeed end. That combines with the tumbling action to move the waste slurry slowly from the high end, where it has entered the cylinder, to the far end where the remaining waste is removed.

As it usually is practiced, anaerobic digestion is an imperfect process. Most anaerobic digesters are used to dispose of waste, not produce energy. So they just flare off methane and CO<sub>2</sub> or release them into the air (Xenergy and Energetic Management Associates, 2003). Not only does that waste energy, it also puts two of the worst greenhouse gases into the atmosphere. Two other drawbacks of anaerobic digestion are its slow rate of decomposition and its incomplete conversion of organic waste.

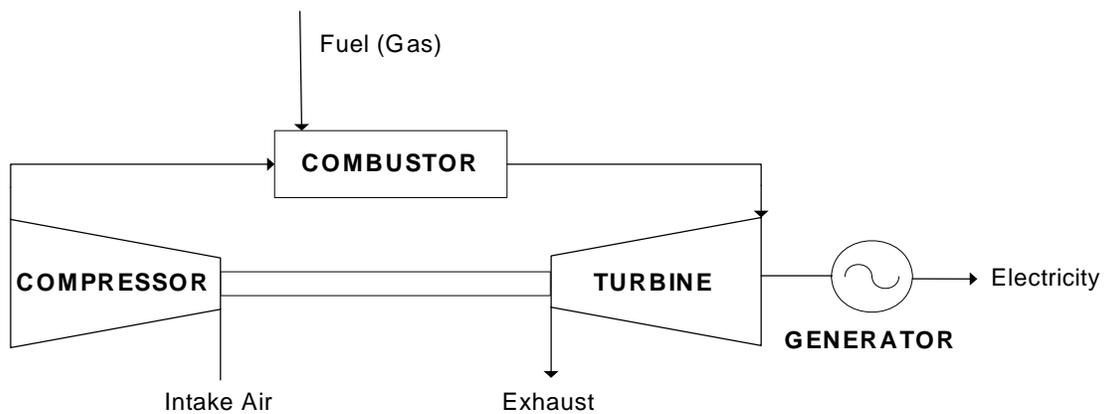
Nevertheless, anaerobic digesters do play a beneficial role in managing wastes. They take up little space, use little energy, and dispose of nasty waste streams, like animal manure, sewage sludge and industrial effluents, that we don't want to see in our groundwater. Many municipal wastewater treatment plants across the U.S. use anaerobic digesters to reduce solids in sewage sludge (Dayton, 2001).

Concerns about the environmental impacts of livestock wastes have rekindled interest in anaerobic digestion. Manures from dairy and swine farms make good feedstocks for anaerobic

digesters because they contain a lot of liquids whereas poultry manure which is higher in solids is harder to process. Gas from digesters can heat farm buildings or fuel internal combustion generator sets (gensets) for electric power. Biogas-fueled gensets convert uncleaned bio-gas to electricity at an efficiency of 18 to 25% (Schmidt and Pinapati, 2000).

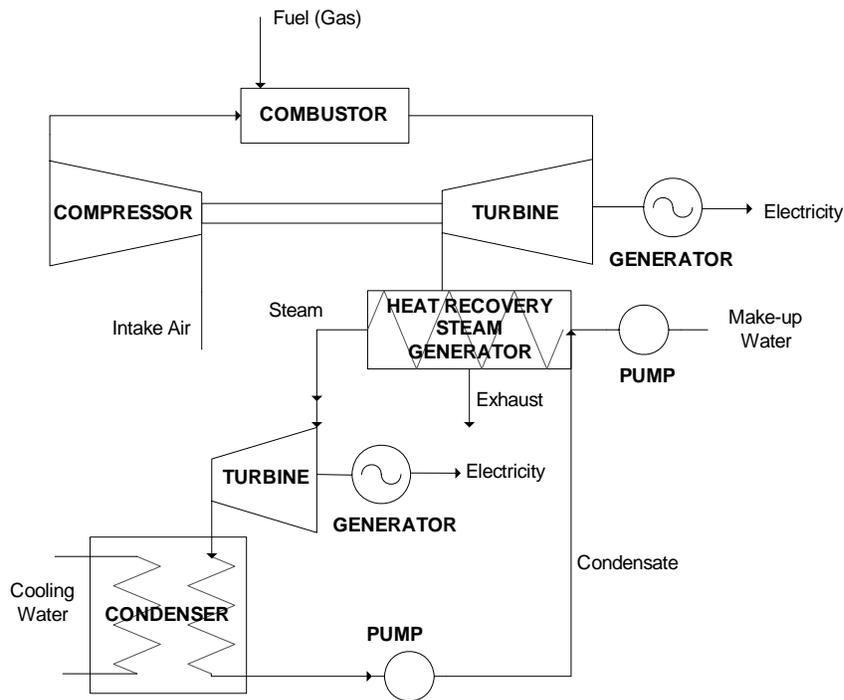
## Thermal Gasification

In a way, thermal gasification is just the opposite of combustion: instead of burning biomass in an oxygen-rich chamber to heat a separate vessel, a gasifier heats biomass to a high temperature inside an oxygen-lean vessel. Starved of oxygen, biomass, rather than burning, gives off combustible gasses that can be used as fuel for further processes. In power plants, for example, bio-gas can fuel simple-cycle or combined-cycle turbines that couldn't burn straight biomass because it would foul their blades.



(Williams and Larson, 1993)

Figure V-4: Simple-Cycle Gas Turbine



(Williams and Larson, 1993)

**Figure V-5: Combined-Cycle Gas Turbine System**

A lot of research has been done on gasification of coal, but little of it transfers to biomass; the two are too different. The same isn't true of natural gas and biogas. In the ethanol industry, several pilot gasification projects are underway that substitute biogas for expensive natural gas without significant changes in burners.

Gasified biomass can do more than just substitute for natural gas in existing applications, however. According to some experts, gasification can release enough energy that it could turn pulp and paper mills into substantial exporters of power to the grid just by gasifying liquid residues it now burns. But at this writing, that industry has yet to install its first gasifier (Jordan and Taff, 2005).

### ***Thermal Gasifier Designs***

The basic process of gasifying biomass thermally doesn't vary significantly from one design to the next, but designs differ in the ways they feed fuel and air in relation to one another. The design types are:

- fixed-bed-updraft,
- fixed-bed-downdraft,
- fluidized bed, and
- low pressure.

**Fixed-bed-updraft.** In these systems, fuel enters from the top of the vessel and air or oxygen from the bottom. Updraft gasifiers have high grate temperatures, so air needs to be cooled to

prevent grate damage. Updraft gasifiers work well with fuels with high water and inorganic content as long as they are large, dense, and uniformly sized.

**Fixed bed-downdraft.** These gasifiers are best for processing biomass with high volatile content. They introduce both the biomass fuel and the air/oxygen mixture from the top of the combustion chamber.

**Fluidized bed.** This design can handle a wide range of relatively unprocessed feedstocks. Biomass fuel feeds continuously into the chamber and air rises through a bed of inert sand or crushed limestone that distributes heat evenly. In a directly heated design, char burns in the gasifier vessel to heat it. In an indirectly heated design, char burns in a separate vessel.

There is good news and bad news about fluidized bed gasifiers. The good news is their superior operating performance. They confer temperature uniformity, tolerance of wet fuels with moisture contents up to 55%, and short reaction times. But fluidized bed gasifiers don't produce gas of the highest quality. The high temperature of the gas exiting the gasifier leaves alkali compounds in a vapor phase, and the gas is high in particulates that have to be filtered (Williams and Larson, 1996).

**Low pressure.** In this process, two separate chemical reactions occur in two separate reactors. In the first reactor, hot sand surrounds biomass, whose volatile gasses in pyrolysis arise from the char, ash and sand to enter a cyclone that divides them into their separate constituents. In the second reactor, the remaining char is burned to heat the first reactor. Gas from this process has a BTU content of around 550 per square foot. Scrubbed of impurities, it can power a gas turbine.

### *Operational Concerns in Gasification*

**Alkali** can cause as much trouble in biogas fueling a turbine as it does in biomass fueling a boiler. Since alkali fouls turbine surfaces, it must be chemically scrubbed from gas going into a turbine. Another way to control alkali is to keep gas at a cooler temperature as it exits the gasifier. Research in the coal industry discovered that at low exit temperatures, alkali compounds condense on particulates in the gas stream instead of on surfaces of equipment (Williams and Larson, 1996). Certain chemical additives also might reduce alkali (Miles et al. 1995).

Research on gas exit temperatures hasn't been incorporated into the design of equipment yet. Until it is, alkali compounds are removed by electrostatic filters, barrier filters, or wet scrubbers. Those devices can't go to work until hot gas from the gasifier has cooled (Stevens, 2001). Unfortunately, however, losing that heat reduces the overall efficiency of the system. Alkali "getters" that can remove alkali at high temperatures may resolve that problem, but they haven't yet been tried in a commercial system (Stevens, 2001).

**Tars** are organic materials in the product stream of the gasification process, mostly aromatic compounds. If the tar condenses, it can do a number of undesirable things:

- form coke on fuel reforming catalysts;
- deactivate sulfur removal systems in co-firing systems;
- erode compressors, heat exchangers indirect combustion systems, and ceramic filters;
- damage gas turbines and engines; and
- frustrate compliance with emissions standards.

In a well designed combustion boiler, tar clean-up is not a critical issue. But in a gasifier, it has critical importance. Cleaning tar brings:

- increased thermal to electrical efficiencies,
- lower emissions, and
- lower treatment costs.

Tars in a gasification system are removed either by a fuel reformer or by tar-destroying catalysts (Dayton, 2001). The lack of a more effective, less expensive tar removal process remains the primary barrier to widespread commercialization of combined-cycle power generators integrated with biomass gasifiers (Klein, 2002). Catalytic processes for reforming tar need to be better understood (Dayton, 2002). For the time being, conditioning hot gas with known catalysts is the best way to mitigate tars from biomass gasification (Dayton, 2002).

**Particulates.** Like emissions from boilers, gasifier exhausts have to be treated by cyclone filters, barrier filters, electrostatic filters, or wet scrubbers (Stevens, 2001). Removing particulate from both biomass and coal efficiently will alleviate problems with them.

## LIQUEFACTION

### Pyrolysis

By decomposing biomass in a vacuum at high temperatures, the process called pyrolysis can produce raw material for fuels to generate electricity. Pyrolysis creates a solid char, liquids called pyrolitics, oxygenated oils, and bio-oils, and the gases methane, CO, and CO<sub>2</sub>.

#### *Bio-oil*

On that menu, the liquid, bio-oil, has interesting potential as a fuel. It is not a hydrocarbon but a single phase, low pH liquid containing as many as 400 different chemical compounds.<sup>2</sup> It includes more water (15 to 40%) than hydrocarbon fuels, and less energy by volume (Ensyn Group, Inc., 2001; Diebold, 2000). That high water content and low pH dictate the use of corrosion-resistant materials in its handling and storage.

In storage, bio-oils can change chemically and physically, increasing in viscosity, losing volatile compounds, polymerizing, and separating into tarry, sludgy, waxy and thin aqueous phases (Diebold, 2000). Thus storage can compromise bio-oil's use as a fuel source. But certain treatments, like solids filtration, alcohol dilution, and emulsification with diesel fuel, can help preserve the stability and combustion properties of bio-oils in storage (Chiaramonti, Oasmaa, and Solanausta, 2007).

Bio-oil has been used successfully in internal combustion engines, boilers and combustion turbines to generate electricity, but its effect on generating equipment can be a problem (Oasmaa, Peacocke, Gust, Meier, and McLellan, 2005). Bio-oil has a well-documented ability to corrode fuel lines and gaskets, as well as foul and corrode fuel injectors and other metal surfaces (Chiaramonti, et. al. 2007).

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<sup>2</sup> The composition of bio-oils varies considerably with the initial biomass source materials. One consequence of this variability of bio-oil composition is significant variability in storage stability and combustion characteristics.

To date at least three commercial facilities have successfully used bio-oil as a fuel source. One has used bio-oil to generate electricity, one has used it for heat, and one has used it for combined heat and power.

- In Wisconsin, the Manitowoc Public Utilities Power Generation Station successfully co-fired bio-oil from the nearby Red Arrow Products Company at a 5% rate in a 20 MW coal-fired boiler (Ensyn Group, Inc. 2001; Sturzl, 1997).
- Red Arrow eventually began to use bio-oil to make their own heat and discontinued deliveries to Manitowoc Public Utilities.
- In West Lorne, Ontario, the DynaMotive Energy Systems Corporation has installed at a wood floor manufacturing facility a fast pyrolysis plant that converts sawdust to bio-oil. The bio-oil provides heat and fuels a 2.5 MW combustion turbine (Stephens, 2006). DynaMotive recently signed a contract with the Ontario Power Authority, under Ontario's Standard Offer Program, to provide power to the grid ("Dyanmotive", 2007).

## ***Biodiesel***

Biodiesel, which is refined from bio-oil, is best known as a bio-based transportation fuel that substitutes for petroleum diesel fuel. But it also can power an electric generator through an internal combustion engine, combustion turbine, or boiler.

Minnesota's Biodiesel Mandate requires that all diesel fuel sold for use in an internal combustion engine contain at least 2% biodiesel fuel by volume (Biodiesel Content Mandate, 2006). This means that all utilities and institutions in Minnesota operating diesel-powered generators, or gensets, now consume B2 fuel. Blended at low levels (<5%) with petroleum diesel, biodiesel can fuel an unmodified diesel engine. At higher levels some modification may be necessary (Bickel, Waytulonis, Zarling, 2004)

A number of municipal utilities have gone well beyond the 2% standard. In Minnesota, some have used biodiesel blends up to B20 in their peaking gensets (SMMPA, 2006; Downer, 2007). In Texas, Biofuels Power Corp. recently began producing 5 megawatts with three Caterpillar generators powered by B100 fuel from a nearby biodiesel plant. The firm also intends to start up a 10 MW combustion turbine co-located with a biodiesel refinery ("Houston Area", 2007). The lower emission levels of biodiesel gensets might allow their increased use as standby and peak-shaving generators without raising overall emissions levels (Barrett, 2004)

Besides their use in local utilities, biodiesel gensets also have a role to play in the booming windpower industry. A recent Minnesota study showed that they can back up wind turbines to qualify for the higher prices paid to firm power generators during peak demand periods (Tiffany, 2005), a strategy that was tested during the summer of 2006 at a wind farm in Beaver Creek, Minnesota (Morrison, 2006). Diesel gensets also can enable wind farms to dispatch electric power when winds aren't turning the turbines. Given the rush to develop windpower, whose intermittence creates problems in managing the grid, and the presence of biomass and wind farms in the same farming regions, biodiesel power generators and wind turbines promise real synergy.

Biodiesel plants cost less, and have smaller environmental footprints, than other types of biofuel plants. The process is simple – simpler than the name applied to it: transesterification of oil. In Minnesota, that oil has come from soy (Carlson, 2006), but animal fats, used cooking oils and other plant oils like canola and camelina also can be made into biodiesel. Most biodiesel plants buy oil from crushing plants, but as they grow larger, they might set up to crush crops themselves. Not only would that eliminate the cost of transportation from crushing plants, it would allow for better use of a full range of local crops.

Biodiesel has somewhat different material characteristics than petroleum diesel. Its energy content is lower on a volume basis than petroleum diesel's, but its lubricity is greater. Blended with petroleum at low levels, biodiesel raises lubricity enough to offset the lubricity loss resulting from the Ultra Low Sulfur diesel fuel mandate. Biodiesel fuel typically reduces emissions of carbon monoxide, carbon dioxide, aromatic hydrocarbons, particulates and SOx. It can increase NOx emissions, but one study found that cooling charge air prior to combustion actually makes biodiesel's NOx emissions less than those from petro-diesel (Bickel, et. al. 2004).

Biodiesel is a complete fuel, not just an additive. Some utilities and institutions have successfully fueled internal combustion gensets with B100 unblended biodiesel (Barrett, 2004; Zeman, 2006). Some utilities also are interested in using biodiesel in combustion turbines and boilers ("Dynamotive", 2007; "New York", 2007). Users of neat biodiesel report generally good results, but they stress the importance of fine tuning generators and emissions equipment, and using hoses and gaskets that don't deteriorate from contact with biodiesel (Zeman, 2006).

In addition to its compatibility with a number of generator types, biodiesel can be used in a number of generating strategies.

## SUMMARY

A summary of the characteristics of different forms of bio-power conversion technologies are given in Tables 2 and 3 on the following pages. The tables are meant to help the reader understand general differences among the strategies.

**Table V-2: Bio-Power Conversion Technology Specifications**

Conversion Technology	Potential Fuels	Boiler Efficiency	Turbine Efficiency	Overall Conversion Efficiency
Pile Burner	Urban wood waste, mill residue, forest residue, ag. residue, energy crops.	50% - 60% <sup>(2)</sup>	20-40% <sup>(4)</sup>	20% - 22% <sup>(1)</sup>
Stokers	Urban wood waste, mill residue, forest residue, some ag. residue. <sup>(1)</sup>	65% <sup>(2)</sup> 68%-80% <sup>(1)</sup>	20-40% <sup>(4)</sup>	23% - 30% <sup>(1,2)</sup>
Fluidized Bed Combustion	Urban wood waste, mill residue, forest residue, ag. residue, municipal sewage. <sup>(1)</sup>	65% <sup>(2)</sup>	20-40% <sup>(4)</sup>	27% - 28% <sup>(1)</sup>
Suspension	Urban wood waste, mill residue, forest residue, ag. residue, energy crops.	80% <sup>(2)</sup>	20-40% <sup>(4)</sup>	30% - 36%
Coal-Fired Co-firing	Coal plus biomass (see combustion fuels)	(see above combustion options) May reduce by 1.5% - 2% <sup>(1)</sup>	(see above combustion options)	22% - 34% <sup>(1)</sup> 33% - 37% <sup>(2)</sup>
Fixed Bed Gasification	Urban wood waste, mill residue, forest residue, ag. residue, energy crops.	N/A	22%-36% <sup>(4)</sup> (37% CC typical <sup>(4)</sup> )	35% - 36% <sup>(1,2)</sup>
Fluidized Bed Gasification	Urban wood waste, mill residue, forest residue, ag. residue, energy crops.		22% - 36% <sup>(4)</sup> (37% CC typical <sup>(4)</sup> )	30% - 40% <sup>(3,1,2,5)</sup>
Anaerobic Digestion	Municipal sewage, animal waste		22% - 40% (spark ignition engine) <sup>(4)</sup>	18% - 25% <sup>(1)</sup>
Natural Gas Co-firing	Natural Gas plus gasified biomass (see gasification fuels)		(see above gas turbine options)	34% - 40% (37% typical) <sup>(4)</sup>

(1) Schmidt and Pinapati, 2000 (2) Bain et al. 2003 (3) BTG, n.d. (4) Oland, 2004 (5) Craig and Mann, 1996 (6) FEMP, 2004

**Table V-3: Bio-Power Conversion Technology Benefits and Limitations**

Conversion Technology	Potential Benefits	Technical Limitations	Economic Limitations
<b>Pile Burner</b>	-- Very simple design -- Cheap to build -- Can handle wet and/or dirty fuels.	-- Up to 65% MCW -- Cyclical operations, erratic combustion, slow response times.	-- O&M costs -- Inability to follow loads
<b>Stokers</b>	-- More efficient than pile burners -- Low fly ash carryover -- Efficiencies could be improved with higher pressures, higher temperatures, and reheat.	-- Emerging opportunity fuels cannot be fired. <sup>(1)</sup> -- Fuel sizes $\leq 3''$ <sup>(6)</sup> -- Not suitable for more difficult ag. residues like rice/wheat straw. <sup>(1)</sup> -- More prone to NO <sub>x</sub> . <sup>(1)</sup>	-- Variations in fuel cost can upset profitability <sup>(1)</sup>
<b>Fluidized Bed Combustion</b>	-- Can handle fuels w/ MCW from 15% to 65% <sup>(1)</sup> -- Handles fuels with high ash content, irregularly shaped, or high MCW -- Lower NO <sub>x</sub> & SO <sub>x</sub>	-- Alkalis and free chlorine. <sup>(1)</sup> -- May have maintenance problems -- Fuel sizes $\leq 3''$ <sup>(6)</sup>	-- High capital costs -- High O&M costs for fuel preparation -- Optimum size: 50 MW
<b>Suspension</b>	-- Fuel flexibility	-- Small, uniform particle sizes -- (Fuel sizes $\leq 1/2''$ ) <sup>(6)</sup> -- Fuels with low MCW	-- Fuel drying equipment
<b>Coal-Fired Co-firing</b>	-- Reduced fuel costs -- Reduced SO <sub>x</sub> , CO <sub>2</sub> , NO <sub>x</sub> -- Reduced disposal costs -- May not affect efficiencies	-- Benefits of co-firing occur only up to 15% (by heat content)	-- Ash composition changes and may affect its salability
<b>Fixed Bed Gasification</b>	-- Simplest design	-- Sensitive to gas impurities -- Low-level gas quality. -- Handles large, dense, uniformly sized fuels. -- Tar removal can be significant	-- Lower ranges only (< 500 kW). <sup>(1)</sup> -- Competitive with DG power only <sup>(1)</sup>
<b>Fluidized Bed Gasification</b>	-- Can use fuels up to 55% MCW <sup>(1)</sup> -- Higher outputs fixed beds <sup>(1)</sup>	-- Sensitive to gas impurities -- Up to 55% MCW	-- Gas treatment reqs -- Not commercially available
<b>Anaerobic Digestion</b>	-- Reduced water and air pollution, avoidance of odor, onsite power and heat, reduced treatment costs, reduced disposal costs	-- Slow decomposition rate and incomplete decomposition -- Variations in gas flow and slow rates of gas flow -- Need to separate organics and inorganics	-- Limited to 2-3 MW <sup>(1)</sup> -- Electricity generation alone is viable in niche applications only <sup>(1)</sup>

(1) Schmidt and Pinapati, 2000 (2) Bain et al. 2003 (3) BTG, n.d. (4) Oland, 2004 (5) Craig and Mann, 1996 (6) FEMP, 2004

## RESEARCH PURSUITS

In 2002, the Biomass Research and Development Technical Advisory Committee (BRDTAC) issued a report detailing a research and development roadmap to identify public policy measures for promoting and developing biobased fuels, power, and products. The committee, representing a wide-range of experts, was established by the Biomass R&D Act of 2000. As a result of their efforts, the following table of short-term and long-term bio-power research needs were identified. These findings are presented here to provide the reader with an understanding of what future bio-power research may be trying to address and thereby provide insights into challenges that bio-power faces today.

An updated report from BRDTAC is due out sometime in 2007.

Table V-4: Bio-Power Generation Research Areas

Process	0-3 Years	4-10 Years	10+ Years
<b>CO-FIRING</b>	Research to improve efficiency of technologies for co-firing		Demonstrate co-firing systems that have 40% or greater efficiency than current systems
<b>DIRECT COMBUSTION</b>	Research to improve the efficiency of direct combustion systems.		Enable commercial deployment of direct combustion systems that are cost-competitive with competing systems.
	Research methods to reduce water content of feedstock for direct combustion systems		
<b>ANAEROBIC DIGESTION</b>	Conduct research to increase rate of decay of resources for anaerobic fermentation.	Test and demonstrate anaerobic fermentation systems with improved operating efficiencies	Enable commercial deployment of anaerobic fermentation systems that are cost-competitive with competing systems
	Begin research to reduce capital costs of anaerobic fermentation systems		
	Design technologies to handle low quality gas	Test and implement technologies to convert low quality gas into useful energy.	
<b>GASIFICATION</b>	Perform research to reduce capital costs of biomass gasification systems	Demonstrate and deploy biomass (forest and agricultural residue) gasification combined-cycle power generation at capacities up to 1,000 dry TPD	Enable biomass gasification systems that are cost-competitive with competing commercial systems.
	Conduct technology demonstrations	Demonstrate and deploy forest products black liquor gasification combined cycle at capacities of 2 million pounds of black liquor solids per day and larger.	Develop and field-test gasification, fermentation, and pyrolysis technologies to produce hydrogen from biomass.
	Demonstrate advanced gasification and biosynthesis gas technology suitable for integrated use for power generation on large scale and in distributed systems, in a biorefinery, and for the production of chemicals, materials, and other products.		
<b>MODULAR SYSTEMS</b>	Evaluate industry standards for grid connection.	Enable deployment of modular systems that can operate in a regulated, grid-based system.	Improve biobased power generation efficiencies through wider application in technologies such as fuel cells, microturbines, and other distributed systems.
	Establish standards for modular biomass systems that enable them to connect to the grid.		
	Continue research to improve performance of modular systems.	Conduct testing of modular systems.	
		Demonstrate stand-alone power facilities with 5 - 50 MW capacity producing electricity from energy crops at an average costs of \$0.05 / kWh or less	

Adapted with modifications from BRDTAC, 2002

# CHAPTER VI : PRESENT APPLICATIONS OF BIOMASS TECHNOLOGIES

Much of this study deals with future development of biomass power generation; trying to answer questions about what kinds of biomass there are, where it is, what its characteristics are, how much it costs, how to collect and process it, what conversion technologies to use, how to plan and finance a project, and so on.

But there already are a number of biomass projects in Minnesota that are worth knowing about because they can teach us lessons their developers had to learn the hard way. And there are many other existing operations that don't use biomass now but might do so in the future. This chapter reviews examples of Minnesota projects to show how technology, biomass, engineering and financing came together.

## CO-FIRING

Co-firing is the use of biomass fuel mixed with other fuels, including fossil fuels. For that reason, it is not only an additional source of energy, it also is a means of conserving and extending fossil resources. As it currently is practiced, co-firing mixes biomass (usually wood) with another fuel (usually coal), usually in a boiler designed for coal. The pulp and paper industry long has co-fired coal with wood waste, and so have utility power plants in areas where wood is cheap and available. In addition to co-firing in combustion boilers, fuels also can be mixed in more sophisticated gasification and combined-cycle technologies. In those cases, co-gasifying may be a more precise term than co-firing.

There are several ways biomass can be co-fired with other fuels. In coal-fired plants, the most common method is simply adding a small percentage of biomass fuel to coal. But for facilities using natural gas or oil, biomass first must be transformed by gasification and/or biorefining into gas or liquid fuels. Biofuels then can combine with fossil fuels to power combustion turbines, add to the steam cycle of a combined-cycle power plant, or mix with other fuels in a gas boiler. (Chiaromonti, et. al., 2007; Hughes, 2002; Sturzl, 1997)

### Co-Firing Biomass with Coal

At present, by far the most common way to co-fire solid biomass is to blend it with coal. Hundreds of U.S. industrial plants, like paper mills, burn their own processing wastes with coal to generate energy and avoid disposal costs. There are several examples of this in Minnesota. The Federal Energy Management Program ranked Minnesota's potential for co-firing as "Good," based on the state's average delivered price of coal, its supply of low-cost biomass residues, and its average landfill tipping fees (FEMP, 2004).

Co-firing coal with biomass in combustion boilers offers advantages over burning biomass alone. Boilers designed exclusively for biomass generally are smaller and less efficient (around 20% efficiency) than larger coal-fired boilers (33 to 37% efficiency). After a coal boiler is tuned to use mixed fuels, co-firing does not result in an appreciable loss in output. Co-firing combustion efficiency still runs at about 33-37% (Bain, et. al., 2003).

Because of the depreciation of existing plants and their connections to existing infrastructure, like water, sewer, roads, rail, and the electric grid, it is much cheaper to convert an existing fossil-

fuel plant to co-fire biomass than it is to build a new biomass plant out of the box. Not only does co-firing allow coal plants to get into the biomass energy business at low capital costs, it also improves their emissions by reducing CO<sub>2</sub> and other pollutants. On the other hand, biomass-only plants eliminate fossil fuels altogether.

Adapting a coal plant to co-fire biomass usually requires only minor modifications. If the fuels to be co-fired have similar characteristics, like chunk wood for a coal stoker plant, or sawdust for a coal suspension burner, and the biomass is a small fraction of total fuel, both can run through the same fuel handling equipment. But if biomass becomes more than a small percentage of total fuel, or if the physical properties of the co-fired fuels differ significantly, the plant will need dedicated biomass handling and processing equipment. In such cases, co-fired fuels don't meet until they reach the boiler or combustion turbine.

Some challenges and limitations that arise from co-firing biomass fuels with hydrocarbons are:

- **Intermingling of ash.** Plants that burn just one type of fuel can earn income from the sale of ash. Coal fly ash is an additive to cement; biomass ash is a soil amendment. Blending the two renders them unusable for either application and sends them to landfills instead of to paying customers.
- **Slagging.** The tendency for deposits to form in boilers or combustion turbines varies considerably depending on the fuels used and their interactions in combustion.
- **Deterioration of catalytic reduction (SCR) emissions control equipment.** Since SCR catalysts can become ineffective when exposed to high-alkaline fuels, SCR manufacturers may void warranties in cases of co-firing (European Commission, 2000.)
- **Limitations of the existing plant's design.** An exhaust system provides a good example of the kind of imbalance that can be created by co-firing biomass. Because biomass fuels have a lower ratio of energy-to-mass than hydrocarbons, biomass fuels give off greater volumes of flue gasses – probably more than the plant was designed to handle. The cost of rebuilding an exhaust system may make co-firing financially unfeasible.

### *Preparing Solid Biomass Fuel for Co-Firing*

The two basic ways to process biomass fuel for combustion in general, drying and sizing, were described in a preceding chapter on handling. Here we review their implications for co-firing.

**Drying.** We have discussed drying as a way to reduce degradation and shipping weight of biomass, but it has no bearing on preparation of fuel for co-firing. According to a recent evaluation of the bio-power industry, drying is not necessary for co-firing because:

- The gain in fuel efficiency doesn't justify its cost.
- Industrial wastes that fuel most co-firing operations usually are fairly dry to begin with (between 6 and 28% moisture content by weight).
- Biomass is only a small percentage of the total fuel used (Bain, et. al., 2003).

**Sizing.** When the percentage of co-fired biomass is low (<2% on a heat input basis), the coal plant's existing equipment probably can reduce it along with coal and send the mixture on to the boiler. Using existing equipment has the obvious benefit of eliminating the cost of additional equipment. When biomass becomes a larger percentage of the fuel supply, sizing equipment comes into play, as we discussed in the chapter on biomass handling.

Table VI-1: Fuel Size Requirements by Combustion Type

Boiler Type	Fuel Size Required (inches)
Pulverized coal	$\leq \frac{1}{4}$
Stoker	$\leq 3$
Cyclone	$\leq \frac{1}{2}$
Fluidized bed	$\leq 3$

(FEMP, 2004)

## Examples of Co-Firing in Minnesota

According to the eGRID database published by the Environmental Protection Agency, ten baseload power plants in Minnesota burn coal to generate electricity. Studies show that, with a few modifications to its boiler and fuel handling equipment, a coal-fired power plant of an appropriate design can co-fire up to 5% biomass without any problems. If all ten plants converted to co-firing at that level, they could produce 260 MW, or 1.5 million MWh, of baseload biomass power annually (2.4% of Minnesota's annual retail electric sales) from 1.1 million tons of biomass.

**Alan S. King plant, Oak Park Heights.** At least one Minnesota power plant has successfully co-fired biomass (in this case wood waste) with coal. From 1988 until 1998, the Allen S. King power plant in Stillwater co-fired 3 to 5% sawdust and sander dust mixed with coal.

The King plant no longer co-fires sawdust, a fact that illustrates the contingent nature of biomass energy economics. Co-firing presented no technical problem. The boilers at the King plant were well suited to burn sawdust because they were designed for pulverized coal in suspension. Handling wasn't a problem, either, because the sawdust would literally blow in, dry, through a pneumatic pipe from a large supplier that happened to be next door, Andersen Window. Andersen reworked its dust collection system to separate pure sawdust from plastic contaminants that would give off corrosive chlorides, and it paid for the blowline so it could capture its waste's value as energy through a favorable contract with NSP subsidiary NRG, the operator of the power plant.

The arrangement seemed like a marriage made in heaven, but it ended in divorce in 1998 because sawdust had become more valuable as animal bedding than it was as boiler fuel. Like any other fuel, biomass is subject to price swings. But unlike most other fuels, biomass prices can swing because of factors having nothing to do with energy.

**District Energy, St. Paul.** District Energy's central heating and power plant operates four gas/oil-fired boilers, two boilers co-firing gas and coal, a fuel-oil backup plant and mobile boiler, which together generate a combined total of 289 megawatts of thermal energy (987 million BTU per hour) and drive an 860-kilowatt turbine generating electricity for internal needs. Since it installed wood-burning capacity in 2003, District Energy has increased its use of woody biomass until it has become more than 80% of its total fuel. The wood comes from tree removals and trimmings in the metropolitan area. (For more details, see the full account in the following section on CHP applications.)

## Co-Firing Gasified or Liquefied Biomass

Co-firing solid biomass with coal may cost less, but converting biomass to a liquid or gas fuel for co-firing offers important benefits:

- It separates streams of residual fly ash that can be sold rather than landfilled;
- It can generate high-value byproducts.

New technologies for turning biomass into liquid and gaseous fuels have multiplied the number of ways it can be co-fired with other fuels. If cleaned by well known chemical processes, bio-gas, bio-oil and bio-diesel can drive combined-cycle turbines without fouling. They also can add energy to combined-cycle facilities during down cycles when the turbine isn't running. In processes other than fueling turbines, biogas doesn't even have to be cleaned.

Liquid and gaseous biomass fuels also can be co-fired with other fuels in internal combustion applications like diesel-fueled gensets and Stirling engines. Blends up to B20 (20% bio-diesel) don't detract from engine performance. Liquid and gaseous biomass fuels also can be co-fired with coal or other fossil fuels in boilers. One innovative design proposes to combine a biomass gasifier with a stoker boiler to burn bark and syngas and generate steam. Recovered heat from the gasifier and boiler would preheat air for two gas-fired, externally-recuperated gas turbines generating electricity. This configuration would reduce consumption of fossil fuel, cut emissions of NO<sub>x</sub>, and increase energy production. (Bryan, Rabovitser, Ghose, and Patel, 2003)

## COMBINED HEAT AND POWER (CHP)

By definition, co-firing refers to the practice of mixing bio-fuels with other fuels. Combined Heat and Power (CHP), on the other hand, may not involve biomass fuel at all. It refers not to the fuels that create energy but to the way a facility employs energy. Combined heat and power, or co-generation, captures some of the heat left over after electric generation to meet thermal requirements (ie. space heating, district heating, process heat and steam, etc.). By capturing steam for further uses, a CHP system dramatically increases its overall efficiency.

Some CHP plants, like those in paper mills, may use biomass, and others, like municipal power plants, seldom do. But biomass may come to play a larger role in all CHP plants in the future.

## Biomass Co-Generation in Industrial Plants

In the energy crisis of the 1970's, some planners envisioned dedicated stand-alone facilities, sometimes called "central stations," built for the specific purpose of converting biomass to electric energy. During that time, California led the nation in developing such stand-alone plants by offering subsidies to developers of biomass generation. By the early 1990s, utilities and investors banking on subsidies had built 61 biomass plants in California.

When the state withdrew those subsidies, leaving biomass plants to compete head to head against fossil fuel plants, many of them shut down. By 2004, 29 of California's original 61 biomass plants had been idled, dismantled, or converted to natural gas. Most shuttered plants were stand-alones built by investors and power companies. Most survivors are adjuncts of manufacturing plants, like lumber mills.

Co-generation plants survived because they have lower costs than stand-alone plants. Their operating costs are lower because they use manufacturing or processing wastes as fuel, avoiding the costs of waste disposal and power purchases. Furthermore, since they are adjuncts

of plants that make profits in other ways, co-generation plants don't have to carry the full financial load of their enterprises.

Capital costs are lower, too, because co-generation takes advantage of existing infrastructures, like:

- An existing site.
- Management and workforce.
- Electrical substations and transmission lines.
- Roads and transportation.
- Supply chains, like loggers or farmers.
- Ability to buy additional biomass fuels, like timber slash, thinnings, wheat straw, or corn stover, from those same suppliers.
- Water and sewer connections and back-up or start-up fuels.
- A large internal power customer.

### ***Sources of Renewable Energy and Fuels for Biomass***

Because so many U.S. timber and crop processors co-generate power from organic wastes, biomass ranks second only to hydro among renewable fuels for power.

**Table VI-2: United States Renewable Energy Generating Capacity**

<b>Renewable Resources</b>	<b>Generating Capacity (MW)</b>
Hydro	93,445 MW
Biomass	11,869 MW
Wind	5,078 MW
Geothermal	2,079 MW
Solar thermal	354 MW
Photovoltaic	58 MW
<b>Total, 2002</b>	<b>112,883 MW</b>

(NREL, 2006)

Among biomass fuels, timber residues predominate.

**Table VI-3: MW of Generating Capacity from U.S. Biomass Resources**

<b>Biomass Resources</b>	<b>Generating Capacity (MW)</b>
Timber residues	7,497 MW
Municipal solid waste	2,970 MW
Biogas	880 MW
Agricultural residues	373 MW
Landfill gas	150 MW
<b>Total 2002 U.S. biomass capacity</b>	<b>11,870 MW</b>

(NREL, 2006)

Underlying the figures above are several important points. The first is that existing biomass power generation is overwhelmingly a byproduct of manufacturing. Of those 7,497 MWs of capacity for timber residues, only 245 belong to utilities owned by the federal government, cooperatives, municipalities, or investors or public authorities. The remaining 7,252 MWs are tied to manufacturing plants, mostly pulp and paper mills. Since virtually all plants burning timber

residues leave energy on the table by using inefficient technologies, their power output could grow significantly by using newer systems.

The second point is that industries processing crops instead of wood generate very little biomass power from their wastes. In 2002, agricultural residues accounted for only 373 MWs of capacity. That quantity may soon increase, however. The rapid growth of ethanol and biodiesel has set the stage for more co-generation with agricultural biomass in bio-fuels plants. Fortuitously, just as ethanol and bio-diesel are coming of age, advanced energy technologies also being perfected.

## **Biomass Co-Generation in Minnesota**

Unlike California, Minnesota never developed a fleet of stand-alone biomass plants. Most of Minnesota's biomass power is generated, as it always has been, in manufacturing plants. The largest of these are five pulp and paper mills. They are old, well established contributors to northern Minnesota's economy, but not to the electric grid.

Minnesota's ethanol plants, on the other hand, are relative newcomers to the state. The oldest one dates from the 1990s. Ethanol has brought new income – but not new electricity – to farmers and rural communities in southern and central Minnesota.

A third Minnesota industry, municipal power, resembles the model of a stand-alone power plant in that it buys fuel rather than tapping an internal waste stream. But municipal plants usually co-generate power as an adjunct of their established facilities. District Energy St. Paul, for example, built America's largest municipal biomass CHP plant by adding a large wood-fired boiler to its existing district heating system. Recently, a joint powers authority of the Iron Range cities of Virginia and Hibbing added wood-fired boilers to their existing municipal CHP plants. In addition to providing power to their own cities, all three municipal plants sell electricity to Xcel Energy.

Those three industries, paper, ethanol and municipal CHP, may provide a larger share of Minnesota's electrical energy in the future. But so far, ethanol is the only one making a start in advanced, high efficiency technologies. We'll review those three industries in their global, national and Minnesota contexts and then focus on specific Minnesota plants that already have developed biomass power or that show the potential to do so.

## **THE U.S. PULP AND PAPER INDUSTRY**

Because the paper industry is global in scope, we can understand Minnesota's industry best in its larger setting. The paper industry is one of the largest industrial consumers of electricity in the U.S., satisfying some of its huge needs internally by burning biomass in the form of bark, wood and pulping wastes, and supplementing that with power purchased from the grid. At present, generators in pulp and paper mills only displace power from the grid; they very rarely export it to the grid.

Although they collectively represent a huge block of biomass power capacity in the United States, present-day pulp and paper mills offer few, if any, examples of advanced energy technologies. They rely on simple, reliable, robust direct-combustion boilers to burn rough, unprepared and undifferentiated wood wastes in a wide range of particle sizes, moistures, and BTU contents. In an industry whose huge capital investments – often more than \$1 billion per mill – dictate 24/7 operation, reliability trumps efficiency. Pulp and paper mill managers don't want

to experiment, especially since they view boiler/generator systems as waste disposals as much as power sources.

Wood nevertheless is the favored fuel of the paper industry. Mills usually back it up with natural gas, oil, coal, or some combination thereof – the mix varies from season to season and year to year – but wood waste always is preferred because of its low cost. Since the alternative to burning waste is hauling it to an expensive landfill, wood actually enters the boiler at a negative value. As disposal costs increase and fossil fuels become more expensive, the gap between the two grows. So mills use backup fuels only when wood wastes run low.

By burning wood wastes backed up by or blended with fossil fuels, some mills have become nearly self-sufficient in electrical energy. For example: Sappi's mill in Cloquet buys only a few percent of its electric power; a Domtar mill in Arkansas with its own generating capacity of 100 MW purchases only 13.8 MW; a GP mill in Georgia with a capacity of 83 MW buys 6.8 MW; a Temple Inland mill in Louisiana with a capacity of 96 MW buys 10 MW; and a MeadWestvaco mill in Maryland with a capacity of 65 MW buys 8.8 MW (RISI, 2006).

## Challenges Facing the U.S. Paper Industry

Considering how much power pulp mills already produce using traditional technologies, one can imagine how much more they could produce with newer, more efficient technologies. But at the moment, the U.S. pulp and paper industry is confronting distracting economic challenges.

Some of those longstanding challenges are:

- The cyclical nature of a commodity industry;
- Chronic overcapacity;
- Fierce price pressures;
- The highest production costs in the world; and
- An industry-wide scramble to consolidate strong mills and shutter weak ones.

Globalization has brought new challenges:

- New international competitors that exacerbate global overcapacity;
- New competitors located within fast-growing Asian markets;
- The loss of U.S. customers, especially in packaging papers, because of off-shore manufacturing;
- Lower costs of labor and timber in developing countries;
- More efficient equipment in new foreign mills;
- Dependency on ever-more-costly foreign oil; and
- The transfer of domestic mill ownerships to global corporations.

Other new challenges emerge from environmental concerns:

- The need to reduce greenhouse gas emissions;
- Timber set-asides that make pulpwood scarce and expensive;
- The fragmentation of timberlands into small private ownerships;
- Sustainable harvest guidelines; and
- More stringent emissions regulations.

These challenges are taking their toll on the American paper industry. Over the past decade, more than 100 mills – mostly old, small, inefficient ones located in the northeastern U.S. – have shut down. More are expected to follow. Many mills still operating have changed hands, some of them several times.

The industry's most strenuous challenge, however, comes from Wall Street. Investors consider the paper industry a poor performer relative to its huge capital assets in timberlands and mills. Faced with shareholder demands to liquidate assets, paper companies have had to choose the real estate business or the manufacturing business and so a great round of selling off timberland and plants is under way. Some companies, like Potlatch – formerly Minnesota's largest forest products manufacturer – have sold mills and become real estate investment trusts. Others are doing the opposite: selling timberland and buying mills. Others are selling both. International Paper, the country's largest paper company, sold its Minnesota mill and two Wisconsin mills in June, 2006, along with 12,000 acres of Minnesota land planted in hybrid poplars. The former owner of a mill in International Falls, Boise Cascade, left the paper industry altogether and bought the retail chain Office Max.

## **Biomass Power in Pulp Mills**

Pulp mills fall into two distinct categories: chemical (or kraft) or mechanical (or groundwood). Chemical mills use a chemical process to separate cellulose for paper from lignin, the organic glue that holds wood fibers together. The lignin-rich liquid residue of the pulping process, "black liquor," is burned in recovery boilers (sometimes called Tomlinson boilers) to make steam and retrieve pulping chemicals for re-use. Steam from these recovery boilers is expanded through turbines to generate electricity before it is piped on to serve mill processes.

Recovery boilers in chemical mills currently used have low thermal efficiencies of just over 10%. Research into black liquor gasification techniques has produced new technologies that raise thermal efficiencies to 20 to 30%, and gasification also can recover processing chemicals more efficiently.

Mechanical mills differ from chemical mills in that they don't separate lignin from pulp. Rather, they defibrate wood mechanically by steaming and grinding it. Some mills add chemicals in a thermo-chemical-mechanical-pulping process (TCMP), but that isn't to be confused with chemical (or kraft) pulping. Unlike chemical mills, even TCMP mechanical mills leave lignin in the wood. Therefore they don't produce black liquor to use as fuel.

Chemical and mechanical mills are alike, however, in their treatment of bark and wood wastes. They burn them in simple direct-combustion boilers to make steam for plant processes and turbine generators.

### ***Potential for Increased Power Generation in Pulp and Paper Mills***

The problems of the paper industry may discourage some companies from making large investments in new energy technologies, but on the other hand they may drive some companies to exploit them. Some paper companies reportedly are studying new energy technologies, like fluidized-bed combustion, gasification, and biorefining, that could transform mills from net importers of electricity into net exporters. With biorefining or cellulosic technologies, they could even make transport fuels from their wastes. There are technology companies seeking partnerships with paper mills to do exactly that.

The time is right. Simple direct combustion boilers burning black liquor and wood wastes have proven to be reliable and durable for many decades, but their time is running out. 67 boilers currently operating in American pulp and paper mills were built before 1960, eight of them before 1931 (NREL, 2006). Those old boilers now are reaching retirement age. The majority of recovery boilers will end their 30- to 40-year lifetimes over the next 10 to 20 years, and many wood waste boilers are older than that. As boilers age and power costs increase, mills have

both the opportunity and the motive to install systems that extract more energy from wood waste (Larson, Consomi, and Katosfky, 2003).

