August 8, 2023

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

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. ET2/RP-22-75

Dear Mr. Seuffert:

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

In the Matter of Great River Energy's 2023-2037 Integrated Resource Plan

The Petition was filed by Great River Energy's David Saggau, Manager, President and CEO on March 31, 2023.

The Department recommends **certain improvements to the planning process**. The Department's team of Donald Hirasuna, Sachin Shah, and Danielle Winner is available to answer any questions the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ Steve Rakow
Analyst Coordinator

SR/ar
Attachment

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. ET2/RP-22-75

I. INTRODUCTION

A. DOCKET HISTORY

On January 21, 2022, Great River Energy (GRE or the Cooperative) filed a request to extend the deadline for GRE's next integrated resource plan (IRP) from April 1, 2022, to April 1, 2023

On April 12, 2022, the Minnesota Public Utilities Commission (Commission) issued an order granting GRE's request.

On October 3, 2022, GRE filed an interim update as required by the Commission's April 12, 2022, Order. The interim update discussed:

- GRE's historic and forecasted CO_2 emissions;
- historic and near future changes to GRE's power supply portfolio;
- GRE's "triple bottom line" decision-making approach;
- recent changes to GRE's forecast of demand and energy requirements;
- external stakeholder engagement process; and
- the status of GRE's transmission system.

On March 31, 2023, GRE filed the Cooperative's *2023-2037 Integrated Resource Plan* (Petition).

On April 5, 2023, the Commission issued its *Notice of Comment Period* (Notice) stating that the following topics are open for comment:

- Should the Commission accept GRE's 2023-2037 Integrated Resource Plan?
- What issues should the Commission consider for GRE's next IRP?
- When should GRE file its next IRP?
- Are there other issues or concerns related to this matter?

Below are the comments of the Minnesota Department of Commerce (Department) regarding the Petition and the topics specified in the Notice.

B. BACKGROUND ON GRE

According to the Petition, GRE provides electricity to approximately 1.7 million people through its 27 member-owner cooperatives and customers. Through the member-owners, GRE serves two-thirds of Minnesota geographically. As a cooperative, GRE's members are both owners and customers. Cooperatives provide services to their members on a not-for-profit basis. Cooperatives are governed by a board of directors elected from the membership which sets policies and procedures that are implemented by the cooperative's management.

GRE provides services to two types of members: All-Requirements (AR) members and Fixed Obligation (Fixed) members. The 19 AR members purchase all their power and energy requirements from GRE, subject to limited exceptions. The eight Fixed members buy a fixed portion of their power and energy requirements from GRE and purchase all supplemental requirements from an alternative supplier.

GRE's portfolio of generation resources as of 2021 is shown in Figures 2 and 3 of the Petition:

- Coal—32 percent of capacity and 57 percent of energy;
- Wind—18 percent of capacity and 25 percent of energy;
- Natural Gas—40 percent of capacity and 3 percent of energy;
- Spot Market—no capacity and 15 percent of energy;
- Hydro—6 percent of capacity and minimal energy; and
- Fuel Oil—5 percent of capacity and minimal energy.

C. RESOURCE NEED AND ACTION PLAN

In GRE's base case, without any new actions, a summer capacity deficit first appears in 2031. Capacity deficits during winter and spring first appear in 2032. This situation is illustrated in Figure 9 of the Petition.

In addition to continuing to operate the existing generating units, GRE proposed the following five-year (2023 to 2027) action plan:

- Convert Cambridge Unit 2 to dual-fuel operation;
- Add 1.5 MW Form Energy multi-day storage pilot project at Cambridge Station.;
- Begin pumped hydro energy storage feasibility study;
- Add up to 866 MW of wind PPAs;
- Increase Renewable Member Resource Option from 5% to 10%;
- Continue registration of demand response resources within the Midcontinent Independent System Operator (MISO) capacity market; and
- Invest in MISO's Long-Range Transmission Plan.

The capacity additions under GRE's preferred plan that are beyond the five-year action plan begin in 2030, involve solar, storage, and wind resources, and are triggered by the capacity deficits.

II. DEPARTMENT ANALYSIS

A. APPLICABLE STATUTES AND RULES

The Commission's IRP process is governed by Minnesota Statutes § 216B.2422 which states in part:

> Subd. 2. Resource plan filing and approval. (a) A utility shall file a resource plan with the Commission periodically in accordance with rules adopted by the Commission. The Commission shall approve, reject, or modify the plan of a public utility, as defined in section 216B.02, Subdivision 4, consistent with the public interest.
>
> …
>
> (c) As a part of its resource plan filing, a utility shall include the least cost plan for meeting 50 and 75 percent of all energy needs from both new and refurbished generating facilities through a combination of conservation and renewable energy resources.
>
> subd. 2a. Historical data and advance forecast. Each utility required to file a resource plan under this section shall include in the filing all applicable annual information required by section 216C.17, subdivision 2, and the rules adopted under that section. To the extent that a utility complies with this subdivision, it is not required to file annual advance forecasts with the department under section 216C.17, subdivision 2.
>
> …
>
> subd. 2c. Long-range emission reduction planning. Each utility required to file a resource plan under subdivision 2 shall include in the filing a narrative identifying and describing the costs, opportunities, and technical barriers to the utility continuing to make progress on its system toward achieving the state greenhouse gas emission reduction goals established in section 216H.02, subdivision 1, and the technologies, alternatives, and steps the utility is considering to address those opportunities and barriers.
>
> Subd. 3. Environmental costs. (a) The Commission shall, to the extent practicable, quantify and establish a range of environmental costs associated with each method of electricity generation. A utility shall use the values established by the Commission in conjunction with other

external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the Commission, including resource plan and certificate of need proceedings.

(b) The commission shall provisionally adopt and apply the draft cost of greenhouse gas emissions valuations presented in the United States Environmental Protection Agency's EPA External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances, released in September 2022, including the time horizon, global estimates of damages, and the full range of discount rates from 2.5 to 1.5 percent, with two percent as the central estimate. The commission shall adopt the estimates contained in the final version of the external review draft report when it becomes available.

…

Subd. 4. Preference for renewable energy facility. The Commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the Commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless the utility has demonstrated that a renewable energy facility is not in the public interest. When making the public interest determination, the Commission must consider:

1) 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;
2) impacts on local and regional grid reliability;
3) utility and ratepayer impacts resulting from the intermittent nature of renewable energy facilities, including but not limited to the costs of purchasing wholesale electricity in the market and the costs of providing ancillary services; and
4) utility and ratepayer impacts resulting from reduced exposure to fuel price volatility, changes in transmission costs, portfolio diversification, and environmental compliance costs.

Subd. 4a. Preference for local job creation. As part of a resource plan filing, a utility must report on associated local job impacts and the steps the utility and the utility's energy suppliers and contractors are taking to maximize the availability of construction employment opportunities for local workers. The commission must consider local job impacts and give preference to proposals that maximize the creation of construction

> employment opportunities for local workers, consistent with the public interest, when evaluating any utility proposal that involves the selection or construction of facilities used to generate or deliver energy to serve the utility's customers, including but not limited to an integrated resource plan, a certificate of need, a power purchase agreement, or commission approval of a new or refurbished electric generation facility. The commission must, to the maximum extent possible, prioritize the hiring of workers from communities hosting retiring electric generation facilities, including workers previously employed at the retiring facilities.
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> Subd. 4b. Preference for domestic content. The commission may give preference in resource selection to projects utilizing energy technologies produced domestically by entities who received an advanced manufacturing tax credit for those technologies under section 45X of the Internal Revenue Code, as allowed under the federal Inflation Reduction Act of 2022, Public Law 117-169.

The Commission's IRP process is also governed by Minnesota Rules 7843. The decision criteria are provided in Minnesota Rules 7843.0500 which states, in part:

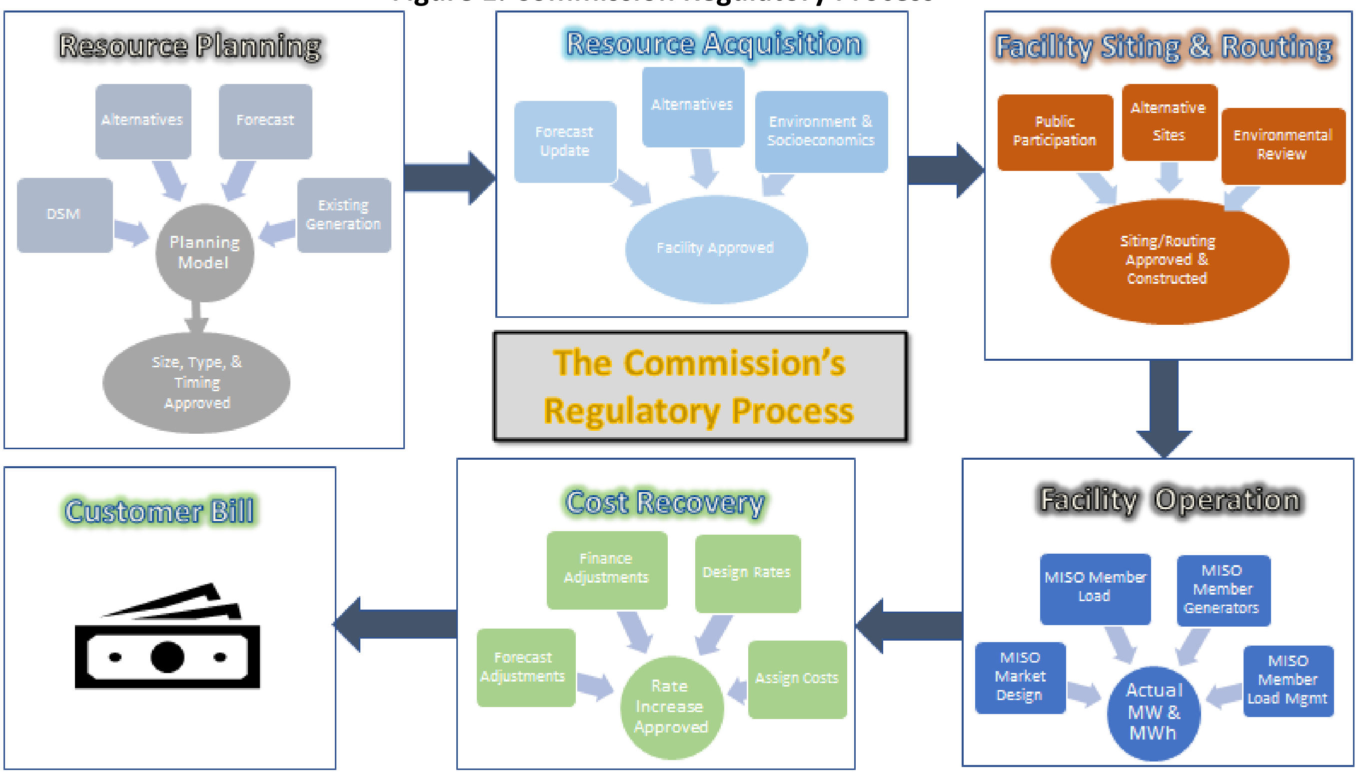
> Subp. 3. Factors to consider. In issuing its findings of fact and conclusions, the Commission shall consider the characteristics of the available resource options and of the proposed plan as a whole. Resource options and resource plans must be evaluated on their ability to:
>
> A. maintain or improve the adequacy and reliability of utility service;
> B. keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;
> C. minimize adverse socioeconomic effects and adverse effects upon the environment;
> 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.

In summary, the Commission evaluates a proposed IRP based upon its ability to create a reliable, low cost, low environmental and socioeconomic impact system that manages risk. In weighing these factors, the Commission considers the statutory preference for renewable energy facilities. As indicated in the Petition's Appendix A, there are numerous other statutes, rules, and Commission orders which impact the decision in this IRP proceeding.

B. OVERVIEW OF DEPARTMENT ANALYSIS

An IRP is the first step in the Commission's overall regulatory process. The Commission's regulatory process as applied to generation units is illustrated in Figure 1 below. The Department notes that, for GRE, the cost recovery step in the Commission's standard process does not apply. In addition, the Commission's order in IRPs for cooperatives such as GRE is advisory in nature.

Figure 1: Commission Regulatory Process



For GRE's IRP, the Department:

- briefly reviewed the Cooperative's 15-year energy and demand forecast process;
- reviewed the Company's EnCompass modeling;
- reviewed the status of GRE's compliance with various Minnesota Statutory goals such as the Carbon free, renewable energy, and solar energy standards;
- reviewed the impact of potential environmental regulations; and
- reviewed the status of GRE's energy efficiency and demand response programs.

Given the advisory nature of GRE's IRP, the Department did not attempt to create an alternative preferred plan.

Lastly, the Department notes that under Minnesota Rules 7843.0600, Subp. 2 the consequences of the Commission's order in this proceeding are clear:

> the findings of fact and conclusions from the Commission's decision in a resource plan proceeding may be officially noticed or introduced into evidence in related Commission proceedings … In those proceedings, the Commission's resource plan decision constitutes prima facie evidence of the facts stated in the decision.

C. IIJA AND IRA IMPACTS

Regarding uncertainty in EnCompass modeling, between the time a utility locks in the final structure of its modeling files and the time comments are due, many market, governmental, and organizational changes will have occurred that ideally would be incorporated. In recognition of this fact the Department reviews EnCompass inputs for such changes and makes changes to inputs and re-runs EnCompass or recommends that the utility consider potential changes in the future.

In recent years major pieces of federal policy have introduced new uncertainty into modeling, particularly the Infrastructure Investment and Jobs Act (IIJA) and the Inflation Reduction Act (IRA). In this case GRE has incorporated at some aspects of the IIJA and the IRA into its modeling inputs. In fact, GRE has incorporated in the Petition a sensitivity that accounts for a very specific IRA/IIJA functions. The sensitivity assumes that rather than pursuing a PPA for wind (which has been GRE's standard practice) GRE would self-build wind and still be able to take advantage of the Production Tax Credit.

In the end, there are numerous factors that are changing at the same time. The modeling inputs need to account for all of the factors and, for key factors, a range of values should be considered. As discussed further below, while the IRA and IIJA are designed to reduce the cost of renewable resources, the most recent data the Department is aware of shows that recent solar and wind prices are much higher than expected.[1] This highlights the importance of considering all of the factors influencing model inputs and not just some of the factors.

D. FORECAST

The Department conducted its review of GRE's IRP with the understanding that the Commission's Order is advisory in this proceeding.

Nineteen of GRE's twenty-eight-member distribution cooperatives are All-Requirements (AR) members. GRE is responsible to meet the requirements of all the AR members' future energy and capacity needs. Connexus, a previous AR member, has now transitioned to be a long-term customer of GRE. Lastly, GRE is also responsible for meeting the fixed amounts of capacity and energy needs of the

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[1] See Figure 2 on page 7 of Northern States Power Company, doing business as Xcel Energy's May 5, 2023 petition in Docket No. E002/M-22-403.

remaining eight Fixed Requirements (FR) 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 FR 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. Six of the eight FR members have elected to reduce their collective energy by approximately 92 percent or 829,789 MWh and their demand by approximately 48 percent or 75 MW.

Previously GRE used an econometric model to forecast the energy requirements of its AR members, and then combined the FR 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 IRP, the Cooperative has switched to a statistically-adjusted, end-use (SAE) model. Generally, in an SAE model, the model variables based on end-use concepts (for example, water heater, refrigerator, heating systems, and cooling systems) are used to forecast sales through an estimated regression model. For example, average customer use or sales is defined as a function of cooling requirements (XCool), heating requirements (XHeat), and other use (XOther). The model variables may incorporate both structural factors such as the average air conditioning saturation and efficiency, and factors that may impact utilization of the stock of equipment including the weather conditions, and for example the electric prices, number of people per household, and average household income. The model is estimated using linear regression that relates actual monthly sales or average use to the constructed end-use variables. The resulting model coefficients (b0, b1, and b2) are used to generate average use and sales forecasts based on projected economic activity, normal weather, and end-use intensity trends. This, for example, is known as a SAE model.

Given that GRE does not need any new resources and the surplus that it expects through 2030, in this IRP the Department neither reviewed the technical details of GRE's forecast nor tested the Company's current statistical models. The Department also did not develop an alternative forecast. The use of SAE models increases model complexity, and are very time, resource, and data intensive. In general, the SAE models are trying to account for changes in efficiency levels, conservation et cetera separately from other factors such as weather and the economy. In order to objectively evaluate the SAE models, the Department would need to, for example, evaluate appliance saturation rates and usages and determine the penetration and participation rates. The costs of doing such intensive work involving SAE models appear to outweigh any benefits compared to the company's former methodology of only using econometric models. In the Department's view, use of econometric models can be a simple process and any historical changes in the efficiency levels, conservation, et cetera will be embedded in the company's historical sales and in the context of resource planning these issues (for example, accounting for changes in efficiency levels) can be mitigated by using ranges of forecasting in capacity expansion models. As a result, GRE's forecasts in this proceeding should not be used in any future certificate of need (CN) proceedings.

E. MODELING AND EXPANSION PLAN

1. Introduction

In this proceeding Great River Energy used EnCompass as a Capacity Expansion Model (CEM), the purpose of which was to determine the least cost expansion plan. An expansion plan, also called a capacity expansion plan, comprises all new generation-related projects begun during the planning period, including built or acquired assets and power purchase agreements. [2] The critical information to be determined about an expansion plan is the size, type, and timing of new projects. Note that while "type" often corresponds with the specific technology being used, it more specifically refers to the function of a particular resource.

In resource planning generally, the Commission's role is to determine if a utility's proposed plan is expected to yield a reliable, low cost, low impact system that manages risk. While the Commission's role in GRE's resource plan is only advisory, the use of the model in this proceeding will also aid the Commission in future GRE certificate of need proceedings.

The Department's role is to evaluate the plan for each of these criteria and recommend modifications as necessary. Environmental impacts are built into the Commission's externality and future carbon cost values, meaning that any modeling runs incorporating these values will automatically be evaluating those criteria. Reliability is also built in through reserve requirements, firm capacity ratings, and related inputs. Thus, all EnCompass runs have same minimum reliability. Further, since EnCompass's function is to minimize cost, the criteria for low-cost is included throughout all modeling results. Thus, when evaluating modeling outputs, the Department's focus is on understanding why the model is producing the results it does, and the risks inherent in those results.

The Department typically evaluates a utility's plan through the following steps:

1. Validating the utility's model results through a "matching" process.
2. Evaluating the utility's base case inputs for reasonableness.
3. Creating a new Department base case, if necessary.
4. Rerunning the utility's scenarios under the new base case assumptions.
5. Running any further scenarios of interest.
6. Evaluating outputs.

Since GRE's resource plan is advisory in nature, the Department did not create a new base or conduct any further studies beyond the utility's results. Instead, the Department focused on evaluating the inputs and outputs of GRE's model and will here provide feedback on ways to improve its model.

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[2] Asset retirements and contract endings also occur during the planning period; however, neither occurrence is actually considered part of the capacity expansion plan. This is because while the model chooses the optimal expansion units, retirements and contract endings must be input into EnCompass. EnCompass therefore "optimizes" project additions but does not optimize retirements. Also note that "generation-related" projects can include energy storage, load management, energy efficiency, and potentially transmission projects necessary for interconnection.

2. *Matching*

First, the Department obtained from GRE the inputs and outputs needed to validate GRE's results, a process the Department often refers to as "matching." The primary purpose of this step is to ensure that the Department is using the same input data as GRE. Theoretically, the Department should be able to load GRE's files into EnCompass, run the model without making any changes, and produce the same results shown in GRE's output files.[3] When running GRE's inputs in EnCompass, if the outputs generated by the Department are different than the outputs GRE sent to the Department, the Department would be unable to rely on GRE's inputs and outputs until the source of any discrepancy is determined and corrected. Once the Department is able to produce the same outputs as GRE reported, using the same inputs that GRE used, the Department has confidence that the databases are sound and can be used to evaluate GRE's resource plan. If parties use different data than the utility, all subsequent party analysis has the potential to be meaningless. Therefore, the matching process is a critical component of analyzing a utility's model.

The Department's first step in this matching process was to recreate GRE's outputs from the Cooperative's input files. GRE provided input files for one database. The Cooperative's database contained one base case and 27 "sensitivity" runs that examined different variables. Each of the Cooperative's scenarios contained one unique dataset to be validated, with the exception of the "Spiritwood Station (SWS) Retirement" sensitivity, which contained two datasets. Therefore, to fully match the Cooperative's results, the Department needed to validate 32 datasets.

The Department compared GRE's net present value (NPV) plan cost to the Department's NPV plan cost for the same run.[4] The following table shows an example of GRE's versus the Department's results for the "New DSM Added" sensitivity.

Table 1: Example of a GRE Run Successfully Matched by the Department

Party	Run Name	MIP	Objective Function (PV $000)	Percent Difference
GRE	New DSM Added	10	2,296,073.47	
DOC	DMatch New DSM Added	10	2,295,801.09	
				0.01%

Table 1 shows that when the Department ran the "New DSM Added" scenario exactly as GRE had submitted it, the Department's plan costs were approximately $272,380 less than GRE's results, in present value terms. The percent difference between GRE's and the Department's results was 0.01 percent. This is an acceptable level of variation because the percentage falls within the MIP stop basis of 10, which permits for a variation of 0.10 percent. For the results to be unacceptably different, the

[3] Given the complexity of utility databases and the repetitive nature of downloading and saving modeling spreadsheets, it is relatively easy for modelers to have mismatched inputs and outputs.

[4] This is found in the Plan Costs report. The NPV plan cost value from the Plan Costs report is the same as the objective function in the System Annual report. Note that the matching process uses different values in production cost runs, but GRE did not submit any production cost runs in this filing.

percent difference between a GRE run and a Department run would need to be greater than 0.10 percent. Therefore, the Department would consider this scenario and component datasets to be "matched."

The Department was able to match most of GRE's model results except for two specific sensitivities: CT Partial Commitment and Wind Self-Build.[5] The Department's full matching results can be found in Attachment 3. The Department has asked for follow-up information from the utility to determine the source of the errors and is not concerned with these results at this time. However, the Department would caution parties that until the Department is able to match the results of those two contingencies, GRE's results of the CT Partial Commitment Run and Wind Self-Build should be considered unvalidated.

The Department recommends that in future filings GRE should ensure that the appropriate input files correspond to reported exports.

3. *GRE's Model*

i. GRE's Inputs

a. Overview

GRE's model includes all known and projected data about GRE's current system. Broadly, this includes energy and capacity sales forecasts, demand-side management, GRE-owned generation and bilateral contracts (provided in Appendix B to the utility's filing), information about the MISO market, and information about projected fuels, system constraints, and emissions pertinent to GRE's resources.

GRE's model comprised one base case and 27 sensitivity scenarios, for a total of 28 scenarios. For each of the 28 scenarios, GRE ran a zonal market simulation using marginal dispatch costs, set to run from 2023-2037. All runs were set to solve to a typical day of the week using a MIP Stop Basis of 10. GRE's runs all used capacity derations with no maintenance shifts were scheduled. GRE's runs all provided an extension period of 15 years past 2037.

Each scenario was set to fully optimize projects during the planning period, meaning that each of the 28 scenarios could theoretically produce a unique capacity expansion plan. However, certain sensitivities used "locked-in" or "forced" projects, meaning that any optimized projects were occurring above and beyond the locked-in projects.

b. Potential Resources

GRE allowed the model to choose from six potential resources for its capacity expansion needs: new demand response, new energy efficiency, a new combustion turbine, a new lithium-ion battery, new solar, and new wind. In one sensitivity ("Self-Build Wind"), the Cooperative also permitted the model to select owned rather than contracted wind. The Cooperative provides in-depth characteristics of

[5] These sensitivities, along with the others examined by GRE, are described in more detail in the section "GRE's Model" below.

each resource in Appendix H to its filing. The Department provides summary information about these resources in the following table.

Table 2: GRE Allowed its Model to Choose from Six Potential Resources, with an Additional Seventh Resource in the "Self-Build Wind"

Potential Resource	Maximum Capacity (MW)	Firm Capacity (% of Maximum Capacity)	Constraints
New Demand Response	Escalates from 3 to 33 MW from 2028 through 2037	Winter 64%; Spring 68%; Summer 100%; Fall 68%	Appears to only be available to add in 2028, impacts occur annually thereafter
New Energy Efficiency	Escalates from 2 to 20 MW from 2028 through 2037		Appears to only be available to add in 2028, impacts occur annually thereafter
New Gas Combustion Turbine (owned)	200 MW	Winter 100%; Spring 84%; Summer 80%; Fall 84%	None permitted to be added prior to 2027; Beginning in 2027, a maximum of four units may be added
New Lithium Ion Battery (owned)	200 MW	95% all seasons	None permitted to be added prior to 2027; Beginning in 2027, a maximum of four units may be added
New Solar PPA	200 MW	Winter 6%; Spring 15%; Summer 45%; Fall 25%	None permitted to be added prior to 2027; Beginning in 2027, a maximum of four units may be added
New Wind PPA	200 MW	Winter 40%; Spring 23%; Summer 18%; Fall 23%	None permitted to be added prior to 2027; Beginning in 2027, a maximum of four units may be added
New Wind (owned)	200 MW	Winter 40%; Spring 23%; Summer 18%; Fall 23%	Only available to be added in the "Self-Build Wind" sensitivity; No units permitted to be added prior to 2027; Beginning in 2027, a maximum of four units may be added

c. Base Case

Some critical features of GRE's base case inputs include:

- GRE's base case uses 50/50 energy and demand sales forecasts for both its All-requirements Members and Fixed Members;[6]
- GRE's does not use separate forecasts for either demand-side management or electric vehicles—therefore, these can be considered embedded into the forecasts;
- GRE's base case includes numerous utility-owned resources, only one of which (the coal portion of Spiritwood Station) is scheduled to cease operations during the planning period—after 2024, Spiritwood will switch entirely to natural gas operations;
- GRE's base case includes numerous bilateral contracts for both energy and capacity, some of which expire during the planning period;
- Purchases from the MISO energy spot market are permitted, but may not exceed 25% of the energy needed to serve GRE's load in any given hour;
- Sales into the MISO energy market are not permitted;
- GRE includes MISO's working seasonal accredited capacity values for each resource; and
- GRE includes MISO's seasonal reserve margins minimums.

d. Sensitivities

GRE's 27 sensitivities were built off of the inputs of its base case. One of these sensitivities—the Cooperative's "Preferred Plan"—reflects GRE's Five-Year Action Plan and "locks in" the Cooperative's planned projects. All 26 other sensitivity scenarios focus on changing one variable from the base case.[7] Table 8 of GRE's filing shows most of the sensitivities by variable, accompanied by brief descriptions. The Department provides similar information in the following table, with a slightly different setup.

