# GREAT RIVER ENERGY
# ALTERNATIVES EVALUATION AND SITE SELECTION STUDY
# FOR THE
# CONSTRUCTION OF GRE'S CAMBRIDGE PEAKING PLANT

GREAT RIVER ENERGY℠

**PREPARED BY GREAT RIVER ENERGY**

**FOR THE**

**RURAL UTILITIES SERVICE**

**APRIL 2005**

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TABLE OF CONTENTS


**EXECUTIVE SUMMARY**……...……*iii*

**1 INTRODUCTION** ..... 1

**1.1 WHO IS GREAT RIVER ENERGY?** ..... 2
**1.2 GRE CONTACT INFORMATION** ..... 3

**2 CAPACITY AND ENERGY NEED SUMMARY** ..... 4

**2.1 GRE'S CAPACITY NEEDS** ..... 4
**2.2 GRE'S ENERGY NEEDS** ..... 9
**2.3 PEAKING RESOURCES BEST MATCH NEED** ..... 11
**2.4 SUMMARY OF GRE'S CURRENT ENERGY AND CAPACITY NEEDS** ..... 11

**3 PROJECT DESCRIPTION** ..... 12

**3.1 PROJECT LOCATION** ..... 12
**3.2 COMBUSTION TURBINE/GENERATOR** ..... 15
**3.3 GENERATOR STEP-UP TRANSFORMERS** ..... 15
**3.4 WATER STORAGE** ..... 15
**3.5 SUBSTATION** ..... 15
**3.6 NATURAL GAS – PRIMARY FUEL** ..... 15
**3.7 PLANT DETAILS & OPERATION** ..... 16
**3.8 MAINTENANCE** ..... 18
**3.9 SITE SELECTION** ..... 18
**3.10 SECURITY & PLANT ACCESS** ..... 18
**3.11 TRANSMISSION INTERCONNECTION AND SERVICE** ..... 19
**3.12 FIRE PROTECTION AND SAFETY** ..... 19
**3.13 AIR EMISSIONS** ..... 19
**3.14 WASTEWATER HANDLING AND DISPOSAL** ..... 21
**3.15 STORM WATER HANDLING AND DISPOSAL** ..... 21
**3.16 OIL WASTE HANDLING AND DISPOSAL** ..... 22
**3.17 SOLID WASTE HANDLING AND DISPOSAL** ..... 22
**3.18 PRIMARY WATER USE** ..... 22
**3.19 NOISE IMPACTS** ..... 22
**3.20 TRAFFIC** ..... 23
**3.21 ECONOMIC CONSIDERATIONS** ..... 24
**3.22 USE OF SPACE** ..... 24
**3.23 REQUIRED PERMITS AND APPROVALS** ..... 25

**4 ALTERNATIVES TO THE PROPOSED PROJECT** ..... 26

**4.1 ALTERNATIVES REVIEW** ..... 26
**4.2 RENEWABLE ENERGY** ..... 27
**4.3 ENERGY CONSERVATION IMPROVEMENTS** ..... 31
**4.4 DESCRIPTION OF ALTERNATIVES** ..... 32
**4.5 ECONOMIC COMPARISONS TO PROPOSED PROJECT** ..... 42
**4.6 CONCLUSION** ..... 43

TABLE OF CONTENTS

**5 SITING ALTERNATIVES ..... 44**

**5.1 SITING CONSTRAINTS ..... 44**
**5.2 INITIAL SITE SCREENING ..... 48**
**5.3 DETAILED SITE EVALUATION PROCESS ..... 50**
**5.4 SITE COMPARISON & SELECTION ..... 52**

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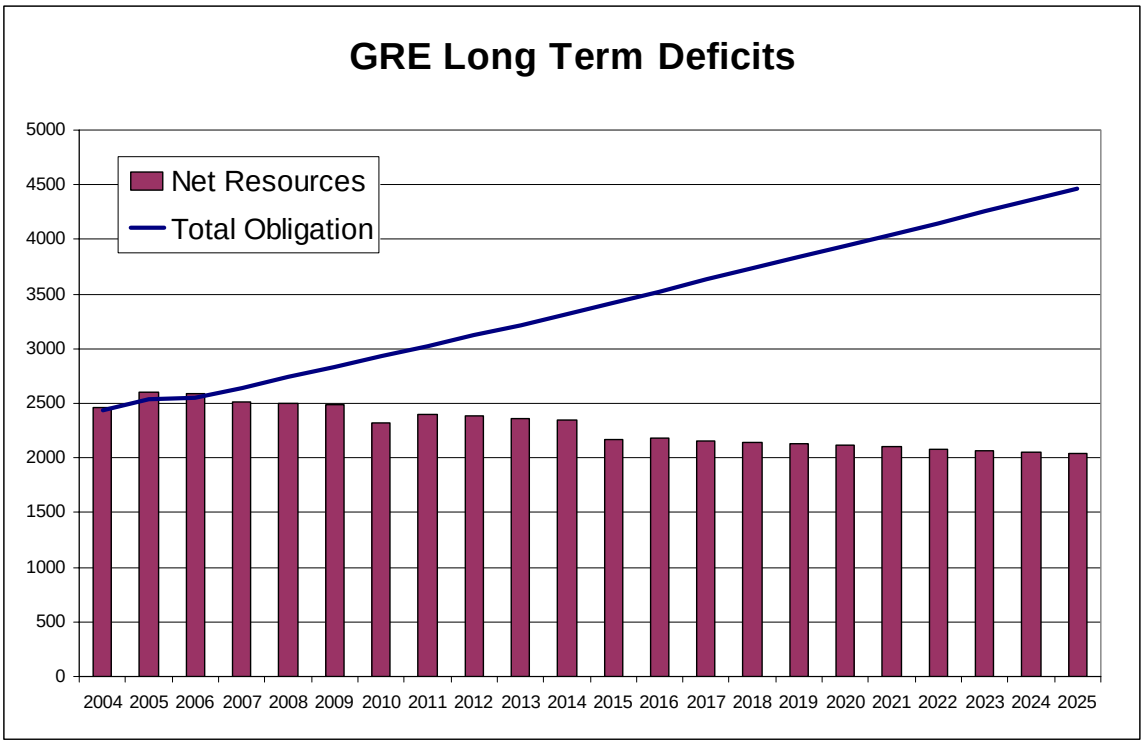
## Executive Summary

Great River Energy (GRE), headquartered in Elk River, Minnesota, is planning to construct a project consisting of a single simple-cycle combustion turbine at its existing Cambridge Peaking Plant located in Cambridge Township, Isanti County, Minnesota (the project). The estimated summertime accredited output of the project will be approximately 170 megawatts (MW). The project is needed for GRE to provide capacity and energy to its member cooperatives starting in summer 2007. GRE is projecting a deficit of approximately 136 MW in summer 2007 without the project.

GRE is a generation and transmission cooperative based in Elk River, Minnesota. GRE provides electrical energy and related services to 28 member cooperatives. Those distribution cooperatives, in turn, supply electricity and related services to more than 580,000 residential, commercial and industrial customers in Minnesota and Wisconsin (or a population of 1.5 million people). GRE's approximately 2,500-megawatt generation system is composed of a mix of baseload and peaking power plants, including coal-fired, refuse-derived fuel, natural gas and oil plants, as well as wind generation.

GRE's summer demand is projected to increase an average of approximately 100 MW per year, which translates into an average annual rate of 3.2 percent over the forecast period. In contrast, energy demand is growing at a rate of 2.4 percent. By summer 2007, a capacity deficit of 136 MW is projected.




The project is being developed to meet GRE's existing and future peaking resource needs. Peaking generation facilities operate for relatively few hours per year. Cambridge

Station is expected to be operated typically during times of peak electrical demand, which generally occur during periods of very high or very low temperatures. A utility's peaking resources often represent as much as 40 percent of its capacity requirement but provide less than five percent of the total energy requirements. As a result, this favors low capital cost technologies because of the severely reduced number of kilowatt-hours (kWh) over which to spread the fixed costs.

GRE cannot satisfy its needs through its existing facilities. GRE has recently upgraded several of its existing generating facilities. Further upgrades would not meet the peaking needs identified in this filing.

The project is the appropriate type of resource to cover peak demands and a small portion of energy requirements. GRE evaluated the proposed project against a fuel-oil fired simple-cycle combustion turbine and an ethanol-fired combustion turbine. The following other resource opportunities were evaluated as alternatives to the project:

- renewable resources including wind, biomass, hydro, and solar
- conservation programs
- distributed generation
- emerging technologies including fuel cells, micro turbines, and energy storage

All of these opportunities were either better suited for base load application, could not be procured and installed in time to meet GRE customers' needs, or are not commercially available.

The project will have minimal environmental impacts. The project utilizes a clean fuel and a combustion technology that have minimal impacts on the surrounding environment. The project is being sited to minimize the construction of the gas pipeline and transmission lines needed to serve the project.

GRE has a long history of cost-effective conservation programs, which have delayed the need for peaking capacity projects like this. In 2004, GRE had approximately 345 MW of its load controlled through demand-side management programs. Cost-effective programs will be continued but are expected to diminish peak demands in the immediate future by an amount insufficient to eliminate the need for the project.

The rural and suburban service territory of GRE's member cooperatives will benefit from the project. The project will help GRE's member cooperatives continue to supply competitively priced power to their customers. Low cost electricity is an important component in supporting stable economic growth in the region.

The proposed GRE self-build alternative has the lowest overall costs and best meets GRE's needs as determined through the solicitation and review of competitive peaking proposals. This document shows that the project is needed, there are no reasonable alternatives to this project, and the project will provide significant benefits to society through maintaining a reliable and economic energy supply.

# 1 Introduction

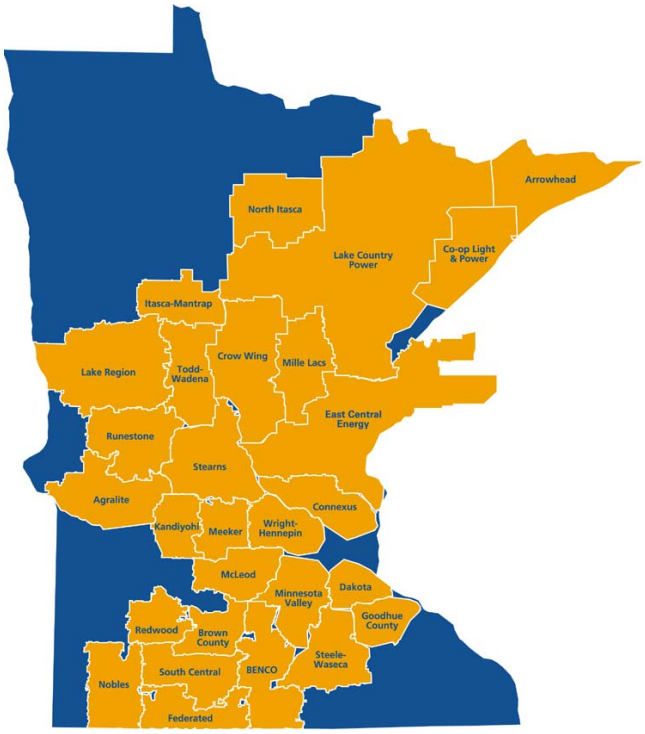
GRE, a Minnesota generation and transmission cooperative, has prepared this study for the Rural Utilities Service (RUS), which is an agency of the U.S. Department of Agriculture. This study demonstrates that GRE is in need of peaking capacity and that construction of a new peaking station consisting of a single simple-cycle combustion turbine is the option that results in the lowest overall cost to GRE's member cooperatives. The project will be constructed at GRE's existing Cambridge Station, in Cambridge Township, Isanti County. The proposed combustion turbines will have a summer capacity of approximately170 MW and will be fueled with natural gas only. Fuel oil for a back-up fuel is not necessary because GRE's peaking needs occur primarily during summer when natural gas to the site would be readily available.

The project is being developed to meet GRE's existing and future peaking resource needs. Peaking generation facilities operate for relatively few hours per year (usually from 500 -1,000 hours). Cambridge Station will typically be operated during times of peak electrical demand, which generally occur during periods of very high or very low temperatures. A utility's peaking resources often represent as much as 40 percent of its capacity requirement but provide less than five percent of the total energy requirements. As a result, this favors low capital cost technologies because of the severely reduced number of kilowatt-hours (kWh) over which to spread the fixed costs.

GRE has covered its growth in capacity needs through a combination of load management programs, capacity transactions with other members in the regional market, and investments in new peaking facilities. Even with GRE's new peaking facilities, the availability of capacity in the MAPP region appears to be tightening, leaving GRE vulnerable to capacity shortages and/or significant increases in the cost of purchasing power. The opening of the MISO markets April 1 could help relieve this situation; however, the practical impacts of the market will not be known soon enough to rely upon for the planning of GRE's near-term capacity deficits.

The project described in this application is consistent with GRE's mission of providing reliable, competitively priced electricity to its member cooperatives. GRE's member cooperatives have approved the installation of these capacity additions through their elected board members.

## 1.1 Who Is Great River Energy?




GRE is a generation and transmission cooperative based in Elk River, Minnesota, formed by the merger of Cooperative Power and United Power on January 1, 1999. Any historical references to GRE are intended to refer to CP and/or UPA to avoid confusing references to the predecessor organizations. GRE provides electrical energy and related services to 28 member cooperatives. Those distribution cooperatives, in turn, supply electricity and related services to more than 580,000 residential, commercial and industrial customers in Minnesota and Wisconsin (or a population of 1.5 million people).

GRE's approximately 2,500-megawatt generation system is composed of a mix of baseload and peaking power plants, including coal-fired, refuse-derived fuel, natural gas and oil plants, as well as wind generation. Over the past couple of years, major improvements have been made at the 1,079-MW Coal Creek Station, located in central North Dakota, to make the plant more efficient, allowing those turbines to generate more electricity without burning additional coal.

GRE owns approximately 4,500 miles of transmission line, including the high capacity, 436-mile direct current, or DC, transmission line that runs from Coal Creek Station to Minnesota. GRE also owns or partially owns more than 100 transmission substations.

Great River Energy employs more than 700 people in Minnesota and North Dakota.

## 1.2 GRE Contact Information

| | |
|---|---|
| Mailing Address: | Great River Energy<br>17845 East Highway 10<br>P.O. Box 800<br>Elk River, MN 55330-0800 |
| Telephone No.: | (763) 441-3121 |
| Project Manager: | Ms. Cynthia Sulzer, P.E.<br>Project Manager<br>Cambridge Peaking Plant<br>(763) 241-2406 |

# 2 Capacity and Energy Need Summary

The project is needed for GRE to provide capacity and energy to its member cooperatives starting in summer 2007. GRE is projecting a deficit of approximately 136 MW in summer 2007 without the project. This projection includes the minimum 15 percent capacity reserve required by MAPP.

## 2.1 GRE's Capacity Needs

GRE is a summer peaking system. The summer demand growth drives GRE's needs for the proposed project. GRE expects to be capacity deficit beginning in the summer of 2007. GRE has adequate capacity to cover its winter peak in the near to medium term.