The economics of paper making will drive it to increased energy efficiency. Purchased power is a major cost for pulp and paper mills. It accounts for as much as 20% of their cost of goods sold, about the same as the timber that forms the product itself. An investment in an efficient power system is likely to pay for itself quickly.

### ***Research to Turn Pulp and Paper Mills into Power Plants***

Collaboration among the U.S. Department of Energy, research universities, and industry laboratories has led to the development of several biomass gasification techniques that now are near commercialization. Several of these technologies have undergone two or more years of full scale commercial testing and are ready for wider adoption.

A number of studies have evaluated the potential impact of new energy technologies on the financial performance of pulp and paper mills. An important Agenda 2020 paper, sponsored by the paper industry calculates that a hypothetical mill now *importing* 36 MW to meet its electricity needs could *export* 15-22 MW by using a mill-scale Black Liquor Gasification-Combined Cycle (BLGCC) system, with no increase in the volume of black liquor it processes (Larson, 2003). In short, by using a gasifier, a pulp mill could turn electricity from an expense into a revenue stream. The next step, adding a larger gas turbine co-firing natural gas with syngas made from black liquor (this would require the purchase of additional wood waste like harvest residues), would increase the mill's power exports to 126 MW, enough to make it small utility-scale power plant.

The implications of biomass technologies extend far beyond the economics of the mills themselves. They presage an era of national energy independence. Sweden hopes to reach that goal by 2030. A Swedish engineer, Ingvar Landalv, visited Minnesota several times in 2005 to talk about a \$30 million pilot plant his firm, Chemrec, has built for the Swedish government. It is a biorefinery attached to a chemical pulp mill's recovery boiler to produce liquid fuels. By 2030, Sweden plans to make all its liquid fuels in pulp mills and all its electricity in nuclear plants (as it largely does already). An American firm, Thermochem Recovery International, is working on a somewhat different biorefining technology with funding from the U.S. Department of Energy. Enzymic cellulosic processes also may a future role in using mill and forest wastes to make liquid fuels.

Not every mill will adopt advanced energy technologies. Chemical paper mills probably will lead because of their high power consumption and valuable black liquor waste stream. The Upper Midwest will not benefit as greatly from this trend as the Southeastern United States, where two-thirds of the nation's chemical pulping capacity resides. Chemical mills aside, however, more energy-efficient use of wood wastes could help any mill survive this difficult period of shut-downs and consolidations.

## **Minnesota's Pulp and Paper Industry**

Minnesota is home to eight paper mills. Two of them, Liberty Paper in Becker and Rock-Tenn in St. Paul, recycle paper and thus have no wood waste to burn. (They do remove contaminants, like adhesives and inks, that can be used in Refuse Derived Fuel (RDF), but that is not our subject.) Another paper mill, Wausau Paper in Brainerd, also does not generate wood waste because it buys all of its pulp. Three mechanical mills, UPM Blandin in Grand Rapids, Stora Enso in Duluth and International Paper in Sartell, do have wood waste to burn because they make

pulp from logs. Minnesota's two chemical mills, Sappi in Cloquet and Boise in International Falls, burn black liquor in recovery boilers and wood waste in combustion boilers.

**Table VI-4: Minnesota's Five Papermills Burning Wood Residues to Generate Power**

Name	Location	Type	Headquarters	Primary Product
Boise Paper	Int'l Falls	Chemical	Chicago	Business papers
Sappi Fine Paper	Cloquet	Chemical	South Africa	Coated publication paper
Stora Enso	Duluth	Mechanical	Finland	Catalogue and insert paper
UPM Blandin	Grand Rapids	Mechanical	Finland	Lightweight coated magazine paper
Verso	Sartell	Mechanical	Memphis	Lightweight coated magazine paper

## Opportunities to Increase Power in Minnesota Mills

As the headquarters listed in the above table show, Minnesota mills are part of a global industry. Therefore owners of Minnesota's mills make investments based on global strategies, not local loyalties; they send their capital to any point on the globe where they find financial advantage. Stora Enso, for example, the Finnish owner of Duluth's super-calendered papermill, recently announced it will build the world's largest pulp mill in Chile. And Stora Enso's Duluth mill has to compete for investment capital against sister mills around the world.

### *Minnesota's Chemical Paper Mills*

Because mills vary in engineering design, financial circumstances and business strategies, specific prospects for biomass power investments can be identified only on a case-by-case basis. Sappi and Boise Cascade, Minnesota's only chemical mills and therefore our only candidates to gasify and/or biorefine black liquor, exhibit basic differences.

**Sappi Fine Paper, Cloquet.** Sappi's pulp mill is more modern than its paper mill. In the 1990s, the pulp mill's former owner, Potlatch, invested more than \$500 million to rebuild it. Potlatch later sold the pulp mill and its adjoining paper mill to Sappi North America. Sappi's president, Kathleen Walters, called the pulp mill the "jewel" that attracted her to the deal.

One of the most modern pulp mills in the U.S., Sappi Cloquet has made itself nearly self-sufficient in energy. The huge investments that already have been made in the mill make it unlikely that the company would install new technologies. But the energy landscape is changing quickly, and since Sappi does a lot of business in Europe, where modern gasification was first developed, the company must be aware of its potential.

**Boise Cascade, International Falls.** Boise's mill is the opposite of Sappi's – a modern paper mill linked to an old pulp mill. Two of Boise's five boilers were installed in 1927, and the other three date from 1947, 1948 and 1957. Three burn natural gas, one burns bark and wood waste, and the fifth, a recovery boiler, burns black liquor. The recovery boiler received a \$30 million refurbishing in 2002, but its basic technology remains traditional. The papermaking side of the mill, on the other hand, was modernized in 1990 with a huge new \$1 billion paper machine which at the time was the fastest in the world.

The corporation once called Boise Cascade, then just Boise, and now Office Max, sold the mill to Madison Dearborn, a Chicago investment group, in 2004. The new owners restored its original name of Boise. It's hard to divine whether the new owners will want make major new

investments, but the old boilers probably need updating. Perhaps a partnership of the City of International Falls and Boise Cascade could build a gasifier to generate more power and help the city dispose of municipal solid waste, a hard thing to do in an area with a very high water table.

### ***Minnesota's Mechanical Pulp and Paper Mills***

Since mechanical mills don't produce black liquor, their biomass fuel is limited to bark and wood waste stripped from pulpwood feedstock. Mill sludge, a wet "fuel" containing 50-60% moisture even after dewatering, might also be burned, although that is done more to avoid landfill than to produce power. Some plants supplement mill wastes with harvest residues (limbs, tops, and unmerchantable wood), providing extra income to loggers while avoiding the high costs of fossil fuels. (see "Laurentian Energy in Hibbing and Virginia," below).

**UPM Blandin/Rapids Energy Center, Grand Rapids.** Blandin provides a good example of power company/ paper mill cooperation. Minnesota Power bought UPM Blandin's internal power facilities consisting of two boilers co-firing wood and coal, two natural gas boilers, two steam generators and a small hydro turbine. The mill now buys steam and electricity from the power plant, which is called the Rapids Energy Center. On rare occasions when demand is very high and so are energy prices, the Center may sell to the grid a very small amount of power from the gas boilers, perhaps one-tenth of 1% of the plant's output. At those times the Energy Center is a de facto peaking plant, and when it sells wood-fired power to the mill it is a base-load plant that serves one captive customer.

Its partnership with Minnesota Power frees Blandin to do what it does best, make paper, and leave power plant operation to the utility. This could be the first step toward turning a paper mill into an exporting biomass power plant.

Blandin recently announced an \$800 million expansion with a large new paper machine that will increase the mill's power demand. This might be an opportune moment for the power utility install more efficient equipment.

**Stora Enso, Duluth.** The Stora Enso mill, which manufactures super-calendared paper for newspaper inserts, catalogues and magazines, provides another example of a utility/paper mill partnership. The pulp and paper mill originally began as a partnership between Minnesota Power, the City of Duluth, and Pentair, a holding company headquartered in Minnesota. Later, the partnership sold the mill to Wisconsin's Consolidated Paper, which in turn sold its entire business to Stora Enso of Finland.

The three founding partners, Pentair, Duluth, and Minnesota Power, combined several facilities to make up the power package. The paper mill was built from scratch, together with an adjacent de-inking mill owned by a consortium of paper companies. But the new mill did not have to include a boiler plant because the City of Duluth refitted two 1930s-vintage coal stoker boilers at its nearby Hibbard Power Station to co-fire wood waste with western coal. After Consolidated sold the mill to Stora Enso, Duluth continued to own the boilers, and Minnesota Power continues to operate them as "Duluth Steam District Number Two."

This cooperative arrangement spared the original partners the cost of a new boiler plant and turbine generator. Stora Enso sends its bark and waste wood, plus market chips and railroad-tie chips, to the boilers, and the Steam District generates power and steam for the mill.

The result has been satisfactory, if not ideal. The boilers occasionally break down, and wood fuel occasionally forms clumps on the grate which call for a blast of extra combustion air from below. Slagging, however, has not been a problem.

The paper mill would like to see the boilers replaced eventually, but its immediate priority is a system to dry and burn the 150 tons of mill sludge it sends each day to landfill. Longer term, Stora Enso's partnership with Minnesota Power could lead eventually to higher and better uses of waste biomass.

**Verso Paper, Sartell.** A former owner of this mechanical mill, Champion, embarked in 1990 on an ambitious program. It would lease or purchase 22,000 acres of farmland to raise hybrid poplars that reach harvest size in ten years. Each year, one-tenth of the acreage would be planted. On the eleventh year, the first tenth would be harvested and the hybrids would begin to regenerate. The year after that, the second year's planting would be harvested, and so on through the ten-year cycle when the first stand again would be ready to harvest.

This plan was strategic for several reasons. Champion's self-sufficiency in hardwood would insulate it from the volatility of aspen prices. (Aspen is half the mill's furnish. The other half is softwoods which the mill would continue to purchase). By controlling more of its supply, the corporation would raise its stock price, and waste from the hybrid harvests could become biomass fuel.

That plan has been somewhat revised by successive changes of ownership. In 2000, Champion sold the Sartell mill to International Paper (IP), which put the hybrid poplar program on hold. IP then resold the mill in June, 2006, to CMP Holdings LLC, a holding company which purchased three other mills to form a new paper company called Verso. The sale included the 12,000 acres of hybrids that Champion had planted, and Verso will begin to harvest that next year.

The Sartell mill has a lot of room for more electric generation. Of its three boilers, the largest co-fires combinations of bark and wood waste, stoker coal, and dewatered paper mill sludge at 50-60% moisture content. The second burns natural gas, and the third burns coal. The plant consumes all its capacity of 22 MW.

**Rock Tenn/The City of St. Paul/Ramsey County.** Like Stora Enso in Duluth, Rock Tenn may enter into a partnership between a paper mill and a municipality, but at this writing that is still in the talking stages. A recycling paperboard mill with no wood residues to burn, Rock Tenn long has bought process and power-generating steam through a pipe from Xcel Energy's High Bridge power plant. But that arrangement ends in mid-2007 when the Xcel Energy plant converts to natural gas. Rock Tenn's continued operation depends on finding a new steam source. For the short term, it will get by with an existing oil-fired boiler. But expensive fuel oil is only a stopgap until something more economical can be installed.

For the long term, Rock-Tenn's engineers considered first an on-site biomass power plant burning agricultural wastes. The Minnesota Department of Employment and Economic Development called on the Agricultural Utilization Research Institute to consult. But the high landed cost of agricultural wastes, along with the logistical and permitting problems in using them in the center of a large metropolitan area, made that idea unworkable.

Then discussions among company, state, city, Port Authority and county officials led to the idea of an RDF gasification plant. The Green Institute recently completed a study investigating the possibility of using biomass at the plant (Nelson, 2007).

The fate of the paper mill has yet to be settled, but the effort to save it displays the kind of cooperative effort needed to move biomass projects forward.

**Table VI-5: Boilers in Forest Products Plants or Municipal CHP Plants in Minnesota**

Plant Name	Utility	City	Year Operational	Unit(s)	Capacity (kW)
Blandin Paper	Blandin Paper Co.	Grand Rapids	1969	1	15,000
Blandin Paper	Blandin Paper Co.	Grand Rapids	1980	2	16,500
Boise Cascade	Boise Cascade Corp.	International Falls	1927	1	4,000
Boise Cascade	Boise Cascade Corp.	International Falls	1927	2	4,000
Boise Cascade	Boise Cascade Corp.	International Falls	1948	3	7,500
Boise Cascade	Boise Cascade Corp.	International Falls	1947	4	7,500
Boise Cascade	Boise Cascade Corp.	International Falls	1957	5	6,300
Verso Paper	Verso Paper	Sartell	1982	3	24,000
Sappi Fine Paper	Sappi North America	Cloquet	1976	1	21,400
Sappi Fine Paper	Sappi North America	Cloquet	1997	2	40,000
Hibbard, M.L.	Minnesota Power	Duluth	1949	3	3,300
Hibbard, M.L.	Minnesota Power	Duluth	1951	4	3,750
Ainsworth Corporation	Potlatch Corporation	Bemidji	1992	1	12,500
St. Paul District Energy	St. Paul District Energy	St. Paul	2002	1	25,000
Laurentian Energy Authority	Hibbing And Virginia Public Utilities	Hibbing And Virginia	2006	2	15,000 - 20,000
<b>Total Capacity (kW)</b>					<b>190,750</b>

From NREL's Renewable Electric Plant Information System (REPIS), <http://www.nrel.gov/analysis/repis/>

## MINNESOTA'S ETHANOL INDUSTRY

Within the past twenty years, Minnesota has become home to 16 ethanol and 3 biodiesel plants that together produce 620 million gallons of biofuel (551 million gallons of ethanol and 69 million gallons of biodiesel). Development of new plants is accelerating, and their capacities are skyrocketing. Early plants might produce 20 million gallons per year. Today, 150-million-gallon plants have been built. Older plants were dominated by local farmers' co-ops, but now Wall Street, large agribusinesses like ADM and Cargill, and even a few petroleum companies have also entered the business.



Ethanol has been hailed as a move toward energy independence, which is an important geopolitical goal. But from an environmental standpoint, ethanol is a paradox: a renewable biomass fuel that replaces one fossil fuel, petroleum, by using two other fossil fuels, natural gas and coal in the form of electricity. These are American fossil fuels rather than Middle Eastern fossil fuels, but they are fossil fuels nonetheless.

Some critics argue that making ethanol takes as much energy as the finished product contains. Industry spokespersons counter that the ratio really is more like one unit of input energy to 1.3 units of ethanol energy. However, it is clear that the most ethanol plants draw on fossil fuels from distant regions and neglect renewable biomass fuels that lie around the plants.

Ethanol expansion will run into natural limitations at some point because even renewable resources are finite. Ethanol plants consume lots of water – four to six gallons of it per gallon of fuel produced. Lack of adequate groundwater already is limiting the development of ethanol plants in some areas of southwestern Minnesota. Another problem is the very select feedstock used to make ethanol. It is becoming difficult to site a new plant without overlapping another plant's corn procurement area. Recent coverage of the industry suggests that if all of the ethanol plants seeking permits in Minnesota are built, they will consume more than 40% of the state's corn crop (Webb, 2006). The food and feed industries are concerned that they are being priced out of their traditional markets by fuel producers.

The ethanol industry will continue to expand, however, as it learns to conserve water, expand its raw material base with wastes like stover and straw by adopting cellulosic processes, and generate its own gas and electricity through gasification of agricultural biomass. Like paper mills, ethanol plants may even become power plants of the future, generating electricity not just for themselves but also for surrounding communities.

## **Biomass Energy in Ethanol Plants**

The ethanol industry already is moving toward greater energy efficiency. Three Minnesota ethanol producers are working toward becoming self-sufficient in energy by installing new technologies. One is using a fluidized-bed boiler, one is using a gasifier, and another is planning to install one. The immediate goals for projects are reducing costs and meeting tougher environmental regulations. But there is a longer-term justification as well. If subsidies for ethanol production eventually decline or even disappear, these plants will be better prepared to compete head-on against other fuels.

There is another potential benefit from investments that capture more energy through advanced technologies like gasification and biorefining. Once a plant becomes self-sufficient in electric power, exporting power is just one step further along the same path. At the moment, only one Minnesota ethanol plant is exporting power – Central Minnesota Ethanol Cooperative (CMEC), which sells all of one megawatt to Xcel Energy. Like most other ethanol plants considering gasification, CMEC's primary interest is in substituting syngas for ever more expensive natural gas. That is an easy substitution because once it is cleaned, syngas burns well in an existing, unmodified natural gas boiler. In the future, a gasifier might fuel a turbine generator producing enough electricity to power the plant and sell to the grid besides. To get to that export stage, however, a plant will have to find additional sources of biomass fuel.

### ***Corn Plus Ethanol in Winnebago***

Corn Plus General Manager Keith Kor has taken several steps to make Corn Plus' 44-million-gallon plant more energy-efficient, beginning with the installation of internal heat transfers that

cut energy consumption 10%. But his biggest energy-saving measure so far is a fluidized-bed boiler that burns an ethanol byproduct, syrup, to reduce his purchases of natural gas. Corn Plus, according to Kor, is the first company in the industry to adopt fluidized-bed technology. It has received a patent on its application in ethanol production.

The fluidized bed boiler has raised the plant's energy efficiency dramatically. Its ratio of outside energy inputs to product energy output is down to one-to-six, and natural gas consumption has dropped 55%. Kor now is working on a plan to make the plant completely independent of outside energy, but details are not public.

### ***Central Minnesota Ethanol Cooperative (CMEC) in Little Falls***

Kerry Nixon, General Manager of Central Minnesota Ethanol Coop, is taking a different route to energy independence. Working with engineer Cecil Massie, he has eliminated all natural gas purchases by installing a gasifier fueled by wood wastes – sawdust, slabs, shavings, off-fall and trimmings from loggers, sawmills and wood shops – available within a 20-mile radius of Little Falls. It's ironic that an ethanol plant, not a paper mill or a lumber mill, is the first facility in Minnesota to gasify wood waste.

Gasification has acquired a reputation for being finicky about fuel, but Massie says it can handle pretty much any kind of biomass as long as it contains less than 30% moisture. Slagging of silica in the wood supply has been a challenge, though. Besides wood, the gasifier is set up to run also on dried distillers grains (a byproduct of ethanol production), stover (corn stalks and leaves), or straw. Since stover and straw contain silica, too, more tweaking will be needed to resolve the slagging problem.

Stricter EPA permitting requirements and higher costs of natural gas are driving CMEC's project. The gasifier will enable the plant to meet lower VOC emissions levels without adding a thermal oxidizer, which would use more natural gas; avoid \$3.5 million per year in natural gas costs; and co-generate about 30% of the mill's electric load. The gasifier's syngas also dries DDGs, and conversely, DDGs could fuel the gasifier if getting wood fuel became a problem. Xcel Energy will purchase 1 MW from the mill, but the plant will purchase 3 MW from the grid. The plant also may sell steam to the city of Little Falls. Payback on the gasifier is estimated at three years.

### ***Chippewa Valley Ethanol Company (CVEC)/Frontline BioEnergy, LLC, Benson***

This is an important project not only in its own right, but also for the multiplier effect it might have throughout the ethanol industry. A Minnesota cooperative ethanol producer, CVEC, and an Iowa biomass gasification engineering firm, Frontline BioEnergy, have formed a joint venture to design and install a prototype gasification system in CVEC's Benson plant to process biomass feedstocks like corn stover, distillers dried grains, corn, wheat straw and wood waste. The syngas produced will replace \$20 million worth of natural gas annually.

CVEC will pay the Iowa firm, Frontline, \$3.4 million for research, \$12.4 million for equipment, and \$1 million for working capital. In return, Frontline will give CVEC an equity position in its company and licensing rights for a limited number of future installations in other plants. Both partners thus will have an incentive to spread gasification technology to as many other plants as they can.

## **MUNICIPAL COMBINED HEAT AND POWER**

European countries, especially Denmark, provide many examples of CHP plants that gasify local biomass, like wood waste and crop wastes, to produce heat and power for small towns. Some

of those Danish plants are tiny, generating only a few MW of power and just enough heat to serve a few thousand residents. They show that biomass economics can work even in small-scale, distributed-energy applications.

The real challenge in biomass CHP is not so much justifying the plant itself as it is justifying the heating pipes. Few small American cities have steam or hot water pipes in their streets, and larger cities are distant from biomass fuel and cannot easily handle it in an urban area. Fortunately, several Minnesota cities are exceptions.

## **Biomass Municipal CHP Plants in Minnesota**

It would be difficult for most Minnesota cities to develop the kind of centralized combined heat and power (CHP) plants seen in Europe because, in a typical sprawling U.S. city, the costs of installing underground pipes and the line losses they would suffer are daunting. Therefore CHP plants usually appear in cities that already have municipal district heating systems and/or high population densities, things rarely found in American communities.

Minnesota does, however, contain some communities with CHP plants using wood wastes for fuel in pre-existent municipal systems: St. Paul, Virginia and Hibbing. Minneapolis has district heating in its downtown, but it burns natural gas for fuel and doesn't generate power.

### ***District Energy in St. Paul***

District Energy, an independent, non-profit CHP plant located on West Kellogg Boulevard in downtown St. Paul, is the largest of its type in the U.S. It provides heat to more than 170 buildings and 300 single-family homes, including the Capitol Complex, Empire Builder Industrial Park, West Side Flats and the Phalen Corridor. That adds up to more than 29 million square feet of building space occupying 80% of St. Paul's central business district and surrounding areas.

District Energy pumps hot water through 97,600 feet of pipes to buildings equipped with heat exchangers that can transfer the heat into their own internal systems. After it gives off its heat, the water returns to District Energy's main plant to be reheated and recirculated.

The plant operates four gas/oil-fired boilers, two coal/gas-fired boilers, a fuel-oil backup plant and mobile boiler, which generate a combined total of 289 megawatts of thermal energy (987 million BTU per hour) and drive an 860-kilowatt turbine generating electricity for internal needs.

In 2003 District Energy added boilers that burn urban tree waste, like trimmings and felled trees, along with clean post-industrial wood wastes like pallets. The plant generates 25 MW of electrical energy for Xcel Energy and 65 MW of thermal energy to heat buildings.

St. Paul's CHP system benefits the city's environment by replacing polluting fossil fuel furnaces with heat from pollution-controlled biomass. At the same time, it benefits developers, building owners and residents by eliminating the need for expensive boilers, auxiliary equipment, and space to house them.

Ironically, District Energy's success may prevent further development of woody biomass plants in the metro area. There is evidence that District Energy consumes most of the area's available tree waste. But other streams, like municipal solid waste, source-separated organics, or sewage, might generate biogas in gasifiers or anaerobic digesters to serve the same kinds of uses.

## *Laurentian Energy in Hibbing and Virginia*

Two municipal power companies, Hibbing Public Utilities and the Department of Public Utilities in Virginia, have joined forces to create the Laurentian Energy Authority. The Authority has installed a wood-fired boiler in each city's CHP plant to make steam for electrical generation and district heating. Since the power plants are located in downtown areas that don't have room for fuel storage, loggers deliver harvest waste (limbs, tops, unmerchantable species) to a concentration yard between the cities where it is weighed, tested, screened, and kept at a 30-60-day supply level for just-in-time truck delivery to the power plants.



(Steve Downer, *MMUA's The Resource*) May 2006

**Figure VI-2: Laurentian Energy Authority Construction**

The managers of the Hibbing and Virginia municipal utilities, Jim Kochevar and Terry Leoni, developed the biomass conversion plan. In particular, the apparent benefits included:

- A 20-year contract with Xcel Energy for 35 MW of electricity to meet the state's biomass mandate;
- An average price of 10.2 cents/kWh;
- \$704,369,000 in gross revenues over the 20-year period;
- A \$20 million annual contribution to the communities' economies in labor, fuels and materials;
- 70 jobs retained and 100 new ones added;
- Environmental benefits from replacing coal with biomass;
- Avoidance of a \$40 million expense for environmental controls;
- A biomass supply of more than 500,000 green tons within a 75-mile radius (per a study by Bill Berguson of Duluth's Natural Resources Research Institute).

Besides buying harvest waste, the utility is planning to develop a “closed loop” biomass supply from hybrid poplar and willow plantations. A total of 1,650 acres were planted by LEA in 2004-2005. The poplar harvest will begin 5 years later.

Laurentian Energy’s selection of boilers demonstrates that real-world constraints sometimes matter more than efficiency. The project is using traditional direct-burn stoker-grate boilers because a short financing timeline precluded a lengthy design process. The equipment also had to fit within limited spaces at the Authority’s existing plants. Even with 1970’s technology, however, the facility should be profitable. It will sell biomass power to Xcel Energy at the price of 10.2 cents/kWh (PUC, 2005); more than double the market price of power from other fuels.

## **BIO-SOLIDS**

Two factors suggest that bio-solids will play an increased role in energy production in Minnesota. The first is an increasing interest in using them, and the other is the development of new technologies that convert them into useful energy without consuming too much of it in the process. Bio-solids soon may begin to generate marketable electricity and thermal energy.

Incinerators, anaerobic digesters and gasifiers all can be used to convert bio-solids, which in Minnesota are found mainly in wastewater treatment facilities and animal barns. Most of Minnesota’s smaller waste water treatment plants use anaerobic digesters to process bio-solids. But three large facilities that process 58% of the state’s municipal waste use incinerators. Anaerobic digesters are used most often to convert animal manures, but a new facility in Benson, Minnesota, is incinerating turkey litter (manure mixed with bedding) to generate electricity.

### **Converting Bio-Solids into Energy**

Considering that around 70% of dry bio-solids are volatile solids containing around 10,000 BTUs per pound, one would expect wastewater to be a great source of renewable fuel. But the amount of energy needed to dry wet bio-solids has discouraged their use as fuel. Waste water entering treatment facilities typically contains only 2% solids. New dewatering technologies involving clarifiers, polymers, filter presses and other means can increase solids content to a range of 8% to 45%. That helps, but solids have to reach 85% for bio-solids to work as combustion fuel. Drying to that level takes much of the energy that bio-solids can produce in combustion.

Gasification might become an alternative to combustion in converting bio-solids to energy. Heavy metals in bio-solids would be released in gasification, but most bio-solids in Minnesota are quite free of them. Gasifiers have lower capital and operating costs than other advanced technologies like fluidized bed incinerators, but since they are less tolerant of moisture, their bio-solids fuel also must be dried to 85% solids.

## **WASTEWATER TREATMENT**

The possibility of creating electric and thermal energy from wastewater treatment may become a reality, however, with some recent innovations in treatment technologies. Upflow sludge blanket digesters, wetland treatment systems, and the Cannon Process use up to 70% less energy than the older systems now in use. In addition to these more energy efficient technologies, advances have been made in maximizing the distribution of heating and cooling in waste water facilities. New plants can distribute heat from heat pumps and chillers much more efficiently than plants built just ten years ago. Retrofits in the commercial sector often

achieve a 50 reduction in overall energy consumption. When 70% less energy is used in treatment, more is available for producing electricity.

## **Energy Generation in Minnesota Plants**

A number of water reclamation facilities in Minnesota process wastewater in anaerobic digesters. Most use the resulting biogas only as a heat source. But five wastewater treatment plants – the Metro Plant in St. Paul, the Rochester Water Reclamation Plant, the Western Lake Superior Sanitary District Wastewater Treatment Plant in Duluth, the Empire Waste Water Treatment Plant in Dakota County, and the Owatonna Waste Water Treatment Plant – use biogas to generate electricity as well. While these five do not currently sell excess electricity to the grid, they do supply a portion of their own internal demands. By adding turbines to anaerobic digesters, wastewater treatment plants throughout the state could generate electricity from biosolids.

### ***The Metro Plant, St. Paul***

The Metro Plant, which has burned biosolids since the 1940's, is a part-time generator of electricity. In 2004-05, the Metro Plant replaced old multiple hearth incinerators with a fluidized bed incinerator. Currently, the Metro Plant generates steam in the new boiler to supply all its heating and some of its processes. During the summer, when the facility doesn't need heating, the incinerator generates 5 MW of electrical power, the net energy from the equivalent of 200 dry tons per day of biosolids.

### ***The Empire Waste Water Treatment Plant, Dakota County***

The Empire Plant receives municipal wastewater from five communities with a total population of approximately 99,000 people. The plant currently can process 12 million gallons per day, but as urban development continues to spread throughout central Dakota County, that soon will double to 24 million gallons per day. The facility extracts biosolids by settling solids in a primary clarifier and secondary clarifier. After some additional thickening, the solids are pumped into an anaerobic digester at a rate of 10 dry tons per day. Like the majority of wastewater digesters in Minnesota, the one at Empire is a low-solids mesophyllic digester operating at roughly 95 degrees F.

For the past 25 years, the Empire plant has burned biogas from the digester in a boiler that makes steam for plant heating and other uses. But now it is beginning to produce electricity as well. As part of an expansion, it has installed two 60 kW microturbines to supply the plant's power. When the expansion is complete the microturbines will consume about 40% of the gas produced by the digester.

In the past, planners have built anaerobic digesters because they reduce biological oxygen demand, nitrogen, and phosphorus in wastewater by 50% or more. In the future, planners will look to them for energy as well. The Empire Wastewater Treatment Plant is a prime example of anaerobic digestion serving both purposes.

# AGRICULTURAL WASTES FOR POWER PRODUCTION

## Turkey Litter

### *Fibrowatt, Benson, MN*

Fibrowatt, a \$202 million 55 MW plant in Benson, Minnesota, is generating electricity from turkey litter and other agricultural biomass fuels. The plant, a project of Fibrominn LLC, Fibrowatt LLC, a subsidiary of Homeland Renewable Energy LLC and Fibrowatt Ltd., has created 30 new jobs in this western Minnesota city. Xcel Energy has signed a 21 year power purchase agreement for electricity from the facility.



(Post, 2007)

**Figure VI-3: The Fibrominn Plant**

## Dairy Manure

The dairy industry increasingly is using anaerobic digesters to process manure. In many cases they serve primarily to reduce odors and other environmental problems. But even small dairy operations can generate enough energy from biogas to reduce their purchases from utilities. Larger dairy operations (750 head or greater) could generate enough to satisfy its own needs and sell a surplus to the local utility.

### *The Haubenschild Dairy Farm*

The Haubenschild Dairy Farm processes manure from its 750-cow herd in an anaerobic digester to produce biogas fuel for a 135 kW engine generator set. The genset powers the entire dairy operation, and the local electric cooperative, East Central Energy, buys enough surplus to power 75 homes. Marketing the electricity as “cow power,” the utility sells it at a slight premium to subscribing customers. In addition to electricity, the genset heats the barn with hot water from its cooling system.



(Nelson and Lamb, 2002)

**Figure VI-4: The Anaerobic Plug-Flow Digester**

## **Municipal Solid Waste/Food Processing Residues**

Anaerobic digesters are versatile enough to handle source-separated organics in municipal solid waste treatment and waste streams high in organic matter from food processing plants. American Crystal Sugar currently digests beet tailings and pulp anaerobically at its East Grand Forks/Moorhead facility and uses the resulting biogas for internal processes. A number of other food processing facilities are considering anaerobic digestion systems.

## **FUTURE TECHNOLOGY OPTIONS**

Fuel cells would use extracted hydrogen from a fuel supply such as natural gas or a bio-gas and generate heat and electricity through electrolysis. Fuel cells have been used in some niche markets, but their commercial availability is limited. Their ability to use syngas from biomass or coal hasn't been demonstrated. Impurities in syngas might preclude its use. (Dayton, 2001).

Modular power systems are small, portable electric generators that can be moved to remote locations. This approach could be particularly attractive for biomass fuels that are widely dispersed.

# CHAPTER VII : GOVERNMENT ACTIONS

## MINNESOTA'S BIOMASS MANDATE OF 1994

### Introduction

The history of Minnesota's Biomass Mandate teaches a number of lessons both for policy makers and project developers. On the policy front, the history illustrates difficulties that may arise when policy mandates overstep technical and economic realities, calling for results that can't be achieved within the current state of the industry. For project developers, the history provides useful lessons regarding the intersection of politics, policy, and markets and the influences and limitations that each of these spheres places on the others.

### History

Minnesota's 1994 Biomass Mandate arose from a pitched legislative battle over a request by Northern States Power (now Xcel Energy) to allow storage of spent nuclear fuel in dry casks at its Prairie Island power plant. In other states, regulatory agencies like Public Utilities Commissions respond to such requests, but Minnesota law required legislative approval. That opened the door to political debate, and a coalition of environmentalists, renewable energy activists, nuclear opponents and Indian tribes opposed NSP's request. Some opponents saw this as an opportunity to close the nuclear plants entirely, while others saw this as an opportunity to extract environmental concessions from the utility. The result, which came on the final day of the session, was a compromise called "The Prairie Island Agreement:" NSP could store nuclear waste in 17 dry casks in exchange for a commitment to build ~425 MW of wind power by 2003 and a further 400 MW if the PUC found that wind power was a least-cost resource. In addition, NSP agreed to contract for 125 MW of biomass power.

The original biomass mandate read as follows:

Sec. 3. [216B.2424] [BIOMASS POWER MANDATE.] A public utility, as defined in Minnesota Statutes, section 216B.02, subdivision 4, that operates a nuclear powered electric generating plant within this state must, by December 31, 1998, construct and operate, purchase, or contract to construct and operate (1) 50 megawatts of electric energy installed capacity generated by farm grown closed-loop biomass; and (2) an additional 75 megawatts of installed capacity so generated by December 31, 2002.

In the years since, the original mandate has been amended and modified in twelve legislative sessions. Some of those amendments clarified sketchy language in the original law. For example, plants now would be permitted to use a certain percentage of non-biomass fuels, like natural gas during plant startup. Other amendments responded to the interests of project developers seeking to build biomass plants under the mandate and very reasonably loosened the unworkable requirement of "farm grown closed-loop biomass," which ruled out wastes. But other amendments suggest that project choice was driven more by considerations that were more political than commercial.

Two of the first three plants to sign Power Purchase Agreements (PPA's) with NSP abided by the terms of the original mandate. The Minnesota Valley Alfalfa Producers (MnVAP) project was to

be a 75 MW plant using alfalfa stems as fuel, and the EPS/Beck project was to burn cultivated whole trees. The third project, St. Paul District Energy, required the first amendment to the statute, allowing the use of waste wood as fuel. The utility argued that the high efficiency of a CHP plant justified a weakening of the fuel standard. The MNVAP and EPS/Beck projects eventually came to an end when they couldn't secure financing. NSP cancelled the MNVAP PPA for non-performance, but the EPS/Beck PPA transferred to other developers with the Laurentian Energy Authority ultimately acquiring it. In the ensuing years, political and market forces both had a role in deciding which projects would be built under the Biomass Mandate.

## The Projects

The following brief history of Biomass Mandate projects is drawn largely from documents from Public Utilities Commission dockets. Other sources include news reports and interviews with interested parties. The history of these projects teaches lessons that policy makers and project developers might heed as they consider the future of biomass power in Minnesota.

### *MnVAP*

Interest in developing a power plant fired by alfalfa stems arose a year or more before the 1994 Prairie Island agreement created the Biomass Mandate. In 1993, NSP asked researchers at the University of Minnesota to identify agricultural products that potentially could be used as fuel. The researchers quickly settled on alfalfa, and that led NSP to conduct an informational meeting with farmers in the Southwestern corner of the state that summer. The outlined project would strip alfalfa leaves from stems and pelletize them for use as high-protein animal feed. The stems would then be gasified to generate up to 75 MW of power. In the following year, a group of farmers formed a cooperative called MnVAP, and a study of the project was conducted by NSP, the University of Minnesota, DOE and EPRI.

Initially MnVAP had seen NSP as a partner, but before the end of 1993 NSP had explained that the utility would not develop the project themselves but would invite MnVAP to participate in the competitive bidding process for biomass power projects (Kokmen, 1999). MnVAP chose to pursue the project, and in mid-1996 won in competitive bidding. They received \$4 million from the Department of Energy for design work and permitting ("Northern States", 1996), and became eligible for up to \$40 million in construction financing ("Minnesota Farmers", 1996). After negotiating for a year and a half, MnVAP and NSP agreed to a PPA, which they filed in February of 1998. The Public Utilities Commission then took 14 months to approve the project (PUC, 1999b). The long approval period was due in large part to the intervention of Minnesota Energy Consumers (MEC), a coalition of large energy customers, who complained that MnVAP's power would cost Minnesota's ratepayers \$30 million more than power from natural gas (PUC, 1998). Although MEC failed to prevent the PUC's approval of the PPA, the delay was largely responsible for the project's slow unraveling over the course of 1999. In early 1999 Enron, a major financial backer of the project, pulled out. The Department of Energy then followed suit by freezing its funding of the project (Kokmen, 1999). By the end of the year NSP had terminated its PPA with MnVAP for nonperformance (NSP, 1999), and MnVAP announced that it would no longer pursue the project. Reports of the episode suggested that the added costs of the prolonged debate over the PPA caused Enron to pulling out of the project. Others conceded that this was a factor, but that the project was probably too ambitious, and that PUC's delay simply gave the financiers an opportunity to reconsider the risks and costs of the project (Kokmen, 1999; Mooney, 2000).

MnVAP's involvement in biomass power continued beyond the termination of their PPA. The co-op actually was close to signing an agreement with Fibrominn for the transfer of their PPA when

NSP cancelled it. In the following year MnVAP and Fibrominn came to an agreement that MnVAP would supply Fibrominn with 50,000 tons of alfalfa stems annually to the plant at Fibrominn's call ("Agreement Could", 2000). MnVAP continues to function. It has developed a business selling pelletized alfalfa leaves for animal feed.

### ***EPS/Beck***

NSP's second round of bidding led to the selection of two biomass projects: St. Paul District Energy and the EPS/Beck Whole Tree Energy project. Each was initially approved to supply 25 MW of biomass power. The EPS/Beck project, located in St. Peter, was to dry and burn whole trees using proprietary harvesting, drying and processing technologies. The trees would be plantation grown hybrid poplars. Approximately 25,000 acres of land would be planted for each 25 MW of capacity. (Ragland, Ostlie, and Berg, 2000)

The original contract specified a 25 MW facility but it gave NSP the option of increasing its size up to 75 MW. As the EPS/Beck and District Energy PPAs were presented to the PUC, the 75 MW MnVAP project was unraveling. This confluence of events ultimately unraveled the EPS project as well.

The Department of Public Service (DPS), which advises PUC, expressed concern at the costs of both the EPS and District Energy PPAs. The Department felt that the mandate had given the projects undue market power because, since NSP could fully recover costs of the mandated projects through rate increases, they had little incentive to negotiate the best price from them. The Department recommended approval of the EPS PPA with modifications, which included a lower price cap and an increase in project size to 50 MW (DPS, 1999). The PUC then deferred both PPA's, encouraged District Energy to improve upon its proposal, encouraged EPS/Beck to develop a 50 MW proposal, and ordered NSP to clarify the status of the MnVap proposal (PUC, 1999a). Both projects returned with PPAs, and the PUC approved them in January of 2000. The order approving EPS/Beck's PPA noted that, except for DPS, the parties involved, NSP and EPS/Beck, favored the 25 MW plant size over a larger plant (EPS/Beck argued that DOE and private lenders might not fund a larger facility). The PUC asked NSP to return to the PUC in a few months to declare their position on the option to increase the size of the project (PUC, 2000a). Despite the protestations of EPS, the PUC approved its project at 50 MW. Perhaps as a consequence, EPS never was able to secure enough financing to move forward. EPS eventually sold its rights and obligations under the contract to NGPP (Xcel Energy, 2003), which was ultimately purchased by the Laurentian Energy Authority.

Biomass project developers should note one important item that appeared in the PUC docket during the approval of NSP's choice to increase the project size to 50 MW from 25 MW. District Energy objected to the approval of the modified PPA. At that time the Biomass Mandate statute disallowed approval of new biomass plants that would adversely affect the fuel supply of an existing biomass plant. District Energy argued that modification of the PPA meant that EPS 50 MW plant was a new facility, and that its plan to use Metro Area wood waste until its tree plantations matured would have an adverse commercial effect on District Energy and its customers (St. Paul Cogeneration, 2000).

The challenge became moot when the PUC ruled that the modified PPA did not create a new project (PUC, 2000a). But the statutory language protecting the fuel supplies of existing projects along with District Energy's use of that language to intervene in another project sends two messages to project developers: first, that the legislature has been willing to intervene in market competition where biomass is concerned, and may do so again if lobbied by biomass consumers; second, that a competitor for fuel may intervene to protect its supplies.

District Energy's intervention reveals its concern about the sufficiency of available feedstocks in the Twin Cities Metropolitan Area. A recent study for the Rock Tenn plant supports the notion that the woody biomass growing in the Twin Cities Metro Area is almost fully utilized (Nelson, 2007). This reminds us that biomass fuels sometimes are in limited supply. Potential consumers of those fuels conduct due diligence to confirm that sufficient fuels are available, and that competition for them is unlikely to develop.

### ***St. Paul District Energy***

In 1997 District Energy and Trigen-Cinergy proposed to NSP a wood fired CHP plant to satisfy part of the Biomass Mandate. At that time, wood waste from the Twin Cities was landfilled or burned in open fires. But the Biomass Mandate and new regulations banning open burning were suggesting that the time had come to use urban wood waste as fuel. The wood-burning plant would adjoin District Energy's existing coal fired boilers that provided much of downtown St. Paul's heat. The new boilers would supplant up to 80% of the coal used to fuel the district heating system and consume up to 280,000 tons of chipped urban wood waste per year.

In early 1999 NSP submitted a PPA for PUC approval. In March of that year the Department of Public Service proposed substantial modifications to the PPA, and recommended approval of the PPA if those modifications were accepted. The PUC in August of 1999 deferred consideration of the PPA and encouraged District Energy to improve upon its proposed terms (PUC, 1999a). In early October NSP submitted updated terms of the PPA and in January of 2000 the PUC approved the PPA (PUC, 2000b). The plant planned to begin operation in 2001 ("Trigen-Cinergy", 1999); but regulatory delays delayed start-up until May of 2003 ("Cinergy Business", 2003).

Two episodes in the project's history illustrate (1) the need for biomass plants to prove they are good neighbors and (2) the challenges biomass consumers face in securing their fuel supplies.

The plant is located in downtown St. Paul, clearly visible from the river. As the start of construction approached, people involved in redeveloping St. Paul's downtown began to express concerns about how well an industrial facility would fit in. The utility explained that they were designing the plant to blend in with its surroundings. They also sought suggestions from their neighbors and other downtown groups (Karlson, 2001). District Energy appeared to successfully allay the concerns of the downtown communities.

Another neighborhood incident concerned the location of a fuel processing facility near a residential area. The boiler plant opened several months later than planned. Meanwhile, one of its wood suppliers had gathered and chipped several months worth of wood fuel on a lot near some houses. Exposed too long to the elements, the chip piles began to smolder and emit odors, leading to fire department calls and neighborhood opposition to a conditional use permit for the processing facility (Monsour, 2003).

The other lesson that St. Paul District Energy teaches is that obtaining a consistent, high-quality fuel supply can be difficult. District Energy initially relied upon independent contractors to deliver wood to their processing yard, but its inconsistent quality became a problem. So the utility created a for-profit subsidiary to manage its fuel supply. Environmental Wood Processing instituted several improvements. They still accept fuel deliveries from independent parties, but they reprocess those to meet plant specifications (Deering, 2006). They also manage the St. Paul transfer station and seek fuels at other municipal transfer stations and compost sites either by signing on as facility managers or by simply offering to chip materials at municipal sites and remove them free of charge (City of St. Louis Park, 2007; City of Albertville, 2007).

## **NGPP**

EPS/Beck assigned its PPA to NGPP in early 2003. NSP's petition for approval of the reassignment explained that NGPP intended to abandon the Whole Tree Energy scheme and burn conventional chipped wood from tree plantations (Xcel Energy, 2003). They also planned move the facility's location to Waseca. NGPP pursued the Waseca plan through 2003; but found that rights to land in the Waseca area cost more than anticipated, and that landowners wanted higher lease payments for tree plantations than the developers could afford. By early 2004 NGPP discussing with the cities of Virginia and Hibbing the best way to transfer the PPA to them (Xcel Energy, 2004). In the ensuing months the legislature reduced the size of the mandate to 110 MW while encouraging NGPP to reduce its project to 35 MW. In early 2004 the PUC put consideration of the docket on hold until negotiations to transfer ownership of the PPA to the cities of Virginia and Hibbing were completed.

### ***Laurentian Energy Authority***

In February of 2004 the Hibbing Public Utilities were pondering the long term future of their power generation facilities. All options were on the table, from closing them to installing natural gas combustion turbines. Among the options was a partnership with NGPP, then stymied in its biomass project in Waseca. ("Projects Wait", 2004b) By Mid-April of that year the cities of Virginia and Hibbing had agreed to enter into a joint venture to replace their aging coal boilers with wood boilers ("Public Utilities Meeting", 2004a), and by late April the cities were lobbying the state legislature to fund their project (Swanson, 2004). After exploring their options, NGP Power transferred their interest in NGPP Minnesota Biomass, LLC to the Laurentian Energy Authority. NGPP then announced it would abandon the project in Waseca and fulfill their contract by leasing and retrofitting the Laurentian Energy Authority's coal fired boilers. The cities formed the Laurentian Energy Authority to develop the project and eventually purchased NGPP to eliminate the complications of working with a third party.

The Laurentian project involved replacing coal fired boilers used by each city's district heating system with boilers that would eventually burn "closed loop biomass" in the form of plantation grown hybrid poplars. Until the poplar plantations become available, the cities will burn logging residues and other wood wastes. They anticipate that by the end of the 20 year PPA, more than half of the plant's fuel will have come from plantations. Besides powering each city's district heating system, the two projects will generate a combined 35 MW of biomass boiler for Xcel Energy, which finally will fulfill the 1994 Prairie Island Mandate. Since the two plants are in the cities' business districts, the wood fuel will be received and processed in a rural wood yard between the two.

