APPENDIX A: LEGISLATIVE AND REGULATORY COMPLIANCE REQUIREMENTS

Table A - 1 Order Point 2: For all future resource plans and Certificates of Need proceedings:

Order	Response
A. GRE should continue striving to save energy equal to 1.5 percent of its annual retail energy sales in a cost-effective manner.	GRE has always met the 1.5% energy savings goal. This plan reflects striving to continue to achieve the 1.5% energy savings goal. Sections 5.1 and 5.2
B. If GRE anticipates the need for new sources of electricity fueled by nonrenewable sources, GRE should provide a plan or plans complying with the requirements of Minn. Stat. § 216B.2422, subd. 2.	Section 11.7
C. GRE should consider making changes to its forecasting process that reduce the need for adjustments.	The forecast used in this resource plan did not require adjustments. Section 8.1
D. GRE should track the process of adjusting its forecasts.	The forecast used in this resource plan did not require adjustments. Section 8.1

Table A - 2 Order Point 3: For all future resource plans:

Order	Response
A. GRE should include an evaluation of potential conservation measures that it does not include in it its Conservation Improvement Program portfolio – including, at a minimum, all the measures identified in the Electric Power Research Institute study that pass the Total Resource Cost test.	Section 5.7 and Appendix E
B. GRE should continue to evaluate compliance with the Renewable Energy Standards, environmental regulations, and environmental compliance.	Section 11
C. GRE should continue to evaluate alternatives to existing generation.	Section 7.4
D. GRE should include the Commission-approved cost of externalities and carbon dioxide regulations in calculating the cost of GRE’s reference case and preferred plan.	Section 9.1

Table A - 3 Order Point 4: For all future resource plans:

Order	Response
A. GRE shall file its next resource plan on or before November 1, 2014.	The resource plan was filed by October 31, 2014

Table A - 4 Minnesota Statutes on Resource Planning:

Minn. Stat. § §	Requirement	Response
216B.2422 Subd. 2	Resource plan filing and approval. *** As a part of its resource plan filing, a utility shall include the least cost plan for meeting 50 and 75 percent of all new and refurbished capacity needs through a combination of conservation and renewable energy resources.	Section 11.7
216B.2422 Subd. 2a	Historical data and advance forecast. Each utility required to file a resource plan under this section shall include in the filing all applicable annual information required by section 216C.17, subdivision 2, and the rules adopted under that section. To the extent that a utility complies with this subdivision, it is not required to file annual advance forecasts with the department under section 216C.17, subdivision 2.	Appendix I
216B.2422 Subd. 2c	Long-range emission reduction planning. Each utility required to file a resource plan under subdivision 2 shall include in the filing a narrative identifying and describing the costs, opportunities, and technical barriers to the utility continuing to make progress on its system toward achieving the state greenhouse gas emission reduction goals established in section 216H.02, subdivision 1, and the technologies, alternatives, and steps the utility is considering to address those opportunities and barriers.	Section 11.8
216B.2422 Subd. 3	Environmental costs. (a) The commission shall, to the extent practicable, quantify and establish a range of environmental costs associated with each method of electricity generation. A utility shall use the values established by the commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource	Section 9.1

Minn. Stat. § §	Requirement	Response
	options in all proceedings before the commission, including resource plan and certificate of need proceedings.	
216B.2422 Subd. 4	Preference for renewable energy facility. The commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest.	Section 11.7
216B.2422 Subd. 6	Consolidation of resource planning and certificate of need. A utility shall indicate in its resource plan whether it intends to site or construct a large energy facility. If the utility's resource plan includes a proposed large energy facility and construction of that facility is likely to begin before the utility files its next resource plan, the commission shall conduct the resource plan proceeding consistent with the requirements of section 216B.243 with respect to the proposed facility. If the commission approves the proposed facility in the resource plan, a separate certificate of need proceeding is not required.	GRE does not intend to site or construct a large generation energy facility prior to its next IRP filing
216C.17 Subds. 2 & 3	Subd. 2 Forecasts. Except as provided in subdivision 3, in addition to supplying the current statistical and short-range forecasting information the commissioner requires, each utility, coal supplier, petroleum supplier and large energy facility in the state shall prepare and transmit to the commissioner by July 1 of each year, a report specifying in five-, ten-, and 15-year forecasts the projected demand for energy within their respective service areas and the facilities necessary to meet the demand. The report shall be in a form specified by the commissioner and contain all information deemed relevant by the commissioner. Subd. 3 Duplication. *** Electric utilities submitting advance forecasts as part of an integrated resource plan filed pursuant to section 216B.2422 and Public Utilities Commission rules are excluded from the annual reporting requirement in subdivision 2.	N/A

Minn. Stat. § §	Requirement	Response
216B.1691 Subd. 2e	Subd. 2e. Rate impact of standard compliance; report. Each electric utility must submit to the commission and the legislative committees with primary jurisdiction over energy policy a report containing an estimation of the rate impact of activities of the electric utility necessary to comply with this section. The rate impact estimate must be for wholesale rates and, if the electric utility makes retail sales, the estimate shall also be for the impact on the electric utility's retail rates. Those activities include, without limitation, energy purchases, generation facility acquisition and construction, and transmission improvements. An initial report must be submitted within 150 days of May 28, 2011. After the initial report, a report must be updated and submitted as part of each integrated resource plan or plan modification filed by the electric utility under section 216B.2422. The reporting obligation of an electric utility under this subdivision expires December 31, 2025, for an electric utility subject to subdivision 2a, paragraph (a), and December 31, 2020, for an electric utility subject to subdivision 2a, paragraph (b).	Section 11.2
216B.1691 Subd. 3	Renewable Energy Objectives: Utility plans filed with commission. (a) Each electric utility shall report on its plans, activities, and progress with regard to the objectives and standards of this section in its filings under section 216B.2422 or in a separate report submitted to the commission every two years, whichever is more frequent, demonstrating to the commission the utility's effort to comply with this section. In its resource plan or a separate report, each electric utility shall provide a description of: (1) the status of the utility's renewable energy mix relative to the objective and standards; (2) efforts taken to meet the objective and standards; (3) any obstacles encountered or anticipated in meeting the objective or standards; and (4) potential solutions to the obstacles.	See worksheet titled A.5 Biennial Compliance Req. in file named GRE A-MN-REC and GP-Rpt-2014.xlsx for compliance report filed 5/30/2014 for Docket No. E999/PR-14-12, Docket No. E999/PR-14-237, and Docket No. E999/PR-02-1240
216B.1612	Priority for C-BED projects. Each utility shall include in its	Section 11.4

Minn. Stat. § §	Requirement	Response
Subd. 5(b)	resource plan submitted under section 216B.2422 a description of its efforts to purchase energy from C-BED projects, including a list of the projects under contract and the amount of C-BED energy purchased.	

Table A - 5 Minnesota Rules on Utility Resource Planning

Part	Requirement	Response
7843.0400	Contents of Resource Plan Filings	
Subp. 1	Advance forecasts. A utility shall include in the filing identified in subpart 2 its most recent annual submission to the Minnesota Department of Commerce and the Minnesota Environmental Quality Board under Minnesota Statutes, sections 216B.2422, subdivision 2a, and 216C.17, and parts 7610.0100 to 7610.0600.	Appendix I
Subp. 2	Resource plan. A utility shall file a proposed plan for meeting the service needs of its customers over the forecast period. The plan must show the resource options the utility believes it might use to meet those needs. The plan must also specify how the implementation and use of those resource options would vary with changes in supply and demand circumstances. The utility is only required to identify a resource option generically, unless a commitment to a specific resource exists at the time of the filing. The utility shall also discuss plans to reduce existing resources through sales, leases, deratings, or retirement. "Derating" means a temporary or permanent reduction in the expected power output of a generating facility.	Sections 2, 9, and Table 9-3
Subp. 3	Supporting information. A utility shall include in its resource plan filing information supporting selection of the proposed resource plan.	Sections 2 and 9
Subp. 3(A)	When a utility's existing resources are inadequate to meet the projected level of service needs, the supporting information must contain a complete list of resource options considered for addition to the existing resources. At a minimum, the list must include new generating facilities of various types and sizes and with various fuel types, cogeneration, new transmission facilities of various types and sizes, upgrading of existing generation and transmission equipment, life extensions of	Appendix B

Part	Requirement	Response
	existing generation and transmission equipment, load-control equipment, utility-sponsored conservation programs, purchases from non-utilities, and purchases from other utilities. The utility may seek additional input from the commission regarding the resource options to be included in the list. For a resource option that could meet a significant part of the need identified by the forecast, the supporting information must include a general evaluation of the option, including its availability, reliability, cost, socioeconomic effects, and environmental effects.	
Subp. 3(B)	The supporting information must include descriptions of the overall process and of the analytical techniques used by the utility to create its proposed resource plan from the available options.	Section 7
Subp. 3(D)	For the proposed resource plan as a whole, the supporting information must include a narrative and quantitative discussion of why the plan would be in the public interest, considering the factors listed in part 7843.0500, subpart 3.	Section 2
Subp. 4	Non-technical summary. A utility shall include in its resource plan filing a non-technical summary, not exceeding 25 pages in length and describing the utility's resource needs, the resource plan created by the utility to meet those needs, the process and analytical techniques used to create the plan, activities required over the next five years to implement the plan, and the likely effect of plan implementation on electric rates and bills.	Section 1
Subp. 5	Combined and common filings. Utilities may combine their individual filings into a single larger filing, as long as the action does not lead to a loss of information. Information common to two or more of the utilities need only be submitted once, as long as the filing clearly shows the utilities to which the information applies.	N/A
7843.0500	Commission Review of Resource Plans	
Subp. 3	Resource options and resource plans must be evaluated on their ability to: A. Maintain or improve the adequacy and reliability of utility service; B. Keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints; C. Minimize adverse socioeconomic effects and adverse effects upon the environment;	Sections 1 and 2

Part	Requirement	Response
	D. Enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and E. Limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.	
7610.0300	Extended Forecast. The following utilities must file the information required by parts 7610.0100 to 7610.0700: Northern States Power Company, Minnesota Power, Otter Tail Power Company, Interstate Power Company, Minnkota Power Cooperative, Cooperative Power Association, United Power Association and Dairyland Power Cooperative, and the Southern Minnesota Municipal Power Agency. Data that is compiled within the same calendar year for either an extended forecast or a certificate of need application may be substituted interchangeably to satisfy those portions of both sets of rules that have identical data requirements. For these cases, references to the material substituted and a copy of the appropriate reference material must be submitted to meet the reporting requirements.	Appendix I

THIS PAGE INTENTIONALLY LEFT BLANK

APPENDIX B: GENERATION RESOURCE CHARACTERISTICS

Table B - 1

Sales Contract Name	MW	Time Pattern	Begin Date	End Date
[Trade Secret data begins				
				Trade Secret data begins]

Table B - 2

Existing Wind Purchase Contracts	End Date	Time Pattern
	[Trade secret data begins	
Trimont Wind Farm		
Prairie Star Wind Farm		
Elm Creek Wind Power Project		
Ashtabula II Wind Energy Center		
Endeavor I Wind Energy Center		
Other small wind		
		Trade secret data ends]

Table B - 3

Other Existing Purchase Contracts	End Date	Time Pattern
Cooperative Community Solar	indefinite	PV Watts Typical year
[Trade secret data begins		
		Trade secret data ends]

Table B - 4

Contracts	Average Heat Rate	2015 Fixed Costs ($/KW)	Variable Cost Non-Fuel ($/MWh)	Forced Outage Rate	Nox Rate #/MWh	SO2 Rate #/MWh	CO2 Rate #/MWh	Hg Rate #/MWh	PM10 Rate #/MWh	CO Rate #/MWh	Pb Rate #/MWh
Spot Market Purchases	N/A	N/A	MN Hub market prices	N/A	1.905	3.992	1,536	0.000034	0.1913	-	-
	[Trade secret data begins										
									Trade secret data ends]		

Table B - 5

Existing Resources	Average Heat Rate	2015 Fixed Costs ($/KW)	Variable Cost Non-Fuel ($/MWh)	Forced Outage Rate	Nox Rate #/MWh	SO2 Rate #/MWh	CO2 Rate #/MWh	Hg Rate #/MWh	PM10 Rate #/MWh	CO Rate #/MWh	Pb Rate #/MWh
Spot Market Purchases	N/A	N/A	MN Hub market prices	N/A	1.905	3.992	1,536	0.000034	0.1913	-	-
	[Trade secret Data Begins										
Coal Creek				2.5%	1.785	3.4755	2,289	0.000087	0.0378	0.37065	0.000048
Stanton Station				2.5%	2.667	3.759	2,205	0.000052	0.126	0.28035	0.000095
Spiritwood				10.0%	1.836	1.224	1,375	0.000082	0.612	3.06	0.000109
Elk River Resource Recovery Station				32.0%	4.975	0.35	4,380	0.000134	0.222	0.92	-
Cambridge 2				15.0%	0.8294	0.0077	1,320	-	0.0726	0.4147	-
Elk River Peaking Station				10.0%	0.396	0.0066	1,300	-	0.077	0.77	-
Lakefield Junction				10.0%	0.3024	0.0036	1,440	-	0.0792	0.7188	-
Pleasant Valley Station				20.0%	0.8602	0.0055	1,308	-	0.0726	0.4488	-
St. Bonifacius				0.0%	14.08	0.808	1,440	-	1.92	0.0528	-
Rock Lake				0.0%	14.08	0.808	1,440	-	1.92	0.0528	-
Maple Lake				0.0%	14.08	0.808	1,440	-	1.92	0.0528	-
Cambridge 1				1.0%	20.9536	0.808	1,440	-	1.92	0.0528	-
Small Diesels				1.0%	14.41	0.561	1,440	-	1.32	0.0363	-
			Trade secret Data Ends]								
Arrowhead Emergency Generation Station *											

Table B - 6

Potential Resources										
	Source	units	AEO	AEO	AEO	AEO	AEO	Lawrence Berkeley National Laboratory	AEO	Hydro
Generation characteristics	Unit		SCGT	SCGT	CCGT	CCGT	CCGT	Wind	Solar	Hydro
	Model		Con	Adv	Con	Adv	Adv w CCS			
	First year available		2018	2018	2018	2018	2018	2017	2015	2020
	Nox	(#/MMBtu)	0.03	0.03	0.0075	0.0075	0.0075			
	SO2	(#/MMBtu)	0.001	0.001	0.001	0.001	0.001			
	CO2	(#/MMBtu)	117	117	117	117	12(9)			
	Hg	(#/MMBtu)								
	PM10	(#/MMBtu)	0.01	0.01						
	CO	(#/MMBtu)	0.01	0.01						
	Construction Time	Months	34	34	38	38	38	12	12	
	Life of Plant	Years	30	30	30	30	30	30	30	20
	FL HR (HHV)	Btu/kWh	10850.0	9750.0	7050.0	6430.0	7525.0			
	Capacity	**MW**	**85**	**210**	**620**	**400**	**340**	**100**	**10**	**200**
	EFORd rate	**Rate**	5.9%	5.9%	5.9%	5.9%	5.9%	15.0%	2.6%	100.0%
Capital Costs	Overnight Construction Cost	$/kW	811	563	764	853	1,746	1,800	4,183	
	Ownership/Transmission	$/kW	361	146	83	129	152	281	527	
	Subtotal	$/kW	1,172	709	847	982	1,898	2,081	4,710	
	IDC/AFUDC	$/kW	78	47	95	110	213	12	122	
	Total Installed Capital Costs	**$/kW**	**1,249.2**	**755.9**	**942.3**	**1,092.3**	**2,110.7**	**2,092.8**	**4,832.0**	
Fixed & Variable Costs	Variable Maintenance Costs	$/MWh	15.45	10.37	3.60	3.27	6.78	-	-	Market less 5 ¢
	Fixed Costs (FOM only)	$/kW	7.34	7.04	13.17	15.37	31.79	50.00	27.75	-
	Fixed Costs (FOM plus depreciation, taxes and insurance)	$/kW	40.83	27.43	38.80	45.08	89.31	107.92	157.25	-

APPENDIX C: CONSERVATION IMPROVEMENT PROGRAM APPROVAL LETTERS

MINNESOTA DEPARTMENT OF COMMERCE

85 7th Place East, Suite 500
St. Paul, Minnesota 55101-2198
www.commerce.state.mn.us
651.296.4026 FAX 651.297.1959
An equal opportunity employer

December 5, 2011

Gary Connett
Director, Member Services
Great River Energy
12300 Elm Creek Boulevard
Maple Grove, MN 55369-4718

RE: 2010 CIP Results and 2012 Plans

Dear Mr. Connett:

Thank you very much for GRE's efforts to report its 2010 CIP results and 2012 CIP plans. Based on the information you submitted, GRE's all-requirements cooperative group saved a total of 183,926,700 kWh at the generator in 2010, approximately 2.1% of total 2005-2007 average retail sales. GRE's fixed sales cooperative group saved a total of 35,589,681 kWh at the generator in 2010, approximately 1.4% of total 2005-2007 average retail sales. We congratulate GRE on your energy efficiency achievements in 2010.

PLAN APPROVAL

My staff has reviewed GRE's 2012 program definitions as reported in the Energy Savings Platform. It appears that GRE has developed a broad array of programs for its members covering the residential, commercial, industrial and agricultural sectors. In addition, we recognize the efforts GRE has taken in the low income sector to facilitate partnerships between its member cooperatives and local Weatherization providers, including development of a Standard Agreement.

As you know, several facilities served by GRE cooperatives have applied for CIP exemption under the new opt-out provisions in Minnesota Statutes §216.241 subd. 1a. Any customer that is approved for electric CIP exemption may not, by law, participate in a CIP program.[1] Consequently, I believe it is reasonable to adjust GRE's goals for 2012 to reflect the exclusion of these customers from available CIP opportunities. Staff will contact you early in 2012 after the Department has completed its review process for sales and revenue information from these customers.

GRE's fixed and all-requirements cooperative groups will each have energy savings goals for 2012 equal to 1.5% of 2008-2010 weather-normalized sales excluding sales to exempt customers during this period. Minimum spending requirements for 2012 are based on 1.5% of 2010 gross operating revenues excluding

[1] Minn. Stat. §216B.241, subd. 1b (c).

Gary Connett
December 5, 2011
Page 2

revenues from large customer facilities.[2] Low-income spending requirements for 2012 will be equal to 0.2% of 2010 gross operating revenue from residential customers. Department staff are currently working with Energy Platforms to develop goal calculations within the Platform including weather-normalization. When this process is complete, the specific savings goal and spending requirements for GRE's all-requirements and fixed cooperative groups for 2012 will appear within the Platform.

General Guidelines

Please note that while the Department is supportive of electric utility infrastructure projects that increase generation and distribution efficiencies, the statutes do not allow us to count these projects towards your minimum CIP spending requirement.[3] The resulting energy savings from these projects do count towards your energy savings goal *on top of* the minimum 1% from energy conservation improvements (i.e., demand-side measures).[4] In addition, load management programs (such as thermal energy storage technologies or air-conditioner cycling) may be used to make up to 50% of a utility or association's minimum spending requirement for energy conservation improvements.[5] However, with the 1.5% energy savings goal in effect beginning in 2010, most electric cooperatives and municipalities will have to focus their CIP budgets on conservation programs instead of load management.

FUTURE REPORTING

This year and last year were transition years for CIP reporting as the Energy Savings Platform tool was being developed. Moving forward, we will require annual one-year plans and one-year status reports on June 1 of each year. For example, on June 1, 2012, you will be required to submit a one-year plan for 2013 and your expenditures and savings for 2011. The plan information will persist from one year to the next so that you do not have to reenter those programs that have not changed. The baseline periods for each program year are shown below.

Table 1: Baseline Periods for Cooperative and Municipal Utilities

Program Year	Savings Goal 1.5% of:	Total Spending Rqmt 1.5% of:	Low Income Spending Rqmt 0.2% of:
2012	2008-2010 average sales	2010 GOR	2010 residential GOR
2013	2009-2011 average sales	2011 GOR	2011 residential GOR
2014	2010-2012 average sales	2012 GOR	2012 residential GOR
2015	2011-2013 average sales	2013 GOR	2013 residential GOR
2016	2012-2014 average sales	2014 GOR	2014 residential GOR
…	…	…	…

[2] A large customer facility is defined in Minn. Stat. §216B.241, subd. 1 (i) as "all buildings, structures, equipment and installations at a single site that collectively (1) impose a peak electrical demand on an electric utility's system of not less than 20,000 kilowatts, measured in the same way as the utility that serves the customer facility measures electrical demand for billing purposes or (2) consume not less than 500 million cubic feet of natural gas annually."
[3] Minn. Stat. §216B.241, subd. 1b (b) requires each electric cooperative association and electric municipal utility to spend 1.5% of GOR annually on *energy conservation improvements.* Minn. Stat. §216B.241, subd. 1 (e) specifically excludes electric utility infrastructure projects from the definition of energy conservation improvements.
[4] Minn. Stat. §216B.241, subd. 1c (d).
[5] Minn. Stat. §216B.241, subd. 1b (e).

Gary Connett
December 5, 2011
Page 3

We are currently developing tools within the Platform to analyze program cost-effectiveness using standard benefit-cost tests. These tools will provide further insight as to the cost-effectiveness of your programs. They will also help us provide recommendations to you to increase the effectiveness of your conservation improvement activities.[6] We encourage utilities to use the Platform to see what other organizations are doing and to benchmark your programs against other similar programs.

Finally, we wish to note that Fresh Energy and the Izaak Walton League have requested the opportunity to review and comment on utility CIP plans starting with the next submissions in June 2012. Please view this as an opportunity to gather new perspectives on your program activities. As a public program, it is important that CIP be transparent and that outside parties be given the opportunity to view program activity and offer recommendations.

DECISION

With this letter, I approve GRE's CIP plan for 2012. Thank you for GRE's continued contributions to Minnesota's energy efficiency and conservation goals. Please contact Joe Plummer at Joe.Plummer@state.mn.us or 651-296-6807 with any questions or concerns.

Sincerely,

William Grant
Deputy Commissioner

WG/JP/sm

[6] Minn. Stat. §216B.241, subd. 1b (g) requires municipalities and cooperatives to analyze the cost-effectiveness of their conservation programs and report this information to the Department. The Department is to review this information and make recommendations, where appropriate, to the municipality or association to increase the effectiveness of its conservation improvement activities.

division of energy resources
Minnesota Department of Commerce
85 7th Place East, Suite 500, St. Paul, MN 55101-2198
main: 651.296.4026
tty: 651.296.2860
fax: 651.297.7891
www.energy.mn.gov

April 16, 2013

Jeffrey Haase
Energy Efficiency Coordinator
Great River Energy
12300 Elm Creek Boulevard
Maple Grove, MN 55369-4718

RE: 2011 CIP Results and 2013 Plans
Docket No.: E,G999/CIP-12-774

Dear Mr. Haase:

Thank you for GRE's efforts to report its 2011 CIP results and 2013 CIP plans in ESP®. Our analysis of this information is presented below. We also address the supply-side efficiency projects your organization reported in 2010 and the plan to carry forward savings in excess of the 1.5% goal achieved in 2010.

2010 SUPPLY-SIDE PROJECTS AND CARRY FORWARD PLAN

Beginning in 2010, GRE's aggregated CIP results have been split between the All-Requirements coop group and the Fixed coop group. Each group is responsible for achieving the 1.5% energy savings goal and 1.5% minimum spending requirement in aggregate.

A summary of the member-side (end-use) and supply-side savings proposed for 2010 for each group, prior to applying the carry forward provision, is shown in Table 1. As we discussed, the Minnesota Department of Commerce (Department) is unable to accept 14,295,639 kWh in supply-side savings initially claimed by the Fixed Group because the Fixed Group did not achieve a minimum of one percent savings through member-side conservation improvements as required by Minn. Stat. §216B.241 subd. 1c (d).[1]

The supply-side savings of 434,888,184 kWh proposed by the All-Requirements group include savings from the DryFining Process at GRE's Coal Creek Station in addition to waste heat to electricity generation and generation efficiency projects. As we discussed, the Department is unable to issue final approval of these savings until general policies are developed for approval of electric utility infrastructure (EUI) projects so that the Department can ensure that GRE's EUI projects are evaluated fairly and consistently with other utilities. The Department plans to convene a workgroup process for this purpose following the 2013 legislative session.

[1] "A utility or association may include in its energy conservation plan energy savings from electric utility infrastructure projects approved by the commission under section 216B.1636 or waste heat recovery converted into electricity projects that may count as energy savings *in addition to a minimum energy-savings goal of at least one percent for energy conservation improvements*" (emphasis added.)

April16, 2013
Page 2

Table 1: 2010 Member and Supply Side Savings, No Carry Forward

		All-Requirements	Fixed
Average Annual Sales	2005-2007 Average Sales (kWh)	8,567,932,700	2,734,980,383
Member-Side Savings	kWh @ Meter	117,226,945	17,201,229
	kWh @ Generator[2]	132,459,825	19,436,417
	Savings %	1.5%	0.7%
Supply-Side Savings	kWh @ Generator	434,888,184	0
	Savings %	5.1%	0%
Total Savings	kWh @ Generator	567,348,009	19,436,417
	Savings %	6.6%	0.7%

For the All-Requirements group, GRE has elected to carry forward savings in excess of 1.5% from 2010 as allowed by Minn. Stat.§216B.241 subd. 1c (b).[3] This would have the effect of reducing the All-Requirements group's total savings in 2010 to 1.5% or 128,518,990 kWh. The Department will reevaluate GRE's 2010 supply-side projects and provide the specific savings figures that GRE may carry forward to 2011 and subsequent years, if any, following conclusion of the workgroup process described above.

2011 SAVINGS ACHIEVEMENT

Minnesota Statutes set a nominal savings goal of 1.5% of average retail sales for each utility association.[4] Cooperative and municipal power providers may fulfill the 1.5% savings goal on an aggregate basis.[5] Based on the information reported in ESP, GRE's All-Requirements group saved a total of 110,152,388 kWh at the generator in 2011, equal to 1.3% of 2005-2007 average retail sales, not including any savings to be carried forward from 2010. GRE's Fixed coops saved a total of 18,243,085 kWh at the generator in 2011, equal to 0.7% of 2005-2007 average retail sales. This figure does not include 2,539,000 kWh of supply-side project savings reported by Federated Rural Electric Association, a member of the Fixed cooperative group, that the Department is unable to accept because the Fixed group did not achieve the minimum one percent savings level.

GRE's savings by member organization are shown below in Tables 2 and 3. While the All-Requirements group came close to reaching the 1.5% goal without inclusion of carry forward savings, the Fixed group fell fall short of this goal (although Agralite, Meeker, and Redwood cooperatives each exceeded the minimum 1% level.) The Department expects both cooperative groups, but in particular the Fixed group, to increase their efforts to achieve the 1.5% savings goal on an aggregate basis.

---

[2] Throughout this document, kWh savings at the generator were calculated assuming an avoided line loss factor of 11.5%, as provided by GRE to Department Staff, using the following formula: (kWh savings @ generator) = (kWh savings @ meter) / (1 – 0.115)

[3] "A utility or association may elect to carry forward energy savings in excess of 1.5 percent for a year to the succeeding three calendar years, except that savings from electric utility infrastructure projects allowed under paragraph (d) may be carried forward for five years."

[4] Minn. Stat. §216B.241subd. 1c (b)

[5] Minn. Stat. §216B.241 subd. 1b (f)

April16, 2013
Page 3

Table 2: 2011 Savings by Organization, All-Requirements Group
(Not Including Any Savings to Be Carried Forward from 2010)

Organization	kWh @ meter	kWh @ generator	2005-2007 average sales	Savings %
Arrowhead Electric Coop, Inc	191,224	216,072	62,560,842	0.3%
BENCO Electric Coop	2,992,417	3,381,262	259,769,020	1.3%
Brown Co Rural Electrical Assn	542,928	613,478	122,201,932	0.5%
Connexus Energy	24,148,565	27,286,514	2,074,503,311	1.3%
Cooperative Light & Power	536,415	606,119	86,954,635	0.7%
Dakota Electric Assn	26,812,958	30,297,128	1,841,090,657	1.6%
East Central Energy	7,980,539	9,017,558	906,938,094	1.0%
Elk River Municipal Utilities	2,093,218	2,365,218	196,263,360	1.2%
Goodhue County Coop Electric Assn	853,933	964,896	84,798,006	1.1%
Itasca Mantrap Coop Electric Assn	5,728,672	6,473,076	197,171,998	3.3%
Kandiyohi Power Coop	1,055,636	1,192,809	143,875,910	0.8%
Lake Country Power	7,829,373	8,846,749	653,304,081	1.4%
Lake Region Electric Coop	3,387,399	3,827,569	381,369,645	1.0%
McLeod Coop Power Assn	690,181	779,866	170,257,591	0.5%
Mille Lacs Electric Coop	1,755,859	1,984,021	186,131,541	1.1%
Nobles Cooperative Electric	1,973,434	2,229,869	151,192,101	1.5%
North Itasca Electric Coop	220,757	249,443	47,386,106	0.5%
Runestone Electric Assn	1,869,266	2,112,165	204,490,876	1.0%
Stearns Coop Electric Assn	4,107,719	4,641,490	422,361,940	1.1%
Steele Waseca Coop Electric	1,996,829	2,256,304	222,184,825	1.0%
Todd Wadena Electric Coop	717,541	810,781	153,126,230	0.5%
TOTAL	**97,484,863**	**110,152,388**	**8,567,932,700**	**1.3%**

Table 3: 2011 Savings by Organization, Fixed Group

Organization	kWh @ meter	kWh @ generator	2005-2007 average sales	Savings %
Agralite Cooperative	1,849,580	2,089,921	180,069,193	1.2%
Crow Wing Coop Power & Light, Inc.	2,174,771	2,457,368	517,881,791	0.5%
Federated Rural Electric Assn	799,465	903,350	185,369,140	0.5%
Meeker Coop Light & Power Assn	1,472,579	1,663,931	151,344,652	1.1%
Minnesota Valley Electric Coop	2,630,165	2,971,938	631,541,133	0.5%
Redwood Electric Coop	733,159	828,428	53,843,279	1.5%
South Central Electric Assn	931,570	1,052,621	173,619,860	0.6%
Wright-Hennepin Coop Electric Assn	5,553,841	6,275,527	841,311,334	0.7%
TOTAL	**16,145,130**	**18,243,085**	**2,734,980,383**	**0.7%**

2011 SPENDING COMPLIANCE

In addition to the 1.5% savings goal, Minnesota Statutes also set minimum spending levels for total CIP spending and low-income spending. The total minimum spending requirement, equal to 1.5% of annual GOR, may be fulfilled by cooperative and municipal power providers.[6] As shown below in Tables 4 and 5, GRE's All-Requirements and Fixed groups each exceeded the minimum 1.5% level for total CIP spending on an aggregated basis.

In contrast to the total CIP spending requirement, the low-income spending requirement, equal to 0.2% of annual residential GOR, must be met at the distribution cooperative and utility level.[7] As indicated in Tables 6 and 7, some of GRE's member cooperatives did not spend the required minimum amount on low-income programs. According to GRE, some community action program (CAP) agencies struggled to maintain their previous program delivery levels in 2011 as they focused on expending American Recovery and Reinvestment Act (ARRA) funds. This situation was exacerbated in 2012 as the CAP agencies reduced their workforces after the ARRA funds were expended.

In discussions with Department Staff, GRE indicated that it is taking steps to help its member cooperatives increase their low-income spending compliance by incorporating weatherization of member homes with delivered fuel heating systems in its standard agreement with CAP agencies, per recent Department guidance[8], and is exploring other options to expand participation in its income-eligible programs.

---

[6] See Minn. Stat. §216B.241 subd. 1b (f)
[7] See Minn. Stat. §216B.241 subd. 7 (a) and (c).
[8] See http://mn.gov/commerce/energy/images/ConserveProgDeliveredFuels.pdf

Table 4: Total CIP Expenditures in 2011, All-Requirements Group

Organization	Total Expenditures	2009 GOR	Total Spending %
Arrowhead Electric Coop, Inc	$119,083	$7,044,218	1.7%
BENCO Electric Coop	$576,502	$26,558,756	2.2%
Brown Co Rural Electrical Assn	$319,376	$11,447,529	2.8%
Connexus Energy	$3,563,247	$197,165,770	1.8%
Cooperative Light & Power	$147,923	$8,885,675	1.7%
Dakota Electric Assn	$4,242,964	$163,526,408	2.6%
East Central Energy	$2,634,367	$94,028,406	2.8%
Elk River Municipal Utilities	$415,183	$24,424,185	1.7%
Goodhue County Coop Electric Assn	$233,712	$9,427,539	2.5%
Itasca Mantrap Coop Electric Assn	$374,935	$18,910,612	2.0%
Kandiyohi Power Coop	$333,602	$16,326,388	2.0%
Lake Country Power	$1,463,449	$69,339,833	2.1%
Lake Region Electric Coop	$639,219	$42,739,673	1.5%
McLeod Coop Power Assn	$412,769	$16,797,898	2.5%
Mille Lacs Electric Coop	$388,827	$20,248,693	1.9%
Nobles Cooperative Electric	$155,127	$12,908,480	1.2%
North Itasca Electric Coop	$67,632	$6,473,477	1.0%
Runestone Electric Assn	$557,367	$22,085,468	2.5%
Stearns Coop Electric Assn	$833,971	$43,309,136	1.9%
Steele Waseca Coop Electric	$458,367	$23,168,992	2.0%
Todd Wadena Electric Coop	$369,299	$14,805,017	2.5%
TOTAL	**$18,306,921**	**$849,622,153**	**2.2%**

Table 5: Total CIP Expenditures in 2011, Fixed Group

Organization	Total Expenditures	2009 GOR	Total Spending %
Agralite Cooperative	$814,254	$17,740,851	4.6%
Crow Wing Coop Power & Light, Inc.	$482,677	$55,127,088	0.9%
Federated Rural Electric Assn	$334,604	$23,094,170	1.4%
Meeker Coop Light & Power Assn	$349,117	$17,557,862	2.0%
Minnesota Valley Electric Coop	$1,261,219	$58,273,819	2.2%
Redwood Electric Coop	$144,772	$7,035,900	2.1%
South Central Electric Assn	$232,571	$14,940,639	1.6%
Wright-Hennepin Coop Electric Assn	$1,332,267	$75,204,331	1.8%
TOTAL	**$4,951,480**	**$268,974,660**	**1.8%**

Table 6: Low-Income Expenditures in 2011, All-Requirements Group

Organization	Low-Income Expenditures	2009 Resid. GOR	Low-Income Spending %
Arrowhead Electric Coop, Inc	$11,163	$3,382,231	0.33%
BENCO Electric Coop	$137,343	$19,275,274	0.71%
Brown Co Rural Electrical Assn	$4,351	$6,145,666	0.07%
Connexus Energy	$297,497	$125,879,444	0.24%
Cooperative Light & Power	$14,420	$5,787,072	0.25%
Dakota Electric Assn	$244,036	$93,557,320	0.26%
East Central Energy	$127,433	$64,802,929	0.20%
Elk River Municipal Utilities	$25,475	$8,309,023	0.31%
Goodhue County Coop Electric Assn	$17,614	$8,709,907	0.20%
Itasca Mantrap Coop Electric Assn	$31,750	$12,310,639	0.26%
Kandiyohi Power Coop	$26,946	$11,309,938	0.24%
Lake Country Power	$100,947	$54,502,170	0.19%
Lake Region Electric Coop	$44,784	$34,424,433	0.13%
McLeod Coop Power Assn	$30,382	$11,425,391	0.27%
Mille Lacs Electric Coop	$25,763	$13,842,173	0.19%
Nobles Cooperative Electric	$5,124	$9,129,082	0.06%
North Itasca Electric Coop	$2,356	$5,381,613	0.04%
Runestone Electric Assn	$50,685	$18,651,981	0.27%
Stearns Coop Electric Assn	$53,888	$27,158,282	0.20%
Steele Waseca Coop Electric	$13,301	$14,398,722	0.09%
Todd Wadena Electric Coop	$3,457	$11,938,237	0.03%
TOTAL	**$1,268,716**	**$560,321,527**	**0.23%**

Table 7: Low-Income Expenditures in 2011, Fixed Group

Organization	Low-Income Expenditures	2009 Resid. GOR	Low-Income Spending %
Agralite Cooperative	$32,944	$9,105,764	0.36%
Crow Wing Coop Power & Light, Inc.	$53,832	$41,252,438	0.13%
Federated Rural Electric Assn	$20,378	$6,623,213	0.31%
Meeker Coop Light & Power Assn	$8,188	$14,218,144	0.06%
Minnesota Valley Electric Coop	$112,781	$39,535,839	0.29%
Redwood Electric Coop	$6,792	$5,103,539	0.13%
South Central Electric Assn	$9,969	$7,633,717	0.13%
Wright-Hennepin Coop Electric Assn	$100,687	$48,071,486	0.21%
TOTAL	**$345,571**	**$171,544,140**	**0.20%**

2013 PLAN APPROVAL

My staff has reviewed GRE's 2013 program definitions in ESP which comprise GRE's 2013 CIP plan. GRE continues to offer its member cooperatives a broad array of residential, low-income, commercial, and agricultural programs encompassing a wide array of end use technologies. In order to increase its savings to the 1.5% level, the Department recommends that GRE evaluate the measures that passed the total resource cost (TRC) test in its recent demand-side management (DSM) potential study that GRE does not currently incent for inclusion in its CIP portfolio. We also recommend that GRE review the new small business and multifamily programs developed by other Minnesota utilities as well as the ongoing conservation applied research and development (CARD) studies in these sectors and consider developing such programs for its members.

For 2013, GRE's savings goals are equal to 1.5% of average weather-normalized sales over 2009-2011, excluding sales to CIP-exempt customers. GRE's total CIP and low-income minimum spending requirements are equal to 1.5% of 2011 gross operating revenues (GOR) and 0.2% of 2011 residential GOR, respectively. These calculations will be built into ESP in a future release.

General Guidelines Regarding Low-Income Programs

As discussed above, while the CIP total spending and savings goals apply at the aggregator level, Minnesota Statutes require that each individual distribution cooperative and municipal utility meet the low-income minimum spending requirement (0.2% of residential GOR). Therefore, each member cooperative or utility should operate one or more low-income programs and is responsible for meeting the annual low-income minimum spending requirement.

General Guidelines Regarding Load Management Programs

With the changes that took effect in 2010, the goal of CIP is now to achieve the 1.5% energy savings on an annual basis, rather than spend a certain amount of money. By statute load management programs (such as thermal energy storage technologies or air-conditioner cycling) may be used to make up to 50% of a utility or association's minimum spending requirement for energy conservation improvements;[9] however, most electric cooperatives and municipalities will have to direct their minimum spend (1.5% of GOR) toward conservation programs as opposed to load management programs in order to achieve the savings goal.

General Guidelines Regarding Electric Utility Infrastructure Projects

While the Department is supportive of electric utility infrastructure projects that increase generation and distribution efficiencies, the statutes do not allow us to count these projects towards your minimum CIP spending requirement.[10] The resulting energy savings from these projects do count towards your energy savings goal *on top of* the minimum 1% from energy conservation improvements (i.e., demand-side measures).[11]

[9] Minn. Stat. §216B.241 subd. 1b (e).
[10] Minn. Stat. §216B.241 subd. 1b (b) requires each electric cooperative association and electric municipal utility to spend 1.5% of gross operating revenues annually on *energy conservation improvements.* Minn. Stat. §216B.241 subd. 1 (e) specifically excludes electric utility infrastructure projects from the definition of energy conservation improvements.
[11] Minn. Stat. §216B.241 subd. 1c (d).

April16, 2013
Page 8

General Guidelines Regarding Green Building Standards

The CIP statutes require that utility plans include one or more program that facilitate ENERGY STAR labeling, LEED certification, or Green Globes certification of commercial buildings and that support Sustainable Buildings 2030 (SB 2030) standards. We recommend that at a minimum, utilities offer subsidies for design assistance and/or certification expenses on a case by case basis within their residential, commercial and industrial program(s).

Third Party Comments

Izaak Walton League of America, Midwest Office (IWLA), Minnesota Center for Environmental Advocacy (MCEA), and Fresh Energy requested the opportunity to review cooperative and municipal utility CIP activities, using the Energy Savings Platform, and issue comments and recommendations starting with the submissions in June 2012. These organizations filed an analysis of program performance based on ESP data from program years 2008 through 2010, recognizing that that data may not be complete for all utilities.[12] The organizations also expressed a desire to file similar comments in the future. While these organizations made clarification regarding their original analysis of the data, please view this as an opportunity to gather new perspectives on program activities. As a public program, it is important that CIP be transparent and that outside parties be given the opportunity to view program activity and offer recommendations.

FUTURE REPORTING

We are now requiring annual one-year plans and one-year status reports on June 1 of each year. The next scheduled report will be on June 3, 2013, when you will be required to submit your expenditures and savings for 2012 and update your program designs in ESP for 2014. Your program designs will persist from one year to the next so that you do not have to reenter those programs that have not changed. The baseline periods for each program year are shown below.

Table 8: Baseline Periods for Savings Goals and Spending Requirements

Program Year	Savings Goal 1.5% of:	Total Spending Rqmt 1.5% of:	Low Income Spending Rqmt 0.2% of:
2013	2009-2011 average sales	2011 GOR	2011 residential GOR
2014	2010-2012 average sales	2012 GOR	2012 residential GOR
2015	2011-2013 average sales	2013 GOR	2013 residential GOR
2016	2012-2014 average sales	2014 GOR	2014 residential GOR
…	…	…	…

[12] Docket No. E,G999/CIP-12-774. To access this analysis through eDockets, go to https://www.edockets.state.mn.us/EFiling and click on “Search Documents”. Select “12” for the year and enter “774” in the number field.

April16, 2013
Page 9

DECISION

With this letter, I accept GRE's results for the 2011 CIP program year and approve GRE's CIP plan for 2013. Thank you for your organization's continued contributions to Minnesota's energy efficiency and conservation goals. Please contact Jessica Burdette at Jessica.Burdette@state.mn.us or (651)296-0404 with any questions or concerns.

Sincerely,

WILLIAM GRANT
Deputy Commissioner

WG/JP/sm
c: Member Cooperatives of Great River Energy, Elk River Municipal Utilities

division of energy resources
Minnesota Department of Commerce
85 7th Place East, Suite 500, St. Paul, MN 55101-2198
main: 651.296.4026
tty: 651.296.2860
fax: 651.297.7891
www.energy.mn.gov

December 6, 2013

Jeffrey Haase
Energy Efficiency Coordinator
Great River Energy
12300 Elm Creek Blvd.
Maple Grove, MN 55369

RE: Conservation Improvement Program (CIP) 2012 Results and 2014 Plans

Dear Mr. Haase:

Thank you very much for Great River Energy's efforts to report 2012 Conservation Improvement Program (CIP) results and a 2014 CIP plan in the Energy Savings Platform (ESP®) on behalf of Great River Energy's members. My staff has finished reviewing this information.

2012 ENERGY SAVINGS REPORTED

Each utility and association has an annual energy savings goal equal to 1.5 percent of gross annual retail sales.[1] Based on the information you provided, Great River Energy members saved a total of 127,028,666 kWh at the generator[2] in 2012, 1.1 percent of average 2008-2010 retail sales.[3] We appreciate Great River Energy's energy efficiency and conservation achievements in 2012.

A summary of Great River Energy's energy savings by member are as follows:

Member Utility	Energy Savings at the Generator (kWh)	% of Retail Sales
Agralite	1,182,678	0.6%
Arrowhead	240,947	0.4%
BENCO	2,890,867	1.1%
Brown Co	594,746	0.4%
Connexus	23,628,782	1.2%
Cooperative	201,661	0.2%

[1] See Minn. Stat. §216B.241 subd. 1c (b).
[2] Based on a transmission and distribution loss factor of 8.0 % previously provided to DER Staff. DER Staff assumed a transmission and distribution loss factor of 8% if no value was provided.
[3] Minnesota Statutes 216B.241 subd. 1c(b) states that the energy savings goal is to be calculated based on the most recent three-year weather-normalized average. This review was based on 2008-2010 retail sales as reported in ESP®.

Crow Wing	3,772,583	0.7%
Dakota	20,660,472	1.1%
East Central	7,183,873	0.8%
Elk River	2,880,635	1.2%
Federated	1,130,165	0.4%
Goodhue	557,615	0.6%
Great River Energy (EUI & Load Mgmt)	20,266,522	NA
Itasca Mantrap	1,872,014	0.9%
Kandiyohi	1,533,314	1.0%
Lake Country	6,607,910	1.0%
Lake Region	2,592,440	0.6%
McLeod	1,056,352	0.6%
Meeker	942,916	0.6%
Mille Lacs	2,011,177	1.0%
Minnesota Valley	7,264,760	1.1%
Nobles	1,448,121	0.9%
North Itasca	470,503	0.9%
Redwood	132,729	0.2%
Runestone	1,691,298	0.8%
South Central	1,598,703	0.9%
Stearns	5,334,299	1.1%
Steele Waseca	1,469,729	0.6%
Todd Wadena	945,013	0.6%
Wright-Hennepin	4,865,842	0.6%
TOTAL	**127,028,666**	**1.1%**

2012 SPENDING REPORTED

Each electric utility is required to invest a minimum of 1.5 percent of its Minnesota gross operating revenues (GOR) on CIP.[4]

For 2012, 2010 revenues were the baseline for establishing these minimum spending requirements. Based on the information you provided, Great River Energy's members invested a total of $20,327,872 in 2012, approximately 1.7 percent of 2010 GOR.

Additionally, Minnesota Statutes require each electric utility to invest a minimum of 0.2 percent of its residential Minnesota GOR on CIP programs that directly serve the needs of low-income persons, including renters.[5] Each member utility is responsible for meeting the low-income spending requirement.

While utilities may claim energy savings that result from EUI projects,[6] Minnesota Statutes do not allow the spending on EUI projects to count towards the CIP spending requirement.[7] Therefore, total 2012 CIP

[4] See Minn. Stat. §216B.241 subd. 1a (2).
[5] See Minn. Stat. §216B.241 subd. 7(a) and (c).

spending does not reflect any EUI spending. The Department is supportive of EUI projects that increase generation and distribution efficiencies and appreciates that utilities are reporting information about these investments through ESP®. Department Staff will work with Energy Platforms in the future to develop functionality to clearly display EUI investments separately from CIP eligible spending within ESP®.

A summary of Great River Energy's investments by member are as follows:

Member Utility	2012 Total Spending ($)	2012 Total Spending (%)	2012 LI Spending ($)	2012 LI Spending (%)	EUI Spending ($)
Agralite	$596,501	3.5%	$16,938	0.2%	$0
Arrowhead	$109,905	1.5%	$16,935	0.3%	$0
BENCO	$574,058	2.1%	$44,676	0.2%	$0
Brown Co	$159,077	1.3%	$15,043	0.2%	$0
Connexus	$3,072,928	1.5%	$293,385	0.2%	$0
Cooperative	$125,988	1.3%	$15,487	0.3%	$0
Crow Wing	$382,043	0.7%	$35,937	0.1%	$0
Dakota	$3,809,219	2.1%	$315,638	0.3%	$0
East Central	$1,819,728	1.8%	$115,507	0.2%	$0
Elk River	$388,567	1.5%	$24,128	0.3%	$0
Federated	$210,172	0.8%	$5,802	0.1%	$0
Goodhue	$229,822	2.3%	$10,927	0.1%	$0
Great River Energy	$3	0.0%	$0	0.0%	$1
Itasca Mantrap	$317,609	1.7%	$19,030	0.2%	$0
Kandiyohi	$303,125	1.8%	$33,703	0.3%	$0
Lake Country	$1,224,614	1.7%	$100,720	0.2%	$0
Lake Region	$700,799	1.7%	$47,655	0.1%	$0
McLeod	$388,964	2.3%	$24,773	0.2%	$0
Meeker	$321,302	1.8%	$7,072	0.0%	$0
Mille Lacs	$407,337	1.9%	$63,277	0.4%	$0
Minnesota Valley	$1,254,068	2.0%	$92,091	0.2%	$0
Nobles	$142,079	1.1%	$29,594	0.3%	$0
North Itasca	$102,767	1.5%	$11,103	0.2%	$0
Redwood	$47,277	0.6%	$6,254	0.1%	$0
Runestone	$447,940	2.0%	$32,141	0.2%	$0
South Central	$137,605	0.9%	$6,568	0.1%	$0
Stearns	$886,631	2.0%	$91,100	0.4%	$0
Steele Waseca	$681,505	2.9%	$9,812	0.1%	$0
Todd Wadena	$350,065	2.4%	$3,485	0.0%	$0
Wright-Hennepin	$1,136,177	1.5%	$121,146	0.2%	$0
TOTAL	**$20,327,872**	**1.7%**	**$1,609,928**	**0.2%**	**$1**

[6] Minn. Stat. §216B.241 subd. 1c (d) allows a utility or associated to include in its energy conservation plan energy savings from electric utility infrastructure projects.
[7] Minn. Stat. §216B.241 subd. 1b (b) requires each electric cooperative association and electric municipal utility to spend 1.5% of gross operating revenues annually on *energy conservation improvements*. Minn. Stat. §216B.241 subd. 1(e) specifically excludes electric utility infrastructure projects from the definition of energy conservation improvements.

Great River Energy
December 6, 2013
Page 4

ADDITIONAL REQUIREMENTS

In addition to meeting the energy savings goal and the total and low-income spending requirements, Minnesota Statutes §§216B.241 and 216B.2411 contain provisions that utilities must meet, including the following:

Research and Development (R&D): Each utility and association may spend up to 10 percent of a utility's minimum spending requirement on R&D (§216B.241, subd. 2(c)).

Distributed and Renewable Generation (DRG): Each utility and association may spend up to 5 percent of a utility's minimum spending requirement on DRG (§216B.2411, subd. 1). Utilities may not use green pricing programs to achieve CIP requirements.

Load-Management Activities: Each utility and association may use load-management activities to achieve up to 50 percent of a utility's minimum spending requirement (§216B.241, subd. 1b(e)).

Green Building Standards: Each utility and association must offer one or more programs that support green building certification of commercial buildings and that support goals consistent with Sustainable Buildings 2030 (SB 2030) standards (§216B.241, subd. 1f(c) and §216B.241, subd. 9(e)). We recommend that at a minimum, utilities offer subsidies for design assistance and/or certification expenses on a case by case basis within their commercial and industrial program(s).

Electric Utility Infrastructure (EUI): As stated above, energy savings from EUI projects count towards CIP energy savings goals. However, according to the Minnesota Statutes, spending on EUI projects may not be counted towards CIP spending requirements.

Great River Energy
December 6, 2013
Page 5

FINDINGS REGARDING 2012 RESULTS

It appears that the CIP activities in 2012 of the members of Great River Energy did not meet the following statutory provisions or CIP policies:

- Savigns of 5,000 kWh was reported for BENCO for the Indirect Education program. An education program should not have energy savings associated with it unless it includes a component where members initiate a request for energy savings measures (e.g. CFL, low-flow aerators, and weather stripping) or such measures are directly installed by a technician during a home visit. Based on the information provided in the description of the program DER Staff believe the energy savings claimed should be removed.

We will open the editing function of ESP® so that you can make the appropriate edits. If you feel there is an error in our analysis or in the information that was reported, please contact Jessica Burdette or Laura Silver.

2014 PLAN REVIEW

My staff has reviewed Great River Energy's program designs for 2014 as reported in ESP®. It appears that Great River Energy has developed a broad array of programs for its members covering the residential, commercial, and industrial sectors. In addition, Great River Energy operates a low-income program to assist low-income members to purchase and install ENERGY STAR qualified appliance and equipment.

FUTURE REPORTING

Annual one-year plans and one-year status reports are due on June 1 of each year. The next scheduled report will be on June 1, 2014, when you will be required to submit your expenditures and savings for 2013 and update your program designs in ESP® for 2015. Your program designs will persist from one year to the next so that you do not have to reenter those programs that have not changed. The baseline periods for each program year are shown below.

Table 1: Baseline Periods for Electric Cooperatives and Municipalities

Program Year	Savings Goal 1.5% of:	Total Spending Rqmt 1.5% of:	Low Income Spending Rqmt 0.2% of:
2013	2009-2011 average sales	2011 GOR	2011 residential GOR
2014	2010-2012 average sales	2012 GOR	2012 residential GOR
2015	2011-2013 average sales	2013 GOR	2013 residential GOR
2016	2012-2014 average sales	2014 GOR	2014 residential GOR
…	…	…	…

Great River Energy
December 6, 2013
Page 6

DECISION

With this letter, I accept as modified Great River Energy's results for the 2012 CIP program year and approve Great River Energy's CIP plan for 2014. Thank you for Great River Energy and its member's continued contributions to Minnesota's energy efficiency and conservation goals. Please contact Jessica Burdette at Jessica.Burdette@state.mn.us or 651-539-1871 or Laura Silver at laura.silver@state.mn.us or 651-539-1873 with any questions or concerns.

Sincerely,

William Grant
Deputy Commissioner

Cc: Member Utilities of Great River Energy

WG/LNS

APPENDIX D: CONSERVATION PLAN SCENARIO ANAYSIS¶

Conservation Plan Scenario Analysis –

Benefit/Cost Results and Rate Impact

Prepared for

Great River Energy

Prepared by

LADCO Services, LLC
7820 Galway Cove
Eden Prairie, MN 55347
(952) 913-3465

October 21, 2014

Table of Contents

Section 1

Introduction

Great River Energy's (GRE) conservation Improvement Plan (CIP) contains both conservation and load management projects. Over the past several years, conservation projects saved energy at a rate of approximately 1% of its annual sales. An additional 0.5% level of savings was realized through supply side efficiency projects. This level of achievement is challenging for rural electric cooperatives, owing to the greater proportion of residential customers, compared to that of investor owned utilities (IOU). Across utilities, the largest conservation savings are attributed to the commercial and industrial classes. Since GRE has a lower proportion of commercial and industrial customers than the IOUs, its savings percentage would be expected to be lower, given the same effort of implementation.

While it would be possible to increase the magnitude of the conservation program, this increased size would be accompanied by increased costs. These costs could be in the form of greater incentives to customers and greater program administrative costs. The measures implemented in more aggressive plans could be the same measures currently implemented, other identified measures or future measures not currently identified. One measure of cost-effectiveness for more aggressive plans would be the standard DSM cost-effectiveness tests, i.e. Participant, Utility, Ratepayer Impact and Societal tests. Resource plans are generally evaluated using the Utility test, which is also known as the Revenue Requirements test. While aggressive conservation may lower revenue requirements and look attractive from that perspective, it does not address the rate impacts caused by the additional conservation. In theory, the Ratepayer Impact test does address the rate impact. Unfortunately it does so in a manner that is not intuitively obvious. A calculation of projected rate impact is required.

This study addresses the cost-effectiveness of various levels of conservation both in terms the cost-effectiveness tests and projected rate impact.

Section 2

Method of Analysis

The conservation portion of GRE's projected 2015 CIP is used as the basis for this study. The conservation portion of the 2015 plan is approximately 0.93% of weather normalized sales. This plan was constructed based on the average levels of achievements across distribution cooperatives for the past three years combined with known kWh reductions from those measures that are known to have increased baselines and reduced kWh savings. It does not include load management programs that also provide some kWh savings. Three additional plans are constructed by increasing participation. The three plans correspond to 1.25% of sales, 1.5% of sales and 2.0% of sales. Costs are escalated in a manner consistent with the Utility Net Benefit correction factors originally agreed to with the DER and other utilities in Docket No. E,G999/CI-08-133. Since a 1.0% of sales plan for GRE is consistent with a 1.5% of sales plan for the IOUs, the factors used to increase an IOU plan from 1.5% to 3% are the same factors used to escalate the GRE plan from approximately 1% to 2%. Although the existing measures are used in the analysis, they are proxies for whatever measures would be implemented to obtain the greater level of savings. Any new measures used to escalate a plan would be expected to require greater incentives than those currently offered, have lower unit savings or both. The focus of this study is the level of savings and costs and not the actual measures.

Each plan is assumed to be implemented from 2015 through 2029, the end of the IRP study period. Since the IRP is filed late in 2014, it is reasonable to assume that any scenario variations would not occur until 2016. Thus, all plans are assumed to be at the base level of 0.93% of sales in 2015, with the variations beginning in 2016. To simplify the analysis, measures are examined at the program level. For example, Residential lighting encompasses all lighting components, such as LED, CFL and holiday lighting. The program loadshapes are proportioned by the historical 2013 components to obtain a reasonable loadshape. Program lives are determined in the same manner.

Each plan is evaluated over the period from 2015 through 2048 to include a complete lifecycle of the plan implemented in 2029, the last year of the IRP study period. Cost effectiveness results are computed for the Participant, Utility, Ratepayer Impact and Societal tests for two cases. The first case assumes that CO_2 is treated as an externality for the entire evaluation period (No CO_2 Case). The second case assumes that CO_2 is treated as an externality until 2019. Beginning in 2019, CO_2 is included as a direct dispatch cost that is avoided (CO_2 Case). Finally a calculation of relative rate impacts between plans is calculated for the year 2019, the last year of the IRP action plan for both the No CO_2 Case and the CO_2 Case.

Section 3

Great River Energy's 2015 Conservation Plan

GRE's projected 2015 conservation plan is shown in Table 3.1 below. The participant incentives, administrative costs and savings at the meter were supplied by GRE. The savings at the generator are a result of the modeling that considers loadshapes and system losses. Costs and savings associated with GRE's load management programs are not included.

TABLE 3.1: Great River Energy Projected 2015 Conservation Plan

	Participant Incentives	Administrative Costs	Savings at Meter	Savings at Generator	Savings at Generator
	($)	($)	(KWh)	(KWh)	(KW)
Commercial Programs	**$3,116,217**	**$1,551,747**	**52,415,120**	**57,701,120**	**10,577**
Commercial Agriculture	$44,345		954,463		
Commercial Custom	$678,378		11,980,550		
Commercial Engineering & Design Assistance	$140,527		1,295,002		
Commercial GSHP	$116,999		2,278,342		
Commercial HVAC	$363,811		1,960,487		
Commercial Motors and Drive	$377,114		9,246,607		
Commercial New Construction Lighting	$527,110		10,431,237		
Commercial Retrofit Lighting	$867,933		14,268,432		
Residential Programs	**$3,269,619**	**$3,375,008**	**37,295,106**	**41,056,271**	**6,523**
Electrically Commutated Motor (ECM)	$248,040		2,084,325		
Energy Star Appliances	$321,855		3,553,071		
Hot Water Savings	$12,593		1,378,896		
Res ASHP	$457,210		7,266,432		
Res Cooling	$790,077		1,616,956		
Res Geothermal	$798,789		10,269,036		
Res Home Energy Savings	$156,003		595,941		
Res HVAC Tune-Up	$41,823		144,301		
Res Lighting	$217,959		7,153,200		
Residential Measurable Behavior Modification	$27,636		2,749,938		
Water Heat	$197,634		483,010		
Income Eligible Programs	**$1,375,799**	**$155,356**	**3,286,077**	**3,617,474**	**555**
Totals	**$7,761,635**	**$5,082,111**	**92,996,303**	**102,374,864**	**17,654**

The savings at the generator of 102,374,864 kWh represent 0.93% of annual sales without opt-out customers. This plan is the basis for the scenario analysis. The report includes assumptions and results for the Commercial/Industrial/Agricultural, Residential and Income Eligible classes as well as for the total plan. Details for the individual programs are shown in the various appendices. These are noted in the upcoming sections. To simplify the analysis, the actual numbers of program participants are not used. Rather participant escalators are used for each scenario. The 2015 plan is assumed to have an escalator of 1.0.

Section 4

Scenario Definition and Associated Input Parameters

Four scenarios are developed for this analysis. These scenarios are defined as:

Base Case Scenario

This scenario is identical to the 2015 conservation portion of the CIP. Costs are escalated by the Consumer Price Index (CPI) each year, beginning in 2016. The measures from the 2015 CIP are used as proxies for measures to be implemented in the future. While the actual measures may vary, the overall spending level and savings level are expected to be representative of the scenario. The Income Eligible programs are not varied by scenario, but are kept at the 2015 level, except for the annual inflation cost escalations, beginning in 2016. The Income Eligible Project is based on customer need and is not easily varied. Increases to the Program are not reasonable. This scenario is used as the basis for determining the other scenarios.

1.25% Scenario

With the exception of the Income Eligible project, incentives are increased 50% from the Base scenario. Administrative costs increase 165%. Participation increases 35.6138%. The Income Eligible project does not change from the Base Case. Savings represent 1.25% of sales.

1.5% Scenario

With the exception of the Income Eligible project, incentives increase 125%. Administrative costs increase 250%. Participation increases 63.4692%. The Income Eligible project does not change from the Base. Savings represent 1.50% of sales.

2.0% Scenario

With the exception of the Income Eligible project, incentives increase 234% to equal full incremental cost. Administrative costs increase 400% above the Base level. Participation increases 119.1799%. The Income Eligible project does not change from the Base Case. Savings represent 2.0% of sales. All percentages are relative to the base scenario.

Table 4.1 below lists the per measure customer and dealer incentives for each customer class of each scenario. Individual measure incentives are shown in Appendix 1 along with the incremental costs GRE assumed. The incentives are set to 30% of assumed incremental cost for the Base Case.

TABLE 4.1: Incentive Variation by Scenario - 2016

	Project Incentive Costs			
Project Description	**Base Case**	**1.25%**	**1.5%**	**2.0%**
Commercial/ Industrial/Agricultural	$3,167,011	$6,442,357	$11,648,448	$23,138,174
Income Eligible	$1,398,225	$1,398,225	$1,398,225	$1,398,225
Residential	3,322,9144	$6,759,494	$12,221,866	$24,277,197
Total	**$7,888,150**	**$14,600,076**	**$25,268,539**	**$48,813,596**

Table 4.2 below lists the participant escalators assumed for each customer class of each scenario. The participation for all programs within a class are escalated using the class escalator.

TABLE 4.2: Participation Escalators for New Participants per Year by Scenario in 2016

	Project Participation Relative)			
Project Description	**Base Case**	**1.25%**	**1.5%**	**2.0%**
Commercial/ Industrial/Agricultural	1.0	1.356138	1.634692	2.191799
Income Eligible	1.0	1.0	1.0	1.0
Residential	1.0	1.356138	1.634692	2.191799

Table 4.3 below lists the annual administrative costs for each customer class, under each scenario. Administrative are not allocated to individual programs within a class.

TABLE 4.3: Administrative Costs by Scenario in 2016

	Project Administrative Costs			
Project Description	**Base Case**	**1.25%**	**1.5%**	**2.0%**
Commercial/ Industrial/Agricultural	$1,577,040	$4,179,157	$5,519,642	$7,885,202
Income Eligible	$157,888	$157,888	$157,888	$157,888
Residential	$3,430,021	$9,089,555	$12,005,072	$17,150,103
Total	**5,164,949**	**13,426,600**	**17,682,602**	**25,193,194**

Each plan assumes implementation at a constant level through the year 2029 for all scenarios, including the Base. Plans projecting impacts this far out are suspect in terms of achievable impacts in the later years. Program costs are escalated at the CPI escalator for each year beginning in 2016.

Section 5

Scenario Results

Each of the Plans is evaluated over a period from 2015 through 2048, with implementation extending through 2029. It is necessary to consider program life past the year of implementation to balance the costs incurred in the first year with benefits in later years. Table 5.1 below lists the 2016 annual energy and peak savings, at the generator, for each project in each scenario. The year 2016 is the first year that the scenarios vary. The cumulative savings for each plan in 2019, the last year of the action plan, are also shown. The cumulative savings include 2015 - 2018 impacts and also factor in losses due to end of measure life. Annual plan level savings and costs are shown in Appendix 2. Individual program savings are shown in Appendix 3.

TABLE 5.1: Energy and Peak Savings by Scenario in 2016

	Total Savings							
Project Description	Base Case		1.25%		1.5%		2.0%	
	MWh	MW	MWh	MW	MWh	MW	MWh	MW
Commercial/ Industrial/Agricultural	57,701	10.6	78,251	14.3	94,324	17.3	126,469	23.2
Income Eligible	3,617	0.5	3,617	0.5	3,617	0.5	3,617	0.5
Residential	41,056	6.5	55,677	8.9	67,114	10.7	89,987	14.3
Total	102,374	17.6	137,547	23.7	165,055	28.5	220,073	38.0
Total in 2019 (incl 2015 – 2016, 2017 &2018)	499,289	87.7	636,626	111.9	744,045	130.8	958,882	168.7

Total plan spending for each scenario in 2016 is shown in Table 5.2 below. Individual program costs are shown in Appendix 4.

