GREAT RIVER ENERGY®

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June 6, 2005

The Honorable Kathleen D. Sheehy
Administrative Law Judge
Office of Administrative Hearings, Suite 1700
100 Washington Square
Minneapolis, MN 55401-2138

Dear Judge Sheehy:

Re: Revisions to Great River Energy's Certificate of Need Application, Docket No. ET2/CN-05-347

On February 28, 2005 Great River Energy (GRE) filed its *Certificate of Need Application for Great River Energy's Cambridge Station* (Petition), Docket No. ET2/CN-05-347. Great River Energy submits the following revised sheets to its Petition, consistent with Minnesota Rules, part 7849.0200, subp. 3. The revised sheets provide updated information on the operational aspects of the proposed Cambridge Station and GRE's supply and demand forecasts.

Specifically, the revisions affect Chapters 3 and 4, and Appendices A, B, and D of the Petition. In Chapter 3, revisions have been made to sections 3.4, 3.7.2, and 3.8, along with Tables 3-1 and 3-3. Tables 4-3 and 4-4 have been revised in Chapter 4. In Appendix A, table A-1 contains corrected customer forecasts and figure A-1 has been changed to include the Scenario 5 forecast, as stated in the text, rather than another demand scenario inadvertently included in the initial application. Great River Energy's load and capability information, tables B-3, B-4, and B-5 of Appendix B, is updated to reflect the expiration date of a power purchase agreement that was incorrect in the original Petition. Finally, in Appendix D, GRE has corrected the length of one of the 69-kV transmission lines that would be affected by the proposed facility.

The revisions have no effect on the proposed size, type, or timing of the proposed Cambridge Station nor do they change GRE's conclusion that the facility is necessary to meet forecasted load for the summer season of 2007.

Also attached is an Affidavit of Service. Questions may be directed to me or to Michele Beck Jensen at 763-241-2398.

Sincerely,

GREAT RIVER ENERGY

Richard R. Lancaster
Vice President, Corporate Services

Enclosures

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AFFIDAVIT OF SERVICE

STATE OF MINNESOTA)
) ss
COUNTY OF HENNEPIN)

In Re: Comments of the Minnesota
Department of Commerce

Docket No. ET2/CN-05-347

Debra K. Cavan, being first duly sworn on oath, deposes and states that on the 6th day of June, 2005, copies of the revised redlined and clean pages for the public and trade secret versions of the certificate of need application in the above referenced matter were hand delivered or mailed by United States first class mail, postage prepaid thereon, to the following:

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ET2/CN-05-347

In the Matter of Certificate of Need
Application for GRE's Cambridge Station

1 Service List

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Debra K Cavan

Debra K. Cavan, CPS

SWORN TO BEFORE ME this
6th day of June, 2005

Theresa M Hoaglund

NOTARY PUBLIC

THERESA M. HOAGLUND
Notary Public-Minnesota
My Commission Expires Jan 31, 2010

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3.2 Combustion Turbine/Generator

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

3.3 Generator Step-Up Transformers

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

3.4 Water Storage

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

3.5 Substation

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

3.6 Natural Gas – Primary Fuel

3.6.1 Overview

The project will utilize a single fuel – natural gas - delivered via Northern Natural Gas Company's (NNG) interstate pipeline. A 0.5 mile, 10-inch lateral

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3.7 Plant Details & Operation

3.7.1 Overview

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

3.7.2 Plant Efficiency

The project will be designed to be one of the most efficient SCCTs in the region with a full load heat rate (higher heating value) of 9,920 Btu/kWh at site-specific conditions during winter months. The heat rate equates to an efficiency of 34.4%. Heat rejected through the exhaust stacks is expected to be 1,176 MMBtu/hr at full load during the summer months.

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Table 3-1 - Project Operational Characteristics

Characteristic	Data	MN Rule
Facility Description		
Unit Type	F-Class	
Prime Mover	Combustion Turbine	
Number of Units	1	
Summer Capability (site specific)[1]	170 MW	7849.0250, A(1)
Winter Capability (site specific)	190 MW	7849.0250, A(1)
Operating Cycle	Simple-cycle	7849.0250, A(2)
Expected Annual Capacity Factor	9.6%	7849.0250, A(2)
Expected Heat Rate/Efficiency (Summer site specific)[2]	10,330 Btu/kWh (HHV)/33.0%	7849.0250, A(4)
Expected Heat Rate/Efficiency (Winter site specific)[2]	9,920 Btu/kWh (HHV)/34.4%	7849.0250, A(4)
Heat Rejected through exhaust (Summer)	1,176 MMBtu/hr	
Heat Rejected through exhaust (Winter)	1,236 MMBtu/hr	
Fuel Description		
Fuel Source: Natural Gas only	Northern Natural Gas Pipeline	7849.0320, C(1)
Fuel Requirement: Natural Gas only (Summer)[2]	1,756 MCf/hr	7849.0320, C(2)
Fuel Requirement: Natural Gas only (Winter)[2]	1,885 MCf/hr	7849.0320, C(2)
Expected Annual Fuel Requirement	1,475,124 MCf	7849.0320, C(2)
Heat Input (Summer - HHV)[2]	1,765 MMBtu/hr	7849.0320, C(3)
Heat Input (Winter - HHV)[2]	1,894 MMBtu/hr	7849.0320, C(3)
Fuel Heat Content: Natural Gas	1.005 MMBtu/MCf	7849.0320, C(4)
Fuel Sulfur Content: Natural Gas	5.5 mg/m^3	7849.0320, C(5)
Fuel Ash Content: Natural Gas	None	7849.0320, C(5)
Fuel Moisture Content: Natural Gas	<80 mg/m^3	7849.0320, C(5)
Water Use		
Estimated maximum groundwater pumping rate[3]	108 gpm	7849.0320, E(1)
Estimated maximum surface water appropriation[3]	0 ft^3/sec	7849.0320, E(1)
Estimated annual groundwater appropriation[4]	3. million gal/yr	7849.0320, E(2)
Annual consumption[4]	9.2 acre-feet	7849.0320, E(3)
Emissions[5]		
Maximum Sulfur Dioxide Emissions[2]	5.7 lb/hr	7849.0320, D(1)
Maximum Nitrogen Oxides Emissions[2]	169 lb/hr	7849.0320, D(1)
Maximum Particulates Emissions[2]	15 lb/hr	7849.0320, D(1)
1,3-Butadiene	0.00072 lb/hr	7849.0320, D(1)
Acetaldehyde	0.067 lb/hr	7849.0320, D(1)
Acrolein	0.011 lb/hr	7849.0320, D(1)
Benzene	0.020 lb/hr	7849.0320, D(1)
Ethyl benzene	0.053 lb/hr	7849.0320, D(1)
Formaldehyde	1.2 lb/hr	7849.0320, D(1)
Naphthalene	0.0022 lb/hr	7849.0320, D(1)
PAH	0.0037 lb/hr	7849.0320, D(1)
Propylene oxide	0.048 lb/hr	7849.0320, D(1)
Toluene	0.22 lb/hr	7849.0320, D(1)
Xylenes	0.11 lb/hr	7849.0320, D(1)

