BEFORE THE MINNESOTA COURT OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St Paul MN 55101-2147

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| IN THE MATTER OF THE APPLICATION FOR A CERTIFICATE OF NEED FOR THE POWERON MIDWEST 765 KV AND 345 KV HIGH VOLTAGE TRANSMISSION LINE PROJECT | MPUC Docket No. E002, ET2, ET6675/CN-25-117<br>CAH Docket No. 28-2500-41617 |

**DIRECT TESTIMONY AND ATTACHMENTS OF ROCK PARK**

**ON BEHALF OF**

**THE MINNESOTA DEPARTMENT OF COMMERCE**
**DIVISION OF ENERGY RESOURCES**

**AUGUST 13, 2026**

DIRECT TESTIMONY OF ROCK PARK
IN THE MATTER OF THE APPLICATION FOR A CERTIFICATE OF NEED FOR THE POWERON MIDWEST 765 KV AND 345 KV HIGH VOLTAGE TRANSMISSION LINE PROJECT

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CAH Docket No. 28-2500-41617

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## I. INTRODUCTION

**Q. Would you state your name, occupation and business address?**

A. My name is Rock Park. I am employed as a Public Utilities Rates Analyst by the Minnesota Commerce Department, Division of Energy Resources (Department). My business address is 85 7th Place East, Suite 280, St. Paul, Minnesota 55101-2198.

**Q. What is your educational and professional background?**

A. I have been employed by the Department since December 2025. Prior to working at the Department, I worked at Geronimo Power (formerly known as National Grid Renewables) from 2022 through December 2025 as, first, a Policy Analyst and later, Policy Manager, on the Policy and RTO Strategy team. I have a Bachelor of Arts in Political Science and Geology from Macalester College in Saint Paul, MN. Please refer to Ex. DOC-__, RP-D-1 (Park Resume).

**Q. What is your experience on regulatory matters?**

A. I have served as the lead analyst, or provided a significant contribution, in the following Dockets before the Minnesota Public Utilities Commission (Commission):

- Docket No. E999/M-25-99—Grid-Enhancing Technologies (GETs) Report
- Docket No. E002, ET2, E017, ET6135/CN-25-116—Certificate of Need Application for the Bison to Alexandria Second Circuit 345 kV Transmission Line Project
- Docket No. E015/CN-25-111—Certificate of Need Application for the Iron Range-St. Louis County-Arrowhead 345 kV Transmission Line Project

- Docket No. ET3, E002/CN-25-121—Certificate of Need Application for the Gopher to Badger Link 765 kV High Voltage Transmission Line Project
- Docket No. E015, ET2, E017/CN-25-109—Certificate of Need Application for the Maple River Cuyuna 345 kV Transmission Line Project
- Docket No. E002/M-26-170—In the Matter of the Petition for Approval of an Electric Service Agreement between Google and Northern States Power Co. d/b/a Xcel Energy
- Docket No. E015/M-26-159—In the Matter of the Petition for Approval of an Electric Service Agreement (ESA) between Google and Minnesota Power

## II. PURPOSE AND SCOPE

**Q. What are your responsibilities in this proceeding?**

A. I am submitting testimony on behalf of the Department regarding a petition for a certificate of need (Application) filed on behalf of Great River Energy (GRE), ITC Midwest LLC (ITC Midwest), and Northern States Power Company doing business as Xcel Energy (Xcel) (together, the Applicants). The joint application petitions the Commission for a certificate of need to construct a 765 kV and 345 kV transmission line in Minnesota ("PowerOn Midwest Project"). My testimony covers the following matters:

- Summary of the Applicant's proposed project Application;
- Analysis of the forecast data provided by the Applicants and Minnesota Rule 7849.0120, subp. A.(1)-(5);
- An overall recommendation; and
- Conditions on the certificate of need (CN).

**Q. Do you testify as to which route for the proposed 765 kV transmission line is appropriate?**

A. No, I do not.

**Q. Please summarize the organization of your testimony.**

A. I begin by summarizing the Application.[1] I then present relevant criteria required to approve a CN in both Minnesota Statutes and Minnesota Rule 7849.0120. Please refer to Ex. DOC-___, RP-D-2 (Park E) for reference to the relevant criteria. Then, I will discuss if the PowerOn Midwest 765 kV Transmission Project meets these criteria, followed by a discussion of whether the Project should have additional considerations or conditions on the CN.

## III. CERTIFICATE OF NEED REQUIREMENTS

**Q. What issue do you address in this section?**

A. I discuss Minnesota Rule 7849.0120 (CN Requirements), which provide the criteria the Commission uses to evaluate a petition for a CN for a transmission line of this length and voltage pursuant to Minnesota Statutes § 216B.243. I also address other relevant statutory criteria that are not reflected in Minnesota Rules. I organize this discussion in

[1] Initial Filing (Feb. 3, 2026) (eDocket Nos. 20262-227787-01, 20262-227787-02, 20262-227787-03, 20262-227787-04, 20262-227787-05, 20262-227787-06, 20262-227787-07, 20262-227787-08, 20262-227787-09, 20262-227787-10, 20262-227787-11, 20262-227787-12, 20262-227787-13, 20262-227787-14, 20262-227787-15) (collectively, Initial Filing). Unless otherwise specified, citations to the "Initial Application" refer to eDocket No. 20262-227787-02.

two parts: part one - criteria related to need analysis, and part two – criteria related to conditions on the certificate of need.

**Q. Are you aware of the criteria established in Minnesota Rule 7849.0120 for demonstrating the need for a large electric facility, and if so, what are those criteria?**

A. Yes, Minnesota Rule 7849.0120 establishes that the Commission must grant a certificate of need to an applicant upon determination that the following four criteria are met. They are:

> A. [T]he probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant’s customers, or to the people of Minnesota and neighboring states, considering:
>
> 1. the accuracy of the applicant's forecast of demand for the type of energy that would be supplied by the proposed facility;
> 2. the effects of the applicant's existing or expected conservation programs and state and federal conservation programs;
> 3. the effects of promotional practices of the applicant that may have given rise to the increase in the energy demand, particularly promotional practices which have occurred since 1974;
> 4. the ability of current facilities and planned facilities not requiring certificates of need to meet the future demand; and
> 5. the effect of the proposed facility, or a suitable modification thereof, in making efficient use of resources;
>
> B. [A] more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record, considering:
>
> 1. the appropriateness of the size, the type, and the timing of the proposed facility compared to those of reasonable alternatives;
> 2. the cost of the proposed facility and the cost of energy to be supplied by the proposed facility

compared to the costs of reasonable alternatives and the cost of energy that would be supplied by reasonable alternatives;

3. the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives; and
4. the expected reliability of the proposed facility compared to the expected reliability of reasonable alternatives;

C. [B]y a preponderance of the evidence on the record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health, considering:
   1. the relationship of the proposed facility, or a suitable modification thereof, to overall state energy needs;
   2. the effects of the proposed facility, or a suitable modification thereof, upon the natural and socioeconomic environments compared to the effects of not building the facility;
   3. the effects of the proposed facility, or a suitable modification thereof, in inducing future development; and
   4. the socially beneficial uses of the output of the proposed facility, or a suitable modification thereof, including its uses to protect or enhance environmental quality; and

D. [T]he record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.

**Q. Do you provide testimony as to factors under Minnesota Rule 7849.0120 subparts B(3) and C?**

A. I do not provide this testimony in detail, but Mr. Hicks provides an overview of Minnesota Rule 7849.0120 B(3) in Ex. DOC-__ at 15-17 (Hicks Direct). I also understand that the Commission's Energy Infrastructure Permitting (EIP) unit will provide background for a determination regarding some considerations, including the effects of the Project on natural and socioeconomic environments and public health, in the environmental report (ER).