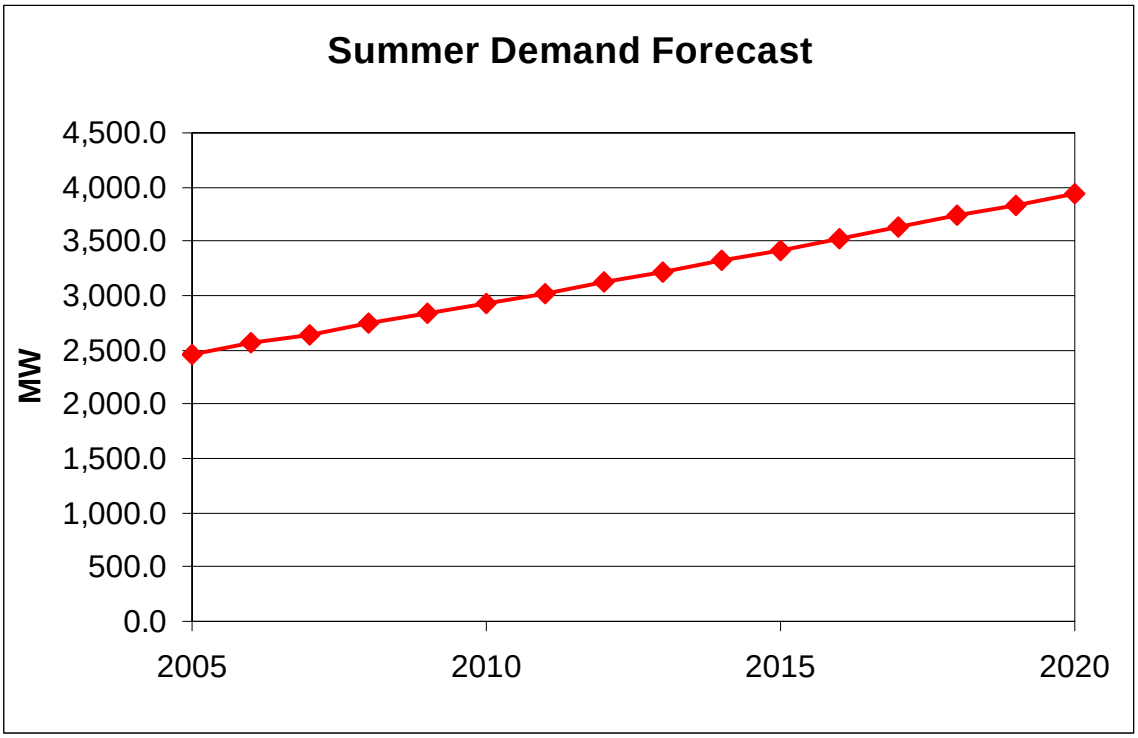
The forecast data presented in this document is derived from GRE's 2002 Long Range Load Forecast. This is the most recent forecast that has been fully approved by the Rural Utilities Service (RUS) and therefore, in accordance with RUS requirements, the 2002 forecast is being used for planning purposes. This forecast was also accepted by the Minnesota Public Utilities Commission (MPUC) in GRE's 2003 Integrated Resource Plan filing. GRE is constantly studying its demand and other aspects of the forecast and is currently in the process of finalizing the 2004 Long Range Load Forecast. Although the new forecast numbers will not be official until approved by GRE's Board of Directors and the RUS, GRE will give an indication of what the most recent studies indicate where relevant in this document.

### 2.1.1 GRE's Capacity Forecast

In developing its long-range forecast, GRE analyzes multiple scenarios varying some assumptions regarding weather and macroeconomics. One of the scenarios is a base-case demand forecast. This represents projected demand in "average" conditions and is expected to cover actual demand 50 percent of the time. However, with the base case, actual demand will also exceed the forecast 50 percent of the time. GRE has determined that it would be too risky to use the base case for planning purposes. Because of the critical nature of meeting its members' demand for electricity, GRE must have a high degree of certainty that its resources will meet its needs. Thus, for planning purposes, GRE utilizes a scenario estimated to capture peak demand 90 percent of the time. This is much more appropriate for GRE's system. In particular, GRE's demand is very sensitive to changes in weather. It is important for GRE to plan sufficiently to meet the potential high demand that could arise during a hot summer. GRE is confident that it can best meet its members' needs by utilizing the higher demand scenario.

GRE's summer demand is expected to increase at an average of approximately 100 MW per year, which translates into an average annual rate of 3.2 percent over the forecast period. In contrast, energy demand is growing at a rate of 2.4 percent.

**Figure 2-1 - Summarizes GRE's Peak Demand Growth***




* This forecast also includes the MAPP reserve requirement of 15 percent.

As mentioned earlier, these forecast numbers come from GRE's 2002 Long Range Load Forecast. Since that time, GRE has continued to study and update its forecast. Preliminary results of its updated forecast reinforce this growth rate and seem to indicate that the growth may increase even further in the later years of the time horizon. GRE will present its updated forecast information, once it has been finalized and internally approved, in its next Integrated Resource Plan filing.

### 2.1.2 GRE's Available Resources

**Table 2-1 - Summarizes GRE's Summer Load and Capabilities**

| Capacity Source | Estimated 2007 Accredited Summer Capacity and Load (MW) |
|---|---|
| GRE Accredited Sources | |
| Cambridge CT | 19.4 |
| Maple Lake CT | 19.1 |
| Rock Lake CT | 19.3 |
| ST. Bonifacius CT | 56.0 |
| Elk River Unit 1 | 10.5 |
| Elk River Unit 2 | 10.5 |
| Elk River Unit 3 | 17.9 |
| Stanton Station [1] | 187.7 |
| Coal Creek Station Unit 1 | 551.0 |
| Coal Creek Station Unit 2 | 561.0 |
| Coal Creek Station Diesel Generator | 2.0 |
| Pleasant Valley Station Unit 11 | 153.6 |
| Pleasant Valley Station Unit 12 | 150.9 |
| Pleasant Valley Station Unit 13 | 122.8 |
| Lakefield Junction Stations Unit 1 | 85.8 |
| Lakefield Junction Stations Unit 2 | 85.4 |
| Lakefield Junction Stations Unit 3 | 85.7 |
| Lakefield Junction Stations Unit 4 | 85.0 |
| Lakefield Junction Stations Unit 5 | 85.9 |
| Lakefield Junction Stations Unit 6 | 85.0 |
| Lakefield Junction Stations Diesel Generator | 2.0 |
| Chandler Hills Wind Farm | 0.1 |
| **Total Accredited Capacity** | 2,396.6 |
| **GRE Total Accredited Purchases** | 783.9 |
| **GRE Total Accredited Sales** | (274.9) |
| **GRE's Net Capability to Serve Load** | 2,905.6 |
| **2007 Load Forecast with 15% Reserves** | (3,041.2) |
| **2007 Capacity Deficit** | (135.6) |

1. Includes the capacity of the diesel back up engine(s)

In general, GRE has three types of existing resources: baseload plants, peaking plants, and long-term purchases (which largely fulfill the role of intermediate resources). In addition, GRE supplements its own resources with market power, when market prices are below the incremental costs of operating its own plants or the contractual terms of its long-term purchases.

GRE's existing baseload resources include Stanton Station, Coal Creek Station and Elk River Station. Both Stanton and Coal Creek Stations are coal-fired plants located in

central North Dakota. Elk River Station is a refuse-derived fuel plant in Elk River, Minnesota. In addition, GRE has a life-of-the-plant contract with Dairyland Power Cooperative to purchase half the output of the Genoa 3 coal-fired plant. Some of GRE's long-term purchases also have a baseload type pricing structure.

GRE also has significant peaking resources. These include the approximately 1000 MW that have been recently added through the Pleasant Valley Station and Lakefield Junction Station, as well as four smaller oil-fired combustion turbines.

An important aspect of GRE's resources not reflected in Table 2-1 is GRE's significant level of demand-side resources. GRE estimates that demand-side programs replaced the need for 345 MW of accredited capacity (factoring in the reserve requirement) during the time of its 2004 summer peak.

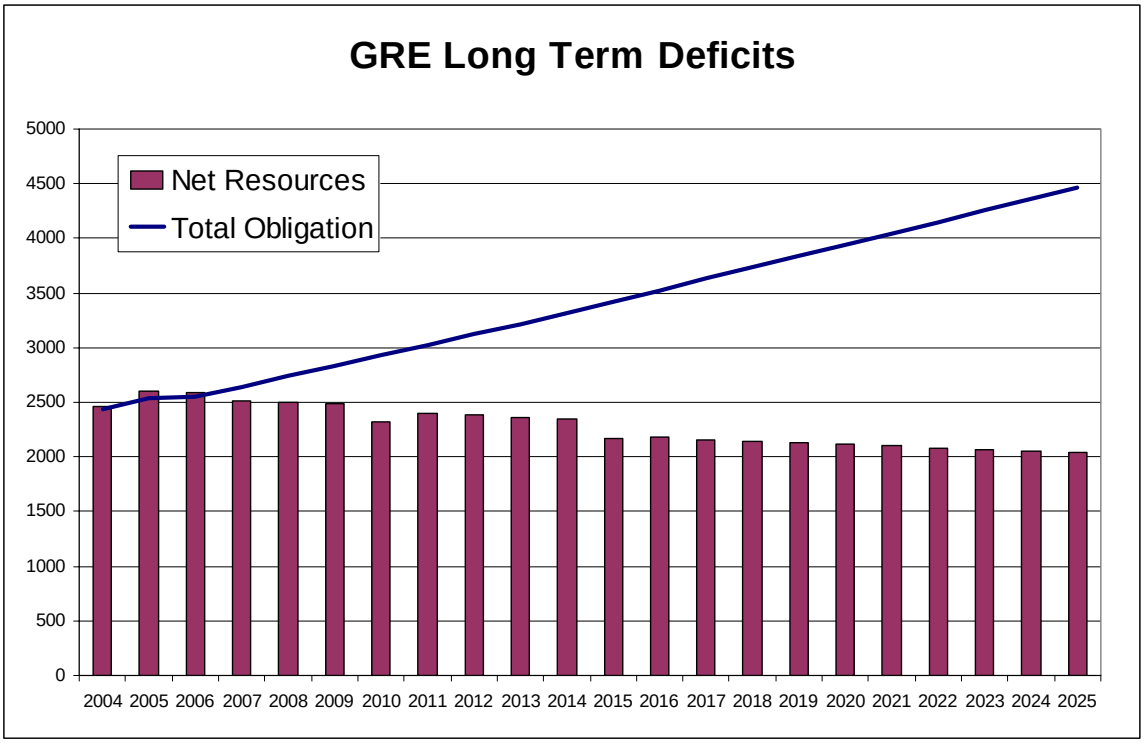
GRE supplements its own resources with other long-term purchase, which are summarized in Table 2-1.

Further, GRE's entire portfolio of generating resources and long-term contracts is supplemented with prudent use of spot market power purchases. GRE uses short-term energy purchases any time the market energy price is lower than the incremental price of the next generating unit or power purchase contract that would otherwise have been used to serve its load. In the past, GRE has also made short-term capacity purchases to fulfill its final capacity needs once a refined short-term forecast is determined. However, the regional capacity market has tightened and GRE's market research indicates that the market could not economically meet its current need for peaking capacity. The impending start of the MISO markets could provide access to a wider market but cannot be relied upon as it is yet untested. Further, the MISO market is designed around energy transactions, not capacity.

### 2.1.3 Overview of GRE's Capacity Forecast

Figure 2-2 summarizes the GRE capacity situation without the project. The line labeled "Total Obligation" is the total load obligation for GRE. The "Net Resources" columns represent the amount of generation supply GRE has available to meet its load obligations, incorporating all of the resources listed above and deducting for the required 15 percent MAPP reserve requirement. The listed capacity of each resource is the MAPP-accredited capacity for the summer season.

**Figure 2-2 - GRE Net Resources vs. Total Obligations**




As the figure illustrates, GRE begins experiencing capacity deficits in 2007. The proposed project is sufficient to bridge the entire gap in 2007 and a large portion of the deficit in 2008. Clearly GRE's needs far exceed this single project. GRE's internal resource planning is an ongoing and iterative process. It expects to present a refined action plan for meeting the remainder of its needs in the planning horizon in its next Integrated Resource Plan.

| Near Term Capacity Surplus/Deficit | | |
|---|---|---|
| **Year** | **Without Project** | **With Project** |
| 2005 | 63 | 63 |
| 2006 | 26.9 | 26.9 |
| 2007 | -135.6 | 44.4 |
| 2008 | -247.1 | -67.1 |
| 2009 | -355.8 | -175.8 |

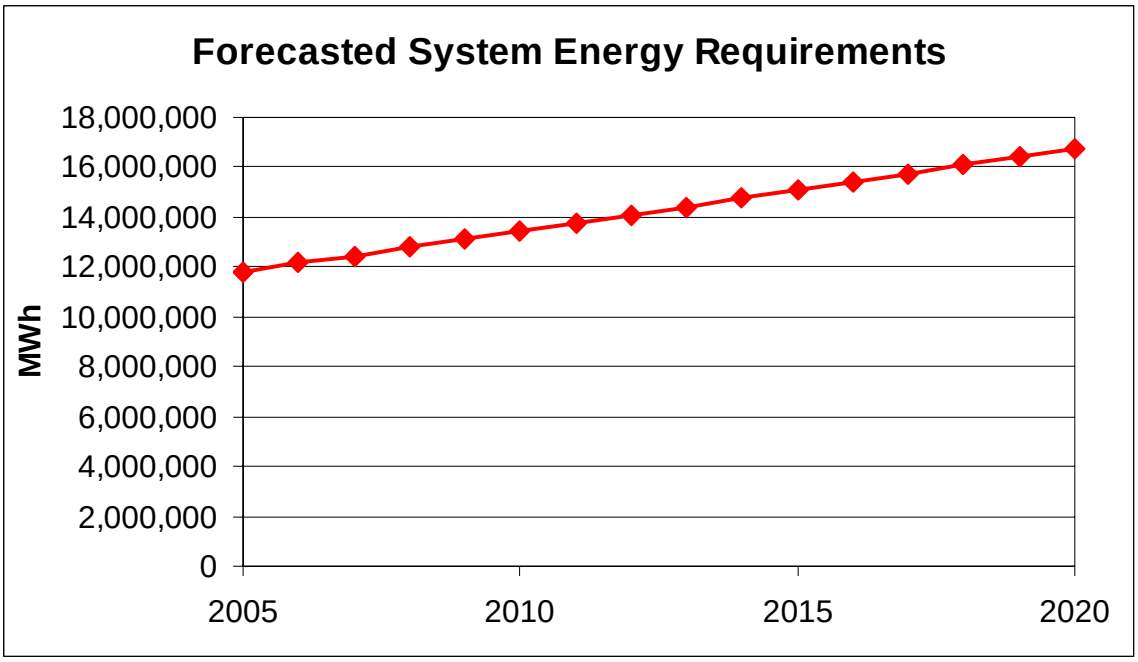
## 2.2 GRE's Energy Needs

GRE utilizes all of its available resources (owned and purchased) in meeting the energy needs of its member cooperatives and non-member contractual obligations. Energy is dispatched in a manner that minimizes cost to its members by factoring in operating and maintenance costs and contractual obligations.

### 2.2.1 GRE's Energy Forecast

GRE's energy forecast is depicted in Figure 2-3. Over the 15-year forecast period shown from 2005 – 2020, GRE's energy needs are projected to grow at an average annual rate of 2.4 percent.

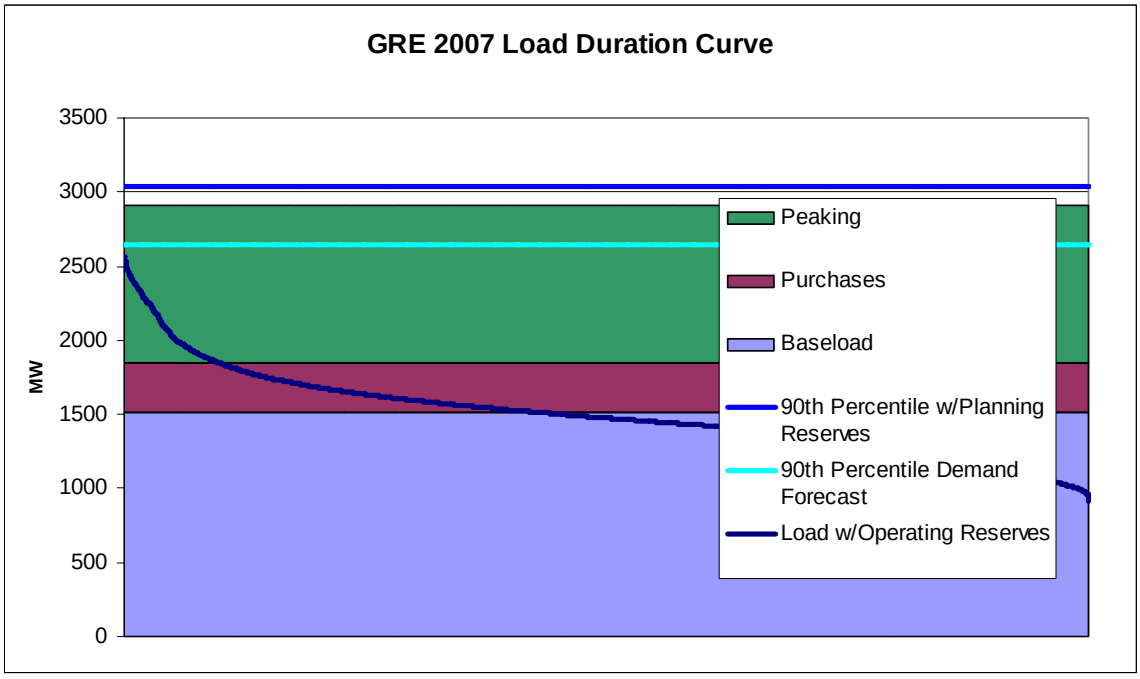
**Figure 2-3 - GRE's Forecast for Energy Growth.**



### 2.2.2 Load Duration Curve

A load duration curve can be used to illustrate how resources are used in serving load. The capacity of the resources available to serve load is stacked under a curve created by sorting the hourly loads from largest to smallest. (Actual dispatch of the units is complicated by operational considerations including minimum loading on units, market energy transactions, scheduled/unscheduled maintenance, operating reserves, transmission system support needs, and daily load swings.) The area under the curve reflects the capacity for the time period covered by the curve. Very simplistically, the resource stacks depict the theoretical resource utilized to meet the load. In reality, dispatch to meet load is much more complicated.

