GREAT RIVER ENERGY®

A Touchstone Energy® Cooperative

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June 27, 2013

Mr. Darrell Nitschke
Executive Director
North Dakota Public Service Commission
600 East Boulevard Avenue – State Capitol
Bismarck, ND 58505-0480

Dear Mr. Nitschke:

Enclosed are an original and ten copies of *Great River Energy's (GRE) North Dakota Ten-Year Plan Report, 2013-2022* (Report) to the North Dakota Public Service Commission (Commission) as required by Chapter 49-22-04 of the North Dakota Century Code (NDCC).

In accordance with Chapter 69-06-02-02 of the NDCC, GRE has provided a copy or notice of the Report to the necessary parties.

GRE has included an extra copy of the Report and a self-addressed stamped envelope and requests that the Commission provide GRE with a file stamped copy.

Please contact me at (763) 445-6103 or lrossmccalib@grenergy.com if you have any questions or comments.

Sincerely,

Laureen Ross McCalib

Laureen L. Ross McCalib
Manager, Resource Planning
GREAT RIVER ENERGY

Enclosures (11)

Cc: NDPSC (10)
County Auditors (4)
ND State Agencies and Officials (Letters of Confirmation only)

1 PU-13-506 Filed 07/01/2013 Pages: 25
2013-2022 Ten year plan
Great River Energy
Laureen L. Ross McCalib

Great River Energy's

North Dakota Ten-Year Plan Report

2013-2022

Submitted to
The North Dakota Public Service Commission

GREAT RIVER
ENERGY®

A Touchstone Energy® Cooperative

July 1, 2013

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INTRODUCTION

This report was prepared in accordance with the North Dakota Public Service Commission's (Commission) Guidelines (Guidelines) for compliance with the requirements of Chapter 49-22-04 of the North Dakota Century Code.

Great River Energy (GRE) has concluded that some information that would be provided under Sections E and F and Exhibits 3 and 5 pursuant to the Guidelines qualifies as Critical Energy Infrastructure Information (CEII) and, therefore, has not included the information in these pages. GRE offers to provide the information to the Commission upon request.

SECTION A: Existing Energy Conversion Facilities

GRE's capacity consists of coal, refuse-derived fuel (RDF), wind, natural gas, and oil-fired units. The coal-fired plants are located at Stanton, Jamestown and Underwood, North Dakota. While the Spiritwood project is complete it is not operating pending the development of a second thermal energy customer or more favorable wholesale electricity market conditions that would support commercial operation of the project. We currently expect Spiritwood will begin commercial operations on November 1, 2014.

GRE currently has no plans to retire any of its existing North Dakota energy conversion facilities within the next 10 years. GRE is currently in arbitration with Dairyland Power Cooperative concerning the future of the Genoa 3 plant. Genoa 3 is located near La Crosse, Wisconsin. GRE believes Genoa 3 has reached the end of its economic life and should be retired.

Table 1 below shows the summer season ratings of GRE's generating plants and Power Purchase Agreements. The ratings are Net Dependable Capacity as determined in the North American Electric Reliability Corporation (NERC) Generating Availability Data System (GADS).

Table 1- GRE's Existing Energy Conversion Facilities

Unit Name	Summer Capacity (MW)
Owned Resources	
Arrowhead (Diesel)	n/a
Cambridge CT (Peaking)	20.8
Cambridge CT2 (Peaking)	156.4
Coal Creek Station (Diesel)	2.1
Coal Creek Station 1 (Coal)	566.1
Coal Creek Station 2 (Coal)	574.9
Elk River CT (Peaking)	183.3
Elk River Station 1-3 (RDF)	28.9
Lakefield (Diesels)	2.0
Lakefield Junction (Peaking)	503.7
Maple Lake CT (Peaking)	20.2
Pleasant Valley Station (Peaking)	407.0
Rock Lake CT (Peaking)	20.8
Spiritwood (Coal)	99.0
St. Bonifacius CT (Peaking)	58.8
Stanton Station (Coal)	188.6
Stanton Station (Diesel)	1.0

SECTION B: **Energy Conversion Facilities Under Construction**

None.

SECTION C: **Proposed Energy Conversion Facilities on Which Construction is Intended Within the Ensuing Five Years**

While GRE has identified no specific facilities for construction in the next five years, GRE continues to evaluate its future needs, including additional renewable energy resources to comply with Minnesota's Renewable Energy Standard.

SECTION D: **Proposed Energy Conversion Facilities During the Next Ten-Year Time Period**

GRE has no specific proposed energy conversion facilities as defined by Chapter 49-22-03 of the North Dakota Century Code.

GRE continues to evaluate its future needs, including additional renewable energy resources to comply with Minnesota's Renewable Energy Standard.

SECTION E: **Existing Transmission Facilities (Electric)**

GRE has concluded that its existing transmission facilities qualify as CEII. A map of the transmission facilities that GRE owns and operates in North Dakota will be made available upon request. Summary information on GRE's North Dakota transmission facilities is provided in Table 2.