1 With evaporative cooler in service.
2 Under base load operations.
3 When unit is on-line.
4 Assuming a 9.6% annual capacity factor and utilization of evapoartive cooler for 5.7% of annual operation.
5 More emissions information can be found in Table 9-2 and Section 9.13 of this document.

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3.8 Employment Opportunities

The labor requirements for the construction, operation, and maintenance phases of the project will benefit the local communities by providing revenue to local businesses. During construction, approximately 75 skilled craft workers will work at the site, most of them for about one year. Day-to-day operation of the plant will be conducted by two to three full-time employees. During scheduled annual maintenance on the plant, seven to ten additional skilled craft workers will work at the site over a two to three week period depending on the level of maintenance activities.

3.9 Maintenance

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

3.10 Site Selection

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

The site selected met all the siting factors considered with the lowest overall costs and environmental impacts.

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Table 3-3 - Project Cost Analysis

Item	Units	Project Data	Assumptions	MN Rule
Project Description				
Base Capability (Summer, site-specific rating)	MW	170	Manufacturer *pro forma* estimate	7849.025, A(1)
Cost Basis	Cal Yr	2004		
Life of Project	Years	30	Typical accounting life	7849.025, C(2)
Operating Cycle		Simple		7849.025, A(2)
Annual Capacity Factor	%	9.6%	PVS experience	7849.025, A(2)
Annual Operating Time	Hours	840	Formula	
Average Annual Availability	%	97.5	PVS ops experience	7849.025, C(3)
Fuel Type		Nat Gas		7849.025, A(3)
Heat Input (HHV)	MMBtu/hr	1,756	Manufacturer *pro forma* estimate	
Heat Rate (HHV) - Summer Rating	Btu/kWh	10,330	Manufacturer *pro forma* estimate	7849.025, A(4)
Efficiency (HHV) - Summer Rating	%	33.0	Formula	7849.025, C(8)
Project Capital Cost	$/kW	406	Overnight cost w/o IDC	
Fixed O&M Costs	$/kW-yr	3.46	PVS experience	
Fuel Costs	$/MMBtu	5.73	EIA *2005 AEO* plus transport & balancing	7849.025, C(4)
Non-Fuel Variable O&M Costs	$/MWh	8.41	Includes fired-hour costs & start charge	7849.025, C(5)
Capacity Costs (Fixed)				**7849.025, C(1)**
Total Project Capital Cost	$	69,020,000	Formula	
Annual Fixed O&M	$	588,200	Formula	
Total Annual Fixed Costs	$	6,523,920	8.6% annual FCs + Fixed O&M	
Project Capacity Cost	$/kW-yr	38.38	Formula	
Project Capacity Cost	$/kWh	0.046	Formula	
Production Costs (Variable)				
Net Annual Generation	MWh	142,800	Formula	
Annual Fuel Consumption	MMBtu	1,475,124	Formula	
Annual Fuel Cost	$	8,456,192	Formula	
Annual Non-Fuel Variable O&M Cost	$	1,200,948	Formula	
Total Project Variable Generation Cost	$	9,657,140	Formula	
Project Fuel Cost	$/kWh	0.059	Formula	7849.025, C(4)
Project Total Energy Cost	$/kWh	0.068	Formula	
Total Cost	**$/kWh**	**0.113**	**Formula**	**7849.025, C(6)**

3.23 Use of Space

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

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

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Table 4-3 – Alternatives' Operational Characteristics

