Minnesota Public Utilities Commission

Staff Briefing Papers

Meeting Date: September 10, 2015 .... **Agenda Item **#5B**

Company:	Great River Energy (GRE or the Cooperative)
Docket No.	**Docket No. ET2/RP-14-813**
	In the Matter of Great River Energy's 2014 Resource Plan
Issue:	Should the Commission accept or reject Great River Energy's 2014-2029 Integrated Resource Plan? What modifications, if any, should the Commission advise Great River Energy to make to its Resource Plan? When should Great River Energy file its next Resource Plan?

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Relevant Documents

Great River Energy, Resource Plan (public and non-public) ....October 31, 2014
Al-Corn Clean Fuel and Heartland Corn Products, Initial Comments .... March 2, 2015
Department of Commerce, Initial Comments (public and non-public) .... March 2, 2015
Environmental Intervenors, Initial Comments (public and non-public).................... March 2, 2015
Great River Energy, Notice of Changed Circumstances .... March 5, 2015
Al-Corn Clean Fuel and Heartland Corn Products, Reply Comments .... May 1, 2015
Environmental Intervenors, Reply Comments (public and non-public)....................... May 1, 2015
Great River Energy, Reply Comments (public and non-public)................................. May 1, 2015
Great River Energy, MISO/LSE Balance Sheet (Non-public) .... June 15, 2015
Department of Commerce, Supplemental Comments .... June 17, 2015
Great River Energy, Supplemental Comments .... June 29, 2015
Environmental Intervenors, Motion to Compel ....July 10, 2015
Great River Energy, Opposition to EI's Motion to Compel ....July 22, 2015

The attached materials are workpapers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless noted otherwise.

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Introduction

Resource planning is defined by Minn. Stat. § 216B.2422 (the IRP Statute) and Chapter 7843 of the Minnesota Rules. A public utility capable of generating 100 megawatts (MW) of electricity and providing electricity to at least 10,000 customers, directly or indirectly, must file an integrated resource plan (IRP) with the Commission.[1]

An IRP should propose a set of supply- and demand-side resource options a utility could use to meet its needs during the fifteen-year forecast period. A utility's energy and demand forecasts are the foundation upon which an IRP is developed. The plan must include "an explanation of the supply and demand circumstances under which, and the extent to which, each resource option would be used to meet those service needs."[2]

An IRP must also contain long-term emission reduction planning. Each utility is required to include in the filing "a narrative identifying and describing the costs, opportunities, and technical barriers to the utility continuing to make progress toward achieving the state greenhouse gas emission reduction goals established in Minn. Stat. § 216H.02, subdivision 1."[3]

Chapter 7843 of the Minnesota Rules authorizes the Commission to make findings of fact and conclusions. In doing so, "the Commission shall consider the characteristics of the available resource options and of the proposed plan as a whole."[4] The Commission evaluates resource plans on their ability to:

A. maintain or improve the adequacy and reliability of utility service;

B. keep the customers' bills and the utility's rates as low as practicable;

C. minimize adverse socioeconomic effects and adverse effects upon the environment;

D. enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and

E. limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

If the Commission concludes that a certain set of resource options is optimal, it may identify those options as a preferred plan. A preferred resource plan "need not have been specifically proposed or advocated by the utility, an intervening party, or other interested person."[5]

[1] Minn. Stat. § 216B.2422. The statute exempts federal power agencies.
[2] Minn. Stat. § 216B.2422, Subd 1 (b).
[3] *Ibid*. at Subd. 2 (c).
[4] Minn. Rule 7843.0500, Subp. 3.
[5] *Ibid*, at Subp.2.

The IRP Statute provides for the Commission to approve, reject, or modify a utility's resource plan or report. However, according to the definition of a "public utility" in Minn. Stat. § 216B.02, subd. 4, the Commission's decision regarding the plan of a cooperative electric association such as Great River Energy (GRE) is advisory in nature.

The Commission rejected Great River Energy's 2012 resource plan. In its September 26, 2013 *Order Rejecting Resource Plan and Setting Future Filing Requirements*, the Commission required the following of GRE:[6]

For all future resource plans:

- GRE should continue striving to save energy equal to 1.5 percent of its annual retail energy sales in a cost-effective manner.
- If GRE anticipates the need for new sources of electricity fueled by nonrenewable sources, GRE should provide a plan or plans complying with the requirements of Minn. Stat. § 216B.2422, subd. 2.
- GRE should consider making changes to its forecasting process that reduce the need for adjustments.
- GRE should track the process of adjusting its forecasts.
- GRE should include an evaluation of potential conservation measures that it does not include in it its Conservation Improvement Program portfolio – including, at a minimum, all the measures identified in the Electric Power Research Institute study that pass the Total Resource Cost test.
- GRE should continue to evaluate compliance with the Renewable Energy Standards, environmental regulations, and environmental compliance.
- GRE should continue to evaluate alternatives to existing generation.
- GRE should include the Commission-approved cost of externalities and carbon dioxide regulations in calculating the cost of GRE's reference case and preferred plan.

For GRE's next resource plan:

- GRE shall file the plan on or before November 1, 2014.
- The Commission may consider, at the request of a party or on its own motion, extending the completeness review comment deadline to review assumptions underlying GRE's resource plan filing as part of its completeness review.

GRE's resource plan was filed on October 31, 2014. On December 2, 2014, the Department of Commerce (Department) filed Comments, which stated it had reviewed Great River Energy's (GRE) 2014 Integrated Resource Plan (IRP) for completeness, pursuant to Minnesota Statutes and Rules and the Commission's September 26, 2013 Order. Based on its review, the Department concluded that GRE's 2014 IRP was complete.

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[6] Docket No. ET-2/RP-12-1114

The parties in this case are: the Department of Commerce (DOC or the Department), the Environmental Intervenors[7] (EI), and Al-Corn Clean Fuel and Heartland Corn (C&I). Several of GRE's members also filed brief letters in support of GRE's resource plan.