Table 2 – GRE's Existing Electric Transmission Facilities in North Dakota

Facility	Voltage (kV)	AC/DC	Install Year
Stanton – Leland Olds	230	AC	1966
Stanton – Mchenry Tap	230	AC	1966
Mchenry Tap – Mchenry	230	AC	1966
Mchenry – Balta	230	AC	1966
Balta – Ramsey	230	AC	1966
Ramsey – Prairie	230	AC	1966
Stanton – Square Butte	230	AC	1966
Mchenry Tap – Coal Creek	230	AC	1979
Stanton - Coal Creek	230	AC	1979
Coal Creek – Dickinson, Minnesota	± 400	DC	1979

GRE is not planning to retire any existing transmission facilities within the next 10 years.

GRE is rebuilding the Ramsey-Prairie line based on poor structure strength. Due to the high water condition in the area, route adjustments may be made to remove the transmission lines from being over the body of water. In some cases, additional easements may be required.

The Commission's Guidelines require a copy of Federal Energy Regulatory Commission (FERC) Form 12. The information previously provided in FERC Form 12 is now found in FERC Form 715. A copy of GRE's most recent filing is available upon request.

SECTION F: Existing Transmission Facilities (Pipeline)

GRE has a water pipeline and accompanying pumping station located near Coal Creek Station that has been in service since August 1, 1979. GRE concludes that the information qualifies as CEII and has not provided it in this document. However, specific information on the facilities and a map will be provided upon request.

SECTION G: Proposed Transmission Facilities on Which Construction is Intended Within the Ensuing Five Years (Electric)

GRE's participation in the CapX2020 transmission initiative is described in Section J. One of three 345 kV transmission lines, Fargo-Monticello, will begin at a new Bison Substation near Fargo and terminate at Monticello, Minnesota, with intermediate substations near Alexandria and St. Cloud, Minnesota. Foundation construction work has begun in North Dakota

Additional information can be found at www.capx2020.com.

SECTION H: Proposed Transmission Facilities on Which Construction is Intended Within the Ensuing Five Years (Pipeline)

None.

SECTION I: Proposed Transmission Facilities During the Next Ten-Year Period (Electric and Pipeline)

MISO evaluated the capacity from the Spiritwood plant and this will require rebuilding an existing Ottertail 115 kV line in the Jamestown area. Additional transmission upgrades are a condition to accommodate part of the output from Spiritwood but they are dependent on other projects and studies.

SECTION J: Regional Coordination

The electric grid is heavily interconnected and must be evaluated, operated, and expanded in a coordinated manner to assure reliability and cost-effectiveness. GRE's transmission planning is closely coordinated with other organizations. GRE is a member of and participates directly in several regional entities:

- The Midcontinent Independent System Operator (MISO), which administers a tariff providing for regional transmission services, energy and ancillary services markets, and resource adequacy requirements. MISO also has responsibilities for regional transmission planning, coordination, and expansion. GRE is a transmission owning member and market participant. Further information about MISO is available on-line at *www.midwestiso.org.* MISO's transmission expansion plans (MTEP-2012 being the most-recently approved plan) are also available at their web site under the "Planning" tab and contained in the "MISO Transmission Expansion Planning (MTEP)" link.

- The Midwest Reliability Organization (MRO), a non-profit organization of regional utilities established to develop regional reliability standards and ensure compliance with standards of the North American Electric Reliability Corporation (NERC) as well as its own. Further information about MRO is available on-line at www.midwestreliability.org and about NERC at www.nerc.com.
- The Mid-continent Area Power Pool (MAPP), which historically provided resource pooling and transmission coordination functions for its members across a large part of the upper Midwest. For GRE and other MISO members, these functions have largely been transitioned to MISO. GRE's transmission system is no longer part of MAPP and GRE is no longer a member of the MAPP generation reserve sharing pool. Further information about MAPP is available on-line at www.mapp.org.
- MISO conducts Sub-regional Planning Meetings (SPMs) four times each year to provide a forum for coordination and discussion of transmission issues and proposed projects among utilities and other interested stakeholders.
- The Minnesota Transmission Owners (MTO) group, a consortium of 16 sponsoring utilities and three participating government agencies, fulfills the utilities statutory obligations for transmission planning in the state of Minnesota. These obligations include the development of the Minnesota Biennial Transmission Plan, as well as studies associated with meeting the Minnesota Renewable Energy Standard (RES) requirements. Further information about the MTO group is available at www.minnelectrans.com.
- CapX2020, a joint initiative of 11 regional transmission utilities to develop a long-range vision and transmission expansion projects to ensure that load in the region can be served reliably, provides outlet capability for renewable and other generation additions and supports regional reliability of the transmission system. As a first phase of transmission expansion, all four CapX2020 projects have received Certificates of Need from the Minnesota Public Utilities Commission.
    - The **Hampton – Rochester - La Crosse 345 kV Project** is an approximately 130-mile transmission line project between the southeast corner of the Twin Cities, connecting to a new substation in north Rochester, continuing eastward crossing the Minnesota River near Alma, Wisconsin and continuing south in Wisconsin to La Crosse, Wisconsin. This project also includes a new 161 kV transmission line between the new North Rochester Substation and the existing North Hills substation in northwest Rochester as well as a new 161 kV line between the North Rochester Substation and the Chester Substation. The route has been approved in both Minnesota and Wisconsin.
    - The **Fargo - Monticello 345 kV Project** is an approximately 240-mile, 345 kV transmission line between Monticello, St. Cloud, Alexandria and Fargo, North Dakota. The 28-mile Monticello – St. Cloud portion of this project has been energized. The approximately 178-mile section between St. Cloud, Minnesota and the Minnesota/North Dakota border near Fargo, North Dakota is currently under construction.
    - The **Brookings County – Hampton 345 kV Project** is an approximately 240-mile, 345 kV transmission line between Brookings County, South Dakota and the southeast corner of the Twin Cities. This project includes a 25-mile, 345 kV segment from the Lyon County substation near Marshall, Minnesota to a new