Characteristic	Project	Oil-Fired Simple-Cycle	Ethanol-Fired Simple-Cycle	MN Rule
Facility Description				
Unit Type	F-Class	F-Class	F-Class	
Prime Mover	Combustion Turbine	Combustion Turbine	Combustion Turbine	
Number of Units	1	1	1	
Summer Capability (site specific)[1]	170 MW	164 MW	164 MW	7849.0250, A(1)
Winter Capability (site specific)	190 MW	190 MW	190 MW	7849.0250, A(1)
Operating Cycle	Simple-cycle	Simple-cycle	Simple-cycle	7849.0250, A(2)
Expected Annual Capacity Factor	9.6%	9.6%	9.6%	7849.0250, A(2)
Expected Heat Rate/Efficiency (Summer site specific)[2]	10,330 Btu/kWh (HHV)/33.0%	10,450 Btu/kWh (HHV)/32.7%	10,450 Btu/kWh (HHV)/32.7%	7849.0250, A(4)
Expected Heat Rate/Efficiency (Winter site specific)[2]	9,920 Btu/kWh (HHV)/34.4%	9,900 Btu/kWh (HHV)/34.5%	9,900 Btu/kWh (HHV)/34.5%	7849.0250, A(4)
Heat Rejected through exhaust (Summer)	1,176 MMBtu/hr	1,154 MMBtu/hr	1,154 MMBtu/hr	
Heat Rejected through exhaust (Winter)	1,236 MMBtu/hr	1,233 MMBtu/hr	1,233 MMBtu/hr	
Fuel Description				
Fuel Source: Natural Gas only	Northern Natural Gas Pipeline	Regional Refineries	Regional Ethanol Plants	7849.0320, C(1)
Fuel Requirement: (Summer)[2]	1,756 MCf/hr	12,695 gal/hr	22,550 gal/hr	7849.0320, C(2)
Fuel Requirement: (Winter)[2]	1,885 MCf/hr	13,933 gal/hr	24,750 gal/hr	7849.0320, C(2)
Expected Annual Fuel Requirement	1,475,124 MCf/yr	11,109,511 gal/yr	19,734,000 gal/yr	7849.0320, C(2)
Heat Input (Summer - HHV)[2]	1,765 MMBtu/hr	1,714 MMBtu/hr	1,714 MMBtu/hr	7849.0320, C(3)
Heat Input (Winter - HHV)[2]	1,894 MMBtu/hr	1,881 MMBtu/hr	1,881 MMBtu/hr	7849.0320, C(3)
Fuel Heat Content	1.005 MMBtu/MCf	0.137 MMBTU/gal	0.0841 MMBTU/gal	7849.0320, C(4)
Fuel Sulfur Content	5.5 mg/m^3	<0.05 percent	Unknown	7849.0320, C(5)
Fuel Ash Content	None	Trace	Unknown	7849.0320, C(5)
Fuel Moisture Content	<80 mg/m^3	Trace	Unknown	7849.0320, C(5)
Water Use				
Estimated maximum groundwater pumping rate[3]	108 gpm	454 gpm	611 gpm	7849.0320, E(1)
Estimated maximum surface water appropriation[3]	0 ft^3/sec	0 ft^3/sec	0 ft^3/sec	7849.0320, E(1)
Estimated annual groundwater appropriation[4]	3. million gal/yr	13 million gal/yr	17 million gal/yr	7849.0320, E(2)
Annual consumption[4]	9.2 acre-feet	38.6 acre-feet	52.0 acre-feet	7849.0320, E(3)
Discharges to water	2.1 million gal/yr	2.1 million gal/yr	2.1 million gal/yr	
Estimated Emission Rates (lbs/hr)				
CO[2]	37	47	47[5]	7849.0320, D(1)
SO_2[2]	5.7	91	91[5]	7849.0320, D(1)
NO_x[2]	169	327	327[5]	7849.0320, D(1)
PM_{10}[2]	15	36	36[5]	7849.0320, D(1)
Other Information				
Land Requirements	2.5 acres	2.5 acres	2.5 acres	
Traffic	Slight increase due to on-site operators	Increased due to fuel deliveries	Increased due to fuel deliveries	
Radioactive Releases	None	None	None	
Solid Wastes Produced	Construction packaging, office waste, waste lubricating oils	Construction packaging, office waste, waste lubricating oils	Construction packaging, office waste, waste lubricating oils	
Noise	≤ 63 dB(A) @ 400 ft.	≤ 63 dB(A) @ 400 ft.	≤ 63 dB(A) @ 400 ft.	
Work Force	2 to 3 FTE	2 to 3 FTE	2 to 3 FTE	
Transmission Requirements	Upgrade 3 sections of 69-kV lines	Upgrade 3 sections of 69-kV lines	Upgrade 3 sections of 69-kV lines	

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

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4.5 Economic Comparisons to Proposed project

