MINNESOTA DEPARTMENT OF COMMERCE

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March 2, 2015 **PUBLIC DOCUMENT**

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **PUBLIC Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. ET2/RP-14-813

Dear Mr. Wolf:

Attached are the **PUBLIC** comments of the Minnesota Department of Commerce, Division of Energy Resources (Department), in the following matter:

Great River Energy's (GRE) 2014 Resource Plan.

The petition was filed on October 31, 2014 by:

Laureen L. Ross McCalib
Manager, Resource Planning
Great River Energy
12300 Elm Creek Blvd.
Maple Grove, MN 55369-4718

The Department recommends **that the Commission accept GRE's 2014 Resource Plan and encourage the Cooperative to implement the modifications recommended by the Department.** The Department's team of Craig Addonizio, Holly Lahd, Zac Ruzycki, Susan Peirce, and Christopher Davis is available to answer any questions the Commission may have.

Sincerely,

/s/ CHRISTOPHER T. DAVIS
Rates Analyst

CTD/lt
Attachment

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

PUBLIC COMMENTS OF THE MINNESOTA DEPARTMENT OF COMMERCE DIVISION OF ENERGY RESOURCES

DOCKET NO. ET2/RP-14-813

I. INTRODUCTION

A. OVERVIEW OF THE FILING

Minnesota Rules part 7843.0300 require electric utilities to file proposed integrated resource plans (IRP) every two years. Great River Energy's (GRE or the Cooperative) most recent IRP in Docket No. ET2/RP-12-1114 was rejected by the Minnesota Public Utilities Commission (Commission) on September 26, 2013.

On October 31, 2014, GRE filed its sixth IRP (Petition).

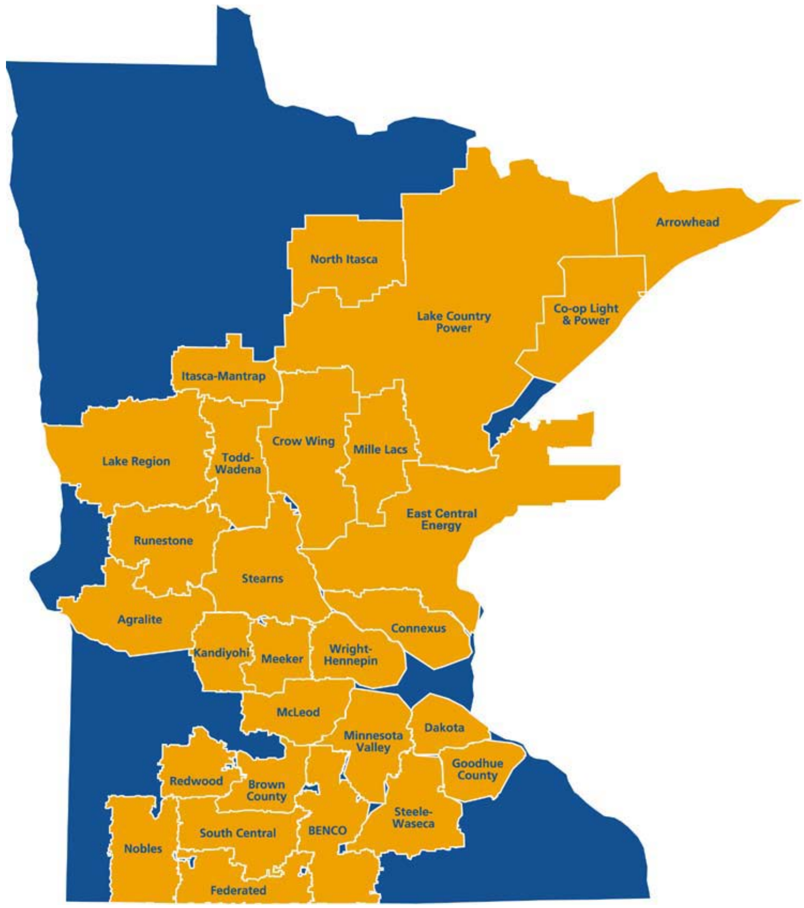
On February 19, 2015, GRE submitted a Notice of Changed Circumstances. GRE stated:

> Dairyland Power Cooperative, LaCrosse, Wis., and Great River Energy, Maple Grove, Minn., announce they have agreed in principle on terms to end Great River Energy's purchase of power and energy from Dairyland Power Cooperative's Genoa Station #3 power plant in Genoa, Wisconsin. Dairyland will continue to operate the plant. The transaction is expected to close and be effective on June 1, 2015, subject to execution of definitive agreements and regulatory approvals. Terms of the transaction are confidential.

B. DESCRIPTION OF GREAT RIVER ENERGY

GRE is a generation and transmission cooperative formed on January 1, 1999 by the merger of United Power Association (UPA) and Cooperative Power Association (CPA). GRE is owned by 28 member distribution cooperatives. GRE's 28 owners serve approximately 655,000 accounts or about 1.7 million customers in Minnesota and a small portion of Wisconsin. GRE's service territory is shown in Figure 1 below.

Figure 1: GRE's Service Territory



Twenty of GRE's members are All Requirements (AR) customers, meaning they purchase all of their energy and capacity requirements from GRE. The other eight members are Fixed Obligation (FO) customers, meaning they purchase a set amount of energy and capacity from GRE and supplemental requirements (above that provided by GRE) from an alternative power supplier.

GRE has a summer peaking system. Its 2014 summer coincident peak was 2,458 MWs. Its 2013 annual sales to members were 12,105,295 megawatt hours (MWh).[1] GRE owns approximately 4,600 miles of transmission lines, including the high voltage, 400-mile direct current (DC) line that runs from Coal Creek Station to Delano, Minnesota.

GRE generated approximately 11 percent of its electricity from renewable energy in 2013, including generation that uses refuse derived fuel from its Elk River Energy Recovery Station and power purchases from eight wind farms in Minnesota, North Dakota and Iowa. GRE reports that hydroelectric power provided 13 percent of the Cooperative's electricity production in 2013. Coal-based energy provided 67 percent in 2013, down from 80 percent in 2005.

[1] GRE's 2014 peak was 4 percent higher than GRE's forecasted 2.355 MW in its 2012 IRP, while GRE's 2013 sales were 6 percent lower than the 12,878,175 MWhs forecasted in GRE's 2012 IRP of 2.355 MW.

C. GRE'S PLANNING APPROACH

The overall planning process that GRE used in its IRP consisted of:

1) Evaluating conservation and energy efficiency potentials;
2) Assessing the total demand forecasts of its AR members and adjusting the load forecast to account for the load of Fixed Obligation (FO) members and transmission losses;
3) Assessing the load and capability chart (L&C) by comparing its load forecast to existing resources;
4) Developing a reference case model that accounts for regulatory and legislative requirements, including environmental costs;
5) Modeling various scenarios to identify potential resource needs;[2]
6) Selecting the preferred plan; and
7) Evaluating impact of key sensitivities on the preferred plan.

D. RESOURCE NEEDS IDENTIFIED BY GRE

As shown in Table 1 below, taken from data provided by GRE under Minnesota Rules 7610.0310, the Cooperative projects a capacity surplus for the duration of the planning period.

Table 1: GRE's Capacity surplus/(deficit)

Year	Surplus (Deficit) in MW
2015	700
2016	512
2017	536
2018	509
2019	566
2020	588
2021	607
2022	583
2023	553
2024	521
2025	461
2026	433
2027	394
2028	346
2029	310

[2] GRE's analysis allowed coal plants to be considered for retirement and coal contracts to be terminated in the modeling process if economic to do so;

GRE projects no capacity needs for the next 15 years. However, energy needs cannot be determined from a load and capability chart; they are best determined through capacity expansion modeling.

The only energy need identified by GRE is to add about 600 MW of wind resources in the 2024 to 2026 time frame to meet Minnesota's Renewable Energy Standard (RES).

E. GRE'S PROPOSED PLAN

Based upon GRE's analysis, the Cooperative proposes a preferred plan that includes:

- Continue conservation and energy efficiency programs, strive to meet 1.5 percent per year Minnesota goal (0.93 percent built into preferred plan);
- Use accelerated depreciation of GRE's two largest coal plants (1,163 MW Coal Creek Station and 187 MW Stanton Station);
- End long-term contractual obligation with Dairyland Power Cooperative (DPC) to purchase 50 percent of the capacity and energy from Genoa 3 coal fired facility (119 MW) in 2016;
- Enter into a 200 MW diversity agreement with Manitoba Hydro to procure 200 MW of hydropower in the summers starting in 2020; and
- Add 600 MW of wind in 2026 to 2029 to comply with the Minnesota Renewable Energy Standard.

II. DEPARTMENT ANALYSIS

A. THE DEPARTMENT'S ANALYTICAL APPROACH

Minnesota Statutes §216B.2422, subd. 2 states that, in the resource plan proceedings of a generation and transmission cooperative such as GRE,

> … the Commission's order shall be advisory and the order's findings and conclusions shall constitute prima facie evidence which may be rebutted by substantial evidence in all other proceedings.

Subdivision 4 of the same statute states:

> 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 … unless the utility has demonstrated that a renewable energy facility is not in the public interest.

The Department conducted its review of GRE's IRP with the understanding that although the Commission's Order is advisory in this proceeding, the analysis supporting the Commission's Order would have significant bearing on GRE's future regulatory proceedings.

Similar to our review of other utilities' resource plans, the Department reviewed GRE's:

- planning method;
- energy and demand forecast;
- demand-side resources;
- resource needs;
- renewable energy standards (RES) compliance; and
- environmental issues.

B. GRE'S PLANNING METHOD

The Department concludes that GRE's overall planning approach is reasonable, with one exception. GRE's approach is reasonable in that it:

- Started with developing a forecast;
- Identified its supply-side resource needs by using a capacity expansion model;
- Considered a reasonable range of potential supply-side resources for meeting those needs;
- Met the requirement of the Commission Order in GRE's 2012 IRP to allow its capacity expansion model to consider the retirement of GRE's coal plants; and
- Performed risk analyses that considered the impact of RES compliance, environmental costs, varying the wholesale market (prices and market access), fuel prices, and varying the load forecast.

A shortcoming in GRE's analysis is that the Cooperative did not use its capacity expansion model to conduct scenario analysis of its four different demand side management (DSM) levels to evaluate the impact of each scenario on its system costs.

D. ENERGY AND PEAK DEMAND FORECASTING

As noted above, twenty of GRE's of twenty-eight member distribution cooperatives are AR members. GRE is responsible to meet the requirements of all of the AR members' future energy and capacity needs. GRE is also responsible for meeting the fixed amounts of capacity and energy needs of the remaining eight FO members, according to their long term power purchase agreements with the Cooperative. In the forecasting section, the Cooperative's energy and demand forecasts combine the FO members' energy and demand requirements with the forecasted energy and demand requirements of the AR members to obtain the total all-requirement energy and demand figures for the planning period.

In this filing the Cooperative incorporated geographic diversity into its forecasts by breaking its system into three regions: Metro, North, and Southern & Western. The Metro region encompasses the Minneapolis/St. Paul area and outlying areas and includes two summer peaking distribution cooperatives serving the seven metropolitan counties. The Northern region includes primarily winter peaking distribution cooperatives in seven counties located north of Interstate 94 (not including the seven metro counties). The Southern & Western region is south of Interstate 94 (excluding the seven metro counties).

As discussed in greater detail throughout this section, the Cooperative performed long-term forecasts of both energy requirements and peak demand from 2015 to 2029. These models have not been used previously in any filed IRPs by the Cooperative. During our review, the Department evaluated the models and results for reasonableness, specifically the following:

- The forecast's methodology (the selection and transformation of dependent and independent variables in the AR members' energy and demand forecasts);
- the residential forecast performed by Clearspring Consulting, which formed the residential customer independent variable for use in the energy forecast models, and
- GRE's study of its peak demand's diversity with the load of the Midcontinent Independent System Operator (MISO).

Each of these areas is discussed below.

1. *Residential Consumer Forecast*

For this resource plan filing the Cooperative hired a consultant, Clearspring Energy Advisors, to perform a residential consumer forecast. Energy demand of residential consumers is one of the most influential variables in determining energy use among GRE's distribution cooperatives.