Hazel Creek Substation in the Granite Falls area, a six-mile, 230 kV transmission line from Hazel Creek to the Minnesota Valley Substation in Granite Falls and a five mile 115 kV transmission line from Cedar Mountain substation to the Franklin substation. The facility is currently under construction with the first phase between the Lyon County, Cedar Mountain and Helena substations expected to be energized in 2013. The entire project is expected to be in-service by early 2015.

- The **Bemidji - Grand Rapids 230 kV Project is** a 68-mile, 230 kV transmission line project from the Wilton substation near Bemidji, Minnesota to the Boswell substation near Grand Rapids, Minnesota. The project was energized and placed into service on September 17, 2012.

CapX2020 and the MTO group have engaged in several planning studies that will provide an updated vision of the transmission system to meet needs further into the future, including delivering renewable energy sufficient to meet the renewable energy requirements of states in the region. The studies were closely coordinated with MISO, neighboring transmission owning utilities and a diverse group of stakeholders formalized as the Technical Review Committee. MISO also has numerous studies underway with similar objectives, but that consider a broader geographic area. GRE and the CapX2020 utilities actively participate in these studies. The studies listed below were intended to provide a roadmap for cost effective transmission expansion that will integrate well with future scenarios, meet future needs and provide flexibility for changing conditions.

- Facilities Study: Manitoba Hydro TSR 500 kV Option 1: This study was commissioned by MISO to evaluate a transmission design alternative for adding 1100 MWs of hydro generation from Manitoba, Canada to the Upper Midwest U.S. The study results were issued in May 2010 and are available through MISO.
- MISO Hydro-Wind Synergy Study: MISO is undertaking a study to determine the energy market impacts of increased levels of Canadian hydropower with MISO wind generation. Manitoba Hydro has proposed more than 2000 MW of additional hydro generation development between 2012 and 2023+ beyond its existing 5,000 MW. Results to date suggest that the value of additional hydropower in the MISO market falls short of the economic cost of the transmission needed to transport it to the market. This synergy study has been conducted under full MISO stakeholder review and the final report will be published in the fall of 2013.
- Northern Area Study: MISO performed a regional study of the northern tier of its system to examine Manitoba Hydro exports, possible generation retirements, load growth and reliability needs. The study area includes Manitoba, North Dakota, Minnesota and Wisconsin. The final study report is expected to be published in June of 2013.

Further information about CapX2020, the proposed projects, and studies are available on-line at www.capx2020.com and www.minnelectrans.com.

- The federal American Recovery and Reinvestment Act (ARRA) has directed the development of interconnection-based transmission plans. Twenty-four planning authorities in the Eastern Interconnection are collaborating in a planning process known as the Eastern Interconnection Planning Collaborative (EIPC). This EIPC process will ultimately generate an interconnection-wide transmission plan for three scenarios chosen from seventy-two "generation futures." The final draft report was released in December 2012. Further information is available at www.eipconline.com.

- In 2011, the Federal Energy Regulatory Commission (FERC) issued FERC Order No. 1000 which removes from Commission-jurisdictional tariffs and agreements a federal right of first refusal for incumbent transmission providers to construct transmission facilities selected in a regional transmission plan for purposes of cost allocation. Referring to the "open" planning principles of FERC Order 890, the Commission determined opportunities exist for undue discrimination and preferential treatment against non-incumbent transmission developers that may result in regional transmission services provided rates, terms and conditions that are not just or reasonable. The rule does not intend to limit, preempt, or otherwise affect state or local laws with respect to construction of transmission facilities, including authority over siting or permitting of transmission facilities.[1]

  As required in FERC Order No. 1000, MISO and the MISO Transmission Owners submitted a compliance filing to FERC in 2012 describing how MISO would comply with the regional transmission planning and cost allocation requirements of Order No. 1000. FERC issued an order conditionally accepting the filing on March 22, 2013. An additional compliance filing is due to FERC by July 20, 2013.