## IV. PROPOSED PROJECT AND APPLICABILITY OF CERTIFICATE OF NEED

**Q. Please describe the proposed project.**

A. The proposed project consists of new 765 kV high-voltage transmission line (HVTL) facilities between the South Dakota and Minnesota border, the Iowa and Minnesota border, and the North Rochester substation. The proposed project also includes a new 345 kV second circuit between the Pleasant Valley substation, North Rochester substation, and the Hampton substation. The proposed project's components are:

- A new 92-mile 765 kV transmission line from the South Dakota and Minnesota border to the existing Lakefield Junction substation in Jackson County, Minnesota;
- A new 18-mile 765 kV transmission line from the Iowa and Minnesota state border to the existing Lakefield Junction substation in Jackson County, Minnesota;
- A new 130-mile long 765 kV transmission line from near the existing Lakefield Junction substation in Jackson County, Minnesota to near the existing Pleasant Valley Substation in Mower County, Minnesota;
- A new 31-mile long 765 kV transmission line from near the existing Pleasant Valley substation in Mower County, Minnesota to near the existing North Rochester substation in Goodhue County, Minnesota;
- A new 31-mile long 345 kV circuit from the Pleasant Valley substation in Mower County, Minnesota to the existing North Rochester substation in Goodhue County,

Minnesota. Between the Pleasant Valley substation and the North Rochester substation, the proposed project replaces existing single-circuit 345 kV structures with double-circuit tubular monopole structures capable of carrying the existing 345 kV circuit, in addition to the proposed new 345 kV circuit;

- A new 38-mile long 345 kV line from the North Rochester substation in Goodhue County, Minnesota to the Hampton substation in Dakota County, Minnesota. Between the North Rochester substation and the Hampton substation, the proposed project places a second 345 kV circuit on existing double-circuit-capable 345 kV structures. According to the application at pg. 5, approximately three dozen (36) new structures will be required along this portion of the proposed project;
- Substation expansions for accommodating 765 kV transmission facilities at Lakefield Junction substation, Pleasant Valley substation, and North Rochester substation; and
- Modification and expansion of the existing substations to support new 345 kV transmission facilities at Pleasant Valley substation, North Rochester substation, and Hampton substation.

**Q. Is the proposed project a large energy facility?**

A. Yes. Minnesota Statutes § 216B.2421 subd. 2 defines a "large energy facility" (LEF), as "any high-voltage transmission line with a capacity of 300 kilovolts or more and greater than one mile in length in Minnesota." This project has both a capacity of over 300 kV and is longer than a mile.

**Q. Is the proposed project part of a MISO Long Range Transmission Plan portfolio?**

A. Yes. The proposed project is part of the Midcontinent Independent System Operator Inc.'s (MISO's) Long-Range Transmission Plan (LRTP) Tranche 2.1 portfolio. As laid out in the initial Application, the proposed project comprises LRTP Tranche 2.1 projects 22, 23, 24, and 25.[2]

## V. NEED ANALYSIS

**Q. What does Minnesota Rule 7849.0120 A require the Commission to consider?**

A. Minnesota Rule 7849.0120 subp. A requires that a certificate of need be granted on determining that "the probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states," considering five subfactors.[3] I will go into detail for each subfactor.

### *A. ACCURACY OF THE FORECAST*

**Q. What does Minnesota Rule 7849.0120 subpart A(1) require the Commission to evaluate?**

A. Minnesota Rule 7849.0120 subp. A(1) requires the Commission to consider "the accuracy of the applicant's forecast of demand for the type of energy that would be supplied by the proposed facility[.]"[4]

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2 Initial Application at 110.

3 Minn. R. 7849.0120.A.

4 *Id.*

**Q. Has the Commission provided guidance clarifying this criterion?**

A. Yes. The Commission's clarified acceptable demand forecast data that could be provided to satisfy Minnesota Rule 7849.0120 subp. A in an order filed on September 23, 2021.[5]

**Q. What did the Commission conclude in the Plum Creek Order regarding the data an applicant must present to demonstrate demand?**

A. The Commission concluded in the Plum Creek Order that the Commission "may evaluate demand using any data it finds persuasive, on a case-by-case basis."[6]

**Q. How did you apply that guidance in formulating your analysis in this proceeding?**

A. I considered the Commission's guidance in the Plum Creek Order to assess the relevance of the forecast demand data provided by the Applicants. The Application contained three main appendices with demand forecast information, alongside sections of their main Application. In Appendix E, the Applicants provide information for Planning Analyses performed for the MISO Transmission Expansion Plan (MTEP) process, MISO Series 1A Futures, and the Voltage Stability Analysis presented by Applicants. Appendix F provides the Annual Electric Utility Forecast Reports (AFR) for GRE and Xcel. Appendix G contains information from the Applicants' Energy Conservation and Optimization

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[5] *In re Appl. of Plum Creek Wind Farm, LLC for a Certificate of Need, Site Permit, and Route Permit for an up to 414 MW Large Wind Energy Conversion System and 345 kV Transmission Line in Cottonwood, Murray, and Redwood Counties*, MPUC Docket Nos. IP-6697/CN-18-699, IP-6697/WS-18-700, and IP-6697/TL-18-701, ORDER GRANTING CERTIFICATE OF NEED AND ISSUING SITE PERMIT AND ROUTE PERMIT (Sept. 23, 2021) (eDocket No. 20219-178198-01) (PLUM CREEK ORDER).

[6] *Id.* at 11.

(ECO) Triennial plan filings. Lastly, Section 5.3 of the Application provides additional information related to integrated resource planning (IRPs). I relied on the listed sources of information within the Application and reviewed prior Commission Orders relating to utility IRPs in formulating my Minnesota Rule 7849.0120 A 1 analysis.

**Q. What forecasts did the Applicants rely upon to demonstrate demand for the type of energy that would be supplied by the proposed project?**

A. The Applicants relied on the analyses provided in Appendix E, from MISO's analysis for the LRTP Tranche 2.1 portfolio. In particular, the Applicants used MISO's MTEP24 Report and the Series 1A Futures Report to support the proposed project need. The Applicants state that the proposed project is needed to support system reliability across the Upper Midwest, deliver increased transfer capability and unlock low-cost generation, and avoid congestion costs from curtailed energy.[7] The Applicants detail their stability and voltage analysis in Appendix E.3.

**Q. Please describe the voltage and stability analyses conducted by the Applicants.**

A. The Applicants retained Power Engineers, Inc. (POWER) to evaluate the proposed project's 345 kV and 765 kV transmission lines as part of the LRTP Tranche 2.1 Portfolio. The study included four planning scenarios, which reflect different load conditions, generation mix, and transmission:

[7] Initial Application at 121.

- The Light Load Scenario: reflects off-peak system conditions with high renewable generation energy in MISO;
- Peak Summer Load: reflects highest load and highly stressed conditions expected during summer months;
- Peak Winter Load: reflects a scenario with the highest load and highly stressed conditions expected during winter months; and
- Average Load: reflects a highly stressed scenario with the highest angular separation and lowest inertia, with highest renewable penetration serving most of MISO load.[8]

POWER then studied the grid outcomes with and without the proposed project, with respect to voltage stability and dynamic stability. For the voltage stability analysis, POWER ran four high wind and four low wind scenarios in the Voltage Security Assessment Tool (VSAT) 24.0 to analyze condition outcomes with and without the proposed project (for a total of 16 scenarios). POWER found that the cases with the proposed project were able to transfer more wind generation to serve load in Minnesota in every scenario compared to the cases without the proposed project.[9] In particular, during the Light Load (light load, high wind) scenario, the grid operations with the proposed project resulted in 6,200 MW additional wind transfer from Local Resource Zone (LRZ) 1-3, relative to only 1,800 MW without the proposed project, resulting in 4,400 MW more wind transfer overall.

[8] Initial Application, Appendix E.3 at 291 (eDockets 20262-227787-07 and 20262-227787-08).
[9] *Id.* at 303.

Similarly, POWER performed a transient stability analysis, which showed that the scenarios with the proposed project had fewer stability issues than scenarios without the proposed project. This was true for the 765 kV contingency events involving the proposed project[10] and for non-proposed project 765 kV contingency events.[11] There were no instances of severe instability observed in cases with the proposed project, while there were four extremely unstable conditions observed without the proposed project.[12] Mr. Hicks further reviews the results presented in Appendix E.3 as it relates to the alternatives analysis of 345 kV lines in DOC Ex.__ at 6-7 (Hicks Direct).

The Applicant's presented voltage and transient stability analysis concludes that the proposed project enables more renewable generation in LRZ 1-3, increases regional transfer capability limits with no risks to the State of Minnesota Bulk Electric System (BES), and the proposed project contributes to improved system stability for all studied planning scenarios.[13] This analysis shows the proposed project's stated need relates to system reliability and increased transfer of low-cost generation throughout the MISO Midwest subregion across a range of demand forecasts, not to peak demand.