Finally, EI filed a Motion to Compel on July 10, 2015. Because the Motion to Compel and GRE's IRP share contextual background, staff scheduled both the Motion to Compel and the GRE's IRP on the same hearing date, but each with separate briefing papers. Staff understands that the Commission may wish to delay a decision on what action to take on GRE's IRP, depending on the decision the Commission makes on the Motion to Compel.

Company Background

GRE is an electric generation and transmission (G&T) cooperative providing wholesale electric service to 28 member electric distribution cooperatives, who in turn serve nearly 655,000 retail customers. Twenty of these members have contracted to purchase from GRE all the electricity required by their customers (All-Requirement, or AR). The other eight members have contracted to purchase a fixed amount from GRE, and are free to seek additional supplies of electricity from other sources (Fixed Obligation, or FO).

GRE's peak demand is approximately 2,500 MW. For comparison, below are the peak demands of other utilities operating in Minnesota, including GRE:

GRE	2,500 MW
Xcel Energy	9,400 MW
Minnesota Power	1,700 MW
Otter Tail Power	780 MW

As a MISO member and market participant, GRE's resource adequacy obligation is identified on a one-year (or Planning Year) basis, and it is determined by the difference between its MISO planning reserve margin (PRM) requirement and the sum of its accredited generating capability, including purchases.

MISO applies its PRM to a load-serving entity's (LSE's) demand *at the time the MISO system reaches its total peak demand*. In other words, MISO no longer applies the PRM to an individual LSE's forecasted peak demand.[8] A diversity factor is calculated to explain the difference between the LSE's load at the time of MISO's peak and the load at the time of an LSE's own peak. The diversity factor and PRM, together, factor into GRE's PRM requirement.[9]

[7] The Environmental Intervenors consist of: Minnesota Center for Environmental Advocacy (MCEA), Fresh Energy, the Izaak Walton League of America – Midwest Office, the Sierra Club, and Wind on the Wires.

[8] This is called the coincident peak method. Prior to 2013, MISO had calculated the PRM by applying a uniform diversity factor to all LSEs in the footprint.

[9] This diversity factor is the primary calculation component of the MISO Value Proposition: Generation Investment Deferral. The lower planning reserve margin, calculated as a result of the regional diversity by MISO, translates into the deferral of constructing new generating resources in the future.

Because GRE's demand is historically much lower during MISO's peak than during its own non-coincident peak, GRE's diversity factor is very high (10 percent), thus significantly reducing its Planning Year reserve obligations. Furthermore, given that GRE already has a net capability of more than 3,000 MW, its capacity position is substantially long for the forecast period.

GRE owns three coal-fired power plants, all of which are located in North Dakota: Coal Creek Station (1,163 MW), Stanton Station (187 MW) and Spiritwood Station (99 MW). GRE's resource plan keeps all of these plants in operation throughout the planning period because, according to GRE:

- Retaining the plants is the least-cost expansion plan;
- They are baseload resources, and removing any of them from GRE's system would significantly and unreasonably expose its members to the wholesale market; and
- GRE has already invested more than $1 billion in its coal facilities, much of which was spent to install emissions control equipment.

Listed below, GRE also owns several large-scale natural gas-fired peaking facilities, all of which are located in Minnesota.

Facility	**Location**	**MW**	**Start of Operation**
Cambridge Station, Unit 2	Cambridge, MN	164	2007
Elk River Peaking Station	Elk River, MN	153	2009
Lakefield Junction Station	Martin County, MN	519	2001
Pleasant Valley Station	Mower County, MN	386	2001, 2002

Because these are peaking facilities, they are designed to operate only during times of peak electrical demand. Thus, while GRE has a significant amount of natural gas capacity, very little of GRE's energy is delivered by its natural gas facilities.

As of 2013, coal-fired energy accounted for 67 percent of GRE's electricity production. The rest of its energy supply consists mostly of renewable energy (11 percent) and hydro (10 percent). GRE's natural gas units listed above deliver about three percent of its energy, with the remainder consisting of wholesale market purchases.

Staff Comment

Resource planning is in many ways a risk assessment. Among the Commission's five factors to consider for its IRP evaluation, two factors directly pertain to risk. Subp. 3(d). of Minn. Rule 7843.0400 states that a resource plan should "enhance the utility's ability to respond to unforeseen changes," and Subp. 3(e). states that plans should "limit the risk of adverse effects on the utility and its customers."

Much of this risk can be reasonably assessed, albeit not perfectly, through sensitivity analysis performed in a utility's expansion plan modeling. Fuel price risk, for instance, can be identified when the cost of an expansion plan varies significantly as a result of small adjustments in prices. Such swings could suggest that a utility is overly dependent on one particular fuel source. Also, testing the impact of the range of the Commission's approved carbon prices can be a reasonable measure of the utility's exposure to environmental regulations risk or coal price risk.

Perhaps the most common way the Commission's orders reflect risk management is by making a size, type, and timing finding. Size and timing generally refers to the number of megawatts which should be added and in what year(s), and these risks can usually be captured within upper and lower forecast bounds. Type refers to whether that expansion resource should be baseload, intermediate, peaking, or renewables.

The type component of size, type, and timing can often be the most contentious because recommendations of type stem from different perspectives on risk, assumptions used, and the weight given to scenarios tested. Disputes in this case concern the types of resources which, according to the parties, most appropriately balance cost, emissions, and system operations. This includes the consideration of retiring one or more of GRE's existing coal-fired assets.

This resource plan docket is somewhat unusual in that the utility does not need any new capacity for the entire planning period. Thus, staff does not believe it is necessary for the Commission to make a specific size, type, and timing finding in this case. However, the Commission can make more general findings and conclusions reflective of its view of record evidence. In doing so, there are several reference points the Commission typically applies, in conjunction with the five factors to consider listed above. These include: the interaction of state-level and MISO-level planning, demand-side management efforts, carbon reduction measures, and the modeling results as a whole. Staff will discuss each of these common reference points in the sections below.