**Figure 2-4 - GRE's Load Duration Curve**




Even though the load duration curve vastly simplifies the complexities associated with resource planning, it provides a useful visual illustration of the nature of GRE's current needs. As can be seen on the graph, the capacity needs are for a very few hours and are largely necessary to cover GRE's reserve requirements at its highest peak loads. Further, this graph suggests that all of GRE's peaking units would run at appropriate capacity factors, approximately ten percent or less[1]. However, GRE expects that all of its peaking plants will operate at even lower capacity factors than this figure would suggest. As already explained, GRE supplements its resources with economic energy purchases from the market.

[1] Generally, peaking plants are projected to run at capacity factors less than ten percent. However, some of GRE's existing peaking facilities at Lakefield Junction have demonstrated the ability to run at capacity factors in the 20 percent range some of the time.

## 2.3 Peaking Resources Best Match Need

GRE's forecasted demand is growing faster than its energy needs, respectively 3.2 percent and 2.4 percent annually. Based on modeling underway for its next forecast, GRE believes its load factor will continue to decline slightly. Thus, GRE's capacity deficit is projected to occur over very few hours. Since the capacity need is much greater than the energy need, a peaking plant is the best match to meet these needs.

This conclusion is consistent with GRE's past analysis. GRE's 2003 Integrated Resource Plan (IRP) presented modeling results that showed building either an intermediate type combined-cycle combustion turbine or a peaking type simple-cycle combustion turbine to be an optimal plan based on very similar Present Value Revenue Requirements (PVRR) for the two plans. In its subsequent IRP update, GRE announced it had entered into a new contract that largely met its intermediate needs. This intermediate purchase appeared to shift GRE's immediate needs more clearly toward peaking, and the analysis completed herein for the proposed project confirms that peaking is the true need.

Recent market conditions have further emphasized the need for peaking power. As has previously been explained, GRE often makes short-term purchases when market energy prices make it advantageous to do so. In many instances, GRE has seen market energy delivered for several hours, only to have its energy schedules cut at the highest peak times due to transmission constraints on the grid. GRE then covers its load by running its existing peaking plants. While the new MISO market may assist in delivering this type of energy, the transmission constraints will be reflected in the price rather than through cut schedules. Thus, GRE is not confident that MISO will significantly improve access to economic energy at the highest peak times. GRE's experience has been that the market is much more reliable at providing energy that fulfills GRE's intermediate needs.

Finally, GRE learned many lessons in 2003 when it pursued the development of a combined-cycle plant. Changing natural gas prices impacted the cost effectiveness of combined cycle. At the higher prices, GRE found that a combined-cycle plant is the preferred alternative only in a very narrow range of expected capacity factors. In the current circumstance where a very low capacity factor is expected to be needed to meet GRE's immediate needs, a combined-cycle plant (or any other intermediate resource) is not an appropriate choice.

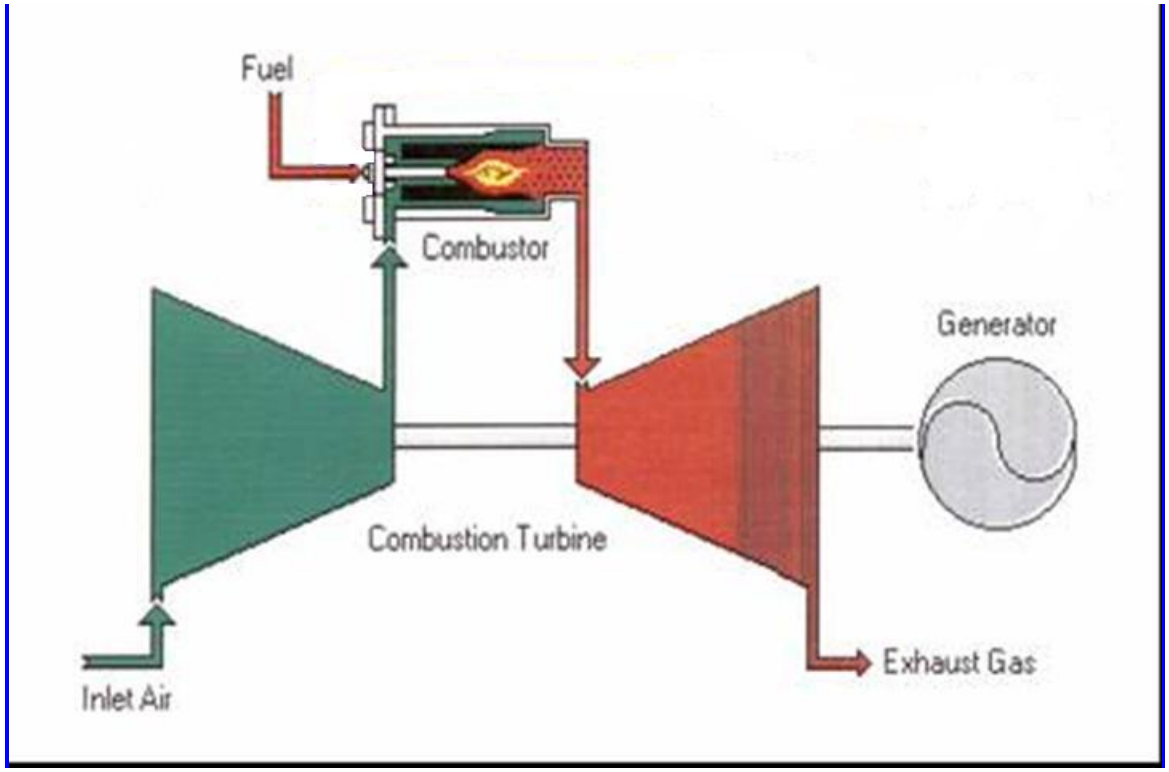
## 2.4 Summary of GRE's Current Energy and Capacity Needs

Clearly GRE is experiencing significant growth in the time horizon presented in this document and will need to make significant investments in new generating resources. This need is despite GRE's best efforts to maximize potential solutions within its system, such as pursuing DSM solutions, upgrades to existing generating facilities and prudent use of the energy markets. While GRE has a need for additional energy, its immediate needs are dominated by capacity rather than energy, which are best met by peaking power.

## 3 Project Description

GRE is proposing to add one simple-cycle combustion turbine (SCCT) generator to its existing Cambridge Peaking Plant near Cambridge, Minnesota. The project is expected to have a summer capability of approximately 170 MW and is expected to be operated primarily during periods when GRE's member demand is the highest. Figure 3-1 depicts the typical SCCT schematic.

**Figure 3-1 - Typical SCCT Schematic**




### 3.1 Project Location

The project will be built at GRE's current Cambridge Peaking Plant site, which is located at 2438 349th Avenue NE, Cambridge, Minnesota. The site is approximately forty miles north of Minneapolis and the specific location of the project will be in the northeast quarter of Section 21, Township 36N, Range 23W in Isanti County. Figure 3-2 depicts the site location.

The site consists of two parcels, one of approximately eleven acres located on the south side of 349th Avenue. The second parcel is approximately two acres directly across 349th Avenue. The site is 1/4 miles east of Minnesota Highway 65. The land immediately surrounding the site is used for agriculture. Figure 3-3 shows the layout of the two parcels with the proposed SCCT.

**Figure 3-2 - Site Location**

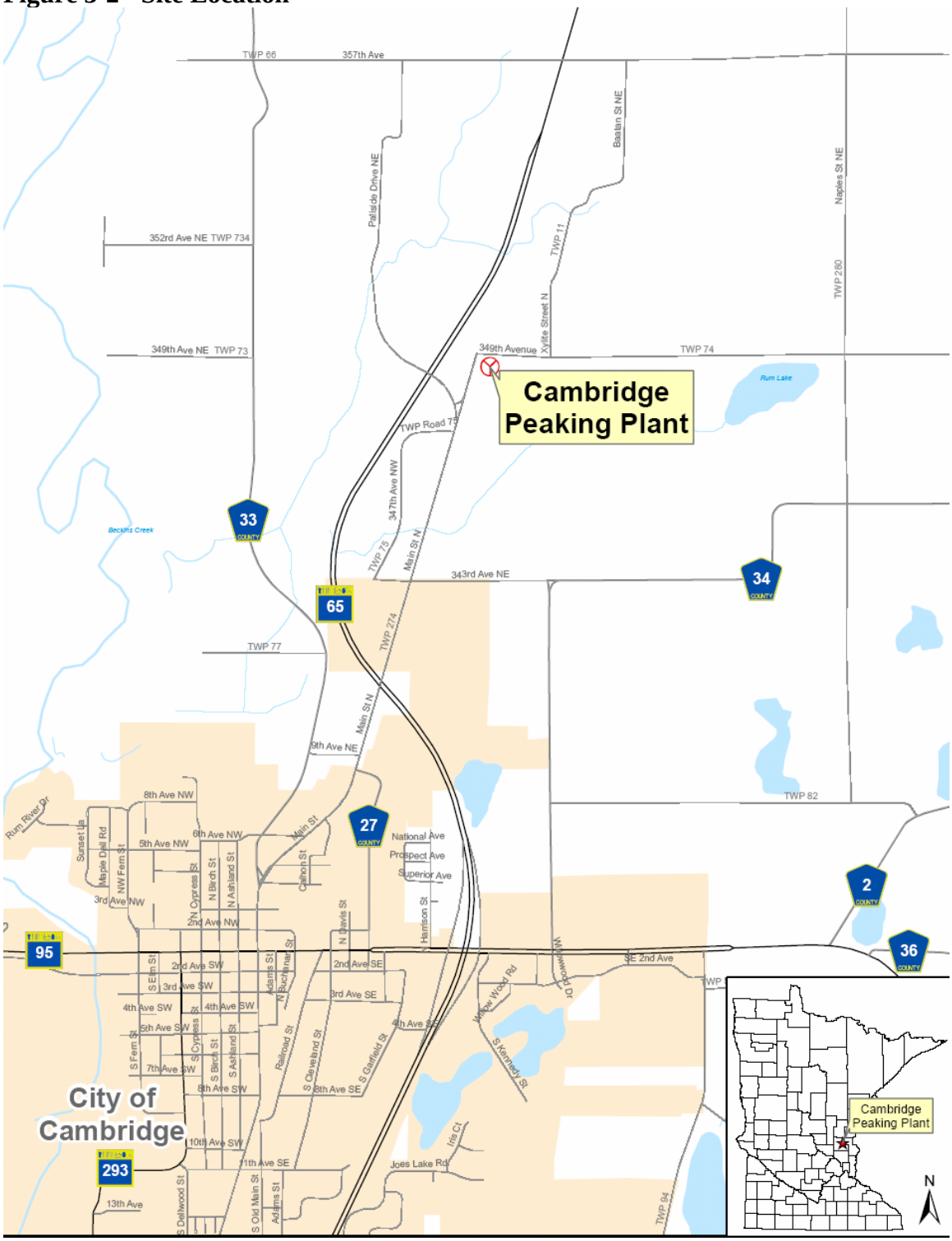
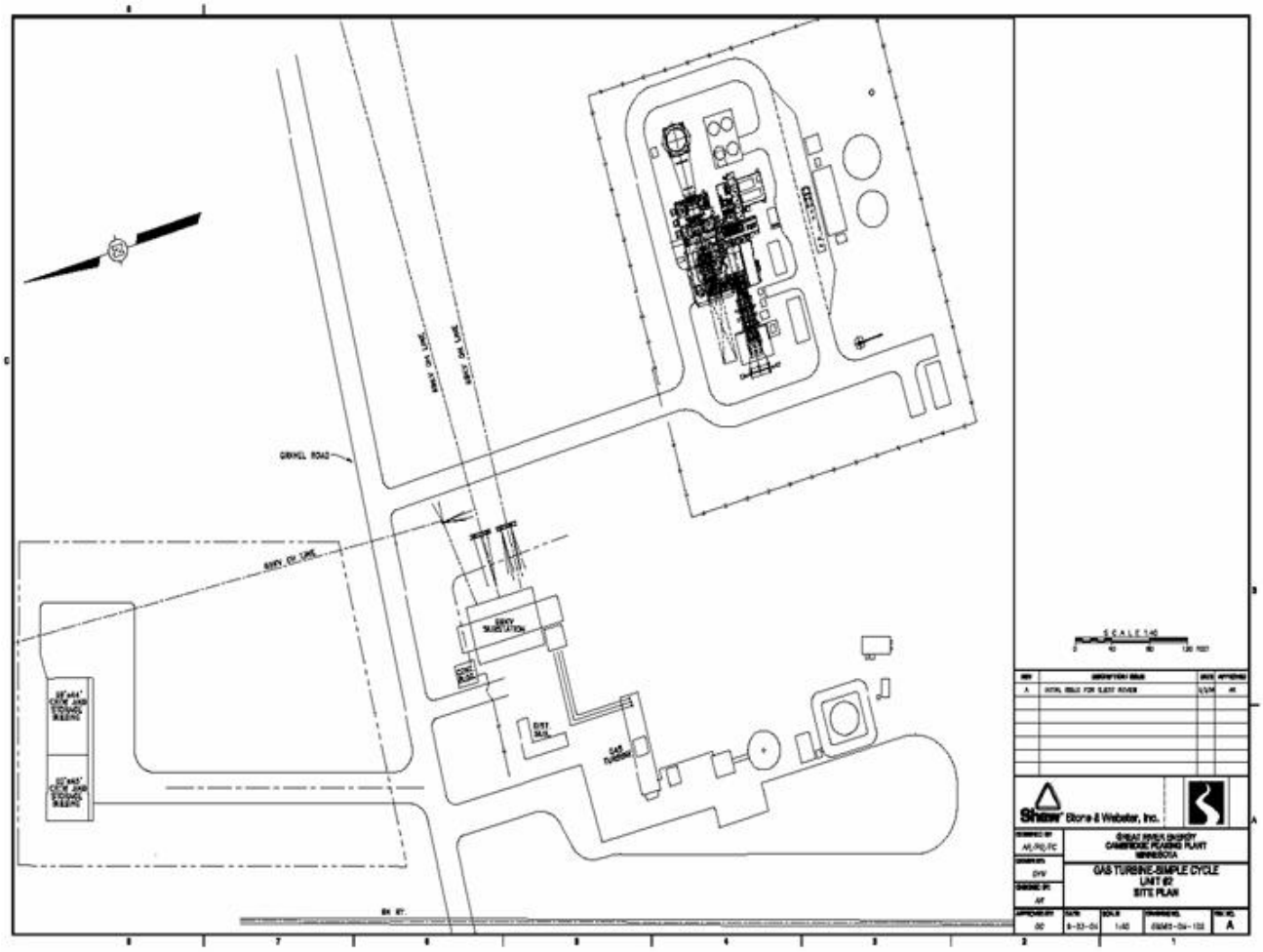


**Figure 3-3 - Site Layout**



### 3.2 Combustion Turbine/Generator

The combustion turbine (CT) for the project will be "F" class technology, which will result in the facility being one of the most efficient simple-cycle generation sources in the region. The project will have a peak output of approximately 170 MW during Mid-Continent Area Power Pool (MAPP) summertime conditions. The project will utilize dry low NOx combustion technology to minimize emissions. The project is proposed to utilize a single fuel – natural gas – for electricity production.

### 3.3 Generator Step-Up Transformers

One generator step-up transformer (GSU) will be used to increase the voltage, supplied by the project at a lower voltage (13.8 -16 kV), up to the substation voltage of 69 kV. Details of the interconnection will be finalized once the interconnection studies have been completed and a final interconnection recommendation is provided by the Midwest Independent System Operator (MISO).

### 3.4 Water Storage

Two water storage tanks will be provided on site. One 300,000-gallon tank will be used to store raw water, and one 200,000-gallon tank will store demineralized water. Demineralized water will be used for operation of the evaporative cooler during the summer months and potentially wet compression power augmentation. Raw water will be used as make-up for the demineralizers, for fire suppression, and other ancillary plant uses.

### 3.5 Substation

The existing substation adjacent to the project site will be modified to interconnect and integrate the plant with the transmission grid. The final design of the substation modifications will be determined by system impact studies currently underway at the MISO. Interconnection voltage will be at 69 kV.