**Q. Please describe MISO's Futures scenarios.**

A. MISO Futures are capacity expansion modeling scenarios that MISO prepares looking 20 years ahead. MISO uses the Futures to inform transmission expansion planning. In 2021, MISO underwent a significant forecasting effort developing three different load

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[10] *Id.* at 307.
[11] *Id.* at 308.
[12] *Id.* at 311.
[13] *Id.* at 367.

growth scenarios, which MISO termed Series 1 Futures. The 2021 Series 1 scenarios were the backbone of the Tranche 1 projects that were approved in MISO's MTEP22. MISO updated load forecasts in July 2022 to reflect electrification of residential, commercial and industrial processes, and increased electric vehicle infrastructure. The updated Futures scenarios became the Series 1A Futures 2023, which are included in the initial Application as Appendix E.2. The Series 1A Futures were used in MISO's MTEP24, which included the LRTP Tranche 2.1 portfolio.

**Q. How were MISO's Series 1A Futures scenarios developed?**

A. MISO developed the Series 1A Futures (Appendix E.2 of the Application) to account for federal and state policy decisions that result in decarbonization and resource retirements, as well as new resource additions due to renewable portfolio standards. MISO highlighted that over 75% of MISO's load is served in states, or by members, with clean energy goals.[14] To reflect the range of possible resource needs of the grid, MISO developed three capacity expansion scenarios. For each scenario, MISO reported both gross and net energy and demand growth. Gross growth is the total energy and demand load growth. Net growth accounts for Distributed Energy Resources (DERs), which include Distributed Generation (DG), Demand Response (DR), and Energy Efficiency (EE).

Futures 1A models a scenario that includes all announced clean energy goals from utility IRP announcements and state legislation and assumes that any "demand and energy growth are driven by existing economic factors."[15] Where a utility has

[14] Initial Application, Appendix E.2 at 171 (eDockets 20262-227787-07 and 20262-227787-08).
[15] *Id.* at 163.

declared clean energy goals that are not reflected in an IRP, or where no state statutes establish energy goals, MISO discounts those goals to 85% to reflect uncertainty of achieving these goals. The compound annual growth rate (CAGR) for gross energy and demand for Future 1A is 0.63% (energy) and 0.77% (demand).[16] The net energy and net demand for the Future 1A, is 0.22% (energy) and 0.36% (demand).

MISO Futures 2A likewise incorporates all announced utility IRP commitments and state legislation, but without the 85% discount which accounts for utilities potentially missing their clean energy milestones. The net CAGR for Future 2A is 0.80% (energy) and 0.82% (demand).[17]

MISO Futures 3A assumes an 80% MISO-wide decarbonization rate and achievement of all utility IRP and state legislative goals, and aggressive retirement schedules. The net CAGR for Future 3A is 1.08% (energy) and 1.14% (demand).[18]

**Q. Which Future did MISO determine to be most aligned with an optimized, least-cost expansion that meets member goals?**

A. MISO found that the Future 2A scenario was the most appropriate, least-cost generation addition forecast to meet member-planned shifts in the energy mix, increased electrification, and any IRP or state legislation. MISO focused on Future 2A as the

16 Initial Application, Appendix E.2 at 186.
17 *Id.*
18 *Id.*

optimal scenario, as this Future scenario preserves all utility IRP and statutorily mandated goals.

**Q. Did MISO evaluate need under a low bookend scenario?**

A. Yes. MISO found that the Futures 1A was an appropriate low-end bookend for the 20-year future forecasts. As noted earlier, Futures 1A models all planned utility IRP and state goals but assigned an 85% achievement rate of clean energy goals not in IRPs or statute to account for the possibility of not achieving these goals.

**Q. How did you verify the reasonableness of the load forecast inputs?**

A. I verified the reasonableness of the load forecasts identified within the *MISO Series 1A Futures Report* scenario. Minnesota Rule 7849.0120 subp. A, which refers to the "people of Minnesota and neighboring states," provides support for considering region-wide forecast inputs for analyzing the proposed project's stated need across the Upper Midwest Subregion. I compared the MISO Series 1A Futures growth rates, presented in Appendix E.2, along with the MTEP24 Report portfolio need in Appendix E.1, with the load forecast data provided by the Applicants, which is provided for GRE and Xcel in Appendix F.1 and F.2 respectively.[19] ITC Midwest, the third Applicant, is a transmission-only utility and does not serve any load in Minnesota. I would note that, while ITC Midwest is a transmission-owning utility, it may still process load interconnection

[19] Initial Application, Appendix F (eDockets 20262-227787-09, 20262-227787-10, 20262-227787-11, 20262-227787-12).

requests as one of the larger transmission owners in MISO. ITC could also see load interconnection requests that are driving recently increasing load demand forecasts in MISO. I also looked at the 2024 AFR data from Docket No. E999/PR-25-11, which provides more methodology behind the AFRs included in Appendix F.1 and F.2 for GRE[20] and Xcel,[21] respectively. Lastly, I reviewed the previous Integrated Resource Plan (IRP) filings for Xcel and GRE, as they file IRPs with the Commission periodically.

**Q. What did you find from your review of the Applicant's load forecast inputs?**

A. Using the Applicants' trade secret Appendix F.1 and F.2 for GRE and Xcel, respectively, I used their 2024 AFR data to identify the forecast years appropriate for this analysis. From reviewing the Department's prior analysis of forecasting in previous CN dockets, I decided to exclude 2024 and 2025, to compare only forecast years to forecast years. I found Applicant's weighted average CAGR to be roughly 2.75% for energy for the Applicants' overall system (Minnesota and other service territories outside of the state) from forecast year 2026 through 2039. For the Minnesota portion of each utility's energy, I found the weighted CAGR to be 3.15% from 2026 through 2039. I found the CAGR for peak demand to be 0.86% for the same time period.

[20] *2024 Electric Utility Annual Report,* MPUC Docket No. E999/PR-25-11, Great River Energy, 2024 Forecast Documentation, Model Report, (July 1, 2025) (eDocket No. 20256-220503-11).

[21] *2024 Electric Utility Annual Report,* MPUC Docket No. E999/PR-25-11, Xcel Energy, 2024 Forecast Methodology, (July 1, 2025) (eDocket No. 20257-220555-05).

**Q. What conclusions did you reach from the AFR data?**

A. After calculating the individual growth rates for each utility, I then calculated the weighted CAGR for the Applicants based on AFR data. I found the weighted CAGR to be higher than the MISO forecast data. As described in Appendix E.2, MISO Futures 2A scenario models net energy growth at 0.80% and 0.82% for net demand growth.[22] My analysis determined Applicants' forecast to have a much higher net energy growth at 2.75% for the Applicant's whole of system service territory and 3.15% for the Minnesota-only portion. My analysis of the Applicants forecast also showed a slightly higher annual growth rate for peak demand than MISO at 0.86%.

**Q. How were large load additions treated in the forecast?**

A. All three Applicants, Xcel, ITC Midwest, and GRE, have new large load additions. For GRE and Xcel those large load additions are not present within the load forecast data discussed above.[23] Xcel reported its large load when the Company filed a petition for approval of an Electric Service Agreement (ESA) with Google, LLC for a data center in Pine Island, MN on April 14, 2026.[24] Xcel also filed an Expedited Project Review (EPR) for a customer load addition at MISO in the June EPR cycle, which was highlighted by MISO in the Expedited Project Review Technical Studies Task Force (EPR-TSTF).[25] The

[22] Initial Application, Appendix E.2 at 187.
[23] Initial Application at 101.
[24] *In re Pet. for Approval of an Electric Service Agreement between Google and Xcel Energy*, MPUC Docket No. E002/M-26-170, Xcel Energy, Petition - New Large Customer Project, (Apr. 14, 2026) (eDocket No. 20264-230408-02).
[25] MISO, *EPR Statistics Update,* Expedited Project Review Technical Studies Task Force (EPR-TSTF) (July 7, 2026) Available at https://cdn.misoenergy.org/20260707%20EPR-TSTF%20Item%2003%20MISO%20EPR%20Statistics766827.pdf

project is currently under study for possible inclusion in future MTEP portfolios. ITC Midwest has also filed a number of EPR requests at MISO, including one in October 2025 which was approved, one EPR request in the April 2026 cycle, and one request in the June 2026 EPR cycle, MISO is currently studying the two most recent submissions.[26] GRE highlighted in its ongoing IRP that it is forecasting a 400 MW large load addition in its service territory. However, GRE has not signed any known service agreements for a large load.[27] As noted in the analysis, the weighted average growth rates for energy and demand for Xcel and GRE are above the MISO forecasts, and it is my estimation that any large load additions would only further increase the weighted average growth rates for energy and demand. However, should the Commission want the Applicants to update their forecasts with these announced large loads, the Commission could order the Applicants to provide an updated forecast for 2026 through 2039 that factors the energy and peak demand growth attributed to the proposed data centers.