TABLE 5.2: Project Costs by Scenario in 2016

	Total Plan Costs			
Project Description	Base Case	1.25%	1.5%	2.0%
Commercial/ Industrial/Agricultural	$4,744,052	$10,621,514	$17,168,090	$31,023,377
Income Eligible	$1,556,113	$1,556,113	$1,556,113	$1,556,113
Residential	$6,752,934	$15,849,049	$24,226,939	$41,427,300
Total	**$13,053,099**	**$28,026,676**	**$42,951,141**	**$74,006,790**

Benefit/cost results for each scenario are shown in Table 5.3 below for the case in which CO_2 is treated as an externality and not as a direct dispatch cost (No CO_2 Case). Program level benefit/cost results are shown in Appendix 5.

TABLE 5.3: Benefit/Cost Results by Scenario – CO_2 as an Externality

Test Perspective	Thousand Dollars Benefits	Costs	Net Benefits	B/C Ratio
Base Case Scenario				
Societal	$1,265,625	$379,180	$886,445	3.34
Utility Cost	$825,649	$147,827	$677,822	5.59
Ratepayer Impact Measure	$2,055,803	$2,890,813	($835,010)	0.71
Participant	$1,955,589	$286,953	$1,668,636	6.82
1.25% Scenario				
Societal	$1,673,942	$578,365	$1,095,577	2.89
Utility Cost	$1,088,334	$302,670	$785,664	3.60
Ratepayer Impact Measure	$2,705,619	$3,907,046	($1,201,427)	0.69
Participant	$2,615,020	$374,874	$2,240,146	6.98
1.5% Scenario				
Societal	$1,993,231	$706,600	$1,286,631	2.82
Utility Cost	$1,293,743	$457,006	$836,737	2.83
Ratepayer Impact Measure	$3,213,453	$4,734,758	($1,521,305)	0.68
Participant	$3,192,794	$443,640	$2,749,154	7.20
2.0% Scenario				
Societal	$2,705,618	$984,147	$1,721,471	2.75
Utility Cost	$1,739,835	$796,657	$943,178	2.18
Ratepayer Impact Measure	$4,310,923	$6,541,048	($2,230,125)	0.66
Participant	$4,555,543	$614,763	$3,940,780	7.41

Benefit/cost results for each scenario are shown in Table 5.4 below for the case in which CO_2 is treated as an externality until 2019 and as a direct dispatch cost beginning in 2019 (CO2 Case). Carbon dispatch costs are developed external to the modeling for use at the plan level. Program level benefit/cost results are not available.

TABLE 5.4: Benefit/Cost Results by Scenario – CO_2 as a Dispatch Cost Beginning in 2019

Test Perspective	Thousand Dollars			B/C Ratio
	Benefits	Costs	Net Benefits	
Base Case Scenario				
Societal	$1,479,040	$379,180	$1,099,860	3.90
Utility	$971,257	$147,827	$823,430	6.57
Ratepayer Impact Measure	$2,687,460	$3,609,254	($921,794)	0.74
Participant	$2,232,373	$286,953	$1,945,420	7.78
1.25% Scenario				
Societal	$1,956,758	$578,365	$1,378,393	3.38
Utility	$1,280,905	$302,670	$978,235	4.23
Ratepayer Impact Measure	$3,539,827	$4,855,464	($1,315,637)	0.73
Participant	$2,980,137	$374,874	$2,605,263	7.95
1.5% Scenario				
Societal	$2,330,329	$706,600	$1,623,729	3.30
Utility	$1,523,046	$457,006	$1,066,040	3.33
Ratepayer Impact Measure	$4,206,091	$5,863,053	($1,656,962)	0.72
Participant	$3,627,005	$443,640	$3,183,365	8.18
2.0% Scenario				
Societal	$3,163,442	$984,147	$2,179,295	3.21
Utility	$2,048,671	$796,657	$1,252,014	2.57
Ratepayer Impact Measure	$5,643,135	$8,053,720	($2,410,585)	0.70
Participant	$5,143,716	$614,763	$4,528,953	8.37

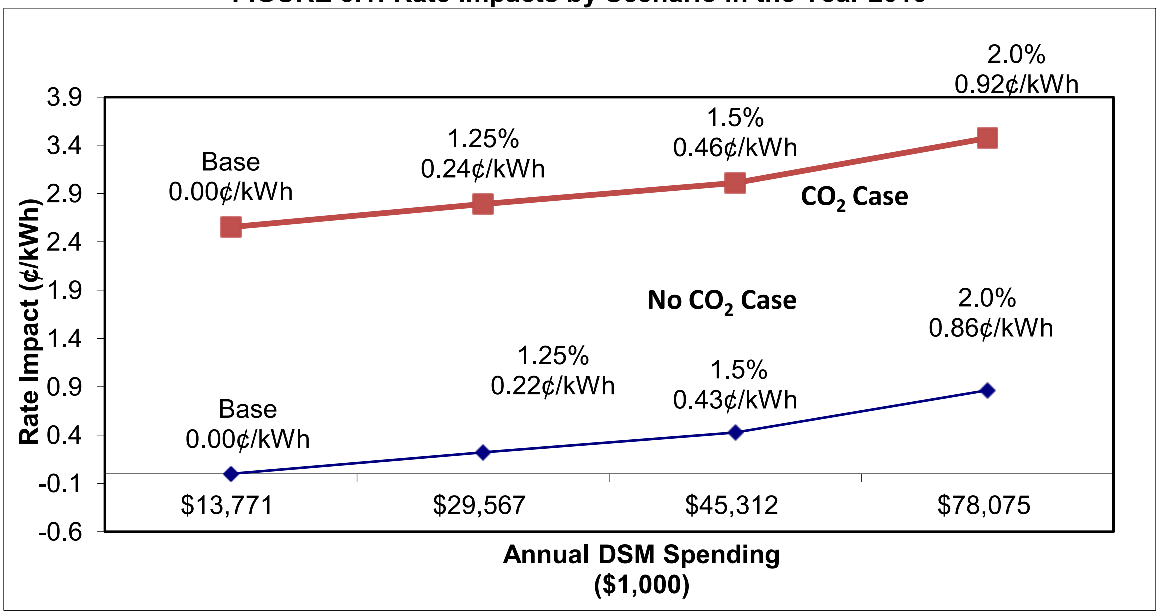
The benefit/cost results indicate the following:

- The Societal, Utility, and Participant tests indicate that the overall program portfolio is cost effective for all scenarios. This suggests that the effects of varying budget, incentives, and participants do not cause a plan to become not cost-effective;
- For the Utility test, the program portfolio becomes less cost effective when going from the Base to the 2% scenario. This suggests diminishing returns when increasing the incentive and administrative cost levels. Participation rates do not increase in proportion to the funding and incentive levels;
- In the Societal test, there is also a decrease in the cost effectiveness as the amount of spending increases. This is caused by the increasing administrative costs;
- The Ratepayer Impact Measure test is not cost effective for any scenario. The present value of the revenue loss and program costs is greater than the present value of the energy and capacity savings;
- The larger incentives in the 1.25%, 1.5% and 2% scenarios increase the cost-effectiveness of the Participant test;
- The introduction of CO_2 as a dispatch cost in the CO_2 Case increases the cost-effectiveness of the Societal, Utility Cost and Participant tests, although the scenarios behave in the same manner as in the No CO_2 Case; and

- The introduction of CO_2 as a dispatch cost decreases the net benefits of the Ratepayer Impact test, although the benefit/cost ratio increases slightly. The increase in the ratio is caused by a compensating benefit and cost due to the wholesale rate.

Examining the results of the Ratepayer Impact Measure Test can provide additional insight. An approximation of relative rate impacts caused by each scenario can be calculated from the results of the cost-effectiveness evaluations. Figure 5.1 below illustrates the impact on average system rate in the year 2019, relative to the Base Scenario for both the No CO_2 Case and the CO_2 Case. .

FIGURE 5.1: Rate Impacts by Scenario in the Year 2019



The rate impacts assume program costs are expensed in the year incurred and also account for energy and capacity savings realized. They represent the change in rates in the year 2019, in 2019 dollars, due to the various scenarios. The rate of the 2% Scenario is 0.86¢/kWh greater than the Base Case rate in 2019 for the No CO_2 Case. This is in addition to the 0.41¢/kWh increase associated with the Base plan, as opposed to no additional conservation after 2014.

The relative increases are slightly greater in the CO_2 Case, although the actual rate increases are substantially greater. The addition of a CO_2 dispatch cost does nothing to change the performance of the scenarios, in terms of relative rate impact, with respect to the Base CO_2 scenario.

Appendix 1

Program Incremental Costs and Incentives by Scenario

Appendix 1: Program Unit Incremental Costs and Incentives by Scenario

	Unit Incremental Costs ($)		Unit Incentives ($)				
				2016			
	2015 All Scenarios	2016 All Scenarios	2015 All Scenarios	Base - 0.93%	1.25%	1.50%	2.00%
Residential							
Residential Appliances	1,072,850	1,090,337	$321,855	$327,101	$490,652	$735,978	$1,090,337
Hot Water Savings	41,977	42,661	$12,593	$12,798	$19,197	$28,796	$42,661
Air Source Heat Pump	1,524,033	1,548,875	$457,210	$464,663	$696,994	$1,045,491	$1,548,875
Residential Cooling	2,633,590	2,676,518	$790,077	$802,955	$1,204,433	$1,806,649	$2,676,518
GSHP - Residential (Ton)	2,662,630	2,706,031	$798,789	$811,809	$1,217,714	$1,826,571	$2,706,031
Res Home Energy Savings	520,010	528,486	$156,003	$158,546	$237,819	$356,728	$528,486
AC Tune-up - Residential	139,410	141,682	$41,823	$42,505	$63,757	$95,636	$141,682
Residential Lighting	726,530	738,372	$217,959	$221,512	$332,268	$498,401	$738,372
Electrically Commutated Motor (ECM)	826,800	840,277	$248,040	$252,083	$378,125	$567,187	$840,277
Residential Measure Behavior Modification	92,120	93,622	$27,636	$28,086	$42,130	$63,195	$93,622
Water Heat	658,780	669,518	$197,634	$200,855	$301,283	$451,925	$669,518
CI&A							
Commercial Agricultural	147,817	150,226	$44,345	$45,068	$67,602	$101,403	$150,226
Commercial Custom	2,261,260	2,298,119	$678,378	$689,436	$1,034,153	$1,551,230	$2,298,119
Commercial Building Engineering & Design Assistance	468,423	476,059	$140,527	$142,818	$214,226	$321,340	$476,059
Commercial GSHP	389,997	396,354	$116,999	$118,906	$178,359	$267,539	$396,354
Commercial HVAC	1,212,703	1,232,470	$363,811	$369,741	$554,612	$831,918	$1,232,470
Commercial Motors and Drives	1,257,047	1,277,537	$377,114	$383,261	$574,891	$862,337	$1,277,537
Commercial New Construction Lighting	1,757,033	1,785,673	$527,110	$535,702	$803,553	$1,205,329	$1,785,673
Commercial Retrofit Lighting	2,893,110	2,940,268	$867,933	$882,080	$1,323,120	$1,984,681	$2,940,268
Income Eligible	**1,375,799**	**1,398,225**	**$1,375,799**	**$1,398,225**	**$1,398,225**	**$1,398,225**	**$1,398,225**

Appendix 2

Annual Plan Savings and Costs

Appendix 2: Annual Plan Savings and Costs
Page 1 of 4

Great River Energy
Base Scenario - Plan Impacts and Costs

Year	Plan Impacts: Energy (MWh)	Plan Impacts: Peak Demand (MW)
2015	102,375	18
2016	201,722	35
2017	300,911	53
2018	400,100	70
2019	499,289	88
2020	598,477	105
2021	697,666	123
2022	796,855	140
2023	896,044	158
2024	995,232	175
2025	1,092,903	192
2026	1,190,574	210
2027	1,288,245	227
2028	1,373,079	243
2029	1,457,913	259

Year	Plan Costs: Incentives ($)	Admin ($)	Total ($)
2015	7,761,635	5,082,111	12,843,746
2016	7,888,150	5,164,949	13,053,099
2017	8,021,460	5,252,237	13,273,696
2018	8,169,055	5,348,878	13,517,932
2019	8,321,816	5,448,902	13,770,718
2020	8,479,098	5,551,886	14,030,984
2021	8,641,897	5,658,482	14,300,379
2022	8,809,550	5,768,257	14,577,807
2023	8,983,979	5,882,468	14,866,447
2024	9,164,557	6,000,706	15,165,263
2025	9,345,099	6,118,920	15,464,018
2026	9,529,197	6,239,463	15,768,660
2027	9,720,734	6,364,876	16,085,610
2028	9,914,176	6,491,537	16,405,713
2029	10,118,408	6,625,262	16,743,671

Savings are at the generator
Peak at 1600 hrs on July weekday

Appendix 2: Annual Plan Savings and Costs
Page 2 of 4

Great River Energy
1.25% Scenario - Plan Impacts and Costs

Year	Plan Impacts: Energy (MWh)	Plan Impacts: Peak Demand (MW)
2015	102,375	18
2016	236,894	41
2017	370,176	65
2018	503,401	88
2019	636,626	112
2020	769,852	135
2021	903,077	159
2022	1,036,302	182
2023	1,169,527	206
2024	1,302,753	229
2025	1,434,460	253
2026	1,565,627	276
2027	1,696,794	299
2028	1,815,124	321
2029	1,928,882	342

Year	Plan Costs: Incentives ($)	Plan Costs: Admin ($)	Plan Costs: Total ($)
2015	7,761,635	5,082,111	12,843,746
2016	14,600,076	13,426,600	28,026,676
2017	14,846,817	13,653,510	28,500,327
2018	15,119,999	13,904,734	29,024,733
2019	15,402,743	14,164,753	29,567,495
2020	15,693,855	14,432,466	30,126,321
2021	15,995,177	14,709,570	30,704,746
2022	16,305,483	14,994,935	31,300,418
2023	16,628,332	15,291,835	31,920,167
2024	16,962,561	15,599,201	32,561,762
2025	17,296,723	15,906,505	33,203,229
2026	17,637,469	16,219,864	33,857,332
2027	17,991,982	16,545,883	34,537,865
2028	18,350,022	16,875,146	35,225,168
2029	18,728,033	17,222,774	35,950,807

Savings are at the generator
Peak at 1600 hrs on July weekday

Appendix 2: Annual Plan Savings and Costs
Page 3 of 4

Great River Energy
1.5% Scenario - Plan Impacts and Costs

Year	Plan Impacts: Energy (MWh)	Plan Impacts: Peak Demand (MW)
2015	102,375	18
2016	264,403	46
2017	424,351	75
2018	584,198	103
2019	744,045	131
2020	903,892	159
2021	1,063,739	187
2022	1,223,586	215
2023	1,383,433	244
2024	1,543,280	272
2025	1,701,609	300
2026	1,858,975	328
2027	2,016,341	356
2028	2,160,870	382
2029	2,297,251	408

Year	Plan Costs: Incentives ($)	Plan Costs: Admin ($)	Plan Costs: Total ($)
2015	7,761,635	5,082,111	12,843,746
2016	25,268,539	17,682,602	42,951,141
2017	25,695,577	17,981,438	43,677,015
2018	26,168,376	18,312,296	44,480,672
2019	26,657,725	18,654,736	45,312,461
2020	27,161,556	19,007,311	46,168,866
2021	27,683,057	19,372,251	47,055,309
2022	28,220,109	19,748,073	47,968,182
2023	28,778,867	20,139,085	48,917,952
2024	29,357,322	20,543,880	49,901,202
2025	29,935,661	20,948,595	50,884,256
2026	30,525,394	21,361,282	51,886,676
2027	31,138,954	21,790,644	52,929,598
2028	31,758,619	22,224,278	53,982,897
2029	32,412,847	22,682,098	55,094,945

Savings are at the generator
Peak at 1600 hrs on July weekday

Appendix 2: Annual Plan Savings and Costs
Page 4 of 4

Great River Energy
2.0% Scenario - Plan Impacts and Costs

	Plan Impacts	
Year	Energy (MWh)	Peak Demand (MW)
2015	102,375	18
2016	319,421	56
2017	532,680	94
2018	745,749	131
2019	958,882	169
2020	1,171,886	206
2021	1,384,955	244
2022	1,598,024	281
2023	1,811,093	319
2024	2,024,162	357
2025	2,235,713	394
2026	2,445,455	431
2027	2,655,197	468
2028	2,852,102	504
2029	3,033,708	539

	Plan Costs		
Year	Incentives ($)	Admin ($)	Total ($)
2015	7,761,635	5,082,111	12,843,746
2016	48,813,596	25,193,194	74,006,790
2017	49,638,546	25,618,959	75,257,505
2018	50,551,895	26,090,348	76,642,243
2019	51,497,215	26,578,237	78,075,453
2020	52,470,513	27,080,566	79,551,079
2021	53,477,947	27,600,513	81,078,460
2022	54,515,419	28,135,963	82,651,382
2023	55,594,824	28,693,055	84,287,879
2024	56,712,280	29,269,785	85,982,065
2025	57,829,512	29,846,400	87,675,912
2026	58,968,753	30,434,374	89,403,128
2027	60,154,025	31,046,105	91,200,130
2028	61,351,090	31,663,923	93,015,013
2029	62,614,923	32,316,199	94,931,122

Savings are at the generator
Peak at 1600 hrs on July weekday

Appendix 3

Total Meter Savings by Program and Scenario

Appendix 3: Total Meter Savings by Program and Scenario

	Annual KWh Savings (KWh)				
		2016			
	2015 All Scenarios	Base - 0.93%	1.25%	1.50%	2.00%
Total Residential	**37,295,106**	**37,295,106**	**50,577,311**	**60,966,012**	**81,743,377**
Residential Appliances	3,553,071	3,553,071	4,818,455	5,808,177	7,787,617
Hot Water Savings	1,378,896	1,378,896	1,869,973	2,254,070	3,022,263
Air Source Heat Pump	7,266,432	7,266,432	9,854,285	11,878,378	15,926,558
Residential Cooling	1,616,956	1,616,956	2,192,816	2,643,226	3,544,043
GSHP - Residential (Ton)	10,269,036	10,269,036	13,926,230	16,786,711	22,507,663
Res Home Energy Savings	595,941	595,941	808,178	974,180	1,306,183
AC Tune-up - Residential	144,301	144,301	195,692	235,888	316,279
Residential Lighting	7,153,200	7,153,200	9,700,726	11,693,279	15,678,377
Electrically Commutated Motor (ECM)	2,084,325	2,084,325	2,826,632	3,407,229	4,568,421
Residential Measure Behavior Modification	2,749,938	2,749,938	3,729,295	4,495,302	6,027,311
Water Heat	483,010	483,010	655,028	789,573	1,058,661
Total CI&A	**52,415,120**	**52,415,120**	**71,082,136**	**85,682,577**	**114,883,408**
Commercial Agricultural	954,463	954,463	1,294,384	1,560,253	2,091,991
Commercial Custom	11,980,550	11,980,550	16,247,279	19,584,509	26,258,958
Commercial Building Engineering & Design Assistance	1,295,002	1,295,002	1,756,201	2,116,929	2,838,384
Commercial GSHP	2,278,342	2,278,342	3,089,746	3,724,387	4,993,668
Commercial HVAC	1,960,487	1,960,487	2,658,691	3,204,792	4,296,993
Commercial Motors and Drives	9,246,607	9,246,607	12,539,675	15,115,354	20,266,704
Commercial New Construction Lighting	10,431,237	10,431,237	14,146,197	17,051,860	22,863,175
Commercial Retrofit Lighting	14,268,432	14,268,432	19,349,963	23,324,492	31,273,535
Total Income Eligible	**3,286,077**	**3,286,077**	**3,286,077**	**3,286,077**	**3,286,077**
Total Plan	**92,996,303**	**92,996,303**	**124,945,524**	**149,934,666**	**199,912,861**
Total Plan at Generator	**102,374,865**	**102,374,865**	**137,546,124**	**165,055,391**	**220,073,825**

Appendix 4

Program Costs by Scenario

Appendix 4: Total Costs by Scenario and Program

		Total Costs ($)				
			2016			
		2015 All Scenarios	Base - 0.93%	1.25%	1.50%	2.00%
Total Residential		**$6,644,627**	**$6,752,934**	**$15,849,049**	**$24,226,939**	**$41,427,300**
Incentives		**$3,269,619**	**$3,322,914**	**$6,759,494**	**$12,221,866**	**$24,277,197**
Residential Appliances		$321,855	$327,101	$665,392	$1,203,097	$2,389,801
Hot Water Savings		$12,593	$12,798	$26,034	$47,073	$93,504
Air Source Heat Pump		$457,210	$464,663	$945,220	$1,709,055	$3,394,823
Residential Cooling		$790,077	$802,955	$1,633,377	$2,953,315	$5,866,388
GSHP - Residential (Ton)		$798,789	$811,809	$1,651,388	$2,985,881	$5,931,076
Res Home Energy Savings		$156,003	$158,546	$322,515	$583,141	$1,158,335
AC Tune-up - Residential		$41,823	$42,505	$86,463	$156,335	$310,539
Residential Lighting		$217,959	$221,512	$450,601	$814,733	$1,618,364
Electrically Commutated Motor (ECM)		$248,040	$252,083	$512,789	$927,176	$1,841,718
Residential Measure Behavior Modification		$27,636	$28,086	$57,134	$103,304	$205,200
Water Heat		$197,634	$200,855	$408,582	$738,758	$1,467,449
Administrative		**$3,375,008**	**$3,430,021**	**$9,089,555**	**$12,005,072**	**$17,150,103**
Total CI&A		**$4,667,964**	**$4,744,052**	**$10,621,514**	**$17,168,090**	**$31,023,377**
Incentives		**$3,116,217**	**$3,167,011**	**$6,442,357**	**$11,648,448**	**$23,138,174**
Commercial Agricultural		$44,345	$45,068	$91,677	$165,762	$329,265
Commercial Custom		$678,378	$689,436	$1,402,455	$2,535,783	$5,037,014
Commercial Building Engineering & Design Assistance		$140,527	$142,818	$290,521	$525,291	$1,043,425
Commercial GSHP		$116,999	$118,906	$241,880	$437,343	$868,727
Commercial HVAC		$363,811	$369,741	$752,130	$1,359,929	$2,701,327
Commercial Motors and Drives		$377,114	$383,261	$779,632	$1,409,656	$2,800,103
Commercial New Construction Lighting		$527,110	$535,702	$1,089,729	$1,970,342	$3,913,836
Commercial Retrofit Lighting		$867,933	$882,080	$1,794,334	$3,244,342	$6,444,476
Administrative		**$1,551,747**	**$1,577,040**	**$4,179,157**	**$5,519,642**	**$7,885,202**
Total Income Eligible		**$1,531,155**	**$1,556,113**	**$1,556,113**	**$1,556,113**	**$1,556,113**
Incentives		$1,375,799	$1,398,225	$1,398,225	$1,398,225	$1,398,225
Administrative		$155,356	$157,888	$157,888	$157,888	$157,888
Total Plan		**$12,843,746**	**$13,053,099**	**$28,026,676**	**$42,951,141**	**$74,006,790**
Incentives		$7,761,635	$7,888,150	$14,600,076	$25,268,539	$48,813,596
Administrative		$5,082,111	$5,164,949	$13,426,600	$17,682,602	$25,193,194

Appendix 5

Benefit Cost Results by Program
(No CO_2 Case)

Appendix 5: Benefit/Cost Results by Program (No CO_2 Case)
Page 1 of 4

Benefit/Cost Results - Base Scenario

Test Perspective	2015 Thousand Dollars			B/C Ratio
	Benefits	Costs	Net Benefits	
Commercial Agricultural				
Societal	$7,750	$2,019	$5,731	3.84
Utility Cost	$5,150	$510	$4,640	10.10
Ratepayer Impact Measure	$14,487	$21,898	($7,411)	0.66
Participant	$12,562	$1,697	$10,865	7.40
Commercial Custom				
Societal	$147,081	$30,891	$116,190	4.76
Utility Cost	$97,024	$7,808	$89,216	12.43
Ratepayer Impact Measure	$244,953	$324,987	($80,034)	0.75
Participant	$177,059	$25,965	$151,094	6.82
Commercial Engineering & Design Assistance				
Societal	$24,988	$6,399	$18,589	3.90
Utility Cost	$15,666	$1,617	$14,049	9.69
Ratepayer Impact Measure	$37,168	$45,776	($8,608)	0.81
Participant	$24,274	$5,379	$18,895	4.51
Commercial Ground Source Heat Pump				
Societal	$49,682	$5,328	$44,354	9.32
Utility Cost	$31,312	$1,347	$29,965	23.25
Ratepayer Impact Measure	$71,403	$81,299	($9,896)	0.88
Participant	$41,208	$4,478	$36,730	9.20
Commercial HVAC				
Societal	$57,184	$16,567	$40,617	3.45
Utility Cost	$36,479	$4,187	$32,292	8.71
Ratepayer Impact Measure	$74,163	$76,171	($2,008)	0.97
Participant	$38,487	$13,925	$24,562	2.76
Commercial Motors & Drives				
Societal	$88,695	$17,172	$71,523	5.17
Utility Cost	$57,475	$4,340	$53,135	13.24
Ratepayer Impact Measure	$158,447	$235,941	($77,494)	0.67
Participant	$134,969	$14,434	$120,535	9.35
Commercial Lighting - New Construction				
Societal	$147,910	$24,001	$123,909	6.16
Utility Cost	$98,515	$6,067	$92,448	16.24
Ratepayer Impact Measure	$238,515	$293,430	($54,915)	0.81
Participant	$153,431	$20,175	$133,256	7.61
Commercial Lighting - Retrofit				
Societal	$205,358	$39,522	$165,836	5.20
Utility Cost	$136,900	$9,990	$126,910	13.70
Ratepayer Impact Measure	$329,121	$403,783	($74,662)	0.82
Participant	$211,562	$33,220	$178,342	6.37
Commercial Administrative Costs				
Societal	$0	$21,252	($21,252)	0.00
Utility Cost	$0	$17,860	($17,860)	0.00
Ratepayer Impact Measure	$0	$17,860	($17,860)	0.00
Participant	$0	$0	$0	#DIV/0!
Total Commercial/ Industrial/Agricultural				
Societal	$728,648	$163,151	$565,497	4.47
Utility Cost	$478,521	$53,726	$424,795	8.91
Ratepayer Impact Measure	$1,168,257	$1,501,145	($332,888)	0.78
Participant	$793,552	$119,273	$674,279	6.65

Discounted to 2015

Benefit/Cost Results - Base Scenario

Test Perspective	2015 Thousand Dollars			B/C Ratio
	Benefits	Costs	Net Benefits	
Income Eligible				
Societal	$41,066	$20,922	$20,144	1.96
Utility Cost	$27,110	$17,623	$9,487	1.54
Ratepayer Impact Measure	$69,815	$122,104	($52,289)	0.57
Participant	$106,880	$18,795	$88,085	5.69

Discounted to 2015

Benefit/Cost Results - Base Scenario

Test Perspective	2015 Thousand Dollars			B/C Ratio
	Benefits	Costs	Net Benefits	
Residential Appliances				
Societal	$35,820	$14,656	$21,164	2.44
Utility Cost	$24,168	$3,704	$20,464	6.52
Ratepayer Impact Measure	$63,224	$102,459	($39,235)	0.62
Participant	$87,453	$14,656	$72,797	5.97
Residential A/C & ASHP Tune-up				
Societal	$635	$1,904	($1,269)	0.33
Utility Cost	$511	$481	$30	1.06
Ratepayer Impact Measure	$1,010	$1,421	($411)	0.71
Participant	$1,107	$1,904	($797)	0.58
Residential Air Source Heat Pump				
Societal	$88,812	$20,820	$67,992	4.27
Utility Cost	$55,552	$5,262	$50,290	10.56
Ratepayer Impact Measure	$159,758	$266,186	($106,428)	0.60
Participant	$237,789	$20,820	$216,969	11.42
Residential Behavorial				
Societal	$1,591	$1,258	$333	1.26
Utility Cost	$1,243	$318	$925	3.91
Ratepayer Impact Measure	$3,728	$7,062	($3,334)	0.53
Participant	$5,478	$1,258	$4,220	4.35
Residential Cooling				
Societal	$65,161	$35,977	$29,184	1.81
Utility Cost	$43,105	$9,094	$34,011	4.74
Ratepayer Impact Measure	$82,586	$83,448	($862)	0.99
Participant	$62,341	$35,977	$26,364	1.73
Residential ECM Motors				
Societal	$24,837	$11,295	$13,542	2.20
Utility Cost	$16,355	$2,855	$13,500	5.73
Ratepayer Impact Measure	$42,497	$68,181	($25,684)	0.62
Participant	$59,239	$11,295	$47,944	5.24
Residential Ground Source Heat Pump				
Societal	$178,028	$36,374	$141,654	4.89
Utility Cost	$110,730	$9,194	$101,536	12.04
Ratepayer Impact Measure	$280,604	$418,148	($137,544)	0.67
Participant	$372,643	$36,374	$336,269	10.24
Residential Home Energy Savings				
Societal	$10,109	$7,104	$3,005	1.42
Utility Cost	$6,782	$1,796	$4,986	3.78
Ratepayer Impact Measure	$15,514	$21,731	($6,217)	0.71
Participant	$18,102	$7,104	$10,998	2.55
Residential Hot Water Savings				
Societal	$10,965	$573	$10,392	19.14
Utility Cost	$7,714	$145	$7,569	53.20
Ratepayer Impact Measure	$21,514	$32,594	($11,080)	0.66
Participant	$25,183	$573	$24,610	43.95
Residential Lighting				
Societal	$70,629	$9,925	$60,704	7.12
Utility Cost	$47,574	$2,509	$45,065	18.96
Ratepayer Impact Measure	$131,156	$206,278	($75,122)	0.64
Participant	$170,175	$9,925	$160,250	17.15
Residential Water Heaters				
Societal	$9,324	$8,999	$325	1.04
Utility Cost	$6,284	$2,275	$4,009	2.76
Ratepayer Impact Measure	$16,140	$21,211	($5,071)	0.76
Participant	$15,647	$8,999	$6,648	1.74
Residential Administrative Costs				
Societal	$0	$46,222	($46,222)	0.00
Utility Cost	$0	$38,845	($38,845)	0.00
Ratepayer Impact Measure	$0	$38,845	($38,845)	0.00
Participant	$0	$0	$0	#DIV/0!
Total Residential				
Societal	$495,911	$195,107	$300,804	2.54
Utility Cost	$320,018	$76,478	$243,540	4.18
Ratepayer Impact Measure	$817,731	$1,267,564	($449,833)	0.65
Participant	$1,055,157	$148,885	$906,272	7.09

Discounted to 2015

Benefit/Cost Results - Base Scenario

Test Perspective	2015 Thousand Dollars			B/C Ratio
	Benefits	Costs	Net Benefits	
Total Plan				
Societal	$1,265,625	$379,180	$886,445	3.34
Utility Cost	$825,649	$147,827	$677,822	5.59
Ratepayer Impact Measure	$2,055,803	$2,890,813	($835,010)	0.71
Participant	$1,955,589	$286,953	$1,668,636	6.82

Appendix 5: Benefit/Cost Results by Program (No CO_2 Case)
Page 2 of 4

Benefit/Cost Results - 1.25% Scenario

Test Perspective	2015 Thousand Dollars			B/C Ratio
	Benefits	Costs	Net Benefits	
Commercial Agricultural				
Societal	$10,338	$2,686	$7,652	3.85
Utility Cost	$6,846	$992	$5,854	6.90
Ratepayer Impact Measure	$19,232	$29,369	($10,137)	0.65
Participant	$16,984	$2,249	$14,735	7.55
Commercial Custom				
Societal	$196,137	$41,087	$155,050	4.77
Utility Cost	$128,948	$15,181	$113,767	8.49
Ratepayer Impact Measure	$325,024	$435,819	($110,795)	0.75
Participant	$239,743	$34,406	$205,337	6.97
Commercial Engineering & Design Assistance				
Societal	$33,314	$8,511	$24,803	3.91
Utility Cost	$20,816	$3,145	$17,671	6.62
Ratepayer Impact Measure	$49,339	$61,730	($12,391)	0.80
Participant	$33,207	$7,127	$26,080	4.66
Commercial Ground Source Heat Pump				
Societal	$66,241	$7,086	$59,155	9.35
Utility Cost	$41,610	$2,618	$38,992	15.89
Ratepayer Impact Measure	$94,805	$108,702	($13,897)	0.87
Participant	$55,508	$5,934	$49,574	9.35
Commercial HVAC				
Societal	$76,234	$22,035	$54,199	3.46
Utility Cost	$48,475	$8,142	$40,333	5.95
Ratepayer Impact Measure	$98,475	$103,653	($5,178)	0.95
Participant	$53,653	$18,452	$35,201	2.91
Commercial Motors & Drives				
Societal	$118,334	$22,840	$95,494	5.18
Utility Cost	$76,421	$8,439	$67,982	9.06
Ratepayer Impact Measure	$210,390	$315,726	($105,336)	0.67
Participant	$181,757	$19,127	$162,630	9.50
Commercial Lighting - New Construction				
Societal	$197,215	$31,925	$165,290	6.18
Utility Cost	$130,913	$11,796	$119,117	11.10
Ratepayer Impact Measure	$316,578	$392,983	($76,405)	0.81
Participant	$207,318	$26,734	$180,584	7.75
Commercial Lighting - Retrofit				
Societal	$273,788	$52,567	$221,221	5.21
Utility Cost	$181,903	$19,423	$162,480	9.37
Ratepayer Impact Measure	$436,740	$541,706	($104,966)	0.81
Participant	$286,869	$44,020	$242,849	6.52
Commercial Administrative Costs				
Societal	$0	$53,757	($53,757)	0.00
Utility Cost	$0	$44,769	($44,769)	0.00
Ratepayer Impact Measure	$0	$44,769	($44,769)	0.00
Participant	$0	$0	$0	#DIV/0!
Total Commercial/ Industrial/Agricultural				
Societal	$971,601	$242,494	$729,107	4.01
Utility Cost	$635,932	$114,505	$521,427	5.55
Ratepayer Impact Measure	$1,550,583	$2,034,457	($483,874)	0.76
Participant	$1,075,039	$158,049	$916,990	6.80

Discounted to 2015

Benefit/Cost Results -1.25% Scenario

Test Perspective	2015 Thousand Dollars			B/C Ratio
	Benefits	Costs	Net Benefits	
Income Eligible				
Societal	$41,066	$20,922	$20,144	1.96
Utility Cost	$27,110	$17,623	$9,487	1.54
Ratepayer Impact Measure	$69,815	$122,104	($52,289)	0.57
Participant	$106,880	$18,795	$88,085	5.69

Discounted to 2015

Benefit/Cost Results -1.25% Scenario

Test Perspective	2015 Thousand Dollars			B/C Ratio
	Benefits	Costs	Net Benefits	
Residential Appliances				
Societal	$47,775	$19,494	$28,281	2.45
Utility Cost	$32,125	$7,203	$24,922	4.46
Ratepayer Impact Measure	$83,950	$138,243	($54,293)	0.61
Participant	$119,217	$19,494	$99,723	6.12
Residential A/C & ASHP Tune-up				
Societal	$851	$2,533	($1,682)	0.34
Utility Cost	$684	$936	($252)	0.73
Ratepayer Impact Measure	$1,347	$2,183	($836)	0.62
Participant	$1,834	$2,533	($699)	0.72
Residential Air Source Heat Pump				
Societal	$118,434	$27,691	$90,743	4.28
Utility Cost	$73,826	$10,232	$63,594	7.22
Ratepayer Impact Measure	$211,757	$356,098	($144,341)	0.59
Participant	$320,549	$27,691	$292,858	11.58
Residential Behavorial				
Societal	$2,119	$1,674	$445	1.27
Utility Cost	$1,649	$618	$1,031	2.67
Ratepayer Impact Measure	$4,948	$9,573	($4,625)	0.52
Participant	$7,537	$1,674	$5,863	4.50
Residential Cooling				
Societal	$86,864	$47,852	$39,012	1.82
Utility Cost	$57,279	$17,681	$39,598	3.24
Ratepayer Impact Measure	$109,662	$116,335	($6,673)	0.94
Participant	$89,794	$47,852	$41,942	1.88
Residential ECM Motors				
Societal	$33,130	$15,023	$18,107	2.21
Utility Cost	$21,741	$5,551	$16,190	3.92
Ratepayer Impact Measure	$56,427	$92,225	($35,798)	0.61
Participant	$81,006	$15,023	$65,983	5.39
Residential Ground Source Heat Pump				
Societal	$237,374	$48,380	$188,994	4.91
Utility Cost	$147,147	$17,876	$129,271	8.23
Ratepayer Impact Measure	$372,414	$560,365	($187,951)	0.66
Participant	$503,060	$48,380	$454,680	10.40
Residential Home Energy Savings				
Societal	$13,482	$9,449	$4,033	1.43
Utility Cost	$9,014	$3,491	$5,523	2.58
Ratepayer Impact Measure	$20,601	$29,942	($9,341)	0.69
Participant	$25,443	$9,449	$15,994	2.69
Residential Hot Water Savings				
Societal	$14,617	$763	$13,854	19.16
Utility Cost	$10,247	$282	$9,965	36.34
Ratepayer Impact Measure	$28,563	$43,351	($14,788)	0.66
Participant	$33,651	$763	$32,888	44.10
Residential Lighting				
Societal	$94,198	$13,201	$80,997	7.14
Utility Cost	$63,231	$4,878	$58,353	12.96
Ratepayer Impact Measure	$174,125	$275,251	($101,126)	0.63
Participant	$228,478	$13,201	$215,277	17.31
Residential Water Heaters				
Societal	$12,431	$11,970	$461	1.04
Utility Cost	$8,349	$4,423	$3,926	1.89
Ratepayer Impact Measure	$21,427	$29,548	($8,121)	0.73
Participant	$22,532	$11,970	$10,562	1.88
Residential Administrative Costs				
Societal	$0	$116,919	($116,919)	0.00
Utility Cost	$0	$97,371	($97,371)	0.00
Ratepayer Impact Measure	$0	$97,371	($97,371)	0.00
Participant	$0	$0	$0	#DIV/0!
Total Residential				
Societal	$661,275	$314,949	$346,326	2.10
Utility Cost	$425,292	$170,542	$254,750	2.49
Ratepayer Impact Measure	$1,085,221	$1,750,485	($665,264)	0.62
Participant	$1,433,101	$198,030	$1,235,071	7.24

Discounted to 2015

Benefit/Cost Results - 1.25% Scenario

Test Perspective	2015 Thousand Dollars			B/C Ratio
	Benefits	Costs	Net Benefits	
Total Plan				
Societal	$1,673,942	$578,365	$1,095,577	2.89
Utility Cost	$1,088,334	$302,670	$785,664	3.60
Ratepayer Impact Measure	$2,705,619	$3,907,046	($1,201,427)	0.69
Participant	$2,615,020	$374,874	$2,240,146	6.98

Appendix 5: Benefit/Cost Results by Program (No CO_2 Case)
Page 3 of 4

Benefit/Cost Results -1.5% Scenario

Test Perspective	2015 Thousand Dollars			
	Benefits	Costs	Net Benefits	B/C Ratio
Commercial Agricultural				
Societal	$12,361	$3,207	$9,154	3.85
Utility Cost	$8,173	$1,759	$6,414	4.65
Ratepayer Impact Measure	$22,939	$35,598	($12,659)	0.64
Participant	$20,831	$2,681	$18,150	7.77
Commercial Custom				
Societal	$234,501	$49,062	$185,439	4.78
Utility Cost	$153,913	$26,901	$127,012	5.72
Ratepayer Impact Measure	$387,616	$528,428	($140,812)	0.73
Participant	$294,724	$41,009	$253,715	7.19
Commercial Engineering & Design Assistance				
Societal	$39,827	$10,163	$29,664	3.92
Utility Cost	$24,844	$5,573	$19,271	4.46
Ratepayer Impact Measure	$58,857	$75,440	($16,583)	0.78
Participant	$41,427	$8,495	$32,932	4.88
Commercial Ground Source Heat Pump				
Societal	$79,192	$8,462	$70,730	9.36
Utility Cost	$49,665	$4,640	$45,025	10.70
Ratepayer Impact Measure	$113,108	$131,163	($18,055)	0.86
Participant	$67,719	$7,073	$60,646	9.57
Commercial HVAC				
Societal	$91,135	$26,312	$64,823	3.46
Utility Cost	$57,858	$14,427	$43,431	4.01
Ratepayer Impact Measure	$117,491	$128,340	($10,849)	0.92
Participant	$68,706	$21,993	$46,713	3.12
Commercial Motors & Drives				
Societal	$141,516	$27,274	$114,242	5.19
Utility Cost	$91,239	$14,954	$76,285	6.10
Ratepayer Impact Measure	$251,017	$381,439	($130,422)	0.66
Participant	$221,661	$22,797	$198,864	9.72
Commercial Lighting - New Construction				
Societal	$235,771	$38,122	$197,649	6.18
Utility Cost	$156,247	$20,903	$135,344	7.47
Ratepayer Impact Measure	$377,592	$475,436	($97,844)	0.79
Participant	$254,091	$31,864	$222,227	7.97
Commercial Lighting - Retrofit				
Societal	$327,284	$62,771	$264,513	5.21
Utility Cost	$217,084	$34,418	$182,666	6.31
Ratepayer Impact Measure	$520,786	$657,088	($136,302)	0.79
Participant	$353,386	$52,468	$300,918	6.74
Commercial Administrative Costs				
Societal	$0	$70,501	($70,501)	0.00
Utility Cost	$0	$58,631	($58,631)	0.00
Ratepayer Impact Measure	$0	$58,631	($58,631)	0.00
Participant	$0	$0	$0	#DIV/0!
Total Commercial/ Industrial/Agricultural				
Societal	$1,161,587	$295,874	$865,713	3.93
Utility Cost	$759,023	$182,206	$576,817	4.17
Ratepayer Impact Measure	$1,849,406	$2,471,563	($622,157)	0.75
Participant	$1,322,545	$188,380	$1,134,165	7.02

Discounted to 2015

Benefit/Cost Results - 1.5% Scenario

Test Perspective	2015 Thousand Dollars			
	Benefits	Costs	Net Benefits	B/C Ratio
Income Eligible				
Societal	$41,066	$20,922	$20,144	1.96
Utility Cost	$27,110	$17,623	$9,487	1.54
Ratepayer Impact Measure	$69,815	$122,104	($52,289)	0.57
Participant	$106,880	$18,795	$88,085	5.69

Discounted to 2015

Benefit/Cost Results -1.5% Scenario

Test Perspective	2015 Thousand Dollars			B/C Ratio
	Benefits	Costs	Net Benefits	
Residential Appliances				
Societal	$57,126	$23,277	$33,849	2.45
Utility Cost	$38,349	$12,763	$25,586	3.00
Ratepayer Impact Measure	$100,160	$169,056	($68,896)	0.59
Participant	$147,473	$23,277	$124,196	6.34
Residential A/C & ASHP Tune-up				
Societal	$1,021	$3,025	($2,004)	0.34
Utility Cost	$820	$1,658	($838)	0.49
Ratepayer Impact Measure	$1,610	$3,147	($1,537)	0.51
Participant	$2,845	$3,025	($180)	0.94
Residential Air Source Heat Pump				
Societal	$141,572	$33,066	$108,506	4.28
Utility Cost	$88,098	$18,131	$69,967	4.86
Ratepayer Impact Measure	$252,254	$430,281	($178,027)	0.59
Participant	$390,126	$33,066	$357,060	11.80
Residential Behavorial				
Societal	$2,532	$1,999	$533	1.27
Utility Cost	$1,967	$1,096	$871	1.79
Ratepayer Impact Measure	$5,903	$11,780	($5,877)	0.50
Participant	$9,440	$1,999	$7,441	4.72
Residential Cooling				
Societal	$103,839	$57,140	$46,699	1.82
Utility Cost	$68,365	$31,331	$37,034	2.18
Ratepayer Impact Measure	$130,840	$148,991	($18,151)	0.88
Participant	$119,642	$57,140	$62,502	2.09
Residential ECM Motors				
Societal	$39,615	$17,939	$21,676	2.21
Utility Cost	$25,954	$9,836	$16,118	2.64
Ratepayer Impact Measure	$67,322	$113,208	($45,886)	0.59
Participant	$100,661	$17,939	$82,722	5.61
Residential Ground Source Heat Pump				
Societal	$283,784	$57,770	$226,014	4.91
Utility Cost	$175,625	$31,676	$143,949	5.54
Ratepayer Impact Measure	$444,192	$678,585	($234,393)	0.65
Participant	$613,534	$57,770	$555,764	10.62
Residential Home Energy Savings				
Societal	$16,120	$11,282	$4,838	1.43
Utility Cost	$10,761	$6,186	$4,575	1.74
Ratepayer Impact Measure	$24,579	$37,732	($13,153)	0.65
Participant	$32,838	$11,282	$21,556	2.91
Residential Hot Water Savings				
Societal	$17,474	$911	$16,563	19.18
Utility Cost	$12,229	$499	$11,730	24.51
Ratepayer Impact Measure	$34,077	$51,875	($17,798)	0.66
Participant	$40,408	$911	$39,497	44.36
Residential Lighting				
Societal	$112,633	$15,763	$96,870	7.15
Utility Cost	$75,478	$8,643	$66,835	8.73
Ratepayer Impact Measure	$207,733	$331,112	($123,379)	0.63
Participant	$276,391	$15,763	$260,628	17.53
Residential Water Heaters				
Societal	$14,862	$14,293	$569	1.04
Utility Cost	$9,964	$7,837	$2,127	1.27
Ratepayer Impact Measure	$25,562	$37,803	($12,241)	0.68
Participant	$30,011	$14,293	$15,718	2.10
Residential Administrative Costs				
Societal	$0	$153,339	($153,339)	0.00
Utility Cost	$0	$127,521	($127,521)	0.00
Ratepayer Impact Measure	$0	$127,521	($127,521)	0.00
Participant	$0	$0	$0	#DIV/0!
Total Residential				
Societal	$790,578	$389,804	$400,774	2.03
Utility Cost	$507,610	$257,177	$250,433	1.97
Ratepayer Impact Measure	$1,294,232	$2,141,091	($846,859)	0.60
Participant	$1,763,369	$236,465	$1,526,904	7.46

Discounted to 2015

Benefit/Cost Results - 1.5% Scenario

Test Perspective	2015 Thousand Dollars			B/C Ratio
	Benefits	Costs	Net Benefits	
Total Plan				
Societal	$1,993,231	$706,600	$1,286,631	2.82
Utility Cost	$1,293,743	$457,006	$836,737	2.83
Ratepayer Impact Measure	$3,213,453	$4,734,758	($1,521,305)	0.68
Participant	$3,192,794	$443,640	$2,749,154	7.20

Appendix 5: Benefit/Cost Results by Program (No CO_2 Case)
Page 4 of 4

Benefit/Cost Results - 2.0% Scenario

Test Perspective	2015 Thousand Dollars			
	Benefits	Costs	Net Benefits	B/C Ratio
Commercial Agricultural				
Societal	$16,406	$4,250	$12,156	3.86
Utility Cost	$10,824	$3,449	$7,375	3.14
Ratepayer Impact Measure	$30,347	$48,208	($17,861)	0.63
Participant	$28,685	$3,544	$25,141	8.09
Commercial Custom				
Societal	$311,213	$65,011	$246,202	4.79
Utility Cost	$203,832	$52,767	$151,065	3.86
Ratepayer Impact Measure	$512,726	$716,007	($203,281)	0.72
Participant	$407,112	$54,214	$352,898	7.51
Commercial Engineering & Design Assistance				
Societal	$52,849	$13,467	$39,382	3.92
Utility Cost	$32,900	$10,931	$21,969	3.01
Ratepayer Impact Measure	$77,888	$103,357	($25,469)	0.75
Participant	$58,369	$11,231	$47,138	5.20
Commercial Ground Source Heat Pump				
Societal	$105,094	$11,212	$93,882	9.37
Utility Cost	$65,774	$9,101	$56,673	7.23
Ratepayer Impact Measure	$149,715	$176,502	($26,787)	0.85
Participant	$92,561	$9,350	$83,211	9.90
Commercial HVAC				
Societal	$120,935	$34,865	$86,070	3.47
Utility Cost	$76,623	$28,298	$48,325	2.71
Ratepayer Impact Measure	$155,522	$179,015	($23,493)	0.87
Participant	$100,115	$29,075	$71,040	3.44
Commercial Motors & Drives				
Societal	$187,881	$36,140	$151,741	5.20
Utility Cost	$120,875	$29,333	$91,542	4.12
Ratepayer Impact Measure	$332,271	$514,213	($181,942)	0.65
Participant	$302,818	$30,138	$272,680	10.05
Commercial Lighting - New Construction				
Societal	$312,860	$50,515	$262,345	6.19
Utility Cost	$206,899	$41,000	$165,899	5.05
Ratepayer Impact Measure	$499,523	$642,146	($142,623)	0.78
Participant	$349,522	$42,125	$307,397	8.30
Commercial Lighting - Retrofit				
Societal	$434,226	$83,177	$351,049	5.22
Utility Cost	$287,411	$67,511	$219,900	4.26
Ratepayer Impact Measure	$688,609	$890,722	($202,113)	0.77
Participant	$489,524	$69,363	$420,161	7.06
Commercial Administrative Costs				
Societal	$0	$100,051	($100,051)	0.00
Utility Cost	$0	$83,093	($83,093)	0.00
Ratepayer Impact Measure	$0	$83,093	($83,093)	0.00
Participant	$0	$0	$0	#DIV/0!
Total Commercial/ Industrial/Agricultural				
Societal	$1,541,464	$398,688	$1,142,776	3.87
Utility Cost	$1,005,138	$325,483	$679,655	3.09
Ratepayer Impact Measure	$2,446,601	$3,353,263	($906,662)	0.73
Participant	$1,828,706	$249,040	$1,579,666	7.34

Discounted to 2015

Benefit/Cost Results - 2.0% Scenario

Test Perspective	2015 Thousand Dollars			
	Benefits	Costs	Net Benefits	B/C Ratio
Income Eligible				
Societal	$41,066	$20,922	$20,144	1.96
Utility Cost	$27,110	$17,623	$9,487	1.54
Ratepayer Impact Measure	$69,815	$122,104	($52,289)	0.57
Participant	$106,880	$18,795	$88,085	5.69

Discounted to 2015

Benefit/Cost Results - 2.0% Scenario

Test Perspective	2015 Thousand Dollars			B/C Ratio
	Benefits	Costs	Net Benefits	
Residential Appliances				
Societal	$149,897	$65,092	$84,805	2.30
Utility Cost	$86,251	$43,534	$42,717	1.98
Ratepayer Impact Measure	$215,809	$371,486	($155,677)	0.58
Participant	$387,301	$65,092	$322,209	5.95
Residential A/C & ASHP Tune-up				
Societal	$1,360	$4,008	($2,648)	0.34
Utility Cost	$1,090	$3,253	($2,163)	0.34
Ratepayer Impact Measure	$2,137	$5,223	($3,086)	0.41
Participant	$5,050	$4,008	$1,042	1.26
Residential Air Source Heat Pump				
Societal	$187,720	$43,816	$143,904	4.28
Utility Cost	$116,557	$35,563	$80,994	3.28
Ratepayer Impact Measure	$332,433	$579,554	($247,121)	0.57
Participant	$531,255	$43,816	$487,439	12.12
Residential Behavorial				
Societal	$3,357	$2,648	$709	1.27
Utility Cost	$2,602	$2,150	$452	1.21
Ratepayer Impact Measure	$7,812	$16,292	($8,480)	0.48
Participant	$13,366	$2,648	$10,718	5.05
Residential Cooling				
Societal	$137,789	$75,716	$62,073	1.82
Utility Cost	$90,537	$61,455	$29,082	1.47
Ratepayer Impact Measure	$173,196	$217,127	($43,931)	0.80
Participant	$182,750	$75,716	$107,034	2.41
Residential ECM Motors				
Societal	$52,586	$23,771	$28,815	2.21
Utility Cost	$34,380	$19,293	$15,087	1.78
Ratepayer Impact Measure	$89,113	$156,061	($66,948)	0.57
Participant	$141,041	$23,771	$117,270	5.93
Residential Ground Source Heat Pump				
Societal	$376,571	$76,551	$300,020	4.92
Utility Cost	$232,560	$62,133	$170,427	3.74
Ratepayer Impact Measure	$587,588	$917,740	($330,152)	0.64
Participant	$837,931	$76,551	$761,380	10.95
Residential Home Energy Savings				
Societal	$21,397	$14,950	$6,447	1.43
Utility Cost	$14,254	$12,134	$2,120	1.17
Ratepayer Impact Measure	$32,536	$53,872	($21,336)	0.60
Participant	$48,303	$14,950	$33,353	3.23
Residential Hot Water Savings				
Societal	$23,187	$1,207	$21,980	19.21
Utility Cost	$16,191	$980	$15,211	16.52
Ratepayer Impact Measure	$45,105	$68,968	($23,863)	0.65
Participant	$53,975	$1,207	$52,768	44.72
Residential Lighting				
Societal	$149,502	$20,888	$128,614	7.16
Utility Cost	$99,970	$16,954	$83,016	5.90
Ratepayer Impact Measure	$274,947	$443,610	($168,663)	0.62
Participant	$373,158	$20,888	$352,270	17.86
Residential Water Heaters				
Societal	$19,722	$18,281	$1,441	1.08
Utility Cost	$13,195	$15,376	($2,181)	0.86
Ratepayer Impact Measure	$33,831	$55,022	($21,191)	0.61
Participant	$45,827	$18,281	$27,546	2.51
Residential Administrative Costs				
Societal	$0	$217,609	($217,609)	0.00
Utility Cost	$0	$180,726	($180,726)	0.00
Ratepayer Impact Measure	$0	$180,726	($180,726)	0.00
Participant	$0	$0	$0	#DIV/0!
Total Residential				
Societal	$1,123,088	$564,537	$558,551	1.99
Utility Cost	$707,587	$453,551	$254,036	1.56
Ratepayer Impact Measure	$1,794,507	$3,065,681	($1,271,174)	0.59
Participant	$2,619,957	$346,928	$2,273,029	7.55

Discounted to 2015

Benefit/Cost Results - 2.0% Scenario

Test Perspective	2015 Thousand Dollars			
	Benefits	Costs	Net Benefits	B/C Ratio
Total Plan				
Societal	$2,705,618	$984,147	$1,721,471	2.75
Utility Cost	$1,739,835	$796,657	$943,178	2.18
Ratepayer Impact Measure	$4,310,923	$6,541,048	($2,230,125)	0.66
Participant	$4,555,543	$614,763	$3,940,780	7.41

APPENDIX E: EPRI TOTAL RESOURCE COST TEST ANALYSIS

Great River Energy contracted the Electric Power Research Institute (EPRI) to conduct an energy efficiency potential evaluation among its residential and small commercial membership. The goal of this project was to produce GRE-specific estimates of energy efficiency savings by applying the approach used in the EPRI National Study. Results are based on commercially available technologies and costs using an equipment stock turnover model. Results are detailed and granular, by residential and small commercial end use. This overall approach makes the results more transparent than other studies that employ a macro “top-down” approach, which is highly sensitive to variations in a few key assumptions. The efficiency potential evaluation looked at potential energy efficiency gains associated with existing and expected technologies in the timeframe from 2009 to 2030. This long term evaluation of energy efficiency potential included projected technology developments that would result in additional energy savings within the forecast period. Many of these technologies were identified as contributing cost-effective energy savings even while some of the technologies are not currently commercially viable. Several technologies that were not specifically included in GRE’s conservation portfolios were cited as passing the Total Resource Cost test. The technologies that were identified as passing the TRC within the GRE EPRI Energy Efficiency Study along with the current status in GRE’s energy efficiency and conservation program offerings are listed in the tables below.

Small Commercial Measures Passing the TRC

End Use	Winning Measure	Available Program	Program / Notes
Central AC	VRF heat pump, EER 18.0	Yes	Custom offering
	Duct testing and sealing	No	Trade ally network not developed, limited member demand
Chiller	EMS	Yes	Custom offering
	Variable air volume system	Yes	Commercial HVAC
Fans - Ventilation	Energy-efficient motors	Yes	Commercial Motors & Drives
	Variable speed control	Yes	Commercial Motors & Drives
Water Heater	CO2, heat pump, EF 4.0	No	Not commercially avaialble
Refrigeration	High-efficiency compressor	Yes	Commercial Refrigeration
	Floating head pressure control	Yes	Commercial Refrigeration
	Reach-in coolers and freezers	Yes	Commercial Refrigeration
Lighting, Screw-In	CFL, non-dimmable	Yes	Commercial Lighting
Lighting, Linear Fluorescent	Induction	Yes	Custom offering, with limited available - greater emphasis being placed on LED
Presonal Comuputers	ENERGY STAR	No	Limited member demand, energy savings and free-ridership concerns
Servers	ENERGY STAR	Yes	Custom, server virtualization
Monitors	ENERGY STAR	No	Limited member demand, energy savings and free-ridership concerns
Copiers Printers	ENERGY STAR	No	Limited member demand, energy savings and free-ridership concerns
Other Electronics	ENERGY STAR	No	Limited member demand, energy savings and free-ridership concerns

Rural Residential Measures Passing the TRC

End Use	Winning Measure	Available Program	Program / Notes
Primary Electric Heating	Heat pump, HSPF 7.7	Yes	Residential Air Source Heat Pump
	Duct Insulation	No	Trade ally network not developed, limited member demand
	Programmable Thermostat	No	Pilot programs underway with programmable communicating thermostats
	Storm doors	No	Allowable under low-income weatherization, energy savings concerns
	Foundation insulation, R4	Yes	New Home Construction
	ENERGY STAR windows	Yes	New Home Construction
	Heat pump maintenance	Yes	AC/ASHP Tune-Up
	Duct repair	No	Trade ally network not developed, limited member demand
	Infiltration control	No	Trade ally network not developed, limited member demand
Ground-Source Heat Pumps	Maximum efficiency	Yes	Residential Ground Source Heat Pump
Central AC	SEER 15 unit	Yes	Residential Central Air Conditioning
	Duct Insulation	No	Trade ally network not developed, limited member demand
	Programmable Thermostat	No	Pilot programs underway with programmable communicating thermostats
	Storm doors	No	Allowable under low-income weatherization, energy savings concerns
	External shades	No	
	Foundation insulation, R4	Yes	New Home Construction
	Reflective roof	No	Limited member demand & product availability
	ENERGY STAR windows	Yes	New Home Construction
	AC Maintenance	Yes	AC/ASHP Tune-Up
	Duct repair	No	Trade ally network not developed, limited member demand
	Infiltration control	No	Trade ally network not developed, limited member demand
	Dehumidifier	Yes	ENERGY STAR Appliances

Room AC	EER > 11.5	Yes	ENERGY STAR Appliances
Water Heating	Heat pump, EF 3.0	Yes	Water Heat
	Inverter-drive clothes washer	No	ENERGY STAR Appliances
	Faucet aerators	Yes	Hot Water Kits
	Pipe insulation	Yes	Hot Water Kits
	Low-flow showerhead	Yes	Hot Water Kits
Refrigerators	ENERGY STAR	Yes	ENERGY STAR Appliances
Lighting, Screw-In	LED	Yes	Residential Lighting
Lighitng, Linear Fluorescent	Super T8	Yes	Residential Lighting
Clothes Washers	Combination washer and dryer	No	ENERGY STAR Appliances
Dishwashers	Advanced technology	Yes	ENERGY STAR Appliances
Furnace Fans	Electronically-commutating motor	Yes	Residential ECM Motor
Other Uses	In-home energy feedback monitor	Yes	Behavioral feedback programs, OPOWER, mymeter & SmartHub

Metro Residential Measures Passing the TRC

End Use	Winning Measure	Available Program	Program / Notes
Primary Electric Heating	Duct Insulation	No	Trade ally network not developed, limited member demand
	Programmable Thermostat	No	Pilot programs underway with programmable communicating thermostats
	Storm doors	No	Allowable under low-income weatherization, energy savings concerns
	ENERGY STAR windows	Yes	New Home Construction
	Heat pump maintenance	Yes	AC/ASHP Tune-Up
	Duct repair	No	Trade ally network not developed, limited member demand
	Infiltration control	No	Trade ally network not developed, limited member demand
Ground-Source Heat Pumps	Maximum efficiency	Yes	Residential Ground Source Heat Pump
Central AC	SEER 14 unit	Yes	Residential Central Air Conditioning
	Duct Insulation	No	Trade ally network not developed, limited member demand
	Programmable Thermostat	No	Pilot programs underway with programmable communicating thermostats
	Storm doors	No	Allowable under low-income weatherization, energy savings concerns
	External shades	No	
	Foundation insulation, R4	Yes	New Home Construction
	Reflective roof	No	Limited member demand & product availability
	ENERGY STAR windows	Yes	New Home Construction
	AC Maintenance	Yes	AC/ASHP Tune-Up
	Duct repair	No	Trade ally network not developed, limited member demand
	Infiltration control	No	Trade ally network not developed, limited member demand
	Dehumidifier	Yes	ENERGY STAR Appliances

Room AC	EER > 11.5	Yes	ENERGY STAR Appliances
Water Heating	Heat pump, EF 3.0	Yes	Water Heat
	Inverter-drive clothes washer	No	ENERGY STAR Appliances
	Faucet aerators	Yes	Hot Water Kits
	Pipe insulation	Yes	Hot Water Kits
	Low-flow showerhead	Yes	Hot Water Kits
Refrigerators	ENERGY STAR	Yes	ENERGY STAR Appliances
Lighting, Screw-In	LED	Yes	Residential Lighting
Lighitng, Linear Fluorescent	Super T8	Yes	Residential Lighting
Clothes Washers	Combination washer and dryer	No	ENERGY STAR Appliances
Dishwashers	Advanced technology	Yes	ENERGY STAR Appliances
Other Uses	In-home energy feedback monitor	Yes	Behavioral feedback programs, OPOWER, mymeter & SmartHub

APPENDIX F: MODEL SENSITIVITIES MATRIX

Assumptions		Sensitivities	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
(S)tatues, (R)ules, and (O)rders				x	x	x	x					x		x		x																		x
MN Externalities (CO2 Costs listed below)	MN + 200 Miles (means all MN + G3),	0$	x	x				x		x		x		x		x			x		x				x					x	x	x	x	x
		Low			x																	x				x								
		Med				x			x		x		x		x		x	x		x			x				x		x					
		High					x																	x				x						
Carbon Regulatory Cost Estimates ($/ton CO2)	All Generation, Apply 2019+	$0	x	x				x		x		x		x		x			x		x				x					x	x	x	x	x
		Low			x																	x				x								
		Med				x			x		x		x		x		x	x		x			x				x		x					
		High					x																	x				x						
Demand & Energy		Low (0.64% lower growth)										x	x																					
		Med	x	x	x	x	x	x	x	x	x					x	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x
		High 2.67% higher growth												x	x														x					
New Resource Costs	Solar Gen.	- 30%								x	x																							
		EIA + CPI-U	x	x	x	x	x	x	x			x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
	Wind Gen.	- 30%																x																
		Expected LB Labs + CPI-U	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
	Gas Fired Gen.	Expected + CPI-U	x	x	x	x	x	x	x	x	x	x	x			x	x				x	x	x	x	x	x	x	x	x	x	x	x	x	x
		+ 25%												x	x			x																
	Hydro	200 MW 2020 ($0.05 Below)	x	x	x	x	x			x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	
		200 MW 2020 ($0.05 Above)						x	x																									
LMP Prices		Low - 20%										x	x																					
		Med	x	x	x	x	x	x	x	x	x					x	x	x	x	x										x	x	x	x	x
		High + 50%												x	x																			
Market Interaction		0 MW																			x	x	x	x	x	x	x	x	x					
		400 MW	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x														x
Coal Prices		Low -10 %										x	x																					
		Med	x	x	x	x	x	x	x	x	x					x	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x
		High + 25%												x	x														x					
Natural Gas Prices		Low - 20%										x	x																					
		Med	x	x	x	x	x	x	x	x	x					x	x	x	x	x	x	x	x	x	x	x	x	x		x	x	x	x	x
		High + 50%												x	x														x					
Planning Reserve		GRE Peak (15%) on ICAP																	x	x					x	x	x	x						
		MISO-Coin (7.3 %) on UCAP	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x			x	x	x	x					x	x	x	x	x	x
Diversity Factor		GRE Peak (0%)																	x	x					x	x	x	x						
		MISO-Coin (10%)	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x			x	x	x	x					x	x	x	x	x	x
RPS		Not Forced														x	x	x	x	x														
		25% by 2025	x	x	x	x	x	x	x	x	x	x	x	x	x						x	x	x	x	x	x	x	x		x	x	x	x	x
		40% by 2025																											x					
EE/Cons Forecast Additon		Cur	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x			x	x		x
		Med High																																
		High																											x	x			x	
Cust. Owned DG Forecast Addition		Cur	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x		x	x			x
		1.5% by 2020																											x			x	x	
PHEV Forecast Addition		Cur	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x		x		x		x
		5% by 2029																											x		x		x	
Retirements/Going Forward Costs ($)		Genoa 3		x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
		Stanton		x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
		Coal Creek		x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x

THIS PAGE INTENTIONALLY LEFT BLANK

APPENDIX G: ENERGY AND DEMAND FORECAST METHODOLOGY

Great River Energy

2014 Energy Requirement and Peak Demand Forecast Technical Summary

Docket No. ET2/RP-14-813

Submitted to the Minnesota Public Utilities Commission
November 1, 2014

Page Intentionally Left Blank

Table of Contents

Table of Figures

Table of Tables

Executive Summary

The following document is a technical summary of Great River Energy's (GRE) All Requirement member 15-year energy and demand requirement forecast. GRE is a twenty-eight member generation and transmission cooperative where twenty of the members are All Requirement (AR) members and eight of the members are Fixed members. The Fixed members have entered into a long term power purchase contract and purchase only a fixed amount of capacity and energy from GRE. For the remaining twenty members, GRE is responsible for almost all of their future energy and capacity requirements.