Table 3: Each of GRE's 27 Sensitivities by Variable Changed, Compared to Base Case Assumptions

Sensitivity Name	Sensitivity Description	Base Case Description	Variable
Preferred Plan	• Locks in 200 MW Battery in 2030, no batteries permitted to be added before 2030; • Locks in 200 MW Solar PPA in 2031, no solar permitted to be added before 2031;	• Does not lock in any potential resources; • No battery, gas CT, solar, or wind permitted to be added prior to 2027; up to four units of each permitted to be added beginning in 2027	

[6] This means that the forecast is projected to be too low 50% of the time and too high 50% of the time.
[7] The Department notes that changing "one variable" should not always be taken literally, as sometimes to focus on the impact of one variable, more than one variable might need to be changed in the actual model.

	• Locks in 400 MW Wind PPA in 2032, no wind permitted to be added before 2032 or after 2032; • No demand response, energy efficiency, or gas combustion turbines permitted to be added at any time		
High Externality/High Regulatory	• High values for criteria pollutants; • CO_2 regulatory costs of \$25/ton starting in 2025 and escalating thereafter	No externality or carbon costs	Externality and Future Carbon Costs
High Externality/High Environmental	• High values for criteria pollutants; • CO_2 environmental costs of \$52.91/ton starting in 2023 and escalating thereafter	No externality or carbon costs	
Low Externality/Low Environmental	• Low values for criteria pollutants; • CO_2 environmental costs of \$11.32/ton starting in 2023 and escalating thereafter	No externality or carbon costs	
Reference (All High Externality Costs)	• High values for criteria pollutants; • CO_2 environmental costs of \$52.91/ton and escalating thereafter; • CO_2 regulatory costs of \$25/ton starting in 2025 and escalating thereafter	No externality or carbon costs	
Low Externality/Low Regulatory	• Low values for criteria pollutants; • CO_2 regulatory costs of \$5/ton starting in 2025 and escalating thereafter	No externality or carbon costs	

High Load Forecast	• For both capacity and energy forecasts: 90% of the time the actual demand will be lower than the forecast, 10% of the time the actual demand will be above forecast	• Uses a 50/50 capacity and energy forecasts: 50% of the time the actual demand will be lower than the forecast, 50% of the time the actual demand will be higher than the forecast	Sales Forecast
Low Load Forecast	For both capacity and energy forecasts: 10% of the time the actual demand will be lower than the forecast, 90% of the time the actual demand will be above forecast	Uses a 50/50 capacity and energy forecasts: 50% of the time the actual demand will be lower than the forecast, 50% of the time the actual demand will be higher than the forecast	
Extreme Summer and Winter	Extreme weather forecast for two summers and winters	Uses a 50/50 capacity and energy forecasts: 50% of the time the actual demand will be lower than the forecast, 50% of the time the actual demand will be higher than the forecast	
High Prices	Monthly values increased 100% for following prices: • MN Hub Off-Peak Price • MN Hub On-Peak Price • Ventura Price	Uses monthly values for MN Hub Cost Curve and Ventura Forward Curve developed by ACES Transmission Group	Market and Marginal Fuel (Natural Gas) Prices
Low Prices	Monthly values increased 100% for following prices: • MN Hub Off-Peak Price • MN Hub On-Peak Price • Ventura Price	Uses monthly values for MN Hub Cost Curve and Ventura Forward Curve developed by ACES Transmission Group	
No Market Purchases	No spot market energy purchases allowed	Purchases from the MISO energy spot market are permitted, but may not exceed 25% of the energy needed to serve GRE's load in any given hour	Market Purchases

High Market Purchases	Purchases from the MISO energy spot market are permitted, but may not exceed 75% of the energy needed to serve GRE's load in any given hour	Purchases from the MISO energy spot market are permitted, but may not exceed 25% of the energy needed to serve GRE's load in any given hour	
Seasonal Planning Reserve Margin Change	PRM set to be higher in summer and lower in other seasons: • Winter: 20.5% • Spring: 19.5% • Summer: 12.4% • Fall: 9.9%	Uses MISO's existing seasonal PRM: • Winter: 25.5% • Spring: 24.5% • Summer: 7.4% • Fall: 14.9%	MISO Reserve Margin
SWS Retirement	Retirement date set at 12/31/2030; capital expenditures and book life changed	No planned retirement, fixed costs depreciated until retirement	Spiritwood Station
CT Partial Commit	• Scenario Commitment option set to "Partial Commit," startup costs and max energy changed; • Note: purpose of sensitivity is to include start charges for CTs without using a capacity factor constraint	• Scenario Commitment option set to "No Commit"; • Note: "No Commit" option used for base case and all other sensitivities	Combustion Turbine and CT Dispatch
Low Wind Price	New Wind PPA energy price set at $35/MWh	New Wind PPA energy price set at $45/MWh	Wind
Self-Build Wind with PTC	Uses National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB) "Moderate" Price with declining cost curve and production tax credit	New Wind PPA energy price set at $45/MWh	
Low Solar	• New Solar PPA energy price set at $40/MWh; • New Wind PPA energy price set at $45/MWh	• New Solar PPA energy price set at $50/MWh; • New Wind PPA energy price set at $45/MWh	Solar

Low Renewables	• New Wind PPA energy price set at $35/MWh; • New Solar PPA energy price set at $40/MWh	• New Solar PPA energy price set at $50/MWh; • New Wind PPA energy price set at $45/MWh	Solar and Wind
No Battery Offered	No Batteries permitted to be added at any time	Up to four 200 MW batteries permitted to be added at any time beginning in 2027	Batteries
Storage Costs Flat	Uses NREL ATB "Moderate" price with a flat cost	Uses NREL ATB "Moderate" price with declining cost curve for a 4-hour lithium-ion battery	
Registered LMR Increase	• Maximum Capacity of registered LMRs set to approximately four times base case value; • Seasonal firm capacity percentage for registered LMRs lower all year (47-57%) and peaking in winter (100%)	• Maximum Capacity of registered LMRs set to current planned amount; • Seasonal firm capacity percentage for registered LMRs higher all year (64-68%) and peaking in summer (100%)	Demand Response
DSM Program Additions	• New energy efficiency forced in in 2028 (escalates from 2 to 20 MW maximum capacity from 2028 through 2037); • New demand response forced in in 2028 (escalates from 3 to 22 MW maximum capacity from 2028 through 2037)	Demand response and energy efficiency allowed to be selected in 2028 as new resources but not forced in (forecast includes embedded DSM)	Energy Efficiency and Demand Response
Lower Regional Resource Assessment (RRA) Accreditation	Uses future RRA estimates for firm capacity accreditations: • Battery: Winter 82%; Spring 76%; Summer 82%; Fall 68% • Solar: Winter 1%; Spring 17%; Summer 23%; Fall 18% • Wind: Winter 37%; Spring 12%; Summer 18%; Fall 21%	Uses MISO Loss of Load Expectation (LOLE) Effective Load Carrying Capability (ELCC) estimates for firm capacity accreditations: • Battery: 95% all seasons • Solar: Winter 6%; Spring 15%; Summer 45%; Fall 25% • Wind: Winter 40%; Spring 23%; Summer 18%; Fall 23%	Seasonal Accredited Capacities

Extend Wind Contracts	• Elm Creek PPA extends past planning period; • Prairie Star PPA extends past planning period	• Elm Creek PPA ends during planning period; • Prairie Star PPA ends during planning period	Existing Contracts
MH Contract Ends	• Manitoba Hydro Purchase Contract ends during planning period	• Manitoba Hydro Purchase Contract extends past planning period	

On page 34 of its filing, GRE states:

> GRE modeled a number of sensitivity scenarios using the variable ranges defined in Tables 7 and 8 above. These scenarios were used to evaluate the robustness of the Preferred Plan and identify drivers of different resource additions. Table 9 summarizes the change in resource type and amount (additions or subtractions) by modeled scenario as compared to the base case capacity expansion, which aligns with the Preferred Plan.

The Department notes that, unless we set up GRE's database incorrectly, the sensitivities test the robustness of the base case, not the robustness of the preferred plan. While the base case and preferred plan do share the same size and type of expansion plan units, they do not share the same timing.

e. Commission's Externalities and Cost of Carbon Futures

Five of GRE's sensitivities incorporated the Commission's externality and future carbon cost figures approved the Commission's September 30, 2020 Order in Docket Nos. E999/CI-07-1199 and E999/DI-19-406. The following table, taken from that Order, shows the Commission's five required treatments of carbon costs.[8]

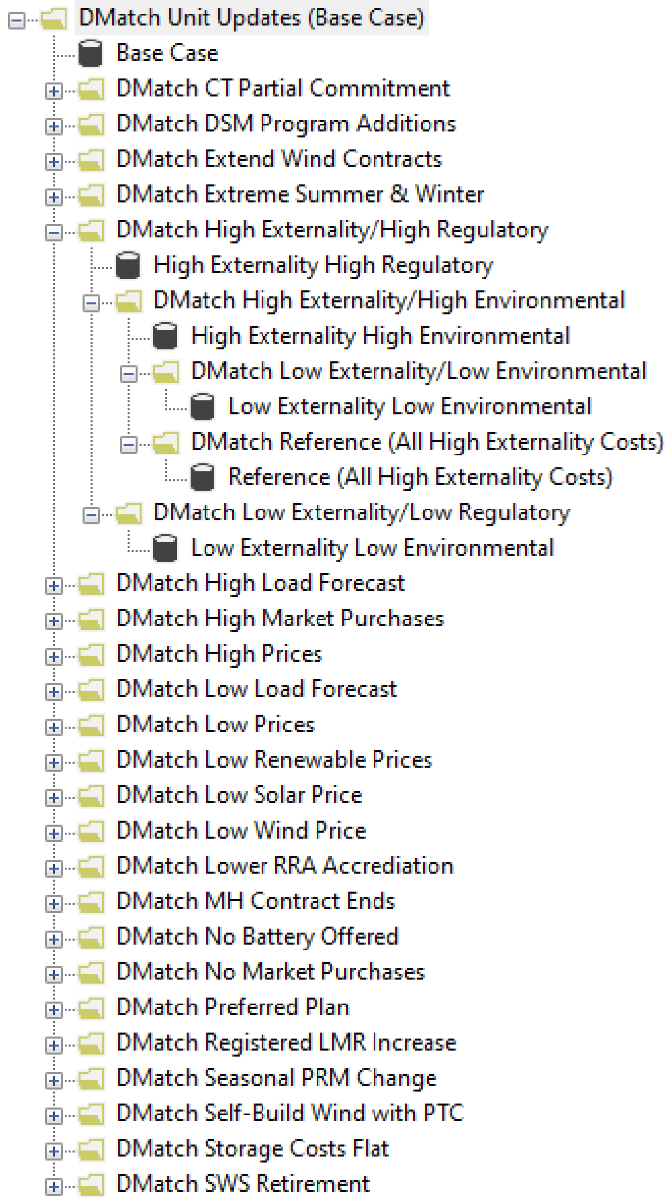
[8] The specific externality and carbon values used by GRE can be found in Tables 6 and 7 of GRE's filing.

Table 4: Commission Required Externality and Carbon Cost Future Scenarios

Scenarios:	Before 2025		2025 and Thereafter	
	Environmental Cost	Regulatory Cost	Environmental Cost	Regulatory Cost
Low Environmental Cost	Low End	-	Low End	-
High Environmental Cost	High End	-	High End	-
Low Environmental/ Regulatory Costs	Low End	-	-	$5/Ton
High Environmental/ Regulatory Costs	High End	-	-	$25/Ton
Reference Case Scenario	Middle to High End	-	Middle to High End	Middle to High End

GRE's model chose all "High End" values for the Commission's Reference Case scenario. Critically, however, GRE's Reference Case is not applied to any other runs. No other sensitivities run by GRE—including the Base Case and the Preferred Plan—incorporate any externality costs or carbon costs. The below screen shot of GRE's EnCompass scenario tree structure shows how the Base Case is the "parent" scenario of all other runs. This means that all other runs use the externality and carbon cost assumptions of the Base Case, and these assumptions are zero in the Base Case. Instead, GRE introduces a set of "child" externality and carbon cost futures that overwrite the assumptions of the Base Case but do not apply to any other scenarios.

Figure 2: Screenshot of GRE's EnCompass Scenario Sensitivity Tree



For a brief overview of externalities and carbon costs, see Attachment 4 to these Comments.

ii. GRE's Outputs

a. Expansion Plan

GRE reports the capacity additions relative to the base case for each sensitivity in Table 9 of its Comments. The Department shows similar information in the following table but uses total number of units added for each sensitivity.

Table 5: Total Number of Capacity Expansion Plan Resources Chosen in Each of GRE's Sensitivities

Sensitivity Scenario Name	Battery (200 MW)	DR (3 to 33 MW)	EE (2 to 20 MW)	Gas CT (200 MW)	Solar (200 MW)	Wind (200 MW)
Base	1				1	2
Preferred Plan	1*				1*	2*
Low Externality/Low Regulatory	1				1	2
Low Externality/Low Environmental	1				1	2
Reference (All High Externality Costs)	1				1	2
High Externality/High Regulatory	1				1	2
High Externality/High Environmental	1				1	2
High Load Forecast	1				1	2
Low Load Forecast	1				1	1
Extreme Summer and Winter	2				2	2
High Market and Marginal Fuel (NG) Prices	3				2	3
Low Market and Marginal Fuel (NG) Prices	2				2	1
No Market Purchases	2			1	2	2
High Market Purchases	1	1*			1	1
Seasonal PRM Change	1				2	1
SWS Retirement 2030	2				1	2
Low Solar PPA Price	1				3	1
Low Wind PPA Prices	1				1	2
Low Renewable PPA Prices	1				1	2
Storage Costs Flat	1				1	2
No Battery Storage Offered				1	2	1
Self-Build Wind with PTC	2					3**
Forced DSM Program Additions	1	1*	1*		1	2
Registered LMRs Increase	1				2	1
Lower RRA Accreditation	1				1	2
CT Partial Commit	1				3	1
Extend Wind Contracts	1				1	1
MH Contract Ends	2				1	2
Rounded Averages	1	0	0	0	1	2

The Department observes the following about GRE's outputs:

- Natural Gas Combustion Turbines were selected in only two sensitivities: No Market Purchases and No Battery Offered;
- Unless forced into the model, Demand Response and Energy Efficiency were never selected;
- Batteries were selected in every contingency in which a battery was permitted to be selected, with one battery selection being the most common among the sensitivities run; and
- Solar and Wind PPAs were both chosen in each contingency except for Self-Build Wind, with wind being chosen at a slightly higher frequency than solar in the sensitivities examined.

In sum, the Department observes that the rounded averages calculated from the Cooperative's reported additions match the Cooperative's base case and preferred plan.

The Department notes that while the utility's base case and expansion plan add the same size and type of units, the timing is different for each. The following charts show the difference in timing of project capacity additions (in firm MW) between the Cooperative's base case and preferred plans, plotted against the Cooperative's total system reserve margin.

Chart 1: GRE's Optimized Base Case Incremental Additions (Firm MW) by System Reserve Margin

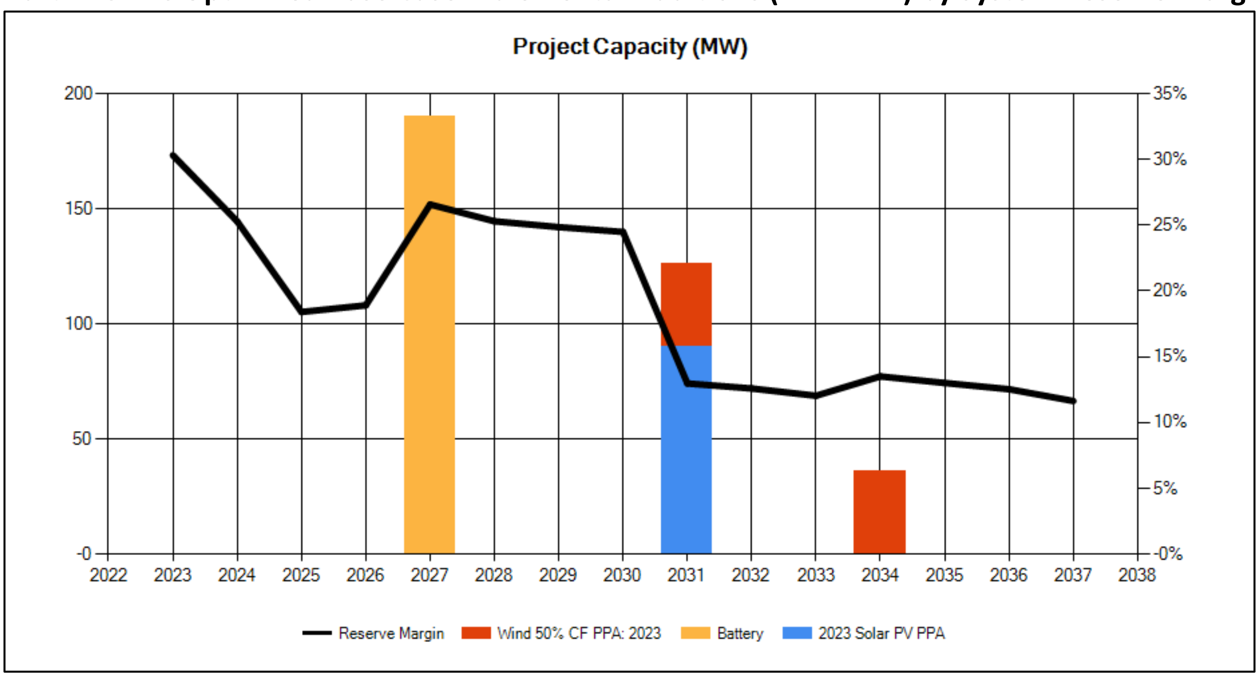
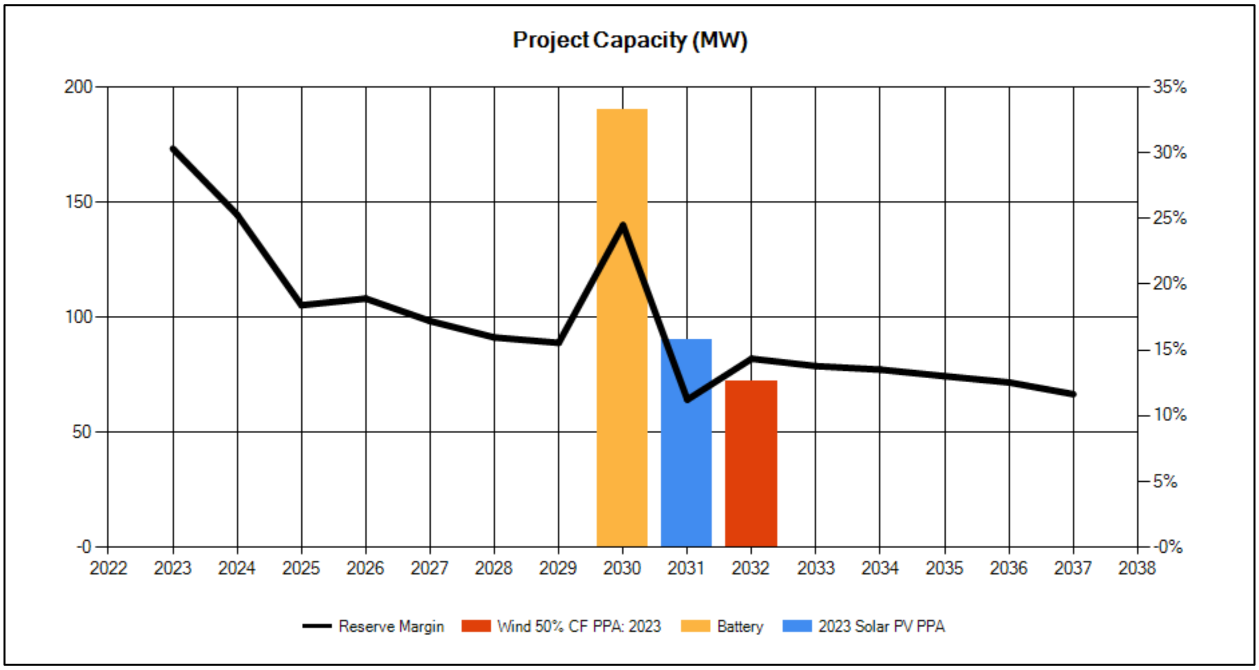


Chart 2: GRE's Locked-In Preferred Plan Incremental Additions (Firm MW) by System Reserve Margin



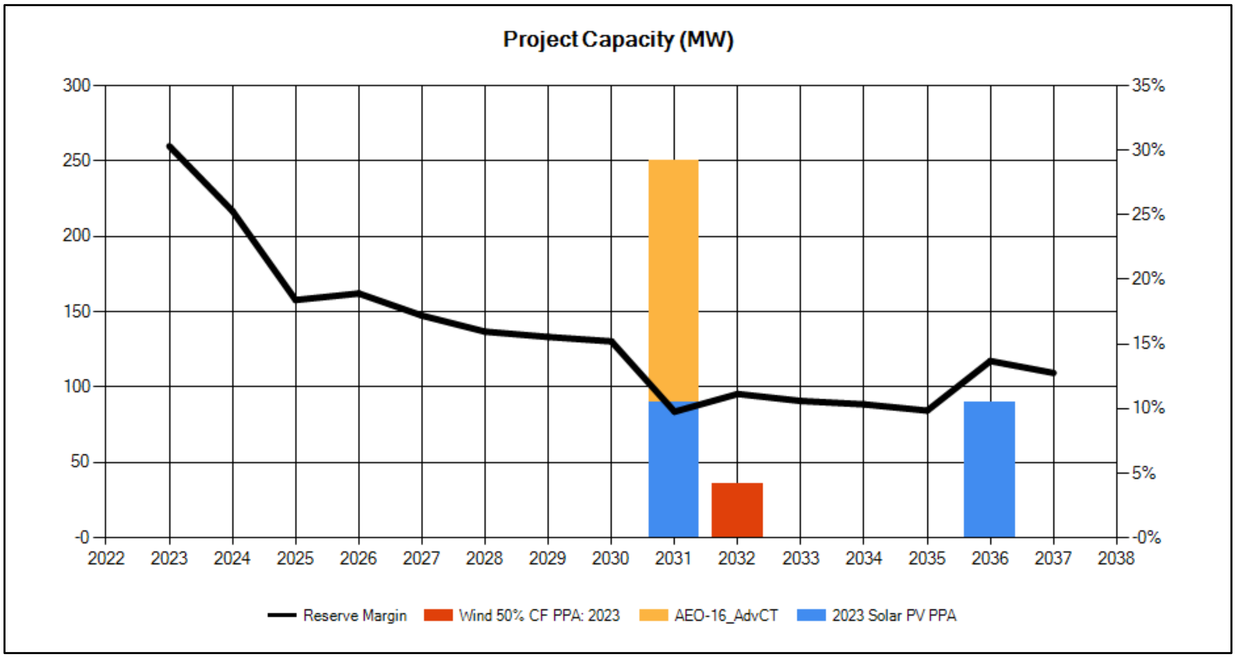
The difference in the above capacity additions show us that under GRE's base case conditions, the model adds a battery in 2027, solar in 2031, and wind in both 2031 and 2034. In GRE's preferred scenario, GRE has locked in the size, type, and timing of the resources, putting the battery in 2030, solar in 2031, and wind in 2032.

The reserve margin line helps determine the degree to which the system is overbuilt (has a margin above the minimum requirement) in terms of meeting MISO's minimum reserve margin thresholds). In the above charts, we can see that in 2023, the reserve margin is higher, indicating that the system will have less of a problem meeting minimum reserve margins if unforeseen events happen (and thus skews towards being overbuilt), whereas in 2037, the reserve margin is lower, indicating GRE has fewer surplus reserves or "cushion." In turn, this indicates GRE's system could have more of a problem meeting minimum reserve margins if unexpected things happen (and thus skew towards being underbuilt). The 2031 and 2034 adds appear to be needed, in part, to meet minimum reserves. It does not look like the 2027 add is needed to meet minimum reserves. Note that there is no risk of not meeting the reserve margins in the model, as these are input floors that cannot be violated; rather, the concern is the real-life implications. Simply put, this chart tells us that GRE's system becomes slightly riskier over the course of the planning period. This is not an unusual result as excess reserves have a cost and the model will attempt to minimize those costs.

