ENVIRONMENTAL REPORT

ELK RIVER PEAKING STATION

PUC DOCKET NO. ET2/CN-07-678

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Abstract

Great River Energy (GRE), headquartered in Elk River, Minnesota, has applied for a certificate of need to construct a large energy project consisting of a single simple-cycle combustion turbine (SCCT). The Elk River Peaking Station (ERPS) would have an estimated accredited summer output of approximately 175 megawatts (MW). The proposed project consists of a single, simple-cycle combustion turbine generator (CT) with a nominal summer generating capacity of 175 MW and other associated facilities. The facility will use natural gas and ultra-low sulfur distillate fuel oil.

The addition of this generating unit at the Elk River site falls within the definition of a large energy facility in Minnesota Statutes 216B.2421 and, thus, requires a Certificate of Need from the Commission prior to construction.

The Department of Commerce (DOC), Energy Facilities Permitting (EFP) is responsible for preparing the Environmental Report ("ER") required for the Certificate of Need. This report has been prepared as per Minnesota Rule 7849.0010-0110.

The preferred project site is on GRE's campus in Elk River, Sherburne County, Minnesota.

The alternative site, required under the large electric power generating plant site permit application full review process, is located on GRE's property in the city of Rosemount in Dakota County, Minnesota

Persons interested in receiving additional information regarding this project can register their names on the Project Docket webpage at:

http://energyfacilities.puc.state.mn.us/Docket.html?Id=19178

or by contacting Bill Storm, Energy Facilities Permitting, 85 7th Place East, Suite 500, St. Paul, Minnesota 55101, phone (651) 296-9535, e-mail: bill.storm@state.mn.us.

Many of the documents of interest regarding this matter, including this Environmental Report, are available online at the above webpage.

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1.0 INTRODUCTION

Great River Energy (GRE) filed a Certificate of Need (CON) application with the Minnesota Public Utilities Commission (PUC) on May 18, 2007, for the Elk River Peaking Station (ERPS). The PUC Docket No. for that proceeding is ET2/CN-07-678. On August 1, 2007, the PUC found the GRE CON application to be substantially complete (**Appendix A**).

The Minnesota Department of Commerce (Department) performs environmental review on applications for certificate of need on large energy projects. The Minnesota Public Utilities Commission (Commission) is the final decision making body in these matters. This Environmental Report (ER) document covers the environmental review requirements for the large energy project certificate of need determination.

Chapter 1 provides specific information about the proposed project. Chapter 2 provides information on the regulatory procedures and processes. Chapter 3 provides information on potential alternatives to the proposed project. Chapter 4 provides the environmental analysis required for certificate of need applications under Minnesota Rule 7849.7010 - .7070. Chapter 5 describes the additional permits that may be required for this project.

1.1 Project Description

The proposed project consists of a single natural gas-fired simple-cycle combustion turbine generator (CT) with a nominal summer generating capacity of 175 MW and other associated facilities. **Figure 1-1** shows the locations for the preferred and alternative sites.

1.2 Project Location

The proposed site for the project is on GRE's campus in Elk River, Sherburne County, Minnesota. The Elk River campus currently includes Elk River Station, a Refuse-Derived-Fuel (RDF) combustor that co-produces electricity, and GRE's corporate offices. The site is an area of approximately 11-acres in the northeast portion of the campus.

1.3 Design

A simple cycle combustion turbine (CT) has three major components: (1) a compressor, (2) a combustion chamber, (3) and a turbine. Air is drawn into the compressor, compressed, and discharged to the combustion chamber, mixed with fuel and ignited. The resulting expanding hot gases are sent through the turbine blades, causing them to rotate. The rotating turbine blades turn a shaft connected to a generator that produces electricity. Exhaust gases are emitted to the atmosphere through a stack that is expected to be about 90 feet tall.

The combustion turbine generator for the project will be "F" class technology, such as a Siemens Model 5000F. The project will have a peak output of approximately 175 MW during Midwest Area Power Pool (MAPP) summer peaking conditions. When operating on distillate fuel oil during typical winter conditions, the unit has a nominal capacity of approximately 211 MW.

The unit has a maximum capability of 224 MW. However, the Midwest Independent Transmission System Operator (MISO) transmission service request is limited to 200 MW.

The Midwest Independent System Operator (also known as MISO) monitors 920,000 miles of the high voltage transmission system throughout the Midwest. MISO operates one of the largest real time energy markets in the world. The main function of MISO is its reliability function. System operators known as Reliability Coordinators and Reliability Anaylst monitor the system 24/7. The RC/RA uses a model of the system and calculates power flows across the country.

The use of the power flow model gives the ability to calculate parallel flows caused by line outages and predict overloads before they occur. The MISO is an essential link in the safe, cost-effective delivery of electric power across much of North America. MISO is committed to reliability, the nondiscriminatory operation of the bulk power transmission system, and to working with all stakeholders to create cost-effective and innovative solutions for our changing industry.

As a fully integrated regional transmission organization, the non-profit Midwest ISO assures industry consumers of unbiased regional grid management and open access to the transmission facilities under Midwest ISO's functional supervision. MISO optimizes the efficiency of the interconnected system, provides regional solutions to regional planning needs and continually minimizes any risk to reliability.

The CT's primary fuel will be natural gas, chosen for its low air emissions and ready availability from a nearby pipeline. Dry low nitrogen oxides (NOx) combustion technology will be employed to minimize emissions when utilizing natural gas for fuel. Ultra-low sulfur diesel fuel will be used as a back-up fuel when natural gas is unavailable. Demineralized water injection will be employed to minimize NOx emissions when utilizing diesel fuel. In addition to the CT, new plant equipment will include:

- A generator step-up transformer.
- Less than 500 feet of transmission line from the transformers to the existing substation at the preferred site or less than 1,000 feet of transmission line from a new switchyard to the existing transmission line at the alternative site.
- A new lateral natural gas pipeline, town-border-station, and meter.
- An evaporative cooler.
- An exhaust stack with silencer.

1.4 Electrical Interconnection

The proposed site for the project will include upgrades to the existing site substation and one of the 69-kV transmission lines originating from the substation. No change in the operating voltage and no significant realignment of this line are required for the project. The existing 69-kV and 230-kV substations will be modified to accommodate the electrical output from the project.

The proposed site has two existing 230-kV outlets, seven existing 69-kV lines and an existing 33-MW RDF-fired generation plant.

Preliminary results from the MISO studies indicate that sections of 69-kV lines will need to be upgraded to accommodate the interconnection of the project . The project will include upgrading approximately 5.41 miles of 69-kV transmission line in Sherburne and Anoka counties as part of the Elk River Peaking Station transmission system. The project transmission line rebuilds may involve changing to taller poles (from approximately 40-55 feet to 60-65 feet above ground) and upgrading wire size. The upgrade of transmission capability will also entail improvements to a 0.19-mile section of 69-kV transmission line at the existing substation at County Road 78 (Hanson Blvd.) and Bunker Lake Blvd. Details of the interconnection will be finalized once the interconnection studies have been completed and a final interconnection recommendation is provided by the MISO (expected by mid-December 2007).

1.5 Fuel Supply

The project will use natural gas as its primary fuel and ultra-low sulfur distillate fuel oil as its backup fuel. Natural gas would be transported to the proposed site by the Northern Natural Gas pipeline system.

Fuel oil would be delivered by truck, most likely from the oil terminal in Roseville, Minnesota. At either site, the tanks would be equipped with secondary containment structures in accordance with state and federal regulations.

At either the preferred or alternative site, Northern Natural Gas would construct and own the lateral pipeline from the interconnection at the existing high pressure pipeline to the new town-border station. Great River Energy will own a short segment of the interconnection that will extend from the town border station to the combustion turbine; the specific length and route is undetermined at this time. Northern Natural Gas would obtain any permits or approvals required for the Northern Natural Gas segment of the proposed gas interconnection.

The Northern Natural Gas pipeline system can supply the proposed project during the period from April to November. Northern Natural Gas has indicated that winter natural gas deliverability will be curtailed from November to April due to high local home and commercial heating load.

An existing 846,000-gallon above ground tank would be used to store fuel oil. Great River Energy would limit the amount of fuel stored in the tank to approximately 600,000 gallons to ensure that the volume of oil and oil products stored at the Elk River campus would be less than one million gallons.

The Elk River campus's Spill Prevention Control and Countermeasure (SPCC) Plan would be amended to address the new fuel storage.

1.6 Water Supply

The largest source of operational water demand is for control of NOx emissions when the CT is operating on fuel oil. The water used for NOx control will require treatment with a de-

mineralizer water treatment system. Source water will be treated in a rented trailer-mounted de-mineralizer system and pumped to an onsite storage tank. De-mineralized water demand by the CT when operating on fuel oil is approximately 100 to 120 gallons per minute (gpm) depending on the CT's operating load. Approximately 460,000 gallons of water would be used for NOx control if fuel oil were used for 76 hours in a year.

The second largest source of operational water demand is the CT evaporative cooler. The evaporative cooler is used on hot days to cool and increase the density of air being used by the CT, which increases the CT's power output and efficiency. When the evaporative cooler is in operation, approximately 60 to 85 gpm of water is required, depending on the ambient air temperature, the relative humidity, and the facility operating power level. Approximately 1,000,000 gallons of water would be used if the evaporative coolers were operated for 300 hours in a year.

Untreated source water will also be used to supply fire suppression water. The maximum instantaneous use rate for fire suppression water is expected to be 1,500 gpm. Peak demand for drinking water, sanitary water, and other ancillary plant water uses is expected to be approximately 50 gpm.

Water will be supplied by the Elk River Municipal Utilities (ERMU) at the proposed site.

The plant's water supply will come from ERMU, which operates 7 wells with a combined capacity of approximately 6,800 gpm. The project would have a peak water usage rate of 600 gpm for the demineralization process. This usage would occur over approximately 24 hours to fill an existing 846,000-gallon above ground storage tank on site, and GRE expects that the tank would require filling only once or twice per year. The Project could have a peak use of 85 gpm for evaporative cooling that could be coincidental with ERMU's summer peak demand.

Evaporative cooling is not critical for the plant's operation. In the event that ERMU could not operate a well due to maintenance or other reasons, GRE would be willing to coordinate with ERMU and not operate the evaporative coolers during their peak. Considering the flexibility GRE has in scheduling water usage, the project would not have a significant impact on the ERMU water supply system.

1.7 Wastewater Management

The sources and types of water discharges include the evaporative cooler blow down, compressor section wash water, de-mineralizer concentrate, sanitary waste, and stormwater runoff from the site.

The main source of operations wastewater would be the evaporative cooler. The evaporative cooler is used on hot days to cool and increase the density of air being used by the CT, which increases the CT's power output and efficiency. When the evaporative cooler is in operation, approximately 30 to 60 gpm of blow down wastewater would be generated, depending on the ambient air temperature, the relative humidity, and the facility operating power level.

Compressor section wash water will be generated periodically during cleaning of the turbine compressor. This cleaning is necessary to promote efficient, reliable operation of the CT. Compressor wash water will be discharged to an onsite storage tank. The wash water will be analyzed and proper disposal options will be determined based on the analytical results.

Spill containment will be provided around oil-containing equipment. During rain events, rainwater can collect in the spill containment areas. The containment basins are visually inspected during routing site checks. If water is found within the containment and there is no visible oil sheen, the water would be discharged to the ground surface where it will infiltrate into the ground and possibly flow to the onsite stormwater pond. If there is a visible sheen, the water would be pumped to the plant's oil/water separators for treatment. The oil recovered in the separator will be reclaimed and processed offsite.

Evaporative cooler wastewater stream would be piped to an onsite lift station that will discharge to the ERMU sewer system along U.S. Highway 169.

The wastewater discharge will not significantly impact the city wastewater treatment plant (WWTP). The city WWTP has an average discharge of 1.1 million gallons per day (MGD) and a maximum discharge of 1.2 MGD. ERPS would contribute up to 13 percent of the flow to the plant at its maximum discharge, but less than 0.3 percent on average. Discharge to the WWTP will require a pre-treatment permit that will include contaminant discharge limits.