Load and Capability

The three coal plants and four natural gas peaking facilities listed above comprise most of GRE's supply-side capability. (GRE also has some small-scale combustion turbines and an emergency diesel generator, in addition to more than 240 MW of bilateral contracts.) As noted, GRE's coal plants are all located in North Dakota, while its major peaking units are located in Minnesota. In the context of complying with the U.S. Environmental Protection Agency's Clean Power Plan (also referred to as the 111(d) Rule), GRE has no 111(d) affected facilities in Minnesota.

In terms of load, GRE projects a capacity surplus throughout its planning period. As shown in Table 1 from the Department's comments, reproduced below, GRE expects to sustain a capacity surplus of more than 500 MW until 2025.

GRE's Capacity Position

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

There are several reasons introduced to either explain or criticize GRE's current excess capacity position. According to GRE, the Cooperative experienced a significant drop in energy sales. Year-over-year, weather normalized energy sales from All-Requirement members were consistently more than four percent prior to 2008, which then reduced to a low of negative one percent in 2009. In addition, planning to the MISO coincident peak further reduces GRE's resource adequacy obligation (discussed above as the diversity factor adjustment).

According to the C&I Customers, GRE's excess capacity is the result of overly optimistic load projections of need and future sales. Furthermore, the C&I Customers ascribe GRE's excess capacity to overall poor decision-making by constructing several unneeded facilities. The C&I customers specifically point the Commission to the Cambridge 2 Station in 2007, the Elk River Peaker in 2009, and the Spiritwood Station.

EI echoes C&I's criticism, stating, "GRE has significant excess capacity on its system, particularly since Spiritwood came on line in November 2014. Spiritwood, coupled with low levels of load growth, has likely contributed to some risky courses of action that GRE has adopted in order to cover its increasing operating costs."[10]

[10] Environmental Intervenors Initial Comments, p. 12.

There is no dispute that GRE expects excess capacity through the remainder of the planning period. However, there is significant dispute over the Cooperative's action plan. According to Subp. 2 of the Commission's IRP Rules, a resource plan must, at a minimum:

- show the resource options a utility believes it might use to meet its needs;
- specify how the implementation and use of those resource options would vary with changes in supply and demand circumstances; and
- discuss plans to reduce existing resources through sales, leases, deratings, or retirements.

Both EI and C&I recommend the Commission deny GRE's resource plan, in part on the basis that GRE did not appropriately contemplate plans to reduce existing resources. The Department recommends the Commission accept GRE's plan, with a modified (higher) energy savings goal.

Action Plan

While the Department uses the Strategist capacity expansion model to conduct its modeling and analysis, GRE uses the Ventyx software System Optimizer. Like Strategist, System Optimizer can evaluate resource expansion plan options, including adding or retiring generation resources. Also, like Strategist, System Optimizer solves for the least cost expansion plan by identifying the Net Present Value of the Revenue Requirements (PVRR) over the study period.

As can be expected, since there is no need for new capacity in the long-run, there is little capacity expansion in the short-run. The table below shows this result – no new additions are expected in the five-year action plan. Beyond the five-year action plan, GRE includes in the Additions column a new hydro purchase in 2020 (Year 6) and hard-wires 600 MW of wind in 2026-2029 to comply with the Minnesota RES.

In the Subtractions column, GRE assumes it will terminate a long-term obligation to purchase power from Dairyland Power Cooperative's Genoa Unit 3 (Genoa 3), a coal-fired plant in Wisconsin. The expiration of that purchase power agreement will remove 119 MW from GRE's system.[11]

[11] On June 1, 2015, GRE and Dairyland completed the transaction that terminates GRE's obligation to purchase 50 percent of the capacity and energy output of Genoa 3. As part of the transaction, GRE has agreed to a capacity purchase of MISO Zonal Resource Credits (ZRCs) from DPC in a quantity roughly equivalent to 50 percent of the accredited capacity of Genoa 3 for a period of four years following the completion of the transaction. The purchase of ZRCs became effective on June 1, 2015, and will terminate on May 31, 2019. No DPC or Genoa 3 energy is associated with the ZRC purchase.

Additions							**Subtractions**				
	New Solar	New Wind	New CT	New CC	New Hydro		Genoa 3	Spirit-wood	Stanto n	Coal Creek 1	Coal Creek 2
2015											
2016							**(119)**				
2017											
2018											
2019											
2020					200						
2021											
2022											
2023											
2024											
2025											
2026		100									
2027		100									
2028		200									
2029		200									

While GRE proposed limited capacity expansion in the short-run, both C&I and EI assert that the termination of its Genoa 3 obligation in 2016 does not go far enough in addressing its capacity surplus throughout the forecast period, and the IRP does not meet the requirement that "the utility must discuss plans to reduce existing resources through sales, leases, deratings, or retirements" in Minn. R. 7843.0400, subp. 2. Both C&I and EI criticism is focused primarily on GRE's Spiritwood Station.

According to C&I, GRE failed to disclose in its IRP that GRE created a customer for Spiritwood's steam for the express purpose of generating a need for Spiritwood to be operational. C&I explained that while GRE's 2014 IRP describes that Spiritwood is now operational and is selling its steam to the Dakota Spirit AgEnergy Facility (Dakota Spirit), the ownership structure of Dakota Spirit reveals that GRE is a majority owner of the company that owns Dakota Spirit. As described by C&I, "GRE is using a facility that it created and owns to provide an after-the-fact justification for the necessity of the nearly $500 million Spiritwood facility" and "GRE's artificial generation of demand for Spiritwood cannot be used to justify GRE's costly building and operation of the unneeded Spiritwood facility." C&I concluded that GRE's IRP fails to establish the legitimate need for Spiritwood's operation, and does not consider the retirement or sales of energy to a legitimate, third-party purchaser that is not financed from GRE's ratepayers.[12] Moreover, C&I stated that GRE had refused to provide any information on whether Spiritwood or Dakota Spirit is profitable, and therefore C&I assumed that GRE is operating Spiritwood at a loss and these losses are passed on to ratepayers.[13]

[12] Al-Corn Clean Fuel and Heartland Corn Products Initial Comments, pp. 7-9
[13] Al-Corn Clean Fuel and Heartland Corn Products Reply Comments, p. 6.

