# SEBESTA BLOMBERG

# BIOMASS-TO-ENERGY FEASIBILITY STUDY


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# Section 1
# Introduction

This report examines the feasibility of biomass-to-energy projects. It is designed to examine and analyze options available, and feasibility of, a variety of biomass-to-energy plant options. This section identifies the project team, the project objectives, and the project schedule.

## How to Use this Report

There are four ways to find information in this report:

1. The Table of Contents lists the sections of the report.
2. The first page of each section includes a section table of contents.
3. The header at the top of every left-hand page contains the report name and the name of the section to which the report is opened.
4. The footer at the bottom of every page contains the page number, the project number, and the revision date.

## Project Team Members

The following personnel make up the Biomass-to-Energy project team.

### *Sebesta Blomberg & Associates, Inc*

- John Carlson Principal
- Ed Snouwaert Division Leader
- David Boyles Energy Specialist
- Ann Curnow Environmental Group Leader
- Manny Day Electrical Group Leader
- Cecil Massie Process Development Group Leader
- Tom Schubbe Energy & Utility Group Leader
- Amit Shukla Biochemical Project Engineer
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### *Primenergy, Inc*

- Bill Scott President
- Kevin McQuigg Director of Process & Application Engineering
- Michael Sharon Senior Project Manager

### *Rahr Malting Co.*

- Gary V. Lee President
- Paul Kramer Vice President of Malt Operations
- Dale Lundquist Manager of Engineering and Process Design

## Project Objectives

The following list defines the project objectives.

- Define commercial equipment for gasification of Rahr Malting Co. by-products.
- Identify commercially available spark ignited engine generators (SIEG) and combustion turbines (CT) capable of running on 150 BTU synthesis gas (syngas).
- Define equipment requirements to co-generate electricity and heat and to distribute the heat and power as required.
- Determine the emission characteristics and regulatory issues related to the proposed co-generation systems.
- Complete 20-year economic analysis for each co-generation scenario.
- Analyze the technical and economic tradeoffs of steam turbines versus combustion turbines for generation of power.
- Determine the regional and national market characteristics of biomass co-generation.

# Section 2
# Executive Summary

This section contains an executive summary of the Biomass-to-Energy Feasibility Study.

## Purpose and Perspective

The purpose of this study was to assess the economic and technical feasibility of producing electricity and thermal energy from biomass by gasification. For an economic model we chose a large barley malting facility operated by Rahr Malting Co. in Shakopee, Minnesota. This plant provides an excellent backdrop for this study because it has both large electrical loads and thermal loads that allowed us to consider a wide range of sizes and technical options. In the end, eleven scenarios were considered ranging from 3.1 megawatts (MWe) to 19.8 MWe.

By locating the gasification and generation at an agricultural product processing plant with large electrical and thermal loads, the expectation was that some of the limitations of stand-alone biomass power plants would be overcome. In addition, since the process itself created significant volumes of low value biomass, the hope was that most of the biomass gathering and transport issues would be handled as well.

The development of low-BTU gas turbines is expected to fill a niche between the upper limit of multiple spark ignited engine set systems around 5 MWe and the minimum reasonable scale for steam turbine systems around 10 MWe.

**Executive Summary**

At the time of the proposal in June 2001, there were no commercially available combustion turbines capable of operating on the low BTU gas produced by the gasifier in the 5 to 10 MWe range. Our expectation was that the conclusion of our study would be that a follow-on project to develop such a turbine would be recommended. In the actual event, Alstom debuted a modified Typhoon turbine designed to use low BTU synthesis gas generating 3.1 MWe of power and has a demonstration plant in operation in England. Alstom has also announced plans to build an 11 MWe version of this design. In addition, Siemens has announced construction of a 0.4-MWe thermal input pilot plant in Germany running on a clean air turbine design. A 2.2-MWe prototype is being advertised for this technology. Therefore, we conclude that the private sector, albeit foreign, has taken up the challenge to provide low-BTU fired combustion turbines. The expected outcome of this study being overtaken by developments in the marketplace, this study has been tailored to provide the reader with a roadmap to evaluate the options and benchmark new technologies against current ones.

## Technical Assessment:

Four processes for power production from biomass are technically feasible. They include: spark ignited engines, combustion turbines, steam turbines and clean air turbine or CAT technology. Each has advantages and disadvantages but the economics clearly favor the spark-ignited engines up to the 5-MWe level.

The combustion turbine manufacturer, Alstom, has demonstrated the benefits of using a standard design as the starting point by making relatively minor modifications to the combustion chamber and firing systems. Indeed, by using a “bolt-on” approach Alstom has shown how to reduce the technical risk of the project to manageable dimensions. Even so, the low-BTU gas version costs about $3 million, $1 million more than the same turbine running natural gas, and owing to the higher parasitic load produces much less power. New turbines being built today have the conversion feature built into them and in the long run this should reduce or eliminate the premium for the synthesis gas capable turbine.

Engine sets burning low BTU gas are a proven technology and there is very little, if any, technical risk associated with them. A number of plants operating on engine sets exist around the world. These engine sets are a mainstay of landfill gas recovery and other low value fuel supplies. Plants now in operation or under construction will provide real-world operating experience on which to base funding decisions. In the area of low-BTU engine sets, Primenergy has a number of installations that are ready to proceed to commercialization.

Serious concerns remain, however, in areas other than the turbine or engine set. While Primenergy has demonstrated a successful gas cleaning technology, the worrisome co-product is a water and tar mixture whose ultimate fate is unclear. In addition, there is no operating history to suggest the lifetime effects of low BTU gas on performance.

For conceptual simplicity the clean air turbine is the clear winner. It requires no synthesis gas conditioning technology because the products of combustion do not come in contact with either a turbine or an engine set. Instead, heat is transferred via a heat exchanger to a compressed air stream, which then passes through a turbine. During our study we considered the clean air turbine but dismissed it as economically and technically suspect. The design of a heat exchanger capable of handling the corrosion and fouling issues was considered too difficult and likely to fail.

During the study, however, Siemens announced development of the SiPeb® clean air turbine technology including a demonstration plant in Sulzbach-Rosenberg, Germany. The claimed improvement in this technology is the use of regenerative heating to alternately absorb heat from the combustion gases and transmit heat to the clean, compressed air. The unit has been in operation since October of 2001 at a capacity of 440-kWth inputs. In our opinion this technology warrants further evaluation but was announced too late to be included in this study.

## Environmental Effects:

Environmentally speaking, the biomass /combustion turbine system is a relatively poor performer. Uncontrolled emissions of criteria pollutants carbon monoxide (CO), volatile organic carbon (VOC), and sulfur dioxide (SO2) are higher from the biomass plant than from natural gas per kilowatt-hour of power produced. Biomass power production is on a par with natural gas in NOx emissions. A clear advantage emerges, however, from co-generation on site when compared to current practice. Under this circumstance the biomass firing replaces coal emissions from the power plant and the natural gas emissions from a boiler. NOx, carbon monoxide, and VOC emissions are notably reduced. Sulfur dioxide emissions would remain higher.

The uncontrolled emission levels from the turbine are probably unacceptable because they are so high relative to other options. A key development would be a process for recovering NOx and SOx in a form suitable for fertilizer. Since our focus is on agricultural residues, returning these nutrients to the farm may be a highly desirable resolution. Of particular interest is the emerging technology being promoted by EnviroScrub of Bloomington, Minnesota. EnviroScrub claims to achieve nearly complete recovery of both NOx and SOx emissions in usable form. Pollution control options, however, were not included in the economic analysis.

## Economics:

Eleven scenarios were evaluated. Economic return was determined based on avoided cost of purchased natural gas and electricity. Prices for natural gas, electricity, and biomass were escalated according to Office of Management and Budget estimates over the twenty-year life of the project. Projects were depreciated over a 7-year schedule on a straight line. Financing was assumed to be 20 years with 5% interest. Using these values and operating and capital cost estimates for each case, the internal rate of return for each case was estimated.

None of the cases showed an attractive return. All, but one, are negative and the best case showed only low single digit returns over the twenty year life. The one positive return was a spark ignited engine option.

A sensitivity analysis shows that this project would be attractive under any of the following scenarios:

a. Biomass is free or has negative value

b. Natural gas prices escalate sharply

c. Purchased electricity costs increase two fold

Interestingly, reducing the capital cost by 50% would not be enough to make these projects attractive to ordinary investors. In any event we do not predict significant (greater than 20%) capital reductions are possible since most of the elements of each process are fully developed technologies.

## 1 Alstom Typhoon Turbine:

The objective under solicitation DE-PS26-01NT41130 was to facilitate the development of advanced biomass power generation systems that offer significant improvements in thermal efficiency and environmental performance. These systems were to be predominantly based on advanced biomass gasification technologies and could incorporate advanced turbine and stationary fuel cell technology for production of electricity from biomass. The project team decided to investigate the advanced combustion turbine option while at the same time considering other pertinent technologies including spark-ignited engine sets, steam turbines, and clean air turbines (CAT) for Rahr Malting Co.

**Executive Summary**

At the start of the project our objective was to generate 12 MWe peak electrical power and recover the heat for Rahr's process. The fuel for the gasifier is byproducts from the malting operation and other agricultural residues. We found that it was not economical to generate more than the base-load of about 4.5 MWe for Rahr. In addition, after review of available technologies, we found the only low-BTU combustion turbine available was a 4.7 MWe Typhoon combustion turbine from Alstom Power Co. After parasitic loads are factored in, this turbine generates a net power output of 3.1 MWe, less than the 5-MWe program objective. Using the Typhoon turbine, the overall thermal efficiency would be 55% as compared to the program objective of 60%. The program power production efficiency objective was 35% and the Typhoon turbine provides 20%. Our overall thermal efficiency objective was 60% and the typhoon turbine affords 55%. We achieved our objective of using more than 95% synthesis gas as fuel since the Typhoon turbine technology in association with Primenergy's gasifier can use 100% synthesis gas as fuel. The projected cost of electricity would be about $0.07/kWh. After a seven-year depreciation period, the production costs would be $0.030/kWh, competitive with coal-based electricity

In the 1 Alstom Scenario, the biomass cogeneration plant consumes 51,000 tons of biomass per year to produce 3.1MWe of power and 32 MMBTU/hr heat. In addition, Rahr has a supplemental heating requirement on top of the heat recovered from the cogeneration plant. This supplemental heat will be provided by gasifying about 18,000 tons /yr of biomass for a total biomass consumption of 69,000 tons/ year. Rahr produces 60,000 tons of biomass byproduct from its own process and has confirmed access to 120,000 tons/yr from nearby sources. Based only on the Rahr cogeneration plant, and not the supplemental heating plant, there is enough corn stover left in the U.S. to build approximately 3,800 plants with the same biomass tonnage usage as Rahr's. These biomass plants could fulfill 3.0% of the nation's electricity and 4.6% of natural gas usage per year.

## Conclusions and Recommendations:

Biomass based power production will be attractive under certain specific circumstances but will not become generally attractive until energy prices increase significantly and disproportionately relative to biomass energy. There is some hope that this will occur as the most significant biomass supply, corn stover, is available for the cost of harvest.

The technology to implement any of the options considered in this study is feasible and ready for implementation pending resolution of environmental issues

# Section 3
# Technical

Eleven different scenarios were considered for Rahr ranging in size from 3.1 MWe to 19.8 MWe cogeneration systems (see Section 6 on page 6-19). However, based on the fact that advanced turbines are the focus of the NETL solicitation and that the Alstom low BTU Typhoon turbine is closest to commercialization, a 3.1 MWe cogeneration system was chosen for Rahr. The following discussion covers the plant efficiency and acceptable biomass fuels of the 3.1 MWe combustion turbine cogeneration plant.

## Drawings and Flowsheets

See Appendix A on page 9-3 and Appendix G on page 17 for details of the layout and mass and energy balance of the 3.1 MWe cogeneration biomass plant.

## Discussion

The four major equipment systems in the energy plant are the gasifier, gas clean-up and conditioning, combustion turbine, and heat recovery. Please refer to the gasifier process flow diagram, Appendix A on page 83, for additional details regarding the gasifier system discussion below. Biomass is fed to the gasifier from a bucket elevator and ash is collected at the bottom of the gasifier. The synthesis gas contains tars generated during the gasification process and fly ash. The hot synthesis gas from the gasifier is sent to the cyclone filters to remove most of the ash. The gas is then cooled in an indirect heat exchanger to approximately 500°F. In the heat exchanger, synthesis gas is on the tube side and water on the shell side.

From the heat exchanger, the synthesis gas goes to a direct contact spray scrubber, which utilizes a hydrocarbon medium (refined oil) to cool the gas below its water dew point and scrub out condensed moisture, tar, and particulate. The liquid blow-down (wastewater) is then removed from the system. The sub-cooled, water-saturated synthesis gas transfers from the direct contact scrubber at approximately 105°F and flows to two Particulate and Aerosol Removers (PARs) in series. The PARs utilize motor-enhanced centrifugal force to accelerate the synthesis gas tangentially to over 300 mph. This propels the remaining particulate and tar into the walls of the PARs.

The accumulated tar/particulate flows into the PAR sumps. From the PARs, the gas flows to the variable-frequency-controlled ID Fan. A pressure transmitter on the gasifier controlling the gasifier pressure controls the speed of the fan. The synthesis gas exits the ID Fan through a cooling water-jacketed duct. The cooling water-jacketed duct removes the energy imparted by the ID Fan, cooling the synthesis gas. A chevron style mist eliminator at the end of the water-jacketed duct removes moisture and entrained oil/tar. The above steps yield a synthesis gas at approximately 105°F to 110°F (depending on cooling water supply temperature). The synthesis gas is accumulated in a surge tank and then flows to the combustion turbine via the synthesis gas compressor.

The Alstom Typhoon turbine uses diesel fuel to start-up and then transfers to synthesis gas after steady state is reached. Therefore, a supply of diesel fuel will be required for start-up and for back-up in case there are problems with the biomass plant. Furthermore, the Alstom turbine is capable of running on natural gas when the combustor of the turbine is replaced. Thus, the unit is modular and capable of functioning even when the biomass plant malfunctions. Rahr has access to natural gas pipeline but does not have easy access to diesel fuel. Because the turbine can be modified to run on natural gas, Rahr will find this feature convenient in case the biomass plant fails.

## Performance Characteristics of the Plant

The overall thermal efficiency of the cogeneration plant is 55%, which is calculated by adding the energy output in the form of electricity and heat and dividing by the biomass fuel input. The heat that is recovered is from the turbine exhaust and the indirect contact gas cooler-scrubber. This heat is directly recovered by linking Rahr's glycol system to these heat sources. There are other smaller heat sources but it was determined that the heat from these sources could not be economically recovered. By linking the Rahr glycol heater to the biomass plant, we increase efficiency and save money that would have been used to design and install such a heat recovery system. The total power output is 3.12 MWe and the recoverable heat is 32 MMBTU/hr.

When natural gas is burned, the Alstom Typhoon turbine generates 4.7 MWe of power. However, when synthesis gas is used the total power output drops to 3.4 MWe. This output loss is mainly due to the synthesis gas compressor, which consumes 1.3 MWe. The gasifier itself uses about 0.3 MWe leading to an overall power output of 3.1 MWe.

## Acceptable Fuels/Fuel Flexibility

Estimates conclude that in order to generate 3.1 MWe-Year of electricity and 32 MMBTU/hr of heat from the co-generation process, Rahr Malting will use approximately 51,000 tons of biomass per year. In order to produce the remaining heat necessary to run the malting plant, Rahr must burn an additional 18,000 tons of biomass per year. Rahr has confirmed access to 160,000 tons/year of biomass, both as by-products from its own process, and from other agricultural processing plants and local corn farms (see Table 3-1). Rahr produces about 60,000 tons of malting by-products per year in its malting process, and intends to use this waste stream as biomass fuel. Based on availability and pricing, Rahr intends to use oat hulls, corn stover and switch grass for additional fuel (see Table 3-1) when the economics favor using these alternate fuels.

Rahr's by-product consists of several different biomasses, depending on which part of the malting process the biomass comes from, including: malt sprouts, barley needles, wheaty barley, and dust chaff. Pictures of these by-products are included in Appendix H on page 19. An elemental lab analysis was performed on these by-products, corn stover, and oat hulls. Moisture content, BTU value, and ash content of all biomasses are listed in Appendix H on page 19. Based on the projected ratio of biomasses and individual lab results, Primenergy performed mass and energy balances and sizing of the process equipment.

**Table 3-1: Available Biomass at Rahr Malting Co.**

| Biomass Option | Price ($/ton) | Volume (tons/yr) |
|---|---|---|
| Rahr By-Products | 20-30 | 60,000 |
| Oat Hulls | 20-30 | 60,000 |
| Corn Stover | 40-50 | 30,000 |
| Switch Grass | 30-40 | 10,000 |

## Areas of Uncertainty

As the project progresses, a pair of issues would need to be addressed. Firstly, about 1 tanker truck per day of wastewater will be generated as part of the proposed biomass plant. This wastewater is produced in the Particulate and Aerosol Removal part of the process (see Appendix A on page 9-3). The cost and method of disposal still needs to be resolved. Secondly, the synthesis gas produced from Primenergy's biomass plant has not been shown to work with Alstom's Typhoon turbine. Alstom has a commercial low BTU Typhoon turbine at an installation in Yorkshire, England where wood chips are used in a biomass gasification combined cycle 10-MWe power plant (http://www.arbre.co.uk/index.htm). Yet the Primenergy gasifier is a different technology and, it will be the first time that Alstom will try to use this new turbine in connection with Primenergy's gasifier. With DOE funding, we hope that the perceived risk associated with this integration aspect of the project will be overcome and a demonstration plant built.

# Section 4
# Environmental Assessment

This study included a review of the environmental implications of gasifying a biomass and combusting the resulting synthesis gas. For a technology to be viable it has to be able to obtain the necessary environmental approvals. Beyond viability, an environmentally superior technology is one that has less of an impact on the environment than the technology it replaces in terms of air emissions, water usage, waste generation, and demand of non-renewable resources such as fossil fuels.

To evaluate the environmental impact from biomass gasification/combustion the following items were reviewed.

- Expected air emissions from the biomass gasification/combustion process,
- Comparison of emissions from the combustion of synthesis gas against traditional fuel sources,
- Anticipated advantages of reducing the reliance on a coal fired power plant, and
- Additional environmental consideration such as water requirements and ash disposal.

This study is limited to reviewing environmental considerations for the installation of an Alstom Typhoon turbine, designed to run on synthesis gas and produce net 3.1 megawatts of electricity. This environmental study is restricted to the co-generation plant and does not take into account the emissions from the gasification of the biomass to supply Rahr's supplemental heating needs. Other engine manufacturers and engine sizes were considered for operational feasibility (discussed in other chapters of this report), but Alstom turbine is the focus of this environmental study since it is the only combustion turbine found to be closest to commercialization.

The report sections that follow present the environmental review completed as part of this biomass gasification study.

**Environmental**

# Air Emissions

One of the primary environmental impact indicators is the type and amount of air emissions that are expected from a process. The type and amount of emissions will determine what type of air permitting will be required. Permitting requirements for the most part are related to the emissions of criteria pollutants. Criteria pollutants have been defined by the US Environmental Protection Agency (EPA) to be Nitrogen Oxide ($NO_x$), Sulfur Dioxide ($SO_2$), Particulate Matter (PM), Volatile Organic Compounds (VOC), and Lead (Pb).

In order to assess the environmental performance, it is necessary to compare potential emissions from a turbine operating on synthesis gas to potential emissions generated from a same size turbine operating on conventional fuels i.e. diesel and natural gas. Another piece of the environmental performance puzzle is to understand the benefit of generating electricity on-site. On-site generation eliminates transmission losses and displaces the need to purchase electricity generated from coal combustion. Additionally, thermal energy produced by the turbine can be utilized to displace thermal requirements at the facility that are currently satisfied by natural gas combustion.