### 3.6 Natural Gas – Primary Fuel

The project will utilize a single fuel – natural gas - delivered via Northern Natural Gas Company's (NNG) interstate pipeline. A 0.5 mile, 10-inch lateral natural gas pipeline will be constructed off of Northern Natural Gas Pipeline's 16-inch trunk-line. A town border station will be constructed on GRE's site.

GRE anticipates purchasing Interruptible Transport (IT) Service from NNG. If significant winter operation is anticipated, GRE may pursue purchasing firm transport capability on the secondary market. In addition, GRE will take advantage of some of NNG's tarriffed balancing services to optimize operation of the project and ensure an adequate supply of natural gas for variable operations. GRE has experience in purchasing/scheduling natural gas at the mid-continent cash hubs. GRE will leverage its

experience in the natural gas market with its conservative approach to price risk management in order to optimize operations and ensure an adequate fuel supply while providing rate certainty for its member cooperatives.

## 3.7 Plant Details & Operation

### 3.7.1 Overview

The project will operate as a peaking facility to provide electric energy during times of GRE's peak demand. GRE currently fulfills its peaking needs primarily through the operation of its Pleasant Valley Station and Lakefield Junction Station. Pleasant Valley and Lakefield Junction are dual-fuel peaking plants that became commercially operational in May of 2001. It is anticipated that the project will have an annual capacity factor of approximately five to ten percent. The plant is expected to have a short start-up sequence for an "F Class" machine at 8 minutes, and the ramp rate is expected to be 12 MW/minute. Table 3-1 provides *pro forma* details of the project's operational characteristics.

### 3.7.2 Plant Efficiency

The project will be designed to be one of the most efficient SCCTs in the region with a full load heat rate (higher heating value) of 9,730 Btu/kWh at site-specific conditions. The heat rate equates to an efficiency of 37%. Heat rejected through the exhaust stacks is expected to be 1,013 MMBtu/hr at full load during the summer months.

## Table 3-1 - Project Operational Characteristics

| Characteristic | Data |
|---|---|
| **Facility Description** | |
| Unit Type | F-Class |
| Prime Mover | Combustion Turbine |
| Number of Units | 1 |
| Summer Capability (site specific)[1] | 170 MW |
| Winter Capability (site specific) | 190 MW |
| Operating Cycle | Simple-cycle |
| Expected Annual Capacity Factor | 9.6% |
| Expected Heat Rate/Efficiency (Summer site specific)[2] | 10,200 Btu/kWh (HHV)/35% |
| Expected Heat Rate/Efficiency (Winter site specific)[2] | 9,730 Btu/kWh (HHV)/37% |
| Heat Rejected through exhaust (Summer) | 1013 MMBtu/hr |
| Heat Rejected through exhaust (Winter) | 1188 MMBtu/hr |
| **Fuel Description** | |
| Fuel Source: Natural Gas only | Northern Natural Gas Pipeline |
| Fuel Requirement: Natural Gas only (Summer)[2] | 1,546 MCf/hr |
| Fuel Requirement: Natural Gas only (Winter)[2] | 1,771 MCf/hr |
| Expected Annual Fuel Requirement | 1,305,360 MCf |
| Heat Input (Summer - HHV)[2] | 1554 MMBtu/hr |
| Heat Input (Winter - HHV)[2] | 1780 MMBtu/hr |
| Fuel Heat Content: Natural Gas | 1.005 MMBtu/MCf |
| Fuel Sulfur Content: Natural Gas | 5.5 $mg/m^3$ |
| Fuel Ash Content: Natural Gas | None |
| Fuel Moisture Content: Natural Gas | <80 $mg/m^3$ |
| **Water Use** | |
| Estimated maximum groundwater pumping rate[3] | 108 gpm |
| Estimated maximum surface water appropriation[3] | 0 $ft^3$/sec |
| Estimated annual groundwater appropriation[4] | 3. million gal/yr |
| Annual consumption[4] | 9.2 acre-feet |
| **Emissions[5]** | |
| Maximum Sulfur Dioxide Emissions[2] | 5.7 lb/hr |
| Maximum Nitrogen Oxides Emissions[2] | 169 lb/hr |
| Maximum Particulates Emissions[2] | 15 lb/hr |
| 1,3-Butadiene | 0.00072 lb/hr |
| Acetaldehyde | 0.067 lb/hr |
| Acrolein | 0.011 lb/hr |
| Benzene | 0.020 lb/hr |
| Ethyl benzene | 0.053 lb/hr |
| Formaldehyde | 1.2 lb/hr |
| Naphthalene | 0.0022 lb/hr |
| PAH | 0.0037 lb/hr |
| Propylene oxide | 0.048 lb/hr |
| Toluene | 0.22 lb/hr |
| Xylenes | 0.11 lb/hr |

1 With evaporative cooler in service.

2 Under base load operations.

3 When unit is on-line.

4 Assuming a 9.6% annual capacity factor and utilization of evapoartive cooler for 5.7% of annual operation.

5 More emissions information can be found in Table 3-2.

## 3.8 Maintenance

GRE has extensive experience operating and maintaining (O&M) CTs including General Electric (GE) Frame 5, Pratt & Whitney FT4, GE 7EA, Siemens V84.3A2, and Westinghouse 501D5A. GRE maintains those units using a combination of GRE staff and unit vendor staff through Long-Term Service Agreements. GRE is committed to providing its operations and maintenance staff with the very best in continuing education and training to ensure a high level of reliability and availability of its generation assets. GRE will continue to utilize its O&M model for the project by utilizing the human intelligence it has gained from O&M on its existing facilities to train and cross-train the project operators. An existing warehouse will be utilized to house the critical parts and tools needed for maintenance and reliable operations. GRE will maintain the project according to prudent utility practice with the intent to provide excellent reliability and availability.

## 3.9 Site Selection

GRE considered numerous sites before identifying the preferred site. Several factors were considered when evaluating sites including access to an existing electric transmission system, access to existing high pressure natural gas pipelines, cost of developing new infrastructure versus developing a site with legacy infrastructure, land use constraints, water availability and disposal, local government support, ambient air quality classification, and other environmental constraints.

The site selected met all the siting factors considered with the lowest overall costs and environmental impacts. Details of the site selection analysis are presented in Section 5.

## 3.10 Security & Plant Access

Access to the project and substation will be restricted through the use of perimeter fences and monitored access gates. On-site security cameras will be installed to assist in monitoring the site.

### 3.10.1 Road Access

The site is near Minnesota Highway 65. Access to the site from the highway will be via County Road 30. The primary plant entrance will be located off of 349$^{th}$ Ave. NE on the north side of the site.

### 3.10.2 Rail Access

A rail line exists adjacent to the selected site. The nearest siding is located in Cambridge - approximately two miles southwest of the selected site. This siding will be used for the delivery of major equipment during construction.

### 3.10.3 Security Measures

The project site will be surrounded by an 8-foot high, chain-link fence. Access into the project will be controlled by an automatic gate with the option for manual operations from the project's Control Room. The project site will be monitored through closed circuit television linked to the project's Control Room and GRE's 24-hour System Operations Center in Elk River, Minnesota. GRE will work with the local law enforcement agencies to ensure the highest level of security.

## 3.11 Transmission Interconnection and Service

The existing 69-kV substation will be modified to accommodate the electrical output from the project generator. The substation bus feeds four 69-kV lines as well as the local distribution substation located at the site. Preliminary results from the MISO transmission studies indicate that sections of the three 69-kV lines will need to be upgraded either through reconductoring or rebuilding at the 69-kV voltage. As of this writing the MISO engineering studies have not been finalized.

The final results of the MISO studies are expected in the first half of 2005**.**

## 3.12 Fire Protection and Safety

The project design will include a 300,000-gallon raw water storage tank, with approximately 200,000 gallons of that reserved for fire protection needs. The design of the project will include a pressurized hydrant loop around the facility. The design of all buildings and enclosures will meet State Fire Marshall, as well as insurance, and local fire codes.

A $CO_2$ fire suppression system will be installed inside the turbine enclosure, and fire detection equipment and alarms will be included in the control system.

Safety procedures, as mandated by OSHA, will be followed during the construction and operations of the facility.

## 3.13 Air Emissions

### 3.13.1 Emissions from Operation

The project will be fueled by natural gas, one of the cleanest fuels for producing electricity, which will result in substantially lower emissions than would occur with other fuels such as oil. Table 3-2 summarizes the expected emission from a new F-Class combustion turbine on a typical summer day. Emissions of nitrogen oxides (NOx) will be minimized by the use of dry low NOx combustion technology. GRE's Pleasant Valley Station operates Siemens-Westinghouse V84 CTs, which are F-Class machines. The rates shown in Table 3-2 are manufacturer's data for a V84. While GRE expects the unit to operate below these rates, the manufacturer's information is not guaranteed at this time

and would not apply if equipment from a different manufacturer were to be procured. Nevertheless, the data is representatively conservative.

An air emission source permit will need to be obtained from the Minnesota Pollution Control Agency (MPCA) prior to starting construction of the project and to authorize operation of the project. Because GRE plans to operate the project as a peaking unit, GRE intends to cap annual air emissions from the project such that it could not be continuously operated at its rated capacity.

Impacts to the ambient air quality are expected to negligible given the low emission rates, the expected operating capacity of the project, and the exhaust gas characteristics. Estimates of actual impacts will be generated through computer-based dispersion modeling of the worst-case emissions scenario for the project as part of the MEQB site permitting process. At this time, modeling has not been completed.

**Table 3-2 - Air Emission Estimates[1]**

| Emission Type | Estimated Emission Rate (lb/hr) | Emissions at 840[2] hours of operation (tons) |
|---|---|---|
| Nitrogen Oxides | 169 | 71 |
| Carbon Monoxide | 37 | 16 |
| Volatile Organic Compounds | 9.4 | 3.9 |
| Particulate Matter | 15 | 6.1 |
| Sulfur Dioxide | 5.7 | 2.4 |
| Formaldehyde | 1.2 | 0.5 |
| Toluene | 0.22 | 0.05 |
| Xylene | 0.0.11 | 0.1 |
| Acetaldehyde | 0.07 | 0.03 |
| Ethyl Benzene | 0.05 | 0.02 |
| Propylene Oxide | 0.05 | 0.02 |
| Benzene | 0.02 | 0.008 |
| Acrolein | 0.01 | 0.004 |
| Poly Aromatic Hydrocarbons | 0.004 | 0.002 |
| Naphthalene | 0.002 | 0.0009 |
| 1,3-Butadiene | 0.0007 | 0.0003 |

1. Manufacturer's information for a Siemens-Westinghouse V84 fueled with natural gas at baseload conditions, 90ºF, 60% relative humidity, and evaporative coolers on. Actual emissions would be higher on a cold, winter day; however, the project is being installed primarily as a summer peaker and therefore summer operating data is shown.
2. 840 hours of baseload operation is roughly equivalent to a 9.6% capacity factor.

### 3.13.2 Fugitive Dust

Operation of the project will not result in additional fugitive dust emissions from the site. Fugitive dust emissions could be generated during the site preparation and construction activities, and any such emissions will be minimized by the application of water or dust suppressants.

## 3.14 Wastewater Handling and Disposal

### 3.14.1 Operations Wastewater

The project will not require large volumes of water for operation. The only source of operations wastewater will be the evaporative cooler. When the evaporative cooler is in operation, approximately 15-75 gpm of blow down will be generated. The actual blow down rate will be determined based on water quality data for the site, which has not yet been obtained.

Some of the wastewater (compressor wash water) will be generated during maintenance on the CT. This process wastewater will be stored in an on-site tank. The process wastewater will be off-loaded into tanker trucks and hauled to a municipal wastewater treatment plant for ultimate treatment and disposal.

Some of the wastewater from the site (except for the compressor wash water and sanitary wastewater) will be processed through an oil/water separator and then pumped to an onsite retention pond. GRE plans to seek a wastewater permit from the MPCA that will allow it to discharge the retention pond to an adjacent ditch that would likely flow into Beckins Creek, which discharges to the Rum River.

## 3.15 Storm Water Handling and Disposal

The project will include numerous catch basins for oil-containing equipment. The catch-basins are often exposed to ambient weather conditions and capture storm water run-off. The drains from the catch basins will discharge to the oil/water separator. The water from the oil/water separator will be pumped to the on-site retention pond where it will mix with the evaporative cooler blow down water. GRE plans to obtain a NPDES wastewater discharge permit from the MPCA that will allow us to discharge the retention pond to an adjacent ditch.

### 3.15.1 Handling during Construction

A construction storm water permit will be obtained prior to any site grading. Storm water will be managed in accordance with the permit.

### 3.16 Oil Waste Handling and Disposal

The only waste oil generated by the project will be from periodic changes in lubricating oils. These oils will be collected and handled for disposal in accordance with state regulations.

### 3.17 Solid Waste Handling and Disposal

There will be minimal amount of solid wasted generated by the operation of the project. Typical wastes will include used shop rags, which will be handled and disposed of off site in accordance with state regulations.

Solid waste generated during the construction of the project will include packaging and freight materials, paints, solvents, and adhesives. All wastes will be managed in accordance with state regulations and disposed of off site.

### 3.18 Primary Water Use

Water will be provided by on-site wells. Raw water will be pumped from the wells into the service water tank, which will supply raw water to the evaporative cooler and also to the demineralizer skid. The demineralized water will be used primarily for evaporative cooling and potentially wet compression power augmentation. The instantaneous maximum use rate for the raw water source is expected to be 108 gallons per minute (gpm).

Well water will also be used to supply other plant water needs such as fire suppression and other ancillary plant water uses. The instantaneous maximum use rate for these services is expected to be 50 gpm.

Drinking water will be provided by bottled water.

### 3.19 Noise Impacts

Noise from operation of the new CT will comply with the state noise standards. The new combustion turbine is expected to be quieter than the existing oil-fired combustion turbine at Cambridge Station. If both turbines are operating simultaneously, the noise level at the nearest residence is estimated to increase by less than three decibels (A scale-weighted (dBA). According to the Minnesota Pollution Control Agency's document, *A Guide to Noise Control in Minnesota*[3], plus or minus three decibels is the "threshold of perception" for the human ear while plus or minus five decibels is "clearly noticeable." [pg. 9]. Thus, noise from the new CT is not expected to be noticeable at the nearest residences. Currently, noise sources in the area surrounding the site are primarily associated with traffic flow on Highway 65 and local county roads, rail traffic on the Burlington Northern Santa Fe (BNSF) rail line adjacent to the site and operation of GRE's existing peaking plant.

[3] [http://www.pca.state.mn.us/programs/pubs/noise.pdf]

Construction noise will be mitigated by requiring the construction contractor to use properly muffled equipment, by routing truck traffic to the greatest extent possible away from area residents and by restricting night-time activities.

## 3.20 Traffic

### 3.20.1 Construction Traffic

Traffic on County Road 30 and on 349th Avenue NE will increase during construction. The amount of traffic is not expected to exceed the level that can be safely accommodated. Discussions will be held with Township and County officials and local residents to minimize the local impact of the construction traffic. Approximately 100 construction workers are expected to be on site during peak construction activities.

### 3.20.2 Operations Traffic

During operation, the additional traffic due to the project will be minimal. The project is expected to have a full time staff of approximately 2 people, spread over one to two shifts of operation.

## 3.21 Economic Considerations

The project costs are summarized in Table 3-3. The information contained therein is based on GRE's on-going operating experience at Pleasant Valley Station (PVS), manufacturers' estimates and publicly available information. A comparison of the project with potential alternatives is provided in Section 4.