Recommended Measures for Regional Coordination:

None beyond the activities described here in Section J.

SECTION K: Environmental Information

Clean Air Act Title IV Requirements. Coal Creek, Stanton and Spiritwood stations, as well as several of GRE's combustion turbine stations, have affected units under the federal acid rain regulations (Title IV of the Clean Air Act Amendments).

These regulations limit NO_X levels at Coal Creek Station to 0.40 lb/MMBtu at each unit and at Stanton Station to 0.46 lb/MMBtu for Unit 1 and 0.40 lb/MMBtu for Unit 10. The facilities comply with their applicable limits through the installation of low NO_X burners and other combustion controls including over-fire air. All affected GRE facilities have proper pollution control equipment and operational procedures to ensure compliance with their applicable NOx limits.

The acid rain program also creates a market for SO_2 emission allowances. Under this program, the U.S. Environmental Protection Agency (EPA) allots a specified number of SO_2 allowances to each unit for each year. Each unit is required to hold one SO_2 allowance for each ton of SO_2 emissions on a calendar year basis. Utilities' options for compliance are to:

- "under-control" and buy allowances,
- "over-control" and sell allowances, or
  - hold allowances for future use;
  - trade or transfer allowances in power sales or other transactions,

[1] North Dakota is among five states with statutes (Indiana, Minnesota, Oklahoma, and South Dakota) providing a right of first refusal for incumbent transmission providers.

- pool allowances with other utilities to mitigate risk, or
- use allowance futures contracts and options to hedge against future price changes.

Upgrades have been made to the scrubbers on both units at Coal Creek Station and on Unit 10 at Stanton Station.

Coal Creek Station's two units are allotted 44,497 SO_2 allowances per year. Through its use of improved scrubbing and our DryFining^{TM} technology, the station has reduced emissions of pollutants, including SO_2, while improving overall plant efficiency. (See Coal Drying Section)

Stanton Station's two units are allotted 8,781 SO_2 allowances per year. In 2004, Stanton Station switched from lignite to Powder River Basin (PRB) coal, resulting in lower emissions.

No additional modifications should be required for continued compliance with the SO_2 provisions of the acid rain program.

Regional Haze. EPA published final regional haze regulations in 1999. The goal of these regulations is to improve visibility in Class I areas, such as national parks and wilderness areas, by gradually reaching "natural conditions" in 2064. The first phase of this rule requires certain power plants to install Best Available Retrofit Technology (BART) to control SO_2, NO_X and particulate matter (PM) emissions. In December 2009, North Dakota Department of Health (NDDH) issued its final BART determinations for public comment as part of its regional haze State Implementation Plan (SIP). These emission controls must be installed and operational no later than five years after EPA approves North Dakota's SIP or finalizes its own Federal Implementation Plan (FIP). EPA's final SIP/FIP determinations for North Dakota were published on April 6, 2012. EPA approved North Dakota's SIP relative to Stanton Station and portions relative to Coal Creek Station with the exception of NOx. EPA also finalized its own FIP for Coal Creek Station NOx emissions. As a result, BART controls must be installed no later than April 2017.

GRE disagrees with EPA's FIP for Coal Creek Station NOx which would require selective non-catalytic reduction (SNCR) technology. In April 2012 GRE filed a petition for review with the Eighth Circuit Court of Appeals. North Dakota has also filed a petition with the Eighth Circuit. The court heard oral argument on May 14, 2013. A ruling is not expected until Fall 2013.

GRE (and, separately, NDDH) filed a petition for reconsideration with EPA on March 1, 2013. The petition requests that EPA review GRE's supplemental analysis and NDDH's supplemental evaluation, and confirm the state's original determination that SNCR is not required for Coal Station NOx control.

Coal Creek and Stanton stations have been working diligently on their BART control strategies required by the SIP and do not anticipate any difficulty meeting the regulatory timelines.

In 2018, NDDH is expected to start the second round of regional haze reductions. Cost effective controls and associated visibility improvements will again be determined for all emission sources in the state with an expected compliance date of 2023 for any applicable control requirements.

Mercury and Hazardous Air Pollutants. Since the late 1990s GRE has been an industry leader in researching mercury reduction technologies at our plants. We continue to work with partners such as Electric Power Research Institute (EPRI), U.S. Department of Energy (DOE), and North Dakota's Energy & Environmental Research Center (EERC) to identify and test novel mercury reduction technologies.

In February 2012, EPA published its final Mercury and Air Toxics Standards (MATS) rule for electric generating units which took effect on April 16, 2012. The rule establishes emission limits for essentially four categories of hazardous air pollutants: mercury, non-mercury metals, acid gases and volatile organic compounds (VOCs.)

Utilities have three years to comply with the rule (April 2015). The rule provides for an optional one-year extension by the state and a second one-year extension by EPA if certain conditions are applicable. GRE has not applied for an extension. Our North Dakota plants have been working diligently on control strategies required by the MATS rule and do not anticipate any difficulty meeting the regulatory timelines.