### *Potential Emissions from Synthesis Gas*

The process that is being reviewed has one emission point, the turbine exhaust. In order to understand what is being emitted and why, a brief explanation of the process follows. Please see Appendix A on page 9-3 for a schematic of the process.

Biomass is combusted in a gasifier to produce synthesis gas. The synthesis gas passes through a series of cooling and cleaning mechanisms before being mixed with outside air to fire the Alstom turbine. The turbine is designed to produce net 3.1 MWe of power, as well as, approximately 32 million BTU per hour of recoverable heat from the turbine and cleaning steps.

Air emissions data is not available from actual applications. Alstom Power provided emission rates for its turbine operating on synthesis gas, based on its experience using conventional fuels and the expected constituents in synthesis gas. The data is considered “best estimates based on available information” and is conservative. Alstom Power does not guarantee the emission rates provided as part of this study.

The emission rates are presented as potential emissions. Potential emissions are determined by assuming the process is operated at maximum capacity 24 hours a day, 365 days a year (8,760 hours). Table 4-1 presents the emissions from the biomass gasification/combustion process. Alstom Power was not able to provide emission rates for VOC or PM from synthesis gas. However, it was able to provide the VOC emission rates for its turbine operating on natural gas. VOC emissions from natural gas and synthesis gas are expected to be similar, so the VOC rate for natural gas was used. Alstom Power did not have enough data to provide an estimate for PM.

When the Typhoon combustion turbine is operated on natural gas or diesel fuel, the net power output is much higher (4.7 MWe) compared to when it is operated on synthesis gas (3.1 MWe). This lower net power output when the combustion turbine operates on synthesis gas is caused by the higher energy consumption required to compress the synthesis gas before it goes into the turbine. This compression is not required when the turbine operates on natural gas. In order to compare emissions from fossil fuels and synthesis gas, the total annual emissions have been normalized per megawatt-year.

**Table 4-1: Potential Emissions From Synthesis Gas per Megawatt-Year**

| Criteria Pollutant Emissions | | | | | |
|---|---|---|---|---|---|
| $NO_x$ Tons/yr | CO Tons/yr | $SO_2$ Tons/yr | $PM_{10}$ Tons/yr | Lead Tons/yr | VOC Tons/yr |
| **22.61** | **19.78** | **16.95** | Not available | **0** | **0.283** |

In addition to emissions from the products of combustion, the process to generate synthesis gas from biomass will generate emissions of particulate matter from handling the biomass. The amount of particulate matter emissions from the material handling process has not been quantified as part of this review process. Emissions generated from material handling would have to be included to obtain regulatory approval for construction and operation.

**Environmental**

### *Comparison of Emissions*

The emissions from the Alstom combustion turbine operating on synthesis gas were compared to potential emissions from the same size turbine operating on natural gas and diesel fuel. The comparison was made to determine if operating a turbine on synthesis gas, as opposed to fossil fuels, would result in lower or higher emissions of any of the criteria pollutants.

The emissions for turbines operating on natural gas and diesel were calculated using emission factors presented in USEPA AP42 Emission Factors, Chapter 3.1, Stationary Gas Turbines. The following tables present the emissions from a turbine comparable to the Alstom turbine, operating on different fuel types.

**Table 4-2: Potential Emissions of Turbine Operating on Natural Gas per MWe-Yr**

| Criteria Pollutant Emissions | | | | | |
|---|---|---|---|---|---|
| $NO_x$ Tons/yr | CO Tons/yr | $SO_2$ Tons/yr | $PM_{10}$ Tons/yr | Lead Tons/yr | VOC Tons/yr |
| **22.87** | **5.86** | **3.36** | **0.468** | Not Determined | **0.151** |

**Table 4-3: Potential Emissions of Turbine Operating on Diesel (No. 2 Fuel Oil) per MWe-Yr**

| Criteria Pollutant Emissions | | | | | |
|---|---|---|---|---|---|
| $NO_x$ Tons/yr | CO Tons/yr | $SO_2$ Tons/yr | $PM_{10}$ Tons/yr | Lead Tons/yr | VOC Tons/yr |
| **62.90** | **0.24** | **3.61** | **6.857** | **0** | **0.030** |

Please note that all emission calculations are estimated as the worst-case scenario without control equipment. Figure 4-1 graphically presents the comparison of the fuel types. Lead and PM have been purposely left out of this comparison.

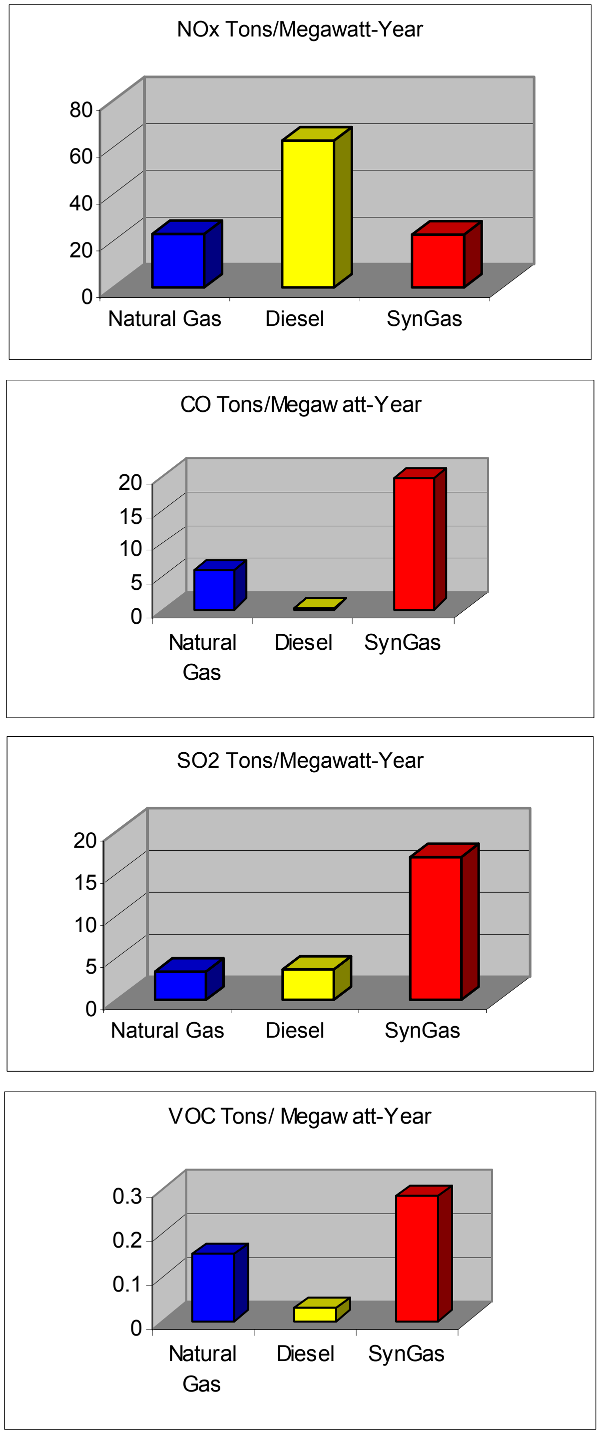


**Figure 4-1**

*Comparison of Emissions.*

**Environmental**

The $NO_x$ graph depicts levels for synthesis gas comparable to fossil fuel levels. As for the remaining criteria pollutants, preliminary figures show synthesis gas at higher concentrations than fossil fuels. Preliminary figures may be misleading due to the lack of actual test information from the combustion of synthesis gas.

### *Emission Reductions from Displacement of Electrical/Thermal Demand*

In order to better understand the benefits of an alternative fuel source, the evaluation of environmental impacts should consider the advantages of displacing electrical and thermal demands that are being satisfied by conventional fuel sources.

Rahr Malting (Rahr), the host facility for the biomass study, purchases electricity from a centrally located coal fired power plant. The process of generating and transmitting electricity to Rahr from a central plant is less efficient than if electricity was generated on-site. About half of the electricity produced at a central power plant is lost due to the inefficiencies inherent with transmission lines. Not only is transmission an inefficient process, but also coal fired electrical generating plants are about 33 to 40 percent efficient at generating electricity. For example, to deliver 5 MWe of energy, a power plant would need to actually produce 25 MWe. Overall process efficiency at a coal power plant is often recognized in the 20 percent range. The proposed biomass project is expected to be approximately 55 percent efficient.

Not only is Rahr Malting a consumer of electricity, but it also has thermal demands that are currently satisfied by on-site natural gas combustion. The biomass combustion project would not only supply Rahr with 3.1 MWe of net power but also meet 32 MM BTU of Rahr's thermal load.

In order to compare the emissions resulting from the Rahr biomass co-generation plant to an equivalent fossil fuel plant, the emissions from a 15.5 MWe coal fired power plant with 40% fuel efficiency and 50% transmission loss were added to the emissions from a boiler firing at 40 MM BTU per hour with 80% efficiency. In other words, taking the efficiencies into account, the coal power plant delivers 3.1 MWe power and the boiler provides 32 MMBTU/hr heat. This combined figure is then weighted against the emissions from the biomass plant (see Table 2-4).

**Table 4-4: Combined Power & Heat Emissions (Tons/MWe-Yr)**

| Criteria Pollutant Emissions | | | | | | |
|---|---|---|---|---|---|---|
| | $NO_x$ | CO | $SO_2$ | $PM_{10}$ | Lead | VOC |
| **Current *** | **32.6** | **21.64** | **4.21** | **0.87** | **0.001** | **0.47** |
| **Syn Gas** | **22.61** | **19.78** | **16.95** | **NA** | **0** | **0.28** |

* Combined emissions from a coal power plant that delivers 3.1 MWe and a boiler that supplies 32 MMBTU/Hr.

Process efficiency relates directly to the environment. If less fuel is required to generate electricity or produce heat then less products of combustion are created.

## Environmental Summary

In addition to air emissions, the biomass gasification process will have other environmental impacts that will need to be considered such as.

- Water usage
- Ash disposal, and
- Material handling

Some of these items may even trigger additional permitting requirements and or environmental review requirements. At the time of this study, not enough information was available to evaluate these issues in detail.

Not enough data is currently available to thoroughly review the environmental advantages of synthesis gas. However, it appears that the advantages may range from potentially lower emissions to providing solutions to the expected future shortfalls in fossil fuels.

# Section 5
# Biomass Supply Feasibility Criteria

There are various sources of biomass that can be used as fuel to produce energy. However, the selection of the biomass is critical for the success of any biomass to energy project. This success hinges on biomass availability and pricing. This section provides a description of the biomass supply criteria necessary for a successful biomass to energy project both in Minnesota and across the nation.

## Model for Success

The Rahr site is an excellent model for successful biomass co-generation that has potential for replication across the United States. Many agricultural processing and ethanol plants fit the characteristics of this model. Plants fitting the model have several features that make them attractive: high-energy consumption, on-site biomass availability, and proximity to alternative biomass supplies. First, these plants consume enormous amounts of electricity and heat in the processes through pumps, fans, dryers, kilns, etc. Secondly, a large percentage of required biomass is available on-site. These plants produce by-products that are currently disposed of, or sold as low-value animal feed. The low-value byproduct could alternatively be used as fuel to power and heat their processes, thereby reducing natural gas and electrical expenses. Finally, additional biomass is available near the plants so that the total biomass expense is minimized. Agricultural processing and ethanol plants are typically located near farms where agricultural residues can be obtained inexpensively. Proximity to farms and other agricultural processing plants, and the fact that much of the biomass is available on site, reduces transportation costs, making the economics of biomass co-generation more attractive.

**Biomass Supply Feasibility Criteria**

## Economic Considerations

The Rahr case highlights critical cost considerations for any economic evaluation of biomass energy production. First, the cost per BTU of biomass supplied to the energy plant must be compared with that of natural gas or other existing fuel cost. In the case of Rahr, natural gas is used for comparisons. If the biomass cost is low compared with that of natural gas, then the plant is a good candidate for biomass energy production. A second consideration is the transportation cost for delivery of biomass. Lower transportation cost makes it economically feasible to collect biomass from a larger geographic area. Third, the biomass supply pricing structure should be stable over time. Unstable prices create market volatility, problems in obtaining sufficient quantities, and overall cost fluctuations for the energy plant. Finally, availability of sufficient biomass in the market place for all of the competing biomass users is another important factor that can affect seasonal price and availability. A biomass-to-energy plant designed to use a wide variety of fuels reduces the negative effects of price spikes and/or seasonal price variations.

## Biomass Availability

Assuming a sufficient amount of biomass is not available on-site, additional biomass must be obtained off-site. There are a variety of options for additional biomass. For example, biomass is usually available at generators such as soybean processing plants that produce soybean hulls. Otherwise, biomass such as corn stover may be available from corn farms. By obtaining biomass directly from the biomass generators, biomass may be available at lower prices, bypassing distribution channels. Alternately, biomass can be obtained from brokers, traders, or other commercial distribution channels. An advantage of working with a broker or trader is that the brokers have multiple sources and a wider range of biomass fuels and pricing/delivery options. Furthermore, since the brokers deal with buying and selling biomass on a daily basis, they can manage market volatility and may be able to obtain more stable, long-term supply prices. (For more information about biomass availability in Minnesota, see Section 3.5)

## Operational Considerations

A facility considering a biomass energy plant must have the capability to obtain and handle enormous amounts of biomass and have the ability to store it under the right conditions. If these considerations are overlooked, a facility will risk loosing money on the project. The following issues must be considered, both technically and economically: on-site biomass storage, biomass availability and pricing, and biomass quality control.

### *On-Site Biomass Storage*

The proposed facility must have sufficient on-site storage capacity to handle the enormous volumes of biomass for processing. Storage silos, conveyor belts, and other material handling equipment must be sized and priced.

### *Biomass Availability and Pricing*

Market price fluctuations, transportation scheduling, and other similar availability factors can affect biomass purchasing and delivery. Therefore, the facility should be able to stockpile biomass. For example, a company using oat hulls as fuel, when the price of oat hulls increases should have the capability to interrupt this supply and switch to another less costly fuel. This switch might create material storage problems and delivery volume changes.

### *Biomass Quality Control*

Biomass humidity and moisture content are important considerations. Biomass with less moisture allows a more efficient gasification process and yields more energy for the same mass of input material.

Also, in cases where the biomass is wet, it might be necessary to dry biomass coming into the plant and provide humidity controlled storage facilities. Some examples of biomass that might need to be dried are wet distillers grains from ethanol fermentation process. In addition, the facility must define quality of the biomass going into the plant and specify any grinding or chopping equipment necessary to prepare the biomass for gasification. It is also necessary to control dust and odors during biomass preparation.

Finally, a proposed facility must manage biomass shelf life to avoid degradation during storage. Biomass degradation represents financial and energy loss.

## Minnesota Biomass Supply Assessment

Minnesota produces several different types of low-value biomass for possible use in a biomass-to-energy plant. Also, Minnesota supports a large number of farms and agricultural processing facilities. Therefore, currently, there is no shortage of biomass volume. Biomass types include farming residues such as corn stover, agricultural processing outputs such as malting by-products, and energy crops such as switch grass. Each of these biomasses has advantages and disadvantages.

### *Corn Stover—Price and Availability*

In Minnesota, corn stover is one of the most attractive fuels for biomass-to-energy projects because of low cost and high availability. Currently, corn stover is available for about $45/ton, which is essentially the cost to collect and transport the material. This price is lower than most other forms of biomass currently available in the market. Corn stover is available at these low prices because the main source of farming revenue usually comes from corn sales. Stover is not normally relied upon for significant income. Therefore, production costs associated with the land and farming equipment are not generally included in the selling price of stover. This existing pricing structure for growing and harvesting stover will tend to keep the price low. Currently, most corn stover is not harvested because there is no demand for it. As the biomass market for corn stover grows, more farmers will harvest stover. This increase in harvest of stover will create significant new income for farmers.

There is an abundant supply of corn stover in Minnesota. In 2000, approximately 27-million tons of corn stover was available in Minnesota (see Figure 5-1), a vast majority of which was left on the field. This estimate was determined by assuming that the weight of corn stover is about 50% of the weight of corn that is harvested. The data for the amount of corn harvested was found from the USDA web site[1]. Assuming 30% of this available stover is left on the fields for soil erosion control, and the remaining 70% is harvested, 19-million tons of stover is potentially available as a fuel source[2].

As discussed above, the Rahr co-generation plant (not including the supplemental biomass plant) will consume about 51,000 tons per year of biomass to generate 280-billion BTU of heat and 27-million kWh of electricity. Assuming all the harvested corn stover in Minnesota is utilized as fuel, over 370 plants with similar tonnage requirements as Rahr's could operate on corn stover alone. The 370 plants could supply over 103-trillion BTU of heat and 10-billion kWh of electricity annually. The 103-trillion BTU of energy per year equates to approximately the same amount of energy (BTU) produced by burning103-billion cubic feet of natural gas.

In 2000, Minnesota consumed a total of about 60-billion kWh of electricity and 333-billion cubic feet of natural gas (see Figure 5-2 and Figure 5-3)[3]. Therefore, the corn stover that is currently left on the fields in Minnesota could supply approximately 17% of the electricity requirements and 31% of the natural gas requirements for the entire State.