The Laurentian Energy Authority's projects came to fruition quite quickly after the second amendment to the PPA was approved in August of 2005. In October of that year a contract for the construction of the new boilers was announced ("Foster Wheeler", 2005). Construction was completed and power generation had begun at the Laurentian Energy Authority in December of 2006 ("Biomass generation", 2006).

In previous years the facility has been the recipient of funding from the federal government. The funding has included:

- A grant of \$250,000 from the U.S. Department of Agriculture to fund the harvest of timber from 180 acres within Superior National Forest. ("Rep. Oberstar", 2005)
- A grant of \$1,200,000 from the U.S. Department of Energy to study potential wood resources and the effects of using "forest waste products for biomass burning projects at the Virginia and Hibbing public utilities." ("Grant Will Help", 2006)

## *Fibrominn*

Concerns about the environmental effects of stored turkey litter (manure and wood shavings used as bedding) at regional turkey producers led to the development of a 55 MW Fibrominn plant in Benson. The turkey litter in question often was used as a fertilizer, particularly by organic farmers. Since growers had a narrow window of time to apply the fertilizer each year, it had to be stockpiled year round by the turkey producers until it was called for. The resulting odors and flies were beginning to aggravate local residents, who complained to local authorities. Poultry producers then reached out to FibroWatt, a UK firm that had built three power plants fueled by turkey litter (Crosby, 2007; Dale, 2007).

These efforts arose around the time the MnVAP project was beginning to unravel. During the 2000 legislative session, after the MnVAP PPA had been cancelled, Fibrominn successfully lobbied the legislature to let them supply those MW's under the biomass mandate. The resulting amendments to the Biomass Mandate:

- Allowed poultry litter to satisfy up to 50 MW of the biomass mandate.
- Enabled NSP to forgo a competitive bidding process for their remaining MW of compliance under the mandate.
- Required the PUC to grant preliminary approval of a PPA with a turkey litter fired plant within 30 days of filing, provided the PPA was filed prior to September 1, 2000. Such approval would be based solely on the cost of the PPA being less than or equal to the cost of prior PPA's approved for the satisfaction of the biomass mandate.
- Required all contracts for biomass powered facilities filed with the PUC by September 1, 2000 be approved by July 1, 2001.

On August 31, 2000, Xcel Energy and Fibrominn executed a PPA and submitted it to the PUC for preliminary approval. On May 8<sup>th</sup> of 2001 the PUC approved the PPA (PUC, 2001). On August 28<sup>th</sup> of that year Fibrominn applied to the Minnesota Pollution Control Agency for an air emissions permit. The process for acquiring the air emissions permit took significantly longer than expected. A draft air emissions permit was not released for public comment until August 2, 2002, and the final permit was not received until October.

This delay in permitting resulted in a number of complications for Fibrominn and Xcel Energy. Fibrominn's next major milestone was to be a financial closing by July 1, 2002. That couldn't take place because the air emissions permit hadn't yet been granted. A series of extensions followed, and the project did not complete its financing until December 15, 2004 (Xcel Energy, 2005).

The project hit a small snag in the fall of 2005 when Hurricane Katrina threatened to delay a shipment of Chinese-made boiler components that were headed toward the port of New Orleans. Fortunately, the components were running ahead of schedule (Xcel Energy, 2006). Since then the project has proceeded as planned and began operation in 2007.

The project's record indicates that Fibrominn handled quite adeptly the politics necessary to bring the project to fruition. At the state level, the developers inserted language that allowed turkey litter to satisfy the biomass mandate and eliminated the competitive bidding process. The project's success at the local level is notable as well. The project began as a partnership between Fibrominn and the city of Benson. The city owns the land and facility and leases them to Fibrominn on a long term contract. The record also shows that Fibrominn made a concerted effort to involve the townspeople and provide them with a communications channel to the project developers. A Citizen's Advisory Panel, consisting of twelve independent community members, convened in April of 2001 and began to hold regular meetings. It gave the

community a sounding board for their concerns with issues like noise, odors and truck traffic (Fibrominn, n.d.).

### ***Northome Biomass Plant (Itasca Power)***

Concerned about the long delays in the Fibrominn project, Xcel Energy, the legislature, and the PUC began to worry that projects to meet the mandate might be completed late, or not at all. They designed an emergency process to use in the event that attempts to meet the mandate failed. The delays also brought a number of developers to offer their projects to the PUC and the legislature as solutions to Xcel Energy's difficulties. One interesting offer came from Minnesota Power, which offered to sell biomass power to Xcel Energy from their existing biomass boilers (Minnesota Power, 2003). Xcel Energy rejected that offer, but the political efforts of one project developer were more difficult to ignore.

In May of 1999 Itasca Power Company and Great River Energy entered in to an agreement under which GRE would purchase the output of a proposed Northome Biomass plant, and GRE would build a transmission line to connect the project to the regional grid ("Great River Energy", 1999). The Northome plant was to be a small (15 MW) facility, fired with waste wood from nearby wood products mills. In addition to generating electricity, the facility would provide steam to nearby industrial customers (IPC, 2005).

Despite their agreement with Great River Energy, Itasca Power lobbied the legislature to make Xcel Energy enter into a PPA with Itasca Power in 2001 "on an equal basis" with other projects Xcel Energy was working with to meet the mandate. Over the course of the following five years, Xcel Energy and Itasca Power engaged in a series of negotiations and regulatory proceedings but never were able to arrive at a mutually agreeable PPA. Itasca Power's continual efforts to convince both the state legislature and the PUC to force Xcel Energy to sign a PPA with them were no more successful. A press release from December of 2005 on Itasca Power's website announced the cancellation of the project (IPC, 2005). The final mention of Itasca Power in the PUC's regulatory record comes in a Progress Report to the PUC in the first quarter of 2006 in which Xcel Energy mentions that Itasca Power indicated that the price of any PPA would "have to be substantially higher than previously discussed, *primarily due to a shortage in the area of wood residue fuel*" (emphasis added). (Xcel Energy, 2006).

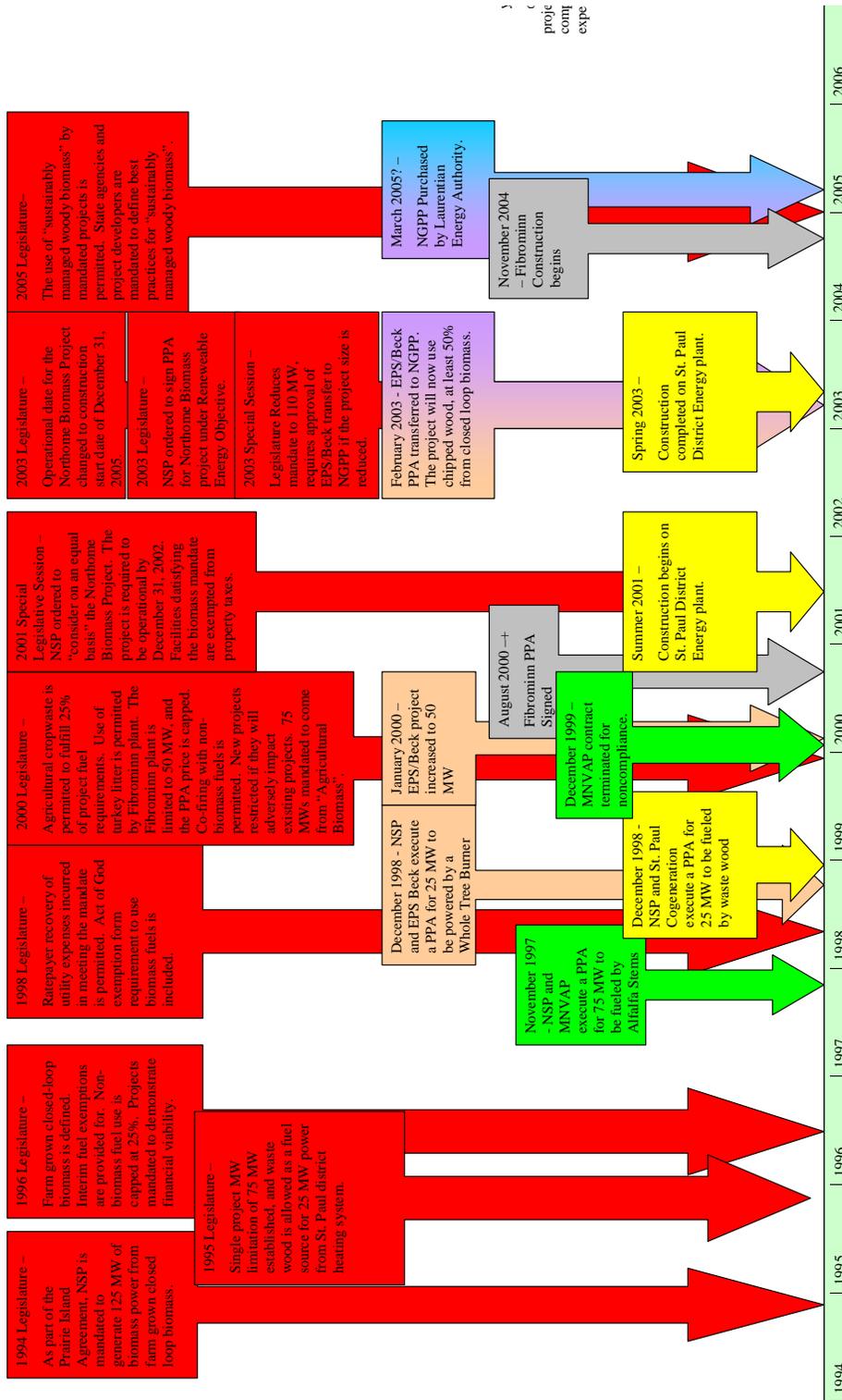


Figure VII-1: A Timeline of Minnesota's Biomass Mandate

# GOVERNMENT ECONOMIC DEVELOPMENT INCENTIVES FOR BIOMASS POWER PROJECTS

Government incentives for renewable power generation are a moving target. The Minnesota State Legislature and the United States Congress currently are deliberating a flurry of bills encouraging all varieties of renewable energy. So any account of incentives must be updated frequently as some of those bills pass into law. Rather than provide only a snapshot of today's programs, which will be superseded by tomorrow's, we supply addresses of websites that will supply current information.

Another reason to check with the agencies before planning a project around government programs is that some of those programs which look good on paper have no funding. That seems to be true especially of federal programs. They survive on the page in the hope that some day the Congress will see fit to replenish them.

Most existing government incentives promote energy efficiency and conservation on the demand side, not renewable capacity on the supply side. Even when incentives are designed to encourage the production of renewable energy, they tend to focus on efforts by small communities, farms, private businesses and family households to generate power for internal consumption using small technologies like wind generators, photovoltaic and solar thermal panels, and anaerobic digesters. Few programs target biomass plants large enough to export power to the grid.

In the aggregate, local initiatives and small technologies can make valuable contributions to our overall renewable energy portfolio. But since boilers, turbines and gasifiers are expensive, biomass plants generally operate at utility scale or else co-generate power as adjuncts of substantial manufacturing or processing enterprises.

Aside from programs targeting renewable energy projects, however, there are many larger economic development programs that can help any kind of project, including biomass energy. Minnesota through the years has been in the forefront nationally in establishing agencies and programs to help businesses grow.

Those programs can work well for co-generation, which probably will continue to be the dominant form of biomass project, because they tend to favor expansions by existing businesses rather than start-ups. Therefore we begin with a survey of generic economic development programs and follow that with a look at programs specifically aimed at renewable energy development.

## General-Purpose Economic Development Programs

Though incentives designed specifically for large scale biomass power generation are few, developers of biomass plants can take advantage of many generic economic development programs. Fortunately for Minnesota biomass energy developers, one of the nations most powerful is available through the Minnesota Department of Trade and Economic Development (DEED). It's commonly know as JOBZ

## ***Minnesota Jobs Opportunities Building Zones (JOBZ)***

The JOBZ program exempts sales, property, and state corporate income taxes, offering the biomass power developer several advantages unusual among economic development incentives:

- **Unlimited project scale.** Many government programs target small businesses, either by putting a top limit on the cost of the project, like the \$20 million cap of the federal Industrial Development Bond program, or by offering loans too small to be attractive to a large project, like the \$500,000 maximum advance of the Minnesota Investment Fund. But JOBZ works for very large as well as very small projects
- **Substantial economic benefit.** Many government programs consist of below-market loans at rates somewhat lower than those of conventional financing. Usually those take the form of gap loans supplemental to more substantial first-position commercial financing. In both their amount of funding and their interest-rate advantages, those programs operate on the margins and appeal primarily to relatively small projects. With JOBZ, however, the larger the project, the larger the value of its tax exemptions. In the case of costly biomass power plants, they could be worth millions of dollars. .
- **Minimal paperwork.** For a property tax exemption, the business signs a simple contract with the city called the Business Subsidy Agreement. The Minnesota Department of Revenue issues a certificate for the sales tax exemption. And by including a schedule with its state tax return, the company takes its corporate income tax deduction.
- **Criteria based on capital investment and financial performance rather than body count.** Some programs base financial assistance *quid pro quo* on the number of jobs the project creates – this many dollars for that many jobs. While cities offering JOBZ in fact may set a minimum number of jobs or a minimum wage level, most do not. A highly automated project with high capital costs and healthy profits -- but relatively few workers -- can take full advantage of all tax deductions.
- **Eligibility.** Many economic development programs benefit only manufacturers, but power generation facilities are eligible for JOBZ. The only type of business specifically excluded is local retail. The program has been applied to non-manufacturing projects, like distribution warehouses.
- **Focus on Minnesota regions with biomass potential.** The seven Metro counties, plus Wright and Sherburne, are excluded from the program. The rest of the state's 87 counties are eligible, and those happen to be the likeliest counties to attract biomass power development.

### JOBZ Zones and Subzones

JOBZ benefits attach to specific parcels of land, or to vacant buildings, that have been designated by communities throughout Minnesota. Those locally designated sites, called "subzones," are organized into ten large administrative "zones" that cover the entire state, with the exception of the metro counties referred to above. Ten Zone Administrators provide support services to the total of more than 300 communities enrolled in the program at its inception on January 1, 2004.

JOBZ benefits attach to specific subzones. To receive tax-exemptions, the business activity must occur on the JOBZ site. That excludes, for example, contractors whose work occurs at remote jobsites. It also would rule out the gathering of biomass feedstocks away from the plant.

But the magic circle of tax benefits can be moved if a developer prefers a particular site not currently enrolled in JOBZ. The local city council, school board and county board can pass resolutions that transfer JOBZ status from one place to another within the city, to locations

elsewhere in the county, or even to other cities. In the case of a co-generation plant attached to manufacturing or processing facility, JOBZ status could be conferred to a generation site as long as it can be clearly delineated. The program can't designate equipment mixed in with an existing plant.

The city exercises total and arbitrary discretion over JOBZ in its community. It does not have to extend exemptions to any project that it doesn't want. Once it does approve a project, however, it must provide the whole JOBZ exemption package for the entire term of eligibility. It can't pick and choose certain benefits or terms.

When it comes to state taxes, as distinct from local taxes, even if the JOBZ project is fully approved by local taxing authorities and the Minnesota Department of Employment and Economic Development, it ultimately must conform to rules of the Minnesota Department of Revenue regarding JOBZ exemptions. For questions on state tax treatment, contact Anne Gravelle, 651-556-6836.

### Prevailing wage

An important caveat to anyone considering a greenfield project in JOBZ: in order to qualify for exemptions, the *building* must be constructed by workers paid prevailing wages for that county. *Equipment installation*, however, does not fall under that requirement. The Minnesota Department of Labor and Industry, which promulgates lists of prevailing wages, makes a straightforward distinction between construction and equipment installation. If the work is done under a *construction* contract, it is construction and therefore subject to prevailing wage; if it is done under an *installation* contract, it is installation and therefore not subject to prevailing wage.

For details on prevailing wages, go to: [www.doli.state.mn.us](http://www.doli.state.mn.us), click on *Prevailing-Wage Rates*, click on the Minnesota map labeled *Commercial*, and then click on the county where you plan to build.

### JOBZ Tax Exemptions

JOBZ exemptions fall into three categories: 1) **Sales and Use**; 2) **Real Estate**; and 3) **Corporate Franchise** (income). The program also provides a tax credit against income or a cash payment in the absence of income provided that wages average above a certain annual threshold, which currently is in the low thirty thousand-dollar range.

### Sales and Use Tax

Real estate and corporate income tax exemptions begin once a facility is up and running. But the Sales and Use Tax exemption takes effect as soon as the developer signs a Business Subsidy Agreement with the city. Once that is in place, the developer or its contractor can take Sales and Use Tax exemption on purchases of building material and equipment while the plant is under construction.

Until the end of the JOBZ period the sales tax exemption applies also to further purchases. Goods and materials for resale always have been tax-exempt, but JOBZ exemptions include items not for resale but for consumption at the plant: IT systems, supplies, furniture, material handling equipment, and even vehicles (except for over-the-road trucks).

## Real Estate Tax Exemptions

Since real estate taxes are levied by local municipalities, counties and school districts, JOBZ is as much a local incentive as it is a state incentive. For a greenfield project, taxes currently paid on the bare land will continue to be paid, but taxes on improvements will be exempt. An addition to an existing plant can qualify for JOBZ, but the existing plant will continue to pay the same property tax as before. A vacant building placed by the city in JOBZ will be tax-exempt to a new user.

## Corporate Franchise Tax Exemption

The JOBZ Franchise Tax exemption applies to profits directly attributable to the JOBZ project. A Minnesota start-up in JOBZ, or a company new to Minnesota, would receive the deduction on its entire Minnesota profit. But if the company maintains other operations in non-JOBZ Minnesota locations, the JOBZ exemption is prorated on the basis of the company's total Minnesota employment. If the company has shut down at a non-JOBZ site and moved to a JOBZ site, it must employ 20% more workers and its deduction is prorated by subtracting the number of jobs at its former location from its new total. Minnesota Department of Revenue Schedule M500 details that calculation.

Note that of the three categories of exemptions -- Sales, Corporate and Property -- only the Corporate Tax exemption is prorated for a relocating company. Sales and use tax and property tax connected to the JOBZ project are entirely exempt regardless of the company's other -- or previous -- Minnesota employment.

## JOBZ Timeframe

The JOBZ program took effect on January 1, 2004. Since then, more than 300 projects have signed onto it. Under the existing statute, exemptions for all existing and future projects are to expire at the same time: JOBZ's expiration date, December 31, 2015. Thus, the nearer we get to 2016, the less cumulative benefit a new JOBZ project will receive. But a bill introduced at the legislature in 2006 would provide a full 10 years of benefits to any project that begins before 2016.

For detailed information on JOBZ, go to [www.deed.state.mn.us](http://www.deed.state.mn.us) and click on the *JOBZ* logo. Among many files on that site, you will find a useful calculator to help you estimate the value of the deductions based on your own company's numbers.

For a discussion of JOBZ eligibility for your project, call Dentley Haugesag at the Minnesota Department of Employment and Economic Development, 651-297-1174, or send an email to: [dentley.haugesag@state.mn.us](mailto:dentley.haugesag@state.mn.us)

For information on JOBZ tax forms, go to: <http://www.taxes.state.mn.us>, click on *2006 income tax forms and instructions*, and click on *JOBZ*.

## ***Tax Increment Financing (TIF)***

TIF is a method used by Minnesota municipalities to help finance business expansions and developments. Tax increment financing districts are established under the provisions of Minnesota Statutes, Section 469.174 through 469.179. Under that statute, cities use increased taxes generated by projects in TIF districts to pay off bonds issued to fund development costs.

The businesses compensate the cities by paying taxes they normally would have to pay regardless.

TIF and JOBZ therefore are mutually exclusive. Companies in JOBZ zones do not pay property taxes that would be captured to pay TIF bonds.

Although TIF is subject to state statute, the project's home city administers it. The person with whom to begin a discussion of TIF is the city administrator in the municipality where the project will be located. A good introduction to the complicated TIF process is online at: [www.fryberger.com/Admin Gov](http://www.fryberger.com/Admin_Gov).

### ***Economic Development Tax Abatement***

Minnesota Statutes Sections 469.1812 to 469.1815 created an alternative to TIF. A political subdivision may "abate" all or a portion of its property tax on one or more parcels of real or personal property, including machinery, for economic development purposes, subject to a duration limit and a limit on the amount of abatements. The "abatement" can take a number of different forms, including:

- A rebate of property taxes to the property owner;
- A reallocation of taxes to pay bondholders;
- A reallocation of taxes to pay for public infrastructure costs; OR
- A deferment of property taxes.

Revision Date: August 23, 2006

### ***Minnesota Small Business Development Loan Program (SMDP)***

The Small Business Development Loan Program, administered by the Minnesota Department of Employment and Economic Development under the federal Revenue Expenditure and Control Act of 1968, makes fixed-asset, first-lien, fixed-rate loans to aid job growths and manufacturing expansions. The Minnesota Agricultural and Economic Development Board (MAEDB) funds the loans by issuing tax-exempt Industrial Development Bonds (IDBs), backed by a state reserve fund, at the prevailing tax-exempt market rate at the time of issue.

The federal statute authorizing the program limits IDB eligibility to manufacturing industries, but co-generation projects by manufacturing companies may be eligible, as long as they increase employment and use some of the electricity in their processes. Bond counsel would determine eligibility.

Assets financed by IRBs can be real estate, equipment, or a combination of the two. Total project costs can't exceed \$20 million. Although the program is authorized to lend up to 80% of project cost, SMBP usually makes loans ranging from \$1 million to \$5 million with a maximum term of 20 years. Collateral includes the assets financed and the owners' personal guarantees.

MAEDB does not charge a fee, but bond issuance costs of 4% are charged against the advance, and 10% of the bond issue is kept in an escrow account. Funds are disbursed upon execution of the required loan documents and sale of the bonds. DEED accepts applications year-round basis, but they must be received by the first of each month to be considered at that month's MAEDB meeting.

For more information, contact Paul A. Moe at 651-297-1391 or toll-free at 800-657-3858. See also: Small Business Development Loan - Annual Program Summary, report primarily for legislators.

(Several commercial lenders also offer below-market financing using tax-exempt industrial revenue bonds. Call 651-297-1174 for further information.)

### ***Minnesota Investment Fund***

DEED's Minnesota Investment Fund makes grants on a project-by-project basis to local units of government that they in turn use to make subordinated below-market-rate loans to expanding businesses for fixed-assets. (*Note that the city receives a grant, but the company receives a loan.*) Cities, counties, townships, and recognized Indian tribal governments are eligible grant recipients.

The loans can finance 30% of the project's capital cost up to a maximum of \$500,000. 50% of other debt in the project must come from a commercial lender. The term is usually 10 years or less, and eligible industries are manufacturing and technology.

For further information, go to: [www.deed.state.mn.us/programs/mninvestfund](http://www.deed.state.mn.us/programs/mninvestfund)

Or contact:

Meredith Udoibok, Acting Director  
Phone: 651.297.4132 or toll-free: 800.657.3858  
E-mail: [Meredith.Udoibok@state.mn.us](mailto:Meredith.Udoibok@state.mn.us)  
Website: [www.deed.state.mn.us/bizdev/InvFd/](http://www.deed.state.mn.us/bizdev/InvFd/)

### ***Minnesota Border Cities Enterprise Zone Program***

The Border-Cities Enterprise Zone Program provides business tax credits (property tax credits, debt financing credit on new construction, sales tax credit on construction equipment and materials, and new or existing employee credits) to businesses existing in, or relocating to, the Border-Cities Enterprise Zone cities of Breckenridge, Dilworth, East Grand Forks, Moorhead, and Ortonville.

All businesses are eligible except for recreation or entertainment concerns, fraternal or veteran's establishments, public utilities, financial institutions, and retail food or beverage service business operating under a franchise agreement that requires a location in the state. Businesses apply for tax credits through the local Enterprise Zone administrators.

For additional information, contact Meredith Udoibok at 651-296-5005 or toll-free at 800-657-3858. See also: Border-Cities Enterprise Zone Program - Annual Program Summary, primarily for legislators.

### ***Minnesota Job Skills Partnership (MJSP)***

The Jobs Skills Partnership program makes grants up to \$400,000 to accredited training institutions for customized, on-the-job training of incumbent employees. The company receiving the training provides a match to the grant, but the match can include in-kind contributions in the form of certain salaries, equipment, facilities and so on.

Contact:

Paul D. Moe, Director

Phone: 651-282-9814; Toll-free: 800-657-3858; TTY: 651-296-3900

E-mail: [Paul.Moe@state.mn.us](mailto:Paul.Moe@state.mn.us) Website: [www.deed.state.mn.us/mjsp/](http://www.deed.state.mn.us/mjsp/)

### ***Minnesota Indian Business Loan***

The Minnesota Indian Business Loan Program supports the development of Indian-owned and operated businesses to promote economic opportunities for Native American people throughout Minnesota. Eligible applicants are enrolled members of a federally recognized Minnesota-based band or tribe. Businesses receiving loans may operate anywhere in the state, but most are located on reservations. Eligible costs include start-up and expansion expenses (including those for machinery and equipment), inventory and receivables, working capital, new construction, renovation, and site acquisition. Refinancing of existing debt is not permitted.

Each band or tribe receives funds from the Indian Business Loan Fund proportional to its number of enrolled members. The Department of Employment and Economic Development (DEED) administers the program and services loans, approved by the appropriate tribal council, that can cover up to 75% of project cost. Owners must provide between 5% and 10% of the financing needed to undertake the project, depending on the requirements of the lending band or tribe.

DEED can accept applications, subject to the availability of funds, and forward them to the appropriate tribal council for further consideration, or applicants can send them directly to the council. Applications must include a business plan describing the business, its product or service, management, organization, market, operations, and financial projections. The tribal councils are:

- Bois Forte Reservation, 218-757-3263;
- Fond du Lac Reservation (Planning Division), 218-879-2642;
- Grand Portage Reservation, 218-475-2279;
- Leech Lake Band of Ojibwe, 218-335-8237;
- Lower Sioux Community, 507-697-6185;
- Mille Lacs Band of Ojibwe (Corp. Commission), 320-532-8817;
- Prairie Island Community, 651-385-2554;
- Red Lake Band of Chippewa, 218-679-3341;
- Shakopee-Mdewakanton Community, 952-445-8900;
- Upper Sioux Community, 320-564-3853;
- White Earth Reservation, 218-983-3285.

## **Bureau of Indian Affairs (BIA)**

### ***Bureau of Indian Affairs Loan Guaranty Program***

The federal BIA Loan Guaranty Program guarantees loans made to tribe members up to 90% or a maximum of \$500,000. For details, go to: [www.doi.gov/bureau-indian-affairs](http://www.doi.gov/bureau-indian-affairs)

Or contact:

Minneapolis Area Credit Office  
Bishop Henry Whipple Federal Building  
One Federal Drive, Room 550

Fort Snelling, MN 55111-4007  
612-713-4400, Ext. 1181

## Minnesota Regional Development Commissions (RDCs)

Regional development organizations are multi-county planning and development districts that promote cooperation among citizens, local government officials, and the private sector. Authorized by legislation in the late 'sixties and implemented in the early 'seventies, Minnesota's 9 Regional Development Commissions (RDCs) respond to economic development needs in rural communities.

Each RDC is governed by a policy board that includes elected officials, business leaders and citizen representatives. Some administer JOBZ zones in their regions, and all provide area residents with a portal to state and federal development programs.

The RDCs are good places for entrepreneurs to begin the complicated process of putting a project together. Professional staff provide technical assistance in business planning and finance. The RDCs are adept at packaging project financing from a host of diverse sources, an important skill considering that most economic development projects use a patchwork of programs to secure their necessary funding.

The Regional Development Commissions are:

**Region Five Development Commission**, serving Cass, Crow Wing, Morrison, Todd and Wadena Counties. Contact:

Region Five Development Commission  
611 Iowa Ave. N.E. · Staples, MN 56479  
Phone: 1-218-894-3233, Fax: 1-218-894-1328 Email: [info@regionfive.org](mailto:info@regionfive.org)

**Mid-Minnesota Development Commission**, serving Kandiyohi,

McLeod, Meeker and Renville Counties. Contact:

MMDC  
333 Sixth Street SW, Suite 2  
Willmar, MN 56201-5615  
Phone: 320-235-8504; Toll Free: 1-800-450-8608; Fax: 320-235-4329

**Southwest Regional Development Commission**, serving Lincoln, Lyon, Redwood, Pipestone, Murray, Cottonwood, Rock, Nobles and Jackson Counties. Contact:

Southwest Regional Development Commission  
2401 Broadway Ave, Suite 1  
Slayton, MN 56172  
Phone: 507-836-8547, Fax: 507-836-8866. Email: [srdc@swrdc.org](mailto:srdc@swrdc.org)

**The East Central Regional Development Commission**, serving Chisago, Isanti, Kanabec, Mille Lacs and Pine Counties. Contact:

East Central Regional Development Commission  
100 Park Street South  
Mora, MN 55051  
Phone: 320-679-4065; Fax: 320-679-4120; Bob Voss, Executive Director

**West Central Initiative**, serving Becker, Clay, Douglas, Grant, Otter Tail, Pope, Stevens, Traverse and Wilkin Counties. Contact:

West Central Initiative  
1000 Western Avenue  
Fergus Falls, MN 56537  
Phone: 218-739-2239; Toll-Free: 800-735-2239; Fax: 218-739-5381. [www.wcif.org](http://www.wcif.org)

**Headwaters Regional Development Commission**, serving Beltrami, Clearwater, Hubbard, Lake of the Woods, and Mahnommen Counties. Contact:

Headwaters Regional Development Commission  
403 Fourth Street NW, Suite 310 (P.O. Box 906)  
Bemidji, MN 56619-0906  
Phone: 218-444-4732; Fax: 218-444-4722; Email: [hrdc@hrdc.org](mailto:hrdc@hrdc.org)

**Upper Minnesota Valley Regional Development Commission**, serving Big Stone, Chippewa, Lac Qui Parle, Swift, and Yellow Medicine Counties. Contact:

Upper Minnesota Valley Regional Development Commission  
323 West Schlieman Ave.  
Appleton, MN 56208  
Phone: 320-289-1981; Fax: 320-289-1983; Email: [umvrdc@umvrdc.org](mailto:umvrdc@umvrdc.org)

**Arrowhead Regional Development Commission**, serving Aitkin, Carleton, Cook, Douglas (Wisconsin), Koochiching, Lake and St. Louis Counties. Contact:

Arrowhead Regional Development Commission  
221 West 1st Street  
Duluth, MN 55802  
Phone: 218-722-5545; Toll-Free: 800-232-0707; Fax: 218-529-7592(Fax)  
Email: [info@ardc.org](mailto:info@ardc.org)

**Region Nine Development Commission**, representing Blue Earth, Nicollet, Brown, Faribault, Le Sueur, Martin, Sibley, Waseca and Watonwan Counties. Contact:

Region Nine Development Commission  
410 E Jackson St. P.O. Box 3367  
Mankato, MN 56002, Suite 400  
Phone: 507-387-5643; Toll-Free: 800-450-5643; Fax (507)387-7105

The former **Region Ten**, encompassing Rice, Goodhue, Wabasha, Steele, Dodge, Olmsted, Winona, Freeborn, Mower, Fillmore and Houston Counties, is served by **Southeastern Minnesota Development Corporation (SEMDC)**, which contracts with cities and counties in the region. Contact:

Southeastern Minnesota Development Corporation  
111 West Jessie Street  
PO Box 684  
Rushford, MN 55971  
Phone: 507-864-7557; Fax: 507-864-2091; Email: [ron.zeigler@semdc.com](mailto:ron.zeigler@semdc.com)

## USDA Rural Development

Because biomass is mostly agricultural, USDA Rural Development programs can play a role in the development of biomass power. The agency offers programs both for economic development in general and for renewable energy development in particular. Following is a summary of USDA's general economic development programs. Energy-specific programs appear later in this report.

### *USDA Rural Development Business & Industry Loan Guarantees (B&I)*

**Loan guarantees** for businesses borrowing to save or create jobs, or to improve the local economy or environment in rural areas, are available for quality commercial loans of up to \$10 million. The Administrator in Washington may increase the limit to \$25 million for high-priority projects, and the cap for agricultural cooperatives that process their commodities in rural areas increases to \$40 million. There is no lower limit.

**Eligible areas** are rural, as defined at: <http://maps.ers.usda.gov/loanlookup/viewer.htm>. In Minnesota, rural areas generally include all except: Duluth and adjacent cities; La Crescent; Minneapolis/St. Paul and approximately two rings of suburbs; Moorhead; Rochester; and St. Cloud and adjacent cities.

**Eligible lenders** include most banks and commercial lenders, plus Farm Credit System institutions, CoBank, credit unions supervised by the NCUA, regulated insurance companies and the National Rural Utilities Cooperative Finance Corporation. Rural Utility Service borrowers and other non-traditional lenders may be considered for eligibility based upon their experience and expertise.

**Eligible borrowers** are individuals, cooperatives, corporations, partnerships, non-profit corporations (except charitable or fraternal ones), Indian tribes or public bodies.

**Guaranteed percentage** of the loan is negotiated with the agency. The maximum generally is 80% for loans up to \$5 million; 70% for loans between \$5 and \$10 million; and 60% for loans above \$10 million.

**Fees** charged by USDA Rural Development include a one-time, up-front fee of 2% of the amount guaranteed. A 0.25% annual fee will be applied to the guaranteed portion of the principal balance at fiscal year end.

**Rates and terms** are negotiated between lender and borrower. Rates may be fixed or variable. Maximum term for working capital is 7 years, for machinery and equipment, 15 years and for real estate, 30 years. Balloons are not allowed.

**Minimum equity** of 20% is required in a new business and 10% in an existing business. The borrower must provide regularly financial statements prepared in accordance with Generally Accepted Accounting Principles (GAAP).

**Collateral** sufficient to secure the entire loan, after discounting in accordance with the bank's normal policies, must be ensured by the lender, and personal and corporate guarantees are required of the borrower.

**Eligible purposes** include buildings, equipment, and permanent working capital. The purchase of stock in a start-up cooperative is eligible, provided that such purchase is required of all

members, that the members are family-sized farms, and that commodities produced by its members are to be processed by the cooperative.

*Further Information* about USDA business programs in general can be found at <http://www.rurdev.usda.gov/rbs/busp/bpdir.htm>. A copy of regulations (RD 4279-A and 4279-B for loan making and RD 4287-B for loan servicing) can be found on the Web at [http://rdinit.usda.gov/regs/regs\\_toc.html](http://rdinit.usda.gov/regs/regs_toc.html) in pdf, doc, and txt formats.

USDA eForms that can be completed on a computer using Adobe Acrobat are available at <http://forms.sc.egov.usda.gov/>. This site lists USDA forms in zip format: [www.usa-federal-forms.com/itaop-by-form/200.html](http://www.usa-federal-forms.com/itaop-by-form/200.html).

Write to the Business Programs, Suite 410, 375 Jackson Street, St. Paul, MN 55101, call David Gaffaney at 651-602-7814 (TDD at 651-602-7830), or email: [david.gaffaney@mn.usda.gov](mailto:david.gaffaney@mn.usda.gov). You also may contact Robyn Jensen at 651-602-7812 or [robyn.jensen@mn.usda.gov](mailto:robyn.jensen@mn.usda.gov).

### ***USDA Rural Development Intermediary Re-lending Program (IRP)***

**Program Purpose** is to fund soft costs, like working capital, interest, feasibility studies, and professional services, and hard costs, like land, building construction or repair and equipment, for innovative business and community development projects.

**Intermediaries** who borrow funds to relend to projects may be private nonprofit corporations, state or local governments, Indian tribes, or cooperatives. The ultimate recipients must be unable to obtain credit elsewhere.

**Eligible areas** are rural, with a population less than 25,000.

**Maximum funding** available to any one intermediary is \$15 million, but each specific loan to that intermediary is limited to \$750,000. The maximum loan to an ultimate recipient is the lesser of \$250,000 or 75% of the total project cost. However, no more than 25% of an IRP loan approved may be used for loans to ultimate recipients that exceed \$150,000. The interest rate to an intermediary is 1%. The maximum term is 30 years. Rates to ultimate recipients will be negotiated with the intermediary, with lower rates encouraged.

**Collateral** can be real or personal property or other pledged security of the intermediary or ultimate recipient.

**Program funding** in FY 2005 was \$15.8 million nationwide.

This program is administered by the B&I Division, Rural Development, Washington, D.C. 20250. However, applications are filed at the USDA Rural Development State Office, Suite 410, 375 Jackson St., St. Paul, MN 55101. Phone: 651-602-7812 or 651-602-7791.

**Further Information** about USDA business programs in general can be found at <http://www.rurdev.usda.gov/rbs/busp/bpdir.htm>.

## **Iron Range Resources**

Headquartered in Eveleth, Minn., Iron Range Resources (IRR) is a unique state agency designed to help strengthen and diversify the economy of northeastern Minnesota. Specifically, Iron Range Resources serves the interests of the Taconite Assistance Area (TAA), a geographical

region encompassing approximately 13,000 square miles that stretches from Crosby, Minn., across the state's Cuyuna, Mesabi and Vermilion iron ranges to the North Shore of Lake Superior.

The agency and its programs receive no money from the state general fund. The agency's funding comes from a percentage of production taxes assessed in lieu of property taxes on the area's iron mining companies. The production tax provides approximately half of the agency's budget. The other half comes from non-mining sources, such as revenue from its facilities, interest earned on its fund accounts, and interest generated from its loan programs.

The TAA includes much of Minnesota's forests and many of its forest industries. Papermills and OSB/waferboard plants are biomass energy plants to begin with because they generate heat, steam and power from wood waste. But they have even greater potential to leverage biomass resources to produce larger amounts of energy, as we note elsewhere in this paper. A likely ally in that endeavor is Minnesota Power (MP), the Duluth-based utility that serves most of northeastern Minnesota. MP already has forged waste-to-energy partnerships with papermills in Duluth and Grand Rapids.

The Taconite industry also is a player in biomass energy. U.S. Steel's Minntac plant in Mountain Iron burns sawdust fuel supplied by Hill Wood Products in Cook, MN. Like papermills, taconite processing plants have untapped potential. MP is planning a series of co-generation facilities to capture waste heat from sources like Minntac. Much of that heat derives originally from fossil fuels, but MP's plan at least conserves energy that otherwise would be wasted by venting it into the air.

Two IRR programs that spur economic development will play an important role in the energy future of northeastern Minnesota: the Business Development Financing Program and the Venture Capital Investment Program.

### ***Iron Range Resources Business Development Financing***

The purpose of the Iron Range Resources' Business Development Financing program is to increase, expand and diversify the area's economic base by assisting private investment in manufacturing or innovative technologies. It can finance up to 50% of eligible project costs for start-ups or expanding businesses. Preference will be given to:

- Manufacturing or assembly operations
- Projects which attract income and investment from outside of the TAA
- Technologically innovative projects

Except in equity stock purchases, Iron Range Resources requires personal guarantees from all company owners whose interest is 20% or more. Corporate guarantees will be required if a separate corporation owns 20% of the company seeking financial assistance from the agency.

IRR Business Development Financing takes three forms: Bank Participation, Direct Loans, and Loan Guarantees.

**Bank Participation Loans:** Iron Range Resources purchases a portion of a loan originating with a commercial bank or other regulated lender, sharing with the lender a first position lien on the financed assets and/or other assets as required. Generally, the participation by Iron Range Resources in any single project is limited to \$250,000.

The interest rate on the agency's purchased participation will be set as low as 3 percentage points beneath credit obligations of the United States Government with a comparable term, but

not less than 1%. The interest rate is set at the time the participation loan is approved by Iron Range Resources. The interest rate on the bank portion of the loan is negotiated between the business and the bank.

**Direct Loans:** Iron Range Resources can make loans directly to the eligible business. Collateral is negotiable, but typically it includes a first lien on financed assets and/or other assets. The interest rate will be set at one percentage point below U.S. Government obligations with a comparable term, but not less than 3%. The interest rate is set at the time the loan is approved by Iron Range Resources.

**Loan Guaranties:** Iron Range Resources will consider making a limited guarantee on a commercial loan to an eligible business. Terms and conditions of the guarantee are negotiated between the lender and the agency.

**Allowable Use of Proceeds:**

- Land and Building Acquisition
- Building Renovation
- Land Improvements
- Machinery/Equipment Purchase
- New Building Construction
- Inventory Purchase

If a project involves construction, the agency will participate only in take-out financing. Construction lending must be financed by another lender. Program financing cannot be used for debt refinancing or acquisition of an existing business.

The approval process begins with review of the pre-application by the agency's Development Strategies Division. If the pre-application meets guidelines for eligibility, the agency sends a full application to the applicant.

For more information, contact Development Strategies Division at Iron Range Resources. Phone: 218-744-7400; Toll-free: 1-877-829-3936;

Email: [DevelopmentStrategies@IronRangeResources.org](mailto:DevelopmentStrategies@IronRangeResources.org).

### ***Iron Range Resources Venture Capital Investment Program***

IRR is unusual among public economic development agencies in offering venture capital as well as debt financing. It seeks to invest its venture funds in technologically innovative firms located in its region.

Technology-based businesses may qualify for equity investments including, but not limited to:

- common stock
- preferred stock
- convertible debentures

The agency investment is at par with other private and/or public investors. The agency traditionally partners with a lead investor when considering such investments.

Businesses that seek Venture Capital Investment must have a technology component, demonstrate a commitment to the region by planning to locate a portion of its business within

the boundaries of the Taconite Assistance Area, and employ residents of the area. Iron Range Resources may require that stock options or warrants be tendered to the agency. Generally, the agency makes passive investments, but it sometimes requires a seat on the Board of Directors. The agency's seeks to exit the investment in 5-10 years.

Applications will be evaluated on:

- Management character and capability
- Economic viability of business
- Potential impact to area
- Marketability of product(s)
- Existing or potential competition
- Exit strategy

Contact Development Strategies Division at Iron Range Resources for more information. Phone: 218-744-7400; Toll-free: 1-877-829-3936;

E-mail: [DevelopmentStrategies@IronRangeResources.org](mailto:DevelopmentStrategies@IronRangeResources.org)

## New Markets Tax Credits

The New Markets Tax Credit (NMTC) program was enacted in December 2000 as part of the bipartisan Community Renewal Tax Relief Act. The purpose of the NMTC is to spur private investment in low-income urban and rural communities. The program is based on the idea that there are viable business opportunities in low-income communities and that a federal tax credit would provide attractive incentive to increase the flow of investment capital to such areas. Between 2002 and 2007, the NMTC will provide for up to \$15 billion in investments in low-income communities. The Community Development Financial Institutions (CDFI) Fund of the U.S. Treasury Department administers the NMTC program.

**What is a Community Development Entity (CDE) and how are CDEs certified?** The investment vehicle for the NMTC is a Community Development Entity (CDE). An organization must be certified by the CDFI Fund as a CDE to be eligible for NMTCs. Two important considerations for certification are that the organization must have a track record and demonstrate accountability to the community. After receiving certification, a CDE may then apply for credits through an annual competition conducted by the CDFI Fund. CDEs successful in receiving an allocation must have a strong business plan, good management, proven track record of working with investors and proposed projects that will have a substantial impact in low-income communities. In March 2003, the CDFI Fund made its first allocation of \$2.5 billion in NMTCs to a total of 66 CDEs. Over 300 Community Development Entities (CDEs) applied in the first round, requesting \$26 billion in credits.

**How does a CDE market the credit to investors?** Once an allocation has been awarded, a CDE must then seek private investment in exchange for the credit. The CDE has five years to place the credits, after which time the credits can be recaptured and transferred to another CDE. Corporate and individual taxpayers may receive a federal tax credit of 39% over seven years in return for their equity investment in a CDE. With the proceeds from these equity investments, CDEs must provide investments of equity, loans, lines of credit and technical assistance to qualified businesses. CDEs have one year to place the funds in qualified investments. In general, if *substantially all* (i.e. 85%) of the proceeds from the credit are not placed in qualified investments, the CDE would be out of compliance. At that point, recapture penalties would be applied to the investor.

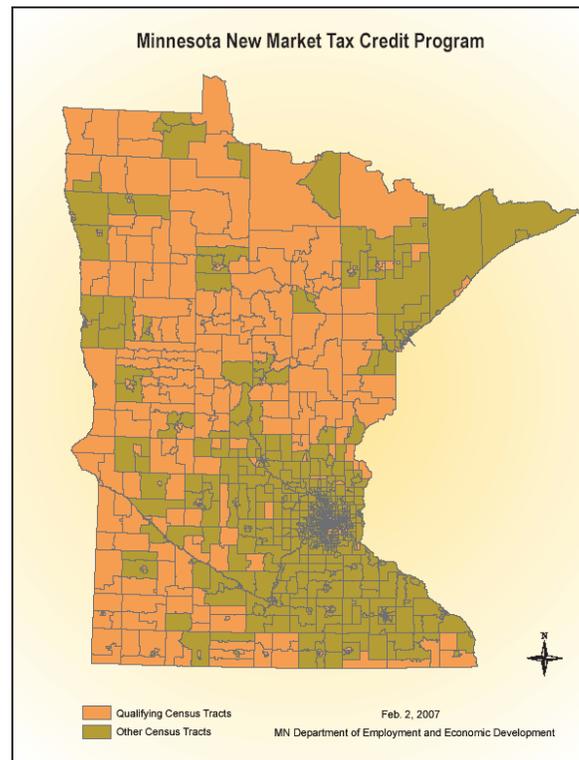
An equity investment qualifies for the tax credit if:

1. such credit is acquired by the investor at its original issue solely in exchange for cash;
2. *substantially all* of such cash is used by the CDE to make a *qualified low-income community investment*; and
3. the investment is designated by the CDE as a *qualified equity investment* which may also include the purchase of a qualified equity investment from a prior holder.