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

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

Item	Units	Project	Oil-Fired Simple-Cycle	Ethanol-Fired Simple-Cycle	Assumptions	MN Rule
Project Description						
Base Capability (Summer, site-specific rating)	MW	170	164	164	Manufacturer *pro forma* estimate	7849.025, A(1)
Cost Basis	Cal Yr	2004	2004	2004		
Life of Project	Years	30	30	30	Typical accounting life	7849.025, C(2)
Operating Cycle		Simple	Simple	Simple		7849.025, A(2)
Annual Capacity Factor	%	9.6%	9.6%	9.6%	PVS experience	7849.025, A(2)
Annual Operating Time	Hours	840	840	840	Formula	
Average Annual Availability	%	97.5	97.5	97.5	PVS ops experience	7849.025, C(3)
Fuel Type		Nat Gas	No. 2 Fuel Oil	Ethanol		7849.025, A(3)
Heat Input (HHV)	MMBtu/hr	1,756	1,714	1,714	PVS ops experience	
Heat Rate (HHV) - Summer Rating	Btu/kWh	10,330	10,450	10,450	PVS ops experience	7849.025, A(4)
Efficiency (HHV) - Summer Rating	%	33.0	32.7	32.7	Formula	7849.025, C(8)
Project Capital Cost	$/kW	406	430	443	Overnight cost w/o IDC	
Fixed O&M Costs	$/kW-yr	3.46	3.46	3.46	PVS experience	
Fuel Costs	$/MMBtu	5.73	7.66	20.56	EIA *2005 AEO* plus transport & balancing	7849.025, C(4)
Non-Fuel Variable O&M Costs	$/MWh	8.41	12.62	12.62	Includes fired-hour costs & start charge	7849.025, C(5)
Capacity Costs (Fixed)						**7849.025, C(1)**
Total Project Capital Cost	$	69,020,000	70,520,000	72,652,000	Formula	
Annual Fixed O&M	$	588,200	567,440	567,440	Formula	
Total Annual Fixed Costs	$	6,523,920	6,632,160	6,815,512	8.6% annual FCs + Fixed O&M	
Project Capacity Cost	$/kW-yr	38.38	40.44	41.56	Formula	
Project Capacity Cost	$/kWh	0.046	0.048	0.049	Formula	
Production Costs (Variable)						
Net Annual Generation	MWh	142,800	137,760	137,760	Formula	
Annual Fuel Consumption	MMBtu	1,475,124	1,439,760	1,439,760	Formula	
Annual Fuel Cost	$	8,456,192	11,035,129	29,601,466	Formula	
Annual Non-Fuel Variable O&M Cost	$	1,200,948	1,738,531	1,738,531	Formula	
Total Project Variable Generation Cost	$	9,657,140	12,773,660	31,339,997	Formula	
Project Fuel Cost	$/kWh	0.059	0.080	0.215	Formula	7849.025, C(4)
Project Total Energy Cost	$/kWh	0.068	0.093	0.227	Formula	
Total Cost	**$/kWh**	**0.113**	**0.141**	**0.277**	**Formula**	**7849.025, C(6)**

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

APPENDIX A FORECAST

REVISED by GRE, 6/3/05

This appendix provides the details and methodology of Great River Energy's load forecast. As described in Section 2, GRE used its 2002 Long Range Load Forecast ("2002 load forecast" or "2002 LRLF").

Great River Energy provides service to 28 member systems. One of these member systems has a small amount of service territory in Wisconsin. However, the sales to Wisconsin is less the one-tenth of one percent of GRE's total energy sales and therefore have been rounded to zero for the purposes of this application. Thus, all energy consumption of Great River Energy members is reported here as Minnesota sales.

A.1 Consumers and Annual Consumption

The following table itemizes data concerning ultimate consumers. GRE serves no mining loads or electrified transportation.

Table A-1 – Consumers by Customer Class

Historical Consumers												
	Farm	Non-farm	Residential	Irrigation	Commercial	Industrial	Mining	S&H Lighting	Electric Trans.	Other	Sales for Resale	Total
1992	44,631	361,109	405,740	1,842	20,401	193	0	1,863	0	403	11	430,453
1993	45,760	370,236	415,996	1,875	20,978	203	0	1,945	0	403	11	441,411
1994	46,988	380,178	427,166	1,941	21,683	213	0	2,003	0	406	11	453,423
1995	48,160	389,661	437,821	2,019	22,236	225	0	2,056	0	407	12	464,776
1996	49,342	399,220	448,562	2,125	23,035	265	0	2,150	0	406	13	476,556
1997	50,414	407,896	458,310	2,205	25,047	336	0	2,245	0	477	11	488,631
1998	51,453	416,302	467,756	2,296	26,856	350	0	2,344	0	486	12	500,100
1999	52,744	426,747	479,491	2,357	28,166	363	0	2,406	0	494	14	513,291
2000	54,157	438,181	492,338	2,439	29,477	376	0	2,547	0	500	13	527,690
2001	55,442	448,575	504,017	2,486	30,911	397	0	2,687	0	503	13	541,014
Forecast Consumers												
	Farm	Non-farm	Residential	Irrigation	Commercial	Industrial	Mining	S&H Lighting	Electric Trans.	Other	Sales for Resale	Total
2002	56,943	460,725	517,668	2,518	32,082	410	0	2,771	0	505	11	555,965
2003	58,471	473,080	531,551	2,553	33,030	425	1	2,924	1	506	11	571,002
2004	60,003	485,479	545,482	2,586	33,934	438	2	3,048	2	508	11	586,010
2005	61,537	497,893	559,430	2,620	34,844	450	3	3,173	3	509	11	601,043
2006	63,019	509,884	572,903	2,654	35,749	464	4	3,252	4	511	11	615,552
2007	64,465	521,579	586,043	2,688	36,642	473	5	3,331	5	512	11	629,711
2008	65,913	533,299	599,213	2,721	37,544	486	6	3,412	6	514	11	643,913
2009	67,365	545,043	612,408	2,756	38,449	498	7	3,492	7	515	11	658,143
2010	68,821	556,822	625,642	2,789	39,362	511	8	3,571	8	517	11	672,419
2011	70,280	568,627	638,906	2,824	40,276	521	9	3,652	9	518	11	686,726
2012	71,744	580,470	652,214	2,852	41,202	534	10	3,731	10	520	11	701,084
2013	73,210	592,335	665,545	2,881	42,136	545	11	3,811	11	521	11	715,472
2014	74,677	604,207	678,885	2,909	43,068	557	12	3,892	12	523	11	729,869
2015	76,149	616,115	692,264	2,938	44,010	568	13	3,971	13	524	11	744,311
2016	77,619	628,009	705,628	2,967	44,953	580	14	4,050	14	526	11	758,743
2017	79,091	639,918	719,009	2,996	45,906	591	15	4,129	15	527	11	773,198
2018	80,563	651,829	732,392	3,025	46,866	603	16	4,210	16	529	11	787,668
2019	82,034	663,733	745,767	3,054	47,829	614	17	4,290	17	530	11	802,129
2020	83,509	675,663	759,172	3,082	48,806	623	18	4,369	18	532	11	816,632
2021	84,985	687,607	772,593	3,112	49,796	635	19	4,450	19	533	11	831,168