Clearspring's residential consumer forecast linked the household forecasts of primary counties served and took into account the changes in the share of households served by the GRE distribution member cooperatives. The study compared the share of Minnesota homes currently served by GRE to levels in previous years and found that GRE's share of residential consumer homes served has nearly doubled over the past 40 years, to 20 percent of all households in Minnesota. The study indicated that although the trend of growth flattened during the "Great Recession" the housing market is rebounding; Clearspring anticipates that the recovery will lead to more substantial growth in residential customer load in the suburban areas served by GRE member systems. The residential forecast indicates that beginning in 2023, GRE will return to a pre-recession growth rate observed in the 1990's.

The Department commends the Cooperative for obtaining an independent third-party consultant to develop an analysis of residential growth on its system. A copy of the study was attached to the Cooperative's resource plan in Appendix G, and enumerates the study assumptions and results as well as the methodology of the consultant in creating its residential consumer forecast. Based on our review, the Department concludes that the Cooperative's residential forecast is reasonable.

2. *Energy Forecast*

   a. *Steps in GRE's Energy Forecast*

GRE forecasted its energy requirements using the following steps. First, each AR member was assigned to one of the three forecast regions. Second, the Cooperative constructed regression models for each region. Third, the econometric results were added to the fixed member energy amount to obtain the combined AR and Fixed energy obligation for the Cooperative. GRE assumed that future load control would be the same as in the past.[3] Fourth, GRE made the following adjustments:

- Added direct current (DC) line and other transmission losses;
- Added Southern Minnesota Electrical Cooperative (SMEC) load;[4] and
- Subtracted Elk River Municipal Utilities' load.[5]

b. Energy forecast econometric modeling

GRE considered the following independent variables in its energy forecast econometric model:

- Residential Consumers;
- Employment;
- Cooling degree days (effect of weather on summer cooling load);
- Heating degree days (effect of weather on winter heating load);
- GRE wholesale member rate;
- Employment-to-population ration; and
- Residential propane price.

The Metro, Northern, and Southern & Western models' specifications are shown in Table 2 below:

Table 2: Specification of GRE's Three Residential Models

Metro Region

$$\begin{aligned}\ln(Annual\ Metro\ Region\ Energy) &= \beta 0 + \beta 1 \ln(Metro\ Region\ Residential\ Consumers - 1) + \beta 2 \ln(Metro\ Region\ Employment\ MA2) \\ &+ \beta 3 \ln(Metro\ Region\ CDD65) + \beta 4 \ln(Wholesale\ Rate\ RealMA3)\end{aligned}$$

Northern Region

$$\begin{aligned}\ln(Annual\ Northern\ Region\ Energy) &= \beta 0 + \beta 1 \ln(Northern\ Region\ Residential\ Consumers - 1) + \beta 2 \ln(Northern\ Region\ HDD65) \\ &+ \beta 3 \ln(Northern\ Region\ Employment{:}\ Population\ Ratio) + \beta 4 \ln(Wholesale\ Rate\ RealMA3)\end{aligned}$$

Southern & Western Region

$$\begin{aligned}\ln(Annual\ Southern\ \&Western\ Region\ Energy) &= \beta 1 \ln(Southern\&Western\ Region\ HDD65) \\ &+ \beta 2 \ln(Southern\&Western\ Region\ Residential\ Consumers - 1) + \beta 3 \ln(Wholesale\ Rate\ RealMA3) \\ &+ \beta 4 \ln(Residential\ Propane\ Real)\end{aligned}$$

[3] Historical load control was embedded in the energy forecasting data, with the assumption that GRE's load control program will remain consistent into the future.
[4] Five of GRE's AR members are also part of SMEC, which proposes to purchase the electric distribution systems and load that is currently being served by Interstate Power and Light (IPL). That petition is expected to be brought before the Commission in Docket No. E001, et. al./PA-14-322. If that proposal is approved, beginning in 2024, these five AR members would serve load previously served by IPL.
[5] GRE currently provides wholesale service to AR member Elk River Municipal Utilities, but the power purchase agreement expires on September 30, 2018.

The Cooperative made several transformations to the variables, both dependent and independent, as part of its model development process.[6] For example, GRE applied natural log transformations to both the dependent and independent variables. The Cooperative also created lagged and moving average variables and included them in the models, and additionally included an autoregressive term in their modeling to address serial correlation. In Department IR 7, the Department asked the Cooperative to explain the log transformations. In response, GRE stated:

> The primary reason for transforming the independent and dependent variables with the natural logarithm in the 3 regional energy and demand forecasts was for easier interpretation of the coefficients during the model fitting process. By taking the natural log of both the independent and dependent variables, the resulting regression coefficients' will be elasticities.[7]

The Department was not convinced that GRE's transformation improved the model and evaluated alternative model specifications with the log transformations reversed to determine if the model's or forecasts changed. Using the same data set as GRE, the Department removed the log transformations, and created regression models to forecast load using eViews. After the log transformations were removed, some variables dropped out of the model due to lack of significance. The final specifications for the Department's energy models are shown in Attachment 1.

The Department aggregated GRE's regional AR forecasts from our adjusted models and compared the results to the Cooperative's final values for its forecasting. Figure 2 below illustrates that GRE's and the Department's aggregated AR forecasts from 2015-2029 plotted are close, certainly within the 95% confidence interval of the Cooperative's proposed forecast.

[6] GRE Response to Department IR7, January 29, 2015.
[7] *Id.*

Figure 2: Comparing DOC and GRE All Member Requirements Energy Forecast

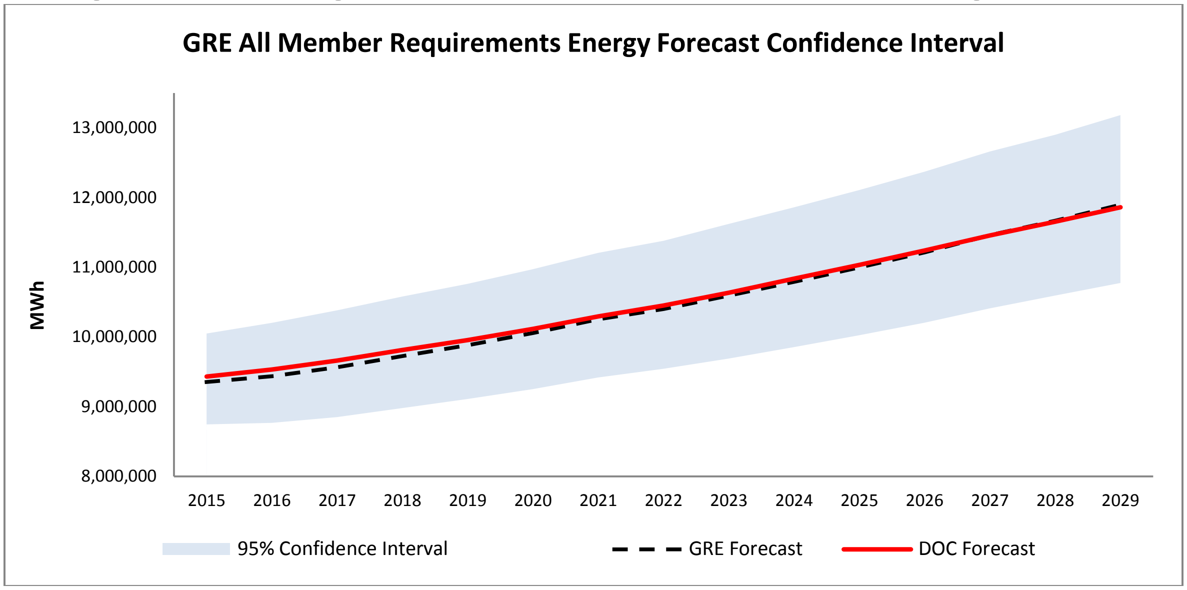


Table 3 below shows the differences between GRE and DOC regional energy forecasts, along with growth rates for the 2015-2029 forecast period. As can be seen, the DOC's Southern & Western and Northern regional models indicate slower growth than GRE's models for the same regions. However, the Metro region is GRE's main driver of growth, and there is little difference between DOC and GRE forecasts for this region.

Table 3: GRE's and DOC's Regional and All Member AR Forecasts

GRE FORECASTS

Year	Metro Region Energy (MWh)	Metro Region Year-Over-Year Growth (%)	Northern Region Energy (MWh)	Northern Region Year-Over-Year Growth (%)	Southern & Western Region Energy (MWh)	Southern & Western Year-Over-Year Growth (%)	GRE's All Requirement Member's Annual Energy (MWh)	All Requirement 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%

DOC FORECASTS

Year	Metro Region Energy (MWh)	Metro Region Year-Over-Year Growth (%)	Northern Region Energy (MWh)	Northern Region Year-Over-Year Growth (%)	Southern & Western Region Energy (MWh)	Southern & Western Year-Over-Year Growth (%)	DOC's All Requirement Member's Annual Energy (MWh)	All Requirement Year-Over-Year Growth (%)
2015	4,447,828		2,887,561		2,098,470		9,433,859	
2016	4,530,734	1.9%	2,887,113	0.0%	2,117,921	0.9%	9,535,768	1.1%
2017	4,614,305	1.8%	2,905,531	0.6%	2,145,036	1.3%	9,664,871	1.4%
2018	4,703,379	1.9%	2,932,899	0.9%	2,178,054	1.5%	9,814,332	1.5%
2019	4,798,229	2.0%	2,953,149	0.7%	2,206,139	1.3%	9,957,516	1.5%
2020	4,899,118	2.1%	2,980,317	0.9%	2,237,749	1.4%	10,117,184	1.6%
2021	5,006,330	2.2%	3,016,761	1.2%	2,274,652	1.6%	10,297,744	1.8%
2022	5,117,448	2.2%	3,034,626	0.6%	2,299,272	1.1%	10,451,347	1.5%
2023	5,235,417	2.3%	3,069,356	1.1%	2,333,611	1.5%	10,638,384	1.8%
2024	5,360,465	2.4%	3,107,907	1.3%	2,369,611	1.5%	10,837,983	1.9%
2025	5,487,132	2.4%	3,145,336	1.2%	2,405,114	1.5%	11,037,583	1.8%
2026	5,615,480	2.3%	3,186,369	1.3%	2,442,646	1.6%	11,244,495	1.9%
2027	5,742,128	2.3%	3,234,545	1.5%	2,483,584	1.7%	11,460,256	1.9%
2028	5,870,420	2.2%	3,268,252	1.0%	2,516,221	1.3%	11,654,893	1.7%
2029	6,000,397	2.2%	3,307,694	1.2%	2,552,204	1.4%	11,860,295	1.8%
5-Year (CAGR)		2.0%		0.6%		1.3%		1.4%
10-Year (CAGR)		2.1%		0.9%		1.4%		1.6%
15-Year (CAGR)		2.2%		1.0%		1.4%		1.6%

Table 4 below shows the aggregated AR forecasts for both the Department's and the Cooperative's residential forecasting models.

Table 4: GRE and DOC Total Energy Forecasts

GRE ENERGY REQUIREMENT FORECAST

Year	50/50 All Requirement Member Forecast (=)	Elk River Municipal (-)	DC Line Losses (+)	Transmission Losses (+)	Allliant Load Southern Coops Forecasts (+)	Fixed Member Requirements (+)	Dakota Spirit Ag (+)	GRE Energy Requirement Forecast
	(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%**

DOC ENERGY REQUIREMENT FORECAST

Year	50/50 All Requirement Member Forecast (=)	Elk River Municipal (-)	DC Line Losses (+)	Transmission Losses (+)	Allliant Load Southern Coops Forecasts (+)	Fixed Member Requirements (+)	Dakota Spirit Ag (+)	DOC Energy Requirement Forecast
	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
2015	9,433,859	0	559,055	537,515	0	2,553,891	34,667	13,118,987
2016	9,535,768	0	560,637	541,894	0	2,561,282	41,600	13,241,182
2017	9,664,871	0	559,055	547,217	0	2,551,863	41,600	13,364,605
2018	9,814,332	0	559,055	554,422	0	2,550,478	41,600	13,519,887
2019	9,957,516	(288,298)	559,055	548,411	0	2,550,478	41,600	13,368,762
2020	10,117,184	(288,298)	560,637	556,220	0	2,550,478	41,600	13,537,821
2021	10,297,744	(288,298)	559,055	565,156	0	2,550,478	41,600	13,725,735
2022	10,451,347	(288,298)	559,055	571,780	0	2,550,478	41,600	13,885,961
2023	10,638,384	(288,298)	559,055	580,374	0	2,550,478	41,600	14,081,593
2024	10,837,983	(288,298)	560,637	589,314	0	2,550,478	41,600	14,291,715
2025	11,037,583	(288,298)	559,055	606,801	182,190	2,550,478	41,600	14,689,409
2026	11,244,495	(288,298)	559,055	616,635	182,190	2,550,478	41,600	14,906,155
2027	11,460,256	(288,298)	559,055	627,653	182,190	2,550,478	41,600	15,132,934
2028	11,654,893	(288,298)	560,637	637,107	182,190	2,550,478	41,600	15,338,608
2029	11,860,295	(288,298)	559,055	647,340	182,190	2,550,478	41,600	15,552,660
*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**	**0.47%**
							10-Year CAGR	**0.96%**
							15-Year CAGR	**1.22%**

Attachment 1 includes the Department's specification of GRE's model after removing the log transformation.