Greenhouse Gas Emissions. In late 2009, EPA issued its final Greenhouse Gas Reporting Rule, which requires GRE facilities to track and report greenhouse gas emissions. GRE has been tracking and reporting CO_2 emissions to EPA for all Acid Rain affected units since 1995. The new EPA GHG reporting rule increases the number of GHGs that must be reported and adds additional smaller emission units at our plants to our existing tracking and reporting compliance programs. Sulfur hexafluoride (SF_6) emissions from our transmission facilities must also be reported. GRE is in compliance with the reporting deadlines.

EPA has promulgated four greenhouse gas (GHG) rules/findings which regulate GHGs for the first time under the Clean Air Act. Facilities making "major modifications," as defined for criteria pollutants under New Source Review (NSR), must now complete best available control technology (BACT) evaluations for GHGs. All four rules/findings have been the subject of numerous consolidated lawsuits brought by various interested parties (industry, state/local governments, environmental advocacy groups). On June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit issued an order upholding EPA's GHG regulations that were the subject of the consolidated lawsuits. Numerous parties filed petitions for a Writ of Certiorari on April 19, 2013.

GRE is active in trying to shape federal environmental legislation and regulation in concert with National Rural Electric Cooperative Association and other associations. GRE continues to be a funding member of the Energy & Environmental Research Center's Plains CO_2 Reduction partnership (PCO_2R) which conducts research into CO_2 sequestration. Internally, GRE continues to evaluate opportunities for carbon reduction and offsets. In assessing generating technologies to meet its customers' needs, GRE includes externality costs for CO_2 emissions.

Fly Ash Sales. GRE has actively pursued beneficial reuse opportunities for the coal combustion products generated at Coal Creek Station and Stanton Station.

As a by-product of coal combustion, GRE generates approximately 520,000 tons of fly ash per year at Coal Creek Station. Historically, fly ash was stored in landfills, but over the last 10 years GRE has been very successful in finding alternative uses for it. It is primarily used as a partial replacement for cement, which makes the concrete stronger and more durable than concrete made with cement alone. It has also been used in other products. For example, fly ash was used in the backing of the carpet in GRE's new headquarters building.

Beneficial use of ash, in lieu of landfilling, avoids cement production, reducing CO_2 emissions in the cement production process. For each ton of fly ash that is used as a cement replacement, greenhouse gas emissions are estimated to be reduced by just over 0.8 tons. Since 1998, more than three million cumulative tons of CO_2 have been avoided through beneficial use of GRE ash.

Stanton Station fly ash has been used to replace cement and scoria fines as a product to absorb the oil/water sludge created during oil well drilling and for soil stabilization. Stanton continues to improve upon their fly ash utilization in the oil field industry. No Stanton Station fly was landfilled in the last year.

Through the beneficial use of ash, GRE also avoids storing the ash in landfills, resulting in cost savings of over $7 per ton. Since 1998, over $22 million in cumulative landfilling costs have been avoided through beneficial use.

Coal Combustion Residuals (CCR) Disposal. Recent developments could potentially disrupt the market for ash use. The large release of fly ash, bottom ash, and scrubber sludge from the Tennessee Valley Authority's Kingston Plant has brought renewed scrutiny of the disposal of CCRs. EPA is considering options for regulating the disposal of all CCRs. One of their options is to regulate these materials as "hazardous waste" under RCRA Subtitle C or some variant. The results of this form of regulation could be far reaching. A RCRA Subtitle C listing would require significantly different facility designs and greatly increase the cost of disposal. It could also impact the beneficial use market including fly ash sales. Consumers and sellers could be adverse to the risk of handling a material with potential RCRA Subtitle C liabilities. In some states, it could make the use of the materials illegal. EPA is also considering regulation of CCRs under Subtitle D, which could involve more stringent landfill and monitoring requirements, in addition to the potential need to convert from wet to dry handling. A final CCR rule is not expected until 2014.

Cogeneration for an Ethanol Plant. Blue Flint Ethanol is located adjacent to our Coal Creek Station, which provides steam for the ethanol plant's distiller's grain drying and other system thermal requirements. In addition to the benefit of using low pressure steam that would normally be unused, the project results in much lower emissions than a stand-alone ethanol plant.

The primary benefit of locating the ethanol plant adjacent to Coal Creek Station is to allow for beneficial use of low temperature/quality energy from Coal Creek Station by the ethanol facility. Approximately 60 percent of the process steam for the ethanol facility comes from recovery and use of low pressure steam at Coal Creek Station. This steam is not usable in Coal Creek Station's steam cycle, and it would normally be rejected to the cooling towers as waste heat. The remaining 40 percent of the ethanol plant's process steam needs are for higher pressure steam, which also comes from Coal Creek Station.

Coal Drying Project. The DryFining system, operated and maintained by NoDak Energy Services (a subsidiary of the North American Coal Corporation), produced refined coal throughout 2013. The system processed 2,783,896 wet tons (prior to drying) YTD through May 2013, which constituted about 94 percent of the wet tons being supplied to the plant, Refined coal production through the month of May was 2,483,541 tons.