Some stormwater will also be discharged to the ERMU WWTP system. The oil/water separator will discharge to the pumping station along with any evaporative cooler blow down and ultimately piped to the ERMU WWTP system. Some wastewater is also generated from sanitary waste. This wastewater will be discharged to the sanitary sewer system.

1.8 Air Pollution Control

The project will employ simple cycle combustion turbine technology using both natural gas and fuel oil as the fuel source. The CT will be equipped with Best Available Control Technology (BACT) for NOx emissions.

The CT air pollution controls are inherent to its design and so emission performance would not be different if the project were constructed at the preferred or the alternative site. Great River Energy will propose BACT as dry low-NOx combustors when firing natural gas and water injection for NOx control when firing fuel oil.

BACT will ultimately be defined by the air emissions permitting process, which is administered by the Minnesota Pollution Control Agency (MPCA). The anticipated permitting approach will be to limit annual operation such that annual emissions of all Prevention of Significant Deterioration (PSD) pollutants except NOx will be less than the PSD significance threshold. Thus, NOx will be the only pollutant to require a BACT analysis. Siting the project at the proposed site will require a major amendment to the existing air permit to incorporate the PSD permit conditions.

1.9 Construction

Mobilization at the site would be the first construction activity, with Great River Energy setting up field offices and the Contractor following with mobilization and setup of construction offices, security fencing, and entrances.

Upon issuance of the necessary permits, construction will begin. The area where the new turbine would be located will be excavated approximately 2-4 feet to prepare the area for pouring of concrete footings and foundations. For the preferred and the alternative sites, it is expected that pilings will not be required and that the surficial groundwater table is at a great enough depth that dewatering would not be necessary for construction of foundations.

Underground services will be installed. At the same time, the foundations for the generator step-up transformer and miscellaneous equipment will be formed. Extensive concrete work for all foundations will follow. Rough-ins for cable and pipe will be installed in the various foundations. Within two to three months of initial mobilization, deliveries will begin arriving at the site. These shipments will continue over a four to five month period. Shipments of the transformer, turbine and generator will likely be via rail, with other equipment likely being shipped by truck. The timing of these shipments will coincide with the completion and readiness of their respective foundations.

Rail shipments will be coordinated by the heavy haul subcontractor. This equipment will be lifted from the rail cars and loaded onto transport vehicles to be driven on site. A construction crane will be located on site to lift large equipment from transport vehicles onto foundations.

The combustion turbine, generator, and transformer for the new generating unit will be set first, followed by the remaining auxiliary equipment. Erection of the turbine's modular air inlet and the exhaust stack will take place next.

The greatest number of onsite workers will be present during the erection of the turbines, detailed wiring and piping, and while work is being performed in the substation. Gas pipeline work will occur while the site work is being completed.

Great River Energy will be constructing an overhead transmission line from the generator step-up transformers to the onsite substation or switchyard as plant work nears completion. Work will also be ongoing in the substation or switchyard to install breakers, a transformer, and additional protection devices. Final stages of construction activities will include installation of the inlet air filter and bird screen, completion of equipment platforms, insulation, and painting. Pre-operational testing will take place for one to two months in preparation for start-up of the new unit currently targeted for May 2009. The initial turbine start-up requires a two-week schedule.

The first days will fire gas in the unit and bring it up to full speed with no load on the turbine. Next, the turbine will be run and synchronized with the grid at a low load. Subsequently the

unit's output will be slowly raised to its maximum capacity while testing the performance of various plant systems.

After the completion of testing, Great River Energy and the contractor will begin to demobilize the site. By early Fall 2009, trailers, construction equipment and temporary fencing are expected to be removed from the site.

1.10 Operation

The proposed project will operate as a peaking facility to provide electricity during times of peak demand, typically during very hot and very cold days. Great River Energy currently fulfills its peaking needs primarily with its Pleasant Valley Station (424 MW) and Lakefield Junction Station (515 MW). Pleasant Valley and Lakefield Junction are dual-fuel peaking plants that began commercial operation in May of 2001. Great River Energy's Cambridge Station Unit 2 (approximately 150 MW) is also a peaking facility, which recently began operation in June of 2007.

Typical full load heat rates (higher heating value) are 10,395 British Thermal Units per kilowatt-hour (Btu/kWh), while utilizing natural gas during the summer months, and 9,751 Btu/kWh, while utilizing ultra-low sulfur diesel during the winter months. These heat rates equate to an efficiency of approximately 33 percent and 35 percent, respectively.

Great River Energy anticipates the proposed project will have an annual capacity factor of approximately 5 to 10 percent. The plant will have a short start-up sequence, which is characteristic for an "F-Class" machine. When operating on natural gas, the start-up time would be approximately ten minutes, and the ramp rate would be approximately 30 MW per minute. When operating on distillate oil, the start-up time would be approximately 30 minutes, and the ramp rate is expected to be approximately 10 MW per minute.

Operational characteristics of the project are summarized in **Table 1-1**.

1.11 Maintenance

Great River Energy has extensive experience operating and maintaining CTs including types such as the General Electric (GE) Frame 5, the Pratt & Whitney FT4, the GE 7EA, the Siemens V84.3A2, and the Westinghouse 501D5A. Great River Energy maintains those units using a combination of Great River Energy staff, the CT manufacturer staff through long-term service agreements, and subcontractors. Great River Energy is committed to providing its operations and maintenance (O&M) staff with the very best in continuing education and training to ensure a high level of reliability and availability of its generation assets.

1.12 Sources of Information

Much of the information contained within this document was provided by the applicant or the applicant's representatives in the form of the Application for a Certificate of Need and correspondence. The reader is also referred to the Draft Environmental Impact Statement (DEIS) prepared by the DOC EFP staff as part of the Site Permitting process for this project.

Additional sources of information are listed below:

- Minnesota Pollution Control Agency (http://www.pca.state.mn.us/)
- Minnesota Department of Natural Resources (http://www.dnr.state.mn.us/index.html)
- Minnesota Department of Health (http://www.health.state.mn.us/)
- U. S. Environmental Protection Agency (http://www.epa.gov/)
- Electric Power Research Institute (http://www.epri.com/default.asp)
- U. S. Department of Agriculture Natural Resources Conservation (http://soils.usda.gov/about/)
- Minnesota Geological Survey (http://www.geo.umn.edu/mgs/)
- Department of Administration, State Demographic Center (http://www.demography.state.mn.us/)
- Federal Emergency Management Agency (http://www.fema.gov/)
- U. S. Department of Energy, Energy Information Administration (http://eia.doe.gov/)
- Energy Planning Report, Department of Commerce 2001.
- DEIS Faribault Energy Park, Department of Commerce 2004.
- Environmental Report Trimont Wind Project, Department of Commerce, 2004.

2.0 REGULATORY PROCESS AND REQUIREMENTS

This project requires two distinct processes for the Commission: the first is determining the need for the project and the second is determining the site to be selected.

2.1 Certification of Need Requirement

On May 18, 2007, Great River Energy made an application to the Minnesota Public Utilities Commission (PUC) for a Certificate of Need for the Elk River Peaking Station project pursuant to the provisions of Minnesota Statutes 216B.243 and Minnesota Rules, Chapter 7849. The PUC issued an Order finding the CON application to be substantially complete on August 1, 2007. The docket number for this filing is ET2/CN-07-678.

As part of the review of a Certificate of Need application the Department is required to prepare a document called an Environmental Report (ER). Minn. Rules 4410.7030. The Department Energy Facility Permitting (EFP) staff prepared an ER based on its analyses of the information and data supplied in the Certificate of Need application and several other relevant sources. In the ER the Department evaluated the general potential impacts from construction, operation, and maintenance of the proposed large energy project and discussed ways to mitigate these potential impacts.

Two public information meetings were held, August 17, 2007 (Elk River) and August 18, 2007 (Rosemount); these meetings were held in conjunction with those required for the siting process and are discussed in subsection 2.2 below.

2.2 Site Permit Requirement

On June 14, 2007, GRE submitted an application for a Site Permit for the proposed Elk River Peaking Station. The PUC issued an Order finding the Site Permit application to be complete on August 1, 2007, and authorized the Department to initiate the full review process under Minn. Rules 7845.5010 to .6500. The docket number for this filing is ET2/GS-07-715.

The addition of this generating unit at the Elk River site falls within the definition of a large electric power generating plant (LEPGP) in the Power Plant Siting Act and, thus, requires a Site Permit from the Commission prior to construction. Minnesota rules 7845.5010 to .6500 provide for three different procedures for obtaining a site permit: full review, alternative review, and local review. GRE is applying for a site permit following the full review process. The project is not eligible for the alternative process because the proposed unit will be fueled by both natural gas and fuel oil. In the full review process, the applicant must identify in the application the preferred site for the power plant and one alternative site, respectively Elk River and Rosemount.

The Department Energy Facility Permitting (EFP) staff prepares a document called an Environmental Impact Statement (EIS). An EIS is a written document that describes the human and environmental impacts of a proposed large electric power generating plant (and selected alternative sites) and methods to mitigate such impacts. The public has the opportunity to

comment on the scope of the EIS and the draft EIS through comment periods and at the Department sponsored information/scoping meetings.

As stated above, two public information/scoping meetings were held, August 17, 2007 (Elk River) and August 18, 2007 (Rosemount). Approximately 12 persons, excluding Department/PUC staff and the applicant's representatives, attended the meetings. The purpose of the public meetings was to provide the public with information about the project, afford the public an opportunity to ask questions and present comments, and to solicit input on the content of the ER and the scope of the EIS documents.

During the initial public information/scoping meetings concerns raised regarding need included fuel type, load service area, simple cycle versus combined cycle operation, and cost of electricity. On the siting application concerns raised included air emissions, water usage, potential for future expansion, future plans for the alternative site (i.e., Rosemount), and potential noise impacts.

The comment period was held open until 5:00 pm August 13, 2007.

One comment letter was received regarding GRE's proposed Elk River peaking station; a request that the use of utility scale batteries be considered in place of the natural gas facility. This issue, along with the typical large energy projects need and siting issues, have been incorporated into the proposed Orders on the Content of the Environmental Report and the Scope for the Environmental Impact Statement (**Appendix B**).

3.0 ALTERNATIVES TO THE PROPOSED LEPGP

Under Minn. Rules part 7849.7060, subpart 1, the Environmental Report must include a general description of the alternatives considered, an analysis of the potential human and environmental impacts of these alternatives and possible mitigative measures, and an analysis of the feasibility and availability of each alternative. In this case the scoping order identified the following alternatives that will be analyzed in this document: the no build alternative, demand side management, purchase power, alternative fuels (fossil fuel technologies and renewable resource technologies), emerging technologies, up-grading existing facilities, and new transmission. Each of these alternatives is addressed in turn below.

3.1 No-Build Alternative

The no-build alternative means that GRE does not build anything. Electric power will continue to be supplied in the manner and with the facilities that are presently in existence.

Impacts. Often, in conducting environmental review, the analysis of the no-build alternative involves a discussion of the environmental impacts of continuing the status quo. For example, with a proposed highway project, the no-build alternative would take into account the impacts associated with continuing to have traffic increase along existing roads and highways and for development to occur along these existing arteries.

When a certificate of need is required for a proposed project, however, the no-build alternative takes on a different aspect. If the PUC determines that the need for additional power has not been established, no certificate of need will be issued and nothing new will be constructed. Whatever impacts would result from the proposed project will not occur.

If GRE establishes that there is a need for additional power, but no new facility is authorized, the potential impacts are twofold. One, there could be a shortage of electricity, with all the ramifications that result from a shortage of electricity on hot days in the summer. Two, the electricity will come from someplace else, with the impacts that result from the generation and transmission of electricity from these other sources. These impacts are explored below with the various alternatives.

One impact of not building the proposed facility is that anticipated wages and tax revenues to the local economy would be lost. In the Certificate of Need application, Section 7.2, GRE discusses the socioeconomic impacts associated with delay or the no build alternative. About 100 construction jobs will be created over the one year project construction period and approximately $8 million of payroll will be added to the regional economy. Operation of the new facility will require two to three full-time positions.