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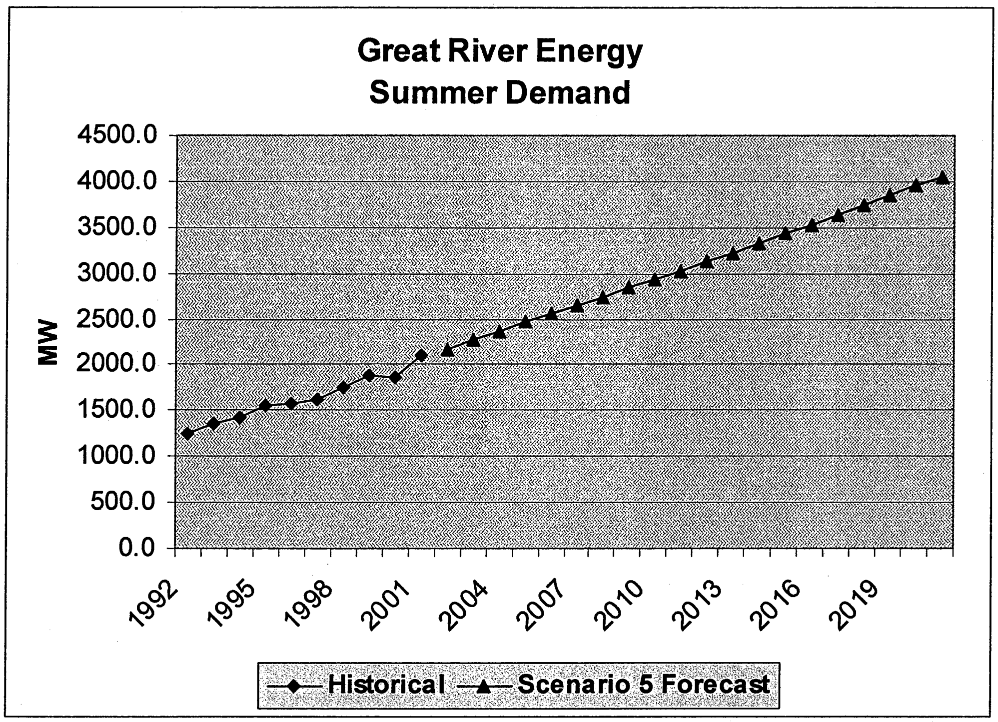
A.2 Peak Demand

Great River Energy has been a summer peaking system since 1987. Figure A-1 shows GRE's forecasted demand at the level used for planning purposes. This is scenario 5, as described below, and has also been referred to as the high probability demand scenario in Section 2 of this application.

Figure A-1 – Great River Energy Summer Demand



A.2.1 Summer Demand Scenarios

GRE developed five scenarios for its forecasted demand analysis.

1) Most probable economic assumptions, with normal weather.
2) Most probable economic assumptions, with severe weather causing higher loads.
3) Most probable economic assumptions, with mild weather causing lower loads.
4) Normal weather with more pessimistic macroeconomics assumptions causing lower loads.
5) Normal weather with more optimistic macroeconomics assumptions causing higher loads.

Scenario 1 is the base case reported in the 2002 LRLF. This forecast does not reflect the highest possible load. Factors such as weather and the economy will cause fluctuations around the base case level.

Scenarios 4 and 5, which reflect the effects of varying economic activity, were calculated by assuming 60 percent and 135 percent of forecast growth. These

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Table B-3 – GRE System Load and Capability – Summer Forecasted Demand