**Biomass Supply Feasibility Criteria**

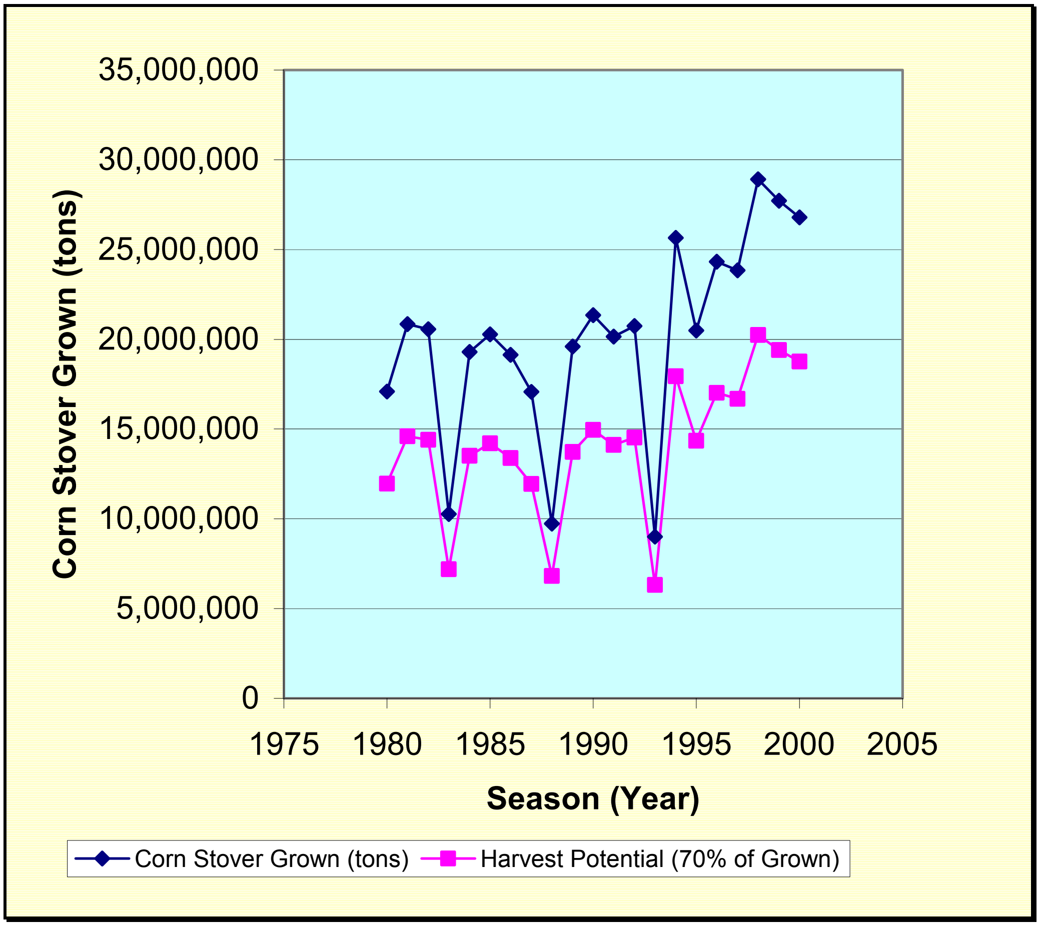


**Figure 5-1**

*Corn Stover Produced in Minnesota*

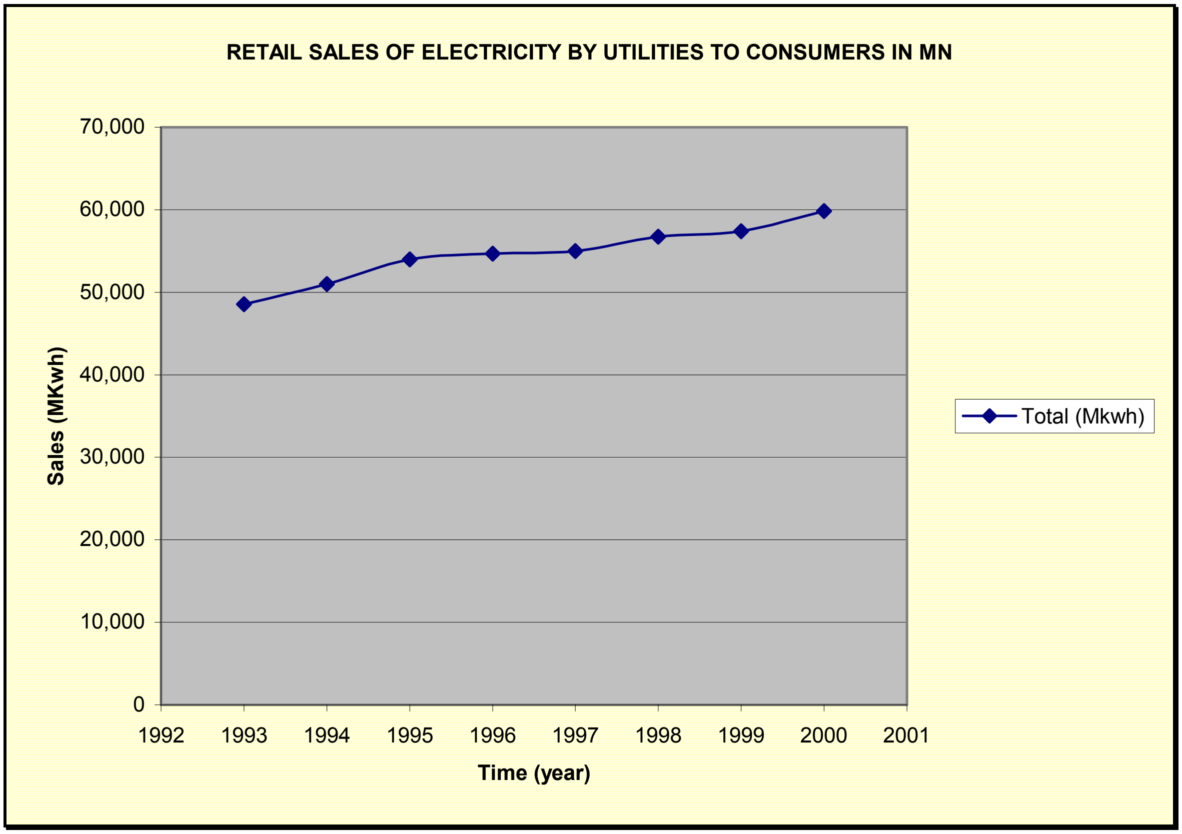


**Figure 5-2**

*Sales to Consumers from Electrical Utilities in Minnesota*

## Biomass Supply Feasibility Criteria

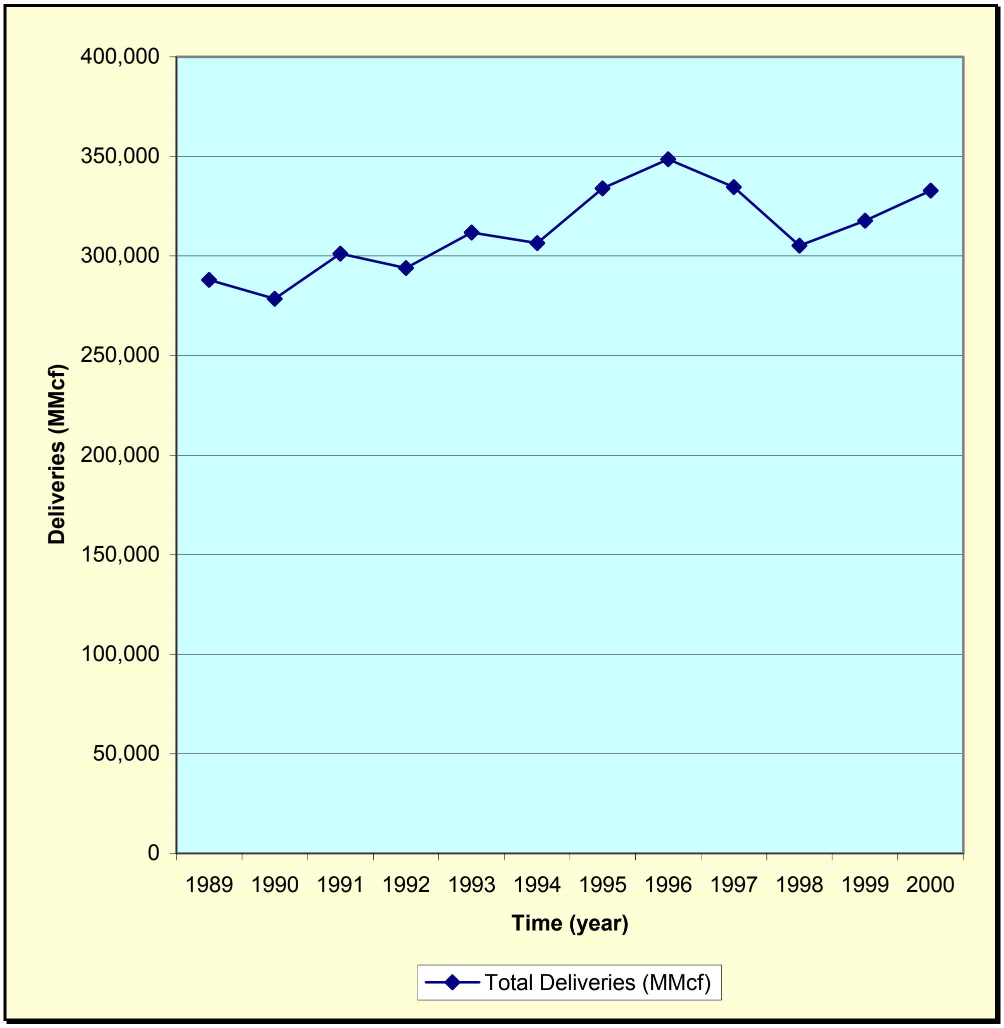


**Figure 5-3**

*Total Deliveries to Consumers in MN (MMcf)*

### *Corn Stover—Economic Considerations*

If corn stover is collected for use as fuel, it will eventually require some level of size reduction or grinding prior to gasification. There are advantages to grinding the stover at the farm, if possible, prior to shipment to the energy plant. Grinding stover at the farm increases its density, which means more mass of stover can be transported per truck. Thus, the transportation and material handling costs would be reduced. Finally, grinding at the farm avoids regulatory dust control and permitting problems that could exist if the grinding had to be completed at the energy plant site.

### *Agricultural By-Products—Price and Availability*

"Feedstuffs" is a weekly publication that publishes the prices for a wide variety of feed ingredients that are potential biomass candidates for energy production. According to Feedstuffs, many agricultural by-products exist as potential fuel sources for a gasification project. Normally, these by-products are sold as animal feed ingredients to feed companies. The by-products are created as part of agricultural processes such as soybean conversion into soybean oil where soybean hulls become the by-product.

It is also important to bear in mind that some materials are not reasonable for this type of gasification based on either high prices or technical problems. For example, most animal by-products are not ideal fuel sources for this particular gasification project. Animal byproducts are not ideal for this application based on high capital costs necessary to meet emission standards. Soybean meal, which costs $179 per ton, is an unreasonable fuel because it is a high feed value byproduct. For this analysis, a ceiling price of $100/ton is used to define economic viability for biomass based on the current market prices. The biomasses selected for this project are listed in Table 5-1: Recommended Biomass For Rahr Malting Co.

**Biomass Supply Feasibility Criteria**

**Table 5-1: Recommended Biomass For Rahr Malting Co.**

| Biomass Option | Price ($/ton) | Volume (tons/yr) |
|---|---|---|
| **Rahr By-Products** | 20-30 | 60,000 |
| **Oat Hulls** | 20-30 | 60,000 |
| **Corn Stover** | 40-50 | 30,000 |
| **Switch Grass** | 30-40 | 10,000 |

Choosing a single source for fuel based on pricing can create problems as illustrated in the following example. In Figure 5-4, re-ground oat feed is shown as the cheapest source of biomass ranging in price from $20-30/ton. Re-ground oat feed is a by-product of oat processing. Last year, in Minnesota, the estimated amount produced was only 100,000 tons (see Figure 5-5)[3]. This re-ground oat hull estimate is determined by assuming that the hull represents 30% by weight of the oats harvested. Assuming that all the oats in Minnesota are harvested, the resulting oat hulls are sufficient to satisfy Rahr's annual requirements. Based on Rahr's annual consumption of 51,000 tons/year of biomass for the cogeneration plant (does not include Rahr's supplemental heating), at most one additional plant the size of Rahr could operate in Minnesota because the two plants would consume the State's entire supply of oat hulls. Also, this example illustrates that the supply of oat hulls is limited and dropping sharply (see Figure 5-5). Therefore even a slight increase in consumption demand could result in a large price increase and a negative effect on plant economics. This example reinforces the need for alternate sources of biomass for any biomass-to-energy plant.

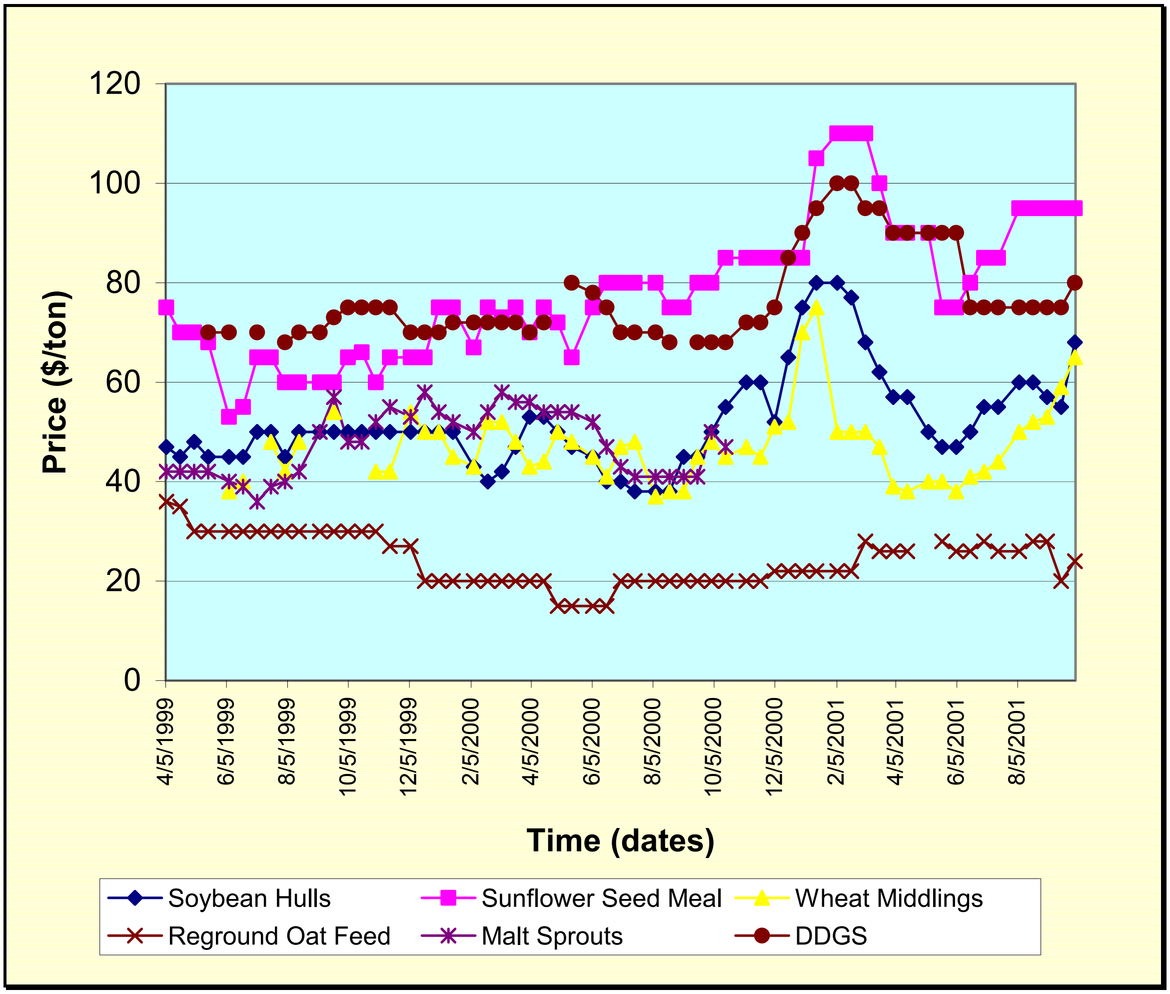


**Figure 5-4**

*Minneapolis Feed Ingredient Prices (Feedstuffs Magazine)*

**Biomass Supply Feasibility Criteria**

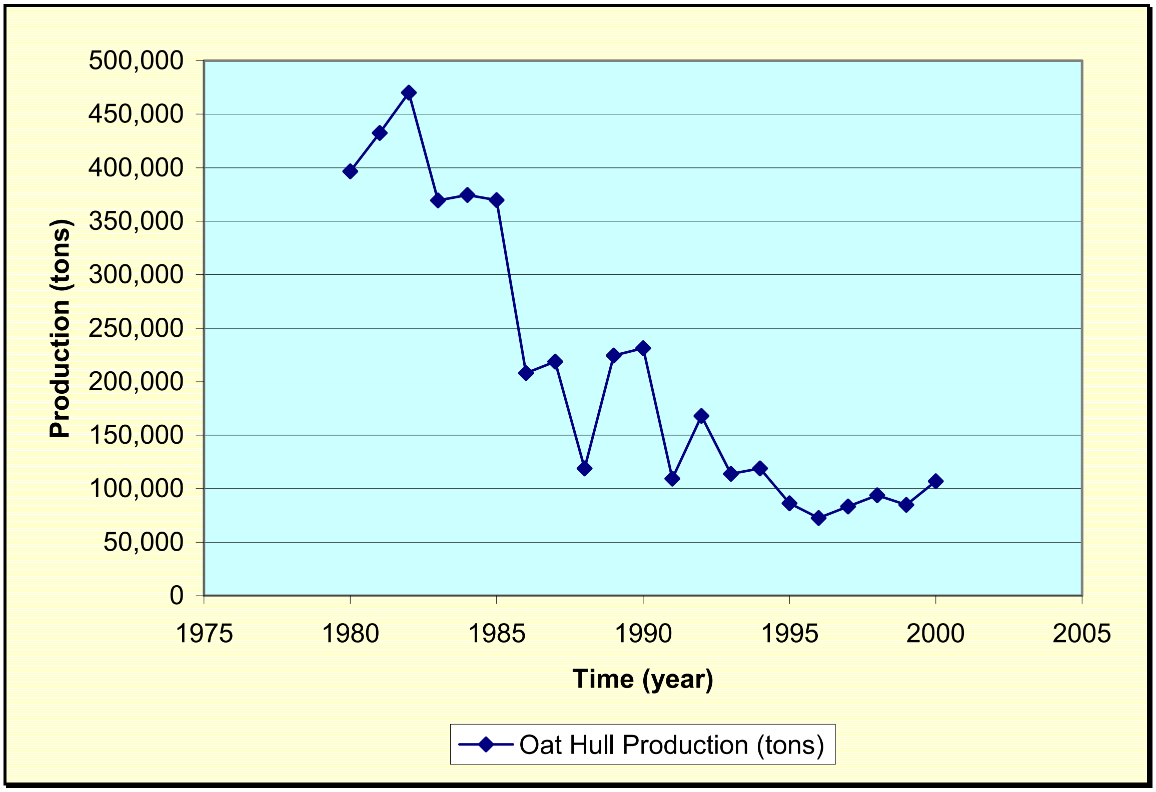


**Figure 5-5**

*Maximum Estimated Oat Hull Production in Minnesota (Tons)*

### *Agricultural By-Products—Economic Considerations*

Low biomass costs can be easily achieved if local resources are available and used efficiently. However, prices and availability of agricultural byproducts will be subject to seasonal fluctuations. Additionally, since these agricultural by-products are sources of animal feed, there will be competition for limited resources. Competition will also affect pricing and availability of biomass.

**NOTE: Basing a biomass-to-energy plant design on a portfolio of biomass sources is the most prudent approach.**

### *Switch Grass—Availability and Economic Considerations*

Switch grass, a perennial warm season grass native to the North American prairie from the Gulf of Mexico to Canada, is another biomass candidate. The advantage of using switch grass is that it is a perennial plant that requires no fertilizer for growth. Furthermore, switch grass has excellent gasification characteristics.

Unlike other biomasses, such as corn stover that is harvested only once a year, switch grass can be grown and harvested repeatedly over much of the year, thereby offering greater flexibility. Also, since switch grass does not require fertilizer, the total farming cost is reduced resulting in lower biomass costs.

One important economic consideration for switch grass is that it is not normally an agricultural byproduct. Therefore, the land and equipment costs associated with harvesting switch grass must be factored into the total cost. Since there is no, existing, large scale example of switch grass production, the actual economics of using switch grass as a biomass fuel is difficult to determine conclusively.

## United States Biomass Supply Assessment

The biomass availability in the United States reflects that in Minnesota. As discussed below, the corn stover production is approximately 10 times the production in Minnesota. The following is a breakdown of various biomass supplies in the United States and their prices.

## Biomass Supply Feasibility Criteria

### *Corn Stover—Price and Availability*

Just as in Minnesota, there is an abundant supply of corn stover across much of the United States. In 2000, 279,674,024 tons of corn stover was produced in the U.S. (see Figure 5-6)[5]. If 70% (195,771,817 tons) could be harvested, then over 3,800 biomass energy plants, equivalent in size to Rahr's could be supplied with biomass. The electricity generated from these plants would be approximately 104-billion kWh, and the heat recovered would amount to 1.06-quadrillion BTU per year. The 1.06-quadrillion BTU equates to 1.06-trillion cubic feet of natural gas per year. In the year 2000, approximately 3,412,766 MMkWh of electricity and 23-trillion cubic feet of natural gas were consumed in the U.S. (see Figure 5-7 and Figure 5-8)[6]. Therefore, approximately 3.0% of the nation's electricity and 4.6% of the country's natural gas needs can be fulfilled by biomass power plants that run on corn stover alone.