**Q. Did you identify any discrepancies in the forecast data?**

A. I did not identify any discrepancies in the forecast data provided. To better address the large load data discussed above, I recommend Xcel clarify in rebuttal testimony if and how a large load addition in Xcel's service territory would or would not change the load forecast. Since GRE's large load addition in their IRP has no accompanying electric service agreement, the proposed large load in their service territory is less certain and a

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26 *Id.*

27 *In re Great River Energy's 2026-2040 Integrated Resource Plan*, MPUC Docket No. ET2/RP-26-145, Great River Energy, DOC 14-16 GRE Question, (May 8, 2026) (eDockets No. 20265-231606-01).

more conservative approach would be to not include forecasted large loads. Additionally, I recommend ITC Midwest provide a discussion of the impact that any prospective large load additions would have on their forecasted demand as a transmission-only utility. While I do point out that the current forecasts could be updated and recommend some clarifications, I am not recommending that the load forecasts be updated at this time, as any forecast increases due to large loads would only strengthen the need for the project and not change my recommendation.

**Q. How did you review Commission Orders from prior IRPs?**

A. I reviewed the IRP orders for the Applicants who file IRPs in Minnesota, Xcel and GRE. I conducted my review to verify the appropriateness of the presented forecasts and to confirm resource acquisition and load growth estimates.

**Q. Did you find any relevant information in your review of past IRP orders?**

A. Yes. When the Commission approved GRE's last IRP, though advisory in nature, the Commission found that there were weaknesses in GRE's demand forecast. Specifically, the Commission's order stated:

> First, the Commission concurs with the Department that the shortcomings in GRE's demand forecast may not require the Commission to reject GRE's plan outright, but they render the forecast insufficient to support any claim for a Certificate of Need—so the Commission will make that finding. Second, the Commission will recommend that GRE, when it models scenarios for its next resource plan, include a range of demand forecasts for electric vehicles. Finally, the Commission will recommend that GRE work

> with the Department to address forecasting issues before GRE develops its next resource plan.[28]

GRE's demand forecast alone was determined to be insufficient to justify a CN for a large energy facility. However, given that the proposed project's stated need relates to increased regional transfer capability rather than GRE's peak demand or generation , the GRE IRP Order can be taken in the broader context of regional grid needs and multiple Applicant's IRPs. GRE also recently filed its 2026 – 2040 IRP, which features a larger range of load growth scenarios.[29] Xcel's most recent IRP settlement included many new generation resources to meet increased demand load growth from large data centers, EV deployment, and beneficial electrification of home and commercial heating and cooling. The Commission found that:

> The settlement agreement reasonably supports energy adequacy, reliability, and affordability and minimizes adverse socioeconomic and environmental impacts, all while accounting for significant anticipated load growth and compliance with the state's carbon-free goals.[30]

The IRP Orders present another verified analysis of forecasting with up-to-date inputs and assumptions, and occur frequently enough to iterate on load forecasts, resource retirements, and resource acquisition proceedings. The Commission's Order in

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[28] *In re Great River Energy's 2023– 2037 Integrated Resource Plan,* MPUC Docket No. ET2/RP-22-75, ORDER ACCEPTING 2023-2037 RESOURCE PLAN AND SETTING FUTURE FILING REQUIREMENTS, (June 11, 2024) (eDocket No. 20246-207588-01).

[29] *In re Great River Energy's 2026-2040 Integrated Resource Plan,* MPUC Docket No. ET2/RP-26-145, 2026–2040 Integrated Resource Plan (Apr. 1, 2026) (eDocket No. 20264-229919-01).

[30] *In re Xcel Energy's 2024–2040 Upper Midwest Integrated Resource Plan*, MPUC Docket No. E002/RP-24-67, *ORDER APPROVING SETTLEMENT WITH MODIFICATIONS* at 8 (Apr. 21, 2025) (eDocket No. 20254-217941-01) (XCEL IRP ORDER)

Xcel's most recent IRP substantiates the load forecast in the AFR docket and corroborates the load growth that MISO has forecasted in its Future 2A scenario. While the Commission's Order from GRE's most recent advisory-only IRP does not substantiate GRE's forecasting enough for a CN for a generation facility, their most recently filed IRP includes more varied scenarios of load forecasting. Thus, the IRP Orders present a reliable benchmark to also compare the reasonableness of the presented forecasts.

**Q. Based on your analysis, what do you conclude regarding Minnesota Rule 7849.0120 A 1?**

A. Based on my analysis, I conclude that the Applicants' forecast of demand for the type of energy that would be supplied by the proposed project is reasonable.

*B. CONSERVATION IMPACTS*

**Q. What does Minnesota Rule 7849.0120 subpart A(2) require the Commission to consider?**

A. Minnesota Rule 7849.0120 subp. A(2) requires the Commission to consider "the effects of the applicants existing or expected conservation programs and state and federal conservation programs."[31]

**Q. What is the stated need for the proposed project?**

A. As discussed in Section 1.4 of the Application, the proposed project is needed to:

> 1) mitigate system overloads to maintain system reliability to meet existing and future energy needs; 2) meet growing electrical

[31] Minn. R. 7849.0120 subp. A.

demand in a cost-effective manner; and 3) to support the energy transition.[32]

**Q. What information did the Applicants provide regarding their existing and planned demand-side management and conservation programs?**

A. The Applicants provided additional details on their conservation and energy efficiency programs in Appendix G.

**Q. Please summarize each Applicant's performance against its Energy Conservation and Optimization obligations under Minnesota Statutes § 216B.241, subd. 1c.**

A. Under Minnesota Statutes § 216B.241 subd. 1c, the ECO Act statute, public utilities are required to achieve energy savings "equivalent to 1.75 percent of gross annual retail electric sales." Only public utilities as defined under Minnesota Statutes § 216B.02 Subd. 4 are required to make a filing under Minnesota Statutes Section 216B.241, so Xcel is required, and GRE is exempt. However, GRE has similar Energy Conservation and Optimization (ECO) requirements under Minnesota Statutes Section 216B.2403. Xcel provided reference to their ECO achievements in Appendix G. Xcel presented findings from its 2024 – 2026 ECO Triennial Plan in Docket No. E002/CIP-23-92.[33] According to Xcel's 2024 -2026 ECO Triennial Plan, Xcel proposes a goal of 1,871 GWh over the three year period, or about 626 GWh/year.[34] Likewise, in Xcel's Conservation Improvement

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32 Initial Application at 8.

33 *Minn. Elec. and Nat. Gas Energy Conservation and Optimization Program,* MPUC Docket No. E,G002/CIP-23-92, Xcel Energy, 2024 Status Report and Associated Compliance Filings, (Apr. 1, 2025) (eDocket No. 20254-217130-01) (2024 ECO Status Report).

34 Initial Application, Appendix G at G-4 (eDocket No. 20262-227787-13).

Plan (CIP) status filing for 2024, Xcel stated that it had surpassed the mandated 1.75% energy savings, achieving 1.90% electric savings with 516.4 GWh of energy savings.[35] GRE has filed information related to its energy savings and energy efficiency programs in its 2026-2037 IRP, which discusses its five energy efficiency programs. GRE describes an "all of the above" approach to energy efficiency, whereby GRE uses a) equipment incentive programs, b) consumer behavior programs, c) supply-side efficiency, d) market transformation, and e) demand response, noting that they also operate one of the most robust demand response efforts in the nation.[36]

**Q. Are energy efficiency and demand-side management embedded in the historic data used to develop the Applicants' forecasts?**

A. I reviewed the "2024 Forecast Reports" for annual electric forecasts from GRE and Xcel in the Docket No. 25-11 and confirmed that it matches the data in Appendix F for both GRE and Xcel.[37] Since the data sources were the same, I then reviewed the Forecast Methodology presented by Xcel and GRE in Docket No. 25-11. Both Xcel and GRE state that the effects of demand-side management (DSM), inclusive of energy efficiency and distributed solar generation, have been factored into their forecast data. GRE stated that "the SAE [statistically adjusted end-use] data captures energy efficiency changes for

[35] 2024 ECO Status Report at 3.

[36] Initial Application, Appendix G at G-2.

[37] I note that the Initial Application on pg. 101 lists this material as being found in Docket No. E999/PR-23-11, which corresponds to the 2022 Electric Utility Annual Report information. The 2024 Forecast Report was filed on July 1, 2025 in Docket No. E999/PR-25-11.

residential and commercial end-uses,"[38] and Xcel performed "adjustments to forecast to show the impact of all planned DSM in future years."[39] Therefore, the forecasts provided in Appendix F are for net energy and net peak demand.