If the proposed project is not constructed or delayed indefinitely, GRE's costs would increase because more expensive alternative resources would need to be utilized to meet capacity and energy needs. These higher costs would in turn result in higher rates for GRE's members. The specific impact would depend on the length of the delay.

Feasibility and Availability. The no-build alternative is not one that requires any analysis regarding its feasibility or availability.

3.2 Demand Side Management

Demand side management (DSM) is the practice of reducing customers' demand for energy through programs such as energy conservation and load management so that the need for additional generation capacity is eliminated or reduced. More detail on GRE's conservation and load management programs is available in Appendix C of GRE's Certificate of Need Application, dated May, 2007.

Impacts. Demand side management can minimize environmental effects by avoiding the construction and operation of new generating facilities. Those impacts that would result from the construction of the proposed facility, or from the supply of the additional power through other means, would be avoided if DSM were sufficient to reduce the need for additional power.

Feasibility and Availability. A determination of whether demand side management can reduce the anticipated need for additional power is what the Public Utilities Commission will determine in the certificate of need proceeding. A conclusion that DSM will eliminate the need for additional power is essentially a decision to deny the requested certificate of need.

The only information reviewed for this document regarding the feasibility of DSM is that information provided by GRE in its Certificate of Need Application, dated May, 2007. GRE concludes in its application that DSM is not a feasible alternative to the proposed project.

According to GRE, the demand for electrical power will continue to grow at an average rate of 3.8 percent per year or an average of an additional 120 MW for the GRE service area each year. The methodology used to develop the forecast demand and other forecast details required by Minnesota Rules part 7849.0270 were described in Appendix A of the CON application.

In 2006, GRE had approximately 107 MW of its peak load controlled through DSM programs. Cost-effective programs continue, but are not expected to diminish peak demands in the immediate future by an amount sufficient to eliminate the need for the project. Additionally, the project proposed here is intended to address the peak demands for power in the hot summer months. DSM is designed to reduce the demand for power over long terms. It is not practical to expect that the results of the program can be doubled or tripled in less than a year, the time remaining after the result of the Commission's Need decision

3.3 Purchase power

Purchased power is exactly what it says – the purchase of electricity from another entity. Utilities like GRE enter into power purchase agreements with other generators of electricity. A power purchase agreement is a contract between a wholesale supplier of electricity and an entity that sells the energy to retail consumers.

Impacts. The environmental impacts associated with the purchase of electricity depend for the most part on how the electricity that is purchased was generated. Presently, GRE purchases significant amounts of electricity in the summertime. This electricity comes from various sources, including some from coal-fired power plants and some from hydro facilities. It is difficult to discuss with any specificity what the comparable impacts are at this juncture.

Feasibility and Availability. The feasibility and availability of short-term and long-power purchase agreements are discussed separately below. The information is taken from GRE's certificate of need application. GRE analyzed the potential alternative of purchased power in two fundamental categories: 1) long-term contracts dedicating specific resources to meet GRE needs and 2) short-term market purchases.

Short Term Power Purchase Agreements. The option to use short-term capacity purchases was analyzed based on recent market experience and market intelligence regarding the expected future availability of this power. Short-term capacity purchases are contracted purchases that consider a minimum of a 30-day agreement.

GRE has previously utilized power purchases to defer building or purchasing additional generation. For example, in 2005, GRE signed a three-year purchase agreement for capacity to meet the 2008 peaking need identified in the 2005 GRE Integrated Resource Plan. The purchase allowed GRE to defer the need for the 2008 peaking facility. The purchase expires in 2008. GRE has been unable to find additional similar purchases to meet its need in 2009.

GRE's policy regarding use of short-term capacity purchases is to analyze its position on approximately a season-ahead basis. If GRE is short capacity, it will pursue capacity and firm transmission purchases to cover the difference. Generally, this situation would only occur in the case that GRE's revised short-term forecast is higher than expected for the summer season.

GRE's energy position is also analyzed on a season-ahead basis. If market conditions indicate that prices are below the price of the MISO resources that GRE had planned to use to serve its load, then GRE would make forward energy purchases. Also, energy purchases are sometimes necessary to cover expected energy deficits due to scheduled outages.

Daily, weekly, and hourly type purchases apply only to energy transactions that are lower than the expected prices from the MISO resources that would otherwise serve GRE's load.

Long Term Purchase Power Agreements. The long-term option, utilizing a power purchase agreement to purchase capacity and energy from an existing resource or a resource built specifically to meet GRE needs, was analyzed using the results from GRE's 2006 RFP (see Appendix F GRE's May, 2007, CON Application).

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 being a not-for-profit organization. These facts were reflected in GRE's overall proposal price. Purchased power contracts are typically less flexible

than desired for a peaking resource. Purchases generally require scheduling energy on a day-ahead basis with limited flexibility intra-day 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 can allow maximizing the dispatch of its other resources.

3.4 Alternative Fuels

One of the issues to be examined in the Environmental Report is the possibility of using a different energy source than the one proposed by the project proposer. In this case GRE has proposed to install a natural gas-fired simple cycle turbine. Other types include a coal-fired boiler; a natural gas-fired combined cycle; and a fuel oil-fired simple cycle, although as mentioned earlier, no specific project is reviewed in this analysis.

3.4.1 Coal Fired Boiler

This option is the burning of coal to generate electricity. Coal plants are generally baseload plants that operate nearly all the time. The Coal Creek Station near Underwood (approximately 1,200 MW), and the Stanton Station near Stanton (approximately 188 MW), are examples of two baseload coal plants owned by GRE.

Impacts. The direct environmental impacts of coal burning include air emissions, solid waste (ash) generation, waste heat discharge to air and water, and rail traffic. Burning coal results in the emission of various air pollutants, including sulfur dioxide, nitrogen oxides, particulate matter, mercury, carbon monoxide, and carbon dioxide.

It is not possible to build a new coal-fired plant by the summer of 2009, when GRE says the new Elk River Peaking Station (ERPS) facility must be online, and it is not likely that one of GRE's existing coal-fired power plants could provide the peaking power to be provided by the ERPS, but just to put the environmental impacts into perspective, it is possible to calculate a "ball-park" figure of how much of certain pollutants would be emitted if the power to be generated by the new natural gas turbine at the ERPS were generated instead at an existing coal plant.

The Minnesota Pollution Control Agency has determined the emission rates per unit of electricity generated for a number of generating facilities in the state. These results are found in the Energy Planning Report prepared by the Department of Commerce in 2001 at page 95, Figure A-4. That report is available at:

http://www.state.mn.us/mn/externalDocs/Energy_Planning_Report_121602022402_2002PlanningRpt.pdf

If it is assumed that the ERPS turbine runs at full capacity for the maximum 1300 hours per year that GRE intends, the emissions associated with such generation at another facility can be calculated. If this electricity were replaced by electricity generated at Xcel Energy's Sherco Plant, for example, the additional emissions of NOx, SO_2 and CO_2, based on the PCA figures in the Planning Report, would be:

341 tons/year of NOx

341 tons/year of SO2

272,000 tons/year of CO2.

(The math is as follows: 1300 hours/yr times 320 megawatts = 416,000 MWhrs/yr. 416,000 MWh/yr times 0.003 lb NOx/kWh times 1000 kWh/MWh times 1 ton/2000 lbs = 624 tons/yr.) (The emission rate per unit of electricity is the same for both NOx and SO2 and 2.39 lbs per kWh for CO2.) Presently, emissions from existing baseload generating plants in Minnesota total approximately 80,000 tons for NOx, 90,000 tons for SO2, and 34 million tons for CO2.

Feasibility and Applicability. A coal-fired facility may serve as an intermediate load unit; however, coal-fired power plants are best suited for base load (steady, high-capacity) duty. Coal-fired units are not well suited to operate as peaking plants because of the long lead time (a day or more) necessary to bring a coal-fired plant online at full capacity.

Coal-fired power plants typically expect an annual outage rate for maintenance of 11 percent. Unplanned outages typically consume another 4 percent of the unit's availability. The net availability of coal-fired units is expected to be in the range of 85 percent.

The total capital requirement for a hypothetical coal-fired power plant is estimated to be $1,100/kW6. A typical energy cost for a hypothetical coal-fired power plant is estimated to be 3.5 cents per kWhour. Building a coal-fired power plant is a major construction project with a 24- to 36-month or longer time frame. While the construction work force is of a significant size, its contribution to the local economy is temporary. Power plants in today's market are operating with significantly fewer staff than in the past and are probably not regarded as having a key impact on local employment rates. Power plants in Minnesota are assessed a significant local property tax that can be viewed as likely offsetting the tax burden on other local enterprise.

3.4.2 Oil Fired Simple Cycle

GRE has proposed to install a simple cycle natural gas-fired system. A simple cycle system could be built to burn fuel oil instead of natural gas.

The simple cycle power plant is similar to the technology described for combined cycle except that the heat from the combustion turbine exhaust gases is not recovered for secondary electric generation from a steam turbine. Because of this difference, simple cycle technology has a significantly lower efficiency than combined cycle technology.

Ancillary equipment is likely limited to:

- natural gas vaporizers;
- possible ammonia storage if post-combustion NOx control is required;
- control buildings;
- fuel oil storage tanks;
- a fuel forwarding system (pumps/piping/controls) to transfer fuel oil from storage to the turbine; and,

- fuel heating systems for winter operations.

Impacts. There will be more emissions into the air from burning fuel oil than from burning natural gas. Emissions from burning the fuel will be determined by the qualities of the particular fuel oil burned. **Table 3-1** contains a comparison of the operational data for an oil-fired simple cycle and the natural gas-fired units proposed. **Table 3-2** contains a comparison of the cost of electricity between the proposed project and an oil-fired simple cycle facility.

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.

The Elk River Peaking Station DEIS contains additional information on the emissions associated with burning fuel oil.

Environmental impacts in terms of energy efficiency (input fuel energy per kilowatt-hour produced), would not show a distinct advantage for a simple cycle turbine vs. a combined-cycle plant or a coal-fired plant. The energy efficiency for simple cycle turbine generators can be expected to be in the range of 25 to 30 percent, regardless of fuel. The direct environmental impacts of operating a simple cycle plant burning natural gas include air emissions, waste heat discharge via the stack and the potential for on-site ammonia storage if post-combustion NOx control is required.

Feasibility and Applicability. There is no technical reason why any turbines GRE installs at the ERPS facility could not have the capability of burning fuel oil. The use of fuel oil would also result in higher operating costs than the natural gas-fired alternative. Higher operating costs mean this alternative would not run as much thus limiting the opportunities to provide ancillary services such as load following and load regulation while operating.

3.5 Natural Gas Fired Combined Cycle

A gas-fired combined cycle power plant is a combination of combustion turbine technology, heat recovery, and electric generation. In the combustion turbine, incoming air is compressed and mixed with the natural gas fuel. Igniting this mixture results in an expansion of gases (the combustion products and excess air) through a power turbine that in turn drives an electric generator. Hot exhaust gases exiting the combustion turbine pass through a heat recovery steam generator (HRSG) to produce steam that is used to drive a steam turbine connected to a second electric generator. Typically, of the overall electric output from a combined cycle unit, two-thirds is produced by the combustion turbine, and one-third is produced by the steam turbine generator.

Other major combined-cycle plant equipment would include:

- a system (e.g., condenser or cooling tower) to condense the steam turbine exhaust steam;

- a water treatment equipment to provide high-quality makeup water to the steam cycle;
- electrical switchgear to provide power to auxiliary plant equipment;
- water storage tanks and fuel oil storage tanks (if applicable);
- natural gas vaporizers;
- possible ammonia storage if post-combustion NOx control is required; and, operations and maintenance buildings.

***Impacts*.** The **e**nvironmental impacts, in terms of energy efficiency (input fuel energy per kilowatt-hour produced), show a distinct advantages for a combined-cycle project vs. a simple cycle project. The energy efficiency for a combined cycle plant can be expected to be in the range of 45 to 50 percent. The direct environmental impacts of operating a combined-cycle plant burning natural gas include air emissions, wastewater discharge, waste heat discharge to air and water and the potential for on-site ammonia storage if post-combustion NOx control is required.