The Department notes that all sensitives except the "No Battery Storage Offered" add a battery in 2027. It appears that the reason this is such a heavily favored selection has to do with the 200 MW reduction in capacity from Rainbow Energy occurring in 2025. Since the Cooperative's Preferred Plan holds off on the battery addition until 2030, the Department is slightly concerned about the period of time between 2027 and 2030 in which GRE could be more heavily exposed to market prices.

However, this concern is tempered by the fact that given that, as noted above, the 2027 battery selection does not appear to be needed to meet the minimum reserve margin. Further, while the Cooperative's "No Battery Storage Offered" sensitivity adds a CT in lieu of a battery, this addition does not occur until 2031; this reinforces the idea that the 2027 addition is not critical for reliability purposes. The following chart shows the expansion plan for this sensitivity (note that the yellow capacity addition is a CT instead of a battery).

Chart 3: GRE's "No Battery Storage Offered" Sensitivity Incremental Additions (Firm MW) by System Reserve Margin



Given these results, the Department is cautiously optimistic about the Cooperative's plan to delay the battery capacity addition until 2030.

b. Costs

GRE reported the Present Value Revenue Requirement (PVRR) for most sensitivities and the PVSC (Present Value Societal Cost) for the Commission's required externality and carbon cost future sensitivities. This information can be seen in Figure 12 of GRE's filing. GRE reports its least-cost sensitivity to be the "Self-Build Wind with PTC" sensitivity at approximately $5 billion and the highest-cost sensitivity to be the "High Market and Natural Gas Prices" sensitivity at approximately $6.4 billion. GRE identifies its Base Case and Preferred Plan to cost approximately $5.3 billion.

The Department notes that while PVRR reflects all system costs associated with a particular plan, it is not the value that EnCompass is attempting to minimize. EnCompass does not solve to minimize the PVRR because the PVRR includes fixed and must-run costs of existing resources that cannot be economically retired—in other words, costs that will be included in every run, regardless. Instead, EnCompass solves to minimize a figure called the "Objective Value," which is sometimes referred to simply as the "Plan Cost" or "PV Plan Cost."[9] The Objective Value instead focuses on costs that can be minimized within the model. For capacity expansion plans, this includes total optimized production costs (including variable costs of all units and fixed costs of new projects or assets that can be retired), as well as project carrying costs, tariffs, market costs, and environmental program penalties. This means that Plan Costs are a part of PVRR, and so Plan Costs will always be smaller in value than PVRR.

While, for GRE's IRP, rankings tend to align between PV Plan Cost and PVRR, they will not always be the same due to the complexities of capturing different cost streams in the model. The following table shows the Department's PV Plan Cost and PVRR results for GRE's sensitivities, ranked from least cost to highest cost. While plan ranks generally tend to align, they are not exactly the same.

Table 6: GRE's Sensitivities Ranked from Least Cost to Highest Cost, in Both Present Value Plan Cost and Present Value Revenue Requirement[10]

Plan Rank (least cost to highest cost)	Sensitivity Scenario Name	PV Plan Cost ($000, $2023)	Sensitivity Scenario Name	PVRR ($000, $2023)
1	Low Prices	1,754,938	Self-Build Wind with PTC	9,653,082
2	Self-Build Wind with PTC[11]	1,850,130	Low Prices	9,869,940
3	Market Purchases	1,920,394	High Market Purchases	10,209,561
4	Extend Wind Contracts	1,965,310	CT Partial Commitment	10,288,844
5	CT Partial Commitment[12]	1,966,608	Low Load Forecast	10,303,102
6	Low Load Forecast	1,994,090	Low Renewable Prices	10,349,677
7	Low Renewable Prices	2,004,657	Low Wind Price	10,381,270
8	Low Wind Price	2,020,455	Extend Wind Contracts	10,436,496
9	Low Solar Price	2,051,787	Low Solar Price	10,483,402
10	Registered LMR Increase	2,079,606	Lower RRA Accreditation	10,507,058
11	Seasonal PRM Change	2,079,732	Preferred Plan	10,520,912
12	Base Case	2,080,798	Base Case	10,525,408

[9] The Objective Value is the figure used in the Department's matching process.
[10] The Department used a discount rate of 5.5% to align with GRE's weighted average cost of capital and debt rate.
[11] Self-Build Wind with PTC costs reflect the Department's results, not GRE's.
[12] CT Partial Commit costs reflect the Department's results, not GRE's.

13	Low Externality/Low Environmental	2,080,798	Low Externality/Low Environmental	10,525,408
14	Low Externality/Low Regulatory	2,080,798	Low Externality/Low Regulatory	10,525,408
15	High Externality/High Regulatory	2,080,798	High Externality/High Regulatory	10,525,408
16	High Externality/High Environmental	2,080,798	High Externality/High Environmental	10,525,408
17	Reference (All High Externality Costs)	2,080,798	Reference (All High Externality Costs)	10,525,408
18	Lower RRA Accreditation	2,083,349	Seasonal PRM Change	10,544,520
19	Storage Costs Flat	2,090,114	Registered LMR Increase	10,547,127
20	Extreme Summer & Winter	2,102,088	SWS Retirement	10,547,644
21	Preferred Plan	2,123,863	Storage Costs Flat	10,551,389
22	MH Contract Ends	2,135,470	No Battery Offered	10,572,257
23	High Load Forecast	2,150,640	Extreme Summer & Winter	10,589,591
24	No Battery Offered	2,181,133	MH Contract Ends	10,630,911
25	DSM Program Additions	2,295,801	High Load Forecast	10,699,683
26	SWS Retirement	2,359,152	DSM Program Additions	10,973,385
27	No Market Purchases	2,795,355	No Market Purchases	11,903,572
28	High Prices	3,067,184	High Prices	12,529,194

Note that in the above table, the Base Case and the five sensitivities devoted to the Commission's externality and carbon cost futures (plan ranks 12-17) have the exact same PV Plan Cost and PVRR values.[13] For these five Commission futures, GRE reported the Present Value of Societal Cost (PVSC), not PVRR. To get PVSC in GRE's results, the analyst must add the externality costs onto the PVRR values. This can be seen in the following table.

[13] The Department discusses the reason for this result in Section D.3. below.

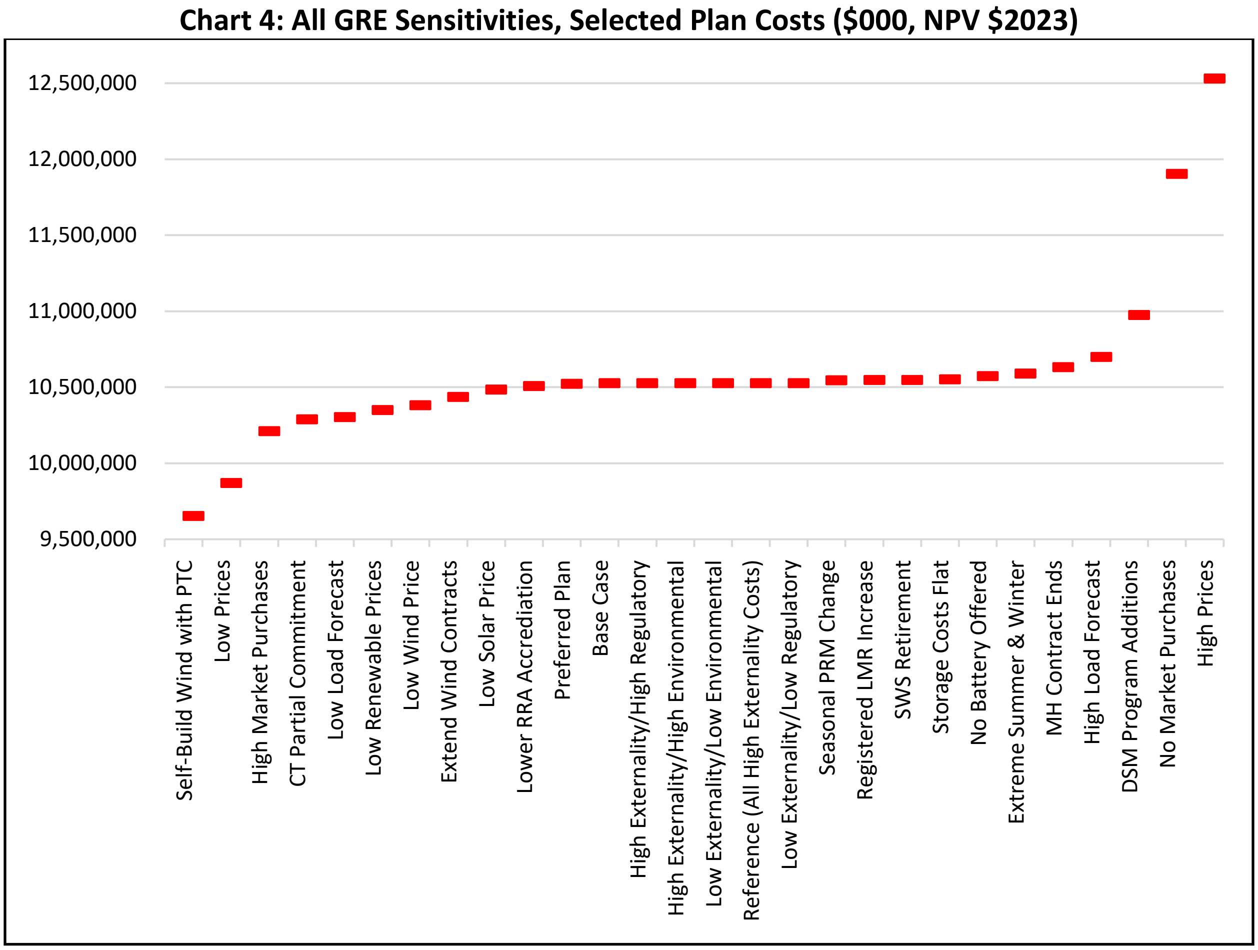
Table 7: GRE's PVRR versus PVSC for Base Case and five Commission Externality and Regulatory Cost of Carbon Futures

Sensitivity	PVRR (no externality or carbon costs, $000, $2023)	PVSC (includes externality and carbon costs, $000, $2023)
Base Case	10,525,408	10,525,408
Low Externality/Low Environmental	10,525,408	10,585,739
Low Externality/Low Regulatory	10,525,408	10,670,576
High Externality/High Regulatory	10,525,408	10,674,332
High Externality/High Environmental	10,525,408	10,773,576
Reference (All High Externality Costs)	10,525,408	10,858,413

Typically, the Department recommends that the Commission approve the plan with the lowest cost PVSC. As can be seen in the above table, however, GRE only calculated the PVSC for the Base Case. This is discussed in further detail in Section D.2. below. For future IRPs the Department recommends GRE consider using some level of externalities as the base case. Other modeling recommendations are at the end of this section.

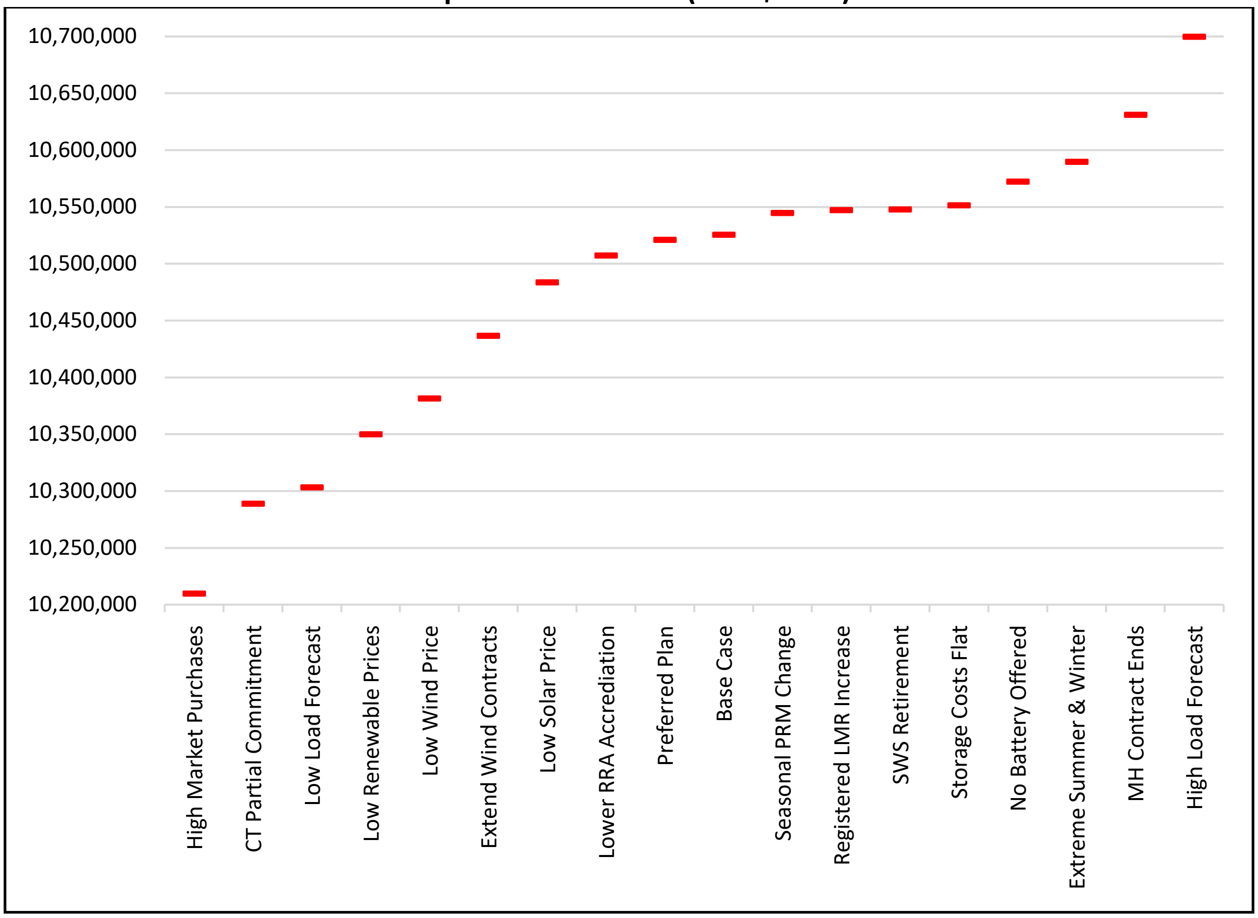
One important consideration in determining least cost plan is EnCompass's use of mixed integer programming and the resultant convergence tolerance. A more detailed discussion of this is provided in Attachment 5 to these Comments. Simply put, the modeler must take into consideration that certain plans may be essentially the same.

To do this, the Department plotted the PVRR of the calculated cost of selected plan, equivalent cost of ideal plan, and equivalent maximum cost for each sensitivity examined by GRE. The below chart is the result, in which only the selected plan values can be seen.



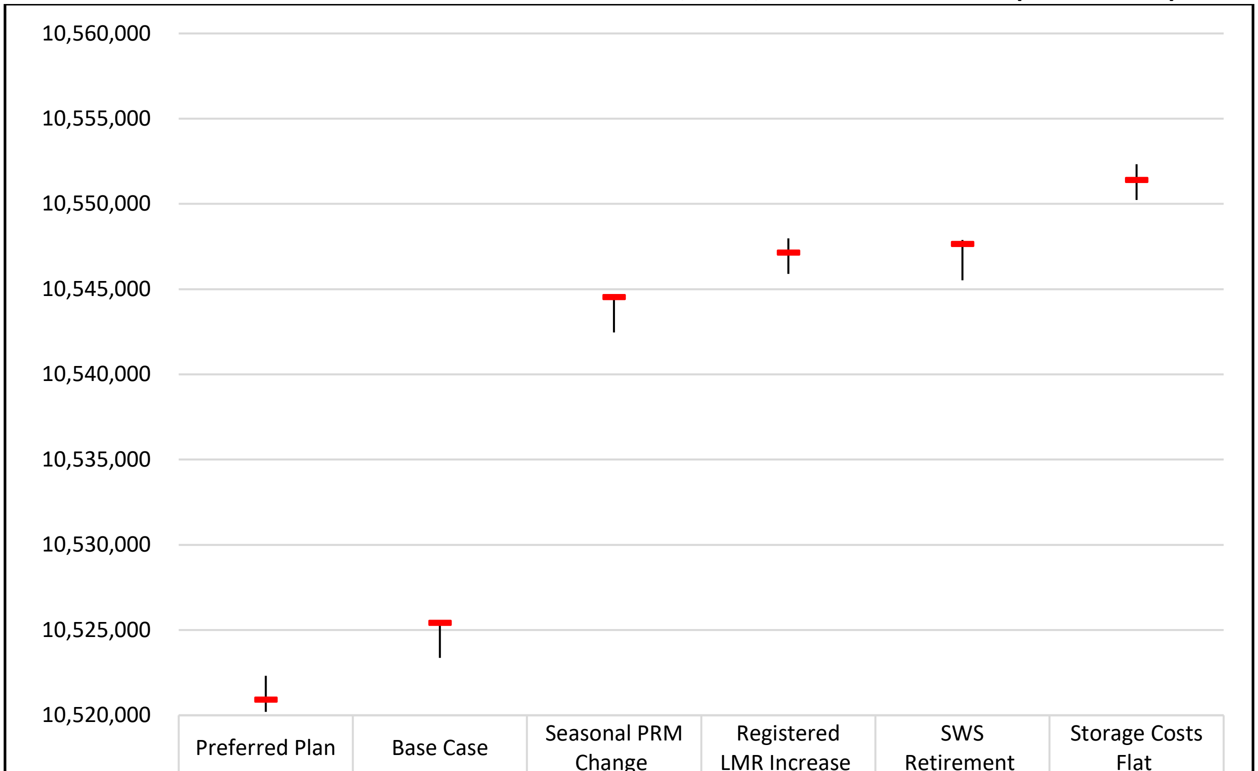
Notably, many plans fall right along with $10.5 billion mark. To zoom in on these values, the Department removed the outliers at either end of the above curve along with the duplicate values from the Commission's externality and carbon cost futures. The Department plotted the following chart:

Chart 5: GRE's Selected Plan Costs with Min and Max Ranges for Select Sensitivities, Outliers and Duplicates Removed (NPV $2023)



In the above chart, the red horizontal bars show the calculated cost of selected plan. The equivalent cost of ideal plan and equivalent maximum cost can almost be seen as small vertical bars. From here, the Department zoomed in on the plans with the most similar costs: Preferred Plan, Base Case, Seasonal PRM Change, Registered LMR Increase, SWS Retirement, and Storage Costs Flat. These were plotted on the following chart, along with a table showing min, max, and selected values.

Chart 6: GRE Sensitivities Closest in Cost: Min, Max, and Selected Plan (NPV $2023)



	Preferred Plan	Base Case	Seasonal PRM Change	Registered LMR Increase	SWS Retirement	Storage Costs Flat
Max	10,522,324	10,525,441	10,544,537	10,547,970	10,547,884	10,552,328
Min	10,520,201	10,523,363	10,542,459	10,545,892	10,545,527	10,550,239
Selected	10,520,912	10,525,408	10,544,520	10,547,127	10,547,644	10,551,389

This chart shows that there is no meaningful difference between the Registered LMR increase plan and the SWS Retirement plan because their potential cost ranges overlap.

iii. Emissions

On page 44 of its filing, GRE discussed a methodology for calculating emissions that it identified as the Department's retail ratepayer methodology. This methodology involved the following steps:

- Start with total annual Minnesota member retail sales in MWh;
- Calculate direct emissions (tons) by multiplying MWh generated by the corresponding CO2 intensities from GRE-owned generation, assuming no net annual market sales;
- If there are net annual sales from GRE-owned resources, subtract these emissions by multiplying average GRE-owned CO2 intensity by the number of MWh sold;
- Calculate emissions associated with PPAs and net annual market purchases by multiplying annual MWh by the corresponding CO2 intensity;
- For PPA MWhs without a corresponding REC retirement in M-RETs, the Midwest Reliability Organization West (MROW) regional grid CO2 intensity will be applied.

GRE also provided clarification as to how it determined certain carbon intensities associated with bilateral contracts and market purchases. Further, GRE stated its preference for calculating emissions by accounting for REC retirements, and provided in Table 10 of its filing a summary of actual and projected emissions under the Preferred Plan:

Table 10 - GRE's contribution to statewide CO_2 emissions

Source	Actual 2005 (tons)	Actual 2021 (tons)	Forecasted 2037 (tons)
CO_2 from GRE's power plants	13,186,213	9,501,086	479,565
CO_2 associated with non-specific net market purchases	-1,633,482	108,695	1,145,161
CO_2 associated with retirement of non-energy-related RECs	-	-273,138	-1,052,051
GRE's contribution to statewide CO_2 emissions	**11,552,731**	**9,336,642**	**572,676**
CO_2 reduction relative to 2005		**19%**	**95%**

GRE later updated its preferred plan emissions results calculation in response to Department Information Request 7 (DOC IR 7) which is provided in Trade Secret and Public versions in eDockets. The Department summarizes that emissions information in the following table.

Table 8: Summary of GRE's reported emissions for its preferred plan, 2023-2037 totals

Emissions Calculation Component	Total CO2 Emissions 2023-2037 (tons)
GRE Fleet Emissions	4,172,936
Emissions associated with PPAs	32,085,243
Emissions associated with net annual market purchases or sales	12,161,556
Adjustments for REC Treatment	5,383,188
Other Adjustments	(442,298)
Total CO2 emissions associated with MN electric sales	53,360,625
Emissions associated with Transmission losses	3,341,419
Emissions associated with Distribution Losses	2,187,485

GRE did not provide a comparative analysis of emissions across sensitivities.

In addition to restating its preference for incorporating RECs into the retail ratepayer calculation methodology, the Cooperative stated that it does not think emissions due to its bilateral contracts with Rainbow Energy should count towards the emissions calculations, as these contracts are purely financial in nature. Provided that these contracts specifically stipulate that emissions should remain with the seller at the point of MISO interconnection, the Department is not opposed to this consideration. In that case, the actual energy flow would more appropriately be thought of in two separate transactions: Rainbow to MISO and MISO to GRE. GRE should calculate Rainbow-specific emissions by multiplying total Rainbow energy purchases by the MISO carbon intensity factor.

The Department also agrees with the Cooperative's assessment that accounting for RECs is allowed in the calculation of GRE's contribution to statewide CO2 emissions for some purposes. Specifically, if the utility wants to demonstrate that its preferred plan will comply with state requirements, an adjustment for RECs is a reasonable addition. In the instant modeling discussion, however, the Department is less concerned with the retirement of RECs, since this figure appears to simply act as a true-up to ensure that GRE will meet the state's emissions reduction goals. Instead, for modeling purposes the Department is interested in understanding which sensitivities will produce the most and least emissions, and how the Preferred Plan falls along that spectrum. For purposes of comparing emissions across sensitivities, therefore, the Cooperative should leave RECs out. The Department provides a specific recommendation below.