In the absence of a response from GRE to its Information Request, EI made its own calculations of Spiritwood's revenue based on MISO's locational marginal pricing (LMP) data for Spiritwood and concluded that GRE is likely operating Spiritwood at a loss. EI stated further that GRE's modeling demonstrates that retirement of Stanton Station is cost effective. Therefore, EI concluded "given the fact that Spiritwood is not profitable, retiring excess capacity on GRE's system, such as Stanton Station, should be a priority to reign in these risky business practices."[14]

GRE responded to EI's calculation of Spiritwood's profitability by stating that "[t]he profitability of Spiritwood Station has no bearing on whether the modeling recommends retirement of Stanton Station—a completely different facility," in addition to being highly critical of the methodology EI used to conclude Spiritwood is not profitable.[15] GRE did not respond to C&I and EI's assertions with statements or facts that indicate that Spiritwood is, in fact, not operating at a loss.

In its March 2, 2015 Comments, the Department expressed concern with GRE's cost assumptions for the potential hydro resource available in its capacity expansion modeling. The Department was concerned that the range of cost assumptions considered by GRE is both too narrow and too low.[16]

Despite these shortcomings, the Department recommended that the Commission approve GRE's modeling, with the understanding that the potential hydro addition has been shown to be cost effective only under the narrow parameters modeled by GRE and whether the hydro is cost-effective will depend on the final terms of the agreement GRE is able to negotiate with Manitoba Hydro. The Department stated its recommendation was based on the fact that GRE's analysis indicates that it will be able to reliably serve its load with or without the hydro resource.[17]

<u>Staff Comment</u>

A. Zonal Resource Credits

Each year, every LSE in the MISO footprint must meet its PRM requirement with zonal resource credits (ZRCs), which are megawatt units of planning resources that have been converted into a credit eligible to be offered into MISO's voluntary planning resource auction. When an LSE meets its PRM requirement, it has demonstrated that it has acquired enough capacity (or ZRCs) to meet its coincident peak demand forecast, plus the PRM, and minus netted planning resources. Planning resources that clear in the Auction are obligated to provide capacity for the entire

[14] Environmental Intervenors Reply Comments, pp. 1-5. See also companion briefing papers on EI's Motion to Compel for more background information on this issue.
[15] GRE Supplemental Comments
[16] Department Comments, pp. 22-23. In response to the Department's concern, GRE stated that it had not identified the type of hydro product it may end up purchasing, and therefore it was not able to provide an estimate of its costs. GRE stated that the hydro product could be energy only, a diversity exchange agreement, a combined capacity and energy product, or any combination of these. GRE Reply Comments, p. 10.
[17] Department Supplemental Comments, p. 2.

Planning Year. (MISO Planning Years begin on June 1st and run through May 31st of the following year.)

What a modeling exercise does not completely capture is the value of GRE's excess capacity, or rather the value of GRE's ZRCs. This is not to say excess capacity is always prudent – GRE makes the case that its current position is beneficial to its members, while EI and the C&I Customers strongly contend that it isn't. Staff raises this issue to point out that it is difficult, if not impossible, to accurately model the value maximization of a utility's ZRCs—which can be sold in forms of one-year or multi-year agreements—against a scenario such as retiring a coal-unit. Staff certainly agrees with the parties that GRE's current and future resource plan(s) should continue to evaluate retirement options for its coal-fired fleet, but these questions should be appropriately framed. And it is most accurate to frame GRE's five-year action plan in the context of: value maximization for surplus ZRCs, the operational value of its existing coal-fired plants as baseload resource, and remaining economic life for existing assets.

GRE is currently engaged in several transactions as sellers of one-year and multi-year capacity contracts, and GRE plans to continue to pursue other opportunities as a prospective seller. For example, as the Commission is aware, GRE bid a capacity-only proposal into Xcel's recent competitive resource acquisition process for the 2016, 2017, and 2018 MISO Planning Years. While that particular bid was not ultimately selected, the point is that there is a marketplace for ZRCs in which the Cooperative is actively participating, and GRE's capacity expansion modeling cannot completely reflect this strategy. Thus, it may appear that, because of the outputs of the modeling runs, the Cooperative's five-year action plan is essentially nothing, but the reality is that GRE's action plan is to maintain its existing baseload while shopping its significant amount of surplus ZRCs. While this may be an unusual action plan, depending on the circumstances, it may not inherently be an unreasonable one.

B. Replacement Capacity & Energy

All of GRE's resources are dispatched by MISO in its energy market, so the operation of GRE's resources will be the same whether or not GRE sells its ZRCs. Similarly, GRE's emission levels will be the same whether or not GRE sells its ZRCs. Thus, the dominant way for GRE to make significant step-downs to its emissions profile would be to remove its coal-fired resources from its system.

In addition to the economic modeling, there are operational aspects to consider, as well as risk, when discussing replacement capacity and energy. The table below, from GRE's reply comments, shows historic actual annual production for Stanton Station, and the original modeled annual production. If Stanton Station is dispatched consistent with recent history, it can be expected to generate approximately 1,200-1,400 GWh per year. According to GRE, removing this facility from its system would result in GRE's members purchasing far more energy from the wholesale market, which GRE maintains is an unreasonably risky alternative.