In February 2004, the Environmental Quality Board completed an Environmental Impact Statement on a proposed combined cycle natural gas plant – the Faribault Energy Park Generation Facility – in Rice County. EQB Docket No. 02-48-PPS-FEP. The reader is referred to that document for more information about combined cycle natural gas plants. The EIS and other documents related to that project can be found at

http://www.eqb.state.mn.us/Docket.html?Id=3217

***Feasibility and Applicability*.** The combined cycle technology, both natural gas fired and fuel oil fired, is generally not considered for peaking service due to the relatively high capital cost when compared to simple cycle plants. Although it is more efficient to operate over longer periods than simple cycle, combined cycle technology is not as well suited to fast startup and short deployments because of the time required to bring the steam side of the plant into operation. The complexity of combined cycle plants and associated permitting and construction makes commercial availability of such a plant by 2009 unachievable.

Combined cycle plants are well suited to meet intermediate load needs. Secondary service modes of base load and peak load are also achievable. A combined cycle plant is more economical to keep on heated standby than a coal-fired boiler would be. A combined cycle plant has a shorter construction period compared to a coal-fired plant.

Combustion turbine-based power generation can expect to reflect a planned outage rate of about 7 percent and an unplanned outage rate of about 5 percent. However, properly operated and maintained combined-cycle facilities will achieve 90 to 95 percent availability.

A combined-cycle plant can generally demonstrate high reliability. Natural gas-fired combined cycle facilities typically have fuel oil backup to address the potential interruption of natural gas supply.

The total capital requirement for a gas-fired combined-cycle power plant is estimated to be $590/kW. A typical energy cost for a gas-fired combined cycle power plant is estimated to be 4.6 cents per kW-hour. Building a combined-cycle power plant is a major construction project with a 12- to 24-month time frame. The construction work force is sizeable, however, its contribution to the local economy is temporary. A combined-cycle unit fired with pipeline natural gas will require significantly fewer staff than a corresponding coal-fired facility having to deal with major coal and ash handling operations. A combined cycle plant is not regarded as having a key impact on long-term local employment rates. A combined cycle plant would be subject to applicable property tax assessments.

3.6 Renwable Sources of Energy

GRE also considered possible renewable energy sources as part of its certificate of need application, including wind, solar, biomass, hydropower, and landfill gas. Each of these alternative energy sources is addressed below. Again, no specific proposals or projects have been identified.

3.6.1 Wind Technology

Wind energy technology consists of a set of wind-driven turbine blades that turn a mechanical shaft coupled to a generator, which in turn produces electricity. The major components of the wind turbine include:

- the rotor blades;
- gear box;
- generator;
- nacelle (gearbox/generator housing); and,
- tower.

Wind turbines are either horizontal access or vertical access machines, which make full use of lift generating air flows. Each type of turbine has advantages and disadvantages. Most types are commercially available, although the horizontal access turbine is predominant. Horizontal access turbines are typically built with two or three turbine blades. Turbines for utility applications are normally installed in clusters of 5 to 50 megawatts, and may be referred to as wind farms.

Impacts. Wind turbine generation has many environmental advantages over fossil fuels because there are no air emissions nor solids or water discharges associated with operating the turbines. Turbines may encounter some siting opposition with regard to noise and aesthetics. In many cases, the original use of the land (i.e., agriculture) can continue in the presence of the turbine installation.

The EQB completed an Environmental Report on a proposed wind project – the Trimont Wind Project – for the Public Utilities Commission. PUC Docket No. IP-6339/CN-03-1841. That document and others relating to that project can be found at

http://www.eqb.state.mn.us/Docket.html?Id=5208

Feasibility and Availability. GRE Energy eliminated wind technology from further consideration because its lack of reliability makes it unsuitable for peaking service. The reliability of a wind turbine-based generating facility depends on the wind, which is highly intermittent. The objective of the application to provide on-demand generation for peak load cannot be served by a variable energy non dispatch able resource.

Applicability for wind turbines is defined primarily by problems with reliability of the plant's "fuel", the wind. A wind turbine installation cannot adequately meet intermediate and peaking load needs. The variable nature of wind patterns does not support a strategy to address the growing demand for electric power in the near term. Siting of a large wind turbine installation is also predicated on locating candidate areas that have wind energy data that would support the project economics.

Wind turbines are generally expected to have an availability in the high 90-percent range (i.e., the turbines are capable of providing generating service). Even when wind energy is present, wind turbines can only generate power within an optimum range of wind speeds.

The total capital requirement for a wind turbine installation is estimated to be in the range of $1,000/kW. Typical energy cost for a wind turbine is estimated to be 5.4 cents per kW-hour. Building a wind farm project, like other power projects, would utilize a significant work force for the duration of construction. Operating a wind farm does not require a large staff. Wind power electricity often qualifies for tax credits or production incentives on a cents per-kilowatt basis.

3.6.2 Solar Technology

Technologies for converting solar energy to electricity include thermal conversion (typically using sunlight to generate steam to turn a turbine) and photovoltaic (direct conversion of sunlight to direct current power). Thermal or concentrating solar power technology (parabolic troughs, power towers, and dish/engine systems), converts sunlight into electricity efficiently with minimal effects on the environment. Trough systems predominate among today's commercial solar-powered plants. Trough systems focus the sun at 30 to 60 times its normal intensity to heat a heat transfer fluid (synthetic oil). The hot oil is pumped to a generating station heat exchanger to produce steam. Finally, electricity is produced in conventional steam turbine generators. Trough systems may be configured as hybrids to operate on natural gas on cloudy days or after dark. Natural gas provides 25 percent of the output of the Barstow plants.[1]

The "photovoltaic effect" is the basic physical process through which a photovoltaic (PV) cell converts sunlight into electricity. Solar energy (composed of photons) is transferred to the electrons of atoms making up the PV cell. Higher energy electrons begin to flow and become

[1] http://www.sandia.gov/Renewable_Energy/solarthermal/NSTTF/question.htm

electric current. By grouping single PV cells into arrays, and then placing many arrays together, power plants of up to 6.5 megawatts have been built.

Impacts. Solar power generation has many environmental advantages over fossil fuels because there are no air emissions or solids discharges associated with operating the systems. Trough/gas hybrid systems do utilize a steam loop, which requires process and cooling water, some water treatment and some wastewater discharge (blowdown).

Feasibility and Applicability. Like wind turbine generation, the applicability for solar generation is defined primarily by its fuel availability. Solar power systems generally represent even less capacity than a wind turbine installation and, combined with a dependence on quality insolation rates, cannot meet intermediate load and peaking service needs. The variable nature of solar intensity does not support a strategy to address the growing demand for peak electric power in the near term. Siting of a large solar power plant is also predicated on locating candidate areas that have the solar energy data that would support the project economics.

Solar power plants are generally expected to have an availability in the 90-percent range (i.e., the installations are capable of providing generating service if sufficient solar energy is present).

A solar power installation cannot meet an objective of providing a guaranteed performance to the end user of generated power. The hybrid design of some solar plants, utilizing natural gas during periods of poor solar intensity, acknowledges that solar energy cannot be depended upon to maintain a capacity rating.

The total capital requirement for a photovoltaic power plant is estimated to be $4,000/kW. Typical energy cost for a hypothetical photo voltaic power plant is estimated to be 48.4 cents per kW-hour. A trough/gas hybrid plant is estimated to have a total capital requirement in the range of $3,240/kW. Building a solar generation project, like other power projects, could utilize a significant work force for the duration of construction. Operating solar generation facilities does not require employing a large staff.

GRE eliminated solar generation from further consideration because its lack of reliability makes it unsuitable for peaking service. Like wind, solar power generation has real environmental advantages; however, like wind, solar radiation is a variable energy source that is not able to meet the intent of the project to provide peaking power generation on demand. Geography also plays a role in that Minnesota is not a prime location for significant solar power generation projects. Additionally, solar technology has significantly higher costs per kilowatt to install.[2]

3.6.3 Direct Fired Biomass

The process of direct-firing biomass fuels is very similar to the firing of other solid fuels. Fuel handling and storage, fuel firing, ash handling and disposal, air emissions, water consumption, and wastewater management will have many similarities to coal-fired systems. The primary activity steps for a biomass plant include:

[2] http://www.eere.energy.gov/solar/cs_ca_substation.html

- Biomass fuel receiving;
- On-site processing (size reduction, drying, screening)
- Fuel storage/conveying
- Boiler (usually a stoker design)
- Ash and flue gas handling
- Air emission controls (baghouse/ESP for particulate; ammonia for NOx control)
- Steam turbine
- Cooling tower.

Biomass fuels can be harvested from the forest, collected as waste materials from processing plants or agriculture, or grown in biomass plantations. Fuel may be shipped to the power plant by truck, rail or barge depending on the plant location and type. Fuel will generally be stockpiled as insurance against interruptions in supply. Depending on the fuel characteristics, drying and size reduction may be necessary prior to firing. Drying is sometimes accomplished by utilizing the heat from stack gases. Prepared fuel is fed to the furnace and the resulting heat is used to generate steam. The steam from the boiler is piped to, and drives, a steam turbine, which in turn drives an electric generator to produce saleable electrical power.

GRE has significant experience with biomass resources, which aided in its analysis of whether biomass could serve its current needs. GRE operates a 33-MW power plant (Elk River Station) that burns Refuse Derived Fuel (RDF). RDF is the material produced from processing municipal waste, which is then used as the main fuel to produce electricity. As a waste-to-energy power plant, it diverts about 270,000 tons of municipal solid waste from community landfills annually.

In addition to its Elk River Station facility, GRE purchases the biomass output energy from other biomass facilities. GRE purchases the output from a 3.2-MW landfill-gas-fueled facility located in Elk River, Minnesota. GRE also purchases the output from two generators that produce electricity by combusting gases from anaerobic dairy manure digesters. The purchases are very small (410 kW total) in relation to GRE's identified need.

Impacts. Waste streams from the furnace include stack gases, bottom ash, and boiler water blowdown. Bottom ash produced in many biomass combustion plants is often of a quality that can be sold, or used as a soil conditioner/fertilizer due to the lack of many trace metals, which often contaminate coal ash. Boiler blowdown, along with other process wastewater streams, will typically be treated to remove solids, oils, and grease prior to discharge. Cooling water used to condense the steam exhausted from the turbine would most likely be cooled using a direct contact cooling tower. The use of a cooling tower represents a significant consumption of water.

The stack gases will contain particulate matter as well as gaseous pollutants. If a thermal drier with auxiliary firing is used, the drying step will increase energy use and environmental emissions.

Typically, stack gases will pass through an air pollution control device where particulate matter is removed. A large new boiler will likely be required to also address the control of NOx and CO

emissions. Viewing environmental impacts indirectly in terms of energy efficiency (input fuel energy per kilowatt hour produced), biomass-fired plants typically operate in a range of 20 – 30 percent efficiency.

Biomass power production is affected by a greater variability in biomass fuel quality than is coal-fired power production. Variability in moisture and ash content are characteristic of a diverse fuel source and leads to variability in heat value on a mass basis. The direct environmental impacts of biomass burning are similar to those for coal combustion and include air emissions, solid waste (ash) generation, waste heat discharge to air and water, and truck and/or rail traffic.

The EQB evaluated a biomass plant in the Environmental Report on the Trimont Wind Project. The reader is referred to that document for additional information about the possible environmental effects of a biomass plant burning hybrid willows, poplars, and corn stover.

Feasibility and Applicability. A biomass facility may serve as an intermediate load unit; however, biomass-fired power boilers are best suited for base load (steady, high-capacity) duty. Stoker boilers are not well suited to operate as peaking plants because of the long lead time (a day or more) necessary to bring a solid fuel-fired plant on-line at full capacity. The forest products and agriculture industries in Minnesota offer a wide variety of available biomass fuels.