**Table 3-3 - Project Cost Analysis**

| Item | Units | Project Data | Assumptions |
|---|---|---|---|
| **Project Description** | | | |
| Base Capability (Summer, site-specific rating) | MW | 170 | Manufacturer *pro forma* estimate |
| Cost Basis | Cal Yr | 2004 | |
| Life of Project | Years | 30 | Typical accounting life |
| Operating Cycle | | Simple | |
| Annual Capacity Factor | % | 9.6% | PVS experience |
| Annual Operating Time | Hours | 840 | Formula |
| Average Annual Availability | % | 97.5 | PVS ops experience |
| Fuel Type | | Nat Gas | |
| Heat Input (HHV) | MMBtu/hr | 1,554 | PVS ops experience |
| Heat Rate (HHV) - Summer Rating | Btu/kWh | 10,200 | PVS ops experience |
| Efficiency (HHV) - Summer Rating | % | 35 | Formula |
| Project Capital Cost | $/kW | 406 | Overnight cost w/o IDC |
| Fixed O&M Costs | $/kW-yr | 3.46 | PVS experience |
| Fuel Costs | $/MMBtu | 5.73 | EIA *2005 AEO* plus transport & balancing |
| Non-Fuel Variable O&M Costs | $/MWh | 8.41 | Includes fired-hour costs & start charge |
| **Capacity Costs (Fixed)** | | | |
| Total Project Capital Cost | $ | 69,020,000 | Formula |
| Annual Fixed O&M | $ | 588,200 | Formula |
| Total Annual Fixed Costs | $ | 6,523,920 | 8.6% annual FCs + Fixed O&M |
| Project Capacity Cost | $/kW-yr | 38.38 | Formula |
| Project Capacity Cost | $/kWh | 0.046 | Formula |
| **Production Costs (Variable)** | | | |
| Net Annual Generation | MWh | 142,800 | Formula |
| Annual Fuel Consumption | MMBtu | 1,305,360 | Formula |
| Annual Fuel Cost | $ | 7,483,015 | Formula |
| Annual Non-Fuel Variable O&M Cost | $ | 1,200,948 | Formula |
| Total Project Variable Generation Cost | $ | 8,683,963 | Formula |
| Project Fuel Cost | $/kWh | 0.052 | Formula |
| Project Total Energy Cost | $/kWh | 0.061 | Formula |
| **Total Cost** | **$/kWh** | **0.106** | **Formula** |

## 3.22 Use of Space

The project will be located on land that is currently used for utility operations. Adjacent property is used for agricultural and transportation purposes.

The project boundaries will utilize the parcel south of 349th Avenue NE for the CT, substation, water tanks and other balance of plant equipment. The parcel north of 349th Avenue NE will be utilized for shop space and parts storage.

## 3.23 Required Permits and Approvals

Table 3-4 lists permits and approvals that may be required to construct and operate the project.

**Table 3-4 - Potential Approvals Required for Construction and Operation**

| Approval Type | Authority | Comments |
|---|---|---|
| Certificate of Need | Minnesota Public Utilities Commission | Required for construction of the power plant. |
| Environmental review and assessment:<br>1. RUS Finding of No Significant Impacts (FONSI) for the plant site and transmission line.<br><br>2. MEQB Site Permit for the plant site. | Rural Utilities Service - Environmental Assessment with Scoping<br><br>Minnesota Environmental Quality Board - Site Permit | Requirements of these two reviews are fairly similar. There are some procedural differences, but GRE will attempt to complete the reviews jointly and concurrently. Minn. Rules exempt the transmission lines from review, but RUS rules will require certain lines to be included. |
| Permanent Exemption for New Facilities | Department of Energy | Allows the use of natural gas for power production. |
| Sales Tap Approval | Federal Energy Regulatory Commission | Approval to tap into the existing interstate gas pipeline. This will be obtained by the pipeline company. |
| Part 70 Air Emissions Source Construction and Operating Permit | Minnesota Pollution Control Agency | This permit cannot be issued until after issuance of the MEQB Site Permit. The permit must be issued before starting construction. |
| Storm Water Construction Permit | Minnesota Pollution Control Agency | A general permit is available for most construction projects. |
| National Pollutant Discharge Elimination System (NPDES) Permit | Minnesota Pollution Control Agency | This permit would authorize the discharge of the evaporative cooling water and site storm water runoff after plant construction. |
| Groundwater Appropriation Permit | Minnesota Department of Natural Resources | Notification of well drilling and appropriation of surface or groundwater water. |
| Spill Prevention Control and Countermeasure (SPCC) Plan | Minnesota Pollution Control Agency | GRE must update the existing SPCC Plan within six months of bringing additional oil storage capacity on site. |
| Electrical Inspection | Board of Electricity | Permit and inspection of building electrical systems. |
| Public Water Supply Plan Review | Minnesota Department of Health | Potable water supply. |
| Local Building & Construction Permits | Isanti County Cambridge Township | |

# 4 Alternatives to the Proposed Project

## 4.1 Alternatives Review

GRE considered the following characteristics when reviewing the possible alternatives to the proposed project:

- Suitability for operating at less than 20 percent capacity factor.
- Ability to procure and install the alternative in the time frame required to meet GRE's need (summer 2007).
- Reliability of the technology.
- Timeliness when called upon to operate.
- Energy efficiency (heat rate).
- Cost effectiveness.
- Environmental impacts.
- Ability to limit the risk to GRE from financial, social and technological risk to GRE and its member-owners cannot control.

### 4.1.1 Primary Objectives for Screening

Using the characteristics listed above to review every possible alternative would be a lengthy process. Therefore, GRE first screened potential alternatives to see if they met a few critical objectives, including:

- Ability to procure and install at least 170 MW of summer accredited capacity prior to the summer of 2007.
- Operating characteristics suitable to peaking operation (rapid availability, dispatchable, extremely reliable operation).
- Cost-effective when compared to the proposed project.

If an alternative met the first two of these three objectives, it was considered as a suitable alternative and analyzed further in Section 4.5.

### 4.1.2 Alternative Resources Considered

Prior to completing a more extensive analysis of alternatives, GRE examined whether renewable energy or energy conservation measures could meet the needs. After considering those alternatives, GRE analyzed the following resource types, discussed further in Section 4.4.

- Purchased power
- Upgrades to existing resources
- New transmission
- Other Fossil-Fuel Technologies, including:
    - Coal
    - Oil-fired combustion turbine
    - Combined cycle combustion turbine
- Customer-owned distributed generation

- Emerging technologies, including:
  - Micro turbines
  - Fuel cells
  - Energy storage (such as batteries, pumped storage hydro, compressed air energy storage, and super conducting magnetic energy storage)

## 4.2 Renewable Energy

As GRE continues to grow, its new generation resources will include more renewable energy sources. GRE's generation mix already includes wind energy, refuse-derived fuel and hydropower. The organization is looking at ways to further diversity its energy portfolio by exploring biomass, fuel cells and other technologies as available.

GRE considered several different types of renewable energy resources in its analysis including wind, biomass (including an ethanol-fueled peaking plant), hydro and solar. GRE's strong commitment to add renewable resource development is however unable to satisfy its current need for additional peaking power in the near term.

### 4.2.1 Wind

Wind energy is a renewable resource that has been well utilized because of its reasonable average energy cost and abundant supply in the region. GRE's wind energy is an integral part of its overall energy portfolio. GRE's wind energy serves the Wellspring Renewable Energy Program subscribers. Six megawatts for the Wellspring Wind Energy program comes from the Chandler Hills Wind Farm and six megawatts from a project in Dodge Center, Minnesota. In addition, GRE purchases six megawatts from a wind project in Jackson County, Minnesota.

GRE's commitment to wind energy is expanding with power from Minnesota's first commercial-scale, landowner-developed wind farm this fall. Trimont Area Wind Farm (TAWF), a coalition of landowners in Jackson and Martin counties, won the contract to serve GRE through a request for proposals (RFP) process initiated in 2003. Subsequent to its selection by GRE, TAWF chose PPM Energy to develop the project on its behalf. and the 100-MW wind project is expected to be online in October 2005.

Improvements have been made to increase wind turbine reliability and decrease costs over the last several years. However, the average cost of wind generation is not the most relevant measure in this analysis to meet current capacity and energy needs. It is whether the resource can meet the primary objectives of GRE's immediate capacity and energy needs, namely, adequate capacity online and accredited prior to summer 2007, and operating characteristics suitable to peaking operation.

Wind generation is not an effective resource to meet peaking needs because of its intermittent nature and the low correlation of wind output to summer peak conditions. Having a dispatchable resource is a key objective of this project. Because wind generation does not have suitable operating characteristics to meet GRE's peaking needs, it will not be considered for further evaluation.

### 4.2.2 Biomass

Biomass encompasses a wide variety of renewable fuels. Renewable fuels may be utilized via burning in a steam cycle, gasified for use in a combustion turbine or burned directly in a combustion turbine or other internal combustion device. Solid biomass fuels include wood and waste wood, switchgrass and alfalfa stems. Ethanol derived from corn is also considered a renewable fuel.

GRE has significant experience with biomass resources, which aided in its analysis of whether biomass could serve its current needs. GRE operates Elk River Station that burns refuse-derived fuel (RDF) – material produced from processing municipal waste – to produce electricity. As a waste-to-energy power plant, Elk River Station diverts about 270,000 tons of municipal solid waste from community landfills annually.

GRE continues to aggressively pursue anaerobic digester technology in dairy applications. Anaerobic digesters show a lot of potential for mitigating the environmental impacts of dairy and swine feedlots while producing renewable energy. GRE implemented a special Biomass Grant Program to encourage the development of additional renewable energy technologies using biomass resources to show their commitment. The organization awarded its first $100,000 biomass grant in 2003. Also, GRE and the Electric Power Research Institute (EPRI) are working together to install a 55-kW Stirling engine at a dairy farm near Princeton, Minnesota. The stirling engine is an external combustion engine capable of utilizing heat from a wide range of gaseous fuels including fuels with high levels of contaminants.

GRE's role serving rural cooperatives makes it well suited to continue pursuing the development of these types of biomass. However, the analysis shows that this type of development will not be adequate to meeting the needs of the currently proposed project. Having 170 MW of solid fuel biomass capacity available by 2007 is not feasible due to limited fuel availability and siting issues.

Furthermore, solid fuel power plants have operating characteristics consistent with baseload resources. For example, solid fuel plants generally operate at a higher capacity factor to allow planning and scheduling of producing and delivering the fuel to the power plant. Also, having a dedicated source of solid fuel is incompatible with a resource such as a peaking resource, which operates on an intermittent basis.

At the capacity factors expected for the project, a large biomass plant would not be a cost effective peaking alternative. This analysis is consistent with the conclusion Dr. Rakow (Lakefield, page 10) reached, citing a DOE study of six different biomass technologies. Solid fuel-based biomass is excluded from further analysis based on unavailability for summer 2007 and unsuitable operating characteristics.

### 4.2.3 Ethanol-Fueled Peaking Plant

An ethanol-fueled peaking is a logical renewable alternative to meet GRE's peaking needs. If the same equipment proposed for this project could be used for an ethanol-fired facility, the criterion of availability of 170 MW for summer 2007 could be met. However, the turbine manufacturers have no experience with firing ethanol in this equipment, and significant fuel storage and handling issues would arise with using ethanol as a primary fuel. In order to be accredited on ethanol, a 170-MW power plant would need approximately 400,000 gallons of ethanol stored on site. Other technical and economic issues are discussed further below.

Technical Issues: Combustion turbine manufacturers have shown little interest in developing a combustion turbine to burn ethanol; however, they do acknowledge that it is technically possible to do so. Naphtha, a liquid fuel similar to ethanol, is burned in combustion turbines, especially in Southeast Asia.

GRE staff interviewed three major combustion turbine manufacturers regarding the prospect of developing a combustion turbine that would burn ethanol. The manufacturers indicated that they do not foresee a sufficient market to justify the research and development effort necessary to commercially develop an ethanol-fired combustion turbine. Even if GRE were willing to underwrite the costs of the effort, two of the three manufacturers indicated that they would not be able to dedicate any use of their combustion turbine testing facilities for such a purpose for two to three years because of other research and development currently underway. Unit output levels, emissions and construction materials would all have to be investigated further.

In general, the effects of burning ethanol in a combustion turbine are expected to include:

- Higher NOx emissions requiring the use of water injection (similar to fuel oil).
- More corrosion resistant materials required for fuel handling and storage components.
- The need to inject lubricity-improving additives.
- Maintenance costs equal to or higher than with the use of No. 2 fuel oil, which are higher than with natural gas as fuel.
- Increased ventilation and hazard detection equipment.
- Slightly higher output may be possible, but the heat rate would probably also be higher (less efficient).
- A requirement that the combustion turbine start up on natural gas, then switch to ethanol, which would require an initial investment in natural gas infrastructure to deliver the start-up fuel.

Economic Issues: The most expensive consideration of burning ethanol in a combustion turbine is the cost of the ethanol itself. GRE determined that the price of ethanol is reasonably estimated to range between $1.00 and $1.35 per gallon. Table 10-1 depicts the per-gallon price of ethanol, the equivalent price per million British Thermal Units (MMBtu) of ethanol, the estimated fuel cost of electricity production per megawatt hour and the price that natural gas would have to be to result in the same fuel cost of electricity production. For instance, ethanol priced at $1.00 per gallon could produce electricity at a

cost of $136.00 per MWh. The natural gas price would have to be as high as $12.95 per MMBtu to produce electricity at that same price.

**Table 4-1 - Comparison of Fuel-Related Electricity Production Costs from a SSCT burning Ethanol vs. Natural Gas**

| Ethanol Price ($/gallon) | Ethanol Price ($/MMBtu) | Fuel Cost of Electricity Production ($/MWh) | Equivalent Natural Gas Price ($/MMBtu) |
|---|---|---|---|
| 0.50 | 5.91 | 68.00 | 6.48 |
| 1.00 | 11.81 | 136.00 | 12.95 |
| 1.20 | 14.18 | 163.00 | 15.52 |
| 1.40 | 16.54 | 190.00 | 18.10 |

For comparison purposes, an ethanol-fueled alternative is included for further analysis in Section 4.5, even though the technical feasibility of converting the combustion turbines to burn ethanol is very much in doubt.

### 4.2.4 Hydro

Hydro resources are typically baseload or intermediate in nature rather than peaking. Initial capital costs are also usually high compared with peaking resources.

Within Minnesota (and the region) the potential for new hydro facilities is limited. In his direct testimony in Docket No. IP3/CN-98-1453, (Lakefield Junction, pages 8 and 9), Dr. Steve Rakow (DPS) cited a DOE study that indicated no sites with the potential for 100 MW or more of new hydro generation within Minnesota. The study indicated three sites in South Dakota with greater than 100 MW of capacity could be developed, two of which two are controlled by the Corps of Engineers, and all significantly less than the capacity contemplated by this project. Dr. Rakow concluded that while Manitoba has substantial potential hydro resources yet to be developed, significant additional transmission would need to be built in order to bring those resources into the U.S. The cost of the added transmission ($180 million) makes further development of Canadian hydropower uneconomic compared with this project. Conditions have not changed substantially although discussions are taking place to remedy some of these obstacles.

Hydropower cannot be developed by 2007, and it cannot meet the project's objectives for peaking plant operating characteristics. Therefore, hydro is not a reasonable alternative and will not be evaluated further.

### 4.2.5 Solar

Solar power is another intermittent resource similar to wind, except that there is less experience with solar generation in this region. As with wind, solar receives a relatively low ratio of accredited capacity to nameplate rating under the MAPP capacity

accreditation process, requiring greater amounts of solar capacity to meet the project's objectives. The necessary amount of solar generating capacity could not be online by summer 2007. It also does not have appropriate operating characteristics. Therefore, solar fails to meet the primary objectives and will not be considered for further evaluation.

## 4.3 Energy Conservation Improvements

Through the use of load management and conservation measures, GRE reduced its summer peak demand in 2004 by 300 MW. This was achieved primarily through load management programs such as residential cycled air conditioners, interruptible irrigation, peak shave water heaters, and customer-owned generation. GRE expects to see continued, significant growth in these programs. In 2005, the impact of demand-side management programs on summer peak reduction is expected to increase by another 20 MW. It is likely that the success of these programs has delayed the need for additional peaking power; however, it is infeasible that an additional increase in the participation of these programs could entirely replace the 170 MW need for the current project.

GRE has a strong commitment to conservation as well as load management. In the past, the focus has been more directed to load management, as those programs best complemented the profile of the GRE's resources. In more recent years, GRE has increased its emphasis on conservation. GRE exceeds the legislative mandate of spending on demand-side management (DSM) programs, and it invests significant efforts into evaluating the programs to ensure its focus is on the programs where energy savings could have the greatest impact for GRE and its members. To enhance these evaluations, in 2003 GRE retained Global Energy Partners, an EPRI affiliated company, to conduct an assessment of the organization's DSM effort and to assist in the development of new, cost-effective load management and conservation programs. The assessment found GRE's overall program to be quite comprehensive and also provided a useful estimate of the overall potential for energy and capacity savings from various DSM programs.

Because of GRE's currently identified need for peaking power, GRE has put additional attention specifically on programs designed to reduce summer peak demand. GRE's load is dominated by residential customers; thus, the primary driver behind summer peaks is air conditioning load. The best programs to address this need through conservation and demand-side changes are rebates for high efficient air conditioners and cycled air conditioning. Consequently, GRE has increased its emphasis on these programs. For example, GRE increased its contribution for rebates for residential high-efficiency central air conditioners from $250 to $300. GRE has also increased the rebate to its member cooperatives from $50 to $65 for each new resident participating in the cycled air conditioning program. The increased emphasis on air conditioning programs has also been adopted by GRE's member cooperatives. For example, one of GRE's largest member cooperatives recently began offering the cycled air conditioning program to its consumers.