**Q. Did MISO separately model energy efficiency, demand response, and distributed generation in developing the Futures?**

A. Yes, MISO separately modeled energy efficiency, demand response, and distributed generation in the Futures Series 1A. These analyses were part of the Futures Series 1A report in Appendix E.2, and Applicants discuss MISO's inclusion of Distributed Energy Resources (DERs) in their modeling assumptions. MISO modeled three types, energy efficiency (EE), demand response (DR), and distributed generation (DG) in Appendix G and in MISO Futures Series 1A in Appendix E.2. Thus, when MISO proposed its LRTP Tranche 2.1 portfolio, which is based on the Future 2A scenario, DERs were already included in the modeling and planned transmission expansion.

**Q. Please describe that modeling and its results.**

A. MISO commissioned Applied Energy Group (AEG) to develop DER technical potential throughout the MISO footprint. AEG used survey data from MISO's load-serving entities and other research to make their three blocks of EE, DR, and DG resources. AEG treated Future 1 as the minimum expected deployment of DERs, and Future 1A preserves all the

[38] *Minn. Elec. Util. Info. Reporting,* MPUC Docket No. E999/PR-25-11, Great River Energy, 2024 Forecast Documentation at 11 (July 1, 2025) (eDocket No. 20256-220503-11).

[39] *Minn. Elec. Util. Info. Reporting,* MPUC Docket No. E999/PR-25-11, Xcel Energy, 2024 Forecast Methodology at 7 (July 1, 2025) (eDocket No. 20257-220555-05).

assumptions within Future 1. Future 2A and Future 3A both build in more incremental blocks of DERs for selection. AEG offered each of these 15 blocks into the capacity expansion model, EGEAS, as alternatives to supply-side resources (such as large generators, renewable facilities, etc.) to determine whether the model would choose to dispatch the DERs.[40] The model showed considerable DER potential for DR, EE, and DG, and the model added most of the offered and available DER. As seen in Table 4, AEG found that the Future 1A minimum DER additions were 10.8 GW of DR, 17.7 GW of EE, and 19.9 GW of DG.[41] AEG also found the 20-year technical potential DERs for Future 2A were 11.2 GW of DR, 19.4 GW of EE, and 19.9 GW of DG. Of those potential units, the EGEAS model selected 11.2 GW of DR, 17.7 GW of EE, and 19.9 GW of DG instead of additional supply-side resources.

**Q. After the models selected those distributed resources, was the proposed project still needed?**

A. Yes. MISO's Futures assumptions indicate that, including the previously discussed DER additions, additional generation resources of 214.3 GW are needed to support the energy load growth the regional grid expects to experience over the next 20 years.[42] Thus, the potential DERs added by MISO could not meet the stated need.

40 Initial Application, Appendix E.2, Tables 4 and 5 at 207-208.
41 *Id.*
42 *Id.* at 267.

**Q. Can the demand or transmission need underlying this Application be met more cost effectively through energy conservation and load management?**

A. Based on the material presented in Appendix E.1 and E.2, the needs underlying this proposed project cannot be met more cost effectively through energy conservation and load management.

**Q. Based on your analysis, what do you conclude regarding Minnesota Statutes § 216B.243, subd. 3 and Minnesota Rule 7849.0120 subpart A(2)?**

A. Based on my analysis of the energy and conservation programs presented within the application, as well as the demand-side management presented by MISO within the MISO Futures 2A, the Applicants' existing or expected conservation programs cannot address the claimed need.

*C. PROMOTIONAL PRACTICES*

**Q. What does Minnesota Rule 7849.0120 subpart A(3) require the Commission to consider?**

A. Minnesota Rule 7849.0120 subp. A(3) requires the Commission to consider "the effects of promotional practices of the applicant that may have given rise to the increase in the energy demand, particularly promotional practices which have occurred since 1974."[43]

[43] Minn. R. 7849.0120 subp. A (3).

**Q. What does the Application state regarding promotional activities?**

A. The Application for the proposed project states that:

> the Applicants have not conducted any promotional activities or events that have triggered the need for the Project. Rather, the Project is driven by regional reliability issues related to the clean energy transition and meeting public policy objectives.[44]

Thus, the Applicants state that demand growth is not the stated need for the proposed project, and the Applicants likewise state that they have not conducted any promotional activities or events that have triggered the need for the proposed project.

**Q. Did you find any evidence that the Applicants conducted promotional activities that created the need for the proposed project?**

A. No, I have not found any evidence that Applicants have conducted promotional activities that created the need for the proposed project.

**Q. Based on your analysis, what do you conclude regarding Minnesota Rule 7849.0120 subpart A(3)?**

A. Based on my analysis, I conclude that promotional practices of the Applicants have not created the need for the proposed project.

[44] Initial Application at 146.

*D. NON-CN FACILITIES ANALYSIS*

**Q. What does Minnesota Rule 7849.0120 subpart A(4) require the Commission to consider?**

A. Minnesota Rule 7849.0120 subp. A(4) states that the Commission must consider "the ability of current facilities and planned facilities not requiring certificates of need to meet the future demand."[45]

**Q. How does MISO account for existing and approved transmission facilities in its planning process?**

A. MISO accounts for existing transmission facilities in its base scenario for its planning process. As laid out in MISO's Business Practice Manual 20 (BPM 20), MISO's transmission owners "are responsible for submitting data for their existing and approved transmission facilities."[46] These existing and approved projects are submitted to MISO and then added to MISO's base case scenario. MISO then solicits feedback on the base model from stakeholders to make sure that all existing facilities are properly accounted for.

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45 Minn. R. 7849.0120. subp. A(4).

46 MISO, *Business Practice Manuals, BPM 020 – Transmission Planning* at 27 (July 2025). Available at https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/.

**Q. Does that methodology already account for the ability of current facilities and planned facilities not requiring certificates of need to meet future demand?**

A. Yes, this approach accounts for existing facilities, and thus the ability of current and planned facilities not requiring CNs to meet future demand.

**Q. How do Applicants study the system performance of the proposed project with the current and existing transmission system?**

A. The Applicants seek a certificate of need for LRTP segments 22 through 25. For the study of the proposed project's impact, the Applicants included segment 26 just as MISO did in their analysis. Applicants define segments 22 through 26 as "Studied Projects."[47] To study the impact of the project the Applicants first study the impact of all MISO approved transmission expansions (including LRTP), they then run the same analysis but remove the Studied Projects. The difference between the two studies illuminates the impact of segments 22 through 26. Applicants discuss how the Studied Projects resolve 1,313 NERC reliability violations across 102 different facilities, mitigate 1,300 GWh of load being at risk of being unserved over a year, enable 3,010 GW of forecasted load.[48] Additionally, Applicants discuss the local reliability benefits enabled by the proposed project in southern Minnesota. Southern Minnesota has large amounts of existing solar, wind, and natural gas peaking generation. A regional backbone 765 kV transmission would provide increased transfer capability, allowing generation resources to output more hours and avoid curtailment when generation output is abundant, and

[47] Initial Application at 110.
[48] *Id.* at 105.

conversely would allow for import of lower-cost resources at times when local generation is not available or more costly. The Applicants found that these improvements over the existing infrastructure are said to enable $7.7 billion to $25.3 billion in economic savings over the first 20 years of the proposed project's in-service date.

**Q. Is there a scenario with the existing transmission system that mitigates the identified reliability violations or increases transfer capability without the portfolio?**

A. No. The system performance with the Studied Projects outperforms the existing transmission system in terms of reducing reliability violations, improving congestion, enabling more low-cost generation to interconnect, and greatly increasing transfer capability to pull on a wider region's generation capability.[49]

**Q. How does the Application address upgrades to the existing transmission system?**

A. The Applicants address upgrades to the existing system in Section 7, "Alternatives To The Project."[50] Applicant's discussion of upgrades to the existing transmission system is presented as an alternative within this section. Department witness, Mr. Hicks, presents more analysis of alternatives relating to the system portfolio without the proposed project in the alternatives analysis.[51]

[49] *Id.* at 134-135.

[50] *Id.* at 147.

[51] Ex. DOC-__ at 8 (Hicks Direct)

**Q. Based on your analysis, what do you conclude regarding Minnesota Rule 7849.0120 subpart A(4)?**

A. Based on my analysis, I conclude that the ability of current facilities and planned facilities not requiring certificates of need to meet the future demand could not meet the proposed project's stated need.