Biomass power plants are expected to have an annual outage rate for maintenance of 10 percent. Unplanned outages typically consume another 5 percent of the unit's availability. The net availability of biomass-fired units is expected to be in the range of 85 percent.

A biomass-fired plant can generally demonstrate high reliability (both the adequacy and security aspects) for base load and intermediate load service. The supply of biomass fuel in quantities sufficient to generate power at the hundred MW level and higher will require development of a fuel collection plan; however, Minnesota's agricultural and silva-cultural industries can likely support a reliable fuel supply.

The total capital requirement for a hypothetical wood burning power plant is highly variable and size dependent. Higher capacity plants will generally be much cheaper. Capital costs are estimated to be in the range of $1,100 to $1,840/kW. Typical energy cost for a wood burning power plant is estimated to be 4.9 cents per kW-hour. Building a biomass-fired power plant is a major construction project with a 24 to 36 month or longer time frame. While the construction work force is of a significant size, its contribution to the local economy is temporary. The long-term operation of a biomass power plant would not be regarded as having a large impact on local employment rates via plant staffing. The creation of a (larger) biomass-for-fuel market may be an opportunity for farmers and landowners to exploit biomass materials that would otherwise be neglected as an income producing source.

The plant would be subject to applicable property taxes that can be viewed as likely offsetting the tax burden on other local enterprise.

GRE eliminated biomass from further consideration because a biomass-fired plant cannot meet the peaking generation objectives of the project efficiently. Historically, biomass operation has not been available in sizes necessary to meet the needs of this project. Additionally, biomass generation takes long lead times to develop, has high capital cost and is most efficient in a base load application.

3.6.4 Hydropower

Hydropower is clearly the major player in the renewable group of power options, accounting for about 97 percent of renewable generation. Hydroelectric power plants convert the potential energy of water, pooled at a higher elevation, into electricity by passing the water through a turbine and discharging it at a lower elevation. The water turns the turbine connected to an electric generator thus producing electrical energy. The turbines and generators are installed in, or adjacent to, dams, or use pipelines (called penstocks) to carry the pressurized water below the dam or diversion structure to the powerhouse. Hydropower projects are generally operated in a run-of-river, peaking, or storage mode.

Run-of-river projects use the natural flow of the river and produce relatively little change in the stream channel and streamflow. A peaking project impounds and releases water when the energy is needed. A storage project extensively impounds and stores water during high-flow periods to augment the water available during low-flow periods, allowing the flow releases and power production to be more constant. Many projects combine the modes. The capacity of a hydropower plant is primarily a function of two variables: (1) flow rate expressed in cubic feet per second (cfs); and (2) hydraulic head which is the elevation difference the water falls in passing from the reservoir through the turbine. Depending on the particular waterway being considered, project design may concentrate on either of these variables (high head/low flow or low head/high flow).

Most conventional hydropower plants include the following major components:

- Dam; controls the flow of water and increases the elevation to create the head. The reservoir that is formed is in effect stored energy.
- Penstock; carries water from the reservoir to the turbine in a power plant.
- Turbine; turned by the force of water pushing against the blades.
- Generator; connects to the turbine and rotates to produce the electrical energy.

The principal advantages of using hydropower are its large renewable domestic resource space, the absence of polluting emissions during operation, its capability in some cases to respond quickly to utility load demands, and its very low operating costs. Disadvantages can include high initial capital costs and potential site-specific and cumulative environmental impacts.

Xcel Energy eliminated hydropower from further consideration because of its long lead time. Development of hydropower potential requires a prolonged study to determine environmental and hydrologic impact. New hydropower sites will also require siting of transmission systems through remote areas, which typically require a long approval process. The current project's

primary objectives include near-term capacity that hydropower cannot address because of its long development lead times.

Impacts. Hydropower projects are not sources of the typical air and water emissions and solid waste disposal issues associated with solid fuel-fired power production; however, hydropower has faced scrutiny for its significant environmental impacts (i.e., altered river basin hydrology, fish mortality, fish migration interference, decrease in water quality, and flooding of land).

Feasibility and Applicability. Hydroelectric plants are operated in several modes. Plants with large water storage capability lend themselves well to peaking power production and hydroelectric plants are able to come on line much quicker than steam generating systems. Run-of-river plants are more likely to produce a more constant power output though that output is dependent on water levels and, in cold climates, ice conditions.

The U.S. Department of Energy's (DOE) Hydropower Program has developed an estimate of undeveloped hydropower in the United States.[3] The study and its model estimate a hydroelectric potential of about 2,500 MW to be available at more than 450 potential sites located within MAPP region states. Those potential megawatts come from additional capacity at existing hydro plants (about 800 MW), from existing dams not equipped with power generating equipment (about 1,200 MW), and from sites which would require dam construction (about 400 MW).

While it is possible that some of the identified potential hydropower could be developed, exploiting the potential requiring dam construction would need to also consider that transmission systems may not exist in remote areas containing hydropower potential. Development of hydropower, and associated transmission systems, faces the scrutiny of a general environmental trend toward releasing water reservoirs where possible. Developing capacity of a hundred MW or more would require development of multiple existing and/or potential hydropower sites. Such an effort would take several years of environmental study and negotiation to acquire water use and land rights, and permits and licensing for dams and/or transmission lines.

There is potential for additional hydropower development within the MAPP region. It is unclear whether that potential can be practicably realized. The timetable to develop those resources is not likely to be able to meet near-term capacity and energy requirements.

During periods of normal precipitation and ice-free conditions, the availability of established hydropower generation is typically in the range of 95 percent.

The hydropower sector of power generation is well established with proven technologies installed as standard design. In mechanical terms, hydroelectric plants are highly reliable.

Because hydropower depends on water flow, hydroelectric plants are susceptible to fluctuations in output as a function of weather patterns. Reliability can suffer during periods of drought or during periods of freezing conditions in northern climates. Weather-induced fluctuation in

[3] http://hydropower.inel.gov/techtransfer/pdfs/doe_hydropower_fy03_annual_report_final.pdf

power output may be less pronounced than it is for wind or solar power; however, for long-term planning to meet projected demand, hydropower may be better suited to reliably provide peak load capacity.

The total capital requirement for a hypothetical hydropower power plant is estimated to be $2,000/kW. Typical energy cost for a hydropower plant is estimated to be 6.6 cents per kW hour. Most of the potential sites within MAPP have capability of less than 10 MW and economies of scale cannot be realized. Annual operating expenses would likely be less than for a fuel-fired power plant because the hydropower energy source (pooled water) is not typically a purchased input.

Building a hydroelectric power plant is a major construction project with a several-year time frame.

The construction work force is of a significant size, however, its contribution to the local economy is temporary. The long-term operation of a hydroelectric power plant would not be regarded as having a large impact on local employment rates via plant staffing. The creation of a new reservoir does have the potential for creating commerce from recreational activity if fisheries and surrounding land area are developed to attract the public.

3.6.5 Landfill Gas

The most common use of landfill gas (LFG) is for on-site electricity generation by firing stationary engine generator sets. Some LFG facilities are used to fire boilers or turbines. LFG that is sufficiently processed could be an energy source for fuel cell operation. Electric generating plants using LFG and those using natural gas or distillate oil are nearly identical; however, firing LFG does require gas processing and careful monitoring of equipment because LFG tends to be more corrosive.

Significant quantities of LFG are emitted from municipal solid waste where it has been deposited in landfills; however, LFG typically has a medium Btu content and is not typically a source of energy on a scale larger than a few megawatts.

LFG recovery for energy is practiced in the United States, Europe and other countries around the world.

A typical system consists of the following components:

- the gas collection system, typically a series of wells strategically placed throughout the landfill, which gathers the gas being produced within the landfill;
- the gas processing system and engine/generator set , which cleans the gas and converts it into electricity; and
- the interconnection equipment, which delivers the electricity from the project to the final user.

Impacts. LFG projects are expected to be a net benefit to the environment by reducing the amount of LFG emissions to the atmosphere; however, some of the landfill emission reductions are offset by the combustion emissions such as NOx and CO from the combustion equipment. From an energy efficiency perspective, LFG collection systems (i.e., the well networks) are not totally efficient, and combined with the inherent inefficiencies of combustion equipment, the overall energy efficiency of an LFG system generally less than 30 percent.

Feasibility and Applicability. LFG power generation projects are generally sited on large landfills and produce power in the range of kilowatts, perhaps 1 to 2 megawatts. The driver for LFG power generation is the utilization of a fuel source that would otherwise be flared to avoid an explosion hazard and to avoid an emission source by producing saleable energy. A LFG plant could reasonably be viewed as an emission control technology. LFG does not exist at the levels needed to support large energy needs.[4]

The availability of a LFG-fired generation system is expected to be similar to systems firing natural gas (i.e., availability greater than 90 percent); however, the corrosive nature of landfill gas does introduce more potential for equipment problems.

Because of the small-scale nature of most LFG plants, a LFG power installation project typically does not have an objective of providing a guaranteed performance from the perspective of the utility customer. Power output for LFG plants depends upon the LFG production rate that does not adjust to power demand. LFG-generated power can replace a percentage of baseload generation and subsequently conserve fossil fuels.

The total capital requirement for developing a LFG power plant ranges from $1,100 to $1,700/kW; however, the LFG volumes do not exist within one MAPP site necessary to fuel a plant with a hundred MW or higher capacity. Typical energy cost for a hypothetical LFG power plant is estimated to be 6.0 cents per kW-hour. Annual operating expenses may be less than for a typical fuel-fired power plant because the LFG is not typically a purchased input; however, municipalities associated with landfills may require a royalty to be paid from energy sales.

Landfill gas (LFG)-fired generation should be eliminated from further consideration primarily because potential landfill sites are not large enough to meet the project's primary objectives.

3.6.6 Ethanol-Fueled Peaking Plant

An ethanol-fueled peaking facility appears to be a logical renewable alternative to meet GRE peaking needs. If the same equipment proposed for the proposed project could be used for an ethanol-fired facility, the criterion of availability of at least 157 MW for summer 2009 could be met.

In general, the impacts of burning ethanol in a CT include the following:

- The use of water injection (similar to fuel oil) to mitigate higher NOx emissions.

[4] http://www.eia.doe.gov/cneaf/solar.renewables/page/landfillgas/landfillgas.html

• The use of more corrosion-resistant materials required for fuel handling and storage components.
• The need to inject lubricity-improving additives into the fuel.
• Stable or higher maintenance costs than with the use of fuel oil as the primary fuel, which are higher than with natural gas as the primary fuel.
• Increased use of ventilation and hazard detection equipment.
• Slightly higher output may be possible, but the heat rate would probably also be higher (and, thus, less efficient).
• The requirement that the CT starts up on natural gas, then switches to ethanol. This would require an initial investment in a natural gas infrastructure to deliver the start-up fuel.

Impacts. Since ethanol is cleaner burning than liquid fossil fuels and is a renewable resource, its impacts on air quality and greenhouse gas emissions are expected to be lower. Biofuels such as ethanol and biodiesel have the potential to displace a significant amount of petroleum around the world over the next decades. Impacts of the increased use of biofuels may include: reductions in oil demend, reductions in greenhouse emissions, increased agriculture revenues.

Feasibility and Applicability. There are several technical and operational issues with ethanol. First of all, the turbine manufacturers do not have sufficient experience with firing ethanol in this equipment and currently would not warranty a CT to fire ethanol. Second, there would be significant fuel transportation, storage, and handling issues with using ethanol as a primary fuel. To be an accredited facility using ethanol, a 175-MW power plant would need approximately 400,000 gallons of ethanol stored on site. Lastly, ethanol is not economically competitive with other fuels.

The most expensive consideration when burning ethanol in a CT is the cost of the ethanol. GRE would need to burn denatured ethanol, which is typically a blend of 95 percent ethanol and 5 percent unleaded gasoline. There are no readily available forecasts for denatured ethanol; however, based the AEO2007 forecast for E85 (85 percent ethanol and 15 percent gasoline) plus inspection and transportation fees, the 20-year average price for E85 is $1.85/gallon (2009$).