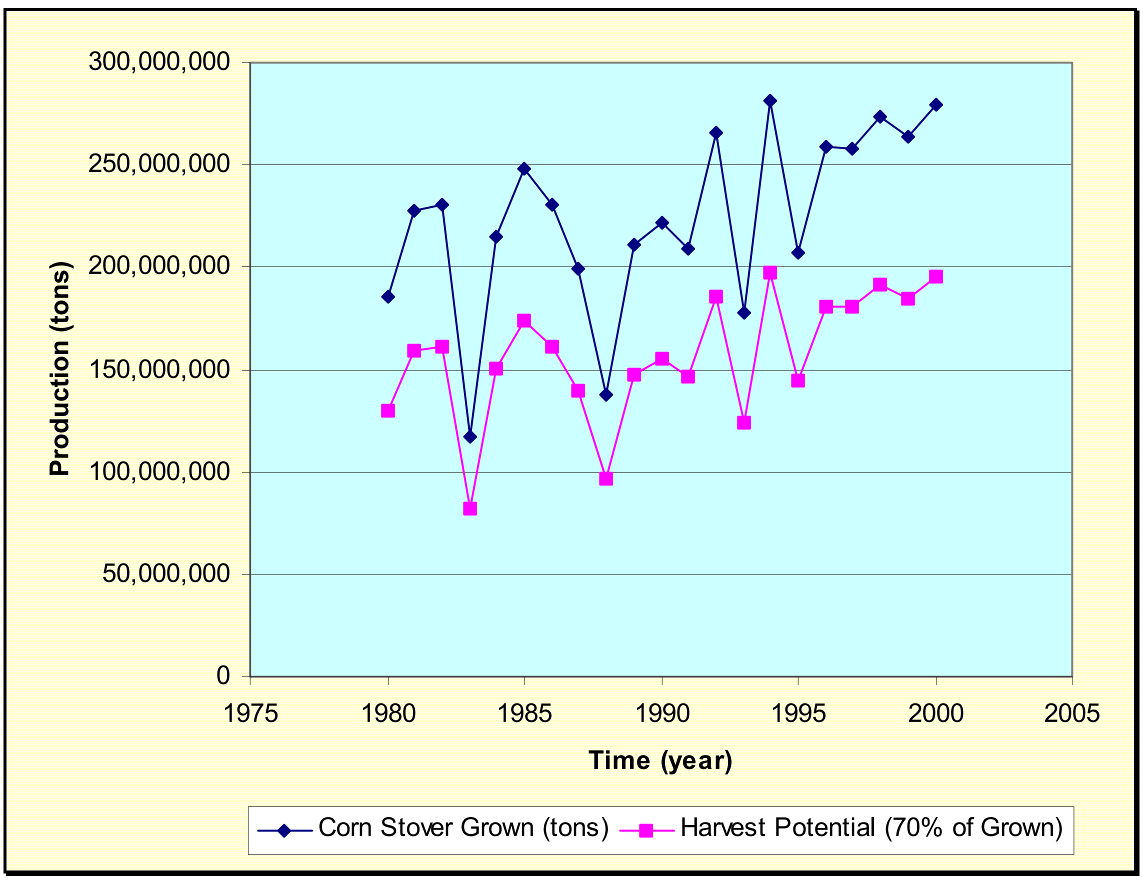


**Figure 5-6**

*Corn Stover Production in the United States*

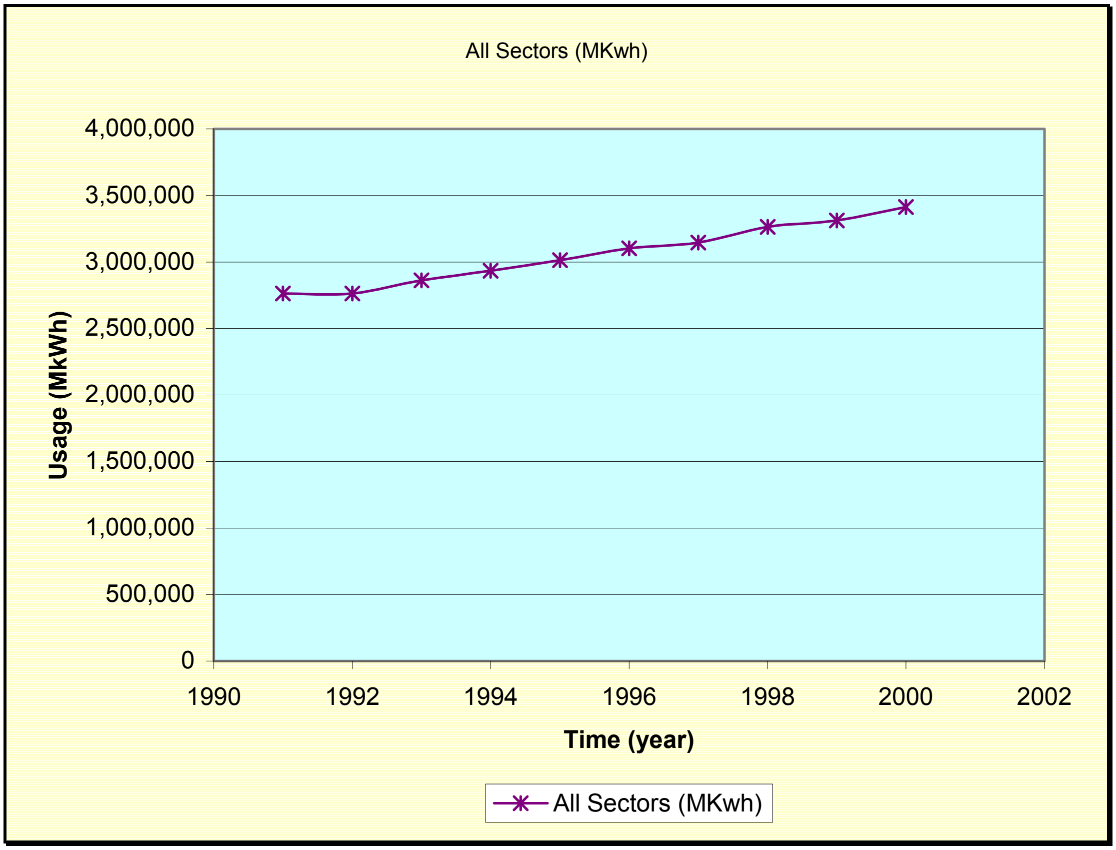


**Figure 5-7**

*Historical Energy Consumption in the United States*

## Biomass Supply Feasibility Criteria

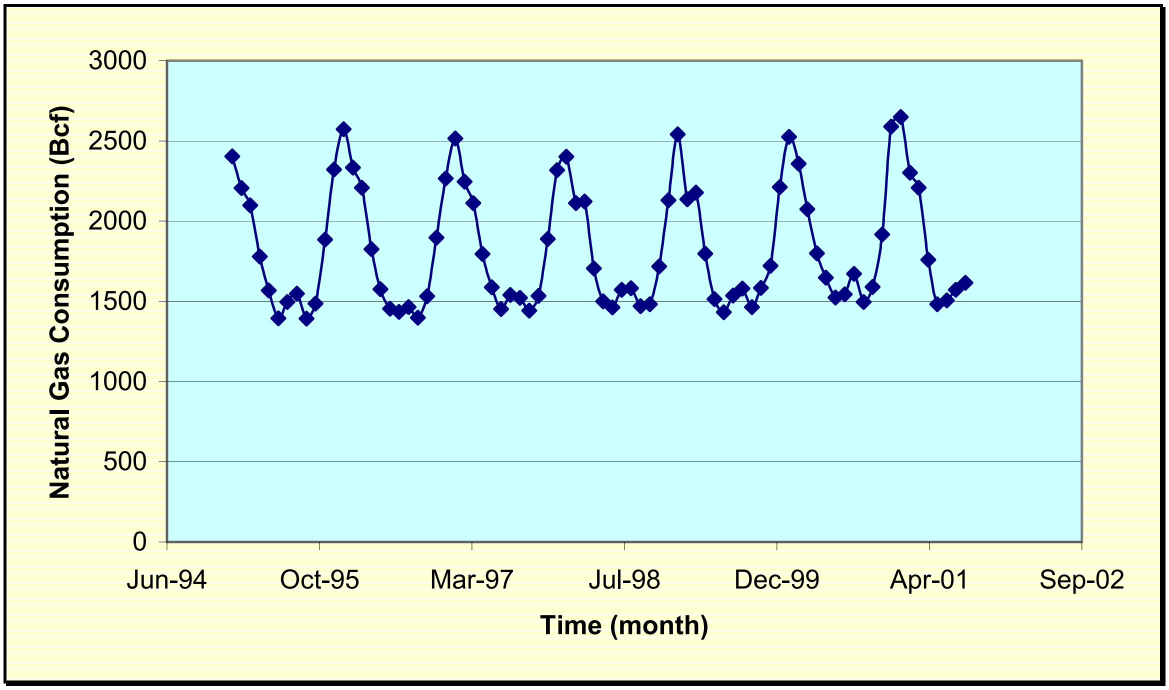


**Figure 5-8**

*Natural Gas Consumption in the United States*

### *Agricultural By-Products—Price and Availability*

As discussed above, according to *Feedstuffs*, re-ground oat feed, at $20 to $30 per ton, is one of the lowest cost sources of biomass available in the United States. Other biomasses range in price from $30 to $100 per ton, and the actual delivered price is dependent on transportation costs.

Based on oat harvest numbers from 2000, the estimated volume of oat hulls that were generated from America's oat fields was 716,000 tons annually (see Figure 5-9). Given that 100% of the oat hulls available in the entire US could be collected, this would be sufficient to supply fuel for only fourteen plants, equivalent in size to Rahr's. As discussed above, basing a biomass plant solely on oat hulls is not recommended. The US supply (similar to the Minnesota supply) of oat hulls is limited and dropping sharply (see Figure 5-9). The limited and declining supply means that even a slight increase in demand could create supply and pricing problems. Hence, even on a national scale, basing a biomass energy plant on a portfolio of biomass sources would be the recommended approach.

**Biomass Supply Feasibility Criteria**

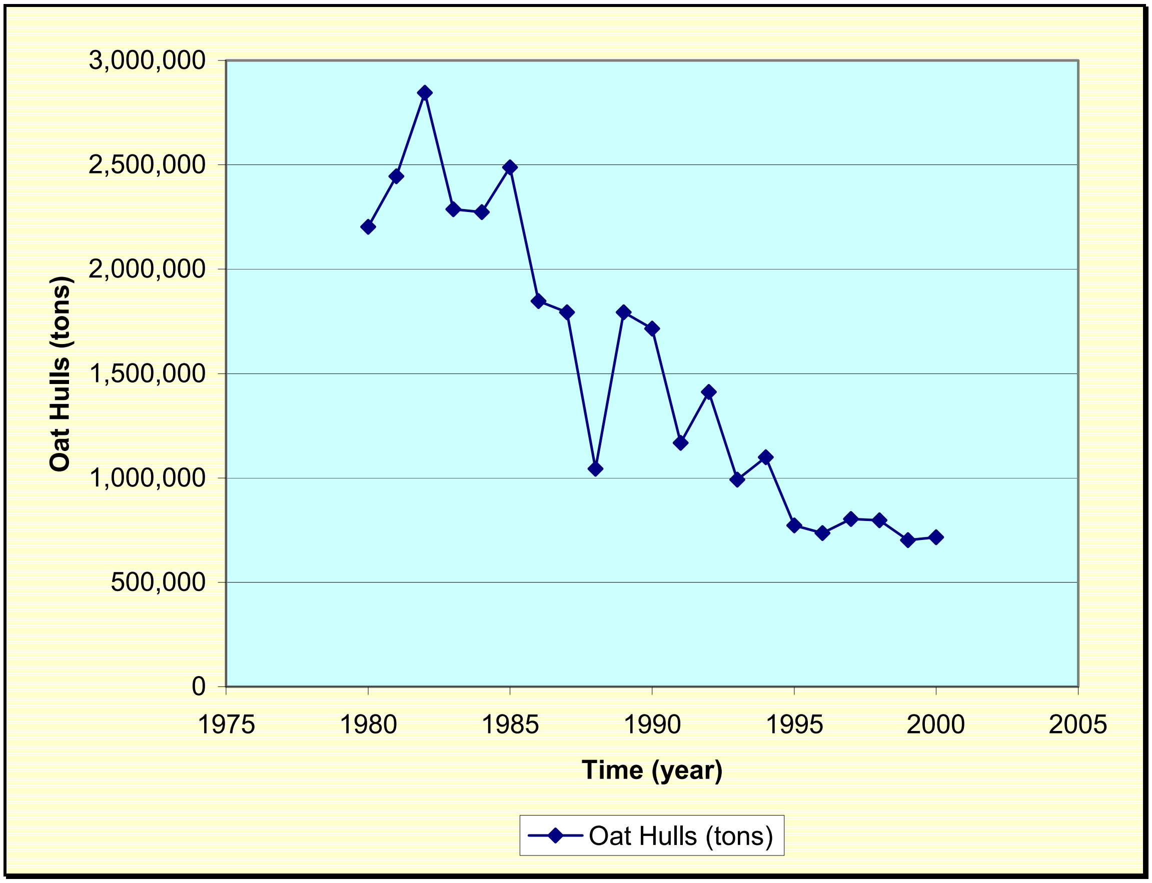


**Figure 5-9**

*Oat Hull Production in the United States*

# Section 6
# Economics

Several different scenarios were considered during the economic evaluation of this project. We studied a vast majority of combinations and permutations possible at Rahr Malting Co. Combinations of diverse technologies including combustion turbines, spark-ignited engine sets, indirect turbine, mixed-air turbines, and steam turbines were considered (see Table 6-1).

Rahr's electrical and thermal demands vary with time (see Figure 6-1). Rahr has a peak electrical demand of about 12 MWe and a base load of approximately 4 MWe. Depending on the scenario, each scenario satisfies a portion of the electrical and thermal demand of Rahr.

**Table 6-1: Description of the Various Scenarios***

| Scenario | Technology | Manufacturer |
|---|---|---|
| 1.1** | 1 combustion turbine | Alstom |
| 1.2** | 1 direct fired custom combustion turbine | Primenergy |
| 2.1 | 3 combustion turbines | Alstom |
| 2.2 | 2 combustion turbines, 2 engine sets | Alstom, Jenbacher |
| 2.3 | 2 custom turbines | Primenergy |
| 2.4 | 2 mixed air & syngas custom turbines | Primenergy |
| 2.5 | 2 indirect turbines | Primenergy |
| 2.6 | 4 engine sets | Jenbacher |
| 2.7** | 2 engine sets | Jenbacher |
| 3.1 | 6 combustion turbines | Alstom |
| 4** | 1 steam turbine | Primenergy |

* See Appendices A-F for the process flow diagrams.
** Single train.

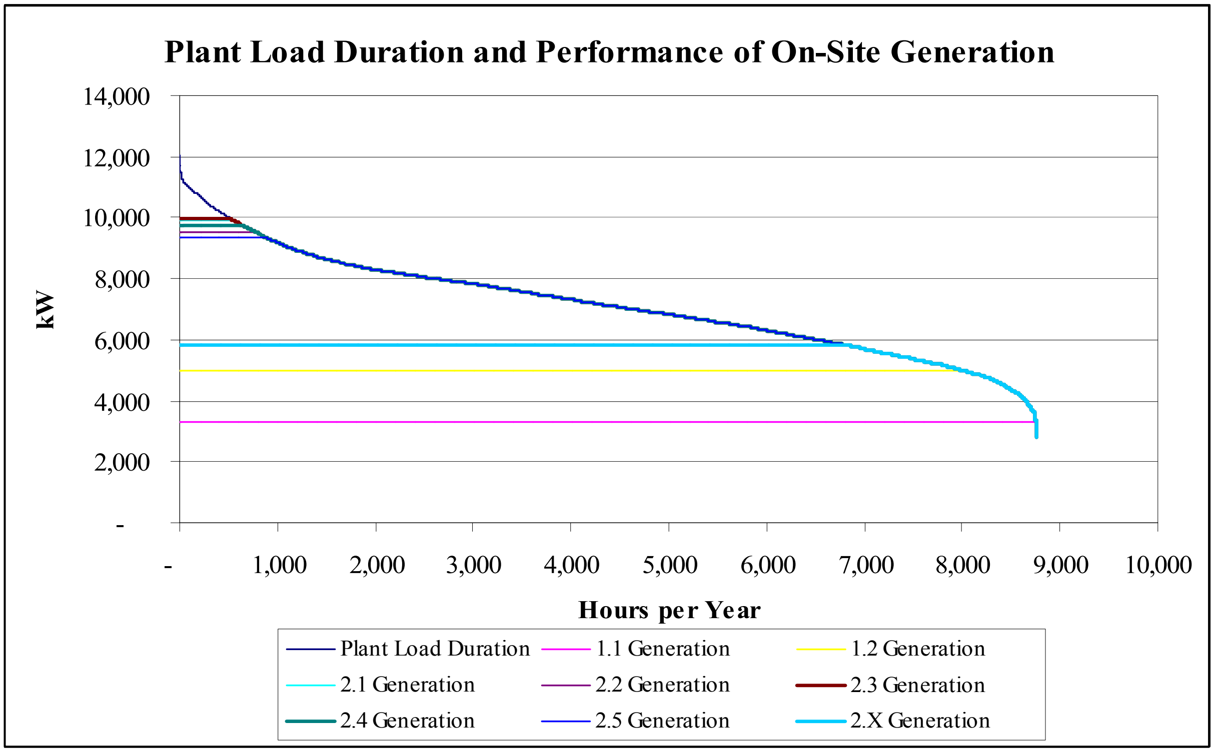


**Figure 6-1**

*Plant Load Duration & Performance of On-Site Generation*

In most of the scenarios described above, biomass is gasified in Primenergy's gasifier(s) and the synthesis gas is cleaned and conditioned. The clean low BTU synthesis gas is then fed to combustion turbine(s) and/or spark-ignited engine set(s) to generate electricity. The exceptions to this scheme are Scenarios 2.5 and 4. In Scenario 2.5, the gas cleanup system is not as rigorous. Instead, the synthesis gas is removed of particulates and is combusted in a combustor. The heat generated is recovered to drive a hot air turbine (see process flow diagram, Appendix E). Scenario 4 is similar to 2.5 in the sense that the recovered heat is used to make steam, which, in turn, drives a steam turbine to generate electricity (see process flow diagram, Appendix F). The heat off all these processes is recovered in Rahr Malting's glycol heaters enabling each scenario to be as economically efficient as possible.

In all of the combustion turbine cases, except Scenario 2.4, synthesis gas and air are compressed separately. In most cases, synthesis gas is compressed in a compressor and then sent to the combustion turbine where it blends with the atmospheric air and combusts to create electricity. In Scenario 2.4, however, synthesis gas and air are compressed together in the same compressor and then processed by the combustion turbines. Having one compressor instead of two saves on the compressor cost but may come as a compromise to safety. For the sake of the study, it was assumed that Scenario 2.4 would be possible even though safety would be an issue.