For 2013, the DryFining system continued to comply with the IRS Section 45 emissions performance requirements. On December 13, 2012 the Coal Creek Station staff conducted a three hour NO_x emissions test to qualify the DryFining tons for the next six months. The test demonstrated acceptable emissions of 0.169 lbs/mmBTU for Unit 1 and 0.120 lbs/mmBTU for Unit 2, versus compliance targets of less than 0.226 lbs/mmBTU for Unit 1 and less than 0.161 lbs/mmBTU for Unit 2. For 2013, the Unit 1 emissions for SO_2 averaged 0.332 lbs/mmBTU since January 1st, versus the Section 45 target of 0.366 lbs/mmBTU, while Unit 2 SO_2emissions averaged 0.348 lbs/mmBTU since January 1st, versus the Section 45 target of 0.360

lbs/mmBTU. Since January 1, the DryFining system achieved a 9.2 percent moisture (and reject) removal rate and 7.4 percent sulfur removal from the incoming lignite.

GRE is actively involved in commercializing the proprietary DryFining technology subject to multiple patents that have been awarded. We have recently completed a feasibility assessment for an electric utility in India and are currently negotiating a similar study for a power plant retrofit in Indonesia. We have hosted power plant engineers and academic consultants from all over the world where there is interest in drying and cleaning low rank coals for domestic energy production.

Effluent Limitations Guidelines. Effluent limitations guidelines are national standards, based on the performance of treatment and control technologies, for wastewater discharges to surface waters and municipal sewage treatment plants. EPA published proposed guidelines on June 7, 2013. A public comment period is scheduled to end on August 6 unless EPA grants extensions requested by several parties. We are evaluating the potential impact to our facilities.

Impaired Waters and Total Maximum Daily Loads. Every two years EPA, under the Clean Water Act, requires states to publish and submit an updated list of waters that do not meet designated uses due to pollutant impacts. The §303(d) impaired waters list includes lakes, streams and rivers with impairments for use as drinking water, fishable waters, swimming, industrial use and/or irrigation.

Once a water body is listed, the state must begin the process of addressing the impairment. The first stage of this process is development of a total maximum daily load (TMDL). A TMDL is the total maximum daily pollutant load a water body can receive from all sources while maintaining applicable water quality standards and supporting the water body's designated uses.

The development of a TMDL is designed to assess the load on a water body from point sources, non-point sources, and natural background conditions. Once these loads are quantified, each source can be assigned a given amount of pollutant load expected to ensure the receiving water body will meet water quality standards and designated uses.

At this time, states are generally in the water body assessment phase, but TMDLs have either been developed or are in development for an increasing number of water bodies. As this process proceeds, TMDLs will likely be developed for water bodies to which GRE either has or is seeking permitted discharges. This could change discharge limits, result in limits for additional analytical parameters or even possibly preclude permitting of a new or expanded discharge to a given water body. The most likely affected parameters include mercury, phosphorous, total suspended solids, and temperature.

In many instances the impairments mentioned above have significant contributions from non-point and natural background sources. Due to the difficulty in controlling the loads from these sources, significant reduction goals may be allocated to point sources such as GRE's permitted discharges. Retrofitting existing facilities and implementing new pollutant reduction technologies will likely require significant capital expenditure to achieve relatively small reductions for a given pollutant. Based on this it appears pollutant trading and restoration projects will play a significant role in the TMDL process. GRE will continue to monitor TMDL development and assess potential impacts to our facilities.

Aquatic Life Protection at Cooling Water Intake Structures. Section 316(b) of the Clean Water Act requires that the location, design, construction, and capacity of a cooling water intake structure (CWIS) reflect the best available technology (BAT) for minimizing environmental impact including threat to aquatic life. As part of a settlement agreement EPA began development of new regulations to address impacts to aquatic life at CWISs. In March 2011 EPA released the second version of the draft rule which addresses existing facilities.

The draft rule would require all facilities withdrawing greater than two million gallons per day (MGD) to conduct baseline studies and address impingement. The two options for impingement reduction are to either install technology to reduce impingement mortality by 88 percent annually and no less than 69 percent in any given month, or reduce intake flow to less than 0.5 feet per second. The first option also requires performance monitoring for any technology installed. Facilities must also minimize entrapment.

The draft also would require entrainment reductions for all facilities greater than two MGD, however, baseline entrainment studies are only required for facilities with greater than 125 MGD withdrawals. Based on this information it would then be up to the entity that administrators the NPDES program to determine BTA.

Any new requirements could affect Coal Creek Station, Stanton Station and Elk River Station. Currently Stanton and Elk River stations have completed initial strategy analyses for compliance with the new rule and are conducting baseline and limited planning exercises based on available information. Stanton has also conducted some baseline impingement monitoring. On July 18, 2012 EPA announced that the date for promulgation of its final rule for existing facilities was extended to June 27, 2013. EPA did not meet its deadline.