In addition, GRE has increased other programs that are shown to be very cost effective and address the types of energy usage most prevalent in the GRE service territory. In

2003, GRE began offering ENERGY STAR Residential Appliance Rebates for clothes washers, dishwashers, and refrigerators. Also, GRE and its member cooperatives award approximately $1 million each year in grants to its commercial and industrial customers for energy efficiency projects. GRE offers a variety of load management and conservation programs and continues to evaluate the impact of additional programs to conserve energy and reduce load. These programs will continue to evolve and shift as the organization's energy needs change.

Despite GRE's increased commitment to conservation, it is not a practical alternative to the proposed project. First, changes to demand behavior require time to develop. It is unreasonable to think that an additional 170 MW savings during peak usage could be achieved by 2007. Such a change would represent over a 50-percent increase above current programs and participation. Further, successful programs will see diminished increases as the market for participation becomes saturated. Consumer behavior and preferences limit the potential participation in many conservation programs, especially those requiring cut backs at the time of greatest demand. GRE already sees a high percentage of its customers with air conditioners participating in the cycled air program and expects participation numbers to level out. However, GRE's commitment to conservation will not diminish and it will continue to examine its changing energy needs and the potential role of conservation in managing its needs. GRE will always work to design conservation and other demand-side management programs with the goal of maximizing benefits to its members both in terms of overall energy savings and the potential avoided costs of new generation.

## 4.4 Description of Alternatives

### 4.4.1 Purchased Power

GRE issued a request for proposals (RFP) for a variety of resources in March 2004. Thirty-one proposals from 17 entities were received in response to the Peaking and Intermediate portion of the RFP, including several proposals from GRE. Only five of the 31 bids included the use of existing generating sources. The remaining proposals relied on new generating sources. The RFP review process determined that the GRE self-build option was superior to the other proposals on cost and responsiveness to GRE's needs.

GRE's self-build option has some definite benefits over purchasing capacity and energy from other entities. GRE's status as a cooperative affords it some financial advantages including low cost financing and lower overhead due to it being a not-for-profit organization. These facts were reflected in GRE's overall proposal price. Purchase power contracts are typically less flexible than desired for a peaking source. Purchases generally require scheduling energy on a day-ahead basis with limited flexibility intraday to respond to unexpected changes in load, availability of other owned resources and the impact of real time transmission availability to support short-term energy purchases. A GRE-owned generation resource can be ramped up and down to follow load and to allow maximizing the dispatch of its other resources.

In addition to long-term contracting of capacity and energy needs typically met through an RFP process, GRE has and will continue to use spot market purchases to meet its short-term obligations whenever the market is economically competitive. However, for long-term planning purposes, spot market purchases are not an appropriate option.

Purchasing power is not evaluated further as an option since the RFP review process has already determined that the GRE self-build proposal is the best alternative based on cost and overall responsiveness to GRE's needs.

### 4.4.2 Upgrades to Existing Resources

Whenever possible, GRE endeavors to undertake capital projects at its legacy generation facilities that add or "free-up" incremental capacity. Over time, GRE has found that it can be less expensive to build incremental capacity at existing facilities rather than developing new resources. That philosophy of adding incremental capacity has been proven in recent history.

### 4.4.3 Historical Upgrades

In the fall of 2001, General Electric (GE) sent notification to GRE recalling the seventeenth stage compressor blades on each of the six combustion turbines at Lakefield Junction Station. Since the units were being disassembled to replace the recalled equipment, it became economically feasible to engage in a power upgrade project to each of the six units at the same time. The overall efficiency of each unit was improved by 2.2 percent. Further, the capacity of Lakefield Junction was increased by 25 to 30 MW depending on ambient temperature and humidity.

In April 2002, GRE transmission completed significant upgrades to its DC Line and associated converter stations. The MAPP Design Review Subcommittee (DRS) approved the upgrades and granted GRE approval to increase the rating of the DC Line in April, 2003. The rating increase has subsequently allowed GRE to accredit the full net capability of both Coal Creek Station units adding 32 MW of accredited capacity to GRE's summer and winter capability.

In 2002, the Minnesota Pollution Control Agency and the Minnesota Environmental Quality Board both approved a modification to the air permit at GRE's Saint Bonifacius (St. Boni) peaking plant to allow for operation of that facility above 50 MW. Subsequently, GRE worked with MAPP to determine what transmission upgrades would be necessary for St. Boni to operate above 50 MW. It is anticipated that the transmission upgrades and reconfiguration will be completed by May 2005. As a result of the environmental permit change and transmission work, GRE should realize 6 MW of additional capacity in the summer and 20 MW of additional capacity in the winter at St. Boni.

These examples demonstrate GRE's commitment to continuous analysis of potential upgrades and improvements to its generating facilities.

### 4.4.4 Future Upgrades

There are very few upgrades currently available to existing GRE generating facilities.

GRE has analyzed adding inlet fogging power augmentation to St. Boni. Inlet fogging is a process that adds small water droplets to the inlet air on a combustion turbine; thus, increasing the mass flow into the compressor. It is estimated that inlet fogging could add 4 to 5 MW of additional capacity at less than $100/kW of installed cost. It is likely that GRE will undertake this power upgrade after the transmission constraint outlined in Section 4.4.3 is lifted.

GRE has also considered adding wet compression power augmentation to Pleasant Valley Station units 11 and 12. Wet compression is another process where water droplets are introduced to the compressor inlets; thus, increasing mass flow by cooling the inlet air and adding water mass. It is estimated that wet compression could add 15 to 20 MW of capacity per unit. In order for the upgrade project to be economical, the upgrade would have to be installed along with some other maintenance activity requiring disassembly of the compressors and turbines. This project carries additional risk because it has not been completed on any other turbines of its kind. GRE will monitor whether circumstances arise that make this project reliable and cost effective.

Finally, GRE has also analyzed adding inlet cooling and water injection power augmentation to each of its three oil-fired GE Frame 5 combustion turbines – Cambridge, Maple Lake and Rock Lake. It is estimated that such power upgrades could add 2.7 to 4.3 MW per unit. However, GRE estimates that the power upgrades to those legacy facilities would cost twice as much as adding capacity by building a new combustion turbine. Since it is not cost effective, GRE will not pursue these upgrades at this time.

GRE will continue to analyze all upgrade possibilities. At this time, none of the upgrades in progress or identified for potential future projects are appropriate to meet GRE's immediate needs.

### 4.4.5 New Transmission

The current environment in the electric industry does not allow transmission lines to be a true alternative to generating resources in most instances. However, new transmission could be considered an alternative if it provided access to existing generating resources in other regions that are currently inaccessible because of the lack of transmission infrastructure. The key obstacle of this alternative is that the existing timelines for planning, permitting and constructing additional transmission would not allow the necessary facilities to be online in a timely manner to meet GRE's immediate needs. In addition, the policies and processes associated with planning and constructing transmission create additional uncertainties.

The planning process for new transmission is done on a regional basis, overseen by a regional authority (the Midwest ISO for this region), rather than being integrated with generation planning within individual utilities. In fact, the process does not directly address transmission as a substitute for generation. In some instances, the transmission

planning process might address existing pervasive bottlenecks in the regional bulk transmission system. These have the indirect effect of making existing power elsewhere in the region available to meet GRE's needs.

At any given time, many studies are underway to identify new or upgraded transmission facilities required to deliver the output of possible new generating resources. These studies may identify conditions that indicate that larger or different facilities should be constructed from those required to eliminate the existing bottlenecks, but the construction of such facilities is uncertain as many generating projects do not come to fruition. These factors make accessibility to generating resources hard to precisely identify.

Regulatory uncertainty further complicates this issue. The current methodology for recovering investments in the transmission system generally assigns costs equally to all customers within a transmission zones, with some provisions for direct assignment. This methodology has created barriers to the development of certain types of transmission projects, including many high voltage projects that deliver power across zones or transmission developed for economic rather than purely reliability issues. Industry groups are looking at appropriate methods for identifying benefits and assigning costs but the issue remains very much unresolved.

In addition, major inter-state transmission projects require coordination of permitting and other regulatory approvals in multiple states. While this does not necessarily introduce delay, it could result in longer timelines or risk for a transmission project, particularly if different jurisdictions perceive the benefits differently. Industry groups are also looking to streamline the processes for inter-state activities and reduce risk, but this is in the early stage of development.

Because of the lead time to construct new bulk transmission facilities and regulatory uncertainties, particularly surrounding cost recovery, new transmission lines are not a reasonable alternative to meet GRE's immediate needs and will not be evaluated further.

### 4.4.6 Other Fossil Fuel Technologies

The following conventional fossil fuel technologies were screened to determine if they meet the primary project objectives:

- Coal-fired technologies including pulverized coal, fluidized bed and gasification combined cycle.
- Oil-fired combustion turbine.
- Natural gas-fired combined cycle.

Coal-Fired Technologies: Coal-fired technologies are usually associated with intermediate and baseload facilities due to their high capital costs and slow start-up times. Operating one of these coal-fired technologies as a peaking facility by keeping them in "stand-by" mode greatly reduces their efficiency and increases emissions. Further, it increases the wear and tear on the equipment, which can lead to more frequent forced and planned outages.

Siting and permitting of a new coal-based power plant in Minnesota would likely be a lengthy and contentious process due to social and environmental concerns. This process, along with the additional time needed to construct a coal-based facility, would push the availability of the capacity past the summer 2007 time frame needed to satisfy one of the project's primary objectives. The earliest any of the coal-based projects currently under development could be on line is 2011.

Coal-fired technologies fail to meet the primary objectives due to the lengthy time needed to site, permit and construct them as well as inappropriate operating characteristics. Therefore, coal-based projects will not be considered for further evaluation.

Oil-Fired Combustion Turbine (simple cycle): This alternative is similar to the proposed project except No. 2 fuel oil would be the primary fuel. No back-up fuel would be needed since on-site oil storage tanks would be used to provide the necessary run time. The same or largely similar units as described in Section 3 would be utilized. Because of the similarities between this alternative and the proposed project, this alternative meets the first two primary objectives for the project.

Since the need to be near an adequate gas supply would no longer be a concern, siting this type of unit is simplified but emissions would be more of a concern. Burning fuel oil would result in higher emissions of sulfur dioxide, carbon monoxide and nitrogen oxides than a natural gas-fired alternative. Table 4-3 summarizes the other major operational differences between this alternative and GRE's project.

Using oil for fuel results in higher operating costs than a natural gas-fired alternative. Higher operating costs mean this alternative will not run as much, limiting the opportunities to provide ancillary services such as load following and regulation while operating.

Because this alternative meets the first two primary screening objectives, it will be evaluated further in Section 4.5.

Combined Cycle: The combined cycle plant requires a 24-month construction period. The associated permitting and longer construction time-frame makes commercial operation by summer 2007 unachievable.

The combined cycle technology is generally not considered for peaking service due to higher capital and fixed O&M costs compared with simple cycle technology. In addition, the combined cycle plant is not suited for service requiring fast starts and short operation schedules.

Because this alternative does not meet the first two primary screening objectives, it will not be evaluated further in Section 4.5.

### 4.4.7 New Customer-Owned Generation

Several of GRE's member systems have very actively promoted installing customer-owned generation ("distributed generation"). Approximately 130 MW of customer-owned generation are already in place and 25 MW of additional customer-owned generation is expected to be in place by 2006. The 130 MW represents the capacity benefit from these generators in the summer season. This is an appropriate benchmark for inclusion since GRE's system peaks in the summer. It should be noted that if these generators are utilized in other seasons, the benefit would be one half or one third as large.

The distributed generation is utilized to serve loads that are interrupted from the system. This type of use results in the peak reduction of the MW of avoided capacity amount plus 15 percent. This is because each MW of peak load demand requires 15 percent more capacity because of the MAPP reserve sharing agreement and the distributed generation reduces the peak load and all of its requirements. If the generation is accredited by MAPP and operated in parallel to the system, the 15 percent adjustment would not apply.

While the peak reduction is an attractive characteristic of these resources, the emissions are more of a concern. The small size of each distributed generation unit allows them to be subject to less stringent air emission requirements, resulting in higher total emissions than larger alternatives, which are subject to more stringent air emission restrictions. Further, it is unrealistic to expect that enough generators could be installed in a time frame to satisfy GRE's current needs. In addition to the already planned distributed generation, it would require more than 70 diesel engine generator sets of two MW to be installed to meet GRE's 2007 needs. This is not feasible due to the large number of sites involved and the associated infrastructure needs for each site.

Because this alternative does not meet the first two primary screening objectives it will not be evaluated further in Section 4.5.

### 4.4.8 Emerging Technologies

There are a number of emerging technologies that have the potential to dramatically impact how electricity is produced, delivered and used. Many of these technologies are small enough to be located very close to the point of consumption, minimizing the need for new transmission and distribution. These technologies include:

- Fuel Cells.
- Micro Turbines.
- Energy Storage (such as batteries, pumped storage hydro, compressed air energy storage, and super conducting magnetic energy storage).

Fuel Cells: Fuel cells convert hydrogen rich fuels directly to electricity through electrochemical reactions. The reactants, fuel and oxidant (air or oxygen) are fed to separate anode and cathode electrodes. Electricity is generated by the transport of ions generated by the anode reaction across the electrolyte separating the anode and cathode.

Because this is not a combustion process, there are no air emissions other than water vapor and carbon dioxide. Fuel cells are very efficient, even in small plant sizes.

Phosphoric acid fuel cells (PAFC) are currently available in 200-kW unit sizes. Their cost is in excess of $2000/kW, making them uneconomical. Molten carbonate (MCFC) and solid oxide fuel cells (SOFC) are not yet commercially available although the developers are hopeful they will become available in the next several years. Proton exchange membrane (PEM) fuel cells have created interest recently, primarily for automotive and transit applications. They are also under development for stationary power applications but are not yet commercially available.

While there is much interest in fuel cells and great expectations for commercial availability of various fuel cells, it is unreasonable to expect them to be available in sufficient quantity to meet the identified need by 2007. Most fuel cells are also baseload in nature and would not be cost effective at the low capacity factors typical of a peaking resource. Therefore, this technology will not be considered for further analysis.

Micro-turbines: Micro-turbines are small combustion turbines with capacities in the range of 30 to 250 kW. Micro-turbines are well suited for distributed generation applications. The units are small and relatively efficient for their size. Installed costs range from $450 to $700 per kW and efficiencies range from 22 percent to 30 percent. Micro-turbines for distributed generation are being developed by several potential vendors. These units have a single shaft with the generator, air compressor and turbine mounted on air bearings to eliminate the need for bearing lubrication. Power electronics convert the high frequency AC current from the generator to DC current. An inverter then converts the DC current to AC current at a standard distribution voltage. Due to the small size of the units, they can be online in a relatively short time and can be mounted on a pole, platform, in a substation, on a roof, in a vault or on a pad.

Micro-turbines are a rapidly developing technology. Although long term reliability is projected to be good, micro-turbines are not in commercial use at this time and, therefore, their reliability has not been demonstrated in real world applications. There is considerable uncertainty on the long-term O&M costs and operating life for this technology. Because micro-turbines are not commercially proven at this time, they were not selected for further evaluation.

Energy Storage: Energy storage can be used to dampen out fluctuations in the demand for electrical energy. It also allows for the possibility that electricity can be generated at low cost at times of low demand and then retrieved from storage during periods of high demand. Energy storage options include:

- Batteries.
- Pumped storage.
- Compressed air.
- Superconducting magnets.

Batteries: Batteries are well known for their ability to store electrical energy. Batteries represent a resource option for electric utilities but lead acid batteries, the most common type used for storage in larger scale applications, have a limited life (1500 to 2000 charge-discharge cycles) and are expensive. Advanced batteries are being developed that may increase the cycle life and lower costs.

As a result of the high cost of this option and limited experience in the use of batteries in utility-sized applications, this option was not considered for further evaluation.

Pumped Storage Hydro: Pumped storage hydro refers to an energy storage technology where water is pumped to a high reservoir during off-peak hours and released to generate electricity during on-peak hours. This is a mature technology. A primary problem with pumped hydro is locating suitable sites. Minnesota state law prohibits the use of the Mississippi river as a water source for pumped storage facilities.

Because no suitable sites were identified, this option was not considered for further evaluation.

Compressed Air: With this option, electricity is used during off-peak periods to compress air in underground caverns or porous rock reservoirs. During on-peak periods, the stored air can be released to provide compressed air for the combustion portion of a combustion turbine.