3. *Demand Forecast*

The Cooperative also created demand forecasts for the same three regions considered in the energy forecasting process. The Northern and Southern & Western regions are winter peaking, while the Metro region is summer peaking. Monthly non-coincident peak regression models and forecasts were developed, and the Cooperative indicated that its historical load control is embedded in the data, with the assumption that the load control program will continue to be used in the future at the same level it is now. The three regions' aggregated demand forecasts produced the GRE system peak demand forecast.
The Cooperative created models for each forecast region with the same method as its energy models. GRE used log-log transformations so that the coefficients in the econometric equations become elasticities, making the equation easier to interpret. In

addition, GRE used the following variables to describe the regional monthly coincident peak with GRE's system:

- Weather Variables;[8]
- Monthly Energy Sales; and
- Monthly Binary Variables.

GRE aggregated the models to produce the total AR member coincident peak demand forecast, which was then added to the fixed member requirements and adjusted as discussed above for transmission losses, SMEC and the Elk River Municipal Utility. Below is an example of the structure of GRE's Metro regional demand model:

$$
\begin{aligned}
\ln(\mathit{Metro\ Region\ Demand}) &\\
&= \beta 0 + \beta 1 \ln(\mathit{Metro\ Region\ Energy\ Use}) + \beta 2 \ln(\mathit{Metro\ Region\ HotTemp\ Index}) + \beta 3(\mathit{Jan}) \\
&+ \beta 4(\mathrm{Feb}) + \beta 5(\mathit{Mar}) + \beta 6(\mathit{Apr}) + \beta 7(\mathit{May}) + \beta 8(\mathit{Jun}) + \beta 9(\mathit{July}) + \beta 10(\mathit{Aug}) + \beta 11(\mathit{Oct}) \\
&+ \beta 12(\mathit{Nov}) + \beta 13(\mathit{Dec})
\end{aligned}
$$

GRE used the same structure for its Northern and Southern & Western regions demand models, with explanatory and binary independent variables.

The Department did not include the same graphical and tabular data as it did for the energy forecast analysis, as the outcome is largely the same. The log transformations resulted in no large departure from non-transformed variables, and the growth rates obtained by the Department's models and those calculated by the Cooperative are essentially the same. Attachment 1 includes the Department's specifications of GRE's models.

4. Energy and Demand Forecast Discussion

Attachment 2 contains the outputs from the Department's energy and demand models and the data comparing the Department's demand forecasts with the Cooperative's. Although the Cooperative's log transformation may not be necessary, the Department's and GRE's energy and demand forecasts provided similar results. Given that the Cooperative provides wholesale service to twenty-eight geographically dispersed member distribution cooperatives, the Department concludes that it is reasonable for GRE to use a forecasting model that is easily understood. The Department commends the Cooperative for its efforts to improve its forecasting through refinements to its residential forecast, updates to additions and subtractions, and the overall clarity and level of explanation that accompanies into the forecast in this filing.

Thus, the Department recommends that the Commission approve the energy and demand forecasts proposed by the Cooperative.

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[8] In the demand models Hot Temp Index and Cold Temp Index were both used as weather variables. These indices were created by the Cooperative to isolate the slopes of the heating and cooling trends and take into account the differences in cooling and space heating demand. Temperatures at the time of the regions' coincident peaks were transformed into either the Hot Temp Index or Cold Temp Index contingent upon the temperature at the time of peak demand by subtracting 65° from the peak temperature.

E. DEMAND-SIDE RESOURCES

1. Introduction

One purpose of resource planning is to estimate the optimal amount of demand-side resources for meeting the Company's future needs. Minn. Stat. 216B.2401 states:

> The legislature finds that energy savings are an energy resource, and that cost-effective energy savings are preferred over all other energy resources. The legislature further finds that cost-effective energy savings should be procured systematically and aggressively in order to reduce utility costs for businesses and residents, improve the competitiveness and profitability of businesses, create more energy-related jobs, reduce the economic burden of fuel imports, and reduce pollution and emissions that cause climate change.
>
> Therefore, it is the energy policy of the state of Minnesota to achieve annual energy savings equal to at least 1.5 percent of annual retail energy sales of electricity and natural gas through cost-effective energy conservation improvement programs and rate design, energy efficiency achieved by energy consumers without direct utility involvement, energy codes and appliance standards, programs designed to transform the market or change consumer behavior, energy savings resulting from efficiency improvements to the utility infrastructure and system, and other efforts to promote energy efficiency and energy conservation.

In analyzing the appropriateness of a utility's energy savings plan within an IRP, the Department considers, along with other factors, the Company's:

- historical energy savings achievements;
- annual and lifetime costs of different energy savings levels;
- comparison of average supply and demand side resource costs; and
- impact of different amounts of energy savings on total system costs.

The Department evaluates GRE's energy savings levels with these three factors in the following sections.

2. GRE's Historical Energy Savings Achievements

The Department evaluated GRE's energy savings in part by examining GRE's reports of its annual energy and demand savings in its Conservation Improvement Program (CIP).

A utility's energy savings can be measured in three ways:

a. by annual first-year energy savings in the year DSM measures are installed, and
b. by the total energy saved during the lifespan of the DSM measures.

In addition to energy conservation by its members, GRE includes utility infrastructure savings in its IRP and CIP energy savings reporting. For CIP goals and reporting purposes, Minnesota Statutes 216B.241 Subd. 1c states:

> 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. Electric utility infrastructure projects must result in increased energy efficiency greater than that which would have occurred through normal maintenance activity.

GRE reported electric utility infrastructure savings in 2009, 2010, and 2012. The Department's comments in this IRP are focused on the energy savings achieved by the Company through member initiatives.

In its annual CIP Reporting in the Department's Energy Savings Platform (ESP), GRE files information on its annual energy savings and expenditures. GRE's CIP data for 2008 through 2013 is summarized in Table 5 below.

Table 5: GRE Energy Savings and Spending, 2008 – 2013

Year	CIP Expenditures[9]	First-Year Demand Savings at the Generator (MWh)	First-Year Savings Cost ($/kWh)	Estimated Lifetime Cost ($/kWh)[10]
2008	$23,009,820	107,566	$0.214	$0.014
2009	$25,388,861	90,291	$0.281	$0.018
2010	$26,337,053	134,428	$0.196	$0.013
2011	$18,306,921	97,485	$0.188	$0.012
2012	$21,194,205	95,147	$0.223	$0.014
2013	$15,575,524	99,134	$0.157	$0.010
Average	$20,353,426	106,549	$0.191	$0.012

[9] CIP Expenditures are GRE's total CIP expenditures less Utility Infrastructure Expenditures.
[10] In response to the Departments IR 5, GRE reported that the average measure life for all CIP programs in the IRP energy savings proposal is 15.38 years. Estimated lifetime cost is calculated by dividing first-year savings cost by GRE's average measure life.

While analyzing historical energy savings data provides useful information on DSM average costs and the types of DSM programs a utility has pursued in the past, the level of historical savings is only one factor to consider when determining the level of energy and demand savings a utility can and should procure in the future.

3. Energy Savings in Current IRP

GRE developed four Minnesota DSM scenarios for analysis in this IRP by varying the percent of retail sales saved: base (0.93 percent), 1.25 percent, 1.5 percent, and 2.0 percent annual demand savings. In its IRP filing GRE indicated that any changes to the DSM levels could be implemented in 2016 at the earliest. Table 6 below compares the four scenarios' 2016 energy savings, budgets, and average costs. The Department did not evaluate the reasonableness of the annual budgets GRE provided for each DSM scenario.

Table 6: GRE's Four DSM Scenarios by 2016 Annual Savings and Budgets[11]

Scenario	Base - 0.93%	1.25%	1.50%	2.00%
First-Year Savings at Generator (MWh)	102,375	137,546	165,055	220,074
Plan Budget	$ 13,053,099	$ 28,026,676	$ 42,951,141	$ 74,006,790
$/first year kWh savings	$ 0.128	$ 0.204	$ 0.260	$ 0.336
$/lifetime kWh savings	$ 0.008	$ 0.013	$ 0.017	$ 0.022

Table 7 shows the cumulative DSM impacts by 2029 under the four scenarios.

Table 7: GRE's Cumulative DSM Impacts by 2029

Cumulative DSM by 2029	Base (0.93%)	1.25%	1.50%	2.00%
Cumulative Energy Savings (MWh)	1,457,913	1,928,882	2,297,251	3,033,708
Cumulative Peak Demand Savings (MW)	259	342	408	539

4. DSM Energy Saving Lifetime Costs

Comparing DSM lifetime costs to total system costs per kWh in the IRP allows parties to better compare these two types of energy resources. Table 4 compares lifetime costs and average supply side energy cost per kWh for GRE's four DSM scenario, as modeled by GRE in cases 21 and 25 (which produce GRE's preferred plan). Though costs vary each year, for simplicity Table 7 focuses on costs in 2016, since GRE indicates that is the first year a change in DSM levels could be implemented.

[11] Savings levels and budgets were provided by GRE in Department IRs 3 – 5. To estimate cost per lifetime kWh savings, the Department used GRE's estimated average savings lifetime of 15.38 years.

Table 8: DSM and System Costs per kWh

		2016 Costs ($/kWh)
DSM Scenarios	Base (0.93 %)	$ 0.008
	1.25%	$ 0.019
	1.50%	$ 0.029
	2.00%	$ 0.041
Supply Side Modeling	Average System Cost	[TRADE SECRET DATA HAS BEEN EXCISED]

The data in Table 7 demonstrate that the average cost per kWh saved in the Base (0.93), 1.25, and 1.5 Percent and 2.0 Percent Scenarios are lower than the average system cost in 2016. This result is why GRE's analysis indicated that all four levels of DSM are cost-effective from the utility and societal perspective. Thus, although GRE has no need for new capacity, increased energy savings would result in savings to GRE's system and would not impact GRE's resource choices in the planning period.

5. *Using Capacity Expansion Model to Evaluate Different Levels of DSM*

GRE included higher energy savings in combination with higher levels of renewables in Case 27 (Expansion Plan L) and Case 32 (Expansion Plan B). It is not clear which of the four DSM scenarios GRE used in these cases, and based on the data provided the Department could not isolate the effect of higher energy savings from other case assumptions in GRE's expansion plan modeling. Using the capacity expansion model is a more robust approach to evaluating how potential DSM programs interact with the Cooperative portfolio of resources. The Department recommends that GRE use its capacity expansion model to evaluate different levels of DSM in isolation from additional renewables scenario in all future resource plans.

6. *Department Recommendations*

Based on our analysis, the Department recommends that the Commission approve annual energy savings of 137,546 MWh (the energy savings levels associated with GRE's 1.25 percent energy saving scenario).[12] The Department recommends this higher saving goal than GRE's preferred base level savings for the following reasons:

1. The average cost of the annual 137,546 MWh energy savings is less than [TRADE SECRET DATA BEGINSHAS BEEN EXCISED] in 2016. While higher levels of savings are also lower cost than the average system cost, the Department recommendations balance the cost-effective savings with GRE's ability to achieve the near-term higher savings. As shown in Table 5 below, GRE has not consistently achieved this level of savings in recent years.

2. The higher level of savings would position GRE to meet the CIP statutory goals of at least 1.5 percent annual savings, including a minimum of 1.0 percent energy

[12] The Department emphasizes the energy savings levels instead of the percent of retail sales here because the percent of retail sales for many utilities continues to change as different customers are allowed to opt-out of the State's Conservation Improvement Program.

conservation improvements (demand side savings). It is not clear from GRE's IRP whether GRE can continue to rely on electric utility infrastructure savings to meet its CIP goals. Achieving a higher level of cost-effective demand side savings from its members would reduce GRE's dependence on finding more electric utility infrastructure savings beyond normal maintenance activity.

3. Higher energy savings levels would increase the Cooperative's ability to both make further progress towards the State's greenhouse gas reduction goal and complying with the Environmental Protection Agency's (EPA) 111 (d) proposed rule, which is discussed below.