FORECASTED DEMAND (2002 LRLF)	2537.2	2558.2	2644.5	2740.4	2834.9	2930.7	3022.5	3126.5	3221.0	3322.2	3422.1	3527.4	3634.1	3738.0	3839.3	3944.6
GRE SYSTEM LOAD & CAPABILITY																
NEEDS:	**GRE and Shakopee**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**	**GRE**
DATE: 02-09-2005																
	Summer 2005	***Summer 2006***	***Summer 2007***	***Summer 2008***	***Summer 2009***	***Summer 2010***	***Summer 2011***	***Summer 2012***	***Summer 2013***	***Summer 2014***	***Summer 2015***	***Summer 2016***	***Summer 2017***	***Summer 2018***	***Summer 2019***	***Summer 2020***
1 MONTHLY SYSTEM DEMAND PLUS CID SERVED (2+3)	2537.2	2558.2	2644.5	2740.4	2834.9	2930.7	3022.5	3126.5	3221.0	3322.2	3422.1	3527.4	3634.1	3738.0	3839.3	3944.6
2 SCHEDULE L PURCHASED AT PEAK	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3 MONTHLY SYSTEM DEMAND	2537.2	2558.2	2644.5	2740.4	2834.9	2930.7	3022.5	3126.5	3221.0	3322.2	3422.1	3527.4	3634.1	3738.0	3839.3	3944.6
4 ANNUAL SYSTEM DEMAND	2537.2	2558.2	2644.5	2740.4	2834.9	2930.7	3022.5	3126.5	3221.0	3322.2	3422.1	3527.4	3634.1	3738.0	3839.3	3944.6
5 SEASONAL FIRM PURCHASES	435.3	430.8	414.8	414.8	414.8	239.8	239.8	239.8	239.8	239.8	89.8	89.8	89.8	89.8	89.8	89.8
6 SEASONAL FIRM SALES	116.0	126.0	126.0	81.0	81.0	81.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7 MONTHLY ADJUSTED DEMAND (3-5+6)	2217.9	2253.4	2355.7	2406.6	2501.1	2771.9	2782.7	2886.7	2981.2	3082.4	3332.3	3437.6	3544.3	3648.2	3749.5	3854.8
8 ANNUAL ADJUSTED DEMAND (4-5+6)	2217.9	2253.4	2355.7	2406.6	2501.1	2771.9	2782.7	2886.7	2981.2	3082.4	3332.3	3437.6	3544.3	3648.2	3749.5	3854.8
9 NET GENERATION CAPACITY	2390.6	2390.6	2390.6	2390.6	2390.6	2390.6	2390.6	2390.6	2390.6	2390.6	2390.6	2390.6	2390.6	2390.6	2390.6	2390.6
10 PART POWER PURCHASES	344.2	355.7	305.7	203.9	203.9	203.9	203.9	203.9	203.9	203.9	203.9	186.3	186.3	186.3	186.3	186.3
11 PART POWER SALES	132.0	134.0	130.0	80.0	80.0	30.0	30.0	30.0	30.0	30.0	30.0	0.0	0.0	0.0	0.0	0.0
12 ADJ NET CAPABILITY (9+10-11)	2602.8	2612.3	2566.3	2514.5	2514.5	2564.5	2564.5	2564.5	2564.5	2564.5	2564.5	2576.9	2576.9	2576.9	2576.9	2576.9
13 NET RESERVE OBLIGATION (8*15%)	332.7	338.0	353.4	361.0	375.2	415.8	417.4	433.0	447.2	462.4	499.8	515.6	531.6	547.2	562.4	578.2
14 FIRM CAPACITY OBLIGATION (7+13)	2550.6	2591.4	2709.1	2767.6	2876.3	3187.7	3200.1	3319.7	3428.4	3544.8	3832.1	3953.2	4075.9	4195.4	4311.9	4433.0
15 CAPACITY SURPLUS/DEFICIT (12-14)	*52.2*	*20.9*	*-142.8*	*-253.1*	*-361.8*	*-623.2*	*-635.6*	*-755.2*	*-863.9*	*-980.3*	*-1267.6*	*-1376.3*	*-1499.0*	*-1618.5*	*-1735.0*	*-1856.1*
16 EFFECTIVE RESERVE (%)	***17.4%***	***15.9%***	***8.9%***	***4.5%***	***0.5%***	***-7.6%***	***-7.8%***	***-11.2%***	***-14.0%***	***-16.8%***	***-23.0%***	***-25.0%***	***-27.3%***	***-29.4%***	***-31.3%***	***-33.2%***
FIRM PURCHASES																
WAPA (Kandiyohi)	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
MHEB Diversity Exchange	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	0.0	0.0	0.0	0.0	0.0	0.0
WAPA (CP)	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5	86.5
CMMPA (Wright-Hennepin)	6.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CMMPA (Dakota Electric)	4.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CMMPA (Minnesota Valley)	5.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CMMPA (Stearns)	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MMPA (Steele Waseca)	1.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BEPC (Wright-Hennepin)	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MP	130.0	130.0	130.0	130.0	130.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MP	45.0	45.0	45.0	45.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL FIRM PURCHASES	***435.3***	***430.8***	***414.8***	***414.8***	***414.8***	***239.8***	***239.8***	***239.8***	***239.8***	***239.8***	***89.8***	***89.8***	***89.8***	***89.8***	***89.8***	***89.8***
FIRM SALES																
NSP (Koch)	81.0	81.0	81.0	81.0	81.0	81.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SRE (SMMPA)	35.0	45.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL FIRM SALES	***116.0***	***126.0***	***126.0***	***81.0***	***81.0***	***81.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***
PART POWER PURCHASES																
ELKR	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
MOLK	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
GSE (Genoa #3)	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3
EA (Lake Marion and Hastings)	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	0.0	0.0	0.0	0.0	0.0
MHEB	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MP (EXCLUSIVES)	90.3	101.8	101.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL PART POWER PURCHASES	***344.2***	***355.7***	***305.7***	***203.9***	***203.9***	***203.9***	***203.9***	***203.9***	***203.9***	***203.9***	***203.9***	***186.3***	***186.3***	***186.3***	***186.3***	***186.3***
PART POWER SALES																
NSP Diversity Exchange	50.0	50.0	50.0	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WLMR	28.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	0.0	0.0	0.0	0.0	0.0
GSE (Netting)	4.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SRE (GSE)	50.0	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL PART POWER SALES	***132.0***	***134.0***	***130.0***	***80.0***	***80.0***	***30.0***	***30.0***	***30.0***	***30.0***	***30.0***	***30.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***

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Table B-4 – GRE Load and System Capability – Winter Forecasted Demand