4. *Considerations for Future Analyses*

The Department reviewed GRE's inputs and outputs and found the Cooperative's assumptions to be generally sound. The Department suggests the following for GRE's consideration in future resource planning dockets:

- Use of a "setup" file;
- Alternative database structure;
- Regulatory costs assignment;
- Additional resources;
- Market sales;
- Sensitivity emissions reporting;
- Convergence tolerance; and
- Arbitrage uncertainty.

i. Setup File

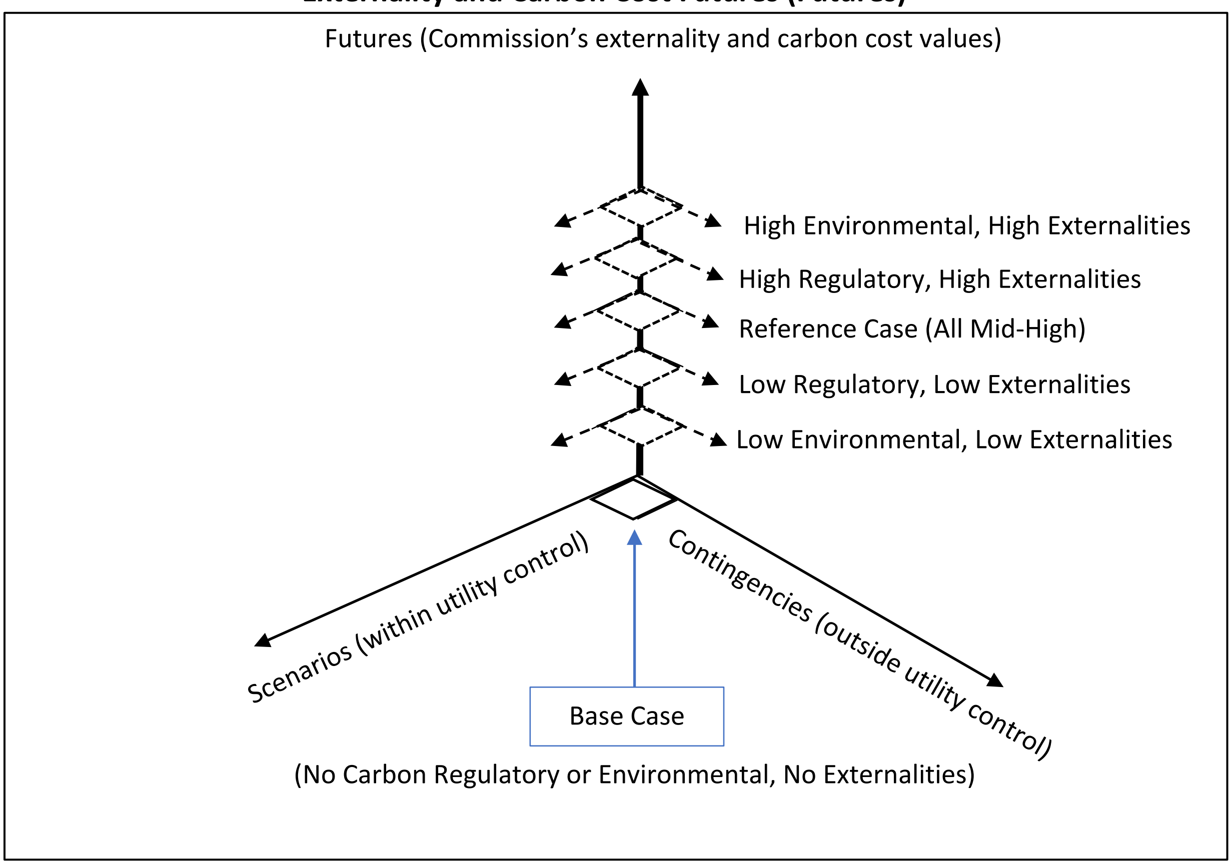
In response to Department Information Request 1, Great River Energy provided all datasets needed to reconstruct its database, along with instructions about how the Department should reconstruct the scenario tree within the database. To improve GRE's ability to document EnCompass runs, in the future, GRE should consider using a "setup" file that automatically pulls in all datasets into the database and places them in the appropriate locations within the scenario tree. This would mitigate the risk of the Department or other parties incorrectly re-creating the scenario tree or choosing incorrect scenario settings. For example, it is possible that this could be contributing to the Department's inability to match the two specific GRE sensitivities discussed above. For a brief description of how to generate and use a setup file, see Department Attachment 7 to these Comments.

ii. Database Structure

The Department notes potential changes to the structure of GRE's database and its consequent results. Although GRE examined a number of different sensitivities, each sensitivity was applied only to the base case. Further, GRE only ran a cursory five externality and carbon cost futures, again only applied to the base case. From Department's perspective, some (non-zero) externality and carbon cost futures should be applied to all runs by being built into the base case. This is because these types of costing lenses are what provides meaningful insight as to the societal cost of each plan. With the current database structure, however, information gleaned from the modeling was somewhat limited.

In addition, the Department notes that the Cooperative's database could be built around one base case and three different variable types: variables within in the Cooperative's control ("scenarios"), variables outside of the Cooperative's control ("contingencies"), and the Commission's externality and carbon cost futures ("futures"). The following is a visual depiction of this structure:[14]

Figure 3. Visual Depiction of Department's Suggested Database Structure, Using Variables Within GRE's Control (Scenarios), Variables Outside of GRE's Control (Contingencies), and Commission's Externality and Carbon Cost Futures (Futures)[15]



[14] This depiction assumes that no regulatory, environmental, or externality cost are captured in the base case, as with GRE's model. However, utilities may decide to use one of the Commission's futures in its base case.
[15] Base case here is no regulatory/environmental/externality costs but could be any Commission future.

If the Department were running a full analysis of GRE's model, we would first restructure GRE's database according to the above depiction. Therefore, the first matrix of runs (those on the base case level without any regulatory, environmental, or externality costs) would look something like the following table.

Table 9: Department's Preferred Setup of Scenarios by Contingencies, with Actual Runs Performed by GRE Demarcated with an "X"

		Base Case	Scenarios (Variables within GRE's Control)*							
			Pref Plan	DSM Prog Adds	Self-Build Wind	No Batt	Extend Wind Contracts	MH Contract Ends	Reg LMR Increase	SWS Retire
Base Case		X	X	X	X	X	X	X	X	X
Contingencies (Variables Outside of GRE's Control)	Low Sales Forecast	X								
	High Sales Forecast	X								
	Extreme Summer and Winter	X								
	Low Market and Marginal Fuel (NG) Prices	X								
	High Market and Marginal Fuel (NG) Prices	X								
	Low Renewable Prices	X								
	Low Solar Prices	X								
	Low Wind Prices	X								
	Storage Cost Curve Flat	X								

	Lower RRA Accredit	X								
	Seasonal PRM Change	X								
	No Market Purchases	X								
	High Market Purchases	X								

The Department notes that this matrix is an example based on the Department's understanding of what is and isn't within the Cooperative's control, but GRE should arrange scenarios and contingencies as it sees fit considering the under control/not under control distinction.

After completing the runs, the Department would be able to analyze the above table with questions such as:

- Under a high sales forecast contingency, which of GRE's scenarios produces the least cost expansion plan?
- Which contingency has the potential to create the biggest cost impact under GRE's preferred plan?
- Which scenario most frequently produces the highest emissions?
- If GRE allows the Manitoba Hydro contract to end, will the capacity expansion plan be meaningfully different across different contingencies?

The Department could then apply the Commission's futures to that same matrix of 144 runs, resulting in a total of 864 runs. In addition, the Department could create a separate database for each future, simply making six copies of the database and adding the relevant futures dataset to the parent scenario(s) of each database. Overall, the tradeoff is the increased information provided by the increased run versus the increased time required to perform the runs, manage the data, and the increased potential for error due to the need to manage increased amount of information.
After completing runs in all of the databases under this structure, the Department would then be able to compare the six databases with questions such as:

- Are the very lowest cost and highest cost runs the same across every future?
- Under a low market and marginal fuel prices contingency, will the dispatch routine of the Preferred Plan change under the regulatory futures?
- Does a high regulatory cost future meaningfully impact plan carbon emissions if GRE chooses to retire Spiritwood Station early?
- What is the most common expansion plan found in each future?

As demonstrated in the above questions, the key outputs the Department is interested in are: expansion plans, costs, and emissions. The Department suggests that in future plans, GRE may wish to develop a database around such a structure or something similar to help provide more meaningful information about these key outputs. Note that the Department has used such a structure in some resource plans (See Minnesota Power's IRP modeling in Docket No. E015/RP-21-33) and not others (see Northern States Power Company d/b/a Xcel Energy's IRP modeling in Docket No. E002/RP-19-368).

iii. Commission's Externality and Carbon Cost Futures

GRE did not properly incorporate the regulatory carbon cost component of the Commission's futures into EnCompass. However, the Department notes that this has less to do with a failure on GRE's part and more to do with a quirk of the modeling software.

Significantly, any costs given the title "externality costs" or "ExternCost" in EnCompass are not factored into the model's decision-making, either in the capacity expansion plan or dispatch routines. Instead, EnCompass simply keeps track of externality costs and after the model makes its capacity expansion and dispatch decisions, EnCompass makes that total available in the Company Annual report. The modeler can then tack externality costs onto the final revenue requirement if they so choose to calculate and compare the PVSC of different runs. Since externality costs do not impact either the expansion plan or the dispatch routine of the model, two scenarios that are identical, save for the presence of externality costs, will yield identical expansion plan projects and revenue requirements. GRE's model attempts to incorporate the Commission's directive to examine regulatory carbon costs—that is, carbon costs that have become internalized into rates[16]—but unfortunately, the utility has labeled those costs as externality costs in EnCompass. This error means that although GRE's "CO2 Reg" costs are supposed to impact the model's expansion plan and dispatch decision-making, they do not. This is evidenced in the results of the five Commission externality and carbon cost future scenarios modeled by GRE: each scenario produces the exact same expansion plan and expansion plan cost.[17]

There appears to be a fairly straightforward fix to this issue. The below screenshots show how CO2 Reg time series should be classified as "AllowCost" instead of "ExternCost" in a dataset. The Department recommends that GRE follow up with Anchor Power Solutions to ensure that this fix would be sufficient.

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[16] Per Commission requirements, regulatory cost futures assume that the externality costs of carbon become internalized into the cost of a given resource; subsequently, these costs would be passed along as rates reflected in MP's Locational Marginal Prices (LMPs) in the MISO marketplace. As a result, the model's capacity expansion and dispatch routine decisions are based upon costs that reflect the internalization of externality costs.

[17] See Table 5 above for expansion plans, see Attachment 3 for plan costs.

Figure 4: CO2 Reg Should be Classified as "AllowCost" Instead of "ExternCost"

	A	B	C	D	E
1	**Name**	**Emission**	**AllowCost**	**ExternCost**	
2	CO2 Environmental	CO2		CO2 Env	
3	CO2 Regulatory	CO2		CO2 Reg	
4					
5					
6					

	A	B	C	D	E
1	**Name**	**Emission**	**AllowCost**	**ExternCost**	
2	CO2 Environmental	CO2		CO2 Env	
3	CO2 Regulatory	CO2	CO2 Reg		
4					

At this time, this CO2 regulatory cost misapplication has the most potential to meaningfully impact the Department's recommendations. The Department typically recommends plans based on least-cost PVSC with a mid-range regulatory future, but no plans examined include regulatory costs. It's possible, therefore, that the Department would instead recommend that GRE pursue the base case timing for its capacity additions, or other course of action within the utility's control. The Cooperative also did not provide clarity on this front by comparing emissions across potential plans. This means that it is unclear to the Department which plan has the lowest environmental impact with correct consideration of externalities.

Finally, the Department notes that other utilities continue to label the Commission's externality or environmental cost values as externality costs in EnCompass. As a result, the Commission's "Low Environmental Cost" and "High Environmental Cost" futures produce the exact same expansion plan, plan costs, revenue requirements, and PVRR as each other and as base case runs.[18] The difference is simply the cost stream tacked on at the end to create the PVSC. The regulated utilities have all expressed an interest to the Department in determining a common way of handling this issue; the Department recommends that GRE confer with other utilities and potentially other interested parties to determine a best practice to address externality and environmental costs.

[18] Assuming the base case has no regulatory, environmental, or externality costs.

iv. Additional Resources

a. Resources Known but Not Modeled

The Department notes that there were three specific resources that are known or planned but not incorporated into the model:

- The availability of Arrowhead Emergency Station, a fuel oil reciprocating engine;
- The plan to add a 1.5 MW Form Energy battery storage pilot project in 2024; and
- The planned conversion of Cambridge 2 into a dual fuel plant as part of the five-year action plan.

Although none of these unmodeled resources are likely to impact the Cooperative's results, it is unclear to the Department why these appear to have been omitted from the model. In the future, the Department suggests that GRE either incorporate all known resources into its model or explain why the resource has been omitted.

b. Additional Potential Resources

As discussed above, GRE made six resources available to the model with an additional resource (self-build wind) available in one sensitivity. Of the four EnCompass databases that the Department has now reviewed, GRE's potential resources offered into the model were the fewest in number. Other utilities have made available to their model natural gas combined cycle units, which GRE did not examine, as well as transmission additions and different sizes of batteries, CTs, DSM, solar, and wind. Unlike the other utilities, however, GRE compared a self-build wind option versus a PPA. Further, the Department is unaware of another utility besides GRE that examined a CT partial commitment option.

It may also be worthwhile for GRE to incorporate certain transmission components into future resource plans. For example, Minnesota Power's model forced "transmission project" to be built anytime a new wind or solar project was built as a generic resource. Separately, MP's model forced certain reliability mitigation options (for example, a large transmission project or a combination of a small transmission project and a CT) to be selected when the model retired large baseload plants. Xcel's model used both "transmission cost free units", which reuse the existing interconnection rights of retiring baseload plants and generic units that had a transmission cost component included in the overall cost. These modeling options are available should GRE's engineers require transmission to accompany resource additions/subtractions or should the Cooperative wish to capture different types of cost streams in the model.

The Department also suggests GRE consider looking at a couple different sizes of each type of potential resource.[19] Other utilities tended to analyze a smaller-sized project and larger-sized project for each technology. For example, Minnesota Power used two small demand response projects (4-8 MW) and two large demand response projects (100 MW). Xcel offered different levels of DSM resources in accordance with the Department's statewide potential DSM study. All three regulated utilities looked at different sizes and types of gas peaking units. However, there is also a risk with using smaller project sizes; it could be that the MIP range is too large for a small change in the expansion plan to be meaningful. For example, the Department would caution GRE and other parties away from making an infinite number of 10MW dispatchable resources available. On the other hand, it may be prudent to offer say, one 100 MW battery and one 200 MW battery instead of only 200 MW batteries. One question the Department has an interest in is if there are alternative ways to model DSM, such that it wouldn't only be available to be added in a singular year.

While there are certain benefits to offering fewer resources in the model—such as smaller problem sizes and faster run times—the Department suggests that in future modeling, the Cooperative try to include a slightly broader range of potential resources. This should be done within reason, since too many offerings can create too big of a problem for the model. A reasonable alternative may be to conduct a pre-input study of different potential alternatives to winnow down the best available alternatives. From the Department's perspective, the best slate of available resource alternatives will provide a small but comprehensive smorgasbord of size and type of available resources.

v. Market Sales

GRE did not model any scenarios that permitted market sales, in large part due to historical practice that aligns with the Department's past preferences. In the past, the Department preferred to set market sales at zero to ensure that expansion plan resources are added solely to meet utility load, not to increase utility revenues through selling excess energy and capacity into the MISO market. The reason that utilities shouldn't build simply to sell to MISO is because like any market, the MISO market is unlikely to perform exactly as parties expect it to, particularly over the course of fifteen years. If prices are expected to be high and a utility builds generation to take advantage of those prices, ratepayers win if that is the correct future. But ratepayers lose if prices are lower than expected. The Department therefore advocates the following philosophy: utilities should not be using ratepayer dollars purely to speculate on market prices.

However, assuming zero market sales is becoming increasingly problematic as more intermittent resources are added to GRE's and other utility's systems. This has to do primarily with energy, not capacity. Sometimes, GRE's system will overproduce energy through energy-intensive, lower-accredited capacity resources (such as wind or, to a lesser extent, solar). A classic example would be if

[19] The Department is cognizant of GRE's use of sensitivities to test different sizes of resource additions—such as the CT Partial Commit, the Additional DSM Program, or the Registered LMR Increase sensitivities. While the Department considers these to be useful exercises, they are not a replacement for offering different sizes and types of resources for the model to choose from.

the wind is blowing at night (producing lots of energy), but there is low demand for energy (because everyone is sleeping). If the model does not allow GRE to sell that excess energy (supply greater than GRE's demand) into the MISO spot market (particularly when GRE's batteries are already charged), then there is no sink in the model for the energy. In EnCompass, the wind will simply be reported as curtailed. So, in this example the wind is undervalued in the model due to a lack of a sink. While this was not a significant issue in the past when systems had small amounts of non-dispatchable resources, this is no longer the case for GRE (or many utilities in Minnesota).

The Department therefore suggests that in future plans, GRE try to pinpoint a moderate level of market sales to include in its base case, or at least in some scenarios. One option could be to simply set maximum energy and capacity sales limits for the model. Another would be to incorporate GRE's an estimate of GRE's connection size with MISO into the model as the forward and reverse sales limits, then temper that with a different maximum sales limit. If GRE should choose to incorporate sales into future resource plans, the Department notes that GRE should continue to be vigilant about avoiding capacity that is built solely to chase market prices.

vi. Sensitivity Emissions Reporting

GRE provided its updated preferred plan emissions calculation in response to DOC IR 7 but did not provide a comparison of emissions across sensitivities. The Department requests that in future analyses, the Cooperative provide such an analysis. Per the above discussion, the Department recommends that GRE use MISO carbon intensity rates for energy purchases from Rainbow (if the Rainbow contract does not involve actual energy purchases) and provide the relevant portions of the Rainbow contract(s) to demonstrate why a market carbon intensity rate is the more appropriate value. Further, the Department recommends that GRE continue to use REC accounting to demonstrate compliance with state emissions reduction goals but remove these figures when comparing emissions across sensitivities.

vii. Convergence Tolerance

As with GRE, the Department continues to learn about EnCompass's use of mixed integer programming, convergence tolerance, and the implications for plan results. The Department has provided in Attachment 5 its current understanding of these functions, as well as an analysis in Charts 4 to 6 above. The purpose of such charts is to illustrate scenarios where the costs are clearly different and scenarios where the costs are essentially the same to EnCompass.

The Department encourages the Cooperative to develop such an analysis in future resource plans. Further, the Department suggests that GRE consider the MIP stop basis and convergence tolerance when developing the size of its potential resources.

viii. Arbitrage uncertainty

"Arbitrage" refers to a battery's ability to "buy low, sell high." That is, a battery can be charged during off-peak times and discharged during on-peak times, thereby using the price differential to GRE's benefit. GRE informed the Department, however, that it has concerns that the EnCompass software could be over-valuing this battery arbitrage benefit. Specifically, the Cooperative has concerns with the model's ability to capture real-world dynamics. Potentially EnCompass can extract all value that it can out of a battery through perfect foresight of future market prices. However, In the real world it is unlikely that a battery could be operated in such a perfect manner.

The Department was unaware of this particular consideration and thanks the Cooperative for explaining this issue. It is especially important for GRE, given the Cooperative's large, planned storage additions. The Department requests that GRE keep parties updated as to any further knowledge learned about this arbitrage uncertainty in GRE's next RIP.

5. Modeling Conclusions

Nothing in GRE's Five-Year Action Plan is objectionable, although the Department notes that the step down of the Rainbow PPA has the potential to create the most risk for GRE's ratepayers because of the Cooperative's market exposure. GRE's further plan to delay the battery addition until 2030 when the model prefers to add it in 2027 keeps GRE in this riskier position longer. However, the Cooperative's reserve margins will theoretically provide enough of a cushion to shield its ratepayers. Further, the Department notes that GRE's delay will allow the Cooperative more time to study the battery pilot project, hopefully mitigating unforeseen operational risks. Ultimately, the Commission is not responsible for costs at GRE, and so the increased risk on the cost side, while important, is of lesser concern for a generation and transmission cooperative than an investor-owned utility.

The Department considers GRE's Preferred Plan to be generally reasonable in terms of cost, reliability, and risk. Relative environmental impact at this time is unknown. Therefore, the Department is generally supportive of GRE's Preferred and Five-Year Action Plans.

F. ENVIRONMENTAL AND OTHER REGULATORY ISSUES

The items addressed in this section indirectly relate to GRE's plans to reliably meet their peak demand for electricity. The following items discuss standards that could feasibly constrain GRE's choices of what types of energy resources to draw upon and what types of technology will be used to produce electricity. Such constraints might contribute to improved environmental conditions, but as a tradeoff also raise the cost to produce electricity from some resources now and in the future. As a result, GRE might end up with a different mix of resources used to produce electricity and different technologies might be used by GRE to reliably meet peaks in electricity demand.

For most of the regulations, GRE plans to meet the standards set forth in statute and federal regulations. Although in some cases, more information about the regulations may be needed to determine whether

GRE's current plan will comply with the standards. This is because there are many recently established and forthcoming standards. Some of the forthcoming standards may have more costly consequences, such as a current noncompliance at the Coal Creek power plant.

Because there are so many newly established and forthcoming regulations, there is added uncertainty regarding the reliability of any current plans at this moment, which elevates the importance of monitoring future plans for compliance. For purposes of the current IRP, GRE is mostly compliant. In a few instances this is not true and GRE is not compliant, but decisions have not been made on how to bring GRE or associated parties into compliance. Until those decisions are made, little is known whether compliance with regulations will change GRE's plans for the future. Consequently, the Department only makes a couple of technical recommendations. These regard how to calculate sales and how to count carbon emissions hereafter.

GRE or associated parties are currently noncompliant with the following matters.

- low-income spending standard within the Conservation Improvement Program (CIP);
- disposal of ash from the Coal-Creek plant; and
- noncompliance with the transport rule.

Although there is no foretelling the future, compliance with these standards, may result in changes to future plans by GRE.

1. Changing Regulatory Landscape

Multiple changes to regulatory standards were authorized in the last few years and several regulations were newly proposed. Both Minnesota and the federal government published new standards regarding conservation, renewable energy, pollutants, and the creation of jobs. During the 2023 Minnesota Legislative Session alone, legislators authorized a carbon-free act, an additional renewable energy objective, and requirements to report job impacts.

Table 10 below lists the Acts and regulations that apply to GRE and are addressed in these comments. The table includes a brief description of each standard, its current status, and the last year when the regulation was acted upon. For some federal regulations, the Department mentions proposed rules, which are not finalized and effective, until after public comment and a formal review process.

Table 10: History of Regulations Relevant to GRE's IRP

Section	Description	Year of Most Recent Action	Type of Action
216B.2401 to 216B.241	Conservation Improvement Program	2021	Amended
216B.1691, subd. 2t.	Carbon Free Standard	2023	Enacted
216H.02, subd. 1	Greenhouse Gases	2023	Amended
216B.1691, subdivision 2a	Eligible Energy Technology Standard (Renewable Energy)	2023	Amended
216B.2422, subd. 4a	Preference for Local Job Creation Employment Opportunities.	2023	Amended
83 FR 36435	Combustion Coal Residuals	2020	Final Rule
88 FR 933687	Good Neighbor Plan	2023	Final Action on Disapproval
86 FR 2305476	Cross State Air Pollution Rule	2011	Final Rule
40 CFR Parts 72 through 78.	Acid Rain Program	1995	Final Rule
EPA-HQ-OAR-2023-0072	Greenhouse Gas Standards for Fossil Fuel Fired Power Plants	2023	Proposed Rule
EPA-HQ OAR-2018-0794	Mercury and Toxic Substances (MATS)	2023	Proposed Rule
88 FR 5558	Ambient Air Quality Standard for Particulate Matter	2023	Proposed Rule
64 FR 35714	Regional Haze Program	1999	Final Rule

*NOTE: GRE states they are not subject to the Minnesota Mercury Emissions Reduction Act (2022 Minnesota Statutes §§ 216B.58 to 216B.82). GRE's combustion turbines are exempt because the process only combusts fuel oil or natural gas.

Because a number of regulations are recently effective, and some are still proposals, GRE is facing a changing regulatory environment. Since 2021, 10 of 13 regulations have become effective or proposed. The changes to regulations include new regulations, such as Minnesota's carbon-free rule, but as explained below, some are revisions to already existing regulations. To what extent these regulations will affect GRE's investments and plans is currently somewhat difficult to ascertain, especially with those rules that are still being proposed. However, future plans, including the next IRP, should bear more information.

One summary implication from the combined regulations is a push from fossil-fuels like coal and natural gas toward renewable and cleaner energy sources. Regulations that incentivize or restrict electricity from fossil fuels include the Minnesota Carbon-Free Act, Greenhouse Gases regulation, and Eligible Technology standards. In addition, federal regulations include Coal Combustion Residuals, Good Neighbor Plan, Cross State Air Pollution Rule, Acid Rain Program, Greenhouse Gas Standards for Fossil Fuel Fired Power Plants, Mercury and Toxic Substances, and Ambient Air Quality Standard for Particulate Matter. The combination of new, revised and existing regulations likely makes it comparatively more expensive to produce electricity from fossil fuels, especially coal. In the short run, the costs of electricity rises as coal becomes more expensive to produce (but with the benefit of decreased pollution).

What follows is a more detailed description of federal and state standards. Because there are many standards, 13 total, the Department provides detailed descriptions of the standards that are more important for this current IRP. The Department only provides brief descriptions of the less important ones with a more detailed description of the standard and GRE's compliance in Attachment 1. The rules described in the main text include Minnesota Laws, and any noncompliance with federal regulations.

2. *Minnesota Laws*

Several Minnesota Laws regulate climate related emissions and job impacts in the community. The combined regulations regarding GRE can be somewhat unique in that it is a cooperative instead of an investor-owned utility. But as a utility, GRE is subject to certain regulations. Below are descriptions of the regulations of concern and a discussion on whether GRE is compliant. Depending upon GRE's and associated parties' future decisions to fall into compliance, along with the role of noncompliance in future certificate of need proceedings, future IRPs may change, albeit with in conjunction with market and technological changes.

i. *CIP Goals*

In a separate docket, the Department reviews GRE's plans for compliance with the goals in GRE's CIP. As describe below, GRE has historically not met CIP standards in energy savings and low-income spending. Going forward, changes have been made to the energy conservation goal, making it somewhat uncertain whether GRE will comply in the future. But at least for the low-income standard, GRE has a record of noncompliance. If trends continue, GRE may continue to remain noncompliant. The Department recommends that, in the next IRP, GRE provide updated summary information on compliance and a discussion of GRE's work toward achieving compliance with the CIP letters, especially with the energy savings and low-income standards.

In 2007, the Minnesota legislature set a conservation goal for electric utilities with the next Generation Act.[20] The goal was for electric utilities to produce energy savings equal to 1.5 percent of total energy sales. Since then, the Energy Conservation and Optimization Act of 2021 (ECO) was enacted in May 2021. ECO primarily serves to modernize CIP to provide a more holistic approach to energy efficiency programming. Notable highlights of the ECO Act concerning consumer-owned utilities (COUs) include providing the opportunity to optimize energy use and delivery through the inclusion of load management and efficient fuel switching programs and providing greater planning flexibility.