F. REVIEW OF GRE'S MODELING

GRE used Ventyx, Inc.'s System Optimizer Model (SOM) to conduct its modeling in the instant IRP, the same model the Cooperative used in its last IRP.[13] SOM is a capacity expansion model, and its proper use will allow GRE to determine the least cost expansion plan in the IRP, including the size, type, and timing of resource additions generally and the relevant levels of DSM and renewables in particular. GRE's use of a capacity expansion model will also allow future GRE certificate of need proceedings to focus on which alternative best meets the IRP-determined size, type and timing of resources rather than revisiting the issues of the least-cost level of renewables and DSM.

The Department did not conduct independent modeling of GRE's system in the Docket. However, the Department analyzed GRE's modeling efforts by reviewing its model inputs, scenarios modeled, and model outputs.

1. Review of Model Inputs and Scenarios Modeled

a. Summary of Scenarios

GRE modeled 32 cases that reflected a variety of sensitivities. The major assumption categories for which GRE modeled sensitivities were:

- externalities (zero, low, medium and high);
- demand and energy forecast (low, medium and high);
- cost of new resources;
- market interaction;
- spot market and fuel prices (low, medium and high);
- reserve margin and diversity factor;
- renewal portfolio standards (0 percent requirement, 25 percent requirement, and 40 percent requirement);
- energy efficiency and conservation;
- distributed generation penetration levels; and
- economic retirement of coal plants.

[13] Ventyx Inc. also developed Strategist, the software package often used by the Department to evaluate resource plans and other related dockets.

b. Externalities

GRE modeled cases that included no externalities, and cases that applied the Commission's low, medium and high externality values as prescribed in Docket No. E999/CI-00-1636. In the low, medium, and high cases, GRE also used the Commission-approved CO_2 regulatory costs of $9 to $34 per ton beginning in 2019, as required by the Commission in Docket No. E999/CI-07-1199.

Additionally, the Department notes that the Commission's Order in GRE's previous IRP (Docket No. ET2/RP-12-1114) required the Company to include the Commission-approved cost of externalities to calculate the cost of GRE's reference case and preferred case. Consistent with the Commission's order, GRE identified a reference case (Case 4) based on the mid-point of the Commission's externality values and GRE's preferred plan is the expansion plan produced by several cases that reflect the Commission's medium externality values.

c. Cost of Existing and New Resources

Appendix B to GRE's IRP shows GRE's cost and operating inputs for its existing resources, as well as the potential resources made available for the model to add during the planning period. GRE relied on the Energy Information Administration (EIA) as the source of its cost estimates for its potential thermal and solar resources. Cost estimates for potential wind resources were sourced from the Lawrence Berkeley National Laboratory. As discussed in greater detail below, the cost estimate used for the potential hydro resource was simply GRE's forecast of market prices.

GRE also modeled cases that included sensitivities on the costs of potential resources. In particular, GRE modeled cases that reflected a 25 percent increase in capital costs for thermal generation, and a 30 percent decrease in capital costs for solar and wind generation.

The Department reviewed these cost inputs and sensitivities and concludes they are generally reasonable, with the exception of the cost estimates used for the potential hydro resources. GRE's assumption that the hydro energy would be priced at spot market prices may be unrealistically low, and the range of cost sensitivities analyzed is too narrow. Further, GRE assigned no price to the capacity associated with the potential hydro resource, which may not be a reasonable assumption. The Department discusses the impacts of these assumptions in greater detail below.

d. Market Interaction

GRE described its energy market interaction assumptions on page 88 of its IRP. In 19 of GRE's 32 cases, GRE assumed access to the energy market with an interconnection of 400 MW. In the remaining 13 cases, GRE assumed no market access. Additionally, GRE stated that it did not rely on the market for capacity in any of the cases.
The Department notes that in cases with market interaction, GRE allowed both spot purchases and spot sales of energy. Typically, the Department recommends that utilities

not model spot sales to ensure that resources are added to serve customer needs and not for the purpose of making sales to the spot market, even if the sales appear to be profitable.

As discussed further below, GRE's allowance of market sales does not appear to have had a significant impact on its modeling results. Thus, the Department concludes that GRE's treatment of market access in this IRP is reasonable, and that the cases with no market access provide an informative test of the system's reliance on the market. However, the Department recommends that, in future IRPs, GRE eliminate market sales, while allowing purchases, in at least some of the cases it analyzes.

Given GREs current capacity surplus, its assumption of no market capacity likely had no impact on its modeling results. However, the Department notes that it generally allows purchases of market capacity during the first five years of the planning period to potentially act as a bridge before a new resource can be brought online. The Department eliminates purchases of market capacity in years six and beyond to prevent utilities from relying on short-term capacity purchases as a long-term resource.

e. Reserve Margin

In 26 of the 32 cases GRE analyzed, the Company planned to meet its coincident peak (i.e. GRE's expected load at the time of MISO's system-wide peak). In the remaining six cases, GRE analyzed the effects of planning to its non-coincident peak (i.e. GRE's system peak). In the 26 coincident peak (CP) cases, GRE assumed a 10 percent diversity factor, meaning it reduced its forecasted system peak by 10 percent to estimate its expected load at the time of MISO's peak. In those cases, GRE applied a 7.3 percent planning reserve margin and used the unforced capacity (UCAP) ratings of its units to assess its load and capability position. The Department notes that MISO's UCAP planning reserve margins for the 2014-15 and 2015-16 planning years were 7.3 percent and 7.1 percent, respectively.

In the six non-coincident peak (NCP) cases, GRE planned to its system peak, rather than its expected load at the time of MISO's peak (*i.e.*, GRE did not apply a diversity factor). Additionally, in these cases, GRE used the installed capacity (ICAP) rating of its generating units to assess its load and capability position and applied a 15 percent planning reserve margin. The Department notes that MISO's ICAP planning reserve margins for the 2014-15 and 2015-16 planning years were 14.8 percent and 14.3 percent, respectively.

Table 8 summarizes GRE's capacity position under its medium demand forecast under both the coincident and non-coincident peak reserve assumptions and GRE's preferred expansion plan in selected years during the planning period.

Table 9: Summary of GRE Reserve Calculations

	2015	2020	2025	2029
Coincident Peak Reserve Assumption				
Forecast CP (10% Diversity Factor)	2,207	2,246	2,410	2,542
Reserve margin	7.3%	7.3%	7.3%	7.3%
Reserve obligation	161	164	176	186
MISO obligation with reserves	2,368	2,409	2,586	2,728
UCAP Capacity - Expansion Plan E	3,068	3,198	3,248	3,314
Actual Surplus	861	952	837	772
Actual Reserve Margin	39.0%	42.4%	34.7%	30.4%
Non-Coincident Peak Reserve Assumption				
Forecast NCP	2,452	2,495	2,678	2,825
Reserve margin	15.0%	15.0%	15.0%	15.0%
Reserve obligation	367	374	402	424
MISO obligation with reserves	2,819	2,869	3,080	3,249
ICAP Capacity - Expansion Plan E	3,505	3,447	3,397	3,423
Actual Surplus	1,053	952	719	599
Actual Reserve Margin	42.9%	38.2%	26.8%	21.2%
Difference in obligation (ICAP-UCAP)	452	460	494	521
Difference in capacity (ICAP-UCAP)	437	249	149	109
Difference in obligation (ICAP-UCAP)	15	210	344	411

Source: Output files provided in response to MCEA Information Request No. 2. The Department notes that there was an error in GRE's initial modeling in the cases which applied the ICAP reserve assumptions. GRE corrected the error and provided updated output files to the Department. The top-ranked expansion plans in those cases did not change.

As shown, GRE's reserve obligation is much higher when the ICAP assumptions are applied. However, as also shown, the ICAP ratings of GRE's existing and new resources are higher than their UCAP ratings. The last row in the table presents the net impact of ICAP reserve assumption and capacity ratings, and demonstrates that the ICAP assumptions are more stringent, as the impact of the 15 percent reserve margin outweighs the increases in capacity ratings.

f. Coal Retirements

GRE allowed its coal units to be retired on the basis of cost in 31 of the 32 cases it analyzed. **[TRADE SECRET DATA HAS BEEN EXCISED]**.

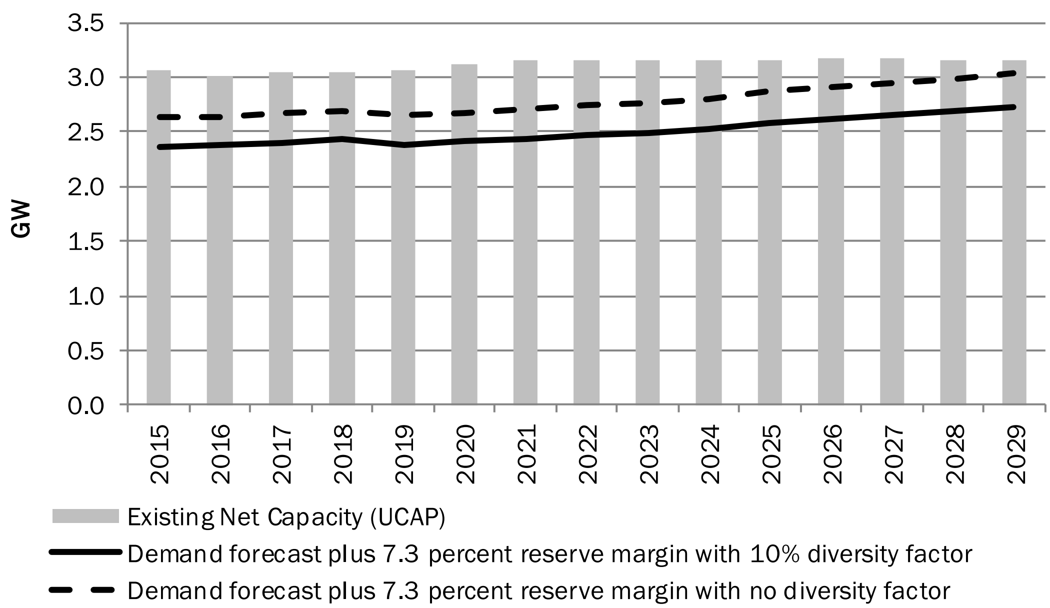
g. Other Modeling Assumptions

GRE allowed wind, solar and hydro to be selected on the basis of cost alone. Unless otherwise specified, capacity expansion models often attempt to add resources only when a modeling constraint such as reserve margin is violated; as long as the system being modeled has adequate reserves, the model will not test the addition of a new unit. By allowing the units to be selected on the basis of cost alone, the model will attempt to add these resources regardless of whether they are needed to meet a reserve requirement, and evaluate whether they are cost-effective on the basis of cost alone.

2. Discussion of Modeling Results

As described above, GRE currently has a significant capacity surplus. Figure 3 below illustrates GRE's capacity position assuming no retirements of its coal plants. As shown, even with the conservative assumption of a zero percent diversity factor, GRE has excess capacity (based on its UCAP ratings) throughout the entire fifteen year planning period.

Figure 3:
GRE's Current Capacity Position
Assuming No Coal Retirements



Largely as a result of this excess capacity, retirement of one or more of GRE's coal plants was determined to be cost effective in each of the 31 cases in which economic retirement of the plants was an option (one of GRE's 32 cases did not allow retirements of coal plants). More specifically, Genoa 3 was selected for retirement in all 31 cases. In nine of those 31 cases, Stanton Station was also selected for economic retirement. And in four of those nine cases, one or both of the units at Coal Creek Station were selected for economic retirement.

These results indicate a clear priority ranking for potential coal plant retirements. Genoa 3 is always retired first. Stanton Station is always retired second, and only if Genoa 3 has retired as well. The units at Coal Creek Station are always retired last, and only if Genoa 3 and Stanton Station are retired as well.

One other consistent result is the addition of renewables late in the planning period in order to meet Minnesota's Renewable Energy Standards. In all cases in which GRE planned for Minnesota's current RES standard of 25 percent of retail sales from renewable energy in 2025, 300 MW to 700 MW of new wind additions were selected, depending on the forecast assumption, over the period 2025-2029. Generally, GRE is expected to be just compliant through 2024 or 2025 with its current level of renewables, but new renewables will be required to meet the marginal annual increases in its RES requirement caused by load growth.

Another result that was generally consistent across the modeled cases was the addition of 200 MW of hydro in 2020. In all 31 cases in which the hydro was allowed to be selected, it was selected, even in the one case in which no coal retirements were allowed. However, as described further below, the Department has some concerns with the assumptions for hydro used by GRE that raise questions regarding the need and cost-effectiveness of this resource.