The GRE energy and demand requirement will be calculated by the summation of the following:

1. All Requirement Energy and Demand Forecast
2. Fixed member long-term power purchase contract demand and energy obligations
3. Transmission and DC Line Losses
4. Known Future Energy and Demand Additions and Subtractions
    a. A current load that will have a contract expire and GRE will not be renewing it.
    b. A future load that GRE is currently obligated to serve.

The All Requirement member energy and demand econometric forecasts were developed using metered data with historic load control embedded in the data. An assumption is made that our historic growth in load control programs will continue to be the same going forward along with how these load control programs are implemented.

Due to the geographic and economic diversity of GRE's membership, the twenty All Requirement members were broken down into 3 distinct forecast regions: Metro Region, Northern Region, Southern & Western Region. By breaking up the All Requirement members into three distinct regions, differences in regional weather, air conditioning saturations, space and water heating fuel types, and localized econometric variables were accounted for by region in the forecast process.

GRE's five-year (2015-2019) compounded annual growth rate (CAGR) energy requirement indicates a 0.48% increase in energy per year. It is important to note that this growth rate is significantly impacted by the Elk River Municipal contract expiring. The 10 and 20-year CAGR's show a 0.99% and 1.28% growth rate, respectively.

GRE's five-year (2015-2019) demand requirement compounded annual growth rate (CAGR) indicates a 0.15% increase in demand per year. It is important to note that his growth rate is significantly impacted by Elk River Municipal contract expiring. The 10 and 20-year CAGR's show a 0.72% and 1.02% growth rate, respectively.

Additional forecast sensitivities were developed to investigate increased levels of conservation and efficiency, customer owned distributed generation, and customer owned electric vehicles.

Year	50/50 All Requirement Member Forecast (=)	Elk River Municipal (-)	DC Line Losses (+)	Transmission Losses (+)	Allliant Load Southern Coops Forecasts (+)	Fixed Member Requriements (+)	Dakota Spirit Ag (+)	Current Trends*
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
2015	9,356,229	0	559,055	537,515	0	2,553,891	34,667	13,041,357
2016	9,439,215	0	560,637	541,894	0	2,561,282	41,600	13,144,629
2017	9,566,910	0	559,055	547,217	0	2,551,863	41,600	13,266,644
2018	9,728,411	0	559,055	554,422	0	2,550,478	41,600	13,433,966
2019	9,883,123	(288,298)	559,055	548,411	0	2,550,478	41,600	13,294,368
2020	10,056,657	(288,298)	560,637	556,220	0	2,550,478	41,600	13,477,294
2021	10,255,236	(288,298)	559,055	565,156	0	2,550,478	41,600	13,683,226
2022	10,402,439	(288,298)	559,055	571,780	0	2,550,478	41,600	13,837,053
2023	10,593,414	(288,298)	559,055	580,374	0	2,550,478	41,600	14,036,623
2024	10,792,093	(288,298)	560,637	589,314	0	2,550,478	41,600	14,245,825
2025	10,998,505	(288,298)	559,055	606,801	182,190	2,550,478	41,600	14,650,331
2026	11,217,028	(288,298)	559,055	616,635	182,190	2,550,478	41,600	14,878,688
2027	11,461,867	(288,298)	559,055	627,653	182,190	2,550,478	41,600	15,134,544
2028	11,671,973	(288,298)	560,637	637,107	182,190	2,550,478	41,600	15,355,688
2029	11,899,353	(288,298)	559,055	647,340	182,190	2,550,478	41,600	15,591,718
*Current Trends Forecast Components (All Forecasts Share these Components regardless of sensitivities)								
**Five-year CAGR is significantly impacted with the loss of Elk River Municipal in 2019.							5-Year CAGR**	**0.48%**
							10-Year CAGR	**0.99%**
							15-Year CAGR	**1.28%**

Demand Forecast

Year	50/50 All Requirement Member Forecast (=)	Elk River Municipal (-)	DC Line Losses (+)	Transmission Losses (+)	Allliant Load Southern Coops Forecasts (+)	Fixed Member Requriements (+)	Dakota Spirit Ag (+)	Current Trends* Coincident Summer Peak
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
2015	1,769	0	77	102	0	498	5	2,452
2016	1,782	0	77	103	0	498	5	2,466
2017	1,802	0	77	104	0	498	5	2,487
2018	1,828	0	77	105	0	498	5	2,514
2019	1,853	(70)	77	103	0	498	5	2,466
2020	1,880	(70)	77	104	0	498	5	2,495
2021	1,912	(70)	77	106	0	498	5	2,528
2022	1,935	(70)	77	107	0	498	5	2,552
2023	1,965	(70)	77	108	0	498	5	2,584
2024	1,996	(70)	77	109	0	498	5	2,617
2025	2,029	(70)	77	112	27	498	5	2,678
2026	2,063	(70)	77	114	27	498	5	2,714
2027	2,101	(70)	77	115	27	498	5	2,754
2028	2,134	(70)	77	117	27	498	5	2,788
2029	2,169	(70)	77	118	27	498	5	2,825
*Current Trends Forecast Components (All Forecasts Share these Components regardless of sensitivities)								
**Five-year CAGR is significantly impacted with the loss of Elk River Municipal in 2019.							5-Year CAGR**	**0.15%**
							10-Year CAGR	**0.72%**
							15-Year CAGR	**1.02%**

System Narrative

GRE System Description

Great River is a not-for-profit electric cooperative owned by 28 member distribution cooperatives. The distribution cooperatives are located from the outer-ring suburbs of the Twin Cities, north to the Arrowhead region of Minnesota and south to the farming communities in the southwest part of the state. Great River Energy's largest distribution cooperative serves more than 125,000 member-consumers, while the smallest serves approximately 2,400. Great River Energy is member-controlled and governed by a democratically elected board of directors who are electric cooperative members themselves.

Collectively, Great River Energy's member cooperatives serve approximately 645,000 member-consumers – or about 1.7 million people. Great River Energy owns and maintains a resource mix that includes 11 power plants and more than 4,500 miles of transmission lines, making it the second largest power supplier in Minnesota. Great River Energy owns more than 3,000 (MW) of generation capability that consists of a diverse mix of baseload and peaking power plants, including coal, refuse-derived, natural gas and fuel oil, as well as wind generation.

MN Climate

The climate of Minnesota is typical of a continental climate, with hot summers and cold winters. Minnesota's location in the Upper Midwest allows it to experience some of the widest variety of weather in United States, with each of the four seasons having its own distinct characteristics. The areas near Lake Superior in the Minnesota Arrowhead Region experience weather unique from the rest of the state. The moderating effect of Lake Superior keeps the surrounding area relatively cooler in the summer and relatively warmer in the winter, giving that region more of a maritime climate

Winter in Minnesota is characterized by cold (below freezing) temperatures. Snow is the main form of winter precipitation. Annual snowfall extremes have ranged from over 170 inches (432 cm) in the rugged Superior Highlands of the North Shore to as little as 10 inches (25 cm) in southern Minnesota. Temperatures as low as −60 °F (−51 °C) have occurred during Minnesota winters. Spring is a time of major transition in Minnesota. Snowstorms are common early in the spring, but by late-spring as temperatures begin to moderate the state can experience tornado outbreaks, a risk which diminishes but does not cease through the summer and into the autumn.

In summer, heat and humidity predominate in the south, while warm and less humid conditions are generally present in the north. These humid conditions help kick off thunderstorm activity 30–40 days per year. Summer high temperatures in Minnesota average in the mid-80s F (30 C) in the south to the upper-70s F (25 C) in the north, with temperatures as hot as 114 F (46 C) possible. The growing season in Minnesota varies from 90 days per year in the Iron Range to 160 days in southeast Minnesota. Tornadoes are possible in Minnesota from March through November, but the peak tornado month is June, followed by July, May, and August. The state averages 27 tornadoes per year. Minnesota is the driest state in the Midwest. Average annual precipitation across the state ranges from around 35 inches (890 mm) in the southeast to 20 inches (510 mm) in the northwest. Autumn weather in Minnesota is largely the reverse of spring weather. The jet stream—which tends to weaken in summer—begins to re-strengthen, leading to a quicker changing of weather patterns and an increased variability of temperatures. By late October and November these storm systems become strong enough to form major winter storms. Autumn and spring are the windiest times of the year in Minnesota.

MN Economy

Great River Energy serves a territory that until recently included some of the fastest growing counties in the Twin Cities metropolitan area. These areas have been significantly impacted by the "Great Recession" and the resulting national economic downturn. Previous high unemployment and foreclosure rates have reduced both residential and small commercial development in these areas. Recent state and national improvements in employment and real estate values have stabilized Great River Energy residential energy growth and we are seeing modest growth in accounts added.

To the south and west of the Twin Cities are agriculture areas primarily reliant on corn and soybeans. Some of these areas have been losing population with the decline in the number of people working on farms. One recent growth area in the southwest economy is the construction of ethanol plants. In the central part of the GRE service territory is also potato farming and related processing.

The GRE service territory in the northern part of Minnesota has many lakes and forests. The timber and tourism industries are substantial. Many people are retiring to lake homes in this region and this trend is expected to continue or accelerate.

Forecast Regions

Due to the geographic and economic diversity of GRE's membership, the twenty All Requirement members were broken down into 3 distinct forecast regions. By breaking up the All Requirement members into three distinct regions, differences in regional weather, air conditioning saturations, space and water heating fuel types, and localized econometric variables were accounted for by region in the forecast process.

Forecast Geographic Regions

Geographic regions were chosen based on both physical location and underlying economic influences.

The Northern forecast region is primarily made up of winter peaking distribution cooperatives and the local economy is primarily based on tourism, forestry and some agricultural activities. This area is defined by All Requirement member distribution cooperatives north of Interstate 94 and excludes the 7 metropolitan counties (Figure 1).

The Southern & Western forecast region is primarily made up of summer peaking distribution cooperatives. The economy if this area is heavily influenced agriculture and food processing. This region is the most rural of the three forecast regions and has the fewest number of customers. This area is defined by All Requirement member distribution cooperatives south of interstate 94 and excludes all 7 metropolitan counties (Figure 1).

The Metro forecast region is made up of 2 All requirement member distribution cooperatives and is in or directly influenced by the 7 metropolitan counties (Figure 1). This region is summer peaking. The greater Minneapolis-Saint Paul Metro area is home to 18 of Minnesota's 19 fortune 500 headquarters. This area has the second largest economy in the Midwest, behind only Chicago.

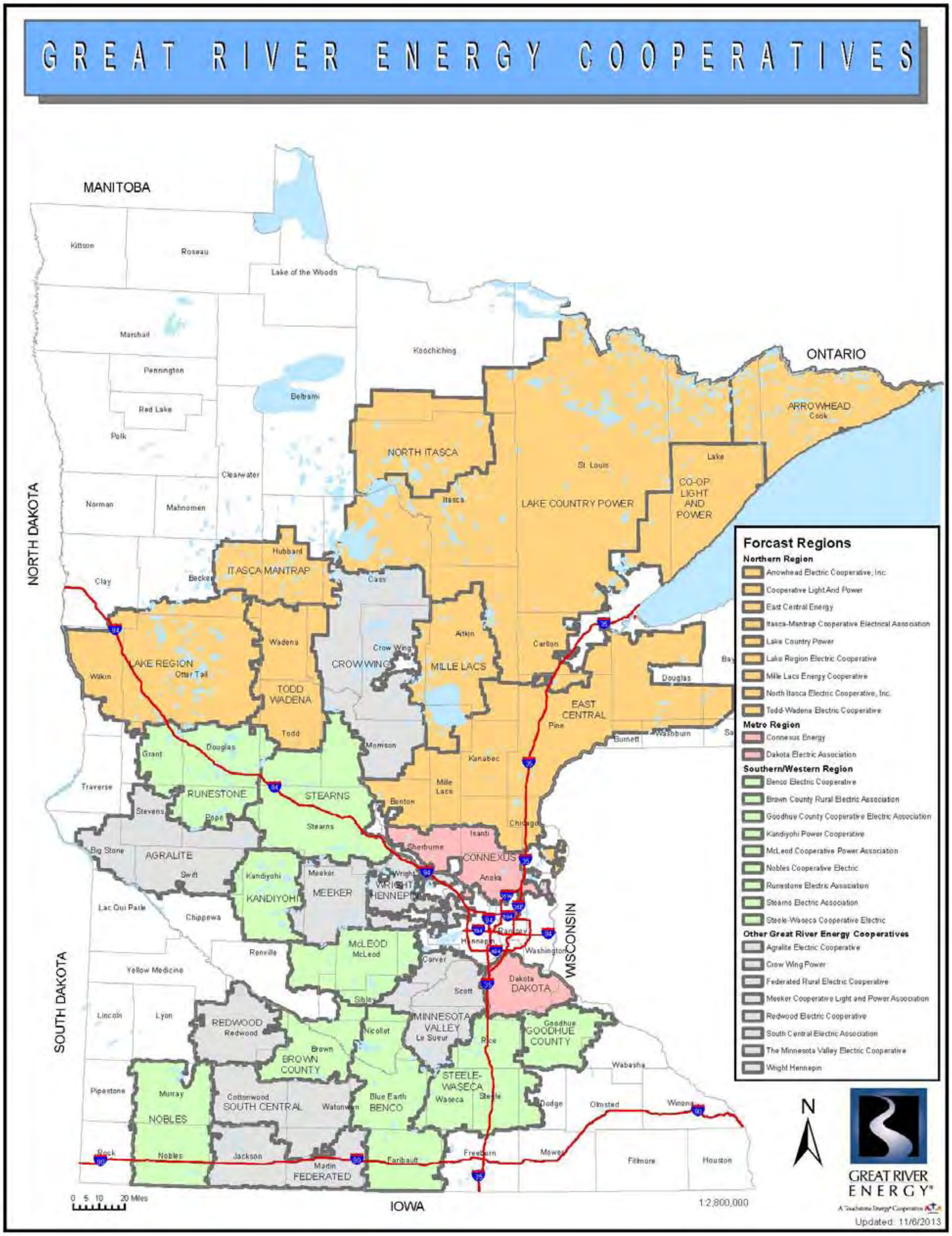
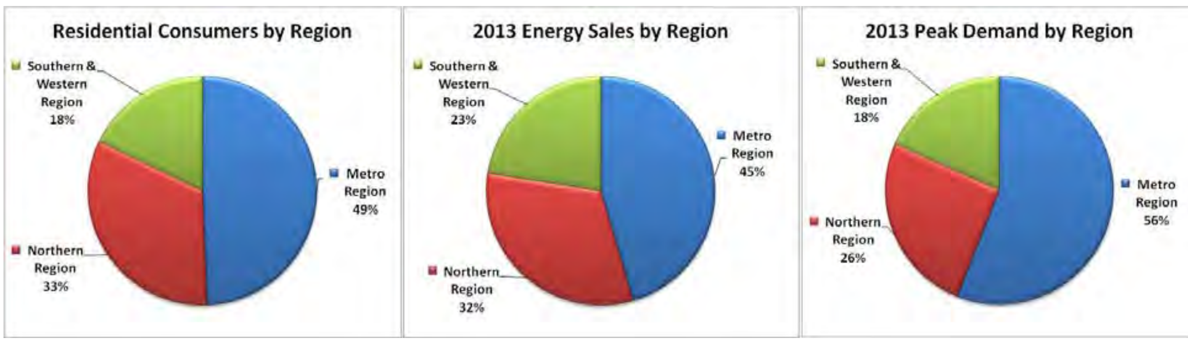


Figure 1. Great River Enregy 2014 Integrated Resource Plan forecast regions.

Forecast Region Customer, Energy Sales, and Peak Demand Characteristics

The Metro region is the largest region in terms of residential customers, annual energy sales, and contribution to GRE's coincident peak demand (Figure 2.). The Southern & Western region has least residential consumers, annual energy sales and contribution to GRE's coincident peak demand (Figure 2). Overall, the two member distribution cooperatives that make up the Metro region have the highest individual influence on energy sales, peak demand, and customers.

Figure 2. Forecast region's residential consumers, annual energy sales, and contribution to GRE's coincident peak demand.



Forecast Region fuel types and central air-conditioning saturation

Each forecast region has distinctly different trends in space heating fuel types. These space heating fuel types have a direct influence on each regions contribution to the GRE winter peak. In the Metro region, natural gas is the leading fuel type with over 80% saturation (Figure 3). In the Northern and Southern & Western region, propane is the dominant space heating fuel type with close to 40% saturation (Figure 3). The Southern & Western region shows higher concentrations of Natural gas than the Northern region and the Northern region shows higher concentrations of Electric space heat than the Southern & Western regions (Figure 3).

Natural gas is the leading water heating fuel type in the Metro region with almost 80% saturation (Figure 4). In both the Northern and Southern & Western regions, electricity is the dominant water heating fuel type, 70% and 60% respectively (Figure 4). Propane is the second leading fuel type in the Northern and Southern & Western regions, 20% and 22% respectively (Figure 4).

Central air conditioning saturation in the Metro region is highest with over 70% (Figure 5). It is important to note that Figure 5 represents central air conditioning only. If you were to include the other types of air condition equipment, i.e. window units, mini split ductless, the AC saturation is over 90% in single family homes in the Metro Region. The Southern & Western region has 60% saturation of central air conditioning units, and the Northern Region has 50% central AC saturation (Figure 5.).

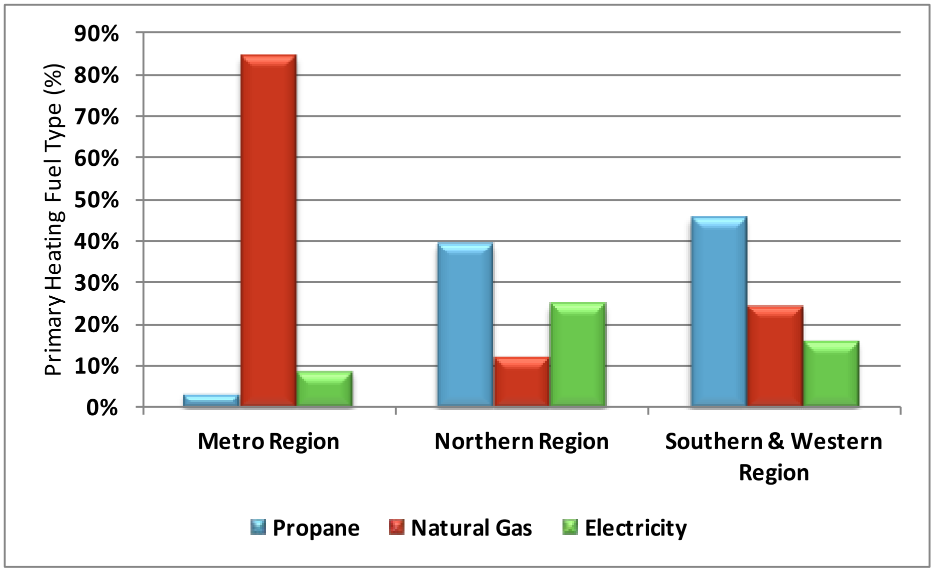


Figure 3. Primary space heating fuel types for the 3 forecast regions.

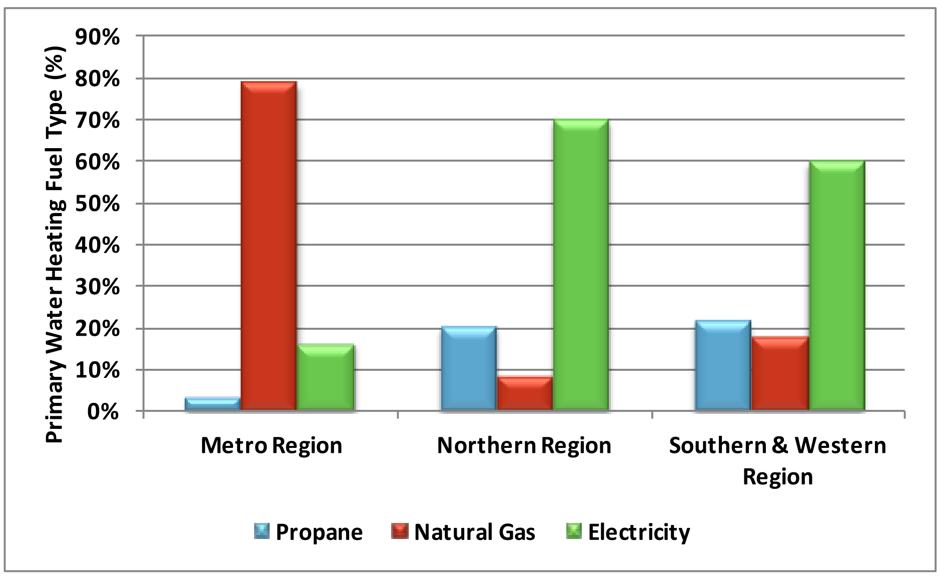


Figure 4. Primary water heating fuel types for the 3 forecast regions.

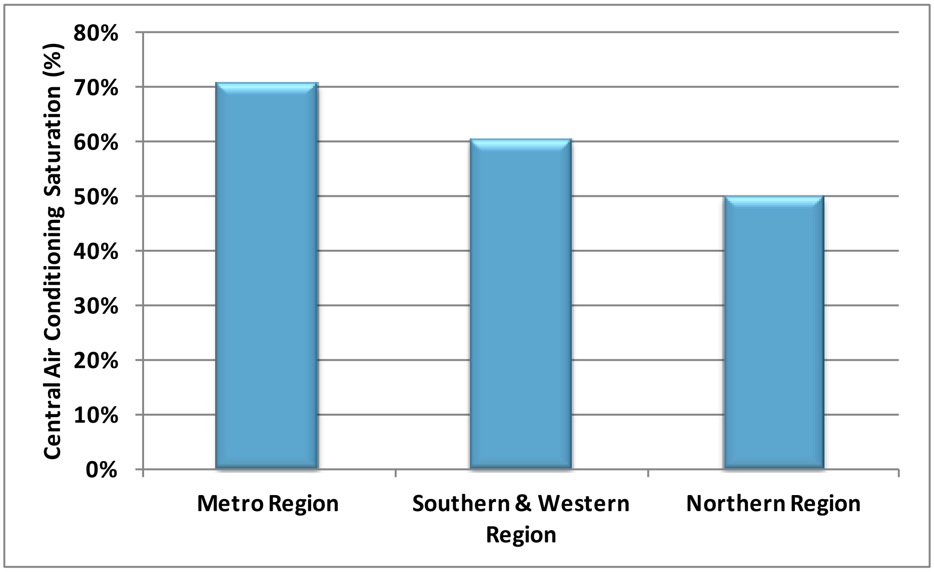


Figure 5. Central Air Conditioning Saturations for the 3 forecast regions.

Forecast Region Weather

Annual heating degree day (HDD) trends for the three forecast regions are representive of their geographic location. The Southern & Western region on average has the fewest HDDs, and as you move north, the HDDs increase (Figure 6). The Metro and Southern & Western regions have similar average HDDs; however, there is a dramatic increase in HDD for the Northern region (Figure 6). On average the Metro and Southern & Western regions have approximately 7,500 HDDs and the Northern Region has approximately 9,900 HDDs (Figure 6).

Annual cooling degree day (CDD) trends for the three forecast regions show the exact opposite relationship of HDD. As you move south to north across the regions, the CDDs decrease (Figure 7). Again, like the HDD trends, the CDD trend represents each of their geographic regions. The CDD in the Metro and Southern & Western regions have similar average CDDs; however, there is a significant decrease in CDDs for the Northern region (Figure 7). On average the Metro and Southern & Western region have 800 and 700 CDDs, respectively; however, CDDs decrease to an average of 200 for the Northern region (Figure 7).

Figure 6. Annual and average heating degree days for the three forecast regions.

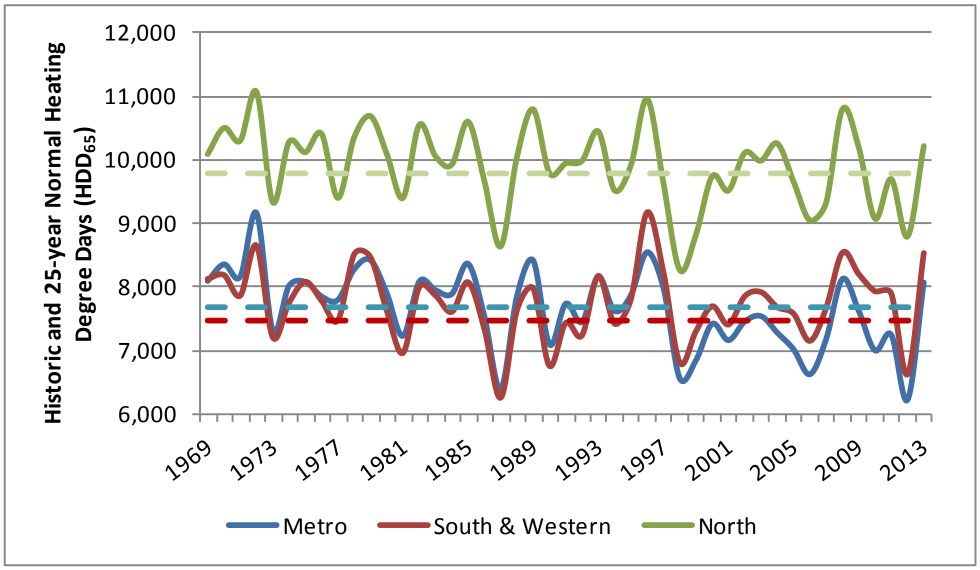
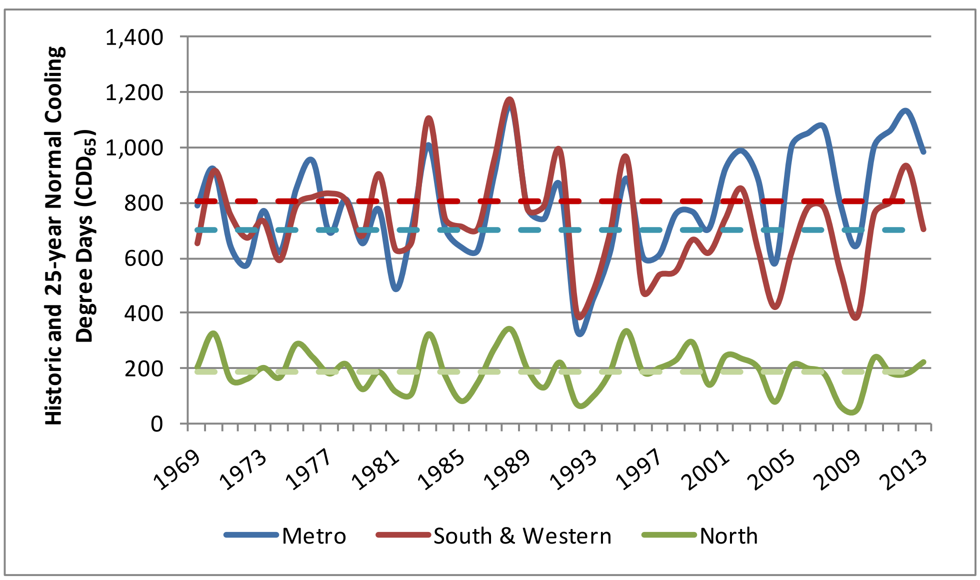


Figure 7. Annual and average cooling degree days for the three forecast regions.



Energy Regression Model Development

Description and Assumptions

Great River Energy (GRE) is a twenty-eight member distribution cooperative where twenty of the members are All Requirement (AR) members and eight of the members are Fixed members. The Fixed members have entered into a long term power purchase contract to purchase only a fixed amount of capacity and energy from GRE. For the remaining twenty members, GRE is responsible for almost all of their energy. *The following econometric forecasts are for the AR members only.* Each of the AR members were broken up into one of three forecast regions: Metro, Northern, and Southern & Western. To calculate the combined AR and Fixed energy obligation, the Fixed member energy amount will be added to the three aggregated regional forecasts.

Energy sales forecasts were developed using metered data with historic load control embedded in the data. An assumption is made that our historic load control program will remain consistent into the future, i.e. our historic growth in load control will continue to be the same going forward alone with how these load control programs are implemented. All energy forecast results reflect load control.

Independent Variables

Metro Region

Metro Employment

The Minneapolis-St. Paul area is the second largest economic center in the Midwest, behind Chicago. The economy of this area is based in commerce, finance, rail and trucking services, health care and industry. Five Fortune 500 companies make their headquarters in this area: Target, U.S. Bancorp, Xcel Energy, Ameriprise Financial, and Thrivent Financial for Lutherans. Like many metropolitan areas across the United States, employment was significantly impacted from the Great Recession of 2008 (Figure 8). However, as of recently, unemployment has deceased to pre Great Recession levels, 4.7% as of January 2014.

A scatterplot of Metro Region energy sales vs. Metro Region Employment shows a slight non-linear relationship (Figure 9.) A natural log transformation was used on the employment data to prior to fitting the model (Figure10.)

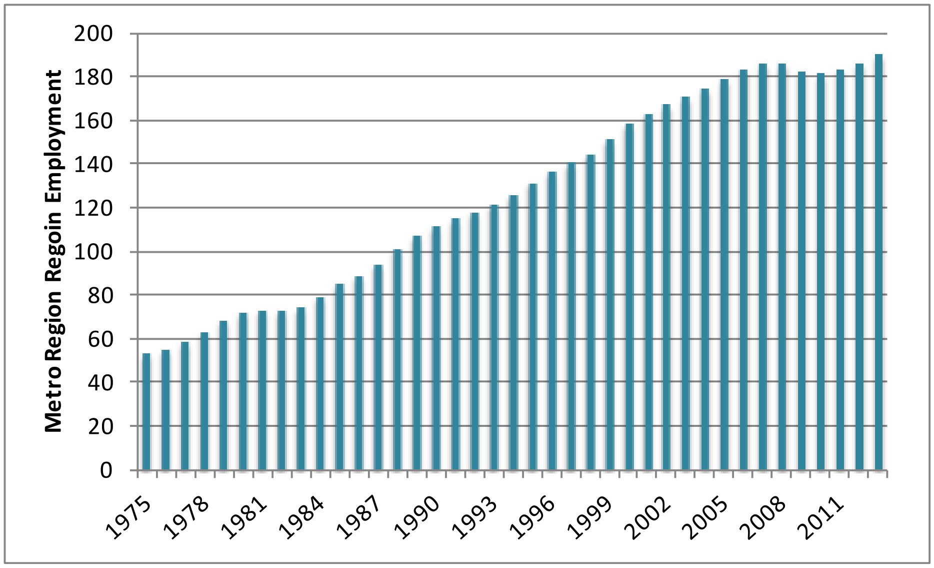


Figure 8. Historic Metro Region Employment (1000's of Jobs).

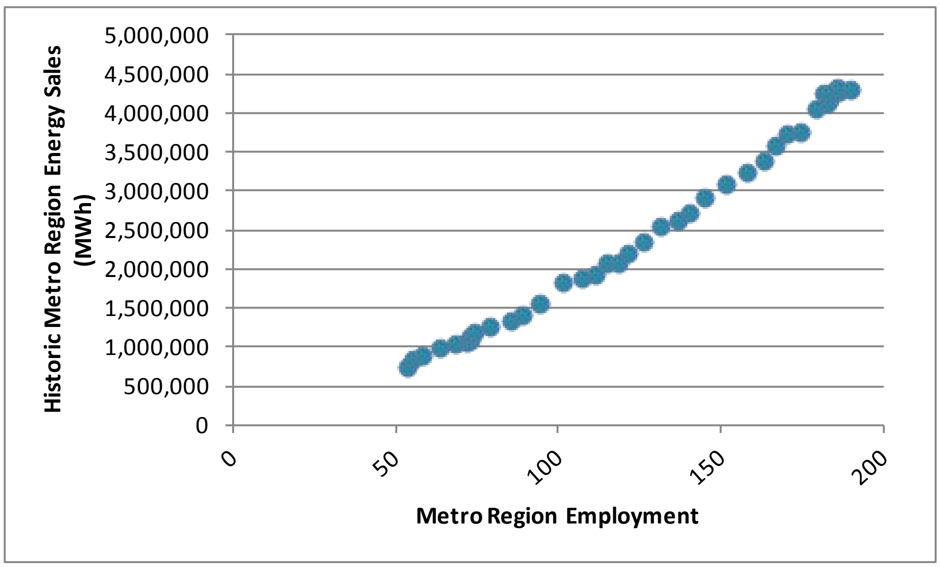


Figure 9. Scatterplot of Metro Region energy sales vs. Metro Region employment

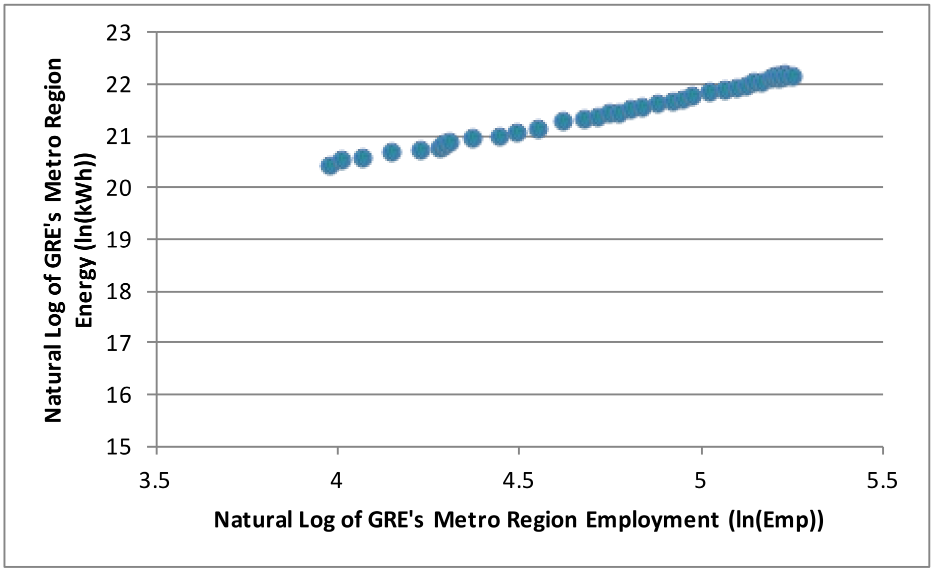


Figure 10. Scatterplot of natural log of Metro Region energy sales vs. natural log of Metro Region employment.

Residential Consumers

Residential consumers are a key driver for both energy and seasonal peak demand forecasts. Ninety-two percent of the Metro Region's end-use customers are responsible for 51% of the region's energy sales (Figure 11 and 12). The data source for residential customers and energy sales is the RDUP Form 7 Part O (a reporting form developed by the Rural Development Utilities Program).

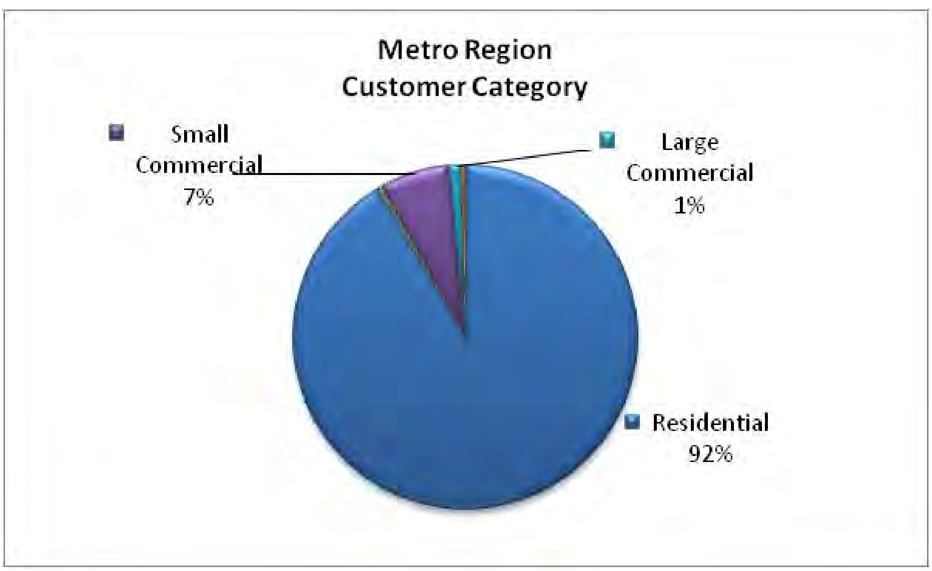


Figure 11. Metro Region customer breakdown.

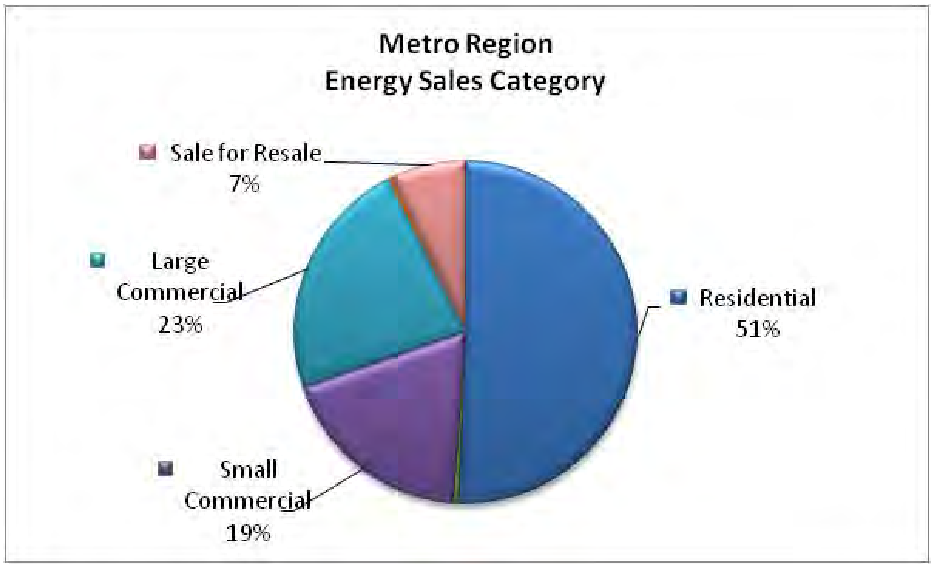


Figure 12. Metro region energy sales break down.

The Metro Region's residential consumer growth has been and continues to be significantly impacted by the economic downturn starting year-end 2007 (Figure 13). Residential consumer growth suddenly flattened starting year-end 2007 and continued to be relatively flat through 2012 (Figure 13). This change in residential account growth has had a strong impact on the Metro Region's annual energy sales.

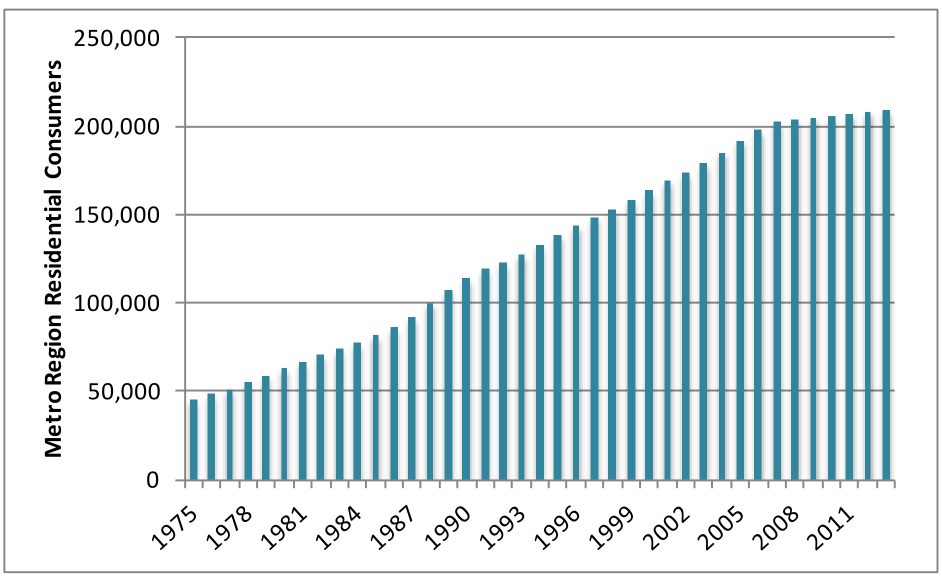


Figure 13. Historical Metro Region residential customers.

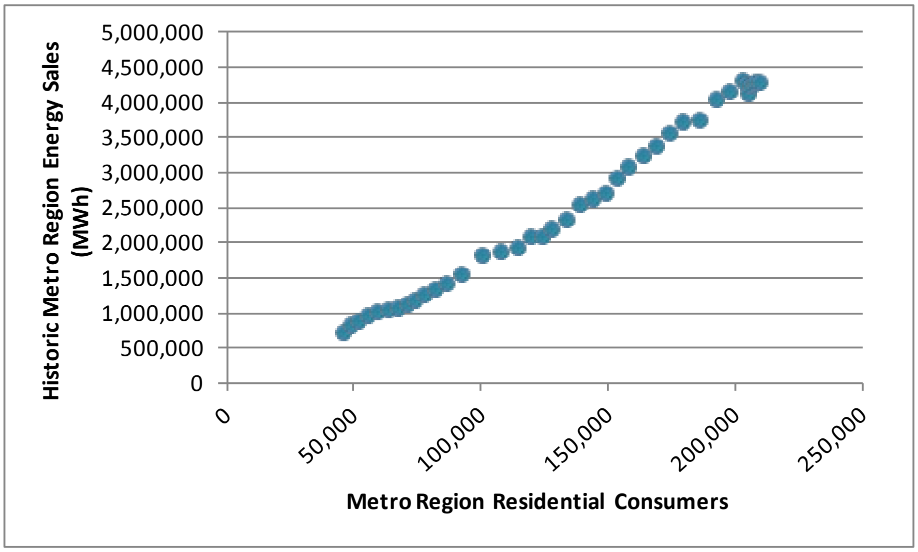


Figure 14. Scatterplot of annual Metro Region's energy sales and annual residential consumers.

There is a strong positive correlation between the Metro Region's energy sales and residential consumers (Figure 14.) As the number of residential consumers increase, so do the Metro Regions annual energy sales. This strong relationship allows residential consumers to be a key driver in an econometric energy sales forecast.

The number of residential consumers is expected to increase in the future, but at a pace well below the growth observed prior to the housing market crash. The number of GRE-Metro residential consumers is projected to increase at a rate of 1.3 percent over the next decade as the housing market recovers, with slightly stronger growth over the remainder of the forecast horizon. The long-term growth rate of roughly 1.5 percent is less than half of the pace observed during the 1990s and well below the 1980s growth rate, as shown in the table to the right.

The slower future growth rate reflects the fact that development in GRE's Metro region is in a somewhat mature phase of growth, and the long-term household growth forecasts from the MN State Demographer are lower than the household growth observed prior to 2006. The declining growth rate forecast is reflective of lower expectations for birth rates and in-migration in the future compared to the past several decades, along with baby boomers moving through the age cohorts. The combination of these factors suggests a resumption of growth at a more moderate pace than what was observed before 2006 (Figure 15). Details on the development of the GRE Metro Region residential consumer forecast can be found in Exhibit C.

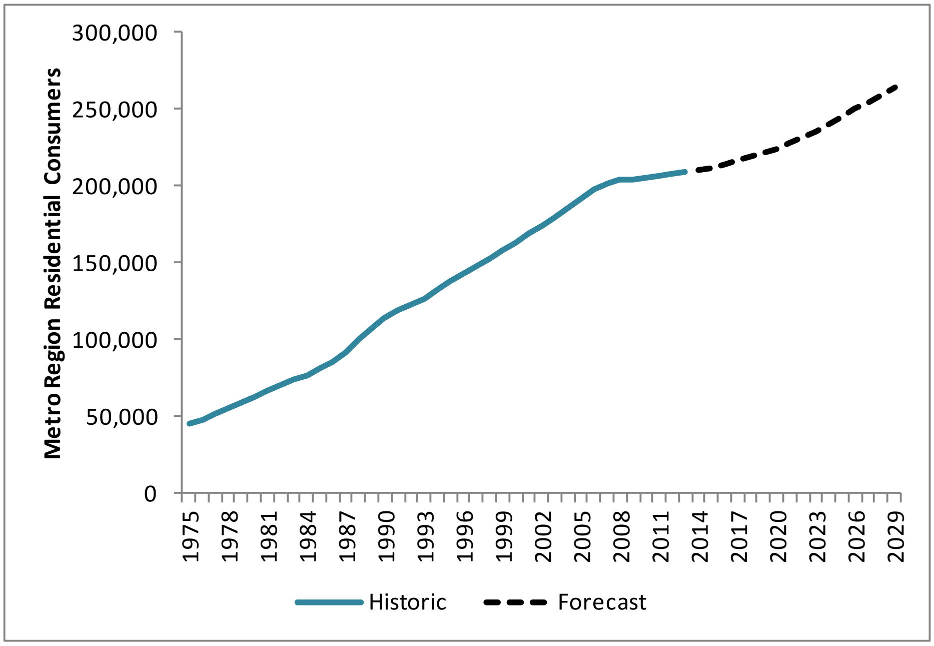


Figure 15. Metro Region Historic and forecast residential consumers.

Cooling Degree Days

The location for determining historic and normal heating degree days for the Metro Region is the MSP-St. Paul airport given the centrality of this location to the Metro Region. Figure 16 shows the annual CDD_{65} from 1975-2013 along with the calculated normal monthly CDD_{65}. The normal annual cooling degree days was calculated by taking mean CDD_{65}s from 1984 – 2013, 30-year normal (Figure 16).

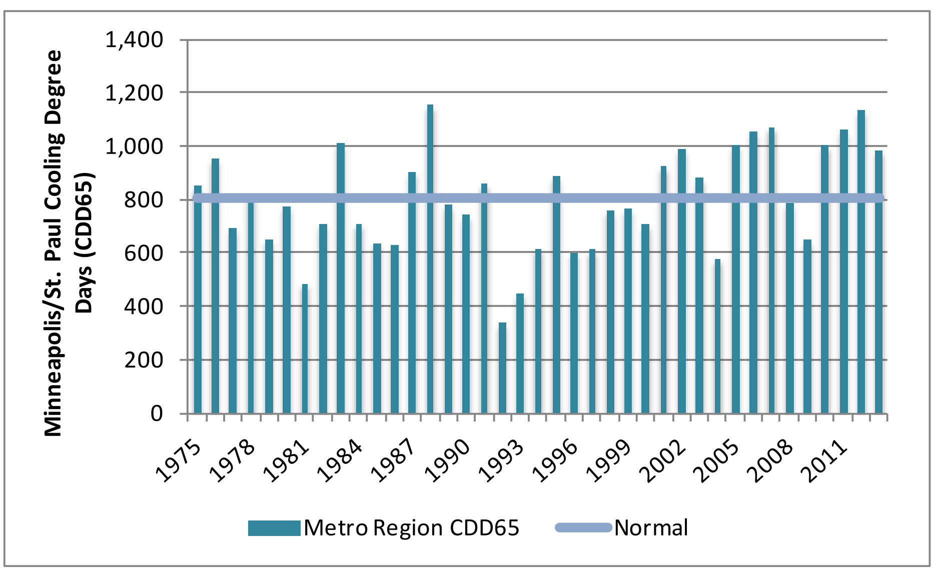


Figure 16. Metro Region historic and normal heating degree days (CDD_{65})

The scatterplot of the Metro Regions energy sales vs. CDD_{65} does show that as cooling degree days increase, annual energy sales increases (Figure 17). A natural log transformation was applied to CDD_{65} prior to fitting the model (Figure 18).

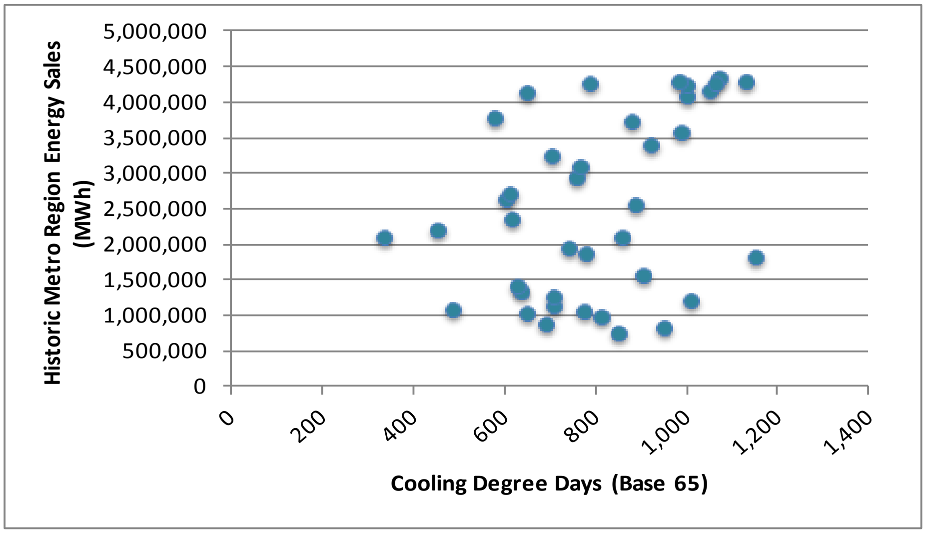


Figure 17. Scatterplot of Metro Region's energy sales and cooling degree days (CDD_{65}).

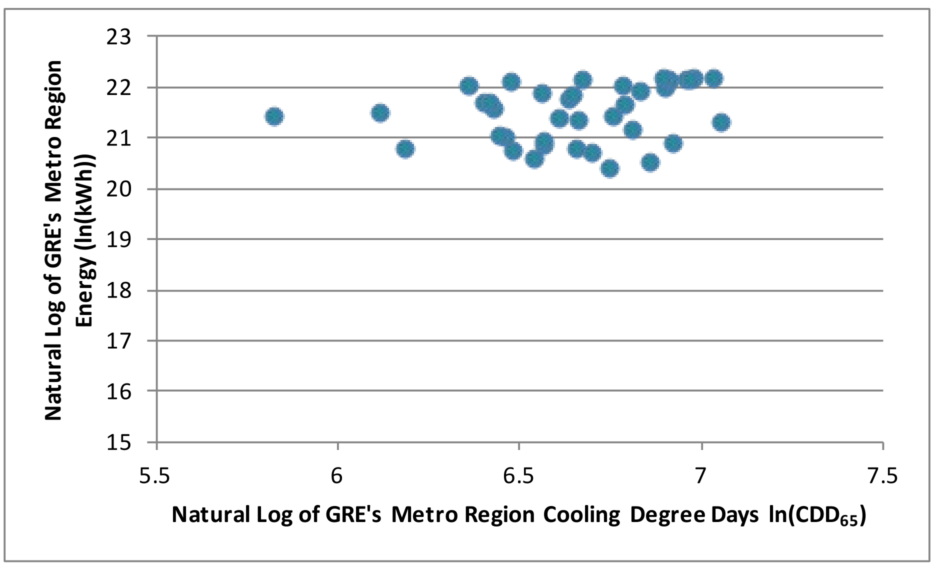


Figure 18. Scatterplot of Metro Region's energy sales vs. natural log of cooling degree days (CDD_{65})

GRE Whole Sale Energy Rate

Looking at GRE's Wholesale Energy rate shows two periods of sustained annual energy increased, 1977-1984 and 2007-Present, and one sustained period of rate decreases, 1985-2006 (Figure 19). With exception to the period from 1977-1984, the Metro Region's energy sales responded inversely to the wholesale rate. As rates steadily decreased from 1985-2006, energy sales steadily increased, however, as wholesale rates steadily increased through 2013, energy sales decreased (Figures 19 and 20). A natural log transformation was applied to GRE's historic whole sale energy rate prior to fitting the model (Figure 21).

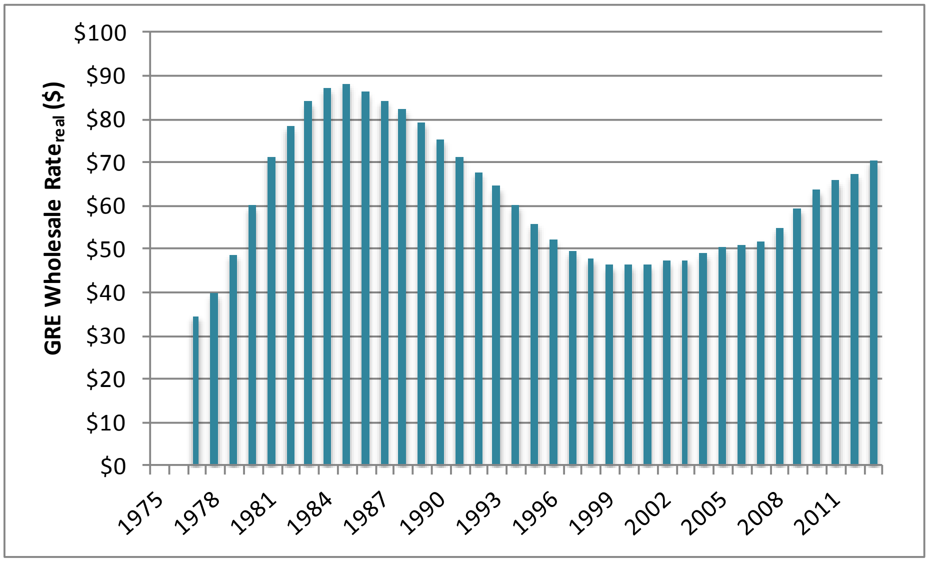


Figure 19. Historical GRE wholesale rates ($/MWH).

[Trade Secret Begins

Trade Secret Ends]

Figure 20. Scatterplot of Metro Region's energy sales and GRE's wholesale rate.

[Trade Secret Begins

Trade Secret Ends]

Figure 21. Scatterplot of Metro Region's natural log of energy sales and natural log of GRE's wholesale energy rate.

Northern Region

Heating Degree Days

The location for determining historic and normal heating degree days for the Northern Region is Hibbing, MN given the centrality of this location to the Northern Region. Figure 16 shows the annual HDD_{65} from 1975-2013 along with the calculated normal monthly HDD_{65}. The normal annual heating degree days was calculated by taking mean HDD_{65} from 1984 – 2013, 30-year normal (Figure 22).

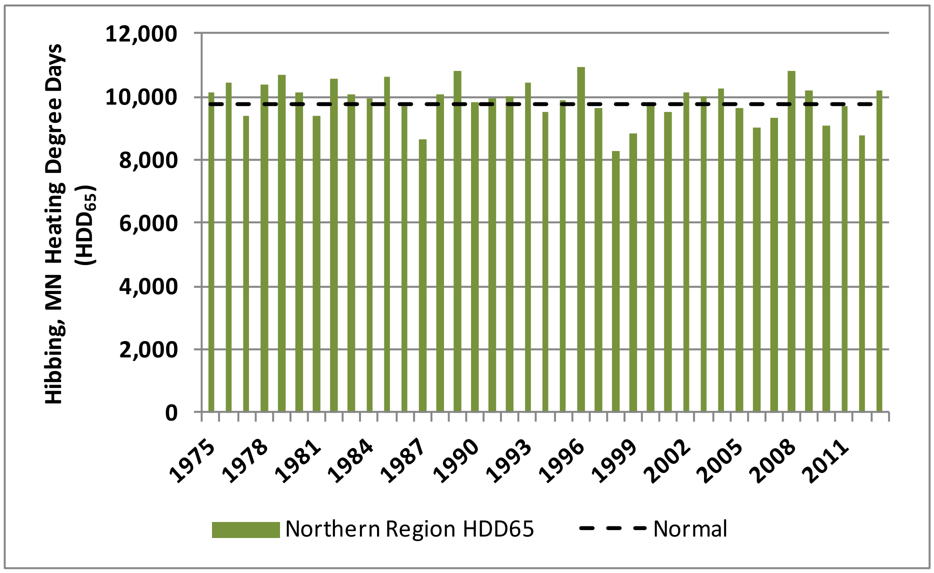


Figure 22. Northern Region historic and normal heating degree days (HDD_{65})

The scatterplot of the Northern Region's energy sales vs. HDD_{65} does show that as heating degree days increase, annual energy sales increases (Figure 23). A natural log transformation was applied to HDD_{65} prior to fitting the model (Figure 24).

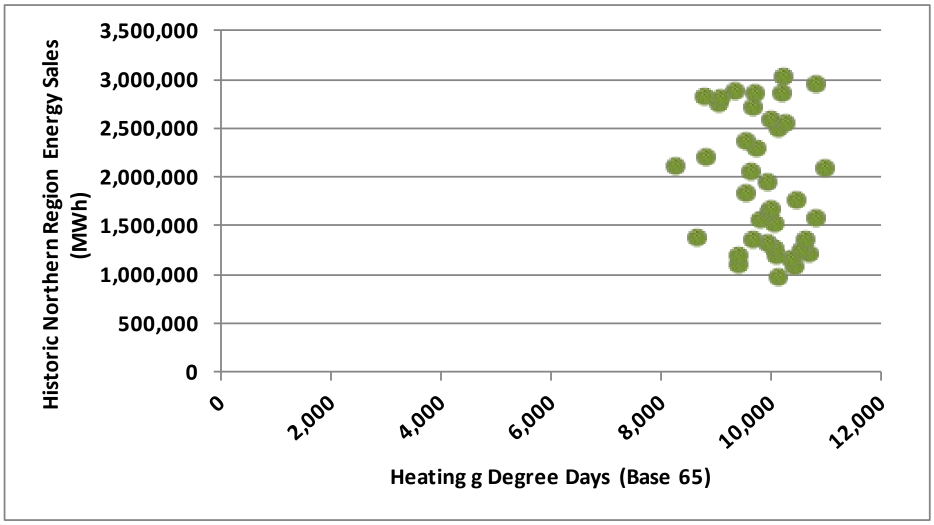


Figure 23. Scatterplot of Northern Region's energy sales and heating degree days (HDD_{65}).

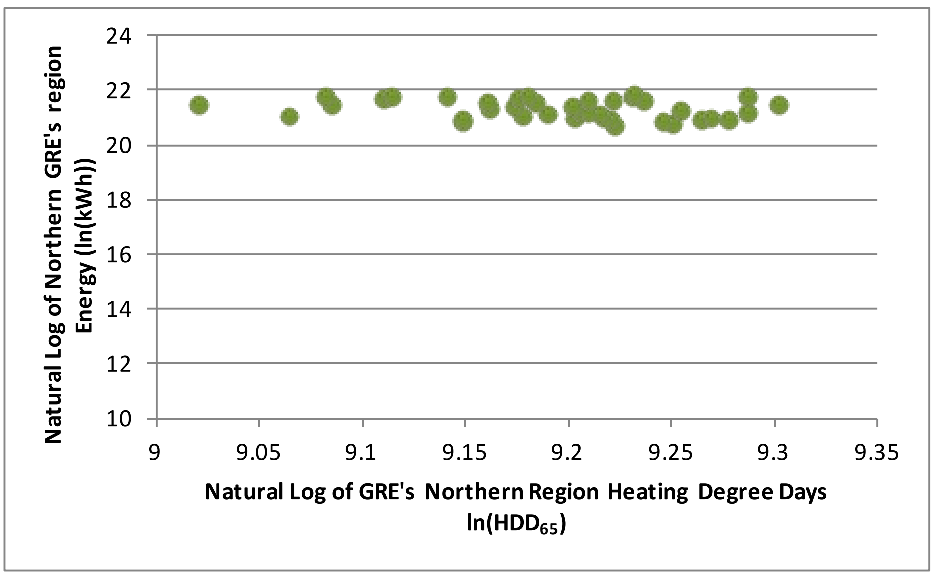


Figure 24. Scatterplot of natural log Northern Region's energy sales vs. natural log of heating degree days (HDD_{65})

Employment:Population Ratio

An employment-to-population ratio was calculated by dividing the total employment of the Northern Region by the total population of the northern region. This ratio was used to see if labor market conditions have an impact on energy sales. From the early 80's to 2008, the employment-to-population ration was increasing from around 0.40 to 0.58 (Figure 25). It is important to note that when compared to the employment-to-population ratio on a national level, the observed ratio is surprisingly low. The national employment-to-population ratio for this time frame was 0.68 to 0.71. Since 2008, the Northern Region employment-to-population rationhas slightly decreased and as of recently, started to increase slightly (Figure 25).

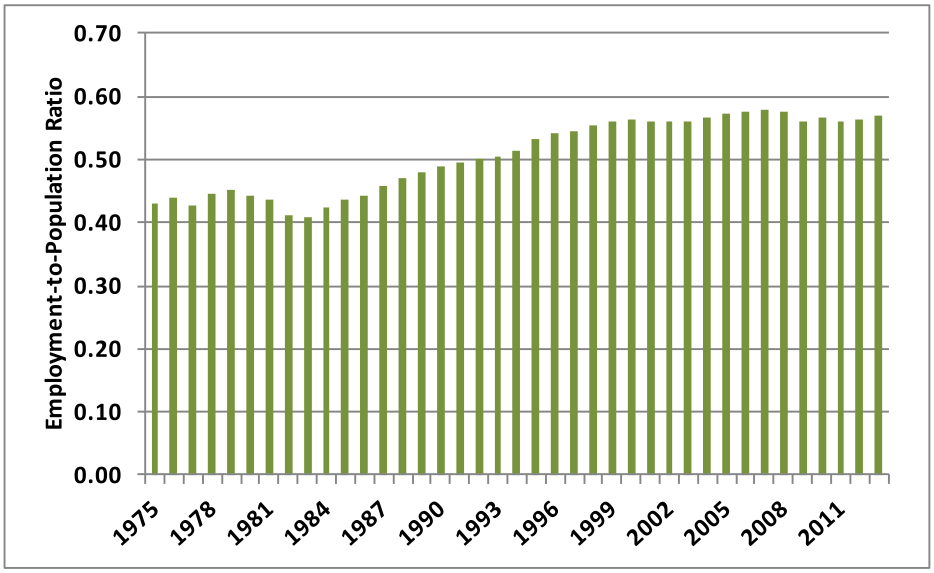


Figure 25. Northern Region's historic employment-to-population ratio.

The relationship between Northern Region Energy sales does show that as the employment-to-population ration increase, the annual energy sales increase (Figure 26). A natural log transformation was applied to employment-to-population ratio prior to fitting the model (Figure 27).