Also, the legislation included more goals than the energy conservation goal in 2007. Some of these goals are now specific to cooperatives.

- Total energy savings of 1.5 percent of Gross Annual retail Sales, which is somewhat less challenging than the 1.75 percent goal for public utilities. Prior to the ECCO Act, both cooperatives and public utilities had the same goal at 1.5 percent.
- Total spending on energy efficiency improvements of at least 1.5% of gross operating revenues if an electric coop falls short of achieving the minimum energy savings goal from energy conservation improvements of 0.95% for three consecutive years while also spending less than 1.50% of the utility's gross operating revenues on energy conservation improvements.
- Spending on energy conservation program for low-income customers of at least 0.2% of gross operating revenue from residential customers.

Note that Attachment 2 lists more of the CIP goals and subgoals.[21]

Attachment 2 includes further analysis regarding compliance with CIP goals. As described, GRE has historically not met CIP standards in energy saving and low-income spending for each of the years 2016-2020. Changes have been made to the calculation of energy savings, so it is uncertain whether GRE will comply in the future. GRE has a record of noncompliance for the low-income standard. However, average shortfall from the goal is small ($17,516), in part because the member cooperatives are small. The lack of compliance in low-income spending may be more relevant if there are vulnerable or important communities within the member cooperative territories. For those communities, it may be more important to monitor compliance in future IRPs.[22]

CIP goals are relevant because compliance can impact GRE's mix of energy sources for electricity and its future plans to ensure sufficient capacity for its customers. For example, if GRE falls short of compliance with the CIP goals, compliance can be remedied through increased spending and achievement in the area of conservation and energy efficiency. In turn energy conservation and energy efficiency measures may increase the use of renewable energy sources to produce electricity

[20] https://www.revisor.mn.gov/laws/2007/0/136/#:~:text=CHAPTER%20136%2D%2DS.F.No.%20145 Article 2 Sec. 4

[21] The ECO Act added subgoals, such as Savings from energy conservation improvements (including savings from electrical utility infrastructure improvements, efficient fuel switching, and thermal energy savings) equivalent to at least 0.95% of retail energy sales.

[22] The percentage shortfall varies, some member cooperatives are as high as 100 percent short of the low-income spending standard.

and may also decrease the demand for electricity. In some cases, the CIP may further affect upcoming certificates of need and energy investments.

ii. Carbon and Greenhouse Gas Emissions

Minnesota law now includes two important standards regarding Carbon and Greenhouse Gas emissions. GRE stated that the proposed plan complied with both of these regulations, but there are a few uncertainties arising from pending rules and a technical matter that should be monitored in future IRPs. One of the standards was enacted into law by the Minnesota legislature in 2023 and established new standards for the use of eligible technologies that produce electricity without Carbon emissions. The second is a 2023 amendment to current law that changed the standards on Greenhouse Gas emissions across all sectors, including emissions from utilities.

iii. Carbon Free Standard

In 2023, Minnesota legislators enacted new standards that will effectively require zero Carbon emissions from electric utilities by 2040. [23] The Commission has opened a generic docket and has indicated it will be exploring how utilities will comply with the new standard.[24].

In theory, the new standards could affect GRE's least cost plan in its IRP. For example, the standards could restrict GRE's plans for purchasing electricity from coal plants. However, GRE stated within its IRP that it meets the new Carbon-free regulation with resources that are considered Carbon free within the statute. The energy sources in GRE's IRP that are potentially eligible as a Carbon-free technology include wind, solar, and hydroelectric resources. Also, although subject to pending Commission action, GRE factored in their use of renewable energy certificates (RECs) to help achieve Carbon emission goals.

The Department investigated GRE's plan to produce electricity by assigning certain resources as Carbon-free. All electricity produced from natural gas and coal were excluded from electricity produced from carbon-free resources. Currently, GRE supplies part of its electricity by generation from its Spiritwood coal plant and by contracted purchases from Rainbow Energy's Coal Creek plant. Coal comprises more than 90 percent of production from the two resources, until 2031, one-year before the complete phaseout of coal from GRE's energy resources. . Data provided by GRE in response to Information Request No. 3 shows that without market purchases and RECs, GRE falls short of the 60 percent standard by 1.2 percent in 2030. Also, GRE falls short by over 11 percent between 2035 and 2037, when the standard increases to 90 percent.[25] However, the Commission's generic docket will provide additional clarity on compliance and GRE's current IR responses should not be taken as evidence of its ability to comply or not comply with the new statute.

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[23] Laws of Minnesota, 2023, Chapter 7, Sec. 10 amends Minnesota Statutes 2022 Sec. 216B.1691 by adding subdivision 2g.
[24] E999/CI-23-151.

[25] It is not clear from the data provided by GRE for this Information Request included sales by GRE members to customers outside of Minnesota.

iv. Greenhouse Gas Reduction Goal—Net Zero by 2050

The Minnesota Legislature also amended the State's existing goals for greenhouse gas emissions in 2023. Minnesota Statutes §216H.02, subd. 1 was amended to achieve net-zero emissions by 2050. This goal applies to all Minnesota emissions across all of Minnesota's sectors. Greenhouse gases include more than Carbon, such as Methane, Nitrogen Dioxide and Sulfur Hexafluoride (SF6), but these other emissions make up a small proportion of GRE's greenhouse gas emissions.

The Department examined data from GRE on greenhouse gas emissions provided in response to Information Request No. 7. Due to some technical changes, the emissions data in the information request are slightly different than what is reported in GRE's IRP and are now more compliant with previous PUC orders.[26]

Based upon GRE's data, the cooperative is compliant with the greenhouse gas standards for all years of the plan. Although the Department chooses not to raise any issues regarding the current IRP, there are issues to monitor in the next IRP.

- GRE claims that the purchases from Rainbow Energy Center are strictly financial transactions and should not result in any greenhouse gas emissions that are attributed to the Cooperative. Although GRE has calculated the greenhouse gases from Coal Creek and included them within this IRP, GRE is awaiting a future decision by the Commission on whether this is necessary in the future.[27]
- GRE stated they calculated Carbon emissions from net market purchases. The calculation subtracted all out-of-state market purchases from market sales to out-of-state buyers of electricity. The Department suggests that GRE should separately calculated emissions sold to the market with a factor reflective of carbon emissions due to electricity production from GRE.

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[26] See the Commission's Order for Docket No. E015/RP-15-690.

[27] The decision of whether to include greenhouse gas emissions from Rainbow Energy's Coal Creek plant involves several issues. (a) The contract is financial in the sense that GRE is purchasing electricity. Whether GRE has the right to choose which customers it will make financial contracts with based upon their energy resources is at question. (b) The Commission eventually must determine under what conditions greenhouse gases associated with power purchase agreements (PPA) should be counted. That is, when are PPAs and financial transaction independent of associated parties use of resources to supply the electricity? If GRE's bilateral contracts with Rainbow Energy are determined to be financial, without regard to the supplier, then GRE's burden in meeting the greenhouse gas standard could be lessened. It might also lower GRE's burden to meet the standards in the Carbon-free act and the standards on renewable energy. If this case can be generalized to other bilateral PPAs, then it could serve as precedent for other utilities, which could further allow for more Carbon emissions. There is also a local control versus statewide control issue. Some may suggest that the state has a right to impose a minimum statewide standard since everyone in Minnesota could in-theory be harmed. On the other hand, GRE's cooperative members do not have to purchase electricity from GRE. They could alternately purchase electricity from some other utility, assuming flexibility in contracting. If a local member cooperative wanted greenhouse gas standards to apply equally to all its generation and purchases, then it may have the choice to contract with another utility, albeit perhaps more expensive. Ultimately, the local choice issue is whether state should impose upon all its consumers a standard for utilities that assigns some of the responsibility for pollution from greenhouse gases to itself, even if not wanted by communities, and even if it may resultantly emit more harmful pollutants because of no assignment of responsibility.

> Whereas emissions purchased from the market should be calculated using an emissions factor representative of the MISO market.

The Department recommends that GRE separately calculates emissions from market sales and market purchases in its next IRP.

3. Renewable Energy Resources

Minnesota Statutes § 216B.1691, subd. 5 provides standards for utilities regarding their mix of electricity from renewable energy sources, commonly known as the RES—Renewable Energy Standard. The statute set a timeline for a utility to reach a certain percentage of electricity from renewable sources, where the percentage increases over time. In 2023, the legislature added to the timeline by requiring utilities to produce electricity with at least 55 percent generated from renewable sources by 2035. Renewable sources are defined in statute as eligible energy technologies and include such sources as wind, solar and hydroelectric.

The Department examined GRE's data and determined that GRE's preferred plan meets the RES set over time. In 2023, GRE exceeds the 20% renewable energy standard by 15 percentage points. By 2037, GRE plans to exceed the renewable standard by 23 percentage points.

The Department will revisit compliance in the Commission's annual RES REC retirement dockets, and the Commission's biennial RES docket.

4. Jobs and Economic Development

A new requirement on job creation was enacted in 2023 and is related to IRPs. GRE is currently compliant with this statute, but more specifics regarding details of the standards may evolve over time. In 2023, the Minnesota Legislature amended the statues regarding IRPs to include a preference for local job creation. The new law requires any utility filing an IRP to include the local job impact from its plans. It also requires the utility to report on steps to help maximize local construction job opportunities, including steps by the utility, its suppliers and its contractors. In evaluating the plan, statutes authorize the Commission to prioritize the hiring of workers from communities that host retiring electric generation facilities. Workers include but is not limited to individuals previously employed at the retiring facility.

The Department asked GRE about local job impacts and steps to maximize local construction opportunities as it relates to the preferred plan. GRE responded by noting that their plan includes increased reliance on carbon-free and renewable energy resources. To achieve these plans, GRE hopes to:

- Work on large wind contracts that total to approximately 1,000 MW and are expected to create more than 1,250 local construction jobs.[28]

[28] The projects are at Dodge County Wind, Three Waters Wind, Discovery Wind, and Buffalo Ridge Wind. The Three Waters Wind project is in Jackson County, MN, and Dickenson County, IA. Discovery is in McLean County, ND. Buffalo Ridge is in

- Continue to employ 550 workers in its Elk River and Maple Grove power plants and field locations.
- Create 50 local construction jobs while converting a combustion turbine in Cambridge to dual-fuel capability (using a secondary source--ultra-low sulfur diesel).[29]

Finally, GRE notes additional economic impacts besides jobs. For example, the cited large wind projects are expected to generate $284 million in payments to local county landowners and $145 million in tax revenue that provides money for local projects, schools, and government services.

The Department determined that for this docket, GRE complies with the statute. However, utilities will experiment with the new statutes over time to determine what is reasonable to fulfill the requirement. At some point, the Commission may want to consider what it expects to see from the utility for compliance. Among the potential considerations are:

- Whether impacts from projects include the number of jobs hired by the utility, jobs in the local economy, or dollars to the local economy. It is more difficult to measure economy-wide impacts because workers employed by GRE may have been employed by another employer, thereby not increasing the economy-wide number of jobs.
- Whether job impacts should be compared across Dockets, plan alternatives within each IRP, or both. To gauge whether the job impacts are high, or low, the Commission will need something to compare against the numbers provided by the utility. After considering several dockets, the Commission might recognize whether the job impact projections are high, or low. For example, the Commission might be able to gauge whether GRE's job numbers regarding wind projects are high compared to other wind projects from other utilities. Alternatively, the PUC may want to consider job impacts across different plan alternatives within a single IRP to aid in making a decision regarding the preferred plan.
- The extent that jobs outside of Minnesota are relevant. GRE included job impacts that would occur in Iowa and North Dakota. The Commission may want to emphasize plans where jobs are created within Minnesota.
- To be able to compare job impacts, some consistency on what is reported would be helpful. For example, the Commission may consider whether they want information on full-time versus part-time work, occupations hired, and salaries paid.[30]

Lincoln County, MN. It is uncertain why GRE did not include job numbers for the Deuel Harvest project, which is in their IRP.

[29] GRE did not estimate Jobs numbers associated with the 1.5 MW Form Energy multi-day storage pilot project. Also, GRE did not estimate job impacts for potential projects past 2030.

[30] Statutes contain other job requirements. In actions related to the carbon-free and renewable energy standards, the Commission is authorized to consider local benefits. Among the benefits are the creation of high-quality jobs in Minnesota, jobs that pay wages that support families, support of the right for workers to organize, and insurance that workers have the necessary tools, opportunities, and economic assistance to successfully adapt during the energy transition, particularly as it relates to environmental justice. (Minnesota Laws of Minnesota, 2023, Sec. 15.

5. *Federal Regulations*

The federal government sets standards that limit the amount of greenhouse gases and other pollutants. Such standards constrain utilities from emitting too much pollution. One of the potential outcomes to having federal standards on top of state standards is that the regulations are more likely to change GRE's and other utilities' choices regarding the capacity and mix of energy sources. It may further change the types of technology used to produce electricity. For example, the Department will discuss a regulatory issue with a liner in a coal ash disposal site that might result in a temporary shutdown of Coal Creek. Finally, regulations can increase the costs to a utility from what might have originally been its least cost plan. But the benefit could be lower pollution levels and increased safety.

In this section, the Department will mainly discuss federal regulations, where GRE, the state, or an interested party is potentially not compliant. The reason is that noncompliance could more likely raise the risk that GRE may change future plans significantly. Although some proposed regulations may also change future GRE plans, their impact is less certain. As noted above, there are many regulations, which we will briefly discuss in the remainder in this section and describe in more detail in Attachment 1.

i. *Inflation Reduction Act of 2022*

One recent Federal action, the Inflation Reduction Act (IRA), may be important to GRE's future plans Unlike the remainder of regulations, the Act provides incentives rather than constraints to reduce pollution. Incentives in the IRA reduce the cost to GRE to adopt technologies and techniques that will reduce greenhouse gases and pollution.

GRE states they are investigating an array of provisions in the IRA, albeit not all provisions apply to cooperatives. Example provisions include ambient-adjusted ratings (AAR) and dynamic line ratings (DLR) technologies that will reduce transmission energy line losses. GRE is also exploring options for assistance on investments that will alleviate transmission congestion. Besides GRE, its member cooperatives are also looking into options to enhance power supply and implement system upgrades.

ii. *Coal Combustion Residuals*

In November of 2020, the U.S. Environmental Protection Agency (EPA) published the final rule on Coal Combustion Residuals (CCR). The CCR rule noted that an impoundment facility will ensure there is no reasonable probability of adverse effects to human health and the environment. GRE's purchases electricity from Rainbow Energy; in turn Rainbow produces electricity from coal at its Coal Creek facility. EPA proposed that the liner used to store the ash from Coal Creek was noncompliant.

The status of GRE's compliance with the CCR is pending. So far, EPA completed taking comments on a proposed denial on January 25, 2023, but has not made any final determination. The proposed denial is with regard to an alternative liner submitted by GRE.[31]

It is uncertain what the final outcome will be regarding EPA's proposed noncompliance. One of the more severe outcomes would be that GRE ends purchases from Coal Creek for a significant period of time. In such an event, future plans for energy mix and capacity might be substantially different.

iii. Good Neighbor Rule

On January 31, 2023, the EPA disapproved Minnesota's State Implementation Plan for meeting Ambient Air Quality Standards in NOX (ozone). The failure to meet standards was to the Good Neighbor (or Interstate Transport) provision of the Clean Air Act. The Good Neighbor provision helps ensure that states do not impact down-wind states ability to meet the health-based standards for NOX.[32] In Minnesota's case, EPA states that NOX emissions interfere with the maintenance of air quality in Illinois. EPA estimates that the provision will reduce NOX emissions in Minnesota by 139 tons, or 5% when comparing 2027 with 2021 emissions.[33]

In response to an Information Request, GRE states that EPA proposed an alternate federal implementation plan that allocated 84 NOX allowances to GRE per Ozone season through 2025, where the Ozone season runs from May 1 through September 30 of each year. Given EPA's tradeable permit allowances GRE expects to have enough allowances to cover any summer emissions through 2025 but may be less certain after that year.[34]

iv. Remaining Federal Rules

GRE is currently compliant with the remaining federal rules investigated for this IRP. In some cases, EPA has submitted proposed rules that revise existing regulations. There is some uncertainty whether GRE will be compliant under the proposed rules if passed without any changes, which will make future plans important to monitor. Currently, the proposed rules are new, and the Department recommends that GRE be given more time to deliberate on the best plan forward.

The table below lists the remaining rules and GRE's current status. More detail on each rule and GRE's status is given in Attachment 2.

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[31] Source was downloaded on July 10, 2023 from https://www.epa.gov/coalash/coal-combustion-residuals-ccr-part-b-implementation.

[32] The provision requires that "each state's SIP contain adequate provisions to prohibit emissions from within the state from significantly contributing to nonattainment or interfering with maintenance of the NAAQS in other states." For more information on the ruling, see Federal Register :: Air Plan Disapproval; Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin; Air Plan Disapproval; Region 5 Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, downloaded on July 11, 2023.

[33] See maps in Good Neighbor Plan for 2015 Ozone NAAQS | US EPA, downloaded on July 11, 2023.

[34] GRE notes that the federal implementation plan could take effect as soon as August. However, GRE further notes that the program has been challenged by several states and has been stayed in at least one region.

Table 11: Remaining Federal Rules Relevant to GRE's IRP

Rule Name, Description, and Brief Analysis of Compliance
Cross State Air Pollution Rule (CSAPR)—The Cross State Air Pollution Rule sets standards meant to reduce smog and soot that travel across state boundaries. Under the final 2011 rule, Minnesota was required to reduce its emissions by participating in CSAPR's tradeable permit program. Today, GRE does not foresee any compliance issues regarding CSAPR.
Acid Rain Rule—The acid rain program required reductions in SO2 and NOX emissions that arise from the production of electricity. GRE states that increased reliance on renewable energy and a shift away from coal fired units has resulted in a surplus of tradeable permits and that GRE does not foresee any issues with compliance.
Greenhouse Gas Rules for Fossil Fuel Fired Power Plants—In May of 2023, EPA proposed a new rule that would limit carbon dioxide emissions from fossil-fuel fired power plants. GRE's Spiritwood Station may be impacted if the final rule is passed without any changes to the current EPA proposal. By 2030, GRE would have to install carbon capture and sequestration to the Spiritwood station if it wants to operate after 2039. Otherwise, Spiritwood can remain in operation until the end of 2039, but will need to co-fire natural gas at least 40% from 2035-2039.
Mercury and Air Toxic Standards (MATS)—National standards for mercury and Hazardous Air Pollutants for electric utilities are authorized under the MATS. In April 2023, EPA proposed updates and more stringent standards to the MATS rule. Among the changes, the proposal would strengthen the standard on particulate matter and tighten restrictions on steam generating and lignite-fired coal power plants. Although GRE states they are currently in compliance with the rule, it is uncertain whether GRE would be compliant with the new proposal. GRE's Spiritwood Station is capable of burning lignite coal. Also, both Spiritwood and Coal Creek are steam generating plants. The Department is uncertain whether GRE's Spiritwood Station would meet the proposed standards. Moreover, the Commission might consider future recommendations regarding Coal Creek if the power plant does not meet the standards in the finalized rule. If in more challenging circumstances for Coal Creek, both the CCR and MATS require changes, this could add to the total costs to operating the power plant.
National Ambient Air Quality Standards (NAAQS)—EPA set Ambient Air Quality standards through the NAAQS rule. The rule regulates 5 pollutants—Carbon Monoxide, Lead, Nitrogen Dioxide, Ozone, Particulate Pollution and Sulfur Dioxide. In a reply to an Information Request, GRE states that the utility does not have any NAAQS compliance obligations at this time.
Regional Haze Program—This rule monitors visibility in National Parks and Wilderness Areas. In Minnesota, the Boundary Waters Canoe Area and Voyagers National Park are included in the rule. Currently, GRE is exempted from any control requirements or emissions reductions in Minnesota's and North Dakota's State Plan. Comprehensive periodic revisions to Minnesota's plan are due in 2028. To the extent that the future revisions result in control requirements or emissions reductions that substantively raise costs, GRE may change its future plans in light of such revisions.

G. REPLY TO COMMISSION NOTICE

The Notice specified four topics as being open for comment:

- Should the Commission accept Great River Energy's (GRE) 2023-2037 Integrated Resource Plan (IRP)?
- What issues should the Commission consider for GRE's next IRP?
- When should GRE file its next IRP?
- Are there other issues or concerns related to this matter?

Regarding the first topic, the Department recommends the Commission accept GRE's IRP.

Regarding the second topic, the Department's recommendations regarding issues for the next IRP are in the recommendations section below.

Regarding the third topic, the Department notes that GRE's preferred plan adds substantial resources in the 2030 to 2032 timeframe. A resource plan filing in the spring of 2027 should enable the Commission to provide meaningful advice to GRE on these additions.

Regarding the fourth topic, one other concern is that there are a number of recent regulations. Many of these regulations either incentivize renewable energy production or penalize electricity produced from fossil fuels, especially coal. This may speed up the shift away from coal. It may also raise issues related to GRE's ability to reliably meet peak load demand in electricity. Future plans will be important to monitor to see how GRE complies with the regulations.

III. DEPARTMENT RECOMMENDATIONS

First, the Department recommends that, in the next IRP, GRE provide updated summary information on compliance and a discussion of GRE's work toward achieving compliance with the CIP letters, especially with the energy savings and low-income standards.

Second, the Department recommends that GRE should separately calculate emissions sold to the market with a factor reflective of carbon emissions due to electricity production from GRE. Whereas emissions purchased from the market should be calculated using an emissions factor representative of the MISO market.

Third, Department recommends GRE incorporate the following modeling suggestions in its next IRP:

- Ensure that the appropriate input files correspond to reported exports;
- Consider the use of a "setup" file for storing and transferring databases via spreadsheets;
- Develop a database around variables the utility has control over (scenarios), variables the utility does not have control over (contingencies), and the Commission's carbon cost and externality futures (futures), as depicted in Figure 3 above;

- Incorporate some level of externality and carbon costs into Base Case assumptions;
- Appropriately incorporate the Commission's regulatory costs into the model;
- Confer with other utilities and potentially other interested parties to determine a best practice to address externality and environmental costs;
- Include in its model a slightly broader range of potential resources, potentially determined through a more exhaustive pre-input study;
- Incorporate all known or planned resources into its model or explain why known or planned resources have been omitted;
- Try to pinpoint a moderate level of market sales to include in its base case, or at least in some scenarios, while being vigilant about avoiding capacity that is built solely to chase market prices;
- Provide a comparative analysis of emissions across sensitivities, using MISO carbon intensity rates for energy purchases from Rainbow if the Rainbow contract does not involve actual energy purchases and removing REC accounting for purposes of comparing sensitivities;
- Provide the relevant portions of the Rainbow contract(s) to demonstrate why a market carbon intensity rate is the more appropriate value;
- Develop a MIP stop basis and convergence tolerance cost analysis and consider these factors when developing the size of potential resources; and
- Continue to monitor battery arbitrage uncertainties in the modeling software and provide an update about further knowledge learned in its next IRP.

Fourth, the Department recommends that GRE's forecasts in this proceeding not be used in any future CN proceeding.

Below are more detailed descriptions of other federal regulations that were briefly discussed in the main body of the comment. GRE appears to be currently compliant with these regulations. Provided below is more background about the rule, GRE's statemen of compliance, and a limited economic analysis.

A. CROSS STATE AIR POLLUTION RULE (CSAPR)

In 2011 EPA finalized the Cross State Air Pollution Rule, which sets standards for SO2 and NOX emissions from upwind states. The standards were meant to reduce smog and soot that travel to other states. Under the final 2011 rule, Minnesota was required to reduce its emissions by participating CSAPR's tradeable permit program.[1]

GRE does not foresee any compliance issues regarding CSAPR. Although their combustion turbines are subject to the rule, GRE has accumulated many allowances. The utility is allocated 11 allowances every year and GRE has accumulated 107 SO2 and 2,100 NOX banked allowances as of 2023.

B. ACID RAIN RULE

The acid rain program required reductions in SO2 and NOX emissions arising from the production of electricity. Under Title IV Acid Deposition Control separate provisions were made for SO2 and NOX. The SO2 program capped emission from electric generating units and allowed for tradeable permits. The NOX program limited emissions from the subset of coal-fired units.

GRE states that increased reliance on renewable energy and a shift away from coal firing units has resulted in a surplus of tradeable permits in which GRE does not foresee any issues with compliance.

C. GREENHOUSE GAS RULES FOR FOSSIL FUEL FIRED POWER PLANTS

In May of 2023, EPA proposed a new rule that would limit carbon dioxide emissions from fossil fuel fired power plants. Starting in 2030 and phased in over time, the proposal would limit emission from certain coal and natural gas types of production, namely new gas-fired combustion turbines, existing coal, oil and gas fired steam generating units, and certain existing gas-fired combustion turbines. The limits were based upon use of technologies such as carbon capture and sequestration and natural gas co-firing.

Although GRE's natural gas combustion turbines in Minnesota would not be affected, GRE's Spiritwood Station may be impacted if the final rule is passed without any changes to the current EPA proposal. By 2030, GRE would have to install carbon capture and sequestration at

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[1] Substantive updates to the rule took place in 2016 and 2021 but did not affect Minnesota. See [Overview of the Cross-State Air Pollution Rule (CSAPR) | US EPA](#).