3. *Concerns Related to Hydro Assumptions*

On page 13 of its IRP, GRE states that it has signed a Memorandum of Understanding (MOU) with Manitoba Hydro Electric Board (MHEB) to jointly investigate the sale of up to 600 MW of electricity from MHEB to GRE commencing in approximately 2020. In its modeling, GRE made 200 MW of new hydro available as a potential resource in 2020. On page 85 of its IRP, GRE states that the Cooperative used its forecast of market prices as the assumed energy cost for the potential hydro resource. GRE also modeled one case in which the cost of the new hydro energy was assumed equal to the market price plus $0.05 per MWh, and one case with a hydro price of the market minus $0.05 per MWh. GRE did not include any costs associated with the capacity of the new hydro, but did include the capacity of new hydro when calculating its load and capability during the planning period in cases in which the new hydro was selected.

Because GRE has not justified such low costs for hydro, GRE's cost assumptions for the potential hydro resource are unreasonable. With respect to the energy produced by the hydro resource, GRE's base cost assumption that the energy cost is equal to spot market prices is low. More importantly the range of sensitivities modeled (market price plus and minus $0.05 per MWh) is much too narrow to consider the selection of 200 MW of hydro to be a robust result. The Department understands that a long term hydro purchase often includes costs greater than the current estimate of future spot market prices to reflect the insurance-value of locking-in future energy prices. Ultimately, GRE's decision will be based upon actual contract terms available in negotiations.

Additionally, regarding the assumption of no cost for hydro capacity, the Department notes that there will be no cost for the MHEB capacity only if GRE negotiates a diversity exchange with MHEB for the capacity, in which GRE trades capacity to MHEB during the winter in exchange for capacity from MHEB in the summer. If a diversity exchange agreement is not an option, further analysis will be required.

In the cases that assume medium demand and apply the UCAP reserve assumption, and in other cases in which either only Genoa 3 is retired, or both Genoa 3 and Stanton are retired, the new hydro appears to be selected on the basis of low energy cost alone, as GRE has enough capacity to meet its reserve requirements throughout the entire planning period, even without the new hydro. Thus, it's possible that the new hydro may be cost-effective as an energy-only resource, but the range of GRE's energy price assumptions is too narrow to consider this a robust result.

In the cases that assume high demand, apply ICAP reserve assumptions, and in which only Genoa 3 or Genoa 3 and Stanton Station are retired, GRE relies on only a small portion of the hydro capacity to meet its reserve obligation, and only very late in the planning period (generally starting in 2027 or 2028). GRE could potentially rely on short-term capacity purchases to fill that need before adding a new resource. However, in the four modeled cases in which one or both of the units at Coal Creek are retired (in addition to Genoa 3 and Stanton Station), GRE relies more heavily on the new hydro capacity to meet its reserve obligation. In the event that the MHEB capacity cost is greater than $0 the Cooperative's expansion plan may be different for those cases.

Lastly, the Department notes that GRE's modeling indicates that the termination of its Genoa 3 contract is not dependent on the addition of the new hydro resource. GRE ran one case in which new hydro was not available as a potential resource, and that case resulted in the termination of GRE's Genoa 3 contract, as well as the addition of 600 MW of renewables in order to comply with the Renewable Energy Standard. Thus, it appears that GRE can terminate its Genoa 3 contract and reliably serve its load without adding the new hydro capacity.

In its reply comments, the Department recommends that GRE provide a discussion justifying its $0 capacity cost assumption for the potential hydro resource..

4. Coal Plant Retirements

As noted above, in all 31 cases in which coal plant retirements were allowed, Genoa 3 was retired. In five cases, both Genoa 3 and Stanton Station were retired. And in four cases, Genoa 3, Stanton Station, and one or both of the units at Coal Creek were retired. As described above, the results of the four cases in which one or both the units at Coal Creek are retired may be skewed by the availability of free hydro capacity, and thus the results of those cases cannot be relied upon for analysis. However, in the five cases in which Genoa 3 and Stanton Station were retired, GRE has enough capacity without the new hydro to meet its reserve obligations when a 10 percent diversity factor is applied. Thus, the Department attempted to compare those five cases with the 22 cases in which only Genoa 3 was retired to determine which assumptions were driving the retirement of Stanton Station.

In cases that assume zero or low externalities, only Genoa 3 is retired, and in cases that assume high externality values, Genoa 3, Stanton, and both units at Coal Creek are all retired. In cases which assume medium externalities, however, the results are mixed. Five retire only Genoa 3, five retire Genoa 3 and Stanton Station, and one retires Genoa 3, Stanton Station, and Coal Creek Unit 1. The differences between the cases that cause only Genoa 3 to be retired versus those that retire Genoa 3 and Stanton Station are as follows:

- two cases assume high demand and energy forecast, and thus there is a need for Stanton's energy and capacity;
- two cases assume no market access, again creating a need for Stanton's energy; and
- one case uses GRE's ICAP/zero diversity reserve margin assumption, which creates a need for Stanton's capacity.

Thus, these results indicate that when GRE no longer receives energy and capacity from Genoa 3,[14] the continued operation of Stanton Station is not cost-effective under some assumptions. Because the economic retirement of both Genoa 3 and Stanton Station is not a robust result, it may be premature to decide to retire Stanton in this proceeding. If, for example, GRE's forecast turns out to be too low, GRE's modeling indicates that keeping Stanton Station online would be more cost effective than retiring and replacing it with a natural gas plant.

The Department recommends that GRE continue to evaluate the potential economic retirement of Stanton Station and Coal Creek Station in future resource plans.

5. *Other Considerations*

   a. *EPA's Clean Power Plan*

In the absence of a final rule with carbon emission guidelines pursuant to the EPA's Clean Power Plan (CPP), it is unclear how to model the effects the CPP may have on GRE's system. Additionally, while the majority of GRE's end-use customers are located in Minnesota, on page 44 of its IRP, GRE states that it has no affected units in Minnesota. Coal Creek, Stanton Station, and Spiritwood are located in North Dakota, and Genoa 3 is located in Wisconsin. The CPP, as currently proposed, has different carbon reduction goals for those states than it does for Minnesota. The CPP's proposed carbon reduction goal for North Dakota, in particular, is much less stringent than Minnesota's goal, and each state may develop its own implementation plan to meet its goal. Thus, it is not clear what GRE's obligations under the CPP will turn out to be, let alone the effect that obligation will have on GRE's system.

Given this uncertainty, GRE analyzed its preferred plan with respect to the nationwide goal of 30 percent reduction in carbon intensity relative to 2005 emissions levels, by 2030. This equates to an 18 percent reduction relative to 2012 emissions levels. GRE calculated that under its preferred plan the Cooperative's carbon intensity would be reduced by 28 percent relative to 2012, well in excess of 18 percent goal. This reduction is largely the result of the termination of GRE's Genoa 3 contract, the addition of 600 MW of wind over the period 2026-2029, and the addition of 200 MW of hydro in 2020. As described above, the

[14] As discussed above, GRE has reached agreement with Dairyland Power Cooperative to end GRE's obligation to purchase 50 percent of the output of Genoa 3.

Department has concerns about the proposed 200 MW MHEB addition that GRE should address in its reply comments. If the hydro is not added to GRE's system, the energy that hydro would have provided will have to come from a different source, likely one of GRE's coal plants, which could have a significant impact on GRE's carbon reduction calculation. However, GRE's modeling indicates that Stanton Station might be a candidate for retirement, and thus additional analysis surrounding its retirement should be performed in GRE's next IRP.

6. Summary and Recommendations

The Department concludes that GRE's modeling inputs and assumptions are generally reasonable, with the exception of GRE's cost assumptions regarding its potential hydro resource.

As described above, GRE's modeling indicates that the addition of a hydro resource with energy priced at or near the spot market and no capacity costs would be cost-effective. However, the Department is not convinced that GRE's energy and price assumptions are reasonable. The Department recommends that GRE provide in reply comments additional explanation of $0 capacity cost assumption.

In future resource plans, the Department recommends that GRE:

- continue to use an appropriate capacity expansion model;
- continue to apply the Commission-approved externality costs and CO_2 regulatory costs in its reference case;
- continue to evaluate cost-effective retirement of its coal plants; and
- evaluate cases in which market sales are prohibited (or priced at zero).

G. COMPLIANCE WITH THE RENEWABLE ENERGY OBJECTIVE

1. Background

In 2007, Minn. Stat §216B.1691 was amended to include the Minnesota RES, which began in 2010. As amended, Minn. Stat. §216B.1691, Subd. 2 sets forth the Renewable Energy Objective in place through 2010 and requires that:

> Each electric utility shall make a good faith effort to generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers or the retail customers of a distribution utility to which the electric utility provides wholesale electric service so that commencing in 2005, at least one percent of the electric utility's total retail electric sales to retail customers in Minnesota is generated by eligible energy technologies, and seven percent of the electric utility's total retail electric sales to retail customers in Minnesota by 2010 is generated by eligible energy technologies.

Minn. Stat. §216B.1691, Subd. 2a establishes the Renewable Energy Standard utilities must meet through 2025 and specifically requires that:

> …each electric utility shall generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota is generated by eligible energy technologies by the end of the year indicated:
>
> - 2012 12 percent
> - 2016 17 percent
> - 2020 20 percent
> - 2025 25 percent

An eligible energy technology is defined by Minn. Stat. §216B.1691, Subd. 1 as an energy technology that:

> Generates electricity from the following energy sources: (1) solar; (2) wind; (3) hydroelectric with a capacity of less than 100 megawatts; (4) hydrogen, provided that after January 1, 2010, the hydrogen must be generated from the resources listed in this clause; or (5) biomass, which includes without limitation, landfill gas, an anaerobic digester system, and an energy recovery facility used to capture the heat value of mixed municipal solid waste or refuse-derived fuel from mixed municipal solid waste as a primary fuel.

Minn. Stat. §216B.1691, subd. 2(d) directs the Commission to "issue necessary orders detailing the criteria and standards by which it will measure an electric utility's efforts to meet the renewable energy objectives of subdivision 2 to determine whether the utility is making the required good faith effort."

The Commission set forth the criteria for determining compliance with the RES Statute after taking comments from effected parties in a number of Orders.[15] Among the resources the

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[15] *In the Matter of Detailing Criteria and Standards for Measuring an Electric Utility's Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. §216B.1691,* Docket No. E999/CI-03-869, Initial Order Detailing Criteria and Standards for Determining Compliance with Minn. Stat. §216B.1691 and Requiring Customer Notification by Certain Cooperative, Municipal, and Investor-Owned Distribution Utilities. (June 1, 2004) *In the Matter of Detailing Criteria and Standards for Measuring an Electric Utility's Good Faith Efforts in Meeting the Renewable Energy Objectives Under Minn. Stat. §216B.1691,* Docket No. E999/CI-03-869; *In the Matter of a Commission Investigation into a Multi-State Tracking and Trading System for Renewable Energy Credits,* Docket No. E999/CI-04-1616, Second Order Implementing Minn. Stat. §216B.1691, Opening Docket to Investigate Multi-State Program for Tracking and Trading Renewable Credits and Requesting Periodic Updates from Stakeholder Group; (October 19, 2004) *In the Matter of Detailing Criteria and Standards for Measuring an Electric Utility's Good Faith Efforts in Meeting the Renewable Energy*

Commission has determined ineligible for meeting the RES are resources used for green pricing, resources that do not meet the statutory definition of eligibility, and generation assigned to compliance for other regulatory purposes such as another state's Renewable Portfolio Standard Requirements (RPS).

The 2007 amendment to Minn. Stat. §216B.1691, Subd. 4 required the Commission to establish a program for tradable Renewable Energy Credits (RECs) by January 2008, and to require all electric utilities to participate in a Commission-approved REC tracking system once such a system was in operation.

The Commission subsequently adopted the use of the Midwest Renewable Energy Tracking System (M-RETS), a multi-state REC tracking system, as the REC tracking system under Minn. Stat. §216B.1691, Subd. 4(d), and required Minnesota utilities to participate.[16] Specifically, the Commission required utilities to complete the online registration process and sign the Terms of Use agreement with the M-RETS system administrator APX, Inc., and receive account approval from APX by January 1, 2008. In addition, the Commission directed utilities to make a substantial and good faith effort to create a system account and sub-accounts for its organization, and to register its generation units/facilities in the M-RETS system by March 1, 2008.