FORECASTED DEMAND (2002 LRLF)	2028.0	2076.0	2128.0	2179.0	2230.0	2278.0	2335.0	2386.0	2440.0	2492.0	2547.0	2599.0	2654.0	2706.0	2760.0	2810.0
GRE SYSTEM LOAD & CAPABILITY																
NEEDS: ***DATE: 02-09-2005***	GRE and Shakopee	GRE	GRE	GRE	GRE	GRE	GRE	GRE	GRE	GRE	GRE	GRE	GRE	GRE	GRE	GRE
	Winter 2005	***Winter 2006***	***Winter 2007***	***Winter 2008***	***Winter 2009***	***Winter 2010***	***Winter 2011***	***Winter 2012***	***Winter 2013***	***Winter 2014***	***Winter 2015***	***Winter 2016***	***Winter 2017***	***Winter 2018***	***Winter 2019***	***Winter 2020***
1 MONTHLY SYSTEM DEMAND PLUS CID SERVED (2+3)	2028.0	2076.0	2128.0	2179.0	2230.0	2278.0	2335.0	2386.0	2440.0	2492.0	2547.0	2599.0	2654.0	2706.0	2760.0	2810.0
2 SCHEDULE L PURCHASED AT PEAK	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3 MONTHLY SYSTEM DEMAND	2028.0	2076.0	2128.0	2179.0	2230.0	2278.0	2335.0	2386.0	2440.0	2492.0	2547.0	2599.0	2654.0	2706.0	2760.0	2810.0
4 ANNUAL SYSTEM DEMAND	2537.2	2558.2	2644.5	2740.4	2834.9	2930.7	3022.5	3126.5	3221.0	3322.2	3422.1	3527.4	3634.1	3738.0	3839.3	3944.6
5 SEASONAL FIRM PURCHASES	306.1	301.6	285.6	285.6	285.6	110.6	110.6	110.6	110.6	110.6	110.6	110.6	110.6	110.6	110.6	110.6
6 SEASONAL FIRM SALES	276.0	276.0	276.0	231.0	231.0	231.0	150.0	150.0	150.0	150.0	0.0	0.0	0.0	0.0	0.0	0.0
7 MONTHLY ADJUSTED DEMAND (3-5+6)	1997.9	2050.4	2118.4	2124.4	2175.4	2398.4	2374.4	2425.4	2479.4	2531.4	2436.4	2488.4	2543.4	2595.4	2649.4	2699.4
8 ANNUAL ADJUSTED DEMAND (4-5+6)	2507.1	2532.6	2634.9	2685.8	2780.3	3051.1	3061.9	3165.9	3260.4	3361.6	3311.5	3416.8	3523.5	3627.4	3728.7	3834.0
9 NET GENERATION CAPACITY	2504.6	2504.6	2504.6	2504.6	2504.6	2504.6	2504.6	2504.6	2504.6	2504.6	2504.6	2504.6	2504.6	2504.6	2504.6	2504.6
10 PART POWER PURCHASES	406.7	418.2	368.2	266.4	216.4	216.4	216.4	216.4	216.4	216.4	216.4	198.8	198.8	198.8	198.8	198.8
11 PART POWER SALES	181.0	181.0	180.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	0.0	0.0	0.0	0.0	0.0
12 ADJ NET CAPABILITY (9+10-11)	2730.3	2741.8	2692.8	2741.0	2691.0	2691.0	2691.0	2691.0	2691.0	2691.0	2691.0	2703.4	2703.4	2703.4	2703.4	2703.4
13 NET RESERVE OBLIGATION (8*15%)	376.1	379.9	395.2	402.9	417.0	457.7	459.3	474.9	489.1	504.2	496.7	512.5	528.5	544.1	559.3	575.1
14 FIRM CAPACITY OBLIGATION (7+13)	2374.0	2430.3	2513.6	2527.3	2592.4	2856.1	2833.7	2900.3	2968.5	3035.6	2933.1	3000.9	3071.9	3139.5	3208.7	3274.5
15 CAPACITY SURPLUS/DEFICIT (12-14)	*356.3*	*311.5*	*179.2*	*213.7*	*98.6*	*-165.1*	*-142.7*	*-209.3*	*-277.5*	*-344.6*	*-242.1*	*-297.5*	*-368.5*	*-436.1*	*-505.3*	*-571.1*
16 EFFECTIVE RESERVE (%)	***32.3%***	***29.7%***	***23.2%***	***24.7%***	***19.4%***	***8.4%***	***9.2%***	***6.7%***	***4.3%***	***1.9%***	***5.5%***	***3.6%***	***1.2%***	***-1.0%***	***-3.1%***	***-5.1%***
FIRM PURCHASES																
WAPA (Kandiyohi)	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
WAPA (CP)	105.3	105.3	105.3	105.3	105.3	105.3	105.3	105.3	105.3	105.3	105.3	105.3	105.3	105.3	105.3	105.3
CMMPA (Wright-Hennepin)	6.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CMMPA (Dakota Electric)	4.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CMMPA (Minnesota Valley)	5.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CMMPA (Stearns)	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MMPA (Steele Waseca)	1.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
BEPC (Wright-Hennepin)	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MP	130.0	130.0	130.0	130.0	130.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MP	45.0	45.0	45.0	45.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL FIRM PURCHASES	***306.1***	***301.6***	***285.6***	***285.6***	***285.6***	***110.6***	***110.6***	***110.6***	***110.6***	***110.6***	***110.6***	***110.6***	***110.6***	***110.6***	***110.6***	***110.6***
FIRM SALES																
MHEB Diversity Exchange	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	150.0	0.0	0.0	0.0	0.0	0.0	0.0
NSP (Koch)	81.0	81.0	81.0	81.0	81.0	81.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SRE (SMMPA)	45.0	45.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL FIRM SALES	***276.0***	***276.0***	***276.0***	***231.0***	***231.0***	***231.0***	***150.0***	***150.0***	***150.0***	***150.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***
PART POWER PURCHASES																
NSP Diversity Exchange	50.0	50.0	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ELKR	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
MOLK	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
GSE (Genoa #3)	184.7	184.7	184.7	184.7	184.7	184.7	184.7	184.7	184.7	184.7	184.7	184.7	184.7	184.7	184.7	184.7
EA (Lake Marion and Hastings)	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	0.0	0.0	0.0	0.0	0.0
MHEB	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MP (EXCLUSIVES)	90.3	101.8	101.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL PART POWER PURCHASES	***406.7***	***418.2***	***368.2***	***266.4***	***216.4***	***216.4***	***216.4***	***216.4***	***216.4***	***216.4***	***216.4***	***198.8***	***198.8***	***198.8***	***198.8***	***198.8***
PART POWER SALES																
GSE (Netting)	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WLMR	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	0.0	0.0	0.0	0.0	0.0
SRE (GSE)	50.0	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MP	100.0	100.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL PART POWER SALES	***181.0***	***181.0***	***180.0***	***30.0***	***30.0***	***30.0***	***30.0***	***30.0***	***30.0***	***30.0***	***30.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***