Spiritwood Station if it wants to operate after 2039. Otherwise, Spiritwood can remain in operation until the end of 2039, but will need to co-fire natural gas at least 40% from 2035 to 2039.

D. MERCURY AND AIR TOXIC STANDARDS (MATS)

National Standards for mercury and Hazardous Air Pollutants for electric utilities are authorized under the Mercury and Air Toxics Standards or MATS.[2] Mercury is a naturally occurring element found in coal and other rocks. One way the pollutants enter the atmosphere is with the production of electricity by using coal-fired power plants. The USGS states that coal-fired plants are one of the main sources of Mercury pollutants.[3] Eventually ending up in lakes and aquatic environment, EPA notes that the main way that people are exposed to mercury is by eating fish and shellfish that have high levels of methylmercury, which is a highly toxic form of mercury.

In a response to an Information Request, GRE states they are compliant with the rule. Spiritwood is subject to MATS and adheres to electric monitoring and reporting standards.

In April 2023, EPA proposed updates and more stringent standards to the MATS rule. Among the changes, the proposal would strengthen the standard on particulate matter and tighten restrictions on lignite coal power plants. EPA states they based their proposal on current technology available to utilities.

It is uncertain whether GRE would be compliant with the new rule, or if the rule came into effect without any changes, whether GRE would be compliant. GRE's Spiritwood Station does burn lignite coal. Also, both Spiritwood and Coal Creek are steam generating units. However, the Department is uncertain whether GRE's Spiritwood station would meet the proposed standards. Moreover, the Commission might consider whether they are concerned about Coal Creek's emissions if the power plant would not meet the proposed standards, and whether meeting the proposed standard might affect the reliability of Coal Creek station.

EPA set technology-based emissions standards for mercury and other hazardous air pollutants (HAP) emitted by units with a capacity of more than 25 megawatts. EPA states that they set the standards based upon the best-performing sources and apply to existing and new EGUs.

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[2] EPA states that regulated pollutants include "mercury; acid gas hazardous air pollutants (HAP) such as hydrogen chloride (H Cl) and hydrogen fluoride; non-mercury HAP metals such as nickel, lead, and chromium; and organic HAP such as formaldehyde and dioxin/furan from coal- and oil-fired power plants." See Fact Sheet (epa.gov) and https://www.epa.gov/stationary-sources-air-pollution/mercury-and-air-toxics-standards. Downloaded on July 12, 2023.

[3] See https://www.usgs.gov/special-topics/water-science-school/science/mercury-contamination-aquatic-environments#overview. Downloaded on July 12, 2023.

EPA claims that MATS, along with significant changes in the power sector, has achieved significant health and environmental benefits by reducing a broad range of hazardous air pollutants. By 2017 mercury emissions had dropped by 86 percent; down to approximately 4 tons. Acid gas HAP and non-mercury metals are down 96 percent and 81 percent respectively when compared to 2010 levels.

E. NATIONAL AMBIENT AIR QUALITY STANDARDS (NAAQS)

EPA sets Ambient Air Quality standards through the NAAQS rule. The rule regulates 5 pollutants—Carbon Monoxide, Lead, Nitrogen Dioxide, Ozone, Particulate Pollution and Sulfur Dioxide. Required by the Clean Air Act, the NAAQS is based upon two types of standards. Public health standards help protect sensitive populations such as asthmatics, children, and the elderly. Public welfare standards help preserve visibility and protect against damage to animals.

In January 2023, the EPA proposed revised the NAAQS standards. The standards would in some cases, reduce the allowable size of particulate matter.[4]

In a response to an Information Request, GRE states that the utility does not have any NAAQS compliance obligations at this time. However, they note that the Minnesota Pollution Control Agency has the responsibility to meet the NAAQS standards. If at some point Minnesota falls out of compliance, GRE may need to adjust their emissions under the NAAQS to conform with Minnesota's State Implementation Plan. Moreover, it is uncertain whether the finalized revision to the NAAQS rule, will affect GRE's compliance requirements. If so, depending upon the extent of the changes to compliance, GRE may need to adjust its energy mix and possibly its capacity.

F. REGIONAL HAZE PROGRAM

This rule monitors visibility in National Parks and Wilderness Areas. In Minnesota, the Boundary Waters Canoe Area and Voyagers National Park are included in this rule. Currently, Minnesota is compliant and GRE is exempted from any control requirements or emissions reductions in Minnesota's and North Dakota's State Plans.[5]

Under the rule, States must coordinate with the EPA, the National Park Service, U.S. Fish and Wildlife Service, the U.S. Forest Service and other interested parties to develop an air quality protection plan. Comprehensive periodic revisions to the State's plan are due in 2028. To the extent that the future revisions result in control requirements or emissions reductions that substantively raise costs, GRE may change its future plans in light of such revisions. However,

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[4] See Proposed Decision for the Reconsideration of the National Ambient Air Quality Standards for Particulate Matter (PM) | US EPA. Downloaded on July 12, 2023.

[5] GRE's combustion turbine facility emissions are each less than 100 tons per year as MPCA's threshold.

for this rule and other recently finalized and proposed rules, the effects are currently more uncertain. This elevates the importance of future IRPs by GRE and other utilities.

In this attachment the Department further examines CIP goals and GRE's history of compliance with the goals.

A. CIP GOALS AND SUB-GOALS

Minnesota's 2022 Statutes include several goals and sub-goals for CIP. Such goals are related to conservation and energy efficiency improvements. The table below lists the quantitatively measurable goals that are applicable to GRE.

Table A2.1 Description of CIP Goals

#	Standard	Amount	Comment	Citation
1.	Total Energy Savings (kWh)*	1.5% of gross annual retail energy sales less revenue from exempt customers.**	Minimum amount.	Minnesota Statutes §§ 216B.2403, 216B.2403, Subd. 2
1.a.	Minimum energy conservation improvements (kWh)***	0.95 percent of gross annual retail energy sales	Minimum amount.	Minnesota Statutes §§ 216B.2403, 216B.2403, Subd. 2
1.b.	Cap on efficient fuel switching improvements (kWh)	0.55 percent of gross annual retail energy sales less revenue from exempt customers	Maximum percentage that can be attributed to energy savings goal. Provision ends July 1, 2026.	Minnesota Statutes § 216B.2403, subd. 2(3)
1.c.	Cap on purchases from Large Solar Energy Plant (kWh)	22 percent of the 1.5 percent energy conservation savings goal	Commission may reject if not in the public interest. Also, not applicable if counts toward renewable energy objectives under Minnesota Statutes 216B.1691.	Minnesota Statutes § 216B.241, subd. 5c(c)
1.d.	Distributed and Renewable Generation Spending Cap ($)	5 percent of the total amount to be spent on energy conservation	Applies to municipality or rural electric association. Eligible distributed energy projects include construction of a facility that uses	Minnesota Statutes § 216B.2411, Subd. 1

#	Standard	Amount	Comment	Citation
			certain renewable energy sources (or fuels), natural gas; and qualifying solar energy projects.****	
1.e	R&D Spending Cap ($)	10 percent of the total amount spent and invested on energy conservation	Maximum allowable percentage that can be claimed	Minnesota Statutes § 216B.2403, Subd. 3(g)
2.	Total Spending on Energy efficiency Improvements ($)*****	1.5% of gross operating revenue less revenues from exempt Customers	Applies to utilities that do not meet their energy conservation goal; or do not spend at least 1.5 percent on energy conservation improvements for three consecutive years.	Minnesota Statutes § 216B.2403, subd. 4
3.	Low-Income Spending ($)	0.2% of gross operating revenue of each member utility	Spending on energy conservation programs for low-income customers and renters.	Minnesota Statutes §§ 216B.241 subd. 1(l) and 216B.241 subd. 5
3.a.	Cap on Low-Income spending for pre-weatherization measures ($)	15 percent of spending on low-income energy conservation	Maximum allowable amount	Minnesota Statutes § 216B.2403 subd. 5(f)

#	Standard	Amount	Comment	Citation

*Upon request by the cooperative, the Commission may reduce the energy savings goal to only include energy conservation improvements of 0.95 percent.
**Gross annual retail sales is defined as weather-normalized sales averaged over the most recent three years. Can carry forward energy savings in excess of the 1.5 percent goal for up to 3 years for most improvements. The exception is that energy utility infrastructure projects may be carried up to 5-years.
***Statutes define an energy conservation improvement as a project that results in a net reduction in electricity consumption. Examples include high-efficiency gas furnaces, LED lighting, and improvements to the energy management of a commercial building (Minnesota Statutes § 216B.2402, subd. 6).
****See Minnesota Statutes § 216B.2411 for eligible renewable energy sources, renewable energy fuels, and qualifying solar projects. Upon approval by the Commission, a municipal, rural electric association, or public utility may assign up to 10 percent of its distributed renewable generation to satisfy the standard on energy efficiency improvements.
***** Here, energy efficiency differs from energy conservation in that it does not include all energy savings. Instead, energy efficiency includes measures or programs that target residential consumer behavior or target commercial and industrial equipment and processes. Only measures or programs that do not reduce the quality or level of service can qualify as an energy efficiency improvement under Minnesota Statutes (Minnesota Statutes § 216B.2402, subd. 7).

B. HISTORY OF CIP COMPLIANCE

Because of its relevance to GRE's IRP, the Department examined GRE's prior record of CIP approvals for the years 2016 through 2020. Tables A2.2a and A2.2b below list CIP goals and whether or not GRE met the goals by year in accord with the CIP letters. The first table (A2.2a) depicts GRE's record of meeting the goals when serving member cooperatives that contract with GRE for all electricity needs. Table A2.2b lists GRE's record when providing service to customers with contracts for a fixed amount of electricity. For brevity purposes, the Department only looked at the main CIP goals.

Shaded in red are the years in which GRE fell short of CIP's statutory goal as stated in the CIP letters. GRE did not meet the energy savings goal for both customer types for 5 out of the 5 years examined by the Department. Also, GRE did not meet the low-income spending goal for all five years in Tables A2.2a and A2.2b.

Table A2.2a GRE's CIP Record When Servicing Customers that Purchase All Electricity from GRE

Metric	Year				
	2016	2017	2018	2019	2020
	Passed	Passed	Passed	Passed	Passed
Energy Savings (kWh)	No	No	No	No	No
Total Spending ($)	Yes	Yes	Yes	Yes	Yes
Low-Income Spending ($)	No	No	No	No	No
R&D Spending Cap ($)	Yes	Yes	Yes	Yes	Yes
Distributed and Renewable Generation Spending Cap ($)	Yes	Yes	Yes	Yes	Yes
Load Management Spending ($)	Yes	Yes	Yes	Yes	Yes

Source: Department's CIP approval letters from Docket Nos. E,G999/CIP-21-24, E,G999/CIP-20-24, E,G999/CIP-19-24, E,G999/CIP-18-500, and E,G999/CIP-18-499.

Table A2.2b GRE's CIP Record When Servicing Customers that Purchase a Fixed Amount of Electricity

Metric	Year				
	2016	2017	2018	2019	2020
	Passed	Passed	Passed	Passed	Passed
Energy Savings (kWh)	No	No	No	No	No
Total Spending ($)	No	No	Yes	No	No
Low-Income Spending ($)	No	No	No	No	No
R&D Spending Cap ($)	Yes	Yes	Yes	Yes	Yes
Distributed and Renewable Generation Spending Cap ($)	Yes	Yes	Yes	Yes	Yes
Load Management Spending ($)	Yes	Yes	Yes	Yes	Yes

Source: Department's CIP approval letters from Docket Nos. E,G999/CIP-21-24, E,G999/CIP-20-24, E,G999/CIP-19-24, E,G999/CIP-18-500, and E,G999/CIP-18-499.

1. Investigation of CIP's Energy Savings Goal

In the last IRP (Docket No. ET2/RP-17-263), the Commission considered GRE's ability to meet the energy savings goal of 1.5 percent. Based upon comments from the Department, the Commission ordered GRE to achieve an average annual energy savings of 1.0 percent , or 122,228,338 kWh. The Department originally recommended a 1.25 percent savings, but recommended further reduction to 1.0 percent after reviewing additional information from GRE and noting that achieving 1.25 percent instead of 1 percent would cost an additional $90 million.[1] Using energy savings statistics from 2018 through 2020 CIP approval letters, GRE fell short of the annual 1.0 percent by 843,000 kWh to 5,975,000 kWh (or from 0.7 to 4.9 percent). However, GRE states that it met the 1.00 percent goal for the years 2015 through 2021. GRE might have actually met this goal by calculating the percentage in a different way than the Department in its CIP letters. Given the timeline for this IRP, the Department will not be able to review the reasonableness of any alternative methods of calculation. It is also important to note that GRE is still subject to the 1.5 percent savings goal under CIP. GRE did not apply for a reduction to this goal.

2. Compliance With the Low-Income Spending Goal

The second compliance issue was with the low-income spending goal, which may be challenging. Not only may GRE have to implement less cost-effective energy improvements, but there may be low take-up rates to low-income CIP programs, especially in more rural areas of the state. Efforts to increase equity may not always be as cost-effective, albeit efforts might in-theory raise revenue by reducing nonpayment among low-income consumers. On this matter, the Commission restated a criterion in its last docket; GRE should “keep the customers’ bills and the utility’s rates as low as practicable.”

Whether More Than One GRE Member is Noncompliant

Another challenge is that all of GRE’s member cooperatives must be compliant with the CIP low-income standard for the Department to deem GRE compliant in any given year. A single member cooperative can be noncompliant and GRE would then be deemed noncompliant as well. Using data from the CIP letters, the Department checked how often GRE was found noncompliant because only one member cooperative was noncompliant. The table below lists the number and percentage of member cooperatives that are noncompliant by customer type for the years 2016 through 2020.

Table A2.3 Number and Percent of GRE’s Member Cooperatives

Not Compliant with Low-income Standard

	Purchase all electricity from GRE		Purchase a Fixed Amount from GRE	
Year	Number	Number	Number	Percent
2016	1	5%	2	25%
2017	3	14%	2	33%
2018	3	14%	2	33%
2019	5	25%	3	50%
2020	8	40%	4	57%

Source: Department’s CIP approval letters from Docket Nos. E,G999/CIP-21-24, E,G999/CIP-20-24, E,G999/CIP-19-24, E,G999/CIP-18-500, and E,G999/CIP-18-499.

[1] The Department also recommended that GRE continue to motivate its members to exceed past energy savings achievements. See Docket No. ET-2/RP-17-286 Order Points Dated November 28, 2018

The table show that more than one member cooperative was noncompliant in all the years, except for 2016. In that year, only one member cooperative that purchased all its electricity from GRE did not meet the low-income goal. In other years two or more member cooperatives did not meet the goal. In the last two years, an increasing number of member cooperatives did not meet the low-income spending goals.

Whether some Member Cooperative Consistently Meet the Goals

Tables A2.4a and A2.4b list the individual member cooperatives and their record in meeting the goals. The tables examines whether there are some members that consistently meet the goals. In examining the tables, a higher proportion of members that purchase all their contracts more consistently met the goals, 16 of the 21 members met the goals for at least four out of the five years. Among members with a fixed contract, only 2 of the 8 member cooperatives more consistently met the goals.

Although several member cooperatives are not compliant, the average dollar shortfall is relatively small—$17,516. Percentagewise, the shortfall varies and can be as high as 100 percent. Many, or all of the member cooperatives are small in size, all were expected to spend less than $100,000. What may be most important in such cases is if there are vulnerable or important communities within the noncompliant member cooperative territories. For example, if spending is relatively low in higher poverty rate communities, or within Indian Country, then there may be added interest in helping individual customers receive the benefits from CIP.

It is also worth noting that several member utilities could have chosen to be exempt from CIP during this timeframe due to their size pursuant to Minnesota Statutes § 216B.2403 subd. 1 but continue to offer programs and reporting with GRE. While the historical sales and revenue from these members are included when calculating CIP goals, and these members contribute to the compliance of GRE's low-income spending standard, they could have chosen not to participate and would not have been required to meet any of the goals. These members include Arrowhead, Brown, Goodhue, North Itasca, Agralite, Redwood, and South Central. Also, Elk River began operating its CIP programs independently as of 2019 and Connexus Energy will be operating independently as of 2023.

Table A2.4a Record of GRE's Customers in Meeting CIP's Low-income Spending Standards—Purchased All Electricity From GRE

Member Organization	2016	2017	2018	2019	2020
Arrowhead Electric Coop. Inc	Yes	Yes	Yes	Yes	Yes
BENCO Electric Coop	Yes	Yes	Yes	Yes	Yes
Brown Co Rural Electrical Assn	Yes	Yes	Yes	Yes	Yes
Connexus Energy	Yes	Yes	Yes	Yes	Yes
Cooperative Light & Power	Yes	Yes	Yes	Yes	Yes
Dakota Electric Assn	Yes	Yes	Yes	Yes	Yes
East Central Energy	Yes	Yes	Yes	Yes	Yes
Elk River Municipal Utilities	Yes	Yes	Yes	NA	NA
Goodhue County Coop Electric Assn	No	Yes	No	No	No
Itasca Mantrap Coop Electric Assn	Yes	Yes	Yes	Yes	No
Kandiyohi Power Coop	Yes	No	No	No	No
Lake Country Power	Yes	Yes	Yes	Yes	Yes
Lake Region Electric Coop	Yes	No	Yes	No	No
McLeod Coop Power Assn	Yes	Yes	Yes	Yes	Yes
Mille Lacs Electric Coop	Yes	Yes	Yes	Yes	No
Nobles Cooperative Electric	Yes	Yes	Yes	Yes	Yes
North Itasca Electric Coop	Yes	Yes	Yes	Yes	No
Runestone Electric Assn	Yes	Yes	Yes	Yes	Yes
Stearns Coop Electric Assn	Yes	Yes	Yes	Yes	No
Steele Waseca Coop Electric	Yes	No	No	No	Yes
Todd Wadena Electric Coop	Yes	Yes	Yes	No	No

Source: Department's CIP approval letters from Docket Nos. E,G999/CIP-21-24, E,G999/CIP-20-24, E,G999/CIP-19-24, E,G999/CIP-18-500, and E,G999/CIP-18-499.

Table A2.4b GRE Customer's Record of Meeting the CIP Low-income Standards—Customers With Fixed Contracts

Member Organization	2016	2017	2018	2019	D2020
Agralite Cooperative	Yes	No	No	No	No
Crow Wing Coop Power & Light. Inc.	No	Yes	No	No	No
Federated Rural Electric Assn	Yes	Yes	Yes	Yes	Yes
Meeker Coop Light & Power Assn	Yes	Yes	No	Yes	No
Minnesota Valley Electric Coop	No	No	Yes	Yes	Yes
Redwood Electric Coop	Yes	Yes	NA	No	No
South Central Electric Assn	Yes	Yes	NA	NA	NA
Wright-Hennepin Coop Electric Assn	Yes	No	Yes	Yes	Yes

Source: Department's CIP approval letters from Docket Nos. E,G999/CIP-21-24, E,G999/CIP-20-24, E,G999/CIP-19-24, E,G999/CIP-18-500, and E,G999/CIP-18-499.

Party	Run Name	MIP	Objective Function (PV $000)	Percent Difference
GRE	Unit Updates (Base Case)	10	2,080,815.23	
DOC	DMatch Unit Updates (Base Case)	10	2,080,798.72	
				0.00%
GRE	CT Partial Commit	10	1,726,943.87	
DOC	DMatch CT Partial Commitment	10	1,966,608.51	
				-12.19%
GRE	Extend Wind Contracts	10	1,965,290.37	
DOC	DMatch Extend Wind Contracts	10	1,965,310.21	
				0.00%
GRE	Extreme Summer & Winter Forecast	10	2,102,104.83	
DOC	DMatch Extreme Summer & Winter	10	2,102,088.19	
				0.00%
GRE	High Externality High Reg	10	2,080,815.23	
DOC	DMatch High Externality/High Regulatory	10	2,080,798.72	
				0.00%
GRE	High Externality High Env	10	2,080,815.23	
DOC	DMatch High Externality/High Environmental	10	2,080,798.72	
				0.00%
GRE	Low Externality Low Env	10	2,080,815.23	
DOC	DMatch Low Externality/Low Environmental	10	2,080,798.72	
				0.00%
GRE	Reference (High Env With High Reg)	10	2,080,815.23	
DOC	DMatch Reference (All High Externality Costs)	10	2,080,798.72	
				0.00%
GRE	Low Externality Low Reg	10	2,080,815.23	
DOC	DMatch Low Externality/Low Regulatory	10	2,080,798.72	
				0.00%
GRE	High Load Forecast	10	2,150,648.83	
DOC	DMatch High Load Forecast	10	2,150,640.64	
				0.00%
GRE	High Market & NG Prices	10	3,067,386.62	
DOC	DMatch High Prices	10	3,067,184.38	
				0.01%
GRE	High Market Purchases	10	1,920,425.60	
DOC	DMatch High Market Purchases	10	1,920,394.75	
				0.00%
GRE	Low Load Forecast	10	1,994,109.44	
DOC	DMatch Low Load Forecast	10	1,994,090.24	
				0.00%
GRE	Low Market & NG Prices	10	1,754,952.06	
DOC	DMatch Low Prices	10	1,754,938.75	
				0.00%
GRE	Low Solar & Wind Prices	10	2,004,673.28	
DOC	DMatch Low Renewable Prices	10	2,004,657.02	
				0.00%
GRE	Low Solar Price	10	2,051,806.34	
DOC	DMatch Low Solar Price	10	2,051,787.65	
				0.00%
GRE	Low Wind Price	10	2,020,471.42	
DOC	DMatch Low Wind Price	10	2,020,455.17	
				0.00%
GRE	Lower RRA Accreditation	10	2,083,366.14	
DOC	DMatch Lower RRA Accrediation	10	2,083,349.89	
				0.00%
GRE	MH Ends Early	10	2,135,486.34	
DOC	DMatch MH Contract Ends	10	2,135,470.98	
				0.00%
GRE	New DSM Added	10	2,296,073.47	
DOC	DMatch DSM Program Additions	10	2,295,801.09	
				0.01%

GRE	No Market Purchaes	10	2,795,365.38	
DOC	DMatch No Market Purchases	10	2,795,355.65	
				0.00%
GRE	Preferred Plan	10	2,123,883.78	
DOC	DMatch Preferred Plan	10	2,123,863.30	
				0.00%
GRE	Registered LMR Increase	10	2,079,751.04	
DOC	DMatch Registered LMR Increase	10	2,079,606.14	
				0.01%
GRE	Seasonal PRM Change	10	2,079,623.94	
DOC	DMatch Seasonal PRM Change	10	2,079,732.61	
				-0.01%
GRE	Storage Costs Flat	10	2,090,131.07	
DOC	DMatch Storage Costs Flat	10	2,090,114.56	
				0.00%
GRE	SWS Retirement 2030	10	2,359,168.51	
DOC	DMatch SWS Retirement	10	2,359,152.38	
				0.00%
GRE	Wind Self-Build	10	1,760,089.98	
DOC	DMatch Self-Build Wind with PTC	10	1,850,130.94	
				-4.87%
GRE	Without Battery Storage	10	2,181,031.68	
DOC	DMatch No Battery Offered	10	2,181,133.57	
				0.00%

Emissions, Externalities, and Carbon Costs

When a fossil-fuel power plant operates it produces various emissions (CO, CO_2, NO_X, SO_X, etc.). To calculate the total externality cost associated with these emissions, the analyst or model:

- Determines the amount of energy produced by the plant over a given period of time (MWh/year)
- Determines the release rate of each type of emission at that specific plant (this can be in tons/MWh or tons/MMBTU [for the fuel] and MMBTU/MWh [for the generator])
- Determines the "tax" rate for each type of emission ($/ton)
- Multiplies the release rate by the tax rate for each type of emission to obtain the externality rate ($/MWh)
- Multiplies the plant's energy produced in a given time (MWh/year) by the externality rate ($/MWh) of each type of emission to obtain the externality cost associated with each emission ($/year)
- Sums the results to get total externality costs ($/year)[1]

Externality costs are typically reported in nominal dollars, but they are not actually built into any electricity prices or rates. They simply represent the cost of societal ills associated with the emissions; nobody pays for them with money.

When externality costs get bundled into the price of electricity (or *internalized*), they are referred to as internalized costs, internalized externality costs, or, in the case of the Commission's futures, "regulatory costs." Unlike externality costs, regulatory costs are actual costs that *do* get paid for with money.[2]

When regulatory costs are present, the price to generate energy at a specific plant or resource is dependent upon emissions production at that plant or resource. Since utilities choose to run and dispatch resources based on price, and since the MISO marketplace facilitates purchases and sales based on price, the inclusion of regulatory costs impacts both utility choices and market outcomes.

[1] In Strategist and EnCompass, this cost is tracked separately from the internal costs and reported as part of societal costs but not revenue requirements..

[2] Note that while there are currently no CO_2 internal costs in rates, there may be some costs for SO_x and NO_x allowances built into rates.