This is an immature technology and existing prototype plants have not performed to expectations. Therefore compressed air was not considered for further evaluation.

Superconducting Magnets: A superconducting magnet refers to a coil that can store electrical energy. Because the coil is superconducting, storage losses are very low. This is an emerging technology that is not fully developed and it was not considered for further evaluation.

None of these emerging technologies are reasonable alternatives based on either the immature state of their development or their being inappropriate for peaking applications at this time.

### 4.4.9 Summary of Preliminary Evaluation

The following table summarizes the conclusions reached in the preceding descriptions of the alternatives with respect to the primary project objectives. It indicates those alternatives that have been screened for further consideration. The next section provides the economic comparison of the selected alternatives.

Table 4-2 shows three alternatives passed the primary screening for further evaluation. These alternatives are all combustion turbine peaking plants, using three different fuel sources: natural gas (the proposed project), fuel oil and ethanol. Table 4-3 shows the operating characteristics of the proposed project and two alternatives. Additional economic analysis will be addressed in the following section.

**Table 4-2 - Summary of Alternatives**

| Primary Objectives | | | |
|---|---|---|---|
| **Alternative** | **170 MW Available for 2007** | **Suitable Operating Characteristics** | **Considered in further Economic Screening** |
| DSM | No | No | No |
| Renewables | | | |
| Wind | No | No | No |
| Biomass | No | No | No |
| Ethanol-fired combustion turbine | Yes | Yes | Yes |
| Hydro | No | No | No |
| Solar | No | No | No |
| Purchased Power – Market | Unlikely | Yes | No |
| Purchased Power – Built for GRE | Yes | No | No |
| Upgrades to Existing Resources | No | No | No |
| New Transmission | No | No | No |
| Coal | No | No | No |
| Oil-fired combustion turbine | Yes | Yes | Yes |
| Combined cycle | No | No | Yes |
| DG/Customer Owned | No | Maybe | No |
| Emerging Technologies | | | |
| Micro turbines | No | No | No |
| Fuel cells | No | No | No |
| Energy Storage | | | |
| Batteries | No | Yes | No |
| Pumped Storage Hydro | No | Yes | No |
| Compressed Air Energy Storage | No | Yes | No |
| Super Conducting Magnetic Energy Storage | No | Yes | No |

## Table 4-3 – Alternatives' Operational Characteristics

| Characteristic | Project | Oil-Fired Simple-Cycle | Ethanol-Fired Simple-Cycle |
|---|---|---|---|
| **Facility Description** | | | |
| Unit Type | F-Class | F-Class | F-Class |
| Prime Mover | Combustion Turbine | Combustion Turbine | Combustion Turbine |
| Number of Units | 1 | 1 | 1 |
| Summer Capability (site specific)[1] | 170 MW | 164 MW | 164 MW |
| Winter Capability (site specific) | 190 MW | 190 MW | 190 MW |
| Operating Cycle | Simple-cycle | Simple-cycle | Simple-cycle |
| Expected Annual Capacity Factor | 9.6% | 9.6% | 9.6% |
| Expected Heat Rate/Efficiency (Summer site specific)[2] | 10,200 Btu/kWh (HHV)/35% | 10,450 Btu/kWh (HHV)/34.6% | 10,450 Btu/kWh (HHV)/34.6% |
| Expected Heat Rate/Efficiency (Winter site specific)[2] | 9,730 Btu/kWh (HHV)/37% | 9,900 Btu/kWh (HHV)/36.5% | 9,900 Btu/kWh (HHV)/36.5% |
| Heat Rejected through exhaust (Summer) | 1,013 MMBtu/hr | 1,061 MMBtu/hr | 1,061 MMBtu/hr |
| Heat Rejected through exhaust (Winter) | 1,188 MMBtu/hr | 1,224 MMBtu/hr | 1,224 MMBtu/hr |
| **Fuel Description** | | | |
| Fuel Source: Natural Gas only | Northern Natural Gas Pipeline | Regional Refineries | Regional Ethanol Plants |
| Fuel Requirement: (Summer)[2] | 1,546 MCf/hr | 12,695 gal/hr | 22,550 gal/hr |
| Fuel Requirement: (Winter)[2] | 1,771 MCf/hr | 13,933 gal/hr | 24,750 gal/hr |
| Expected Annual Fuel Requirement | 1,305,360 | 11,109,511 gal/yr | 19,734,000 gal/yr |
| Heat Input (Summer - HHV)[2] | 1554 MMBtu/hr | 1,714 MMBtu/hr | 1,714 MMBtu/hr |
| Heat Input (Winter - HHV)[2] | 1780 MMBtu/hr | 1,881 MMBtu/hr | 1,881 MMBtu/hr |
| Fuel Heat Content | 1.005 MMBtu/MCf | 0.137 MMBTU/gal | 0.0841 MMBTU/gal |
| Fuel Sulfur Content | 5.5 $mg/m^3$ | <0.05 percent | Unknown |
| Fuel Ash Content | None | Trace | Unknown |
| Fuel Moisture Content | <80 $mg/m^3$ | Trace | Unknown |
| **Water Use** | | | |
| Estimated maximum groundwater pumping rate[3] | 108 gpm | 454 gpm | 611 gpm |
| Estimated maximum surface water appropriation[3] | 0 $ft^3$/sec | 0 $ft^3$/sec | 0 $ft^3$/sec |
| Estimated annual groundwater appropriation[4] | 3. million gal/yr | 13 million gal/yr | 17 million gal/yr |
| Annual consumption[4] | 9.2 acre-feet | 38.6 acre-feet | 52.0 acre-feet |
| Discharges to water | 2.1 million gal/yr | 2.1 million gal/yr | 2.1 million gal/yr |
| **Estimated Emission Rates (lbs/hr)** | | | |
| CO [2] | 37 | 47 | 47 [5] |
| $SO_2$ [2] | 5.7 | 91 | 91 [5] |
| $NO_x$ [2] | 169 | 327 | 327 [5] |
| $PM_{10}$ [2] | 15 | 36 | 36 [5] |
| **Other Information** | | | |
| Land Requirements | 2.5 acres | 2.5 acres | 2.5 acres |
| Traffic | Slight increase due to on-site operators | Increased due to fuel deliveries | Increased due to fuel deliveries |
| Radioactive Releases | None | None | None |
| Solid Wastes Produced | Construction packaging, office waste, waste lubricating oils | Construction packaging, office waste, waste lubricating oils | Construction packaging, office waste, waste lubricating oils |
| Noise | ≤ 63 dB(A) @ 400 ft. | ≤ 63 dB(A) @ 400 ft. | ≤ 63 dB(A) @ 400 ft. |
| Work Force | 2 to 3 FTE | 2 to 3 FTE | 2 to 3 FTE |
| Transmission Requirements | Upgrade 3 sections of 69-kV lines | Upgrade 3 sections of 69-kV lines | Upgrade 3 sections of 69-kV lines |

1 With evaporative cooler in service.
2 Under base load operations.
3 When unit is on-line.
4 Assuming a 9.6% annual capacity factor and utilization of evapoartive cooler for 5.7% of annual operation.
5 Emissions estimates are typically based on operating data from other units in operation. No ethanol-fired combustion turbines are in operation and no manufacturers have tested ethanol-fired turbines. Therefore, emissions are assumed to be equivalent to those from firing fuel oil.

## 4.5 Economic Comparisons to Proposed project

Table 4-4 provides the cost comparison between the project and the alternatives, which have met the initial screening criteria (oil-fired combustion turbine and the ethanol-fired combustion turbine). This table shows that the proposed project is clearly the lowest-cost alternative.

**Table 4-4 - Comparison of Peaking Alternatives – Cost of Electricity**

| Item | Units | Project | Oil-Fired Simple-Cycle | Ethanol-Fired Simple-Cycle | Assumptions |
|---|---|---|---|---|---|
| **Project Description** | | | | | |
| Base Capability (Summer, site-specific rating) | MW | 170 | 164 | 164 | Manufacturer *pro forma* estimate |
| Cost Basis | Cal Yr | 2004 | 2004 | 2004 | |
| Life of Project | Years | 30 | 30 | 30 | Typical accounting life |
| Operating Cycle | | Simple | Simple | Simple | |
| Annual Capacity Factor | % | 9.6% | 9.6% | 9.6% | PVS experience |
| Annual Operating Time | Hours | 840 | 840 | 840 | Formula |
| Average Annual Availability | % | 97.5 | 97.5 | 97.5 | PVS ops experience |
| Fuel Type | | Nat Gas | No. 2 Fuel Oil | Ethanol | |
| Heat Input (HHV) | MMBtu/hr | 1,554 | 1,714 | 1,714 | PVS ops experience |
| Heat Rate (HHV) - Summer Rating | Btu/kWh | 10,200 | 10,450 | 10,450 | PVS ops experience |
| Efficiency (HHV) - Summer Rating | % | 35.4 | 34.6 | 34.6 | Formula |
| Project Capital Cost | $/kW | 406 | 430 | 443 | Overnight cost w/o IDC |
| Fixed O&M Costs | $/kW-yr | 3.46 | 3.46 | 3.46 | PVS experience |
| Fuel Costs | $/MMBtu | 5.73 | 7.45 | 20.22 | EIA *2005 AEO* plus transport & balancing |
| Non-Fuel Variable O&M Costs | $/MWh | 8.41 | 12.62 | 12.62 | Includes fired-hour costs & start charge |
| **Capacity Costs (Fixed)** | | | | | |
| Total Project Capital Cost | $ | 69,020,000 | 70,520,000 | 72,652,000 | Formula |
| Annual Fixed O&M | $ | 588,200 | 567,440 | 567,440 | Formula |
| Total Annual Fixed Costs | $ | 6,523,920 | 6,632,160 | 6,815,512 | 8.6% annual FCs + Fixed O&M |
| Project Capacity Cost | $/kW-yr | 38.38 | 40.44 | 41.56 | Formula |
| Project Capacity Cost | $/kWh | 0.046 | 0.048 | 0.049 | Formula |
| **Production Costs (Variable)** | | | | | |
| Net Annual Generation | MWh | 142,800 | 137,760 | 137,760 | Formula |
| Annual Fuel Consumption | MMBtu | 1,305,360 | 1,439,760 | 1,439,760 | Formula |
| Annual Fuel Cost | $ | 7,483,015 | 10,728,673 | 29,111,947 | Formula |
| Annual Non-Fuel Variable O&M Cost | $ | 1,200,948 | 1,738,531 | 1,738,531 | Formula |
| Total Project Variable Generation Cost | $ | 8,683,963 | 12,467,204 | 30,850,478 | Formula |
| Project Fuel Cost | $/kWh | 0.052 | 0.078 | 0.211 | Formula |
| Project Total Energy Cost | $/kWh | 0.061 | 0.090 | 0.224 | Formula |
| **Total Cost** | **$/kWh** | **0.106** | **0.139** | **0.273** | **Formula** |

As for the biomass alternative analyzed, the table clearly shows that substantial reductions in the cost of ethanol would be needed in order for such an alternative to be competitive with the project. Therefore, an ethanol-fueled peaker is not a reasonable alternative

## 4.6 Conclusion

GRE has examined alternatives to the proposed project. Based on the primary objectives, there are no reasonable alternatives that are available in the necessary timeframe that would reliably and economically meet GRE's peaking resource needs.

# 5 Siting Alternatives

The following sections describe GRE's site selection analysis, which resulted in sites being proposed in Cambridge Township in Isanti County and the City of Elk River in Sherburne County.

## 5.1 Siting Constraints

### 5.1.1 Costs of and Access to Electric Transmission

GRE has various contractual arrangements with utilities with which it is interconnected to provide transmission service for serving load, and in some cases, for integrating resources. GRE is a transmission-owning member of the Midwest Independent System Operator ("Midwest ISO" or "MISO") and receives network integration transmission service under the MISO Open Access Transmission Tariff ("OATT") over its own transmission system and the transmission systems of other MISO transmission owners including:

### 5.1.2 Transmission Technical Considerations

Several aspects of transmission system performance are relevant in the site selection process:

- The transmission system, with the plant and associated transmission facilities added, must meet regional reliability guidelines for line loadings, equipment loadings, voltages, transient stability, and dynamic stability under both peak load and off-peak load conditions with the transmission system intact and with certain specified transmission facility outages.
- The output of the generator must improve or at least not significantly adversely affect flows through regional transmission bottlenecks ("constrained interfaces" or "flowgates").
- Losses need to be estimated and incorporated in the plant economic evaluation.
- The effects of other proposed plants and transmission projects need to be evaluated.

Transmission system studies are expensive and time consuming. Therefore, a limited evaluation was first done on a large number of potential sites, followed by more detailed studies on the final candidate sites.

### 5.1.3 Overall Electric Transmission Focus Area

An initial set of proxy sites was evaluated for screening purposes. These sites were selected based on experience and judgment about potential transmission system impacts and were intentionally scattered across a broad geographic area. The proxy sites were:

- Blue Lake (Shakopee)
- Cambridge vicinity
- Cannon Falls vicinity
- Chisago County Substation

- Elk River
- Lakefield Generating Station (Martin County)
- Pine Lake, Wisconsin
- Empire (Dakota County)
- Willmar

A screening-level study of the transmission performance at each of these locations was performed. This study included an evaluation of:

- existing performance (prior to adding generation),
- system intact thermal overload and voltage performance,
- first-contingency thermal overload and voltage performance,
- system improvements needed to meet regional reliability criteria,
- constrained interface (flowgate) impacts, and
- losses.

The screening study concluded that:

- all of the sites could be made to work with reasonable transmission improvements,
- the Cambridge site resulted in lowest losses, and
- only the Lakefield site had a significant impact on constrained interfaces.

### 5.1.4 Cost of Developing New Electric Transmission Improvements

An ideal site will minimize the cost of adding new transmission by using the unused capacity in existing lines, although most ideal sites will need some sort of transmission substation and line construction. The higher the existing system voltage level, the more likely that there is existing capacity available in the transmission lines thus minimizing construction cost.

The cost of new transmission construction is significant. Single circuit lines cost between $200,000 and $555,000 per mile depending on voltage level and double circuit lines cost between $300,000 and $800,000 per mile. Each line termination costs an additional $300,000 to $900,000 and large power transformers cost $2,000,000 or more.

All the site specific total costs described below include the cost of the generator step-up transformers (GSU) to connect the units to the substation connection voltage.

### 5.1.5 Access to Existing Natural Gas Supplies

A natural gas combustion turbine project must have sufficient high pressure gas available to support projected operation. The natural gas turbine should be located close to a high pressure gas pipeline, in order to minimize project costs.

### 5.1.6 Cost of Developing New Gas Pipelines

Pipeline construction costs vary depending upon terrain, distance, right of way needs and timing of construction. For planning purposes, a pipeline construction cost of $800,000 per mile was used, assuming the installation of a 10 inch pipe. In addition, a pressure regulating and metering station will need to be constructed at an approximate cost of $400,000.

### 5.1.7 Land Use Constraints

Land use constraints consist of avoiding sensitive areas such as:

- Wetlands
- Cultural & Historical Resources
- Threatened or Endangered Species Habitat
- Densely Populated Areas
- Scenic or Recreational Areas
- Waste Disposal Sites

A combustion turbine facility requires a relatively small site area, thereby easing the siting process. The primary environmental impact from a combustion turbine is noise, so siting the facility with an adequate distance to residences is a key criteria. The required distance is dependent upon the sound attenuation equipment provided with the turbines, the number of turbines, the inherent background noise levels in the area and the noise standards with which the project must comply. Generally, these variables will result in a necessary buffer of somewhere between 1,000 to 2,000 feet to the nearest residence.

### 5.1.8 Water Availability and Disposal

A natural gas-fired simple-cycle combustion turbine requires a relatively small quantity of water. Water uses associated with simple cycle combustion turbines include:

- Deminerlized water for inlet cooling and/or water injection (used for power augmentation and NOx control in some cases)
- Turbine wash-down
- Potable water uses

Water resources in Minnesota are generally available to meet these needs. Groundwater resources are adequate in most areas of the state except the southwest portion. Major surface water resources include the Mississippi and Minnesota Rivers.

Effluents from a combustion turbine plant would consist of backwash water from the demineralization equipment, stormwater and sanitary wastes. Sanitary wastes are expected to be quite small and could be handled with an on-site land treatment system. Stormwater will be directed to the local drainage systems. The backwash water could either be treated on site and discharged to a nearby river or ditch system or it could be stored and transported to a municipal wastewater treatment system. If an adequate

discharge location is not nearby, due to the limited quantities expected, the backwash water could be hauled off site for treatment and disposal.