3.6.7 Biodisesel-Fueled Peaking Plant

Description. Biodiesel is a fuel that can be derived from vegetable oils or animal fats and can be used neat (100 percent) or in various blends with petro-diesel. Biodiesel is created through a chemical process called transesterification in which the glycerin is separated from the fat or vegetable oil, leaving behind two products: biodiesel and glycerin, a byproduct used in soaps and other products.

Impacts. Biodiesel reduces the health risks associated with petroleum diesel. Biodiesel emissions show decreased levels of polycyclic aromatic hydrocarbons (PAH) and nitrated polycyclic aromatic hydrocarbons (nPAH), which have been identified as potential cancer causing compounds. In Health Effects testing, PAH compounds were reduced by 75 to 85

percent, with the exception of benzo(a)anthracene, which was reduced by roughly 50 percent. Targeted nPAH compounds were also reduced dramatically with biodiesel, with 2-nitrofluorene and 1-nitropyrene reduced by 90 percent, and the rest of the nPAH compounds reduced to only trace levels.

Feasibility and Applicability. GRE continues to assess the potential to use biodiesel to fuel its peaking plants. To date though, biodiesel-fueled CTs are not commercially available.

One dilemma to using biodiesel to fuel a CT is the lack of a standardized fuel specification for producers. Manufacturers of modern CTs have very tight specifications for the fuel that is used in their machines. This is in part due to the exacting combustion requirements to meet emissions levels, especially for NOx and carbon monoxide (CO). Biodiesel fuel does not meet the requirements for petroleum-based fuel oils in standards published by the American Society for Testing Materials (ASTM) that are used by CT manufacturers. An ASTM committee is presently investigating the development of a separate standard or the modification of the present standards to include biodiesel fuel.

GRE is hoping to resolve some of the concerns with using biodiesel by participating in a program sponsored by the Electric Power Research Institute (EPRI) and Southern Company. GRE is co-funding a demonstration project hosted by Southern Company in which biodiesel fuel will be fired in a Pratt & Whitney CT. The test is expected to identify any long-term maintenance issues and help to identify fuel characteristics that require standardization.

GRE is also evaluating the substitution of biodiesel fuel for No.2 fuel oil as the startup fuel at its coal-fired plants. GRE is examining the storage facilities, piping, pumps, valve, controls, and burners to determine if the biodiesel properties fit within the design parameters of the existing systems with respect to viscosity, specific gravity, atomization, corrosion, and lubricity.

Until the technical concerns of using biodiesel are resolved, biodiesel fails to meet the size and timing criteria to qualify as an alternative to the proposed project.

3.7 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).

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.

3.7.1 Fuel Cells

Fuel cells convert hydrogen rich fuels directly to electricity through electro-chemical 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 CO2. 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 generally in excess of $2000/kW, making them uneconomical. Molten carbonate fuel cells (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. A 1-MW carbonate fuel cell is in a demonstration status. 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 2009. Most fuel cells are also base load in nature and would not be cost effective at the low capacity factors typical of a peaking resource.

3.7.2 Micro Turbines

Micro-turbines are small CTs 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 Alternating Current (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, relatively few micro-turbines are in commercial use at this time and, therefore, their reliability has not been demonstrated in real world applications. Uncertainty still remains on the long-term O&M costs and operating life for this technology. Because micro-turbine reliability has not been commercially proven at this time, they were not selected for further evaluation.

3.7.3 Energy Storage

Energy storage can be used to dampen 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 (1,500 to 2,000 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.

No suitable sites were identified for pumped storage hydro and it is unlikely that a pumped storage hydro source could satisfy the size of the need identified by GRE. Therefore, 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 CT.

In Dallas Center, Iowa, a group of municipal utilities from Iowa, Minnesota, and the Dakotas is proposing to use wind energy to compress air for storage in an underground aquifer. The facility is named the Iowa Stored Energy Plant.

The compressed air could then be released to drive a natural gas-fueled combustion turbine. The project is expected to be operational in 2011. A similar project could not be developed to meet the timing of the need identified by GRE.

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.

3.8 Up-grading Existing Generating Facilities

This alternative is a consideration of whether GRE could upgrade one of its existing generating facilities to provide the additional electricity that is anticipated to be needed at peak periods in the summer. Indeed, GRE's proposal is essentially one to upgrade an existing facility – the Elk River Station with its Refuse-Derived-Fuel combustor.

Impacts. It is impossible to determine the impacts of upgrading another facility without knowing what the facility is. The actual physical construction of an expansion to an existing facility could result in environmental effects. The potential environmental impacts of operating an expanded facility have been discussed to some extent in other portions of this report through the discussion of the various alternatives that were considered.

Feasibility and Availability. There are few upgrades currently available to existing GRE generating facilities. GRE has analyzed adding inlet fogging power augmentation to its St. Boni unit. Inlet fogging is a process that adds small water droplets to the inlet air on a CT, increasing the mass flow into the compressor. GRE estimates that inlet fogging could add 4 to 5 MW of additional capacity at less than $100/kW of installed cost. GRE plans to undertake this power upgrade in the fall of 2007.

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. GRE estimates 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 continues to seek circumstances that could 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 CTs – 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 CT. Since it is not cost effective, GRE has indicated that it will not pursue these upgrades at this time, but 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.

3.9 New Transmission

This alternative considers constructing new transmission facilities rather than new generation.

Impacts. The impacts associated with a transmission line depend to a large degree on the location of the line. Landowners whose property will be crossed by a new transmission line are often opposed to the project, particularly if the landowner perceives no personal benefit from the line. The potential impacts of the 4000 foot transmission line that is proposed as part of this project are a good indication of the kind of impacts that can be caused by any high voltage transmission line.

Feasibility and Availability. The proposed project has the advantage of being in close proximity to an area with a large amount of increasing load. New transmission could be considered an alternative if it provided access to generating resources in other regions. But building new transmission lines to acquire peaking capacity from remote locations would be very expensive and would have a long lead time, thus making it a less attractive option.

Additions to or improvements in the electric transmission system are not viable alternatives to the project, primarily because new transmission lines or transmission system upgrades could not be completed in the timeframe necessary to meet the deficit forecasted for 2009.

4.0 ENVIRONMENTAL EFFECTS

Minnesota Rule 7849.7060, subp. 2 outlines the impacts to be addressed in the Environmental Review for any Large Electric Power Generating Plant in a Certificate of Need proceeding. The environmental report must contain information on the human and environmental impacts of the proposed project associated with the size, type, and timing of the project, system configurations, and voltage.

4.1 Socioeconomic

The direct socioeconomic impacts of construction will generally coincide with the construction period. These direct impacts include the effects on demographics, employment, income, and community services and facilities.

Table 4-1 shows the estimated peak number of workers, by major discipline, required for construction and startup during each quarter of the construction period. The workforce is expected to peak during the third and fourth quarters of 2008, with an expected peak workforce of 183.[5]

Most of the construction workforce is expected to be hired from within the regional area. Given the close proximity to the Twin Cities metropolitan area, it is anticipated that most of the construction management and support category workers will be hired from the regional area.

The project will permanently employ approximately three full-time personnel to operate the plant and perform routine maintenance. The plant will share additional personnel with several other facilities. **Table 4-2** shows an estimated breakdown of operating staff during the three shifts.[6]

In addition to the direct employment and earnings impacts, indirect economic impacts would be generated from the construction and operation of the project through economic multiplier, or ripple effects. Generally, multiplier effects refer to the direct and indirect employment and earnings created in a region due to an increase in final demand such as a new investment.

Indirect employment impacts are those created when construction workers spend their income on goods and services and businesses hire more workers to meet this increased demand. Additional jobs will be created as industries producing the plant equipment for the project increase output and hire more workers.

Primary affected industries include the fabricated metal industry, which produces boilers, ductwork, valves, and pipe fittings; the non-electrical machinery industry, which produces turbines, generator sets, blowers, fans, pumps, and compressors; and the electrical and the electronic equipment industry, which produces electric motors, industrial controls, electric lighting, and wiring equipment. As these industries increase production, they will demand more inputs from their suppliers. Workers in these industries will also spend their income, further

[5] Correspondence with GRE, September 2007.
[6] Ibid.

increasing the demand for goods and services. When the total economic repercussions created from the construction of the project have filtered through the economy, the total employment impact will be a multiple of the direct construction employment at the site.

The total cumulative economic statewide benefit is estimated to be $61 million, as shown in **Table 4-3**. These calculations assume a 30 year operating period.[7]

Demographic changes to the study area attributable to the construction of the project are expected to be minimal. Workers employed to construct the project, and who are currently living within the regional area, are not expected to relocate. These persons will commute to work at the project site.

The Electric Power Research Institute (EPRI) report, *Socioeconomics of Power Plants*, indicated that construction workers will travel an average of 73 miles one-way on a daily basis to a jobsite, even up to a maximum of 115 miles one way.[8] The study, which analyzed the commuting patterns of workers on several electric generating facility projects, concluded that the long commuting distances were acceptable to workers due to the temporary nature of construction employment at a electric generating facility site.

The operations personnel will not be required until the final months of construction. At approximately that time, it is expected that they would relocate on a permanent basis.

Given the temporary duration of employment, it is assumed that construction personnel who relocate will rent an apartment or home during employment. The operations personnel and families will most likely purchase living accommodations due to the lengthy expected plant life.

The supply of housing in the study area can easily accommodate the small number of relocating workers and families.

Since the population increase during the construction period is expected to be limited, the increased demand for school, hospital, fire and ambulance, police, and utility services will not be significant. Similarly, since the number of employees required after the construction period and during the facility's operational life is small, no significant impact will occur on the demand for other community facilities and services due to relocating personnel.

Socioeconomic impacts resulting from the project will be primarily positive, with increased tax revenue and an influx of wages and expenditures made at local businesses during construction.

4.2 Noise

Noise is comprised of a variety of sounds, of different intensities, across the entire frequency spectrum. Humans perceive sound when sound pressure waves encounter the auditory

[7] Ibid
[8] Socioeconomic Impacts of Power Plants, EPRI, Palo Alto, CA: EA-2228

components in the ear. These components convert the pressure waves into perceivable sound. Noise is measured in decibels (dB).

Noise standards have been established by the MPCA, Minnesota Rules part 7030.0040, subp. 2. The MPCA is the regulatory agency responsible for the enforcement of these standards. The standards are consistent with speech (hearing and conversation), annoyance, and sleep requirements for receivers within areas classified according to land use activities.

The MPCA has established various noise area classifications (NAC) and has established noise standards for each classification. The NAC area classification is based on the land use activity at the location of the receiver, and the NAC determines the applicable noise standard. Lower noise levels are required in residential areas, for example, than in industrial zones.

The four noise area classifications are: NAC-1, NAC-2, NAC-3, and NAC-4. Some of the land use activities under NAC-1 include household units, hospitals, religious services, correctional institutions, and entertainment assemblies. NAC-2 land use activities include mass transit terminals, retail trade, and automobile parking. Some NAC-3 land uses include manufacturing facilities, utilities, and highway and street ROW. NAC-4, which has no noise limits, consists of undeveloped and under construction land use areas.[9]

Table 4-4 sets forth the Minnesota Noise Standards for the appropriate land use.

Distance is a main criterion for measuring the strength of noise. For every doubling of distance from the noise source, a decrease of 6dB occurs from isolated sources.

At both the preferred and alternative sites noise would be generated during the construction and operation of the project. Construction noise would be predominantly intermittent sources originating from diesel engine-driven construction equipment. Potential noise impacts would be mitigated by proper muffling equipment fitted to construction equipment and restricting activities conducted during nighttime hours.

Noise from the turbine operation is a result of air flow through the combustion air intake and from the exhaust gases discharging from the stack. The project air inlet will be appropriately sized and fitted with diffusers to minimize velocity and therefore the noise of air moving into the inlets. The stack will be fitted with silencers to reduce the noise of exhaust gases leaving the plant.

Current ambient noise detectable on the proposed site consists of intermittent traffic along the local roads, traffic from US Highways 10 and 169, and operation of the existing facility. The project will not result in any violation of the Minnesota Noise Standards at residences located near the preferred site.