In its December 18, 2007 *Order Establishing Initial Protocols for Trading Renewable Energy Credits,* the Commission adopted a four-year shelf life for all renewable energy credits to be used for compliance with the Minnesota RES. A four-year shelf life allows a REC to be retired towards MN RES compliance in the year of generation and during the four years following the year of generation.

Finally, in its December 3, 2008 *Third Order Detailing Criteria and Standards for Determining Compliance under Minn. Stat. §216B.1691 and Setting Procedures for Retiring Renewable Energy Credits*, the Commission directed utilities to begin retiring RECs equivalent to one percent of their Minnesota annual retail sales for the 2008 and 2009 compliance year by May 1st of the following year. Upon retirement, RECs are transferred into a specific Minnesota RES retirement account and, once retired, are not available to meet other state or program requirements, thus addressing the statutory prohibition against double counting the RECs and promoting the environmental benefits of renewable energy. The Commission further directed the utilities to submit a compliance filing demonstrating their compliance with the RES by June 1.

In addition to amending the RES Statute, Minn. Stat. §216B.241, Subd. 1c(b) was added to establish an energy-savings goal as part of a utility's conservation improvement plan (CIP), and states:

Objectives Under Minn. Stat. §216B.1691, Docket No. E999/CI-03-869, Order After Reconsideration (August 13, 2004).

[16] *In the Matter of a Commission Investigation into a Multi-State Tracking and Trading System for Renewable Energy Credits,* Docket No. E999/CI-04-1616, Order Approving Midwest Renewable Energy Tracking System (M-RETS) Under Minn. Stat. §216B.1691, Subd. 4(d), and Requiring Utilities to Participate in M-RETS (October 9, 2007).

> Each individual utility and association shall have an annual energy-savings goal equivalent to 1.5 percent of gross annual retail energy sales unless modified by the commissioner under paragraph (d). The savings goals must be calculated based on the most recent three-year weather normalized average.

The attainment of the 1.5 percent energy savings goal will reduce a utility's forecasted retail sales, and consequently lower the amount of renewable generation required to meet RES obligations.

2. GRE's Renewable Standard

As discussed above, GRE has both all requirements (AR) members and fixed obligation (FO) members. In response to MCEA IR No. 2, GRE provided its forecasted retail sales for both its AR and FO members. Table 9, below, summarizes GRE's RES requirement in MWhs over the forecast period.

Table 9: GRE's Renewable Energy Standard

Year	MN Retail Sales – All Requirements (MWhs)	MN Retail Sales – Total (AR + FO) (MWhs)	RES Percentage	RES Req. (MWhs) All Req.	RES Req. Total (AR +FO)
2014	8,929,682	11,272,819	12%	1,071,532	1,352,738
2015	8,737,348	11,006,598	12%	1,048,482	1,320,792
2016	8,815,370	11,091,698	17%	1,498,613	1,885,589
2017	8,939,089	11,206,397	17%	1,519,645	1,905,087
2018	9,093,737	11,359,719	17%	1,545,935	1,931,152
2019	8,965,821	11,231,803	17%	1,524,190	1,909,407
2020	9,130,545	11,396,527	20%	1,826,109	2,279,305
2021	9,322,144	11,588,126	20%	1,864,429	2,317,625
2022	9,463,100	11,729,083	20%	1,892,620	2,345,817
2023	9,645,972	11,911,954	20%	1,929,194	2,382,391
2024	9,834,770	12,100,752	20%	1,966,954	2,420,150
2025	10,208,330	12,474,313	25%	2,552,083	3,118,578
2026	10,281,075	12,547,057	25%	2,570,269	3,136,764
2027	10,515,524	12,781,506	25%	2,628,881	3,195,377
2028	10,715,260	12,980,878	25%	2,678,815	3,245,220
2029	10,934,445	13,200,428	25%	2,733,611	3,300,107

3. Generation Resources

a. Existing Resources

GRE has approximately 1,700,000 MWh in annual renewable generation. GRE provided its annual renewable generation forecasted through the planning period including the expiration of power purchase agreements as they occur. Without the addition of new resources or renewal of expiring power purchase agreements, GRE's expected annual renewable generation would fall to 966,964 MWhs by the end of the forecast period.

b. Planned Resources

GRE's preferred plan includes the addition of 100 MW of wind in 2026 and 2027, and 200 MWs of wind in 2028 and 2029, for a total addition of 600 MW. In addition, the forecast does not account for the fact that fixed obligation members self-supply some of the RECs necessary to meet their RES obligations.

4. Compliance with RES

On June 1, 2014, GRE submitted its 2013 RES compliance report in Docket No. E999/PR-14-12. GRE reported that it had Minnesota retail sales of 11,267,383 MWh and retired 1,352,086 RECs, or twelve percent of its retail sales to comply with its 2013 RES requirement.

Table 10 below estimates GRE's ability to comply with its RES requirements based on its planned additions. As reflected in Column c, GRE's scheduled additions beginning in 2026 cover its RES need for its all requirements members. When fixed obligation members are included in the totals, GRE has a REC deficit beginning in 2026. GRE allocates a portion of its RECs to the fixed obligation members based on their cost of participation in various renewable projects. If the REC allocation to fixed obligation members is insufficient to cover the RES requirement for the share of GRE sales to the fixed obligation member, then the fixed obligation member supplies the additional RECs required to meet their requirement. GRE appears to be well situated to meet its RES obligation through at least 2025.

Table 10: RES Compliance with Planned Additions

Year	All Req. RES Req. MWh	GRE Exist + Planned Add. (MWh)	RES Surplus/ (Deficit)	Total RES Req. (AR+FO)	Total Existing + Planned	RES Surplus/ (Deficit)
	(a)	(b)	(c)	(d)	(e)	(f)
			Beg. Bal. 5,191,098			Beg. Bal. 5,243,872
2014	1,071,532	1,565,084	5,684,620	1,352,738	1,726,384	5,617,518
2015	1,048,482	1,572,492	6,208,630	1,320,792	1,730,280	6,027,006
2016	1,498,613	1,572,492	6,282,510	1,885,589	1,730,280	5,871,697
2017	1,519,645	1,556,829	6,319,693	1,905,087	1,712,865	5,679,475
2018	1,545,935	1,550,025	6,323,783	1,931,152	1,704,102	5,452,425
2019	1,524,190	1,532,832	6,332,426	1,909,407	1,682,187	5,225,205
2020	1,826,109	1,532,832	6,039,149	2,279,305	1,682,187	4,628,087
2021	1,864,429	1,532,832	5,707,552	2,317,625	1,682,187	3,992,648
2022	1,892,620	1,529,875	5,344,807	2,345,817	1,678,408	3,325,240
2023	1,929,194	1,515,088	4,930,700	2,382,391	1,659,513	2,602,362
2024	1,966,954	1,515,088	4,478,834	2,420,150	1,659,513	1,841,725
2025	2,552,083	1,260,107	3,186,859	3,118,578	1,404,532	127,678
2026	2,570,269	1,588,607	2,205,197	3,136,764	1,656,593	(1,352,493)
2027	2,628,881	1,917,107	1,493,423	3,195,377	1,985,093	(2,562,776)
2028	2,678,815	2,280,964	1,095,572	3,245,220	2,348,950	(3,459,046)
2029	2,733,611	2,937,964	1,299,925	3,300,107	3,005,950	(3,753,203)

H. ENVIRONMENTAL ISSUES

The Department generally reviews utility resource places for compliance with pending state and national environmental legislation that impacts the electric utility's operations. Below, the Department briefly discusses several environmental issues that have the potential for impacting continued operation of existing resources and choice of future resources.

a. Acid Rain Program

The Clean Air Act's Acid Rain Program established a cap-and-trade program to reduce SO_2 and NO_x emissions. GRE indicates that its Coal Creek Station, Stanton Station and Spiritwood Station along with several combustion turbines are regulated under the Acid Rain Program. GRE installed low NO_x burners, scrubbers and other control equipment which allow it to meet the requirements under the Acid Rain program. The Company indicates that control equipment and other improvements at its largest facilities have resulted in excess SO_2 allowances that can be used for compliance at other affected facilities.

b. Cross State Air Pollution Rule (CSAPR)

The CSAPR was intended to address air quality concerns in downwind states, and would have affected GRE generation units. CSAPR was subject to appeal, and a stay. On October 23, 2014, the stay was lifted, and compliance began January 1, 2015. CSAPR affects only GRE's Minnesota generation facilities. GRE states that it expects to be able to operate within the allowances allocated by CSAPR without implementing additional controls.

c. Regional Haze

The EPA approved North Dakota's state implementation plan (SIP) for regional haze for GRE's Stanton Station and for its Coal Creek Station SO_2 and particulate emissions; however, the EPA sought lower NO_x emissions for the Coal Creek Station than those proposed under the North Dakota SIP. GRE sought appellate court review of the EPA's decision. The Appeals court directed the EPA to accept North Dakota's amended SIP, or reject the plan on different grounds. The EPA has yet to act, but GRE expects the EPA will ultimately approve North Dakota's SIP.

GRE states that it has installed its DryFining system at Coal Creek Station, and is evaluating stack modifications and electrostatic precipitator improvements to reduce particulate matter. At its Stanton Station, GRE is continuing to evaluate sorbent injection to control particulates.

d. Mercury and Air Toxics Standards (MATS)

The MATS rule was finalized in February 2012 and requires emissions limits on mercury and several other hazardous air pollutants. Compliance is required within three years (April 2015) with a first year extension available through the state, and a second year extension available through the EPA. GRE states it has five units at three plants subject to MATS. GRE indicates it has a carbon injection system in place at Spiritwood and has contracted to install an activated carbon injection system at its Stanton facility, and has engaged in testing to identify appropriate scrubber additives at its Coal Creek Station.

e. Clean Power Plan

GRE continues to follow and evaluate the impact of the EPA's recent Clean Power Plan aimed at reducing greenhouse gas emissions on its operations. GRE provided an estimate of its estimated CO_2 emissions using the methodology set forth in the Southern Minnesota Municipal Power Agency's (SMMPA) recent IRP (discussed below). GRE notes that the impact of the Clean Power Plan on its operations is highly dependent on the final rules and the form Minnesota's State Implementation Plan takes; however the Cooperative believes it is well positioned to comply.

f. Other Environmental Regulations

GRE indicates it is continuing to monitor development of possible environmental regulations pertaining to greenhouse gas emissions, clean water regulations and effluent regulations for potential impact on its generation facilities.

The Department concludes that GRE is adequately tracking state and federal environmental regulations and compliance.

I. MINNESOTA GREENHOUSE GAS EMISSIONS REDUCTION GOAL

In 2013, the Minnesota Legislature passed amendments to Minnesota Statute §216B.2422, subd. 4. The newly amended legislation now states (new language underlined):

> 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. The public interest determination must include whether the resource plan helps the utility achieve the greenhouse gas reduction goals under section 216H.02, the renewable energy standard under section 216B.1691, or the solar energy standard under section 216B.1691, subdivision 2f.

On August 5, 2013, the Commission issued a Notice of Information in Future Resource Plan Filings (Commission's Letter). The Commission Letter states, in part:

> **PLEASE TAKE NOTICE** that the Commission expects utilities to include in their resource plans filed after August 1, 2013 an explanation how the resource plan helps the utility achieve the greenhouse gas reduction goals, renewable energy standard, and solar energy standard as listed in the above-referenced legislation. Parties should also be prepared to discuss the matter in comments.

GRE discussed on pages 127-128 its progress towards meeting the State's greenhouse gas reduction goal. GRE states that it has reduced its CO_2 emissions by 19 percent in 2013 from 2005 levels. GRE further states that the carbon reductions are due to the removal of power purchase agreements (PPA) specifically associated with coal facilities, the addition of 46 MWs of wind, the addition of hydro energy and conservation and energy efficiency improvements.

Under its preferred plan, GRE expects to reach or exceed CO_2 emission reductions of 15 percent by 2015 and 26 percent by 2029.

GRE's preferred plan includes the termination of the Genoa 3 contract in 2016. In response to DOC IR No. 1, GRE reports that if the Genoa 3 contract were to continue, its CO_2 emissions would be reduced by 21 percent (as opposed to 26 percent) by 2029.

According to GRE's analysis, the Cooperative is not on a path to meet the State's greenhouse gas reduction goal:

> **216H.02 GREENHOUSE GAS EMISSIONS CONTROL.**
> Subdivision 1. **Greenhouse gas emissions-reduction goal.**
> It is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050. The levels shall be reviewed based on the climate change action plan study.