All the scenarios listed above use proven technologies, except Scenarios 1.2, 2.2, 2.3, 2.4, and 2.5. In these special cases, Primenergy proposes to modify second-hand Solar turbine(s) to burn synthesis gas and make electricity. During normal operation, these Solar turbines combust natural gas to generate electricity. Even though the Solar turbines are altered to use synthesis gas, they will still have to rely on some natural gas. In Table 6-3, please refer to "Cogeneration" row under "%Biomass." This notation shows what percentage of the total fuel going into the cogeneration plant is biomass and what is natural gas. For example, for Scenario 1.2, 84.4% of the fuel going into this particular plant is biomass and the rest is natural gas

## Assumptions

In order to analyze and compare the above scenarios, a computer model was created. Several assumptions were made to construct this model. These assumptions are listed below:

- It was assumed that Rahr's annual consumption of utility services is constant, even though its electrical and thermal demands vary on a daily and seasonal basis. Rahr's electrical demand was determined by looking at its 15-minute interval demand data and utility billings. This data was averaged out for the entire year.
- Thermal requirements and price were found by looking at the thermal load evaluation of Rahr's process and by studying its heating bills. In most scenarios, electrical load following was assumed. When load following is assumed, Rahr has a thermal requirement above the heat recovery capacity of the respective scenario. It was assumed that this supplemental fuel requirement is supplied by either biomass or natural gas, depending on the scenario. This parameter is referred to as "Conventional Boilers" and is denoted by "% biomass" (see Table 6-3).
- The whole economic model was based on the assumption that the energy prices would rise in the future. This escalation in energy prices information was taken from the Office of Management and Budget's (OMB) general inflation and price trend projections from the Annual Energy Outlook (see the Figure 6-2).
- The biomass combustion turbine operation was adjusted for parasitic load. The Alstom turbines were rated as 4.7 MWe when they run on natural gas. However, when the turbines burn synthesis gas, an air compressor has to be introduced to compress the synthesis gas to Alstom's specification. The compressor uses up to 1.3 MWe of power and the remaining 0.3 MWe is consumed by the gasifier system. Hence, for example, in Scenario 1.1, the net power output is 3.12 MWe even though the Alstom turbine is rated higher.
- Not all turbines in the scenarios discussed above operate on 100% synthesis gas. For instance, in Scenario 1.2, 84.4 % of the fuel going into the turbine is synthesis gas (see Table 6-3). The rest of the fuel comes from natural gas. The fuel mix of combustion turbine (biomass vs. natural gas) was taken from manufacturers' recommendations.
- The biomass fuel stock input to gasifier and water requirements to the process were taken from process mass balance sheets of Primenergy.
- The maintenance of the cogeneration process is assumed to be $0.0045/kWh. This price escalates with non-salary general inflation.
- The stand-by electrical service charges were assumed to be $2.20/kW-month.
- The discount rate of 6% was assigned for the net present value calculations.
- A 7-year straight-line depreciation was allocated to all equipment.
- A financing structure of 20-years at 5% was chosen for each scenario.

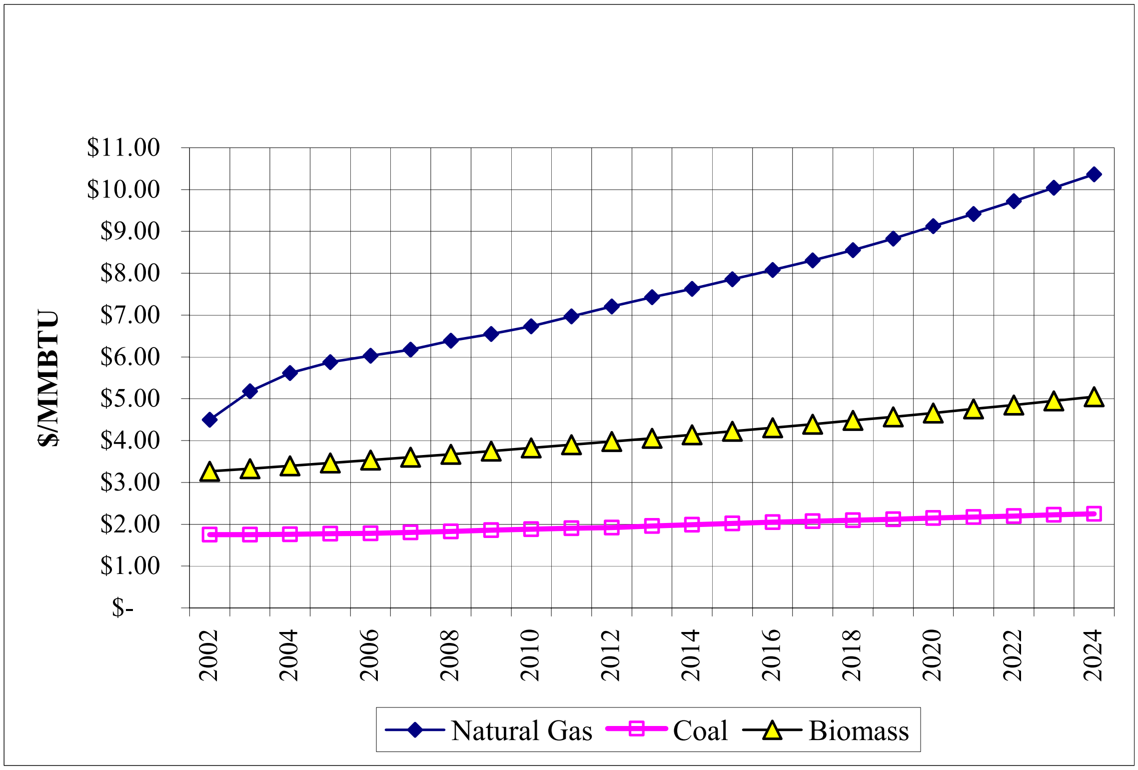


**Figure 6-2**

*Energy Price Forecast*

## Comparison of Economics

In this section, the economics of the different scenarios will be compared (see Table 6-2). In order to understand the following discussion, it is important to understand what costs were assumed for the different fuels. These costs are mainly in the form of fuel prices and are described in the following table:

**Table 6-2: Description of Fuel Prices**

| Fuel | Cost |
|---|---|
| Biomass | $25/ton |
| Natural Gas | $4.00/MMBTU |
| Electricity | $0.045/kWh |

**Economics**

Based on the above fuel costs, the best payback of all the cases happens to be Scenario 2.6. In Scenario 2.6, four spark-ignited engine sets, built by Jenbacher, are used to generate electricity. The heat produced from this process is recovered as Rahr Malting's process heat (see Appendix B for details of the process flow diagram) via its glycol heaters. Based on this scenario, if Rahr invests $15,300,632 to install the biomass plant, it will avoid total energy expenses of $34,053,292 over 20 years. The internal rate of return is 2.3 % (see Table 6-3) without any grant subsidies or tax breaks.

The engine sets scenarios have better economics than combustion turbine cases for two reasons. The Jenbacher engine sets have a low capital investment of $860/kW, much lower than the combustion turbine cases (see Table 6-3). The Jenbacher engine set costs about $1.2 million per unit and produces 1.3 MWe when it uses synthesis gas. In addition, it does not require a compressor as in the case of the combustion turbines. In the combustion turbine scenarios, the synthesis gas compressor costs $1.2 million, and uses 1.3 MWe of power. These two factors combined yield higher electrical generation costs for combustion turbines than for the engine sets.

Both the engine sets and combustion turbine processes yield a thermal efficiency of 54% to 55% as compared to the steam cycle, which yields only 30%. This lower efficiency in the steam cycle is due to the fact that the heat of vaporization of water is lost through the cooling tower because it is low-grade heat, which cannot be recovered. This heat of vaporization amounts to a significant loss of any energy process. Since the steam cycle has a lower thermal efficiency, in Scenario 4, more biomass has to be consumed than where engine sets and combustion turbines are used to yield the same amount of useable energy. This higher biomass usage leads to elevated operating costs, negatively impacts economics, and causes the steam cycle to be a less attractive option than engine sets.

Rahr has a heating demand in addition to the heat recovered from the biomass cogeneration process. This supplemental heating load can either be supplied by gasification of biomass or by natural gas. In all the scenarios, except Scenarios 1.1, 2.7, and 4, the best economics occur when the supplemental fuel requirement is fulfilled by natural gas, not biomass. In these scenarios, the supplemental fuel requirement is much too low to justify investment in additional gasifier system(s). However, in Scenarios 1.1, 2.7, and 4, the supplemental fuel requirement is large enough to validate the investment in an additional gasifier (see Appendix I). In Scenarios 1.1, 2.7, and 4, the savings in natural gas cost as compared to the added equipment cost justifies this added investment.

As can be seen from the Table 6-3, the economics is better for smaller plants than larger ones. The chief reason for this is because much of the equipment is unutilized in larger plants and the heat produced from these processes is not always recovered. As mentioned earlier, Rahr's base electrical load is about 4 MWe. Therefore, plants that are designed specifically to meet this base load will be more utilized than plants that are planned to meet higher loads. Furthermore, the heat from plants designed for higher loads cannot always be recovered. In larger plants where more electricity is generated, the extra heat produced must be wasted to the environment because Rahr does not have a use for it. This wastage of heat decreases the thermal efficiency of the plant and negatively impacts economics. On the other hand, in plants designed to meet just the base electrical load, the equipment is used almost 100% of the time and the heat produced can be fully utilized by Rahr. In these Scenarios efficiency increases, and positively affects economy. These are some of the reasons why Scenarios 1.1, 1.2, 2.6, 2.7, and 4 have a higher payback than others.

**Table 6-3: Variables and Summary of Economics**

**Equipment Cost Reduction Factor** 1 1

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Fuel** | **Natural Gas** | $ 4.00 /MMBTU | **Biomass** | Annual Procurement | 100% | $ 25.00 /Ton | 13.21 MMBTU/Ton | | IPP Merchant Sales | $ 0.0750 /kWh | |
| **Scenario:** | **1.1** | **1.2** | **2.1** | **2.2** | **2.3** | **2.4** | **2.5** | **2.6** | **2.7** | **3.1** | **4** |
| | New Turbine | Direct Fired Turbine | New Turbine | Turbine & SIEG | Direct Fired Turbine | Mixed Air & SynGas | Indirect Turbine | SIEG | SIEG | New Turbine, IPP | Steam |
| | One Alstom | One Custom Turbine | Three Alstom | Two Altsom, Two Jenbacher | Two Custom Turbines | Two Custom Turbines | Two Solar | Four Jenbacher | Two Jenbacher | Six Alstom | Turbine |
| Unit Capacity, Net | 3,120 | 4,992 | 9,900 | 9,296 | 9,984 | 9,725 | 9,334 | 5,392 | 2,696 | 19,800 | 4,718 |
| HRSG | 32,000,000 BTU | 87,760,000 | 96,000,000 BTU | 87,344,211 BTU | 175,520,000 BTU | 103,820,000 BTU | 169,340,000 BTU | 47,520,000 BTU | 23,760,000 BTU | 192,000,000 BTU | 14,150,000 BTU |
| %-Biomass | | | | | | | | | | | |
| Cogeneration | 100% Biomass | 84.4% Biomass | 100% Biomass | 100% Biomass | 84.6% Biomass | 84.4% Biomass | 88.0% Biomass | 100% Biomass | 100% Biomass | 100% Biomass | 100% Biomass |
| Conventional Boilers | 100% Biomass | 0% Biomass | 0% Biomass | 0% Biomass | 0% Biomass | 0% Biomass | 0% Biomass | 0% Biomass | 100% Biomass | 0% Biomass | 100% Biomass |
| **Project Cost** | | | | | | | | | | | |
| Turbine | $ 1,934 /kW | $ 1,708 /kW | $ 1,934 /kW | $ 1,612 /kW | $ 1,691 /kW | $ 626 /kW | $ 696 /kW | $ 860 /kW | $ 860 /kW | $ 1,934 /kW | $ 182 /kW |
| | $ 6,034,080 | $ 8,526,336 | $ 19,146,600 | $ 14,983,293 | $ 16,882,944 | $ 6,087,850 | $ 6,496,464 | $ 4,637,120 | $ 2,318,560 | $ 38,293,200 | $ 858,676 |
| Auxiliary Systems | $ 135 /kW | $ 89 /kW | $ 125 /kW | $ 125 /kW | $ 64 /kW | $ 66 /kW | $ 45.00 /kW | $ 125 /kW | $ 125 /kW | $ 100 /kW | $ 120 /kW |
| | $ 421,200 | $ 444,288 | $ 1,237,500 | $ 1,162,000 | $ 640,973 | $ 643,795 | $ 420,030 | $ 674,000 | $ 337,000 | $ 1,980,000 | $ 566,160 |
| Gasifier | $ 7,000,000 | $ 4,030,000 | $ 7,780,000 | $ 7,500,000 | $ 8,060,000 | $ 6,670,000 | $ 7,220,000 | $ 3,500,000 | $ 8,200,000 | $ 15,860,000 | $ 7,849,196 |
| Thermal Connection | $ 147,897 | $ 147,897 | $ 147,897 | $ 629,732 | $ 419,821 | $ 301,393 | $ 412,963 | $ 412,963 | $ 412,963 | $ 412,963 | $ 1,617,410 |
| Electrical Interconnection | $ 446,302 | $ 477,958 | $ 1,062,129 | $ 1,327,661 | $ 1,062,129 | $ 732,092 | $ 729,793 | $ 729,793 | $ 328,407 | $ 3,186,387 | $ 448,823 |
| Plant Improvements | | | | | | | | | | | |
| Thermal Connection | $ 550,000 | $ 550,000 | $ 550,000 | $ 550,000 | $ 550,000 | $ 550,000 | $ 550,000 | $ 550,000 | $ 550,000 | $ 550,000 | $ 550,000 |
| Electrical | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Subtotal | $ 14,049,479 | $ 13,626,479 | $ 29,374,126 | $ 25,602,686 | $ 27,065,867 | $ 14,435,130 | $ 15,279,250 | $ 9,953,876 | $ 11,596,930 | $ 59,732,550 | $ 11,340,265 |
| 7.1% Mechanical Installation | $ 997,513 | $ 967,480 | $ 2,085,563 | $ 1,817,791 | $ 1,921,677 | $ 1,024,894 | $ 1,084,827 | $ 706,725 | $ 823,382 | $ 4,241,011 | $ 805,159 |
| 12.1% Electric Installation | $ 1,699,987 | $ 1,648,804 | $ 3,554,269 | $ 3,097,925 | $ 3,274,970 | $ 1,746,651 | $ 1,848,789 | $ 1,204,419 | $ 1,403,229 | $ 7,227,639 | $ 1,372,172 |
| Civil/Site Work | $ 250,000 | $ 250,000 | $ 750,000 | $ 500,000 | $ 500,000 | $ 500,000 | $ 500,000 | $ 500,000 | $ 500,000 | $ 3,600,000 | $ 250,000 |
| Subtotal | $ 16,996,979 | $ 16,492,763 | $ 35,763,958 | $ 31,018,401 | $ 32,762,513 | $ 17,706,675 | $ 18,712,866 | $ 12,365,020 | $ 14,323,540 | $ 74,801,200 | $ 13,767,596 |
| 7.5% Eng. & Design | $ 1,274,773 | $ 1,236,957 | $ 2,682,297 | $ 2,326,380 | $ 2,457,188 | $ 1,328,001 | $ 1,403,465 | $ 927,377 | $ 1,074,266 | $ 5,610,090 | $ 1,032,570 |
| Permits | $ 150,000 | $ 150,000 | $ 150,000 | $ 150,000 | $ 150,000 | $ 150,000 | $ 150,000 | $ 150,000 | $ 150,000 | $ 500,000 | $ 150,000 |
| 1.5% Construction Svc. | $ 254,955 | $ 247,391 | $ 536,459 | $ 465,276 | $ 491,438 | $ 265,600 | $ 280,693 | $ 185,475 | $ 214,853 | $ 1,122,018 | $ 206,514 |
| Subtotal | $ 18,676,707 | $ 18,127,112 | $ 39,132,714 | $ 33,960,057 | $ 35,861,139 | $ 19,450,276 | $ 20,547,024 | $ 13,627,872 | $ 15,762,659 | $ 82,033,308 | $ 15,156,680 |
| 7.5% Contingency | $ 1,400,753 | $ 1,359,533 | $ 2,934,954 | $ 2,547,004 | $ 2,689,585 | $ 1,458,771 | $ 1,541,027 | $ 1,022,090 | $ 1,182,199 | $ 6,152,498 | $ 1,136,751 |
| **TOTAL w/o Plant Improvements** | **$ 20,077,460** | **$ 19,486,645** | **$ 42,067,668** | **$ 36,507,062** | **$ 38,550,725** | **$ 20,909,046** | **$ 22,088,051** | **$ 14,649,962** | **$ 16,944,858** | **$ 88,185,806** | **$ 16,293,430** |
| **TOTAL with Plant Improvements** | **$ 20,728,130** | **$ 20,137,315** | **$ 42,718,338** | **$ 37,157,732** | **$ 39,201,395** | **$ 21,559,716** | **$ 22,738,721** | **$ 15,300,632** | **$ 17,595,528** | **$ 88,836,476** | **$ 16,944,100** |
| **Financing** | 5% Interest Rate | 20 Year Term | S-L Depreciation | 7 Years | Discount Rate | 6% | **DOE Demo Grant** | **50%** | **Maximum Grant** | **$ -** | |
| **DOE Domonstration Grant** | **0.0%** | **0.0%** | **0.0%** | **0.0%** | **0.0%** | **0.0%** | **0.0%** | **0.0%** | **0.0%** | **0.0%** | **0.0%** |
| **Annual Payment** | **$ 1,611,067** | **$ 1,563,659** | **$ 3,375,619** | **$ 2,929,421** | **$ 3,093,410** | **$ 1,677,796** | **$ 1,772,402** | **$ 1,175,551** | **$ 1,359,699** | **$ 7,076,257** | **$1,307,427** |
| **Present Value, 20-Year** | | | | | | | | | | | |
| **Avoided Expenses** | **$ 28,439,838** | **$ 24,609,121** | **$ 28,215,702** | **$ 30,340,047** | **$ 18,989,059** | **$ 34,707,841** | **$ 27,363,214** | **$ 34,053,292** | **$ 31,475,617** | **$ 41,209,361** | **$ 24,689,328** |
| **After Tax Cash Flow** | **$ 3,550,013** | **$ 1,349,144** | **$ (15,395,282)** | **$ (9,054,097)** | **$ (19,094,221)** | **$ 7,695,738** | **$ 1,178,568** | **$ 12,452,547** | **$ 8,500,110** | **$ (45,158,058)** | **$ 3,982,341** |
| **Internal Rate of Return** | **-9.3%** | **-16.2%** | **NA*** | **NA*** | **NA*** | **-4.8%** | **-19.0%** | **2.3%** | **-0.8%** | **NA*** | **-6.7%** |

* Indicates that Rahr would lose money every year if it installed this system.

## Rahr Plant Economics (1 Alstom Typhoon Turbine)

The focus of the DOE solicitation is the feasibility of using advanced turbines to generate energy. Therefore, we propose using 1 Alstom Typhoon combustion turbine for Rahr Malting Co. The economics of multiple Typhoon turbines are not as good as 1 Typhoon, and the implementation of multiple turbines is not proposed for Rahr (see "Comparison of Emissions"). This low BTU combustion turbine is currently available in the market, and Alstom is confident about the performance of its turbine based on Primenergy's synthesis gas specifications. Consequently, the risk associated with developing a low BTU turbine will be minimized. This reduced risk is another reason we are proposing using the Typhoon turbine (Scenario 1.1) at Rahr. The following discussion will be for Scenario 1.1, the 1 Typhoon case.

The projected economic return from this biomass cogeneration process would not be attractive at current energy prices even if the capital costs were reduced by about 50% (see "Sensitivity Analysis" on page 6-35). Even with this reduction, the payback is positive but the internal rate of return is negative.

At present, without capital cost sharing, the projected cost of electricity would be about \$0.07/kWh. After a seven-year depreciation period, the production costs would be \$0.030/kWh, competitive with coal-based electricity (see Figure 6-3). With DOE cost sharing, the cost of electricity would be competitive at today's prices. In like manner, with DOE funding, thermal energy would cost approximately \$5.5/MMBTU until depreciation ends, after which, it would be less than \$4/MMBTU (see Figure 6-4).