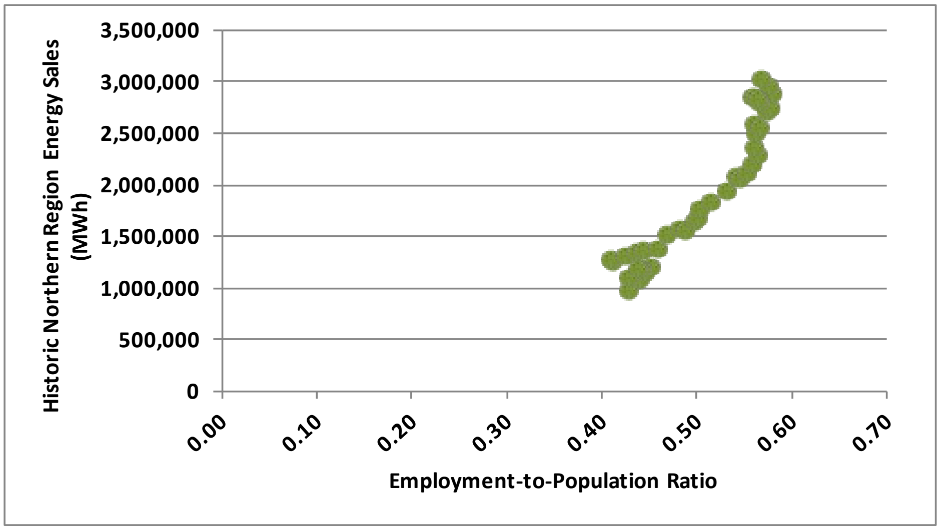


Figure 26. Scatterplot of Northern Region's energy sales and employment-to-population index.

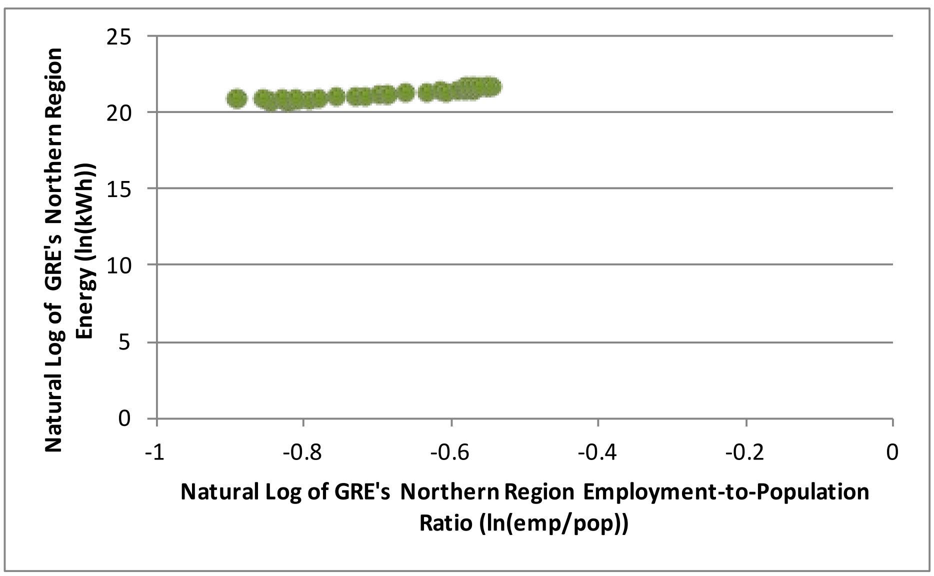


Figure 27. Natural log of Northern Region's energy sales and natural log of the region's employment-to-population ratio.

GRE Whole Sale Energy Rate

Looking at GRE's Wholesale Energy rate shows two periods of sustained annual energy increased, 1977-1984 and 2007-Present, and one sustained period of rate decreases, 1985-2006 (Figure 28). With exception to the period from 1977-1984, the Northern Region's energy sales responded inversely to the wholesale rate. As rates steadily decreased from 1985-2006, energy sales steadily increased, however, as wholesale rates steadily increased through 2013, energy sales decreased (Figures 28 and 29). A natural log transformation was applied to GRE's historic whole sale energy rate prior to fitting the model (Figure 30).

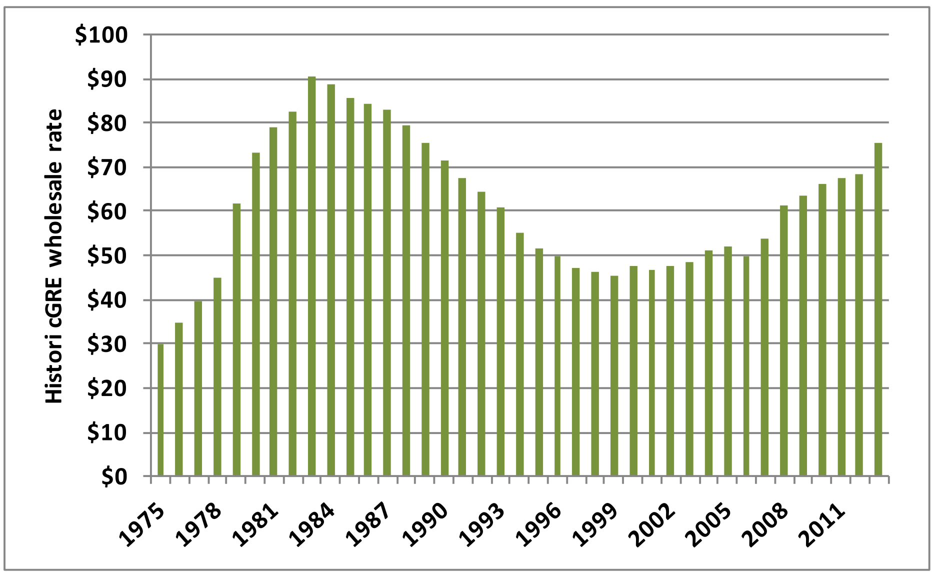


Figure 28. Historic GRE wholesale rates.

[Trade Secret Begins

Trade Secret Ends]

Figure 29. Scatterplot of Northern Region's energy sales and GRE's wholesale rate

[Trade Secret Begins

Trade Secret Ends]

Figure 30. Scatterplot of Northern Region's natural log of energy sales and natural log of GRE's wholesale energy rate.

Residential Consumers

Residential consumers are a key driver for both energy and seasonal peak demand forecasts. Seventy-six percent of the Northern Region's end-use customers are responsible for 60% of the region's energy sales (Figure 11 and 12). The data source for residential customers and energy sales is the RDUP Form 7 Part O (a reporting form developed by the Rural Development Utilities program).

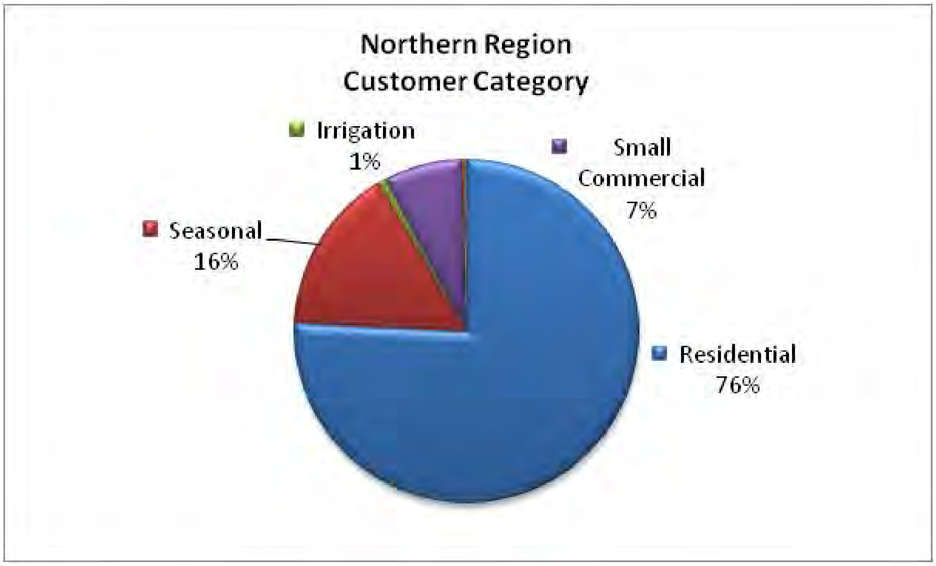


Figure 31. Northern Region customer class breakdown.

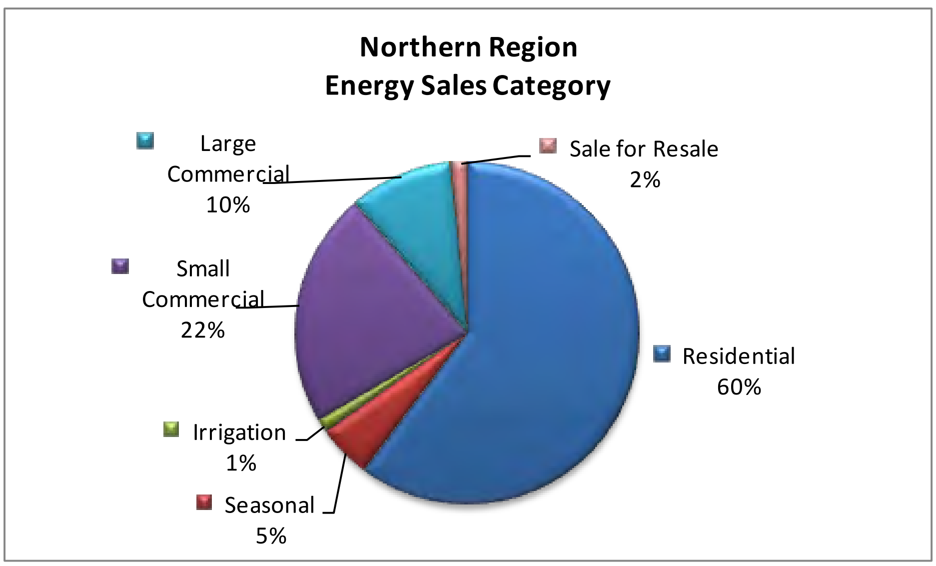


Figure 32. Northern region energy sales by customer class.

The Northern Region's residential consumer growth has been and continues to be significantly impacted by the economic downturn starting year-end 2007 (Figure 33). Residential consumer growth suddenly flattened starting year-end 2007 and continued to be relatively flat through 2012 (Figure 33). This change in residential account growth has had a strong impact on the Northern Region's annual energy sales.

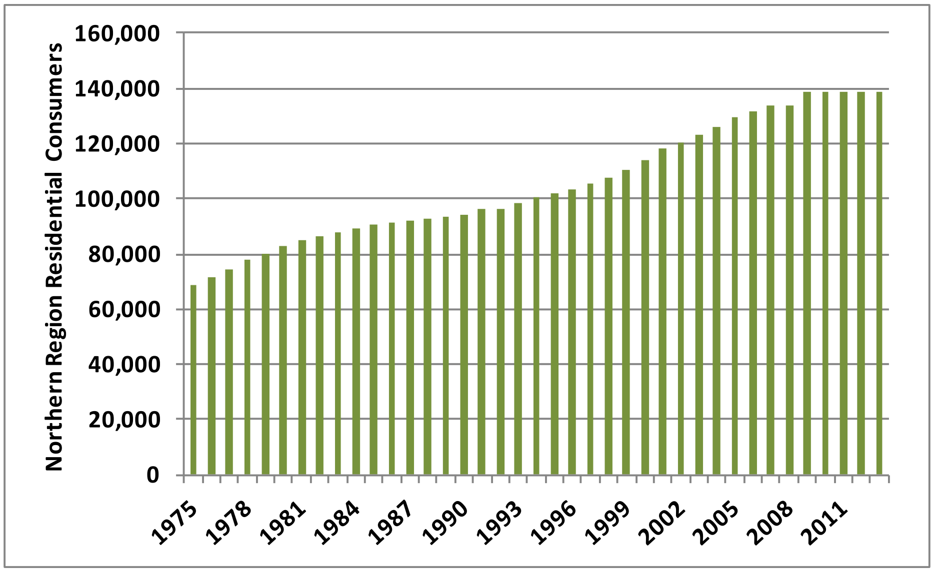


Figure 33. Historic residential consumers in the Northern Region.

There is a strong positive correlation between the Northern Region's energy sales and residential consumers (Figure 34.) As the number of residential consumers increases, so do the Northern Region's annual energy sales. This strong relationship allows residential consumers to be a key driver in an econometric energy sales forecast.

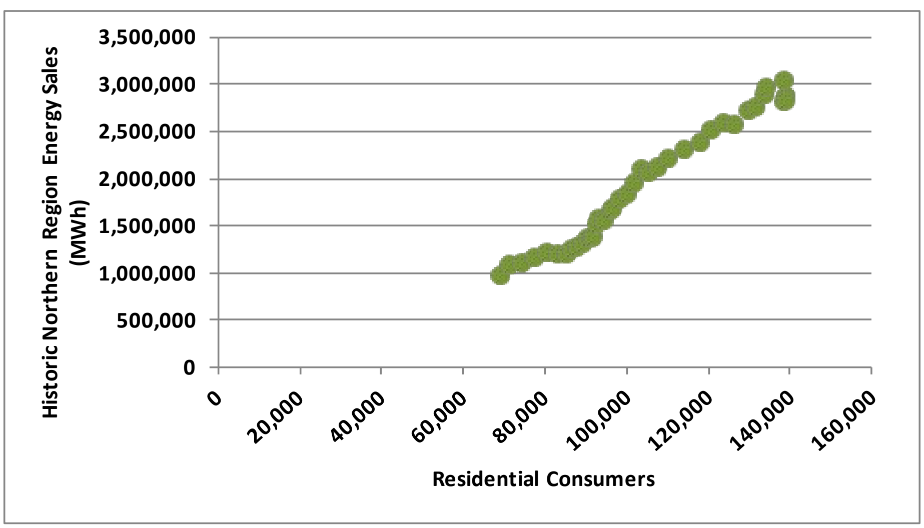


Figure 34. Scatterplot of Northern Region's energy sales vs. Northern Region's residential consumers.

The Northern Region's residential consumers were transformed by taking the natural log prior to being fit in the econometric model (Figure 35).

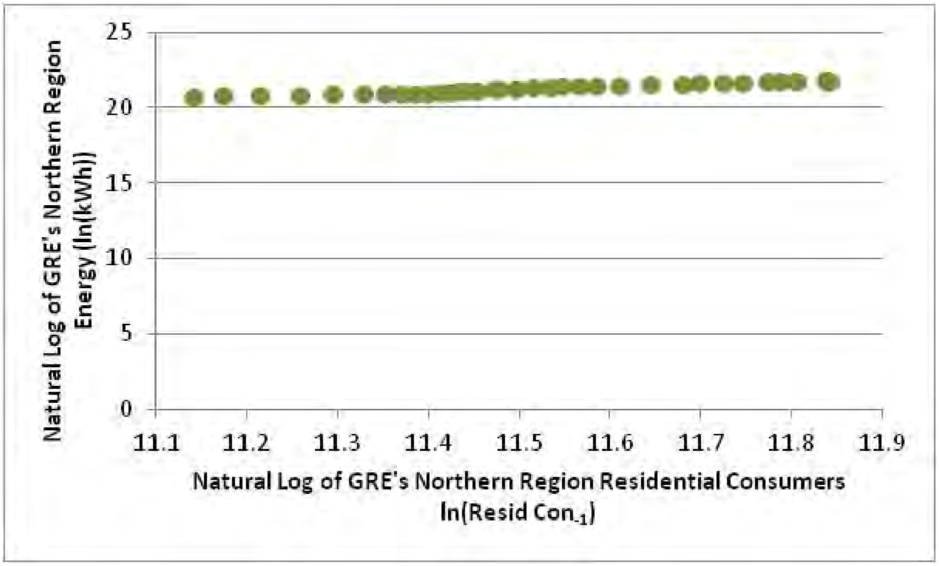


Figure 35. Scatterplot of natural log of Northern Region's energy sales vs. Northern Region's residential Consumers.

Southern & Western Region

Heating Degree Days

The location for determining historic and normal heating degree days for the Southern & Western Region is Owatonna, MN. Figure 36 shows the annual HDD_{65} from 1975-2013 along with the calculated normal monthly HDD_{65}. The normal annual heating degree days was calculated by taking mean HDD_{65} from 1984 – 2013, 30-year normal (Figure 36).

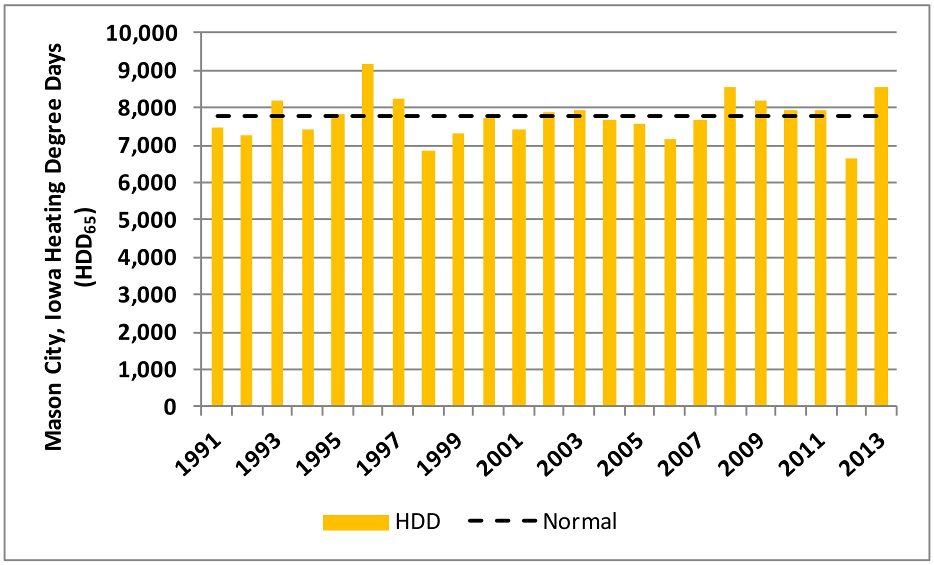


Figure 36. Southern & Western Region historic and normal heating degree days (HDD65)

The scatterplot of the Southern & Western Region's energy sales vs. HDD_{65} does show that as heating degree days increase, annual energy sales increases (Figure 37). A natural log transformation was applied to HDD_{65} prior to fitting the model (Figure 38).

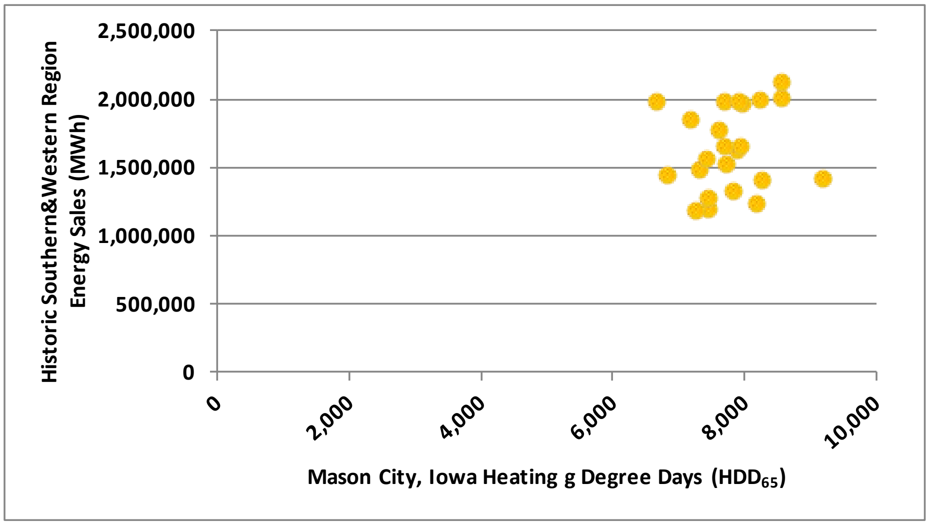


Figure 37. Scatterplot of natural log of Southern & Western region energy sales vs. heating degree days.

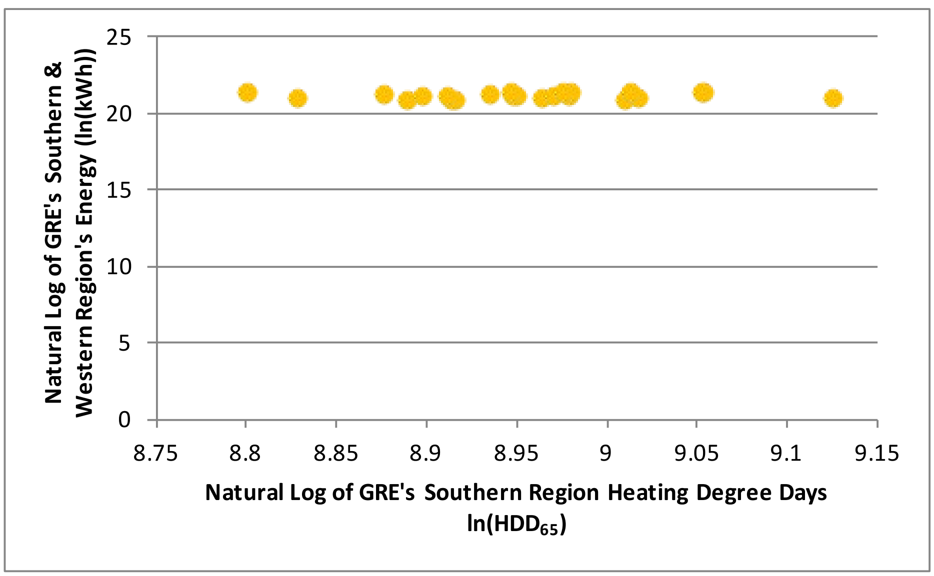


Figure 38. Scatterplot of natural log of Southern & Western Region's energy sales vs. natural log of heating degree days (HDD_{65})

Residential Consumers

Residential consumers are a key driver for both energy and seasonal peak demand forecasts. Eight-four percent of the Southern & Western Region's end-use customers are responsible for 64% of the region's energy sales (Figure 39 and 40). The data source for residential customers and energy sales is the RDUP Form 7 Part O (a reporting form developed by the Rural Development Utilities program).

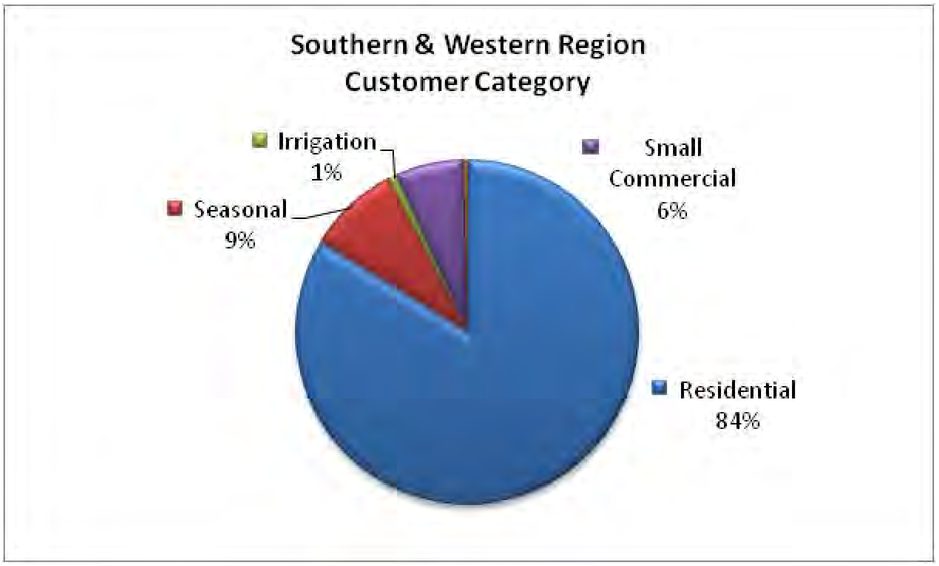


Figure 39. Southern & Western Region Customers by class.

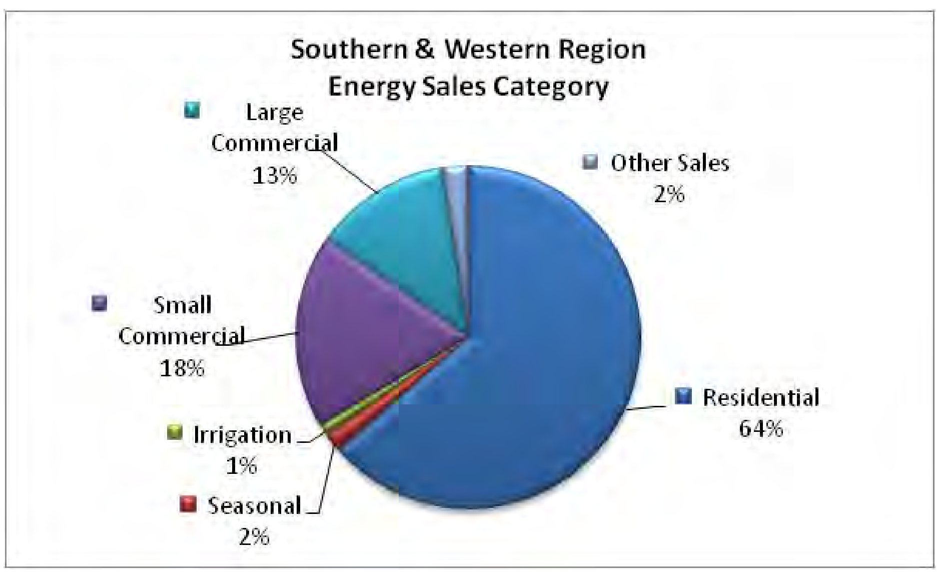


Figure 40. Southern & Western Region energy sales by customer class

The Southern & Western Region's residential consumer growth has been and continues to be significantly impacted by the economic downturn starting year-end 2007 (Figure 41). Residential consumer growth suddenly flattened starting year-end 2007 and continued to be relatively flat through 2013 (Figure 41). This change in residential account growth has had a strong impact on the Southern & Western Region's annual energy sales.

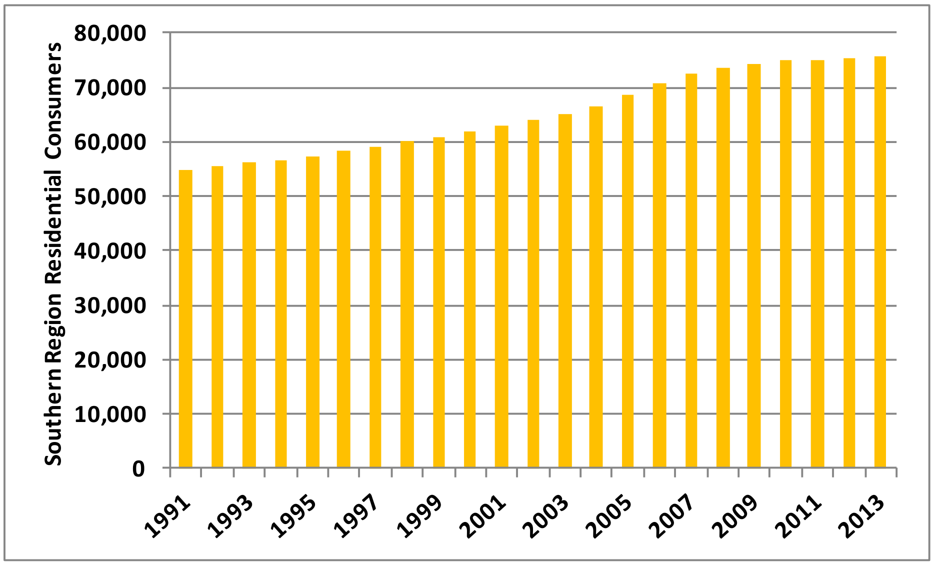


Figure 41. Historic residenital consumers in the Southern & Western region.

There is a strong positive correlation between the Southern & Western Region's energy sales and residential consumers (Figure41). As the number of residential consumers increase, so do the Southern & Western Region's annual energy sales. This strong relationship allows residential consumers to be a key driver in an econometric energy sales forecast.

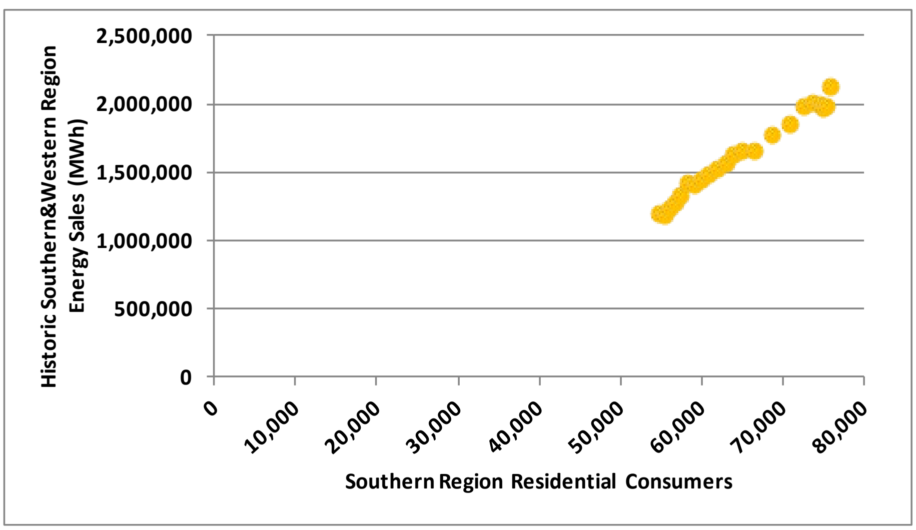


Figure 42. Scatterplot of Southern & Western region's energy sales vs. residential consumers.

The Southern & Western Region's residential consumers were transformed by taking the natural log prior to being fit in the econometric model (Figure 43).

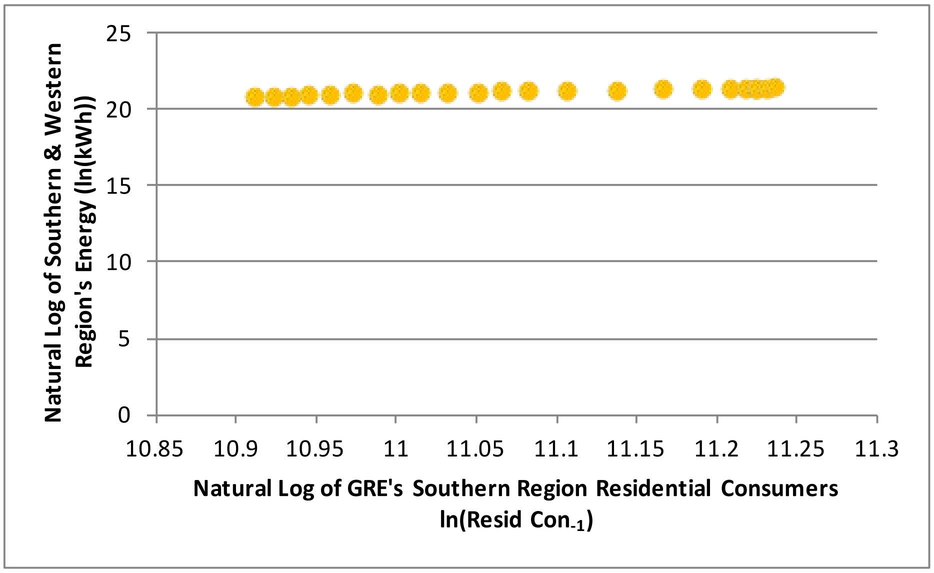


Figure 43. Scatterplot of Southern & Western region's natural log of energy sales vs. natural log of residential consumers.

GRE Wholesale Rate

Looking at GRE's Wholesale Energy rate shows two periods of sustained annual energy increased, 1977-1984 and 2007-Present, and one sustained period of rate decreases, 1985-2006 (Figure 44). With exception to the period from 1977-1984, the Southern & Western Region's energy sales responded inversely to the wholesale rate. As rates steadily decreased from 1985-2006, energy sales steadily increased, however, as wholesale rates steadily increased through 2013, energy sales decreased (Figures 44 and 45). A natural log transformation was applied to GRE's historic wholesale energy rate prior to fitting the model (Figure 46).

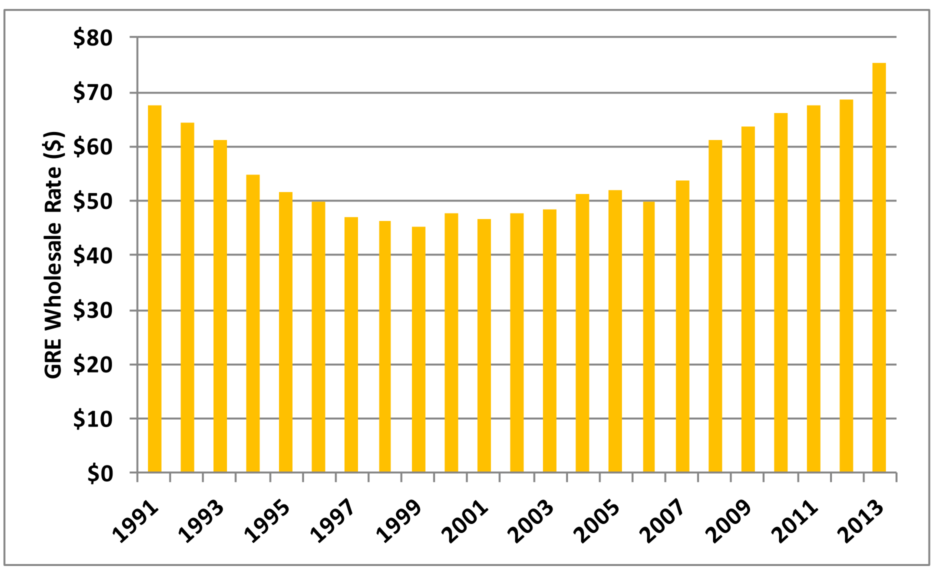


Figure 44. GRE's Historic wholesale rate$_{(real)}$.

[Trade Secret Begins

Trade Secret Ends]

Figure 45. Scatterplot of GRE's wholesale rate vs. the Southern & Western region's energy sales.

[Trade Secret Begins

Trade Secret Ends]

Figure 46. Scatterplot of natural log of Southern & Western regions energy sales vs. natural log of GRE's wholesale rate.

Residential Propane

Residential propane prices have seen a dramatic rise and fall in the past ten years (Figure 47.) Beginning in 2003 propane prices increased year after year until 2008 (Figure 47). As propane prices were increasing during this time, energy sales were also increasing until propane prices reached $2.00/gallon (Figure 48). At $2.00/gallon or greater, energy sales dramatically flattened out (Figure 48). A natural log transformation was applied to HDD_{65} prior to fitting the model (Figure 49).

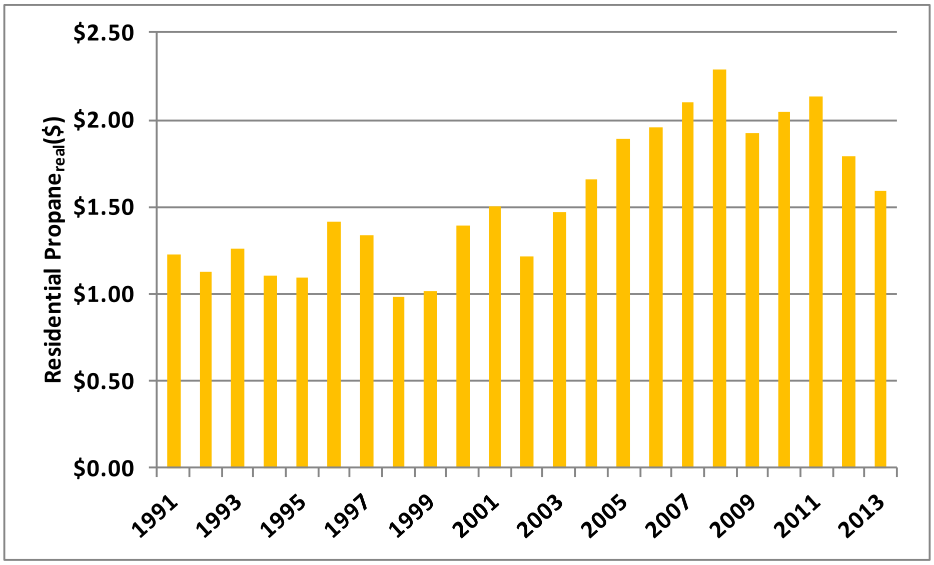


Figure 47. Historic residential propane prices.

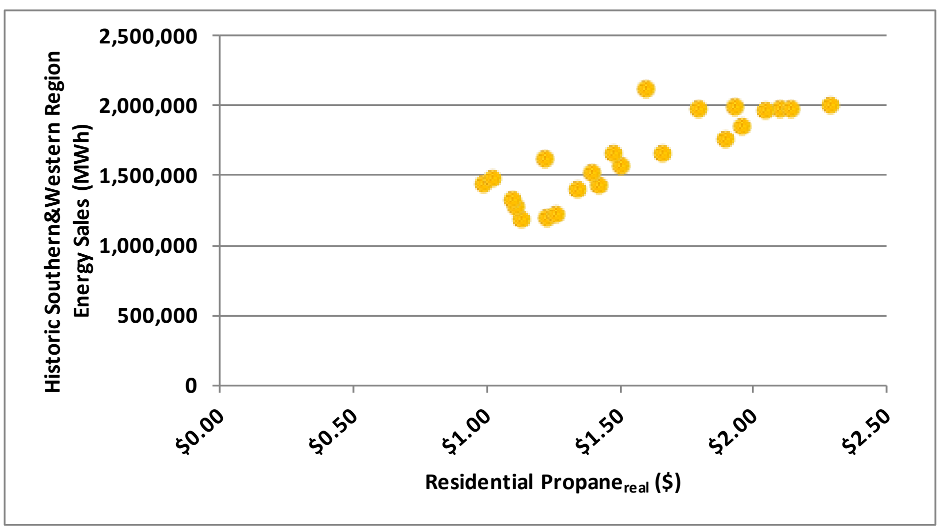


Figure 48. Scatterplot of the Southern & Western region's energy sales vs. residential propane price.

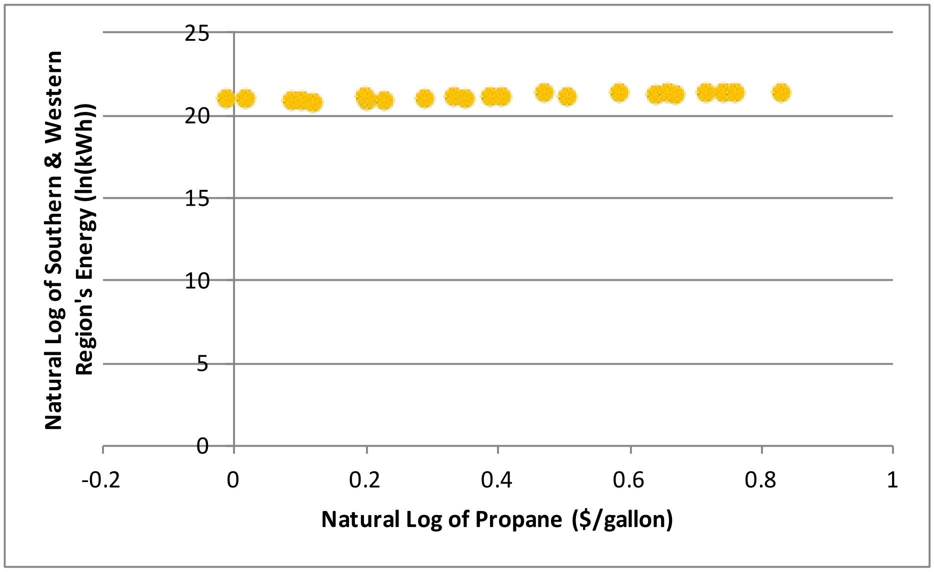


Figure 49. Scatterplot of natural log of Southern & Western Region's energy sales vs. natural log of propane price.

Independent Variable Forecasts

Residential Consumers

Great River Energy's most recent long-term residential consumer forecast was developed in 2012 and used historic data through 2011. The forecast was approved by the Rural Utilities Service and as used in GRE's 2012 Integrated Resource Plan (IRP). In the 2012 IRP review, questions were raised about the long-term forecast methodology and forecasts, particularly the methods used to adjust and revise the forecasts of residential consumers. In response to that feedback, GRE solicited the services of a third party to develop an independent analysis of residential consumer growth on the GRE All Requirement System.

Clearspring Energy Advisors, the consultant hired to perform the independent analysis, has substantial experience in electrical load forecasting for electrical cooperatives. Its methodology links the household forecasts of primary counties served and changes in the share of households served by GRE member cooperatives. This residential consumer forecasts captures the housing market cycle and is driven by county-level household forecasts developed by the Minnesota State Demographic Center. The resulting residential consumer forecasts developed for the three defined forecast regions is illustrated below (Figure 50). A comprehensive description of the forecast methodology, results, and conclusion can be found in Exhibit C.

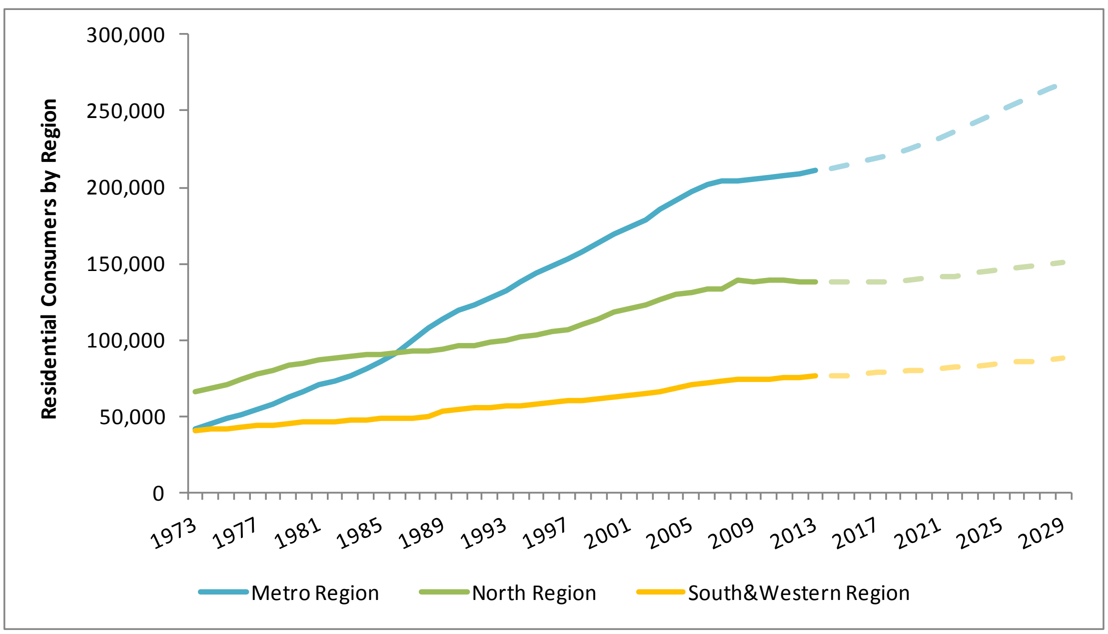


Figure 50. Regional residential consumer forecast study performed by Clearspring Energy Advisors.

Employment

Data source for the Metro Region employment history and projection was provided by Woods and Poole State profile series. This profile series contains some of Woods and Poole regional data and projections for a particular state and all Combined Statistical Areas (CSA's), Metropolitan Statistical Areas (MSAs), Micropolitan Statistical Areas (MICROs), Metropolitan Divisions (MDIVs), and counties in each state.

Woods and Poole demographic and econometric parameters were weighted for each of the forecast regions. Weights were determined by the percentage of the households served in each county that a forecast region serves. The weight was static and based on year-end 2013 residential accounts. For each of the regions forecast, employment was only significant in the Metro region. Historic and forecast weighted employment for the Metro Region can be found in Figure 51.

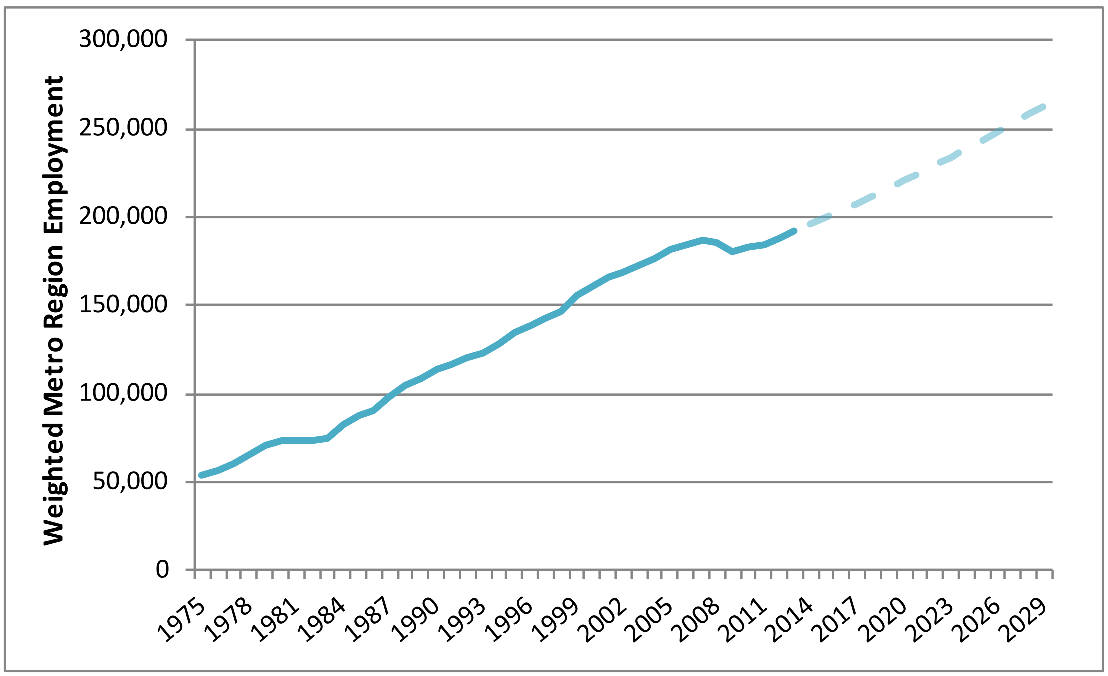


Figure 51. Historic and forecast weighted Metro Region employment (thousand of jobs).

Employment-to-Population Ratio

Data source for historic and forecast employment-to-population ratio for the Northern Region was provided by the Woods and Poole State Profile. A weighted employment-to-population ratio for the Northern Region was calculated by dividing the weighted employment for the region by the weighted population for the region. Employment and population Weights were determined by the percentage of the households served in each county that a forecast region serves. The weight was static and based on year-end 2013 residential accounts. Historic and forecast weighted employment-to-population ratios can be found in Figure 52.

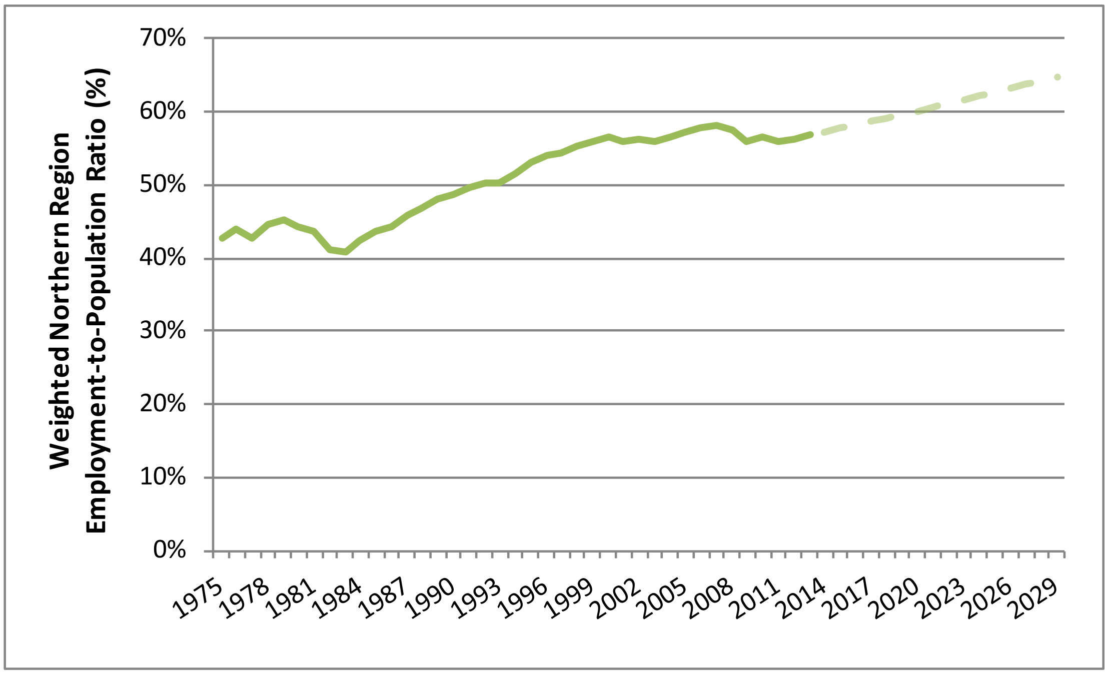


Figure 52. Historic and forecast weighted population-to-employment ratios for the Northern Region.

Cooling Degree Days

That data source for cooling degree days (CDD_{65}) was the Minnesota Climatology Office. Weather stations in Owatonna MN, Hibbing MN, and Minneapolis/St. Paul International Airport were used because of their central location to each of their respective forecast regions: Southern & Western Region = Owatonna, MN, Metro Region = Minneapolis/St. Paul International Airport, and Northern Region = Hibbing, MN. Historic and 25-year normal CDD_{65} can be found in Figure 53. Descriptive statistics for 25-year normal cooling degree days can be found in Table 1.

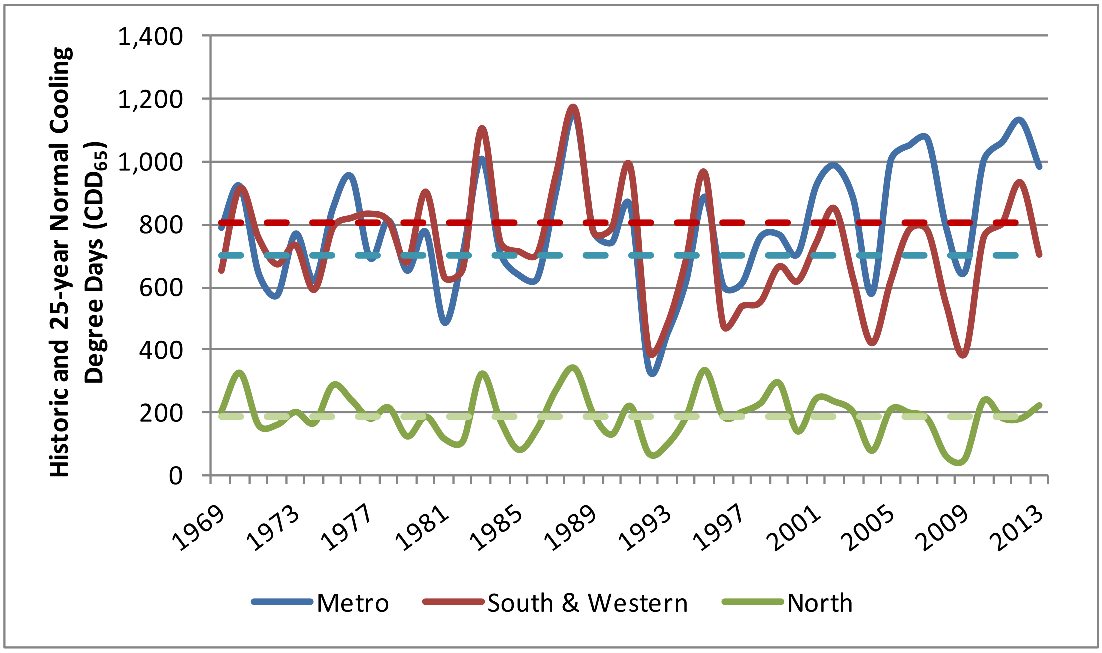


Figure 53. Historic and 25-year normal cooling degree days for the three forecast regions.

Table 1. Twenty-five year normal cooling degree day descriptive statistics for the three fore cast regions.

CDD_{65} 25-Year Normal Descriptive Statistics	Region		
	Metro	Southern & Western (CDD_{65})	Northern
Min	337	387	54
Max	1,152	1,169	344
Mean	815	692	190
Standard Deviation	215	198	77
Coefficient of Variance (CV)	26.4%	28.7%	40.8%

Heating Degree Days

That data source for cooling degree days (HDD_{65}) was the Minnesota Climatology Office. Weather stations in Owatonna MN, Hibbing MN, and Minneapolis/St. Paul International Airport were used because of their central location to each of their respective forecast regions:

Southern & Western Region = Owatonna, MN,
Metro Region = Minneapolis/St. Paul International Airport, and
Northern Region = Hibbing, MN.

Historic and 25-year normal HDD_{65} can be found in Figure 54. Descriptive statistics for 25-year normal cooling degree days can be found in Table 2.

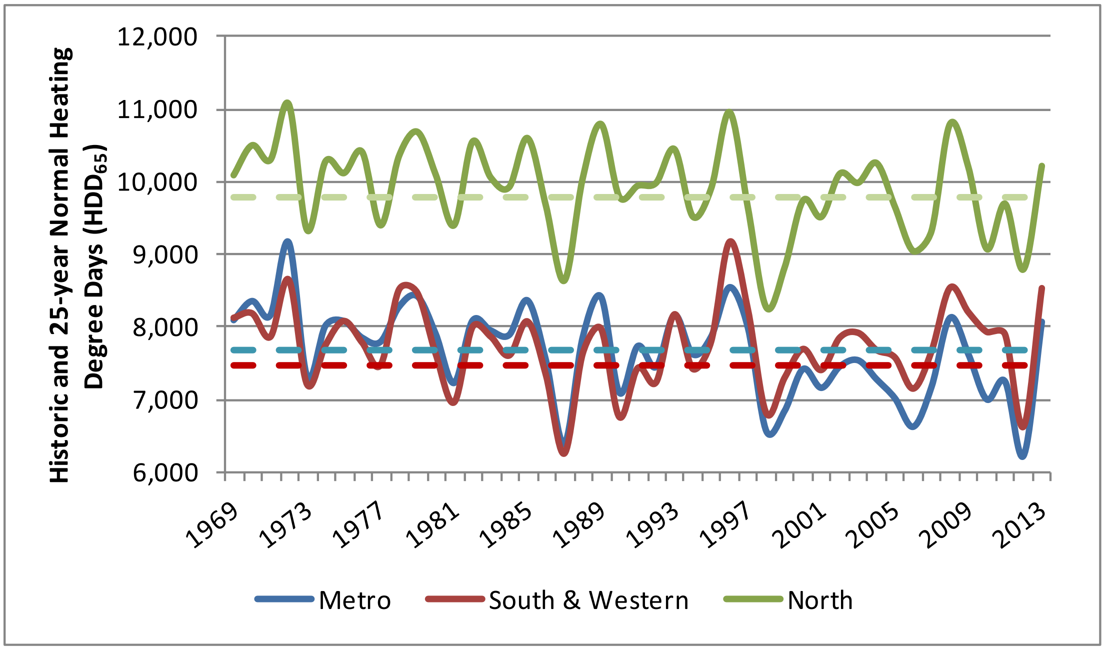


Figure 54. Historic and 25-year normal heating degree days for the three forecast regions.

Table 2. Twenty-five year normal heating degree day descriptive statistics for the three forecast regions.

HDD_{65} 25-Year Normal Descriptive Statistics	Region (HDD_{65})		
	Metro	Southern & Western	Northern
Min	6,218	6,638	8,270
Max	8,534	9,177	10,963
Mean	7,433	7,693	9,776
Standard Deviation	574	574	574
Coefficient of Variance (CV)	7.7%	7.5%	5.9%

Wholesale Rate

[Trade Secret Begins

Trade Secret Ends]

Figure 55. Great River Energy's Historic and Forecast wholesale rate.

Residential Propane

The data source for nominal residential propane was the *Annual Energy Outlook 2013 and historical EIA MN residential propane prices*. The projections in the U.S. Energy Information Administration's (EIA's) *Annual Energy Outlook 2013* (AEO2013) focus on the factors that shape the U.S. energy system over the long term. Under the assumption that current laws and regulations remain unchanged throughout the projections, the AEO2014 Reference case provides the basis for examination and discussion of energy production, consumption, technology, and market trends and the direction they may take in the future. It also serves as a starting point for analysis of potential changes in energy policies.

Real residential propane price base year 2012 was calculated using a Personal Consumption Expenditure Price Index (PCI) (2012=100). The historic and forecast PCI was provided by Woods and Poole State profile. Historic and forecast residential propane can be found in figure 56.

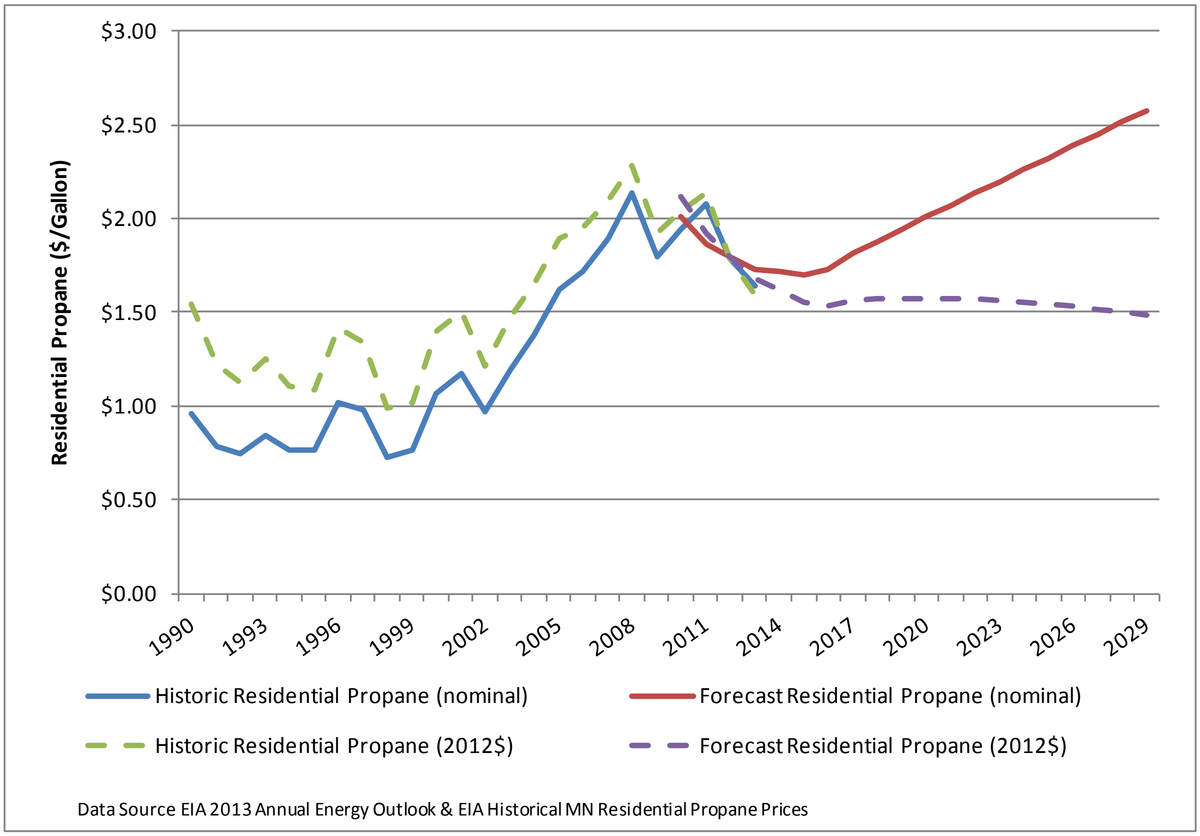


Figure 56. Historic and forecast Minnesota residential propane prices.

This Page Was Intentionally Left Blank

Energy Regression Model's Structural Form and Coefficients

An annual energy model was fit using multiple linear regression techniques with MetrixND© for each of the three forecast regions. For each forecast region, the final model structure is detailed below. Resulting coefficients, T-Stats, and P-values for each regions regression model can be found in Tables 3, 4, and 5.

Metro Region

$$\ln(Annual\ Metro\ Region\ Energy) = \beta_0 + \beta_1 \ln(Metro\ Region\ Residential\ Consumers_{-1}) + \beta_2 ln(Metro\ Region\ Employment_{MA_2}) + \beta_3 \ln(Metro\ Region\ CDD_{65}) + \beta_4 \ln(\text{Wholesale Rate Real}_{\text{MA}\,3})$$

Where:

β_0 = Constant/y-intercept,
β_1 = Natural Log of Metro Regions Residential Consumers lagged 1-year,
β_2= Natural log of Metro Region's Employment, 2-year Moving Average,
β_3 = Natural log of Metro Regions Cooling Degree Days, Minneapolis basetemp 65 and
β_4 =Natural log of GRE's Wholesale Rate Real, 3-year Moving Average.

Table 3. Metro Region energy model regression coefficients, T-Stat, and P-Values.

Variable	Metro Region Coefficient	StdErr	T-Stat	P-Value
Constant	10.90612477	0.905145392	12.0490309	8.83949E-14
LN(Metro Region Residential Consumers $_{-1}$)	0.683168004	0.152325732	4.4849153	9.25325E-05
LN(Metro Region Employment$_{MA\ 2}$)	0.560156192	0.177241592	3.16041053	0.003507535
LN(Metro Region CDD$_{65}$)	0.062448643	0.009172061	6.8085729	1.08779E-07
LN(Wholse Sale Rate Real$_{MA\ 3}$)	-0.113148218	0.027385418	-4.1316958	0.000251844
AR(1)	0.75955906	0.127195341	5.971595	1.23813E-06

Northern Region

$$\ln(Annual\ Northern\ Region\ Energy) = \beta_0 + \beta_1 \ln(Northern\ Region\ Residential\ Consumers_{-1}) + \beta_2 ln(Northern\ Region\ HDD_{65}) + \beta_3 \ln(Northern\ Region\ Employment: Population\ Ratio) + \beta_4 \ln(\text{Wholesale Rate Real}_{\text{MA}\,3})$$

Where:

β_0 = Constant/y-intercept,
β_1 = Natural log of Northern Regions Residential Consumers lagged 1-year,
β_2= Natural log of Northern Regions HDD, Hibbing MN basetemp 65,
β_3 = Natural log of Northern Regions Employment-to-Population Ratio,

β_4 =Natural log of GRE's Wholesale Rate Real, 3-year Moving Average.

Table 4. Northern Region energy model regression coefficients, T-Stat, and P-Values.

	Northern Region			
Variable	Coefficient	StdErr	T-Stat	P-Value
Constant	5.203683551	1.11007785	4.68767443	4.84884E-05
LN(Northern Region Residential Consumers $_{-1}$)	1.285359924	0.084181973	15.2688264	3.68502E-17
LN(Northern Region HDD$_{65}$)	0.237654448	0.051317025	4.63110343	5.71662E-05
LN(Northern Region Employment/Population)	0.749153529	0.161525713	4.63798312	5.6034E-05
LN(Wholse Sale Rate Real)	-0.090970443	0.035294853	-2.5774422	0.014767901
AR(1)	0.382192448	0.16310375	2.34324746	0.025496166

Western & Southern Region

$$\ln(Annual\ Southern\&Western\ Region\ Energy) = \beta_1 \ln(Southern\&Western\ Region\ HDD_{65}) + \beta_2 ln(Southern\&Western\ Region\ Residential\ Consumers_{-1}) + \beta_3 \ln(\text{Wholesale Rate Real}_{\text{MA}\,3}) + \beta_4 \ln(Residential\ Propane\ Real)$$

Where:

β_1 = Natural log of Southern & Western Region HDD, Owatonna, MN Base temp 65,
β_2= Natural log of Southern & Western Region Residential Consumers lagged 1-year,
β_3 = Natural log of GRE's Wholesale Rate Real, 3-year Moving Average and
β_4 =Natural log of Residential Propane Real).

Table 5. Southern & Western Region energy model regression coefficients, T-Stat, and P-Values.