**What is a Qualified Low-income Community Investment?** Qualified low-income community investments may include loans, lines of credit, debt, direct equity investments, purchase of certain loans made by other CDEs, related services to other businesses, and counseling to other CDEs.

Substantially all of the investment must be used, meaning 85% of the cash received from the taxpayer in return for the tax credit must be directly traceable to a qualified low-income community investment, or 85% of the aggregate gross assets of the CDE must be deployed in qualified activities.

**What areas are eligible for the tax credit?** Areas eligible for the tax credit are low-income communities defined as a census tract with a poverty rate of at least 20% or with median income of up to 80% of area median or statewide median, whichever is greater; or for non-metro census tracts 80% of statewide median.



**Figure VII-2: Minnesota New Market Tax Credit Map**

The NMTC may also be used in target areas. A target area is a community within a census tract that does not meet the poverty or median income standard. The target area provision allows

certain communities located in ineligible census tracts to participate in the program. Such communities must have pre-existing boundaries such as established neighborhoods, or political or geographic boundaries; meet the poverty rate or median income standard; and have a demonstrated lack of investment capital.

**What businesses qualify for investments?** Businesses eligible to receive qualified low-income investments are those corporations or partnerships (including sole proprietorships or unincorporated trades or businesses) that are active and located in low-income communities. The business must derive at least half its gross income from activity (i.e. sales, manufacturing) in the eligible area. In addition, a substantial portion of its tangible property as well as services performed by employees of the business must be in an eligible community. CDEs may also provide investments to qualified active low-income businesses that are owned in whole or in part by the CDE.

**Are there any other investment limitations?** Financing of low-income rental housing is not allowed under the NMTC, and the NMTC may not be combined with other federal tax subsidies, including the Low-income Housing Tax Credit. Rental property that derives 80% or more of its income from residential tenants is not eligible. However, a mixed-use development, where less than 80% of the property's gross income is rental income from dwelling units is allowed under NMTC.

**Conclusion.** The broad distribution of NMTCs from the first round of allocations allows for any community in America—urban or rural—to take advantage of this unique opportunity to build a stronger and more diverse economy. Of the 66 CDEs receiving allocations, 16 target a specific city or county, six target more than one city or county, 17 will conduct statewide programs, and 27 will work in more than one state. Of those 27, 15 are nationwide. Now that the opportunity has been made available to previously undercapitalized communities, the challenge is to make it work. For more information, contact:

Lynne Rudolph  
Community Reinvestment Fund  
801 Nicollet Mall, Suite 1800W  
Minneapolis, MN 55402  
Phone: 612-338-3050  
e-mail: [lynne@crfusa](mailto:lynne@crfusa)  
Website: [www.crfusa.com](http://www.crfusa.com)

## U.S. Small Business Administration

### *SBA 7a Term Loan Guaranty Program*

The U.S. Small Business Administration's 7a program provides loan guarantees to approved banks and some other approved lenders. In the event of default by the borrowing Small Business Concern (SBC), the SBA is willing to reimburse up to 85% of the loss that the lender would otherwise sustain. Consequently, lenders may be willing to accept a greater credit risk and grant more favorable terms than they might otherwise. SBA also has a revolving line of credit loan guaranty program but very few banks are willing to participate. SBCs that are poor credit risks or fail to clearly articulate their ability to repay the loan will probably be rejected.

**Loan Amount.** \$100,000 to \$2 million. Although the SBA encourages lenders to make loans as low as \$10,000, the paperwork is too extensive and the bank's set up costs too high to make small loans cost effective. However, smaller banks are often motivated to consider lower loan amounts conventionally and through SBA for existing customers with creditworthy proposals. Some large banks consider making smaller Express Loans to existing businesses with a strong history of cash flow. Two banks make Community Express Loans to under-served borrowers in the \$5,000 to \$50,000 range and may accept tainted credit histories and no collateral.

**Suitable Borrowers.** For-profit SBCs with good credit (business and owners) and a history of sufficient cash flow. Some small community banks make loans to start-up SBCs and require more cash assets, collateral and experienced ownership. SBA defines the maximum size of the business by industry and is based upon either gross revenues or number of employees. Most SBCs qualify. A few industry types are excluded from SBA programs.

**Purpose of the Loan.** To expand, acquire or start a small business. Weaker proposals normally require substantial collateral, such as real estate while stronger proposals are sometimes accepted with less substantial collateral, such as fixtures and equipment.

**Loan to Collateral Value or Cost.** Up to 90% of cost or value is possible for well-established SBCs with quality collateral. 70-80% more typical for most start-ups. Lenders have other critical ratios related to cash flow, liquidity and assets that limit the loan amount available. Credit requirements, collateral prerequisites, cash flow minimums and loan amounts vary among SBA approved lenders. Most have requirements that are more severe than the minimum acceptable to SBA. Be sure to understand what your lender requires before you make application. Please go to [www.sba.gov/financing/index.html](http://www.sba.gov/financing/index.html) for details on SBA's financing programs.

### ***SBA 504 Program***

The U.S. Small Business Administration's 504 program is intended to create jobs based upon a formula that has been modified several times over the years. Particular preference is given to rural, economically disadvantaged areas and minority and female applicants for which SBA may waive the job creation requirement. The loan proceeds must be used to finance long-term assets such as real estate and fixtures which makes the program ideal for construction, for expansion of manufacturing facilities and other job intensive structures.

**Loan Amount.** Typically \$250,000 and up. Because of the complicated processing, lower loan amounts are often relegated to other loan programs and higher amounts may be too risky for most lenders. 504 loans are processed by SBA-licensed Certified Development Corporations (CDC). The CDC creates a SBA guaranteed subordinated debenture (similar to a 2nd mortgage). The debenture, up to \$1.5 million (\$4 million for manufacturing) is piggy-backed with a conventional first mortgage of any amount. It's usually provided by a local bank. The borrowing Small Business Concern (SBC) makes one payment to the CDC which is then proportionately paid to the bank and to the trustee for the debenture holder.

**Interest rate.** The debenture rate is fixed at closing at a rate close to treasury securities of like term. Banks may charge a fixed or floating market rate for their conventional portion along with points and fees. The result is a blended rate to the SBC. The CDC also charges fees.

**Term.** The SBA portion is usually 20 years and the conventional portion is usually 10 years.

**Suitable borrowers.** For-profit SBCs with a history of success in the same industry for which the funds are to be used. There are some company size and industry type exclusions.

**Loan to collateral value or cost.** Up to 90% of the cost for existing SBCs, 85% for start-ups. A classic percentage approved by SBA is where the bank's conventional loan is 50%, the debenture is 40% and the SBC provides 10% or more. An example financing of a \$1,875,000 plant expansion might look like this:

- \$750,000 -- SBA Subordinated debenture @ 6% fixed for 20 years.
- \$937,500 -- Bank conventional loan @ 8%, 10 years adjustable every 3 years.
- \$1,687,500 -- Total loan @ blended rate and term.
- \$187,500 -- Minimum cash requirement from SBC
- \$1,875,000 -- Total plant expansion

The 504 loan has numerous fees, requirements and restrictions. Begin by locating the CDC covering your area to discuss the specific proposal. See [www.sba.gov/financing/sbaloan/cdc504.html](http://www.sba.gov/financing/sbaloan/cdc504.html) for details

## Energy-Specific Incentive Programs

As noted earlier, many energy incentives promote conservation and efficiency rather than production. And some that do promote production focus on a broad variety of small technologies of farm, household or small business scale, not utility scale. The following list of programs concentrates on those particularly relevant to biomass plants or cogeneration projects.

For a complete summary of federal and state energy programs, go to: <http://www.dsireusa.org>

### *The Federal Renewable Electricity Production Tax Credit (REPC)*

Although cogeneration long has been, and probably will continue to be, the predominant source of renewable biomass energy in the nation, it so far has gotten short shrift from government programs, perhaps on the theory that cogeneration is its own reward. An example noted elsewhere in this paper, the U.S. pulp and paper industry, has for more than a century used waste wood to generate thousands of megawatts of electricity for internal use -- not because of mandates or incentives, but because cogeneration saves money.

As a result of those intrinsic economic benefits, policy makers haven't seen fit to create incentives for co-generation comparable to those for dedicated biomass power. "Closed-loop" biomass energy from dedicated energy crops rather than residues has received an annual federal tax credit of 1.9 cents per kWh since 1992. But a credit for "open-loop" biomass (i.e., manufacturing residues, agricultural waste, landfill gas and municipal solid waste) didn't appear until 2004 in the American Jobs Creation Act (H.R. 4520). It gave a reduced credit of just 1 cent to open-loop biomass -- but added the full 1.9 cent credit to refined coal.

For the IRS form on the credit, go to: ([www.irs.gov/pub/irs-pdf/f8835.pdf](http://www.irs.gov/pub/irs-pdf/f8835.pdf).)

The REPC has been extended, expanded or modified through a series of seven federal statutes beginning with the Energy Policy Act of 1992. For a full history, go to: [http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive\\_Code=US13F&State=federal&currentpageid=1&ee=0&re=1](http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US13F&State=federal&currentpageid=1&ee=0&re=1)

## ***The Federal Renewable Energy Production Incentive (REPI)***

The REPI program, which originated in the same Energy Policy Act of 1992 as the REPC outlined above, differs in that it offers not tax deductions to for-profit companies but cash payments to non-profit organizations which, having no profits, have no use for deductions. In 1993, the cash payment was 1.5 cents/kWh, but it is indexed to increase with inflation. Since REPI is the non-profit's alternative to the for-profit REPC, only new facilities owned by state and local governments like municipal utilities, or by not-for-profit electric co-operatives that began processing renewables between October 1, 1993, and September 30, 2003, are eligible. In 2005, Minnesota utilities received a total of \$316,847 from the program.

Like the REPC, the REPI program shows a preference for closed-loop biomass. It assigns renewable projects to one or the other of two tiers. Tier One includes solar, wind, geothermal, and closed-loop biomass projects. Tier Two includes open-loop biomass projects such as landfill gas, digester gas, and agricultural and manufacturing wastes, and co-firing with other fuels. If appropriations fall short of making 100% of payments to all projects, Tier One projects receive their entire payments first; Tier Two projects divide what's left.

General information on REPI is available at: [http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive\\_Code=US33F&State=federal&currentpageid=1&ee=1&re=1](http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US33F&State=federal&currentpageid=1&ee=1&re=1)

While the private sector's REPC tax deduction program is managed by the IRS, the U.S. Department of Energy administers the non-profits' REPI program. DOE's web page REPI is: <http://www.eere.energy.gov/wip/rep.html>

Two DOE information officers are assigned to respond to inquiries about the program. The one to ask about policy issues and the availability of appropriations is: [dan.beckley@hq.doe.gov](mailto:dan.beckley@hq.doe.gov)

Implementation questions, like facility qualifications, applications and payments, go to: [christine.carter@go.doe.gov](mailto:christine.carter@go.doe.gov)

For general federal information on renewable energy go to: <http://www.eere.energy.gov>

## ***Minnesota Renewable Energy Production Incentive***

As its title indicates, this program, dating from 1997, mirrors the federal REPI program in offering cash payments, in this case 1 to 1.5 cents/kWh, to certain types of renewable energy producers over a ten year term. But it differs in that it offers those incentives not only to non-profits but also to commercial companies, residences and tribal councils. It differs further in specifying a narrower selection of eligible project types: wind, hydro and anaerobic digestion. The wind program was closed to new applicants as of January, 2005.

The program was developed for small-scale projects: wind generators below 2 MW total, and on-farm anaerobic digesters.

Further information is available at:

[http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive\\_Code=MN06F&state=MN&CurrentPageID=1&RE=1&EE=1](http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=MN06F&state=MN&CurrentPageID=1&RE=1&EE=1)

The Minnesota Department of Commerce website has a chart with useful thumbnail descriptions of all federal and state renewable energy and energy efficiency incentives at:

<http://www.state.mn.us/portal/mn/jsp/content.do?id=-536881350&subchannel=-536881511&contentid=536885915&contenttype=EDITORIAL&programid=536885394&sp2=y&sc3=null&sc2=null&agency=Commerce>

The Minnesota Department of Commerce Energy Info Center is a good source of current information on energy development incentives in general. Go to:

<http://www.state.mn.us/portal/mn/jsp/content.do?subchannel=-536881511&id=-536881350&agency=Commerce> or call Linda Limback at 651-615-1883.

### ***USDA Renewable Energy Systems and Energy Efficiency Improvements***

Loan guarantees and grants may be available to help agricultural producers and rural small businesses (fewer than 500 employees and less than \$20 million in annual sales) purchase renewable energy systems and improve energy efficiency. "Rural" is defined as an area with less than 50,000 population.

**Renewable energy** means energy derived from wind, solar, biomass, or a geothermal source; or hydrogen derived from biomass or water using one of those energy sources. The program does not include hydro-power. Biomass includes agricultural crops, trees grown for energy production, wood waste and wood residues, plants (including aquatic plants and grasses), residues, fibers, animal and other wastes, fats, oils, and greases, but not paper commonly recycled or unsegregated solid waste.

**The grant** cannot exceed 25% of the cost of the project cost. To be eligible, the applicant must demonstrate financial need. Grants for renewable energy systems range from \$2,500 to \$500,000 and those for energy efficiency improvements arrange from \$2,500 to \$250,000. Applicants must be citizens of the U.S. or legally admitted for permanent residence.

**Total funds available** nationwide for grants each year are approximately \$11.5 million. \$175 million in loan guarantees are available each year. Combinations of guaranteed loans and grants cannot exceed 50% of the eligible project costs. Deadline to apply for grants is usually May. Loan guarantee applications are received all year.

*For further information* call Lisa Noty at 507-373-7960, extension 120, or email [lisa.noty@mn.usda.gov](mailto:lisa.noty@mn.usda.gov). Or go to [www.rurdev.usda.gov/rbs/farbill/06fbnofa.htm](http://www.rurdev.usda.gov/rbs/farbill/06fbnofa.htm).

### **USDA Rural Development Value-added Producer Grant (VAPG)**

The VAPG program assists development of value-added products or renewable energy from agricultural production, focusing on projects at farm scale.

**Grants** up to \$100,000 are available for planning and feasibility studies and up to \$300,000 for working capital.

**Eligible ventures** are those that develop renewable energy from agricultural production and/or use innovative technologies to develop value-added products. All ventures must be economically viable and sustainable. Of the four categories of value-added under this program, two are energy-related: (1) adding value through changing the physical state or form of the products (e.g. processing corn into ethanol); and (2) using agricultural products to produce renewable energy on a farm or ranch.

**Terms.** The grant will not exceed 50% of eligible project costs. Grant recipients must provide one-to-one matching funds. Projects must be completed within one year. Smaller grant requests receive priority points.

**Applications** are received at the USDA Rural Development State Office in St. Paul following the announcement in the Federal Register inviting applications. Selections will be made annually in the USDA Rural Development National Office for fiscal years 2002-2007.

**Further Information** is available from Robyn (651-602-7812), Butch (218-681-2843, ext. 114), or Lisa (507-373-7960, ext.120).

## Xcel Energy Renewable Development Fund Grants

The Renewable Development Fund (RDF) was created in 1999 to provide grants, through a Request for Proposals process, for research and for new projects to produce renewable energy including wind, solar, hydroelectric and fuel cells as well as biomass. The program's first round of grants in 2001 awarded a total of \$16 million to 19 projects. For the second round in 2005, the Minnesota Public Utilities Commission approved 29 projects totaling nearly \$37 million.

Funding is roughly divided equally between R&D and projects that directly result in the production of renewable energy. In May of 2007, the third round of funding was announced, with up to \$23 million available to invest in new ways to produce electricity from renewable resources. The Fund is a member of CESA, the Clean Energy States Alliance.

This paper was funded through the RDF.

## Tribal Energy Program

Tribes may take advantage of a number of the programs listed above. But in addition, the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy has developed a program aimed specifically at tribes, the Tribal Energy Program. It offers financial and technical assistance for feasibility studies and shares the cost of installing renewable energy systems on tribal lands.

For a full account of the program's many aspects, go to:

[www.eere.energy.gov/tribalenergy/](http://www.eere.energy.gov/tribalenergy/)

Or contact the director of the program:

Thomas Sacco  
Weatherization & Intergovernmental Program  
U.S. Department of Energy, EE-2K  
Forrestal Building, MS 5G-045  
1000 Independence Avenue SW  
Washington, DC 20585  
Telephone: (202) 586-0759  
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Email: [Thomas.Sacco@ee.doe.gov](mailto:Thomas.Sacco@ee.doe.gov)

## NEW POLICY INITIATIVES

### Community-Based Energy Development (C-BED)

In 2005 the Minnesota Legislature passed legislation requiring Minnesota's utilities to offer a community-based energy development (C-BED) tariff for wind power generators. In the 2007 legislative session the tariffs were extended to all renewable energy projects, including biomass. The original goal of the tariffs was "to optimize local, regional, and state benefits from wind energy development, and to facilitate development of community-based wind energy projects throughout Minnesota". This is accomplished through a specific rate structure made available to locally owned renewable energy projects that would have difficulty securing financing under traditional rate structures. A C-BED tariff offers a higher rate during the first 10 years of the contract than during the final ten years, but is structured in such a way that the present value of the project for the utility is equal to that of a typical rate agreement. This greatly improves the viability of the project for project developers by increasing revenues during debt repayment, but does not detract from the net present value of the project from the utility's perspective.

The C-BED tariffs are available to projects for which at least 51% of gross revenues from the power purchase agreement will flow to qualifying owners. Qualifying owners include Minnesota residents, limited liability companies composed of Minnesota residents, Minnesota cooperatives and non-profits, or Minnesota political subdivisions and local governments. There are additional limits to individual ownership of C-BED projects. Minnesota's public utilities must submit for approval new C-BED tariffs to the Public Utilities Commission by December 1, 2007. Other utilities must submit new C-BED tariffs within 90 days of the Commission's approval of a public utility tariff.

More information concerning C-BED tariffs can be found at:

<http://www.revisor.leg.state.mn.us/bin/bldbill.php?bill=S0145.2.html&session=ls85>

<http://www.c-bed.org/index.html>

[http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive\\_Code=MN15R&state=MN&CurrentPageID=1&RE=1&EE=1](http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=MN15R&state=MN&CurrentPageID=1&RE=1&EE=1)

### Minnesota's Renewable Energy Standard

Minnesota enacted a Renewable Energy Standard in 2007 that is among the most aggressive in the nation. Under the legislation, renewable electricity must account for 30% of Xcel Energy's total retail electricity sales by 2020, and 25% of the retail electricity sales of other utilities by 2025. Eligible technologies under the standard include solar, wind, hydroelectric facilities less than 100 megawatts (MW), hydrogen and biomass, which include landfill gas, anaerobic digestion and municipal solid waste as well as plants and trees. The legislation also orders the Public Utilities Commission to establish a program for tradable Renewable Energy Credits (RECs) by January 1, 2008. This will enable utilities which have not generated, or have not contracted for, sufficient renewable energy to purchase RECs to meet their requirements.

While wind is the renewable energy utilities will use most to meet the RES, biomass power should get a boost from the legislation as well. Biomass's ability to provide baseload power may be particularly attractive to utilities because the standard is based on energy sales rather than capacity. (Because wind blows only part of the time, turbine capacities are much greater than actual production.) But biomass power costs will have to be reasonably competitive because

escape clauses in the legislation relax the standard if meeting it will be prohibitively expensive. This gives utilities leverage to keep the cost of renewable power down.

Information regarding the bill is available at:

<http://ros.leg.mn/bin/getpub.php?type=law&year=2007&sn=0&num=3>

[http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive\\_Code=MN14R&state=MN&CurrentPageID=1&RE=1&EE=1](http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=MN14R&state=MN&CurrentPageID=1&RE=1&EE=1).

## Carbon Emissions Policy

Minnesota's Next Generation Energy Act of 2007 set out specific goals to reduce greenhouse gas emissions in Minnesota and established a framework to guide the development of policies to achieve those goals. The act says "it is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 15% below 2005 levels by 2015, to a level at least 30% below 2005 levels by 2025, and to a level at least 80% below 2005 levels by 2050. The levels shall be reviewed based on the climate change action plan study." The law directs state agencies to submit to legislature by February 1, 2008 a climate change action plan involving a cap and trade system for greenhouse gas emissions and a state emissions registry. The plan also must develop a statewide or regional inventory of renewable energy resources.

The legislation induces further legislation establishing an enforceable legal framework for lowering greenhouse gas emissions over time. It prohibits the construction of any new large energy facilities that would increase the state's greenhouse gas emissions prior to the enactment of such legislation except for those that already have initiated regulatory proceedings in Minnesota or nearby states.

This law establishes a very clear intent to begin reducing Minnesota's greenhouse gas emissions with specific reference to the state's electrical utilities. In such an environment one would expect the state's utilities to show increased interest in creating power from renewable resources with small carbon footprints.

More information regarding Minnesota's Next Generation Energy Act of 2007 can be found at <http://www.revisor.leg.state.mn.us/bin/bldbill.php?bill=S0145.2.html&session=ls85>.

## Other State Policies

The 2007 legislature enacted a number of policies of interest to bio-power developers which included appropriations for bio-energy projects.

### *NextGen Energy Board*

The Next Generation Energy Act Of 2007, a \$170 million omnibus energy bill signed in May of 2007, will spur research and recommendations on how the state can most efficiently achieve energy independence. Major items include funds and support for the state's renewable resources goal of 25% by 2025; renewable energy research; biomass research and renewable forest resources feasibility studies; plug-in hybrid electric vehicles demonstrations; increasing the number of E85 pumps; increasing the number of on-farm biogas recovery facilities or methane digesters; and increasing the number of certified Energy Star commercial buildings in the state.

The Energy Act also established the NextGen Board charged with addressing the future of biofuels and the development of grant programs to assist renewable energy facilities throughout Minnesota.

The NextGen Board was given advisory status to the Department of Agriculture in the allocation of grant money as well as policy authority to support bioenergy projects. Its role is described below.

The NextGen Energy Board will examine the future of fuels, such as synthetic gases, biobutanol, hydrogen, methanol, biodiesel, and ethanol within Minnesota; develop equity grant programs to assist locally owned facilities; study the proper role of the state in creating financing and investing and providing incentives; evaluate how state and federal programs, including the Farm Bill, can best work together and leverage resources; work with other entities and committee to develop a clean energy program; and report to the legislature with recommendations as to appropriations and results of past actions and projects ("Governor Pawlenty", 2007).

For more information see <http://www.mda.state.mn.us/renewable/nextgen/default.htm>

### ***Reinvest in Minnesota Clean Energy Program***

A clean energy working lands program will be established to acquire easements for land "based on its potential benefits for bioenergy crop production, water quality, soil health, reduction of chemical inputs, soil carbon storage, biodiversity, and wildlife habitat." Lands enrolled in this program may attract bio-power facilities to use various biomass fuels through a stepped incentive.

For more information see <http://ros.leg.mn/bin/getpub.php?type=law&year=2007&sn=0&num=57>.

### ***Cellulosic Biofuel Development***

Minnesota has established a goal to produce sufficient cellulosic biofuels to equal one quarter of the ethanol necessary to meet the state's ethanol content requirement for gasoline. Cellulosic biofuel facilities built to meet that goal might include biomass power generation.

For more information see <http://ros.leg.mn/bin/getpub.php?type=law&year=2007&sn=0&num=45>.

# CHAPTER VIII : ECONOMIC EVALUATIONS

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## BioPower Evaluation Tool

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Center for Energy and Environment

This tool is intended only to provide general guidance in estimating costs of various biomass feedstocks and technological strategies. The tool provides a comparative analysis of various biomass strategies and not necessarily an accurate estimate of actual final costs.

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Figure VIII-1: Start-Up Screen

## BIO-POWER EVALUATION TOOL (BIOPET)

This computer tool was developed as part of this project's overall effort to provide general guidance in estimating costs of various biomass feedstocks and technological strategies. It is meant to provide a means of comparing various biomass strategies; not cost estimates detailed enough to use for a specific project. It allows a relative comparison among varying strategies but not a firm pro forma for a particular one.

The tool allows the user to estimate the annual levelized cost of energy for a proposed power plant based on supply and cost estimates for a range of biomass fuels and power plant characteristics. Although we provide default values most characteristics; users can to assign their own values if they have more specific cost estimates or wish to gauge the effects of changing parameters on project performance. Factory default values are retained within the spreadsheet and always can be restored if necessary.

The Bio-Power Evaluation Tool consists of worksheets to estimate feedstock costs and supply, power plant characteristics and costs, and overall project economics. Users can save feedstock and power plant scenarios as they work and combine those scenarios to assess what combinations of feedstocks and power plants will result in the lowest cost of energy. The Evaluation tool also provides a sensitivity analysis for each final project evaluation so that the user can evaluate how sensitive the proposed project is to changes in various costs.

## Overall Structure

### *Fuel Delivery Path*

It is necessary to develop a full-cost approximation for the delivery of a fully-usable fuel to the power generation facility. This delivery path may take many forms and vary significantly across feedstocks and projects. The user is free to select which options will be included in the normal operation of the proposed project.

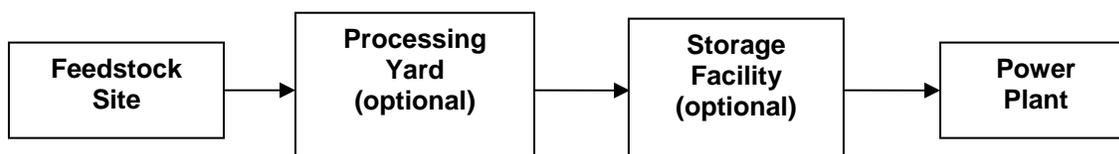


Figure VIII-2: Feedstock Delivery Path

The most complicated delivery path will include stops at all available stages. If storage will not take place at a dedicated storage facility, but will instead take place at the Feedstock Site, Processing Yard or Power Plant, the transport distances under the “Storage” menu should be set to zero. Similarly, if there is not a separate Processing Yard in the delivery path, the distances under “Ship to Processing Yard” should be set to zero.

### *Transportation Costs*

The user may define up to three different methods of transportation (road, rail, and barge) and the associated distances of each for each link in the feedstock delivery chain. The user may therefore set a delivery path for biomass fuels that includes transporting the feedstock X miles by truck, Y miles by train, and Z miles by barge.

A single default cost value is provided for each mode of transportation and each feedstock. If the user anticipates that transportation costs will be different for each link in the feedstock delivery chain, he or she may define different values for each link. This can be done by entering a new cost per ton/mile under the “Processing Yard”, “Storage” and/or “Power Plant” screens and then clicking on the “Save Settings” button. This will assign the new transportation costs to the relevant link in the supply chain. The user may also enter transportation costs in the “Inputs” worksheet accessed through the “View All Inputs” link on the “Feedstock Selection” screen.

Different transportation assumptions may be made depending upon the consistency of the fuel. The user may define the feedstock as a solid or liquid. This distinction was made assuming that transportation of a liquid would require significantly different equipment for loading and unloading needs.

The cost impact of omitting a stage of the delivery path can be observed by use of the drop-down “Yes” and “No” menus for the Processing Yard and Storage Facility. If the value is set to “No,” the stage will be ignored in calculating the delivered cost per MMBTU. It should be noted, however, that *all* costs associated with the stage will be ignored; if the feedstock must be processed before being used, these costs will need to be added to a different stage in order to preserve the accuracy of the calculation.

## Processing Yard

Some biomass feedstocks may be shipped to a processing yard prior to shipment to a storage facility or power plant. There are two general models for processing yards. The first would be a local processing yard to which materials are hauled over a short distance and from which they are hauled to a power plant or storage facility. An example of this would be a wood, or "concentration," yard that receives logging residues from nearby, chips them and loads them for transport. The other model for a processing yard is one relatively close and accessible to the power plant (and perhaps under its management), but not incorporated in to it. Sometimes these processing yards serve plants that lack room on site for fuel processing or storage, as is the case with two power plants in northern Minnesota that share a single processing yard located midway between them. Such partnerships have the added advantage of capturing economies of scale.

## Storage Facility

Some biomass feedstocks will need to be stored at offsite storage facilities until they are needed by the power plant. This is especially the case for biomass like switchgrass or corn stover that are harvested during a narrow window of time but are drawn down over the course of a year. Fuel processing for storage may take place at the storage facility or somewhere else prior to delivery. Storage facilities can take many forms, from open fields with stacks of uncovered bales to large fully enclosed storage barns. To estimate storage costs one must estimate the capital and handling costs associated with each storage method as well as the expected dry matter loss associated with that method. Storing unprotected bales in the open requires no capital expenditure and very little handling; but the loss of dry matter from such a storage method can be quite significant.

## Power Plant

Biomass fuel ultimately must be shipped to the power plant. Once on site, the fuel may go into storage bins or proceed directly into the plant's fuel feeding system. Final processing steps often include screening and size reduction. Default costs for transport to the plant, processing and unloading are provided, or the user can enter more specific costs if they are available.

The evaluation tool is designed to allow the user to develop different "scenarios" that can be combined later to evaluate different options. There are three scenario types: Feedstock, Power Plant, and Project. The Project Scenario is comprised of a combination of the first two.

## ***Scenario Generation***

### Feedstock Scenario

The development of a feedstock scenario allows the user to build a feedstock development and delivery system ending with a cost per MMBTU for a fully-processed fuel at the power plant. You may make as many Feedstock Scenarios as you wish. All Feedstock Scenarios must be logged if they are to be used for future analysis.

### Power Plant Scenario

The development of a power plant scenario allows the user to define the characteristics of an operating power plant. This includes such things as power plant size, capital costs, operating

expenses, rate of return, inflation, etc. Once a scenario has been defined, it must be logged to be used for future analysis.

### Project Summary

Once a Feedstock Scenario and a Power Plant Scenario have been created and logged, it is possible to calculate the estimated cost of delivered energy. One may select a Power Plant Scenario and input different Feedstock Scenarios to evaluate the economic impacts of various options. One may also conduct sensitivity analysis on the Project Scenarios to understand the impacts of fluctuating inputs on the final energy cost. Project Scenarios can also be logged for future reference.

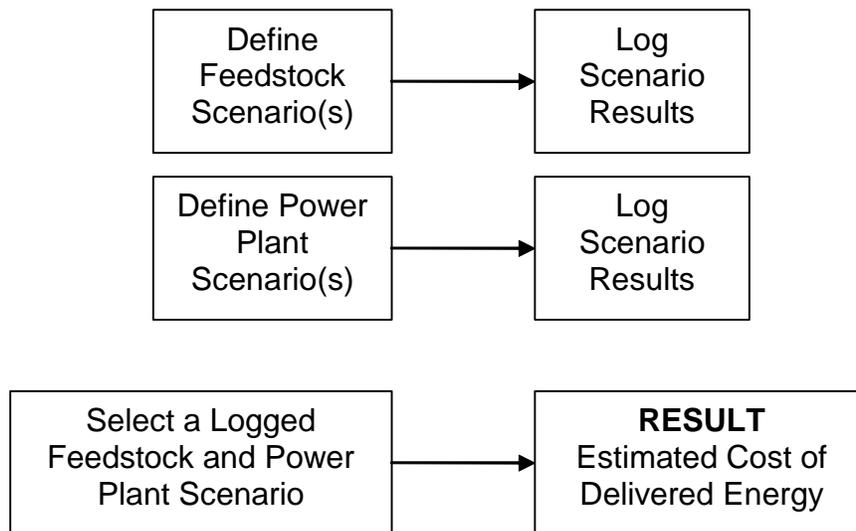


Figure VIII-3: Evaluation Methodology

## Algorithms

### *Basic Cost Calculations*

These are the cost calculations internal to BioPET that estimates project costs throughout the process. They are offered here to provide the user with enough information to understand the calculations and allow the user to manipulate the entries to satisfy individual project concerns. Please refer to the BioPET software manual in Appendix A for even more detail.

### Definitions

Energy Content (ENC) = BTU/dry pound

MCW = Moisture Content by Weight (%)

### Field

Field Costs ( $F_c$ ) = (Payment/Market Price) – (Avoided Disposal Costs) + (Processing Cost) + (Collection/Loading Cost)

## Processing Yard

Transportation to the Yard ( $Y_t$ ) = (Miles by Road) \* (Transportation Cost (\$/ton-mile) + (Miles by Rail) \* (Transportation Cost (\$/ton-mile) + (Miles by Barge) \* (Transportation Cost (\$/ton-mile)

Processing Yard Costs ( $Y_c$ ) = (Processing Cost) + (Collection/Loading Costs)

## Storage Facility

Transportation to Storage ( $S_t$ ) = (Miles by Road) \* (Transportation Cost (\$/ton-mile) + (Miles by Rail) \* (Transportation Cost (\$/ton-mile) + (Miles by Barge) \* (Transportation Cost (\$/ton-mile)

Storage Facility Costs ( $S_c$ ) = (Processing Cost) + (Collection/Loading Costs) + (Storage Costs) \* (Average Number of Months Stored)

## Power Plant

Transportation to Power Plant ( $P_t$ ) = (Miles by Road) \* (Transportation Cost (\$/ton-mile) + (Miles by Rail) \* (Transportation Cost (\$/ton-mile) + (Miles by Barge) \* (Transportation Cost (\$/ton-mile)

Power Plant Costs ( $P_c$ ) = (Processing Cost) + (Unloading Cost) + (Payment)

## Total

Total Cost ( $T_c$ ) (\$/wet ton) =  $F_c + Y_t + Y_c + S_t + S_c + P_t + P_c$

Energy Cost ( $E_c$ ) (\$/MMBTU)  $\frac{T_c \$ / ton * (\frac{1}{1 - MCW})}{(ENC Btu / lb * 2,000 lbs / ton)} * 1,000,000 Btu / MMBtu =$

## ***Utility Economic Evaluation***

The power plant economic analysis used the "Generic Biomass Power Plant Model" developed by the California Biomass Collaborative and available on their website (<http://biomass.ucdavis.edu/index.html>). In addition to the model, the California Biomass Collaborative (CBC, n.d.) details the economic variables and methodology as well as providing an example analysis.

## **Levelized Annual Costs (LACs)**

The Bio-power Evaluation Tool (BioPET) generates estimates of the levelized cost of energy (LCOE) for a number of bio-power facility types using a generic agricultural residue fuel and a generic woody residue fuel. An estimate of the LCOE for an anaerobic digester was estimated as well.

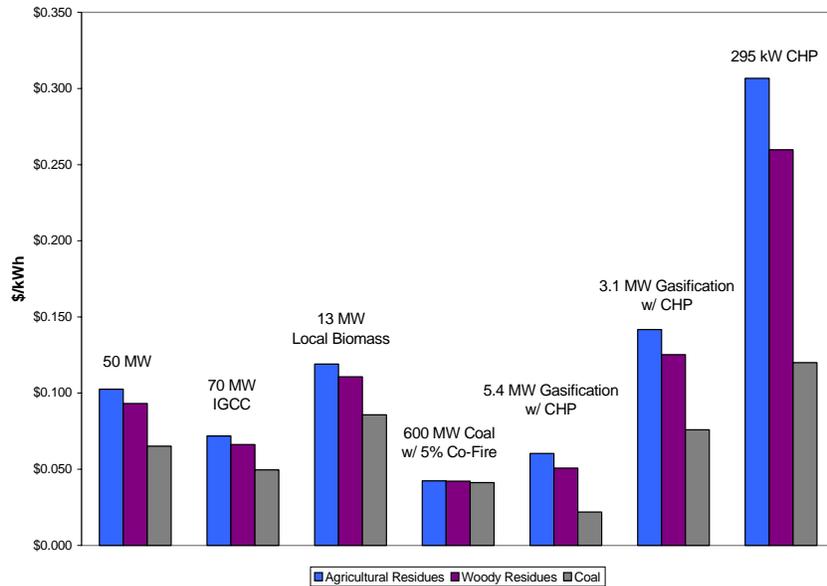


Figure VIII-4: Example LAC Runs

## Simple Sensitivity Analysis

The sensitivity analysis performed on each proposal evaluation illustrates the change in constant levelized cost of energy that one could expect from varying the rate of one of the included variables, while holding all other variables constant. The sensitivity analysis is presented in terms of the relative (%) change of each variable, as opposed to an absolute change in value.

### Sensitivity Analysis

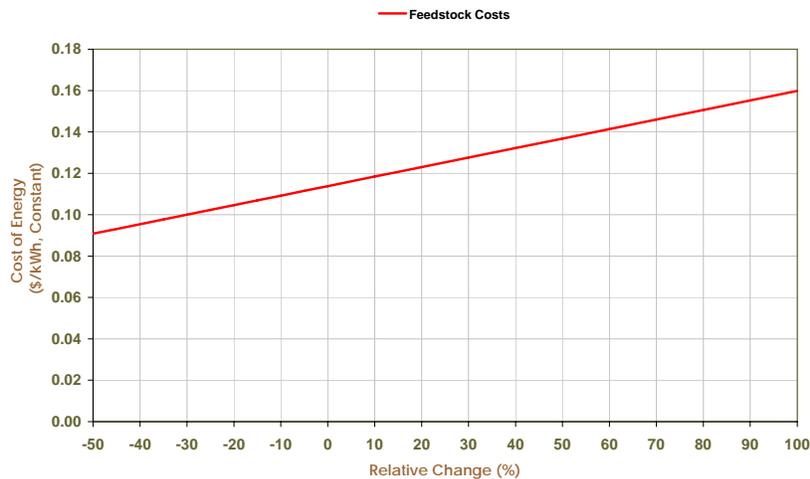


Figure VIII-5: BioPET Sensitivity Analysis Example

## MULTIPLE VARIABLE SENSITIVITY ANALYSIS (MONTE CARLO)

BioPet performs one type of sensitivity analysis, allowing the user to see how variations in a single selected parameter affect outcomes. We also used Monte Carlo techniques to analyze the effects of several variable assumptions jointly.

The single value assigned to each assumption/parameter may not always reflect the true condition of the system we are examining. We know all variables with imprecision. In some cases such as crop yields, the variability is due to stochastic events like climate. In other cases, such as local production participation rates, we simply are ignorant of the “true” value of the factor. But in every case, we can assign a probability density function which describes our prior expectation of each factor’s variability.

The key feature of the Monte Carlo analysis is repetition. Because we don’t know the single “true” value of certain factors, but only the distribution of the probability for that value (assigned by us), we can’t simply run the model once and then report the result. Instead, we run the model over and over, each time sampling from the parameter distributions, according to the stated form of the distribution. In a given run we might draw from the upper end of one parameter’s distribution and the mid-point of another’s. In the next run, the draw might be opposite. And so on, for hundreds or thousands of runs.

For each run, we record the outcomes of the model for that run’s parameter sample selections. Each new set of parameter values yields a different outcome. After hundreds or thousands of runs, we obtain a distribution of outcome estimates. This can be interpreted as the spread of possible outcomes given the stated distributions of the variable assumption. A wide range suggests that we should be very careful about too quickly adopting the single-value outcome of the initial parameters. Too, we can compare among scenarios to see if some have narrower outcome ranges than to others, or if some clearly “outperform” others despite a wide range of parameter uncertainty.

The Monte Carlo simulations were performed using feedstock and power plant templates generated with the BioPET software tool. Most of the variables were generated using the default values within BioPET. For those variables which would be varied within the Monte Carlo Simulation the mean value of the variable’s range was used as a default. Some of the Monte Carlo variables are market or processing costs which have considerable variability. In those cases the mean value is somewhat different than the default value due to fact that the default values were chosen to be representative of current prices as opposed to average long term prices.

These templates include all costs incurred to deliver fuel to the power plant. Any processing costs at the power plant are included in the operating costs of the plant. Four power plant templates were generated. The templates are derived from publicly available documents. Two of the templates are derived from engineering and financial studies of specific projects. The others are derived from more general documents that have contained information on power plant costs.

### Power Plant Assumptions

The source documents for each of the power plant templates use somewhat different financial and operating assumptions. For the purposes of the Monte Carlo simulations a number of uniform assumptions were utilized to provide a degree of standardization across power plants. A uniform mean capacity factor of 85% was utilized for each power plant template. All other

plant characteristics and plant expenses were derived from the source material. The documentation for each power plant template uses quite different financial assumptions. These were standardized across power plants, with the exception of the income escalation variable for the CHP plant, which was modified to account for the potential for rapidly increasing natural gas prices.

### ***50 MW wood- fired stoker boiler***

This template was generated using documentation relating to the Big Stone II coal power plant (Burns & McDonnell, 2005).

The template is meant to represent the costs for a wood-fired stoker boiler built as an additional generating unit at an existing coal fired plant. The expenses included in this template include fixed O&M costs, non-fuel variable O&M costs, and insurance. In addition to wood fuels this plant is assumed to be adaptable to corn stover and switchgrass.

### ***35 MW Biomass Co-Firing (Incremental Costs) and 600 MW Pulverized Coal Plant w/ 35 MW Biomass Co-Firing***

The co-firing cost estimates are derived from documents published by the Chariton Valley Biomass Project (Alliant Energy, et. al., 2002) and documents relating to a proposed pulverized coal plant in South Dakota (Burns and McDonnell, 2005), The Chariton Valley documents were used to create a template for a co-firing operation that could be added to a coal plant template to estimate the blended costs of a co-firing operation. The capital costs for the co-firing template include the costs of the fuel storage, handling and processing facilities needed for a co-firing operation. The operational costs include the additional labor, administrative and maintenance costs needed to operate a co-firing operation. The cost estimates for the coal plant are meant to be representative of the expected costs for a new 600 MW pulverized coal unit built adjacent to an existing coal plant. The expenses included in this template include fixed O&M costs, non-fuel variable O&M costs, and insurance. The 35 MW Co-firing template can be used to estimate the incremental costs of a co-firing operation. The blended template including the 35 MW co-firing template and 600 MW pulverized coal plant can be utilized to estimate the average cost of energy for a co-firing operation.

### ***Industrial CHP with Gasifier and 4 X 1.3 MW Gensets***

This template is based on an economic and technical feasibility study of a biomass gasification CHP system at a large malting facility (Trillium Planning and Development, 2002). A number of scenarios were examined for the study. The template is based on the most economic scenario examined in the study. It includes four Jenbacher Engine sets with a total net capacity of 5.4 MW. The natural gas savings from the thermal energy captured from the system are accounted for as "Other Income". The electrical efficiency represents the Net Electrical Efficiency based on the energy content of the biomass prior to gasification, not the electrical efficiency of the combustion of syngas by the turbine or genset. The operating costs included in this template include labor, maintenance and the cost of standby electrical service.

### ***135 kW Genset w/ Manure Digester***

This template is based on the Haubenschield Dairy Farm Digester near Princeton, MN (Kramer, 2004). The farm operates a plug-flow digester that powers a 135 kW engine generator set. Thermal energy recovered from the genset's cooling jacket is used to heat the barn. The electrical efficiency represents the system efficiency taking into account the efficiency of the

conversion of Volatile Organic Solids to biogas, and the electrical efficiency of the combustion of biogas by the genset. The values used to arrive at the efficiency are: 85% of total solids are VOCs, 35% of VOCs are converted to biogas, and the genset has a 40% electrical efficiency. These values are average values, however, and are known to vary significantly with the manure management practices, the digestion technology, and the generation technology employed. The other income included in the template includes fertilizer and pesticide savings resulting from manure digestion, as well as propane savings arising from heat recovered from the genset's jacket.

### ***Power Plants Summary***

Below is a summary of assumptions used.

**Table VIII-1: Power Plant Characteristics**

Scenario	Capital Cost (\$)	Plant Capacity (kW)	Capacity Factor (%)	Electrical Efficiency (%)
50 MW Biomass	\$150,000,000	50,000	85.0%	24.4%
Co-Firing (Incremental)	\$15,400,000	35,000	85.0%	36.4%
600 MW Coal w/ 5% Co-Fire	\$1,100,000,000	600,000	85.0%	36.4%
5.4 MW Gasification w/ CHP	\$15,300,000	5,392	85.0%	23.8%
135 kW w/ Manure Digester	\$424,000	135	85.0%	11.9%

**Table VIII-2: Power Plant Income (Other) and Expenses**

Scenario	Other Income (\$/year)	Total Expenses (\$/yr)
50 MW Biomass	\$0	\$2,179,487
Co-Firing (Incremental)	\$0	\$1,266,766
600 MW Coal w/ 5% Co-Fire	\$0	\$17,604,724
5.4 MW Gasification w/ CHP	\$3,547,606	\$894,308
135 kW w/ Manure Digester	\$74,000	\$31,374

**Table VIII-3: Power Plant Income and Taxes for All Scenarios**

Capacity Payment (\$/kW - yr)	Interest Rate on Debt Reserve (%)	Federal Tax Rate (%)	State Tax Rate (%)	Production Tax Credit (\$/kWh)
\$0.00	5.00%	34.00%	0.00%	\$0.0000

Table VIII-4: Power Plant Financial Assumptions for All Scenarios

Debt Ratio (%)	Interest Rate (Debt) (%)	Economic Life (years)	Rate of Return (%)	General Inflation (%)	Fuel Escalation (%)	Income Escalation (%)	Expense Escalation (%)
50.0%	7.5%	20	13.5%	2.5%	3.0%	2.5%	2.5%

## Feedstock Assumptions

Feedstock templates were generated for corn stover, switchgrass, logging residues, hybrid poplars, DDGS and dairy manure. The templates incorporate all costs incurred to deliver feedstock to the plant, as well as the cost of storage at the plant. All feedstock processing that occurs at the plant is included in plant operational costs.