### 5.1.9 Access to Roads

The generating facility must have good access to paved roadways during construction and operation. Most portions of the state have a good distribution of paved state or county highways. Generally, sites more than one mile from a paved road were excluded from further consideration.

### 5.1.10 Local Government Support and Cost Implications

To assist in the successful development of a project, support from township, city and county officials is important. Combustion turbine facilities can bring additional tax revenue as well as help support the transmission system in the area. In Minnesota, generation equipment is assessed a personal property tax based on its depreciated value, as well as a real property tax. The personal property tax is considerable and greatly influences the economics of the project. This tax adds approximately $6.50 per kW per year to the cost of the capacity. Other projects in Minnesota have used local support to get an exemption from this tax from the State Legislature.

As part of the siting process, County officials were contacted to gauge their support for a personal property tax exemption. The results of these discussions were then considered when evaluating the siting options.

### 5.1.11 Air Quality

New, large combustion turbine projects will likely come under New Source Review (NSR) rules, unless potentially significant restrictions on annual emissions are accepted that effectively limit the number of hours the plant could operate in a year. NSR rules apply if a facility is classified as a major source (defined as a source with a potential to emit of 250 tons per year or more of any of the six criteria pollutants, or 10 tons per year of any one hazardous air pollutant (HAP), or a combination of 25 tons per year of all HAPs). Large, natural gas-fired combustion turbines usually qualify as a major source due to their potential to emit more than 250 tons per year of NOx and/or CO.

For facilities located in non-attainment areas, the NSR review process is possibly complicated and would likely result in the need for additional equipment to control NOx and/or CO emissions. This equipment adds significant capital and operating costs to the project. However, Minnesota has only a few areas designated as non-attainment, which are located near the more densely populated areas around Minneapolis & St. Paul, Rochester and Duluth.

### 5.1.12 Other Environmental Constraints

Soils and geology of the area must be suitable for construction of the footings needed to support the equipment. Poorly drained soils and karst areas were avoided.

Socioeconomic impacts of a combustion turbine project are relatively minor.

The project does not take up much land, and since the equipment itself is not large, the visual impacts are limited. Employment opportunities for construction workers are moderate (75 to 150 people over a 6- to 10-month timeframe). Operating staff may vary depending upon the number of turbines installed, but would generally range from one to four employees.

## 5.2 Initial Site Screening

### 5.2.1 Methodology

The first step in narrowing down the search for candidate sites for the combustion turbine project was to generate a list of sites that were favorable from an electric transmission standpoint for the reasons described above. The transmission screening identified the following candidate sites:

- Blue Lake (Shakopee)
- Cambridge vicinity
- Cannon Falls vicinity
- Chisago County Substation
- Elk River
- Lakefield Station (Martin County)
- Pine Lake, Wisconsin
- Empire (Dakota County)
- Willmar

All of these sites were carried forward into the initial screening analysis except Lakefield Station due its significant transmission constraint.

These locations were then reviewed for their proximity to a high-pressure natural gas transmission pipe. Sites close to an acceptable high-pressure natural gas pipeline were then studied to determine the specific transmission improvements and gas system connections that would be required and their cost.

Total plant construction and fixed operating costs were estimated for each site. All sites were assumed to have the same capacity factor and fuel costs. A personal property tax exemption was also assumed to apply to each site located in Minnesota. The net present value of each site was then calculated.

Each of the sites was also scored on a qualitative basis to take into account issues that could impact the successful development of a project at the site. This qualitative screening was used to determine if the lowest cost project could reasonably be expected to be successfully implemented.

### 5.2.2 Range of Project Size

Two project sizes were considered in the initial screening analysis: 155 MW and 310 MW. All sites were evaluated at 155 MWs. Greenfield sites were also evaluated at 310 MW. Higher plant capacities were considered for the greenfield sites since they typically

require more development of supply infrastructure and it was desirable to determine if the site could be expanded to include two 155-MW CTs. A 155-MW CT at Cambridge and a 155-MW CT at Elk River were combined as a single site for comparison with the 310-MW Greenfield sites.

### 5.2.3 Initial Screening Results

The results of the initial screening indicated that the Cambridge and Elk River sites had the best overall costs and site screening scores. The results of the screening process are graphically depicted in Figures 5-1 and 5-2 for the 155-MW and 310-MW scenarios, respectively.

**Figure 5-1 – 155 MW CT Site Comparisons**

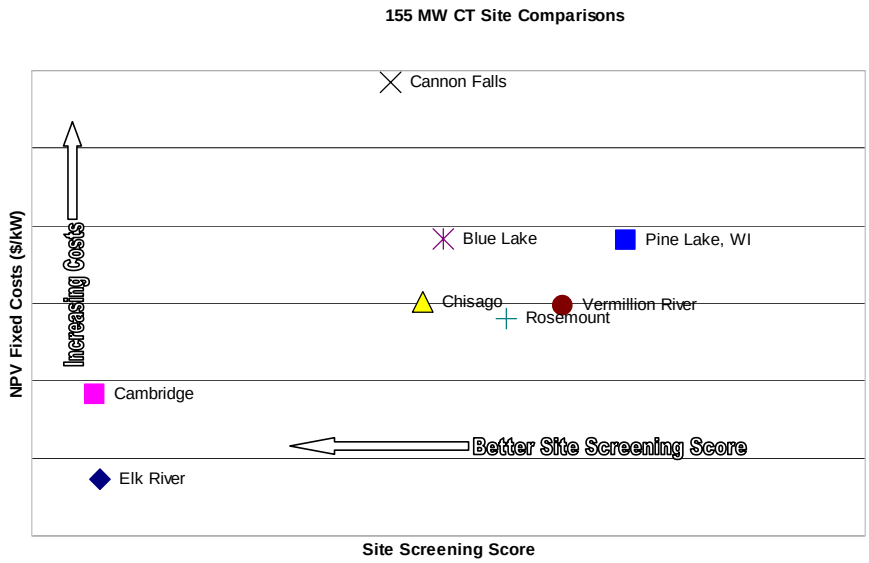
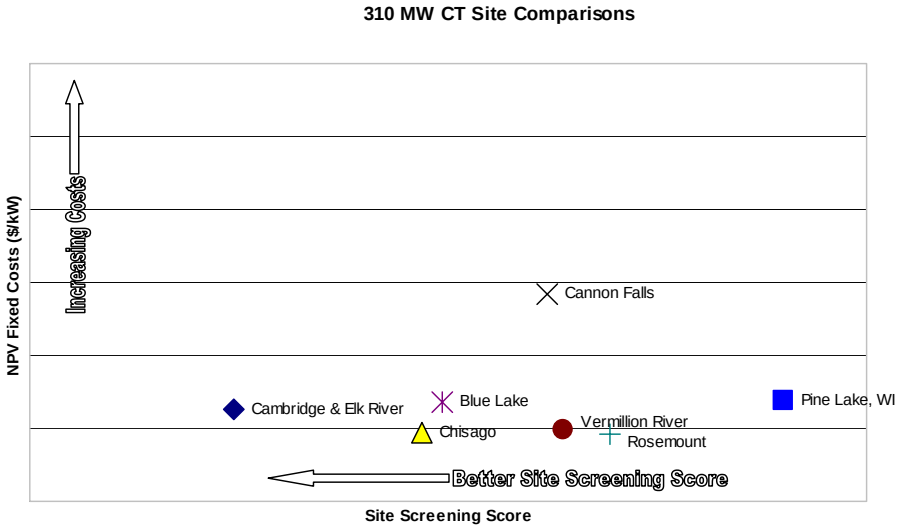



**Figure 5-2 – 310 MW CT Site Comparisons**



## 5.3 Detailed Site Evaluation Process

The initial screening analysis identified the Cambridge and Elk River sites as the best potential locations for the project. In its detailed site evaluation, GRE confirmed and refined some of the assumption used in the initial screening analysis and did a more detailed costing analysis. The results of the detail site evaluation process are discussed in this section.

### 5.3.1 Cambridge Peaking Plant

The Cambridge site is located at an existing substation near the City of Cambridge in Isanti County.

- **Transmission**
  This site has four existing 69-kV outlet lines and a large and growing amount of local load. This proximity to load minimizes the impact of adding generation on the regional transmission system. The impacts for a plant in the 190 MW range are largely confined to the GRE 69-kV system in the general vicinity of the site. Four GRE 69-kV lines would be impacted by the plant addition:

  - Cambridge-Dalbo-Princeton North-Princeton 23.94 miles
  - Cambridge-Braham-Grasston 15.47 miles
  - Cambridge-Rush Tap-Rush City 18.95 miles
  - Cambridge-Cambridge Industrial-Isanti Tap-Athens 12.09 miles

  These lines would need to be evaluated in detail for ampacity and sag clearance to determine whether they would be resagged, reconductored, or rebuilt. In addition, the equipment (bus, jumpers, and switches) within the Cambridge substation would need to be replaced due to higher current flows with a new plant addition.

  The improvements noted above would allow full generation output to be maintained initially upon loss of any single transmission element. However, generator reductions may be needed within 30 minutes of loss of any of the 69-kV lines directly connected to the Cambridge substation.

  Transient stability and constrained interface studies indicated no significant impacts. Adding generation at this location causes a slight (less than 1%) decrease in losses due to the proximity of loads on the 69-kV system.

- **Gas Supply**
  The NNG gas pipeline system in Cambridge consists of a 12-inch and 16-inch pipelines. These pipelines are sufficiently close to the NNG North Branch compressor station, which would provide adequate high pressure gas 10 to 11 months of the year. Natural gas supply to the Cambridge site would be

provided via a tap into the 16-inch Northern Natural Gas (NNG) pipeline. Approximately a 1/2 mile of 10-inch pipeline would be constructed to the Cambridge site. The cost to provide gas pipeline service would be in the range of $1.1 to $1.4 million dollars.

- **Land Use, Water, & Roads**
  All are acceptable for this site.

- **Local Government Support**
  The Cambridge substation is located in Isanti County. GRE discussed the project with the County Board who reacted favorably to it. As evidence of their opinion, the Board passed a resolution in support of the project and state legislation to grant the project a personal property tax exemption.

- **Environmental Constraints**
  There were no major environmental constraints identified for the site. The existing peaking plant is currently permitted as a Major Source with respect to the New Source Review program, but it has never had actually emissions greater than the major source threshold (i.e., 250 tons/yr). Because actual emission are low, the proposed combustion turbine and existing combustion turbine could be permitted as a "synthetic minor source" by limiting total emissions from the plant site to less than 250 tons of any criteria emission. The synthetic minor limits would ensure the New Source Review is not applicable to the plant.

### 5.3.2 Elk River Station

The Elk River site is on Great River Energy's existing campus located within the City of Elk River in Sherburne County. The campus currently includes corporate offices, field service buildings, and the Elk River Station – a waste-to-energy facility.

- **Transmission**
  This site has two existing 230-kV and six 69-kV outlet lines and a large and growing amount of local load. This proximity to load minimizes the impact of adding generation on the regional transmission system. The impacts for an Elk River plant are largely confined to the GRE 69-kV system in the general vicinity of the site. The following GRE facilities are impacted by a plant addition:
  - Elk River – Rice Lake - Zimmerman, 8.08 miles
  - Elk River - Anoka, 5.44 miles
  - Andover – Sderville, 3.58
  - Elk River 230/69-kV transformer #2
  - Elk River – Otsego - Albertville, 9.60 miles

  The ratings of these lines and transformer need to be evaluated in greater detail to determine whether resagging, reconductoring, or replacement would be required.

No significant constrained interface impacts have been observed. Transient stability for this site has not been studied but will be part of the pending MISO queue-order interconnection studies. Losses for an Elk River plant are estimated to be approximately 3%, which is low due to the proximity of loads on the 69-kV system.

- **Gas Supply**
  Natural gas supply to the Elk River site would be provided via a tie into the Northern Natural Gas (NNG), Elk River Town Border Station (TBS). The Elk River TBS is interconnected by a 16-inch mainline gas pipeline to the NNG system. Approximately 1 mile of 8-inch pipeline would be constructed to the Elk River Station site. The NNG pipeline system is able to support a gas-fired combustion turbine only from April 15 through September 1. The NNG pipeline system does not have sufficient pressure to operate a combustion turbine from September 1 through April 15. NNG would valve the Elk River TBS such that no gas service is available during much of the year. The cost to provide gas pipeline service would be more than $2 million dollars.

- **Land Use, Water & Roads**
  All are acceptable for this site.

- **Local Government Support**
  The Elk River campus is located in Sherburne County. GRE discussed the project with the County Board. The Board was not averse to the project, but it could not formulate a resolution in support of the project or state legislation to grant the project a personal property tax exemption. Personal property taxes would add approximately $1.1 million annually to the plant's costs.

- **Air Quality & Other Environmental Constraints**
  Operation at the Elk River site would be more constrained by air permitting requirements than at Cambridge. The existing Elk River Station waste-to-energy facility has actual air emissions exceeding the major source threshold (250 tons/yr), and as such, emissions from the new combustion turbine would have to be limited to less than 40 tons/yr of NOx to ensure that New Source Review requirements do not apply to the new turbine. For a particular turbine, this would effectively limit its operating hours to about 15 percent of what it could operate at Cambridge. There were no other major environmental constraints identified for the site.

## 5.4 Site Comparison & Selection

Comparison of the candidate sites are done both on a qualitative basis and quantitative (cost) basis. A qualitative comparison is provided in the Table 5-1.

The Elk River site is given a neutral rating on gas supply since it meets the goal of summer peaking capacity by having fuel available during the needed peaking months.

The Cambridge site is rated higher (positive) on gas supply because fuel is available for producing energy during more months out of the year.

**5.4.1.1**

**Table 5-1 - Candidate Site Area Comparison**

| | Cambridge | Elk River |
|---|---|---|
| **Transmission Capability** | + | + |
| **Gas Supply** | + | 0 |
| **Land Use** | + | + |
| **Water** | + | + |
| **Roads** | + | + |
| **Local Government Support** | + | - |
| **Environmental** | + | 0 |

Legend: "+" is positive; "-" is negative; "0" is neutral

The Elk River site is given a negative rating for local government support because the County Board could not formulate a resolution supporting the project or state legislation granting a personal property tax exemption for the project. The Cambridge County Board signed a resolution in support of the project and tax exemption.

The Elk River Station is given a neutral rating for environmental since the combustion turbine would either have to be subject to New Source Review requirements or it would be subject to operating restriction that would limit its run time to only about 15 percent of what could it could operate if located at Cambridge.

Table 5-2 provides an economic comparison of the sites for a nominal 170-MW project. As shown in the table, total capital costs would be lower for an Elk River combustion turbine compared with a Cambridge turbine. However, the levelized cash flow shows that the Cambridge option is lower, which is mainly a factor of the personal property tax exemption.

**Table 5-2 - Candidate Site Area Economic Comparison**

| Item | Units | Cambridge | Elk River | Assumptions |
|---|---|---|---|---|
| **Project Description** | | | | |
| Base Capability (Summer, site-specific rating) | MW | 170 | 170 | Manufacturer *pro forma* estimate |
| Cost Basis | Cal Yr | 2004 | 2004 | |
| Life of Project | Years | 30 | 30 | Typical accounting life |
| **Capital Costs ($000s)** | | | | |
| Power Plant | ($) | 54,215 | 59,084 | Overnight cost w/o IDC |
| Gas Supply/Interconnections | ($) | 1,090 | 1,862 | Overnight cost w/o IDC |
| Transmission Infrastructure | ($) | 13,705 | 6,145 | Overnight cost w/o IDC |
| Total Capital Costs | ($) | 69,010 | 67,091 | Overnight cost w/o IDC |
| Total Unit Cost ($/kW) | ($) | 406 | 395 | Overnight cost w/o IDC |
| **Year 2 Fixed Costs ($000s)** | | | | **First Calendar Year of Operation** |
| Annual Project Int/Dep | $ | 6,743 | 6,461 | First Calendar Year of Operation |
| Annual Fixed O&M | $ | 524 | 474 | First Calendar Year of Operation |
| Annual Taxes | $ | 179 | 1,063 | First Calendar Year of Operation |
| Annual Insurance | $ | 229 | 278 | First Calendar Year of Operation |
| Total Annual Fixed Costs | $ | 7,675 | 8,276 | First Calendar Year of Operation |
| Year 2 Unit Fixed Costs | $/kW-yr | 45.14 | 48.68 | First Calendar Year of Operation |
| **Levelized Cash Flow** | **$/kW-yr** | **45.20** | **48.80** | FCs levelized over life of facility |

Based on the qualitative and quantitative analysis of the two sites, Cambridge has been selected as the preferred plant site.