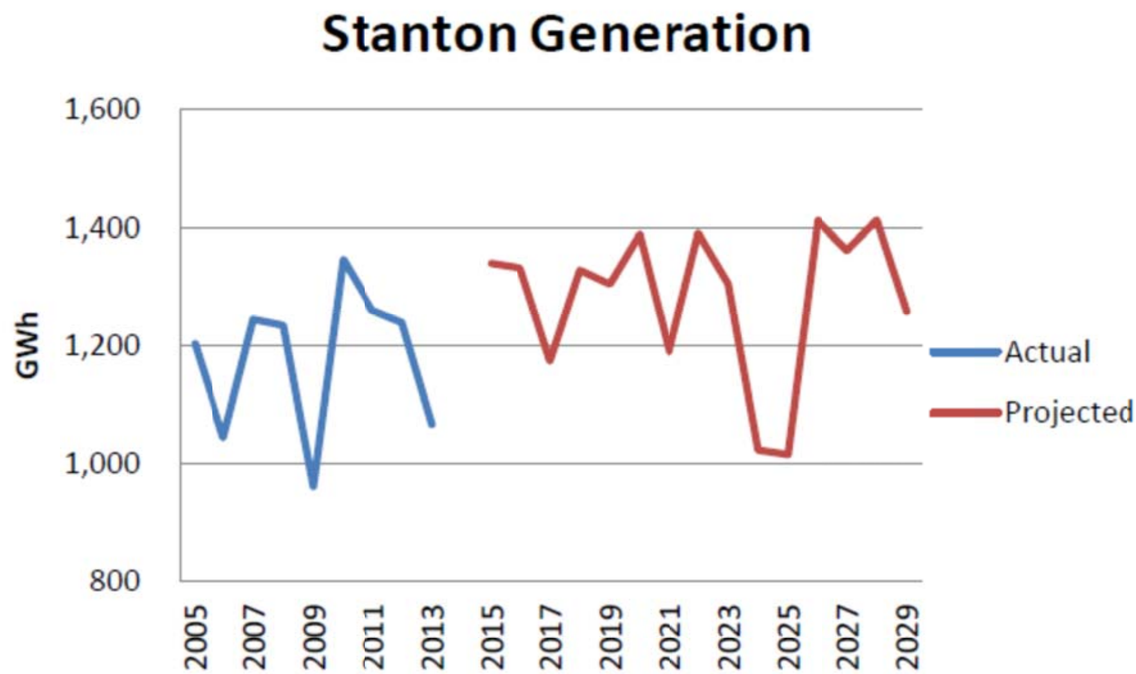

Figure 1: Comparison of Stanton Station actual and original modeled production.

According to the Department's analysis:

> 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.[18]

In staff's view, replacing Stanton Station with another thermal unit is not a probable course of action, and doing so would seemingly be strongly opposed by other parties to this proceeding, particularly the C&I customers. Since GRE has terminated its obligation to purchase energy from Genoa 3, the Department's analysis suggests retiring Stanton as well is not a robust result. Thus, staff agrees with the Department's recommendation that GRE should instead evaluate cost-effective retirement of its coal plants in its next resource plan.

C. Rate Impacts of Retirement

An important aspect of any existing facility retirement analysis must be the rate impacts of doing so. The C&I Customers emphasize that GRE has increased its wholesale rates by 52 percent between 2006 and 2012, and wholesale rates make up approximately 75 percent of a member's

[18] Department comments, p. 24.

retail rates.[19] To balance rate impacts with a long-term transition away from coal-fired energy, GRE began accelerating depreciation at Coal Creek Station and Stanton Station in 2013, and GRE says these coal facilities are now scheduled to be fully depreciated by 2028.

If either Coal Creek or Stanton Station would be retired sooner, presumably the capital depreciation schedule would be brought forward to match the modeled retirement date, and there could be additional decommissioning costs to remove and remediate the site(s) as well. This would likely create further rate increases for GRE's members, and there is little support for the conclusion that replacement energy would be priced low enough to offset these added costs. In future IRPs, staff suggests GRE include in its coal plant retirement analysis a discussion of how various retirement dates would affect rate recovery for potentially retired units.

D. The Role of Environmental Policy

According to EI, "GRE's Preferred Plan will not comply with Minnesota's greenhouse gas reduction targets in Minn. Stat. § 216H.02 or reduce emissions in line with the 30% reduction targeted by the Environmental Protection Agency's Proposed Clean Power Plan to regulate existing emission sources under section 111(d) of the Clean Air Act."[20]

To the latter policy issue, the Clean Power Plan, it is important to note that all of GRE's coal-fired assets are located in North Dakota, which, for state implementation plan purposes, means that decision-making with regard to those affected units will largely be under the jurisdiction of North Dakota regulators. However, Clean Power Plan compliance will likely become (and perhaps already is) a permanent fixture of resource planning, and since IRPs are multi-jurisdictional in nature, decisions in other states are relevant for Minnesota as well. Furthermore, it is statutory requirement that resource plans comply with all applicable state and federal law.

GRE does not have any units in Minnesota which are affected by Section 111(d) of the Clean Air Act. Also, based on GRE's preliminary analysis of the Clean Power Plan, its IRP would comply with 111(d) as initially proposed. (GRE provides a preliminary analysis of Clean Power Plan compliance on pages 40-46 of its Petition.) Since the Rule was finalized on August 3, 2015, EPA has set a more stringent emissions reduction target for the State of North Dakota and a less stringent target for the State of Minnesota. The implications of the revised state-level targets, as well as other changes to the finalized form of the Rule, largely remain to be seen, although they could be significant. Thus, it is probably premature to contemplate Clean Power Plan compliance for this IRP, and other matters such as jurisdiction, timing, and the fact that GRE is not rate-regulated by the Commission are more relevant in this context. But, it can be expected that the effects of the Clean Power Plan will be cemented into GRE's multi-jurisdiction planning efforts moving forward.