[9] http://www.pca.state.mn.us/programs/noise.html

GRE, as part of a noise impact study, developed three noise data points for the Elk River Peaking project: 1) the near-field noise guarantee of 85 dBA, 2) the far-field noise guarantee of 63 dBA, and 3) actual far-field noise monitoring data for the Siemens V84 combustion turbines at Pleasant Valley Station. Using standard formulas for estimating sound attenuation from a point source, GRE estimated that the sound levels at the nearest residence, which is ~1,640 feet from the proposed combustion turbine, would range between 30 and 51 dBA for the three noise data points.

This analysis is conservative in that it does not take into consideration the noise attenuation that will be achieved by the barriers (topography, buildings, trees, etc) between the combustion turbine and the noise receptor. Based on the historic conservativeness of the guarantees relative to actual measurements and the conservativeness of the simple model, noise from the combustion turbine should not result in a violation of the Minnesota noise standard.

4.3 Aesthetics

Area aesthetics will not be significantly changed by the project. The proposed plant site is on the existing Great River Energy campus, and has been previously used for various purposes related to utility operation and maintenance. The plant site and immediate vicinity have an evident industrial/commercial aesthetic. The proposed plant maintains this aesthetic.

The project transmission line upgrades will occur along an existing transmission line corridor. Upgrades to the project transmission lines may involve the use of poles that will be approximately 10-20 feet taller than the existing poles. However, taller poles would not appear significantly different than the existing transmission line configurations, and the current visual aesthetic would be maintained.

4.4 Recreation

Area tourism and recreation will not be adversely impacted by the project.

4.5 Transportation

Traffic near the proposed facilitiy will increase during construction. Local motorists may be temporarily inconvenienced by the increase in large construction vehicles on the roadways and possible delays in traffic. Traffic due to the construction workers could be expected to produce local impacts over a 30-minute period at the beginning and end of the day and each time a change in shift occurs.

4.6 Land Use

The Great River Energy Elk River campus includes offices, warehouses, pole yard and RDF Power Plant. Locating the new generating facility on the existing Great River Energy campus takes advantage of existing infrastructure, including roads, water, and sewer. Since the Project

plant location has been previously used for utility purposes, as a Great River Energy pole yard, the new facility will not notably change the land use of the site. Land use in the vicinity of the project is diverse.

The proposed activities at the plant site meet the Sherburne County land use designation and city of Elk River zoning overlay for the site. Sherburne County Planning and Zoning Department lists the current land use of the project plant location as "Public Utility Land – Preferred" (Sherburne County 2007). The project falls within the approved uses for that designation. Adjacent land uses within one mile of the Project plant location include:

- Public Utility Land – Non-Preferred.
- Residential/Apartments Over 4 Units.
- State Public Property.
- Commercial.
- Industrial.
- Residential 2-3 Units.
- Residential Single Unit.
- Vacant Land.

According to the Elk River Department of Commercial Development, the Elk River Peaking Station site is zoned as Light Industrial/Solid Waste Facility (City of Elk River 2007). The project falls within the approved uses for that designation. Zoning for parcels immediately adjacent to the project plant site includes the following designations:

- Business Park.
- Planned Unit Development.
- Highway Commercial.
- Central Commercial.
- Townhouse/Multi-Family.

The project will not require the displacement of any occupied residences or businesses. Area industries will not be adversely impacted by any component of the proposed project. Work on the project will not displace any other existing or planned land use, including residential land uses. The proposed site for the new generating unit is located within a parcel currently owned by Great River Energy and used for power generation. The nearest residence is located approximately 1,200 feet north-northwest of the project location.

Land use in the vicinity of the project transmission line upgrades is diverse. The project transmission lines cross lands under the zoning authority of the Metropolitan Council (Anoka County), Sherburne County and the city of Elk River. The Metropolitan Council and the Sherburne County Planning and Zoning Department list the following current land uses along the project transmission line upgrade:

- Municipal Property.
- State Public Property.
- Agriculture.

- Residential Single Unit.

As noted previously, the project transmission line upgrades utilize an existing transmission corridor and the substation at County Road 78 and Bunker Lake Blvd. As a result, the project transmission line upgrade will not change current land use of the areas crossed.

According to the city of Elk River Department of Commercial Development, areas crossed by the project transmission line upgrade include the following zoning designations:

- Light Industrial.
- Business Park.
- Planned Unit Development.
- Single Family Residential.
- Agricultural Research.

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The project transmission line upgrade will not require the displacement of any occupied residences or businesses. Work on the upgrade will not displace any other existing or planned land use, including residential land uses.

Forestry

The proposed site does not contain any timber management activities.

Mining

The proposed site does not contain mining activities.

Prohibitive Sites

In accordance with Minn. Rule 4400.3450, no LEPGP may be located in sites deemed prohibitive. The proposed site does not contain any of the prohibitive sites listed in the rule, including:

- National Parks;
- National historic sites and landmarks;
- National historic districts;
- National wildlife refuges;
- National monuments;
- National wild, scenic, and recreational river ways;
- State wild, scenic, and recreational rivers and their land use districts;
- State parks;
- Nature conservancy preserves;
- State Scientific and Natural Areas; and,
- State and national wilderness areas.

4.7 Topography, Soils and Geology

The geology and soils at the plant site, along the transmission line upgrades and at the substation are structurally suitable for construction of the project components. The geology and soils do not present any special concerns related to water or wastewater management for the project.

The entire project, including plant, transmission lines and substation, is located within the Anoka Sand Plain region and is underlain by approximately 150 feet of unconsolidated sediments, according to regional well logs. Pleistocene-aged trace deposits associated with mixed clasts of the Superior and Des Moines lobes are directly beneath the site. These deposits consist primarily of sand, gravelly sand, and cobbly gravel (Meyer et al 1993).

The Soil Survey of Sherburne County, Minnesota (Grimes 1968) indicates soils found on the site are Hubbard loamy sands. Hubbard series soils are nearly level to gently sloping and formed in outwash sands. Soils are excessively drained. The preferred site has been utilized as a utility pole storage yard; thus the soils have been compacted and otherwise altered due to prior activities.

Hubbard series soils do not meet the productivity criteria for prime farmland. There are no prime farmland units associated with the site. The Soil Surveys of Sherburne County (Grimes 1968) and Anoka County (Chamberlain1977) indicate soils found along the transmission line upgrade are:

- Hubbard loamy sands.
- Isanti sandy loam.
- Nymore loamy coarse sand.
- Nymore loamy sand.

Soils at the existing substation were originally mapped as Sartell fine sand and Lino loamy fine sand. These soils types are all formed in outwash sands. The project transmission line upgrade utilizes an existing transmission corridor and substation; thus, the soils have likely been moderately compacted along the existing corridor and moderately to heavily compacted at the substation.

These soils do not meet the productivity criteria for prime farmland. There are no prime farmland units associated with the project transmission line or substation upgrades.

The facility will operate under an existing Minnesota General Industrial Stormwater Discharge Permit (Permit #MNG611000). In addition, the facility will be designed to avoid the discharge of stormwater off the site. In extreme precipitation events, stormwater would be directed to sand filters, and then discharged via the Minnesota DOT-controlled highway 169 drainage ditch to the Mississippi River.

There are no additional stormwater impacts associated with the Project transmission line or substation upgrades.

The project will not impact the geology at the proposed site. Potential impacts of construction are increased impervious surfaces, soil compaction and exposing the soils to wind and water erosion. Impacts to physiographic features should be controlled and minimal during and after construction activities; these impacts will be short term. There should be no long-term impacts resulting from the project at either site.

The Minnesota Pollution Control Agency's (MPCA) Stormwater Program is designed to reduce the pollution and damage caused by stormwater runoff. The MPCA has three stormwater programs for regulating stormwater runoff from three main sources: construction, industrial and municipal.

Areas of larger disturbance (one acre or more), will be addressed in the National Pollution Discharge Elimination System (NPDES) and Stormwater Pollution Prevention Plan (SWPPP) prepared for the project. Mitigation under the NPDES includes implementation of the SWPPP with the appropriate erosion control methods developed specifically for the site.

The MPCA issues combined NPDES/State Disposa System (SDS) permits for construction sites, industrial facilities and municipal separate storm sewer systems. Compliance with the MPCA stormwater program will be a condition of the LEPGP Site Permit.

4.8 Flora and Fauna

According to the MDNR Ecological Classification System (MNDNR 2005), the plant site and its associated components are located along the southern edge of the Anoka Sandplain landform, in the Minnesota and Northeast Iowa Morainal Section of the Eastern Broadleaf Province. Pre-settlement vegetation was primarily composed of oak openings and barrens (savanna) on the upland areas and river bottom forest adjacent to the Mississippi River at lower elevations.

Most of the native vegetation was initially removed to allow the land to be converted first to lumber and then to agricultural uses. More recently, the project plant site has been part of Great River Energy's campus, and has had a number of uses including an ash storage and utility pole yard. These uses and the associated regarding of the land surface have left a mixture of primarily non-native grasses and forbs on the site, with a small stand of red pine (*Pinus resinosa*) to the east.

Any disturbance to vegetation due to the project transmission line upgrade will be minimal and limited to the areas immediately adjacent to pole placements. Remnants of native vegetation communities with pre-settlement characteristics remain in the vicinity of the project plant location. The nearest of these remnants is a series of five islands in the Mississippi River approximately one mile west of the project location. The Minnesota County Biological Survey (MCBS) has mapped these islands as Silver maple – Virginia creeper floodplain forest. This floodplain forest features a canopy of well-spaced silver maple (*Acer saccharinum*), green ash (*Fraxinus pennsylvanica*) and American elm (Ulmus americana), with wood nettle (*Laportea canadensis*) and ostrich fern (*Matteuccia strutheopteris*) in the ground layer. This floodplain

forest has reportedly never been grazed, although the northern island was used as a vegetable garden in the 1930s. The other area of native vegetation communities is approximately 1.25 miles southeast of the project plant location. MCBS mapped this area as a dry oak savanna/oak brushland complex. The area is dominated by a relatively open oak canopy, primarily bur oak (*Quercus macrocarpa*), with native prairie grasses and forbs in the ground layer.

The project is not expected to adversely impact area wildlife. The United States Fish and Wildlife Service (USFWS) lists the bald eagle (*Haliaeetus leucocephalus*) as the only Federally-listed species known to occur in Sherburne County. In order to evaluate the potential presence of State listed species, the MDNR Natural Heritage Program was contacted to review the Natural Heritage Information System (NHIS) database.

Results of the NHIS search identified only the bald eagle as being present in the vicinity of the project plant site. The NHIS records do not indicate that bald eagles nest on the Project plant site itself. Rather, the records show bald eagle nests approximately 3,600 feet to 3,800 feet west of the project plant location, nesting in the floodplain forest on a series of five islands in the Mississippi River. The nearest edge of the nearest island is 3,100 feet west of the Project plant location. If bald eagles were to nest on the mainland side of the river, across from the islands, they would still be over 2,800 feet west of the Project plant location. These distances are more than twice the 0.25-mile (1,320 feet) buffer that the USFWS normally considers to be necessary to avoid disturbance of an eagle nest. A project review request letter has also been sent to the USFWS to determine if the project will affect any threatened or endangered species.

The NHIS records indicate that no other State-listed species are known from the plant site.

The project transmission line and substation upgrades are also not expected to adversely impact area wildlife. The local presence of bald eagles is discussed above. No bald eagle nests are known along the Project transmission line upgrades. The MNDNR Natural Heritage Program was contacted to review the NHIS database for State-listed species. Results of the database search identified the following State-listed species occurring within one mile of the Project transmission line upgrades:

- Loggerhead shrike (*Lanius ludovicianus*), threatened, proposed endangered.
- Blanding's turtle (*Emydoidea blandingi*), threatened.
- Plains pocket mouse (*Perognathus flavescens*), special concern.

These species are all known to occur within Bunker Hills Regional Park, at the far eastern terminus of the project transmission line upgrade near the location of the substation improvements. The transmission line work at the eastern terminus would occur within the existing Great River Energy substation, and would not involve activities that would remove or disturb these species or their habitats.