	Southern & Western Region			
Variable	Coefficient	StdErr	T-Stat	P-Value
LN(Southen & Western Region HDD$_{65}$)	0.206424826	0.032340905	6.38277828	3.91207E-06
LN(Southern & Western Residential Consumers $_{-1}$)	1.795761805	0.027118238	66.2197092	2.76945E-36
LN(Wholesale Rate Real)	-0.128249293	0.021595588	-5.9386803	1.00663E-05
LN(Residential Propane Real)	-0.064622647	0.014523307	-4.4495821	0.000274742

Energy Model-In-Sample Goodness-of-Fit Statistics

The primary in-sample goodness-of-fit statistics used to determine how well the regression models fit the historical data for the three forecast regions are detailed in Table 6.

Table 6. Regional energy model's in-sample goodness-of-fit statistics.

Metro Region Model Statistics		Northern Region Model Statistics		Southern and Western Region Model Statistics	
Iterations	32	Iterations	22	Iterations	1
Adjusted Observations	37	Adjusted Observations	38	Adjusted Observations	23
Deg. of Freedom for Error	31	Deg. of Freedom for Error	32	Deg. of Freedom for Error	19
R-Squared	0.999256501	R-Squared	0.996754418	R-Squared	0.994731919
Adjusted R-Squared	0.999136581	Adjusted R-Squared	0.996247296	Adjusted R-Squared	0.993900117
AIC	-8.18852581	AIC	-7.603363496	AIC	-8.305656349
BIC	-7.927295878	BIC	-7.344797261	BIC	-8.108179094
F-Statistic	8332.743951	F-Statistic	1965.511292	F-Statistic	#NA
Prob (F-Statistic)	0	Prob (F-Statistic)	0	Prob (F-Statistic)	#NA
Log-Likelihood	104.9870017	Log-Likelihood	96.54424216	Log-Likelihood	66.87946174
Model Sum of Squares	9.988821057	Model Sum of Squares	4.244580062	Model Sum of Squares	0.757917264
Sum of Squared Errors	0.007432209	Sum of Squared Errors	0.01382099	Sum of Squared Errors	0.004013915
Mean Squared Error	0.000239749	Mean Squared Error	0.000431906	Mean Squared Error	0.000211259
Std. Error of Regression	0.015483819	Std. Error of Regression	0.020782347	Std. Error of Regression	0.01453474
Mean Abs. Dev. (MAD)	0.010918941	Mean Abs. Dev. (MAD)	0.014438396	Mean Abs. Dev. (MAD)	0.01058473
Mean Abs. % Err. (MAPE)	0.000508199	Mean Abs. % Err. (MAPE)	0.000677716	Mean Abs. % Err. (MAPE)	0.000499204
Durbin-Watson Statistic	2.199881254	Durbin-Watson Statistic	1.698286868	Durbin-Watson Statistic	1.63191059
Durbin-H Statistic	#NA	Durbin-H Statistic	#NA	Durbin-H Statistic	#NA
Ljung-Box Statistic	5.162598473	Ljung-Box Statistic	4.798230202	Ljung-Box Statistic	14.35433546
Prob (Ljung-Box)	0.396360626	Prob (Ljung-Box)	0.440997493	Prob (Ljung-Box)	0.013508637
Skewness	-0.063073807	Skewness	-0.4147779	Skewness	0.222096475
Kurtosis	3.279503235	Kurtosis	2.981115634	Kurtosis	2.372177796
Jarque-Bera	0.144971055	Jarque-Bera	1.090155788	Jarque-Bera	0.566823592
Prob (Jarque-Bera)	0.930079207	Prob (Jarque-Bera)	0.579796619	Prob (Jarque-Bera)	0.753209555

Energy Model Residual Plots

Some informal diagnostic plots of energy residuals are presented to provide information on whether any of the following departures from the regression model are present (Figures 57-59):

(1) The regression model is linear
(2) The error terms do not have a constant variance.

Metro Region

[Trade Secret Begins

Trade Secret Ends]

Figure 57. Metro Region energy model residual plots.

Northern Region

[Trade Secret Begins

Trade Secret Ends]

Figure 58. Northern Region energy model residual plots.

Southern and Western Region

[Trade Secret Begins

Trade Secret Ends]

Figure 59. Southern &Western Region's energy model residual plots.

Predicted Vs. Actual Scatterplots

Scatterplots of actual energy vs. predicted energy sales for the three forecast regions show the expected approximate 1:1 relationship between actual energy sales and predicted energy sales (Figure 60). Across the range of actual energy sales values, there is no discernable trend of under or over-predicting.

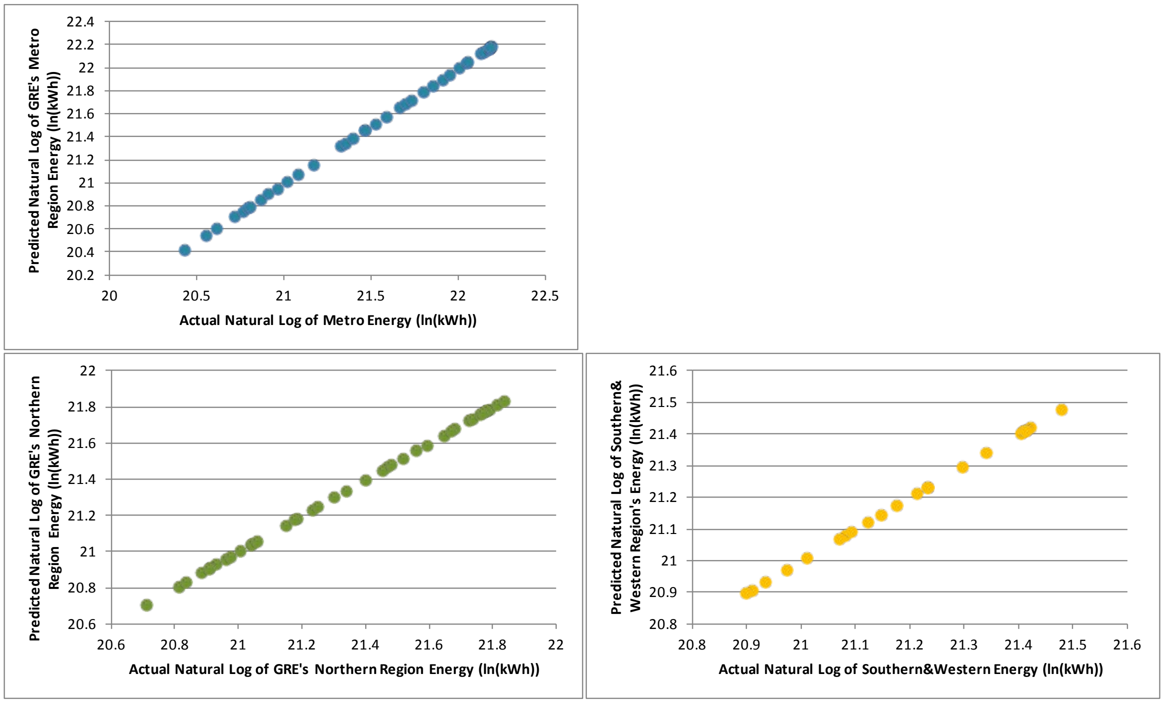


Figure 60. Scatterplot of actual energy sales vs. predicted energy sales for the three forecast regions.

Energy Forecast Results

Metro Region

In the Metro Forecast Region, 5-year compounded annual growth rates for annual energy sales indicate a 1.8% annual increase in energy. The 10-year and 20-year compounded annual growth rates show a 2.0% and 2.1% growth rate, respectively (Table 7).

Northern Region

Five-year compounded annual growth rates in the Northern Forecast Region for annual energy sales indicate a 0.7% annual increase in demand. The 10-year and 20-year compounded annual growth rates show a 1.1 % and 1.3% growth rate, respectively (Table 7).

Southern & Western Region

In the Southern & Western Forecast Region, 5-year compounded annual growth rates for annual energy sales indicate a 1.5% annual increase in energy. The 10-year and 20-year compounded annual growth rates show a 1.5% and 1.6% growth rate, respectively (Table 7).

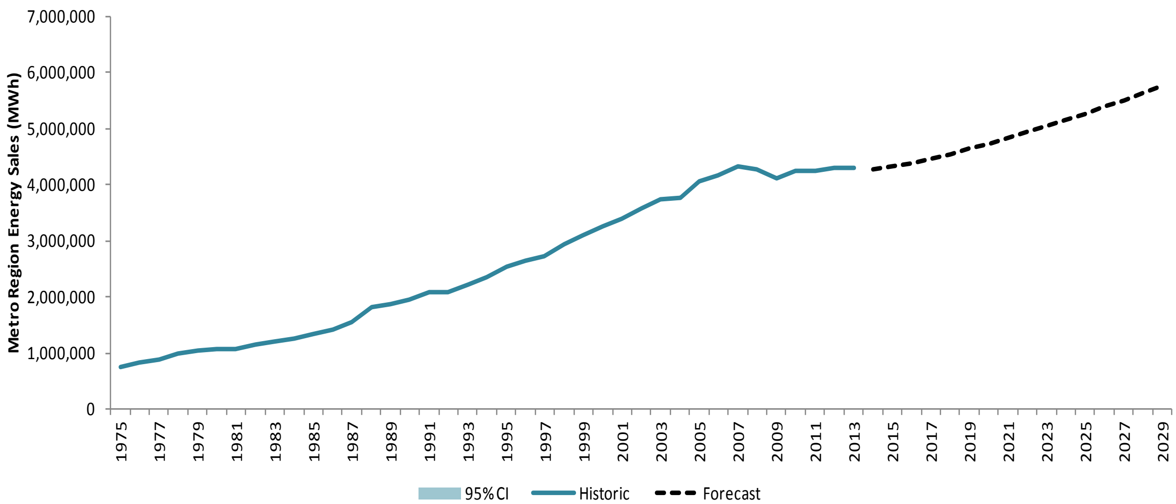
GRE's All Requirement Member Forecast

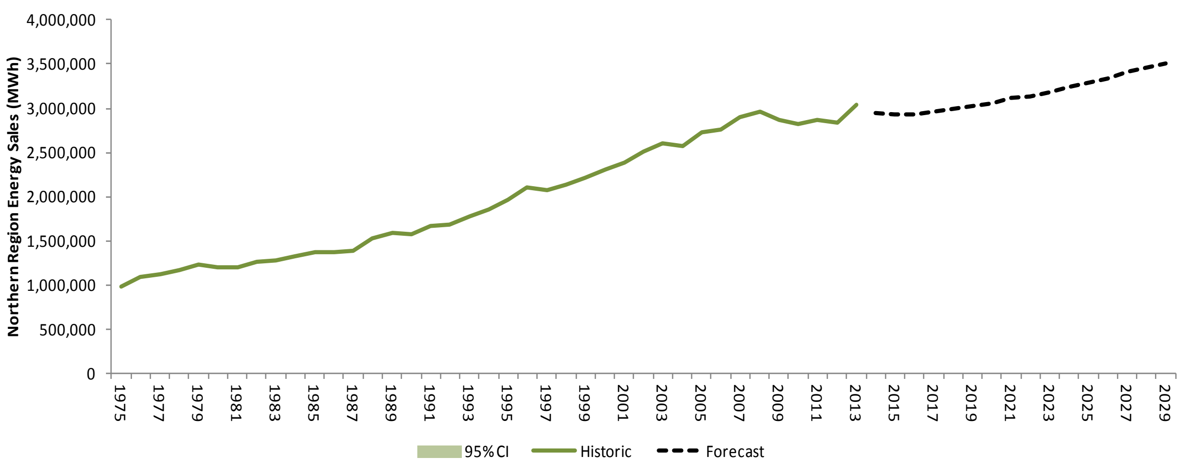
Aggregating the three regional annual energy sale forecasts produces GRE's All Requirement Member energy sales forecast (Table 7).

GRE's All Requirement Member energy sales forecast's 5-year compounded annual growth rate indicates a 1.4% annual increase in demand. The 10-year and 20-year compounded annual growth rates show a 1.6% and 1.7% growth rate, respectively (Table 7).

Table 7 Forecast energy sales for the Northern, Metro, and Southern & Western regions and aggregated All Requirement energy forecast.

Year	Metro Region Energy (MWh)	Year-Over-Year Growth (%)	Northern Region Energy (MWh)	Year-Over-Year Growth (%)	Southern & Western Region Energy (MWh)	Year-Over-Year Growth (%)	GRE's All Requirement Member's Annual Energy (MWh)	Year-Over-Year Growth (%)
2015	4,322,241		2,934,654		2,099,335		9,356,229	
2016	4,387,744	1.5%	2,932,612	-0.1%	2,118,859	0.9%	9,439,215	0.9%
2017	4,459,008	1.6%	2,956,808	0.8%	2,151,094	1.5%	9,566,910	1.4%
2018	4,541,775	1.9%	2,993,522	1.2%	2,193,115	2.0%	9,728,411	1.7%
2019	4,635,694	2.1%	3,022,972	1.0%	2,224,456	1.4%	9,883,123	1.6%
2020	4,734,634	2.1%	3,060,709	1.2%	2,261,314	1.7%	10,056,657	1.8%
2021	4,838,309	2.2%	3,109,673	1.6%	2,307,254	2.0%	10,255,236	2.0%
2022	4,937,189	2.0%	3,136,645	0.9%	2,328,605	0.9%	10,402,439	1.4%
2023	5,041,733	2.1%	3,183,759	1.5%	2,367,922	1.7%	10,593,414	1.8%
2024	5,147,625	2.1%	3,235,554	1.6%	2,408,914	1.7%	10,792,093	1.9%
2025	5,262,971	2.2%	3,286,595	1.6%	2,448,939	1.7%	10,998,505	1.9%
2026	5,381,102	2.2%	3,342,410	1.7%	2,493,515	1.8%	11,217,028	2.0%
2027	5,506,385	2.3%	3,407,584	1.9%	2,547,897	2.2%	11,461,867	2.2%
2028	5,632,020	2.3%	3,455,901	1.4%	2,584,053	1.4%	11,671,973	1.8%
2029	5,759,742	2.3%	3,511,717	1.6%	2,627,894	1.7%	11,899,353	1.9%
5-Year (CAGR)		1.8%		0.7%		1.5%		1.4%
10-Year (CAGR)		2.0%		1.1%		1.5%		1.6%
15-Year (CAGR)		2.1%		1.3%		1.6%		1.7%





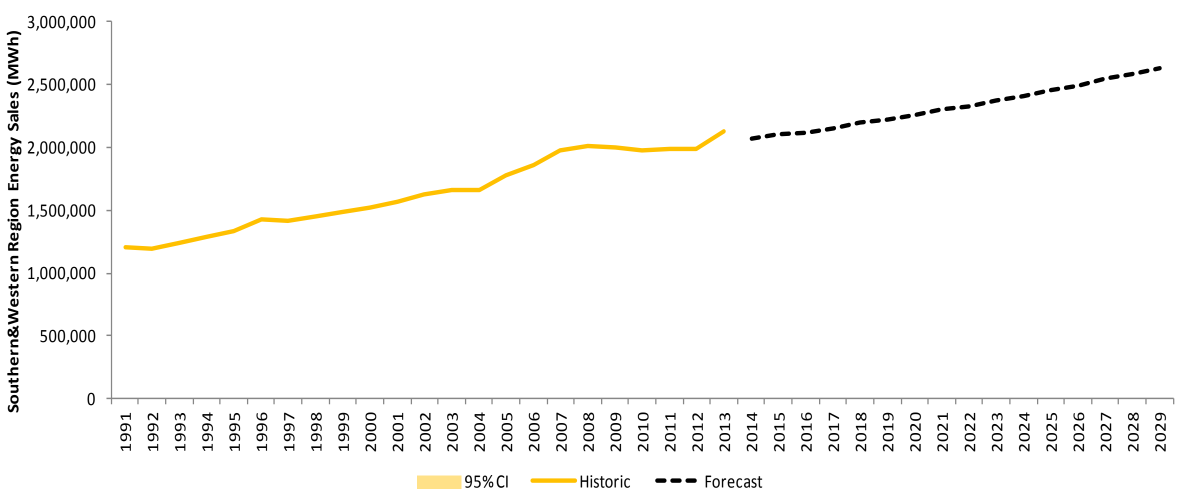


Figure 61. Historic and forecast energy sales for the Northern, Metro, and Southern & Western regions.

Figures 61 and 62 show the historic and forecast energy sales for the three forecast regions and the aggregation of the forecasts to produce the All Requirement energy sale forecast. Also included in these figures is the forecast's upper and lower 95% confidence interval.

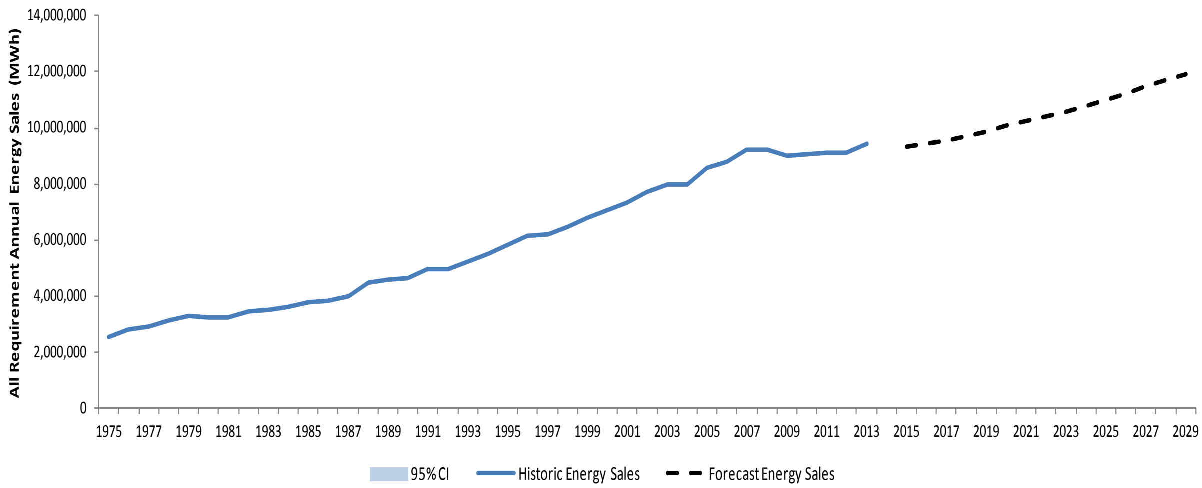


Figure 62. Aggregate Great River Energy All Requirement annual energy sales history and forecast. Composite forecast of the Metro, Northern, and Southern & Western Regions.

Demand Model Development

Description and Assumptions

Monthly non-coincident peak regression models and forecasts were developed for each forecast region using actual meter data with load control embedded in the data. An assumption is made that our historical load control program will remain consistent in the future, i.e. our historic growth in load control will continue to be the same going forward along with how these load control programs are implemented. All monthly peak forecasts include load control.

Monthly peak regression models were developed for GRE's All Requirement members only within a given forecast region. The fixed members have entered into a long term power purchase contract and purchase only a fixed amount of their capacity form GRE. The following demand models and forecast are for the All Requirement members only. To calculate the combined All Requirement and Fixed demand obligation, the fixed amount will be added to the All Requirement member forecast.

Demand models and forecasts developed for each forecast region are coincident to GRE's system peak. The aggregation of the three regional coincident peak demand models produces the GRE coincident peak demand forecast.

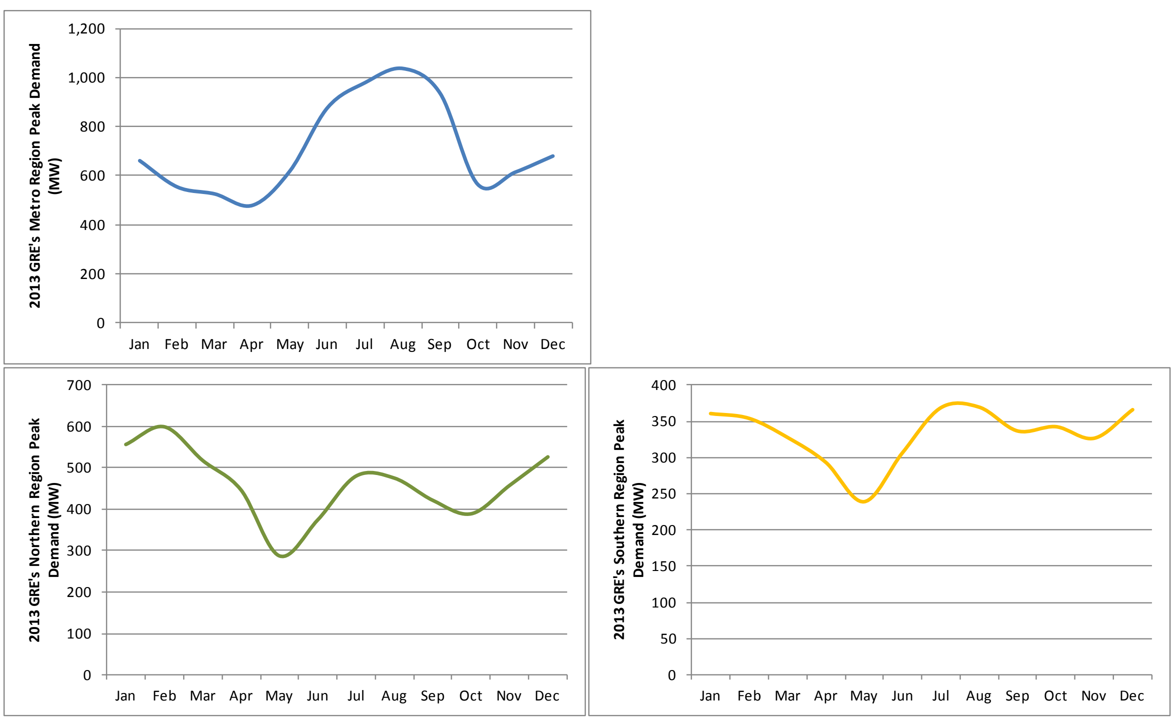


Figure 63. Monthly peak load shapes for each forecast region at the time of GRE's coincident peak in 2013.

Independent Variables

Energy Sales

For each forecast region, energy sales are correlated with monthly peak demand (Figure 64). Each region's monthly peak demand model utilizes historic monthly energy sales and monthly energy sales forecasts described in the previous sections.

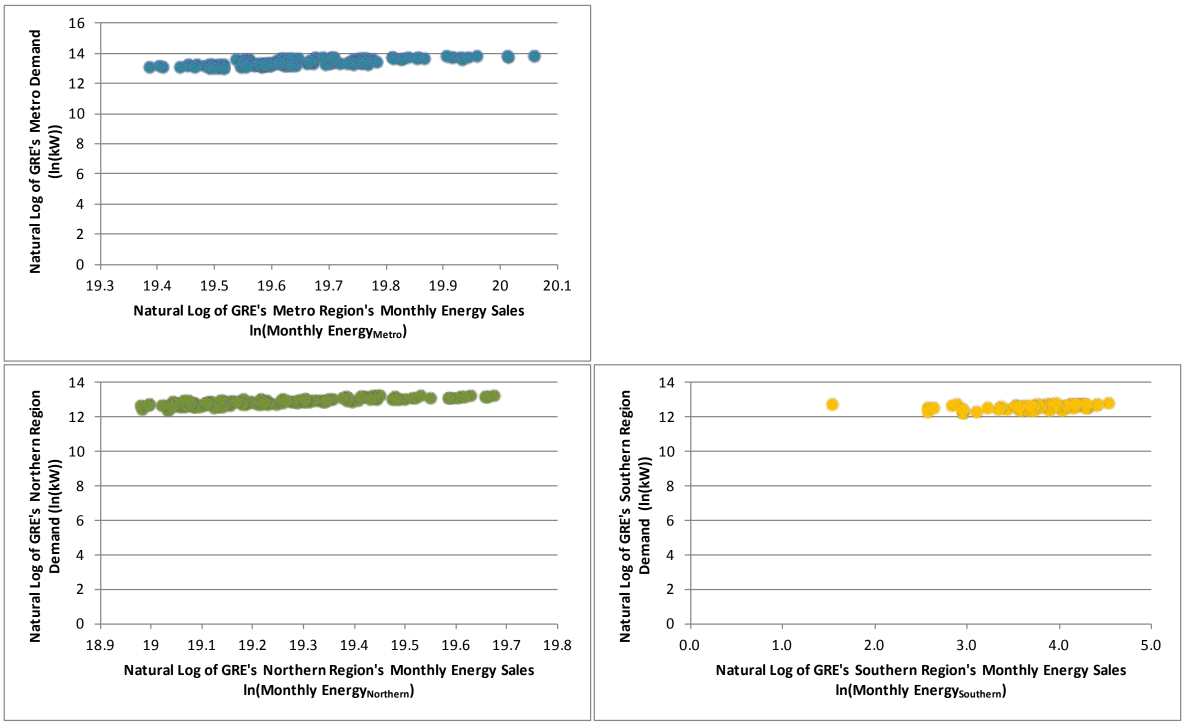


Figure 64. Monthly energy sales by region at the time of GRE's coincident peak.

Monthly Peaking Temperatures

The temperature at the time of the Great River Energy's coincident peak has a profound impact on the magnitude of the peak demand. Temperature is directly related to the amount of heating and cooling loads on the system. When looking at load profiles vs. temperature for each region, two distinct trends can be seen Figure 65, 66, and 67.

1.) Summer and cooling loads appear to be present when temperature exceeds 70° F and rapidly increases as temperatures increase.
2.) Winter heating loads become present when temperatures begin to fall below 50° F.

Temperature is used as an explanatory variable for each of the forecast region's peak monthly demand.

Metro Region

Summer peaking temperatures at the time of GRE Coincident peak in the Metro Region , July and August, range between 81° F and 95° F. Winter peaking temperatures at the time of the GRE coincident peak in the Metro Region, December, January, and February, can range from 32°F to -17°F (Table 8).

Table 8. Monthly Metro Region Peaking Temperatures at the time of Great River Energy's coincident peak.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Minneapolis, MN Temperature (°F)											
2003	3	16	11	33	81	85	86	95	89	80	24	22
2004	-9	6	14	87	75	95	78	81	87	48	36	1
2005	-2	21	23	72	39	81	81	81	90	82	22	5
2006	25	-8	25	40	84	81	82	86	82	38	21	23
2007	8	-11	19	19	86	85	81	86	88	81	14	32
2008	-4	4	2	40	44	76	81	88	84	46	30	37
2009	-17	-1	-2	32	93	89	79	83	83	50	48	14
2010	6	8	22	35	95	90	88	91	73	79	31	7
2011	-13	-6	3	33	87	94	85	86	92	83	36	20
2012	-6	22	40	32	87	89	84	87	88	44	19	16
2013	16	-10	9	23	98	81	94	83	88	37	20	0
Normal	1	4	15	41	79	86	84	86	86	61	27	16

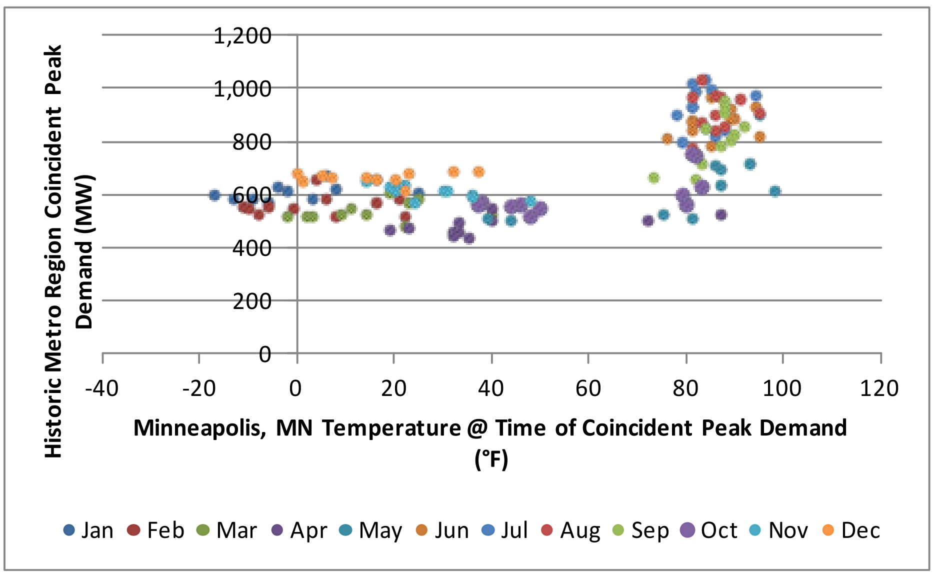


Figure 65. Metro Region temperature vs. load at the time of GRE's coincident peak.

Northern Region

Summer peaking temperatures at the time of GRE Coincident peak in the Northern Region, July and August, range between 75° F and 91° F. Winter peaking temperatures at the time of the GRE coincident peak in the Northern Region, December, January, and February, can range from 17°F to slightly below -28°F (Table 9).

Table 9. Monthly Northern Region peaking temperature at the time of Great River Energy's coincident peak.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	Hibbing, MN Temperature (°F)											
2003	-8	7	4	24	76	74	82	90	85	80	15	11
2004	-9	9	9	82	55	83	80	75	86	50	34	-10
2005	-8	14	18	63	45	75	70	75	81	64	13	10
2006	17	-14	23	39	79	78	74	79	80	32	14	8
2007	-3	-20	16	12	75	79	75	80	69	61	4	16
2008	-7	5	-11	38	39	75	75	78	74	47	23	5
2009	-28	-21	-5	25	86	69	71	78	82	49	43	-4
2010	4	0	15	18	87	82	85	86	70	69	26	1
2011	-25	-19	-7	27	60	79	75	77	77	62	23	14
2012	-14	2	38	25	55	78	76	82	83	45	7	8
2013	-4	-16	5	19	86	71	91	76	81	34	16	-5
Normal	-8	-5	10	34	68	77	78	80	79	54	20	5

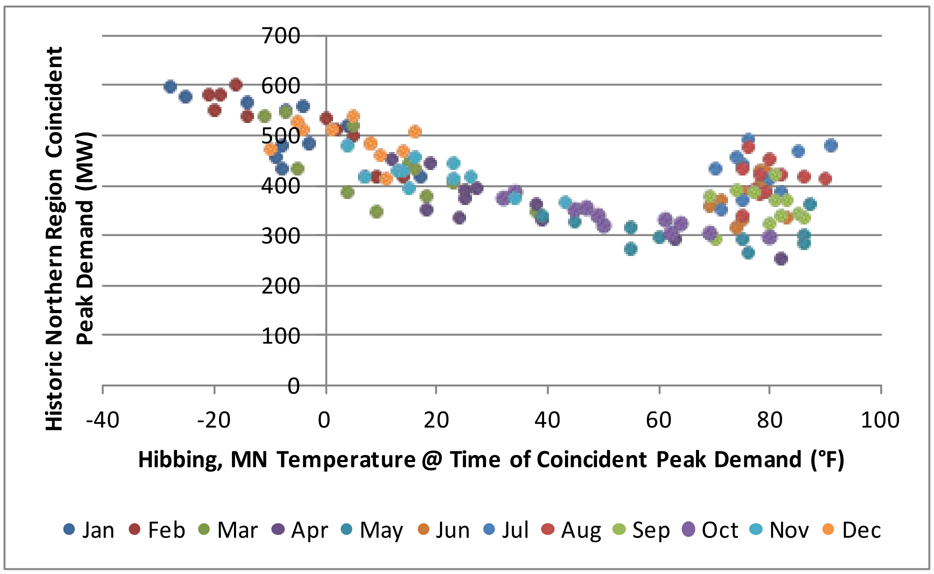


Figure 66. Northern Region temperature vs. load at the time of GRE's coincident peak.

Southern & Western Region

Summer peaking temperatures at the time of GRE Coincident peak in the Southern & Western Region , July and August, range between 79° F and 92° F. Winter peaking temperatures at the time of the GRE coincident peak in the Southern & Western Region, December, January, and February, can range from 30°F to slightly below -27°F (Table 10).

Table 10. Monthly Southern & Western Region peaking temperature at the time of Great River Energy's coincident peak.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
						Mason City, Iowa Temperature (°F)						
2003	7	34	9	46	81	87	91	88	86	81	29	17
2004	-9	9	16	88	83	90	74	79	82	52	30	7
2005	-8	30	27	72	46	77	79	79	88	90	22	0
2006	24	-7	24	43	83	75	80	82	81	36	22	28
2007	9	-16	22	18	85	83	79	83	87	77	14	31
2008	-3	4	13	37	52	76	79	84	83	48	31	16
2009	-27	-6	2	29	85	90	73	82	80	51	47	18
2010	-1	-1	16	26	91	88	85	88	73	79	30	3
2011	-17	-6	6	25	87	91	82	90	96	80	40	21
2012	0	23	46	24	92	86	83	94	92	46	21	14
2013	22	-8	12	24	95	77	92	79	84	39	20	-1
Normal	0	5	18	39	80	84	82	84	85	62	28	14

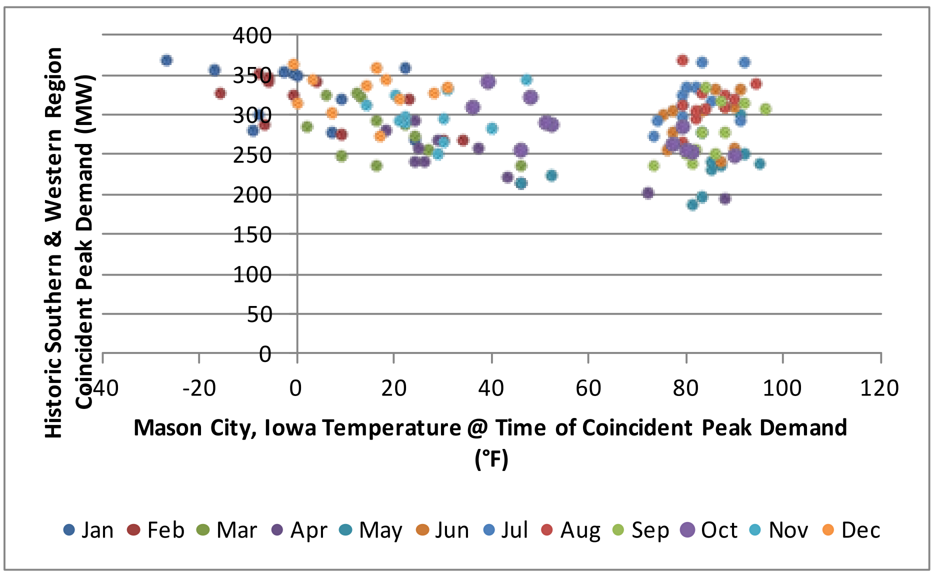


Figure 67. Southern & Western region temperature vs. load at the time of GRE's coincident peak.

Historic and Weather Normal Peaking Temps

Normal monthly peaking temperatures were calculated by averaging temperature at the time of GRE's coincident peak for each month from 2003 through 2013 for each of the forecast regions (Figure 68).

$$\begin{aligned}&Normal\ Monthly\ Coincident\ Peak\ Temps\\&\quad = Average(JanTemp\&Peak_{2003} + JanTemp\&Peak_{2004} + JanTemp\&Peak_{2005}\\&\quad + JanTemp\&Peak_{2006} + JanTemp\&Peak_{2007} + JanTemp\&Peak_{2008} + JanTemp\&Peak_{2009}\\&\quad + JanTemp\&Peak_{2010} + JanTemp\&Peak_{2011} + JanTemp\&Peak_{2012} + JanTemp\&Peak_{2013})\end{aligned}$$

.

.

$$\begin{aligned}&Normal\ Monthly\ Coincident\ Peak\ Temps\\&\quad = Average(OctTemp\&Peak_{2003} + OctTemp\&Peak_{2004} + OctTemp\&Peak_{2005}\\&\quad + OctTemp\&Peak_{2006} + OctTemp\&Peak_{2007} + OctTemp\&Peak_{2008} + OctTemp\&Peak_{2009}\\&\quad + OctTemp\&Peak_{2010} + OctTemp\&Peak_{2011} + OctTemp\&Peak_{2012} + OctTemp\&Peak_{2013})\end{aligned}$$

.

.

$$\begin{aligned}&Normal\ Monthly\ Coincident\ Peak\ Temps\\&\quad = Average(DecTemp\&Peak_{2003} + DecTemp\&Peak_{2004} + DecTemp\&Peak_{2005}\\&\quad + DecTemp\&Peak_{2006} + DecTemp\&Peak_{2007} + DecTemp\&Peak_{2008} + DecTemp\&Peak_{2009}\\&\quad + DecTemp\&Peak_{2010} + DecTemp\&Peak_{2011} + DecTemp\&Peak_{2012} + DecTemp\&Peak_{2013})\end{aligned}$$

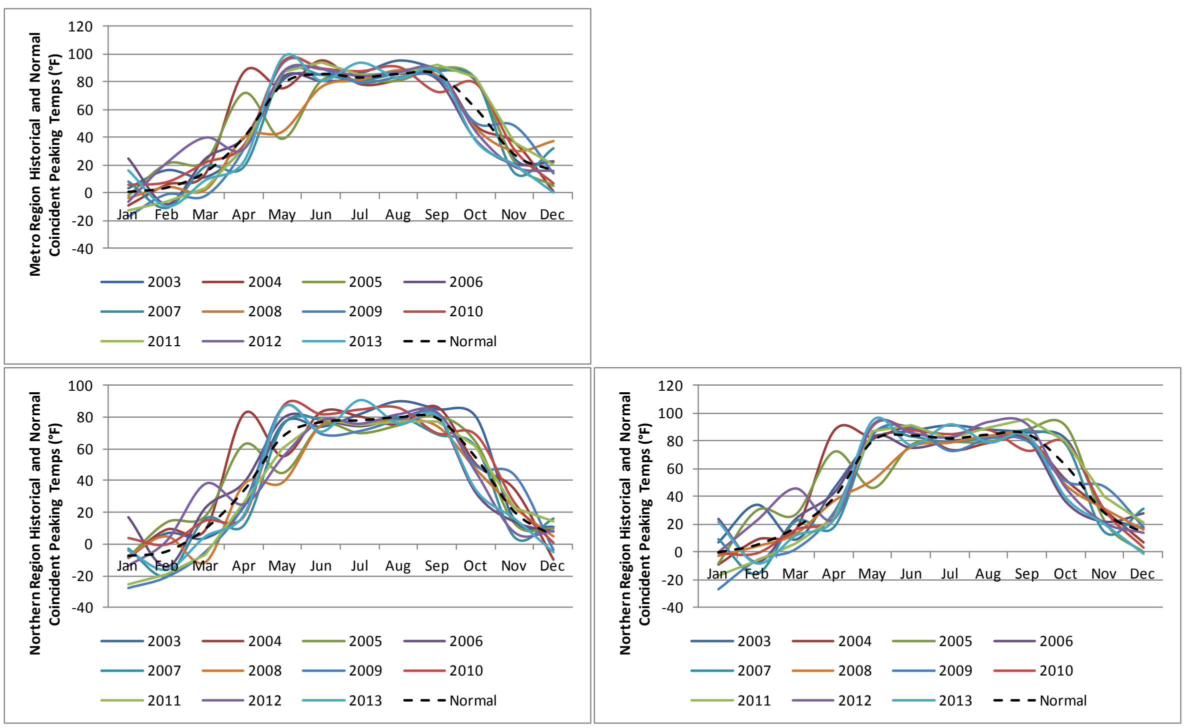


Figure 68. Monthly historic and 11-year normal peaking temperatures by forecast region at the time of GRE's coincident peak.

Peaking Temp Transformations

To take into account the different slope trend of cooling and space heating demand, temperatures at the time of each region's coincident peak were transformed into either a HotTemp or ColdTemp index using one of the following equations.

The HotTemp and ColdTemp index in the regional coincident peak demand models has numerous purposes:

(1) Because of different slope trends in heating and cooling responses to coincident peak demand, the two separate indexes allow for a cooling coefficient and space heating coefficient,
(2) During some shoulder months, the peak demand could be a result from either a cooling load or a space heating load. By having separate cold and hot temp indexes, the regression model can respond accordingly.
(3) Winter peaking temps can have a negative or positive temperature, and by doing a heating temp transformation, the resulting values will always be negative. If you have both negative and positive values for peaking temps, there will be a consequential interaction with the regression model's weather coefficient. By always having a negative value for heating temps, the heating temp will always be consistent with the regression model's heating coefficient.

Historic Hot Temp Index

If Coincident Peak Temp °F ≥ 65 then HotTemp Index = Coincident Peak Temp °F – 65, else 0

Where
Metro Region Peak Temp = temperature at time of coincident peak recorded at the MSP-St. Paul Airport
Northern Region Peak Temp = temperature at time of coincident peak recorded in Hibbing, MN
Southern & Western Peak Temp = temperature at time of coincident peak recorded Mason City, Iowa (Figure 69)

Normal Hot Temp Index

The weather normal HotTemp index was calculated by transforming the monthly historic GRE coincident peak temperatures using the equation above and then average these vales in a process similar to how normal GRE coincident peaking temperatures were calculated. The final weather normal HotTemp index used in the forecast period 2015-2029 can be found in Table 11.

$$\begin{aligned} Average(&JanHotTemp\&Peak_{2003} + JanHotTemp\&Peak_{2004} + JanHotTemp\&Peak_{2005} \\ &+ JanHotTemp\&Peak_{2006} + JanHotTemp\&Peak_{2007} + JanHotTemp\&Peak_{2008} \\ &+ JanHotTemp\&Peak_{2009} + JanHotTemp\&Peak_{2010} + JanHotTemp\&Peak_{2011} \\ &+ JanHotTemp\&Peak_{2012} + JanHotTemp\&Peak_{2013}) \end{aligned}$$

.

$$\begin{aligned} Average(&OctHotTemp\&Peak_{2003} + OctHotTemp\&Peak_{2004} + OctHotTemp\&Peak_{2005} \\ &+ OctHotTemp\&Peak_{2006} + OctHotTemp\&Peak_{2007} + OctHotTemp\&Peak_{2008} \\ &+ OctHotTemp\&Peak_{2009} + OctHotTemp\&Peak_{2010} + OctHotTemp\&Peak_{2011} \\ &+ OctHotTemp\&Peak_{2012} + OctHotTemp\&Peak_{2013}) \end{aligned}$$

.

$$Average(DecHotTemp\&Peak_{2003} + DecHotTemp\&Peak_{2004} + DecHotTemp\&Peak_{2005} + DecHotTemp\&Peak_{2006} + DecHotTemp\&Peak_{2007} + DecHotTemp\&Peak_{2008} + DecHotTemp\&Peak_{2009} + DecHotTemp\&Peak_{2010} + DecHotTemp\&Peak_{2011} + DecHotTemp\&Peak_{2012} + DecHotTemp\&Peak_{2013})$$

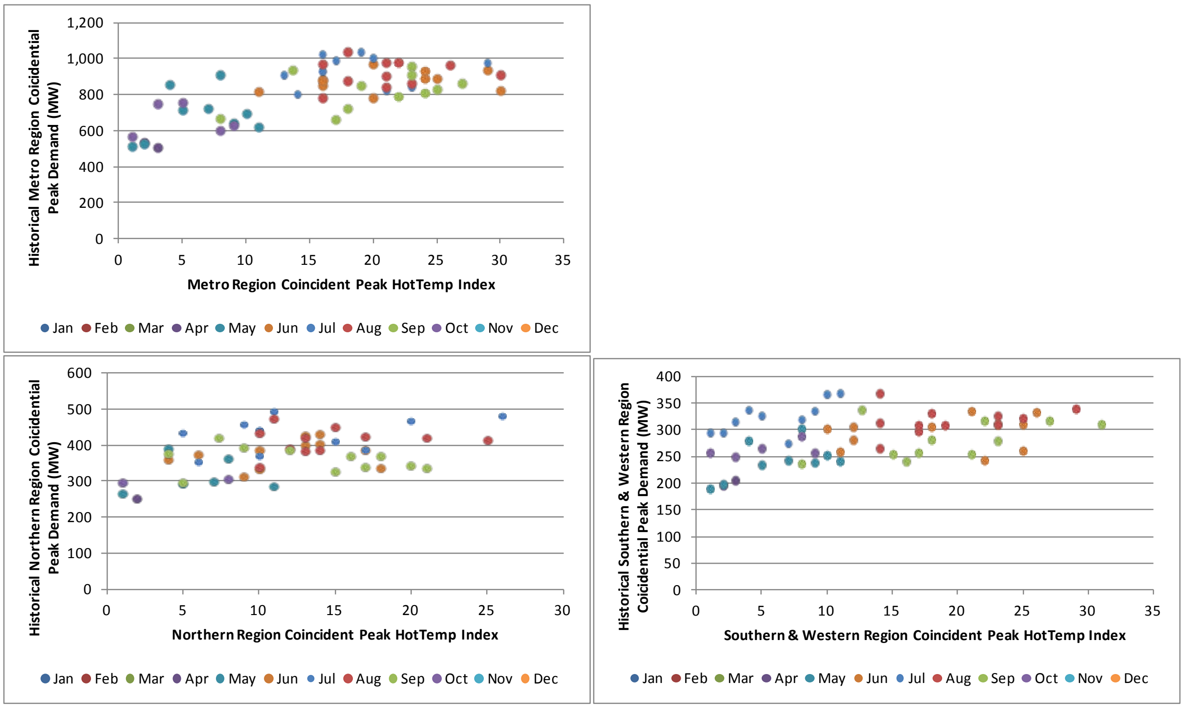


Figure 69. Monthly historic HotTemp index by forecast region at the time of GRE's coincident peak, 2003-2013.

Table 11. Monthly historic and 11-year normal HotTemp index by forecast region at the time of GRE's coincident peak, 2003-2013.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Metro Region HotTemp Index												
2003					16	20	21	30	24	15		
2004				22	10	30	13	16	22			
2005				7		16	16	16	25	17		
2006					19	16	17	21	17			
2007					21	20	16	21	23	16		
2008						11	16	23	19			
2009					28	24	14	18	18			
2010					30	25	23	26	8	14		
2011					22	29	20	21	27	18		
2012					22	24	19	22	23			
2013					33	16	29	18	14			
Normal	0	0	0	0	14	21	19	21	14	0	0	0
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Northern Region HotTemp Index												
2003					11	9	17	25	20	15		
2004				17		18	15	10	21			
2005						10	5	10	16			
2006					14	13	9	14	15			
2007					10	14	10	15	4			
2008						10	10	13	9			
2009					21	4	6	13	17			
2010					22	17	20	21	5	4		
2011						14	10	12	12			
2012						13	11	17	18			
2013					21	6	26	11	7			
Normal	0	0	0	0	3	12	13	15	7	0	0	0
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Southern&Western Region HotTemp Index												
2003					16	22	26	23	21	16		
2004				23	18	25	9	14	17			
2005				7		12	14	14	23	25		
2006					18	10	15	17	16			
2007					20	18	14	18	22	12		
2008						11		19	18			
2009					20	25	8	17	15			
2010					26	23	20	23	8	14		
2011					22	26	17	25	31	15		
2012					27	21	18	29	27			
2013					30	12	27	14	13			
Normal	0	0	0	0	15	19	17	19	13	0	0	0

Historic Cold Temp Index

If Coincident Peak Temp °F < 65 then ColdTemp Index = Coincident Peak Temp °F – 65, else 0

Where

Metro Region Peak Temp = temperature at time of coincident peak recorded at the MSP-St. Paul Airport

Northern Region Peak Temp = temperature at time of coincident peak recorded in Hibbing, MN
Southern & Western Peak Temp = temperature at time of coincident peak recorded Mason City, Iowa (70).

Normal Cold Temp Index

The weather normal ColdTemp index was calculated by transforming the monthly historic GRE coincident peak temperatures using the equation above and then average these vales in a process similar to how normal GRE coincident peaking temperatures were calculated. The final weather normal ColdTemp index used in the forecast period 2015-2029 can be found in Table 12.

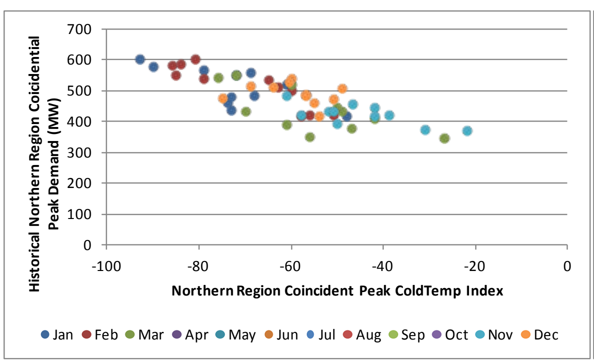
$$Average(JanColdTemp\&Peak_{2003} + JanColdTemp\&Peak_{2004} + JanColdTemp\&Peak_{2005} + JanColdTemp\&Peak_{2006} + JanColdTemp\&Peak_{2007} + JanColdTemp\&Peak_{2008} + JanColdTemp\&Peak_{2009} + JanColdTemp\&Peak_{2010} + JanColdTemp\&Peak_{2011} + JanColdTemp\&Peak_{2012} + JanColdTemp\&Peak_{2013})$$

.

$$Average(OctColdTemp\&Peak_{2003} + OctColdTemp\&Peak_{2004} + OctColdTemp\&Peak_{2005} + OctColdTemp\&Peak_{2006} + OctColdTemp\&Peak_{2007} + OctColdTemp\&Peak_{2008} + OctColdTemp\&Peak_{2009} + OctColdTemp\&Peak_{2010} + OctColdTemp\&Peak_{2011} + OctColdTemp\&Peak_{2012} + OctColdTemp\&Peak_{2013})$$

.

$$Average(DecColdTemp\&Peak_{2003} + DecColdTemp\&Peak_{2004} + DecColdTemp\&Peak_{2005} + DecColdTemp\&Peak_{2006} + DecColdTemp\&Peak_{2007} + DecColdTemp\&Peak_{2008} + DecColdTemp\&Peak_{2009} + DecColdTemp\&Peak_{2010} + DecColdTemp\&Peak_{2011} + DecColdTemp\&Peak_{2012} + DecColdTemp\&Peak_{2013})$$



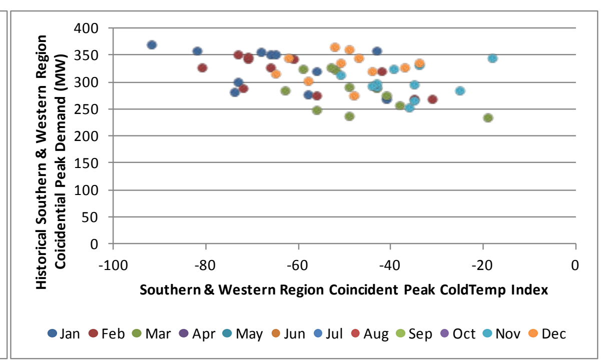


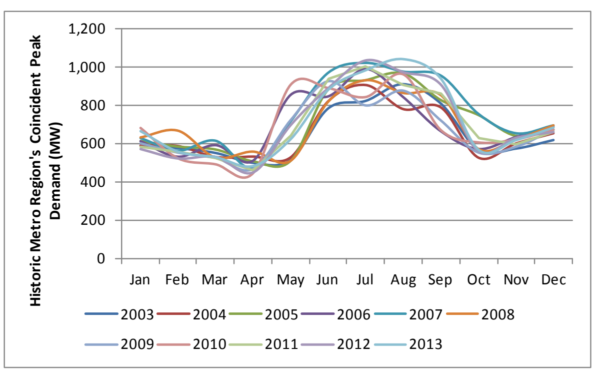
Figure 70. . Monthly historic ColdTemp index by forecast region at the time of GRE's coincident peak, 2003-2013.

Table 12. Monthly historic and 11-year normal HotTemp index by forecast region at the time of GRE's coincident peak, 2003-2013.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Northern Region ColdTemp Index												
2003	-73	-58	-61	-41							-50	-54
2004	-74	-56	-56		-10					-15	-31	-75
2005	-73	-51	-47	-2	-20						-52	-55
2006	-48	-79	-42	-26						-33	-51	-57
2007	-68	-85	-49	-53						-4	-61	-49
2008	-72	-60	-76	-27	-26					-18	-42	-60
2009	-93	-86	-70	-40						-16	-22	-69
2010	-61	-65	-50	-47							-39	-64
2011	-90	-84	-72	-38	-5					-3	-42	-51
2012	-79	-63	-27	-40	-10					-20	-58	-57
2013	-69	-81	-60	-46						-12	-47	-61
Normal	-73	-70	-55	-31	0	0	0	0	0	-12	-47	-61
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Southern & Western Region ColdTemp Index												
2003	-58	-31	-56	-19							-36	-48
2004	-74	-56	-49							-13	-35	-58
2005	-73	-35	-38		-19						-43	-65
2006	-41	-72	-41	-22						-29	-43	-37
2007	-56	-81	-43	-47							-51	-34
2008	-68	-61	-52	-28	-13		-65			-17	-34	-49
2009	-92	-71	-63	-36						-14	-18	-47
2010	-66	-66	-49	-39							-35	-62
2011	-82	-71	-59	-40							-25	-44
2012	-65	-42	-19	-41						-19	-44	-51
2013	-43	-73	-53	-41						-5	-40	-52
Normal	-65	-60	-47	-26	0	0	0	0	0	-5	-40	-52

Monthly Binaries

Monthly binary variables were used in the regional demand forecasts to help explain the intrinsically different levels of peak demand on monthly basis. The use of the binary variables is used to release the y-intercept of the structural model to demine each region's monthly load shape.



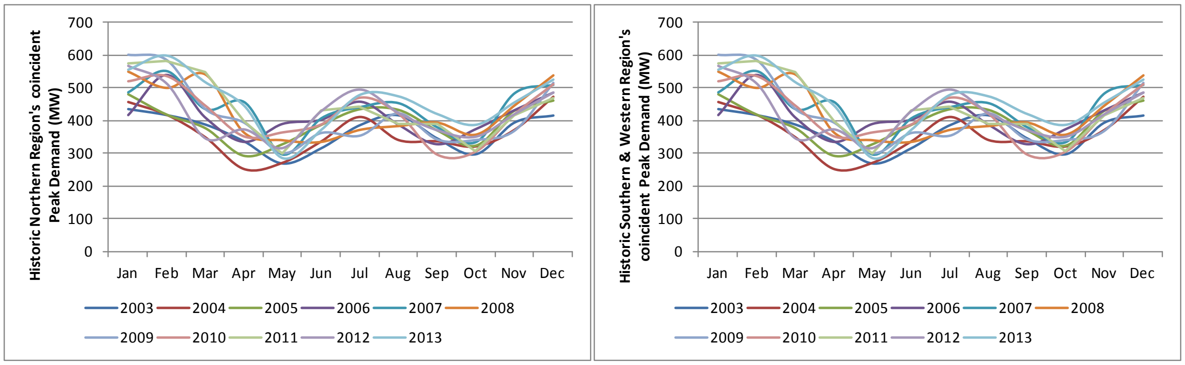


Figure 71. Historic monthly peak load by region at the time of GRE's coincident peak, 2003-2013.

Demand Regression Model's Structural Form and Coefficients

A monthly non-coincident peak demand model by forecast region was fit using multiple linear regression techniques with MetrixND©. Weather variables, monthly energy sales, and monthly binaries were the final independent variables used to describe regional non-coincident peak demand. All resulting models represent the peak demand at the time of GRE's monthly coincident peak.

An annual energy model was fit using multiple linear regression techniques with MetrixND© for each of the three forecast regions. For each forecast region, the final model structure is detailed below. Resulting coefficients, T-Stats, and P-values for each region's regression model can be found in Tables 13, 14, and 15.

Metro Region

$$\begin{aligned}\ln(Monthly\ Metro\ Peak\ Coincident\ Demand) &= \beta_0 + \beta_1 \ln(HotTemp) + \beta_2 \ln(Monthly\ Energy) + \beta_3(January) + \beta_4(February) \\ &+ \beta_5(March) + \beta_6(April) + \beta_7(May) + \beta_8(June) + \beta_9(July) + \beta_{10}(August) \\ &+ \beta_{11}(October) + \beta_{12}(November) + \beta_{13}(December)\end{aligned}$$

where:

β_0 = constant/y-intercept
$\beta_1 \ldots \beta_{13}$ = independent variable coefficients,
HotTemp = Minneapolis/St-Paul Airport HotTemp index at time of coincident peak,
Monthly Energy = Metro region monthly energy,
January = Binary Variable, if month = January than January = 1, else 0,
February = Binary Variable, if month = February than February = 1, else 0,
March = Binary Variable, if month = March than March = 1, else 0,
April = Binary Variable, if month = April than April = 1, else 0,
May = Binary Variable, if month = May than May = 1, else 0,
June = Binary Variable, if month = June than June = 1, else 0,
July = Binary Variable, if month = July than July = 1, else 0,
August = Binary Variable, if month = August than August = 1, else 0,
October = Binary Variable, if month = October than October = 1, else 0,
November = Binary Variable, if month = November than November = 1, else 0,

December = Binary Variable, if month = December than December = 1, else 0

Table 13 Metro Forecast Region demand model regression coefficients, T-Stat, and P-Values.

Variable	Metro Region Coefficient	StdErr	T-Stat	P-Value
Constant	-0.554052341	1.892798246	-0.292716005	0.770259059
ln(HotTempMinneapolis, MN)	0.069947061	0.00985374	7.098529012	5.67408E-10
ln(MetroRegion Monthly Energy Sales)	0.711306975	0.096507481	7.370485339	1.94412E-10
January	-0.127291034	0.042585899	-2.989041804	0.003409679
February	-0.123842409	0.042012231	-2.947770378	0.003861669
March	-0.173650093	0.041893058	-4.145080346	6.83324E-05
April	-0.242151645	0.040702739	-5.949271472	5.722E-08
May	-0.155280514	0.031025031	-5.005007525	2.52991E-06
June	0.010441529	0.031208262	0.334575785	0.738546758
July	-0.068401204	0.041272863	-1.657292467	0.100124591
August	-0.035808815	0.036305269	-0.986325569	0.325983805
October	-0.143823368	0.03474492	-4.139407062	6.97748E-05
November	-0.044033208	0.041930761	-1.050140928	0.295793387
December	-0.059408262	0.043147314	-1.376870466	0.171165677

Northern Region

$$\begin{aligned}\ln(Monthly\ Northern\ Region\ Peak\ Coincident\ Demand) &= \beta_0 + \beta_1 \ln(HotTemp) + \beta_2 \ln(-1 * ColdTemp) + \beta_3 \ln(Monthly\ Energy) \\ &+ \beta_4(January) + \beta_5(February) + \beta_6(March) + \beta_7(April) + \beta_8(May) + \beta_9(June) \\ &+ \beta_{10}(July) + \beta_{11}(August) + \beta_{12}(October) + \beta_{13}(November) + \beta_{14}(December)\end{aligned}$$

where:

β_0 = constant/y-intercept
$\beta_1 \ldots \beta_{14}$=independent variable coefficients,
HotTemp = Hibbing, MN HotTemp index at time of coincident peak,
Cold Temp =Hibbing, MN ColdTemp index at time of coincident peak,
Monthly Energy = Northern region monthly energy,
January = Binary Variable, if month = January than January = 1, else 0,
February = Binary Variable, if month = February than February = 1, else 0,
March = Binary Variable, if month = March than March = 1, else 0,
April = Binary Variable, if month = April than April = 1, else 0,
May = Binary Variable, if month = May than May = 1, else 0,
June = Binary Variable, if month = June than June = 1, else 0,
July = Binary Variable, if month = July than July = 1, else 0,
August = Binary Variable, if month = August than August = 1, else 0,
October = Binary Variable, if month = October than October = 1, else 0,
November = Binary Variable, if month = November than November = 1, else 0,
December = Binary Variable, if month = December than December = 1, else 0

Table 14. Northern Forecast Region demand model regression coefficients, T-Stat, and P-Values.

Variable	Northern Region Coefficient	StdErr	T-Stat	P-Value
Constant	-8.665246199	1.717944337	-5.043962144	2.18475E-06
ln(HotTempHibbing, MN)	0.039976677	0.01420399	2.814468094	0.005733604
ln(ColdTempHibbing, MN)	0.061505827	0.01284479	4.788386984	5.96199E-06
ln(Northern Region Monthly Energy Sales)	1.121216325	0.09032534	12.4130872	6.59528E-18
January	-0.363801202	0.059598841	-6.104165758	3.09287E-08
February	-0.201177655	0.053092629	-3.789182421	0.000247094
March	-0.268968404	0.049196737	-5.467200028	4.03822E-07
April	-0.179936071	0.040988397	-4.389927015	2.75411E-05
May	-0.207732024	0.031596432	-6.574540473	4.64863E-09
June	0.013826132	0.029798136	0.463993202	0.643522675
July	-0.063077644	0.035439592	-1.779863712	0.077698942
August	-0.036896477	0.032480892	-1.13594408	0.258298856
October	-0.226039799	0.037419039	-6.040769675	3.99557E-08
November	-0.269743312	0.047863198	-5.635714327	2.05E-07
December	-0.380073394	0.058158578	-6.535121801	5.44588E-09

Southern & Western Region

$$\ln(Monthly\ Southern\ \&\ Western\ Region\ Peak\ Coincident\ Demand) = \beta_0 + \beta_1 \ln(HotTemp) + \beta_2 \ln(-1 * ColdTemp) + \beta_3 \ln(Monthly\ Energy) + \beta_4(January) + \beta_5(February) + \beta_6(March) + \beta_7(April) + \beta_8(May) + \beta_9(June) + \beta_{10}(July) + \beta_{11}(August) + \beta_{12}(October) + \beta_{13}(November) + \beta_{14}(December)$$

where:

β_0 = constant/y-intercept
$\beta_1 \ldots \beta_{14}$=independent variable coefficients,
HotTemp = Mason City, Iowa HotTemp index at time of coincident peak,
Cold Temp =Mason City, Iowa ColdTemp index at time of coincident peak,
Monthly Energy = Southern & Western region monthly energy,
January = Binary Variable, if month = January than January = 1, else 0,
February = Binary Variable, if month = February than February = 1, else 0,
March = Binary Variable, if month = March than March = 1, else 0,
April = Binary Variable, if month = April than April = 1, else 0,
May = Binary Variable, if month = May than May = 1, else 0,
June = Binary Variable, if month = June than June = 1, else 0,
July = Binary Variable, if month = July than July = 1, else 0,
August = Binary Variable, if month = August than August = 1, else 0,
October = Binary Variable, if month = October than October = 1, else 0,
November = Binary Variable, if month = November than November = 1, else 0,
December = Binary Variable, if month = December than December = 1, else 0

Table 15. Southern & Western Forecast Region demand model regression coefficients, T-Stat, and P-Values.

Southern & Western Region				
Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
Constant	-4.840837976	0.948854739	-5.101769299	1.73767E-06
ln(Southern Region Monthly Energy Sales)	0.922358441	0.05092613	18.11169313	4.93464E-24
ln(HotTempMason City, Iowa)	0.033817841	0.015001542	2.254290964	0.026031201
ln(ColdTempMason City, Iowa)	0.038535884	0.013609549	2.831532784	0.005455584
January	-0.18607965	0.03685076	-5.049547088	2.13701E-06
February	-0.098488288	0.034934011	-2.819266555	0.005654144
March	-0.173769372	0.033518466	-5.184287801	1.25194E-06
April	-0.143548482	0.029652615	-4.841005889	4.85467E-06
May	-0.142310535	0.023415087	-6.077728132	3.44143E-08
June	0.016582533	0.023203477	0.714657231	0.476240105
July	-0.084948644	0.026223519	-3.239406785	0.001566662
August	-0.033196473	0.024706376	-1.34363992	0.181670655
October	-0.108005595	0.026686978	-4.047127244	9.82195E-05
November	-0.137339977	0.032757843	-4.192582983	5.75991E-05
December	-0.180953825	0.035866363	-5.045223749	2.17387E-06

Demand Model In-Sample Goodness-of-fit Statistics

The primary in-sample goodness-of-fit statistics used to determine how well the regression modes fit the historical data for the three forecast regions are detailed in Table 16.

Table 16. Monthly Regional GRE coincident peak demand model's in-sample goodness-of-fit statistics.