## Economics

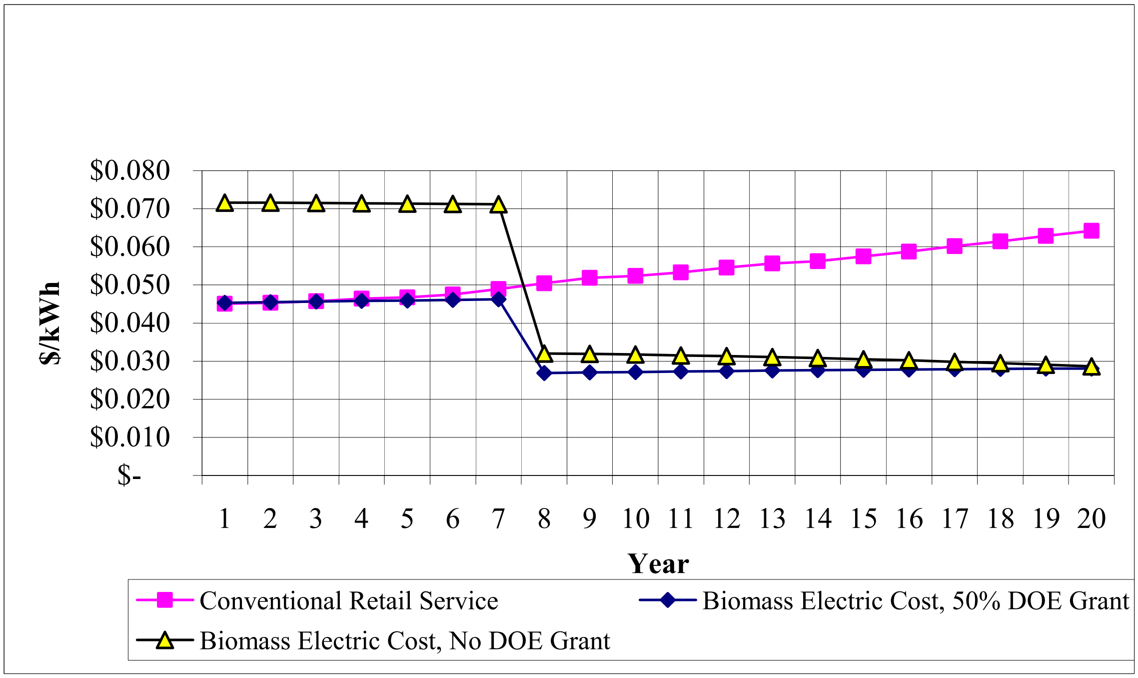


**Figure 6-3**

*Biomass Cogeneration: 1 Alstom Typhoon, Comparison of Electric Costs*

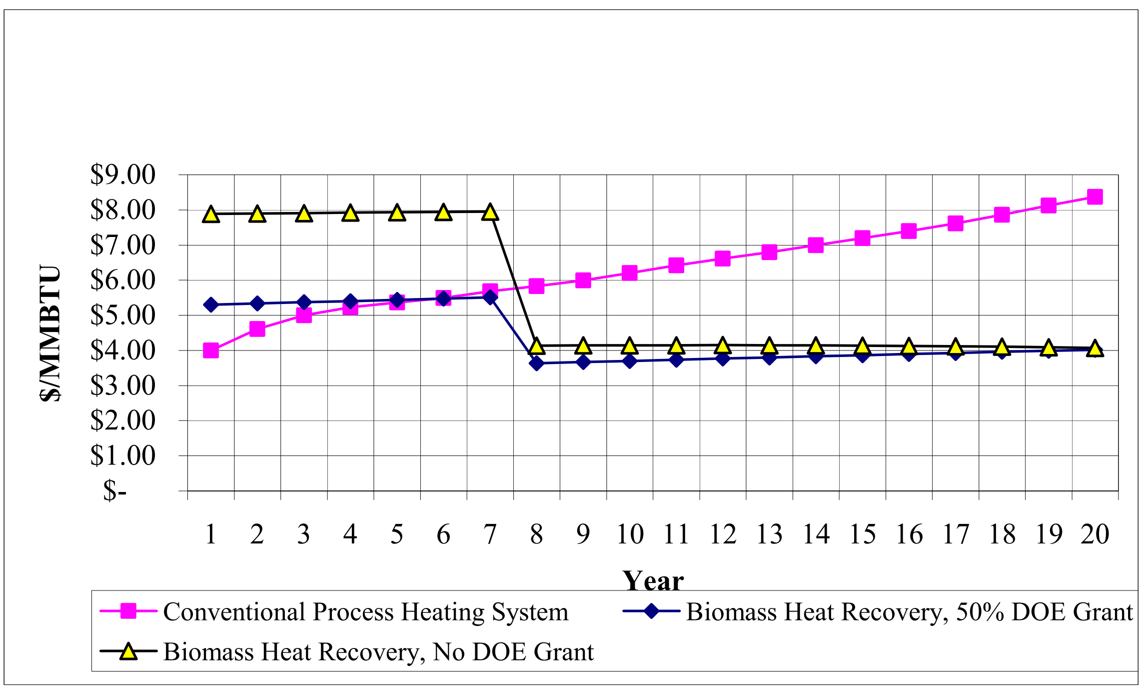


**Figure 6-4**

*Biomass Cogeneration: One Alstom Turbine, Comparison of Process Heating Costs*

### *Capital Costs*

The total equipment cost of the plant is $20,007,460 and it includes the 1 Alstom Typhoon turbine, electrical generation equipment, Primenergy gasifier, gas-cleanup, material-handling equipment, installation, and contingency costs, (see Table 6-4). This price does not include any upgrades that Rahr would have to make to integrate this biomass cogeneration plant into its malting process. Including upgrades, we estimate the total biomass plant cost to be $20,728,130. The breakdown of the various costs is shown below. A detailed breakdown of the different costs is shown in Table 6-5.

**Table 6-4: Breakdown of 1 Alstom Typhoon Turbine Plant at Rahr**

| | |
|---|---|
| Turbines | $6,034,080 |
| Auxiliary Systems | $421,200 |
| Gasifier | $7,000,000 |
| Thermal Connection | $147,897 |
| Electrical Interconnection | $446,302 |
| **Subtotal** | $14,049,479 |
| Mechanical Installation | $997,513 |
| Electrical Installation | $1,699,987 |
| Civil/Site Work | $250,000 |
| Subtotal | $16,996,979 |
| Engineering & Design | $1,274,773 |
| Permits | $150,000 |
| Construction Services | $254,955 |
| Subtotal | $18,676,707 |
| Contingency | $1,400,753 |
| **Total** | **$20,007,460** |

**Economics**

### *Operating Costs*

The Rahr cogeneration plant will use 51,000 tons/yr of biomass to generate 3.12 MWe of power and 32 MMBTU/hr (280,320 MMBTU/yr) of process heat. The Rahr malting process requires additional heat and electricity on top of what the cogeneration plant could supply. It is assumed in this study, for Scenario 1.1, that the additional electricity will be purchased from the grid. The heat will be supplied by gasifying additional biomass since it was found that burning biomass yielded better economics than combusting natural gas. In Table 6-5, under the "Conventional Boilers" row, the "100% Biomass" denotes that the supplemental fuel requirement of Rahr will be provided by biomass. In a similar fashion, "0% Biomass" means the supplemental fuel will be full-filled by natural gas, not biomass. Consequently, for the one Alstom Typhoon case, 100% of the supplemental fuel will be supplied by biomass, requiring an additional gasifier to burn it. An additional 18,000 tons/year of biomass must be burned to produce the remaining 88 MMBTU/hr (770,880 MMBTU/yr) of heat. Hence, Rahr will consume a total of 69,000 tons/year of biomass.

The various operating costs associated with the plant are shown in Table 6-5. The energy costs were projected to twenty years based on inflation and energy price fluctuations with time. As can be seen from the table, based on electricity and natural gas prices of \$0.0450/kWh and 4.00/MMBTU (see Unit Expenses in the Table 6-5) respectively, the total cost of running the Rahr plant for the first year on fossil fuels is projected to be \$5,091,364. If Rahr switches to 100% biomass, the total energy cost is expected to be \$3,558,841, leading to a savings of \$1,532,523. When Rahr will operate on biomass, the above total cost of \$3,558,841 includes the expenditure for residual electric service. Rahr will have to purchase this residual electricity from the grid since the Typhoon turbine will only provide net 3.1-MWe power to the Rahr plant. This residual service amounts to \$1,628,549 for the first year. In addition to the residual service, the Rahr biomass cogeneration plant will have to be maintained. A total maintenance cost of \$122,988 is added to total expenses of the cogeneration plant. Over 20 years, the savings due to the biomass cogeneration plant accumulates to \$28,439,838 based on today's dollar (see NPV, Avoided Expense in Table 6-5. Therefore, if Rahr invests \$20,728,130 to build the Alstom based biomass plant today, it will avoid costs of \$28,439,838 over 20 years generating an internal rate of return of –9.3% (see Table 6-3).

## Table 6-5: Detailed Economics for Scenario 1.1

| Year | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Salary Inflation | | 3.20% | 3.20% | 3.20% | 3.20% | 3.20% | 3.20% | 3.20% | 3.20% | 3.20% | 3.20% |
| Non-salary Inflation | | 2.00% | 2.00% | 2.00% | 2.00% | 2.00% | 2.00% | 2.00% | 2.00% | 2.00% | 2.00% |
| Natural Gas | | 13.3% | 6.4% | 2.6% | 0.6% | 0.4% | 1.5% | 0.5% | 0.8% | 1.5% | 1.5% |
| Electricity | | -1.3% | -1.1% | -0.6% | -1.3% | -0.2% | 1.0% | 1.0% | 0.9% | -1.1% | -0.3% |
| Biomass | | | | | | | | | | | |
| **Unit Expenses** | | | | | | | | | | | |
| Residual Retail Electric Service | | | | | | | | | | | |
| Demand | $ 5.78 /kW | $ 5.82 | $ 5.87 | $ 5.95 | $ 6.00 | $ 6.10 | $ 6.29 | $ 6.48 | $ 6.66 | $ 6.72 | $ 6.84 |
| Energy | $ 0.0322 /kWh | $ 0.03 | $ 0.03 | $ 0.03 | $ 0.03 | $ 0.03 | $ 0.04 | $ 0.04 | $ 0.04 | $ 0.04 | $ 0.04 |
| Blended Retail | $ 0.0450 /kWh | $ 0.05 | $ 0.05 | $ 0.05 | $ 0.05 | $ 0.05 | $ 0.05 | $ 0.05 | $ 0.05 | $ 0.05 | $ 0.05 |
| Natural Gas | $ 4.00 /MMBTU | $ 4.61 | $ 5.00 | $ 5.23 | $ 5.37 | $ 5.50 | $ 5.69 | $ 5.83 | $ 5.99 | $ 6.20 | $ 6.42 |
| Biomass | $ 1.89 /MMBTU | $ 1.93 | $ 1.97 | $ 2.01 | $ 2.05 | $ 2.09 | $ 2.13 | $ 2.17 | $ 2.22 | $ 2.26 | $ 2.31 |
| Water | $ 1.50 /kgal | $ 1.53 | $ 1.56 | $ 1.59 | $ 1.62 | $ 1.66 | $ 1.69 | $ 1.72 | $ 1.76 | $ 1.79 | $ 1.83 |
| **Conventional Operation** | | | | | | | | | | | |
| Electricity | 62,926,168 kWh | 62,926,168 | 62,926,168 | 62,926,168 | 62,926,168 | 62,926,168 | 62,926,168 | 62,926,168 | 62,926,168 | 62,926,168 | 62,926,168 |
| Natural Gas | 564,921 MMBTU | 564,921 | 564,921 | 564,921 | 564,921 | 564,921 | 564,921 | 564,921 | 564,921 | 564,921 | 564,921 |
| Electric Charges | $ 2,831,678 | $ 2,851,327 | $ 2,877,847 | $ 2,917,038 | $ 2,937,917 | $ 2,989,414 | $ 3,079,426 | $ 3,172,386 | $ 3,263,479 | $ 3,293,647 | $ 3,350,137 |
| Natural Gas Expense | $ 2,259,686 | $ 2,606,051 | $ 2,825,169 | $ 2,955,064 | $ 3,031,380 | $ 3,105,071 | $ 3,212,719 | $ 3,292,815 | $ 3,386,486 | $ 3,504,066 | $ 3,626,277 |
| Subtotal, Electricity & Natural Gas | $ 5,091,364 | $ 5,457,378 | $ 5,703,016 | $ 5,872,102 | $ 5,969,297 | $ 6,094,485 | $ 6,292,145 | $ 6,465,201 | $ 6,649,965 | $ 6,797,713 | $ 6,976,414 |
| **Annual Cogeneration Production** | | | | | | | | | | | |
| Electricity | 27,330,736 kWh | 27,330,736 | 27,330,736 | 27,330,736 | 27,330,736 | 27,330,736 | 27,330,736 | 27,330,736 | 27,330,736 | 27,330,736 | 27,330,736 |
| Thermal Cogen, Heat Recovered | 280,315 MMBTU | 280,315 | 280,315 | 280,315 | 280,315 | 280,315 | 280,315 | 280,315 | 280,315 | 280,315 | 280,315 |
| Thermal Supplemental, Fuel | 237,676 MMBTU | 237,676 | 237,676 | 237,676 | 237,676 | 237,676 | 237,676 | 237,676 | 237,676 | 237,676 | 237,676 |
| **Residual Electric Load** | | | | | | | | | | | |
| Electricity | | | | | | | | | | | |
| Demand, monthly average | 6,955 kW | 6,955 | 6,955 | 6,955 | 6,955 | 6,955 | 6,955 | 6,955 | 6,955 | 6,955 | 6,955 |
| Energy | 35,595,432 kWh | 35,595,432 | 35,595,432 | 35,595,432 | 35,595,432 | 35,595,432 | 35,595,432 | 35,595,432 | 35,595,432 | 35,595,432 | 35,595,432 |
| Water | 2,224 kgal | 2,224 | 2,224 | 2,224 | 2,224 | 2,224 | 2,224 | 2,224 | 2,224 | 2,224 | 2,224 |
| Cogeneration Fuel | 671,881 MMBTU | 671,881 | 671,881 | 671,881 | 671,881 | 671,881 | 671,881 | 671,881 | 671,881 | 671,881 | 671,881 |
| Fuel Mix | | | | | | | | | | | |
| Natural Gas | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Biomass | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| Supplemental Fuel | 237,676 MMBTU | 237,676 | 237,676 | 237,676 | 237,676 | 237,676 | 237,676 | 237,676 | 237,676 | 237,676 | 237,676 |
| Fuel Mix | | | | | | | | | | | |
| Natural Gas | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Biomass | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| **Expenses** | | | | | | | | | | | |
| Fuel, Cogeneration System | $ 1,271,730 | $ 1,297,165 | $ 1,323,108 | $ 1,349,570 | $ 1,376,562 | $ 1,404,093 | $ 1,432,175 | $ 1,460,818 | $ 1,490,035 | $ 1,519,836 | $ 1,550,232 |
| Supplemental Fuel | | | | | | | | | | | |
| Biomass | $ 449,870 | $ 458,868 | $ 468,045 | $ 477,406 | $ 486,954 | $ 496,693 | $ 506,627 | $ 516,760 | $ 527,095 | $ 537,637 | $ 548,390 |
| Natural Gas | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Water | $ 3,336 | $ 3,403 | $ 3,471 | $ 3,540 | $ 3,611 | $ 3,683 | $ 3,757 | $ 3,832 | $ 3,909 | $ 3,987 | $ 4,066 |
| * Indicates that Rahr would lose money every | $ 122,988 | $ 125,448 | $ 127,957 | $ 130,516 | $ 133,126 | $ 135,789 | $ 138,504 | $ 141,275 | $ 144,100 | $ 146,982 | $ 149,922 |
| Residual Electric Service | $ 1,628,549 | $ 1,639,849 | $ 1,655,101 | $ 1,677,641 | $ 1,689,649 | $ 1,719,266 | $ 1,771,033 | $ 1,824,496 | $ 1,876,885 | $ 1,894,236 | $ 1,926,724 |
| Stand-by Service Charges | $ 82,368 | $ 82,940 | $ 83,711 | $ 84,851 | $ 85,458 | $ 86,956 | $ 89,575 | $ 92,279 | $ 94,928 | $ 95,806 | $ 97,449 |
| Sub-total Expenses with Cogeneration | $ 3,558,841 | $ 3,607,672 | $ 3,661,392 | $ 3,723,524 | $ 3,775,360 | $ 3,846,480 | $ 3,941,671 | $ 4,039,459 | $ 4,136,952 | $ 4,198,484 | $ 4,276,783 |
| **Avoided Expense, Cogeneration** | $ 1,532,523 | $ 1,849,706 | $ 2,041,624 | $ 2,148,578 | $ 2,193,937 | $ 2,248,005 | $ 2,350,474 | $ 2,425,742 | $ 2,513,013 | $ 2,599,229 | $ 2,699,631 |
| **NPV, Avoided Expense** | $ 28,439,838 | | | | | | | | | | |