*E. EFFICIENT USE OF RESOURCES*

**Q. What does Minnesota Rule 7849.0120 subpart A(5) require the Commission to consider?**

A. Minnesota Rule 7849.0120 subp. A(5) states that the Commission is to consider "the effect of the proposed facility, or a suitable modification thereof, in making efficient use of resources."[52]

**Q. How does the proposed project use existing transmission infrastructure?**

A. The proposed project does not use existing transmission infrastructure. The 765 kV high-voltage transmission line segments will be entirely new transmission infrastructure in Minnesota. Certain 345 kV segments of the proposed project will replace the transmission structures within the existing right-of-way. For example, the segment between the Pleasant Valley Substation and North Rochester substation is proposed as a replacement of a single-circuit 345 kV structure with a double-circuit 345 kV structure. In addition a segment involves stringing additional wires on existing transmission poles.

52 Minn. R. 7849.0120 subp. A(5).

**Q. Does the proposed project require new right of way?**

A. Yes, the proposed project would require new right-of-way. Applicants state that the right-of-way for 765 kV high-voltage transmission generally is a 250-foot-wide right-of-way.[53] The larger right-of-way of a 765 kV structure, however, reduces the overall amount of right-of-way that would be needed if the proposed project were replaced by multiple lower voltage lines. According to the initial application, and discussed further in Mr. Hicks' testimony on alternatives, the single 765 kV corridor minimizes costs and the overall right-of-way, relative to the many additional 345 kV lines that would be needed to achieve the same capabilities as the proposed project.[54] Such upgrades to the existing system would make efficient use of the existing right-of-way.

**Q. How does the proposed project affect the use of existing generation resources?**

A. First, the proposed project increases transfer capability, enabling more existing, low-cost generation to dispatch more energy and avoid curtailment. Second, in addition to avoiding curtailment (which leads to congestion savings), the proposed project will also enable a considerable amount of new generation to interconnect to the system. Applicants estimate that the Studied Projects will result in approximately 24 GW of new generation, 10 GW of which will be in Minnesota.[55] New generation resources within the state borders will enable more local reliability and energy adequacy within LRZ 1,

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53 *Id.* at 5.
54 Ex. DOC-__ at 6 (Hicks Direct).
55 *Id.* at 134.

which will further enable low-cost generation resources to be produced and consumed in-state.

**Q. Would the proposed project relieve constraints that currently cause curtailment or out-of-economic-order dispatch?**

A. Yes, as aforementioned, the project results in congestion savings. Congestion occurs when there is not enough transmission capacity between generation nodes and load, resulting in curtailment of generation resources. To serve the load, the grid operator then dispatches resources out of economic order dispatch, such that more expensive generation resources will serve the load at a higher locational marginal price (LMP). Increased transmission capacity and transfer capability results in more congestion savings, which Applicants discuss in Section 6. Depending on the discount rate, Applicants estimate congestion and fuel savings of between $321 and $660 million in net-present value (NPV) over the first 20 years of operation.[56]

**Q. Based on your analysis, what do you conclude regarding Minnesota Rule 7849.0120 subpart A(5)?**

A. I conclude that the proposed project makes efficient use of resources.

[56] Initial Application at 132.

## VI. OTHER ISSUES

**Q. Has MISO designated the proposed project as a Multi-Value Project?**

A. Yes, MISO has designated the proposed project, along with the whole of the LRTP Tranche 2.1, as a Multi-Value Project (MVP). This designation derives from the Tranche 2.1 portfolio's role in "address[ing] multiple types of transmission issues (public policy, economic reliability, etc.) on a region-wide basis."[57]

**Q. What does an MVP designation mean for cost allocation?**

A. An MVP designation means that the LRTP Tranche 2.1 portfolio qualifies for regional cost allocation, which MISO has determined will be allocated to transmission customers in the MISO Midwest subregion, which is where the portfolio is located and provides proximate benefits. Schedule 26-A of the MISO Tariff governs the MVP cost allocation. Schedule 26-A is based on a usage rate. According to Schedule 26-A, 100% of the annual revenue requirement shall be "allocated on a pro-rata basis to Transmission Customers that withdrew energy in the MISO Midwest MVP Cost Allocation Subregion," and recovered according to the MVP Usage Charge in Attachment MM of the MISO Tariff.[58] The MVP Usage Charge in Attachment MM stipulates that Transmission Owners who withdraw energy will pay the annual revenue requirement through Schedule 26-A charges, which are assessed based on monthly net actual energy withdrawals (MWh) by

[57] MISO, *Business Practice Manuals, BPM 020 – Transmission Planning* at 27 (July 2025). Available at https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/.

[58] MISO, *Attachment FF, Transmission Expansion Planning Protocol* at 74-75 (effective May 28, 2026). Available at https://www.misoenergy.org/legal/rules-manuals-and-agreements/tariff/.

customers.[59] Cost allocation for MVPs results in MISO load being allocated its share of the total costs as a percentage of usage.

**Q. What does that cost allocation structure mean for Minnesota ratepayers if portfolio costs increase?**

A. The cost allocation structure will not change if the portfolio costs increase. Rather, the annual revenue requirement of the portfolio will go up, making the numerator larger for Schedule 26-A charge allocation. In other words, Minnesota's percentage of the pie does not change, but the entire pie does get bigger and thus Minnesota would pay more. Transmission Owners would recover the cost of their investment through their now larger revenue requirement, and Minnesota ratepayers (as well as MISO Midwest ratepayers) would pay more as a share of their monthly net actual energy withdrawals. According to 2023 MISO estimates based on Local Balancing Authority (LBA) percentages, Minnesota ratepayers from the main four utilities in Minnesota (Xcel, GRE, Minnesota Power, and Otter Tail Power Company) would be allocated approximately 17.8% of the total LRTP portfolio costs.

**Q. Have costs for the proposed project or the portfolio changed since the initial estimates?**

A. Yes. When the MISO MTEP24 portfolio was approved, the cost estimates of this project's LRTP segments (2024$) were:

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[59] MISO, *Attachment MM, Multi-Value Project Charge (MVP Charge)*, (effective May 28, 2026), at 18. Available at https://www.misoenergy.org/legal/rules-manuals-and-agreements/tariff/.

- LRTP 22: $1,458,500,000
- LRTP 23: $1,374,800,000
- LRTP 24: $1,194,800,000
- LRTP 25: $222,200,000[60]

The total amount for the proposed project as approved in MISO MTEP24 is $4,250,300,000 (2024$). In the application, the Applicants state the base costs for the proposed project is $3.327 Billion, while the high-range cost (base cost plus 30% contingency) is $4.323 Billion (2024$).[61] On March 31, 2026, MISO updated the Tranche 2.1 Dashboard costs for many Tranche 2.1 projects in the regulatory review process, and noted an ongoing cost review for at least one of the proposed project's segments (LRTP 24).[62] The Tranche 2.1 Dashboard included cost increases for the LRTP 22-25 projects:[63]

- LRTP 22 (updated): $1,739,000,000
- LRTP 23 (updated): $1,398,000,000
- LRTP 24 (updated): $1,955,000,000
- LRTP 25 (updated): $241,000,000[64]

The updated total amount for the proposed project based on the updated MISO Tranche 2.1 Dashboard is $5,333,000,000 (2024$)[65]. It is my understanding that MISO is required by tariff to employ a Variance Analysis for any project segment that experiences a 25% or more cost overrun for the proposed project. Based on my review

60 Midcontinent Independent System Operator. MTEP24 Appendix A-4, Schedule 26A Indicative, MISO, (2024). Available at https://cdn.misoenergy.org/MTEP24720395.zip. Note: the Department added the indicative gross project costs for LRTP 22 – 25 to get $4.25 Billion (2024$).

61 Initial Application at 37.

62 MISO Energy, Multi-Value Project Dashboard, Tranche 2.1 Portfolio, (March 31, 2026), Available at https://cdn.misoenergy.org/Tranche%202.1%20Dashboard732078.pdf?v=20251215144025.

63 Note that while the dashboard indicates that some or all of the facility costs are in nominal values MISO indicated in their IR response (DOC__LH-D-5) that they do not possess nominal costs for the projects.

64 *Id.*

65 See footnote 62

of the MISO Tranche 2.1 Dashboard, it appears that LRTP 24 has experienced 25% or more cost increases from the MTEP24 approval.[66]

**Q. Have you inquired to MISO or the Applicants about these changes in costs since MTEP24 and the Application?**

A. Yes. I asked both MISO and Applicants about the proposed cost increase in information requests, which is also referenced in Mr. Hicks' testimony (DOC Ex. __ at LH-D- 4, 5, and 8) (DOC IR 7, 12 and 13). I requested information on what was driving the cost increases, whether meaningful comparisons could be drawn between 2024$ dollars and nominal dollars, and whether MISO or Applicants expect benefits to increase with the increased costs and therefore maintaining the benefit-cost ratio in accordance with estimates at the time of the MTEP24 approval.