Metro Region Model Statistics	
Iterations	1
Adjusted Observations	132
Deg. of Freedom for Error	118
R-Squared	0.914142191
Adjusted R-Squared	0.90468328
AIC	-5.20208815
BIC	-4.896336431
F-Statistic	96.64349104
Prob (F-Statistic)	0
Log-Likelihood	170.0379315
Model Sum of Squares	6.258159619
Sum of Squared Errors	0.587777127
Mean Squared Error	0.004981162
Std. Error of Regression	0.070577348
Mean Abs. Dev. (MAD)	0.05141144
Mean Abs. % Err. (MAPE)	0.00383436
Durbin-Watson Statistic	1.678065796
Durbin-H Statistic	#NA
Ljung-Box Statistic	32.73909872
Prob (Ljung-Box)	0.109699231
Skewness	0.337129951
Kurtosis	3.47372127
Jarque-Bera	3.734710419
Prob (Jarque-Bera)	0.154531826

Northern Region Model Statistics	
Iterations	1
Adjusted Observations	132
Deg. of Freedom for Error	117
R-Squared	0.882651648
Adjusted R-Squared	0.868609965
AIC	-5.227629659
BIC	-4.900038531
F-Statistic	62.85939098
Prob (F-Statistic)	0
Log-Likelihood	172.723671
Model Sum of Squares	4.244751482
Sum of Squared Errors	0.56433882
Mean Squared Error	0.004823409
Std. Error of Regression	0.069450765
Mean Abs. Dev. (MAD)	0.050051366
Mean Abs. % Err. (MAPE)	0.003877899
Durbin-Watson Statistic	1.66238369
Durbin-H Statistic	#NA
Ljung-Box Statistic	27.46976797
Prob (Ljung-Box)	0.283036768
Skewness	0.238432748
Kurtosis	3.506968908
Jarque-Bera	2.66429996
Prob (Jarque-Bera)	0.263909251

Southern & Western Region Model Statistics	
Iterations	1
Adjusted Observations	132
Deg. of Freedom for Error	117
R-Squared	0.881510406
Adjusted R-Squared	0.867332164
AIC	-5.724320703
BIC	-5.396729575
F-Statistic	62.17346288
Prob (F-Statistic)	0
Log-Likelihood	205.50528
Model Sum of Squares	2.554918064
Sum of Squared Errors	0.343423291
Mean Squared Error	0.002935242
Std. Error of Regression	0.054177872
Mean Abs. Dev. (MAD)	0.039372131
Mean Abs. % Err. (MAPE)	0.003134456
Durbin-Watson Statistic	1.831132451
Durbin-H Statistic	#NA
Ljung-Box Statistic	22.69040339
Prob (Ljung-Box)	0.538130396
Skewness	0.193178723
Kurtosis	3.667892247
Jarque-Bera	3.274436713
Prob (Jarque-Bera)	0.194520377

Demand Model Residual Plots

Some informal diagnostic plots of coincident peak demand residuals are presented to provide information on whether any of the following departures from the regression model are present (Figures 72-74):

(1) The regression model is linear
(2) The error terms do not have a constant variance.

Metro Region

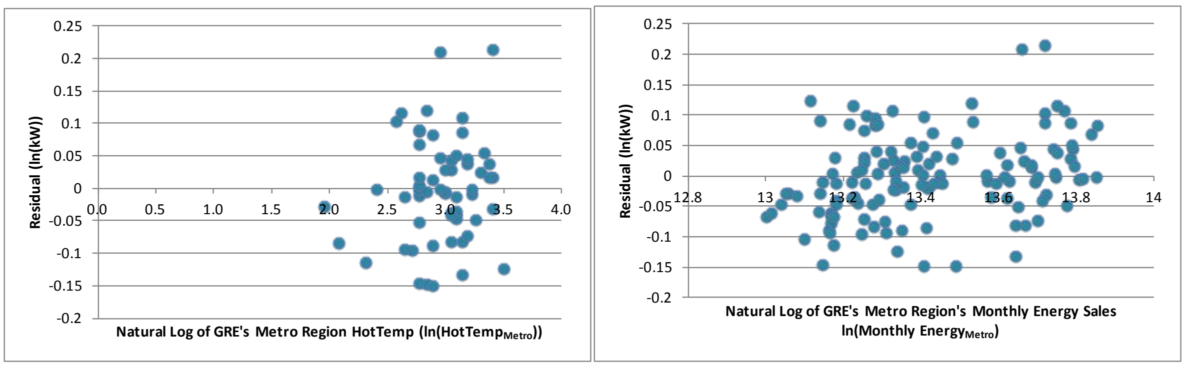


Figure 72. Metro Region non-coincident peak demand model residuals.

Northern Region

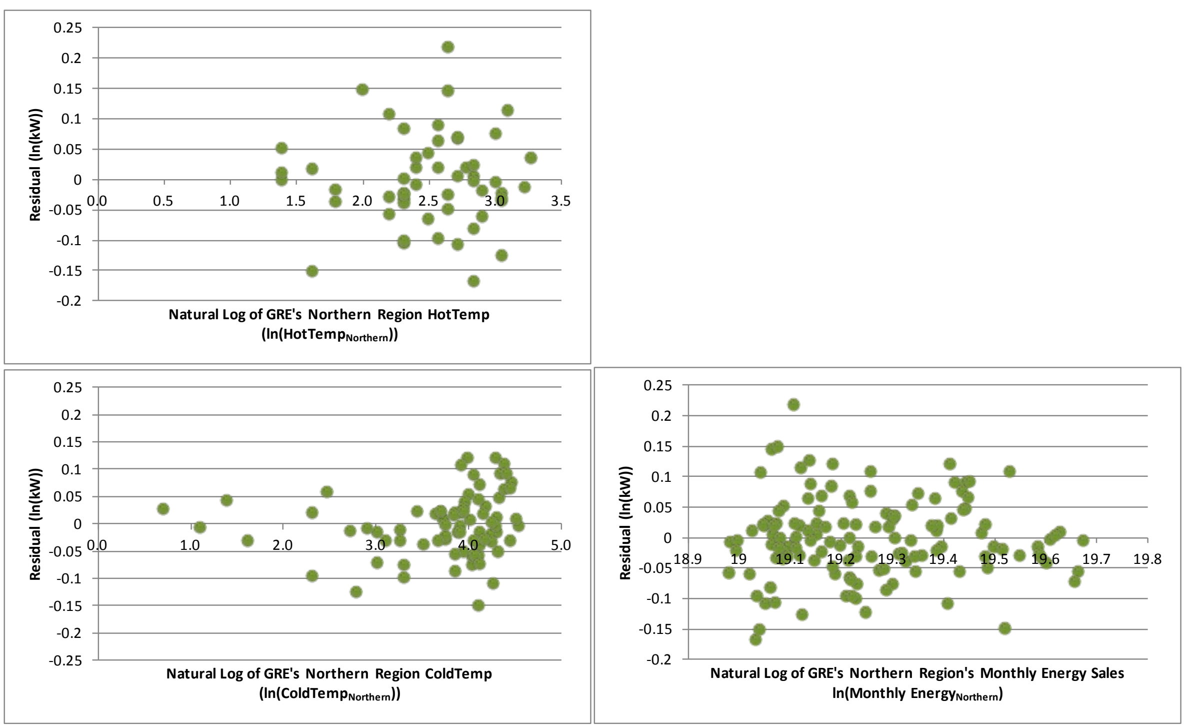


Figure 73. Northern region non-coincident peak demand model residuals.

Southern & Western Region

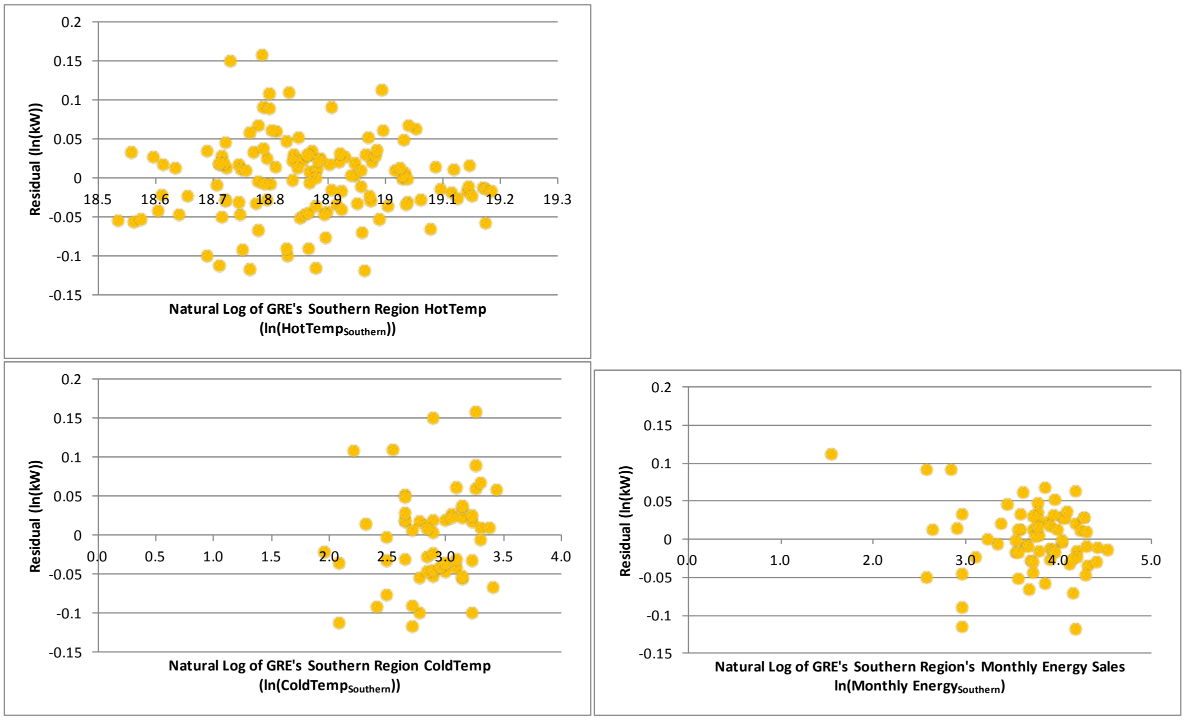


Figure 74. Southern & Western region non-coincident peak demand model residuals.

Predicted Vs. Actual Scatterplots

Scatterplots of actual energy vs. predicted energy sales for the three forecast regions show the expected approximate 1:1 relationship between actual energy sales and predicted energy sales (Figure 75). Across the range of actual energy sales values, there is no discernable trend of under or over predicting.

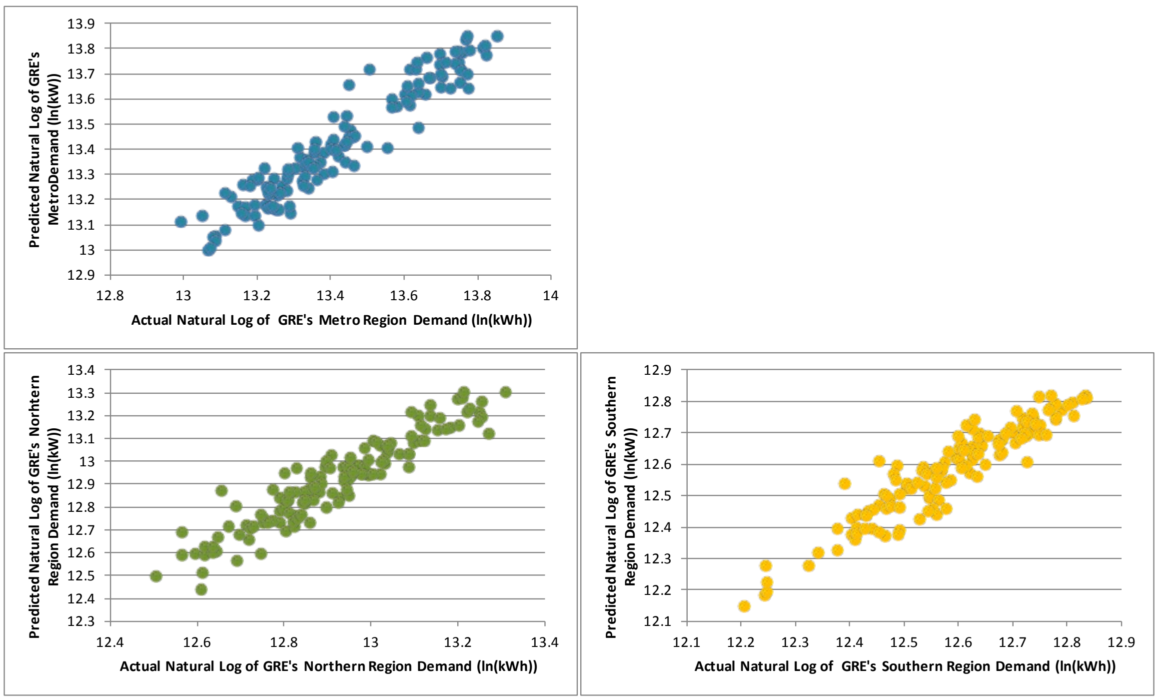


Figure 75. Scatterplot of natural log of actual non-coincident peak demand vs. natural log of predicted non-coincident peak demand for the three forecast regions.

This Page was Intentionally Left Blank

Monthly Peak Demand Results

Metro Region

In the Metro Forecast Region, 5-year compounded annual growth rates for summer and non-coincident peak demand indicate a 0.9% annual increase in demand. The 10-year and 20-year compounded annual growth rates show a 1.4% and 1.6% growth rate, respectively (Table 17).

Figure 76 shows the historical and forecast non-coincident peak demand for the Metro Forecast Region. The figure also includes the upper and lower 95% confidence intervals for the forecast.

Table 17. Forecast of monthly Metro Region peak demand at the time of GRE's coincident monthly peak.

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer	Winter
2015	632	580	558	486	670	906	963	947	819	567	633	692	963	692
2016	639	586	564	491	677	916	974	957	828	573	640	700	974	700
2017	646	593	570	497	685	926	985	968	838	580	648	708	985	708
2018	655	601	578	503	694	938	998	981	849	587	656	717	998	717
2019	664	609	586	511	704	952	1,012	995	861	596	666	727	1,012	727
2020	674	619	595	518	714	967	1,028	1,010	874	605	676	738	1,028	738
2021	685	628	604	526	726	982	1,044	1,026	888	614	686	750	1,044	750
2022	695	637	613	534	736	996	1,059	1,041	901	623	696	761	1,059	761
2023	705	647	622	542	747	1,011	1,075	1,056	914	633	707	772	1,075	772
2024	716	657	631	550	758	1,026	1,091	1,072	928	642	717	784	1,091	784
2025	727	667	641	559	770	1,042	1,108	1,089	942	652	729	796	1,108	796
2026	739	678	652	568	783	1,059	1,126	1,106	957	663	740	809	1,126	809
2027	751	689	662	577	795	1,076	1,144	1,125	973	674	753	822	1,144	822
2028	763	700	673	586	808	1,094	1,163	1,143	989	685	765	835	1,163	835
2029	775	711	684	596	821	1,111	1,182	1,161	1,005	696	777	849	1,182	849
5-Year (CAGR)													**0.9%**	**0.9%**
10-Year (CAGR)													**1.4%**	**1.4%**
15-Year (CAGR)													**1.5%**	**1.5%**

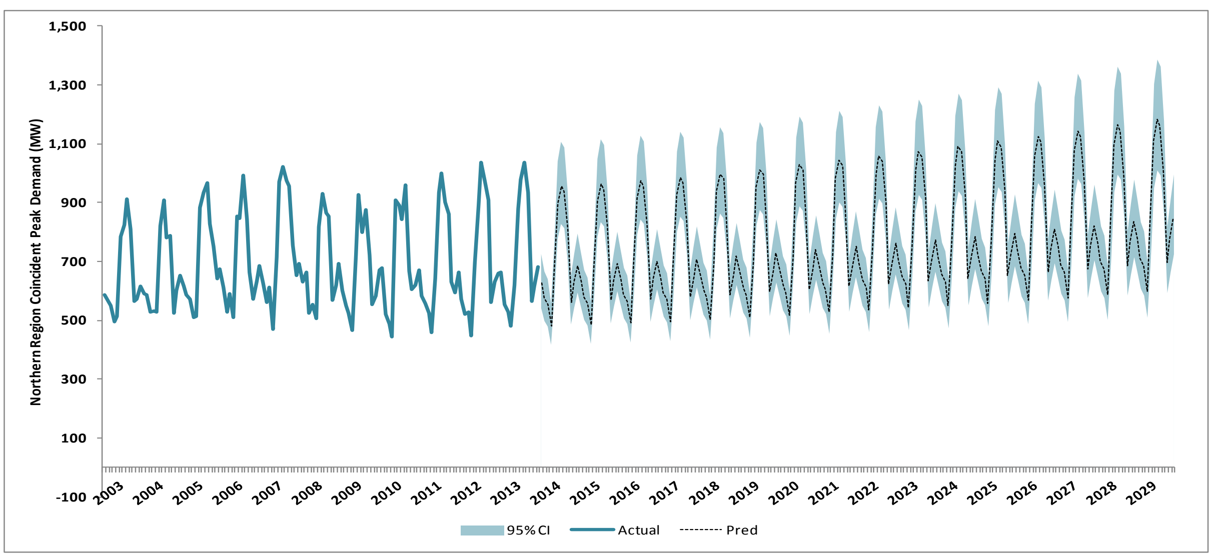


Figure 76. Historic and forecast of monthly Metro Region peak demand at the time of GRE's coincident monthly peak, 2003-2029.

Northern Region

In the Northern Forecast Region, 5-year compounded annual growth rates for summer non-coincident peak demand indicate a 0.9% annual increase in demand. The 10-year and 20-year compounded annual growth rates show a 1.4% and 1.2% growth rate, respectively (Table 18).

Five-year compounded annual growth rates for winter non-coincident peak demand indicate a 0.9% annual increase in demand. The 10-year and 20-year compounded annual growth rates show a 1.4 % and 1.2% growth rate, respectively (Table 18).

Figure 77 shows the historical and forecast non-coincident peak demand for the Northern Forecast Region. The figure also includes the upper and lower 95% confidence intervals for the forecast.

Table 18. . Forecast of monthly Northern Region peak demand at the time of GRE's coincident monthly peak.

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer	Winter
2015	539	539	455	383	297	397	455	435	372	363	446	517	455	538
2016	538	538	454	383	297	397	455	434	371	362	445	517	455	543
2017	543	543	458	386	300	400	459	438	375	366	449	521	459	551
2018	551	551	465	392	304	406	465	445	380	371	456	529	465	557
2019	557	557	470	396	307	411	471	449	384	375	461	534	471	565
2020	565	565	477	401	312	416	477	456	390	380	467	542	477	575
2021	575	575	485	409	317	424	486	464	397	387	475	552	486	580
2022	580	580	490	413	320	428	490	468	401	391	480	557	490	590
2023	590	590	498	420	326	435	499	476	407	397	488	566	499	601
2024	601	601	507	427	332	443	508	485	415	405	497	577	508	612
2025	612	612	516	435	337	451	517	494	422	412	506	587	517	623
2026	623	623	526	443	344	459	527	503	430	420	515	598	527	637
2027	637	637	537	453	351	470	538	514	440	429	527	611	538	647
2028	647	647	546	460	357	477	547	522	447	436	535	621	547	659
2029	659	659	556	468	363	486	557	532	455	443	545	632	557	632
5-Year (CAGR)													**0.6%**	**0.9%**
10-Year (CAGR)													**1.2%**	**1.4%**
15-Year (CAGR)													**1.4%**	**1.2%**

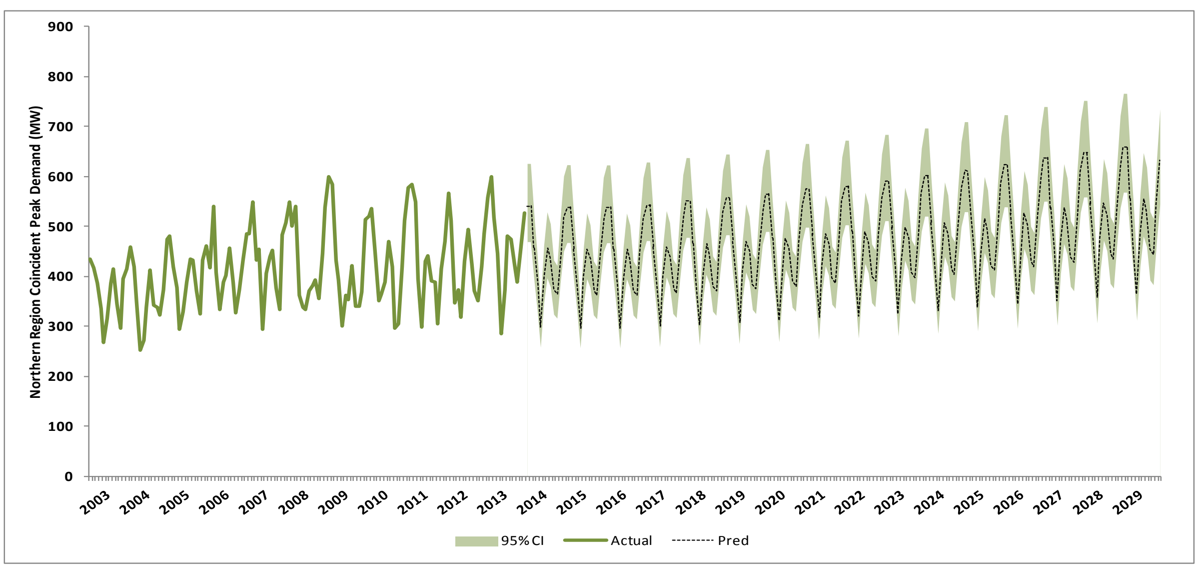


Figure 77. Historic and forecast of monthly Northern Region peak demand at the time of GRE's coincident monthly peak, 2003-2029.

Southern & Western Region

In the Southern & Western Forecast Region, 5-year compounded annual growth rates for summer and winter non-coincident peak demand indicate a 1.0 % annual increase in demand. The 10-year and 20-year compounded annual growth rates show a 1.4% and 1.5% growth rate, respectively (Table 19).

Figure 78 shows the historical and forecast non-coincident peak demand for the Southern & Western Forecast Region. The figure also includes the upper and lower 95% confidence intervals for the forecast.

Table 19. . Forecast of monthly Southern & Western Region peak demand at the time of GRE's coincident monthly peak.

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer	Winter
2015	358	345	308	266	254	321	350	348	302	299	330	363	350	363
2016	361	348	311	268	256	323	353	351	304	302	333	366	353	366
2017	366	353	315	272	260	328	358	356	309	306	338	371	358	373
2018	373	360	321	277	265	334	365	362	314	311	344	378	365	378
2019	378	364	325	281	268	338	370	367	318	316	348	383	370	383
2020	383	370	330	285	272	343	375	372	323	320	354	389	375	391
2021	391	377	336	290	277	350	382	379	329	326	360	396	382	396
2022	394	380	339	293	280	353	386	383	332	329	363	399	386	400
2023	400	386	344	297	284	358	392	389	337	334	369	406	392	406
2024	406	392	350	302	288	364	398	395	343	340	375	412	398	413
2025	413	398	355	307	293	369	404	401	348	345	381	418	404	420
2026	420	405	361	312	298	376	411	408	354	351	387	425	411	428
2027	428	413	368	318	304	383	419	416	361	358	395	434	419	434
2028	434	418	373	322	308	388	424	421	365	362	400	440	424	440
2029	440	425	379	327	313	394	431	428	371	368	406	446	431	446
5-Year (CAGR)													**1.0%**	**1.0%**
10-Year (CAGR)													**1.4%**	**1.4%**
15-Year (CAGR)													**1.5%**	**1.5%**

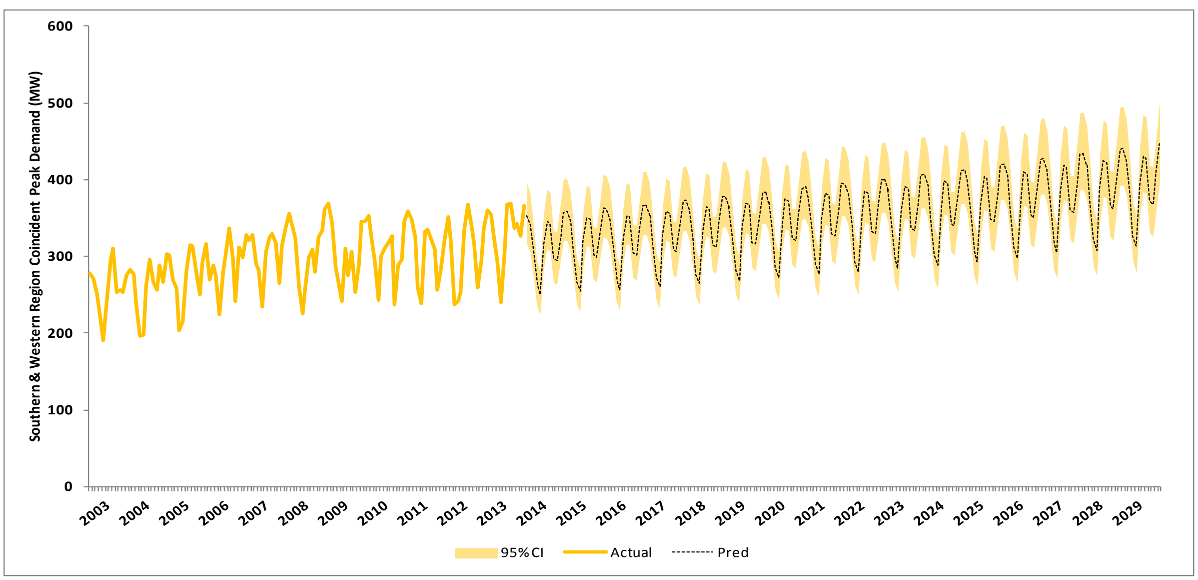


Figure 78. Historic and forecast of monthly Southern & Western Region peak demand at the time of GRE's coincident monthly peak, 2003-2029.

All Requirement Members Coincident Peak Demand Forecast

Aggregating the three non-coincidental monthly peak demand forecasts produces GRE's All Requirement Member coincident peak demand forecast, aggregation of Tables 17, 18, 19.

GRE's All Requirement Member coincident peak demand forecast's 5-year compounded annual growth rate for summer non-coincident peak demand indicates a 0.8% annual increase in demand. The 10-year and 20-year compounded annual growth rates show a 1.4% and 1.5% growth rate, respectively (Table 20).

Five-year compounded annual growth rates for winter non-coincident peak demand indicate a 0.8% annual increase in demand. The 10-year and 20-year compounded annual growth rates show a 1.3 % and 1.5% growth rate, respectively (Table 20).

Table 20. Forecast of GRE's monthly All Requirement member coincident peak demand.

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer	Winter
2015	1,529	1,464	1,320	1,135	1,221	1,624	1,769	1,729	1,493	1,229	1,409	1,572	1,769	1,572
2016	1,538	1,473	1,329	1,142	1,230	1,636	1,782	1,742	1,504	1,237	1,419	1,582	1,782	1,582
2017	1,556	1,489	1,344	1,155	1,244	1,654	1,802	1,762	1,521	1,251	1,435	1,600	1,802	1,600
2018	1,578	1,511	1,363	1,172	1,262	1,678	1,828	1,787	1,543	1,270	1,456	1,623	1,828	1,623
2019	1,599	1,531	1,381	1,187	1,279	1,701	1,853	1,811	1,564	1,286	1,475	1,645	1,853	1,645
2020	1,623	1,553	1,402	1,205	1,298	1,726	1,880	1,838	1,587	1,305	1,497	1,669	1,880	1,669
2021	1,650	1,580	1,426	1,225	1,320	1,755	1,912	1,869	1,614	1,328	1,522	1,697	1,912	1,697
2022	1,669	1,598	1,442	1,239	1,336	1,776	1,935	1,892	1,633	1,343	1,540	1,717	1,935	1,717
2023	1,696	1,623	1,465	1,259	1,357	1,804	1,965	1,921	1,659	1,364	1,564	1,744	1,965	1,744
2024	1,723	1,650	1,488	1,279	1,378	1,833	1,996	1,952	1,685	1,386	1,589	1,772	1,996	1,772
2025	1,751	1,677	1,513	1,300	1,401	1,862	2,029	1,983	1,712	1,409	1,615	1,801	2,029	1,801
2026	1,782	1,706	1,539	1,323	1,424	1,894	2,063	2,017	1,741	1,433	1,643	1,832	2,063	1,832
2027	1,816	1,739	1,568	1,348	1,451	1,929	2,101	2,054	1,774	1,460	1,674	1,867	2,101	1,867
2028	1,844	1,765	1,592	1,369	1,473	1,959	2,134	2,086	1,801	1,482	1,700	1,896	2,134	1,896
2029	1,874	1,795	1,619	1,391	1,497	1,991	2,169	2,121	1,831	1,507	1,728	1,928	2,169	1,928
5-Year (CAGR)													0.8%	0.8%
10-Year (CAGR)													1.4%	1.3%
15-Year (CAGR)													1.5%	1.5%

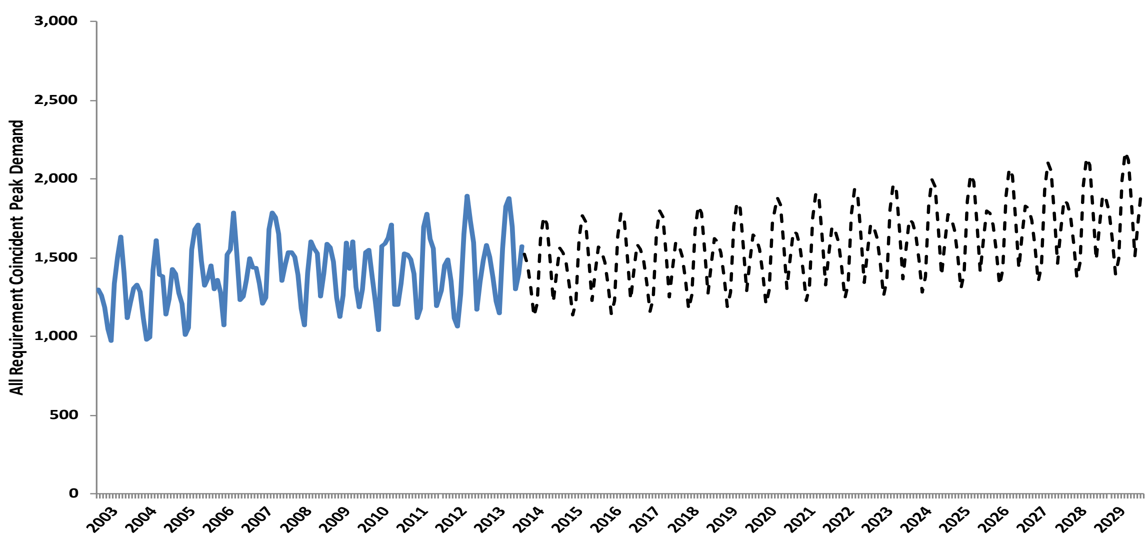


Figure 79. Historic and forecast of monthly All Requirement Member peak coincident peak demand, 2003-2029.

Figure 79 shows the historical and forecast coincident peak demand for GRE's All Requirement Members. The figure also includes the upper and lower 95% confidence intervals for the forecast.

This Page Was Intentionally Left Blank

Energy and GRE Coincident Peak Additions and Subtractions

All energy and coincident peak demand adjustments are due to one of the following:

1.) A long term power contract to purchase a fixed amount of energy and capacity,
2.) A current load that will have a contract expire and GRE will not be renewing it,
3.) Transmission and DC Line Losses, or
4.) A future load that GRE is currently obligated to serve.

Additions:

The following additions have been made to the IRP forecasts (Table 21).

Fixed Member Requirements

Eight of GRE's 28 member distribution members have entered into a long term power purchase contract and purchase only a fixed amount of their capacity and energy from GRE.

Southern Minnesota Electrical Cooperative

Southern Minnesota Electrical Cooperative (SMEC) was formed by 12 electric distribution cooperatives as the single point of contact for the purchase of electric service territory in Southern Minnesota from Alliant Energy. Five of the 12 distribution cooperatives are All Requirement members of Great River Energy. At the end of 2024, a supply agreement with Alliant Energy will be terminated and 5 All Requirement Members in SMEC will be required to serve this load. We talked with the SMEC members who are also GRE members to forecast the additional energy and demand requirements of those new loads on their systems.

Dakota Spirit AgEnergy

When it begins operating in early 2015, Midwest AgEnergy Group's Dakota Spirit AgEnergy biorefinery will produce 65 million gallons of ethanol a year from North Dakota corn, as well as dry and modified distillers grains for live stock, corn oil for biodiesel production and E85.

DC Line Losses

DC line losses with Great River Energy's 400-kV high-voltage direct current (HVDC) transmission line, which transports electricity from GRE's largest generation facility, Coal Creek Station in Underwood, ND., to Minnesota.

Transmission Losses

Transformation losses and transmission losses associated with GRE's 20 All Requirement Members and 8 Fixed Members.

Subtractions

The following subtractions have been made to the IRP forecasts (Table 21).

Elk River Municipal

Currently Elk River Municipal (ERMU) receives wholesale power from GRE through an "all requirement" purchase power agreement with Connexus Energy, one of GRE's 28 member distribution cooperatives.

This power purchase agreement expires on September 30, 2018 after which neither GRE nor Connexus will be serving energy and demand requirements for ERMU.

Table 21. Current trends annual All Requirement energy forecast. Includes all future energy additions, subtractions, DC line losses, and transmission losses.

Year	50/50 All Requirement Member Forecast (=)	Elk River Municipal (-)	DC Line Losses (+)	Transmission Losses (+)	Allliant Load Southern Coops Forecasts (+)	Fixed Member Requriements (+)	Dakota Spirit Ag (+)	Current Trends*
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
2015	9,356,229	0	559,055	537,515	0	2,553,891	34,667	13,041,357
2016	9,439,215	0	560,637	541,894	0	2,561,282	41,600	13,144,629
2017	9,566,910	0	559,055	547,217	0	2,551,863	41,600	13,266,644
2018	9,728,411	0	559,055	554,422	0	2,550,478	41,600	13,433,966
2019	9,883,123	(288,298)	559,055	548,411	0	2,550,478	41,600	13,294,368
2020	10,056,657	(288,298)	560,637	556,220	0	2,550,478	41,600	13,477,294
2021	10,255,236	(288,298)	559,055	565,156	0	2,550,478	41,600	13,683,226
2022	10,402,439	(288,298)	559,055	571,780	0	2,550,478	41,600	13,837,053
2023	10,593,414	(288,298)	559,055	580,374	0	2,550,478	41,600	14,036,623
2024	10,792,093	(288,298)	560,637	589,314	0	2,550,478	41,600	14,245,825
2025	10,998,505	(288,298)	559,055	606,801	182,190	2,550,478	41,600	14,650,331
2026	11,217,028	(288,298)	559,055	616,635	182,190	2,550,478	41,600	14,878,688
2027	11,461,867	(288,298)	559,055	627,653	182,190	2,550,478	41,600	15,134,544
2028	11,671,973	(288,298)	560,637	637,107	182,190	2,550,478	41,600	15,355,688
2029	11,899,353	(288,298)	559,055	647,340	182,190	2,550,478	41,600	15,591,718
*Current Trends Forecast Components (All Forecasts Share these Components regardless of sensitivities)								
**Five-year CAGR is significantly impacted with the loss of Elk River Municipal in 2019.							5-Year CAGR**	0.48%
							10-Year CAGR	0.99%
							15-Year CAGR	1.28%

Table 22. Current trends annual All Requirement coincident peak demand forecast. Includes all future demand additions, subtractions, DC line losses, and transmission losses.

Year	50/50 All Requirement Member Forecast (=)	Elk River Municipal (-)	DC Line Losses (+)	Transmission Losses (+)	Allliant Load Southern Coops Forecasts (+)	Fixed Member Requriements (+)	Dakota Spirit Ag (+)	Current Trends* Coincident Summer Peak
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)
2015	1,769	0	77	102	0	498	5	2,452
2016	1,782	0	77	103	0	498	5	2,466
2017	1,802	0	77	104	0	498	5	2,487
2018	1,828	0	77	105	0	498	5	2,514
2019	1,853	(70)	77	103	0	498	5	2,466
2020	1,880	(70)	77	104	0	498	5	2,495
2021	1,912	(70)	77	106	0	498	5	2,528
2022	1,935	(70)	77	107	0	498	5	2,552
2023	1,965	(70)	77	108	0	498	5	2,584
2024	1,996	(70)	77	109	0	498	5	2,617
2025	2,029	(70)	77	112	27	498	5	2,678
2026	2,063	(70)	77	114	27	498	5	2,714
2027	2,101	(70)	77	115	27	498	5	2,754
2028	2,134	(70)	77	117	27	498	5	2,788
2029	2,169	(70)	77	118	27	498	5	2,825
*Current Trends Forecast Components (All Forecasts Share these Components regardless of sensitivities)								
**Five-year CAGR is significantly impacted with the loss of Elk River Municipal in 2019.							5-Year CAGR**	0.15%
							10-Year CAGR	0.72%
							15-Year CAGR	1.02%

Energy and Coincident Demand Sensitivities

Increased Conservation and Electrical Efficiency

Increased levels of conservation and electrical efficiency were raised from the inherent 1.5% embedded in the base energy forecast to 1.75% and 2.0% (Table 25 and 26).

Distributed Generation

Hourly load shapes were developed to represent an increase in customer owned photovoltaic systems that reduces GRE retail energy sales by 1.5% in 2029. Size and number of systems were considered across the residential, small commercial, and large commercial customer classes. Base hourly load shapes for the residential, small commercial, and large commercial systems were based on hourly photovoltaic data in Minneapolis, MN for an average metrological year provided by, National Renewable Energy Laboratory, PVWatts® Calculator. Table 23 provides a breakdown of all assumptions used to model future customer owned photovoltaic systems. Figures 80 and 81 provide an illustration in the expected reduction in retail energy sales and peak demand due to a 1.5% reduction in retail sales by 2029.

High and Low Load Growth

Hourly load shapes were created by scaling up or down the base forecast. High and low growth sensitivities were by increasing the 15-year compounded annual growth rate of the base forecast by 100% and decreasing the 15-year compounded annual growth rate of the base forecast by 50% (Table 25 and 26).

Table 23. Forecast assumptions for customer owned distributed generation.

2029 Distributed Generation Goals	
Total Retail Energy 2029 (kWh)[1]	14,385,323,121
Total Customer Owned Distributed Generation Goal 2029 (%)[2]	1.5%
Total Customer Onwed Distributed Generation Goal (kWh)[3]	215,779,847
Total Customer Owned Distriubted Generation Goal Year[4]	2029
2029 Distributed Generation Goal Customer Class (%)[5]	
Residential	0.91%
Small Commercial	0.34%
Large Commercial	0.26%
2029 Distributed Generation Goal by Customer Class (kWh)[6]	
Residential	130,845,226
Small Commercial	48,206,136
Large Commercial	36,728,485
Average Distributed Generation Size (KW)[7]	
Residential	7
Small Commercial	20
Large Commercial	250

[1]2029 Total Retail Energy equals the sum of All Requirement Energy Sales, Elk River Municipal Alliant Southern Load Coops, Fixed Member Requirements, and Dakota Spirit Wood Agriculture (does not include DC line losses or Transmission losses)
[2]Total customer owned distributed generation goal (%) represents the percent of total energy that is provided by customer owned distributed generation.
Total customer owned distributed generation goal (kWh) represents the percent of total energy that is proved by customer owned distributed generation.
[4]Total customer owned distributed generation goal year represents the year the total customer owned distributed generation goal (kWh) will be met.
[5]Distributed generation goal by customer class (%) represents the amount of energy produced by each customer class in the goal year.
[6]Distributed generation goal by customer class (kWh) represents the amount of energy produced by each customer class in the goal year.
[7]Average distributed generation size (KW) represents the averages size of the customer owned system.

Graphical illustration of the forecast effects of increased customer owned distributed generation for both energy and demand can be found in Figures 80 and 81.

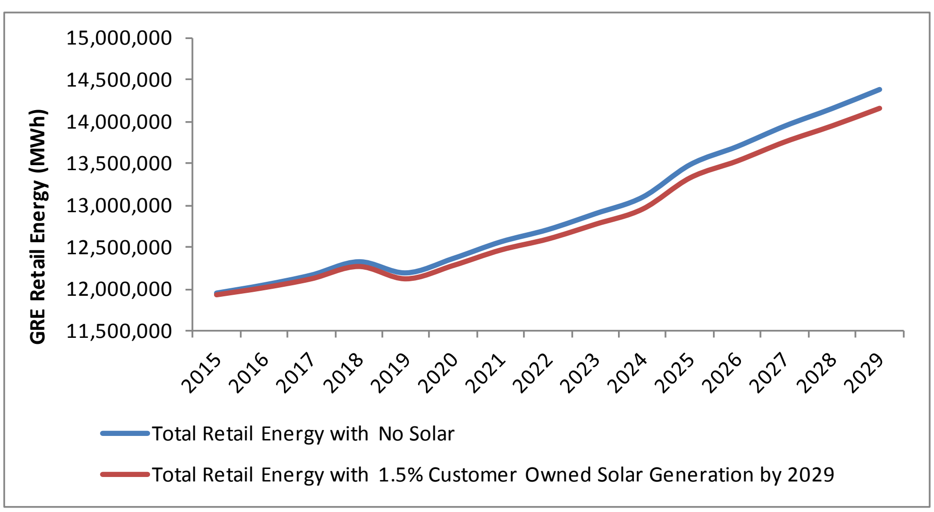


Figure 80. Forecast energy requirement effects of increased customer owned distributed generation.

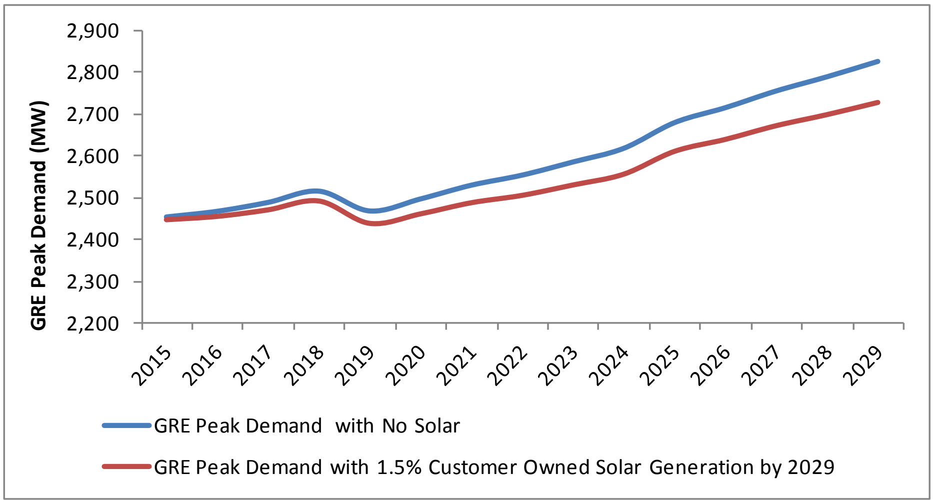


Figure 81. Forecast coincident peak demand effects of increased customer owned distributed generation.

Electric Vehicles

Hourly load shapes were developed to reflect a 5% increase in EV in Great River Energy's metro area by 2029. Charging types and Time-of-Use charging programs were considered in the modeling effort. A description of the EV saturation, charging type of, and charging program saturation assumptions from 2015 to 2029 are found in Table 24.

Table 24. Forecast assumptions for battery operated vehicles.

			Charge Type Saturation		Program Type Saturation	
Year	EV Saturation	EV (Units)	Level-1 (120 V AC)	Level-2 (240 V AC)	None (On-Peak)	Time of Use
2015	0.02%	43	90%	10%	30%	70%
2016	0.03%	65	87%	13%	29%	71%
2017	0.04%	97	84%	16%	27%	73%
2018	0.07%	147	81%	19%	26%	74%
2019	0.10%	221	79%	21%	24%	76%
2020	0.15%	334	76%	24%	23%	77%
2021	0.22%	503	73%	27%	21%	79%
2022	0.32%	759	70%	30%	20%	80%
2023	0.47%	1,144	67%	33%	19%	81%
2024	0.70%	1,724	64%	36%	17%	83%
2025	1.04%	2,599	61%	39%	16%	84%
2026	1.54%	3,918	59%	41%	14%	86%
2027	2.28%	5,907	56%	44%	13%	87%
2028	3.37%	8,905	53%	47%	11%	89%
2029	5.00%	13,424	50%	50%	10%	90%

Graphical illustration of the forecast effects of increased customer owned electric vehicles for both energy and demand can be found in Figures 82 and 83.

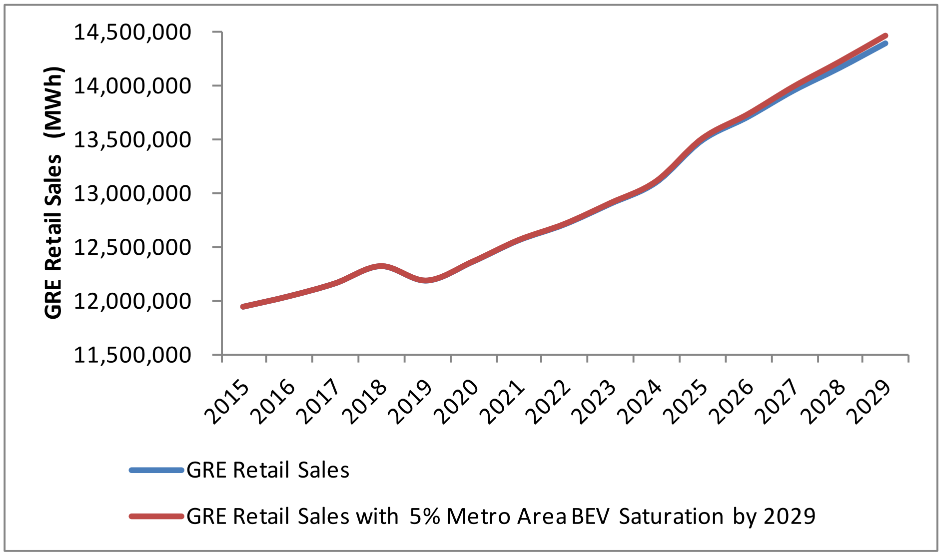


Figure 82. Forecast energy requirement effects of increased customer owned electric vehicle ownership.

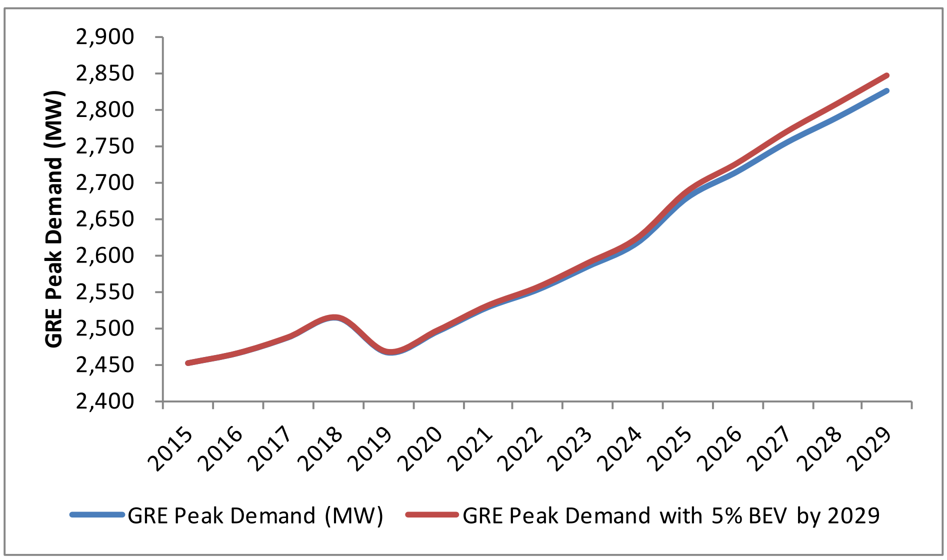


Figure 83. Forecast coincident peak demand effects of increased customer owned electric vehicles.

Table 23. Annual energy forecast sensitivities for high & low growth, increased conservation & efficiency, customer owned distributed generation and electrical vehicles.

Year	Current Trends/Base Forecast (MWh)	High Energy (MWh)	Low Energy (MWh)	Medium High Conservation & Electrical Efficiency (MWh)	High Conservation and Electrical Efficciency (MWh)	Increased Distributed Generation (MWh)	Increased Electric Vehicles (MWh)
2015	13,041,357	13,041,357	13,041,357	13,017,966	12,994,634	13,029,319	13,041,609
2016	13,144,629	13,359,430	13,049,770	13,121,031	13,097,492	13,120,256	13,145,012
2017	13,266,644	13,696,246	13,076,927	13,242,727	13,218,869	13,229,783	13,267,222
2018	13,433,966	14,078,368	13,149,390	13,409,645	13,385,385	13,384,277	13,434,840
2019	13,294,368	14,153,571	12,820,075	13,269,660	13,245,014	13,231,515	13,295,690
2020	13,477,294	14,551,298	13,003,000	13,452,152	13,427,073	13,400,801	13,479,299
2021	13,683,226	14,972,031	13,114,074	13,657,588	13,632,014	13,592,942	13,686,252
2022	13,837,053	15,340,659	13,173,043	13,811,047	13,785,106	13,732,440	13,841,630
2023	14,036,623	15,755,029	13,277,753	14,010,139	13,983,722	13,917,207	14,043,545
2024	14,245,825	16,179,032	13,392,097	14,218,845	14,191,932	14,111,039	14,256,323
2025	14,650,331	16,798,339	13,701,745	14,622,835	14,595,408	14,500,171	14,666,163
2026	14,878,688	17,241,496	13,835,242	14,850,645	14,822,673	14,712,670	14,902,628
2027	15,134,544	17,712,154	13,996,240	15,105,890	15,077,307	14,952,297	15,170,744
2028	15,355,688	18,148,098	14,122,525	15,326,508	15,297,401	15,156,579	15,410,570
2029	15,591,718	18,598,928	14,263,696	15,561,969	15,532,295	15,375,938	15,661,021
5-Year CAGR	0.48%	2.07%	-0.43%	0.48%	0.48%	0.39%	0.48%
10-Year CAGR	0.99%	2.42%	0.30%	0.99%	0.98%	0.89%	0.99%
15-Year CAGR	1.28%	2.57%	0.64%	1.28%	1.28%	1.19%	1.32%

Table 24. Annual coincidental peak demand forecast sensitivities for high & low, customer owned distributed generation and electrical vehicles.

Year	Current Trends/Base Forecast	High Demand	Low Demand	Increased Distributed Generation	Increased Electric Vehicles
	(MW)	(MW)	(MW)	(MW)	(MW)
2015	2,452	2,452	2,452	2,446	2,452
2016	2,466	2,496	2,453	2,454	2,466
2017	2,487	2,548	2,462	2,470	2,488
2018	2,514	2,605	2,476	2,491	2,515
2019	2,466	2,588	2,416	2,438	2,468
2020	2,495	2,647	2,432	2,460	2,497
2021	2,528	2,710	2,452	2,487	2,531
2022	2,552	2,765	2,464	2,505	2,556
2023	2,584	2,827	2,483	2,530	2,589
2024	2,617	2,890	2,503	2,555	2,623
2025	2,678	2,982	2,552	2,610	2,687
2026	2,714	3,048	2,575	2,639	2,726
2027	2,754	3,119	2,602	2,671	2,769
2028	2,788	3,183	2,624	2,698	2,807
2029	2,825	3,250	2,632	2,727	2,846
5-Year CAGR	0.15%	1.36%	-0.37%	-0.09%	0.16%
10-Year CAGR	0.72%	1.84%	0.23%	0.49%	0.75%
15-Year CAGR	1.02%	2.03%	0.51%	0.78%	1.07%

This Page Was Intentionally Left Blank

Exhibits

Exhibit A - Historic Energy Sales and Forecast

Year	Metro Region Energy (MWh)	Year-Over-Year Growth (%)	Northern Region Energy (MWh)	Year-Over-Year Growth (%)	Southern & Western Region Energy (MWh)	Year-Over-Year Growth (%)	GRE's All Requirement Member's Annual Energy (MWh)	Year-Over-Year Growth (%)
1975	743,414		987,617					
1976	839,934	13.0%	1,091,192	10.5%				
1977	890,910	6.1%	1,118,893	2.5%				
1978	985,979	10.7%	1,175,414	5.1%				
1979	1,033,242	4.8%	1,229,525	4.6%				
1980	1,065,560	3.1%	1,205,856	-1.9%				
1981	1,080,827	1.4%	1,200,330	-0.5%				
1982	1,145,011	5.9%	1,267,106	5.6%				
1983	1,200,742	4.9%	1,286,834	1.6%				
1984	1,261,452	5.1%	1,325,759	3.0%				
1985	1,337,713	6.0%	1,369,888	3.3%				
1986	1,421,039	6.2%	1,378,836	0.7%				
1987	1,553,760	9.3%	1,394,804	1.2%				
1988	1,822,403	17.3%	1,528,771	9.6%				
1989	1,873,491	2.8%	1,583,951	3.6%				
1990	1,941,719	3.6%	1,571,312	-0.8%				
1991	2,090,056	7.6%	1,666,505	6.1%	1,203,830		4,960,391	
1992	2,088,710	-0.1%	1,691,570	1.5%	1,191,065	-1.1%	4,971,345	0.2%
1993	2,212,691	5.9%	1,781,272	5.3%	1,234,964	3.7%	5,228,927	5.2%
1994	2,352,470	6.3%	1,851,934	4.0%	1,283,367	3.9%	5,487,772	5.0%
1995	2,549,755	8.4%	1,962,398	6.0%	1,333,246	3.9%	5,845,399	6.5%
1996	2,631,864	3.2%	2,103,305	7.2%	1,429,838	7.2%	6,165,008	5.5%
1997	2,717,602	3.3%	2,071,652	-1.5%	1,413,596	-1.1%	6,202,851	0.6%
1998	2,927,048	7.7%	2,131,149	2.9%	1,446,115	2.3%	6,504,313	4.9%
1999	3,091,160	5.6%	2,211,842	3.8%	1,489,709	3.0%	6,792,712	4.4%
2000	3,247,921	5.1%	2,307,833	4.3%	1,525,684	2.4%	7,081,439	4.3%
2001	3,390,746	4.4%	2,382,405	3.2%	1,572,104	3.0%	7,345,255	3.7%
2002	3,580,149	5.6%	2,511,173	5.4%	1,629,930	3.7%	7,721,253	5.1%
2003	3,734,765	4.3%	2,598,448	3.5%	1,664,361	2.1%	7,997,574	3.6%
2004	3,771,900	1.0%	2,570,599	-1.1%	1,661,879	-0.1%	8,004,377	0.1%
2005	4,067,770	7.8%	2,721,611	5.9%	1,771,927	6.6%	8,561,309	7.0%
2006	4,167,984	2.5%	2,755,414	1.2%	1,853,868	4.6%	8,777,266	2.5%
2007	4,327,343	3.8%	2,898,719	5.2%	1,980,693	6.8%	9,206,756	4.9%
2008	4,270,798	-1.3%	2,966,238	2.3%	2,008,106	1.4%	9,245,142	0.4%
2009	4,123,821	-3.4%	2,871,488	-3.2%	1,997,235	-0.5%	8,992,544	-2.7%
2010	4,244,289	2.9%	2,821,362	-1.7%	1,974,987	-1.1%	9,040,638	0.5%
2011	4,258,933	0.3%	2,874,736	1.9%	1,984,230	0.5%	9,117,899	0.9%
2012	4,293,649	0.8%	2,840,527	-1.2%	1,990,318	0.3%	9,124,494	0.1%
2013	4,295,422	0.0%	3,036,955	6.9%	2,126,993	6.9%	9,459,370	3.7%
2014	4,275,556	-0.5%	2,945,066	-3.0%	2,065,847	-2.9%	9,286,469	-1.8%
2015	4,322,241	1.1%	2,934,654	-0.4%	2,099,335	1.6%	9,356,229	0.8%
2016	4,387,744	1.5%	2,932,612	-0.1%	2,118,859	0.9%	9,439,215	0.9%
2017	4,459,008	1.6%	2,956,808	0.8%	2,151,094	1.5%	9,566,910	1.4%
2018	4,541,775	1.9%	2,993,522	1.2%	2,193,115	2.0%	9,728,411	1.7%
2019	4,635,694	2.1%	3,022,972	1.0%	2,224,456	1.4%	9,883,123	1.6%
2020	4,734,634	2.1%	3,060,709	1.2%	2,261,314	1.7%	10,056,657	1.8%
2021	4,838,309	2.2%	3,109,673	1.6%	2,307,254	2.0%	10,255,236	2.0%
2022	4,937,189	2.0%	3,136,645	0.9%	2,328,605	0.9%	10,402,439	1.4%
2023	5,041,733	2.1%	3,183,759	1.5%	2,367,922	1.7%	10,593,414	1.8%
2024	5,147,625	2.1%	3,235,554	1.6%	2,408,914	1.7%	10,792,093	1.9%
2025	5,262,971	2.2%	3,286,595	1.6%	2,448,939	1.7%	10,998,505	1.9%
2026	5,381,102	2.2%	3,342,410	1.7%	2,493,515	1.8%	11,217,028	2.0%
2027	5,506,385	2.3%	3,407,584	1.9%	2,547,897	2.2%	11,461,867	2.2%
2028	5,632,020	2.3%	3,455,901	1.4%	2,584,053	1.4%	11,671,973	1.8%
2029	5,759,742	2.3%	3,511,717	1.6%	2,627,894	1.7%	11,899,353	1.9%

Exhibit B - All Requirement Member's Historic Peak Monthly Demand Forecast

Metro Region

2014 Integrated Resource Plan Demand Forecast (MWh) - Metro Region																
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer Peak	Winter Peak	Year - Over year Summer Peak Growth	Year - Over year Winter Peak Growth
2003	588	574	548	497	512	783	823	910	809	566	571	616	910			
2004	589	586	528	531	527	822	907	780	790	525	600	654	907	654	-0.3%	
2005	615	585	570	508	512	884	933	968	829	751	642	673	968	673	6.7%	3.0%
2006	611	529	590	509	855	847	991	843	664	570	633	686	991	686	2.4%	2.0%
2007	627	560	613	469	715	969	1,021	975	954	754	652	693	1,021	693	3.0%	1.0%
2008	630	665	523	555	507	818	931	864	852	569	619	693	931	693	-8.8%	-0.1%
2009	600	551	523	466	722	927	800	877	720	552	582	672	927	680	-0.5%	-1.9%
2010	680	520	488	442	907	889	842	961	668	603	619	671	961	671	3.7%	-1.2%
2011	585	555	524	460	643	935	1,001	903	859	629	592	662	1,001	662	4.1%	-1.3%
2012	570	521	529	448	696	890	1,035	974	908	559	629	659	1,035	662	3.5%	-0.1%
2013	662	555	526	480	620	878	980	1,038	936	565	615	681	1,038	681	0.2%	2.9%
2014	627	575	553	482	664	899	956	939	813	563	629	687	956	687	-7.9%	0.9%
2015	632	580	558	486	670	906	963	947	819	567	633	692	963	692	0.8%	0.8%
2016	639	586	564	491	677	916	974	957	828	573	640	700	974	700	1.1%	1.1%
2017	646	593	570	497	685	926	985	968	838	580	648	708	985	708	1.2%	1.2%
2018	655	601	578	503	694	938	998	981	849	587	656	717	998	717	1.3%	1.3%
2019	664	609	586	511	704	952	1,012	995	861	596	666	727	1,012	727	1.5%	1.5%
2020	674	619	595	518	714	967	1,028	1,010	874	605	676	738	1,028	738	1.5%	1.5%
2021	685	628	604	526	726	982	1,044	1,026	888	614	686	750	1,044	750	1.6%	1.6%
2022	695	637	613	534	736	996	1,059	1,041	901	623	696	761	1,059	761	1.4%	1.4%
2023	705	647	622	542	747	1,011	1,075	1,056	914	633	707	772	1,075	772	1.5%	1.5%
2024	716	657	631	550	758	1,026	1,091	1,072	928	642	717	784	1,091	784	1.5%	1.5%
2025	727	667	641	559	770	1,042	1,108	1,089	942	652	729	796	1,108	796	1.6%	1.6%
2026	739	678	652	568	783	1,059	1,126	1,106	957	663	740	809	1,126	809	1.6%	1.6%
2027	751	689	662	577	795	1,076	1,144	1,125	973	674	753	822	1,144	822	1.7%	1.7%
2028	763	700	673	586	808	1,094	1,163	1,143	989	685	765	835	1,163	835	1.6%	1.6%
2029	775	711	684	596	821	1,111	1,182	1,161	1,005	696	777	849	1,182	849	1.6%	1.6%

Northern Region

2014 Integrated Resource Plan Demand Forecast (MWh) - Northern Region																
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer Peak	Winter Peak	Year - Over year Summer Peak Growth	Year - Over year Winter Peak Growth
2003	435	417	387	336	268	315	386	416	345	296	394	415	416			
2004	459	419	350	253	272	338	413	342	338	322	374	475	413	481	-0.8%	
2005	481	419	378	294	330	388	436	433	371	325	432	462	436	540	5.6%	12.3%
2006	417	540	408	334	390	402	458	386	327	374	432	486	458	550	5.1%	1.8%
2007	485	550	434	455	295	406	440	452	378	333	482	508	452	550	-1.3%	0.0%
2008	550	500	541	362	339	334	371	383	393	356	446	539	393	600	-13.1%	9.1%
2009	600	583	433	392	300	361	353	421	341	340	368	514	421	535	7.1%	-10.7%
2010	520	535	445	351	364	388	470	420	295	305	419	511	470	584	11.6%	9.1%
2011	576	584	549	396	298	431	442	391	388	306	416	471	442	566	-5.9%	-3.1%
2012	566	512	346	374	318	429	494	423	371	352	420	485	494	600	11.8%	6.0%
2013	557	600	518	446	286	373	480	475	421	388	457	527	480	541	-2.8%	-9.8%
2014	541	541	456	385	298	399	457	436	373	364	447	519	457	539	-4.8%	-0.4%
2015	539	539	455	383	297	397	455	435	372	363	446	517	455	538	-0.4%	-0.1%
2016	538	538	454	383	297	397	455	434	371	362	445	517	455	543	-0.1%	0.9%
2017	543	543	458	386	300	400	459	438	375	366	449	521	459	551	0.9%	1.4%
2018	551	551	465	392	304	406	465	445	380	371	456	529	465	557	1.4%	1.1%
2019	557	557	470	396	307	411	471	449	384	375	461	534	471	565	1.1%	1.4%
2020	565	565	477	401	312	416	477	456	390	380	467	542	477	575	1.4%	1.8%
2021	575	575	485	409	317	424	486	464	397	387	475	552	486	580	1.8%	1.0%
2022	580	580	490	413	320	428	490	468	401	391	480	557	490	590	1.0%	1.7%
2023	590	590	498	420	326	435	499	476	407	397	488	566	499	601	1.7%	1.8%
2024	601	601	507	427	332	443	508	485	415	405	497	577	508	612	1.8%	1.8%
2025	612	612	516	435	337	451	517	494	422	412	506	587	517	623	1.8%	1.9%
2026	623	623	526	443	344	459	527	503	430	420	515	598	527	637	1.9%	2.2%
2027	637	637	537	453	351	470	538	514	440	429	527	611	538	647	2.2%	1.6%
2028	647	647	546	460	357	477	547	522	447	436	535	621	547	659	1.6%	1.8%
2029	659	659	556	468	363	486	557	532	455	443	545	632	557	632	1.8%	-4.0%

Southern & Western Region

2014 Integrated Resource Plan Demand Forecast (MWh) - Southern & Western Region																
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer Peak	Winter Peak	Year - Over year Summer Peak Growth	Year - Over year Winter Peak Growth
2003	278	270	250	215	189	242	295	310	253	256	253	275	310			
2004	283	277	237	196	198	261	295	266	256	288	267	303	295	303	-4.9%	
2005	301	269	258	204	215	281	315	313	279	250	291	316	315	316	6.5%	4.1%
2006	269	289	275	224	280	301	337	297	241	312	299	328	337	329	7.1%	4.1%
2007	321	329	290	283	234	306	325	329	317	265	314	337	329	356	-2.3%	8.3%
2008	356	343	324	260	226	258	299	308	280	325	333	361	325	369	-1.3%	3.8%
2009	369	344	286	268	242	310	275	307	253	291	346	346	310	353	-4.4%	-4.4%
2010	353	327	293	243	300	311	318	326	237	288	296	345	326	359	5.2%	1.6%
2011	359	349	325	259	238	332	336	322	309	256	285	322	336	352	2.8%	-1.9%
2012	352	320	237	242	253	334	367	340	317	258	294	337	367	360	9.4%	2.4%
2013	360	354	328	293	240	306	368	369	336	342	326	365	369	365	0.5%	1.5%
2014	353	340	304	262	250	316	345	343	297	295	325	358	345	358	-6.4%	-2.0%
2015	358	345	308	266	254	321	350	348	302	299	330	363	350	363	1.5%	1.4%
2016	361	348	311	268	256	323	353	351	304	302	333	366	353	366	0.9%	0.9%
2017	366	353	315	272	260	328	358	356	309	306	338	371	358	373	1.4%	1.8%
2018	373	360	321	277	265	334	365	362	314	311	344	378	365	378	1.8%	1.4%
2019	378	364	325	281	268	338	370	367	318	316	348	383	370	383	1.3%	1.5%
2020	383	370	330	285	272	343	375	372	323	320	354	389	375	391	1.5%	1.9%
2021	391	377	336	290	277	350	382	379	329	326	360	396	382	396	1.9%	1.4%
2022	394	380	339	293	280	353	386	383	332	329	363	399	386	400	0.9%	1.0%
2023	400	386	344	297	284	358	392	389	337	334	369	406	392	406	1.6%	1.6%
2024	406	392	350	302	288	364	398	395	343	340	375	412	398	413	1.6%	1.5%
2025	413	398	355	307	293	369	404	401	348	345	381	418	404	420	1.5%	1.7%
2026	420	405	361	312	298	376	411	408	354	351	387	425	411	428	1.7%	2.0%
2027	428	413	368	318	304	383	419	416	361	358	395	434	419	434	2.0%	1.4%
2028	434	418	373	322	308	388	424	421	365	362	400	440	424	440	1.3%	1.5%
2029	440	425	379	327	313	394	431	428	371	368	406	446	431	446	1.6%	1.4%

All Requirement Members

2014 Integrated Resource Plan Demand Forecast (MWh) - GRE All Requirement Members													
Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer Peak	Winter Peak	Year - Over year Summer Peak Growth	Year - Over year Winter Peak Growth
1,186	1,047	969	1,340	1,503	1,637	1,406	1,118	1,219	1,307	1,637			
1,116	979	997	1,421	1,615	1,388	1,384	1,136	1,240	1,431	1,615	1,431	-1.3%	
1,206	1,006	1,056	1,553	1,683	1,714	1,479	1,326	1,364	1,450	1,714	1,450	6.1%	1.3%
1,274	1,067	1,524	1,550	1,786	1,526	1,231	1,256	1,364	1,500	1,786	1,500	4.2%	3.4%
1,336	1,206	1,244	1,681	1,786	1,756	1,650	1,352	1,448	1,538	1,786	1,538	0.0%	2.5%
1,387	1,177	1,071	1,410	1,601	1,555	1,525	1,250	1,398	1,593	1,601	1,593	-10.4%	3.6%
1,242	1,126	1,264	1,598	1,427	1,604	1,314	1,182	1,296	1,532	1,604	1,552	0.2%	-2.5%
1,226	1,037	1,571	1,588	1,630	1,707	1,201	1,197	1,334	1,527	1,707	1,527	6.4%	-1.6%
1,397	1,115	1,179	1,699	1,778	1,616	1,556	1,191	1,293	1,455	1,778	1,488	4.1%	-2.6%
1,112	1,064	1,266	1,653	1,897	1,737	1,596	1,170	1,343	1,482	1,897	1,579	6.7%	6.1%
1,372	1,220	1,146	1,558	1,828	1,881	1,693	1,296	1,398	1,573	1,881	1,573	-0.8%	-0.4%
1,313	1,129	1,213	1,613	1,758	1,718	1,483	1,221	1,401	1,563	1,758	1,563	-6.6%	-0.6%
1,320	1,135	1,221	1,624	1,769	1,729	1,493	1,229	1,409	1,572	1,769	1,572	0.6%	0.6%
1,329	1,142	1,230	1,636	1,782	1,742	1,504	1,237	1,419	1,582	1,782	1,582	0.7%	0.6%
1,344	1,155	1,244	1,654	1,802	1,762	1,521	1,251	1,435	1,600	1,802	1,600	1.1%	1.1%
1,363	1,172	1,262	1,678	1,828	1,787	1,543	1,270	1,456	1,623	1,828	1,623	1.4%	1.5%
1,381	1,187	1,279	1,701	1,853	1,811	1,564	1,286	1,475	1,645	1,853	1,645	1.3%	1.3%
1,402	1,205	1,298	1,726	1,880	1,838	1,587	1,305	1,497	1,669	1,880	1,669	1.5%	1.5%
1,426	1,225	1,320	1,755	1,912	1,869	1,614	1,328	1,522	1,697	1,912	1,697	1.7%	1.7%
1,442	1,239	1,336	1,776	1,935	1,892	1,633	1,343	1,540	1,717	1,935	1,717	1.2%	1.2%
1,465	1,259	1,357	1,804	1,965	1,921	1,659	1,364	1,564	1,744	1,965	1,744	1.6%	1.6%
1,488	1,279	1,378	1,833	1,996	1,952	1,685	1,386	1,589	1,772	1,996	1,772	1.6%	1.6%
1,513	1,300	1,401	1,862	2,029	1,983	1,712	1,409	1,615	1,801	2,029	1,801	1.6%	1.6%
1,539	1,323	1,424	1,894	2,063	2,017	1,741	1,433	1,643	1,832	2,063	1,832	1.7%	1.7%
1,568	1,348	1,451	1,929	2,101	2,054	1,774	1,460	1,674	1,867	2,101	1,867	1.9%	1.9%
1,592	1,369	1,473	1,959	2,134	2,086	1,801	1,482	1,700	1,896	2,134	1,896	1.5%	1.5%
1,619	1,391	1,497	1,991	2,169	2,121	1,831	1,507	1,728	1,928	2,169	1,928	1.7%	1.7%

Exhibit C Clearspring Energy Residential Consumer Forecast Study

[Trade Secret Begins

Trade Secret Ends]

THIS PAGE INTENTIONALLY LEFT BLANK

APPENDIX H: GRE MISO COINCIDENT PEAK DIVERSITY STUDY

GREAT RIVER ENERGY

LOAD DIVERSITY STUDY BETWEEN

MISO'S COINCIDENT PEAK AND

GREAT RIVER ENERGY'S COINCIDENT PEAK

From 2005 - 2012

Nathan Grahl
Forecasting and Modeling Lead
Great River Energy

GREAT RIVER ENERGY

A Touchstone Energy Cooperative

This page was intentionally left blank

Table of Contents

This page was intentionally left blank

Table of Tables

Table of Figures

This page was intentionally left blank

Executive Summary

A load diversity study was conducted between Great River Energy's(GRE) coincident peak and GRE's load at the time of Midcontinent Independent System Operator's(MISO) coincident peak to determine useful load diversity estimates for evaluating market and load reliability concerns. Also, the probability of occurrence of a load diversity factor was also evaluated. Three methods of calculating load diversity were investigated with actual observed load diversities between GRE's coincident peak and GRE's load at the time of MISO's coincident peak from the summer of 2005 through the summer of 2012. Based on three methods for calculating diversity between GRE's coincident peak and GRE's load at the time of MISO's coincident peak, a diversity factor of 10% resulted. Both the historic average summer diversity and the MISO Casual Diversity methods provided consensus around 10%

This page was intentionally left blank

Introduction

With the issunace of FERC Order on Midcontinent Independent System Operator's (MISO) Resource Adequacy Proposal, FERC Docket No. ER-11-4081-000 Section 69A.1," the demand forecast shall include the annual Coincident Peak Demand within each LBA area in the Transmission Provider Region for the upcoming Planning Year." These LBA demand forecasts must be an estimate of the amount of demand Great River Energy (GRE) contributes to the MISO summer peak.