**Table 6-5: Detailed Economics for Scenario 1.1**

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Salary Inflation | 3.20% | 3.20% | 3.20% | 3.20% | 3.20% | 3.20% | 3.20% | 3.20% | 3.20% |
| Non-salary Inflation | 2.00% | 2.00% | 2.00% | 2.00% | 2.00% | 2.00% | 2.00% | 2.00% | 2.00% |
| Natural Gas | 1.1% | 0.7% | 1.0% | 0.8% | 0.9% | 1.0% | 1.2% | 1.4% | 1.0% |
| Electricity | 0.4% | 0.1% | -0.9% | 0.2% | 0.3% | 0.4% | 0.0% | 0.4% | 0.1% |
| Biomass | | | | | | | | | |

| Year | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|
| **Unit Expenses** | | | | | | | | | |
| Residual Retail Electric Service | | | | | | | | | |
| Demand | $ 7.00 | $ 7.14 | $ 7.22 | $ 7.38 | $ 7.55 | $ 7.73 | $ 7.89 | $ 8.08 | $ 8.24 |
| Energy | $ 0.04 | $ 0.04 | $ 0.04 | $ 0.04 | $ 0.04 | $ 0.04 | $ 0.04 | $ 0.04 | $ 0.05 |
| Blended Retail | $ 0.05 | $ 0.06 | $ 0.06 | $ 0.06 | $ 0.06 | $ 0.06 | $ 0.06 | $ 0.06 | $ 0.06 |
| Natural Gas | $ 6.62 | $ 6.79 | $ 7.00 | $ 7.19 | $ 7.40 | $ 7.62 | $ 7.86 | $ 8.13 | $ 8.37 |
| Biomass | $ 2.35 | $ 2.40 | $ 2.45 | $ 2.50 | $ 2.55 | $ 2.60 | $ 2.65 | $ 2.70 | $ 2.76 |
| Water | $ 1.87 | $ 1.90 | $ 1.94 | $ 1.98 | $ 2.02 | $ 2.06 | $ 2.10 | $ 2.14 | $ 2.19 |
| **Conventional Operation** | | | | | | | | | |
| Electricity | 62,926,168 | 62,926,168 | 62,926,168 | 62,926,168 | 62,926,168 | 62,926,168 | 62,926,168 | 62,926,168 | 62,926,168 |
| Natural Gas | 564,921 | 564,921 | 564,921 | 564,921 | 564,921 | 564,921 | 564,921 | 564,921 | 564,921 |
| Electric Charges | $ 3,429,775 | $ 3,500,315 | $ 3,537,441 | $ 3,614,463 | $ 3,698,799 | $ 3,788,055 | $ 3,865,029 | $ 3,956,687 | $ 4,038,378 |
| Natural Gas Expense | $ 3,737,039 | $ 3,837,911 | $ 3,952,574 | $ 4,062,969 | $ 4,179,205 | $ 4,303,630 | $ 4,439,696 | $ 4,590,573 | $ 4,729,657 |
| Subtotal, Electricity & Natural Gas | $ 7,166,814 | $ 7,338,226 | $ 7,490,015 | $ 7,677,432 | $ 7,878,004 | $ 8,091,685 | $ 8,304,725 | $ 8,547,260 | $ 8,768,035 |
| **Annual Cogeneration Production** | | | | | | | | | |
| Electricity | 27,330,736 | 27,330,736 | 27,330,736 | 27,330,736 | 27,330,736 | 27,330,736 | 27,330,736 | 27,330,736 | 27,330,736 |
| Thermal Cogen, Heat Recovered | 280,315 | 280,315 | 280,315 | 280,315 | 280,315 | 280,315 | 280,315 | 280,315 | 280,315 |
| Thermal Supplemental, Fuel | 237,676 | 237,676 | 237,676 | 237,676 | 237,676 | 237,676 | 237,676 | 237,676 | 237,676 |
| **Residual Electric Load** | | | | | | | | | |
| Electricity | | | | | | | | | |
| Demand, monthly average | 6,955 | 6,955 | 6,955 | 6,955 | 6,955 | 6,955 | 6,955 | 6,955 | 6,955 |
| Energy | 35,595,432 | 35,595,432 | 35,595,432 | 35,595,432 | 35,595,432 | 35,595,432 | 35,595,432 | 35,595,432 | 35,595,432 |
| Water | 2,224 | 2,224 | 2,224 | 2,224 | 2,224 | 2,224 | 2,224 | 2,224 | 2,224 |
| Cogeneration Fuel | 671,881 | 671,881 | 671,881 | 671,881 | 671,881 | 671,881 | 671,881 | 671,881 | 671,881 |
| Fuel Mix | | | | | | | | | |
| Natural Gas | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Biomass | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| Supplemental Fuel | 237,676 | 237,676 | 237,676 | 237,676 | 237,676 | 237,676 | 237,676 | 237,676 | 237,676 |
| Fuel Mix | | | | | | | | | |
| Natural Gas | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Biomass | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| **Expenses** | | | | | | | | | |
| Fuel, Cogeneration System | $ 1,581,237 | $ 1,612,862 | $ 1,645,119 | $ 1,678,021 | $ 1,711,582 | $ 1,745,813 | $ 1,780,730 | $ 1,816,344 | $ 1,852,671 |
| Supplemental Fuel | | | | | | | | | |
| Biomass | $ 559,357 | $ 570,544 | $ 581,955 | $ 593,594 | $ 605,466 | $ 617,576 | $ 629,927 | $ 642,526 | $ 655,376 |
| Natural Gas | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| Water | $ 4,148 | $ 4,231 | $ 4,315 | $ 4,402 | $ 4,490 | $ 4,579 | $ 4,671 | $ 4,764 | $ 4,860 |
| * Indicates that Rahr would lose money every | $ 152,920 | $ 155,979 | $ 159,098 | $ 162,280 | $ 165,526 | $ 168,836 | $ 172,213 | $ 175,657 | $ 179,170 |
| Residual Electric Service | $ 1,972,525 | $ 2,013,094 | $ 2,034,446 | $ 2,078,743 | $ 2,127,246 | $ 2,178,578 | $ 2,222,848 | $ 2,275,562 | $ 2,322,544 |
| Stand-by Service Charges | $ 99,765 | $ 101,817 | $ 102,897 | $ 105,138 | $ 107,591 | $ 110,187 | $ 112,426 | $ 115,092 | $ 117,469 |
| Sub-total Expenses with Cogeneration | $ 4,369,952 | $ 4,458,527 | $ 4,527,831 | $ 4,622,177 | $ 4,721,900 | $ 4,825,570 | $ 4,922,815 | $ 5,029,946 | $ 5,132,090 |
| **Avoided Expense, Cogeneration** | $ 2,796,862 | $ 2,879,699 | $ 2,962,184 | $ 3,055,255 | $ 3,156,104 | $ 3,266,115 | $ 3,381,910 | $ 3,517,314 | $ 3,635,945 |
| **NPV, Avoided Expense** | | | | | | | | | |

## Sensitivity Analysis

Several variables influence the economics of a biomass cogeneration project. Among these factors are biomass, natural gas, electricity, and equipment costs. It is conceivable that lower biomass and equipment costs and higher fossil fuel prices contribute positively to the economics of biomass cogeneration. In this section, the results of manipulating these variables will be discussed in more detail for Scenario 1.1 and briefly addressed for all the other scenarios.

If biomass price is reduced from $25/ton to $0/ton and all the other parameters remain the same, all of the scenarios have a positive cash flow. However, Scenarios 2.1, 2.2, and 2.3 yield a negative rate of return and the others produce positive rates of return (see Table 6-6 below). Again, in these scenarios the biomass plant is designed to generate more energy than Rahr needs, which negatively impacts economics. In Scenario 3.1, the project would yield a negative payback for every year and hence produces an economic loss. The N/A in table designates this economic loss.

Scenario 4 would replace 2.6 as having the best economics under the new circumstances. Scenario 4 would produce a net avoided cost of $57.9 million (today's dollar) over twenty years with an investment of $16.9 million. These savings translate to an internal rate of return of +12.6 % (see Table 6-6). Similarly, based on this reduced biomass price, in Scenario 1.1, if Rahr invests $20.7 million to build the biomass cogeneration plant, it will experience a net avoided cost of $51.5 million in twenty years. This reduced biomass price situation would be applicable where the biomass byproduct does not have a competing market. A given corporation would need to dispose of its biomass byproduct and would not be able to sell it to alternative markets such as the animal feed market. When biomass becomes free, it does not matter how one burns biomass so long as energy is generated from it. Efficiency is not as important in this case since the fuel is so cheap. Therefore, Scenario 4 has the best economics.

**Economics**

If natural gas cost increases from $4/MMBTU to $10/MMBTU, many of the scenarios show improved economics with Scenarios 2.6, 1.1, and 4 still being the best. In Scenario 2.6, an investment of $15.3 million will lead to a savings of $80.7 million over twenty years, which translates to an internal rate of return of +15.8 % (see Table 6-6). In a similar fashion, in Scenario 1.1, if Rahr devotes $20.7 million to build a biomass plant, it will avoid expenses of $86 million in twenty years producing an internal rate of return of +16.1 %. These savings occur because biomass prices would be low in comparison to natural gas prices and, consequently, lead to lower operating costs. In addition, thermal efficiency would be of utmost importance since heating costs would be so much higher. Consequently, the combustion turbine's economics improves so dramatically because it is more thermally efficient than the competing technologies. It is foreseeable that this increase in natural gas prices might occur when the world's oil reserves become strained and natural gas would become a competing source of fuel with liquid fuels. This enhanced demand for natural gas might boost its price and make biomass fuel more appealing.

Another situation when the scenarios show improved economics is when electricity prices rise. If electricity cost jumps to $0.10/kWh, Scenario 2.7 shows the best economics. With a $10.2 million investment, Rahr could save over $62 million over the course of twenty years, which translates to an internal rate of return of 20.4%. When electricity prices rise, biomass becomes more attractive as fuel and the savings associated with producing electricity on-site is high in comparison to buying it from the electric utility company.

Similarly, in Scenario 1.1, if Rahr invests $20.7 million to build this biomass plant, it will avoid total expenses of $73.6 million in twenty years. This leads to an internal rate of return of 13.3%. Once again for this scenario, the engine set is a more attractive option than combustion turbine because the turbine requires a compressor to compress the synthesis gas and the parasitic load to operate the compressor is too great. Engine sets do not require a compressor and the de-rating of the engine sets is not as great as the parasitic loss associated with the compressor. These two reasons combined give a lower overall electrical generation cost and, consequently, lower capital equipment costs for Rahr than the combustion turbine cases. These lower capital equipment costs yield a better rate of return for Rahr.

It is predictable that electricity costs would increase when pollution becomes a major problem and stricter air pollution control equipment are mandated for electrical utility plants.

The added cost of pollution control equipment will add to the price of electricity. Another case when electricity prices might increase is when the U.S. approves the Kyoto Protocol. The cost of reducing carbon dioxide emissions at utility plants would become greater and therefore lead to higher electricity prices. In addition, the government might provide incentives to reduce carbon dioxide emissions in the form of tax breaks or carbon dioxide credits, which might improve the economics of the Rahr biomass plant.

Even when capital equipment costs are cut in half, none of the scenarios show good economics for investors to invest in. The engine sets still offer the best economics with positive internal rates of return while all the other technologies yield negative internal rates of return. Therefore, even when this biomass technology is commercialized and capital equipment costs are considerably reduced; the economics of these technologies are not favorable.

**Table 6-6: Sensitivity Analysis Results Showing Internal Rates of Return**

| Scenario | Biomass = $0/ton<br>Natural Gas = $4/MMBTU<br>Electricity = $0.045/kWh[1] | Biomass = $25/ton<br>Natural Gas = $10/MMBTU<br>Electricity = $0.045/kWh[1] | Biomass = $25/ton<br>Natural Gas = $4/MMBTU<br>Electricity = $0.100/kWh[2] | Capital Equipment Cost = Reduced by 50%[1] |
|---|---|---|---|---|
| 1.1 | +6.2 % | +16.1 % | +13.3 % | -4.6% |
| 1.2 | +4.9 % | +11.4 % | +12.9 % | -8.4% |
| 2.1 | -7.3 % | -0.1 % | -3.5 % | N/A[3] |
| 2.2 | -2.8 % | +4.0 % | +1.1 % | N/A[3] |
| 2.3 | - 15 % | - 11.0 % | - 5 % | N/A[3] |
| 2.4 | +7.0 % | +12.6 % | +14.3 % | -0.7 % |
| 2.5 | +6.2 % | +10.0 % | +11.2 % | -9.4 % |
| 2.6 | +8.1 % | +15.8 % | +15.9 % | +4.4 % |
| 2.7 | +5.2 % | +14.9 % | +20.4 % | +1.2 % |
| 3.1 | N/A[3] | N/A[3] | N/A[3] | N/A[3] |
| 4 | +12.6 % | +19.5 % | +19.2 % | -2.7 % |

[1] Best economics occur for Scenarios 1.1, 2.7, and 4 when biomass is used for supplemental firing. In all other cases best economics arise when natural gas is utilized for supplemental firing.

[2] Best economics for all scenarios occur when natural gas, not biomass, is used for supplemental fuel firing.

[3] The payback is negative for every year for the last twenty years. The internal rate of return could not be calculated.

# Section 7
# Minnesota and United States Benefits

When this biomass plant is successfully demonstrated and the technology is replicated across the country, the state of Minnesota and the United States will realize several profound benefits. These benefits range from less dependence on foreign oil and fossil fuels to the development of bio-refineries to rural economic development and healthier environments. This section describes these benefits in more detail.

## Improved Strategic Security and Balance of Payment for Minnesota

In the year 2000, Minnesota generated approximately 52,000 MMkWh and consumed 60,000 million-kWh (MMkWh) of electricity, causing an import of about 8,000 MMkWh (see Figure 7-1 and Figure 7-2)[7]. If, as mentioned in Section 5, 370 plants with similar tonnage as Rahr's are built in Minnesota, these plants could supply approximately 10,000 MMkWh of electricity, eliminating the electricity deficit. This reduction in dependence of electricity from other states will keep the resources that are currently going out of the state within the state. During 2000, the average price of electricity paid by Minnesota consumers was 5.81 cents per kWh (see Figure 7-3)[8]. Thus, using this electricity price and the amount of electricity that could potentially be saved when the 370 plants that use corn stover are built, Minnesota could potentially save $464 million per year on electricity costs.

## Minnesota and United States Benefits

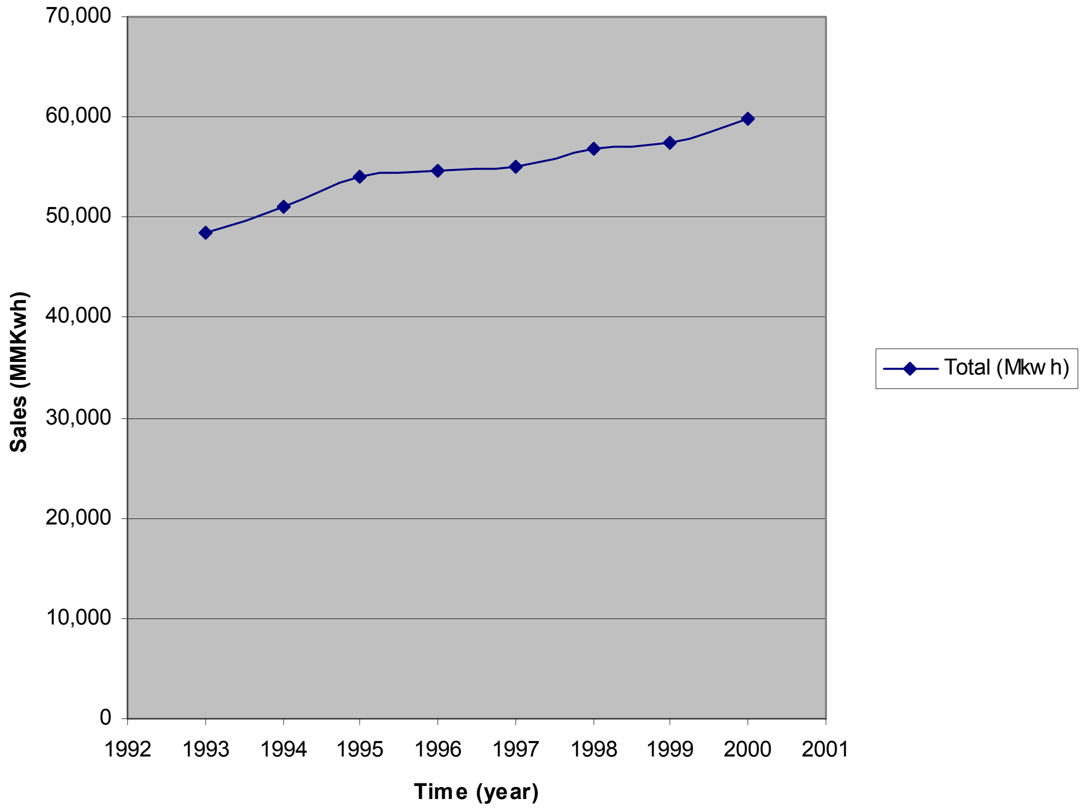


**Figure 7-1**

*Retail Sales of Electricity by Utilities to Consumers in MN*

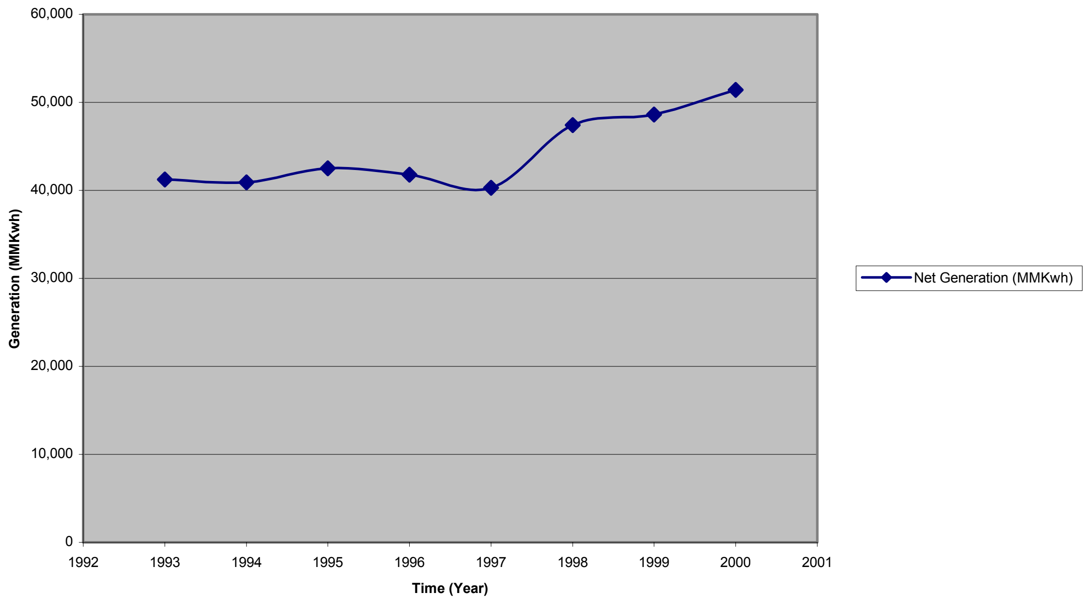


**Figure 7-2**

*Net Generation in MN (MMKwh)*

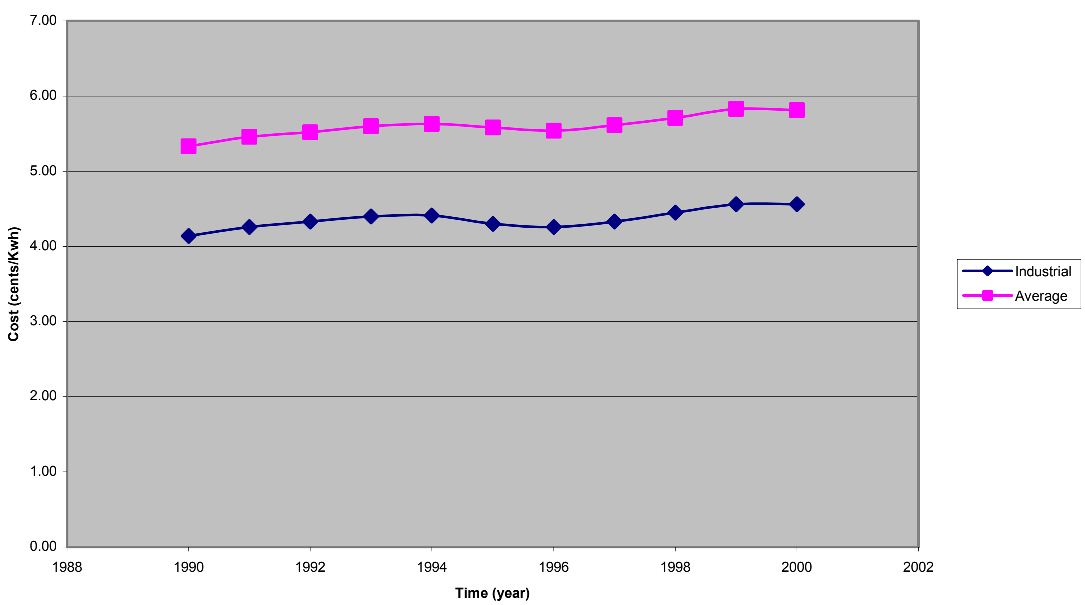


**Figure 7-3**

*Average Annual Electricity Cost in MN*

**Minnesota and United States Benefits**

As far as natural gas is concerned, as discussed in Section 5 of the report, the 370 plants could provide 103-trillion BTU of heat, which amounts to 103-billion cubic feet of natural gas per year. In 2000, Minnesota consumed 333-billion cubic feet of natural gas per year[9]. Since Minnesota imports all of its natural gas, the 370 plants would allow the reduction of imported natural gas by 31%, and also reduce the state's dependence on natural gas by the same percentage.