III. DEPARTMENT RECOMMENDATIONS

A. REPLY COMMENTS

In reply comments, the Department recommends that GRE provide additional explanation of its $0 capacity cost assumption for its potential hydro resources.

B. THIS RESOURCE PLAN

For this resource plan, the Department recommends that the Commission:

- Approve GRE's energy and demand forecast.
- Approve annual energy savings goals of 137,546 MWh annually.

C. FUTURE RESOURCE PLANS

In future resource plans, the Department recommends that GRE:

- continue to use an appropriate capacity expansion model;
- continue to apply the Commission-approved externality costs and CO_2 regulatory costs in its reference case;
- continue to evaluate cost-effective retirement of its coal plants; and
- evaluate cases in which market sales are prohibited (or priced at zero).

/lt

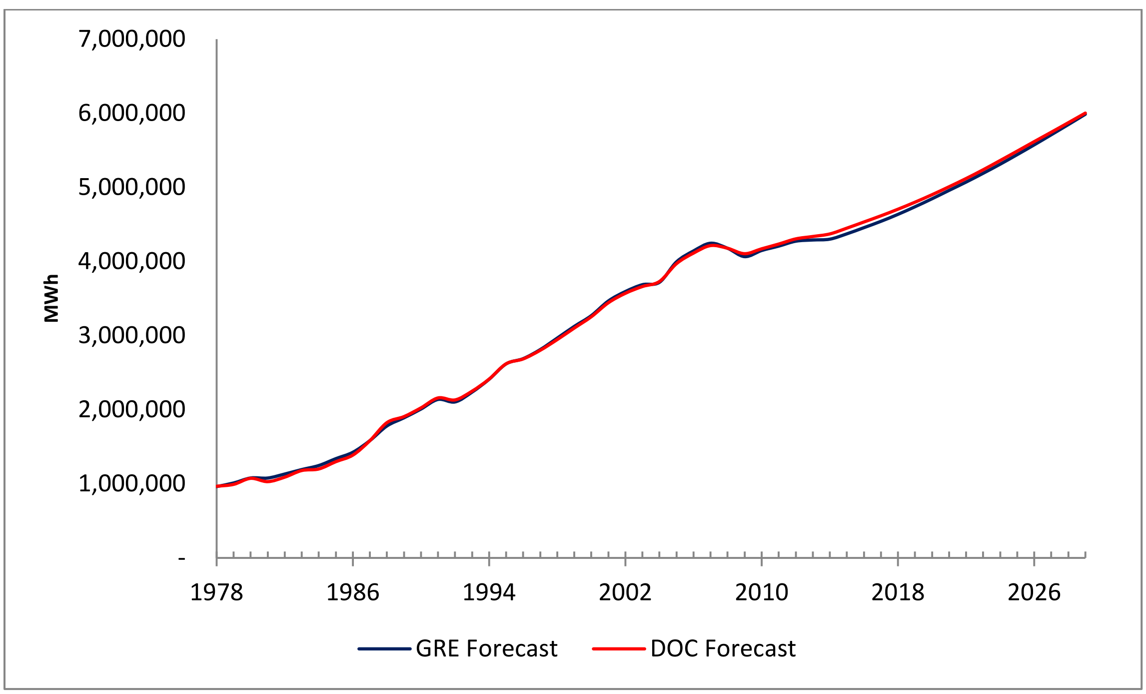
Department Specification of GRE Model
After Removing Log Transformation

Metro Region

$$\underline{Annual\ Metro\ Region\ Energy}$$
$$\underline{= \beta 0 + \beta 1(Metro\ Region\ Residential\ Consumers - 1)}$$
$$\underline{+ \beta 2(Metro\ Region\ Employment\ MA2) + \beta 3(Metro\ Region\ CDD65)}$$

The Department transformed all logged variables to normal form, and removed the wholesale rate real moving average variable, which was insignificant in the Department's model. The Department created a forecast from its altered version of GRE's model. Figure 1 below shows the Cooperative's forecast plotted with the Department's forecast to illustrate any divergence as a result of the transformation and variable omission. The Department's and the Cooperatives models were ostensibly the same, with no significant difference between the two. Table X at the end of this section provides the annual energy figures in addition to the growth rates to provide numerical representation of the differences between the two forecasts. As the metro region is the largest in terms of energy consumption, the similarity of these forecasts indicate that there should be no large difference between the altered non-logged versions of the models the forecasts were created from by the Department and the Company.

Figure 1 – Comparison of GRE and DOC Metro Region Forecasts

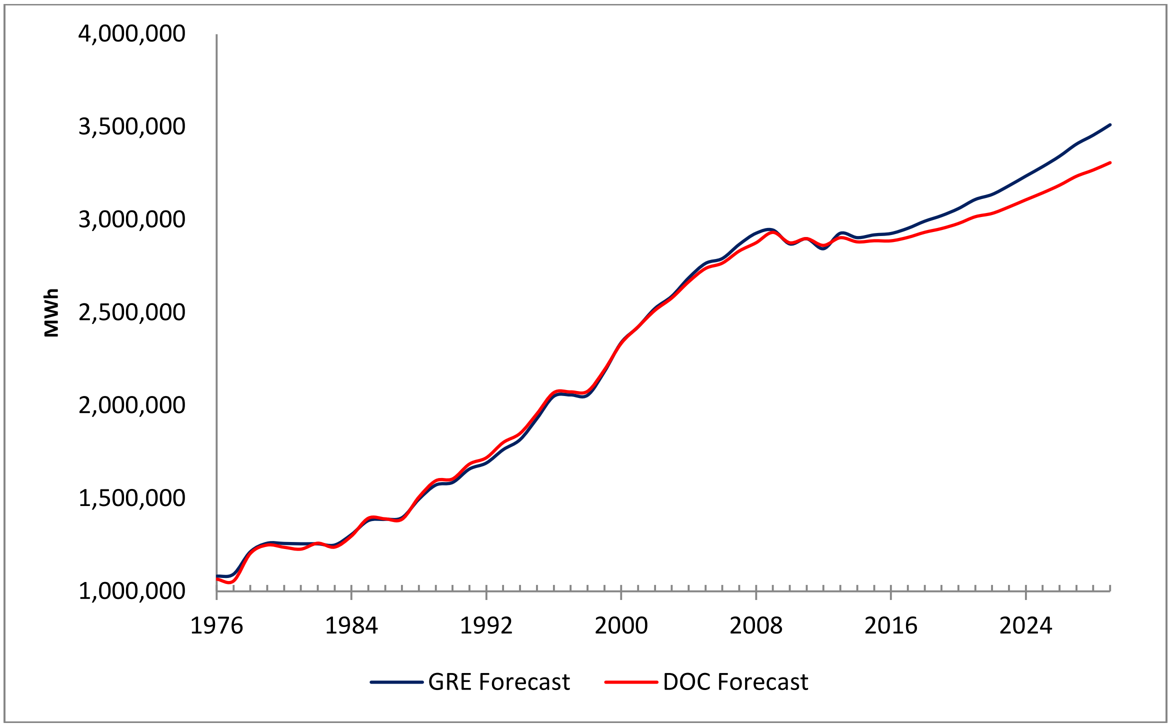


Northern Region

$$\underline{Annual\ Northern\ Region\ Energy}$$
$$\underline{= \beta 0 + \beta 1(Northern\ Region\ Residential\ Consumers - 1)}$$
$$\underline{+ \beta 2(Northern\ Region\ HDD65) + \beta 3(Northern\ Region\ Employment{:}\ Population\ Ratio)}$$
$$\underline{+ \beta 4(Wholesale\ Rate\ RealMA3)}$$

The Department transformed all logged variables to normal form and removed the AR(1) term from the model specified by the Cooperative. The Department's forecast showed a slightly lower projection than the forecast submitted by GRE, and results in a 5.8% lower energy forecast for that region in 2029.

Figure 2 – Comparison of GRE and DOC North Region Forecasts



Southern & Western Region

$$\underline{Annual\ Southern\ \&\ Western\ Region\ Energy}$$
$$\underline{= \beta 0 + \beta 1(Southern\ \& Western\ Region\ HDD65)}$$
$$\underline{+ \beta 2(Southern\ \& Western\ Region\ Residential\ Consumers - 1) + \beta 3(Wholesale\ Rate\ RealMA3)}$$
$$\underline{+ \beta 4(Residential\ Propane\ Real)}$$

The Department transformed all logged variables to normal form and added the suppressed constant term back into the model. Again, the Department's forecast is lower than the Cooperatives after the transformation of the variables from log to normal form. Figure 3 illustrates the Department's non-logged forecast, which was 2.8% lower in 2029 than the Cooperative's proposed forecast with the log transformed variables.

Figure 3 - GRE and DOC Southern & Western Forecast Comparison

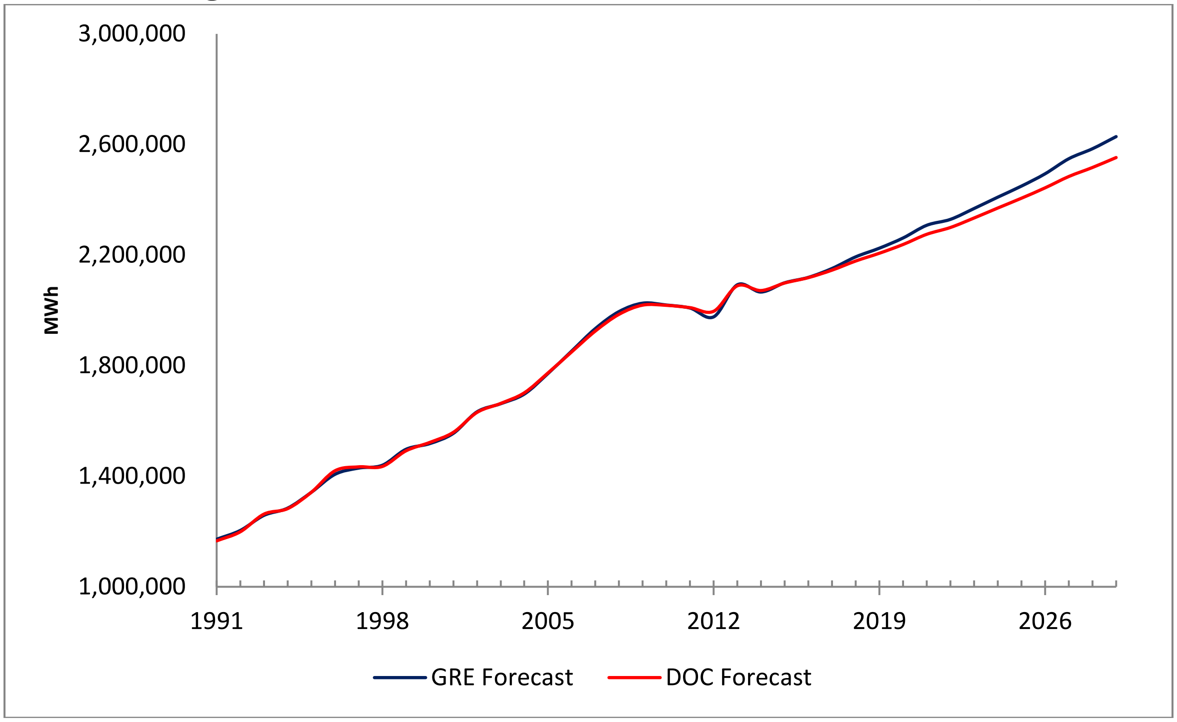


Table 1 - Metro Region DOC Energy Model Output

Dependent Variable: METROENERGY				
Method: Least Squares				
Date: 01/27/15 Time: 14:06				
Sample (adjusted): 1978 2013				
Included observations: 36 after adjustments				
Convergence achieved after 16 iterations				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-1.27E+09	3.73E+08	-3.401809	0.0019
RESCON	12839.47	3982.246	3.224179	0.003
MAWTEMPMETRO2	14213481	4553170	3.121667	0.0039
METROCDD	221408.5	33283.12	6.652277	0
AR(1)	0.87083	0.074599	11.67356	0
R-squared	0.998975	Mean dependent var		2.67E+09
Adjusted R-squared	0.998843	S.D. dependent var		1.20E+09
S.E. of regression	40952644	Akaike info criterion		38.02198
Sum squared resid	5.20E+16	Schwarz criterion		38.24191
Log likelihood	-679.3956	Hannan-Quinn criter.		38.09874
F-statistic	7553.513	Durbin-Watson stat		2.572501
Prob(F-statistic)	0.00E+00			