A load diversity study between GRE's coincident peak and GRE's load at the time of MISO's coincident peak was performed using three methods that utilized observed summer load diversity from 2005 through 2012. The goal of the study was to:

(1) measure the amount of variability in load diversity between GRE's coincident summer peak and MISO's,
(2) determine if there is a statistically different load diversity among the summer months, June through September
(3) Compare three methods of calculating a load diversity factor and make a final decision as to what diversity factor to use.

This page was intentionally left blank

Methods

Testing for a statistically significant demand diversity among the Summer Months

Currently MISO includes the summer months of June, July, August, and September as the months that MISO will experience their coincident peak. Coincidence factors were calculated for each month from 2005-2012 and a series of statistical tests were performed to determine if the average coincident factor from one month will be significantly different from another month's diversity factor. Two tests were used to investigate whether or not there was a significant difference in any of the summer month's average diversity factor: (1) series of paired T-Tests and (2) Comparison of each month's average diversity factor's upper and lower 95% confidence intervals.

A statistical test for μ_1 - μ_2, independent samples

$$H_o: \quad \mu_1 - \mu_2 = 0$$
$$H_a: \quad \mu_1 - \mu_2 \neq 0$$
$$T.S.: \quad \frac{t = \bar{y}_1 - \bar{y}_2 - 0}{s_p\sqrt{{}^1/_{n_1} - {}^1/_{n_2}}}$$
$$R.R.: \quad For\ Type\ 1\ error\ \propto and\ df = n_1 + n_2 - 2$$
$$reject\ H_o\ if\ \ |t| > t_{\propto/_2}$$

Upper and Lower 95% Confidence Intervals comparison

Upper and lower 95% confidence intervals were calculated for each summer months average diversity factor. The average diversity for each summer month was plotted on a line graph along with its associated 95% confidence interval. A quick comparison was made to determine if there was overlap among all the month's upper and lower 95% confidence intervals.

If a significant difference between the month's average diversity factor was documented for either of methods described above, that month's data will be removed from the sample population and treated independently of the other months' diversity factors.

Estimating Load Diversity between GRE's coincident peak and MISO's coincident peak

Upper and Lower 95% Confidence Interval

Once it is determined if all the summer month's diversity factors from 2005-2012 can be pooled and treated equally or if one or more summer months will have to be treated independently, a 95% confidence interval will be created for the average summer month's diversity and/or average monthly diversity. The 95% confidence interval will be constructed by the following equation:

$$0.95 = P\left(\bar{X} - 2.00\frac{\delta}{\sqrt{n}} \le \mu \le \bar{X} + 2.00\frac{\delta}{\sqrt{n}}\right)$$

$$Lower\ Endpoint = \bar{X} - 2.00\frac{\delta}{\sqrt{n}},\ Upper\ Endpoint = \bar{X} + 2.00\frac{\delta}{\sqrt{n}}$$

For determining a diversity factor between GRE's coincident peak the MISO's coincident peak, efforts will be focused on the lower 95% confidence interval.

Descriptive Statistics

Another approach to describing the diversity between the GRE coin and the MISO coincident peak is an examination of some basic summary statistics: range, median, average. By using the summary statistics, you are still choosing from the historic data and you have the ability to choose descriptive statistics such as the lower range, median diversity, and average diversity to represent

MISO Causal Approach

MISO requires that Load Serving Entities develop a coincident factor with causal factors, i.e. weather differences. *For further explanation of the process please see Appendix B Coincident Peak Forecasting Example – Load Forecast Workshop August 22nd, 2013.* GRE spent considerable amount of time investigating causal factors with most of the effort spent on evaluating how different weather conditions between the time of the MISO coincident peak and the time of the GRE coincident peak affect load diversity. GRE was unable to identify a truly elastic relationship between weather differences at the time of the peaks. What was determined was that when temperature is different, regardless if temperature at the time of MISO coincident is greater than or less than the temperature at the time of GRE coincident peak, diversity in load exists (Figure 1).

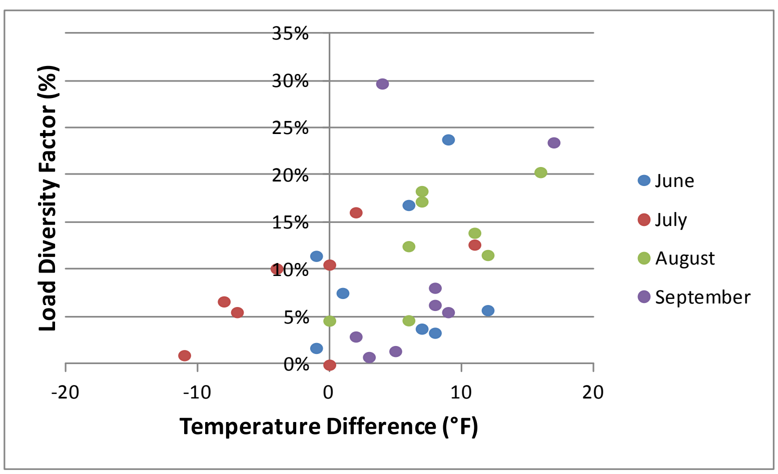


Figure 1 Relationship in diversity factor and temperature difference at the time of the GRE coincident peak and the MISO coincident peak.

Because there was no significant elasticity to suggest that as temperatures between the two coincident peaks increase so does the diversity, a temperature difference variable was transformed by taking the absolute value of the temperature difference (Figure 2).

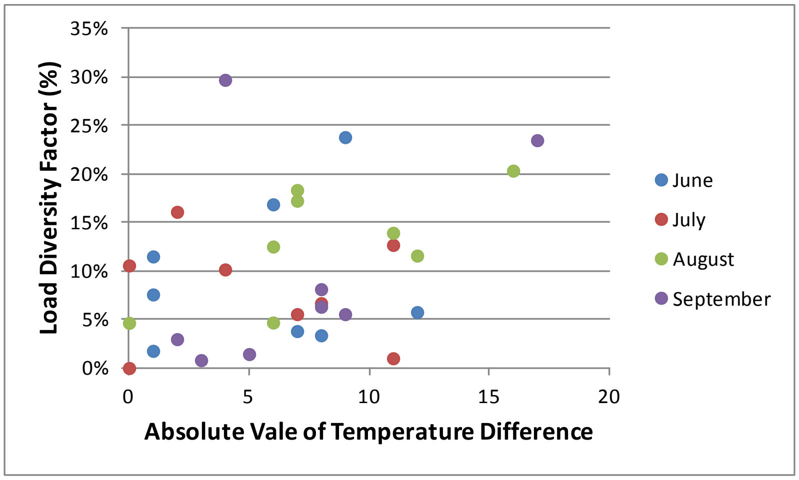


Figure 2 Relationship in diversity factor and absolute value of temperature difference at the time of GRE coincident peak and the MISO coincident peak.

Using the casual factor of absolute temperature difference to explain diversity, a linear regression with the following form was developed to explain the diversity between GRE's coincident peak and MISO coincident peak

$$y = \beta_o + \beta_1 X + \varepsilon$$

where:

y = diversity factor between the load at the time of MISO'scoincident peak and the load at the time of GRE's coincident peak, 1-($MISOc_{oin}/GRE_{Coin}$),
β_o = constant, y-intercept,
X = Absolute temperature difference at the time of GRE's coincident peak and MISO's coincident, peak, ABS($F°_{GRECoin}$ - $F°_{MISOcoin}$) and
E= error term.

The diversity factor between GRE's coincident peak demand and MISO's coincident peak demand will be developed under the following assumptions:

1.) GRE desires a forecast of its peak summer demand, coincident with the expected MISO summer peak,
2.) The primary explanatory factor for the difference in load between the GRE coincident peak hour the MISO coincident peak hour is the temperature,
3.) The difference in these temperatures, whether positive or negative, causes the load to differ and
4.) There are other causal factors, but they are believed to be relatively minor.

Results

Testing for significant difference in diversity in summer months

Paired T-Tests

Utilizing a series of paired T-Test to test whether or not one month's average diversity factor was statistically different from another month's average diversity factor, there were no statistical difference in any of the months compared (Table 2). In order to reject the null hypothesis, the absolute value of the calculated t value would have to be great than 2.3646. In all monthly average diversity factor comparisons, the null hypothesis was never rejected. Based on this statistical test, the difference between each of the month's average diversity factor is equal to 0.

$$H_o: \quad \mu_1 - \mu_2 = 0$$
$$H_a: \quad \mu_1 - \mu_2 \neq 0$$
$$T.S.: \ t = \frac{\bar{y}_1 - \bar{y}_2 - 0}{s_p\sqrt{{}^1/_{n_1} - {}^1/_{n_2}}}$$
$$R.R.: \ For\ Type\ 1\ error\ \propto and\ df = n_1 + n_2 - 2$$
$$reject\ H_o\ if\ |t| > t_{\propto/2}$$

Table 1. T-statistic comparison for each summer month's average diversity factor. The two-tail critical t-value = 2.3644.

	June	July	August	September
June		0.4075	-0.9591	-0.1261
July	0.4075		-1.7374	-0.5770
August	-0.9591	-1.7374		0.7110
September	-0.1261	-0.5770	0.7110	

Comparison of 95% Confidence Intervals

A comparison of each month's average diversity factor's 95% confidence interval indicates each of the months have an overlapping confidence interval (Figure 1). This test indicates that based on a sample size of 8 from years 2005 through 2012 there is no significant difference in the average diversity factor for the months of June, July, August, and September.

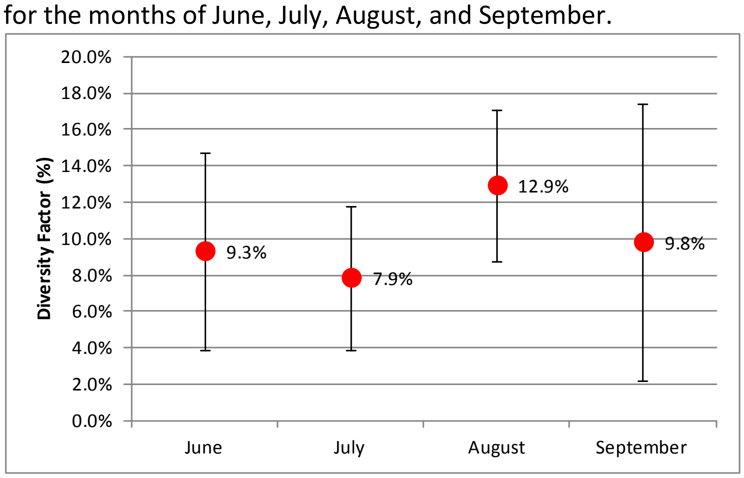


Figure 3. Upper and lower 95% confidence interval comparison of each summer month's average diversity factor.

Based on the results of the T-Tests and the 95% confidence intervals the average diversity factors for each month will be pooled and assumed not to be statistically different from one another.

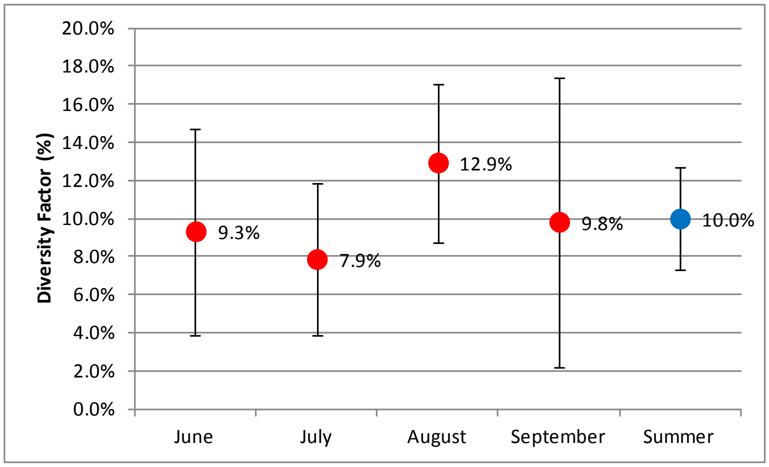


Figure 4 Upper and Lower 95% confidence interval for summer months 2005-2012, 10% +/- 2.7%.

Defining Diversity by Upper and Lower 95% Confidence Interval

It was determined through a series of paired T-Tests and comparing 95% confidence intervals that there were no statistically significant differences in load diversity between GRE's coincident peak and MISO's coincident peak. Based on this conclusion, all the summer month's data were pooled together and a 95% confidence interval was calculated for the all of the summer months. The upper and lower 95% confidence intervals for load diversity were calculated to be 12.7% and 7.3%, respectively. The upper and lower confidence interval was chosen to represent load diversity at extreme levels of market reliance and system load reliability.

Defining Diversity by Summary Statistics

A series of descriptive statistics were calculated from the historic diversity data. The average load diversity was 10.0% with a median of 7.9% and a min and maximum range of 0% and 29.7%, respectively (Table 2).

Table 2. Descriptive statistics for observed load diversity at the time of GRE coincident peak and MISO's coincident peak.

Mean	0.099761
Standard Error	0.013459
Median	0.078604
Mode	#N/A
Standard Deviation	0.076137
Sample Variance	0.005797
Kurtosis	0.039875
Skewness	0.812903
Range	0.297281
Minimum	0
Maximum	0.297281
Sum	3.192364
Count	32

Defining Diversity by a Causal Approach – MISO Preferred Method

Using an adaptation of an approach recommended by MISO (Appendix B) , Load Diversity was explained using the following prediction model:

$$Load\ Diversity = 0.0662301088 + 0.005735547 * 6.5 = 10\ \%$$

where:

Load Diversity =	diversity factor between the load at the time of MISO'scoincident peak and the load at the time of GRE's coincident peak, 1-($MISOc_{oin}$/GRE_{Coin}),
0.0662301088 =	constant, y-intercept,
0.005735547 =	coefficient, an d
6.5 =	Absolute temperature difference at the time of GRE's coincident peak and MISO's coincident, peak, ABS($F°_{GRECoin}$ - $F°_{MISOcoin}$), for summer months between 2005 and 2012.

It is important to note the MISO recommends a causal approach to estimating load diversity but they do not recommend specific explanatory variables to explain load diversity. GRE's causal model uses the absolute difference in temperate at the time of the two peaks to explain diversity. The absolute difference is only recognizing that when the temperature is different at the time of the two peaks, there is diversity. For example, It was determined that whether the temperature difference was – 6 or 6, the actual diversity could be the same. There is no explainable temperature elasticity between actual temperature difference and load diversity.

The regression model indicated statistically significant coefficients for the y-intercept and Abs(TempDiff) variable (Table 4 and Figure 5). The regression does recognize the diversity does change with the absolute temperature difference; however, the adjusted R-square is very weak, 0.115 (Table 4 and Figure 5).

Table 3. Regression statistics for using the absolute difference in peak tempeatues to explain diversity betewen GRE's coincident peak and MISO's coincident peak.

Regression Statistics								
Multiple R	0.339590122							
R Square	0.115321451							
Adjusted R Squa	0.085832166							
Standard Error	0.072796658							
Observations	32							
ANOVA								
	df	*SS*	*MS*	*F*	*Significance F*			
Regression	1	0.020723769	0.020724	3.910622	0.057232979			
Residual	30	0.158980602	0.005299					
Total	31	0.179704371						
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.062301088	0.022900681	2.720491	0.01074	0.015531657	0.109070518	0.015531657	0.109070518
ABS(TempDiff)	0.005735547	0.00290036	1.977529	0.057233	-0.000187778	0.011658873	-0.000187778	0.011658873

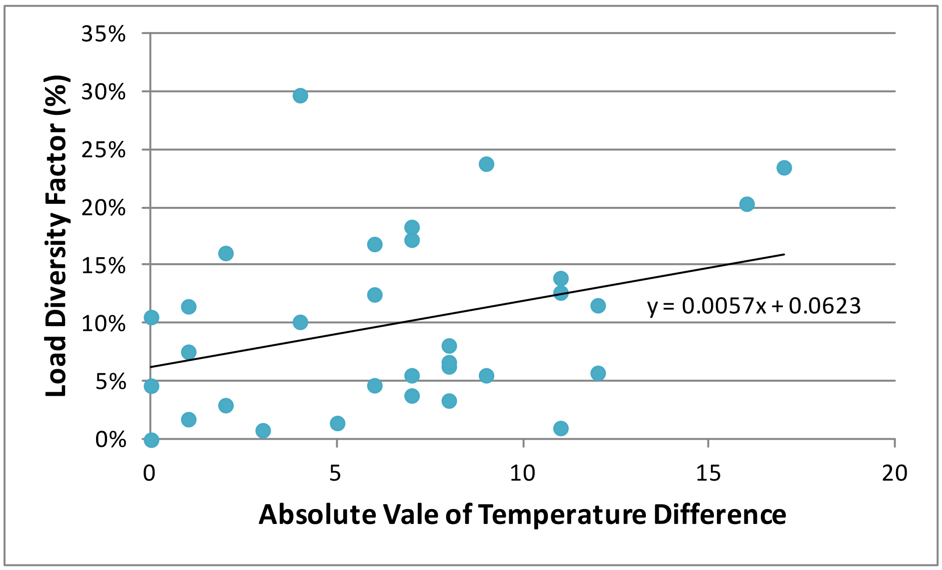


Figure 5. Relationship of load diversity and the absolute temperature difference.

Conclusion

Using the three different methods for estimating load diversity between GRE's coincident peak and MISO's coincident peak, a wide range of statistically credible diversities were estimated and their probability of occurrence (Table 5). Based on consensus between the estimated diversity factor and probability of occurrence between the MISO – Causal Approach and the Historic Average Summer Diversity (Table 5), a diversity factor of 10% will be used to explain the diversity between GRE coincident peak and MISO's coincident peak.

Table 4. Load diversity decision matrix for simulating different levels of market, system load reliability, and probability of occurrence risk.

Diversity Factor Method	Estimated Diversity Factor	Probability of Occurrence Rank
Lower 95% Confidence Interval	7.20%	1(0.15625)
Upper 95% Confidence Interval	12.70%	3(0.125)
Average	10%	4(0.0625)
Median	7.90%	1(0.15625)
Minimum	0%	6(0.03125)
MISO - Causal Approach	10%	4(0.0625)

This page was intentionally left blank

Appendix A

Historic Data

Year	Month	Date $MISO_{Coin}$	Date of GRE_{Coin}	$MISO_{Coin}$ (MW)	GRE $System_{Coin}$ (MW)	Diversity Factor	$MISO_{Coin}$Temp	GRE_{Coin}Temp	Temp Difference	Abs(Temp Difference)	MW Difference
2005	6	6/27/2005 15:00	06/23/2005 13:00	1,692	2,036	0.169	75	81	6	6	344
2005	7	7/25/2005 15:00	07/16/2005 14:00	1,854	2,211	0.161	79	81	2	2	356
2005	8	8/3/2005 16:00	08/02/2005 15:00	2,148	2,253	0.047	81	81	0	0	105
2005	9	9/12/2005 16:00	09/11/2005 21:00	1,476	1,930	0.235	73	90	17	17	454
2006	6	6/22/2006 15:00	06/30/2006 16:00	1,571	2,062	0.238	72	81	9	9	491
2006	7	7/31/2006 16:00	07/28/2006 14:00	2,349	2,373	0.010	93	82	-11	11	24
2006	8	8/2/2006 16:00	08/03/2006 18:00	1,778	2,012	0.116	74	86	12	12	233
2006	9	9/7/2006 16:00	09/07/2006 21:00	1,514	1,616	0.063	74	82	8	8	102
2007	6	6/26/2007 16:00	06/26/2007 15:00	2,143	2,182	0.018	86	85	-1	1	39
2007	7	7/31/2007 17:00	07/26/2007 14:00	2,094	2,331	0.102	85	81	-4	4	237
2007	8	8/8/2007 16:00	08/10/2007 16:00	2,012	2,300	0.125	80	86	6	6	288
2007	9	9/5/2007 16:00	09/04/2007 18:00	2,106	2,136	0.014	83	88	5	5	31
2008	6	6/26/2008 15:00	06/25/2008 15:00	1,725	1,867	0.076	75	76	1	1	142
2008	7	7/29/2008 17:00	07/29/2008 14:00	1,890	2,114	0.106	0	0	0	0	224
2008	8	8/1/2008 16:00	08/18/2008 22:00	1,708	2,064	0.173	81	88	7	7	356
2008	9	9/2/2008 16:00	09/01/2008 17:00	1,404	1,998	0.297	80	84	4	4	594
2009	6	6/25/2009 15:00	06/22/2009 19:00	1,966	2,086	0.058	77	89	12	12	120
2009	7	7/10/2009 16:00	07/10/2009 16:00	1,912	1,912	0.000	79	79	0	0	0
2009	8	8/10/2009 15:00	08/14/2009 16:00	1,818	2,112	0.139	72	83	11	11	295
2009	9	9/14/2009 16:00	09/15/2009 21:00	1,656	1,753	0.056	74	83	9	9	97
2010	6	6/22/2010 17:00	06/22/2010 22:00	2,010	2,089	0.038	83	90	7	7	80
2010	7	7/23/2010 16:00	07/03/2010 18:00	1,913	2,192	0.127	77	88	11	11	278
2010	8	8/10/2010 16:00	08/30/2010 21:00	1,808	2,270	0.204	75	91	16	16	462
2010	9	9/1/2010 16:00	09/01/2010 18:00	1,574	1,622	0.030	71	73	2	2	48
2011	6	6/7/2011 17:00	06/30/2011 22:00	1,998	2,258	0.115	95	94	-1	1	260
2011	7	7/20/2011 17:00	07/20/2011 13:00	2,220	2,380	0.067	93	85	-8	8	159
2011	8	8/2/2011 16:00	08/23/2011 21:00	1,745	2,137	0.184	79	86	7	7	392
2011	9	9/1/2011 16:00	09/01/2011 21:00	1,897	2,065	0.081	84	92	8	8	168
2012	6	6/28/2012 17:00	06/30/2012 18:00	2,126	2,200	0.034	81	89	8	8	74
2012	7	7/23/2012 16:00	07/02/2012 14:00	2,387	2,528	0.056	91	84	-7	7	141
2012	8	8/3/2012 16:00	08/29/2012 18:00	2,182	2,289	0.047	81	87	6	6	107
2012	9	9/4/2012 17:00	09/04/2012 18:00	2,095	2,112	0.008	85	88	3	3	17

Appendix B

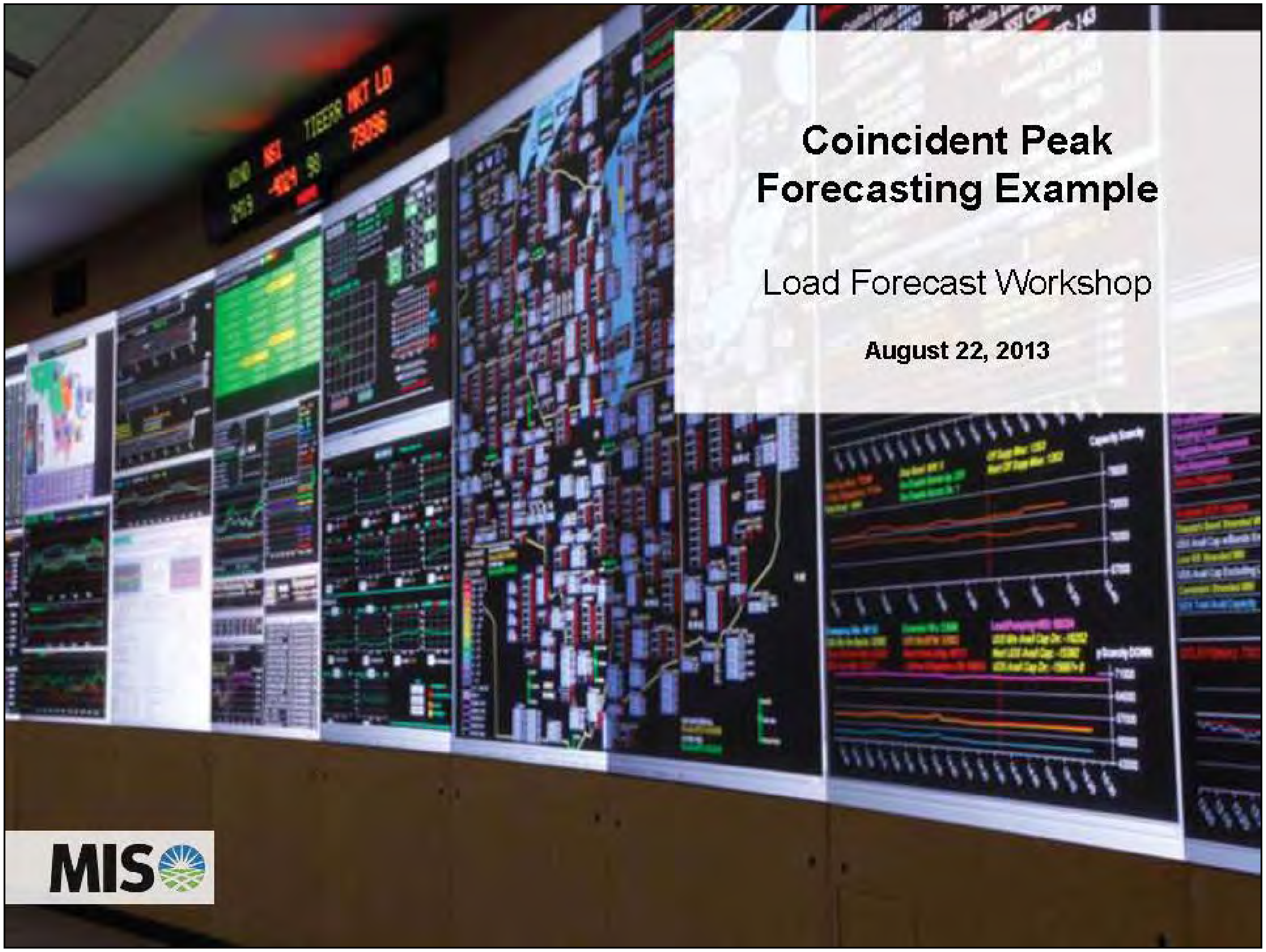
MISO Tariff

69 A.1.1 Forecasted Demand Version: 0.0.0 Effective: 10/1/2012

a. The demand forecasts required in Section 69A.1 shall include: (1) the annual Coincident Peak Demand within each LBA area in the Transmission Provider Region for the upcoming Planning Year: (2) the monthly non-coincident peak Demand and Net Energy for Load within each LBA area, for the upcoming Planning Year and the following Planning Year; and (3) the non-coincident peak Demand and net Energy for Load within each LBA area, for each Summer and Winter Season, for the eight Planning Years subsequent to the two for which monthly values are provided in (2). All of these forecasts shall be submitted by November 1st prior to each Planning Year and shall be consistent with Good Utility Practice. Forecast providers shall use the MECT or other means described in the BPM for Resource Adequacy to submit the requisite information. Details regarding the items required in the Demand forecasts submittal are in the BPM for Resource Adequacy.
b. The supplied Coincident Peak Demand forecasts shall include the Demand expected for the forecast time period (e.g. the Coincident Peak Demand hour) augmented to include the normal Demand from forecasted Demand Resources, whether registered or not registered with the Transmission Provider. All submissions shall include distribution losses, but no transmission losses. The Transmission Provider will be responsible for the calculation of transmission losses for the forecast provided and for annually publishing such forecasts for each LRZ on it website by the first Business Day in January, as specified by the BPM for Resource Adequacy.
c. In order to assist with the development of the Coincident Peak Demand forecasts, the Transmission Provider will make available the historical monthly peak hours for each of the four months June through September, since 2005, for the Transmission Provider Region. On or before March 1st of each year, the Transmission Provider will review a sampling of submitted Demand forecast methodologies and inputs to ensure accuracy and consistency, in accordance with the BPM for Resource Adequacy. If the Transmission Provider determines that the Demand forecast methodologies are inaccurate or inconsistent, the Transmission Provider shall work with the applicable LSEs to reconcile such issues. If reconciliation is not achieved, the Transmission Provider will provide the required forecast values.

Appendix C

MISO Coincident Peak Forecasting Example – Load Forecast Workshop August 22nd, 2013.



overview

- This slide deck will provide an example of the estimation of equations, calculations, supporting data, and results for a hypothetical load serving entity (LSE) preparing a coincident peak load forecast for the resource adequacy process.
- The NCP forecast has already been prepared.
- The data is real.
- *The purpose is to provide LSEs with a basic understanding of the ideas in action – not to provide a prescriptive, compulsory approach.*
- Please ask questions as we proceed.

MISO

2

glossary

- CP — Coincident Peak Demand: LSE peak at the time of MISO's expected or actual peak
- NCP — Non-Coincident Peak Demand: LSE peak whenever it occurs during the month or year
- CF — Coincidence Factor: CP/NCP
  Must be between 0 and 1, inclusively.
- DF — Diversity Factor: 1 – CF

MISO

3

theoretical approach

- The LSE desires a forecast of its peak, coincident with the expected MISO peak.
- The primary explanatory factor for the difference in load between the NCP hour and the CP hour is the temperature.
- The difference in these temperatures, whether positive or negative, causes the loads to differ.
- There are other causal factors, but they are believed to be relatively minor.
- We assume that the values have been increased as necessary to reflect all LMRs that were in operation during the hours affected.

MISO

4

data

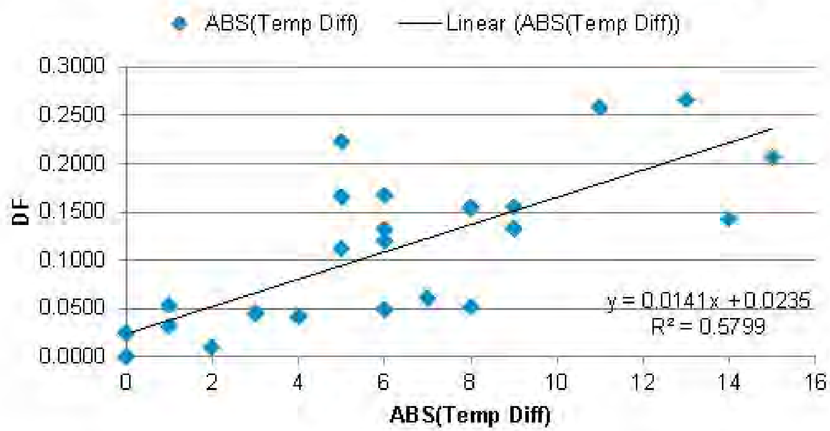
Month	Year	$MISO_{CP}$ kW	NCP kW	$MISO_{CP}$ °F	NCP °F	DF	ABS(Temp Diff)
Jun	2005	918,320	1,070,877	81	95	0.1425	14
Jul	2005	934,884	1,105,691	82	91	0.1545	9
Aug	2005	1,090,203	1,137,329	91	87	0.0414	4
Sep	2005	740,151	952,352	76	81	0.2228	5
Jun	2006	755,396	1,017,800	79	90	0.2578	11
Jul	2006	1,215,007	1,215,007	100	100	0.0000	0
Aug	2006	820,727	985,244	79	85	0.1670	6
Sep	2006	768,011	810,405	83	75	0.0523	8
Jun	2007	1,095,477	1,095,477	84	84	0.0000	0
Jul	2007	1,098,992	1,170,021	88	95	0.0607	7
Aug	2007	1,002,019	1,138,503	86	92	0.1199	6
Sep	2007	1,045,020	1,055,006	89	87	0.0095	2
Jun	2008	889,373	934,779	82	88	0.0486	6
Jul	2008	999,966	1,046,810	90	93	0.0447	3
Aug	2008	875,147	1,007,662	85	79	0.1315	6
Sep	2008	717,578	977,592	67	80	0.2660	13
Jun	2009	929,495	1,046,503	88	93	0.1118	5
Jul	2009	723,403	911,383	73	88	0.2063	15
Aug	2009	859,063	1,028,962	81	86	0.1651	5
Sep	2009	820,326	847,419	79	80	0.0320	1
Jun	2010	964,741	988,473	90	90	0.0240	0
Jul	2010	902,436	1,040,124	84	93	0.1324	9
Aug	2010	911,958	1,078,117	88	80	0.1541	8
Sep	2010	749,824	791,789	74	73	0.0530	1

MISO

Note: This data ends with 2010; you will have 2011 and 2012 data as well.

5

step #1: equation #1: explaining diversity



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.7615
R Square	0.5799
Adjusted R Square	0.5608
Standard Error	0.054
Observations	24

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.086957721	0.086957721	30.36863642	1.5441E-05
Residual	22	0.062994922	0.002863406		
Total	23	0.149952643			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.0235	0.0189	1.25	0.22574	-0.0156	0.0626
ABS(Temp Diff)	0.0141	0.0026	5.51	0.00002	0.0088	0.0194

Is it reasonable?

Is it statistically significant?

MISO

6

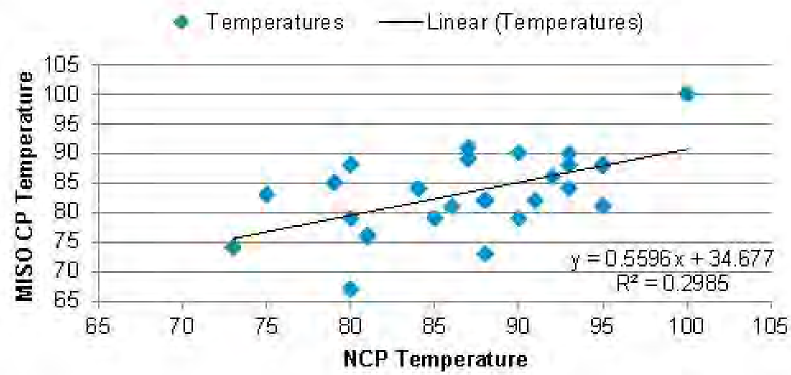
step 2: getting forecast input values

- Equation 1 requires the absolute value of the temperature difference between the two peak hours.
- Perhaps by examining the relationship between the NCP temperature and the CP temperature, we could answer this question.
- If so, we could then use the temperature assumed in the NCP "50/50" forecast to determine the CP temperature, which would then provide us with the temperature difference.

MISO

7

equation #2: NCP to CP temperatures



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.5463
R Square	0.2985
Adjusted R Square	0.2666
Standard Error	5.97
Observations	24

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	334.0066	334.0066	9.361269	0.005741
Residual	22	784.9518	35.67963		
Total	23	1118.958			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	34.7	15.9	2.18	0.0406	1.6	67.7
NCP Temp	0.560	0.183	3.06	0.0057	0.180	0.939

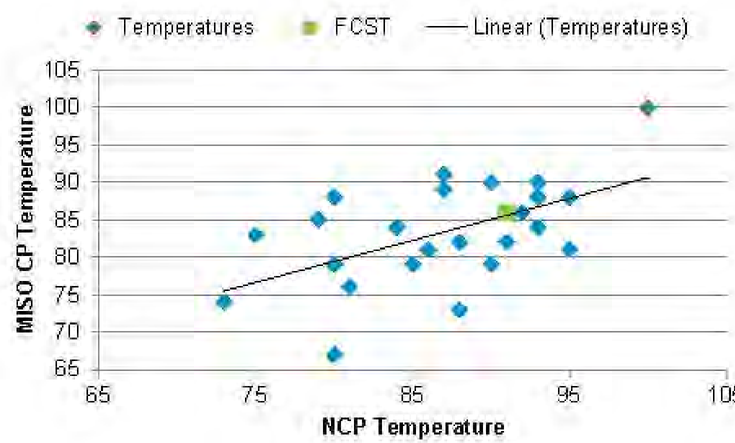
Is it reasonable?

Is it statistically significant?

8

step 3: determining CP temperature

- Let's assume that 91° was used as the "50/50" temperature for the NCP submitted.
- Using Eq.2, input "91" as the NCP Temperature.
- Result?
  86° is the estimated CP Temperature.
- And?
  The temperature difference (for use in Eq.1) is 91-86 = 5.

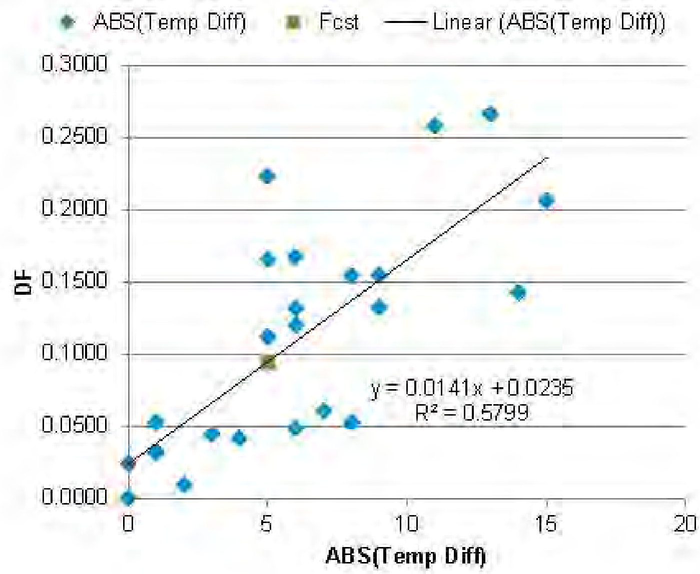


MISO

9

step 4: determining the coincident peak

- From Step 3, the temperature difference is “5”.
- From Eq.1, with an input of “5”, the resulting DF is .0941
- If the DF is .0941, the CF is .9059, and the Coincident Peak forecast is .9059 x NCP forecast



MISO

10

questions?

Contact:

- Ted Kuhn (tkuhn@misoenergy.org)

or

- Mike Robinson (mrobinson@misoenergy.org)

MISO

11

APPENDIX I: MINNESOTA 7610 ELECTRIC UTILITY REPORT

***NOTE, The following document contains a condensed version of the energy and peak demand forecast used in the 2014 MN 7610 filing and 2014 Great River Energy Integrated Resource Plan. For a more thorough and accurate description of the forecast methodology, assumptions, results, and conclusion please refer to APPENDEX D MN Docket No.* ET2/RP-14-813.**

7610.0320 FORECAST DOCUMENTATION

Subpart 1. Forecast Methodology. An applicant may use the forecast methodology that yields the most useful results for its system. However, the applicant shall detail in written form the forecast methodology employed to obtain the forecast provided under parts 7610.0300 to 7610.0315, including:

A. the overall methodological framework that is used;

Forecast Regions

Due to the geographic and economic diversity of GRE's membership, the twenty All Requirement members were grouped into 3 distinct forecast regions. By grouping the All Requirement members into three distinct regions, differences in regional weather, air conditioning saturations, space and water heating fuel types, and localized econometric variables were accounted for by region in the forecast process.

Forecast Geographic Regions

Geographic regions were chosen based on both physical location and underlying economic influences.

The Northern forecast region is primarily made up of winter peaking distribution cooperatives and the local economy is primarily based on tourism, forestry and some agricultural activities. This area is defined by All Requirement member distribution cooperatives north of Interstate 94 and excludes the 7 metropolitan counties.

The Southern & Western forecast region is primarily made up of summer peaking distribution cooperatives. The economy if this area is heavily influenced by agriculture and food processing. This region is the most rural of the three forecast regions and has the fewest number of customers. This area is defined by All Requirement member distribution cooperatives south of Interstate 94 and excludes all 7 metropolitan counties.

The Metro forecast region is made up of 2 All requirement member distribution cooperatives and is in or directly influenced by the 7 Metropolitan Counties. This region is summer peaking. The greater

Minneapolis-Saint Paul Metro area is home to 18 of Minnesota's 19 Fortune 500 company headquarters. This area has the second largest economy in the Midwest, behind only Chicago.

Energy Regression Model Development

Description and Assumptions

Great River Energy (GRE) is a generation and transmission cooperative owned by twenty-eight member distribution cooperative where twenty of the members are All Requirement (AR) members and eight of the members are Fixed members. The Fixed members have entered into a long term power purchase contract to purchase only a fixed amount of capacity and energy from GRE. For the remaining twenty members, GRE is responsible for nearly all of their energy. *The following econometric forecasts are for the AR members only.* Each of the AR members were grouped into one of three forecasts regions: Metro, Northern, and Southern & Western. To calculate the combined AR and Fixed energy obligation, the Fixed member energy amount will be added to the three aggregated regional forecasts.

Energy sales forecasts were developed using metered data with historic load control embedded in the data. An assumption is made that our historic load control program will remain consistent into the future, i.e. our historic growth in load control will continue to be the same growing forward alone with how these load control programs are implemented. All energy forecast results reflect load control.

Demand Model Development

Description and Assumptions

Monthly non-coincident peak regression models and forecasts were developed for each forecast region using actual meter data with load control embedded in the data. An assumption is made that our historical load control program will remain consistent in the future, i.e. our historic growth in load control will continue to be the same going forward along with how these load control programs are implemented. All monthly peak forecasts include load control.

Monthly peak regression models were developed for GRE's All Requirement members only within a given forecast region. The fixed members have entered into a long term power purchase contract and purchase only a fixed amount of their capacity from GRE. The following demand models and forecast are for the All Requirement members only. To calculate the combined All Requirement and Fixed demand obligation, the fixed amount will be added to the All Requirement member forecast.

Demand models and forecast developed for each forecast region are coincident to GRE's system peak. The aggregation of the three regional non-coincident peak demand models produces the GRE coincident peak demand forecast.

B. the specific analytical techniques that are used, their purpose, and the components of the forecast to which they have been applied

For a more thorough and accurate description of the forecast methodology, assumptions, results, and conclusion please refer to APPENDEX D MN Docket No. ET2/RP-14-813

1. **Econometric Modeling**
   Great River Energy utilized an econometric modeling approach to develop three regional annual energy sales forecast.
2. **Loss Factors**
   Loss Factors were used to convert annual All Requirement Energy sales forecast into system energy requirements.
3. **Peak Demand Forecast**
   Econometric modeling approach was used to develop three monthly regional peak demand forecasts .

C. the manner in which these specific techniques are related in producing the forecast

The econometric techniques described in section B were used to simulate effects of weather, demographics, economic variables on annual energy sales and peak demand. Actual historic data is used in combination with forecasts of weather, demographics, and economic data provided by Woods and Poole Economics, Energy Information Administration, Midwest Regional Climate Center, and Minnesota State Demographer.

D. where statistical techniques have been used, the purpose of the technique, typical computations (e.g., computer print outs, formulas used) specifying variables and data, and the results of appropriate statistical tests;

Energy Regression Model's Structural Form and Coefficients

An annual energy model was fit using multiple linear regression techniques with MetrixND© for each of the three forecast regions. For each forecast region, the final model structure is detailed below. Resulting coefficients, T-Stats, and P-values for each region's regression model can be found in Tables 3, 4, and 5.

Metro Region

$$\begin{aligned}\ln(Annual\ Metro\ Region\ Energy) &= \beta_0 + \beta_1 \ln(Metro\ Region\ Residential\ Consumers_{-1}) \\ &+ \beta_2 ln(Metro\ Region\ Employment_{MA_2}) + \beta_3 \ln(Metro\ Region\ CDD_{65}) \\ &+ \beta_4 \ln(\text{Wholesale Rate Real}_{\text{MA}_3})\end{aligned}$$

Where:

β_0 = Constant/y-intercept,
β_1 = Natural Log of Metro Regions Residential Consumers lagged 1-year,
β_2= Natural log of Metro Region's Employment, 2-year Moving Average,
β_3 = Natural log of Metro Regions Cooling Degree Days, Minneapolis basetemp 65 and
β_4 =Natural log of GRE's Wholesale Rate Real, 3-year Moving Average.

Table 1. Metro Region energy model regression coefficients, T-Stat, and P-Values.

Variable	Metro Region Coefficient	StdErr	T-Stat	P-Value
Constant	10.90612477	0.905145392	12.0490309	8.83949E-14
LN(Metro Region Residential Consumers $_{-1}$)	0.683168004	0.152325732	4.4849153	9.25325E-05
LN(Metro Region Employment$_{MA\ 2}$)	0.560156192	0.177241592	3.16041053	0.003507535
LN(Metro Region CDD$_{65}$)	0.062448643	0.009172061	6.8085729	1.08779E-07
LN(Wholesale Sale Rate Real$_{MA\ 3}$)	-0.113148218	0.027385418	-4.1316958	0.000251844
AR(1)	0.75955906	0.127195341	5.971595	1.23813E-06

Northern Region

$$\ln(Annual\ Northern\ Region\ Energy) = \beta_0 + \beta_1 \ln(Northern\ Region\ Residential\ Consumers_{-1}) + \beta_2 ln(Northern\ Region\ HDD_{65}) + \beta_3 \ln(Northern\ Region\ Employment{:}\ Population\ Ratio) + \beta_4 \ln(\text{Wholesale Rate Real}_{\text{MA }3})$$

Where:

β_0 = Constant/y-intercept,
β_1 = Natural log of Northern Regions Residential Consumers lagged 1-year,
β_2= Natural log of Northern Regions HDD, Hibbing MN basetemp 65,
β_3 = Natural log of Northern Regions Employment-to-Population Ratio,
β_4 =Natural log of GRE's Wholesale Rate Real, 3-year Moving Average.

Table 2. Northern Region energy model regression coefficients, T-Stat, and P-Values.

Variable	Northern Region Coefficient	StdErr	T-Stat	P-Value
Constant	5.203683551	1.11007785	4.68767443	4.84884E-05
LN(Northern Region Residential Consumers $_{-1}$)	1.285359924	0.084181973	15.2688264	3.68502E-17
LN(Northern Region HDD$_{65}$)	0.237654448	0.051317025	4.63110343	5.71662E-05
LN(Northern Region Employment/Population)	0.749153529	0.161525713	4.63798312	5.6034E-05
LN(Wholesale Rate Real)	-0.090970443	0.035294853	-2.5774422	0.014767901
AR(1)	0.382192448	0.16310375	2.34324746	0.025496166

Western & Southern Region

$$\ln(Annual\ Southern\&Western\ Region\ Energy) = \beta_1 \ln(Southern\&Western\ Region\ HDD_{65}) + \beta_2 ln(Southern\&Western\ Region\ Residential\ Consumers_{-1}) + \beta_3 \ln(\text{Wholesale Rate Real}_{\text{MA }3}) + \beta_4 \ln(Residential\ Propane\ Real)$$

Where:

β_1 = Natural log of Southern & Western Region HDD, Owatonna, MN Basetemp 65,
β_2= Natural log of Southern & Western Region Residential Consumers lagged 1-year,
β_3 = Natural log of GRE's Wholesale Rate Real, 3-year Moving Average and
β_4 =Natural log of Residential Propane Real).

Table 3. Southern&Western Region energy model regression coefficients, T-Stat, and P-Values.

Southern & Western Region				
Variable	Coefficient	StdErr	T-Stat	P-Value
LN(Southen & Western Region HDD_{65})	0.206424826	0.032340905	6.38277828	3.91207E-06
LN(Northern Region Residential Consumers $_{-1}$)	1.795761805	0.027118238	66.2197092	2.76945E-36
LN(Wholesale Rate Real)	-0.128249293	0.021595588	-5.9386803	1.00663E-05
LN(Residential Propane Real)	-0.064622647	0.014523307	-4.4495821	0.000274742

Table 4. Regional energy model's in-sample goodness-of-fit statistics.

Metro Region Model Statistics			Northern Region Model Statistics			Southern and Western Region Model Statistics	
Iterations	32		Iterations	22		Iterations	1
Adjusted Observations	37		Adjusted Observations	38		Adjusted Observations	23
Deg. of Freedom for Error	31		Deg. of Freedom for Error	32		Deg. of Freedom for Error	19
R-Squared	0.999256501		R-Squared	0.996754418		R-Squared	0.994731919
Adjusted R-Squared	0.999136581		Adjusted R-Squared	0.996247296		Adjusted R-Squared	0.993900117
AIC	-8.18852581		AIC	-7.603363496		AIC	-8.305656349
BIC	-7.927295878		BIC	-7.344797261		BIC	-8.108179094
F-Statistic	8332.743951		F-Statistic	1965.511292		F-Statistic	#NA
Prob (F-Statistic)	0		Prob (F-Statistic)	0		Prob (F-Statistic)	#NA
Log-Likelihood	104.9870017		Log-Likelihood	96.54424216		Log-Likelihood	66.87946174
Model Sum of Squares	9.988821057		Model Sum of Squares	4.244580062		Model Sum of Squares	0.757917264
Sum of Squared Errors	0.007432209		Sum of Squared Errors	0.01382099		Sum of Squared Errors	0.004013915
Mean Squared Error	0.000239749		Mean Squared Error	0.000431906		Mean Squared Error	0.000211259
Std. Error of Regression	0.015483819		Std. Error of Regression	0.020782347		Std. Error of Regression	0.01453474
Mean Abs. Dev. (MAD)	0.010918941		Mean Abs. Dev. (MAD)	0.014438396		Mean Abs. Dev. (MAD)	0.01058473
Mean Abs. % Err. (MAPE)	0.000508199		Mean Abs. % Err. (MAPE)	0.000677716		Mean Abs. % Err. (MAPE)	0.000499204
Durbin-Watson Statistic	2.199881254		Durbin-Watson Statistic	1.698286868		Durbin-Watson Statistic	1.63191059
Durbin-H Statistic	#NA		Durbin-H Statistic	#NA		Durbin-H Statistic	#NA
Ljung-Box Statistic	5.162598473		Ljung-Box Statistic	4.798230202		Ljung-Box Statistic	14.35433546
Prob (Ljung-Box)	0.396360626		Prob (Ljung-Box)	0.440997493		Prob (Ljung-Box)	0.013508637
Skewness	-0.063073807		Skewness	-0.4147779		Skewness	0.222096475
Kurtosis	3.279503235		Kurtosis	2.981115634		Kurtosis	2.372177796
Jarque-Bera	0.144971055		Jarque-Bera	1.090155788		Jarque-Bera	0.566823592
Prob (Jarque-Bera)	0.930079207		Prob (Jarque-Bera)	0.579796619		Prob (Jarque-Bera)	0.753209555

E. forecast confidence intervals or ranges of accuracy for annual peak demand and annual electrical consumption

Table 5. Forecast Confidence intervals for annual peak demand and annual electrical consumption.

	95 % Confidence Interval			
	Lower		Upper	
	Peak Demand	Annual Energy	Peak Demand	Annual Energy
2015	-21.1%	-6.9%	26.7%	7.4%
2016	-21.1%	-7.5%	26.7%	8.1%
2017	-21.1%	-7.9%	26.7%	8.5%
2018	-21.1%	-8.1%	26.8%	8.8%
2019	-21.2%	-8.2%	26.9%	8.9%
2020	-21.2%	-8.4%	27.0%	9.1%
2021	-21.3%	-8.5%	27.1%	9.3%
2022	-21.4%	-8.6%	27.2%	9.4%
2023	-21.4%	-8.9%	27.3%	9.7%
2024	-21.5%	-9.0%	27.4%	9.9%
2025	-21.6%	-9.2%	27.6%	10.1%
2026	-21.7%	-9.3%	27.8%	10.3%
2027	-21.9%	-9.5%	28.0%	10.5%
2028	-22.0%	-9.5%	28.2%	10.5%
2029	-22.1%	-9.8%	28.4%	10.8%

F. a brief analysis of the methodology used, including its strengths and weaknesses, its suitability to the system, cost considerations, data requirements, past accuracy, and any other factors considered by the utility.

Methodology

Due to the geographic an economic diversity of GRE's membership, the twenty All Requirement members were grouped into 3 distinct forecast regions. By grouping the All Requirement members into three distinct regions, differences in regional weather, air conditioning saturations, space and water heating fuel types, and localized econometric variables were accounted for by region in the forecast process. Regional forecasts were developed using econometric models using standard methodologies found in the electrical utility industry. Historic allocation factors based onf RDUP Form 7 data was utilized to develop a set of allocation factors to redistribute the annual energy requirement into different customer classes.

Strengths and Weakness

Strengths

1. Annual energy sales and peak demand explained by localized econometric variables
2. No ex-post facto adjustments/limited use of judgment
3. Easily understood
4. Industry Standard
5. Replicable

Weakness

1. Weather is held constant during the forecast period, i.e. Normal Weather
2. Some econometric variables have constant growth rate and are not responsive to short-term business cycles

Suitability to the System

The regional forecast approach is suitable for Great River Energy's geographic diversity among its distribution cooperatives. The regional approach allows for numerous functional model forms and econometric drivers to describe and forecast energy sales and peak demand for each distinct forecast region.

Cost Considerations

Econometric approach compared to end-use approach is the least expensive option without compromising ease of reliability and reliability.

Date Requirements

The annual energy forecast utilized 38 years of annual historical energy and the peak demand model incorporates 10 years of historical monthly data. As described in Subpart 2, the sources of dependent and independent data comes from data sources internal to GRE, Woods and Poole Economics, Minnesota State Demographer, Energy Information Administration (EIA) and Midwest Regional Climate Center (MRCC).

Past Accuracy

Range of accuracy for the annual energy sales model and peak demand forecast was determined using a backcast to compare actual historical energy and demand against predicted demand and energy. For annual electrical consumption across this historic time period, the average percent difference was 0.09% and the 2013 actual difference was 1.7%. For annual peak demand across the historic time period, the average percent difference was 1.43%, and the 2013 difference between predicted an actual was -6.2%. Note, the higher degree of percent error for annual energy and peak demand in 2013 was primarily due to an unseasonably hot summer and colder than normal November and December.

Subpart 2. Database forecasts. The utility shall discuss in written form the data used in arriving at the forecast presented in part 7610.0310 including

A. a complete list of all data sets used in making the forecast, including a brief description of each data set and an explanation of how each was obtained, (e.g., population projection from the state demographer) (Table 6 and Table 7).

B. a clear identification of any adjustments made to raw data to adapt them for use in forecasts, including the nature of the adjustment, the reason for the adjustment, and the magnitude of the adjustment.

Table 6. In dependenent variables used in annual energy sales forecast.

Forecast Region	Residential Consumers	Employment	CDD_{65}	HDD_{65}	Wholesale Rate	Employment:Population Ratio	Propane $
Metro	x	x	x		x		
Northern	x			x	x	x	
Southern & Western	x			x	x		x

<u>**Independent Variable:** Residential Consumers</u>

Database: MN State Demographer county level household projections

Variables Used: County household projections

Description/Source:
Clearspring Energy Advisors, the consultant hired to develop Great River Energy's regional residential consumer forecasts. The Clearspring Energy Advisors methodology links the household forecasts for the primary counties served and changes in the share of the households served by GRE member cooperatives. The residential consumer forecast captures the housing market cycle and is driven by county –level household forecasts developed by the Minnesota State Demographic Center. *A detailed description of the methodology and results can be found in APPENDEX D MN Docket No. ET2/RP-14-813.*

Adjustments Made
2013-2023 Household data: Slow recovery to more normal market and growth conditions.

2023 & beyond Household data: Stable, moderate growth reflective of a long-term trajectory.
A detailed description of the methodology and results can be found in APPENDEX D MN Docket No. ET2/RP-14-813.

Independent Variable: Employment, Population

Database: Woods and Poole State and County Projections

Variables Used: County level employment and population projections

Description/Source:
State profile economic data for Minnesota and 2 counties in Wisconsin was purchased from Woods and Poole Economics, Inc., 4910 Massachusetts Avenue NW Suite 208, Washington, DC 20016-4368 (www.woodsandpoole.com) . The state profile contains historical data and projections at the county level from 1969 through 2040.
Adjustments Made: None

Independent Variable: $\text{Propane}_{\text{Real}}$

Database: Energy Information Administration

Variables Used: Residential Propane

Description/Source:
Minnesota weekly heating oil and propane prices (October – March). Release date 10/30/2013.
Available from web page: http://www.eia.gov/dnav/pet/pet_pri_wfr_dcus_smn_w.htm

Adjustments Made: Real residential propane price base year 2012 was calculated using a Personal Consumption Expenditure Index (PCI) (2012=100). The historic and forecast PCI was provided by Woods and Poole Economics, Inc.

Independent Variable: Wholesale Member $\text{Rate}_{\text{Real}}$

Database: GRE Internal Data

Variables Used: Wholesale Member Rate

Description/Source:
Wholesale member rate is our total member revenue requirement divided by total annual energy sales. Source of the information is maintained internally by GRE.

Adjustments Made: Real wholesale member rate base year 2012 was calculated using a Personal Consumption Expenditure Index (PCI) (2012=100). The historic and forecast PCI was provided by Woods and Poole Economics, Inc.