### *Corn Stover*

The corn stover scenario includes a \$10 per ton landowner payment, baling costs, loading and unloading costs, 50 miles of road transportation, and 6 months average storage per ton. In this scenario the corn grain produced is assumed to bear the cost of land rents, as well as establishment costs. The \$10 payment is assumed to be sufficient to cover the costs of nutrient replacement, and provide sufficient incentive for the landowner to allow stover harvest.

### *Switchgrass*

The switchgrass scenario assumes that the switchgrass is purchased in bales from the farmer. The range of market prices used represents prices paid for baled hay of low to fair quality in Minnesota during May 2007. The market price is assumed to cover all costs incurred by the farmer to deliver square bales to the farm gate. Added to the market price are loading and unloading costs, 50 miles of road transportation, and 6 months of average storage.

### *Logging Residues*

The logging residue scenario includes a \$2 landowner payment and collecting, forwarding, chipping, loading and unloading costs. It also includes 50 miles of road transport and 6 months of storage. As in the corn stover scenario, the landowner payment is assumed to cover any costs the owner incurs in allowing residue collection.

### *Hybrid Poplar*

The hybrid poplar scenario is analogous to the switchgrass scenario in assuming that the hybrid poplars must bear the full costs incurred by the farmer to establish and maintain a stand. The average stumpage price for aspen for pulp and bolts from 2005 to 2006 in Minnesota is used as a proxy for these costs. This may understate the full costs of a hybrid poplar stand as they are often planted on farm land that has a higher value than timber land. Stumpage prices do, however, indicate the price of a major substitute for hybrid poplar, so they should therefore represent fairly closely the prices farmers can expect to receive for their trees. Added to the stumpage price are harvest, chipping, loading and unloading costs, 50 miles of road transport, and 6 months of storage at the plant.

## DDGs

The DDGs scenario includes only an energy content, market price and moisture content. DDGs are often used as a supplemental feed for beef cattle and other livestock. The market price of DDGs represents the opportunity cost to producers of using DDGs as an energy source. The range of market prices used is the price range of DDGs in Minnesota from May of 2006 to April 2007.

## Dairy Manure

The dairy manure scenario includes only an energy content and moisture content. All other costs are assumed to be born by the dairy operation. The range of moisture contents is taken from the survey of agricultural biogas systems from which the template was derived.

## Feedstock Summary

Below is a summary of assumptions used.

**Table VIII-5: Feedstock Characteristics and Costs**

Biomass Feedstock	Energy Content (BTU/lb)	Market Price (\$/ton)	Amount Collected (%)	MCW (%)	Site Processing Activity	Site Processing Costs (\$/ton)	Collection & Loading (\$/ton)
Corn Stover	8,191	\$10.00	65%	25%	Baling	\$23.57	\$3.22
Switchgrass	7,481	\$60.00	100%	12%	None	\$0.00	\$3.22
Logging Residue	8,669	\$2.00	70%	50%	Chip	\$7.50	\$1.75
Hybrid Poplar	8,430	\$19.50	100%	50%	Chip	\$15.00	\$1.75
DDGs	9,422	\$105.00	100%	11%	none	\$0.00	\$0.00
Dairy Manure	6,757	\$0.00	100%	10%	none	\$0.00	\$0.00

**Table VIII-6: Feedstock Costs**

Biomass Feedstock	Trans. Cost (\$/ton/mi)	Miles	Processing	Processing Costs (\$/ton)	Storage (\$/ton/mth)	Avg. Storage Time (mths)	Collection/ Loading Costs (\$/ton)
Corn Stover	\$0.10	50	None	\$0.00	\$1.71	6	\$3.22
Switchgrass	\$0.10	50	None	\$0.00	\$1.71	6	\$3.22
Logging Residue	\$0.10	50	Chip	\$15.90	\$1.50	6	\$1.75
Hybrid Poplar	\$0.10	50	Chip	\$15.90	\$1.50	6	\$1.75
DDGs	\$0.00	0	None	\$0.00	\$0.00	0	\$0.00
Dairy Manure	\$0.00	0	None	\$0.00	\$0.00	0	\$0.00

**Table VIII-7: Scenario Definitions**

Scenario Number	Biomass Feedstock	Power Plant Strategy	Scenario Number	Biomass Feedstock	Power Plant Strategy
s1	Corn Stover	50 MW Biomass	s10	Switchgrass	600 MW Coal w/ 5.8% Co-Fire
s2	Other/Switchgrass	50 MW Biomass	s11	Logging Residues	600 MW Coal w/ 5.8% Co-Fire
s3	Logging Residues	50 MW Biomass	s12	Timber (Aspen)	600 MW Coal w/ 5.8% Co-Fire
s4	Timber (Aspen)	50 MW Biomass	s13	Corn Stover	5.4 MW Gasification w/ CHP
s5	Stalks (Corn)	Co-Firing (Incremental)	s14	Hay/Straw (Other/Switchgrass)	5.4 MW Gasification w/ CHP
s6	Switchgrass	Co-Firing (Incremental)	s15	Logging Residues	5.4 MW Gasification w/ CHP
s7	Logging Residues	Co-Firing (Incremental)	s16	Timber (Aspen)	5.4 MW Gasification w/ CHP
s8	Timber (Aspen)	Co-Firing (Incremental)	s17	Ethanol DDGs	5.4 MW Gasification w/ CHP
s9	Corn Stover	600 MW Coal w/ 5.8% Co-Fire	s18	Dairy Manure (including benefits)	135 kW w/ Manure Digester
			s19	Dairy Manure (not including benefits)	135 kW w/ Manure Digester

## Probability Distributions

The values and the probability distributions used in the Monte Carlo analysis are based on a number of sources. In some instances the values utilized are the default values in BioPET. In other instances more recent, or complete, data form the basis of the probability distributions. In most instances recent data allowed for the generation of a reasonably accurate range of values. It was not possible, however, to know what the actual distribution of prices would be within the price range. For this reason a simple triangular distribution was chosen. In most cases the peak, or center, of the triangle was placed at the mean value of the range. In a few instances a skewed distribution was chosen where we felt that it was warranted.

Recent price data was used to develop the ranges for the market price of switchgrass (USDA, 2007b), hybrid poplar (Jacobsen, 2007), and DDGS (USDA, 2007c), as well as the harvest costs of logging residues (Lumberjack RC&D, 2005) and hybrid poplars (Schmidt, n.d.). In the case of corn stover baling costs and feedstock energy content the default value from BioPET was used as the mean, and the minimum and maximum values were set at +/- 15% of the mean. Road transport costs were a variable that we felt was likely to have a skewed distribution in the future, due to the likelihood that oil prices were more likely to rise from current levels than fall. For this

reason a range from -20% to +100% of the default values of BioPET were utilized, and the peak of the distribution was placed at the default value. The range of values for manure moisture contents was taken from a document that describes the experiences of farmers operating manure digesters (Kramer, 2004).

The range utilized for power plant capital costs was skewed. A range from 95% to 120% of the default capital cost within BioPET was utilized, with the peak of the distribution at the BioPET default value. Recent news reports of rapidly rising power plant costs led us to assume that capital costs were more likely to rise than to fall in the coming years (Wald, 2007). The range of income values for manure digesters was derived from documentation of a specific manure digester in Minnesota (Kramer, 2004).

**Table VIII-8: Variable Ranges for Feedstock Scenarios**

<b>Feedstock</b>	<b>Proxy</b>	<b>Min</b>	<b>Max</b>	<b>Distribution</b>
Switchgrass Costs	Hay Prices	\$30	\$90	Triangular Centered on Mean
Hybrid Poplar Market Price	Aspen Stumpage	\$12	\$27	Triangular Centered on Mean
Hybrid Poplar Harvest Costs		\$11	\$19	Triangular Centered on Mean
Logging Residue Harvest Costs		\$2	\$13	Triangular Centered on Mean
DDGS Market Price		\$80	\$130	Triangular Centered on Mean
Corn Stover Baling Costs		\$20.03	\$27.11	Triangular Centered on \$23.57
Road Transport Costs		\$0.08 per Mile	\$0.20 per mile	Triangular Centered on Default
Feedstock Energy Content		85% of Default	115% of Default	Triangular Centered on Default
Dairy Manure Moisture Content		85%	99%	Triangular Mean at 90%

**Table VIII-9: Variable Ranges for Power Plant Scenarios**

<b>Feedstock</b>	<b>Min</b>	<b>Max</b>	<b>Distribution</b>
Capacity Factor	65%	90%	Triangular Peak at 85%
Capital Costs	95% of Default	120% of Default	Triangular centered on Default
Digester Other Income	0\$	\$74,000	Triangular Peak at \$50,000

## Results

The results presented here represent the range of values from the 20<sup>th</sup> percentile through the 80<sup>th</sup> percentile. These results illustrate that there is considerable variability in the cost of both biomass feedstocks and biomass power. They also illustrate that the choice of feedstock and plant design each play significant roles in determining a plant's LAC.

Disregarding the manure digester, the results show an overall range of LACs from ~\$0.03 per kWh to ~\$0.185 per kWh.

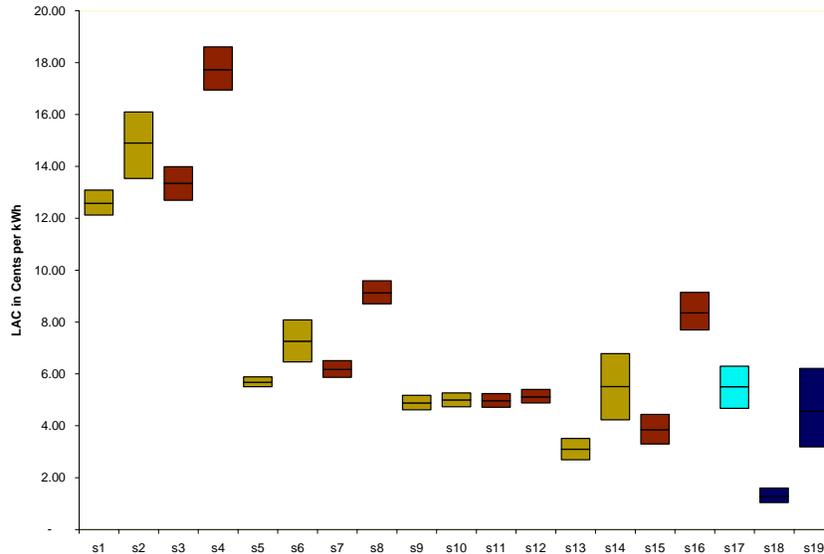


Figure VIII-6: Monte Carlo Results (LAC)

### Feedstock Variability

The resulting feedstock prices illustrate a number of important points. The most apparent of these is that each feedstock has a very different range of prices, both in terms of mean expected price and range of expected prices. Corn stover, for instance has a relatively low mean expected price, with a relatively narrow range of expected prices. Switchgrass, on the other hand, has a mean price that is \$1.60 higher than that of corn stover, and a much greater range of prices \$1.70 between the 20<sup>th</sup> and 80<sup>th</sup> percentile vs. \$0.35 for corn stover.

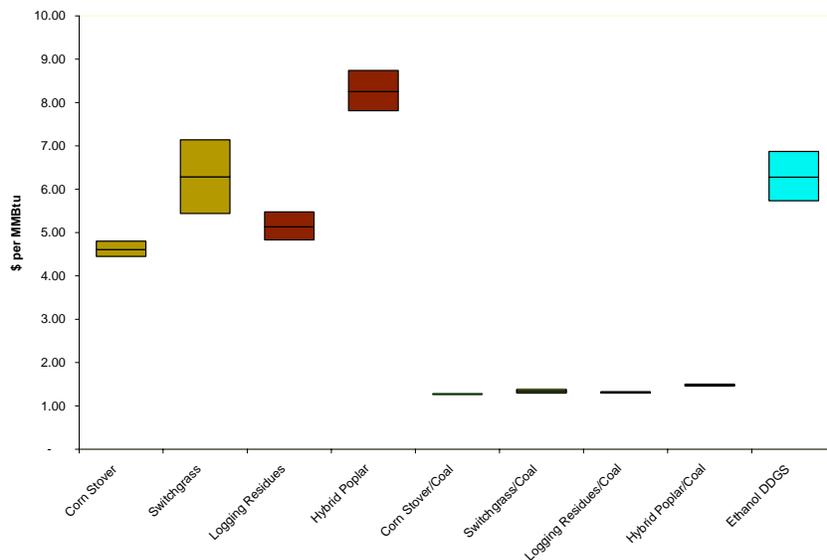


Figure VIII-7: Feedstock Price Variability

The other important point that arises from these results is the dramatic decrease in both mean expected price, and price variability for the co-firing scenarios. This is due largely to the relatively small proportion of the total feedstock price for these scenarios that biomass represents. The difference between the mean expected price of the least and most expensive co-firing scenarios is only \$0.21 per MMBTU, and the expected price variability for any of these scenarios is only a few pennies per MMBTU between the 20<sup>th</sup> and 80<sup>th</sup> percentiles.

### ***Power Plant Design***

Power plant design plays an important role in determining the price of power. The range of prices for the 50 MW, biomass-only, power plant surpasses all but the most expensive power from the other power plant designs. The price ranges for the other power plant designs overlap somewhat. The most cost effective power plant is the CHP facility which gasifies biomass, and generates power with converted gensets. The incremental and total costs of power from co-firing fall between the CHP plant and biomass only power plant. However there is considerable overlap for those three scenarios.

Feedstock costs also play an important role in determining the LAC. Corn stover is the least expensive feedstock for each power plant, followed by logging residues, switchgrass, and finally hybrid poplars. For each biomass only power plant design the most expensive feedstock (hybrid poplar) adds between \$0.04 to \$0.06 per kWh over the cost of power from the least expensive feedstock (corn stover). The effect is greatly reduced when one looks at the total cost of co-firing. As is the case for the feedstock costs of the co-firing scenario both the mean price, and the expected price variability are considerably less in the co-firing scenario than the other scenarios. The difference in the mean LACs for each co-firing scenario is only \$0.0024 between the least and most expensive scenario. The expected range of prices for each scenario is only ~\$0.005 between the 20<sup>th</sup> and 80<sup>th</sup> percentiles.

The cost of power from the manure digester is driven in large part by the non-energy value derived from digester. When no added benefits are included in the cost of energy the price of power from the digester is approximately \$0.046 per kWh, but when there are additional benefits from the operation of the digester the price of power is approximately \$0.013 per kWh.

## CHAPTER IX : OVERCOMING BARRIERS

Minnesota's potential for electric generation from biomass fuels got a great boost in March, 2007 when the legislature enacted, and the governor signed, a renewable energy standard (RES). The formula is simple: in 2010, 10% of electric power from Minnesota utilities must be generated from renewable fuels; in 2015, 15%; in 2020, 20%; and in 2025, 25%. Because Xcel Energy is not credited for "pre-existing" renewables as mandated by the Prairie Island Agreement, it has to meet a higher standard – 30% – sooner – by 2020. That means it will have to add to its portfolio around 3500 MW of renewable generation in a period of twelve years.

Wind is the renewable fuel getting most attention from utilities. Some plan to build and own wind farms to supplement power they buy from developers through Power Purchase Agreements. But wind power aside, the standards will become a powerful incentive for utilities to take a more active role in creating biomass capacity as well. That role may range from retrofitting existing coal plants to co-fire biomass to partnering with manufacturing and processing plants in co-generation projects, as Minnesota Power has done with several pulp and paper mills. Biomass will most likely be especially important to a utility like Minnesota Power, which serves large 24/7 base-load industrial customers in the paper and taconite processing industries of northeastern Minnesota. And since northeastern Minnesota isn't a particularly windy area, turbines wouldn't operate very efficiently there anyway.

That last observation touches on an important point: every renewable power project, especially a biomass power project, must be carefully planned and located in terms of its relation to fuel, technology, transportation, transmission, and markets. Available biomass is a necessary factor, but not a sufficient one, in determining the feasibility of a specific biomass energy project. It takes the whole package to make a renewable energy project work.

Maps in Chapter II of this report show where Minnesota's biomass fuel sources lie. Looking at the big picture, we see Minnesota's biomass growing in two major biomes. In the northeast is boreal forestland, where biomass consists of timber harvest residues, mill wastes, brush, storm blow-down and thinnings. (Roundwood – logs – also could be considered, but that scarce and expensive resource is in high demand for forest products.)

In the farming and livestock raising lands of Central, Southern and Western Minnesota, biomass takes the forms of crop harvest residues, crop processing wastes, and manure. (There has been interest in dedicated energy crops, like hybrid trees and grasses, in farm country, but not much development.) Manure is found most abundantly in dairy area northeast and southwest of the Twin Cities, but turkey and hog production west of the Cities also have potential, as evidenced by the Fibrominn plant in Benson which burns turkey litter.

A lesser biome, the Mississippi Valley coulee region, is covered with dense stands of temperate hardwoods, but its difficult terrain, scenic beauty, and wildlife habitat make timber harvesting problematic in that area. Another smaller biome, in the commercially unproductive marshes and pastures of central Minnesota, eventually may accommodate dedicated energy crops like grasses. Marginal agricultural lands in Northwestern Minnesota also might sustain energy crops. Within each of those big-picture biomes lie a myriad of little but very important sub-biomes – local variations in ecology and crops – accompanied by important infrastructure like roads, rail, transmission lines and facilities that generate wastes.

Since biomass power development, like politics, is local, opportunities in the immediate area sometimes trump biomes. For example, you might expect an ethanol plant in the farmlands of

central Minnesota to burn biomass in the form of DDGs or crop wastes. But Central Minnesota Ethanol Cooperative in Little Falls fuels a gasifier with waste wood from nearby millwork plants and sawmills. The choice of fuel for any specific opportunity will ultimately be decided by its availability and price, not by *a priori* notions of its appropriateness.

Having said that, we suspect that in most cases biomass fuel selection still will depend on the predominant biomass types in the immediate area. The relationships among those biomass resources and all the types of infrastructure necessary to a biomass power plant are complicated but critical. The suite of maps in *gopher* will help the user gain an understanding of resource availability alongside existing infrastructure.

## BIOMASS POWER'S CHALLENGES AND RESPONSES

Given the complexity of developing effective bio-power projects, we try to make it easier by answering the challenges of biomass power development in Minnesota with some solutions to them. Some challenges arise from the properties of biomass itself, while others arise from limitations in technologies, markets, and institutions. Some challenges will be overcome with advances in technology or changes in policy. Other challenges may have to await changes in biomass's cost relative to fossil fuels – not just lower biomass generation costs through the use of more efficient handling and conversion technologies, but also the higher fossil fuel prices that seem inevitable in the current world situation. Biomass applications are businesses that face typical business challenges. But they also have so many contact points with the ecology and with society at large that also present challenges to public policy makers.

## BUSINESS DEVELOPMENT CHALLENGES

There is nothing unique about most challenges facing biomass power developers. They are familiar to entrepreneurs in any emerging technologies:

- High input costs
- Competition for supplies
- Securing supplies
- Information gaps
- High capital costs
- Increased risk in financing new technologies
- Permitting and regulation
- High transaction costs
- Monetizing non-financial benefits
- Marketing byproducts

## High Cost of Biomass Fuels

When comparing current market prices, most biomass fuels cost more than coal, the predominant fuel used in electric power generation. One may wonder how that can be when so many biomass fuels are wastes. The answer is the high cost of energy and effort expended in collecting, transporting, and processing biomass into usable fuel delivered to the power plant. Compared to coal, biomass is a dispersed resource that doesn't lend itself to efficient transportation and handling within our current system. Additionally, the infrastructure for delivering coal quickly and efficiently is the product of various local, state, and federal incentives to support its development over many decades.

Biomass also tends to have a low energy density which means it contains less energy per volume than traditional sources of energy. This results in an increase of overall transportation costs for biomass resources.

### ***Responses to High Costs***

**Using biomass in high-cost applications.** While biomass is typically uncompetitive with coal, it can compete with natural gas. Since natural gas is the fuel of choice for peaking plants – plants that intermittently kick into service during periods of peak electricity needs – perhaps biomass peaking plants could compete with biomass gasified to burn in turbines. Unlike a typical combustion plant, a gasification/combined-cycle plant could respond quickly to the varying demands of the grid. Once it is fully commercialized, which will be soon, biomass gasification technology will take its place in combined-cycle power plants capable of higher efficiencies than steam-cycle plants.

**Lowering harvest, collection, storage and processing costs.** Work has begun on designing a new generation of equipment designed specifically to handle biomass more efficiently. Machinery and strategies for harvesting, collecting and processing corn stover are in the development phase (Atchison and Hettenhaus, 2003 and Glassner, Hettenhaus, and Schechinger, 1998). Other harvest technologies first developed offshore now are making their way into the U.S. When cellulosic processes, the subject of much research and discussion, comes into use commercial use in ethanol plants, there will be a strong impetus to develop more efficient handling of agricultural wastes to feed them. Biomass power plants too will benefit from those new developments.

Forested areas also will see new handling technologies, many of them imported from countries that manage their forests more intensively than we do. For some time, Sweden has used forest residue bundlers to harvest logging residues. American firms have just begun to import and experiment with these machines (Peterson, 2005). Some Minnesota- based research efforts have included the use of logging slash bundlers.

**Using new technologies to extract more energy from biomass.** Biomass gasification technologies have the potential to extract far more energy from a given amount of biomass fuel. We have seen biomass gasification replace natural gas in ethanol plants, and, as suggested above, perhaps it can do it in peaking plants as well.

Several major industries in Minnesota are interested in gasification. The pulp and paper industry could use it to become self-sufficient in energy (Larson, et. al. 2003). Rising natural gas prices and pressures to reduce air emissions will motivate the ethanol industry to adopt it (Sparby and Massie, 2006 and Anfinson, 2005). Central Minnesota Ethanol Co-Op (CMEC) recently started up to do both – eliminate purchases of natural gas and reduce air emissions. The CMEC gasifier is among several biomass gasification systems that represent the first commercial applications of that technology in Minnesota.

**Policies to Encourage Innovation.** State policies to aid the development and adoption of emerging biomass technologies should address various stages of technology development and adoption. In the early stages, funding of product development and research into the economic benefits of new technologies can help to speed commercialization. Once those technologies have become commercially established, information and financial support can reduce financial risk to their adopters.

**Potential Future Carbon Regulation.** In addition to efforts to reduce the cost of biomass, it is becoming more and more likely that there will be some sort of carbon regulation initiated within the decade. Although this won't impact the costs of biomass directly (since burning biomass has a net zero carbon impact<sup>3</sup>), it will increase the costs of fossil fuel resources. This would result in more price competitiveness between traditional electric power resources and biomass options.

## Competition for Fuels

Many of the state's biomass resources already are consumed by industry or agriculture, another reason for the high cost of some biomass fuels. Biomass is a renewable resource, but not an infinite one. Land is one constraint. Roughly half of Minnesota's land is in fields and pasture, 19% is in either developed land or protected wetland, and 29% is in commercial timberland not set aside in wilderness or parks (Miles, Brand, and Mielke, 2006).

Half of that commercially available forest land is publicly owned and thus obliged to serve other purposes besides production, like wildlife, hunting, hiking, and camping. The other half is mostly owned by private parties for a variety of purposes that don't include, and in fact may run counter to, timber harvest – hunting, hiking, and sitting in the shade. Competing uses contribute to perpetual complaints from the forest products industry that commercial harvest is too restricted.

Like forests, agricultural lands are dedicated to many purposes that don't include energy production. The controversy over the use of corn crops in ethanol plants shows how inelastic supply this supply is in the short term. Using food and feed crops for energy competes with their traditional uses.

All of this suggests that there are not huge swaths of unutilized land in Minnesota that can be dedicated to biomass energy feedstocks. Developers of biomass power plants either have to compete with current biomass consumers, like paper mills or food processors, or seek out biomass feedstocks that are underutilized or wasted.

### *Responses to Fuel Competition*

**Avoiding disposal costs.** Since commodity crops are too expensive to use as fuel, the alternative is to use waste biomass. The largest of these resources is corn stover. Others are logging residues, agricultural wastes, manures, food processing wastes, and other byproducts from agricultural processing. The cheapest are likely to be waste streams that, because of avoided disposal costs, enter power plants at a zero, or even negative, cost. As seen earlier, many pulp and paper mills; agricultural processing plants; and large dairy, hog, and poultry facilities already are using waste in this way. But they aren't exploiting as much of its potential energy as they could using state-of-the-art technologies.

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<sup>3</sup> While the combustion of biomass does lead to the release of CO<sub>2</sub> into the atmosphere, biomass fuels are not considered to increase atmospheric CO<sub>2</sub> concentrations. This is because the carbon molecules contained in biomass fuels would have been returned to the atmosphere upon the plant's death and decomposition. In this sense the consumption of biomass fuels does not lead to the emission of greenhouse gases that would not have occurred otherwise. This is contrasted with the combustion of fossil fuels, which returns carbon to the atmosphere that has been sequestered from the atmosphere for tens to hundreds of millions of years. The carbon contained in these fuels would not be emitted to the atmosphere without human activity.

**Learning more about the energy potential and costs of wastes.** This idea goes to the very reason for this study – to present in a flexible, easy-to-use electronic format, BioPET, how much biowaste is generated, how much energy it contains, how much it costs delivered, and how much it is worth converted into electric power. Not only should this tool simplify an assessment of particular feedstocks, it (in conjunction with *gopher*) should help prevent an over-investment in bio-power capacity that would demand more biomass than Minnesota can supply without harming its other industries or its ecosystems.

## Problems in Securing Long-Term Biomass Fuel Supplies

Difficulties in securing fuel supplies contributed to the failure of the EPS/Beck project, which couldn't amass enough land for plantations, and the NGPP project, because Itasca Power couldn't find enough wood waste to fuel the plant. Some realized projects also may have concerns about supply. The Laurentian Energy Authority asked for and received a subsidy from the state for fuel supplies, and District Energy St. Paul has made a concerted effort to expand its control over municipal transfer stations (City of Albertville, 2006; City of St. Louis Park, 2007).

A recent study of alternatives for the Rock-Tenn recycling paper mill, which is losing its long-time steam host, Xcel Energy's High Bridge power plant due to a conversion to natural gas, suggests that nearly all biomass fuels in the Twin Cities Metro area are committed to other uses, including fuel for existing bio-power facilities. The study found that biomass fuels for Rock Tenn would be expensive and complicated. No single feedstock in the area is abundant enough to fuel the mill (Nelson, 2007).

### *Responses to Limited Biomass Fuels*

Response is the right word. Solution would not be. There has been some well intentioned but futile speculation about biomass alternatives. The bio-power developer will have to look long and hard at fuel supply, not just in the context of current availability but also in the context of contingencies that might affect future supply. Since concerted development of dedicated energy crops is uncertain, we have to work with what exists. So the only way to mitigate fuel resource risk is study. Beginning with resources like BioPET and *gopher* is a necessary first step.

## Information Gaps

Investors may lack the technical knowledge to understand a new technology. Confronted with the unknown, they naturally retreat to areas they are familiar with. Studies have found that the inexperience of potential investors has proven to be a serious obstacle to the development of bioenergy facilities (Itron, 2004).

Limited expertise and resources have challenged the adoption of anaerobic digester (AD) biogas power systems on dairy farms. While many farmers may have enough manure to support an AD system tied to generating equipment, they may not have the expertise or the time to operate it (DOC, 2003a).

While the size of Minnesota's biomass resources is known (see Chapter II), the impact that new bio-power facilities would have on their availability and price is difficult to model. There are few bio-power facilities in the Upper Midwest on which to base supply curves.

This lack of information is a particular concern because demand for many biomass feedstocks is inelastic. Substantial new demand for biomass materials could dramatically increase biomass

feedstock prices, and those higher prices could have a devastating short-run effect on both current consumers of biomass and potential new entrants to the marketplace. If substantial portions of the state's biomass production were diverted to bio-power facilities, the pulp and paper and livestock industries would have trouble finding the reasonably priced fiber and feed they need to stay in business. On the other hand, new companies entering the biomass power business on the assumption they can buy feedstocks at current prices may discover that current biomass consumers are willing to outbid them in order to maintain supply. When the Fibrominn plant began construction, concerns were heard that its consumption of 31 to 40% of Minnesota's poultry litter would take that fertilizer away from organic farmers (EQB. 2001b).

### ***Response to Information Gaps***

The solution to problems of this kind lies in modeling the response of biomass markets to the new bio-power plants, as well as continuing efforts to quantify the state's biomass inventories and production. Information tools like BioPET can reduce the gap in information on the availability and costs of biomass resources for power generation.

The advent of several new bio-power facilities and the maturity of the state's corn ethanol and soybean biodiesel industries indicate that biomass development is understood better in Minnesota than in most states. Where gaps remain, potential policy and market-based solutions can help meet the challenge. Minnesota's departments of Agriculture and/or Commerce could give farmers guidance in developing anaerobic digesters, and the Pollution Control Agency could standardize approval processes. Utilities have a stake in partnerships with farmers, too. Dairyland Power Cooperative works with third-party contractors to build and operate digesters and generating equipment on farms. Farmers receive payments for biogas the digesters generate (less management fees), and they don't have to assume the risks and the responsibility of managing the systems.

Some information gaps can be filled only by experience – by doing – because, in the words of Yogi Berra, it's hard to make predictions, especially about the future. Time will determine the highest and best use of Minnesota's unused biomass and the most efficient means of harvesting and processing it. They might become a feedstock for bio-based manufacturing, bio-refining, and cellulosic ethanol.

Studies have shown that the costs of residue collection are sensitive to a number of variables, including road quality, success in reducing contamination by rocks and dirt, and the integration of processing with logging operations (Rawlings, Rummer, Seeley, Thomas, Morrison, Han, et. al. 2004). These questions of operating costs and commercial success in using Minnesota's biomass can be answered only by experience. For the entrepreneurial developer, insufficient information and unforeseen consequences are unavoidable risks. When everybody knows how to do something, they all do it and that floods the market.

### **High Capital Costs**

Not only does biomass fuel currently cost more than coal, plants that use biomass also cost more to build than coal-fired plants. With the possible exception of syngas in a peaking plant, biomass fuels may be best suited to firing base load generating power plants. Unfortunately, a biomass-only, base-load power plant will cost significantly more per MW than a comparable coal plant. It will most likely be smaller (< 60 MW) because the cost of transporting biomass fuels over long distances militates against a larger plant. A biomass plant can't take advantage of economies of scale enjoyed by coal-fired plants.

Recent projects in Minnesota and neighboring states demonstrate that stand-alone biomass power plants cost more than traditional plants. Public records show biomass power plants ranging from \$2,500 to \$3,000 per kW of installed capacity (Burns & McDonnell, 2005; Trillium Planning and Development, 2002; and "Poultry Litter", 2005.) a lot more than the \$1,800 per kW of installed capacity that a 600 MW supercritical pulverized coal power plant (Burns & McDonnell, 2005). They also entail costly handling facilities. The Laurentian Energy Authority in Hibbing/Virginia had to build a wood processing and storage yard between the two cities.

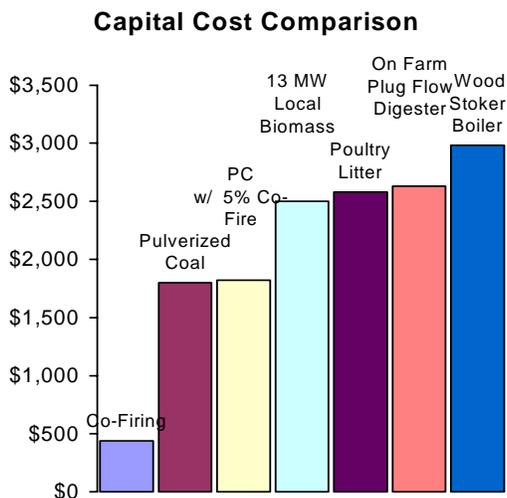


Figure IX-1: Power Plant Capital Costs (\$/kW)

### *Responses to High Capital Costs*

**CHP.** Steam sales (or internal uses of steam) over time might offset the high capital costs of biomass power facilities. It is virtually impossible to find a steam host in Minnesota to serve a canning plant or a paper mill.

**Co-Firing.** Adding biomass fuel to coal at an existing plant costs far less than building a new biomass-only plant or CHP plant, even when including additional equipment costs to handle the new fuel.

**Research Toward Best Practices.** As a matter of policy, support for research into co-firing could lead to promulgation of best practices that could remove much of the technological risk.

### **Difficulties in Financing New Technologies**

MnVAP, EPS/Beck, and Fibrominn all struggled to finance their projects, to a large degree, because of technology risk. Combining technology risk with fuel resource risk, and you have a hard case to present to investors and lenders.

### *Response; Laying the Groundwork*

While firm financial commitments won't be forthcoming until a PPA is signed, it helps to explore financing terms with investors and lenders early in the process in order to avoiding unpleasant surprises later after money has been spent in planning the project.

## Difficulties in Permitting

Biomass projects also have run into problems in permitting and approvals, again because of their novelty. In the case of Fibrominn, the Minnesota Pollution Control Agency required much more information on emissions rates than the developers expected. This kept the project on hold for a long time. PCA needed the data because there is no dataset that regulators can draw on to model emissions from turkey litter. Project developers should anticipate that the permitting process for novel technologies may take longer than permitting for well-characterized technologies.

### *Response to Permitting Difficulties*

These difficulties will lessen as regulators gain more experience with biomass projects and data available from biomass projects increases. As biomass power moves from an experimental technology to one with standardized designs, databases generalized from them will become available to regulators. The MPCA is acting to build its ability to deal with the permitting of biomass facilities.

### *Defining Biomass Power Plants as Waste Combustors*

Waste combustors present a particular issue in permitting. Because the definition of waste in state rules may apply to certain biomass feedstocks, biomass power plants could be subject to standards more stringent than those that apply to traditional power plants.

#### Two ways to avoid waste combustor requirements

To date, biomass developers have addressed that problem by applying for a variance from the Minnesota Waste Combustor Rule. A second way to avoid Waste Combustor standards is to apply for a case-specific Beneficial Use Determination. The granting of a variance or a Beneficial Use Determination serves to clarify only the applicability of the rules governing waste combustors, not the need to satisfy other air emissions permitting requirements.

The MPCA has proposed language that would specifically exempt facilities combusting biomass feedstocks from the state's Waste Combustor rules. The proposed rule change would specifically apply to facilities burning forestry residues, wood mill residues, agricultural residues, dedicated energy crops, finished agricultural products, urban wood wastes, and poultry litter.

## High Transaction Costs

The relatively small scale of bio-power facilities makes transaction costs disproportionately high. Regardless of scale, power plants require engineering studies for design and constructing and contractual arrangements for connecting to the grid and agreeing upon satisfactory rate agreements. Rates depend partly on the avoided generation, transmission, distribution, and emissions costs of the utility. Since those costs are not uniform throughout the state, establishing a reasonable estimate may entail substantial study.

Not only are the costs of such studies high relative to the output of small power generators, the question of who pays their cost is an issue, at least for biomass power plants larger than 10 MW. That is the upper size limit to qualify for PUC's generic interconnection and operating tariffs for distributed power generation in Minnesota (PUC, 2004). For plants under 10 MW, the generic tariffs dictate who pays for studies, how much those studies cost, and how rates and credits will

be calculated. Plants above 10 MW do not qualify for standard interconnection agreements, so they may find transaction costs a barrier.

Other transaction costs for bio-power plants, regardless of size, are interconnection and standby rates. In discussing standardized interconnection agreements between utilities and distributed generation facilities, proponents of distributed generation (DG) often express a concern that utilities could deliberately set rates high to discourage development of DG facilities (DOC, 2003b). Since the PUC chose not to regulate those costs under the generic standards, they remain a potential barrier to the development of biomass power plants of any size.

### ***Response to High Transaction Costs***

Several policy solutions could lessen the negative effects of high transaction costs on the development of bio-power projects. Standard offer contracts would ease the development of renewable energy projects by removing the need to negotiate contracts and by enabling potential bio-power investors to plan projects according to known contract terms. Another solution would be the extension of distributed generation standard interconnection agreements, or at least a portion thereof, to include all bio-power facilities.

## **An Inability to Monetize Benefits**

Biomass power plants, like other environmental projects, have difficulty capitalizing on the external benefits that they may confer on society. Anaerobic digesters (ADs) provide a good example of this problem. Many large dairy facilities impact their neighbors with odors from manure. More important, manure applied to farm fields and spills of untreated manure from ruptured lagoons lead to high levels of runoff that increase the nutrient load in Minnesota's rivers and lakes.

ADs (whether used for energy or not) can dramatically reduce odors and virtually eliminate nutrient runoff. Dairy operations with ADs in operation incur fewer complaints from neighbors and less risk of regulatory actions for excessive nutrient runoff. But the benefits to society of aerobic digestion far surpass those small benefits to dairy operators. If those societal benefits could be monetized, they would improve the economics of AD biogas powered generators (DOC, 2003a).

### ***Response that Monetizes Benefits***

Among policy solutions to remedy this market failure, the state (or local governments) could offer additional incentives to bio-power projects that can demonstrate improvements to local air or water quality.

## **Marketing of Waste Streams from Co-Firing**

Biomass-only power plants can potentially sell fly ash as a soil amendment to foresters or farmers. The Fibrominn poultry litter plant in Benson plans to do just that thereby turning a potential disposal cost into a revenue stream. Coal plants typically sell their fly ash to the concrete industry.

When plants co-fire coal and biomass, however, their fly ash is currently worthless. That's because it doesn't meet the standard of the American Society for Testing and Materials (ASTM) governing the use of fly ash in concrete. The standard (ASTM C618) refers only to fly ash from

power plants burning coal, not fly ash from co-firing applications. And conversely fly ash from coal can't be used as a soil amendment. ASTM is considering a change in the standard, but data on co-fired fly ash is ambiguous. Studies have indicated that some fly ash from some co-firing facilities meets the standards while that from others does not (Dockter and Eylands, 2003 and Baxter and Koppejan, 2004).

Marketability of fly ash is a serious matter. Losing that revenue stream can be a deal breaker for some coal plants interested in co-firing. Economic analysis of one experimental co-firing project found that losing ash sales would have to be offset by switchgrass prices lower than farmers could deliver it for (Antares Group Incorporated, 2002).

### ***Response to Co-Firing Challenge***

Adapting the ASTM standard to allow fly ash from co-firing applications would clarify its marketability. Expanding the standard to a performance standard would increase flexibility for using various ash resources. Research could establish a performance standard that plants interested in co-firing could refer to. Questions whether fly ash from co-firing meets the standard then would be settled on a facility-by-facility basis.

## **LEGISLATIVE AND REGULATORY CHALLENGES**

### **Lessons Learned from the Biomass Mandate**

The state's original biomass mandate contained several provisions that proved to be impassible barriers to cost-effective development of biomass power in Minnesota. The two most problematic were: (1) that biomass power plants be powered by "farm-grown closed-loop biomass" and (2) that those biomass-powered plants be new ones using biomass for most of their fuel.

These provisions are largely responsible for the fact that none of the biomass power used to fulfill the mandate has actually met its original terms (Morris, 2005). By declaring that the mandate could only be met by biomass-only power plants firing farm-grown closed-loop biomass, the original legislation dictated the use of the highest cost/highest risk fuel in the highest cost/highest risk power plants. Years after the original biomass mandate, "farm-grown closed-loop" biomass sources are still non-existent. Growers find excessive the risk of experimental crops with long lead times and high costs of establishment – especially when a market for them doesn't exist.

This history teaches lessons relevant to both policy makers and potential project developers and investors.

### ***Misguided Biomass Mandates***

Poorly considered mandates defy commercial or economic solutions. The Department of Public Service (DPS) captured some of the problem at work between Xcel Energy and project developers in their comments on the proposed PPAs of District Energy and EPS/Beck. As DPS saw it, Xcel Energy was put under pressure to fulfill the mandate quickly with very few options to choose from. Lacking options, Xcel Energy was at a disadvantage in bargaining for better prices. And, in the end, Xcel Energy had little incentive to bargain anyway because the mandate let them pass through higher costs to ratepayers.

To realize its goal, a mandate must be clear and achievable. The combination of the “closed-loop” provision with the aggressive timeframe of the original legislation ensured that the terms of the original legislation could not be met. To expect that sufficient “closed-loop” biomass – an experimental fuel source which had not been tried commercially – would become available within three and a half years of the legislation’s passage to fuel 50 MW, and then 75 MW within another four and a half, is not reasonable. To plan, design, permit, contract for, and build even a small coal plant in four and a half years would be difficult. To raise financing, contract for vast acreages, educate farmers in the techniques of growing experimental closed-loop crops, acquire enough seed or seedlings, plant the necessary acres, and successfully grow, harvest and deliver fuel adequate to operate the plant, all in a very short period of time, was insurmountable.

Considering the pandemonium of the last-minute negotiations leading to the Prairie Island Agreement, it is not surprising that the mandate was unrealistic. Once the failures of the MNVAP and EPS/Beck projects showed that the mandate was unworkable, other project developers saw their opening to seek changes in the statute’s fuel requirements to the benefit of their own projects. Thus rather than being systematically reconsidered, the mandate was tinkered with piecemeal to make it fit specific projects. Successful proposals were driven by political clout and does not necessarily translate into technical ability and economic prudence.

The capital costs of co-firing biomass in a coal-fired power plant are a fraction of the costs of building a new power plant. The only new capital investments needed to co-fire biomass are for fuel handling, storage and processing equipment, and perhaps some minor boiler modifications. The Chariton Valley Biomass project in southern Iowa estimates the capital costs associated with their co-firing initiative at \$439/kW (Antares Group Incorporated, 2002), only 12% of the \$3,600 per kW for the Fibrominn plant in Benson<sup>4</sup> (“Poultry Litter”, 2005).

It has taken 14 years for Xcel Energy to fulfill the Prairie Island biomass power mandate. The Fibrominn facility in Benson combined with the Laurentian Energy Authority facilities in Virginia and Hibbing finally will put Minnesota biomass generation at 110 MW. Were it not for the mandate’s opposition to co-firing and its insistence on “closed loop” biomass, its target could have been met more quickly and less expensively.

### Response to Misguided Policies: Rational Objectives and Funding for Appropriate Research

To achieve their intended ends, mandates must proclaim clear strategic goals and objectives, not micromanage tactics. By advancing a narrow, prescriptive, and impossible project definition, the 1994 biomass mandate was bound to fail. A more generic mandate, like the 2007 Renewable Energy Standards which define renewables broadly and let the utilities decide how to meet clear, simple goals should work more effectively.

In addition to establishing broad goals, the state can further them with appropriate research. The state has funded studies to develop sustainable land management practices and determine emissions levels from biomass gasifiers. That funding may have benefited certain current projects, but the studies, which are public information, will benefit future biomass projects as well.

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<sup>4</sup> \$3,600 per kW is calculated from the \$202 million construction contract to build the 55 MW power plant.

## ***Public and Political Relations***

As the history of Minnesota biomass projects suggests, politics is an inescapable consideration in developing a successful energy project. Local politics can be quite helpful (or quite destructive) because citizens talk to their local elected officials who talk to the legislature who talk to state agencies. Residents may love the idea of a biomass project as long as it isn't built anywhere near their homes.

### Responding in Advance

Responding in advance may seem an oxymoron, but it is important to get out in front of public opinion before it congeals into opposition, as CapX 2020 has tried to do recently by sending letters to citizens even remotely within the area of its projected transmission lines. When local opinion favors a project, it is easier to go to the state for incentives like the tax exemptions and special appropriations that the legislature may provide.

## **The Challenge of Picking Winners in Evolving Technologies**

Policy-makers naturally tend to deal with one issue at a time – a particular problem that needs a particular solution. In a legislative body whose members see the world through differing prisms, issues must be kept within certain bounds in order to be decided. Try to put too many issues in one bill, and political stalemate might follow. Critical though they may be, overarching issues, like how to strike the right balance among conflicting demands on biomass resources, might get lost in parochial bickering when they are written into bills.

Biomass may be about as uncertain a future as can be, fraught as it is with technological risk, financial risk, market risk, policy risk, the risk of unforeseen competition for raw materials, not to mention droughts, floods, infestations, and other natural calamities. So for balanced, long-term economic policy, the public turns to government – not necessarily to dictate to businesses, but to limit their excesses and lead them, with sticks like mandates and carrots like tax incentives, in directions assumed to be more beneficial to the wider public.

Therein lies the rub. As mentioned earlier, lawmakers in the past went too far and prescribed specific means, as they did in the Prairie Island Mandate. The more that policies focused on specific technologies and specific end uses, the more likely those policies were to distort the marketplace. If the state directs rewards or mandates toward biomass electric generation, the market will move in that direction even though fundamental economics may favor other uses, like thermal applications or liquid fuel production.

Distortions like these may limit opportunities to utilize biomass in the future. Over-investment in unsustainable industries could create lobbies that interfere with potentially more productive uses of resources like, say, cellulosic ethanol production or bio-refining.

It is impossible to predict which of these inchoate technologies will add the greatest value to Minnesota's biomass feedstocks. All our analyses are based on current performance. Many advanced biomass conversion technologies, like gasification, cellulosic ethanol, and fast pyrolysis for bio-oil, are too new to offer much in the way of data on which to base projections. We know that liquid fuels command a higher price per BTU than solid or gaseous fuels, so cellulosic ethanol may provide higher returns than biomass power generation. But feedstocks for the chemical industry command even higher prices than liquid fuels, so chemical co-products made in bio-refineries along with liquid fuels may yield a higher return than liquid fuels

alone. A decade or two from now, even newer technologies may emerge that render these speculations moot.