Staff does agree with EI's first argument that one of resource planning's primary functions is to implement Minnesota's state energy policies in a least-cost manner, which includes the statutory directive to ensure that utilities make reasonable progress toward Minnesota's greenhouse gas

[19] C&I Customers comments, p. 6.
[20] EI comments, p. 2.

reduction goals. To this end, staff believes it would be most useful to house into one plan the finalized Clean Power Plan, the Minnesota greenhouse gas reduction goal, and the Commission's CO_2 and environmental externality values, such that they are not competing policy goals. Thus, the most appropriate path forward, in staff's view, is to adopt the Department's recommendation to continue to evaluate cost-effective retirement of its coal plants in subsequent planning processes, and to continue to apply the Commission-approved externality costs and CO_2 regulatory costs in its reference case while doing so. Such an endeavor would take a more holistic approach to environmental policy without unnecessary duplication.

Demand-Side Management

In its September 26, 2013 Order, *In the Matter of GRE's 2012 Integrated Resource Plan*, the Commission included the following Order Points with respect to GRE's energy efficiency and conservation program offerings:

- Order Point 2.A. GRE should continue striving to save energy equal to 1.5 percent of its annual retail energy sales in a cost-effective manner; and
- Order Point 3.A. GRE should include an evaluation of potential conservation measures that it does not include in it its Conservation Improvement Program portfolio – including, at a minimum, all the measures identified in the Electric Power Research Institute study that pass the Total Resource Cost test.

Appendix D of GRE's IRP is a Conservation Plan Scenario Analysis prepared by LADCO Services, LLC (the LADCO Study). From Appendix D-7 of the LADCO study:

> Four scenarios are developed for this analysis. These scenarios are defined as:
>
> *Base Case Scenario*
> This scenario is identical to the 2015 conservation portion of the CIP. Costs are escalated by the Consumer Price Index (CPI) each year, beginning in 2016. The measures from the 2015 CIP are used as proxies for measures to be implemented in the future. While the actual measures may vary, the overall spending level and savings level are expected to be representative of the scenario.
>
> *1.25% Scenario*
> With the exception of the Income Eligible project, incentives are increased 50% from the Base scenario. Administrative costs increase 165%. Participation increases 35.6138%. The Income Eligible project does not change from the Base Case. Savings represent 1.25% of sales.
>
> *1.5% Scenario*
> With the exception of the Income Eligible project, incentives increase 125%. Administrative costs increase 250%. Participation increases 63.4692%. The Income Eligible project does not change from the Base. Savings represent 1.50% of sales.

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

Benefit/cost results for each scenario, with and without CO_2 (as an internalized externality cost), are shown and discussed in Appendix D-11. Below, staff presents only the "No CO_2 Case," since the results are similar with or without CO_2. (Staff highlights the B/C Ratio in Yellow.)

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

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

From page Appendix D-11 of the LADCO Study:

The benefit/cost results indicate the following:

- The Societal, Utility, and Participant tests indicate that the overall program portfolio is cost effective for all scenarios. This suggests that the effects of varying budget, incentives, and participants do not cause a plan to become not cost-effective;
- For the Utility test, the program portfolio becomes less cost effective when going from the Base to the 2% scenario. This suggests diminishing returns when

increasing the incentive and administrative cost levels. Participation rates do not increase in proportion to the funding and incentive levels;

- In the Societal test, there is also a decrease in the cost effectiveness as the amount of spending increases. This is caused by the increasing administrative costs;
- The Ratepayer Impact Measure test is not cost effective for any scenario. The present value of the revenue loss and program costs is greater than the present value of the energy and capacity savings;
- The larger incentives in the 1.25%, 1.5% and 2% scenarios increase the cost-effectiveness of the Participant test.

Staff Comment

According to the LADCO Study, "Resource plans are generally evaluated using the Utility test, which is also known as the Revenue Requirements test." In other words, the Study's results suggest that higher levels of energy savings pass the test which is generally used for resource planning. However, the LADCO Study further states, "While aggressive conservation may lower revenue requirements and look attractive from that perspective, it does not address the rate impacts caused by the additional conservation. In theory, the Ratepayer Impact test does address the rate impact. Unfortunately it does so in a manner that is not intuitively obvious."[21]

GRE, the Department, and EI consider the LADCO study, and by extension the cost-effectiveness of the four DSM scenarios, in very different ways. There appears to be consensus between the Department and GRE that the 1.5 percent and 2.0 percent DSM scenarios are cost prohibitive, although the methods to arrive at these conclusions were different.

The Department recommends the Commission approve a 1.25 percent savings level, based on its own analysis using an approach of comparing the average cost per kWh of savings in each of the four scenarios to the overall average system cost. According to the Department, "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 DSM levels to evaluate the impact of each scenario on its system costs."[22]

In its reply comments, GRE agrees that the 1.5 and 2.0 percent scenarios are cost-prohibitive, but GRE disagrees with the Department's approach of using a utility's average system cost as a threshold cost for energy efficiency programs. GRE then references the LADCO Study as a basis. GRE responds, "The LADCO benefit/cost analysis concluded that the Ratepayer Impact Measure test is not cost effective in any scenario, meaning that costs outweigh benefits with any level of increased conservation."[23]

EI questions the value of LADCO Study altogether, disputing several of the Study's assumptions and describing it as a "flawed analysis." Staff does not repeat all of EI's repudiations of the

[21] Appendix D-3 of GRE's IRP.
[22] Department comments, p. 5.
[23] GRE reply comments, p. 8.

LADCO Study here, but one of their critiques is that the Study uses unreasonable assumptions for incentive levels and administrative costs.