No mitigation is necessary.

4.9 Rare & Unique Natural Resources

The project will not adversely impact Federally- or State-listed threatened or endangered species. The Natural Heritage Program of the MDNR was contacted and asked to review its database to determine if any rare plant or animal species or other significant natural features are known to occur within the project site. No plants or animals of concern were identified that would be adversely impacted by the project.

The MDNR also maps Sites of Biodiversity Significance, and rates them as Outstanding, High, Medium or Below. Sites rated "Below" are areas that have a degree of native community structure that is higher than disturbed or developed areas, but below the level of biodiversity significance for similar communities in the state.) The MDNR has mapped a total of six Sites of Biodiversity Significance (SBS) near the overall project. In the vicinity of the project plant site, SBS are mapped within 2600 feet to the southeast and 5600 feet to the northeast, respectively. Both are rated "Below". The project will have no impact on these sites.

The project transmission line upgrades cross two additional SBS. Both sites are mapped as Dry Sand-Gravel Oak Savanna (Southern Type). One of the sites is rated "Moderate" for biodiversity significance, and the other is rated "Below". Both are crossed along existing transmission line corridors; therefore, there is no additional impact to these sites.

Finally, near the site of the substation improvements, there are two additional SBS. One takes up most of Bunker Hills Regional Park, and is rated "Outstanding." The other is further southeast, and is rated "Below." The proposed activities at the existing substation will have no impact on these sites.

No mitigation would be required.

4.10 Archaeological and Historic Features

The Minnesota State Historic Preservation Office (SHPO) was contacted to request a Historic, Archaeological and Architectural Inventory database search for the project plant site and for areas along and adjacent to the project transmission line upgrade. According to the SHPO database, there are 29 historic and/or architectural sites in Elk River. The closest to the project plant site are the twenty-two sites in the historic downtown area of Elk River, approximately 0.7 mile northwest of the site in the 300-block of Jackson Street, and on the 600- and 700-blocks of Main Street.

The SHPO database query also indicates that there are two known archaeological sites in the project plant vicinity. The nearest is a lithic scatter site approximately 2,300 feet northeast of the project plant site. The other archaeological database record in the vicinity is an artifact scatter approximately 3.8 miles southeast of the project plant site.

Further south and east of the generating facility, along the project transmission line upgrade, SHPO has no Architectural or Historic records. However, there are two archaeological lithic scatter records near the northwest shore of Lake Itasca in Sections 18 and 19 of Township 32

North, Range 25 East. The project transmission line upgrade passes within 2,000 feet of these areas at its closest.
There is an additional archaeological historic documentation record in the southwest quarter of Section 19, Township 32 North, Range 25 East. This record is south of the BNSF railroad line.

The project transmission line upgrade will have no impact on any of the SHPO sites.

No mitigation is necessary.

4.11 Air Quality

The proposed peaking station includes a new combustion source, which will emit products of combustion to the air. Estimated emissions are summarized in **Table 4-5**.

Another potential source of air emissions is fugitive dust from site preparation and construction activities. However, construction-related fugitive emissions will be of a short-term duration and will be controlled by watering or applying dust suppressants to exposed soil surfaces as necessary to reduce the impact on area residents.

A preliminary analysis of the impacts of the estimated combustion emissions, summarized in **Table 4-6**, indicates the project will have no significant impact on area air quality. The potential to impact ambient air quality was modeled using AERMOD. The background concentrations plus modeled concentrations are well below the National Ambient Air Quality Standards and Minnesota Ambient Air Quality Standards for all pollutants, demonstrating that the project will have a minimal impact on area air quality for all pollutants modeled.

The project also triggers the MPCA's requirement to prepare an assessment of air emission risks to human health. The MPCA's "Air Emissions Risk Analysis (AERA) Guidelines" requires the establishment of a baseline risk for the existing site and an analysis of the impact of the new emissions from the turbine installation.[10]

A preliminary air toxics review has been completed for the CT that indicates its incremental impacts are well below the MPCA's risk thresholds. Great River Energy will submit a completed AERA with the air permit application to the MPCA. The results for the CT are summarized in **Table 4-7**. Farmer cancer risks are the highest; however, the farmer scenario is not applicable at the worst-case receptors because these receptors are located on property that has been developed and is no longer suitable for farming.

While incremental impacts from the project are negligible, the MPCA has stressed that understanding the baseline risk is important to its risk decision. Great River Energy has developed the baseline risks associated with the existing operations at the Elk River campus and will work with the MPCA through the air permitting process to complete the baseline risk analysis.

[10] http://www.pca.state.mn.us/air/aera-guide.html

As a condition of the LEPGP site permit, GRE would be required to comply, through the air permitting process, with conditions set by the MPCA. This would be accomplished by GRE submitting an application to amend the Elk River Station's air emission permit, Permit No. 1410003-003. The amendment will incorporate the project into the existing facility air operating permit.

4.12 Water Resources (groundwater, surface water, wetlands)

The project will not significantly impact area water bodies. The project plant site is located within the Mississippi River (St. Cloud) watershed, USGS/MDNR major watershed #17. The nearest named stream is the Mississippi River. The project plant site lies within the USGS/MDNR minor watershed #1700100, an area of approximately 16 square miles.

The project transmission line upgrade is located within portions of three major watersheds.

The project transmission line upgrade will not significantly impact area water bodies. The project transmission line upgrade crosses Trott Brook twice, and an unnamed tributary to Trott Brook once. Trott Brook joins the Rum River approximately 5.5 miles east of the project transmission line upgrade's furthest downstream crossing. Streams will be crossed by spanning, with poles placed in locations that will avoid disturbance to the stream banks. As a result, the project transmission line upgrades will not introduce additional sediments into area streams.

No lakes or major rivers are crossed by the project transmission line upgrade. Letters have been sent to the MDNR and the U.S. Army Corps of Engineers requesting information on potential impacts of the project on area water resources.

The project will not impact area wetlands. No wetlands are located within the project plant site. However, several wetlands are found in the area surrounding the plant site, the nearest of which is an emergent wetland approximately 3 acres in area about 1000 feet north of the plant site. The only other wetlands located within 1,320 feet (0.25 mile) of the project plant site are east of Highway 169 and will not be affected by the project.

The project transmission line upgrade will also not significantly impact area wetlands. However, several wetlands are crossed by the upgrade.

The project transmission line upgrade follows an existing transmission corridor. Wetlands are primarily spanned to minimize disturbance. Wetlands that are too large to span have existing poles. In these situations, disturbances associated with the project transmission line upgrade will be minimal and limited to pole replacement as needed.

If dewatering is necessary, dewatered groundwater will be properly stored and sediments will be settled out and removed before the water is discharged.

As a condition of the LEPGP Site Permit, standard erosion control measures and best management practices (BMP) will be required to minimize potential impacts.[11]

Best Management Practices (BMPs) may include:

- Contain stockpiled material away from stream banks and lake shorelines.
- Stockpile and respread topsoil.
- Locate structures and disturbed areas away from rivers and lakes, whereprактical.
- Use turbidity control methods prior to discharging wastewater from concretebatching or other construction operations to streams or other surface waters. Wastewaters discharged will be free of settleable material.

If it is determined that a Wetland Conservation Act (WCA) or Section 404 permit is necessary, the Applicants will work with the jurisdictional agencies (USACE, MDNR and/or BWSR) to determine the best ways to minimize the impacts and create appropriate mitigation measures.

Proposed construction activities at the sites would result in the disturbance of one acre or more of soils and a National Pollutant Discharge Elimination System (NPDES) stormwater permit would be required. A Stormwater Pollution Prevention Plan (SWPPP) would be prepared that would include erosion control plans and BMPs that would be implemented.

To minimize contamination of water due to accidental spilling of fuels or other hazardous substances, all construction equipment would be equipped with spill cleanup kits.

4.13 Human Health and Safety

The project plant is proposed to be constructed on the existing Great River Energy campus. As a result, the project plant will utilize Great River Energy's existing framework for supporting public health and safety on the campus. This includes facilities and procedures for fire safety, emergency first aid capabilities, and general procedures and policies to ensure a safe operating environment. Fire alarms and emergency fire suppression equipment will be located throughout the facility to provide early detection of fire and enable initial response to reduce the risk and spread of fire. Emergency first aid equipment including eyewash stations and first aid kits will also be installed throughout the facility. Employees would have regular training in safety and first aid. Severe weather shelters will be designated and clearly identified.
Infrastructure on the Great River Energy campus includes water and sewer facilities. The project plant will utilize this existing infrastructure. In addition, the Great River Energy campus is served by Elk River fire and police.

Primary access to the Great River Energy campus is off of U.S. Highway 169 , U.S. Highway 10 or Main Street. Access to the Project plant location will primarily be off Highway 169. The current annual average traffic count on Highway 169 near the plant site is 52,000 vehicles per

[11] http://www.pca.state.mn.us/publications/wq-strm2-05.pdf

day with a heavy commercial vehicle count of 3,700 per day. Traffic on Highway 169 will increase slightly, but the increase will not be perceptible considering the existing traffic volumes.

5.0 OTHER PERMITS AND APPROVALS REQUIRED

Table 5-1 contains a list of the anticipated permits and associated environmental approvals required for the Elk River Peaking Station LEPGP project. Compliance with the terms of all applicable and relevant regulatory permits and approvals would be a condition of any Site Permit issued by the PUC.

In any LEPGP Site Permit the PUC issues, the PUC will describe with specificity the approved site. The approved site may or may not be the site preferred by the applicant. The PUC may impose other conditions in a permit that the PUC determines are reasonable and appropriate (Minn. Rule 7849.5960). Permit conditions typically relate to construction practices and administrative issues like transfer of the permit and permit amendments.

6.0 ACRONYMS, ABBREVIATIONS and DEFINITIONS

ACRONYMS	
AC	Alternating Current
ACSR	Aluminum Conductor Steel Reinforced
APE	Area of Potential Effect
BMPs	Best Management Practices
BPA	Bonneville Power Administration
Commission	Minnesota Public Utilities Commission
CSAH	County State Aid Highway
dB(A)	Decibel (A-weighted)
EMF	Electromagnetic Fields
EPA	Environmental Protection Agency
EQB	Minnesota Environmental Quality Board
FAA	Federal Aviation Administration
FACW	Facultative Wet
FEMA	Federal Emergency Management Agency
FSI	Farmlands of Statewide Importance
GRE	Great River Energy
HVTL	High Voltage Transmission Line
ICD	Implantable Cardioverter/Defibrillator
kV	Kilovolt
kV/m	Kilovolt per meter
LEPGP	Large Electric Power Generating Plant
MBTA	Migratory Bird Treaty Act
MDNR	Minnesota Department of Natural Resources
MNDOT	Minnesota Department of Transportation
Ma	Milliampere
mG	Milligauss
MHz	Megahertz
MISO	Midwest Independent Transmission System Operator
MP	Minnesota Power
MPCA	Minnesota Pollution Control Agency
MVA	Megavolt-ampere
MW	Megawatt
NAC	Noise Area Classifications
NESC	National Electric Safety Code
NIEHS	National Institute of Environmental Health Sciences
NHIS	Natural Heritage Information System
NPDES	National Pollutant Discharge Elimination System
NRHP	National Register of Historic Properties
NRCS	Natural Resources Conservation Service

ACRONYMS	
NWI	National Wetlands Inventory
OBL	Obligate
Ppm	parts per million
RS	Route Segment
RUS	Rural Utilities Service
SHPO	Minnesota State Historic Preservation Office
SNAs	Scientific and Natural Areas
SNF	Superior National Forest
SSC	Species of Special Concern
SWPPP	Stormwater Pollution Prevention Plan
THPO	Tribal Historic Preservation Officer
USACE	United States Army Corps of Engineers
USDOE	United States Department of Energy
USFWS	United States Fish and Wildlife Service
USGS	United States Geological Survey
WMAs	Wildlife Management Areas
WPAs	Waterfowl Production Areas