Any of these technologies can be used to generate electricity. To date, both syngas from biomass gasification and bio-oil from fast pyrolysis have been used to fuel power generation in commercial facilities (Kotrba, 2005; Stephens, 2006). Two cellulosic ethanol facilities recently rewarded funding by the DOE are designed to generate electricity as well as bio-fuel (DOE, 2007).

### Response to the Impossibility of Predicting the Future Development of Biomass Energy

In the face of rapid change, policy makers can encourage the use of biomass best by letting market forces decide the most economically successful combinations of applications and technologies. Policy makers can benefit from computer models that explore consequences of policy decisions, like one that Sandia National Laboratories is designing for the Minnesota Bio-Business Alliance. But they must bear in mind that even sophisticated computer tools are not crystal balls. Contingency always has ruled human affairs, and that won't change any time soon.

## **Broad and Narrow Policy Measures**

### ***Broad Policy Measures***

Broad policy measures use financial incentives or regulatory pressures to encourage the development of renewable energy. They depend on the profit motive and the need to comply with regulatory pressures to move private enterprise in a publicly beneficial direction.

### Renewable Energy Standard

A good example of a broad policy measure is Minnesota's aggressive renewable energy standards law of 2007 setting clearly-defined goals for electric utilities without prescribing the means to reach them. The law requires that 25% of utilities' retail sales must come from renewable fuels by the year 2025 except Xcel Energy, whose goal is 30% by 2020. The standard ramps up gradually over the years until it reaches those levels. The statute defines renewables broadly, including as biomass fuels things like municipal solid waste, and leaves each utility to decide how it wants to configure its portfolio of renewables. Xcel Energy is counting mostly on wind, while Minnesota Power, due to location and load demands, will probably use as much biomass as possible.

Even though wind will be by far the pre-eminent renewable fuel that utilities will use to meet the standard, the statute will encourage biomass projects too because they will count as much as wind power in the renewable portfolio. This motivation may make utilities willing to pay more for biomass power, provide technical expertise to project developers, minimize transaction costs, and minimize barriers arising from transmission. The renewable energy credit tracking system will give independent biomass power producers a way to market their renewable energy credits and improve their financial results.

### Production Incentives or Tax Credits

Electricity generated with biomass fuels may be eligible for federal production tax credits and on-farm anaerobic digesters qualify for Minnesota's Renewable Energy Production Incentive. Production tax credits and incentives have been powerful drivers of the wind industry in the

United States and Minnesota. The success of these programs in the wind industry lies in the fact that wind-generated electricity competes closely with more traditional forms of new generation capacity. Other renewable energy technologies have not benefited as much from these subsidies because the subsidy is not sufficient to make these technologies economically viable. Minnesota could increase biomass power generation by expanding its production incentive program to cover more biomass-related technologies.

One option to potentially expand the effectiveness of such an initiative is to vary it by fuel source or technology. This could help ensure that different feedstocks and technologies are developed regardless of market maturity. Levels could be adjusted by cost or risk assessment. Caution must be maintained so as not to develop too specific of a structure and suffer the same fate as the 1994 Biomass mandate. If such a strategy were to be implemented, it must be reviewed periodically to adjust to changes in the marketplace.

### Standard Offer Contracts

Standard offer contracts have been used successfully in other countries to promote renewable generation. These are contracts, with terms set by the state, that govern the relationship between qualifying renewable energy generators and local utilities. Standard offer contracts minimize transaction costs by providing project developers with known prices and contractual terms. They can also serve as an incentive mechanism if the price is set at a level attractive to potential investors. Like tax credits and production incentives, the prices set by these contracts varies according to fuel type and/or generation technology. It should be remembered that just mandating standard offer contracts is not enough to increase renewable energy capacity. Regulatory processes and utility policies still can erect barriers, intentional or not, to projects that plan to use standard offer contracts. To ensure that standard offer contracts achieve their full potential, regulators need to ensure that transaction costs associated with permitting and interconnection are minimized.

### Renewable Energy Credits and Carbon Offsets

Renewable energy credits, or carbon emission offsets, provide renewable energy producers an indirect means of monetizing some of the non-energy benefits of their facilities. There are a number of renewable energy credit and carbon offset programs. Some base their rates on the number of kWh that a user wishes to offset. Rates for these programs vary from 0.5¢ per kWh to 7.5¢ per kWh. Others base their rates on the number of tons of carbon dioxide emissions that a user wishes to avoid. Rates for these programs range from \$5 to \$12 per ton of CO<sub>2</sub> avoided (EERE, 2006). These programs employ a number of strategies. Some collect funds and offer the funds as a subsidy to new renewable energy facilities to enhance their economic viability. Other programs offer credits for renewable energy already produced.

The Midwest Renewable Energy Tracking System (M-RETS) is particularly relevant to biomass power projects in Minnesota because it probably will become the system of record for Minnesota's new renewable energy standard. It will track actual generation by renewable energy generators so that utilities can purchase and trade renewable energy credits to meet state renewable energy standards. The system will allow utilities to meet renewable energy standards with projects that they do not own, or are not in their service areas. It also serves the important function of providing renewable energy generators with a potential revenue stream.

Carbon offsets were recently cited in an argument against an approval needed by a large new coal-fired plant. The Minnesota Department of Commerce recommended that the Minnesota Public Utilities Commission deny approval of new transmission capacity for the Big Stone II

project in South Dakota because it expected that carbon dioxide emissions would be regulated in the future.

The application should not be approved unless the Applicants develop and submit for Commission review a plan to offset the 4.7 million tons of CO<sub>2</sub> emissions enabled by the proposed transmission lines. Since carbon costs are expected in the future, it is necessary to address these costs in a reasonable manner. If carbon costs are not adequately addressed, it would be unreasonable to find that the proposed project is in the public interest (DOC, 2007).

The commission suggested a number of actions that could be taken to address the cost of carbon emissions. They included:

- adding DSM energy savings above the least-cost amount as determined in each utility's resource plan as approved by the PUC;
- generating additional wind power, including C-BED resources, above the least-cost amount determined in each utility's resource plan as approved by the PUC;
- shutting down older high-emission generating facilities and replacing the energy with more efficient or lower carbon-emitting sources;
- joining an organization such as the Chicago Climate Exchange or executing an arrangement directly with a carbon-emitting entity to fund that entity's reductions in carbon emissions;
- purchasing agricultural or timber lands to be managed for the purposes of carbon offset-sequestration; or
- using any other reasonable means that lead the Department to conclude that carbon offsets have been created.

The inclusion of carbon emissions costs in the regulatory process has positive implications for biomass power projects. The inclusion of carbon emissions costs in the costs of fossil fuels will lessen their relative price advantage over biomass fuels. This has the potential to improve the economic viability of biomass power.

The use of renewable energy credits and carbon offsets in the regulatory process is new. Regulators face a number of hurdles in ensuring that these new tools are well regulated and implemented. They must verify that credits or offsets actually represent what they are marketed to represent. Ensuring that renewable energy credits are based on the actual generation of existing renewable energy generators (such as M-RETS) should be relatively simple because that can be verified through the generator's metering equipment. It may be harder to ensure that renewable energy credits used to subsidize new renewable energy facilities are properly accounted for because they must be applied to facilities that do not yet exist. Verification of carbon offsets, particularly offsets based on sequestration of carbon in the soil, can be particularly problematic. The rate at which carbon is sequestered in soil is not yet well understood, and it may vary considerably by soil type and land use practices. In addition, verifying that carbon remains sequestered requires that limitations be placed on the use of the land for decades, if not centuries.

### Carbon Emissions Tax

Taxing carbon emissions is a policy tool that may facilitate the growth of biomass power. Biomass fuels are considered to be carbon neutral and, as such, would not be taxed like fossil fuels under a carbon emissions tax. This tax advantage will make biomass fuels comparatively cheaper than they are currently. While individual states may have the power to impose a carbon tax on their own authorities, doing so would put them at a competitive disadvantage

against states that have not done so. For this reason most expect that any future carbon emissions taxes in the United States will be imposed at the federal level.

### ***Narrow Policy Measures***

Some more tailored policies are designed to overcome specific barriers to biomass power development. They rely upon the ability of the state to control the regulatory process, provide financial backing to projects, or even direct state funding towards specific research or infrastructure needs of project developers.

#### Minimizing Transaction Costs

Through its regulatory power, the state can ensure that transaction costs between biomass power developers and utilities are minimized. This can be achieved through standard offer contracts, standardized interconnection agreements (which utilities in Minnesota have been directed to develop), or net metering laws. These instruments can assist biomass power producers as well as power producers using other renewable fuels. Utilities have a mixed history in their dealings small power producers. Some are quite supportive of small facilities, while others have shown a reluctance to remove barriers that discourage small power producers from trying to interconnect with the grid. Policy makers should bear in mind that attempts to minimize transaction costs should consider all aspects of the transactions between regulated utilities and small renewable energy generators.

#### Advancing New Technologies

Minnesota already is pursuing policies to further the development of biomass power technologies and other biomass energy applications. Funding for basic research and product development is available from a number of sources, including state universities, the Renewable Development Fund, and other biomass-focused institutions. New technologies can further biomass power development by lowering power plant capital costs, increasing power plant efficiencies, reducing harvest and processing costs, improving knowledge of sustainable practices, and finding new uses of waste streams.

New technologies can also be advanced by addressing the high costs of purchasing new technologies. Commercial lenders will often require a substantial premium for loans on technologies that lack an established commercial track record. The state can play a role to minimize the technology risk associated with such loans by providing loan guarantees, grants. or subsidies for project developers.

### **Facilitating Regulatory/Project Development Process**

The state could alleviate a number of the barriers that arise during the project development process. Regulations concerning the applicability of waste combustor rules should be clarified. In addition the state should consider a blanket personal property tax exemption for biomass facilities. Section 272.02 of Minnesota Statutes 2006 contains specific exemptions for all of the existing and proposed biomass facilities in the state. To receive those exemptions project developers must expend considerable effort lobbying the state legislature. If it is the policy of the state to encourage biomass power development, the legislature should remove this obstacle and institute a blanket exemption.

The technical capability of regulatory agencies to process permit applications for biomass facilities could be improved (it is our understanding that the PCA will be addressing the issues

surrounding air permits for biomass facilities). This could make one of the more challenging aspects of project development less frustrating, and potentially timelier.

The state can also address project development costs by focusing on the infrastructure necessary for biomass power facilities. This can take the form of infrastructure funding for specific projects, such as road improvements to handle increased traffic. Such funding could alleviate local concerns about traffic levels, road conditions, and noise pollution. It may also take the form of infrastructure improvements that would benefit the biomass power industry as a whole. Examples of this may be the improvement of rail lines that would reduce transportation costs for biomass fuels.

### ***Tax Exemptions***

Another legislative barrier to biomass power development can be found in Minnesota Statutes 297A and 272 which authorize tax exemptions for power plants. The legislature's clear signal that they will exempt most electrical generating facilities from these taxes makes it inevitable that facilities will seek exemptions from the legislature. This may provide a significant barrier to smaller biomass power facilities that may not have the resources to lobby for such exemptions. A more cost effective policy may be to simply exempt those electrical generating facilities that utilize renewable energy sources to eliminate the need to lobby for special treatment.

### **Local Challenges**

Any proposed power plant is likely to face some degree of opposition due to its effects on the local environment. Concerns about local air quality, increased traffic from fuel deliveries, increased noise, and the disposal of waste materials are likely to be raised by local citizens and groups concerned about a plant's effects on its surroundings.

**Air emissions.** In many instances a biomass-powered plant presents fewer challenges to the micro-environment than a coal plant. Mercury emissions, SO<sub>2</sub> emissions, and waste disposal problems are less because biomass contains little mercury and sulfur. In fact, ash from biomass plants is marketed as a soil amendment. Other emissions, such as NO<sub>x</sub> and particulate matter, are comparable to hydrocarbon fuel sources.

On the other hand, incomplete combustion in a biomass plant can generate higher carbon monoxide emissions than a plant fired by coal or natural gas. Carbon monoxide emissions lead to increased ozone levels and diminished air quality. The air quality effects of CO depend largely on local atmospheric conditions.

**Odors.** Biomass fuel sources can give off strong odors during transportation and storage. For certain biomass fuels (turkey litter or manures, for example), odors need to be considered throughout the design process. Fibrominn has instituted operation and design strategies to minimize odor, like operating handling and storage facilities under negative air pressure and washing all delivery trucks before they leave the plant. For other fuels odors become a problem only if fuels are stored for extended periods of time before burning. Careful attention to the plant's siting and design, along with careful planning of the fuel delivery, processing and storage operations, should minimize objections from neighbors.

**Traffic.** A biomass plant's effects on local traffic can be substantial. Study of delivery frequency for the Ottumwa (Iowa) Generating Station, which is planning 35 MW of switchgrass co-firing, indicates that 40 flat-bed deliveries per day will be needed to furnish 200,000 tons of switchgrass per year, a 50% increase over its past traffic (Antares Group Incorporated, 2002). While the OGS

study estimates that this increase will not pose any problems at the plant itself, this great an increase in truck traffic could tax local infrastructure and stir up opposition.

**Responding to community concerns.** Project developers can avoid local political opposition by giving careful attention to project design and including the local community in the planning process. At the state policy level, support for local infrastructure improvements would help develop public support for bio-power projects.

## QUESTIONS OF SUSTAINABILITY

The sustainability of using large amounts of biomass to generate electricity (or produce liquid fuels) is still very much in question. All plants uptake nitrogen compounds and other minerals from the soil for their metabolic processes. Since those minerals remain in the tissues of plants when they are harvested, they must be replaced to maintain the soil's fertility. Questions about the rate at which biomass harvests deplete the soil are central to many debates on the sustainability of biomass power plants.

Other environmental concerns are the effects of biomass harvest on soil erosion and wildlife habitat. The 2005 legislation mandated that the Minnesota Department of Natural Resources and Forest Resources Council generate "(g)uidelines or best management practices for sustainably managed woody biomass". The guidelines will be based on recent scientific information and public comment. They must pay "particular attention to soil productivity, biological diversity ... and wildlife habitat." Research into the sequestration of carbon on forest and brush lands also was called for.

Research must guide the development of future biomass power projects. This particular project applies specifically to woody biomass; issues surrounding other potential feedstocks for biomass power may be quite different. For that reason, research into sustainable practices regarding other biomass sources like corn stover or switchgrass will be needed to write guidelines for other kinds of biomass power projects.

Since water is a necessary input to virtually all electrical generating technologies, sufficient water supplies are important requirements for biomass power projects. This poses a challenge in certain regions of Minnesota, where competition for water is beginning to intensify. In recent years a number of projects, including ethanol plants, have been stalled by constraints on water supplies (Gordon, 2005).

Local and regional factors, like reservoirs and rivers, the needs of local municipal water systems, and potential effects of a new water user on its neighbors, determine whether water is available. There can be no statewide policy solution. True, the Minnesota Department of Natural Resources issues permits to use water from aquifers and streams, but it does so on the basis of local effects, and it has denied permits to ethanol projects in Southwestern Minnesota (Wilson, 2007). Developers of biomass power plants must determine early on whether water is available for the project.

# CHAPTER X : SEEKING OPPORTUNITIES

We mentioned earlier that availability and price determines the choice of biomass fuel choice. Availability and price of fuel certainly matter greatly to utilities assessing biomass as a way to meet Minnesota's new energy standards, as do capital costs, infrastructure costs, operating costs, timelines, and any other factors that contribute to the delivered cost of power. Those factors depend on strategic choices of technologies and plant configurations. Some utilities may decide to retrofit existing facilities for biomass fuel before considering expensive greenfield biomass plants. Our analyses using the Bio-Power Evaluation Tool (BioPET) suggest that the most economic opportunities for biomass power generation lie in co-firing biomass with coal in existing or expanded power plants.

Combined heat and power (CHP) facilities also may convert to biomass fuel, especially if they now are purchasing natural gas at increasingly high prices. Indeed, a number of industrial facilities within Minnesota either have begun to use biomass fuels in their existing operations or are considering doing so.<sup>5</sup> Plants already generating steam and electricity with biomass may find it feasible to expand their capacities and sell biomass power to utilities who need it to meet the renewable energy standards.

Other promising technologies include biodiesel power generators and anaerobic digesters running electrical generators. Direct combustion or gasification of biomass in stand-alone, or central station, plants is less attractive. BioPET analysis of stand-alone biomass power projects suggests that, since their energy would be expensive we probably won't see many of those plants built in Minnesota.

## OPPORTUNITY 1: CO-FIRING COAL WITH BIOMASS

According to the eGRID database published by the Environmental Protection Agency, ten baseload power plants in Minnesota burn coal to generate electricity. Depending on their design, and with some investment in boiler modifications and fuel handling equipment, many of them could co-fire biomass with coal. The literature on co-firing suggests that a 5% co-firing rate can be achieved without making major changes in the facility's overall operations. Applying that percentage to Minnesota's existing utility coal-fired plants would result in the amounts in the table below.

The table below is probably a significant overestimate of Minnesota's potential co-firing capacity for a number of reasons. Many of these facilities consist of multiple boilers. If a plant operator chose to initiate a co-firing operation at one of these facilities it may not make sense (or be possible) to co-fire in all of a facility's boilers. In addition to this there may be technical, logistical (such as a lack of available space), and economic factors (not enough available biomass within an appropriate distance) that would prohibit these facilities from pursuing a co-firing operation. The table here is presented to provide the reader with a frame of reference for the theoretical potential of co-firing existing coal plants with biomass.

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<sup>5</sup> These include Rahr Malting, the Central Minnesota Ethanol Cooperative (CMEC), the Chippewa Valley Ethanol Cooperative (CVEC), Corn Plus Ethanol and Rock Tenn.

**Table X-1: Biomass Consumption at Existing Utility Coal Plants  
Under a 5% Co-Fire Assumption**

Plant Name	County	Plant Total Capacity (MW)	Possible Annual Biomass Consumption (Tons)	Biomass Fueled Capacity (MW)
Allen S King	Washington	598	88,065	25
Austin Northeast	Mower	32	6,381	1
Black Dog	Dakota	700	51,978	26
Clay Boswell	Itasca	1,073	219,658	54
High Bridge	Ramsey	277	62,837	14
Hoot Lake	Otter Tail	138	28,981	7
Riverside	Hennepin	404	77,157	19
Sherburne County	Sherburne	2,129	551,458	106
Silver Lake	Olmsted	99	12,539	5
Syl Laskin	St Louis	116	29,153	6
<b>TOTAL</b>		<b>5,574</b>	<b>1,138,207</b>	<b>262</b>

## OPPORTUNITY 2: BIOMASS COMBINED HEAT AND POWER

Some current projects to reduce or eliminate purchases of natural gas suggest that avoiding fossil fuel costs will justify the costs of many future biomass projects. The Koda Energy project at the Rahr Malting facility, for example, will substitute biomass for a substantial portion of the natural gas the plant now uses for process heat. It also will generate 12 MW of excess power for sale. The gasifier at Central Minnesota Ethanol Cooperative (CMEC) will eliminate purchases of natural gas and generate 1 MW of green electricity to sell to Xcel Energy. Chippewa Valley Ethanol Cooperative (CVEC) also will avoid purchases of natural gas through gasification, but, unlike CMEC, it doesn't plan to generate power.

These projects go beyond the old model of waste-to-energy, which was to use residues generated on-site. Rather than using its own DDG residues, CMEC initially will fuel its gasifier with waste wood from manufacturers in the area. It has signed a 10 year supply contract with the fuel supplier, who has nearly two years' supply on hand. If later it finds it can't buy enough wood, CMEC will apply for permission to gasify its DDGs. CVEC, on the other hand, will use DDGs from the outset, but it will test its system's ability to handle other fuels besides its own residues. Rahr Malting will use its own malting residues, but it has sized its system to handle several times more than that so it can buy other agricultural and processing residues from suppliers in the region.

## OPPORTUNITY 3: SUBSTITUTING BIOMASS FOR COAL

A number of CHP facilities that burn coal, like the three American Crystal Sugar plants, St. Johns University, and the New Ulm Public Utilities plant, also may see advantages in switching to biomass. Because they are major biomass processors, the American Crystal Sugar plants look especially promising as biomass power producers. They can sell some of their byproducts at good prices, but others of lesser value could serve as fuels.

## OPPORTUNITY 4: RETROFITTING EXISTING BIOMASS FACILITIES

Minnesota's pulp and paper mills already burn biomass to generate electricity and process heat for use on site. The REPIS database, which provides information on renewable energy facilities in the country, shows that most of the boilers in use at those facilities are more than 30 years old, and some are as old as 80 years.

When the time comes to replace those old direct-fire boilers, new systems employing more advanced technologies could extract much more useful energy from the same amount of biomass fuel. A Biomass Integrated Gasification Combined Cycle (BMIGCC) system could double the facility's electrical generation while continuing to meet thermal loads. In effect, the BMIGCC system would turn a kraft pulp mill into a utility-scale power plant.

Minnesota Power, which already has formed partnerships with some of its pulp and paper customers to operate traditional boiler plants, could move farther in that direction by helping to build state-of-the-art biomass power facilities at the mills. Minnesota's new renewable energy standards provide a new incentive to the state's utilities to join in such investments.

## OPPORTUNITY 5: BIOMASS POWER AT ETHANOL FACILITIES

We have mentioned the gasifier at Central Minnesota Ethanol that produces syngas to replace natural gas. Syngas also fuels a turbine that generates electricity to use internally and sell to Xcel Energy. The gasifier's biomass fuel is not processing waste but waste wood purchased from area manufacturers.

Another interesting project, this one located outside Minnesota, is similar in using outside biomass for process energy. The E3 BioFuels ethanol plant in Mead, Nebraska is built next to a 27,000-head feedlot. Manure from the feedlot is run into an anaerobic digester to produce biogas fuel for the ethanol plant's boilers. As yet the plant doesn't generate electricity, but the project shows how two seemingly unrelated segments within agriculture can become symbiotic (Gillam, 2007).

Two cellulosic ethanol projects that recently received federal funding do plan to generate electricity on site. Abengoa Bioenergy in Chesterfield, MO, will sell excess power to a neighboring corn mill. ALICO, Inc. in LaBelle, FL, will use an innovative combination of gasification and fermentation to generate ethanol, hydrogen, ammonia, and 6.25 megawatts of power (DOE, 2007).

Traditional dry-grind corn ethanol plants generate a byproduct called dried distillers grains (DDGs) that they currently sell for animal feed. A recent study (Morey, Tiffany, and Hatfield, 2005) evaluated the potential of DDGs, as well as corn stover, to serve as fuel in scenarios beginning with satisfaction of thermal loads, proceeding through energy self-sufficiency, and ending with export of power to the grid. This last scenario had the facility consuming all the DDG's produced on site (17.5 lbs per bushel of corn consumed) or 22.1 lbs of corn stover per bushel of corn consumed, resulting in net energy of 3.27 kWh per gallon of ethanol produced (4.36 kWh gross energy). If all dry-grind ethanol distilleries in Minnesota adopted the ultimate scenario they would generate gross power of 208 MW, of which 156 net MW would be surplus for sale to the grid.

**Table X-2: Potential Generating Capability of Minnesota's Ethanol Plants**

Plant Name	County	Plant Total Capacity (Gallons)	Gross Generating Capacity (MW)	Net Generating Capacity (MW)	Green Tons DDGS Consumed	Green Tons Stover Consumed
Northstar	Blue Earth	48,000,000	20	15	420,000	530,400
Al-Corn	Dodge	34,000,000	14	11	297,500	375,700
Corn Plus	Faribault	45,000,000	19	14	393,750	497,250
Pro-Corn	Fillmore	40,000,000	17	13	350,000	442,000
Exol/Agri Resources	Freeborn	40,000,000	17	13	350,000	442,000
Bushmills	Kandiyohi	40,000,000	17	13	350,000	442,000
Central Minnesota Ethanol	Morrison	22,000,000	9	7	192,500	243,100
MN Energy	Renville	18,000,000	8	6	157,500	198,900
Corn-er Stone	Rock	21,000,000	9	7	183,750	232,050
Heartland	Sibley	37,000,000	16	12	323,750	408,850
DENCO	Stevens	24,000,000	10	8	210,000	265,200
Chippewa Valley ethanol	Swift	44,000,000	19	14	385,000	486,200
Ethanol 2000	Watonwan	30,000,000	13	10	262,500	331,500
Granite Falls Energy	Yellow Medicine	48,000,000	20	15	420,000	530,400
<b>TOTAL</b>			<b>208</b>	<b>156</b>	<b>4,646,250</b>	<b>5,867,550</b>

The decision whether to build generation into a project whose primary motive is replacing natural gas may depend on electrical rates. Operations with high load factors and low electrical rates, like ethanol plants, may not be able to justify the cost of a turbine even if one were technically feasible (Nilles, 2006). Ethanol plants wanting to add electric generation may have to seek financial and technical help from utilities who can add the outputs to their renewable energy portfolios.

## **OPPORTUNITY 6: BIODIESEL IN GENERATOR SETS**

In the case of ethanol, electricity is used to make biofuel; but in the case of biodiesel generators, biofuel is used to make electricity. Standby diesel generators, diesel genset peaking plants, dual fuel capable combustion turbines and fuel oil fired boilers all can run, in whole or in part, on biodiesel fuel. In some instances, biodiesel may work even better than petroleum-based diesel fuel.

Using biodiesel in standby generators offers several benefits. Sometimes operators of standby generators take out permits allowing them to run only during outages because the application

for a full-time permit is more complicated. Gensets burning B100 (100%) biodiesel emit far fewer pollutants, like hydrocarbon, sulfur, carbon monoxide and particulates, than generators using petro-diesel (although NOx emissions may be higher). Thus standby generators burning biodiesel perhaps could operate more hours per year without exceeding permit restrictions. If that were the case, utilities and their large commercial and industrial customers could treat standby generators as dispatchable peaking generators.

A recent report in The MMUA Resource reviewed a number of diesel generators operated as peaking plants by municipal electric cooperatives. Attracted by the high lubricity of biodiesel fuel as well as the chance to support local biodiesel industries, the co-ops have begun to add up to 20% biodiesel into their fuel mix. Last year, locally-owned municipal power plants generated 932 megawatt hours of electricity with biodiesel.

Besides standby and peaking generators, baseload generators are being tested using biodiesel. McMinnville Electric, in Tennessee, has been running long term tests with B100 in a 2 MW generator. The somewhat lower BTU content of the B100, as well as its somewhat different chemical composition and emissions profile, have required minor adjustments to equipment. The New York Power Authority recently tested biodiesel in the boiler of the 885 MW Charles Poletti Power Project in Astoria, NY, in mixtures ranging from B5 to B20. The Authority reports that efficiency rose and emissions fell.

Using the eGRID database, we estimate the fuel oil consumed by all Minnesota electric generating facilities in 2004 at approximately 63,970,000 gallons, close to the 63,150,000 gallons of our annual biodiesel production capacity. We don't expect utilities to use 100% of our biodiesel production as a substitute for petro-diesel, but there is plenty to add to the fuel mix of standby and peaking generators, which burn approximately 2.2 million gallons per year. Even if they used pure, unmixed biodiesel, they would consume just 3.5% of the state's biodiesel capacity.

## **OPPORTUNITY 7: ANAEROBIC DIGESTERS**

The attractiveness of anaerobic digesters will depend in large part on the non-energy benefits provided by the digester and on the ability of farmers to monetize those benefits. Savings from reduced use of fertilizers and herbicides may be nearly as large as revenue from electricity sales. From a strictly cost of electricity perspective, anaerobic digesters typically result in electricity costs of around 12¢/kWh. However, if the cost avoidance (and resulting operational benefits) created by the digestion process are included, the resulting cost of electricity (and therefore the cost that the owner would need to recover in order to be financially whole) is more on the order of 4¢/kWh.

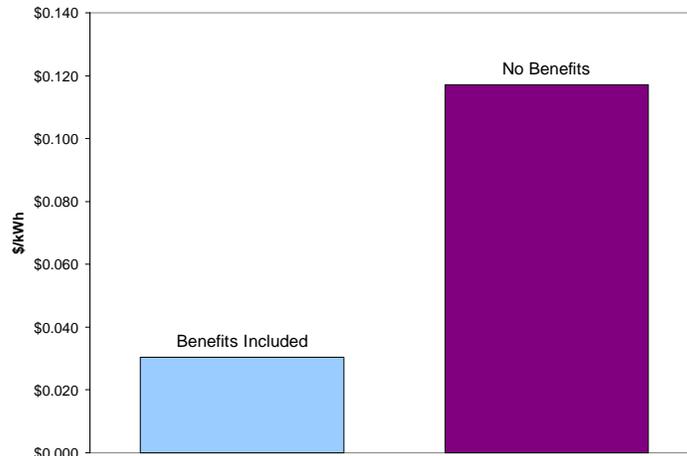


Figure X-1: Comparison of Anaerobic Digesters

## OPPORTUNITY 8: ELECTRIC-ONLY POWER PLANTS

Electric-only power plants fueled by biodiesel are likely to be the least cost-effective type of biomass power plants. This is largely due to the fact that such facilities would be expensive baseload facilities burning expensive fuels. There are two options for electric-only biomass plants: direct combustion and gasification.

**Direct combustion electricity-only.** Of all available options, direct combustion plants would generate the most expensive biomass power. Capital and fuel costs would be high, and combustion boilers inefficient. Size constraints imposed by costs of collecting and transporting biomass would prevent them from taking advantage of economies of scale important in baseload facilities.

**Gasification electricity-only.** Gasification technologies are more promising than direct combustion technologies for generating electricity because they offer a wider range of applications. They can be used in conjunction with combined-cycle facilities, combustion turbines, gensets or simple syngas-fired boilers. If gasifiers become less costly, their compatibility with downstream technologies like these will make them the obvious choice for many biomass power plants in the years to come.

## OTHER CHP OPPORTUNITIES

A number of studies have examined prospects for developing combined heat and power plants in general, and some have considered their development in Minnesota in particular. Typical candidates exhibit large, relatively constant thermal and electrical demands and a low power to heat ratio.

One study (Minnesota Planning, 2001) which has proven prophetic, found that, at the time of its writing, the four most attractive prospects among Minnesota's industrial and commercial facilities were Rahr Malting, Chippewa Valley Ethanol, the Duluth Steam Cooperative and St. Mary's Duluth Clinic Health Systems. Rahr now is building a biomass-fired CHP system and Chippewa is developing a biomass gasification project.

While this study did not focus specifically on the use of biomass fuel, those two projects were in a good position to use it. The study also looked for promising candidates in categories like agricultural processing, food processing, pulp and paper and mining, but wasn't able to adduce enough information for a conclusive evaluation.

Some other categories which typically are located in urban areas, like commercial buildings, hospitals and district energy systems, are unlikely to adopt biomass CHP because of its noise, dust and problematic logistics.

## SUMMARY

The table below summarizes opportunities to develop biomass power in Minnesota and compares their potential according to important criteria. Industrial CHP and co-firing in existing coal plants are the most attractive options in terms of economics and scale. Biodiesel and anaerobic digesters are economically viable in certain circumstances, but they will contribute little to Minnesota's total electrical generation. Biomass-only power plants may have the greatest energy potential, but since they are the most expensive of the options, they will not be economically feasible unless costs of other fuels increase dramatically. They also compete directly against existing uses of biomass resources rather than complimenting them, as co-generation does.

**Table X-3: Bio-Power Opportunities in Minnesota**

Opportunity	Minimal Infrastructure Upgrades	Fuel Costs	Capital Costs	Strengthens Existing Business	Potential Magnitude
Co-Firing	Yes	Medium	Low	Possibly	High
Industrial CHP	Yes	Low to High	High	Likely	Medium to High
Biodiesel Generators	Yes	High	Low	Possibly	Low to Medium
Anaerobic Digesters	No	Low	High	Likely	Low
Electric Only	No	High	Very High	No	Medium to High

# CHAPTER XI: BIOMASS POWER PROJECT DEVELOPMENT HANDBOOK

## INTRODUCTION

A biopower project is a multifaceted endeavor which might take several years from start to finish. The process requires expertise in a wide range of subjects, from agricultural practices and power plant economics to the regulation and financing. Such a broad range of knowledge can be found only in specialists in these areas. Whether those specialists are partners in the project or independent consultants, their work in developing a bio-power project will require substantial investments of time and money.

This Project Development Handbook provides a starting point for parties interested in developing a biomass power facility. Its first section is a list of the Conditions Precedent typically required prior to the financing of a project. These may vary for different projects, but the list gives an indication of the many issues that must be dealt with to complete a project successfully. The second section provides greater detail on some of the Conditions Precedent listed in the first section. This is far from a complete “how to” guide for biomass power projects, but it does focus on information on topics specific to biomass power.

## CONDITIONS PRECEDENT

Certain Conditions Precedent will need to be met in order to obtain financing for a biopower facility. These Conditions Precedent represent the current understanding of key requirements typically imposed by bond insurers, rating agencies, letter of credit banks, and investors. They may change, or new conditions may be added, as the project develops. Typical Conditions Precedent are as follows.

**Power Purchase Agreement:** a Power Purchase Agreement with a credit- worthy, ratable utility. The Power Purchase Agreement will be reviewed to verify that Project Economics properly represent the contact and conditions through the full term of the financing. The agreement should show annual rate escalators based on inflation.

**Steam Off-Take Agreement:** an agreement with a credit-worthy or ratable steam purchaser for the full term of the financing, or, in the absence of a full term agreement, a cancellation penalty that provides the energy island owner a revenue base sufficient to re-position the facility, find alternative users or alternative sources of revenue from electrical generation. The steam off-take agreement rate should be based on indexes and adjustable to changing fuel costs and uncontrollable circumstances such as changes in state or federal regulations.

**Biomass Fuel Supply Contract:** assurance of biomass fuel supply along with an indexed cost structure with a ratable or credit-worthy fuel consolidator or generator. The contract with the fuel supplier will need to be structured to avoid its characterization as speculative. The agreement should be for the full term of the financing.

**Ash Disposal:** an ash disposal plan and facility to address Minnesota Pollution Control Agency requirements.

**Waste Landfill:** a contract with a landfill stating and securing the term and charges for disposing of non-processable biomass from the power facility.

**Permits:** all permits relating to air quality, water, wastewater, storm water, fuel storage, land use, fuel processing, construction and operation. Certain permits will be contingent on final tests during facility start-up prior to a Certificate of Commercial Operation.

**Construction Agreement:** a fixed-price contract with a reputable, credit-worthy prime contractor experienced in managing complex energy projects who can assure completion and specified performance. A letter from the general contractor's surety company indicating their willingness to underwrite the surety guarantees for the project will be required.

**Technology Agreement:** an agreement with a reputable or credit-worthy vendor to supply a market-tested process technology with full guarantees. The agreement must provide for full design "Chute-to-Stack" Drawings, specifications and stand-by availability of replacement parts and components, and such other support needed to keep the facility operating at a minimum level of 85% of capacity.

**Operating Agreement:** an operating plan that includes the staff experience, the training regime, and the capital improvement and maintenance budget that assure proper operation of the new facility. If the operator is to be an entity other than the owner, then the operator should not only be credit-worthy or reputable but also demonstrate experience in managing multi-fuel energy facilities.

**Supply Agreements:** bids from suppliers of key components based on their respective designs for the project. These will be needed before prime contractors can make firm bids to the Owner of the overall project. Included, but not limited, in that list of components are the following:

- Turbine Generator
- Air Pollution Control Equipment
- Boiler
- Combustion Equipment
- Cranes
- Fuel Processing and delivery Equipment
- Ash Removal Equipment
- System Controls

Any warranties and guarantees for the supply of these components will need to be reviewed by owner's counsel and bond counsel.

**Risk Management Assessment:** a thorough risk assessment of the of the new facility's supply, construction, start-up and operating periods undertaken by the owner and its engineers, risk managers and prime contractor. A plan for managing the varying degrees of risk should be developed and reasonable methods of mitigating project risk through insurance or bonding should be considered.

**Labor Agreement:** some form of agreement with labor and trade unions that the biomass energy project will be exempt from any work shut-downs or strikes. An accelerated project timetable and/or time-limited project financing may require such an agreement.

**Finance Plan:** a plan of finance, drawn up by the owner and its attorneys, financial advisors, bond underwriters and feasibility consultants, that includes provisions for revenue flexibility, supplemental funding and operating and debt reserves. The plan and the structure of any

financial obligations must give priority to funding the project's construction, operation, maintenance and rate stabilization reserve before any net revenues can be transferred to the owners.

**Consulting Engineer:** a third-party engineer engaged by the owner at its own expense to provide a technology review to bond insurers or extenders of letters of credit.

**Site Control:** a purchase agreement, along with complete environmental review and contracts for utility access, on the energy island facility site. This must be provided prior to closing on project financing.

## OTHER CONSIDERATIONS

### Ownership and Financial Structure

A power plant may be owned publicly, privately, or both publicly and privately. The project may be partially financed with tax-exempt debt depending on the fuel type employed and the opinion of counsel. Financing for a publicly owned facility may be secured, partially or completely, by the full faith and credit pledge of the city. An alternative to ownership by the city alone might be joint ownership with regional counties. A public/private partnership could include equity contributions by public entities, the private project developer/operator, and the steam purchaser. Depending on the terms of the contracts and the credit commitments of the parties to a public/private partnership, debt-to-equity ratios may range from 80/20% to 60/40%. A principal concern will be the stranded/unamortized debt beyond the negotiated term of the steam purchaser's contract.

### Feedstock and Site Selection

The interwoven choices of feedstocks and plant location are critical in deciding the success or failure of a biopower project. In some instances, one or both of those decisions will be obvious. This would be the case for projects generating power for use on site with a fuel generated on site, or projects designed to satisfy a thermal load at an existing consumer. Where the choice of feedstock and location are not so obvious the process of selecting each will require evaluation of a number of factors.

### Sufficient Feedstock Supplies

The success of any bio-power facility depends on the long-term supply of feedstock. This means much more than just determining that sufficient biomass currently is available within a cost-effective distance of the plant. Investors and lenders will want to see a long-term fuel supply plan ensuring that it will be available in the future. Better yet would be a long term fuel supply contract with an established supplier. Unfortunately, this may be difficult to achieve because the biomass fuel market is immature and localized. Long-term fuel supply may entail the development of a subsidiary fuel supplier or a co-op dedicated to delivering sufficient biomass to the plant.

### Access to Existing Utility Infrastructure

Finding a site with existing access to necessary utilities helps to avoid significant capital costs. Depending on power plant design, a bio-power facility may need access to natural gas

pipelines, city water and sewer connections, electrical distribution and/or transmission infrastructure. The cost of extending utility infrastructure to connect with a new facility can be considerable. Minimizing these costs is a major consideration in developing a cost-effective biopower project.

## **Access to Adequate Transportation Infrastructure**

If a biopower project is to rely on biomass fuels generated offsite, it will have to find a location with transportation infrastructure capable of supporting the additional use that will result. If a facility is to utilize rail infrastructure, access to a rail siding will be necessary. If a facility is to rely on road transport for delivery of fuels, developers must ensure that the road infrastructure between the bio-power facility and its fuel supplies is rated for the additional heavy truck traffic and that if seasonal weight restrictions apply they can be accommodated. Other related considerations include facility design that will minimize the turnaround time for delivery trucks or trains. This will help minimize delivered fuel costs by reducing the downtime of fuel suppliers' equipment.

## **Sufficient Water Supplies**

Nearly all biopower facilities require some amount of water for plant operations. Water can come from deep or shallow aquifers, surface waters or municipal water supplies. The costs and benefits for each of these sources can vary considerably. Municipal water supplies are likely to be the most expensive and their quantity may be limited. Any facility that will withdraw 10,000 or more gallons of water per day will require a water appropriations permit. To securing the permit the project will have to show that the withdrawal will not have an adverse effect on neighbors or the environment. Ground water supplies are quite limited in portions of the state, so steps should be made to ensure access to adequate supplies early in the planning process. In recent years a number of industrial facilities have been denied water permits due to limited availability.

## **Supportive Local Community**

The support of the local community is a crucial element for any large biopower facility. Local support can be achieved through public input during the planning stages and/or providing local residents with a stake in a facility's success.

## **FACILITY DESIGN**

Project developers face a number of crucial design decisions early in the planning process. Among the most important is the decision whether the facility will supply power to the grid or merely offset power purchased from the grid. That choice, along with the project's potential to serve a thermal load as a CHP plant, will determine the fundamental economic parameters of the project. Another design option is a conversion technology that allows the use of multiple fuels.

## **FINANCING**

Funding expensive projects like power plants usually involves more than one financing vehicle. Some equity – what lenders call “feet-to-the-fire” money – almost always is the first requirement. Some of that may come from the New Markets Tax Credits program (see Chapter VII, above) or

from local, regional or state venture funds. (Professional venture capital firms are not interested in project financing.)

First-position commercial lenders often limit their loans to 50% of the assets financed. If equity investment doesn't provide the balance of project cost, the developer may resort to a number of government "gap" financing programs that take a subordinate position to the commercial loan (Chapter VII). In larger projects, a bundle of those gap loans from various agencies may be needed to rise to the necessary level. From a collateral standpoint, commercial lenders regard subordinated debt as virtual equity because in a default the first position lender has a lien on all of the assets financed. But from a cash-flow standpoint the first-position lender will be concerned if it sees payments on subordinated debt biting too deeply into cash.

Government first-position loan programs are tax-exempt, but they don't work for power projects. Industrial Development Bonds (IDBs) are capped by federal law at 80% of a maximum total project cost of \$20 million, too low for most power projects. And in any case they are restricted to manufacturers. In rare cases, municipalities have issued general obligation bonds for facilities that can provide some public benefit – a recycled paper mill once was financed as a municipal waste treatment plant – but that can be contentious.

A developer contemplating a bio-power project is well advised to discuss financing options early with a reputable investment bank. As the development moves forward, project financing will condition many of its decisions

## **Biomass Project Finance Steps**

The typical financing of a bio-power project occurs in four phases that covering a period of ten to twelve weeks: Planning, Documentation, Issuance and a Post Sale phase.

**Planning Phase.** The Planning Phase entails a number of meetings for finance team members. They will prepare a detailed analysis of options for the structure of the financing. At the end of the Planning Phase a plan will be decided upon, and a preliminary schedule of events will be drafted.

**Documentation Phase.** During the Documentation Phase, staff and legal counsel will develop resolutions, indentures, loan agreements and any required notices. All necessary economic data will be assembled for inclusion in the offering documents. Presentation packages will be developed for rating agencies and bond insurers. Finally, legal counsel will draft the preliminary offering documents, as well as any supplementary amendments to the loan agreement or indenture.

**Issuance Phase.** During the Issuance Phase, the materials prepared for rating agencies and bond insurers will be distributed. Potential investors will receive a prospectus and indicate their level of interest during a survey. A pricing plan will be developed and the interest rate environment will be assessed. The loan or bond syndicate will need to be organized and managed, and the distribution of bonds planned. Briefing materials need to be prepared to educate interested investors in the key features of the loan or bonds. The final step during the issuance phase is the actual purchase of the loan or bonds by investors.

**Post-sale Phase.** The Post-sale Phase involves the transfer of all funds and the management of the bond or loan proceeds. All final documents must be prepared, and an official statement released summarizing the results of the issuance. Finally a post-sale analysis will be prepared for the finance team.

## **ENVIRONMENTAL PERMITS**

A bio-power project will need a number of environmental permits from the state. The permits required for a given facility will vary depending on its size, the fuels it will use, and its emissions and effluents. Since projects vary so much in their particulars, we won't try here to summarize all the specific permits that might be called for.

## **ENVIRONMENTAL ASSESSMENTS**

There are three general types of environmental assessments that the Minnesota Environmental Quality Board may require of specific bio-power projects: an Environmental Assessment Worksheet (EAW) and/or an Environmental Impact Statement (EIS). These assessments are preliminary to any other governmental approvals. The EQB offers a third alternative to communities rather than to specific projects: the Alternative Urban Area-wide Review (AUAR).

### **Environmental Assessment Worksheet**

Environmental Assessment Worksheets (EAW) are prepared by the Responsible Governing Unit (RGU) for a proposed facility. Following the completion of the EAW the RGU must distribute the EAW to the Environmental Quality Board and all offices on the EQB's official distribution list. Notice of the EAW will be published in the EQB Monitor, which begins the 30-day public comment period. Following the public comment period the RGU will respond to comments, issue findings of fact, and decide if an Environmental Impact Statement is necessary. If no EIS is necessary the project is eligible to receive state permits.

### **Environmental Impact Statement**

An environmental impact statement is a much more in-depth review of the environmental effects of a proposed facility. An EIS may be required by the RGU based on the Findings of Fact of the EAW. The EIS analyzes environmental, social, and economic impacts of a proposed project. The first step of an EIS is scoping or deciding what impacts and alternatives will be covered by the EIS and to what extent. It is prepared by the RGU and submitted for public review and comment for at least 25 working days (EQB, 1998). The RGU then completes the final document based on the comments received, and makes a decision as to the sufficiency of the EIS. If the EIS is deemed sufficient the facility becomes eligible for state permits.

The rules governing the need for an EAW, or EIS, and the assignment of the RGU are complex. The environmental Quality Board, the Minnesota Pollution Control Agency and the Minnesota Public Utilities commission all have information available on their websites to help project developers navigate the process.

### **Alternative Urban Area-Wide Review**

In the AUAR process, the RGU, in advance of any specific development project, prepares a review of an entire area within its jurisdiction rather than one isolated site. That is sent to the EQB and. Any subsequent project within the AUAR boundaries that conforms to the AUAR's characterizations is approved without having to go through other reviews.

The EQB staff recommend the AUAR over an EIS because it offers advantages to community and developer alike: a holistic rather than piecemeal approach, fewer public hearings, a shorter timeline, lower overall costs, and pre-approved sites for development.