The Minnesota Legislature directed the Minnesota Commission to develop externality and regulatory (internal) costs. The Commission produced an order that calculated CO_2 internal costs implements a nationwide CO_2 emissions tax starting in 2025. In other words, the Commission envisioned a theoretical future in which CO_2 externality costs are internalized in rates. However, it is also possible that this does not happen. Therefore, starting in 2025, there are two potential futures of the treatment of CO_2 externality and regulatory costs: either there is no emissions tax and the externality costs associated with emissions remain 100% externality costs, or *some* externality costs remain externality costs (non-CO_2) and *some* externality costs (CO_2) are internalized in rates via the assumed nationwide CO_2 emissions tax and become regulatory costs.

In resource planning, the externality costs associated with the emissions from all of a utility's resources remain externality costs and will not affect the dispatch order or the Present Value Revenue Requirement (PVRR). Externality costs *will* affect the Present Value Social Cost (PVSC), since PVSC is equal to PVRR + externalities. Therefore, if CO_2 externality costs remains externality costs after 2025, the only thing to be determined is the externality rates: for example, should they be high, middle, or low? In EnCompass, GRE captures these two options in the sensitivities "Low Externality/Low Environmental" and "High Externality/High Environmental."

If Congress decides to enact some type of CO_2 emissions tax, then CO_2 externality costs associated with emissions are internalized as regulatory costs (limited to CO_2 in the PUC's order); the remaining externality costs (all except CO_2) continue to be considered externality costs. In EnCompass, GRE captures various options in the sensitivities "High Externality/High Regulatory," "Low Externality/Low Regulatory," and "Reference (All High Externality Costs)."

EnCompass and Convergence Tolerance

A. Background

When used as a capacity expansion model, EnCompass uses a mathematical method called mixed integer programming (MIP) to determine the least cost expansion plan. At a high level, EnCompass's MIP process involves two basic steps. In the first step EnCompass determines the potential ideal (or lowest possible cost) expansion plan by adding fractions of units. For example, the potential ideal plan may involve adding 30 percent of a wind unit in 2025, 70 percent of a solar unit in 2027, and 20 percent of a combustion turbine unit in 2030. The assumption is that fractions of units are not possible in the real world, and thus a second step is necessary.

In the second step EnCompass experiments by adding whole units and not fractions of units in order to create feasible plans. For example, a feasible plan may involve adding one wind unit in 2025 and one combustion turbine unit in 2030. EnCompass continues to experiment until it finds a feasible plan (using whole units) that falls within an acceptable cost range. EnCompass then ceases experimenting and reports of the results of the feasible plan.

The range of acceptable costs is defined by the modeler and is referred to as the "MIP Stop Basis." EnCompass's MIP Stop Basis input is a fraction of the cost of the potential ideal plan. The potential ideal plan still includes fractional units, so the ideal (using whole units) plan cost must be higher than the potential ideal plan. During the MIP process, the costs of this potential ideal plan will increase as potential feasible plans are evaluated and eliminated from consideration. For example, if the cost of the potential ideal plan is $6.527 billion[1] and the MIP Stop basis input is 80 (which is 0.0080) then the maximum allowed cost would be $6.579 billion.[2] The first feasible plan that EnCompass finds that has a cost between $6.527 billion and $6.579 billion would be reported by EnCompass as the expansion plan.[3]

Note that any changes to EnCompass inputs that change the costs considered in creating the ideal plan (such as fuel costs or the demand and energy forecasts) will change the range of acceptable costs even if the MIP Stop Basis input was not changed. Thus, use of a higher MIP Stop Basis does not necessarily mean a wider range of acceptable costs if the other inputs were changed as well. For example, in a first run EnCompass might calculate a potential ideal plan

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[1] The ideal cost includes only variable costs of existing units and all costs (fixed and variable) for new units. So, the ideal cost excludes fixed costs of existing units.

[2] The equation is $6.527 billion * [1 + (80/10,000)] = $6.579 billion.

[3] It is possible to require EnCompass to find and report on multiple plans but that and other complications are not discussed here.

cost of $1.000 billion. If the MIP Stop Basis input is 80, then the range of acceptable costs is from $1.000 billion to $1.008 billion. This creates a gap of $8 million for feasible plans. Second, assume that the modeler runs a contingency with a lower energy and demand forecast, resulting in a potential ideal plan cost of $0.500 billion. If the MIP Stop Basis input remains at 80, then the range of acceptable costs narrows to between $0.500 billion and $0.504 billion. This leaves a gap of only $4 million for feasible plans. Since the cost of expansion units has not changed, the resulting $4 million gap might be too small for EnCompass to fit in whole expansion units (other than fractions).[4] However, if the MIP Stop Basis input is increased from 80 to 160, then the range of acceptable costs broadens to between $0.500 billion and $0.508 billion (a gap of $8 million again). Thus, the use of a higher MIP Stop Basis in the second (low forecast) EnCompass run creates the same $8 million range of acceptable costs as in the first EnCompass run.

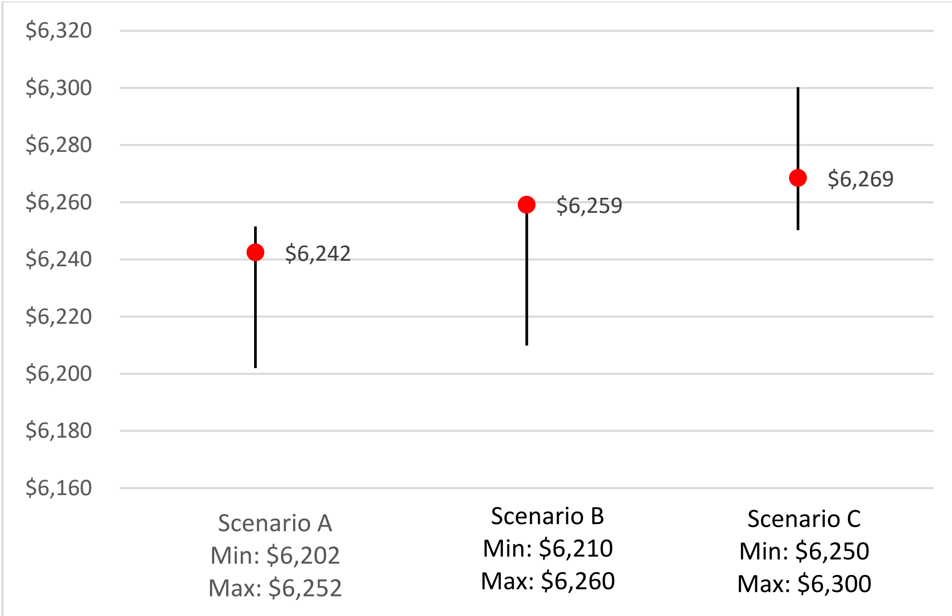
As shown above, everything else held constant, the smaller the MIP Stop Basis input the narrower the range of acceptable costs becomes. However, EnCompass, on average, will require a longer duration to find a feasible plan and may not be able to find a plan at all if computing resources are limiting.

B. Understanding EnCompass Cost Results

When comparing the costs of various plans to each other it is important to keep the convergence tolerance of the EnCompass modeling process in mind. For example, in Chart 1 below the lines represents the range of acceptable costs (from the potential ideal plan's cost to the maximum allowed cost) for three scenarios. The dots represent the cost reported by EnCompass for the feasible plan for the three scenarios. For simplicity, assume the only difference among the three scenarios is that they have different expansion units available to be added. Of the three plans, at first glance "Scenario A" is clearly reported as least cost, "Scenario B" has a cost higher by $17 million, and "Scenario C" has a higher cost than Scenario A by $27 million.

Chart A5.1: MIP Convergence Example ($ million)

[4] While the numbers are hypothetical, this situation was encountered by the Department in past proceedings.



However, when examining the bars in Chart A5.1, which shows the range of acceptable costs, it is possible for both Scenarios A and B to have feasible plans with costs lower than the $6,242 million reported for Scenario A because both extend below $6,242 million. Likewise, it is not possible for Scenario C to have a feasible plan with a cost lower than the $6,242 million because the bar (the range of acceptable costs) does not extend far enough. In this example, given the information in Chart 1 the Department would conclude two things. First, Scenario C clearly cannot be least cost since Scenario A has a reported cost lower than the potential ideal (or lowest possible) cost of Scenario C. Second, the reported costs of Scenario A and B are within the tolerance inherent in the model; one plan cannot be said to be cheaper than the other.[5]

C. Understanding EnCompass Expansion Unit Results

The convergence tolerance inherent in EnCompass's cost minimization routine also impacts how to understand the number of expansion units added. Table 1 below shows the solar unit capacity added in four contingencies for 12 different example scenarios.[6] These results were taken from an early test run of EnCompass in a past proceeding and do not represent the Department analysis here. Instead, the results are merely used to illustrate the matter at hand.

[5] The existence of a margin of error for a modeling result is not unique to EnCompass and has been discussed by the Department in past resource plan comments regarding Strategist results.

[6] These results were taken from an early test run of EnCompass and do not represent Department Staff's final analysis in the instant proceeding. Instead, the results are merely used to illustrate the matter at hand.

Table A5.1: Solar Expansion Units Added (50 MW each) When Varying Solar and Wind Prices, Compared to Base Case Prices, Across Twelve Different Scenarios;

(Highlighted Cells Are What the Department Expected Should be the High Values)

	Low Wind Prices	High Wind Prices	Low Solar Prices	High Solar Prices
Scenario 1	100	300	750	50
Scenario 2	50	300	(50)	(100)
Scenario 3	(200)	(150)	750	(150)
Scenario 4	(250)	50	850	(250)
Scenario 5	-	250	650	(50)
Scenario 6	(150)	100	700	-
Scenario 7	650	650	750	(50)
Scenario 8	(450)	-	50	(550)
Scenario 9	100	100	50	(100)
Scenario 10	150	350	450	400
Scenario 11	100	250	450	(50)
Scenario 12	(250)	150	200	(600)
Increase	6	10	11	2
Decrease	5	1	1	9
Increase > 100 MW	2	7	9	1
Decrease <= 100 MW	5	1	-	4

For ease of understanding, in Table A5.1 the capacity added is shown as the change in capacity added from the base case of that scenario. For example, in Scenario 1, changing to low wind prices resulted in EnCompass adding an additional 100 MW of solar capacity.

When reviewing the data in Table A5.1 the Department expected the following results:

- Increase in wind prices—results in more solar capacity added;
- Decrease in wind prices—results in less solar capacity added;
- Increase in solar prices—results in less solar capacity added, and
- Decrease in solar prices—results in more solar capacity added.

The Department understood that this would not always be the result because complex system effects may lead to unexpected results. However, the expectation was that the expected results should appear in the vast majority of the cases. The actual result, in the contingency where wind prices are decreased, was the most common result is that more solar capacity is added rather than less.

To understand why an unexpected result was occurring so frequently, the Department considered several potential explanations. One explanation of importance is that the net cost increase/decrease of adding/subtracting 50 MW or 100 MW of solar capacity might be so low that the cost increase leaves several plans within the acceptable range of costs determined by the MIP process.

The hypothetical cost range discussed in Table 1 was $6.527 billion to $6.579 billion.[7] In contrast, a 50 MW solar unit added in 2027 might impose a cost increase of about $14 million[8] in net present value. If the actual least cost plan is $6.550 billion the net cost increase of adding another 50 MW of solar results in a plan with a total cost of $6.564 billion, still within the acceptable range. From this it can be seen that the existence of a range of acceptable costs implies that cost changes that are small in magnitude may be within the convergence tolerance of the model. In this example, there are at least two plans (with and without the hypothetical solar unit added in 2027) within the acceptable range and either might be reported by EnCompass.

In summary, a 50 MW wind and solar expansion unit may be too small for EnCompass to truly determine if the addition of subtraction of one or two units is cost effective. Therefore, if utilities decide to use discrete unit sizes, they should consider MIP convergence tolerance in determining the sizes to use.

D. Using EnCompass's Potential Ideal Plan

Another way to run EnCompass is to skip the step where the model determines the best combination of whole units to add and have the model simply report the potential ideal plan. For example, in a given year EnCompass might show 0.4 wind units, which is equivalent to using 40 percent of the cost and capacity values of a full wind unit. The next year EnCompass might show 0.6 wind units. This is the same as adding another wind unit with 20 percent of the cost

[7] While not drawn from the results of any one actual scenario, this range is reflective of the ranges actually found in portions of Department analyses in a prior IRP.

[8] Calculated assuming a 50 MW unit, added in 2027, priced at $45 per MWh (escalated at two percent annually), with a 22 percent capacity factor, the ability to recover from the market (or avoid generation from existing units) only 75 percent of its costs—so that 25 percent of its costs represent a net cost increase to ratepayers, all discounted to the starting year of the model run.

and capacity values of a full unit. This option has the advantage of keeping all costs and constraints intact but bypassing the step in which EnCompass searches for the best way to round the units up or down, and thus reducing runtime. In addition, this approach avoids the variability that is inherent in the MIP acceptable cost range process.

However, use of the potential ideal plan raises the question "does adding a fraction of a unit actually provide meaningful resource planning information?" One response would be that, since the expansion plan is based on long-term forecasts, the IRP process can only determine the approximate size, type, and timing of new units. Thus, the specific values must be interpreted as including a degree of uncertainty and acquiring approximately the capacity selected would be reasonable.

A second response would be that wind turbines and solar panels actually come in very small sizes, less than 10MW per wind turbine and smaller for solar panels. Therefore, wind and solar projects could be developed in nearly any size. This means that adding fractions of wind and solar units is reasonable.[9] A more difficult question is how to consider the capacity units such as combustion turbines. Department Staff has consistently assumed that the CT units are merely generic capacity. This means that anything that can perform essentially the same function would be acceptable. Since load management can serve many of the same functions as a CT it would be acceptable. Capacity (in the form of load management) can be acquired in nearly any size as well. Therefore, units being selected in a resource plan do not have to be acquired in any one size increment.

Overall, the Department concludes that reporting the potential ideal plan costs is a reasonable way to use EnCompass.

E. Calculating and reporting the MIP convergence tolerance

In past analyses, the Department calculated the MIP convergence tolerance as follows.

First, the Department calculated the cost of the potential ideal plan and maximum allowed cost to obtain the range of acceptable costs (the black bars on the MIP Convergence chart). Second,

[9] One limiting factor is that, to actually be acquired, generation projects above a certain size must go through the MISO generation interconnection queue. Projects in MISO's queue tend to come in sizes rounded to 50 MW. But, that is not required. Of course, there are ways around the need to get through the MISO generation interconnection queue—such as connecting to the distribution grid.

the Department also obtained the cost of the feasible plan from the outputs reported by EnCompass at the end of each run (the red dots on the MIP Convergence chart).

It must be understood that, during the MIP convergence tolerance process, EnCompass ignores fixed costs of existing units since such costs cannot impact the model's decision. However, in certain cases (such early baseload unit retirement), the different scenarios have differing levels of fixed costs for existing units due to the different retirement dates.

It should also be noted that in expansion plan runs as performed by all utilities, the MIP convergence tolerance is reported only once, covering the entire planning period. In the production cost runs for some utilities, the MIP convergence process is reported every 28 days, making it impossible to calculate the MIP convergence values from the production cost run.[10]

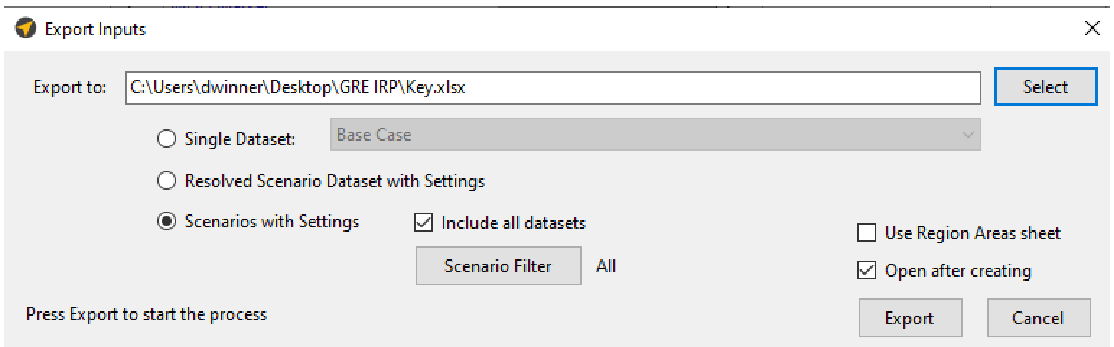
The range of acceptable costs (from the potential ideal plan's cost to the maximum allowed cost) was transferred to the newly calculated feasible plan cost.[11] These calculations are then put into a chart where the range of acceptable costs is represented by a black bar and the feasible plan that was selected is represented by the red dot. The purpose of such a chart is to illustrate scenarios where the costs are clearly different and scenarios where the costs are essentially the same to EnCompass. See the main text for example charts.

[10] EnCompass reports a different MIP value for each 28-day interval.

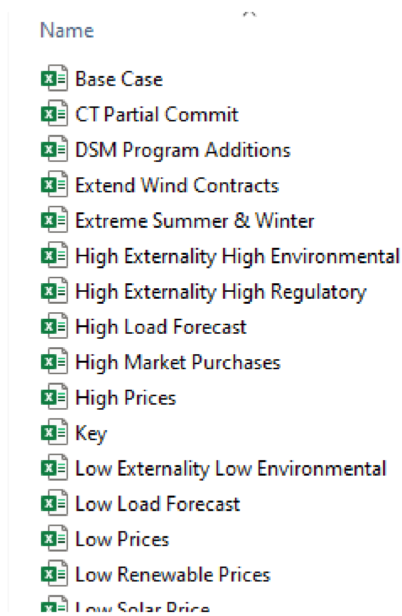
[11] For example, assume in the expansion plan run the feasible plan cost was $5 and the range of acceptable costs was from $1 ($4 below feasible) to $7 ($2 above feasible). If the re-calculated cost was $10, the range of acceptable costs becomes $6 (again $4 below feasible) to $12 (again $2 above feasible).

Setup File

The following is a technical discussion of how to generate and use a “setup” file. A setup file is generated from using the “Export Inputs” function and selecting “Scenarios with Settings” and “include all datasets.” In the following screenshot, the Department named the setup file “Key.”



The setup file then is nestled amongst the other exported datasets on the modeler’s local or network drive, as shown:



In addition, the Department notes:

- It is critical that the setup file be in the same folder with all datasets needed to reconstruct the database.
- Multiple setup files (and thus databases) may be stored in the same folder.

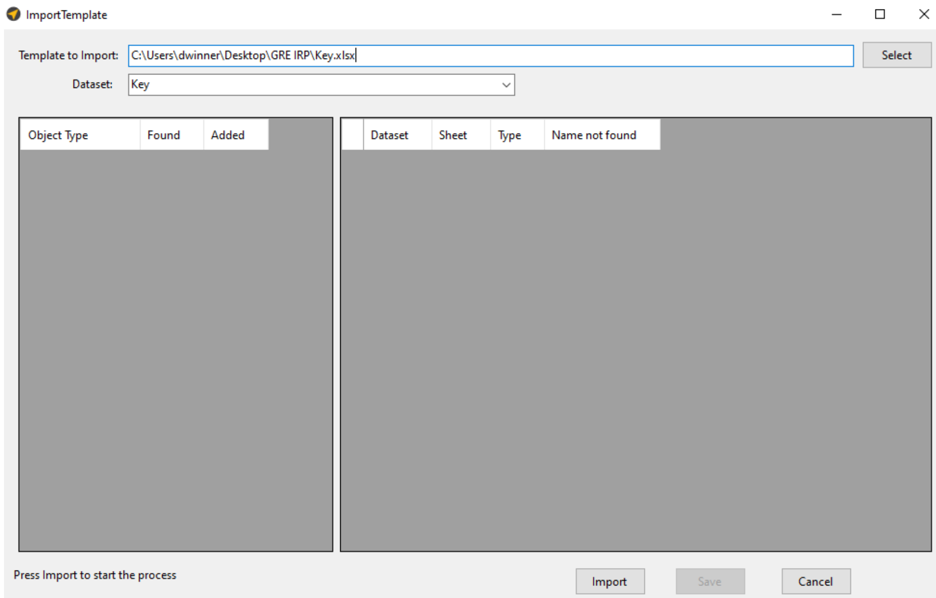
- Not all datasets in the folder need be used by a setup file.

The following screenshot shows information included the setup file, such as scenario tree information and scenario settings.

	A	B	C	D	E	
1	Name	Parent	Dataset:1	Dataset:2	Dataset:3	Dataset:4
2	DMatch Unit Updates (Base Case)		Base Case			
3	DMatch Low Externality/Low Environmental	DMatch High Externality/High Environmental				
4	DMatch Reference (All High Externality Costs)	DMatch High Externality/High Environmental				
5	DMatch High Externality/High Environmental	DMatch High Externality/High Regulatory				
6	DMatch Low Externality/Low Regulatory	DMatch High Externality/High Regulatory	Low Externality Low Environmental			
7	DMatch ReRun Self-Build Wind with PTC	DMatch Self-Build Wind with PTC				
8	DMatch CT Partial Commitment	DMatch Unit Updates (Base Case)	CT Partial Commit			
9	DMatch DSM Program Additions	DMatch Unit Updates (Base Case)		DSM Program Additions		
10	DMatch Extend Wind Contracts	DMatch Unit Updates (Base Case)			Extend Wind Contracts	
11	DMatch Extreme Summer & Winter	DMatch Unit Updates (Base Case)				Extreme Su
12	DMatch High Externality/High Regulatory	DMatch Unit Updates (Base Case)				
13	DMatch High Load Forecast	DMatch Unit Updates (Base Case)				
14	DMatch High Market Purchases	DMatch Unit Updates (Base Case)				
15	DMatch High Prices	DMatch Unit Updates (Base Case)				
16	DMatch Low Load Forecast	DMatch Unit Updates (Base Case)				

1	Scenario	CommitOpt	ConvBasis	DataOption	ExtDays	ForcedOpt	In
2	DMatch Unit Updates (Base Case)	2	10	0	15	1	
3	DMatch DSM Program Additions	2	10	0	15	1	
4	DMatch Extend Wind Contracts	2	10	0	15	1	
5	DMatch Extreme Summer & Winter	2	10	0	15	1	
6	DMatch High Externality/High Regulatory	2	10	0	15	1	
7	DMatch High Externality/High Environmental	2	10	0	15	1	
8	DMatch Low Externality/Low Environmental	2	10	0	15	1	
9	DMatch Reference (All High Externality Costs)	2	10	0	15	1	

To reconstruct the database using the setup file, the modeler simply imports the setup file when prompted to do so:



If a dataset referenced in the setup file is not present in the drive folder, EnCompass will prompt the modeler at this stage that the dataset was not found.

Should GRE choose to use a setup file to transfer its database in the future, the Department recommends the utility do a test run to ensure that the database is reconstructed correctly and that all needed datasets are present.