Table 2- Northern Region DOC Energy Model Output

Dependent Variable: NORTHENERGY				
Method: Least Squares				
Date: 01/27/15 Time: 14:26				
Sample (adjusted): 1975 2013				
Included observations: 39 after adjustments				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-1985324630	208738181.8	-9.5110756	4.14E-11
RESCON	25776.68759	1125.669708	22.8989795	3.04E-22
NORTHHDD	46858.92577	12208.89978	3.8380957	5.14E-04
EMPPOPNORTH	1914568742	450682032.6	4.24815858	0.000158127
WSRATE_REAL	-3267940.493	717666.8544	-4.553562	6.46E-05
R-squared	0.995813274	Mean dependent var		1957569917
Adjusted R-squared	0.995320717	S.D. dependent var		662615943.5
S.E. of regression	45326430	Akaike info criterion		38.21588793
Sum squared resid	6.99E+16	Schwarz criterion		38.42916506
Log likelihood	-740.2098146	Hannan-Quinn criter.		38.29240993
F-statistic	2.02E+03	Durbin-Watson stat		1.500448449
Prob(F-statistic)	6.69E-40			

Table 3 - Southern and Western Region DOC Energy Model Output

Dependent Variable: SOUTHENERGY				
Method: Least Squares				
Date: 02/04/15 Time: 09:07				
Sample (adjusted): 1991 2013				
Included observations: 23 after adjustments				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-836857126.7	172460990.2	-4.852443011	0.000127904
SOUTHHDD	40205.56755	10439.60703	3.851252968	1.17E-03
RESCON	43635.40353	1593.302864	27.38676023	4.00E-16
LNWSRATE_REAL	-146166410.6	40281400.7	-3.628632769	0.001920846
PROP_REAL	-59326557.35	29767875.84	-1.992972481	0.061648309
R-squared	0.99352417	Mean dependent var		1642088977
Adjusted R-squared	0.992085097	S.D. dependent var		300334063.7
S.E. of regression	2.67E+07	Akaike info criterion		37.22934128
Sum squared resid	1.29E+16	Schwarz criterion		37.47618785
Log likelihood	-423.1374247	Hannan-Quinn criter.		37.2914225

Table 4 - Metro Region DOC Demand Model Output

Dependent Variable: METRODEMAND				
Method: Least Squares				
Date: 02/09/15 Time: 15:17				
Sample (adjusted): 2003M01 2013M12				
Included observations: 132 after adjustments				
Variable	Coefficier	Std. Error	t-Statistic	Prob.
C	232031.6	67034.58216	3.461372	0.000749
MINNEAPOLISHOTTEMP	5306.654	904.8838875	5.864459	4.20E-08
MONTHLYSALES_KWH_	0.001445	0.000195267	7.401706	2.16E-11
JAN	-140075	28584.22575	-4.90045	3.08E-06
FEB	-129088	27740.09861	-4.6535	8.60E-06
MAR	-157596	27713.28207	-5.68667	9.56E-08
APR	-181874	27184.40823	-6.69037	7.87E-10
MAY	-123811	22212.69209	-5.5739	1.60E-07
JUN	10003.38	22622.63724	0.442184	0.659165
JULY	-41945.1	31367.41921	-1.33722	0.183723
AUG	-18962.8	26623.9423	-0.71225	0.477718
OCT	-122169	24534.01518	-4.97959	2.20E-06
NOV	-82901.9	27720.67264	-2.99062	0.00339
DEC	-98640	29093.70033	-3.39042	0.00095
R-squared	0.910118	Mean dependent var		691252.4
Adjusted R-squared	0.900216	S.D. dependent var		162143.6
S.E. of regression	51219.03	Akaike info criterion		24.62561
Sum squared resid	3.1E+11	Schwarz criterion		24.93137
Log likelihood	-1611.29	Hannan-Quinn criter.		24.74986
F-statistic	91.90999	Durbin-Watson stat		1.602212
Prob(F-statistic)	2.84E-55			

Table 5 - Northern Region DOC Demand Model Output

Dependent Variable: NORTHDEMAND				
Method: Least Squares				
Date: 02/03/15 Time: 15:57				
Sample (adjusted): 2003M01 2013M12				
Included observations: 132 after adjustments				
Variable	Coefficier	Std. Error	t-Statistic	Prob.
C	38690.88	28552.60381	1.355074	0.178004591
HIBBINGHOTTEMP	1134.064	554.8207721	2.044018	0.043196691
HIBBINGCOLDTEMP	1874.25	268.0729191	6.991568	1.80E-10
MONTHLYSALES	0.001627	0.000142836	11.38833	1.12E-20
JAN	-162908	22786.92423	-7.14921	8.11E-11
FEB	-89525.7	20516.9631	-4.3635	2.77E-05
MAR	-109382	17785.37786	-6.1501	1.11E-08
APR	-67828.3	14222.37518	-4.76912	5.38E-06
MAY	-63574.2	11451.04731	-5.55183	1.79E-07
JUN	9122.069	11301.24513	0.807174	0.421204233
JULY	-3361.12	12994.40955	-0.25866	0.796352722
AUG	1688.893	12038.14175	0.140295	0.88866805
OCT	-69227.2	12877.43678	-5.37585	3.95E-07
NOV	-99578.4	16349.49451	-6.09061	1.47E-08
DEC	-155084	21054.33599	-7.36587	2.69E-11
R-squared	0.901357	Mean dependent var		414311.6274
Adjusted R-squared	0.889553	S.D. dependent var		79242.9175
S.E. of regression	26335.2	Akaike info criterion		23.3018452
Sum squared resid	8.11E+10	Schwarz criterion		23.62943632
Log likelihood	-1522.92	Hannan-Quinn criter.		23.4349632
F-statistic	76.36383	Durbin-Watson stat		1.547917954
Prob(F-statistic)	6.07E-52			

Table 6 - Southern & Western Region DOC Demand Model Output

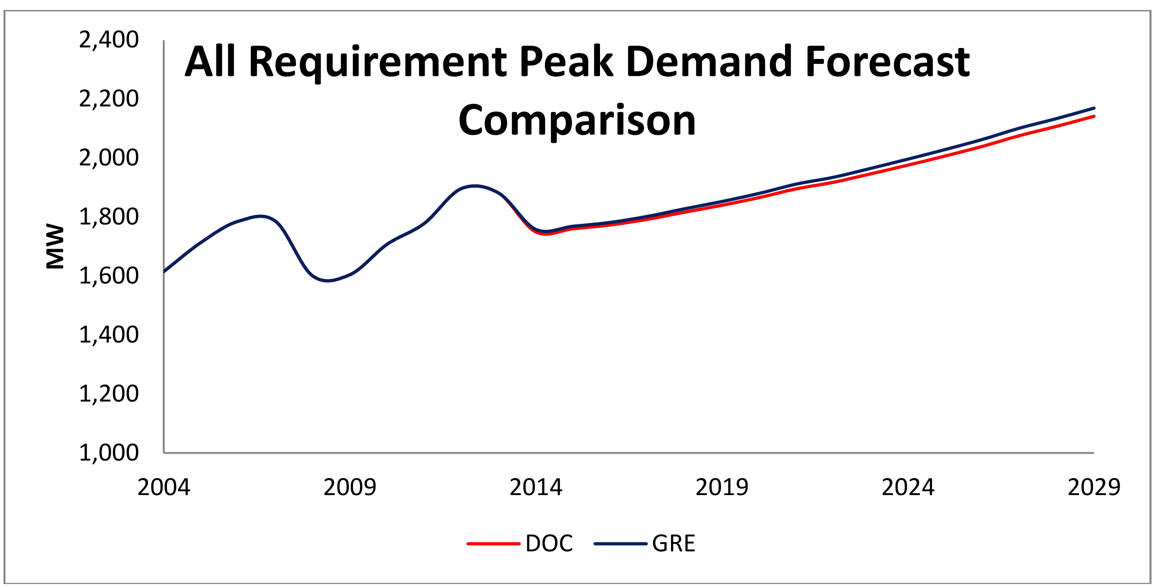
Dependent Variable: SOUTHWESTDEMAND				
Method: Least Squares				
Date: 02/03/15 Time: 16:01				
Sample (adjusted): 2003M01 2013M12				
Included observations: 132 after adjustments				
Variable	Coefficier	Std. Error	t-Statistic	Prob.
C	46011.14	14007.04637	3.284857	0.001347
MONTHLYSALES	0.001635	9.20E-05	17.76867	5.06E-35
MASONCITYHOTTEMP	492.4809	272.1162625	1.809818	0.072891
MASONCITYCOLDTEMP	424.5289	150.8609724	2.814041	0.005741
JAN	-51712.9	11512.86613	-4.49175	1.67E-05
FEB	-24136	10767.63203	-2.24154	0.026877
MAR	-43713.8	9674.052139	-4.51867	1.50E-05
APR	-34768.6	8270.357427	-4.204	5.15E-05
MAY	-35963	6600.339434	-5.44866	2.85E-07
JUN	5544.131	6593.339111	0.840868	0.402137
JULY	-19747.2	7496.859281	-2.63407	0.009578
AUG	-5578.22	6989.633197	-0.79807	0.426446
OCT	-25841.8	7391.36946	-3.49621	0.000668
NOV	-32164.6	9034.284736	-3.56028	0.000537
DEC	-47782.3	10369.20481	-4.6081	1.04E-05
R-squared	0.879984	Mean dependent var		294579.2
Adjusted R-squared	0.865624	S.D. dependent var		42028.34
S.E. of regression	15406.49	Akaike info criterion		22.22961
Sum squared resid	2.78E+10	Schwarz criterion		22.5572
Log likelihood	-1452.15	Hannan-Quinn criter.		22.36273
F-statistic	61.27666	Durbin-Watson stat		1.913194
Prob(F-statistic)	5.06E-47			

Table 7 - GRE and DOC All Requirement Peak Demand Forecasts

GRE Forecast														
	1	2	3	4	5	6	7	8	9	10	11	12		
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%**

DOC Forecast														
	1	2	3	4	5	6	7	8	9	10	11	12		
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Summer**	**Winter**
2015	1,530	1,460	1,323	1,130	1,214	1,608	1,760	1,718	1,474	1,246	1,408	1,572	1,760	1,572
2016	1,541	1,469	1,333	1,138	1,223	1,619	1,773	1,730	1,484	1,255	1,417	1,583	1,773	1,583
2017	1,559	1,485	1,349	1,152	1,237	1,634	1,792	1,748	1,499	1,270	1,433	1,602	1,792	1,602
2018	1,583	1,506	1,369	1,170	1,255	1,654	1,817	1,770	1,517	1,290	1,454	1,626	1,817	1,626
2019	1,604	1,525	1,388	1,186	1,272	1,673	1,840	1,792	1,535	1,308	1,473	1,648	1,840	1,648
2020	1,629	1,547	1,409	1,205	1,291	1,694	1,866	1,816	1,555	1,328	1,494	1,674	1,866	1,674
2021	1,658	1,573	1,434	1,226	1,313	1,718	1,896	1,843	1,578	1,352	1,519	1,703	1,896	1,703
2022	1,679	1,591	1,452	1,242	1,329	1,736	1,918	1,864	1,595	1,369	1,537	1,724	1,918	1,724
2023	1,707	1,615	1,475	1,263	1,350	1,760	1,946	1,890	1,617	1,391	1,561	1,752	1,946	1,752
2024	1,736	1,640	1,500	1,284	1,372	1,784	1,976	1,918	1,639	1,415	1,586	1,782	1,976	1,782
2025	1,765	1,666	1,526	1,306	1,395	1,809	2,007	1,946	1,663	1,439	1,612	1,812	2,007	1,812
2026	1,797	1,694	1,553	1,330	1,419	1,836	2,040	1,977	1,688	1,465	1,639	1,844	2,040	1,844
2027	1,833	1,726	1,584	1,356	1,446	1,865	2,076	2,011	1,716	1,494	1,670	1,881	2,076	1,881
2028	1,863	1,752	1,610	1,379	1,469	1,891	2,108	2,040	1,740	1,518	1,696	1,911	2,108	1,911
2029	1,896	1,781	1,638	1,403	1,494	1,919	2,142	2,071	1,766	1,545	1,724	1,945	2,142	1,945
5-Year (CAGR)													**0.8%**	**0.8%**
10-Year (CAGR)													**1.4%**	**1.4%**
15-Year (CAGR)													**1.4%**	**1.5%**

Figure 4 - GRE and DOC All Requirement Peak Demand Forecasts



CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Public Comments

Docket No. **ET2/RP-14-813**

Dated this 2nd day of March 2015

/s/Sharon Ferguson

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