SECTION L: Projected Demand for Service

Projected Demand. GRE's forecasted peak demands and energy requirements are provided in Exhibit 4.

Manner and Extent of Meeting Projected Demand. In addition to GRE's current generation capability, GRE has entered into a number of transactions of various types and durations with other utilities. These transactions help to utilize GRE's resources more effectively while deferring the need for new additions. GRE is a full transmission and market participant of the Midcontinent Independent System Operator (MISO), which operates short term energy and ancillary services markets that provide economic dispatch of generation and transmission congestion management over a broad region. In June 2009, MISO also began administering resource adequacy requirements to ensure that there is sufficient capacity available to meet expected demand requirements within its footprint.

Meeting summer peaks is GRE's primary resource capacity concern. GRE added combustion turbines In 2001, 2002, 2007, and 2009.

GRE is pursuing additional opportunities for conservation, energy efficiency, and load management. GRE, in concert with its member systems, strives to meet the 1.5 percent Energy Efficiency Policy Goal established by Minnesota statute.

Given the current forecast of future demand and energy over the next 10 years GRE has no need for additional resources to meet those needs.

GRE intends to continue to evaluate improvements to existing facilities, biomass and other non-wind renewables, combined heat and power projects, and energy storage (both utility-side and customer-side).

Load Centers. The service areas of GRE's 28 member cooperatives, shown in Figure 1, are located mainly in Minnesota and a small area in northwestern Wisconsin. Twenty of the member cooperatives are all-requirements customers. Eight member cooperatives purchase a fixed amount of capacity and associated energy from GRE and meet their growth with purchases from other energy suppliers.

Fuel Sources and Transportation. Stanton Station originally burned lignite, but switched to Powder River Basin subbituminous coal in 2004. The coal is mined near Decker Montana and is transported to the plant via rail.

Coal Creek Station's generating units burn lignite that is mined at the adjacent Falkirk Mine and transported to the plant via trucks and conveyor belts.

When in operation Spiritwood Station is expected to burn refined lignite produced at Coal Creek Station which will be transported via rail to Spiritwood Station.

The Elk River generating plant burns refuse-derived fuel (RDF). Municipal wastes are transported by truck to a processing plant near Elk River where they are converted to usable fuel. The RDF is trucked to the Elk River generating facility.

GRE has two combustion turbine peaking facilities (Pleasant Valley and Lakefield Junction) located in southern Minnesota. These facilities use natural gas as their primary fuel which is transported by pipelines and fuel oil as a back-up fuel, which is transported by truck.

GRE has six combustion turbine peaking facilities (Cambridge I, Cambridge II, Rock Lake, Maple Lake, St. Bonifacius, and Elk River Peaking Station) located in central Minnesota. Cambridge II is fueled with natural gas. The Elk River Peaking Station can use either natural gas or fuel oil. The remaining facilities use fuel oil, which is transported by truck. St. Bonifacius is also connected to a fuel oil pipeline, which adds a fuel transport option.