Independent Variable: HDD_{65} and CDD_{65}

Database: Midwestern Regional Climate Center – MRCC Applied Climate System

Variables Used: Monthly Owatonna, MN HDD_{65} & CDD_{65}
Monthly St. Cloud, MN HDD_{65} & CDD_{65}
Monthly Minneapolis/St. Paul Airport HDD_{65} & CDD_{65}

Description/Source:
Monthly HDD_{65} and CDD_{65} were obtained from 1961 through July of 2013 from the Midwestern Regional Climate Center. (http://mrcc.isws.illinois.edu/). Weather stations in Owatonna, MN, St. Cloud, MN, and Minneapolis/St. Paul Airport were used to represent the three forecast regions.

Adjustments Made: None

Table 7. Independent variables used in monthly peak demand forecast.

Forecast Region	HotTemp	ColdTemp	Monthly Energy Sales	Monthly Binaries
Metro	x		x	x
Northern	x	x	x	x
Southern & Western	x	x	x	x

Independent Variable: Monthly Energy Sales

Database: Regional Annual Energy Projections from regional annual energy sales forecast.

Variables Used: Metro Region Annual Energy Sales, Northern Region Annual Energy Sales, and Southern & Western Region Annual Energy Sales

Description/Source:
The data source for monthly energy sales are the annual regional energy sales forecasts described previously in Subpart 1 and Subpart 2.

Adjustments Made: Annual energy sales were broken down into monthly energy sales using historic and forecast monthly allocation rates.

Independent Variable: HotTemp and ColdTemp

Database: GRE Internal Weather Data

Variables Used: Hibbing, MN Temperature, Mason City, Iowa Temperature, Minneapolis/St. Paul Temperature

Description/Source
To take into account the different slope trend of electric cooling and space heating demand, temperatures at the time of each forecast region's coincident peak were transformed into either a HotTemp or Cold Temp Index. Source of the data came from GRE's Internal weather station data. Temperature locations at the time of GRE's coincident peak were Minneapolis/St. Paul Airport, Hibbing, MN and Mason City Iowa.

The HotTemp and ColdTemp index in the regional coincident peak demand models has numerous purposes:

(1) Because of different slope trends in heating and cooling responses to coincident peak demand, the two separate indexes allow for a cooling coefficient and space heating coefficient,
(2) During some shoulder months, the peak demand could be a result from either a cooling load or a space heating load. By having separate cold and hot temp indexes, the regression model can respond accordingly.
(3) Winter peaking temps can have a negative or positive temperature, and by doing a heating temp transformation, the resulting values will always be negative. If you have both negative and positive values for peaking temps, there will be a consequential interaction with the regression model's weather coefficient. By always having a negative value for heating temps, the heating temp will always be consistent with the regression model's heating coefficient.

HotTemp Index:

If Coincident Peak Temp °F ≥ 65 then HotTemp Index = Coincident Peak Temp °F – 65, else 0

Where
Metro Region Peak Temp = temperature at time of coincident peak recorded at the MSP-St. Paul Airport
Northern Region Peak Temp = temperature at time of coincident peak recorded in Hibbing, MN
Southern & Western Peak Temp = temperature at time of coincident peak recorded Owatonna, MN.

ColdTemp Index:

If Coincident Peak Temp °F < 65 then ColdTemp Index = Coincident Peak Temp °F – 65, else 0

Where
Metro Region Peak Temp = temperature at time of coincident peak recorded at the MSP-St. Paul Airport
Northern Region Peak Temp = temperature at time of coincident peak recorded in Hibbing, MN
Southern & Western Peak Temp = temperature at time of coincident peak recorded Owatonna, MN.

Adjustments Made: None

Subpart 3. Discussion. The utility shall discuss in writing each essential assumption made in preparing the forecasts, including the need for the assumption, the nature of the assumption, and the sensitivity of forecast results to variations in the essential assumptions.

1. **Monthly Allocation Factors**
   Need: Forecast monthly allocation factors were used to break down annual energy sales into monthly energy sales
   Assumption: Average historic monthly percent energy sales will probably resemble future monthly energy percent sales during the forecast period.
   Sensitivity: Nothing to test
2. **Customer Class Allocation Factors**
   Need: Forecast customer class allocation factors were used to break down forecast annual energy sales into RUS customer classes
   Assumption: Average historic energy sale percents by RDUP customer class will probably resemble future energy sale percents by RDUP class during the forecast period.
   Sensitivity: Nothing to Test
3. **Cooling/Heating breakpoint of 65 degrees Fahrenheit**
   Need: Temperature break point was needed to separate cooling temperatures verse heating temperatures for the three forecast regions.
   Assumption: If Coincident Peak Temp °F < 65 then ColdTemp Index = Coincident Peak Temp °F – 65, else 0, and If Coincident Peak Temp °F ≥ 65 then HotTemp Index = Coincident Peak Temp °F – 65, else 0
   Sensitivity: Nothing to test
4. **Load control is embedded in the historic and forecast Data**
   Need: Load Management is used at Great River Energy during monthly peaking conditions to establish a monthly billing peak. The forecast is made to match controlled loads.
   Assumption : Historical load control program will remain consistent in the future, i.e. our historic growth in load control will continue to be the same going forward along with how these load control programs are implemented.
   Sensitivity: Nothing to Test
5. **Econometric Data**
   Need: Econometric data is required to provide projections of household growth, employment, population, and fuel prices. These future projections must be representative of each forecast region.
   Assumption: Woods and Poole Economic Data, MN State Demographer Data, and Energy Information Administration are representative of the three forecast regions.
   Sensitivity: Nothing to test

Subpart 4. Subject of assumption. The utility shall discuss the assumptions made regarding the availability of alternative sources of energy, the expected conversion from other fuels to electricity or vice versa, future prices of electricity for customers in the utility's system and the effect that such price changes will likely have on the utility's system demand, the assumptions made in arriving at any data requested in part 7610.0310 that is not available historically or not generated by the utility in preparing its own internal forecast, the effect of existing energy conservation programs under federal or state legislation on long-term electrical demand, the projected effect of new conservation programs that the utility deems likely to occur through future state and federal legislation on long-term electrical demand, and any other factor considered by the utility in preparing the forecast. In addition the utility shall state what assumptions were made, if any, regarding current and anticipated

saturation levels of major electrical appliances and electric space heating within the utility's service area. If a utility makes no assumptions in preparing its forecast with regard to current and anticipated saturation levels of major electrical appliances and electric space heating, it shall simply state this in its discussion of assumptions.

Great River Energy incorporated the member wholesale rate into each of the region's forecast and for each forecast region, the resulting coefficient was negative. In each region, for every 1% change in the wholesale member rate, there is a slight decrease in energy sales, ~0.1%.

Great River Energy forecast assumes availability of alternative forms of energy in the future will be similar to what has been observed in the past.

Great River Energy did not make any explicit assumptions or adjustments about current or anticipated saturation levels of major residential or commercial appliances during the forecast process. No explicit assumptions were made in regards to seeing an increase or decrease in electrical space heating systems.

Subpart 5. Coordination of forecasts with other systems. The utility shall provide in writing:

A. a description of the extent to which the utility coordinates its load forecasts with those of other systems, such as neighboring systems, associate systems in a power pool, or coordinated organizations

Great River Energy does not coordinate its long-term forecasts with those of other systems.

B. a description of the manner in which such forecast are coordinated, and any problems experienced in efforts to coordinate load forecast.

Great River Energy does not coordinate its long-term forecasts with those of other systems.

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT

7610.0120 REGISTRATION

ENTITY ID#	121
REPORT YEAR	2013

Number of Power Plants	11

UTILITY DETAILS

UTILITY NAME	Great River Energy
STREET ADDRESS	12300 Elm Creek Boulevard
CITY	Maple Grove
STATE	MN
ZIP CODE	55369-4718
TELEPHONE	763/241-5775
	Scroll down to see allowable UTILITY TYPES
* UTILITY TYPE	COOP

CONTACT INFORMATION

CONTACT NAME	Nathan Grahl
CONTACT TITLE	Forecasting and Modeling Lead
CONTACT STREET ADDRESS	12300 Elm Creek Blvd
CITY	Maple Grove
STATE	MN
ZIP CODE	55369
TELEPHONE	763-445-6918
CONTACT E-MAIL	ngrahl@GREnergy.com

UTILITY OFFICERS

NAME	TITLE
Michael A. Thorson	Chair
Brad Leiding	Vice-Chair
Gary Wilson	Secretary
Robert Thompson	Treasurer

PREPARER INFORMATION

PERSON PREPARING FORMS	Nathan Grahl
PREPARER'S TITLE	Forecasting and Modeling Lead
DATE	6/30/2013

COMMENTS

ALLOWABLE UTILITY TYPES

Code
Private
Public
Co-op

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0150 FEDERAL OR STATE DATA SUBSTITUTION

			FILING CYCLE (enter an "X" in the cell)		
FEDERAL AGENCY	FORM NUMBER	FORM TITLE	MONTHLY	YEARLY	OTHER
DOE	EIA 861	Annual Electric Utility Report		X	

COMMENTS
2014 Submission of the EIA 861 is not due until August, 2014. GRE will submit the EIA 861 when comleted in July.

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY

A utility shall provide the following information for the last calendar year:

B. LARGEST CUSTOMER LIST - ATTACHMENT ELEC-1

If applicable, the Largest Customer List must be submitted either in electronic or paper format. If information is Trade Secret, note it as such.

See "LargestCustomers" worksheet for data entry.

C. MINNESOTA SERVICE AREA MAP

The referenced map must be submitted either in electronic or paper format.

See Instructions for details of the information required on the Minnesota Service Area Map.

[Trade Secret Begins

RESALE ONLY

D. PURCHASES AND SALES FOR RESALE

UTILITY NAME	INTERCONNECTED UTILITY	MWH PURCHASED	MWH SOLD FOR RESALE

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY

A utility shall provide the following information for the last calendar year:

B. LARGEST CUSTOMER LIST - ATTACHMENT ELEC-1

If applicable, the Largest Customer List must be submitted either in electronic or paper format. If information is Trade Secret, note it as such.

See "LargestCustomers" worksheet for data entry.

C. MINNESOTA SERVICE AREA MAP

The referenced map must be submitted either in electronic or paper format.

See Instructions for details of the information required on the Minnesota Service Area Map.

Trade Secret Ends]

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

A utility shall provide the following information for the last calendar year:

E. RATE SCHEDULES	**The rate schedule and monthly power cost adjustment information must be submitted in electronic or paper format.**

See Instructions for details of the information required on the Rate Schedules and Monthly Power Cost Adjustments.

F. REPORT FORM EIA-861	**A copy of report form EIA-861 filed with the US Dept. of Energy must be submitted in electronic or paper format.**

A copy of the report form EIA-861 filed with the Energy Information Administration of the US Dept. of Energy must be submitted.

G. FINANCIAL AND STATISTICAL REPORT	**If applicable, a copy of the Financial and Statistical Report filed with the US Dept. of Agriculture must be submitted in electronic or paper format.**

For rural electric cooperatives, a copy of the Financial and Statistical Report to the US Dept of Agriculture must be submitted.

H. GENERATION DATA

If the utility has Minnesota power plants, enter the fuel requirements and generation data on the Plant1, Plant2, etc. worksheets.

I. ELECTRIC USE BY MINNESOTA RESIDENTIAL SPACE HEATING USERS

See Instructions for details of the information required for residential space heating users.

COL. 1 NO. OF RESIDENTIAL ELECTRICAL SPACE HEATING CUSTOMERS	COL. 2 NO. OF RESIDENTIAL UNITS SERVED WITH ELECTRICAL SPACE HEATING	COL. 3 TOTAL MWH USED BY THESE CUSTOMERS AND UNITS
61,304	61,304	1,188,276

Comments

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

J. ITS DELIVERIES TO ULTIMATE CONSUMERS BY COUNTY FOR THE LAST CALENDAR YEAR

ENERGY DELIVERED TO ULTIMATE CONSUMERS BY COUNTY

COUNTY CODE	COUNTY NAME	MWH DELIVERED	COUNTY CODE	COUNTY NAME	MWH DELIVERED
1	Aitkin	192143.558	46	Martin	81910.15245
2	Anoka	1773458.66	47	Meeker	54797.31053
3	Becker	107670.074	48	Mille Lacs	192774.5249
4	Beltrami	553.384872	49	Morrison	127019.5412
5	Benton	100085.404	50	Mower	0
6	Big Stone	8217.39685	51	Murray	47386.35746
7	Blue Earth	147306.773	52	Nicollet	107544.8336
8	Brown	51278.4408	53	Nobles	47436.51057
9	Carlton	79901.8069	54	Norman	0
10	Carver	121493.654	55	Olmstead	580.4676724
11	Cass	257459.851	56	Otter Tail	280357.3216
12	Chippewa	2244.92944	57	Pennington	0
13	Chisago	174677.313	58	Pine	211907.7842
14	Clay	6341.22187	59	Pipestone	835.3830573
15	Clearwater	335.949867	60	Polk	0
16	Cook	42876.3808	61	Pope	48115.26142
17	Cottonwood	26989.5296	62	Ramsey	80746.27028
18	Crow Wing	682489.509	63	Red Lake	0
19	Dakota	2059738.21	64	Redwood	47986.26386
20	Dodge	13379.6055	65	Renville	19789.16627
21	Douglas	113508.811	66	Rice	114334.6946
22	Faribault	40656.495	67	Rock	324.8711889
23	Fillmore	0	68	Roseau	0
24	Freeborn	2162.94357	69	St. Louis	474893.9207
25	Goodhue	112966.97	70	Scott	429143.2696
26	Grant	19634.5931	71	Sherburne	436028.5239
27	Hennepin	424871.809	72	Sibley	48008.35008
28	Houston	0	73	Stearns	447043.6499
29	Hubbard	164120.72	74	Steele	47049.59721
30	Isanti	338632.699	75	Stevens	24344.9099
31	Itasca	295768.171	76	Swift	36902.74305
32	Jackson	32962.5977	77	Todd	166685.7067
33	Kanabec	120817.222	78	Traverse	0
34	Kandiyohi	137347.688	79	Wabasha	3013.966761
35	Kittson	0	80	Wadena	67939.68561
36	Koochiching	9637.60626	81	Waseca	18253.51179
37	Lac Qui Parle	0	82	Washington	69708.47315
38	Lake	82746.407	83	Watonwan	23035.1927
39	Lake of the Woods	0	84	Wilkin	19269.27633
40	Le Sueur	84407.6776	85	Winona	0
41	Lincoln	23.2050849	86	Wright	460691.9747
42	Lyon	1849.44478	87	Yellow Medicine	0
43	McLeod	82231.831		Burnett, Douglass, Washburn, WI	65,413.99
44	Mahnomen	0		GRAND TOTAL (Entered)	12,214,262
45	Marshall	0			
				GRAND TOTAL (Calculated)	12214262

<= (Should equal "Megawatt-hours" column total on ElectricityByClass worksheet)

COMMENTS

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

J. ITS DELIVERIES TO ULTIMATE CONSUMERS BY MONTH FOR THE LAST CALENDAR YEAR

See Instructions for details of the information required concerning electricity delivered to ultimate consumers.

Past Year Entire System		A Non-Farm Residential	B Residential With Space Heat	C Farm	D Small Commercial & Industrial	E Irrigation	F Large Commercial & Industrial	G Street & Highway Lighting	H Other (Include Municipals)	I Total (Columns A through H)
January	No. of Customers	471,258	61,237	61,110	42,921	2,661	2,753	4,548	613	647,001
	MWH	583,268	98,679	59,620	211,723	103	160,515	2,808	873	1,117,590
February	No. of Customers	470,561	61,146	60,874	43,015	2,648	2,704	4,176	589	645,713
	MWH	506,171	98,760	53,018	215,588	108	151,352	2,823	838	1,028,658
March	No. of Customers	470,958	61,197	60,927	43,074	2,647	2,711	4,243	588	646,345
	MWH	432,074	98,787	46,966	197,675	106	157,873	2,871	867	937,218
April	No. of Customers	471,166	61,225	60,956	43,098	2,647	2,715	4,258	587	646,652
	MWH	352,967	98,802	40,382	199,854	494	151,408	2,771	834	847,512
May	No. of Customers	467,871	60,797	61,039	43,136	2,663	2,708	4,270	588	643,071
	MWH	336,531	98,903	40,996	210,647	3,215	170,116	2,878	829	864,115
June	No. of Customers	471,604	61,282	62,001	43,201	3,570	2,711	4,280	587	649,236
	MWH	425,854	98,977	57,010	232,076	13,700	180,190	2,841	554	1,011,201
July	No. of Customers	472,039	61,338	62,156	43,274	3,650	2,714	4,309	586	650,066
	MWH	595,501	99,062	98,550	261,357	48,362	192,451	2,973	899	1,299,155
August	No. of Customers	472,367	61,381	62,339	43,308	3,729	2,723	4,308	587	650,742
	MWH	485,315	99,162	77,950	237,192	33,893	185,538	2,439	883	1,122,371
September	No. of Customers	472,934	61,455	62,431	43,392	3,749	2,743	4,345	588	651,637
	MWH	376,483	99,175	52,054	220,116	12,946	167,802	2,390	840	931,806
October	No. of Customers	473,161	61,484	62,458	43,417	3,753	2,752	3,357	501	650,883
	MWH	387,148	99,280	44,605	221,860	2,568	166,436	2,875	889	925,660
November	No. of Customers	473,595	61,541	62,044	43,396	3,288	2,750	4,284	858	651,754
	MWH	440,668	99,328	47,433	216,159	201	163,583	2,884	797	971,054
December	No. of Customers	473,802	61,568	61,644	43,363	2,857	2,755	4,211	1,128	651,328
	MWH	594,731	99,362	60,586	230,523	132	168,756	2,956	876	1,157,922
	Total MWH	5,516,710	1,188,276	679,169	2,654,770	115,829	2,016,020	33,509	9,979	12,214,262

Comments

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0600 OTHER INFORMATION REPORTED ANNUALLY (continued)

ELECTRICITY DELIVERED TO ULTIMATE CONSUMERS IN MINNESOTA SERVICE AREA IN LAST CALENDAR YEAR

See Instructions for details of the information required concerning electricity delivered to ultimate consumers.

Exclude station use, distribution losses, and unaccounted for energy losses from this table altogether.

Classification of Energy Delivered to Ultimate Consumers (include energy used during the year for irrigation and drainage pumping)	In this column report the number of farms, residences, commercial establishments, etc., and not the number of meters, where different. Number of Customers at End of Year	This column total should equal the grand total in the worksheet labeled "ElectricityByCounty" which provides deliveries by county. Megawatt-hours (round to nearest MWH)	This column total will be used for the Alternative Energy Assessment and should not include revenues from sales for resale (MN Statutes Sec. 216B.62, Subd. 5). Revenue ($)
Farm	63,043	794,998	84,923,372
Nonfarm-residential	531,702	6,704,986	716,240,518
Commercial	43,216	2,654,770	225,761,480
Industrial	2,724	2,016,020	129,480,062
Street and highway lighting	4,301	33,509	5,713,614
All other	659	9,979	27,648,910
Entered Total	645,646	12,214,262	1,189,767,956
CALCULATED TOTAL	645,646	12,214,262	1,189,767,956

Comments

Non-farm ($/kWh)	Residential ($/customer)
CHECK	CHECK

REMEMBER TO SEND THE FOLLOWING ATTACHMENTS:	
1	If applicable, the Largest Customer List (Attachment ELEC-1), if the separate LargestCustomers spreadsheet file was not used (pursuant to MN Rules Chapter 7610.0600 B.)
2	Minnesota service area map (pursuant to MN Rules Chapter 7610.0600 C.)
3	Rate schedules and monthly power cost adjustments (pursuant to MN Rules Chapter 7610.0600 E.)
4	Report form EIA-861 filed with US Dept. of Energy (pursuant to MN Rules Chapter 7610.0600 F.)
5	If applicable, for rural electric cooperatives, the Financial and Statistical Report filed with US Dept. of Agriculture (pursuant to MN Rules Chapter 7610.0600 G.)

Great River Energy

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPO 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Elk River Station	PLANT ID	121004
STREET ADDRESS	17845 East Highway 10		
CITY	Elk River		
STATE	MN	NUMBER OF UNITS	3
ZIP CODE	55330		
COUNTY	Sherburne		
CONTACT PERSON	Tim Steinbeck		
TELEPHONE	763-241-2495		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1951	REF	41,497	
2	USE	ST	1951	REF	39,620	
3	USE	ST	1959	REF	64,595	
				Plant Total	145,712	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	8.04	8.04	71.4	100	0.15	
2	8.13	8.13	67.7	100	0.39	
3	15.05	15.05	59.3	100	0.66	
Plant Total	31.22	31.22				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	REF	79,864	TON		NG	11,868	MCF	
2	REF	77,546	TON		NG	12,199	MCF	
3	REF	123,354	TON		NG	17,724	MCF	
Plant Total					TDF		TONS	

Plant1 8/12/2014

Great River Energy

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPO 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Coal Creek	PLANT ID	121003
STREET ADDRESS	PO Box 780		
CITY	Underwood		
STATE	ND	NUMBER OF UNITS	2
ZIP CODE	58576		
COUNTY	McLean		
CONTACT PERSON	John Weeda		
TELEPHONE	701-442-3211		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1979	LIG	4,603,252	
2	USE	ST	1980	LIG	4,233,674	
Plant Total				Plant Total	8,836,926	

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	560.2	560.2	101.1	100	3.85	
2	579.7	579.7	89.4	99.9	2.28	
Plant Total	1139.9	1139.9				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	LIG	3,623,565	TONS		FO2	161,547	GAL	
2	LIG	3,304,312	TONS		FO2	212,051	GAL	
Plant Total			Tons					

Plant2 8/12/2014

Great River Energy

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPO 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Coal Creek Diesel	PLANT ID	121005
STREET ADDRESS	PO Box 780		
CITY	Underwood		
STATE	ND	NUMBER OF UNITS	1
ZIP CODE	58576		
COUNTY	McLean		
CONTACT PERSON	John Weeda		
TELEPHONE	701-442-3211		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	STB	IC	1979	DIESEL		
				Plant Total	0	

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1						
Plant Total	0	0				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	FO2							

Plant3 8/12/2014

Great River Energy

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPO 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Maple Lake	PLANT ID	121008
STREET ADDRESS			
CITY	Maple Lake		
STATE	MN	NUMBER OF UNITS	1
ZIP CODE			
COUNTY	Wright		
CONTACT PERSON	Nathan Domyahn		
TELEPHONE	763-445-5822		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	STB	GT	1978	FO2	220	
				Plant Total	220	

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	21.7	26.9	0.1	100	82.86	
Plant Total	21.7	26.9				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	FO2	24,640	GAL					

Plant4 8/12/2014

Great River Energy **Confidential**

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPO 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Rock Lake	PLANT ID	121011
STREET ADDRESS			
CITY	Pine City		
STATE	MN	NUMBER OF UNITS	1
ZIP CODE			
COUNTY	Pine		
CONTACT PERSON	Nathan Domyahn		
TELEPHONE	763-445-5822		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	STB	GT	1978	FO2	217	
				Plant Total	217	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	22.5	28	0.1	99.8	40.82	
Plant Total	22.5	28				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	FO2	32,513	GAL					

Plant5 8/12/2014

Great River Energy

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPO 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Stanton Station	PLANT ID	121012
STREET ADDRESS	Highway 2004		
CITY	Stanton Station		
STATE	ND	NUMBER OF UNITS	1
ZIP CODE	58571		
COUNTY	Mercer		
CONTACT PERSON	John Weeda		
TELEPHONE	701-442-3211		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1966	LIG	1,071,191	
				Plant Total	1,071,191	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	186.9	186.9	71	99.8	0	
Plant Total	186.9	186.9				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	LIG	609,463	TON		FO2	135,243	GAL	

Plant6 8/12/2014

Great River Energy

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPOR 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	St. Bonifacious
STREET ADDRESS	PO Box 393
CITY	St. Bonifacious
STATE	MN
ZIP CODE	55375
COUNTY	Carver
CONTACT PERSON	Nathan Domyahn
TELEPHONE	763-445-5822
PLANT ID	121006
NUMBER OF UNITS	1

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	STB	GT	1978	FO2	538.00	
				Plant Total	538.00	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	61.5	72.7	0.1	100	0.01	
Plant Total	61.5	72.7				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	FO2	64,407	GAL					

Plant7 8/12/2014 Page 1

Great River Energy

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPO 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Lakefield Junction	PLANT ID	121014
STREET ADDRESS	2159 20th Ave		
CITY	Trimont		
STATE	MN	NUMBER OF UNITS	6
ZIP CODE	55176		
COUNTY	Martin		
CONTACT PERSON	Nathan Domyahn		
TELEPHONE	763-445-5822		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	STB	GT	2001	NG	28,131	
2	STB	GT	2001	NG	19,968	
3	STB	GT	2001	NG	31,912	
4	STB	GT	2001	NG	21,633	
5	STB	GT	2001	NG	15,999	
6	STB	GT	2001	NG	10,604	
				Plant Total	128,247	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	86.6	101.5	3.7	100	0.06	
2	88.5	101.5	2.6	100	3.16	
3	86.4	101.3	4.2	100	0	
4	87.2	102.3	2.8	100	2.35	
5	87.5	102.5	2.1	100	18.05	
6	86.7	101.7	1.4	100	0	
Plant Total	522.9	616.8				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	NG	347,632	MCF		FO2	1,866	GAL	
2	NG	252,560	MCF		FO2	2,251	GAL	
3	NG	394,001	MCF		FO2	2,003	GAL	
4	NG	278,079	MCF		FO2	1,987	GAL	
5	NG	197,660	MCF		FO2	1,844	GAL	
6	NG	134,630	MCF		FO2	1,546	GAL	

Plant8 8/12/2014

Great River Energy

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPO 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Pleasant Valley Station	PLANT ID	121013
STREET ADDRESS	68435-310th Street		
CITY	Dexter		
STATE	MN	NUMBER OF UNITS	3
ZIP CODE	55926		
COUNTY	Mower		
CONTACT PERSON	Nathan Domyahn		
TELEPHONE	763-445-5822		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
11	STB	GT	2001	NG/FO2	71,858	
12	STB	GT	2001	NG/FO2	77,870	
13	STB	GT	2002	NG/FO2	15,905	
				Plant Total	165,633	

C. UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
11	154.2	175.7	5.3	99.9	5.35	
12	151.6	175.7	5.9	99.9	9.21	
13	118	135.1	1.5	100	1.1	
Plant Total	423.8	486.5				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
11	NG	836,378	MCF		FO2	22,495	GAL	
12	NG	961,815	MCF		FO2	15,643	GAL	
13	NG	198,802	MCF		FO2	0	GAL	

Plant9 8/12/2014

Great River Energy

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPO 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Cambridge	PLANT ID	121002
STREET ADDRESS			
CITY	Cambridge		
STATE	MN	NUMBER OF UNITS	1
ZIP CODE			
COUNTY	Isanti		
CONTACT PERSON	Nathan Domyahn		
TELEPHONE	763-445-5822		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	STB	GT	1978	FO2	353	
2	STB	GT	2007	NG	82695	
				Plant Total	83048	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	22.1	28	0.2	99.9	17.24	
2	158.4	185	6	100	2.85	
Plant Total	180.5	213				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	FO2	37,428	Gal					
2	NG	965,697	MCF					

Plant10 8/12/2014

Great River Energy

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPO 2013

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Elk River Peaker	PLANT ID	121015
STREET ADDRESS	17845 East Hwy 10		
CITY	Elk River		
STATE	MN	NUMBER OF UNITS	1
ZIP CODE	55330		
COUNTY	Sherburne		
CONTACT PERSON	Nathan Domyahn		
TELEPHONE	763-445-5822		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	STB	GT	2009	NG/FO	80511	
				Plant Total	80511	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	188.1	223	4.9	99.9	9.72	
Plant Total	188.1	223				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	NG	887,424	MCF		FO2	153,407	GAL	

Plant11 8/12/2014

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

INSTRUCTIONS

The individual worksheets in this spreadsheet file correspond closely to the tables in the paper forms received by the utility.
The instructions provided with the paper forms also pertain to the data to be entered in each of the worksheets in this file.
PLEASE DO NOT CHANGE THE NAME OR ORDER OF ANY OF THE WORKSHEET TABS IN THIS FILE

In general, the following scheme is used on each worksheet:

Cells shown with a light green background correspond to headings for columns, rows or individual fields.
Cells shown with a light yellow background require data to be entered by the utility.
Cells shown with a light brown background generally correspond to fields that are calculated from the data entered, or correspond to fields that are informational and not to be modified by the utility.

Each worksheet contains a section labeled Comments below the main data entry area.
You may enter any comments in that section that may be needed to explain or clarify the data being entered on the worksheet.

Please complete the required worksheets and save the completed spreadsheet file to your local computer.
Then attach the completed spreadsheet file to an e-mail message and send it to the following e-mail address:

rule7610.reports@state.mn.us

If you have any questions please contact:

Steve Loomis
MN Department of Commerce
steve.loomis@state.mn.us
(651) 539-1690

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

7610.0120 REGISTRATION

ENTITY ID#	121
REPORT YEAR	2013
RILS ID#	U12555

UTILITY DETAILS	
UTILITY NAME	Great River Energy
STREET ADDRESS	12300 Elm Creek Boulevard
CITY	Maple Grove
STATE	MN
ZIP CODE	55369-4718
TELEPHONE	763/241-5775
	Scroll down to see allowable UTILITY TYPES
* UTILITY TYPE	COOP

CONTACT INFORMATION	
CONTACT NAME	Nathan Grahl
CONTACT TITLE	Forecasting and Modeling Lead
CONTACT STREET ADDRESS	12300 Elm Creek Blvd
CITY	Maple Grove
STATE	MN
ZIP CODE	55369
TELEPHONE	763-445-6118
CONTACT E-MAIL	ngrahl@GREnergy.com

COMMENTS

PREPARER INFORMATION	
PERSON PREPARING FORMS	Nathan Grahl
PREPARER'S TITLE	Forecasting and Modeling Lead
DATE	6/17/2014

ALLOWABLE UTILITY TYPES

Code

Private

Public

Co-op

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item A. SYSTEM FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS

Provide actual data for your entire system for the past year, your estimate for the present year and all future forecast years.

Please remember that the number of customers <u>should reflect the number of customers at year's end, not the number of meters</u>.

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	SYSTEM TOTALS	Calculated System Totals
Past Year	2013	No. of Cust.	63,873	530,873	43,216		2,724	4,301	659		645,646
		MWH	887,996	6,612,212	2,654,849		2,016,080	33,510	9,979		12,214,626
Present Year	2014	No. of Cust.	64,380	535,071	43,751		2,745	4,288	518		650,753
		MWH	866,877	6,454,955	2,591,709		1,968,132	32,713	9,742		11,924,129
1st Forecast Year	2015	No. of Cust.	64,766	538,000	44,163		2,780	4,291	518		654,518
		MWH	871,949	6,492,719	2,606,871		1,979,646	32,904	9,799		11,993,889
2nd Forecast Year	2016	No. of Cust.	65,182	541,180	44,575		2,821	4,292	518		658,569
		MWH	877,982	6,537,642	2,624,908		1,993,344	33,132	9,867		12,076,875
3rd Forecast Year	2017	No. of Cust.	65,619	544,580	45,026		2,866	4,295	518		662,904
		MWH	887,265	6,606,768	2,652,663		2,014,420	33,482	9,971		12,204,569
4th Forecast Year	2018	No. of Cust.	66,066	548,144	45,491		2,916	4,296	518		667,432
		MWH	899,006	6,694,194	2,687,765		2,041,077	33,925	10,103		12,366,071
5th Forecast Year	2019	No. of Cust.	66,530	551,928	45,974		2,966	4,299	517		672,215
		MWH	889,295	6,621,879	2,658,730		2,019,028	33,559	9,994		12,232,484
6th Forecast Year	2020	No. of Cust.	67,026	555,882	46,467		3,016	4,300	517		677,209
		MWH	901,911	6,715,819	2,696,448		2,047,670	34,035	10,136		12,406,018
7th Forecast Year	2021	No. of Cust.	67,532	559,925	46,982		3,066	4,303	517		682,325
		MWH	916,347	6,823,317	2,739,609		2,080,447	34,580	10,298		12,604,597
8th Forecast Year	2022	No. of Cust.	68,033	564,004	47,512		3,115	4,304	517		687,486
		MWH	927,049	6,903,003	2,771,604		2,104,743	34,983	10,418		12,751,800
9th Forecast Year	2023	No. of Cust.	68,554	568,222	48,058		3,163	4,307	517		692,821
		MWH	940,933	7,006,385	2,813,112		2,136,265	35,507	10,574		12,942,776
10th Forecast Year	2024	No. of Cust.	69,080	572,492	48,599		3,210	4,308	517		698,206
		MWH	955,376	7,113,937	2,856,295		2,169,057	36,052	10,737		13,141,455
11th Forecast Year	2025	No. of Cust.	69,611	576,830	49,136		3,256	4,311	517		703,661
		MWH	970,382	7,225,675	2,901,159		2,203,127	36,619	10,905		13,347,867
12th Forecast Year	2026	No. of Cust.	70,164	581,337	49,668		3,301	4,312	517		709,300
		MWH	986,269	7,343,969	2,948,654		2,239,195	37,218	11,084		13,566,390
13th Forecast Year	2027	No. of Cust.	70,724	585,917	50,195		3,346	4,315	517		715,014
		MWH	1,004,069	7,476,509	3,001,870		2,279,607	37,890	11,284		13,811,228
14th Forecast Year	2028	No. of Cust.	71,282	590,488	50,717		3,389	4,316	517		715,014
		MWH	1,019,343	7,590,247	3,047,537		2,314,286	38,466	11,456		13,811,228

* MINING needs to be reported as a separate category only if annual sales are greater than 1,000 GWH. Otherwise, include MINING in the INDUSTRIAL category.

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item A. MINNESOTA-ONLY FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS

Provide actual data for your Minnesota service area only, for the past year, your best estimate for the present year and all future forecast years.

Please remember that the number of customers should reflect the number of customers at year's end, not the number of meters.

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	MN-ONLY TOTALS	Calculated MN-Only Totals
Past Year	2013	No. of Cust.	63,873	530,873	43,216		2,724	4,301	659		645,646
		MWH	887,996	6,612,212	2,654,849		2,016,080	33,510	9,979		12,214,626
Present Year	2014	No. of Cust.	64,380	535,071	43,751		2,745	4,288	518		650,753
		MWH	866,877	6,454,955	2,591,709		1,968,132	32,713	9,742		11,924,129
1st Forecast Year	2015	No. of Cust.	64,766	538,000	44,163		2,780	4,291	518		654,518
		MWH	871,949	6,492,719	2,606,871		1,979,646	32,904	9,799		11,993,889
2nd Forecast Year	2016	No. of Cust.	65,182	541,180	44,575		2,821	4,292	518		658,569
		MWH	877,982	6,537,642	2,624,908		1,993,344	33,132	9,867		12,076,875
3rd Forecast Year	2017	No. of Cust.	65,619	544,580	45,026		2,866	4,295	518		662,904
		MWH	887,265	6,606,768	2,652,663		2,014,420	33,482	9,971		12,204,569
4th Forecast Year	2018	No. of Cust.	66,066	548,144	45,491		2,916	4,296	518		667,432
		MWH	899,006	6,694,194	2,687,765		2,041,077	33,925	10,103		12,366,071
5th Forecast Year	2019	No. of Cust.	66,530	551,928	45,974		2,966	4,299	517		672,215
		MWH	889,295	6,621,879	2,658,730		2,019,028	33,559	9,994		12,232,484
6th Forecast Year	2020	No. of Cust.	67,026	555,882	46,467		3,016	4,300	517		677,209
		MWH	901,911	6,715,819	2,696,448		2,047,670	34,035	10,136		12,406,018
7th Forecast Year	2021	No. of Cust.	67,532	559,925	46,982		3,066	4,303	517		682,325
		MWH	916,347	6,823,317	2,739,609		2,080,447	34,580	10,298		12,604,597
8th Forecast Year	2022	No. of Cust.	68,033	564,004	47,512		3,115	4,304	517		687,486
		MWH	927,049	6,903,003	2,771,604		2,104,743	34,983	10,418		12,751,800
9th Forecast Year	2023	No. of Cust.	68,554	568,222	48,058		3,163	4,307	517		692,821
		MWH	940,933	7,006,385	2,813,112		2,136,265	35,507	10,574		12,942,776
10th Forecast Year	2024	No. of Cust.	69,080	572,492	48,599		3,210	4,308	517		698,206
		MWH	955,376	7,113,937	2,856,295		2,169,057	36,052	10,737		13,141,455
11th Forecast Year	2025	No. of Cust.	69,611	576,830	49,136		3,256	4,311	517		703,661
		MWH	970,382	7,225,675	2,901,159		2,203,127	36,619	10,905		13,347,867
12th Forecast Year	2026	No. of Cust.	70,164	581,337	49,668		3,301	4,312	517		709,300
		MWH	986,269	7,343,969	2,948,654		2,239,195	37,218	11,084		13,566,390
13th Forecast Year	2027	No. of Cust.	70,724	585,917	50,195		3,346	4,315	517		715,014
		MWH	1,004,069	7,476,509	3,001,870		2,279,607	37,890	11,284		13,811,228
14th Forecast Year	2028	No. of Cust.	71,282	590,488	50,717		3,389	4,316	517		715,014
		MWH	1,019,343	7,590,247	3,047,537		2,314,286	38,466	11,456		13,811,228

* MINING needs to be reported as a separate category only if annual sales are greatere than 1,000 GWH. Otherwise, include MINING in the INDUSTRIAL category.

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item B. FORECAST OF ANNUAL SYSTEM CONSUMPTION AND GENERATION DATA (Express in MWH)

NOTE: (Column 1 + Column 2) = (Column 3 + Column 5) - (Column 4 + Column 6)

It is recognized that there may be circumstances in which the data entered by the utility is more appropriate or accurate than the value in the corresponding automatically-calculated cell.
If the value in the automatically-calculated cell does not match the value that your utility entered, please provide an explanation in the Comments area at the bottom of the worksheet.

		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	CALCULATED
		CONSUMPTION BY ULTIMATE CONSUMERS IN MINNESOTA in MWH [7610.0310 B(1)]	CONSUMPTION BY ULTIMATE CONSUMERS OUTSIDE OF MINNESOTA in MWH [7610.0310 B(2)]	RECEIVED FROM OTHER UTILITIES in MWH [7610.0310 B(3)]	DELIVERED FOR RESALE in MWH [7610.0310 B(4)]	TOTAL ANNUAL NET GENERATION in MWH [7610.0310 B(5)]	TRANSMISSION LINE SUBSTATION AND DISTRIBUTION LOSSES in MWH [7610.0310 B(6)]	TOTAL WINTER CONSUMPTION in MWH [7610.0310 B(7)]	TOTAL SUMMER CONSUMPTION in MWH [7610.0310 B(7)]	(GENERATION + RECEIVED) MINUS (RESALE + LOSSES) MINUS (CONSUMPTION) SHOULD EQUAL ZERO
Past Year	2013	12,214,626		5,223,658	2,820,613	10,512,460	700,879	6,351,606	5,863,020	0
Present Year	2014	11,924,129		4,400,319	2,568,253	10,776,273	684,210	6,200,547	5,723,582	0
1st Forecast Year	2015	11,993,889		4,418,209	2,973,618	11,237,511	688,213	6,236,822	5,757,067	0
2nd Forecast Year	2016	12,076,875		4,417,811	2,266,962	10,619,001	692,975	6,279,975	5,796,900	0
3rd Forecast Year	2017	12,204,569		4,326,220	1,944,219	10,522,870	700,302	6,346,376	5,858,193	0
4th Forecast Year	2018	12,366,071		4,417,320	2,884,482	11,542,802	709,569	6,430,357	5,935,714	0
5th Forecast Year	2019	12,232,484		4,382,925	2,594,160	11,145,623	701,904	6,360,892	5,871,593	0
6th Forecast Year	2020	12,406,018		4,392,940	2,477,835	11,202,775	711,861	6,451,130	5,954,889	0
7th Forecast Year	2021	12,604,597		4,389,173	2,682,202	11,620,882	723,256	6,554,391	6,050,207	0
8th Forecast Year	2022	12,751,800		4,391,756	2,257,947	11,349,693	731,702	6,630,936	6,120,864	0
9th Forecast Year	2023	12,942,776		4,381,542	2,093,063	11,396,957	742,660	6,730,243	6,212,532	0
10th Forecast Year	2024	13,141,455		4,404,329	2,990,828	12,482,015	754,061	6,833,556	6,307,898	0
11th Forecast Year	2025	13,347,867		5,018,825	2,847,784	11,942,730	765,905	6,940,891	6,406,976	0
12th Forecast Year	2026	13,566,390		5,808,422	3,669,985	12,206,396	778,444	7,054,523	6,511,867	0
13th Forecast Year	2027	13,811,228		5,874,071	4,088,442	12,818,092	792,493	7,181,839	6,629,390	0
14th Forecast Year	2028	14,021,334		6,070,549	3,728,258	12,483,591	804,548	7,291,094	6,730,241	0

COMMENTS

Several elements of this table no longer make sense in the context of participating in the MISO energy market. GRE's load and generation are no longer linked in the manner they were historically. MISO determines the economic dispatch of all the units within the MISO footprint and the actual operation of GRE's generation would only match GRE's load by happenstance, it is no longer a requirement. All of GRE's generation is sold into the MISO market and GRE's entire load is served/purchased from the MISO market. As such we can no longer identify the counter parties with whom transactions are done and detailing information as "received from other utilities" and "sold for resale" no longer make sense. Consumption by Ultimate Consumer outside of Minnesota im MWH is less than 1% of the total so it was not included

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item C. PEAK DEMAND BY ULTIMATE CONSUMERS AT THE TIME OF ANNUAL SYSTEM PEAK (in MW)

	FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	SYSTEM TOTALS	Calculated System Totals
Last Year Peak Day 2013	140	1110	442	0	309	5	2	2,341	2,008

7610.0310 Item D. PEAK DEMAND BY MONTH FOR THE LAST CALENDAR YEAR (in MW)

	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
Last Year 2013	2,011	1,926	1,772	1,555	1,505	2,001	2,326	2,341	2,098	1,671	1,781	2,002

COMMENTS

This is an estimate based on the percent of energy sales by classification. Calculated system total does not equal system total because it does not include sales for resale, own use & losses. Peak demand has been adjusted for our fixed member requirement and does not include their growth

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item E. PART 1: FIRM PURCHASES (Express in MW)

[Trade Secret Begins

NAME OF OTHER UTILITY =>			[redacted]	[redacted]					
Past Year	2013	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
Present Year	2014	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
1st Forecast Year	2015	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
2nd Forecast Year	2016	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
3rd Forecast Year	2017	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
4th Forecast Year	2018	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
5th Forecast Year	2019	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
6th Forecast Year	2020	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
7th Forecast Year	2021	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
8th Forecast Year	2022	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
9th Forecast Year	2023	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
10th Forecast Year	2024	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
11th Forecast Year	2025	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
12th Forecast Year	2026	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
13th Forecast Year	2027	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
14th Forecast Year	2028	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					

Trade Secret Ends]

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item E. PART 2. FIRM SALES (Express in MW)

[Trade Secret Begins

NAME OF OTHER UTILITY =>									
Past Year	2013	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
Present Year	2014	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
1st Forecast Year	2015	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
2nd Forecast Year	2016	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
3rd Forecast Year	2017	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
4th Forecast Year	2018	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
5th Forecast Year	2019	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
6th Forecast Year	2020	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
7th Forecast Year	2021	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
8th Forecast Year	2022	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
9th Forecast Year	2023	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
10th Forecast Year	2024	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
11th Forecast Year	2025	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
12th Forecast Year	2026	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
13th Forecast Year	2027	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					
14th Forecast Year	2028	Summer	[redacted]	[redacted]					
		Winter	[redacted]	[redacted]					

Trade Secret Ends]

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item F. PART 1. PARTICIPATION PURCHASES (Express in MW)

[Trade Secret Begins

NAME OF OTHER UTILITY =>										
Past Year	2013	Summer								
		Winter								
Present Year	2014	Summer								
		Winter								
1st Forecast Year	2015	Summer								
		Winter								
2nd Forecast Year	2016	Summer								
		Winter								
3rd Forecast Year	2017	Summer								
		Winter								
4th Forecast Year	2018	Summer								
		Winter								
5th Forecast Year	2019	Summer								
		Winter								
6th Forecast Year	2020	Summer								
		Winter								
7th Forecast Year	2021	Summer								
		Winter								
8th Forecast Year	2022	Summer								
		Winter								
9th Forecast Year	2023	Summer								
		Winter								
10th Forecast Year	2024	Summer								
		Winter								
11th Forecast Year	2025	Summer								
		Winter								
12th Forecast Year	2026	Summer								
		Winter								
13th Forecast Year	2027	Summer								
		Winter								
14th Forecast Year	2028	Summer								
		Winter								

COMMENTS

MINNESOTA ELECTRIC UTII

7610.0310 Item F. PART 1. PARTICIPATI(

		NAME OF OTHER UTILITY =>	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Past Year	2013	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Present Year	2014	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1st Forecast Year	2015	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2nd Forecast Year	2016	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3rd Forecast Year	2017	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4th Forecast Year	2018	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5th Forecast Year	2019	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6th Forecast Year	2020	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7th Forecast Year	2021	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8th Forecast Year	2022	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9th Forecast Year	2023	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10th Forecast Year	2024	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11th Forecast Year	2025	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12th Forecast Year	2026	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13th Forecast Year	2027	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14th Forecast Year	2028	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

MINNESOTA ELECTRIC UTII

7610.0310 Item F. PART 1. PARTICIPATI

		NAME OF OTHER UTILITY =>	
Past Year	2013	Summer	
		Winter	
Present Year	2014	Summer	
		Winter	
1st Forecast Year	2015	Summer	
		Winter	
2nd Forecast Year	2016	Summer	
		Winter	
3rd Forecast Year	2017	Summer	
		Winter	
4th Forecast Year	2018	Summer	
		Winter	
5th Forecast Year	2019	Summer	
		Winter	
6th Forecast Year	2020	Summer	
		Winter	
7th Forecast Year	2021	Summer	
		Winter	
8th Forecast Year	2022	Summer	
		Winter	
9th Forecast Year	2023	Summer	
		Winter	
10th Forecast Year	2024	Summer	
		Winter	
11th Forecast Year	2025	Summer	
		Winter	
12th Forecast Year	2026	Summer	
		Winter	
13th Forecast Year	2027	Summer	
		Winter	
14th Forecast Year	2028	Summer	
		Winter	

Trade Secret Ends]

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item F. PART 2: PARTICIPATION SALES (Express in MW)

[Trade Secret Begins

NAME OF OTHER UTILITY =>			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Past Year	2013	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Present Year	2014	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
1st Forecast Year	2015	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2nd Forecast Year	2016	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3rd Forecast Year	2017	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4th Forecast Year	2018	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5th Forecast Year	2019	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6th Forecast Year	2020	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7th Forecast Year	2021	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8th Forecast Year	2022	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9th Forecast Year	2023	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10th Forecast Year	2024	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11th Forecast Year	2025	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12th Forecast Year	2026	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13th Forecast Year	2027	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14th Forecast Year	2028	Summer	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		Winter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Trade Secret Ends]

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item G. LOAD AND GENERATION CAPACITY (Express in MW)

[Trade Secret Begins

			Column 1 SEASONAL MAXIMUM DEMAND	Column 2 SCHEDULE L PURCHASE AT THE TIME OF SEASONAL SYSTEM DEMAND	Column 3 SEASONAL SYSTEM DEMAND	Column 4 ANNUAL SYSTEM DEMAND	Column 5 SEASONAL FIRM PURCHASES (TOTAL)	Column 6 SEASONAL FIRM SALES (TOTAL)	Column 7 SEASONAL ADJUSTED NET DEMAND (3 - 5 + 6)	Column 8 ANNUAL ADJUSTED NET DEMAND (4 - 5 + 6)	Column 9 NET GENERATING CAPABILITY
Past Year	2013	Summer	2,511		2,511	2,511	[redacted]	[redacted]	2,354	2,354	2624
		Winter	2,183		2,183	2,511	[redacted]	[redacted]	2,181	2,509	2824
Present Year	2014	Summer	2,435		2,435	2,435	[redacted]	[redacted]	2,293	2,293	2631
		Winter	2,167		2,167	2,435	[redacted]	[redacted]	2,180	2,448	2815
1st Forecast Year	2015	Summer	2,452		2,452	2,452	[redacted]	[redacted]	2,307	2,307	2720
		Winter	2,152		2,152	2,452	[redacted]	[redacted]	2,207	2,507	2914
2nd Forecast Year	2016	Summer	2,466		2,466	2,466	[redacted]	[redacted]	2,319	2,319	2720
		Winter	2,167		2,167	2,466	[redacted]	[redacted]	2,220	2,519	2914
3rd Forecast Year	2017	Summer	2,487		2,487	2,487	[redacted]	[redacted]	2,338	2,338	2720
		Winter	2,177		2,177	2,487	[redacted]	[redacted]	2,228	2,538	2914
4th Forecast Year	2018	Summer	2,514		2,514	2,514	[redacted]	[redacted]	2,362	2,362	2720
		Winter	2,196		2,196	2,514	[redacted]	[redacted]	2,245	2,562	2914
5th Forecast Year	2019	Summer	2,466		2,466	2,466	[redacted]	[redacted]	2,311	2,311	2720
		Winter	2,220		2,220	2,466	[redacted]	[redacted]	2,265	2,511	2914
6th Forecast Year	2020	Summer	2,495		2,495	2,495	[redacted]	[redacted]	2,342	2,342	2720
		Winter	2,192		2,192	2,495	[redacted]	[redacted]	2,238	2,542	2914
7th Forecast Year	2021	Summer	2,528		2,528	2,528	[redacted]	[redacted]	2,370	2,370	2720
		Winter	2,217		2,217	2,528	[redacted]	[redacted]	2,259	2,570	2914
8th Forecast Year	2022	Summer	2,552		2,552	2,552	[redacted]	[redacted]	2,392	2,392	2720
		Winter	2,247		2,247	2,552	[redacted]	[redacted]	2,290	2,595	2914
9th Forecast Year	2023	Summer	2,584		2,584	2,584	[redacted]	[redacted]	2,424	2,424	2720
		Winter	2,267		2,267	2,584	[redacted]	[redacted]	2,308	2,624	2914
10th Forecast Year	2024	Summer	2,617		2,617	2,617	[redacted]	[redacted]	2,455	2,455	2720
		Winter	2,296		2,296	2,617	[redacted]	[redacted]	2,334	2,655	2914
11th Forecast Year	2025	Summer	2,678		2,678	2,678	[redacted]	[redacted]	2,514	2,514	2720
		Winter	2,347		2,347	2,678	[redacted]	[redacted]	2,383	2,714	2914
12th Forecast Year	2026	Summer	2,714		2,714	2,714	[redacted]	[redacted]	2,548	2,548	2720
		Winter	2,383		2,383	2,714	[redacted]	[redacted]	2,417	2,748	2914
13th Forecast Year	2027	Summer	2,754		2,754	2,754	[redacted]	[redacted]	2,586	2,586	2720
		Winter	2,416		2,416	2,754	[redacted]	[redacted]	2,447	2,786	2914
14th Forecast Year	2028	Summer	2,788		2,788	2,788	[redacted]	[redacted]	2,618	2,618	2720
		Winter	2,452		2,452	2,788	[redacted]	[redacted]	2,482	2,818	2914

Trade Secret Ends]

COMMENTS

MINNESOTA ELECTRIC UTI

7610.0310 Item G. LOAD AND GENERAT

[Trade Secret Begins

			Column 10	Column 11	Column 12	Column 13	Column 14	Column 15
			PARTICIPATION PURCHASES (TOTAL)	PARTICIPATION SALES (TOTAL)	ADJUSTED NET CAPABILITY (9 + 10 - 11)	NET RESERVE CAPACITY OBLIGATION	TOTAL FIRM CAPACITY OBLIGATION (7 + 13)	SURPLUS (+) OR DEFICIT (-) CAPACITY (12 - 14)
Past Year	2013	Summer	[redacted]	[redacted]	2,925	172	2,526	399
		Winter	[redacted]	[redacted]	2,955	183	2,365	591
Present Year	2014	Summer	[redacted]	[redacted]	2,937	167	2,460	477
		Winter	[redacted]	[redacted]	2,961	179	2,359	602
1st Forecast Year	2015	Summer	[redacted]	[redacted]	3,065	168	2,476	589
		Winter	[redacted]	[redacted]	3,052	183	2,390	662
2nd Forecast Year	2016	Summer	[redacted]	[redacted]	3,057	169	2,488	570
		Winter	[redacted]	[redacted]	3,052	184	2,403	649
3rd Forecast Year	2017	Summer	[redacted]	[redacted]	3,102	171	2,508	594
		Winter	[redacted]	[redacted]	3,097	185	2,413	684
4th Forecast Year	2018	Summer	[redacted]	[redacted]	3,102	172	2,535	567
		Winter	[redacted]	[redacted]	3,107	187	2,432	675
5th Forecast Year	2019	Summer	[redacted]	[redacted]	3,112	169	2,479	632
		Winter	[redacted]	[redacted]	3,107	183	2,448	659
6th Forecast Year	2020	Summer	[redacted]	[redacted]	3,112	171	2,513	599
		Winter	[redacted]	[redacted]	3,107	186	2,424	683
7th Forecast Year	2021	Summer	[redacted]	[redacted]	3,162	173	2,543	619
		Winter	[redacted]	[redacted]	3,157	188	2,447	710
8th Forecast Year	2022	Summer	[redacted]	[redacted]	3,162	175	2,567	595
		Winter	[redacted]	[redacted]	3,157	189	2,479	677
9th Forecast Year	2023	Summer	[redacted]	[redacted]	3,162	177	2,601	560
		Winter	[redacted]	[redacted]	3,157	192	2,500	657
10th Forecast Year	2024	Summer	[redacted]	[redacted]	3,162	179	2,634	527
		Winter	[redacted]	[redacted]	3,157	194	2,528	629
11th Forecast Year	2025	Summer	[redacted]	[redacted]	3,162	184	2,698	464
		Winter	[redacted]	[redacted]	3,143	198	2,581	561
12th Forecast Year	2026	Summer	[redacted]	[redacted]	3,168	186	2,734	434
		Winter	[redacted]	[redacted]	3,163	201	2,618	545
13th Forecast Year	2027	Summer	[redacted]	[redacted]	3,151	189	2,775	376
		Winter	[redacted]	[redacted]	3,146	203	2,651	495
14th Forecast Year	2028	Summer	[redacted]	[redacted]	3,138	191	2,809	329
		Winter	[redacted]	[redacted]	3,132	206	2,687	445

Trade Secret Ends]

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item H. ADDITIONS AND RETIREMENTS (Express in MW)

		ADDITIONS	RETIREMENTS
Past Year	2013	0	0
Present Year	2014	0	0
1st Forecast Year	2015	0	0
2nd Forecast Year	2016	0	0
3rd Forecast Year	2017	0	0
4th Forecast Year	2018	0	0
5th Forecast Year	2019	0	0
6th Forecast Year	2020	0	0
7th Forecast Year	2021	0	0
8th Forecast Year	2022	0	0
9th Forecast Year	2023	0	0
10th Forecast Year	2024	0	0
11th Forecast Year	2025	0	0
12th Forecast Year	2026	0	0
13th Forecast Year	2027	100	0
14th Forecast Year	2028	500	0

COMMENTS

MW additions in 2024 - 2026 are nameplate wind power purchase contracts to meet renewable energy requirements.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

Please use the appropriate code for the fuel type as shown in the list at the bottom of the worksheet.

		FUEL TYPE 1		FUEL TYPE 2		FUEL TYPE 3		FUEL TYPE 4	
		Name of Fuel	Coal	Name of Fuel	NG	Name of Fuel	REF	Name of Fuel	FO2
		Unit of Measure	1000 lbs	Unit of Measure	Mcf	Unit of Measure	1000 lbs	Unit of Measure	1000 Gals
		QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED
Past Year	2013	15,074,680	10,040,806	5,445,677	291,453	559,894	145,712	376	4278
Present Year	2014	17,332,000	10,451,040	3,369,636	698,650	566,651	151,133	441	4760
1st Forecast Year	2015	18,933,660	10,663,387	3,369,636	698,650	566,651	151,139	441	4760
2nd Forecast Year	2016	17,729,720	9,999,436	3,369,636	698,650	566,651	151,140	441	4760
3rd Forecast Year	2017	17,409,360	9,845,232	3,369,636	698,650	566,651	151,141	441	4760
4th Forecast Year	2018	19,027,060	10,711,866	3,369,636	698,650	566,651	151,142	441	4760
5th Forecast Year	2019	18,205,380	10,222,063	3,369,636	698,650	566,651	151,143	441	4760
6th Forecast Year	2020	18,090,680	10,256,075	3,369,636	698,650	566,651	151,144	441	4760
7th Forecast Year	2021	18,893,440	10,568,239	3,369,636	698,650	566,651	151,145	441	4760
8th Forecast Year	2022	18,205,380	10,222,063	3,369,636	698,650	566,651	151,146	441	4760
9th Forecast Year	2023	18,134,280	10,265,462	3,369,636	698,650	566,651	151,147	441	4760
10th Forecast Year	2024	19,061,780	10,739,942	3,369,636	698,650	566,651	151,148	441	4760
11th Forecast Year	2025	18,143,440	10,118,527	3,369,636	698,650	566,651	151,149	441	4760
12th Forecast Year	2026	18,084,280	10,265,462	3,369,636	698,650	566,651	151,150	441	4760
13th Forecast Year	2027	19,005,380	10,712,528	3,369,636	698,650	566,651	151,151	441	4760
14th Forecast Year	2028	18,311,780	10,292,414	3,369,636	698,650	566,651	151,152	441	4760

LIST OF FUEL TYPES

BIT - Bituminous Coal
COAL - Coal (general)
DIESEL - Diesel
FO2 - Fuel Oil #2 (Mid-distillate)
FO6 - Fuel Oil #6 (Residual fuel oil)
LIG - Lignite

LPG - Liquefied Propane Gas
NG - Natural Gas
NUC - Nuclear
REF - Refuse, Bagasse, Peat, Non-wo
STM - Steam
SUB - Sub-bituminous coal

HYD - Hydro (water)
WIND - Wind
WOOD - Wood
SOLAR - Solar

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0500 TRANSMISSION LINES

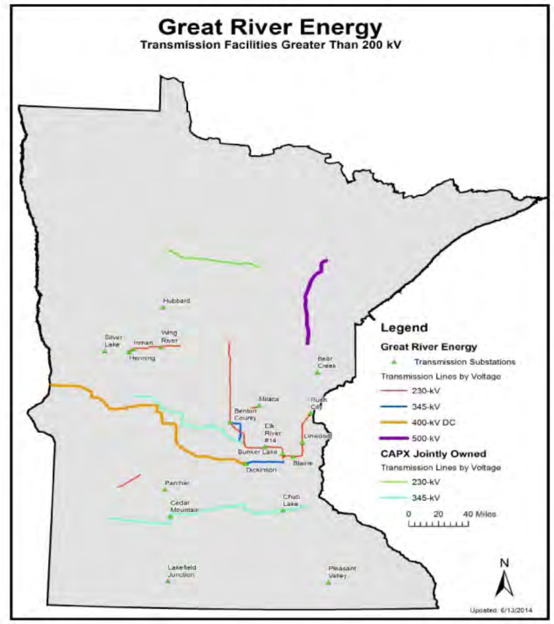
Subpart 1. **Existing transmission lines.** Each utility shall report the following information in regard to each transmission line of 200 kilovolts now in existence:
- A. a map showing the location of each line;
- B. the design voltage of each line;
- C. the size and type of conductor;
- D. the approximate location of d.c. terminals or a.c. substations; and
- E. the approximate length of each line in Minnesota.

Subpart 2. **Transmission line additions.** Each generating and transmission utility, as defined in part 7610.0100, shall report the information required in subpart 1 for all future transmission lines over 200 kilovolts that the utility plans to build within the next 15 years.

Subpart 3. **Transmission line retirements.** Each generating and transmission utility, as defined in part 7610.0100, shall identify all present transmission lines over 200 kilovolts that the utility plans to retire within the next 15 years.

In Use (enter X for selection)	To Be Built (enter X for selection)	To Be Retired (enter X for selection)	DESIGN VOLTAGE	SIZE OF CONDUCTOR	TYPE OF CONDUCTOR	D.C. OR A.C. (specify)	LOCATION OF D.C. TERMINALS OR A.C. SUBSTATIONS	INDICATE YEAR IF "TO BE BUILT" OR "RETIRED"	LENGTH IN MINNESOTA (miles)
X			230 kV	795	ACSR	AC	From Mud Lake to Riverton		8.57
X			230 kV	795	ACSR	AC	From Benton County to Mud Lake		54.19
X			230 kV	795	ACSR	AC	From Benton County to Monticello		21.61
X			230 kV	795	ACSR	AC	From Elk River to Monticello		16.9
X			230 kV	795	ACSR	AC	From Elk River to Bunker Lake		16.19
X			230 kV	795	ACSR	AC	From Bunker Lake to Blaine		12.94
X			230 kV	795	ACSR	AC	From Blaine to Linwood		16.95
X			230 kV	795	ACSR	AC	From Linwood to Rush City		24.32
X			230 kV	795	ACSR	AC	From Rush City to Arrowhead		0.59
X			230 kV	795	ACSR	AC	From Rush City to Red Rock		0.59
X			230 kV	795	ACSR	AC	From Willmar to Granite Falls [GRE/WMU]		30.9
X			230 kV	1,272	ACSR	AC	From Benton County to Milaca [SMMPA/GRE]		26.05
X			230 kV	795	ACSR	AC	From Wing River to Inman		19.44
X			230 kV	795	ACSR	AC	From Henning to Inman		3.72
X			230 kV	795	ACSR	AC	From Riverton to Wing River [MP/GRE]		49.28
X			345 kV	2-954	ACSR	AC	From Dickinson (Rockford) to Maple Grove		18.57
X			345 kV	2-954	ACSR	AC	From Maple Grove Tap to NSP Coon Creek		8.39
X			345 kV	1,192	ACSR	AC	From Sherburne Co. to Benton Co		21.4
X			+/-410 kV	1,590	ACSR	DC	From MN/ND border to Dickinson(Rockford)		177
X			500 kV	3-1192	ACSR	AC	From Forbes to Denham		69.77
X			345 kV	2-954	ACSS	AC	From Monticello to Quarry		28
X			230 kV	795	ACSR	AC	From Wilton to Boswell	2012	70
X			345 kV	2-954	ACSS	AC	From Quarry to Alexandria Switching Station	2013	78
	x		345 kV	2-954	ACSS	AC	From Alexandria Switching Station to MN/ND border	2015	100
X	x		345 kV	2-954	ACSS	AC	From SD/MN border to Hampton Corner	2013-2015	207
	x		345 kV	2-954	ACSS	AC	From Lyon County to Hazel Creek	2015	25
	x		345 kV (operate at 230 kV)	2-954	ACSS	AC	From Hazel Creek to Minnesota Valley	2015	5

COMMENTS



MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

7610.0600, Item A. 24 - HOUR PEAK DAY DEMAND

Each utility shall provide the following information for the last calendar year:
A table of the demand in megawatts by the hour over a 24-hour period for
1. the 24-hour period during the summer season when the megawatt demand on the system was the greatest; and
2. the 24-hour period during the winter season when the megawatt demand on the system was the greatest

	DATE	DATE	
	8/26/13	1/2/13	<= ENTER DATES
TIME OF DAY	MW USED ON SUMMER PEAK DAY	MW USED ON WINTER PEAK DAY	
0100	1,885	1,730	
0200	1,735	1,708	
0300	1,598	1,610	
0400	1,520	1,575	
0500	1,470	1,557	
0600	1,468	1,570	
0700	1,540	1,653	
0800	1,682	1,806	
0900	1,773	1,811	
1000	1,873	1,736	
1100	1,968	1,683	
1200	2,086	1,635	
1300	2,201	1,618	
1400	2,280	1,610	
1500	2,341	1,639	
1600	2,270	1,672	
1700	2,161	1,680	
1800	2,054	1,747	
1900	2,075	1,946	
2000	2,062	2,011	
2100	2,056	1,997	
2200	2,217	1,955	
2300	2,232	1,867	
2400	2,109	1,774	

COMMENTS
This reflects GRE's transmission Peak and includes our All Requirement Members, Fixed Members and their growth (not served by GRE), and losses.