## **Size Criteria for Environmental Reviews**

The following information provides a general overview of the considerations for different sized plants. It should not be seen as a definitive explanation of the environmental permitting process.

### ***<5 MW***

Proposed Electric Generating facilities at a single site of less than 5 MW capacity are exempted from the EAW process.

### ***5 MW to 25 MW***

Proposed electric generating facilities with a capacity from 5 to 25 MW have the option of initiating the environmental review process. These facilities may also be compelled to do so by their RGU, or through a public petition.

### ***25 MW to 50 MW***

An Environmental Assessment Worksheet will need to be completed for electrical generating facilities with a capacity between 25 and 50 MW. The Environmental Quality Board is the Responsible Governing Unit (RGU) for these facilities.

### ***50 MW to 80 MW***

The Minnesota Public Utilities Commission is responsible for the permitting and environmental assessment of electric generating facilities with a capacity greater than 50 MW. Such facilities may be subject to a full review, which includes the proposal of an alternate site, the preparation of an Environmental Impact Statement by the Department of Commerce, and a contested case hearing.

Proposed facilities between 50 MW and 80 MW capacities have the option of pursuing an alternative permitting process. This involves the generation of an environmental assessment by the Department of Commerce, followed by a public hearing under procedures established by the PUC. There is no need to propose an alternate site for these facilities. These facilities also have the option of requesting that a local unit of government be assigned jurisdiction over the permitting and environmental assessment for the project.

The following websites are useful places to start investigating the process:

- <http://www.pca.state.mn.us/news/eaw/index.html>
- <http://www.eqb.state.mn.us/EnvRevGuidanceDocuments.htm#Environmental%20assessment%20worksheets>
- <http://energyfacilities.puc.state.mn.us/powerplants.html>

## AIR PERMITS

The Minnesota Pollution Control Agency is responsible for granting air quality permits. To receive an air quality permit a facility must meet a number of state and federal requirements to minimize the impact of a facility on the local environment. Generally, any facility that has the potential to emit (PTE), a regulated pollutant at quantities greater than specified amounts, must obtain an air quality permit. Regulated pollutants include hazardous air pollutants (HAPs) and criteria pollutants. HAPs are chemicals that are known, or suspected to, cause cancer or other serious illnesses. Criteria pollutants are known to have impacts on human health and welfare.

Generally, permits may be necessary to satisfy federal, and/or state regulations. Minnesota has somewhat lower PTE thresholds for some pollutants than the federal government, so in some instances a facility may not require a federal permit but still require a state permit. Any federal air quality permit for a power plant will be an individual total facility permit. Minnesota offers a number of simplified air quality permits for facilities whose PTE is sufficient to trigger permitting requirements but which are unlikely to exceed emissions thresholds in practice, or commit to maintaining their emissions below threshold levels.

Further information regarding air quality permits can be found at the MPCA website (<http://www.pca.state.mn.us/air/permits/forms.html>).

### Air Emissions Risk Analysis (AERA)

An AERA may be a component of an EAW, EIS or a prerequisite for an air quality permit. An AERA is a standardized process used to assess the health impacts of a facility's air emissions. It looks at emissions rates, toxicity and dispersion modeling to generate a risk assessment. It also includes an analysis of proximity to residences, as well as proposed operating procedures and risk-minimizing procedures. This information is used to estimate a facility's impact on human health.

The MPCA will request the submittal of an AERA for any electrical generating facility greater than 25 MW. Smaller facilities may still require an AERA if the expected emissions of any criteria pollutant are greater than 100 tons per year after the use of control equipment. Further information regarding AERAs is available at <http://www.pca.state.mn.us/air/aera.html>.

## WATER PERMITS

The Minnesota Department of Natural Resources is the agency primarily responsible for granting water appropriation permits. The primary consideration in the water appropriations permitting process are the sufficiency of water supply and natural resource impacts of the permitted water use. Minnesota requires a water appropriation permit if a facility will utilize more than 10,000 gallons per day or one million gallons per year of surface or ground water.

### Ground Water

If a facility's source will be ground water, an aquifer test is necessary to confirm the sufficiency of supply to the site. This entails withdrawing water from the aquifer at the proposed rate for the facility for seven days. During this time nearby private wells must be monitored for any impacts.

## Surface Water

If a facility is to rely on surface waters some of the primary considerations relate to the maintenance of habitat quality and the ability to continue to use a water body for existing and higher priority uses.

More information regarding water appropriations permit requirements can be found at [http://www.dnr.state.mn.us/waters/watermgmt\\_section/appropriations/permits.html](http://www.dnr.state.mn.us/waters/watermgmt_section/appropriations/permits.html).

## Water Discharge Permit

The Minnesota Pollution Control Agency is responsible for the issuance of water discharge permits. A power plant may require a National Pollutant Discharge Elimination System (NPDES) and/or a State Disposal System (SDS) permit. If required, these permits must be issued prior to the start of construction. Further information can be found on the MPCA website at <http://www.pca.state.mn.us/water/permits/index.html>.

## Public Waters Work Permit

A bio-power project that will impact a body of water may require a public waters work permit. The Minnesota Department of Natural Resources is the agency responsible for these permits. Information regarding the requirements for these is available at [http://www.dnr.state.mn.us/waters/watermgmt\\_section/pwpermits/requirements.html](http://www.dnr.state.mn.us/waters/watermgmt_section/pwpermits/requirements.html).

## UTILITY INTERCONNECTION AND RATE AGREEMENTS

The terms of utility interconnection and rate agreements will vary depending on project size. Minnesota has enacted a number of measures to facilitate the interconnection of small distributed generating facilities. Facilities with generating capacity of 10 MW or less are eligible for standardized interconnection and rate agreements. Larger facilities must negotiate a PPA with a purchasing utility, or choose to sell power to the wholesale market.

### Utility Interconnection

With direction from the legislature, the Minnesota Public Utilities Commission has established standards relating to the interconnection process and requirements for electric generators of 10 MW or less. The order establishing these standards is available here <https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=1904618>.

In addition, local utilities may have information regarding the interconnection process on their websites.

Facilities larger than 10 MW are not governed by the standardized requirements. Those interested in a plant larger than 10 MW should contact their local utility to enquire about the interconnection process.

## Rate Agreements

### *Facilities of <40 kW*

While few biomass facilities will be less than 40 kW in capacity, those that are meet eligible for net metering – receiving payments for any net energy exported to the grid at the “average retail utility energy rate.” Those interested may contact their utility to enquire about the specific terms of a net metering arrangement.

### *Facilities < 10 MW*

The legislature has required that the state's utilities establish generic tariffs for distributed generation facilities. These standardized rate agreements are meant to apply to generation facilities with 10 MW or less of capacity. Unlike the statewide standardized interconnection agreement, each utility has developed a unique distributed generation tariff. Although these tariffs should be made available to the public, some utilities regard information contained in the tariffs as trade secrets. For this reason interested parties may need to sign a non-disclosure agreement in order to see the proposed rate structure.

### *Facilities > 10 MW*

Facilities with generating capacity greater than 10 MW will most likely need to sign a Power Purchase Agreement (PPA) with one of the state's utilities. Such an agreement does not necessarily have to be with the local utility. In certain circumstances, state law requires the local utility to provide wheeling or exchange agreements to other utilities within the state. If the power purchase agreement is made with a regulated utility, the Public Utilities Commission (PUC) will need to approve the PPA.

Often a PPA is necessary to secure financing for a facility. It is possible for project developers to circumvent a PPA by constructing a facility to provide power to the wholesale market, but this is a much riskier strategy, and may not be possible if the project will involve substantial debt financing.

### *Allocation of Environmental Attributes*

A biomass power facility may be able to market a number of environmental attributes such as Renewable Energy Credits (RECs) or possibly carbon emission reduction credits. The ability to market these credits may enable a biopower project to command a premium for its electrical generation.

Minnesota's utilities are required to increase their use of renewable energy to 25% by 2025. To facilitate this renewable energy standard, the legislation allows utilities to use Renewable Energy Credits to count toward renewable energy generation portfolio requirements just as though they were purchasing renewable power and retailing it.

Project developers should consider their ability to generate renewable energy credits, and be sure that any PPA is clear as the allocation of the facility's RECs. A bio-power facility does not necessarily have to sell its RECs to the same party purchasing its power. It may sell them to a different utility or to a broker that resells RECs. There is a growing voluntary market for RECs. In this market, environmental organizations purchase renewable energy credits and sell them to

individuals who wish to support the development of renewable energy or reduce their greenhouse gas emissions.

The Midwest Renewable Energy Tracking System (M-RETS) was recently established to facilitate the tracking of RECs. It provides a standardized system for generating, tracking and retiring RECs within a number of Midwestern states. While this system will greatly facilitate trade in RECs, M-RETS is not itself a market. To date there is no established, liquid, market where REC generators can easily sell their product. Without such a market a bio-power facility probably will find it advantageous to enter into a long term contract for its RECs. More information about the M-RETS system is available here <http://mrets.net/index.asp>.

A biomass power facility may also be able to sell carbon emission reduction credits, or other environmental rewards. These markets differ somewhat from RECs and involve a different set of standards for certification. In most instances it will not be possible to sell both a REC and a carbon emissions reduction credit for the same quantity of energy; but the ability to sell credits into both markets may enable a facility to pursue the best price for its environmental rewards.

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# APPENDIX A : BIOPET MANUAL

(version 1.1)

**Navigation Bar**

- Main
- Directory
- Feedstock
  - Availability
  - Defaults
  - Processing
  - Storage
  - Power Plant
- Power Plant
  - Expenses
  - Financing
- Project Summary
- Logs
  - Feedstock
  - Power Plant
  - Project

**BioPower Evaluation Tool**

Main

Worksheets

- Step 1) Define and Save Feedstock Scenarios
- Step 2) Define and Save Power Plant Scenarios
- Step 3) Evaluate and Save Project Summaries

Tools

- User's Manual
- Scenario Logs
  - Feedstock
  - Power Plant
  - Project

Resources

- Minnesota Directory

Internet Links

- Xcel Energy's Renewable Development Fund
- CEE Reports

Center for Energy and Environment

This tool is intended only to provide general guidance in estimating costs of various biomass feedstocks and technological strategies. The tool provides a comparative analysis of various biomass strategies and not necessarily an accurate estimate of actual final costs.

#### LEGAL NOTICE

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Figure A-1: Main Screen

## INTRODUCTION

This Bio-Power Evaluation Tool was developed to provide general guidance in estimating costs of various biomass feedstocks and technological strategies used to generate electricity from biomass. It is meant to provide a means of comparing various biomass strategies; however it should not be assumed to generate cost estimates of sufficient detail for use as final cost estimates for a proposed project.

The tool allows a user to estimate the annual levelized cost of energy for a proposed power plant based on supply and cost estimates for a range of biomass fuels and power plant characteristics. Default values are provided for most characteristics; however the user is able to assign their own values if they have more specific cost estimates or wish to evaluate the effects of changing parameters on project performance. Factory default values are retained within the spreadsheet and can be restored if necessary.

The Bio-Power Evaluation Tool consists of worksheets to estimate feedstock costs and supply, power plant characteristics and costs, and overall project economics. Users can save feedstock and power plant scenarios as they work and combine those scenarios to assess what combinations of feedstocks and power plants will result in the lowest cost energy. The Evaluation tool also provides a sensitivity analysis for each final project evaluation so that the user can evaluate how sensitive the proposed project is to changes in various costs.

## OVERALL STRUCTURE

The evaluation tool is designed to allow the user to develop different “scenarios” that can be combined later to evaluate different options. There are three scenario types: Feedstock, Power Plant, and Project. The Project Scenario is comprised of a combination of the first two.

### Feedstock Scenario

The development of a feedstock scenario allows the user to build a feedstock development and delivery system ending with a cost per MMBTU for a fully-processed fuel at the power plant. You may make as many Feedstock Scenarios as you wish. All Feedstock Scenarios must be logged to be used for future analysis.

### Power Plant Scenario

The development of a power plant scenario allows the user to define the characteristics of an operating power plant. This includes such things as power plant size, capital costs, operating expenses, rate of return, inflation, etc... Once a scenario has been defined, it must be logged to be used for future analysis.

### Project Summary

Once a Feedstock Scenario and a Power Plant Scenario have been created and logged, it is possible to calculate the estimated cost of delivered energy. One may select a Power Plant Scenario and input different Feedstock Scenarios to evaluate the economic impacts of various options. One may also conduct sensitivity analysis on the Project Scenarios to understand the impacts of fluctuating inputs on the final energy cost. Project Scenarios can also be logged for future reference.

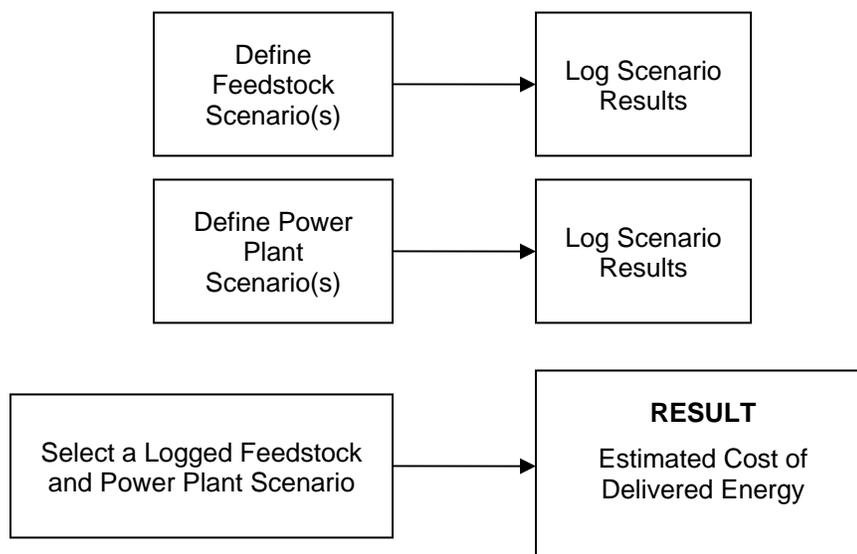


Figure A-2: Evaluation Methodology

The screenshot shows the 'Main Feedstock Screen' with a navigation bar on the left and a main form area. The navigation bar includes links for Main, Directory, Feedstock, Availability, Defaults, Processing, Storage, Power Plant, Power Plant Expenses, Financing, Project Summary, Logs, Feedstock, Power Plant, and Project. The main form area is titled 'Feedstock' and contains the following elements:

- Scenario:** A text input field with the placeholder '<Enter Name>'.
- Feedstock:** A dropdown menu currently showing '<User Defined Field 1>', with a 'Rename Feedstock' button next to it.
- Energy Content:** A text input field with the value '0 Btu/lb'.
- Payment / Market Price:** A text input field with the value '\$ - / ton'.
- Avoided Disposal Costs:** A text input field with the value '\$ - / ton'.
- Recoverable Portion:** A text input field with the value '0%'.
- Moisture Content:** A text input field with the value '0%'.
- Site Processing:** A dropdown menu currently showing 'none'.
- processing cost:** A text input field with the value '\$ - / ton'.
- Feedstock Type:** A dropdown menu currently showing 'fine solids'.
- collection / loading:** A text input field with the value '\$ - / ton'.
- Availability:** A section with a 'Check Availability' button.
- Processing Yard?:** A dropdown menu currently showing 'Yes', with a 'Ship to Processing Yard' button.
- Storage?:** A dropdown menu currently showing 'Yes', with a 'Storage' button.
- Power Plant:** A section with a 'Ship to Power Plant' button.
- Buttons:** 'Restore Look-ups', 'Save Settings', 'Restore Factory Defaults', and 'Save this Feedstock'.
- Calculate:** A 'CALCULATE' button.
- Result:** A display area showing '\$0.00' and '\$ / MMBTU Delivered to the Power Plant (Processed)'.

Figure A-3: Main Feedstock Screen

## BIOMASS FEEDSTOCKS

The user can choose from over 60 biomass feedstocks from the pull down menu, or create their own. Each feedstock can be assigned values for a number of characteristics. Where possible, generic data for each characteristic is provided for each feedstock. In cases where generic information is not provided, or when the user has specific information for a known feedstock source, the user can provide their own information or use values of other feedstocks as a substitute.

After updating information for a feedstock (if needed) clicking "Save Settings" will save the user-provided information and over-write the default values. This allows a feedstock whose attributes vary from the default to be used in multiple feedstock scenarios without requiring re-entry of data in each scenario. Clicking the "Restore Factory Defaults" will return all feedstock information to their original factory-set default values. Clicking "Restore Look-Ups" will reset on-screen values to the saved numbers associated with the currently-selected feedstock, effectively undoing any unsaved changes.

New feedstocks can be created by selecting one of the "User Defined Field" options from the dropdown menu, entering the relevant data, and clicking on "Save Settings." If desired, the user can also rename feedstocks (e.g., to make the name easier to recognize than "User Defined Field").

## Field Characteristics

### *Energy Content*

Each fuel comes with a default value for energy content. The energy content provided is the high heating value for each fuel, which disregards the moisture content of the fuel. Biomass feedstocks are variable by nature, and therefore may vary significantly in their as-harvested/processed energy content. If the user has more specific energy content the default values can be overwritten.

### *Payment/Market Price*

The Payment/Market Price is the price paid to the landowner for the feedstock itself, or the right to harvest the feedstock. If the proposed project is to be fueled with agricultural products for which there is a pre-existing market current market prices should be utilized. Market prices for some commonly traded feedstocks have been provided based on currently available information. If a market price is not provided they can often be found on the web.

For feedstocks for which there is not an existing market price a landowner payment should be entered that represents the price paid for the right to harvest the feedstock. A value of \$10/ton has been entered as a default value for many feedstocks.

Typically, market prices represent the price paid for feedstock that is ready for transportation to storage or the power plant. Additional fields (described below) are provided for a number of other costs, such as on-site processing. Users can choose to break each cost out separately or use the Market Price field to represent the total of all costs prior to the fuel leaving the point of production. The important point is simply to avoid double-counting, so that (for example) processing costs that are folded into the market price are not entered again on the Processing line.

### *Avoided Disposal Costs*

If the fuel is derived from a waste stream, such as processing wastes, or urban wood waste a value can be provided for the avoided cost of disposal.

### *Recoverable Portion*

Some biomass feedstocks cannot be fully recovered. This may be due to the potential for increased soil erosion or decreased soil carbon if too much of the feedstock is removed. It may also be due to technological limitations relating to harvest technology. The percentage of each feedstock that can be removed is highly dependent upon local soil types as well as agricultural practices. For instance, a high percentage of corn stover can be removed only where no-till or mulch till practices are employed. Where these practices are not utilized corn stover should not be harvested. A single value has been assumed for the recoverable portion of each feedstock. The value used represents an average estimate.

### *Moisture Content*

The moisture content of biomass fuels has a significant impact on the percentage of the energy content of the fuel that can be used to produce power. This is due to the energy needed to evaporate the moisture found in the fuel. A fuel's moisture content will depend on the time of

harvest, the extent to which the fuel was dried after harvest and the way in which the fuel was processed and stored. Default values have been provided for a number of the fuels in the model.

### ***Site Processing***

Some degree of processing may be necessary at the source of the biomass feedstock. Agricultural residues may need to be dried and/or baled in the field. Logging residues may be chipped prior to shipment to a storage facility or the power plant. Food processing wastes may need to be dewatered prior to use in an anaerobic digester. Default cost values are provided for each processing option. If more accurate information is available user defined values can be substituted.

### ***Feedstock Type***

The physical characteristics of the feedstock will affect the fuel's collection and loading costs. Bales are handled with different equipment than loose woodchips.

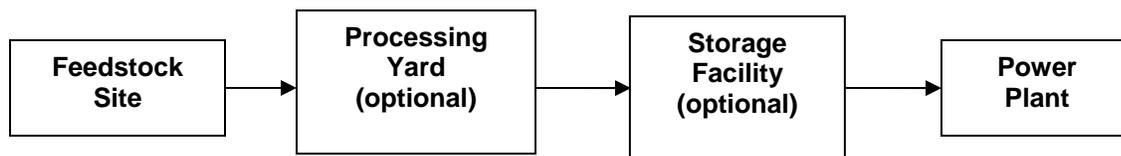
### ***Availability***

The feedstock availability tool provides an estimate of the quantity of a given biomass feedstock available within a defined radius of the desired county. County level feedstock availability was derived from a number of sources including the National Agricultural Statistics Service county level database. For some feedstocks the quantity available had to be inferred from the available data. For instance the quantity of corn stover available was derived from the quantity of corn harvested in each county, based on the typical ratio of corn stover to corn grain.

For the purposes of determining the quantity of fuel available at various transport distances from a proposed facility the biomass resources of each county were assigned to a point at the geographical center of the county. The biomass resources available within 25 to 150 miles (in 25-mile increments) of the county center are determined by the county centers that fall within each radius. For this reason the feedstock availability tool should only be used to gauge the order of magnitude of specific biomass resources within a region. For instance a county center that falls just within the 25-mile radius of another county center may have biomass resources assigned to it that could be significantly more than 25 miles from the original county center depending upon county geography. A proposal for a commercial bio-power plant should include much more detailed estimates of available biomass than what is generated by this tool.

## **Defining the Fuel Delivery Path**

It is necessary to develop a full-cost approximation for the delivery of a fully-usable fuel to the power generation facility. This delivery path can vary significantly across feedstocks and projects and may take many forms. The user is required to select which options will be included in the normal operation of the proposed project.



**Figure A-4: Feedstock Delivery Path**

The most complicated delivery path will include stops at all available stages. If storage will not take place at a dedicated storage facility, but will instead take place at the Feedstock Site, Processing Yard or Power Plant the transport distances under the “Storage” menu should be set to zero. Similarly, if there is not a separate Processing Yard in the delivery path, the distances under “Ship to Processing Yard” should be set to zero.

### ***Transportation Costs***

The user may define up to three different methods of transportation (road, rail, and barge) and the associated distances of each for each link in the feedstock delivery chain. The user may therefore set a delivery path for biomass fuels that includes transporting the feedstock X miles by truck, Y miles by train, and Z miles by barge.

A single default cost value is provided for each mode of transportation and each feedstock. If the user anticipates that transportation costs will be different for each link in the feedstock delivery chain he may define different values for each link. This can be done through entering a new cost per ton/mile under the “Processing Yard”, “Storage” and/or “Power Plant” screens and then clicking on the “Save Settings” button. This will assign the new transportation costs to the relevant link in the supply chain. The user may also enter transportation costs in the “Inputs” worksheet accessed through the “View All Inputs” link on the “Feedstock Selection” screen.

Different transportation assumptions may be made depending upon the consistency of the fuel. The user may define the feedstock as a solid or liquid. This distinction was made assuming that transportation of a liquid would require significantly different equipment for loading and unloading needs.

The cost impact of omitting a stage of the delivery path can be observed by use of the drop-down “Yes” and “No” menus for the Processing Yard and Storage Facility. If the value is set to “No,” the stage will be ignored in calculating the delivered cost per MMBTU. It should be noted, however, that *all* costs associated with the stage will be ignored; if the feedstock must be processed before being used, these costs will need to be added to a different stage in order to preserve the accuracy of the calculation.

## Processing Yard

Figure A-5: Feedstock to Processing Yard Screen

Some biomass feedstocks may be shipped to a processing yard prior to shipment to a storage facility or power plant. There are two general models for processing yards. The first would be local processing yards where materials are hauled a short distance to a local processing facility before shipment to the plant or storage. Instances of this may include logging residues transported a short distance to a central yard where it can be chipped and loaded for transport. The other model for a processing yard is one that is relatively close and accessible to the power plant, and often under the control of the power plant. Such processing yards may be advantageous to facilities with little room for processing or storage. For example, in one known proposal, two separate facilities plan on using a single processing yard due to their inability to store significant quantities of fuel on-site. The partnership will also allow each individual project to capture some economies of scale.

# Storage Facility

**Navigation Bar**

Main

Directory

Feedstock

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Power Plant

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Financing

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Feedstock

Power Plant

Project

## Storage

Scenario  Restore Lookups

Feedstock  Save Settings

Storage Facility

*MN County Distances*

Transportation to Storage solid

Road	miles	\$	-	/ton/mile
Rail	miles	\$	-	/ton/mile
Barge	miles	\$	-	/ton/mile

Storage Processing none

processing cost \$ - / ton

Feedstock Type bundled solids

storage costs	\$	-	/ ton / month	6	Number of Storage Months (average)
collection / loading	\$	-	/ ton		

**Figure A-6: Feedstock to Storage Facility Screen**

Some biomass feedstocks will need to be stored at offsite storage facilities until they are needed by the power plant. This will often be the case for facilities dependent upon biomass that is harvested during a narrow window of time during the year (switchgrass or corn stover for instance). Fuel processing for storage may take place at the storage facility or prior to delivery. Storage facilities can take many forms from stacks of uncovered bales in a field to relatively large fully enclosed storage barns. To estimate storage costs one must estimate the capital and handling costs associated with each storage method as well as the expected dry matter loss associated with each method. Storing unprotected bales in the open requires no capital expenditures and very little handling; however the loss of dry matter from such a storage method can be quite significant.

MN County Distances			
Transportation to Power Plant			<input type="text" value="solid"/>
Road	0 miles	\$ -	/ton/mile
Rail	0 miles	\$ -	/ton/mile
Barge	0 miles	\$ -	/ton/mile
Power Plant Processing			<input type="text" value="none"/>
processing cost		\$ -	/ton
Feedstock Type			<input type="text" value="fine solids"/>
unloading		\$ -	/ton
payment		\$ -	/ton

Figure A-7: Feedstock to Power Plant Screen

## Power Plant

Biomass fuel must ultimately be shipped to the power plant. Once on site the fuel may be stored or immediately processed to generate electricity. Final processing steps often include screening and size reduction to the appropriate particle size. Default costs for transport to the plant, processing and unloading are provided, or the user can provide more specific costs if available.

## Calculate

Once the fuel characteristics and the delivery path are defined, a calculation for the delivered cost of a fully-processed feedstock to the Power Plant is provided. It is the experience of bio-power facilities that a diversity of fuel supplies enables them to keep their costs low as well as enable them to ensure a reliable supply. In addition, the relatively high cost of transporting biomass fuels can have a profound effect on the cost of delivered fuel. For these reasons a user may find it advantageous to estimate the costs of a number of biomass feedstocks transported over a range of distances for a given location. This will enable the user to generate a more comprehensive picture of the biomass fuels available within a region as well as the range of delivered costs that each fuel can be sourced for.

## Save This Feedstock

Each Biomass Feedstock Scenario must be saved in the Feedstock Log. Once all data has been entered, click "Save This Feedstock" to save the feedstock scenario. The cost per MMBTU will be recalculated before saving in order to ensure that the most recent changes are preserved, and the new feedstock scenario is then available for comparison with other scenarios. The data for the scenario can be reviewed, edited, copied, and deleted by selecting "Feedstock" under

“Logs” in the Navigation Menu. Note that every time the user clicks “Save This Feedstock,” a new entry is created in the Feedstock Log, even if an identical entry exists. For this reason, edits should be made in the log, and the Feedstock Worksheet used to create new scenarios.

## ELECTRIC GENERATING FACILITY

The Power Plant Definition worksheet allows the user to generate a number of proposed power plants in order to evaluate the effects of changing power plant characteristics and economic assumptions on proposed projects. Each proposed power plant can be saved with the “Add to Power Plant Log” button. The user must provide many of the values for this worksheet. There are built-in financing assumptions for this worksheet, though these can be replaced with user input.

The economic engine for the Power Plant section is based on the “Generic Biomass Power Plant Model” developed at the University of California – Davis. More highly technical users may get more value from using this and other tools that can be accessed via the web.<sup>6</sup>

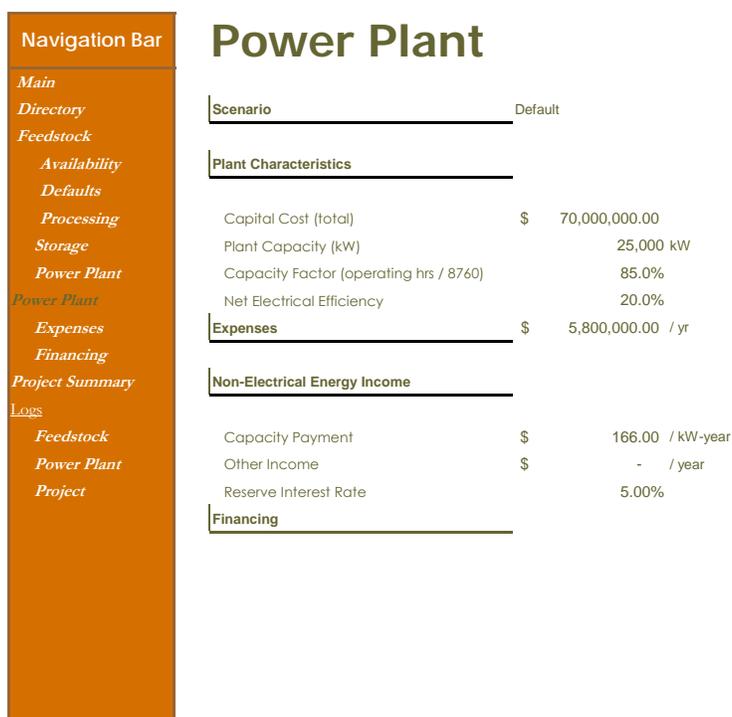


Figure A-8: Power Plant Screen

### Power Plant Characteristics

The user must generate estimates for basic power plant characteristics. Overall plant capacity, as well as total capital costs must be estimated.

<sup>6</sup> California Biomass Collaborative. *Energy Cost Calculator Website*  
<http://faculty.engineering.ucdavis.edu/jenkins/CBC/Calculator/index.html>

## ***Capital Cost***

Users must estimate the capital costs of a proposed facility. For new biomass powered plants the Energy Information Agency (EIA) estimates the costs of a new facility to be \$1,809 per kW. For proposals to co-fire biomass with coal the EIA estimates that expenditures of \$108 to \$248 per kilowatt of biomass capacity will be necessary.

## ***Plant Capacity***

The optimal capacity of a proposed plant will largely depend upon the low cost biomass resources available to the plant. Building a plant that is too large for the local and regional resource base to support will likely lead to high fuel costs, and potentially an inability to supply sufficient fuel for the plant. As a general rule biomass plants are assumed to draw their fuel supplies from a fifty-mile radius. Transporting biomass fuels for more than 50 miles by road may be uneconomical. Procuring low cost fuels from greater distances may be possible if rail transport is utilized. This will largely depend on a facility's ability to take advantage of existing rail infrastructure.

## ***Capacity Factor***

The capacity factor of an electric generating plant plays an important role in the plant's economics. More reliable plants have a greater opportunity to generate revenue than less reliable plants because they operate for more hours out of the year, thus producing more electricity to sell to the utility. The capacity factor measures reliability by representing the average amount of time that the plant is expected to be operating at full capacity over the course of a year, expressed as a percentage. A plant that operated at full capacity all year would thus have a 100% capacity factor, while time spent operating at less than full capacity, or time when the plant was shut down for maintenance (scheduled or unscheduled) would reduce the capacity factor. For example, a plant that experienced 100 hours per year of maintenance or other shutdown, and operated at 80% capacity the rest of the year, would have a capacity factor of 79.1%

## ***Net Electrical Efficiency***

Net electrical efficiency is the ratio of electrical energy output from the plant to the energy contained in the fuel input. This measures how efficiently the plant converts the fuel energy to electricity.

## **Non-Electrical Energy Income**

### ***Capacity Payments***

A plant's reliability also presents opportunities to generate revenue through the capacity payments paid by the utility. Plants that are more reliable have the potential to receive higher capacity payments for the capacity that they provide to the system.

Independent power producers are paid by utilities based on the utility's avoided energy and capacity costs. Capacity payments are based on a utility's avoided capital costs, fixed O&M costs, and startup costs for a new capacity addition. Proposed facilities greater than 10 MW in size must negotiate the rates that they will receive from the utility.

2001 legislation ordered Minnesota's utilities to establish standards for the interconnection and operation of distributed generation facilities under 10MW. While the utilities are not required to offer standard contracts, the model contracts that each utility must propose is intended to provide distributed generation facilities under 10 MW with sufficient information to plan for new facilities.

### *Other Income*

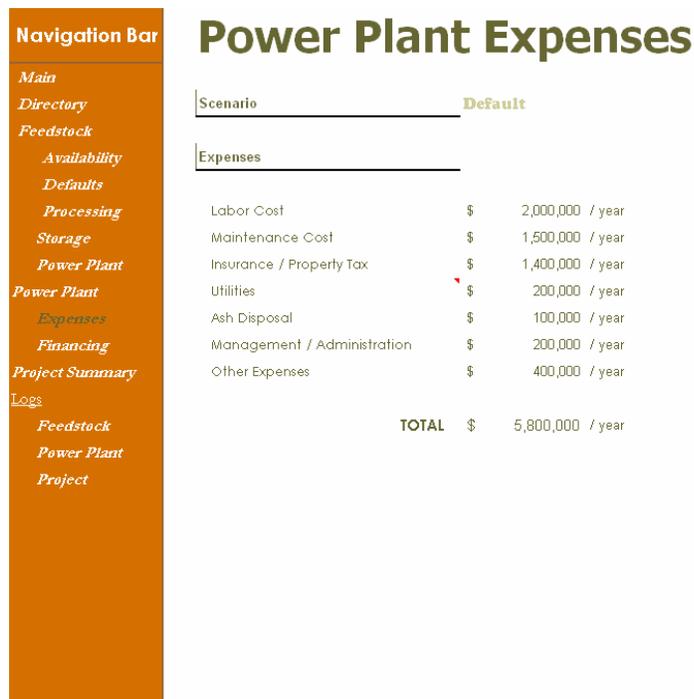
In addition to capacity payments independent power producers can potentially receive credit for a utility's avoided distribution costs, as well as renewable energy credits and emission credits. According to PUC, 2005b, generators should receive no additional credits for diversity, line losses, or reliability.

Some biomass facilities may derive income from waste heat or excess biogas to industrial or commercial facilities. The waste products from biomass energy facilities may have some commercial value as well. Anaerobic digester waste is often used as a high quality soil amendment. Ash may be used as a soil amendment in some circumstances, or it may be used as a component of cement.

### *Interest Rate*

Enter the expected rate of interest that will be earned on the project's debt reserve.

No estimates are provided for these potential sources of revenue; however the user may enter estimates of their own.



**Figure A-9: Power Plant Expenses Screen**

## **Expenses**

A number of common expenses are included in the expense detail. Expenses are incorporated into the cost estimate on an annual cost basis, as opposed to a per kWh basis.

### ***Labor Costs***

These include the salaries of plant employees.

### ***Maintenance Costs***

All power plants require occasional maintenance. Maintenance costs (as well as the downtime associated with plant maintenance) can have a significant effect on a plant's economic success.

### ***Insurance/Property Tax***

Power plants will need to be insured and pay property taxes.

### ***Utilities***

Power plants may need connection to water supply, sewage and the electrical grid. Plants must contract with the utility if backup power to the plant will be needed.

### ***Ash Disposal***

The ash produced by a power plant may need to be landfilled.

### ***Management/Administration***

These represent the costs of managing and administering a plant.

### ***Other Expenses***

Any other expenses can be accounted for here.

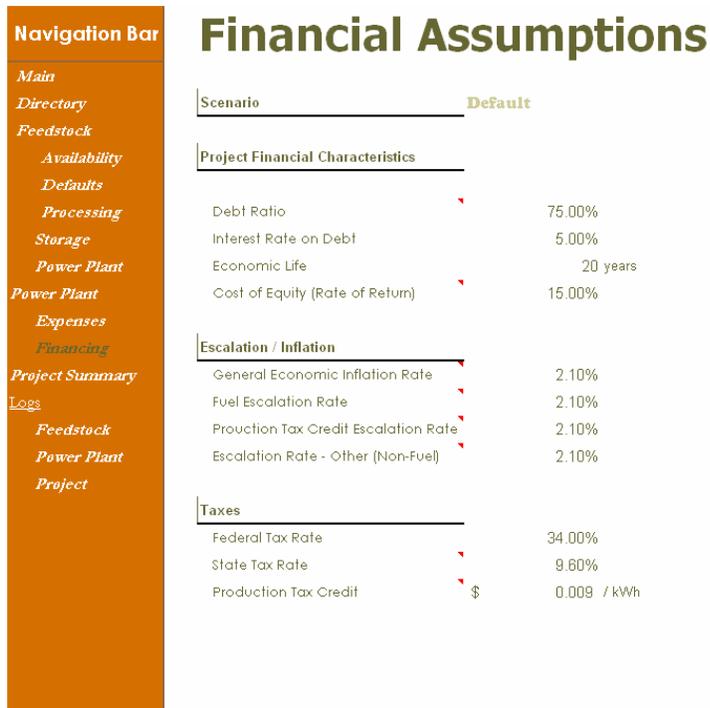


Figure A-10: Financial Assumption Screen

## Financing

For a more detailed explanation of the financing of power plants see Appendix C.

### *Debt Ratio*

The debt ratio is the percentage of the project's costs that are financed. The remaining funds are assumed to come from private equity. The default ratio of 75% is common.

### *Interest Rate on Debt*

The interest rate on debt is the interest rate paid on loans to finance the project.

### *Economic Life*

When estimating the costs of a plant it is common to assume a 20-year commercial life of the plant.

### *Cost of Equity (Rate of Return)*

The cost of equity is the rate of return that would have been achieved with any private equity used to finance the project, if it had not been invested in the project. This is a measure used by firms to ensure that they direct their investments to ensure the highest return possible.

## ***General Economic Inflation Rate***

The general economic inflation rate represents the rate of degradation of the purchasing power of the dollar. In 2005 the rate was 3.4%. Rates have been rising generally since January of 2002. Inflation rates are difficult to predict, however they can have a significant influence on investment decisions and outcomes. Current and historical inflation data is available at the U.S. Department of Labor Bureau of Labor Statistics ([www.bls.gov](http://www.bls.gov)).

## ***Fuel Escalation Rate***

Enter the nominal rate at which fuel costs are expected to increase. This figure should include any increase due to inflation: if real fuel costs are expected to increase at 1% and inflation is 2.1%, then the Fuel Escalation Rate should be 3.1%. If fuel costs are expected to decrease over time, subtract the real change in price from the inflation rate.

## ***Production Tax Credit Escalation Rate***

The Federal Production Tax Credit (see below) is indexed to inflation and re-calculated each year. Thus, the most appropriate value for this field would be the same as the General Economic Inflation Rate. Other values can be entered if changes to federal policy are anticipated.

## ***Escalation Rate - Other (Non-Fuel)***

This represents the Non-fuel escalation rate. This accounts for the escalation of costs not associated with general inflation, fuel costs, or the escalation of available Production Tax Credits.

## ***Federal Tax Rate***

The default federal tax rate is 34%. If another federal tax rate is relevant it can be user defined.

## ***State Tax Rate***

The default state tax rate is 9.6%. If another state tax rate is relevant it can be user defined. Participation in Minnesota's JOBZ program could significantly change a facility's state tax burden through 2015.

## ***Production Tax Credit***

There is a federal tax credit for 10 years for projects installed by January 1, 2008. As of 2005, this credit is worth \$0.009/kWh; the credit is increased annually to keep pace with inflation. There is a state payment of \$0.015/kWh for ten years for generation from on-farm anaerobic manure digester systems.

## **Save This Power Plant**

Each Power Plant Scenario must be saved in the Power Plant Log. Once all data has been entered, click "Save This Power Plant" to save the power scenario. The new power plant scenario is then available for comparison with other scenarios. The data for the scenario can be reviewed, edited, copied, and deleted by selecting "Power Plant" under "Logs" in the

Navigation Menu. Note that every time the user clicks “Save This Power Plant,” a new entry is created in the Power Plant Log, even if an identical entry exists. For this reason, edits should be made in the log, and the Power Plant Worksheet used to create new scenarios.

Figure A-11: Project Summary Screen

## PROJECT SUMMARY

Once the first two worksheets have been completed, the Evaluate the Complete Project worksheet provides a means of pairing various feedstock(s) and power plant scenarios. This should enable a user to determine which combination of feedstock(s) and power plant will generate the lowest cost energy. Each project scenario can be saved to the project scenarios log.

A percentage (on an output basis) can be entered for situations in which multiple feedstocks are used (ie. co-firing, seasonal variation, etc...). The percentage should always sum to 100%.

## Results

Each project scenario is capable of generating a levelized annual cost of energy (in cents/kWh) and overnight cost (in \$/kW). The levelized cost of energy is the real (inflation-adjusted) cost, while the overnight cost is presented in nominal (current-dollar) terms. The levelized annual cost of energy is the inflation-adjusted price that a plant must receive for its electricity that ensures that costs will be covered and equity fully paid off at the end of the economic life of the project. Overnight cost is the full capital cost of the plant without the inclusion of interest paid on loans during the construction period.

## Sensitivity Analysis

The sensitivity analysis performed on each proposal evaluation illustrates the change in constant levelized cost of energy that one could expect from varying the rate of one of the included

variables, while holding all other variables constant. The sensitivity analysis is presented in terms of the relative (%) change of each variable, as opposed to an absolute change in value.

### Sensitivity Analysis

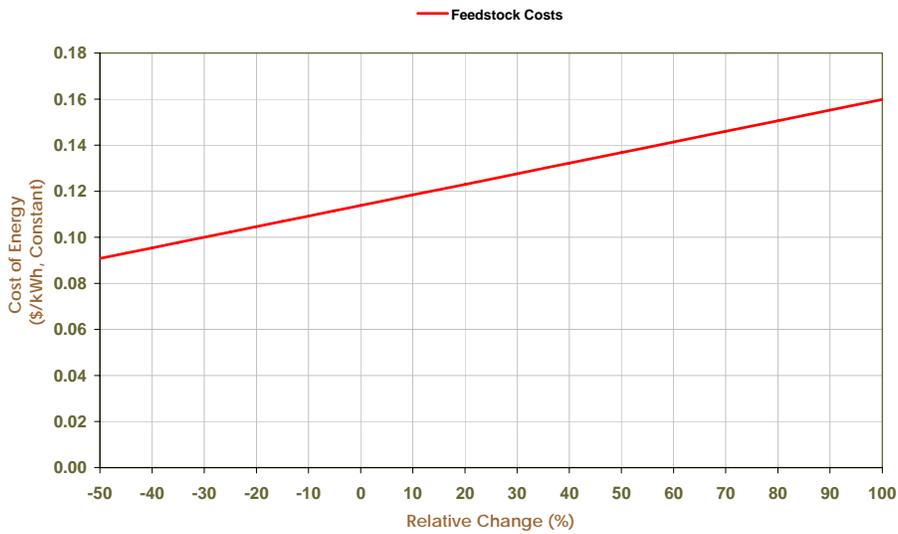


Figure A-12: Sensitivity Analysis Graph

## LOGS

Since the Feedstock Log and the Project Scenario Log each have a comparative data point that allows the user to evaluate different strategies (ie. \$/MMBtu and \$/kWh respectively), basic graphing functionality was included to compare all data entries. This can be found at the far right column of each Log sheet. When pressed it creates a chart as shown in the example below.

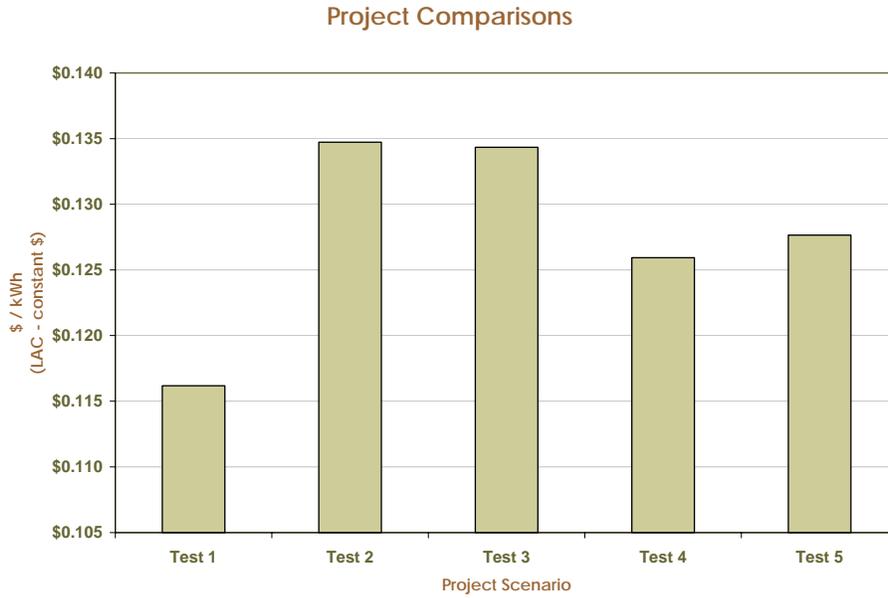


Figure A-13: Example of Project Log Scenario Graph

**Navigation Bar**

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- [Project](#)

## Minnesota Biomass Directory

Find (please enter only one)

Name

OR

Category

Show all sorted by:

Category

Figure A-14: Directory Screen

## RESOURCE DIRECTORY

Additionally, a directory of organizational resources for those considering developing biomass projects in Minnesota is available for reference. The directory can be viewed alphabetically or categorized by the general type of work that they do. Many of the organizations are involved in various aspects of biomass projects. This list does not imply that the organizations shown cannot also assist in other needs. Also, this list is not meant to be an endorsement of any of the organizations listed.