**Q. What were MISO's and Applicants' responses to requests for information?**

A. Applicants stated that the cost increases affect LRTP22-25, including the portions of LRTP22 and 23 that are outside of the state of Minnesota.[67] Applicants stated that the "baseline cost for LRTP24 is approximately 64 percent above MISO's initial cost estimate," and described the factors that have led to the cost increase.[68] MISO also indicated that the current costs under review do not constitute a Variance Analysis on their own, but that MISO is currently reviewing costs to confirm that the 25% threshold

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66 *Id.*
67 Ex. DOC__LH-D-4 at 2.
68 *Id.*

as defined in the MISO Tariff has been met. MISO also stated that the fourth quarter of 2025 costs "listed for LRTP 22-25 in the Multi-Value Project Dashboard for the Tranche 2.1 portfolio were reported in 2024$" and "MISO does not possess detailed cost estimates for the individual components of the proposed project in nominal (2025$)."[69] With this response from MISO, the updated Tranche 2.1 Dashboard and the Applicants' initial baseline cost in the initial application are able to be compared, as they are all in 2024$. Thus, I find that the costs currently under review by MISO in the updated Tranche 2.1 Dashboard are reported at $5.33 Billion (2024$), whereas the Applicants' baseline estimate and baseline estimate plus 30% contingency are between $3.327 Billion and $4.323 Billion (2024$), respectively.

**Q. What did MISO say with respect to re-evaluating the benefit-cost ratio of the LRTP Tranche 2.1 Portfolio?**

A. MISO indicated that, despite the cost change under review as well as any Variance Analyses that may occur in the future, "MISO does not reperform the benefit-to-cost ratio analysis based on the outcome of a Variance Analysis."[70] However, MISO does plan to re-perform a benefit-cost analysis of the LRTP Tranche 2.1 projects, in accordance with Section VII of Attachment FF to the MISO Tariff, which will occur in the triennial review, conducted during the MTEP27 development process.[71] Pursuant to Section VII in Attachment FF of the MISO Tariff, during this Triennial MVP Review, MISO

69 Ex. DOC__LH-D-5.
70 *Id.* At 1.
71 Ex. DOC__LH-D-8.

will perform updated cost and benefits calculations on a 20-year and 40-year basis. Cost calculations "shall use the updated project costs and in-service dates provided in the latest MTEP quarterly status report," while benefits calculations "shall use updated future scenarios from the latest MTEP planning cycle."[72] Thus, MISO will update its benefit-cost analysis in advance of the MTEP27 planning cycle. I find MISO's provision of additional information on the future triennial review and benefit-cost analysis reasonable.

## VII. CONDITIONS ON THE CERTIFICATE OF NEED

**Q. Has the Commission issued conditions to control costs in other certificates of need proceedings?**

A. Yes, the Commission has generally supported conditions to control costs in CN proceedings. In Docket No. E002, ET6675/CN-17-184, Department witness Mr. Johnson noted that "the Commission has generally not allowed approval of projects in such proceedings to constitute a 'blank check' for cost recovery in riders when actual costs are greater than the estimated costs the utility represented in regulatory approval proceedings."[73] Recently, the Commission has issued conditions to control costs in the following dockets:

- Docket No. E002/CN-23-532; and
- Docket No. E015, ET2/CN-22-416.

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[72] MISO, *Attachment FF, Transmission Expansion Planning Protocol* at 85-85 (effective May 28, 2026). Available at https://www.misoenergy.org/legal/rules-manuals-and-agreements/tariff/.

[73] *In re Appl. of Xcel Energy and ITC Midwest LLC for a Certificate of Need for the Huntley- Wilmarth 345 kV Transmission Line Project*, MPUC Docket No. E002, ET6675/CN-17-184, Direct Testimony of Mark A. Johnson on Behalf of the Minnesota Department of Commerce at 11-12(Nov. 7, 2018) (eDocket No. 201811-147664-02) (Mark Johnson Direct Testimony).

In Docket No. E002/CN-23-532, the Commission ordered that Xcel fully justify the reasonableness of recovery of any cost overruns, bear the burden of proof in any future regulatory proceeding relating to the recovery of costs above those forecasted in the proceeding, and file a final cost estimate within 45 days of the preconstruction meeting.[74] In Docket No. E015, ET2/CN-22-416, the Commission ordered that Minnesota Power would be required to bear the burden of proof in any regulatory proceedings related to cost recovery for any costs above $1.21 Billion, which was roughly the midpoint of the proposed project's initial application amount of between $970 Million - $1.35 Billion.[75]

**Q. Do you recommend conditions on the granting of a CN?**

A. Yes. I recommend conditioning the granting of the CN on compliance with the following ratepayer protection mechanisms.

**Q. Please describe your first recommended condition.**

A. My first recommendation is that the Commission order the Applicants to file in this docket a final cost estimate or cost cap amount within 60 days of any Commission Order approving a route permit. I recommend the Applicants include, along with the final cost

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[74] *In re Appl. of Xcel Energy for a Certificate of Need and Route Permit for the Mankato–Mississippi 345 kV Transmission Line Project in Southeast Minnesota,* MPUC Docket No. E002/CN-22-532, ORDER ADOPTING ADMINISTRATIVE LAW JUDGE REPORT AS MODIFIED, FINDING ENVIRONMENTAL IMPACT STATEMENT ADEQUATE, GRANTING CERTIFICATE OF NEED, AND ISSUING ROUTE PERMIT at 16, (Apr. 14, 2026) (eDocket No. 20264-230391-01).

[75] *In re Appl. of Minn. Power and Great River Energy for a Certificate of Need and Route Permit for an Approximately 180-mile, Double Circuit 345 kV Transmission Line,* MPUC Docket No. E015, ET2/CN-22-416, ORDER GRANTING CERTIFICATE OF NEED AND ISSUING ROUTE PERMIT at 10 (Feb. 28, 2025) (eDocket No 20252-215918-01).

estimate, a detailed justification for any upward departure from the cost estimate in the initial Application, as well as the initial MISO MTEP24-approved costs.

**Q. Please describe your second recommended condition.**

A. My second recommendation is to cap Xcel's rider cost recovery for the proposed projects at the base case plus 15% contingency as an appropriate midpoint between the base case and the high range case, and require Xcel to bear the burden of proof relating to the reasonableness of recovering any cost overruns in any future regulatory proceeding relating to recovery of costs for the proposed project.

**Q. Please describe your third recommended condition.**

A. My third recommendation is that the Commission order the Applicants, beginning with the first calendar year after issuance of the CN, and annually thereafter until all associated portfolio projects are placed in service, to file in this docket a report that:

a. identifies the current cost estimate for each project in the portfolio, as reflected in MISO's most recent cost tracking and any MTEP variance requests, compared against the approved costs;
b. states the resulting aggregate portfolio cost and any changes from the initial approved portfolio cost; and
c. estimates the share of any portfolio cost increase allocable to Xcel's ratepayers based on load ratio share.

**Q. Please describe your fourth recommended condition.**

A. My fourth recommended condition is for the Commission to order the Applicants to provide all details of the Variance Analysis, should MISO perform a Variance Analysis for LRTP 24 or any other LRTP project segment that experiences cost increases at or above

25%. This recommendation includes providing detailed assessments and estimates of line-item expenses in .csv format that have driven the cost increase, including, but not limited to, equipment market and design impacts, land and site work impacts, and preconstruction, indirect costs, and other impacts. The information should be provided in this docket within ten days of any filing of cost review or Variance Analysis being submitted or approved with MISO.

**Q. Please describe your fifth recommended condition.**

A. My fifth recommendation is for the Commission to order Xcel to wait until the first rate case after the proposed project is placed in service to request recovery of any cost overruns from Minnesota ratepayers.