While not making any comments with regard to the reasonableness of these assumptions, staff shows in the table below the increases in incentive and administrative costs compared to the baseline 1.0 percent savings. This illustrates that these changes could perhaps play a significant role in the disparity between the Ratepayer Impact Measure and the other tests:

Scenario	Incentive Costs, % Change from Base	Admin. Costs, % Change from Base	B/C Ratio, Utility Cost Test	B/C Ratio, Rate Impact Test
1.0% (base)	-	-	6.57	0.74
1.25%	+50%	+165%	4.23	0.73
1.5%	+125%	+250%	3.33	0.72
2.0%	+234%	+400%	2.57	0.70

As shown in the table, there is a diminishing B/C (benefit-cost) ratio with each higher increment of savings; however, each scenario easily passes the utility cost (or revenue requirement) test. Interestingly, the B/C ratio for the Rate Impact test does not fluctuate significantly, despite major ramp-ups to incentive and administrative costs. Instead, the B/C ratio appears to be nearly unaffected by the level of DSM among the four scenarios in the Ratepayer Impact Measure test.

The Ratepayer Impact Measure test is only one of four tests used to measure DSM in the LADCO Study. However, GRE does not appear to give any weight to the other three tests, including the Utility cost test. This is likely due to the significant spending required to achieve higher levels of DSM in the early years of those scenarios. Staff provides in the table below assumed project costs by scenario in 2016, replicated from page 7 of the Study (Appendix D-9):

Project Costs by Scenario in 2016

Base case (1%)	1.25%	1.5%	2.0%
$13,053,099	$28,026,676	$42,951,141	$74,006,790

As shown in the table above, the total 2016 project costs associated with each increment of energy savings are significant—almost doubling in total dollars with each increment—likely due to the initial ramp-ups in incentives and administrative costs. However, according to EI, there is reason to question the extent of the assumed 2016 incentive and administrative costs. Moreover, according to the Study, the B/C ratios are positive in the long-run.

Minn. Stat. § 216B.2401 (Energy Savings Policy Goal) reads, in part:

> 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.

Additionally, Minn. Rule 7843, Subp. 3 (Commission Review of Resource Plan) states that, among the five factors to consider, resource plans must be evaluated on their ability to "keep the customers' **bills** and the utility's rates as low as practicable" and to "minimize adverse socioeconomic effects and adverse effects on the environment."[24] (Emphasis added.) While the LADCO study provides a rate impact, it does not assess customers' total bill impact, which could be positive or negative depending on the customers' usage behavior. With regard to socioeconomic and environmental impact, the Study suggests that higher levels of DSM pass the societal and utility cost tests, even without assuming CO_2 externality costs.

An underlying issue here may be less about which scenario is preferable than about how to model, what to assume, and how to evaluate various levels of DSM. This issue is common in resource planning. To the Department's point, should DSM costs be included and modeled within a utility's capacity expansion plan? To GRE's point, should DSM, as a resource option, be included up to a point where it raises member rates? To EI's point, should a benefit-cost test apply to the utility system as a whole and not only to the Ratepayer Impact Measure? And because utility DSM programs are so specific to its service territory, how can the Commission determine whether the assumptions used in the analysis, specifically incentive and administrative costs, are reasonable ones to make?

There are several competing methodologies applied to the DSM analysis used to evaluate GRE's resource plan. Setting aside the question of the validity of the LADCO Study itself, what is clear is the statutory directive in Minn. Stat. § 216B.2401 that "cost-effective energy savings are preferred over all other energy resources." What is less clear is what "cost-effective" means. In staff's view, when including the findings of the LADCO Study, along with the Department's analysis and recommendations, staff believes there is sufficient evidence for GRE to procure higher levels of energy savings. However, to the concerns of GRE and its members who filed comments,[25] there also appears to be significantly higher program costs associated with each 0.25 percent higher DSM increment, which coincide with a questionable benefit. To balance these concerns, staff believes it would be reasonable for the Commission to advise GRE to increase its energy savings levels to, at least, a level equivalent with the 1.25 percent energy saving scenario.

Moving forward, staff acknowledges that the several different, competing methodologies with which to model DSM and interpret its "cost-effectiveness" impedes the Commission's ability to make DSM decisions within resource planning. Thus, DSM analysis could improve by proceeding as part of an ongoing, multi-stakeholder conversation. Such a path forward can, and probably should, proceed without a Commission order to do so. This said, the Commission can certainly direct parties and stakeholder to proceed however it wishes.

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[24] Minn. Rule 7843, Subp. 3.

[25] Several of GRE's members filed comments urging the Commission not to increase the annual energy conservation goal. These members include: Benco Electric Cooperative, Dakota Electric Association, East Central Energy, Itasca-Mantrap, Lake Country Power, Lake Region Electric Cooperative, Meeker Cooperative Light & Power Association, Redwood Electric, South Central Electric Association, and Wright-Hennepin.

The options before the Commission in the decision options section include:[26]

1. making no modification to GRE's DSM plan; or
2. adopting the Department's recommendation to increase GRE's annual energy savings to 137,546 MWh (the energy savings levels associated with GRE's 1.25 percent energy saving scenario).

Solar Energy

GRE provides on pages 11-12 of its IRP Petition a narrative discussion of its members' solar initiatives, as well as of its own PV array at GRE's headquarters in Maple Grove.

The C&I Customers contend that GRE's solar array is an example of GRE's wasteful spending decisions.

EI believes GRE unreasonably overestimated solar costs in developing its modeling assumptions.

Staff notes that because GRE is not subject to the Minnesota Solar Energy Standard, it is not required to include in its IRP a plan for procuring solar energy. GRE did include solar PV as a resource option for System Optimizer to select, but no solar was chosen as part of the expansion plan. This is not a surprising modeling result because the fact that GRE has surplus capacity means solar PV would have needed to be a deterministic addition.