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Table B-5 – Simplified Summer GRE System Load and Capability

SIMPLIFIED SUMMER GRE SYSTEM LOAD & CAPABILITY

DATE: 02-09-2005	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
PURCHASES (* 15% ADDED FOR FIRM PURCHASES)																
* WAPA (Kandiyohi)	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
* MHEB Diversity Exchange	172.5	172.5	172.5	172.5	172.5	172.5	172.5	172.5	172.5	172.5	0.0	0.0	0.0	0.0	0.0	0.0
* WAPA (CP)	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5	99.5
* CMMPA (Wright-Hennepin)	6.9	6.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
* CMMPA (Dakota Electric)	4.6	4.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
* CMMPA (Minnesota Valley)	5.8	5.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
* CMMPA (Stearns)	3.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
* MMPA (Steele Waseca)	1.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
* BEPC (Wright-Hennepin)	1.2	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
* MP	149.5	149.5	149.5	149.5	149.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
* MP	51.8	51.8	51.8	51.8	51.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ELKR	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
MOLK	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
GSE (Genoa #3)	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3	172.3
EA (Lake Marion and Hastings)	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6	0.0	0.0	0.0	0.0	0.0
MHEB	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MP (EXCLUSIVES)	90.3	101.8	101.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PURCHASES (TOTAL)	**844.8**	**851.1**	**782.7**	**680.9**	**680.9**	**479.7**	**479.7**	**479.7**	**479.7**	**479.7**	**307.2**	**289.6**	**289.6**	**289.6**	**289.6**	**289.6**
SALES (* 15% ADDED FOR FIRM SALES)																
* NSP (Koch)	93.2	93.2	93.2	93.2	93.2	93.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
* SRE (SMMPA)	40.3	51.8	51.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NSP Diversity Exchange	50.0	50.0	50.0	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WLMR	28.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	0.0	0.0	0.0	0.0	0.0
GSE (Netting)	4.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SRE (GSE)	50.0	50.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SALES (TOTAL)	**265.4**	**278.9**	**274.9**	**173.2**	**173.2**	**123.2**	**30.0**	**30.0**	**30.0**	**30.0**	**30.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
GENERATION (TOTAL)	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**	**2390.6**
FORECASTED LOAD	2537.2	2558.2	2644.5	2740.4	2834.9	2930.7	3022.5	3126.5	3221.0	3322.2	3422.1	3527.4	3634.1	3738.0	3839.3	3944.6
FORECASTED LOAD (PLUS 15% RESERVES)	**2917.8**	**2941.9**	**3041.2**	**3151.5**	**3260.1**	**3370.3**	**3475.9**	**3595.5**	**3704.2**	**3820.5**	**3935.4**	**4056.5**	**4179.2**	**4298.7**	**4415.2**	**4536.3**
SURPLUS/DEFICIT (GENERATION + PURCHASES - SALES - LOAD PLUS 15% RESERVES)	52.2	20.9	-142.8	-253.1	-361.8	-623.2	-635.6	-755.2	-863.9	-980.3	-1267.6	-1376.3	-1499.0	-1618.5	-1735.0	-1856.1

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1.0 Executive Summary

This report addresses the installation of the Cambridge Station, a natural gas peaking plant near Cambridge, Minnesota, which will be owned and operated by Great River Energy (GRE), of Elk River, Minnesota to serve its native load. The plant will consist of one machine with top output 190 MW. The summer maximum capability is expected to be around 170 MW. The results have shown that Cambridge Station will be a prudent development in the MAPP/MISO region with system response comparable or better than the existing system today.

Cambridge generation has an impact on the following transmission lines which will have to be rebuilt or reconductored to a higher capacity conductor, or have a temperature analysis for sag clearance:

- Cambridge-Dalbo-Princeton North-Princeton 22.64 mile, 69 kV line
- Cambridge-Braham-Grasston 15.47 mile, 69 kV line
- Cambridge-Rush Tap-Rush City 18.95 mile, 69 kV line
- Cambridge-Cambridge Industrial-Isanti Tap-Athens 12.09 miles, 69 kV line

Also, the existing substation bus, jumpers, and switches are underrated with the addition of the generation and are to be replaced with higher ampacity equipment.

With the Cambridge Station plant being designed for peaking purposes, it is expected that the transmission system will operate similar to existing conditions, except during periods of high load in the GRE service territory. One concern is that Cambridge Station is placed on the GRE 69 kV system which is a rather low voltage for such a large plant. However, the load served by this 69 kV system is significant such that power produced will basically stay in the 69 kV system.

GRE has designed transmission system improvements so that full unit output can be initially maintained during first contingency conditions. Reductions may need to be made on unit output to return the transmission system to a safe operating level if the contingency remains after a time period of 30 minutes. The critical outages are the loss of the 69 kV lines directly off the Cambridge 69 kV bus. The Cambridge Station facilities will provide voltage support to an area that has present voltage concerns during system intact and contingent situations.