Figure 1 – GRE's Members and Their Service Areas

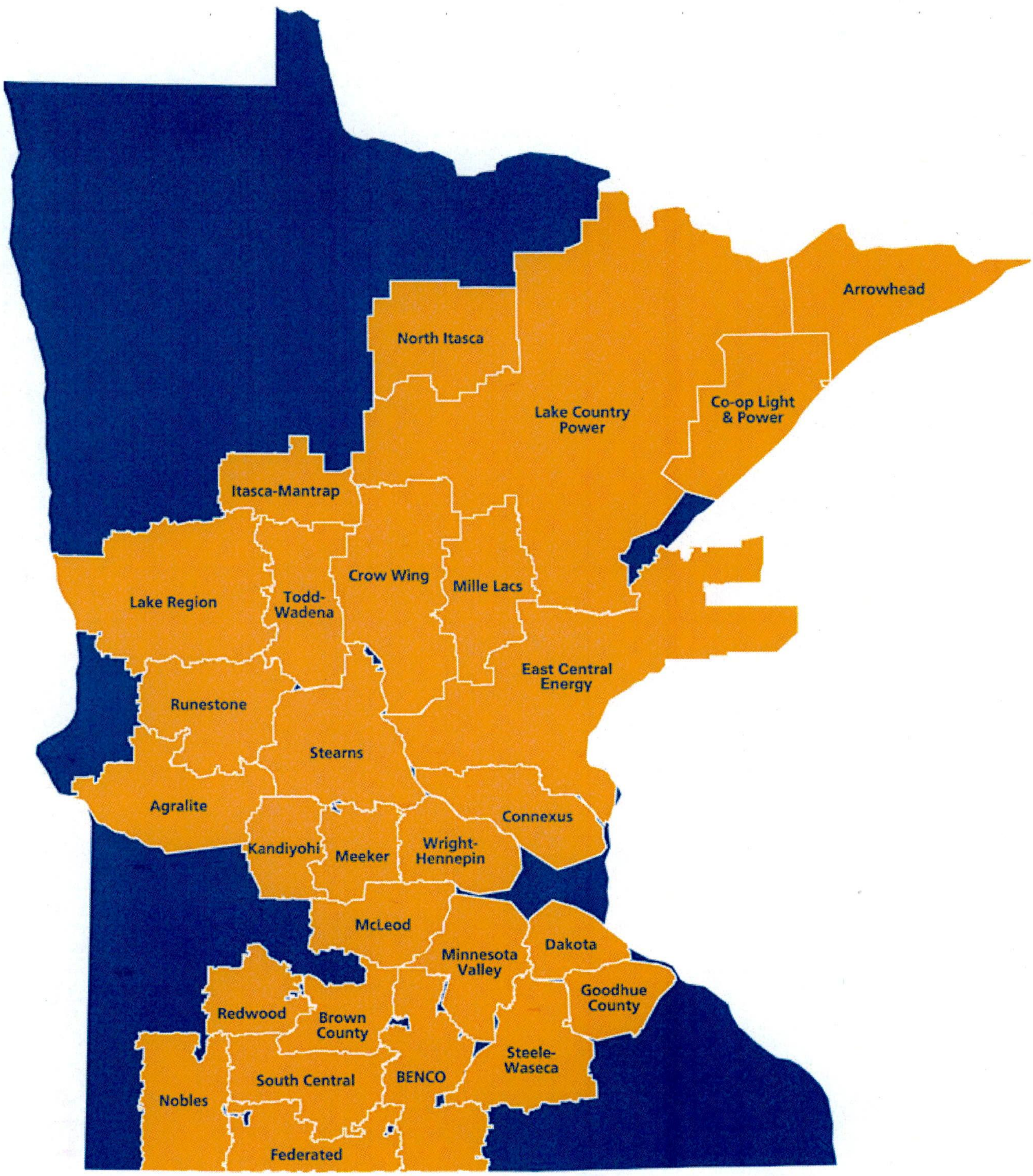

Exhibit 1

U.S. Department of Energy
Energy Information Administration Form EIA-767

(Forms supplied upon request.)

Exhibit 2

Federal Energy Regulatory Commission Form 715

(Forms supplied upon request.)

Exhibit 3

Location of the Coal Creek Station

Water Intake Pipeline

(Map supplied upon request.)

Exhibit 4

Projected Load Growth

and

Forecast Methodology

Demand and Energy Forecasts

The forecast shown below is an econometric forecast developed for GRE's 2012 Resource Plan 2013-2027 submitted to the Minnesota Public Utilities Commission November 1st, 2012 for our 20 All Requirement Members plus fixed amounts of capacity and energy to serve eight Fixed Members who purchase their load growth from alternate suppliers. These forecasts were developed in the winter of 2012. In addition to GRE's member system's demand and energy, they include transmission losses and GRE's own use.

The following figures show GRE's expected value energy and demand forecast from 2013 through 2027.

Year	All Requirement (MWh)	Fixed (MWh)	DC Line Losses (MWh)	GRE System Requirement (MWh)
2013	9,677,148	2,763,027	438,000	12,878,175
2014	9,803,203	2,763,027	438,000	13,004,230
2015	9,948,118	2,686,007	438,000	13,072,125
2016	10,108,641	2,693,476	439,200	13,241,318
2017	10,276,822	2,686,498	438,000	13,401,320
2018	10,452,799	2,686,498	438,000	13,577,297
2019	10,636,193	2,686,498	438,000	13,760,691
2020	10,818,782	2,693,476	439,200	13,951,459
2021	11,021,157	2,686,498	438,000	14,145,655
2022	11,222,527	2,686,498	438,000	14,347,025
2023	11,430,040	2,686,498	438,000	14,554,538
2024	11,636,688	2,693,476	439,200	14,769,364
2025	11,859,953	2,686,498	438,000	14,984,451
2026	12,076,258	2,686,498	438,000	15,200,756
2027	12,292,956	2,686,498	438,000	15,417,454
5-year CAGR ('13-'17)				1.00%
10-year CAGR ('13-'22)				1.21%
15-year CAGR ('13-'27)				1.29%

Year	All Requirement (MW)	Fixed (MW)	DC Line Losses (MW)	GRE System Requirement (MW)
2013	1,766	517	50	2,333
2014	1,788	517	50	2,355
2015	1,813	517	50	2,380
2016	1,840	517	50	2,407
2017	1,869	517	50	2,435
2018	1,898	517	50	2,465
2019	1,929	517	50	2,496
2020	1,961	517	50	2,527
2021	1,993	517	50	2,560
2022	2,027	517	50	2,594
2023	2,061	517	50	2,628
2024	2,097	517	50	2,663
2025	2,133	517	50	2,699
2026	2,168	517	50	2,735
2027	2,204	517	50	2,771
5-year CAGR ('13-'17)				1.08%
10-year CAGR ('13-'22)				1.18%
15-year CAGR ('13-'27)				1.24%

Exhibit 5

GRE

North Dakota Transmission Map

(Map supplied upon request.)