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
Comments

Docket No. ET2/RP-22-75

Dated this **8th** day of **August 2023**

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Steve	Albrecht	Steve.Albrecht@shakopeedakota.org	Shakopee Mdewakanton Sioux Community	Shakopee Mdewakanton Sioux Community 2330 Sioux Trail NW Prior Lake, MN 55372	Electronic Service	No	OFF_SL_22-75_RP-22-75
Jared	Alholinna	jalholinna@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 55369	Electronic Service	No	OFF_SL_22-75_RP-22-75
Keith	Anderson	keith.anderson@shakopeedakota.org	Shakopee Mdewakanton Sioux Community	Shakopee Mdewakanton Sioux Community 2330 Sioux Trail NW Prior Lake, MN 55372	Electronic Service	No	OFF_SL_22-75_RP-22-75
VJ	Arganwal	agarwalvj@gmail.com		N/A	Electronic Service	No	OFF_SL_22-75_RP-22-75
Ray	Auginaush, Sr.	ray.auginaush@whiteearth-nsn.gov	White Earth Nation	White Earth Tribal Headquarters 35500 Eagle View Road Ogema, MN 56569	Electronic Service	No	OFF_SL_22-75_RP-22-75
Dale	Aukee	daukee@grenergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	OFF_SL_22-75_RP-22-75
Mark	Bakk	mbakk@lcp.coop	Lake Country Power	26039 Bear Ridge Drive Cohasset, MN 55721	Electronic Service	No	OFF_SL_22-75_RP-22-75
Tosha	Barthel	tbarthel@grenergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	OFF_SL_22-75_RP-22-75
Daniel	Becchetti	dbecchetti@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 55369	Electronic Service	No	OFF_SL_22-75_RP-22-75
Todd	Beck	tbeck@grenergy.com	Great River Energy	N/A	Electronic Service	No	OFF_SL_22-75_RP-22-75
Amadeo	Bellino	Amadeo.Bellino@whiteearth-nsn.gov	White Earth Nation	White Earth Tribal Headquarters 35500 Eagle View Road Ogema, MN 56569	Electronic Service	No	OFF_SL_22-75_RP-22-75

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Melanie	Benjamin	melanie.benjamin@millelacsband.com	Mille Lacs Band of Ojibwe	43408 Oodena Drive Onamia, MN 56359	Electronic Service	No	OFF_SL_22-75_RP-22-75
Laura	Bishop	Laura.Bishop@state.mn.us	MN Pollution Control Agency	520 Lafayette Rd Saint Paul, MN 55155	Electronic Service	No	OFF_SL_22-75_RP-22-75
Sarah	Bohrer	sbohrer@grenergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	OFF_SL_22-75_RP-22-75
Hunter	Boldt	hunterboldt@redlakenation.org	Red Lake Nation	15484 Migizi Drive Red Lake, MN 56671	Electronic Service	No	OFF_SL_22-75_RP-22-75
Peter	Boney	pboney@boisforte-nsn.gov	Bois Forte Band of Chippewa	Bois Forte Tribal Government 5344 Lakeshore Drive Nett Lake, MN 55772	Electronic Service	No	OFF_SL_22-75_RP-22-75
Sheldon	Boyd	sheldon.boyd@millelacsband.com	Mille Lacs Band of Ojibwe	43408 Oodena Drive Onamia, MN 56359	Electronic Service	No	OFF_SL_22-75_RP-22-75
Jon	Brekke	jbrekke@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Electronic Service	No	OFF_SL_22-75_RP-22-75
B. Andrew	Brown	brown.andrew@dorsey.com	Dorsey & Whitney LLP	Suite 1500 50 South Sixth Street Minneapolis, MN 554021498	Electronic Service	No	OFF_SL_22-75_RP-22-75
Marvin Ray	Bruneau	Marvin.Bruneau@millelacsband.com	Mille Lacs Band of Ojibwe	43408 Oodena Drive Onamia, MN 56359	Electronic Service	No	OFF_SL_22-75_RP-22-75

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron	60 S 6th St Ste 1500 Minneapolis, MN 55402-4400	Electronic Service	No	OFF_SL_22-75_RP-22-75
Scott	Buchanan	ScottBuchanan@fdlrez.com	Fond du Lac Band of Lake Superior Chippewa	1720 Big Lake Road Cloquet, MN 55720	Electronic Service	No	OFF_SL_22-75_RP-22-75
Shelley	Buck	shelley.buck@piic.org	Prairie Island Indian Community	Prairie Island Indian Community 5636 Sturgeon Lake Road Welch, MN 55089	Electronic Service	No	OFF_SL_22-75_RP-22-75
Robert	Budreau	robert.budreau@llojibwe.net	Leech Lake Band of Ojibwe	190 Sailstar Drive NW Cass Lake, MN 56633	Paper Service	No	OFF_SL_22-75_RP-22-75
Cathy	Chavers	cchavers@boisforte-nsn.gov	Bois Forte Band of Chippewa	Bois Forte Tribal Government 5344 Lakeshore Drive Nett Lake, MN 55772	Electronic Service	No	OFF_SL_22-75_RP-22-75
Marc	Child	mchild@GREnergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	OFF_SL_22-75_RP-22-75
Michael	Childs, Jr.	michael.childsjr@piic.org	Prairie Island Indian Community	Prairie Island Indian Community 5636 Sturgeon Lake Road Welch, MN 55089	Electronic Service	No	OFF_SL_22-75_RP-22-75
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_22-75_RP-22-75
Sean	Copeland	seancopeland@fdlrez.com	Fond du Lac Band of Lake Superior Chippewa	1720 Big Lake Rd Cloquet, MN 55720	Electronic Service	No	OFF_SL_22-75_RP-22-75

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Rebecca	Crooks Stratton	Rebecca.Crooks-Stratton@ShakopeeDakota.org	Shakopee Mdewakanton Sioux Community	Shakopee Mdewakanton Sioux Community 2330 Sioux Trail NW Prior Lake, MN 55372	Electronic Service	No	OFF_SL_22-75_RP-22-75
Brooke	Cunningham	Health.Review@state.mn.us	Minnesota Department of Health	PO Box 64975 St. Paul, MN 55164-0975	Electronic Service	No	OFF_SL_22-75_RP-22-75
Miyah	Danielson	MiyahDanielson@FDLREZ.COM	Fond du Lac Band of Lake Superior Chippewa	1720 Big Lake Road Cloquet, MN 55720	Electronic Service	No	OFF_SL_22-75_RP-22-75
Jason	Decker	jason.decker@llojibwe.net	Leech Lake Band of Ojibwe	190 Sailstar Drive NW Cass Lake, MN 56633	Electronic Service	No	OFF_SL_22-75_RP-22-75
Bobby	Deschampe	robertdeschampe@grandportage.com	Grand Portage Band of Lake Superior Chippewa	PO Box 428 Grand Portage, MN 55605	Electronic Service	No	OFF_SL_22-75_RP-22-75
Kami	Diver	KamiDiver@fdlrez.com	Fond du Lac Band of Lake Superior Chippewa	1720 Big Lake Road Cloquet, MN 55720	Electronic Service	No	OFF_SL_22-75_RP-22-75
Becky	Dobbs	bdobbs@grenergy.com	Great River Energy	N/A	Electronic Service	No	OFF_SL_22-75_RP-22-75
Shane	Drift	sdrift@boisforte-nsn.gov	Bois Forte Band of Chippewa	Bois Forte Tribal Government 5344 Lakeshore Drive Nett Lake, MN 55772	Electronic Service	No	OFF_SL_22-75_RP-22-75
Wally	Dupuis	WallyDupuis@fdlrez.com	Fond du Lac Band of Lake Superior Chippewa	1720 Big Lake Road Cloquet, MN 55720	Electronic Service	No	OFF_SL_22-75_RP-22-75
Kevin	Dupuis, Sr.	kevindupuis@fdlrez.com	Fond du Lac Development Corp.	Reservation Business Committee 1720 Big Lake Rd Cloquet, MN 55720	Electronic Service	No	OFF_SL_22-75_RP-22-75

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Jamie	Edwards	jamie.edwards@millelacsband.com	Mille Lacs Band of Ojibwe	43408 Oodena Drive Onamia, MN 56358	Electronic Service	No	OFF_SL_22-75_RP-22-75
Michael	Fairbanks	Michael.Fairbanks@whiteearth-nsn.gov	White Earth Reservation Business Committee	PO Box 418 White Earth, MN 56591	Electronic Service	No	OFF_SL_22-75_RP-22-75
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_22-75_RP-22-75
Terri	Finn	terri.goggleye@llojibwe.net	Leech Lake Band of Ojibwe	N/A	Electronic Service	No	OFF_SL_22-75_RP-22-75
Christine	Fox	cfox@itasca-mantrap.com	Itasca-Mantrap Coop. Electric Assn.	PO Box 192 Park Rapids, MN 56470	Electronic Service	No	OFF_SL_22-75_RP-22-75
Lucas	Franco	lfranco@liunagroc.com	LIUNA	81 Little Canada Rd E Little Canada, MN 55117	Electronic Service	No	OFF_SL_22-75_RP-22-75
Gary	Frazer	gfrazer@mnchippewatribe.org	Minnesota Chippewa Tribe	PO Box 217 Cass Lake, MN 56633	Electronic Service	No	OFF_SL_22-75_RP-22-75
Stacey	Fujii	sfujii@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Electronic Service	No	OFF_SL_22-75_RP-22-75
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_22-75_RP-22-75
Shannon	Geshick	shannon.geshick@state.mn.us	Minnesota Indian Affairs Council (MIAC)	N/A	Electronic Service	No	OFF_SL_22-75_RP-22-75
Allen	Gleckner	gleckner@fresh-energy.org	Fresh Energy	408 St. Peter Street Ste 350 Saint Paul, Minnesota 55102	Electronic Service	No	OFF_SL_22-75_RP-22-75

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Robbie	Goggleye	rgoggleye@boisforte-nsn.gov	Bois Forte Band of Chippewa	Bois Forte Tribal Government 5344 Lakeshore Drive Nett Lake, MN 55772	Electronic Service	No	OFF_SL_22-75_RP-22-75
Sachiko	Graber	sachiko.graber@TNC.ORG	The Nature Conservancy in Minnesota, North Dakota and South Dakota	1101 West River Parkway Suite 200 Minneapolis, MN 55415-1291	Electronic Service	No	OFF_SL_22-75_RP-22-75
Jeffrey	Haase	jhaase@grenergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	OFF_SL_22-75_RP-22-75
Hal	Halpern	halhalpern@clpower.com	Cooperative Light & Power	1554 Hwy 2 P0 Box 69 Two Harbors, MN 55616	Electronic Service	No	OFF_SL_22-75_RP-22-75
Jeremy	Hamilton	jhamilton@uppersiouxcommunity-nsn.gov	Upper Sioux Community	Upper Sioux Community PO Box 147 Granite Falls, MN 56241	Electronic Service	No	OFF_SL_22-75_RP-22-75
David A.	Hansen	Hansen@federatedrea.coop	Federated Rural Electric Association	77100 U.S. Highway 71 PO Box 69 Jackson, MN 56143	Electronic Service	No	OFF_SL_22-75_RP-22-75
Amy	Hastings	amyh@uppersiouxcommunity-nsn.gov	Upper Sioux Community	5722 Travers Lane PO Box 147 Granite Falls, MN 56241	Electronic Service	No	OFF_SL_22-75_RP-22-75
Erik	Hatlestad	erik@cureriver.org	Cure River	117 1st St Montevideo, MN 56265	Electronic Service	No	OFF_SL_22-75_RP-22-75
Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_22-75_RP-22-75
Kristin	Henry	kristin.henry@sierraclub.org	Sierra Club	2101 Webster St Ste 1300 Oakland, CA 94612	Electronic Service	No	OFF_SL_22-75_RP-22-75

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Ronald	Horman	rhorman@redwoodelectric.com	Redwood Electric Cooperative	60 Pine Street Clements, MN 56224	Electronic Service	No	OFF_SL_22-75_RP-22-75
Robbie	Howe	robbie.howe@llojibwe.net	Leech Lake Band of Ojibwe	190 Sailstar Drive NW Cass Lake, MN 56633	Electronic Service	No	OFF_SL_22-75_RP-22-75
John	Ihle	ljihle@rrt.net	PlainStates Energy LLC	27451 S Hwy 34 Barnesville, MN 56514	Electronic Service	No	OFF_SL_22-75_RP-22-75
Annie	Jackson	Cheryl.Jackson@whiteearth-nsn.gov	White Earth Nation	White Earth Tribal Headquarters 35500 Eagle View Road Ogemo, MN 56569	Electronic Service	No	OFF_SL_22-75_RP-22-75
Faron	Jackson, Sr.	faron.jackson@llojibwe.net	Leech Lake Band of Ojibwe	190 Sailstar Drive NW Cass Lake, MN 56633	Electronic Service	No	OFF_SL_22-75_RP-22-75
Justin	Jahnz	justin.jahnz@ecemn.com	East Central Energy	412 Main Ave N Braham, MN 55006	Electronic Service	No	OFF_SL_22-75_RP-22-75
Kevin	Jensvold	kevinj@uppersiouxcommunity-nsn.gov	Upper Sioux Community	PO Box 147 Granite Falls, MN 56241-0147	Electronic Service	No	OFF_SL_22-75_RP-22-75
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_22-75_RP-22-75
Johnny	Johnson	Johnny.Johnson@piic.org	Prairie Island Indian Community	5636 Sturgeon Lake Road Welch, MN 55089	Electronic Service	No	OFF_SL_22-75_RP-22-75
Annette	Johnson	Annette.johnson@redlakenation.org	Red Lake Nation	15484 Migizi Drive Red Lake, MN 56671	Electronic Service	No	OFF_SL_22-75_RP-22-75

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Jody	Johnson	jody.johnson@piic.org	Prairie Island Indian Community	5636 Sturgeon Lake Rd Welch, MN 55089	Electronic Service	No	OFF_SL_22-75_RP-22-75
Veda	Kanitz	vmkanitz@gmail.com		N/A	Electronic Service	No	OFF_SL_22-75_RP-22-75
Jenny	Kartes	jkartes@arrowhead.coop	Arrowhead Electric Cooperative, Inc.(P)	PO Box 39 5401 W Hwy 61 Lutsen, MN 55612	Electronic Service	No	OFF_SL_22-75_RP-22-75
David	Kempf	dkempf@grenergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	OFF_SL_22-75_RP-22-75
Arthur	LaRose	arthur.larose@llojibwe.net	Leech Lake Band of Ojibwe	190 Sailstar Drive NW Cass Lake, MN 56633	Electronic Service	No	OFF_SL_22-75_RP-22-75
Matthew	Lacey	Mlacey@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Electronic Service	No	OFF_SL_22-75_RP-22-75
Robert L	Larsen	robert.larsen@lowersioux.com	Lower Sioux Indian Community	PO Box 308 39527 Reservation Highway 1 Morton, MN 56270	Electronic Service	No	OFF_SL_22-75_RP-22-75
Mark	Larson	mlarson@meeker.coop	Meeker Coop Light & Power Assn	1725 Highway 12 E Ste 100 Litchfield, MN 55355	Electronic Service	No	OFF_SL_22-75_RP-22-75
Cheri	Lenzmeier	cheril@mvec.net	Minnesota Valley Electric Cooperative	125 Minnesota Valley Electric Dr Jordan, MN 55352	Electronic Service	No	OFF_SL_22-75_RP-22-75
Dan	Lesher	dlesher@grenergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	OFF_SL_22-75_RP-22-75

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michelle	Lommel	mlommel@GREnergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	OFF_SL_22-75_RP-22-75
Shena	Matrious	Shena.Matrious@millelacsband.com	Mille Lacs Band of Ojibwe	43408 Oodena Drive Onamia, MN 56349	Electronic Service	No	OFF_SL_22-75_RP-22-75
April	McCormick	aprilm@grandportage.com	Grand Portage Band of Lake Superior Chippewa	PO Box 428 Grand Portage, MN 55605	Electronic Service	No	OFF_SL_22-75_RP-22-75
Ronald	Meier	rmeier@mcleodcoop.com	Mcleod Cooperative Power	3515 11th St East Glencoe, MN 55336	Electronic Service	No	OFF_SL_22-75_RP-22-75
Peder	Mewis	pmewis@cleangridalliance.org	Clean Grid Alliance	570 Asbury St. St. Paul, MN 55104	Electronic Service	No	OFF_SL_22-75_RP-22-75
Valentina	Mgeni	Valentina.Mgeni@piic.org	Prairie Island Indian Community	Prairie Island Indian Community 5636 Sturgeon Lake Road Welch, MN 55089	Electronic Service	No	OFF_SL_22-75_RP-22-75
Cole W.	Miller	cole.miller@shakopeedakota.org	Shakopee Mdewakanton Sioux Community	Shakopee Mdewakanton Sioux Community 2330 Sioux Trail NW Prior Lake, MN 55372	Electronic Service	No	OFF_SL_22-75_RP-22-75
Gregory C.	Miller	gmiller@dakotaelectric.com	Dakota Electric Association	4300 220th Street West Farmington, MN 55024	Electronic Service	No	OFF_SL_22-75_RP-22-75
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_22-75_RP-22-75

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Sarah	Mooradian	cure@cureriver.org	Clean Up the River Environment CURE	117 South 1st Street Montevideo, MN 56265	Electronic Service	No	OFF_SL_22-75_RP-22-75
Travis	Morrision	travis.morrison@boisforte-nsn.gov	Bois Forte Band of Chippewa	Bois Forte Tribal Government 5344 Lakeshore Drive Nett Lake, MN 55772	Electronic Service	No	OFF_SL_22-75_RP-22-75
David	Morrison, Sr.	david.morrison@boisforte-nsn.gov	Bois Forte Band of Chippewa	Bois Forte Tribal Government 5344 Lakeshore Drive Nett Lake, MN 55772	Electronic Service	No	OFF_SL_22-75_RP-22-75
Evan	Mulholland	emulholland@mncenter.org	Minnesota Center for Environmental Advocacy	1919 University Ave W Ste 515 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_22-75_RP-22-75
Sonny	Myers	smyers@1854treatyauthority.org	1854 Treaty Authority	4428 Haines Rd Duluth, MN 55811-1524	Electronic Service	No	OFF_SL_22-75_RP-22-75
Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment	212 3rd Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_22-75_RP-22-75
Deb	Nelson	dnelson@grenergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	OFF_SL_22-75_RP-22-75
Duane	Ninneman	duane@cureriver.org	Clean Up the River Environment	117 South 1st St Montevideo, MN 56265	Electronic Service	No	OFF_SL_22-75_RP-22-75
Joseph	OBrien	joey.obrien@lowersioux.com	Lower Sioux Indian Community	39527 Highway 1 Morton, MN 56270	Electronic Service	No	OFF_SL_22-75_RP-22-75

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kevin	OKeefe	kevin.okeefe@lowersioux.com	Lower Sioux Indian Community	39527 Highway 1 Morton, MN 56270	Electronic Service	No	OFF_SL_22-75_RP-22-75
Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	OFF_SL_22-75_RP-22-75
Gregory	Padden	gpadden@grenergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	OFF_SL_22-75_RP-22-75
Marsha	Parlow	mparlow@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Electronic Service	No	OFF_SL_22-75_RP-22-75
Priti	Patel	ppatel@grenergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369-4718	Electronic Service	No	OFF_SL_22-75_RP-22-75
Earl	Pendleton	earl.pendleton@lowersioux.com	Lower Sioux Indian Community	39527 Highway 1 Morton, MN 56270	Electronic Service	No	OFF_SL_22-75_RP-22-75
Gordon	Pietsch	gpietsch@grenergy.com	Great River Energy	12300 Elm Creek Blvd. Maple Grove, MN 55369-4718	Electronic Service	No	OFF_SL_22-75_RP-22-75
Joe	Plumer	joe.plumer@redlakenation.org	Red Lake Nation	15484 Migizi Drive Red Lake, MN 56671	Electronic Service	No	OFF_SL_22-75_RP-22-75
Kevin	Pranis	kpranis@liunagroc.com	Laborers' District Council of MN and ND	81 E Little Canada Road St. Paul, Minnesota 55117	Electronic Service	No	OFF_SL_22-75_RP-22-75
Robert	Prescott	robert.prescott@lowersioux.com	Lower Sioux Indian Community	39527 Highway 1 Morton, MN 56270	Paper Service	No	OFF_SL_22-75_RP-22-75

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Mark	Rathbun	mrathbun@grenergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	OFF_SL_22-75_RP-22-75
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_22-75_RP-22-75
Greg	Ridderbusch	greg.ridderbusch@connexusenergy.com	Connexus Energy	14601 Ramsey Boulevard Ramsey, MN 55303	Electronic Service	No	OFF_SL_22-75_RP-22-75
Stephan	Roos	stephan.roos@state.mn.us	MN Department of Agriculture	625 Robert St N Saint Paul, MN 55155-2538	Electronic Service	No	OFF_SL_22-75_RP-22-75
Alan	Roy	Alan.Roy@whiteearth-nsn.gov	White Earth Nation	White Earth Tribal Headquarters 35500 Eagle View Road Ogema, MN 56569	Electronic Service	No	OFF_SL_22-75_RP-22-75
Mark	Royseth	mroyseth@grenergy.com	Great River Energy	N/A	Electronic Service	No	OFF_SL_22-75_RP-22-75
Bill	Rudnicki	bill.rudnicki@shakopeedakota.org	Shakopee Mdewakanton Sioux Community	Shakopee Mdewakanton Sioux Community 2330 Sioux Trail NW Prior Lake, MN 55372	Electronic Service	No	OFF_SL_22-75_RP-22-75
Zachary	Ruzycki	zruzycki@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, Minnesota 55369	Electronic Service	No	OFF_SL_22-75_RP-22-75
Mike	Saer	msaer@grenergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	OFF_SL_22-75_RP-22-75
Miranda	Sam	Miranda.Sam@lowersioux.com	Lower Sioux Indian Community	39527 Reservation Highway 1 PO Box 308 Morton, MN 56270	Electronic Service	No	OFF_SL_22-75_RP-22-75

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Adam	Savariego	adams@uppersiouxcommunity-nsn.gov	Upper Sioux Community	5722 Travers Lane PO Box 147 Granite Falls, MN 56241	Electronic Service	No	OFF_SL_22-75_RP-22-75
Peter	Schaub	pschaub@GREnergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	OFF_SL_22-75_RP-22-75
Ronald J.	Schwartau	rschwartau@noblesce.com	Nobles Cooperative Electric	22636 U.S. Hwy. 59 Worthington, MN 56187	Electronic Service	No	OFF_SL_22-75_RP-22-75
Jessie	Seim	jessie.seim@piic.org	Prairie Island Indian Community	5636 Sturgeon Lake Rd Welch, MN 55089	Electronic Service	No	OFF_SL_22-75_RP-22-75
Darrell	Seki, Sr.	dseki@redlakenation.org	Red Lake Nation	15484 Migizi Drive Red Lake, MN 56671	Electronic Service	No	OFF_SL_22-75_RP-22-75
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_22-75_RP-22-75
Joel	Smith	jsmith@mnchippewatribe.org	Minnesota Chippewa Tribe	PO Box 217 Cass Lake, MN 56633	Electronic Service	No	OFF_SL_22-75_RP-22-75
Nizhoni	Smith	nizhoni.smith@lowersioux.com	Lower Sioux Indian Community	PO Box 308 39527 Reservation Highway 1 Morton, MN 56270	Electronic Service	No	OFF_SL_22-75_RP-22-75
Roger	Smith, Sr.	RogerMSmithSr@fdlrez.com	Fond du Lac Band of Lake Superior Chippewa	1720 Big Lake Road Cloquet, MN 55720	Electronic Service	No	OFF_SL_22-75_RP-22-75

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Beth	Soholt	bsoholt@cleangridalliance.org	Clean Grid Alliance	570 Asbury St Ste 201 Saint Paul, MN 55104	Electronic Service	No	OFF_SL_22-75_RP-22-75
Marie	Spry	mariespry@grandportage.com	Grand Portage Band of Lake Superior Chippewa	PO Box 428 Grand Portage, MN 55605	Electronic Service	No	OFF_SL_22-75_RP-22-75
Wallace	St. John, Sr.	Wally.StJohn@millelacsband.com	Mille Lacs Band of Ojibwe	43408 Oodena Drive Onamia, MN 56359	Electronic Service	No	OFF_SL_22-75_RP-22-75
LeRoy	Staples Fairbanks III	leroy.fairbanks@llojibwe.net	Leech Lake Band of Ojibwe	190 Sailstar Drive NW Cass Lake, MN 56633	Electronic Service	No	OFF_SL_22-75_RP-22-75
Donna	Stephenson	dstephenson@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 55369	Electronic Service	No	OFF_SL_22-75_RP-22-75
Cooper	Stewart	cooper@strongholdicf.com		N/A	Electronic Service	No	OFF_SL_22-75_RP-22-75
Mark	Strohfus	mstrohfus@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Electronic Service	No	OFF_SL_22-75_RP-22-75
Samuel	Strong	Sam.strong@redlakenation.org	Red Lake Nation	15484 Migizi Drive Red Lake, MN 56671	Electronic Service	No	OFF_SL_22-75_RP-22-75
Timothy	Sullivan	tsullivan@whe.org	Wright Hennepin Coop. Electric Assn.	6800 Electric Drive PO Box 330 Rockford, MN 55373	Electronic Service	No	OFF_SL_22-75_RP-22-75
David	Sunderman	daves@benco.org	BENCO Electric Cooperative	PO Box 8 Mankato, MN 56002-0008	Electronic Service	No	OFF_SL_22-75_RP-22-75

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_22-75_RP-22-75
Camille	Tanhoff	kamip@uppersiouxcommunity-nsn.gov	Upper Sioux Community	5722 Travers Lane PO BOX 147 Granite Falls, MN 56241	Electronic Service	No	OFF_SL_22-75_RP-22-75
Tim	Thompson	tthompson@lrec.coop	Lake Region Electric Cooperative	PO Box 643 1401 South Broadway Pelican Rapids, MN 56572	Electronic Service	No	OFF_SL_22-75_RP-22-75
Caralyn	Trutna	carrie@uppersiouxcommunity-nsn.gov	Upper Sioux Community	Upper Sioux Community P.O. Box 147 Granite Falls, MN 55372	Electronic Service	No	OFF_SL_22-75_RP-22-75
Jackie	Van Norman	jvannorman@grenergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	OFF_SL_22-75_RP-22-75
Sam	Villella	sdvillella@gmail.com		10534 Alamo Street NE Blaine, MN 55449	Electronic Service	No	OFF_SL_22-75_RP-22-75
Trent	Waite	twaite@grenergy.com	Great River Energy	N/A	Electronic Service	No	OFF_SL_22-75_RP-22-75
Heather	Westra	heather.westra@piic.org	Prairie Island Indian Community	5636 Sturgeon Lake Rd Welch, MN 55089	Electronic Service	No	OFF_SL_22-75_RP-22-75
Steve	White	steve.white@llojibwe.net	Leech Lake Band of Ojibwe	190 Sailstar Drive NW Cass Lake, MN 56633	Electronic Service	No	OFF_SL_22-75_RP-22-75
Cody	Whitebear	cody.whitebear@piic.org	Prairie Island Indian Community	5636 Sturgeon Lake Road Welch, MN 55089	Electronic Service	No	OFF_SL_22-75_RP-22-75

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
John	Williams	jwilliams@grenergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	OFF_SL_22-75_RP-22-75
Virgil	Wind	virgil.wind@millelacsband.com	Mille Lacs Band of Ojibwe	43408 Oodena Drive Onamia, MN 56359	Electronic Service	No	OFF_SL_22-75_RP-22-75
Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine	225 South Sixth Street, Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_22-75_RP-22-75
Laurie	York	laurie.york@whiteearth-nsn.gov	White Earth Reservation Business Committee	PO Box 418 White Earth, MN 56591	Electronic Service	No	OFF_SL_22-75_RP-22-75