Distributed Generation

Minn. Stat. §216B.2426 states that the Commission shall ensure that opportunities for the installation of distributed generation (DG) are considered "in any proceeding under section 216B.2422…"

Commission staff issued Information Requests (IRs) #1-7 to GRE to inquire about GRE's role in assisting its members in making DG available to retail customers. Staff has not attached the responses here but they are filed in the record and staff does not have any concerns with the responses.[27]

GRE's 28 member distribution cooperatives are also required to file annual reports with information, including the rates they charge to Qualifying Facilities (QFs). [28] Staff was unable to confirm that all 28 members filed their annual reports for 2015. While it is not GRE's obligation to file the reports, staff is aware that other entities, such as MRES, send a reminder to their members in advance of the reports being due. If the Commission is interested, the Commission may wish to ask GRE if it is to do the same. Staff has not included this as a decision option.

[26] The Environmental Intervenors did not make an overt recommendation for DSM. Instead, their recommendation is for the Commission to deny GRE's plan. However, EI's comments suggest they support the 2 percent scenario.
[27] See GRE's December 29, 2014 submission in eDockets, responding to PUC IRs #1-7.
[28] See Dockets 15-9 and 15-10 for this year's reports.

Deadline for GRE's Next Resource Plan

Finally, the Commission often includes in its IRP Order a variance of the "July 1st of every other year" filing date requirement defined in Minn. Rule 7843, Subpart 2. When setting the deadline for a utility's next IRP filing, the Commission's past practice is to take under consideration several different factors: the parties' recommendations, balancing the span of time between IRPs and the flexibility of the ordering requirements, and if there is an issue the Commission would like to see more fully developed in the next IRP.

In Otter Tail's 2014 IRP, the Commission required Otter Tail to stay on the two-year rule, to allow the parties and the Commission to revisit the issue of greenhouse-gas reduction in a relatively short period of time, with the benefit of greater clarity on Clean Air Act regulations. (Otter Tail filed for a six-month extension to its resource plan filing date, and this item is on the agenda for the same hearing as GRE's instant resource plan.)

In Interstate Power & Light's 2014 IRP, the Commission set the deadline for IPL's next resource plan filing exactly two years after the matter came before the Commission.

Similarly, in Minnesota Power's 2013 IRP, the Commission set MP's next resource plan deadline approximately two years after the matter came before the Commission. This was because of the Commission's requirement for MP to submit a proposal to procure 200 MW of intermediate capacity in the 2015-2017 timeframe. Since the Commission requested an actual proposal, the parties and the Commission agreed to more time.

For GRE, staying on the two-rule would set its next IRP filing date at November 1, 2016. Staff takes no position on whether this is the most appropriate date or not. However, staff does believe that, given GRE's excess capacity and energy-rich generation position, it would be reasonable to vary the rule to allow GRE more time for a new filing, especially if the Commission advises modifications to GRE's supply- or demand-side action plan.[29] In the event of a modified energy savings level, for example, a new resource plan filing in fourteen months may not be able to yield materially different results with regard to higher DSM achievements.

Also, since GRE's EPA Clean Power Plan compliance is, as it appears at this time, likely to come from its North Dakota regulators, GRE *might* be able to give more specific long-term plans for its North Dakota coal assets if a filing is made in early-2017. Thus, staff includes as an alternative decision option a May 1, 2017 filing date, which is a six-month extension to the two-year rule. Staff invites parties to discuss at the hearing their preferences for GRE's next resource plan filing.

[29] Staff also notes that in the most recent other cooperative resource plan filing addressed by the Commission, the cooperative was given an extension to July 1, 2019, conditioned upon status updates in 2017 about DSM, DG, and federal environmental regulations. See ORDER ACCEPTING RESOURCE PLAN AND SETTING FUTURE FILING REQUIREMENTS, Docket No. ET6, ET6132/RP-14-526, Issued July 22, 2015 (Minnkota Power Cooperative).

Decision Options

A. Should the Commission accept or reject Great River Energy's 2014-2029 Integrated Resource Plan?

1. Accept Great River Energy's resource plan (GRE, Department, staff).

2. Reject GRE's resource plan (Al-Corn Clean Fuel and Heartland Corn Products (C&I), Environmental Intervenors).

3. Neither accept nor reject GRE's plan due to missing information and analytical deficiencies. However, find that GRE's filing is useful for resource planning purposes and for maintaining reliability over at least the next several years in the Cooperative's system. *(Staff note: this language is similar to the language the Commission adopted for GRE's 2005 resource plan.)*

B. What modifications, if any, should the Commission advise Great River Energy to make to its Resource Plan?

1. Load and Capacity

   a. GRE should discuss plans to reduce existing resources by considering the retirement of Spiritwood or the sales of energy from Spiritwood to a legitimate, third-party purchaser other than Dakota Spirit; or

   b. GRE should discuss plans to reduce existing resources by considering the retirement of Stanton Station

2. Demand Side Management

   a. Make no modification to GRE's DSM plan; or

   b. Adopt the Department's recommendation to increase GRE's annual energy savings to 137,546 MWh (the energy savings levels associated with GRE's 1.25 percent energy saving scenario) (*Department, staff*);

3. Additional Recommendations for Future Resource Plans, (DOC Recommendations)

   a. GRE should continue to use an appropriate capacity expansion model (*Department*);

   b. GRE should continue to apply the Commission-approved externality costs and CO_2 regulatory costs in its reference case (*Department*);

c. GRE should continue to evaluate cost-effective retirement of its coal plants (*Department*);

   i. GRE should include in its coal plant retirement analysis the rate impact of various retirement dates, as well as a discussion of any decommissioning and site remediation costs (*Staff*)

d. GRE should use a broader range of cost assumptions for potential hydro resources (*Department*); and

e. GRE should evaluate cases in which market sales are prohibited (or priced at zero) (*Department*).

C. When should Great River Energy file its next Resource Plan?

1. GRE should file its next resource plan on or before November 1, 2016;

2. GRE should file its next resource plan on or before May 1, 2017; or

3. Some other date, if requested