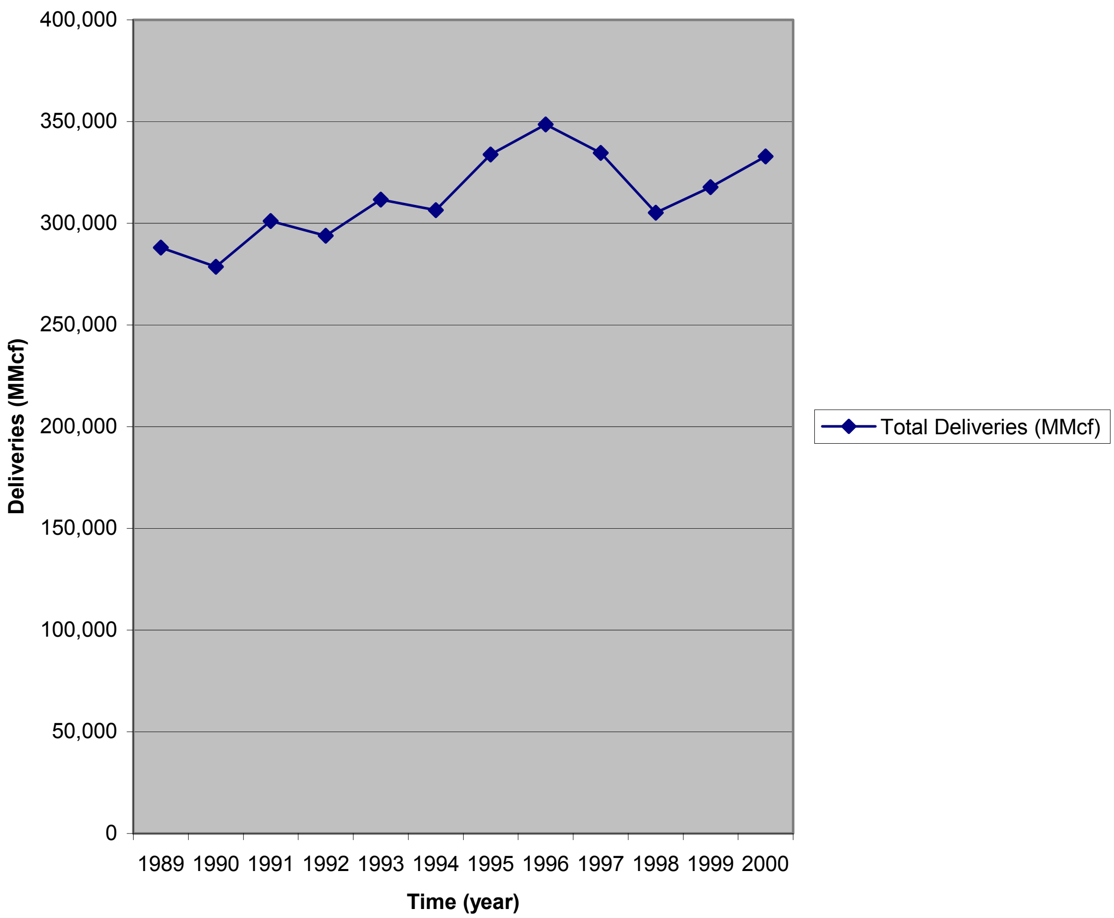


**Figure 7-4**

*Total Deliveries in MN (MMcf)*

In 2000, Minnesota consumers (industrial, residential, commercial, and utilities) spent approximately $2 billion on natural gas (see Figure 7-5)[10]. The average cost of natural gas for 2000, was $6.90 per thousand cubic feet (Mcf) (see Figure 7-6)[11]. If, as discussed above in Section 5 of the report, 103 billion cubic feet of natural gas could be saved, this would be a savings of about $0.7 billion per year.

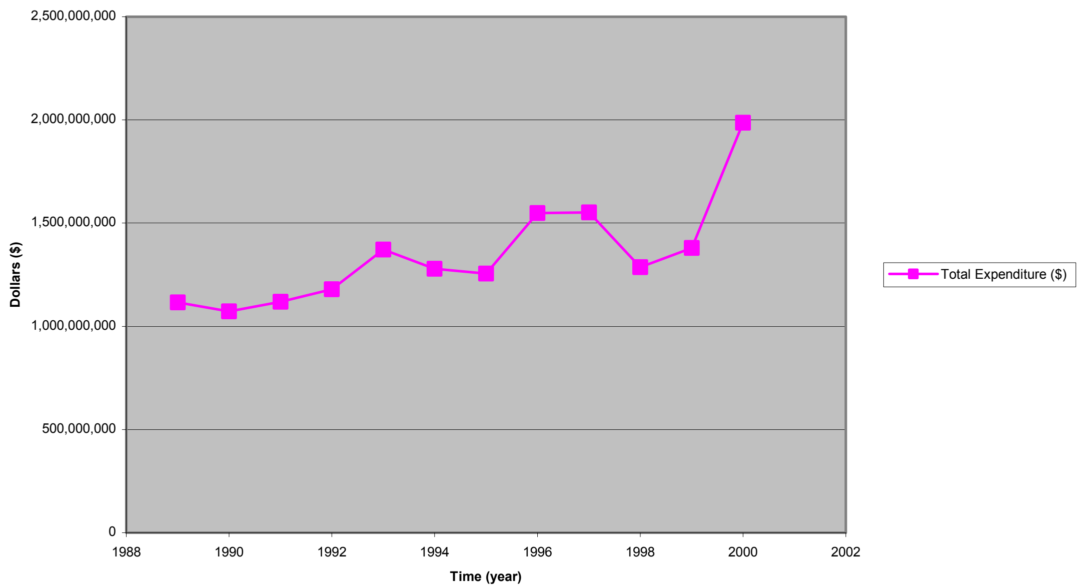


**Figure 7-5**

*Natural Gas Expenditure in MN*

**Minnesota and United States Benefits**

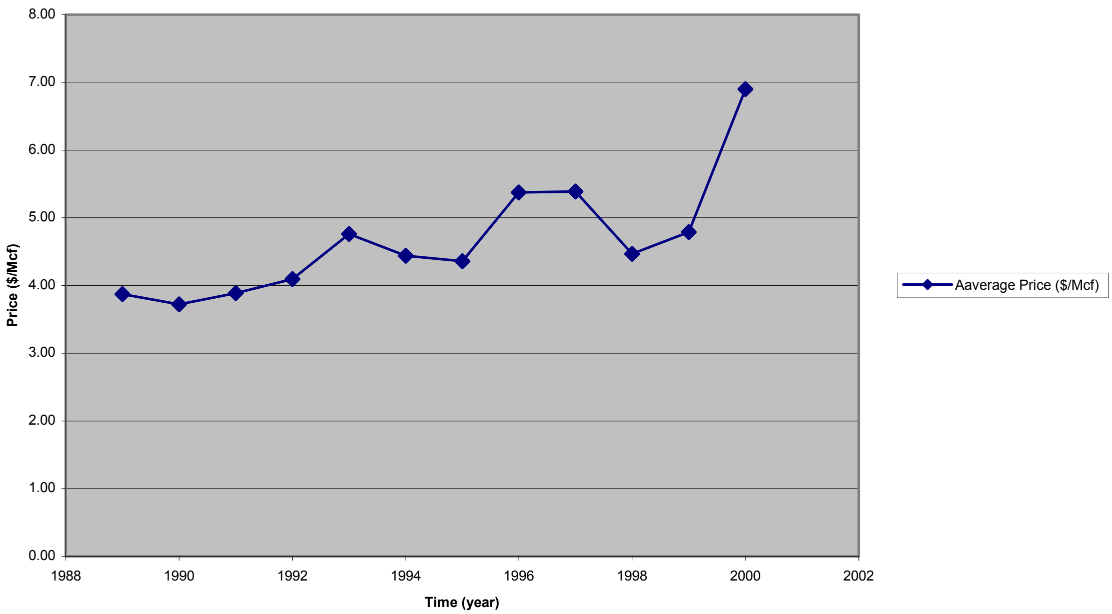


**Figure 7-6**

*Average Natural Gas Price in MN*

## Improved Security and Balance of Payments for the United States

Today most power plants run on fossil fuels such as natural gas, oil, and coal. To date, the U.S. imports about 60% of its oil needs from foreign countries. This high dependence on foreign fuel means the U.S. is at the mercy of these countries during an economic and political crisis.

Last year, the United States generated approximately 110,000 MMkWh of electricity from petroleum (see Figure 7-7)[12]. If, as discussed in Section 5, 3,800 power plants similar to Rahr's could be built that run on biomass, approximately 103,000 MMkWh could be generated from this renewable source. Thus, this generation of electricity based on biomass would reduce the dependence of the United States on oil-based generation by 94 %.

In 2000, the United States consumed about 22.71 trillion cubic feet of natural gas (see Figure 7-8)[13]. If 3,800 plants could be built across the United States, 1.06-quadrillion BTU of heat could be produced from these biomass plants. This heat is equivalent to 1.06 trillion cubic feet of natural gas per year. Therefore, replacing these fuels with biomass will benefit the strategic security of the United States by reducing our dependence on fossil fuels and in particular on imported oil.

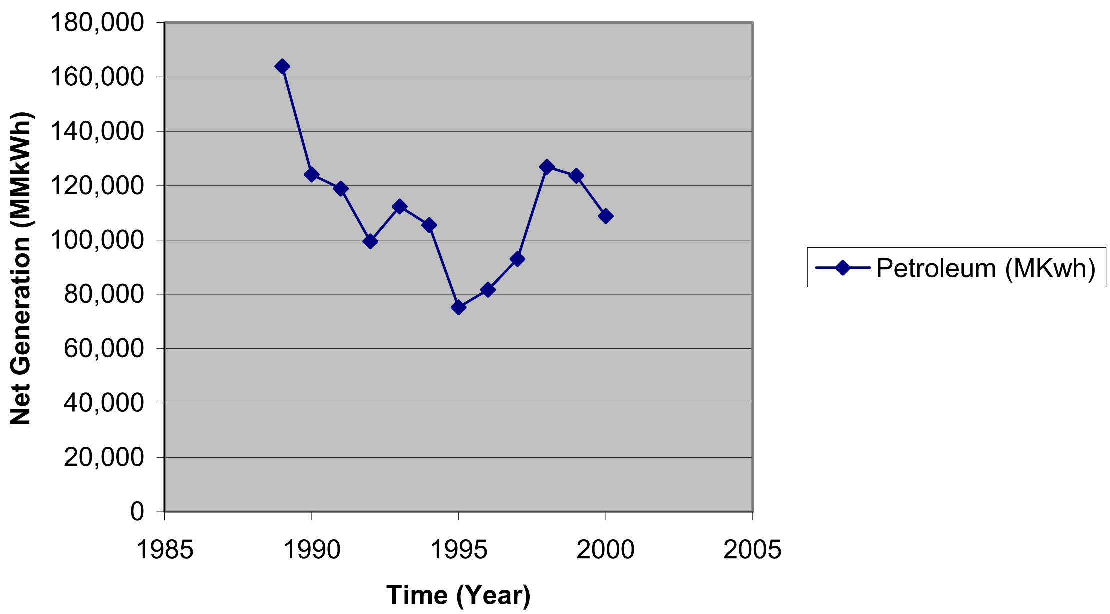


**Figure 7-7**

*Net Generation From Petroleum in US (MMkWh)*

**Minnesota and United States Benefits**

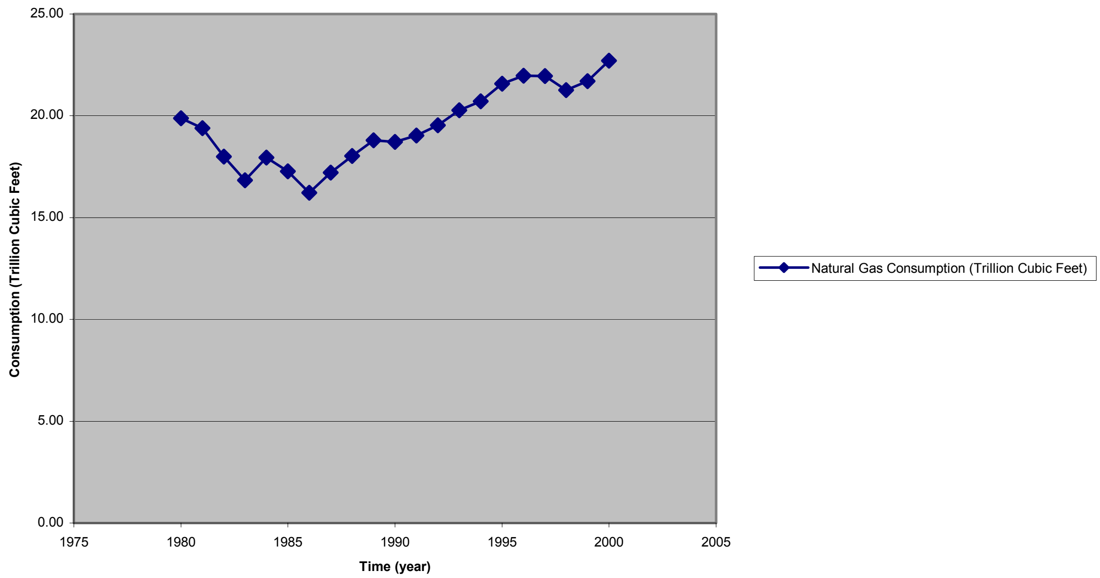


**Figure 7-8**

*Natural Gas Consumption in US*

## Healthier Rural Economies

Since most industries that can expect to benefit from the proposed biomass plant are located near the source of their feed stock, rural farming communities, the proposed biomass plant will promote rural economic development by fostering the development of an abundant, reliable, locally based fuel supply. As mentioned Section 5, the proposed process will utilize these local, untapped fuel sources to generate energy, both for the plants themselves and for the farming communities where they are located. The collection and use of corn stover as energy fuel, using gasification for these industries will create an additional revenue stream for the farmers amounting conservatively to an additional $45 to $60 per acre. An additional group of custom farming operations will be expected to grow up for the purpose of harvesting corn stover. These custom operators will hire more workers, purchase more equipment, and stimulate the local economies through increased commerce.

A study done by the state of Wisconsin supports the fact that producing energy based on biomass rather than fossil fuels can lead to healthier rural economies. This study showed that if Wisconsin could utilize $2 billion worth of energy derived from biomass fuel instead of fossil fuels, the state would create 63,234 job-years of employment, raise mean wages by $1.2 billion and produce $4.6 billion more of goods and services over the life of the technology (Page 44 Biomass for Renewable Energy, Fuels, and Chemicals, Donald L. Klass, 1998). This study also demonstrated that the additional capital and commercial activity would create the tax base with which to support public schools, public infrastructure and a more diverse work force and demographic.

## Improved Environmental Quality

Biomass power is one of the most attractive options for addressing concerns over carbon dioxide, a major constituent of greenhouse gas. Since, the proposed process consumes biomass and no other fossil fuels, it will not contribute to atmospheric carbon dioxide. When biomass is oxidized, trees and other plants will sequester or capture the atmospheric carbon dioxide, converting it back into biomass, thus leading to no net increase in the carbon dioxide in the atmosphere. By contrast, when fossil fuels are burned, the carbon dioxide released adds to the total carbon dioxide in the atmosphere and contributes to global warming.

As far as emissions are concerned, gasification for power production is superior to coal firing in combination with natural gas for heat (see Section 4). Both coal and biomass contain bound sulfur and nitrogen that, when oxidized, can form sulfur oxides (SOx) and nitrogen oxides (NOx). Gasification offers the advantage that most sulfur oxides are captured in the ash and consequently do not require much effort to control SOx emissions. Treatment of the tail gas after the generator has been demonstrated to successfully control NOx emissions. Air born emissions of combustion turbines using biomass can be comparable to that of natural gas combustion.

## Technology Export

The proposed biomass plant and the engineering expertise associated with it have a high probability of being exported to foreign countries. The development of a successful biomass to electricity process will find widespread applications to regions where fossil fuels are not abundant. For example, in rice producing nations such as Japan, which imports all of its fuels, farms produce rice crops that lead to large amounts of excess rice straw that is frequently burned for disposal. In the proposed process, these rice straws could be burned as precious fuel reducing their dependence on fossil fuels. Other crops such as sugar cane are also logical candidates for the application of this technology.

Since the proposed process relies on very little water, and there is frequently a dearth of potable water in developing nations limiting the use of steam turbines, the combustion turbine technology will find widespread applications in these countries. This export of the technology will lead to more jobs, from engineering to manufacturing to general labor within the U.S.

## Sustainable Resource Supply

As discussed above, in the case of Rahr Malting's Shakopee plant, the majority of the biomass required for the biomass plant is produced during the malting process. Any additional biomass will be supplied by corn stover from neighboring farms. Basing the biomass plant on corn stover serves two purposes. First, it assures of a continuing supply of biomass for the plant because there appears to be a limitless amount of corn stover in Minnesota. Second, it benefits the farmers and the local economy when corn stover is used for the cogeneration process. Once this project is successful and the technology is embraced by similar industries across the U.S., it's easy to see that this would improve the economics of crop production across the whole landscape of the United States.

There is ample supply of corn stover in the U.S. In 2000, an estimated 279 million dry tons of stover were produced but less than 1% of that was collected for industrial processing[14]. Large-scale demonstration projects (50,000 acres) have shown corn stover can be collected and delivered locally for less than $45 per dry ton. At Rahr Malting, since much of the biomass comes from the malting process, only a small geographic area is needed to supply the corn stover.

There are four benefits of removing some of the corn stover from farms. Firstly, the farmer saves on the cost of plowing the stover under the earth thereby reducing the cost of growing the next crop. Secondly, the farmer saves on the cost of applying nitrogen to the soil. Farmers must apply more nitrogen fertilizer to compensate for the excess carbon content in the soil. Thirdly, the farmer is assured of good soil quality since the farmer could use low till or no till farming that reduces soil erosion. Fourthly, since the farmer does not have to plow the ground, low till or no till farming leads to lower production costs.

## Specific Industries Benefits

The results of this demonstration plant will minimize several technical and economic risks associated with biomass co-generation. By demonstrating the technical and commercial viability of co-generation from biomass, Sebesta and its partners will provide the operational data to show technical and economic viability of this system. The integration of the commercially available components into an operating demonstration plant will help overcome the perceived technical risks and encourage capital investments.

In addition, the proposed technology will improve the economics of corn ethanol plants. The byproduct from ethanol production, dried distiller's grains (DDGS), are dropping in market value as the market is flooded with the byproduct because more and more ethanol plants are coming online. In the mean time, the energy costs for these plants is rising rapidly. If the proposed technology can use DDGS as fuel, the successful demonstration of this technology will remove the risk of investing in an unproven technology, leading to more capital investments and improving the economics of producing ethanol.

A successful demonstration will also lead to the next generation of biorefinery/ethanol plants, as well as improvements and enhancements in other food processing facilities. Sebesta Blomberg is currently designing the next generation of biorefinery/ethanol plants based on processing of genetically modified corns capable of producing enzymes, sweeteners and other high value products. These processes are energy intensive and require substantial thermal and electric service. Ironically, in these plants, the production of ethanol becomes the byproduct and the major income stream is generated from the high value protein and lipid fractions. Our analysis of these facilities has already shown that the byproducts such as distillers' grains of this process will be best used as energy.

**Minnesota and United States Benefits**

Thus, the proposed process is likely to achieve acceptance in the broad agricultural regions of the United States. Most production plants in agricultural regions, including agricultural commodity and corn ethanol plants have concurrent requirements for electricity and heat. The development of a co-generation process capable of using process byproducts and locally available crop residue, as fuel will dramatically reduce the dependence of these plants on natural gas and oil based standby fuels. Ultimately, as the technology becomes more popular and different industries start adopting it into their processes, the nation will become less dependent on foreign oil and also on natural gas supply which can then be more available for other critical applications such as fertilizer production. Hence, the proposed process will convert a renewable agricultural byproduct into a replacement for natural gas, imported oil and coal based electricity.

# Section 8
# References


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