<u>CONSULTING</u>	Provides technical reviews, plans, advice, and/or insight into the actual development, construction, and operation of biomass electric power plants
<u>FINANCING</u>	Offers financing alternatives
<u>NON-PROFIT/ADVOCACY</u>	Promotes various biomass strategies and has particular insights on political and/or strategic issues
<u>RESEARCH</u>	Evaluates newer technologies and approaches
<u>TECHNICAL VENDOR</u>	Provides equipment for biomass applications
<u>TRADE GROUP</u>	Member-based industry organizations that work on biomass issues
<u>UTILITY</u>	Electricity providers that have been involved in biomass projects

This list is focused on organizations that are in Minnesota, do business in Minnesota, have been involved in Minnesota projects, or have a particular understanding of the biomass feedstocks/technologies that are particular to Minnesota. It is not meant to be an exhaustive list, but it is representative of the organizations that are available to assist interested parties.



## APPENDIX B : INDUSTRY CONTACT LIST

Organizational resources for those considering developing biomass projects in Minnesota are presented in two formats. The first is an alphabetical list, the second is a list categorized by the general type of work that they do. However many of the organizations are involved in various aspects of biomass projects and this list does not imply that the organizations shown cannot also assist in other needs.

<u>CONSULTING</u>	Provides technical reviews, plans, advice, and/or insight into the actual development, construction, and operation of biomass electric power plants
<u>FINANCING</u>	Offers financing alternatives
<u>NON-PROFIT/ADVOCACY</u>	Promotes various biomass strategies and has particular insights on political and/or strategic issues
<u>RESEARCH</u>	Evaluates newer technologies and approaches
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<u>TRADE GROUP</u>	Member-based industry organizations that work on biomass issues
<u>UTILITY</u>	Electricity providers that have been involved in biomass projects

This list is focused on organizations that are in Minnesota, do business in Minnesota, have been involved in Minnesota projects, or have a particular understanding of the biomass feedstocks/technologies that are particular to Minnesota. It is not meant to be an exhaustive list, but it is representative of the organizations that are available to assist interested parties.

**Table B-1: Alphabetized List**

<b>Company Name City, State Zip Main Phone Website</b>	<b>Category</b>	<b>Brief Description</b>
Agriculture Utilization and Research Institute Crookston, MN 56716-0599 (800) 279-5010 www.auri.org	Research	Conducting research on value-added products from agriculture, including pelletized fuel, energy crops, and community anaerobic digestors. Offices are in Crookston (headquarers), Marshall, and Waseca.
AgSTAR Washington, DC 20460 (202) 343-9041 www.epa.gov/agstar/index.html	Research	Technical assistant program though the U.S. Environmental Protection Agency for anaerobic digester systems for animal agriculture.
AgStar Financial Services Rochester, MN 55901 (507) 529-2049 www.agstar.com	Financing	Provide financing for anaerobic digester and wind projects. Financed Haubenschild project near Princeton, MN.
Alliant Energy Madison, WI 53707-1007 (800) 255-4268 www.alliantenergy.com	Utility	Has three anaerobic digesters (0.8 MWs). Also, the Chariton Valley Biomass Project (a cooperative effort with Chariton Valley Resource Conservation and Development, and the U.S. Dept. of Energy) is an initiative to develop switchgrass and other grasses as a supplemental for coal-fired power plants.
Barr Engineering Hibbing, MN 55746 (218) 262-3465 www.barr.com	Consulting	Design wood handling systems. Helped design system for Virginia/Hibbing biomass district heating.
Black and Veatch Ann Arbor, MI 48105 (734) 665-1000 www.bv.com	Consulting	One of largest power plant engineering companies in the world, have designed and built numerous biomass plants. Did conceptual engineering for Phillips Biomass Project.
CH2MHill Eagan, MN 55121 (651) 688-8100 www.ch2m.com	Consulting	Environmental review and air permitting expertise. Also have biomass power plant division.

<p>Clean Energy Resource Teams (CERTs) St. Paul, MN 55108 (612) 624-2293 www.cleanenergyresourceteams.org</p>	<p>Non-profit/ advocacy</p>	<p>Working to create regional resources for clean energy and economic development for communities across the state. Website has case studies and resources for developing clean energy projects, including biomass.</p>
<p>Cornerstone Partners Minneapolis, MN 55403 (847) 601-3812 www.cornerstonepartners.info</p>	<p>Financing</p>	<p>Provide financial services to biomass and other power projects, including financial model development and equity and debt placement.</p>
<p>Delve Energy Medina, MN 55340 (763) 478-3580 www.delveenergy.com/</p>	<p>Consulting</p>	<p>Experience with Combined Heat and Power applications.</p>
<p>Department of Energy - Biomass Division Washington, DC 20585  www1.eere.energy.gov/biomass</p>	<p>Research</p>	<p>Expertise in small biomass, biorefinery technologies and applications.</p>
<p>Electric Power Research Institute Palo Alto, CA 94304 (650) 855-2000 www.epri.com</p>	<p>Research</p>	<p>Funded by utilities, do research on biomass, among other issues. Involved in fuel cell application on Haubenschild Farms digester, near Princeton, MN.</p>
<p>Energy Products of Idaho Coeur d'Alene, ID 83815-8928 (208) 765-1611 www.energyproducts.com/</p>	<p>Technology vendor</p>	<p>Produce fluidized bed and gasifier biomass conversion technologies.</p>
<p>Environomics Salt Point, NY 12578 (845) 635-4206 www.waste2profits.com/index.htm</p>	<p>Consulting</p>	<p>Consulting and design services for anaerobic digesters. Was involved with Haubenschild digester near Princeton, MN.</p>
<p>FibroWatt Newtown, PA 19067 (267) 352 0014 www.fibrowattusa.com</p>	<p>Technology vendor</p>	<p>Building a turkey litter plant near Benson, MN.</p>

Foster Wheeler Clinton, NJ 08809-4000 www.fwc.com	Technology vendor	Design and build biomass thermal and power plants. Built the U of M steam plant fluidized bed coal/biomass boiler.
Fresh Energy St. Paul, MN 55102 (651) 225-0878 www.fresh-energy.org	Non-profit/advocacy	Comprehensive list of state-level biomass policy measures/papers.
FVB Energy Minneapolis, MN 55402 (612) 607-4544 www.fvbenergy.com	Consulting	One of the largest district heating firms in the world, involved with multiple biomass combined heat and power projects.
GHD, Inc. Chilton, WI 53014 (920) 849-9797	Consulting	Have built and designed multiple digester systems in Wisconsin.
Golder and Associates Roseville, MN 55113 (651) 697-9737 www.golder.com	Consulting	Environmental review and air permitting expertise. Involved with air permitting for several Minnesota biomass projects.
Great Plains Institute for Sustainable Development (GPISD) Minneapolis, MN 55407 (612) 278-7150 www.gpisd.net	Non-profit/advocacy	Work in Upper Midwest, researching energy crop production and utilization.
HDR Minneapolis, MN 55416-1567 (763) 591-5400 www.hdrinc.com	Consulting	Engineering and environmental review expertise. Did work for former NGPP hybrid power project near Waseca.
HGA Minneapolis, MN 55401 (612) 758-4463 www.hga.com	Consulting	Designing biomass campus heating system for University of Minnesota Morris.

Home Farms Technologies Brandon, Manitoba R7A 5A3 Canada (877) 464-7667 www.homefarmstech.com	Technology vendor	Produce small scale biomass gasifiers. Working on several potential applications in Minnesota.
Initiative for Renewable Energy and the Environment - University of Minnesota St. Paul, MN 55108 (612) 624-7266 www1.umn.edu/iree	Research	Provide financial and research support for renewable energy production across Minnesota.
Institute for Agriculture and Trade Policy (IATP) Minneapolis, MN 55404 (612) 870-0453 www.iatp.org	Non-profit/advocacy	Work on developing new, sustainable markets for family farmers and foresters, including bio-energy, wood waste, and energy crop utilization.
Institute for Local Self-Reliance (ILSR) Minneapolis, MN 55414 (612) 379-3815 www.ilsr.org	Non-Profit/Advocacy	Comprehensive understanding of state/regional biomass and distributed generation policies/rules.
Izaak Walton League of America, Midwest Office 1619 Dayton Avenue, Suite 202 St. Paul, MN 55104 www.iwla.org	Non-Profit/Advocacy	State, regional, and national energy policy knowledge on renewable energy as well as other environmental concerns.
John Madole and Associates Minneapolis, MN 55436 (952) 927-5179	Consulting	Consulting services on wood procurement and anaerobic digestion. Conducted wood assessment study for District Energy St. Paul.
L & J Dairy Services Harmony, MN 55939 (507) 261-1379	Consulting	Consulting on anaerobic digester systems.
Laurentian Engineering Group Duluth, MN 55811 (218) 733-999 www.legroup.com	Consulting	Power engineering and air permit consulting. Involved in the conversion of Hibbing plant to wastewood firing.

Market Street Energy St. Paul, MN 55102-1611 (651) 297-8955 www.districtenergy.com	Consulting	Consulting unit of District Energy St. Paul. Did some conceptual engineering for Rock-Tenn project in St. Paul.
Minnesota Department of Agriculture St. Paul, MN (800) 967-2474 www.mda.state.mn.us/	Financing	Involved in promoting anaerobic digesters for the MN dairy industry, run loan program for digesters.
Minnesota Department of Commerce - State Energy Office St. Paul, MN 55101 (651) 296-5175 www.commerce.state.mn.us	Research	State planning studies on biogas and plant energy. Once on the website, do an internal search for "bioenergy" to access documents.
Minnesota Milk Producers Waite Park, MN 56387 (877) 577-0741 www.mnmilk.org/	Trade group	Involved in promoting anaerobic digesters for the MN dairy industry.
Minnesota Power Duluth, MN 55802 (218) 722-2641 www.mnpower.com	Utility	Operates two biomass-fueled facilities: Rapids Energy Center at Grand Rapids and Hibbard Energy Center in Duluth that mainly consume production waste from adjacent paper mills and purchased wood. Both units also burn coal.
National Renewable Energy Laboratory Golden, CO 80401 www.nrel.gov	Research	Expertise in national planning on bioenergy resources and applications.
Northland Securities Minneapolis, MN 55402 (612) 851-4952 www.northlandsecurities.com	Financing	Handle many financial services related to biomass projects, including project due diligence, bond issuing, equity placement. Doing financing for Virginia/Hibbing biomass district heating plant.
Prime Energy Tulsa, OK 74158 (918) 835-1011 www.primenergy.com	Technology vendor	Produce gasifier for thermal/power applications. Providing gasifier for Little Falls ethanol plant.

RCM Digesters Berkeley, CA 94704 (510) 834.4568 www.rcmdigesters.com	Consulting	Design and build anaerobic digesters for animal agriculture industry. Designed Haubenschild system near Princeton, MN.
Recovered Energy Resources Rochester, MI 48308 (540) 675-2492 www.recoveredenergyresources.com	Technology vendor	Produce small scale biomass gasifiers. U of M Morris considering this technology.
RW Beck St. Paul, MN 55121 (651) 994-8415 www.rwbeck.com/home.asp	Consulting	History of work in MN on analysis of waste streams. Nationally, have acted as owners engineer for numerous biomass projects
Sebesta Blomberg Roseville, MN 55113-0020 (651) 634-0775 www.sebesta.com	Consulting	Engineering & environmental review expertise for bioenergy facilities. Involved in Little Falls ethanol plant gasifier.
The Green Institute Minneapolis, MN 55407 (612) 278-7100 www.greeninstitute.org	Non-profit/advocacy	Expertise in developing small wood combined heat and power projects.
The Minnesota Project St. Paul, MN 55104 (651) 645-6159 www.mnproject.org	Non-profit/advocacy	State level biomass policy knowledge, background developin anaerobic digesters, rural renewable energy projects.
Tim Goodman and Associates St. Louis Park, MN 55426 (952) 544-6005	Consulting	Waste and recycling consultant. Has completed analysis of waste wood industry in St. Paul/Minneapolis area.
University of Minnesota, Dept. of Applied Economics St. Paul, MN 55108-6040 (612) 625-1222 www.apec.umn.edu	Research	Currently studies include: food marketing and consumption economics; economic development, trade and policy; production and managerial economics; resource and environmental economics; public sector economics; and agribusiness management.

University of Minnesota, Dept. of Biosystems and Ag Engineering St. Paul, MN 55108 (612) 625-4215 www.bae.umn.edu	Research	Involved with researching and assessing anaerobic digester systems.
University of North Dakota - Energy & Environmental Research Center Grand Forks, ND 58202-9018 (701) 777-5000 www.eerc.und.nodak.edu	Research	Mapped biomass resources regionally, expertise in small biomass power system technologies and applications.
Utility Engineering Minneapolis, MN 55402 (612) 215-1304 www.ue-corp.com	Consulting	Power plant engineering, as well as fuels assessment work. Conducted a fuels assessment for a project in Minnesota.
West Central Research and Outreach Center Morris, MN 56267 (320) 589-1711 wcroc.coafes.umn.edu	Research	Developing a campus heating system fueled by biomass for U of M Morris as well as conducting other related research.
Wolf and Associates Elk River, MN 55330 (763) 576-9040	Consulting	Design and build fuel handling systems. Built St. Paul District Energy fuel handling system.
Xcel Energy Minneapolis, MN 55401-1993 (800) 328-8226 www.xcelenergy.com	Utility	Xcel Energy has contracted for the development of 110 megawatts of electricity generated by biomass-fueled technologies. Waste wood, fast-growth poplar trees, and poultry litter will all be used as fuel to generate electricity.

**Table B-2: Categorized List**

CATEGORY	COMPANY NAME CITY, STATE ZIP MAIN PHONE WEBSITE	BRIEF DESCRIPTION
CONSULTING	Barr Engineering Hibbing, MN 55746 (218) 262-3465 www.barr.com	Design wood handling systems. Helped design system for Virginia/Hibbing biomass district heating.
CONSULTING	Black and Veatch Ann Arbor, MI 48105 (734) 665-1000 www.bv.com	One of largest power plant engineering companies in the world, have designed and built numerous biomass plants. Did conceptual engineering for Phillips Biomass Project.
CONSULTING	CH2MHill Eagan, MN 55121 (651) 688-8100 www.ch2m.com	Environmental review and air permitting expertise. Also have biomass power plant division.
CONSULTING	Delve Energy Medina, MN 55340 (763) 478-3580 www.delveenergy.com/	Experience with Combined Heat and Power applications.
CONSULTING	Environomics Salt Point, NY 12578 (845) 635-4206 www.waste2profits.com/index.htm	Consulting and design services for anaerobic digesters. Was involved with Haubenschild digester near Princeton, MN.
CONSULTING	FVB Energy Minneapolis, MN 55402 (612) 607-4544 www.fvbenergy.com	One of the largest district heating firms in the world, involved with multiple biomass combined heat and power projects.
CONSULTING	GHD, Inc. Chilton, WI 53014 (920) 849-9797	Have built and designed multiple digester systems in Wisconsin.

CONSULTING	Golder and Associates Roseville, MN 55113 (651) 697-9737 www.golder.com	Environmental review and air permitting expertise. Involved with air permitting for several Minnesota biomass projects.
CONSULTING	HDR Minneapolis, MN 55416-1567 (763) 591-5400 www.hdrinc.com	Engineering and environmental review expertise. Did work for former NGPP hybrid power project near Waseca.
CONSULTING	HGA Minneapolis, MN 55401 (612) 758-4463 www.hga.com	Designing biomass campus heating system for University of Minnesota Morris.
CONSULTING	John Madole and Associates Minneapolis, MN 55436 (952) 927-5179	Consulting services on wood procurement and anaerobic digestion. Conducted wood assessment study for District Energy St. Paul.
CONSULTING	L & J Dairy Services Harmony, MN 55939 (507) 261-1379	Consulting on anaerobic digester systems.
CONSULTING	Laurentian Engineering Group Duluth, MN 55811 (218) 733-999 www.legroup.com	Power engineering and air permit consulting. Involved in the conversion of Hibbing plant to wastewood firing.
CONSULTING	Market Street Energy St. Paul, MN 55102-1611 (651) 297-8955 www.districtenergy.com	Consulting unit of District Energy St. Paul. Did some conceptual engineering for Rock-Tenn project in St. Paul.
CONSULTING	RCM Digesters Berkeley, CA 94704 (510) 834.4568 www.rcmdigesters.com/	Design and build anaerobic digesters for animal agriculture industry. Designed Haubenschild system near Princeton, MN.

CONSULTING	RW Beck St. Paul, MN 55121 (651) 994-8415 www.rwbeck.com/home.asp	History of work in MN on analysis of waste streams. Nationally, have acted as owners engineer for numerous biomass projects
CONSULTING	Sebesta Blomberg Roseville, MN 55113-0020 (651) 634-0775 www.sebesta.com	Engineering & environmental review expertise for bioenergy facilities. Involved in Little Falls ethanol plant gasifier.
CONSULTING	Tim Goodman and Associates St. Louis Park, MN 55426 (952) 544-6005	Waste and recycling consultant. Has completed analysis of waste wood industry in St. Paul/Minneapolis area.
CONSULTING	Utility Engineering Minneapolis, MN 55402 (612) 215-1304 www.ue-corp.com	Power plant engineering, as well as fuels assessment work. Conducted a fuels assessment for a project in Minnesota.
CONSULTING	Wolf and Associates Elk River, MN 55330 (763) 576-9040	Design and build fuel handling systems. Built St. Paul District Energy fuel handling system.
FINANCING	AgStar Financial Services Rochester, MN 55901 (507) 529-2049 www.agstar.com	Provide financing for anaerobic digester and wind projects. Financed Haubenschild project near Princeton, MN.
FINANCING	Cornerstone Partners Minneapolis, MN 55403 (847) 601-3812 www.cornerstonepartners.info	Provide financial services to biomass and other power projects, including financial model development and equity and debt placement.
FINANCING	Minnesota Department of Agriculture St. Paul, MN (800) 967-2474 www.mda.state.mn.us/	Involved in promoting anaerobic digesters for the MN dairy industry, run loan program for digesters.

FINANCING	Northland Securities Minneapolis, MN 55402 (612) 851-4952 www.northlandsecurities.com	Handle many financial services related to biomass projects, including project due diligence, bond issuing, equity placement. Doing financing for Virginia/Hibbing biomass district heating plant.
NON-PROFIT/ADVOCACY	Clean Energy Resource Teams (CERTs) St. Paul, MN 55108 (612) 624-2293 www.cleanenergyresourceteams.org	Working to create regional resources for clean energy and economic development for communities across the state. Website has case studies and resources for developing clean energy projects, including biomass.
NON-PROFIT/ADVOCACY	Fresh Energy St. Paul, MN 55102 (651) 225-0878 www.fresh-energy.org	Comprehensive list of state-level biomass policy measures/papers.
NON-PROFIT/ADVOCACY	Great Plains Institute for Sustainable Development (GPISD) Minneapolis, MN 55407 (612) 278-7150 www.gpisd.net	Work in Upper Midwest, researching energy crop production and utilization.
NON-PROFIT/ADVOCACY	Institute for Agriculture and Trade Policy (IATP) Minneapolis, MN 55404 (612) 870-0453 www.iatp.org	Work on developing new, sustainable markets for family farmers and foresters, including bio-energy, wood waste, and energy crop utilization.
NON-PROFIT/ADVOCACY	Institute for Local Self-Reliance (ILSR) Minneapolis, MN 55414 (612) 379-3815 www.ilsr.org	Comprehensive understanding of state/regional biomass and distributed generation policies/rules.
NON-PROFIT/ADVOCACY	Izaak Walton League of America, Midwest Office 1619 Dayton Avenue, Suite 202 St. Paul, MN 55104 www.iwla.org	State, regional, and national energy policy knowledge on renewable energy as well as other environmental concerns.
NON-PROFIT/ADVOCACY	The Green Institute Minneapolis, MN 55407 (612) 278-7100 www.greeninstitute.org	Expertise in developing small wood combined heat and power projects.

NON-PROFIT/ADVOCACY	The Minnesota Project St. Paul, MN 55104 (651) 645-6159 www.mnproject.org	State level biomass policy knowledge, background developin anaerobic digesters, rural renewable energy projects.
RESEARCH	Agriculture Utilization and Research Institute Crookston, MN 56716-0599 (800) 279-5010 www.auri.org	Conducting research on value-added products from agriculture, including pelletized fuel, energy crops, and community anaerobic digestors. Offices are in Crookston (headquarers), Marshall, and Waseca.
RESEARCH	AgSTAR Washington, DC 20460 (202) 343-9041 www.epa.gov/agstar/index.html	Technical assistant program though the U.S. Environmental Protection Agency for anaerobic digester systems for animal agriculture.
RESEARCH	Department of Energy - Biomass Division Washington, DC 20585 www1.eere.energy.gov/biomass	Expertise in small biomass, biorefinery technologies and applications.
RESEARCH	Electric Power Research Institute Palo Alto, CA 94304 (650) 855-2000 www.epri.com	Funded by utilities, do research on biomass, among other issues. Involved in fuel cell application on Haubenschild Farms digester, near Princeton, MN.
RESEARCH	Initiative for Renewable Energy and the Environment - University of Minnesota St. Paul, MN 55108 (612) 624-7266 www1.umn.edu/iree	Provide financial and research support for renewable energy production across Minnesota.
RESEARCH	Minnesota Department of Commerce - State Energy Office St. Paul, MN 55101 (651) 296-5175 www.commerce.state.mn.us	State planning studies on biogas and plant energy. Once on the website, do an internal search for "bioenergy" to access documents.
RESEARCH	National Renewable Energy Laboratory Golden, CO 80401 www.nrel.gov	Expertise in national planning on bioenergy resources and applications.

RESEARCH	University of Minnesota, Dept. of Applied Economics St. Paul, MN 55108-6040 (612) 625-1222 www.apec.umn.edu	Currently studies include: food marketing and consumption economics; economic development, trade and policy; production and managerial economics; resource and environmental economics; public sector economics; and agribusiness management.
RESEARCH	University of Minnesota, Dept. of Biosystems and Ag Engineering St. Paul, MN 55108 (612) 625-4215 www.bae.umn.edu	Involved with researching and assessing anaerobic digester systems.
RESEARCH	University of North Dakota - Energy & Environmental Research Center Grand Forks, ND 58202-9018 (701) 777-5000 www.eerc.und.nodak.edu	Mapped biomass resources regionally, expertise in small biomass power system technologies and applications.
RESEARCH	West Central Research and Outreach Center Morris, MN 56267 (320) 589-1711 wcroc.coafes.umn.edu	Developing a campus heating system fueled by biomass for U of M Morris as well as conducting other related research.
TECHNOLOGY VENDOR	Energy Products of Idaho Coeur d'Alene, ID 83815-8928 (208) 765-1611 www.energyproducts.com/	Produce fluidized bed and gasifier biomass conversion technologies.
TECHNOLOGY VENDOR	FibroWatt Newtown, PA 19067 (267) 352 0014 www.fibrowattusa.com	Building a turkey litter plant near Benson, MN.
TECHNOLOGY VENDOR	Foster Wheeler Clinton, NJ 08809-4000 www.fwc.com	Design and build biomass thermal and power plants. Built the U of M steam plant fluidized bed coal/biomass boiler.
TECHNOLOGY VENDOR	Home Farms Technologies Brandon, Manitoba R7A 5A3 Canada (877) 464-7667 www.homefarmstech.com	Produce small scale biomass gasifiers. Working on several potential applications in Minnesota.
TECHNOLOGY VENDOR	Prime Energy Tulsa, OK 74158 (918) 835-1011 www.primenergy.com	Produce gasifier for thermal/power applications. Providing gasifier for Little Falls ethanol plant.

TECHNOLOGY VENDOR	Recovered Energy Resources Rochester, MI 48308 (540) 675-2492 www.recoveredenergyresources.com	Produce small scale biomass gasifiers. U of M Morris considering this technology.
TRADE GROUP	Minnesota Milk Producers Waite Park, MN 56387 (877) 577-0741 www.mnmilk.org/	Involved in promoting anaerobic digesters for the MN dairy industry.
UTILITY	Alliant Energy Madison, WI 53707-1007 (800) 255-4268 www.alliantenergy.com	Has three anaerobic digesters (0.8 MWs). Also, the Chariton Valley Biomass Project (a cooperative effort with Chariton Valley Resource Conservation and Development, and the U.S. Dept. of Energy) is an initiative to develop switchgrass and other grasses
UTILITY	Minnesota Power Duluth, MN 55802 (218) 722-2641 www.mnpower.com	Operates two biomass-fueled facilities: Rapids Energy Center at Grand Rapids and Hibbard Energy Center in Duluth that mainly consume production waste from adjacent paper mills and purchased wood. Both units also burn coal.
UTILITY	Xcel Energy Minneapolis, MN 55401-1993 (800) 328-8226 www.xcelenergy.com	Xcel Energy has contracted for the development of 110 megawatts of electricity generated by biomass-fueled technologies. Waste wood, fast-growth poplar trees, and poultry litter will all be used as fuel to generate electricity.



# APPENDIX C : FEEDSTOCK CHARACTERISTICS

Biomass Feedstock	Sub-Division	dry-weight HHV (Btu/lb)	dry-weight HHV (kJ/g)
<b>Agricultural residues</b>			
Alfalfa	alfalfa	7,729	17.99
Barley	grain	8,063	18.77
	straw	7,600	17.69
	dry beans	10,230	23.81
Beans	straw	7,523	17.51
	canola	10,230	23.81
	meal	8,934	20.80
Canola	oil	17,370	40.43
	grain	8,100	18.86
	stover	8,191	19.07
Corn	cob	7,911	18.42
	silage	8,145	18.96
	sweet corn grain	8,100	18.86
	ethanol	13,103	30.50
Ethanol	ethanol DDGS	9,422	21.93
	switch grass	7,936	18.47
Grasslands	prairie grass	7,000	16.29
	brushland	6,000	13.97
Oats	straw	8,242	19.19
	grain	8,063	18.77
Potato	potato	7,561	17.60
Soybean	grain	10,230	23.81
	hulls	7,570	17.62
	oil	16,883	39.30
Sugarbeets	sugarbeet	7,561	17.60
	sugarbeet pulp	7,345	17.10
Sunflower	grain	10,230	23.81
	straw	8,191	19.07
	hulls	9,654	22.47
Wheat	flour	6,444	15.00
	grain	8,063	18.77
	mids	8,415	19.59
	straw	7,375	17.17
Miscellaneous	sugar	7,561	17.60
	other hay	7,481	17.41

<b>Forest residues</b>			
General	hardwood	8,430	19.62
	softwood	8,771	20.42
Birch	birch	8,650	20.14
	birch and maple mix	8,453	19.68
Cedar	northern white cedar	8,400	19.55
Cottonwood	cottonwood/willow	8,436	19.64
Fir	douglas fir	9,043	21.05
Hemlock	western hemlock	8,613	20.05
Maple	maple	8,575	19.96
Oak	red oak	8,690	20.23
Pine	white pine	8,919	20.76
Poplar	aspen/poplar	8,914	20.75
	hybrid poplar	8,178	19.04
Spruce	spruce	8,759	20.39
Miscellaneous	forest residue	8,669	20.18
	land clearing wood	7,408	17.24
	peat	4,000	9.31

Biomass Feedstock	Sub-Division	dry-weight HHV (Btu/lb)	dry-weight HHV (kJ/g)
<b>Urban wood waste</b>			
Wood	demolition wood waste	7,916	18.43
	urban wood waste	8,361	19.46
Yard	yard waste	7,009	16.32

<b>Mill residue</b>			
Mill Residue	aspen	8,501	19.79
	black liquor	5,880	13.69
	hardwood pellet	8,573	19.96
	hog fuel	7,681	17.88
	sawdust (red oak)	8,374	19.49
	wood sludge	2,000	4.66
	wood waste	8,658	20.15

<b>Animal waste</b>			
Bovine	beef cow-calf manure	6,757	15.73
	beef feeders manure	6,757	15.73
	dairy manure	6,757	15.73
	tallow	15,766	36.70
Poultry	broiler chicken manure and litter	6,225	14.49
	layer chicken manure	6,225	14.49
	turkey manure & litter	5,795	13.49
	feathermeal	16,900	39.34
	poultry fat	15,766	36.70
Swine	hog manure	8,235	19.17
	lard	15,766	36.70
Other	horse manure & litter	0	0.00
	sheep manure	6,757	15.73
Miscellaneous	glycerol	15,036	35.00
	grease	16,900	39.34
	meat meal/tankage	16,900	39.34

<b>Municipal sewage</b>			
Municipal sewage	sludge waste	3,756	8.74

<b>Fossil Fuels</b>			
Coal	Anthracite Coal	13,000	30.26
	Bituminous Coal	12,000	27.93
	Lignite Coal	10,000	23.28
Fuel Oil	No. 2	19,400	45.16
	No. 6	18,600	43.30
Natural Gas	Natural Gas	23,100	53.77



# APPENDIX D : DATA SOURCES

## INTRODUCTION

The following pages contain information on the resources and assumptions used to develop the default feedstock values used in BioPET. The first entry under "Price" for each of these feedstocks is often "Farm Gate", "Local Elevator", or "Plant Gate". This is to indicate the location in the fuel supply chain where the price is set. Farm Gate prices signify that the feedstock is available at the given price at the farm of origin, often in a baled form. Local Elevator prices indicate that the given price is the price paid for the fuel delivered to a local grain elevator. Plant Gate prices are often noted in relation to crop processing residues. These prices are the price paid for the feedstock when it is picked up from the plant of origin.

Some feedstocks have more detail than others based upon readily acceptable information. Other feedstocks were incorporated as placeholder for common applications, but collection of the data was outside the purview of this workscope. The original factory settings are provided as a starting point for scenario generation. The user should feel free to use their own data in any of these scenarios.

For each major feedstock category a handful of sources provided values for each of the individual feedstocks. To simplify the appendix those major sources are noted at the beginning of each major feedstock category. Where a different source was used for a specific value it is noted separately, and the values that it supports are noted.

## CROP RESIDUES

### Major Sources

- **Material Characteristics**
  - (Miles, et al., 1995)
  - (Bain, et al., 2003)
  - (AURI, n.d.)
- **Inventory/Availability**
  - (NASS, 2006)
- **Prices**
  - Farm Gate
  - (UMES, 2006)
- **Transport and Storage Costs**
  - (Petrolia, 2005)
  - Re-bale Costs - (Antares Group Incorporated, 2002).
  - **Cost of Holding in Storage (\$/T/month)** of stover, hay and straw cost was based on estimates in Sustainable Biomass Energy Production (Tiffany, 1995). Storage cost including losses was \$6.84. Average storage time was 4 months.
  - **Rail hauling to storage plant(\$/T/mi)** for large square bales is based on a gondola car with 28 bales and the Renville to Twin Cities grain hopper car rate of \$445 a car.
  - **Rail hauling to storage plant(\$/T/mi)** for large round bales is based on a gondola car with 18 bales and the Renville to Twin Cities grain hopper car rate of \$445 a car.

- **Barge hauling to storage plant (\$/T/mi)** for large square bales is based on a barge with 768 bales or 619 tons per barge and barge rate from Winona to the Twin Cities of \$6400 per barge.
- **Barge hauling to storage plant(\$/T/mi)** for large round bales is based on a barge with 384 bales or 272 tons per barge and barge rate from Winona to the Twin Cities of \$6400 per barge.
- **Truck loading at storage (\$/T)** of bales includes labor costs of \$1.125 per bale and loader costs of \$1.152 per bale for a total of \$2.277 per bale or \$3.221 per ton.
- **Rail and barge loading at storage (\$/T)** of bales includes labor costs of \$1.375 per bale and loader costs of \$1.152 per bale for a total of \$2.527 per bale or \$3.574 per ton. Siding costs are not included. Rail takes 3 times as long to load because of the need to move bales longer distances and because loading can only be done from one side.
- **Truck unloading of bales at the plant (\$/T)** for trucks was assumed to take .5 minutes per bale plus 20% overhead at a labor rate of \$15 per hour for a cost of \$.15 a bale. It was assumed that the capital cost of unloading equipment is included in plant costs.
- **Rail and barge unloading of bales at the plant (\$/T)** was assumed to take 1.5 minutes per bale plus .1 minute overhead at a labor rate of \$15 per hour for a cost of \$.40 a bale. It was assumed that the capital cost of unloading equipment is included in plant costs.

## Feedstock Specific Assumptions

### *Barley Straw*

- **Inventory/Availability**
  - Barley straw was assumed to be 90% of the as reported weight of barley grain. Barley straw was assumed to have 10% moisture and was converted to dry tons.

### *Switchgrass/Other Hay*

- **Inventory/Availability**
  - Other hay as reported was assumed to have 12% moisture and was converted to dry tons.

### *Wheat Straw*

- **Inventory/Availability**
  - Wheat straw was assumed to be 90% of the as reported weight of wheat grain. Wheat straw was assumed to have 16% moisture and was converted to dry tons.

### *Corn Stover*

- **Inventory/Availability**
  - Dry corn stalk residue was estimated to be 85% of the computed weight of dry corn grain.

### *Sunflower Stalks*

- **Inventory/Availability**
  - Sunflower stalks were assumed to be 90% of the as reported weight of sunflower seeds. Sunflower stalks were assumed to have 10% moisture and were converted to dry tons.

## *Sweet Corn Stalks*

- **Inventory/Availability**
  - Sweet corn stalks were assumed to be 100% of the as reported weight of sweet corn and have 76% moisture and were converted to dry tons.

## *CRP Grass*<sup>7</sup>

- **Inventory/Availability**
  - (USDA, 2006)

# CROPS

## *Major Sources*

- **Material Characteristics**
  - (AURI, n.d.)
- **Inventory/Availability**
  - (NASS, 2006)
- **Prices**
  - Local Elevator
  - This is assumed to include all costs required to deliver the feedstock to the plant or processing facility. Only storage, further processing and additional transportation costs should be added to estimate the final processed fuel costs.
  - 2004 marketing year average prices (Hartwig and Lofthus, 2005)
- **Transport and Storage Costs**
  - Commodity transportation costs are estimated as \$.157 per ton mile. This is based on the 25 mile rate estimate of the USDA Grain Transportation Report (GTR) estimate for the North Central region of the 1<sup>st</sup> quarter of 2006.
  - Although not included in the Inputs worksheet the monthly cost of storing commodity grains is 1.5% of the crop's value.
  - **Rail hauling to storage plant (\$/T/mi)** for corn grain is based on the Renville to Twin Cities tariff for a shipment of 25 100 ton cars, a distance 110 miles.
  - **Truck, rail and barge loading at storage (\$/T)** of corn grain consists of a 3.5 cent a bushel elevation charge or \$.1.25 a ton.
  - **Truck, rail and barge unloading of corn grain at the plant (\$/T)** is 1.5 cents per bushel or \$.534 per ton.

## *Alfalfa Hay*

- **Inventory/Availability**
  - Alfalfa hay as reported was assumed to have 9.6% moisture and was converted to dry tons.

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<sup>7</sup> The federal Conservation Reserve Program (CRP) pays landowners to temporarily (10 or 15 years) convert their cropland to permanent cover such as grassland or trees. These lands are not permitted to be harvested under current program rules, but they remain a potential source of biomass materials. We estimated the energy content of these lands by first aggregating all 25 official cover types (warm season grass, wetlands, wildlife plots, cool season grass, etc.) into three main categories: grass, trees, and other. We then applied a common yield estimate for each broad category. For grasses, we used 2.2 TAY, based on the research of Tilman, et al. 2001. For trees, we assumed 1 TAY, based on a low-yield estimate that we used in the forest softwood feedstock calculations noted above. The energy content of each broad category was calculated using the parameters reported in the previous phase of this project.

- Prices
  - Farm Gate
  - (UMES, 2006)
- Transport and Storage Costs
  - See explanation under crop residues.

### *Barley Grain*

- Inventory/Availability
  - Barley grain was assumed to be reported in 48lb bushels of 14.5% moisture and converted to dry tons.

### *Canola Grain*

- Inventory/Availability
  - Canola was reported in pounds with 13% moisture and converted to tons of dry matter. Canola straw was not included.

### *Corn Grain*

- Inventory/Availability
  - Corn grain was assumed to be reported as 56lb. bushels with 15.5 % moisture. This was converted to tons of dry matter.

### *Corn Silage*

- Inventory/Availability
  - Corn silage as reported was assumed to be 70% moisture and converted to dry tons.
- Prices
  - Farm Gate
  - (Shoemaker, 2003)

### *Dry Bean Grain*

- Inventory/Availability
  - Dry edible beans were reported in pounds and assumed to have 10% moisture and were converted to dry tons. Dry edible bean straw was not included.

### *Oat Grain*

- Inventory/Availability
  - Oat grain was assumed to be reported in 32lb bushels of 14% moisture and converted to dry tons.

### *Potato*

- Inventory/Availability
  - Potato tubers in hundred weights of with 21.2% moisture and converted to tons of dry matter. Potato tops were not included.

### *Soybean Grain*

- Inventory/Availability
  - Soybeans were assumed to be reported as 60lb. bushels of 13% moisture beans and converted to dry tons. Soybean straw was not estimated.

### *Sugar Beets*

- Material Characteristics
  - (Duke, 1983)
- Inventory/Availability
  - Sugar beet roots were reported in tons with 16.4% moisture and converted to tons of dry matter. Sugar beet tops were not included.

### *Sunflower Grain*

- Inventory/Availability
  - Sunflower seeds, both oil and confectionary reported in hundred weights of 10% moisture and converted to dry tons.

### *Sweet Corn Grain*

- Inventory/Availability
  - Sweet corn as reported was assumed to have 10.3% moisture. This was converted to dry tons.

### *Wheat Grain*

- Inventory/Availability
  - Wheat grain was assumed to be reported in 60lb bushels of 13.5% moisture and converted to dry tons.

## **CROP PROCESSING RESIDUES**

### *Major Sources*

- Material Characteristics
  - (AURI, n.d.)
- Inventory/Availability
  - (Jordan and Taff, 2005)
  - (Grain and Milling Annual, 2005)
- Prices
  - Plant Gate
  - (Schroeder, 2006)

### *Ethanol DDGS*

- Material Characteristics
  - (Morey, et. al. 2005)
- Inventory/Availability
  - DDGS production was estimated using a conversion rate of 18 lbs DDGS production per bushel of corn used at each plant. Corn inputs per plant were estimated as 0.4 bushels per gallon of ethanol produced at each plant.

### *Ethanol Feed*

- Material Characteristics

### *Glycerol from Biodeisel*

- Inventory/Availability

- Glycerol production is assumed to be 0.2 pounds per gallon of produced biodiesel.

### ***Soybean Hulls***

- **Inventory/Availability**
  - Soybean hulls were assumed to constitute 6% of the weight of soybeans. Soybean hull production was estimated from the known capacity of soybean processing plants in MN.

### ***Soybean Meal***

- **Inventory/Availability**
  - Soybean meal was assumed to constitute 76% of the weight of soybeans. Soybean meal production was estimated from the known capacity of soybean processing plants in MN.

### ***Soybean Oil***

- **Inventory/Availability**
  - Soybean oil was assumed to constitute 18% of the weight of soybeans. Soybean oil production was estimated from the known capacity of soybean processing plants.

### ***Wheat Midds***

- **Inventory/Availability**
  - Wheat midds were assumed to compose 8.82 dry pounds per bushel of wheat. Wheat midd production was estimated from the known capacity of Minnesota's flour mills.
- **Prices**
  - Plant Gate
  - (UME, 2006)

## **WOOD**

### ***Major Sources***

- **Material Characteristics**
  - (Miles, et. al. 2006)
- **Inventory/Availability**
  - (Miles, et. al. 2006)
- **Prices**
  - Delivered Fuel Cost.
  - The prices used combine stumpage prices with estimated costs of timber harvest, assembly and shipping.
  - Stumpage Prices - (Kilgore and Blinn, 2003)

## *Aspen<sup>8</sup>*

- Material Characteristics
  - (Gaur and Reed, 1998)

## *Brushland*

- Inventory/Availability
  - ("Brushland: Acres by County", 2000)

## *CRP Trees<sup>9</sup>*

- Inventory/Availability
  - (USDA, 2006)

## *Urban Wood*

- Inventory/Availability
  - (Perlack, et. al., 2005)

## *Mill Residues (Barks, Slabs, and Edgings)*

- Material Characteristics
  - Assumed to be the same as Logging Residues
- Inventory/Availability
  - Inventory from primary sources
  - (Jacobson, 2007)

## *Mill Residues (Sawdust)*

- Material Characteristics
  - Assumed to be the same as Logging Residues
- Inventory/Availability
  - Inventory from primary sources
  - (Jacobson, 2007)

## **MANURES**

### *Major Sources*

- Material Characteristics
  - (MWPS, 2004)
- Inventory/Availability

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<sup>8</sup> Minnesota forest production is estimated periodically (annually, starting in 2004) by the US Forest Service and reported in the Forest Inventory Analysis (FIA) database (U.S. Forest Service, n.d.). Data is reported for each tree species in each county, but these local estimated means are associated with extremely wide variance, made explicit by the Forest Service. After consulting with the maintainers of the FIA database, we decided to use for present purposes the county mean acreage for the three species groupings: softwoods, aspen, and hardwoods-not-aspen. These acreage numbers were used along with multi-county (we used the four Minnesota FS analysis region boundaries for this assignment) annual increment ("growing biomass") estimates to calculate an annual green-tons growth estimate for the three groupings in each county. To convert these to dry tons per year, we used average moisture content estimates.

<sup>9</sup> Ibid.

- Manure inventories are based on NASS county level livestock inventories. While these data are not complete, they allow for a rough estimate of actual animal populations and manure production using assumptions based on common industry practices.

### *Hog Manure*

- Material Characteristics
  - (Jensen, Timpe, and Laumb, 2003)

## **ANIMAL PROCESSING WASTES**

### *Major Sources*

- Material Characteristics
  - (Dozier, 2002)
- Inventory/Availability
  - Rendered products were estimated through the use of USDA county level inventories of relevant livestock. From those inventories the USDA's mortality ratio and the individual ratios of rendered products to the total production of rendered products were used to estimate the county level availability of each rendered product.
- Prices
  - (UME, 2006)
  - (Schroeder, 2006)

## **OTHER WASTE STREAMS**

### *Landfill Gas*

- Material Characteristics
  - (PCA, 2006)
- Inventory/Availability
  - (PCA, 2006)

### *Municipal Solid Waste (MSW)*

- Material Characteristics
  - (EIA 2007)
  - (Foth & Van Dyke and Associates, 2006)
- Inventory/Availability
  - (PCA, 2006)
  - (Foth & Van Dyke and Associates, 2006)

### *WWTP Sludge Waste*

- Material Characteristics
  - (Kokmen, 1999)
- Inventory/Availability
  - (DuFresne, 2005)

# FOSSIL FUELS

## *Minnesota Average Coal*

- **Material Characteristics**
  - This figure was arrived at by calculating the weighted average of the BTU content of the coal used by one of Minnesota's major investor owned utilities, Xcel Energy. The information used to arrive at this figure was found in Xcel Energy's Application for Resource Plan Approval 2005 – 2019.
- **Prices**
  - [http://tonto.eia.doe.gov/state/state\\_energy\\_profiles.cfm?sid=MN](http://tonto.eia.doe.gov/state/state_energy_profiles.cfm?sid=MN)

## *Coal (Bituminous)*

- **Material Characteristics**
  - [http://en.wikipedia.org/wiki/Bituminous\\_coal](http://en.wikipedia.org/wiki/Bituminous_coal)
- **Prices**
  - <http://www.eia.doe.gov/cneaf/coal/page/acr/table31.html>

## *Coal (Sub-Bituminous)*

- **Material Characteristics**
  - [http://en.wikipedia.org/wiki/Sub-bituminous\\_coal](http://en.wikipedia.org/wiki/Sub-bituminous_coal)
- **Prices**
  - <http://www.eia.doe.gov/cneaf/coal/page/acr/table31.html>

## *Coal (Lignite)*

- **Material Characteristics**
  - <http://en.wikipedia.org/wiki/Lignite>
- **Prices**
  - <http://www.eia.doe.gov/cneaf/coal/page/acr/table31.html>

## *Fuel Oil (No. 2)*

- **Material Characteristics**
  - <http://www.eia.doe.gov/emeu/iea/tablec1.html>
- **Prices**
  - [http://tonto.eia.doe.gov/dnav/pet/pet\\_pri\\_wfr\\_dcus\\_nus\\_w.htm](http://tonto.eia.doe.gov/dnav/pet/pet_pri_wfr_dcus_nus_w.htm)

## *Fuel Oil (No. 6)*

- **Material Characteristics**
  - <http://www.eia.doe.gov/emeu/iea/tablec1.html>
- **Prices**
  - [http://tonto.eia.doe.gov/dnav/pet/pet\\_pri\\_resid\\_dcu\\_SMN\\_m.htm](http://tonto.eia.doe.gov/dnav/pet/pet_pri_resid_dcu_SMN_m.htm)

## *Natural Gas*

- **Material Characteristics**
  - <http://www.eia.doe.gov/emeu/aer/txt/ptb1304.html>
  - [http://en.wikipedia.org/wiki/Natural\\_gas](http://en.wikipedia.org/wiki/Natural_gas)
- **Prices**
  - [http://tonto.eia.doe.gov/dnav/ng/ng\\_pri\\_sum\\_dcu\\_nus\\_m.htm](http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm)

## *Propane*

- Material Characteristics
  - <http://www.eia.doe.gov/emeu/iea/tablec1.html>
  - <http://en.wikipedia.org/wiki/Propane>
- Prices
  - [http://tonto.eia.doe.gov/dnav/pet/pet\\_pri\\_wfr\\_dcus\\_nus\\_w.htm](http://tonto.eia.doe.gov/dnav/pet/pet_pri_wfr_dcus_nus_w.htm)