**Q. Why do your recommendations focus on Xcel only?**

A. The Commission does not have authority over the rates of GRE and ITC Midwest.

**Q. Why are these conditions appropriate in this proceeding?**

A. These conditions are appropriate for three reasons. First, the cost exposure for Minnesota ratepayers is not limited to the proposed project, but to the whole LRTP Tranche 2.1 Portfolio. MISO approved the LRTP Tranche 2.1 Portfolio in its entirety, and under Schedule 26-A, the annual revenue requirement for the entire portfolio across the MISO Midwest Subregion. As a result, Minnesota ratepayers will pay a share of cost increases on any project in the portfolio, including other projects within the state and projects that are beyond Minnesota's borders. These costs will be variable by utility, so each Applicant will pay a different share, commensurate to its monthly energy actuals. Second, costs have already increased. MISO's March 31, 2026 Tranche 2.1 Dashboard indicates increases across the LRTP 22 – 25 segments, in addition to many more projects that have not yet entered the regulatory approval process in their respective states. LRTP segment 24, in particular, appears to have exceeded the 25 percent threshold that triggers a Variance Analysis under MISO's Tariff. The Commission is responsive to reasonable costs, but it also needs all appropriate data to be able to determine the reasonableness of cost increases. The cost increases present in the Tranche 2.1 Dashboard are beyond the base case plus 30% high contingency laid out in the Initial Application. Third, this proceeding is the Commission's opportunity to establish cost discipline within the LRTP Tranche 2.1 Portfolio. The Commission has recognized that a CN should not be a "blank check" for cost recovery. The recommended conditions address each of these points. The final cost estimate and cost cap establish a clear benchmark against which the Commission can measure reasonableness of recovery for any overrun; burden of proof and rate case requirements ensure that any overruns are justified before ratepayers pay them; and the annual Portfolio reporting gives the Commission and ratepayers ongoing visibility into the regional cost drivers that will ultimately determine what Minnesota ratepayers pay. Together, these conditions protect ratepayers with transparency and accountability for costs.

## VIII. CONCLUSION

**Q. Based on your analysis of the five considerations in subpart A, what do you conclude?**

A. Based on my analysis of the five considerations in Minnesota Rule 7849.0120 subp. A, I conclude that the probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the Applicants, to the Applicants' customers, and to the people of Minnesota and neighboring states.

## IX. SUMMARY OF RECOMMENDATIONS

**Q. Based on your investigation, what do you recommend?**

A. My recommendations are as follows:

- I recommend the Commission find, pursuant to Minnesota Rules 7849.0120 subp. A, that the probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states.
- I recommend the Commission order the Applicants to file a final cost estimate for the proposed project or cap amount within 60 days of the Route Permit being granted.
    - Within the final cost estimate, the Applicants should include a detailed justification for any upward departure from the cost estimate in the initial Application, as well as the initial MISO MTEP24-approved costs.
- I recommend the Commission cap Xcel's rider cost recovery for the transmission project at the base case plus 15% contingency as an appropriate midpoint between the base case and the high range case and require the Xcel to bear the burden of proof relating to the reasonableness of recovering any cost overruns in any future regulatory proceeding relating to recovery of costs for the proposed project.

- I recommend that that the Commission order the Applicants, beginning with the first calendar year after issuance of the certificate of need, and annually thereafter until all associated portfolio projects are placed in service, to file in this docket a report that:
    - identifies the current cost estimate for each project in the portfolio, as reflected in MISO's most recent cost tracking and any MTEP variance requests, compared against the approved costs;
    - states the resulting aggregate portfolio cost and any changes from the initial approved portfolio cost; and
    - estimates the share of any portfolio cost increase allocable to Xcel's ratepayers based on load ratio share.

- I recommend the Commission order the Applicants to provide all details of the Variance Analysis, should MISO perform a Variance Analysis for LRTP 24 or any other LRTP project segment that experiences cost increases at or above 25%. This recommendation includes providing detailed assessments and estimates of line-item expenses in .csv format that have driven the cost increase, including, but not limited to , equipment market and design impacts, land and site work impacts, and preconstruction, indirect costs, and other impacts. The information should be provided in this docket within ten days of any filing of cost review or Variance Analysis being submitted or approved with MISO.
- I recommend the Commission order Xcel to wait until the first rate case after the proposed project is placed in service to recover any cost overruns from Minnesota ratepayers.

**Q. Have you completed your Direct Testimony?**

A. Yes.

# Rock Park

Minnesota Department of Commerce
85 7th Place East, Suite 280
St. Paul, MN 55101-2145

**EDUCATION**

**Macalester College** **Saint Paul, MN**
*Dual Degrees: B.A., Political Science and B.A., Geology, Minor in Chemistry* *May 2022*

**RELEVANT WORK EXPERIENCE**

**Minnesota Department of Commerce** **Saint Paul, MN**
*Public Utilities Rates Analyst 4* *December 2025 – Present*
• Assigned analyst for grid-enhancing technologies (GETs) Report
• Lead analyst in numerous high-voltage transmission line certificate of need proceedings
• Monitor regional energy market stakeholder proceedings in the Midcontinent Independent System Operator, Inc. (MISO)

**Geronimo Power (fka National Grid Renewables)** **Bloomington, MN**
*Policy Manager, Midwest* *June 2025 - December 2025*
• Led government relations, regulatory affairs, legislative activity, and external relationship management in Minnesota, Wisconsin, and Illinois.
• Guided project management for key legislative, regulatory, or administrative initiatives to achieve internal consensus and meet external needs.

*Policy Analyst* *November 2022 - June 2025*
• Principal researcher for regulatory proceedings relating to utility resource plans, resource acquisitions, miscellaneous filings, and Minnesota's community solar garden program.
• Researched proposed bill language, existing statutes, case law, and rules to identify proposed impacts of policies and history of policy development in a 15-state footprint.

| Statute or Rule Citation | Notes | Witness |
|---|---|---|
| **7849.0120 CRITERIA.** A certificate of need must be granted to the applicant on determining that: | | |
| A. the probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states, considering: | Section I. | Park |
| (1) the accuracy of the applicant's forecast of demand for the type of energy that would be supplied by the proposed facility; | | Park |
| (2) the effects of the applicant's existing or expected conservation programs and state and federal conservation programs; | | Park |
| (3) the effects of promotional practices of the applicant that may have given rise to the increase in the energy demand, particularly promotional practices which have occurred since 1974; | | Park |
| (4) the ability of current facilities and planned facilities not requiring certificates of need to meet the future demand; and | | Park |
| (5) the effect of the proposed facility, or a suitable modification thereof, in making efficient use of resources; | | Park |
| B. a more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record, considering: | DOC Ex. (Hicks Direct) | |
| (1) the appropriateness of the size, the type, and the timing of the proposed facility compared to those of reasonable alternatives; | | Hicks |
| (2) the cost of the proposed facility and the cost of energy to be supplied by the proposed facility compared to the costs of reasonable alternatives and the cost of | | Hicks |

| | | |
|---|---|---|
| energy that would be supplied by reasonable alternatives; | | |
| (3) the effects of the proposed facility upon the natural and socioeconomic environments compared to the effects of reasonable alternatives; and | Addressed in Environmental Report (ER) | PUC Energy Infrastructure Permitting (EIP) |
| (4) the expected reliability of the proposed facility compared to the expected reliability of reasonable alternatives; | | Hicks |
| C. by a preponderance of the evidence on the record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health, considering: | See DOC Ex. __ (Hicks Direct) | |
| (1) the relationship of the proposed facility, or a suitable modification thereof, to overall state energy needs; | | Hicks |
| (2) the effects of the proposed facility, or a suitable modification thereof, upon the natural and socioeconomic environments compared to the effects of not building the facility; | | EIP |
| (3) the effects of the proposed facility, or a suitable modification thereof, in inducing future development; and | | EIP |
| (4) the socially beneficial uses of the output of the proposed facility, or a suitable modification thereof, including its uses to protect or enhance environmental quality; and | | EIP |
| D. the record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments. | | Hicks |
| **Minn. Stat. § 216B.243, subd. 3(9)** | | Hicks |

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| **Minn. Stat. § 216B.243, subd. 3a**<br>**Minn. Stat. § 216B.2422, subd. 4** | | Hicks |
| **Minn. Stat. § 216B.2426** | | Hicks |
| **Minn. Stat. § 216B.1694, subd. 2(a)(4)** | | Hicks |
| **Minn. Stat. § 216B.243, subd. 3(10)**<br>**Minn. Stat. § 216B.1691, subd. 2a**<br>**Minn. Stat. § 216B.1691, subd. 2f**<br>**Minn. Stat. § 216B.1691, subd. 2g** | | Hicks |
| **Minn. Stat. § 216B.243, subd. 3(12)** | | Hicks |
| **Minn. Stat. § 216H.03, subd. 3** | | Hicks |
| **Minn. Stat. § 216B.2422, subd. 4a** | | Hicks |
| **Minn. Stat. § 216B.2422, subd. 4b** | | Hicks |
| **Commission's Order in Docket No. E,G999/CI-22-624** | | Hicks |